STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED ADOPTION OF
20.2.51 NMAC – *METHANE ABATEMENT*

No. EIB 26-78 (R)

New Mexico Environment Department,

***Petitioner*.**

NEW MEXICO ENVIRONMENT DEPARTMENT
TECHNICAL TESTIMONY OF CINDY HOLLENBERG

My name is Cindy Hollenberg, and I serve as the Bureau Chief of the Air Quality Bureau ("AQB") of the Environmental Protection Division of the New Mexico Environment Department ("Department"). In my role, I am responsible for oversight of the Air Quality Program, including permitting, ambient air quality monitoring, regulation development, and administration and operations of the AQB as authorized under the New Mexico Air Quality Control Act, NMSA 1978, Sections 74-2-1 through 74-2-17 ("AQCA"). I also collaborate with the Department's Environmental Protection Compliance and Enforcement Bureau ("EPCEB") in the Department's Compliance and Enforcement Division, which is responsible for assuring compliance with air quality permit conditions and state and federal regulations.

My duties include prioritizing planning efforts, assuring compliance with all U.S. Environmental Protection Agency ("EPA") requirements to fulfill our responsibilities as a delegated authority, and strategizing with the Department's Senior Leadership regarding the Bureau's plan for resource usage. Together, the AQB and EPCEB implement and maintain oversight of the federal and state laws, regulations and policies to fulfill New Mexico's delegated authority to protect air quality in the State.

I'm presenting this written technical testimony on behalf of the Department to offer evidence in support of the adoption of proposed rule 20.2.51 NMAC, *Methane Abatement* ("Methane Abatement Rule"). The purpose of my testimony is to provide an overview of the authority and responsibility of the Department to protect New Mexico's air; to discuss the need for the Methane Abatement Rule to address climate change and its environmental and health impacts on New Mexico; to describe the Governor's mandate to reduce greenhouse gas ("GHG") emissions, previous state actions to reduce methane, and the need for additional state action on methane; to describe how the Methane Abatement Rule builds on existing state rules and highlight economic benefits to reducing methane; to discuss stakeholder engagement and how the Department met statutory and regulatory requirements to provide notice to the public; and to provide an overview of the general provisions of the Methane Abatement Rule.

I. QUALIFICATIONS

I hold a Bachelor of Science in Biology Teaching from Purdue University, and a Master of Public Administration in Environmental Science and Policy from Columbia University. I started with the AQB in 2013 as an environmental planner, moving to Inspections Manager, followed by Enforcement Manager, Compliance and Enforcement Section Chief, and finally Bureau Chief of the AQB. I also currently hold the position of President of the Western States Air Resources Council ("WESTAR"), an organization of eight western state air agencies formed to promote the exchange of information, serve as a forum to discuss western regional air quality issues of common concern, and share resources for the common benefit of the member states. My full educational and work background are set forth in my resume, which is marked as **NMED Exhibit 3**.

II. STATE MANDATE TO REDUCE EMISSIONS

The purpose of the Environmental Improvement Act, NMSA 1978, 74-1-1, is to "to ensure an environment that in the greatest possible measure will confer optimum health, safety, comfort and economic and social well-being on its inhabitants; will protect this generation as well as those yet unborn from health threats posed by the environment; and will maximize the economic and cultural benefits of a healthy people." The AQCA, at NMSA 1978, 74-2-5(A), authorizes the Environmental Improvement Board to "prevent or abate air pollution." Air pollution is defined in the AQCA as "the emission, . . . of one or more air contaminants in quantities and of a duration that may with reasonable probability injure human health or animal or plant life or as may unreasonably interfere with the public welfare, visibility or the reasonable use of property."

Recognizing the urgency of the threats that climate change poses to the people, ecosystems, and economy of New Mexico, Governor Michelle Lujan Grisham issued Executive Order 2019-003 "Executive Order on Addressing Climate Change and Energy Waste Prevention" in January 2019. **NMED Exhibit 9**. This order requires the State to reduce greenhouse gas emissions by 45% by 2030 as compared to 2005 levels.

The Executive Order specifically recognizes that methane is "a powerful greenhouse gas, 84 times more effective at trapping heat than carbon dioxide over a 20-year timeframe." The order further recognizes that "the oil and gas industry is the largest industrial source of methane emissions." The Executive Order recognizes that "emissions, venting, flaring, and leaks of natural gas by New Mexico's oil and gas industry results in the waste of an important source of domestic energy to the tune of an estimated $244 million per year."

The proposed Methane Abatement Rule addresses the Executive Order's mandate to develop "a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable." The order recognizes that "efforts to reduce methane emissions throughout New Mexico will have a significant climate benefit as well as prevent the waste of energy resources". As the Department will make clear in its explanation of the rationale for the rule, the two central provisions of the proposed rule will achieve these twin goals.

The Department, in proposing this rule, recognizes that we are again in a period of retrenchment of federal environmental policy. Part of the motivation for proposing the rule now is the rollback of federal environmental protections. Without federal protections, states must rely on their own statutory authorities (such as the AQCA) to protect the environment over which they have jurisdiction. The Executive Order recognizes that "federal rollbacks of climate protections, waste prevention, and clean air rules have made it imperative for New Mexico to act to protect our citizens and our economy from the damages of climate change impacts" and the imperatives are even more urgent in 2026 as climate impacts in New Mexico have become more severe. Adoption of the Methane Abatement Rule is an economically beneficial step to address the State's mission to reduce abate air pollution in order to protect the health of New Mexico residents and the ecosystems on which our economy depends.

III. THE NEED FOR ADDITIONAL STATE ACTION TO REDUCE METHANE EMISSIONS

There are two central reasons why the Department is proposing methane mitigation measures currently. First, the federal rules that mandate methane reductions in the oil and gas sector across the country have been pared back, and EPA has announced that further revisions

are being pursued. It is expected that the revisions will significantly weaken the rule's ability to abate methane emissions. Therefore, to meet the AQCA's statutory obligations and the statewide greenhouse gas reduction targets, New Mexico cannot rely on federal mandates embodied in OOOOc and must take the lead in adopting state-level programs to reduce emissions. Second, emissions inventory projections show that the state will not meet the greenhouse gas emission reductions mandated by Executive Order 2019-003 without additional efforts to reduce methane emissions.

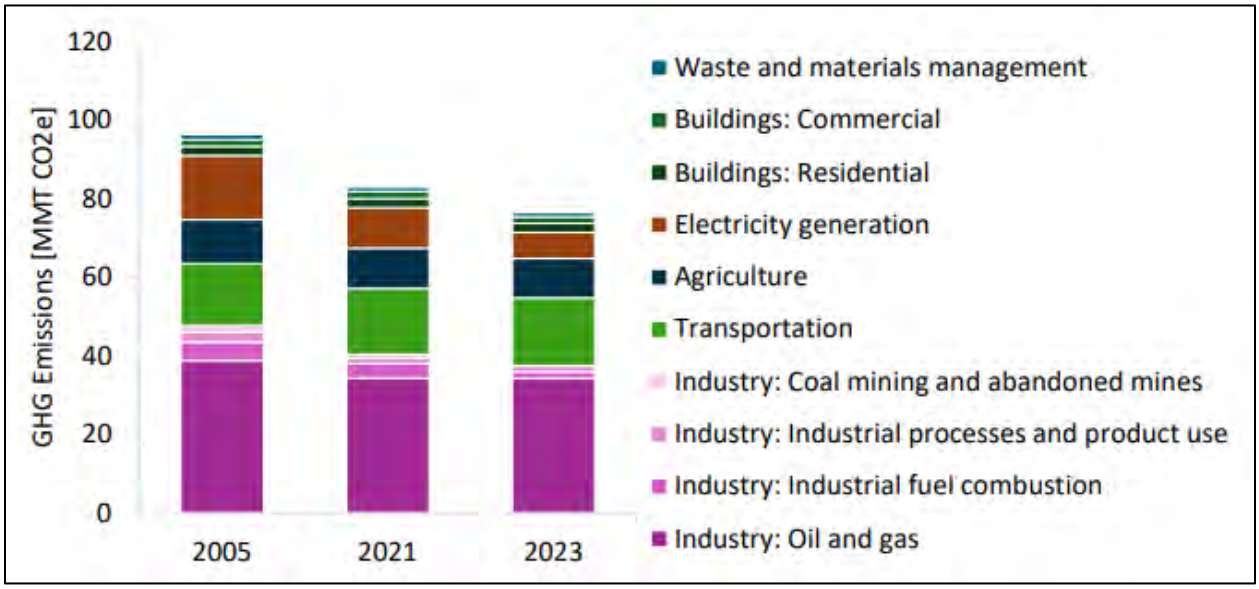
State Climate Action Plan

Following Governor Michelle Lujan Grisham's 2019 Executive Order and supported by a federal Climate Pollution Reduction Grant, the State of New Mexico pursued development of a state Climate Action Plan. The New Mexico Environment Department and the Energy, Minerals and Natural Resources Department jointly developed and published a Priority Climate Action Plan in March 2024 and a Comprehensive Climate Action Plan in December 2025. The Comprehensive Climate Action Plan provides an actionable roadmap to meet New Mexico's climate pollution reduction targets. **NMED Exhibit 10.** The goals of the Plan are to reduce greenhouse gas emission by 45% by 2030 and reach net-zero GHG emissions by 2050, while improving public health and air quality, promoting economic growth through clean energy jobs and career pathways, and ensuring that the benefits reach all New Mexicans. The Plan presents 45 economy-wide emission reduction measures, which are organized by sector. The Methane Abatement Rule would codify Measure I-5 proposed in the Industry Sector section of the Plan. Measure I-5: Building on Success of Ozone Precursor Rule "formalizes the NMED's ability to reduce CH4 emissions from the oil and gas industry by implementing a super-emitter monitoring program to identify and respond to large methane leaks, while imposing additional requirements

for pneumatic controllers." ***Id*. at 48**. This measure contains the two provisions proposed in the Methane Abatement Rule—the Super-Emitter Program and a zero-emitting process controller mandate. Of the first provision, the Plan states: "NMED participation in a super-emitter monitoring program increases investigation of CH4 releases reported by third parties, with a goal of reducing the number of annual CH4 super-emitter events occurring in New Mexico over time." ***Id***. Of the process controller requirement, the Plan states: "New equipment regulations will aim to eliminate all CH4 emissions from pneumatic controllers by requiring replacement of existing pneumatic controllers with zero-bleed controllers." ***Id***. This measure was the guide used in the NMED's development of the Methane Abatement Rule.

The measures in the Climate Action Plan were developed based on an analysis of greenhouse gas emissions in the state. Greenhouse gas emissions inventories, which track greenhouse gas emissions in the state by sector, were completed for the years 2005, 2018, 2021, and 2023, with a revised inventory for the baseline year 2005 published with the 2021 inventory in 2024. **NMED Exhibits 11, 12, and 13**. Greenhouse gas emissions by sector for the years 2005 (revised), 2021, and 2023 are presented in Figure 5 below.

Figure 1: Statewide Annual Emissions: 2005, 2021, and 2023[1]



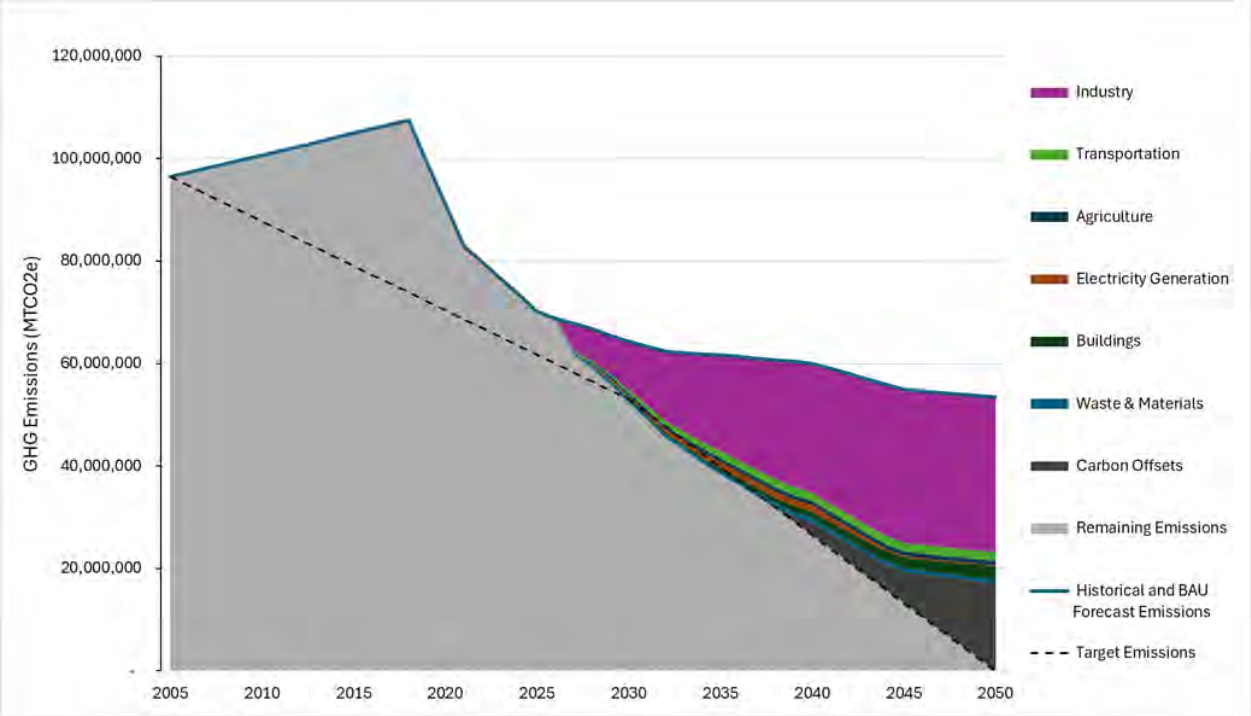
Across these three inventories, the oil and gas sector is the largest source of statewide greenhouse gas emissions. Industry sector emissions declined between 2005 and 2023, however, emissions from the oil and gas sector have remained flat between 2021 and 2023.[2] Emissions from the oil and gas sector made up 45% of total statewide emissions in 2023.[3]

Most projected emissions reductions—approximately 83%—from implementation of the measures detailed in the Climate Action Plan are projected to be achieved through actions taken

[1] New Mexico Climate Action Plan, NMED Exhibit 10, at 18.
[2] "Between 2021 and 2023, industry-related emissions fell by 7%, despite increases of 46% and 40% in oil and gas production, respectively. This decrease was largely due to a 56% decrease in emissions from industrial fuel combustion and a 91% decrease in emissions from coal mining and abandoned mines. For industrial fuel combustion, the majority of the decrease can be attributed to CO2 emissions from petroleum fuel combustion. For 2023, the GHGI Team adjusted distillate fuel and motor gasoline quantities to avoid double-counting with the nonroad transportation sector. This adjustment was not made for 2021 and, therefore, is the main reason for the 56% decrease in reported emissions. For coal mining and abandoned mines, the decrease in emissions can be attributed to the San Juan mine in New Mexico. This underground mine was operational in 2021 but not in 2023." New Mexico Climate Action Plan, NMED Exhibit 10, at 18-19.
[3] Calculated from data in Table 2 of the New Mexico Climate Action Plan, NMED Exhibit 10, at 17-18.

in the industry sector.[4] Figure 6 below graphically represents these projected emissions reductions through 2050.

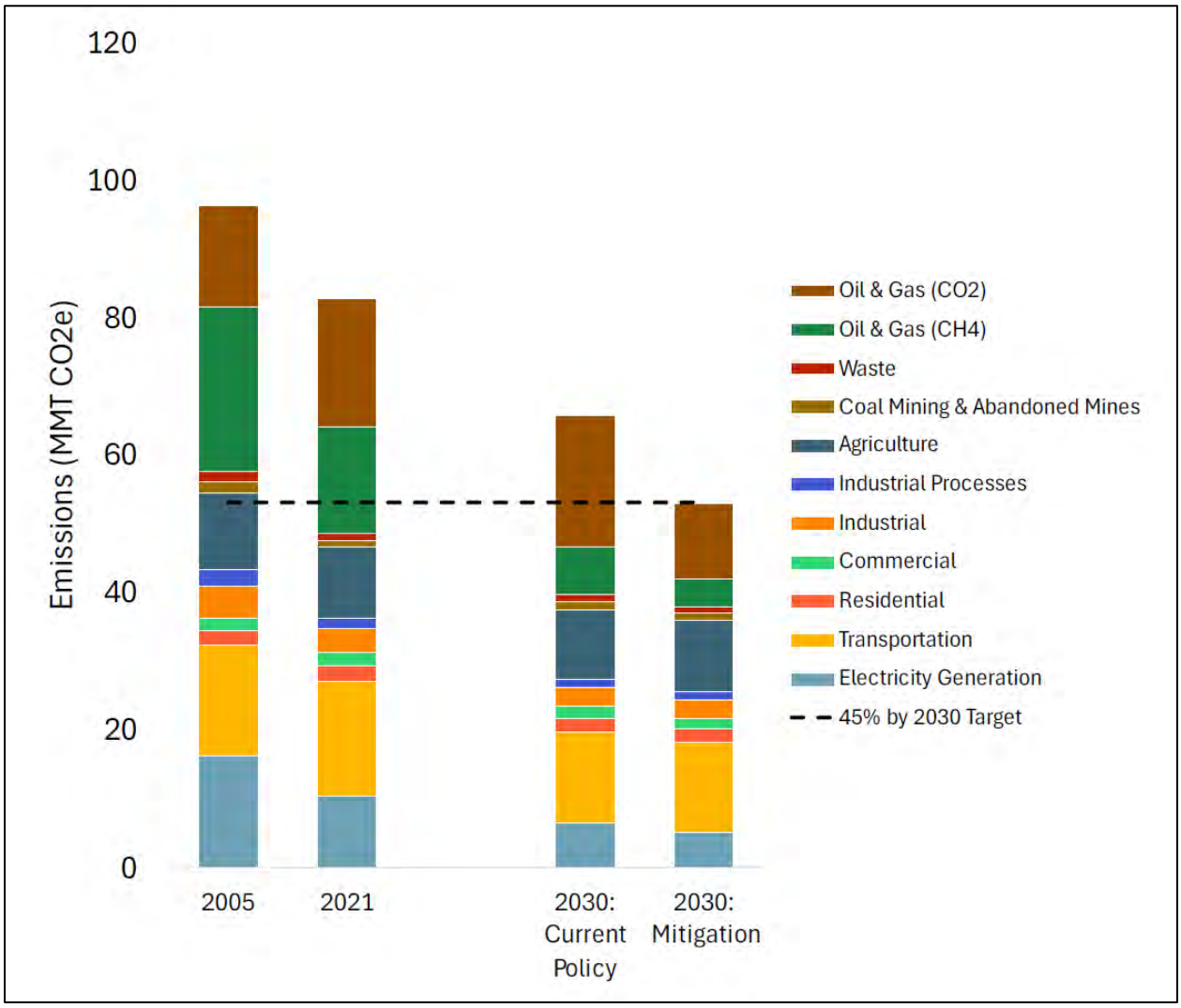
Figure 2: GHG Emissions and Projected Emission Reductions from the Implementation Scenario[5]



Of these industry sector projected reductions, the vast majority are projected to be achieved through greenhouse gas emissions reductions in the oil and gas sector, as shown below in Figure 7. The bulk of projected reductions to reach the 2030 mitigation scenario are coming from the brown and dark green bars, which represent reductions of carbon dioxide and methane from the oil and gas sector, respectively. These bars represent a 56% reduction in greenhouse gas emissions in the sector compared to 2021 levels by 2030.[6]

[4] Calculated from data in Table 5 of the New Mexico Climate Action Plan, NMED Exhibit 10, at 26.
[5] New Mexico Climate Action Plan, NMED Exhibit 10, at 27.
[6] Calculated from data in Table 9 of the New Mexico Greenhouse Gas Emissions Inventory and Forecast, NMED Exhibit 12, at 25.

Figure 3: Projected greenhouse gas emissions in New Mexico in 2030 with current policy and mitigation scenarios[7]



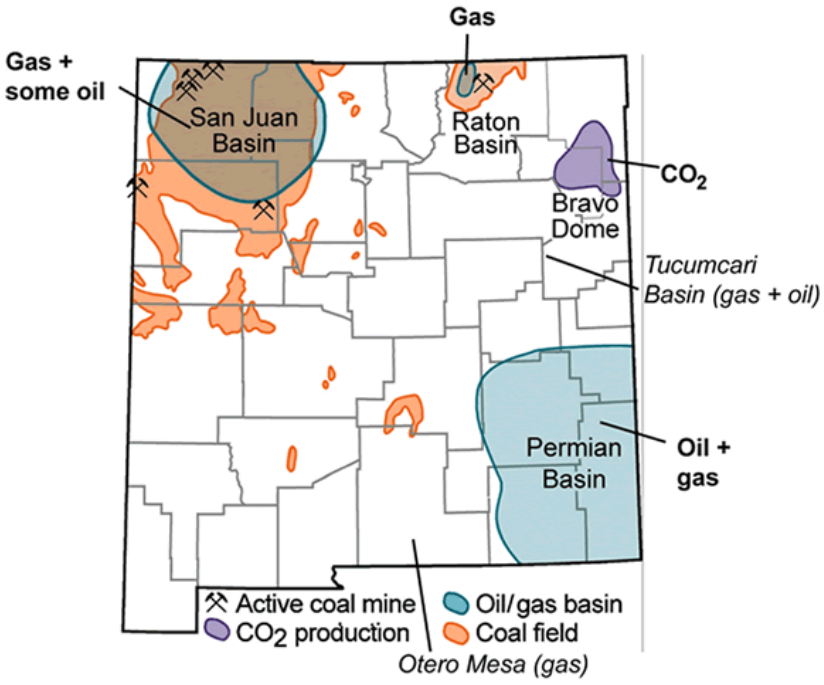
The 2023 statewide inventory shows that methane made up 23% of total greenhouse gas emissions in the state in 2023. Methane from the oil and gas sector made up 15.5% of total greenhouse gas emissions in the state in 2023.[8] Given the high proportion of greenhouse gases produced by the oil and gas sector, emissions in this sector must be reduced if the state is to meet the targets set in Executive Order 2019-003. The proposed Methane Abatement Rule addresses

[7] New Mexico Greenhouse Gas Emissions Inventory and Forecast, NMED Exhibit 12, at 24.
[8] Calculated from Eastern Resources Group, New Mexico 2023 Greenhouse Gas Inventory Supporting Data, available at: https://www.env.nm.gov/climate-change-bureau/greenhouse-gas-emissions-inventories/

the 15.5% of statewide greenhouse gas emissions coming from methane emissions in the oil and gas sector.

The oil and gas sector in New Mexico has grown dramatically over the past ten years. In 2025, the most recent data available from the federal Energy Information Agency, New Mexico was responsible for 16% of US crude oil production and 9% of US natural gas production.[9] New Mexico is currently the second largest producer of oil in the country. Oil and gas production in New Mexico is concentrated in the Permian Basin in the southeast of the state and the San Juan Basic in the northwest of the state, as shown below in Figure 8.

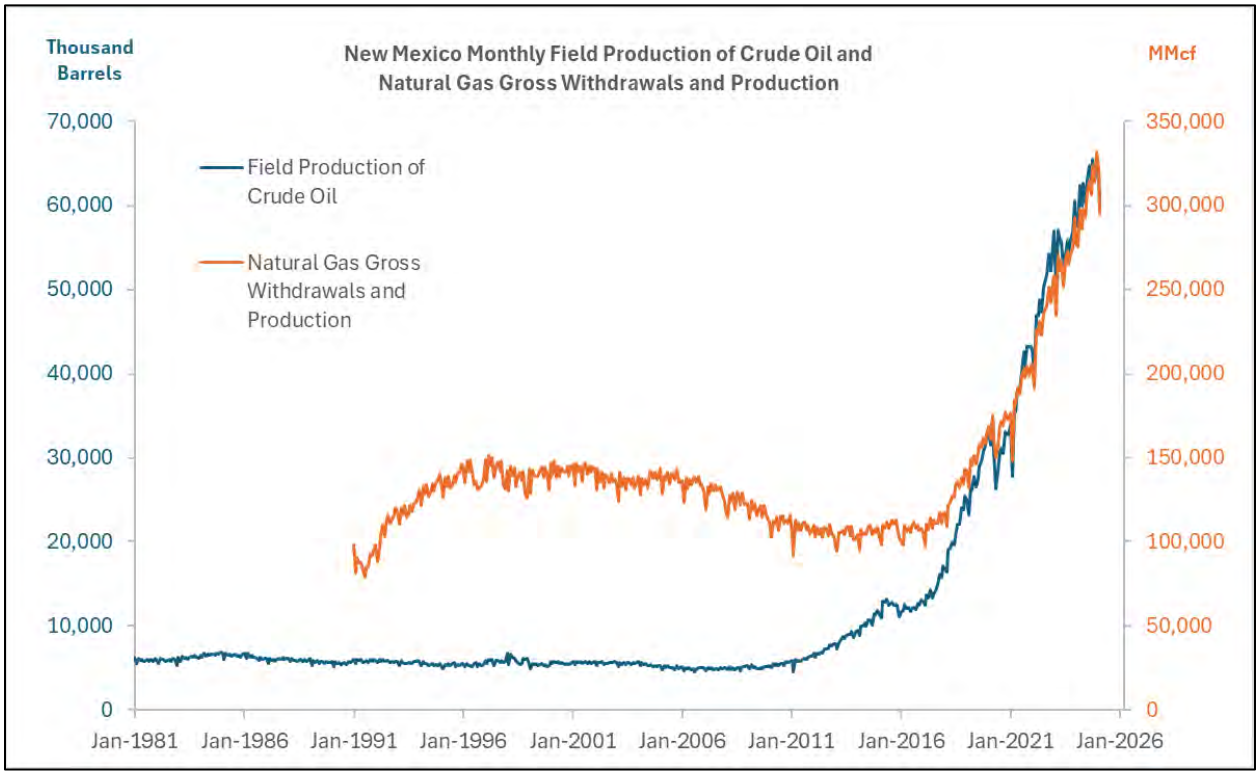
Figure 4: San Juan and Permian Basins in New Mexico



[9] U.S. Energy Information Administration, *Petroleum & Other Liquids: Crude Oil Production*, https://www.eia.gov/dnav/pet/PET_CRD_CRPDN_ADC_MBBL_A.htm; *see also* U.S. Energy Information Administration, *Natural Gas: Natural Gas Gross Withdrawals and Production*, https://www.eia.gov/dnav/ng/NG_PROD_SUM_A_EPG0_FGW_MMCF_A.htm.

From 2011 to 2024 oil production in the state increased tenfold and natural gas production more than doubled.[10] Figure 9, below, illustrates the production of crude oil and the natural gas gross withdrawals and production in New Mexico.

Figure 5: Monthly Field Production of Crude Oil and Natural Gas Gross Withdrawals and Production[11]



These increases in production mean more methane emissions from the sector, making it even more imperative that the state take action to address emissions.

[10] U.S. Energy Information Administration, *Petroleum & Other Liquids: New Mexico Field Production of Crude Oil*, https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpnm1&f=m; *see also* U.S. Energy Information Administration, *Natural Gas: New Mexico Natural Gas Gross Withdrawals*, *https://www.eia.gov/dnav/ng/hist/n9010nm2M.htm*.
[11] Ibid.

IV. THE URGENCY TO ADDRESS CLIMATE CHANGE

The Department recognizes that our statutory responsibility to abate air pollution must include additional focus on greenhouse gases, due to the numerous environmental and health impacts of climate change. As a first step, the Department included in its strategic plan to prioritize a methane abatement rule, focused on closing the gaps between federal regulations and current state rules.

Unequivocally, human activity has increased atmospheric greenhouse gas concentrations, which are causing warming of the planet, leading to a range of impacts that are collectively referred to as "climate change." Natural variation in the Earth's climate has occurred over millions of years, which scientists are able to analyze using data from ice cores, ocean sediments, and geological materials. However, human activity—primarily the burning of fossil fuels, and secondarily oil and gas extraction and processing, transportation, electricity generation, agriculture, and disposal of waste—has increased the concentration of atmospheric gases that trap heat, increasing the greenhouse effect leading to global warming, or climate change. This is referred to as the anthropogenic, or human-caused, greenhouse effect. As a result of human impacts, the average global surface temperature has increased approximately 1.3°C (2.3°F) from pre-industrial levels. Land surfaces have warmed at nearly twice the rate of oceans, and land surfaces now average 2°C (3.6°F) of total temperature increase. These temperature shifts originated from human activities that drove the emission of greenhouse gases, increasing dramatically in the twentieth century and continuing in the twenty first century, leaving today's planet to feel the delayed impacts of emissions that occurred up to a century ago.

The rate of global warming is also increasing as humans continue to engage in activities that generate greenhouse gases. Since 1850, which coincides with the industrial revolution, the

Earth's temperature had risen by an average of 0.06°C (0.11°F) per decade. However, the planetary warming rate has significantly accelerated since 1982. The rate of warming has increased to 0.20°C (0.36°F) per decade, representing a more than threefold increase in the rate of warming from before 1982.[12] Indeed, the 10 warmest years in the historical record have all occurred between 2015 and 2026.

Figure 1 shows the increase in global average surface temperature that has occurred over the past 45 years.

Figure 6: Change in Global Average Surface Temperature from 1880 to 2024[13]

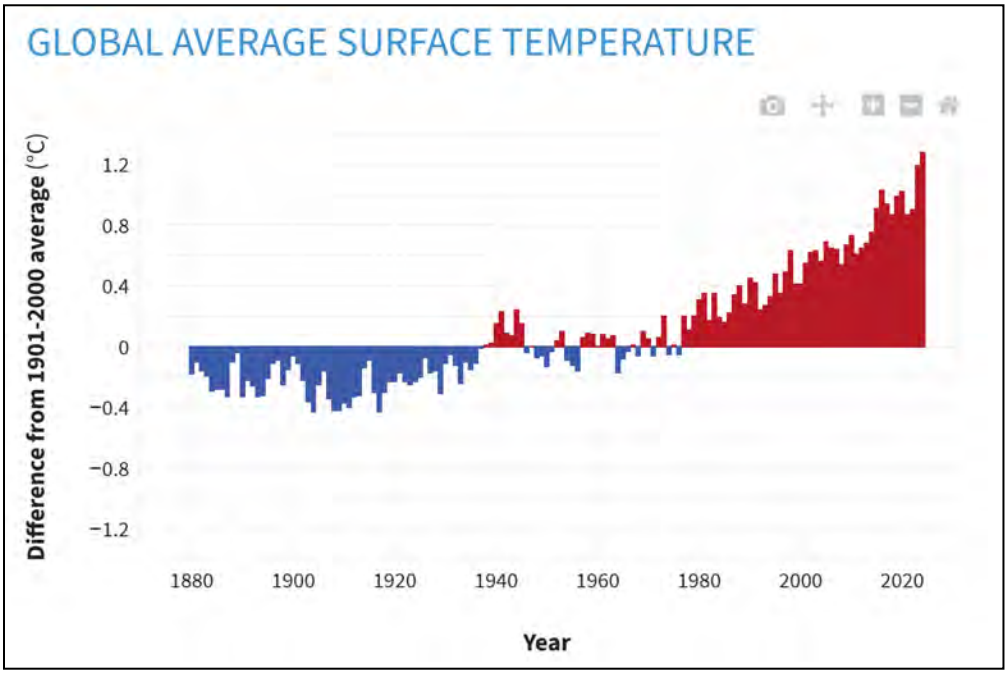
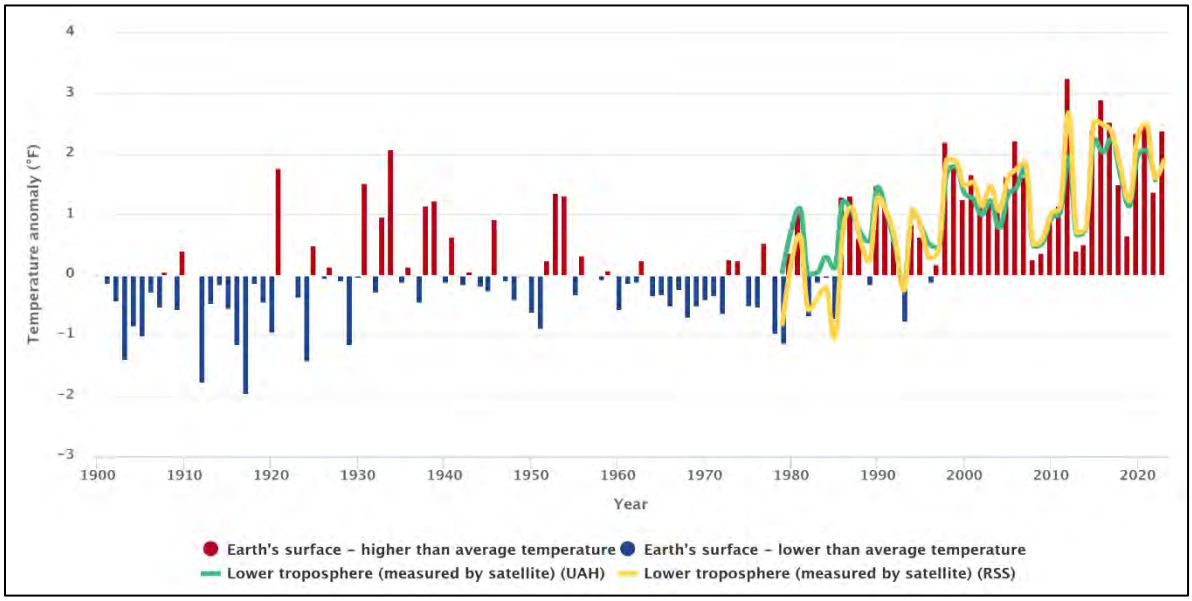


Figure 2 shows this consistent warming in the contiguous United States.

[12] NOAA, *Climate change: global temperature*, https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature.
[13] Source: https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature

Figure 7: Temperatures in the contiguous 48 states in the U.S., 1901-2023[14]



With a business-as-usual scenario for global warming, meaning that humanity continues to emit greenhouse gases without adopting additional mitigation policies, models project planetary warming of 3°C (5.4°F) by 2100. While several degrees may not seem like a large amount to humans who are accustomed to experiencing significant seasonal fluctuations in temperature in most parts of the world, an average land surface temperature increase of 2°C profoundly affects the functioning of Earth systems. Planetary warming of 3°C would severely increase the impacts of climate change and result in a fundamentally different climate for humans and other living beings. While many life forms have evolved and coped with climatic changes over millions of years, human life as we know it has evolved in a stable climate, the geological epoch of the Holocene, which began approximately 11,700 years ago, and which

[14] EPA, *Climate Change Indicators: U.S. and Global Temperature*, https://19january2021snapshot.epa.gov/climate-indicators/climate-change-indicators-us-and-global-temperature_.html. Accessed August 14, 2025; currently archived by the EPA.

made agriculture (and as a consequence, human civilization) possible. Humanity is, in effect, running an experiment without guardrails on the foundation of its existence.

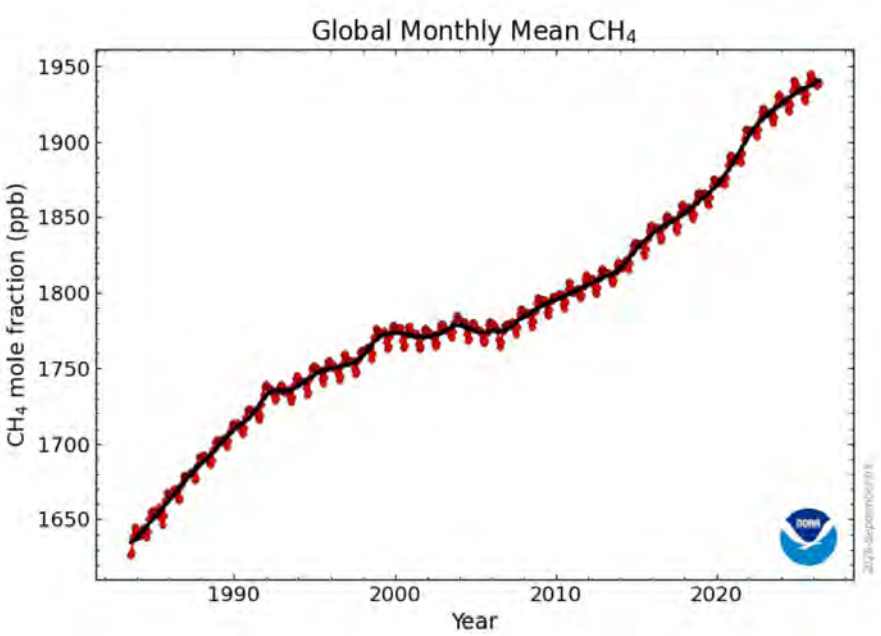
Methane as a Greenhouse Gas

Methane ("CH4") is the second most important GHG after carbon dioxide, responsible for approximately 20% of the global direct radiative forcing, or warming, since 1750.[15] In 2019, calculated global atmospheric methane concentrations reached 1866 parts per billion. This concentration is unprecedented in at least 800,000 years according to analysis of ice core records.[16] The graph below (Figure 3) from the National Oceanic and Atmospheric Administration ("NOAA") shows globally-averaged, monthly mean atmospheric methane abundance determined from marine surface sites from 1983, when NOAA began tracking these values, to 2024.

[15] Forster, P., T. Storelvmo, K. Armour, W. Collins, J.-L. Dufresne, D. Frame, D.J. Lunt, T. Mauritsen, M.D. Palmer, M. Watanabe, M. Wild, and H. Zhang, 2021: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity. In: *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 923–1054, doi: 10.1017/9781009157896.009, available at https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter07.pdf.

[16] Gulev, S.K., P.W. Thorne, J. Ahn, F.J. Dentener, C.M. Domingues, S. Gerland, D. Gong, D.S. Kaufman, H.C. Nnamchi, J. Quaas, J.A. Rivera, S. Sathyendranath, S.L. Smith, B. Trewin, K. von Schuckmann, and R.S. Vose, 2021: Changing State of the Climate System. In *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 287–422, doi:10.1017/9781009157896.004, available at https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter02.pdf.

Figure 8: Global Monthly Mean Methane, 1983-2024[17]



The increase in atmospheric methane concentrations is estimated to have driven radiative forcing with an attendant warming effect of 0.5°C (with a 90% confidence interval of 0.3°C to 0.8°C).[18]

Though anthropogenic carbon dioxide is present in the atmosphere at much higher concentrations than anthropogenic methane, methane is a much more potent GHG.[19] Compared to carbon dioxide, methane has a much stronger Global Warming Potential, a measure used by

[17] NOAA, *Trends in Atmospheric Methane (CH4)*, https://gml.noaa.gov/ccgg/trends_ch4/.
[18] IPCC, 2023: *Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland, 184 pp., doi: 10.59327/IPCC/AR6-9789291691647, available at https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_FullVolume.pdf.
[19] Szopa, S., V. Naik, B. Adhikary, P. Artaxo, T. Berntsen, W.D. Collins, S. Fuzzi, L. Gallardo, A. Kiendler-Scharr, Z. Klimont, H. Liao, N. Unger, and P. Zanis, 2021: Short-Lived Climate Forcers. In: *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 817–922, doi: 10.1017/9781009157896.008, available at https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter06.pdf.

scientists to compare the warming impacts of GHGs. Global Warming Potential takes into account both the radiative efficiency of a GHG, i.e., how effectively it absorbs infrared radiation which causes warming, and the GHG's atmospheric lifetime, or how long it lasts in the atmosphere. Methane is shorter lived in the atmosphere than carbon dioxide—it lasts approximately 12 years, whereas carbon dioxide persists for 100 years in the atmosphere—but has a large radiative forcing capacity during its atmospheric lifetime. Over a 20-year period, methane traps about 82 times as much heat as carbon dioxide; over 100 years, methane traps about 29 times as much heat.[20] Therefore, methane has a more potent short-term impact on global warming, which drives the urgency to abate methane emissions quickly. Early mitigation of methane would significantly increase the possibility of limiting global warming to 1.5°C or 2°C.[21]

Mitigation and methane abatement are among the most immediate and cost-effective ways to limit global warming, achieve monetized benefits from reduced climate damage, and significantly reduce and prevent climate-based public health burdens. The U.S. EPA data indicates that the oil and gas industry could mitigate 38% of its projected methane pollution by 2030 by implementing simple, cost-effective fixes such as upgrading equipment and locating and

[20] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, available at https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf.

[21] IPCC, 2018: *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty* [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA, 616 pp. https://doi.org/10.1017/9781009157940, available at https://www.ipcc.ch/site/assets/uploads/sites/2/2022/06/SR15_Full_Report_HR.pdf.

fixing pipe leaks.[22] The United Nations Environment Programme estimated that the majority of major methane abatement potential in the oil and gas industry is highly affordable, costing less than US$600 per ton of methane reduced.[23] All methane abatement mitigations collectively have a high economic return of $4,300 per ton of abated methane in global monetized benefits across market and non-market impacts; nearly 85% of targeted measures, including reducing leaks in the fossil fuel industry, have benefits that outweigh the net costs.[24]

Recognizing that methane contributes to ground-level ozone formation and that ground-level ozone impacts health, each million metric tons of methane reduced would prevent approximately 1,430 premature deaths due to ozone alone. In addition, this amount of methane reduction could avoid approximately 4,000 asthma-related emergency department visits and 90 hospitalizations per year. [25]

Ultimately, reducing methane emissions utilizing control measures costs significantly less than the estimated human health and economic cost of not implementing mitigation measures. Because "the greatest targeted abatement potential very likely lies within the fossil-fuel sector," prioritizing methane abatement controls in the oil and gas sector provides a highly affordable, rapid mechanism to slow global warming while unlocking hundreds of billions of dollars in annual public health, agricultural, and economic benefits. [26]

[22] U.S. EPA. (2019). *Global non-CO2 greenhouse gas emission projections & mitigation potential: 2015–2050* (EPA-430-R-19-010). https://www.epa.gov/sites/default/files/2019-09/documents/epa_non-co2_greenhouse_gases_rpt-epa430r19010.pdf
[23] United Nations Environment Programme and Climate and Clean Air Coalition (2021). *Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions*. Nairobi: United Nations Environment Programme. https://wedocs.unep.org/items/4d9774f8-1a9d-42d1-be2c-122408159b15
[24] Ibid.
[25] Ibid.
[26] Ibid.

Methane as Ozone Precursor

Methane emissions are not only an effective driver of radiative forcing that exacerbates climate change; methane also acts as a chemical driver of tropospheric, or ground-level, ozone synthesis, contributing to air pollution worldwide.[27] **NMED Exhibit 14a**. Exposure to elevated levels of ground-level ozone is associated with a range of adverse health effects. It can irritate and inflame the airways, leading to symptoms such as coughing, throat irritation, shortness of breath, and chest discomfort. For individuals with pre-existing respiratory conditions like asthma or emphysema, ozone exposure can worsen symptoms and increase the risk of complications. Even short-term exposure can trigger respiratory distress, while long-term exposure has been linked to the development of chronic conditions, including chronic obstructive pulmonary disease.[28] Certain populations are more vulnerable to ozone-related health impacts. Children, older adults, and individuals with lung disease face heightened risks. In addition, people who are physically active outdoors, particularly during peak ozone hours, typically from midday to early evening, are more likely to experience symptoms due to increased inhalation of polluted air during exercise or work. It has been estimated that long-term ozone exposure was the cause of 1 million respiratory deaths in adults worldwide in 2010.[29] **NMED Exhibit 14b**.

[27] Mar, K. A., Unger, C., Walderdorff, L., & Butler, T. M. (2022). *Beyond Carbon dioxide equivalence: The impacts of methane on climate, ecosystems, and health*. *Environmental Science & Policy*, *134*, 127–136, doi.org/10.1016/j.envsci.2022.03.027.

[28] World Health Organization Regional Office for Europe. (2013). Health effects of ozone. In: *Review of evidence on health aspects of air pollution – REVIHAAP Project: Technical report*, available at https://www.ncbi.nlm.nih.gov/books/n/revieviheaaspair/pdf/; *see also* EPA, *Health Effects of Ozone Pollution*, https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution.

[29] Malley, C. S., Henze, D. K., Kuylenstierna, J. C. I., Vallack, H. W., Davila, Y., Anenberg, S. C., Turner, M. C., & Ashmore, M. R. (2017). Updated global estimates of respiratory mortality in adults ≥30 years of age attributable to long-term ozone exposure. *Environmental Health Perspectives*, *125*(8), 087021.

In addition to its public health impacts, sustained long-term exposure to high concentrations of ground-level ozone can cause significant environmental harm.[30] Sensitive vegetation and ecosystems such as forests, parks, and wildlife reserves are particularly vulnerable. Ozone levels are often high during warm weather, which frequently coincides with the growing season, leaving plants especially susceptible to damage from ozone, which acts as a powerful phytotoxin, resulting in diminished crop productivity.[31,32,33] **NMED Exhibits 14c, 14d, and 14e**. Ozone damage extends to ecosystems and biodiversity by weakening forest health and altering wildlife habitats.[34] Ozone-driven ecosystem disruption has downstream effects on humanity through effects on the carbon sequestration potential of plant species, which makes plants more susceptible to invasive species, generating economic damage and crop loss.

The economic consequences of tropospheric ozone can be measured in healthcare costs, lost economic productivity (lost days of work due to respiratory illness), and diminished agricultural production. Increases in respiratory-related human mortality risk from the tropospheric ozone produced from methane emissions in 2020 was estimated to be $1,800 per ton of CH4 (95% confidence interval: $760-$2,800/metric ton CH4).[35] **NMED Exhibit 14f**. A 2021 study conducted by the United Nations Environment Programme and Climate and Clean

[30] EPA, *Health Effects of Ozone Pollution*, https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution.
[31] Emberson, L. (2020). Effects of ozone on agriculture, forests and grasslands. *Philosophical Transactions of the Royal Society A: Mathematical, Physical and Engineering Sciences*, 378(2183), 20190327.
[32] Sampedro J. et al. (2023) *Marginal Damage of Methane Emissions: Ozone Impacts on Agriculture*. Environ Resour Econ (Dordr). doi: 10.1007/s10640-022-00750-6.
[33] Lu, H., Xi, D., Guo, T., & Cheng, Y. F. (2026). Environmental impacts of methane emissions from the oil and gas industry. *Cell Reports Sustainability*, 3(1), Article 100587.
[34] IPCC, 2023: *Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland, 184 pp., doi: 10.59327/IPCC/AR6-9789291691647, available at https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_FullVolume.pdf.
[35] McDuffie, E.E., Sarofim, M.C., Raich, W., Jackson, M., Roman, H., Seltzer, K., Henderson, B.H., Shindell, D.T., Collins, M., Anderton, J. Barr, S., and Fann, N. 2023. The Social Cost of Ozone-Related Mortality Impacts From Methane Emissions. Earth's Future, 11(9), p.e2023EF003853.

Air Coalition, which included the additional cardiovascular mortality risk due to elevated ozone concentrations, estimated that sustained reductions of a million tons of methane emissions per year could prevent about 1,430 premature deaths annually, along with preventing the loss of 145,000 tons of wheat, soybeans, maize and rice.[36]

V. CLIMATE CHANGE IMPACTS IN NEW MEXICO

Climate change is a global challenge with localized impacts. The southwestern U.S. is feeling the impacts of climate change acutely and will continue to experience increasingly severe climate impacts that affect the wellbeing of the region's people, ecosystems, and economy. The Sixth Assessment Report of the Intergovernmental Panel on Climate Change finds that summer daily maximum temperature is increasing in Southwest U.S. desert regions with projections of decreased total precipitation, reduced groundwater recharge in major southwest U.S. aquifers, projected long-term reduction in water availability (e.g., from the Colorado River and Rio Grande) that will have substantial ecological and economic impacts given the region's heavy water demands, and aridification that will reduce forage production, affecting the region's livestock industry.[37] These findings are echoed by the Fifth National Climate Assessment ("NCA"), which reports with very high confidence that climate change has reduced surface water and groundwater availability for people and nature in the Southwest, with high confidence that

[36] United Nations Environment Programme and Climate and Clean Air Coalition (2021). Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions. Nairobi: United Nations Environment Programme, available at https://www.ccacoalition.org/sites/default/files/resources//2021_Global-Methane_Assessment_full_0.pdf.

[37] Hicke, J.A., S. Lucatello, L.D., Mortsch, J. Dawson, M. Domínguez Aguilar, C.A.F. Enquist, E.A. Gilmore, D.S. Gutzler, S. Harper, K. Holsman, E.B. Jewett, T.A. Kohler, and K.A. Miller, 2022: North America. In: *Climate Change 2022: Impacts, Adaptation and Vulnerability*. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [H.-O. Pörtner, D.C. Roberts, M. Tignor, E.S. Poloczanska, K. Mintenbeck, A. Alegría, M. Craig, S. Langsdorf, S. Löschke, V. Möller, A. Okem, B. Rama (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA, pp. 1929–2042, doi:10.1017/9781009325844.016, at 1936-37, 1953, 1956, available at https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_Chapter14.pdf.

there are inequities in how these impacts are experienced, with high confidence that higher temperatures have intensified drought and will lead to a more arid future, and with high confidence that, without adaptation, these changes will exacerbate existing water supply–demand imbalances.[38] The NCA summarizes peer-reviewed research that finds that increasing temperatures are leading to hotter extreme heat events, drier soils, greater atmospheric evaporative demand, and reduced flows in major river basins, including New Mexico's Rio Grande.[39] The Assessment notes that since 2000, the Southwest has experienced an exceptional "megadrought," marking the first two decades of the 21st century as the driest 22-year period in 1,200 years.[40] Annual temperatures in the Southwestern U.S. are projected to rise relative to the 1971-2000 baseline: 1.4–1.7°C by 2021–2050, 1.9–2.5°C by 2041–2070, and 2.5–4.4°C by 2071–2099, with increases of temperatures more pronounced in summer and fall.[41] **NMED Exhibit 14g**. Increasing temperatures will result in more frequent and prolonged heat waves, lengthen the frost-free season by 25–40 days, increase evapotranspiration, decrease snowpack volume, especially at the lowest elevations currently accumulating snow, and affect the timing and duration of snowmelt in mountainous regions, which in turn will affect water availability.[42] Precipitation is projected to decrease in the Southwest, with the most dramatic decreases expected to occur in the spring and summer.[43]

[38] USGCRP, 2023: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, at 28-9, available at https://toolkit.climate.gov/NCA5_2023_FullReport; *see also* EPA, 2016: *What Climate Change Means for New Mexico*, EPA 430-F-16-033, available at https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-nm.pdf.
[39] Ibid.
[40] Ibid.
[41] Hurteau, M. D., Bradford, J. B., Fulé, P. Z., Taylor, A. H., & Martin, K. L. (2014). Climate change, fire management, and ecological services in the southwestern US. *Forest Ecology and Management*, *327*, 280-289.
[42] Ibid.
[43] Ibid.

Climate change is already having a significant impact on New Mexico, causing harm to the people, ecosystem, economy, and lifeways of the State, and these impacts will become more severe as climate change worsens. In a 2013 report, the U.S. Bureau of Reclamation found that temperatures in the Upper Rio Grande Basin ("Basin"), covering New Mexico and Southern Colorado, rose at a rate of just under 0.7°F per decade, a rate double the global rate of temperature increase and unprecedented over the last 11,300 years.[44] The Bureau projected that average temperatures in the Basin may rise by an additional 4-6°F by the end of the 21st century. Impacts include record-high temperatures, below-average precipitation, historically low snowpack, and critically low runoff and river flows.[45] Together, these impacts have increased ecosystem vulnerability to wildfires,[46] threatened short- and long-term water supplies,[47] negatively affected agricultural productivity and ecosystem functioning,[48] and increased challenges to public health and infrastructure. **NMED Exhibit 14h**. The economic consequences of these impacts will be costly. A 2009 analysis by Sandia National Laboratories estimated the economic costs of climate change across the country from 2010-2050. For New Mexico, they estimate billions of dollars of loss.[49] New Mexico has a vested interest in slowing climate

[44] Llewellyn, D. and S. Vaddey (2013). *West-Wide Climate Risk Assessment: Upper Rio Grande Impact Assessment*. U.S. Department of the Interior, Bureau of Reclamation, Upper Colorado Region, Albuquerque Area Office, available at https://www.usbr.gov/watersmart/baseline/docs/urgia/URGIAMainReport.pdf.
[45] EPA (2016). *What Climate Change Means for New Mexico*. EPA 430-F-16-033, available at https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-nm.pdf; *see also* New Mexico Bureau of Geology and Mineral Resources (2022). *Climate change in New Mexico over the next 50 years: Impacts on water resources*. New Mexico Bureau of Geology and Mineral Resources, Bulletin 164, available at https://mainstreamnm.org/wp-content/uploads/2024/01/Leap-Ahead-Report.pdf.
[46] Balik, J.A., et al. (2026). Snowpack decline kindles more severe fire in the western United States. Environ. Res. Lett. 21 064010.
[47] New Mexico Water and Infrastructure Task Force. (2022) *Facing New Mexico's 21st Century Water Challenges; A Report of the New Mexico Water Policy and Infrastructure Task Force*, available at https://digitalrepository.unm.edu/cgi/viewcontent.cgi?article=1084&context=utton_pubs.
[48] United Nations Environment Programme, *Facts about Methane*, https://www.unep.org/en/explore-topics/energy/facts-about-methane.
[49] Backus, G. A., et al. (2010). *Executive Summary for Assessing the Near-Term Risk of Climate Uncertainty: Interdependencies Among the US States.* SAND2010-2200. Albuquerque, NM: Sandia National Laboratories, available at https://digital.library.unt.edu/ark:/67531/metadc836188/m2/1/high_res_d/1028887.pdf.

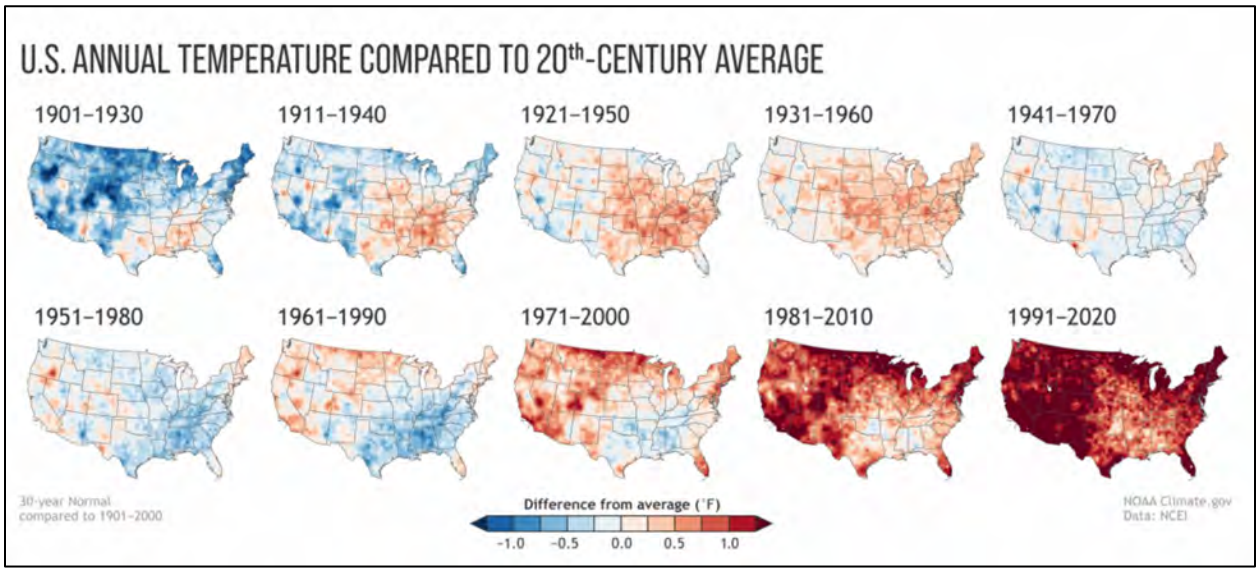
change, through abatement of greenhouse gas emissions, to protect its people and resources. The rest of this section will summarize these impacts in more detail.

Rising Temperatures

Warming temperatures have multiple, far-reaching consequences that affect overall human well-being and the functioning of natural systems that have evolved around regional historical climate baseline conditions. Climate baselines, commonly referred to as climate normals, are averages of key climate observations calculated over a 30-year period.[50] The current U.S. Climate Normals (1991–2020), updated once each decade, serve as the standard reference for determining how temperature, precipitation, and other climate variables compare to typical conditions at a given location.[51] These normals provide an important benchmark for assessing climate variability and long-term change. Today, normal annual temperatures across the United States are warmer than the 20th-century average in virtually every region, reflecting the widespread influence of ongoing climate warming (see Figure 1).[52]

[50] NOAA, *Climate change and the 1991–2020 U.S. climate normals*, https://www.climate.gov/news-features/understanding-climate/climate-change-and-1991-2020-us-climate-normals.
[51] Ibid.
[52] Ibid.

Figure 9: Annual U.S. temperature compared to the 20th-century average for each U.S. Climate Normals period from 1901-1930 (upper left) to 1991-2020 (lower right)[53]



In the graphic above, places where the normal annual temperature was 1.25°F or colder than the 20th-century average are darkest blue, and places where normal annual temperature was 1.25°F or warmer than the 20th-century average are darkest red, showing both the geographical variation in climate impacts and the overall trend in warming.

Across New Mexico, average observed temperatures have risen by more than 2°F since the beginning of the 20th century.[54] Temperatures across the Southwest have remained consistently above average, contributing to some of the warmest annual temperatures on record, including daytime and nighttime temperatures across New Mexico reaching record highs over

[53] Maps by NOAA Climate.gov, based on analysis by Jared Rennie, North Carolina Institute for Climate Studies/NCEI. https://www.noaa.gov/news/new-us-climate-normals-are-here-what-do-they-tell-us-about-climate-change

[54] Frankson, R., K.E. Kunkel, L.E. Stevens, and D.R. Easterling (2022). *New Mexico State Climate Summary 2022*. NOAA Technical Report NESDIS 150-NM. NOAA/NESDIS, Silver Spring, MD, 5 pp., available at https://statesummaries.ncics.org/downloads/NewMexico-StateClimateSummary2022.pdf.

the past decade.[55] These temperature trends reflect unprecedented historical warming in the State and it is projected to continue throughout this century.[56]

Threats to Water Resources

The most severe and far-reaching climate change impacts on New Mexico are threats to the state's water resources. The state reports that in the next fifty years New Mexico will have 25% less water resources and a shortage of 750,000 acre-feet of water, which is insufficient to meet the state's water needs.[57] New Mexico is an arid region that has a water-limited ecosystem, with swings of intense drought and precipitation, making the state's communities especially vulnerable to the accelerating effects of climate change.[58] Drought occurs when a water deficit at the land surface ensures that water demands cannot be met. Groundwater systems are interconnected with surface water, where surface waters are either recharging groundwater systems or groundwater is discharging into surface waters, sustaining base flows.[59] Drought exacerbates aridification, dries up soil for longer periods of time making droughts more severe, increases the need for irrigation water supply, and increases evaporation rates, and thus there is a cumulative need for additional water that in turn reduces the water supply.[60,61]

[55] Ibid.
[56] Ibid.
[57] Office of the Governor of the State of New Mexico, *50-Year Water Action Plan*, available at https://www.nm.gov/wp-content/uploads/2024/01/New-Mexico-50-Year-WaterAction-Plan.pdf.
[58] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[59] Ibid.
[60] EPA (2016). *What Climate Change Means for New Mexico*. EPA 430-F-16-033, available at https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-nm.pdf.
[61] New Mexico Bureau of Geology and Mineral Resources (2022). *Climate change in New Mexico over the next 50 years: Impacts on water resources*. New Mexico Bureau of Geology and Mineral Resources, Bulletin 164, available at https://mainstreamnm.org/wp-content/uploads/2024/01/Leap-Ahead-Report.pdf.

New Mexico's persistent drought conditions are driven by increased temperatures and increasingly unpredictable precipitation patterns, both driven by climate change.[62] Climate models predict that precipitation will become more variable with pronounced swings in the hydrologic cycle, characterized by periods of both unusually wet and unusually dry conditions.[63] Historical examples of climate change-driven variability in precipitation in New Mexico include the driest on record monsoon in 2020 and the contrasting unusually wet monsoon seasons of 2006 and 2013, which caused extensive flooding across the state.[64]

Observed declines in western snowpack over the last century have been mainly driven by warming temperatures, resulting in smaller snowpack volumes, snow lines moving to higher elevations, and earlier snowmelt.[65] These effects are worsened by dust and other light-absorbing particles that settle on the snowpack, causing it to melt more quickly.[66] A warmer climate reduces the proportion of winter precipitation that falls as snow and accelerates snowmelt, leading to diminished seasonal snowpack.[67] **NMED Exhibit 14i**. Decline in snowpack limits the supply of spring and summer snow melt that recharges water to rivers and reservoirs.[68] A reduced snowpack decreases streamflow and river discharge in headwater systems, limits the supply of spring and summer snow melt that recharges water to rivers and reservoirs, affecting

[62] U.S. Department of Agriculture, *Drought and Northwest Agriculture in a Changing Climate*, https://www.climatehubs.usda.gov/hubs/northwest/topic/drought-and-northwest-agriculture-changing-climate#risingtemperatures.
[63] Frankson, R., K.E. Kunkel, L.E. Stevens, and D.R. Easterling (2022). *New Mexico State Climate Summary 2022*. NOAA Technical Report NESDIS 150-NM. NOAA/NESDIS, Silver Spring, MD, 5 pp., available at https://statesummaries.ncics.org/downloads/NewMexico-StateClimateSummary2022.pdf.
[64] Ibid.
[65] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[66] Ibid.
[67] Vano, J.A. (2020). Implications of losing snowpack. *Nat. Clim. Chang.* 10, 388–390. https://doi.org/10.1038/s41558-020-0769-1.
[68] EPA (2016). *What Climate Change Means for New Mexico*. EPA 430-F-16-033, available at https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-nm.pdf.

downstream water resources, altering ecosystem structure and function, threatening snow-dependent species, and shortening winter recreation and tourism seasons.[69,70,71] During the 2024–2025 New Mexico winter season, snowpack levels were the lowest on record, which, combined with warmest annual temperatures on record, created exceptional drought conditions in the spring of 2025.[72] **Id**.

Increased water scarcity will affect all parts of the state, but impacts will vary across regional ecosystems. Native landscapes, vegetation, and soils will suffer negative effects, including: widespread ecosystem die-off events of forests, shrublands and grasslands; reduction in vegetation cover and rainfall infiltration; increased overland runoff, flooding, and arroyo incision; atmospheric dustiness; and upland erosion by overland flow and downstream sediment deposition.[73] Higher temperatures drive increased evapotranspiration and decreased snowpack, both of which lead to decreases in surface water supplies.[74]

Climate change impacts on the Rio Grande River are particularly devastating to the state. Reduced snowpack has led sections of the Rio Grande, the lifeblood of the state, to frequently run dry since 2022, resulting in damage to riverine and riparian habitats, reduced irrigation water for farmers, and reduced surface water and groundwater for drinking water supplies. The Middle

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[69] Ibid.
[70] New Mexico Bureau of Geology and Mineral Resources (2022). *Climate change in New Mexico over the next 50 years: Impacts on water resources*. New Mexico Bureau of Geology and Mineral Resources, Bulletin 164, available at https://mainstreamnm.org/wp-content/uploads/2024/01/Leap-Ahead-Report.pdf.
[71] Frankson, R., K.E. Kunkel, L.E. Stevens, and D.R. Easterling (2022). *New Mexico State Climate Summary 2022*. NOAA Technical Report NESDIS 150-NM. NOAA/NESDIS, Silver Spring, MD, 5 pp., available at https://statesummaries.ncics.org/downloads/NewMexico-StateClimateSummary2022.pdf.
[72] Vano, J.A. (2020). Implications of losing snowpack. *Nat. Clim. Chang.* 10, 388–390. https://doi.org/10.1038/s41558-020-0769-1.
[73] New Mexico Bureau of Geology and Mineral Resources (2022). *Climate Change and New Mexico's Water Resources: A 50-Year Outlook*. New Mexico Earth Matters, Winter 2022, available at https://www.nmlegis.gov/handouts/WNR%20072522%20Item%205%20Gutzler1.pdf.
[74] Gutzler, D. S. (2013). Chapter 4. Climate and drought in New Mexico. In: *Water Policy in New Mexico, Addressing the challenge of an uncertain future*. Brookshire, D.S., et al., Eds. RFF Press, 56-70.

Rio Grande Conservancy District has not been able to store native Rio Grande water for non-Pueblo users since 2020 and is currently using groundwater to meet Albuquerque's drinking water needs, drawing down a finite underground water supply.[75] Agricultural water users will be severely affected by increasing water scarcity, as water is preferentially transferred to maintain urban and industrial users, whose economic productivity is greater. Total annual economic losses are estimated in the vicinity of $300 million; under severe climate changes, where runoff is reduced by nearly 30%, both economic and non-economic losses are likely to be significantly higher.[76]

Wildfires and Flash Flooding

Warming temperatures, drought, and earlier snowmelt have been linked to an increasing number of large fires in the Western U.S. since the 1980s.[77] **NMED Exhibits 14j and 14k**. Wildfires in the Southwest in the past two decades have been more frequent, larger, and more severe. Severe drought and increased temperatures in the Southwest since the late 1990s have resulted in substantial vegetation mortality across millions of hectares of woodlands and forests in the first decades of the 21st century, building up fuel stocks that exacerbate wildfires.[78] **NMED Exhibit 14l**.

[75] Fallon Fischer, KRQE News, *Rio Grande once again goes dry in Albuquerque*, https://www.krqe.com/news/albuquerque-metro/rio-grande-once-again-goes-dry-in-albuquerque/.
[76] Hurd, B.H. and Coonrod, J. (2008). *Climate Change and Its Implications for New Mexico's Water Resources and Economic Opportunities*. Technical Report 45, NM State University, College of Agriculture and Home Economics, Cooperative Extension Service, Agricultural Experiment Station, available at https://pubs.nmsu.edu/research/economics/TR45.pdf.
[77] Westerling, A. L. (2016). Increasing western US forest wildfire activity: sensitivity to changes in the timing of spring. *Philosophical Transactions of the Royal Society B: Biological Sciences*, *371*(1696), 20150178; *see also* Dennison, P. E., Brewer, S. C., Arnold, J. D., & Moritz, M. A. (2014). Large wildfire trends in the western United States, 1984–2011. *Geophysical Research Letters*, *41*(8), 2928-2933.
[78] Allen, C. D. (2007). Interactions across spatial scales among forest dieback, fire, and erosion in northern New Mexico landscapes. *Ecosystems*, *10*(5), 797-808.

Wildfires endanger human life and property, change the composition of ecosystems, are economically costly, and impact human health through degradation of air quality. The two largest wildfires in New Mexico's recorded history have occurred in the past three years. In 2022, the Calf Canyon/Hermits Peak Fire burned 341,735 acres in northern New Mexico, and the Black Fire burned 325,136 acres in Southwestern New Mexico. As the frequency and severity of such megafires intensify across the region, they exert an evolutionary pressure that selectively favors fire-adapted species. Consequently, the emerging post-fire plant life may no longer resemble the regions pre-existing historic native plant communities.[79] **NMED Exhibit 14m**. Wildfires drive vegetation conversion in the Southwest, particularly from forests to shrublands, which impacts watersheds and aquatic resources through degradation of riparian systems, risks to riparian and riverine species, and increased invasions by non-native species.[80] Post-fire ecosystem recovery is further hindered by climate-induced aridification that limits tree seedling and shrub establishment.[81] An analysis of severe wildfires in New Mexico in 2022, unparalleled in the state's history, found significant impacts on air quality—six large wildfires emitted 152 thousand tons of fine particulate matter ($PM_{2.5}$) and 287 thousand tons of volatile organic compounds to the atmosphere. The analysis estimates that exposure to wildfire-generated $PM_{2.5}$ was responsible for 171 excess cases of asthma emergency department visits and 18 deaths in New Mexico.[82] **NMED Exhibit 14n**.

[79] McKenzie, D., Gedalof, Z. E., Peterson, D. L., & Mote, P. (2004). Climatic change, wildfire, and conservation. *Conservation biology*, *18*(4), 890-902.
[80] USGCRP, 2023: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, at 28-29, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[81] Ibid. at 28-27.
[82] Maji, K. J., Ford, B., Li, Z., Hu, Y., Hu, L., Langer, C. E., ... & Russell, A. G. (2024). Impact of the 2022 New Mexico, US wildfires on air quality and health. *Science of the Total Environment*, *946*, 174197.

Climate change is projected to bring more extreme weather to the New Mexico, with precipitation events that contribute to increased flooding, exacerbated by aridification and severe wildfire events.[83] **NMED Exhibit 14h**. During normal precipitation conditions, vegetation helps absorb rainwater; however, NM's summer thunderstorms are often associated with intense rainfall over a brief time period, producing more water than the ground can absorb.[84] On top of soil already hardened by decades-long drought, severe rainstorms can rapidly turn into flash floods, threatening local communities. Whenever there is an intense wildfire, the burned vegetation and charred soil form a water-repellent layer that prevents water absorption and, as a result, during subsequent heavy rainfall events, properties located below or downstream of the burn areas are at an increased risk of flooding.[85] Regional models have indicated that short-duration (15-min) high intensity rainfall, the kind that can trigger dangerous mudslides and debris flows after a wildfire, will continue to intensify in the Southwest.[86] **NMED Exhibit 14o**.

The New Mexico Energy Minerals and Natural Resources Department reported evidence of this relationship after major wildfires, such as the 2022 Hermits Peak/Calf Canyon Fire, where burn scars contributed to severe flooding during subsequent storms, costing Congressionally approved funding of $4 Billion to support New Mexicans affected by these events and financial assistance from FEMA amounting to more than $84 Million in Public and Individual Assistance

[83] Balik, J.A., et al. (2026). Snowpack decline kindles more severe fire in the western United States. Environ. Res. Lett. 21 064010.
[84] National Weather Service, *NWS ABQ Monsoon awareness - Flash floods*, https://www.weather.gov/abq/prepawaremonsoonflashfloods.
[85] New Mexico Energy, Minerals and Natural Resources Department, *Post wildfire coordination*, https://www.emnrd.nm.gov/sfd/post-wildfire-coordination/.
[86] Thomas, M.A., Michaelis, A.C., Oakley, N.S. *et al.* (2024). Rainfall intensification amplifies exposure of American Southwest to conditions that trigger postfire debris flows. *npj Nat. Hazards* 1, 14. https://doi.org/10.1038/s44304-024-00017-8.

Program funding to homeowners, businesses, Tribes, and local governments.[87] In 2025, the village of Ruidoso, New Mexico, was the victim of sequential flash flooding events after suffering the South Fork and Salt wildfires in 2024. On July 8, 2025, the Rio Ruidoso crested at a record-breaking 20.24 feet, causing a flood that damaged 200 homes and took the lives of three people, including two children. Since the 2024 fires, the river has crested at or over ten feet seven times. The damage caused by the July 8, 2025 flood alone was estimated to require $100 million to rebuild and mitigate.[88] The major risk posed by runoff from extreme precipitation events is a threat to human safety, business and home infrastructure, water management infrastructure and fresh water resources.[89,90] Approximately 16% of the dams in New Mexico store hazardous mine tailings or wastewater, these pose an increased risk of failure due to extreme precipitation events and pose a serious environmental risk to downstream watersheds.[91]

Threats to Ecosystems

Climate change affects ecosystems directly by changing the conditions that allow organisms to thrive in concert. Hotter annual temperatures, more frequent extreme heat events,

[87] New Mexico Energy, Minerals and Natural Resources Department, Climate Policy Bureau (2024). *New Mexico climate adaptation and resilience plan*, available at https://cloud.env.nm.gov/resources/_translator.php/NzgyYTRmNGNiNGYzNTQ2MTRiOWNiN2I5MV8xODMwNzk~.pdf.
[88] Kylee Howard, Albuquerque Journal, *Why does it keep flooding in Ruidoso?*, https://www.abqjournal.com/news/article_32450742-9e0b-4875-ae41-c043617fa7ce.html; *see also* Morgan Lee, Susan Montoya Bryan and Roberto Rosales, AP News, *As many as 200 homes damaged as officials survey the aftermath of a deadly New Mexico flood*, https://apnews.com/article/flash-floods-new-mexico-mountain-village-ruidoso-350c1673cdc9c41796d1319e19914314.
[89] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[90] EPA (2022). *Office of Water 2022–2026 climate adaptation implementation plan: Advancing climate change adaptation and resilience through EPA's water programs*. EPA-800-R-22-001, available at https://www.epa.gov/system/files/documents/2022-10/bh508-OW-12113_ClimateAdaptatImplementPlan_508final.pdf.
[91] EPA (2016). *What Climate Change Means for New Mexico*. EPA 430-F-16-033, available at https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-nm.pdf.

extreme and prolonged drought, more variable precipitation, and decline of snowpack and surface water flows all fundamentally alter the biotic and abiotic conditions of ecosystems. Climate change-induced disturbances in ecosystems are most pronounced at the boundaries between ecosystem types, where plant and animal communities are vulnerable to small shifts in ecosystem conditions.

Climate change impacts also intensify existing stressors on ecosystems. Hotter and drier conditions make trees water-stressed, which in turn makes them more vulnerable to pests and diseases, including bark beetles, which have ravaged Western conifer forests. Cold winter temperatures historically control the lifecycles of many pests.[92] **NMED Exhibit 14p**. Pest damage correlates with maximum temperatures, consistent with recent deviations from the historical baseline.[93] Unseasonably warm winters in New Mexico for the last two years have driven a dramatic increase in insect-caused tree death observed statewide.[94] The rising annual temperatures allow these pests to persist year-round, while severe drought stress leaves NM forests highly vulnerable to bark beetle infestations that have killed over 209,000 acres of trees in 2025.[95]

Species that are especially vulnerable to climate change impacts are those already at risk of extinction, specialist and sedentary species, and taxa endemic to mountainous regions.[96] Fish

[92] Clipp, H.L., et. al. (2026) *Warming temperatures and shifting precipitation patterns may exacerbate pest damage in North American forests*. Nat Ecol Evol. doi: 10.1038/s41559-026-03039-9.
[93] Ibid.
[94] USDA Forest Service (2026). *Forest Health Conditions in Arizona & New Mexico, 2025*. PR-R3-16-25, available at https://www.fs.usda.gov/media/234542.
[95] John Miller, Albuquerque Journal, *NM Forestry Division: Bark beetle tree mortality more than doubled for second consecutive year*, https://www.abqjournal.com/news/nm-forestry-division-bark-beetle-tree-mortality-more-than-doubled-for-second-consecutive-year/2955134.
[96] New Mexico Department of Wildlife (2025). State Wildlife Action Plan for New Mexico. New Mexico Department of Wildlife, Santa Fe, New Mexico, USA, at 118, available at https://wildlife.dgf.nm.gov/download/new-mexico-state-wildlife-action-plan-swap-final-

and riparian species are affected by warmer water temperatures, earlier peak flows, increased rainfall variability, and lower summer base flows. Migratory bird species are vulnerable to habitat loss and degradation of wintering grounds, breeding sites, and stopover sites. Reptiles are particularly vulnerable to increased temperatures, given their dependence on ambient temperatures for thermal regulation, and amphibians are dependent on water availability for survival. Among mammals, species that are geographically isolated or migratory are most vulnerable. Species are coping with multiple, overlapping sources of pressure, including reduction of native habitat, competition with invasive species, and pathogens. Climate change impacts add additional pressures that compound multiple anthropogenic existing threats.

Impacts on Agriculture

The Fifth National Climate Assessment states with high confidence that continuing drought and water scarcity will make it more difficult to raise food and fiber in the Southwest and extreme heat events will increase animal stress and reduce crop quality and yield, thereby resulting in widespread economic impacts.[97] Projections show that by midcentury the Southwest will experience longer, hotter growing seasons, a northward shift in plant hardiness zones, and expanded areas of heat stress exposure to crops and livestock.[98] The livelihoods of farmers and ranchers and the agricultural productivity of the state are threatened by prolonged, severe drought. Increased temperatures drive higher rates of evapotranspiration, increasing demand for fresh water for irrigation, and decreasing snowpack, which results in reduced surface water for

2025/?ind=17520976476241&filename=2025%20State%20Wildlife%20Action%20Plan%20for%20New%20Mexico.pdf&wpdmdl=51964&refresh=686ee37d997eb1752097661.

[97] USGCRP, 2023: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, at 28-18, available at https://toolkit.climate.gov/NCA5_2023_FullReport.

[98] Ibid.

irrigation. Generational farming communities dependent on acequia irrigation, dryland farmers growing rain-fed crops, and producers raising livestock on rangelands are particularly vulnerable to reduced water supplies.[99] The impact of rising temperatures on New Mexico cereal crop production is causing forage yield declines.[100] **NMED Exhibit 14q**. This, together with the supplanting of cereal forage with woody plants, is affecting New Mexico livestock production. These impacts hit Tribal Nations especially hard; researchers at Utah State University estimated the economic impacts of ongoing drought on the cattle industry on Tribal lands in New Mexico range from $193,000 on Mescalero Apache Tribal land to $2.896 million for Navajo Nation, with total economic losses of $4.481 million for the Tribal lands in New Mexico evaluated in the study.[101]

Impacts of Climate Change on Community Wellbeing and Lifeways in New Mexico

In New Mexico, climate change is already undermining and threatening ecosystem services, public health, the State's heritage, community well-being, homes, infrastructure, and economic stability.[102,103] Safety and wellbeing in the face of climate change, are now being measured and modeled more accurately and can help researchers understand and model interdependencies, feedbacks, and cascading risks for interconnected systems such as the food–

[99] Ibid.
[100] Sawalhah, M. N., Holechek, J. L., Cibils, A. F., Geli, H. M., & Zaied, A. (2019). Rangeland livestock production in relation to climate and vegetation trends in New Mexico. *Rangeland Ecology & Management*, *72*(5), 832-845.
[101] Drugova, T., Curtis, K. R., & Kim, M. K. (2020). Impacts of Drought on Tribal Economies in New Mexico. Utah State University Extension, Applied Economics/2020-03pr, available at https://extension.usu.edu/apec/files/ImpactsofDroughtonTribalEconomiesinNewMexico.pdf.
[102] New Mexico Bureau of Geology and Mineral Resources (2022). *Climate change in New Mexico over the next 50 years: Impacts on water resources*. New Mexico Bureau of Geology and Mineral Resources, Bulletin 164, available at https://mainstreamnm.org/wp-content/uploads/2024/01/Leap-Ahead-Report.pdf.
[103] Hurd, B.H. and Coonrod, J. (2008). *Climate Change and Its Implications for New Mexico's Water Resources and Economic Opportunities*. Technical Report 45, NM State University, College of Agriculture and Home Economics, Cooperative Extension Service, Agricultural Experiment Station, available at https://pubs.nmsu.edu/research/economics/TR45.pdf.

energy–water nexus.[104] Specifically, these models show how climate change creates cumulative impacts that intersect with pre-existing community inequities.[105] When climate change impacts an at-risk community, the lack of financial resources drastically magnifies the damage and risk; furthermore, these communities often experience the greatest levels of vulnerability despite having contributed least to global greenhouse gas emissions.[106] This baseline at-risk susceptibility is starkly evident in New Mexico, which currently has the 3rd highest poverty rate in the nation and according to the 2023 "kids count data book" New Mexico ranks low in child well-being, poverty, and family economic security.[107]

Human health

In New Mexico, the health effects of climate change are both widespread and complex, as more frequent and intense extreme heat, drought, flooding, and wildfires increasingly undermine the physical health of residents throughout the Southwest.[108] The immediate health threats from extreme events include bodily harm, development or exacerbation of acute and chronic health issues and even death, mental health impacts from trauma and displacement; as well as job loss compromising access to healthy food, secure housing, education and medical care.[109] These

[104] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[105] Ibid.
[106] Ibid.
[107] Clara Bates, Source NM, *National report again ranks New Mexico last in child well-being*, https://sourcenm.com/2025/06/09/national-report-again-ranks-new-mexico-last-in-child-well-being/.
[108] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[109] EPA (2023). *Climate Change and Children's Health and Well-Being in the United States*. U.S. EPA. 430-R-23-001, at 58, available at https://www.epa.gov/system/files/documents/2023-04/CLiME_Final%20Report.pdf.

health impacts are exacerbated among individuals who are particularly vulnerable to climate change, including older adults, outdoor workers, and low-income populations.[110]

For example, one flood event (exacerbated by the natural phenomena described in a previous section) can transport debris, chemicals, fertilizer, bacteria from agricultural runoff and sewers, as well as overwhelmed storm systems and other contaminants that are harmful to humans.[111] Flood waters can disrupt access to drinking water and reduce its quality, in addition to disrupting access to health care due to blocked roads or damaged healthcare facilities.[112,113]

Heat is another health hazard and is already the leading weather-related cause of death in the United States and is expected to increase with climate change.[114,115] The adverse effects of heat can exacerbate pre-existing health conditions related to cardiovascular and respiratory diseases, diabetes, adverse pregnancy and birth outcomes, and increase emergency room visits and hospitalizations.[116] Farmworkers are more at risk of heat stress and death than other U.S.

[110] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[111] Payton, E. A., et al. (2023). Chapter 4. Water. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, p. 4-17, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[112] Hurd, B.H. and Coonrod, J. (2008). *Climate Change and Its Implications for New Mexico's Water Resources and Economic Opportunities*. Technical Report 45, NM State University, College of Agriculture and Home Economics, Cooperative Extension Service, Agricultural Experiment Station, available at https://pubs.nmsu.edu/research/economics/TR45.pdf.
[113] Hayden, M. H., et al. (2023). Chapter 15. Human Health. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, p. 15-17, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[114] National Weather Service, *Weather Related Fatality and Injury Statistics*, https://www.weather.gov/hazstat.
[115] WildEarth Guardians (2025). *The 2025 New Mexico Spill Report Land, Air, &Water Pollution from Oil & Gas*, available at https://pdf.wildearthguardians.org/site/DocServer/WildEarth-Guardians-annual-spill-report-2025.pdf.
[116] Ibid.

workers; the number of unsafe working days for farmworkers due to heat is projected to double by the middle of the century.[117]

Water and Food security

Climate change in New Mexico is a combined crisis that affects water security, food production, infrastructure, and community well-being. The interaction of drought, heat, and extreme rainfall creates a cycle of stress that threatens both agricultural systems and the people who depend on them.[118] The State is especially vulnerable to climate change because it is already an arid region, so anything that interferes with the ability to rely on systems that make life sustainable in this region is detrimental to the well-being of all living things that depend on that natural cycle reliability.[119]

However, the impacts on food and water security are not experienced equally. Many communities in the State with the least resources are at most risk. This includes any communities that rely on subsistence farming, grazing and local water acquisition, food sovereignty, New Mexico traditional culture and indigenous traditional knowledge systems.[120] Traditional food practices include acequia irrigation systems: *"Pueblo and Hispanic farming communities have maintained acequia-based irrigation systems for centuries, shaping a land-based culture that links agricultural practice to identity, heritage, and stewardship."*[121] **NMED Exhibit 14r**. In

[117] Bolster, C.H., et al. (2023). Chapter. 11. Agriculture, food systems, and rural communities. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, p. 11-16, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[118] White, D.D., et al. (2023). Chapter 28. Southwest. In: *Fifth National Climate Assessment*. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA, available at https://toolkit.climate.gov/NCA5_2023_FullReport.
[119] Ibid.
[120] Office of the Governor of the State of New Mexico, *50-Year Water Action Plan*, available at https://www.nm.gov/wp-content/uploads/2024/01/New-Mexico-50-Year-WaterAction-Plan.pdf.
[121] Olofinsao, O. A., Wang, J., & Berrens, R. P. (2026). A Tale of Two Irrigated Agricultures in the Middle Rio Grande Basin. *Sustainability*, *18*(7), 3191. https://doi.org/10.3390/su18073191.

addition, water rights and highly politicized access to water and water resources can create conflicts.[122] As drought intensifies, competition for water can deepen inequalities between urban users, agriculture, and rural communities.[123] ***Id.*** Low-income rural communities lack the capital required to modernize small-scale water system infrastructure that can fail due to climate-related drought or flooding. These climate threats are compounded in regions where a large portion of the population works outdoors, exposing residents to both unsafe drinking water and extreme heat.

Extreme heat poses additional challenges for livestock, particularly dairy cows, whose milk production and quality can decline under heat stress.[124] At the same time, heavier and more intense rainstorms can damage crops, erode nutrient-rich topsoil, delay planting, and disrupt farm operations, reducing the number of days farmworkers can work, and threatening agricultural livelihoods.[125]

Housing security

Overall, rising temperatures compound existing inequities, making already vulnerable communities even more susceptible to climate-related risk. As an example, the urban heat island effect, which occurs in areas of pavement and buildings (that absorb heat) with few green spaces (that provide some cooling relief), occurs more significantly in historically low-income neighborhoods. These neighborhoods that house low-income residents, older adults, and people experiencing homelessness face disproportionately higher exposure to extreme heat and its

[122] Office of the State Engineer, *Water Resource Allocation Program (WRAP)*, https://www.ose.nm.gov/WR/.
[123] Olofinsao, O. A., Wang, J., & Berrens, R. P. (2026). A Tale of Two Irrigated Agricultures in the Middle Rio Grande Basin. *Sustainability*, *18*(7), 3191. https://doi.org/10.3390/su18073191.
[124] EPA, *Extreme Heat*, https://www.epa.gov/climatechange-science/extreme-heat.
[125] EPA, E*xtreme precipitation*, https://www.epa.gov/climatechange-science/extreme-precipitation.

associated health impacts.[126] Individuals with less education, less wealth, people with limited English proficiency, and certain immigrant communities are more likely forced to live in locations that have poorly maintained infrastructure, experience extreme heat and live within floodplains or risk-prone areas.[127,128] In Albuquerque, NM, Localized Constructed Analogs (LOCA) projection models estimate that the city will experience 45 days per year over 97.0ºF by 2050, compared to 7 days above 97.0ºF in 1990.[129] Low-income areas have inefficient housing structures, making them harder to cool, hence making energy bills higher, or worse yet with some communities lacking basic electricity access.[130]

Increased fire activity often directly affects housing security. In 2024, the White House approved a Major Disaster Declaration for the South Fork and Salt Fires, which destroyed 1,400 structures, with more than 150 additional losses caused by post-fire flooding and 7 flash flood emergencies.[131,132] The collective property loss off this extreme event was estimated at $700 million dollars.[133]

[126] EPA, *What are heat islands?*, https://www.epa.gov/heatislands/what-are-heat-islands.
[127] EPA (2021). *Climate Change and Social Vulnerability in the United States: A focus on Six Impacts*. EPA 430-R-21-003, available at https://www.epa.gov/system/files/documents/2021-09/climate-vulnerability_september-2021_508.pdf.
[128] EPA, *What are heat islands?*, https://www.epa.gov/heatislands/what-are-heat-islands.
[129] ClimateCheck, *Climate Change Hazard Ratings for Albuquerque, NM*, https://climatecheck.com/newmexico/albuquerque.
[130] EPA, *Heat Islands and Equity*, https://19january2021snapshot.epa.gov/heatislands/heat-islands-and-equity_.html.
[131] EPA, *New Mexico South Fork and Salt Fires*, https://response.epa.gov/site/site_profile.aspx?site_id=16547.
[132] Energy, Minerals and Natural Resources Department, *Post Wildfire Coordination South Fork Fire – Watershed Stabilization Program*, https://storymaps.arcgis.com/stories/379dac34d69f4895b66f57feb0318614.
[133] Village of Ruidoso Emergency Management, *The South Fork and Salt Wildfire Impacts and Sequence of Events Report*, available at https://www.nmlegis.gov/handouts/ERDPC%20091124%20Item%203%20The%20South%20Fork%20&%20Salt%20Wildfire-%20Impacts%20&%20Sequence%20of%20Events%20Report.pdf.

VI. STATE ACTION TAKEN TO REDUCE METHANE EMISSIONS

The State of New Mexico has already taken significant steps to reduce methane emissions from the oil and gas sector, which the Methane Abatement Rule builds upon. In 2021, under the authority of the Oil and Gas Act, the Oil Conservation Commission adopted rules to reduce waste from venting and flaring of natural gas by operators in the oil and gas sector in New Mexico. In 2022, under the authority of the Environmental Improvement Act NMSA 74-1-5 and the Air Quality Control Act NMSA 74-2-5, the Environmental Improvement Board adopted a rule to reduce emissions of ozone precursors compounds—nitrogen oxides and volatile organic compounds—through requirements for emissions reductions of the chemicals in equipment and process of oil and gas operations and mandates for leak detection and repair. The Methane Waste Rules reduce methane emissions directly through prohibitions on venting and flaring of natural gas (19.15.27 and 19.15.28 NMAC). The Ozone Precursor Rule, 20.2.50 NMAC, reduces methane emissions indirectly through requirements to reduce the emission of volatile organic compounds and through mandates to conduct routine leak detection and repair.

The Methane Waste Rules effective May 25, 2021, aim to reduce waste of natural gas through elimination of routine natural gas venting and flaring.[134,135] Implementation of the rules proceeded in two phases. Phase 1 initiated a robust natural gas loss reporting program. Phase 2 began in 2022 and established enforceable targets for operators to reduce natural gas waste starting from the level of natural gas waste identified in Phase 1. This phase required operators to reduce their waste by a fixed amount each year to achieve a gas capture rate of 98% by December 31, 2026. Additionally, the rule prohibits routine venting and flaring in upstream

[134] https://www.srca.nm.gov/parts/title19/19.015.0027.html
[135] https://www.srca.nm.gov/parts/title19/19.015.0028.html

(production wells and facilities) and midstream (gas gathering pipelines and boosting facilities) segments of the oil and gas sector. The rules carve out exceptions for venting and flaring where there are limited and well-defined operational reasons for these practices, including exigent safety concerns. Regulated operators are required to report all flaring and venting to the Oil Conservation Division. Venting and flaring that is authorized by the aforementioned exceptions still counts against an operator's gas capture percentage, so there is an incentive to minimize the use of these exceptions.

The Ozone Precursor Rule, 20.2.50 NMAC ("Part 50"), was promulgated in 2022 and designed to regulate the amount of nitrogen oxides ("NOx") and volatile organic compounds ("VOC") emitted from the oil and gas sector in New Mexico.[136] By reducing the amount of NOx and VOC being emitted, this rule directly reduces the atmospheric ozone concentration by preventing these compounds, known as ozone precursors, from reacting with ultraviolet light in the atmosphere to form ozone. Part 50 contains provisions for multiple categories of emissions units, and outlines emissions standards for new and existing emissions units. While compliance with several of the provisions was required upon promulgation, implementation of the provisions that set new emissions standards was strategically designed in a different manner. All new units that were installed and became operational after Part 50 became effective were required to comply with their respective emissions standards upon startup. Owners or operators are required to systematically phase existing units into compliance with the new emissions standards based on a staged timeline, divided into three waves, that varies based on what type of emissions unit is being regulated. Full compliance with all the provisions in Part 50 is scheduled for January 1,

[136] https://www.srca.nm.gov/parts/title20/20.002.0050.html

2030, when owners or operators are required to replace a required number of existing pneumatic controllers and pumps that are subject to the rule with non-emitting units.

The emissions standards contained in Part 50 provide the Department with the ability to systematically reduce VOC emissions over time, but routine operation of emissions units is not the main source of VOCs and, by extension, ozone. Leaks from defective, worn out, broken, or otherwise compromised components are a very large source of VOC emissions in the oil and gas sector. As such, Part 50 sought to address this problem by requiring all owners or operators to conduct regular leak detection and repair (LDAR) inspections to prevent these sorts of issues from going unnoticed for long periods of time. If a leak or leaks are detected during a routine inspection, the owner or operator would then become responsible for having the leak or leaks repaired pursuant to the requirements of the Rule. This rule is only regulating emissions units that are in New Mexico counties where ambient ozone concentrations are measured to exceed 95% of the National Ambient Air Quality Standards.

These rules have been effective at reducing methane emissions from the oil and gas sector in New Mexico. Satellite observations of methane emissions in 2024-2025 show that New Mexico's methane rules cut oil and gas facility methane emissions in the Permian Basin by half compared to neighboring Texas.[137] The results show a significant difference in methane intensity—a ratio of emitted methane divided by output of natural gas product—between the New Mexico and Texas sub-basins of the Permian Basin despite a greater increase in oil and gas production in the New Mexico sub-basin since 2020—approximately 20% growth in Texas and more than 100% growth in New Mexico. The methane captured in New Mexico was valued at

[137] https://www.governor.state.nm.us/2025/09/22/new-mexico-methane-rules-slash-emissions-by-half-compared-to-texas-reductions-generate-152m-for-new-mexico/

$125 million in additional natural gas production and $27 million in tax and royalty revenue, which supports ongoing economic opportunity for the state of New Mexico.[138]

VII. OVERVIEW AND STATUS OF FEDERAL RULE

Recognizing the threat posed by climate change, the contribution made to cumulative national emissions by the oil and gas sector, and the need to take immediate action to reduce emissions, and acting under the authority of the Clean Air Act, the EPA promulgated *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* on March 8, 2024. 89 FR 17043. This rule is codified in the Code of Federal Regulations ("CFR") at Title 40, Chapter 1, Subchapter C, Part 60, Subparts OOOOb and OOOOc.[139,140]

OOOOb and OOOOc were developed based on years of technical research by the EPA and represent the best practice emission reduction measures aimed to maximally reduce emissions while still being technologically and financially feasible for the regulated sector. It is important to note that the EPA studied New Mexico's Ozone Precursor Rule and Methane Waste Rules when drafting OOOOb and OOOOc. Because New Mexico took steps to regulate this sector before the federal government did, many parts of the federal rule parallel New Mexico's rules. The areas in which there is no overlap between the federal rule and state rules will be explained in the next section, which provides an overarching justification for the proposed rule.

OOOOb and OOOOc contain the provisions responsible for regulating the complex landscape of emissions units that can be found in the oil and gas sector. This includes best

[138] Ibid.
[139] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOb
[140] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOc

practices, emissions standards, emissions guidelines, repair requirements, and recordkeeping and reporting for an extensive list of equipment. As mentioned above, New Mexico has already taken large steps in regulating VOC and methane emissions from equipment located in the oil and gas sector, and OOOOb and OOOOc were largely based on the regulatory processes that are contained in Part 50 and the Methane Waste Rules. OOOOb and OOOOc both took the framework that had been established in the state level rules one step further by having more stringent requirements for emissions reductions and reducing the number of exceptions present in some areas of the state rules.

For pieces of equipment such as process controllers, Part 50 requires compliance with new emissions standards or replacement with zero-emissions units for a large percentage of existing units and requires all new facilities to comply with the emissions requirements upon startup. For example, owners or operators are required to replace between 80% and 98% of the existing natural gas-driven process controllers (also referred to as pneumatic controllers) and pneumatic pumps at their facilities by January 1, 2030, with zero-emissions units, and facilities that were constructed on or after the effective date of Part 50 were required to comply with the zero-emissions requirement upon startup. OOOOc strengthens these requirements by requiring 100% of existing process controllers be replaced with zero-emissions units, thus creating a regulatory gap between the more stringent 100% replacement requirement and the existing state rules that only require between 80% and 98% replacement of these units. As described in the technical testimony of Mr. Ken Miller, proposed Part 51 would close this regulatory gap by requiring 100% of the existing process controllers present in the oil and gas sector to be replaced with zero-emissions units by January 1, 2031.

The federal rule also established a Super-Emitter Program to be administered by the EPA. The EPA proposed this program to complement other provisions of OOOOb and OOOOc that address methane leaks. The Super-Emitter Program addresses the widespread problem of abnormally large emissions events, known as super-emitter events, which emit large quantities of methane. The EPA reviewed recent scientific studies, which "indicate that a small portion of sources contribute almost 50 percent of the methane emissions in the oil and gas sector, and on a global scale, the largest of these emissions sources may represent as much as 12 percent of global methane emissions from oil and gas production."[141] As the EPA states in the final rule, "this program is designed to provide a transparent, reliable, and efficient mechanism by which the EPA will provide owners and operators with timely notifications of super-emitter emissions data collected by the EPA-certified third parties using the EPA-approved remote sensing technologies (*e.g.*, satellites)."[142] This program is intended to complement routine leak detection and monitoring (LDAR) requirements by creating a mechanism to help identify super-emitter events, which are unpredictable, and then regulatorily compel their investigation and repair. A Super-Emitter Program obviates the possibility that a large leak could go undetected for the period that spans the LDAR requirements, which vary across types and location of oil and gas infrastructure, but which at the maximum are annual requirements. A large super-emitter event that goes undetected for a year results in a huge amount of methane emissions; this is precisely what the federal Super-Emitter Program was designed to avert by provisioning a secondary regulatory mechanism that functions as a backstop to other requirements of the rule.

[141] https://www.federalregister.gov/d/2024-00366/page-16877
[142] https://www.federalregister.gov/d/2024-00366/page-16877

The mechanics of the federal Super-Emitter Program are relatively straightforward given that the EPA took on the responsibility of program administration rather than delegating this responsibility to states. Lacking its own capacity to conduct remote-sensing of methane, the EPA would invite applications from entities using approved remote-sensing technologies (aerial and satellite), vet these applications using a pre-established framework, and certify approved entities as Third-Party Notifiers. Certified Third-Party Notifiers would then continuously monitor the United States for super-emitter events, which the EPA defines as any large methane leak that has an emissions rate greater than or equal to 100 kilograms per hour. A certified Third-Party Notifier that detects a super-emitter event is required to send a notification to the EPA within 15 calendar days with information such as the date the super-emitter event was detected, the location, calculated emissions rate, and identification of any owners or operators of any oil and gas facility that is located within 50 meters of the super-emitter event. Upon receipt of a super-emitter event notification from a certified Third-Party Notifier, the EPA would be responsible for reviewing the notification for accuracy and completeness. The EPA has five calendar days to complete a review of the information contained in the super-emitter event notification to determine if the data are accurate and complete. If they determine the information is sufficiently supported, an identification number would then be assigned to the super-emitter event, and the EPA would send the notification to the owners or operators identified by the certified Third-Party Notifier.

An owner or operator who receives a notification of a super-emitter event from the EPA is required to conduct an investigation to identify potential source(s) of the super-emitter event. This investigation must be initiated within five calendar days of receiving the notification and completed within 15 calendar days. The express purpose of this investigation is to identify any

potential source or sources of emissions that created the super-emitter event. Owners or operators are first required to confirm that their facility is located within 50 meters of the super-emitter event; if so, they continue with the investigation, and if not, they record this in a report that is then submitted to the EPA as a conclusion to the investigatory process. The investigation consists of items such as regular maintenance schedules, operations reports, and physically screening the facility for leaks if review of the operations and maintenance documents do not identify a potential source of the super-emitter event. Once the source of the super-emitter event is identified during the facility screening, the owner or operator is then responsible for repairing the components that are responsible for the super-emitter event. The findings of the investigation along with any repair procedures undertaken, or reason that the repair was delayed, are then compiled into a report that is submitted to the EPA for review. If a situation arises where a super-emitter event is ongoing at the time of the report being submitted, the owner or operator must update the initial report with the exact super-emitter event end date and time within 5 business days of the event's successful repair.

The EPA has signaled to state environmental regulatory agencies that additional revisions to the rule are forthcoming.[143] It is possible that the federal rule will be significantly amended such that methane emission reductions projected to be achieved by the rule are greatly reduced or the federal rule may be rescinded altogether. Should this occur, the onus will be on states to reduce methane emissions from the oil and gas sector using their state-level regulatory authority.

[143] EPA released a pre-publication version of a proposed rule amending OOOOb and OOOOc on the evening of October 27, 2026. *See* Additional Reconsideration Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Proposed rule (Pre-publication version signed by EPA Administrator Lee Zeldin on October 27, 2026), available at https://www.epa.gov/system/files/documents/2026-10/san-12726-ong-reconsideration-2-nprm-preamble-20261015-clean.admin_disclaimer.pdf. The Department has not yet evaluated the proposed rule, which must be published in the Federal Register and go through notice and comment rulemaking prior to adoption.

Because the oil and gas sector in New Mexico constitutes nearly half of the greenhouse gas emissions in the state, New Mexico is proposing a rule that closes the gap between state rules that already achieve the reductions projected by compliance with OOOOc and the areas in which state rules fall short of OOOOc. In other words, New Mexico is building on the regulatory framework of the Methane Waste Rules and the Ozone Precursor Rule by proposing to establish a state Super-Emitter Program and requiring 100% zero-emitting process controllers. In the absence of an effective federal framework, New Mexico must rely on State authority and implementation of its own rules to significantly reduce methane emissions.

VIII. BUILDING ON EXISTING STATE RULES

As discussed above, the Methane Waste Rules and the Ozone Precursor Rule have shown success at abating methane emissions. However, additional action for the state will benefit not only the people, ecosystems, and economy of New Mexico, but produce savings for operators in the oil and gas sector. The Methane Waste Rules have reduced emissions directly through prohibition of routine methane venting and flaring, which could be the source of large methane emission events. But the rule is limited to emissions from venting and flaring. The Ozone Precursor Rule indirectly reduces methane emissions through regulation of VOC emissions and requires routine leak detection and repair (LDAR), which can catch leaks that cause large methane emission events. However, the LDAR required is not frequent enough to catch large leaks in a timely manner, so large leaks could go undetected and the leak unrepaired for up to the interval required by the rule for LDAR—three months in most cases and up to a year in some cases. Because large methane leaks can emit metric tons of methane into the atmosphere if undetected, it is imperative that the State act to close this regulatory gap by instituting a Super-Emitter Program to continuously monitor for large leaks and require timely investigation and

repair. Finally, the Ozone Precursor Rule requires transition to non-emitting process controllers, but these requirements fall short of 100%. The proposed Methane Abatement Rule extends the process controller requirements of the Ozone Precursor Rule to 100% non-emitting to completely abate emissions from this segment of oil and gas infrastructure, which has historically been a significant source of methane emissions in the state.

IX. IMPLEMENTATION

Prior to the development of the Methane Abatement Rule, the Compliance & Enforcement Division of the Department engaged in some limited projects in response to OOOOb and OOOOc. Since 2022, EPCEB has been receiving reports of potential releases of VOC from the non-profit organization Earthworks, in the form of complaints submitted through the public complaints portal and, on occasion, through direct email to the complaints program supervisor. These complaints are investigated according to standard complaint procedures. At this time there have not been any enforcement cases generated from these investigations.

EPCEB conducted a pilot project in FY 2026 which used latitude and longitude from super emitter reports and automation to match facilities with air permits to super emitter events with data from Carbon Mapper, which displays information on methane releases based on data gathered via satellite. Credible evidence letters, which requested facility response and confirmation of correct leak attribution, were generated with automation tools and sent to the active contact listed for the facility. The facilities that the Department reached out to responded that they did act on any equipment leaks in a timely manner or attributed responsibility for the leak to pipeline operations. The Department found no information to indicate otherwise.

A lesson learned from the Credible Evidence letter pilot project was that having accurate operator contact information for facilities is a critical part of appropriate response and will be critical to the success of the Methane Abatement Rule implementation. Companies must keep their contact information updated, pursuant to permit conditions and regulatory requirements contained in 20.2.70.404A(2) NMAC for Title V facilities, 20.2.72.212C NMAC for minor source facilities, and 20.2.73.200E(3) NMAC for NOI designated facilities.

Because the Department does not currently have a methane standard which allows for limits in permits, a super-emitter event does not in and of itself represent a violation of a permit condition or a state rule. However, releases of methane are always accompanied by releases of other gases which may be regulated by permitted limits. Companies have a duty to calculate any other regulated pollutants and submit an excess emissions report whenever amounts exceed permitted limits, pursuant to 20.2.7 NMAC.

The Department does intend to enforce on, to the best of its ability, owners or operators that do not keep their contact information and ownership status up to date, pursuant to permit conditions and the various permitting regulations. In addition, failure to respond to Department notifications as required in this rule will be considered violations of the rule unless approval from the Compliance & Enforcement Division has been documented and only for circumstances beyond the owner or operator's control. (This does not include failure to update contact information or failure to notify the Department of ownership changes.)

Implementation of any rule, including the Methane Abatement Rule (especially the Super Emitter Program) requires Department Resources to implement. The Department is willing to procure the resources necessary to provide timely notification to industry as a service for facility owners due to the significant methane reductions that can be achieved through this program.

EPCEB is currently taking steps to create positions which will be dedicated to implementation of this proposed rule and further implementation of Part 50. In other words, the Department is invested in the success of this proposed rule.

X. STAKEHOLDER ENGAGEMENT AND OUTREACH

As described above, methane is an ongoing and well researched source of air pollution in New Mexico. The Department performed an analysis of existing state rules in comparison to the requirements contained in OOOOb and OOOOc. This analysis uncovered regulatory gaps between the existing state rules and the federal requirements. To address these gaps, the Department determined a new rule designed to directly regulate methane emissions as appropriate, necessary, and reasonable for New Mexico. The Department further determined that the most appropriate place to begin was through establishment of the super-emitter program and zero-methane emission requirements for process controllers, given the amount of methane being emitted from each of these source categories.

Proposed Part 51 represents the Department's prioritization of methane as a pollutant causing harm to the environment and to the health and welfare of those residing in the State. The proposed rule closes regulatory gaps and is grounded by the extensive research and sound science presented in my testimony and the testimony of the other two technical witnesses for the Department, and was drafted with significant consideration to not only the need to protect the environment and health of the people of New Mexico, but also with direct input and significant communication with representatives from the regulated community, environmental non-governmental organizations, and individuals. As mentioned earlier, the EPA took several points of inspiration from New Mexico's existing rule – Part 50 – when drafting OOOOb and OOOOc, then strengthened requirements in some areas. The Department took a similar approach when

developing proposed rule 20.2.51 NMAC by starting with provisions that are contained in the OOOOb and OOOOc requirements and using them as a framework on which to base the provisions that are now contained in Proposed Part 51. As Dr. Jessica Hejny will discuss in her testimony, the Department performed an extensive analysis of the documented methane emissions from super-emitter events which led the Department to make some targeted deviations from the federal framework in the proposed rule. As Mr. Ken Miller will discuss in his testimony, the Department largely based the provisions related to emissions standards for process controllers on the federal requirements that are found in the OOOOc model rule. As drafted, the proposed rule contains the provisions necessary to establish and implement both of these programs.

The Department provided both formal and informal opportunities for interested stakeholders to submit comments, request meetings, or ask clarifying questions on the proposed rule. As a matter of policy, all outreach communications from the Department are distributed in English and Spanish, as are all publications submitted to newspapers, posted online, or otherwise made publicly available. Informal meetings with stakeholders have been occurring throughout the rule development and rulemaking process.

Outreach began with a stakeholder comment period to solicit feedback and engage with interested parties prior to filing a petition to the Environmental Improvement Board. This comment period started with an announcement sent via a listserv on July 16, 2026. **NMED Exhibit 15**. This announcement contained a link to the Air Quality Bureau's Proposed Regulations website, which had been updated with the stakeholder review draft of the rule along with a summary, and solicited public comments from all recipients who were interested in making them. **NMED Exhibit 16**. This informal public comment period ended on July 29, 2026.

During this comment period, the Department received requests to meet with representatives from Oxy USA, Inc, along with a request to meet with representatives from the New Mexico Oil and Gas Association ("NMOGA"). The Department met with Oxy USA, Inc. and NMOGA representatives individually at their requests on August 6, 2026. Additional meetings or phone conversations were ongoing throughout the rule development. The Department presented the draft rule and answered questions at a NMOGA membership meeting on July 28, 2026. The Department held further informal conversations with NMOGA following this meeting. During these meetings, industry representatives asked numerous questions related to specific aspects of the stakeholder review draft that these parties were interested in, which the Department answered.

The Department met with members of various environmental non-government organizations ("eNGOs") on July 16, 2026, August 5, 2026, and September 21, 2026, and held informal conversations with representatives following these meetings. These meetings helped the Department understand which points these representatives were concerned about, and consider how the Department could address those concerns without undermining the effectiveness of the proposed rule.

The Department also held an informational webinar to provide an overview of the proposed rule's requirements on October 8, 2026, from 4:00 pm until 6:00 pm. that was well attended by members of the public. **NMED Exhibit 17**. After the presentation, the Department answered questions from several interested individuals and provided clarification regarding some of the rule's provisions. For example, during the conversation, the following question was raised regarding process controller emissions:

> Routing emissions to an ECD [enclosed combustion device] was an acceptable control in New Mexico's Ozone Precursor Rule, Part 50. But, as proposed, in Part 51, this is no longer an acceptable means of control. Can NMED provide more insight as to why routing emissions to a permitted control device is not an acceptable compliance option in this rulemaking?

The Department provided the following answer in response to this question:

> Our rule is modeled after the Federal model rule promulgated in 2024 that contained new emissions requirements for natural gas driven process controllers in addition to numerous other things. EPA provided a model rule that states could take with a minimal amount of work or modification to adopt the requirements into their own state rules. We largely used the process controller provisions from the EPA model rule, and EPA does not allow routing emissions from process controllers to control devices such as flares, for example, except in very limited circumstances. The Department believes these circumstances do not apply in New Mexico as the exceptions are for very specific types of sites in very remote locations in Alaska. The Department didn't see any reason to deviate from that and create an exception in New Mexico. New Mexico also has existing rules on the books limiting venting and flaring. The Department sees this rule as complementary to, and building on, those two existing rules that were discussed in the presentation; the Methane Waste Rule and the Ozone Precursor Rule, so these rules would all would work together to reduce or abate methane from the oil and gas sector.

The Department also held an open question and answer session on October 14, 2026, to address any questions that may have arisen after the initial presentation had concluded. The

Department was available from 4:00 pm until 6:00 pm on that date and was joined by ten other interested parties. During this session, the Department received several relevant questions. For example, one series of questions related to the data source for bar charts showing emissions reduction estimates that were provided in the presentation, and whether or not those estimates included the reductions that had already been realized from the implementation of Part 50. The Department responded, stating that these charts came from a report drafted by E3, a contractor who had been commissioned by the New Mexico Climate Change Bureau, and that the information, including the data sources and how the reductions were calculated, could be found on the Climate Change Bureau's website. The Department also received comments that commended the proposed rule. One person stated during the meeting: I just wanted to take this opportunity to say that I think that the lack of a huge turnout tonight is a reflection of the support that you've got and appreciation for the work at NMED has done in putting this rule together, the importance of the rule, and the comfort level that the NGOs, environmental NGOs have for the rule. Bravo to all of you, and I think the turnout here reflects support and comfort rather than lack of interest. The Department announced both of these meetings on its website and via a listserv email that was distributed on October 2, 2026. **NMED Exhibits 16 and 18.** The Department also posted recordings of the meetings on its website after each meeting. **NMED Exhibit 16**.

At the conclusion of the public comment period on July 29, 2026, the Department received 16 separate comment submissions from: eNGOs such as Environmental Defense Fund (EDF), Earthworks, and WildEarth Guardians; industry representatives such as the Independent Petroleum Association of New Mexico ("IPANM"), NMOGA, Permian Basin Petroleum Association ("PBPA"), ExxonMobil; and several individuals or communities such as Mom's

Clean Air Force. **NMED Exhibit 19**. The Department also received requests to meet with representatives from Oxy USA, Inc, and NMOGA to discuss comments and request clarification on the stakeholder review draft rule. The majority of these comments focused mainly on provisions where commenters felt there were points that the draft rule could be either better aligned with the federal framework, suggestions for how to make the rule more durable and robust, or providing suggestions that the Department determined were too granular or specific to be placed in the rule itself, but were appropriate to consider when developing an implementation guidance document that would accompany the rule should it be adopted. As mentioned above, the Department largely based the requirements that are contained in Proposed 20.2.51 NMAC on those that are found in the federal rule, with the exception of some aspects of the super-emitter provisions that are further discussed in the testimony of Dr. Jessica Hejny, and the removal of some exceptions that were found in the requirements for process controllers that did not apply to New Mexico. After a thorough review of the over 100 individual comments contained in these submitted documents and taking the expressed concerns raised during individual meetings under consideration, the Department chose to make several amendments to the rule in response to comments where it made sense to do so. These changes will be addressed in Section XI of my testimony.

XI. CHANGES MADE TO THE RULE IN RESPONSE TO COMMENTS

As described earlier, the Department took all of the comments and information received during public informational meetings under consideration during the rule development process. The Department determined that several comments and concerns that were raised had merit and made changes to the rule in response as reasonable and warranted. NMOGA submitted a comment that stated the federal rule allows for exemptions for process controllers that function

as emergency shutdown devices and requested that this exemption be included in the proposed rule, as they are important safety mechanisms. The Department recognizes the importance of safety mechanisms in facilities such as these and added this exemption to the rule prior to petitioning the Board. They also stated that there should be a provision stating that the Department would be required to review each notification received by third-party notifiers for accuracy and completeness, and that public postings should be updated to reflect the investigatory outcome of each of the super-emitter events for which the Department notifies an owner or operator. Again, the Department recognizes the merits behind a secondary review of all notifications that are received from certified third-party notifiers, along with ensuring that any notifications that are publicly posted be updated after receiving and verifying the report received from owners or operators that shows the outcome of a super-emitter event. The Department subsequently revised the rule to include these provisions prior to petitioning the board.

Numerous representatives from both eNGOs and industry commented, expressing concern regarding the repair timeline requirements imposed in the Super Emitter provisions of the rule, citing reasons such as site access, severe weather events, or repairs that may require specialized equipment or personnel to complete. In response to these comments along with additional information that was obtained during meetings with representatives from these and other entities in the period of time between the submittal of the petition and the date the NOI was due, the Department determined that amendments to the rule to address this concern was not only warranted, but necessary.

As described in the testimony of Dr. Jessica Hejny, super-emitter event investigatory processes and any necessary repairs were initially required to be completed within three calendar days of receiving the notification from the Department. After thorough consideration of not only

the comments that were received during the public comment period, but also information that was received during additional collaborative meetings with stakeholders, the Department determined that meeting this repair deadline could present a technical challenge in certain situations. In response, the Department has now made a substantive amendment to the proposed rule. Specifically, the Department changed the repair deadline to fifteen calendar days instead of three, to allow time to mobilize the personnel necessary to complete the investigation and repair processes for most events. **NMED Exhibit 1 at 5, Line 24; NMED Exhibit 2 at 5, Line 24**. As soon as the Department had finalized the decision to make an amendment to the repair timeline, the Department circulated a notification on October 20, 2026, describing this change to counsel representing all parties that had filed an entry of appearance in this proceeding. Although the revised proposed rule allows significantly more time to investigate and repair, the Department expects that owners or operators will repair in as timely a manner as possible given that saleable resources would otherwise be lost.

The Department made one other minor amendment to the deadline for submitting the super-emitter event report to the Department. Originally, an owner or operator had three calendar days from the date they received the super-emitter event notification from the Department to complete and submit the investigation report to the Department for review. This has now been amended to state that owners or operators must complete and submit the investigation report to the Department within five business days of completing the investigation and repairs. **NMED Exhibit 1 at 6, Lines 35-36; NMED Exhibit 2 at 6, Lines 35-36**. This recognizes that the owner or operator will need time to finalize this report after the inspection and repairs are completed. These changes are located in Section 104 and Section 105 of the proposed rule, both of which will be described in detail in the testimony of Dr. Jessica Hejny.

The Department also made several technical corrections to the proposed rule in the time between filing the petition and filing the NOI. In several places the proposed rule did not specify an entity to which reports would be sent. The revised proposed rule specifies that the reports must be submitted to the Department. **NMED Exhibit 1 at 6, Line 35, and 12, Line 16; NMED Exhibit 2 at 6, Line 35, and 12, Line 16**.

XII. PROPOSED RULE GENERAL AND NONCOMPLIANCE PROVISIONS

While the super-emitter and process controller provisions will be discussed in detail in the testimony of Dr. Jessica Hejny and Mr. Ken Miller, here I will provide an overview of the general and "noncompliance" provisions of the proposed rule along with a summary of what those provisions entail.

20.2.51.1 – Issuing Agency

The Environmental Improvement Board is the issuing agency pursuant to the Air Quality Control Act. **NMED Exhibit 1 at 1, Line 5**.

20.2.51.2 – Scope

This section specifies to whom the rule applies. Part 51 applies to all persons who own or operate a source located within 50 meters of a super-emitter event detected by a certified third-party notifier to whom a super-emitter event notification is provided by the Department, and all persons who own or operate a process-controller designated facility in areas of the State for which the Department has jurisdiction. Although the main justification for this rule focuses on the oil & gas industry, other facility types (e.g., landfills with a gas collection system) could hypothetically also have a super-emitter event recorded by a notifier. Therefore, the rule applies to any type of facility, not just oil & gas-related facilities. **NMED Exhibit 1 at 1, Lines 8-10**.

20.2.51.3 – Statutory Authority

This section explains the Board's authority to adopt the rule. The Board is authorized to adopt Part 51 pursuant to the New Mexico Environmental Improvement Act, Sections 74-1-1 to 74-1-18 NMSA 1978, including specifically Paragraph (4) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-17 NMSA 1978, including specifically Subsection B and Paragraph (6) of Subsection D of Section 74-2-5 NMSA 1978. **NMED Exhibit 1 at 1, Lines 13-16**.

20.2.51.4 – Duration

This section defines how long the rule remains in effect. Part 51 will be permanently in effect from the effective date provided in the rule. **NMED Exhibit 1 at 1, Line 19**.

20.2.51.5 – Effective Date

This section establishes the date on which the rule becomes effective. Pursuant to the State Rules Act, a rule becomes effective on the date it is published in the New Mexico Register, unless a later date is provided by law or in the rule. If adopted, Part 51 will become effective upon publication of the rule in the New Mexico Register. **NMED Exhibit 1 at 1, Line 22**.

20.2.51.6 – Objective

This section identifies the purpose of the rule. The stated objective of Part 51 is to establish a methane super-emitter program and methane standards for process controller designated facilities. **NMED Exhibit 1 at 1, Lines 26-27**.

20.2.51.7 – Definitions

Subsections A through Y define the terms as used in the rule. These definitions include:

- A – Closed vent system
- B – Date of detection
- C – Deviation
- D – Emergency shutdown device
- E – Gathering and boosting station
- F – Injection well site
- G – kg/hr
- H – Natural gas-driven process controller
- I – Natural gas processing plant
- J – No identifiable emissions
- K – Operator
- L – Optical gas imaging or OGI
- M – Owner
- N – Process controller
- O – Process controller designated facility
- P – Produced water
- Q – Qualified professional engineer
- R – Routed to a process or Route to a process
- S – Self-contained natural gas-driven process controller
- T – Source
- U – Super-emitter event
- V – Third-party notifier
- W – Tank battery

- X – Transmission compressor station
- Y – Well site **NMED Exhibit 1, p. 1, Lines 30-56, p. 2, Lines 1-52.**

20.2.51.8 – Severability

This section states that if any provision of the rule – or its application to any person or circumstance – is held invalid, the remainder of the rule shall not be affected. **NMED Exhibit 1 at 3, Lines 1-3**.

20.2.51.9 – Construction

This section states that the rule shall be liberally construed to carry out its purpose. **NMED Exhibit 1 at 3, Line 6**.

20.2.51.10 – Savings Clause

This section states that repeal or supersession of prior versions of the rule shall not affect administrative or judicial action initiated under those prior versions. **NMED Exhibit 1 at 3, Lines 9-10**.

20.2.51.11 – Compliance with Other Regulations

This section states that compliance with the rule does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules, or regulations. **NMED Exhibit 1 at 3, Lines 13-15**.

20.2.51.12 – Documents

This section specifies where documents incorporated and cited in the rule may be viewed. **NMED Exhibit 1 at 3, Lines 18-20**.

20.2.51.301 – Noncompliance

This section holds two subsections that identify potential avenues the Department may choose to lever against entities who are found to be out of compliance with any of the provisions of the proposed rule. **NMED Exhibit 1 at 14, Lines 31-35**.

Finally, the provisions that are related to the super-emitter response program and the process controller emissions standards are contained in Sections 101 through 207 of the proposed rule. As mentioned earlier in this section, these Sections will be discussed in detail in the testimonies of Dr. Jessica Hejny, marked as **NMED Exhibit 7**, and Mr. Ken Miller, marked as **NMED Exhibit 8**.

XIII. LEGAL PUBLIC NOTICE REQUIREMENTS

Pursuant to the public notice requirements in Subsection E of Section 14-4-2, *Provide to the Public*, NMSA 1978 (2017); Section 14-4-5.2, *Notice of Proposed Rulemaking*, NMSA 1978 (2017); Section 14-4-5.3, *Public Participation, Comments and Rule Hearings*, NMSA 1978 (2017); Subsection N of 20.1.1.7 NMAC, *Provide to The Public*; 20.1.1.301 NMAC, *Notice of Hearings*; and 1.24.15.9 NMAC, *Requirements For Notices*, NMED prepared, published, posted and distributed the "New Mexico Environmental Improvement Board Notice of Rulemaking Hearing to Consider the Adoption of Proposed New Rule 20.2.51 NMAC – *Methane Abatement*, EIB 26-78 (R)" ("Public Notice") in both English and Spanish. **NMED Exhibits 20 and 21**. The Department described in the Public Notice all of the statute-required and rule-required information about the rulemaking matter and rule-making process, thus complying with Subsection E of Section 14-4-2, NMSA 1978 (2017); Section 14-4-5.2, NMSA 1978 (2017); Section 14-4-5.3, NMSA 1978 (2017); Subsection N of 20.1.1.7 NMAC; 20.1.1.301 NMAC; and

1.24.15.9 NMAC. For example, for public participation, the Public Notice contained details about how to attend the Board hearing in person or via WebEx and listed three ways to provide written public comment: 1) via a comment form posted on the Department's online Public Comment Portal;[144] 2) via e-mail to the Board Administrator's e-mail address; and 3) via physical mail delivered to the Board Administrator's postal address. The Public Notice also included the Board Administrator's telephone number in case the public had questions or comments. As of October 26, 2026, the Board Administrator has received no public comments via any of the methods described in the public notice. **NMED Exhibit 22**.

Pursuant to 20.1.1.301 NMAC, *Notice of Hearings*, the Department published the Public Notice, in both English and Spanish, in the Albuquerque Journal, Hobbs News-Sun, and Las Cruces Sun News on Sunday, September 20, 2026; the Tri-City Record on Monday, September 21, 2026; the Santa Fe New Mexican on Tuesday, September 22, 2026; the Artesia Daily Press and Carlsbad Current Argus on Wednesday, September 23, 2026; and the Roswell Daily Record on Thursday, September 24, 2026. **NMED Exhibit 23**.

The Department complied with Subsection A of Section 14-4-5.2, NMSA 1978 (2017) of the *State Rules Act* by publishing the Public Notice in the New Mexico Register, Volume XXXVII, Issue 18, on September 22, 2026. **NMED Exhibit 24**.

The Department also complied with Section 14-4A-4, *Rules Affecting Small Business*, NMSA 1978 (2005) of the *Small Business Regulatory Relief Act* by providing notice and copies of the Department's petition and proposed rules to the Small Business Regulatory Advisory

[144] The comment form was posted on the Public Comment Portal and commenting opened on or about December 24, 2026, prior to publication of the Public Notice in the New Mexico Register. A link to the comment form was included in the Public Notice.

Commission via e-mail on September 23, 2026, and October 26, 2026. **NMED Exhibit 25**. The Department has received no questions or comments from Commission members as of October 26, 2026.

Pursuant to Section 14-4-5.2, NMSA 1978; Section 14-4-5.3, NMSA 1978 (2017); and Subsection N of 20.1.1.7 NMAC, the Department 'provided to the public' notice of proposed rulemaking, which included:

1) Posting it on the Department's website. **NMED Exhibit 26**;

2) Posting it on the New Mexico Sunshine Portal. **NMED Exhibit 27**;

3) Making it available in the Department's district, field and regional offices. **NMED Exhibit 28**;

4) Sending it via e-mail on September 22, 2026, and September 29, 2026, to persons who made a written request for notice of announcements addressing the subject matter of the rulemaking proceeding and who provided an e-mail address to the board administrator. **NMED Exhibit 29**;

5) Sending it via e-mail on September 30, 2026, to the person(s) who participated in the rulemaking by filing an Entry of Appearance and providing an e-mail address to the board administrator. **NMED Exhibit 30**;

6) Sending it via postal mail on or about September 29, 2026, to persons who have provided a postal address. **NMED Exhibit 31**;

7) Sending it via e-mail on September 22, 2026, to the New Mexico Legislative Council for distribution to appropriate interim and standing legislative committees.[145] **NMED Exhibit 32**.

In furtherance of public outreach, the Department developed a Public Involvement Plan ("PIP") which was posted on AQB's webpage. **NMED Exhibit 33**. The Department developed this PIP to outline public participation opportunities and information that may be needed to participate in the methane abatement rule project. As part of the PIP, the Department committed to providing notice to:

1) Twenty-three active land grants (Abiquiu, Anton Chico, Atrisco, Cañon de Camué, Cebolleta, Chililí, Cristóbal de la Serna, Cubero, Don Fernando de Taos, Juan Bautista Baldez, Manzano, San Antonio de Las Huertas, San Antonio del Rio Colorado, San Joaquín del Rio de Chama, San Miguel del Bado, Santa Barbara, Santo Domingo de Cundiyó, Santo Tomas Apóstol del Río de Trampas, Tajiqu, Tecolote, Tierra Amarilla, Town of Tomé, and Town of Torreón), via e-mail, completed on September 22, 2026. **NMED Exhibit 34**. The Department has received no comments from land grants as of October 26, 2026.

2) Five Councils of Governments (Northwest NM COG, Mid-Region COG, Eastern Plains COG, Southwest NM COG, South Central COG) and two Economic Development Districts (North Central NM Economic Development District and Southeastern NM Economic Development District) via e-mail, completed on September 22, 2026. **NMED Exhibit 35**. The Department has received no comments from COGs or EDDs as of October 26, 2026.

[145] The Department subsequently noticed a typographical error in the Council's email address and resent the notice on September 29, 2026, to ensure delivery. The Council acknowledged receipt of the resent notice later that day.

3) Twenty-five Pueblos, Nations, and Tribes (Acoma, Cochiti, Isleta, Jemez, Laguna, Nambe, Ohkay Owingeh (San Juan), Picuris, Pojoaque, San Felipe, San Ildefonso, Sandia, Santa Ana, Santa Clara, Kewa (Santo Domingo), Taos, Tesuque, Zia, Zuni, Ysleta del Sur, Navajo Nation, Navajo Nation Council, Jicarilla Apache, Mescalero Apache, and Fort Sill Apache), via certified mail, completed on September 18, 2026, and via e-mail, completed on September 22, 2026. **NMED Exhibit 36**. The Department has received no comments from Pueblos, Nations, and Tribes as of October 26, 2026.[146]

XIV. CONCLUSION

The Environmental Improvement Act's purpose is "to create a department that will be responsible for environmental management and consumer protection in this state in order to ensure an environment that in the greatest possible measure will confer optimum health, safety, comfort and economic and social well-being on its inhabitants; will protect this generation as well as those yet unborn from health threats posed by the environment; and will maximize the economic and cultural benefits of a healthy people." **74-1-2 NMSA 1978**

The Board is charged by the EIA to protect human health and the environment and resources of the state, and by the AQCA to "Prevent or Abate Air Pollution." The Board must consider, when deliberating as to whether to adopt a regulation, "all relevant facts and circumstances presented at the public hearing, including but not limited to:

(1) character and degree of injury to or interference with health, welfare, animal and plant life, property and the environment;

[146] The Pueblo of Isleta responded to the Department's September 22, 2026, email on September 23, 2026, requesting a meeting to discuss the proposed rule. The Department requested dates and times that would work for the Pueblo, which the Pueblo's Environmental Director said she would provide after conferring with her team. However, she never followed up with the Department and the requested meeting never occurred.

(2) the public interest, including the social, economic and cultural value of the regulated activity and the social, economic and cultural effects of environmental degradation; and

(3) technical practicability, necessity for and economic reasonableness of reducing, eliminating or otherwise taking action with respect to environmental degradation.

Through its testimony today, the Department demonstrates that methane is a harmful pollutant which injures or interferes with health, welfare, animal life, property and the environment. The Department demonstrates that the Methane Abatement Rule serves the public interest. Finally, the Department demonstrates the rule is technically practicable, necessary and economically reasonable.

The severity of climate change impacts that New Mexico is already facing, and which will continue to compound as the planet warms, necessitates an immediate, robust response by the state to mitigate greenhouse gas emissions. Reducing greenhouse gas emissions from the oil and gas sector, by far the largest source of greenhouse gases in the state, is key to this effort. This proposed rule forms a part of a broader effort to reduce statewide emissions and builds on rules adopted in the last five years to reduce oil and gas sector emissions.

Therefore, the New Mexico Environment Department respectfully requests that the Environmental Improvement Board adopt the Methane Abatement Rule as submitted to the Board on October 30, 2026 to fulfill its mandate of protecting human health and the environment.

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED ADOPTION OF
20.2.51 NMAC – *METHANE ABATEMENT*

No. EIB 26-78 (R)

New Mexico Environment Department,

***Petitioner*.**

NEW MEXICO ENVIRONMENT DEPARTMENT
TECHNICAL TESTIMONY OF DR. JESSICA HEJNY

My name is Dr. Jessica Hejny; I am a Control Strategies Manager with the New Mexico Environment Department ("NMED" or "Department") Air Quality Bureau ("AQB"). I'm presenting this written technical testimony on behalf of the Department to present evidence in support of adopting proposed rule 20.2.51 NMAC, *Methane Abatement*. The purpose of my testimony is to provide the rationale for the Department's proposal of a state-level methane Super-Emitter Program and explain the components of this program.

I. QUALIFICATIONS

I have been a manager in the Control Strategies Unit since October 2024. In my position, my duties include leading the development of and rulemaking process for new state-level air quality regulations and managing the development of state plans to comply with federal rules. I hold a Bachelor of Arts degree in Politics from New York University, a Master of Arts degree in International Affairs from the School of International Service at American University, a Master of Science degree in Political Science from the University of Oregon, and a doctorate in Political Science with a focus on Environmental Policy from the University of Oregon. Before joining

NMED, I worked as a professor for 7 years and then at the Albuquerque Police Department on consent decree compliance and police reform for 3.5 years. My full background and qualifications are set forth in my résumé, which is marked as **NMED Exhibit 4**.

II. INTRODUCTION

The Environmental Improvement Board (EIB) has a legislative mandate to "prevent or abate air pollution" per the Air Quality Control Act. NMSA 1978, § 74-2-5(A). In making its rules, the environmental improvement board "shall give weight it deems appropriate to all facts and circumstances, including: (1) character and degree of injury to or interference with health, welfare, visibility and property; (2) the public interest, including the social and economic value of the sources and subjects of air contaminants; and (3) technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved." NMSA 1978, § 74-2-5(F).

Furthermore, per the Environmental Improvement Act, the role of the New Mexico Environment Department ("the Department) is to "be responsible for environmental management and consumer protection in this state in order to ensure an environment that in the greatest possible measure will confer optimum health, safety, comfort and economic and social well-being on its inhabitants; will protect this generation as well as those yet unborn from health threats posed by the environment; and will maximize the economic and cultural benefits of a healthy people." NMSA 1978, § 74-1-2. The Department has proposed this rule, and specifically the Super-Emitter Program provision that my testimony discusses, in response to this legislative mandate and in fulfillment of its statutorily-defined role.

Given the urgency of addressing climate change and the impacts of climate change on human health and the environment, scientists and researchers have turned their attention to understanding the dynamics of greenhouse gas emissions and their impacts. This literature first focused on the impacts of increased carbon dioxide emissions, but research on methane has grown in scope and importance over the past 15 years due to the short-term climate forcing impacts of methane emissions and the climate change mitigation achievable by reducing these emissions. This research has explored the sources of methane emissions, the distribution of methane emissions within sectors, and the policy implications of this empirical research. Pertinent to the present testimony, researchers have found that the oil and gas sector is one of the primary contributors to methane emissions globally and the largest emitter of methane emissions in the U.S. Research on the dynamics of methane emissions from the sector has shown that emissions emanate from both routine operations and unintentional leaks and occur across the oil and gas supply chain. Analysis of the distribution of these emissions reveals that they are skewed—a small fraction of sites produce a disproportionate amount of methane emissions, largely from unintentional leaks, many of which are very large (i.e., have a high emission rate). Because methane leaks are both a contributor to climate change and lost revenue for operators who extract and sell natural gas, there is a strong incentive to curb these unintentional emissions. Reducing large leaks—referred to as "super-emitter events"—has a double benefit of substantially reducing methane emissions by reducing the frequency of high-emitting emission events and obviating the waste of a finite resource. Because of the size of some of these leaks (which will be explored in detail in the sections below), the potential abatement is high enough to reduce statewide methane emissions. Reducing statewide methane emissions is necessary to meet the statewide greenhouse gas emission targets set in Executive Order 2019-003 and will

effectively contribute to mitigating the high short-term global warming potential of methane emissions, both of which fulfill the Department's and EIB's responsibilities to abate air pollution to protect the people, environment, and economy of New Mexico.

The Super-Emitter Program provisions of the Methane Abatement Rule are designed to achieve these ends. The proposed program is modeled on the federal Super-Emitter Program, promulgated by the Environmental Protection Agency (EPA) in federal rule, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (89 FR 17043), on March 8, 2024.[1] The framework of the program is relatively simple—for the federal rule, the EPA would certify Third-Party Notifiers to ambiently monitor methane emissions across the country and submit notification of super-emitter event detections to EPA; EPA would then notify any oil and gas operators within 50 meters of the identified super-emitter event, which would trigger a requirement for the operators to conduct an investigation to determine if their facility could be the source of the methane leak; if the operator positively identifies a leak, they are obligated to repair it; the operator would then submit a super-emitter event report to the EPA. The EPA pursued this regulatory pathway to abate methane emissions from the oil and gas sector precisely because of the copious research that has shown the abatement potential of addressing super-emitter events. The Department sees this same potential in New Mexico, and, because of the uncertainty of the status of the federal rule (EPA Administrator Zeldin announced the

[1] EPA released a pre-publication version of a proposed rule amending OOOOb and OOOOc on the evening of October 27, 2026. *See* Additional Reconsideration Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Proposed rule (Pre-publication version signed by EPA Administrator Lee Zeldin on October 27, 2026), available at https://www.epa.gov/system/files/documents/2026-10/san-12726-ong-reconsideration-2-nprm-preamble-20261015-clean.admin_disclaimer.pdf. The Department has not yet evaluated the proposed rule, which must be published in the Federal Register and go through notice and comment rulemaking prior to adoption.

forthcoming reconsideration of parts of the rule, including proposed rescission of the federal Super-Emitter Program on October 7, 2026), determined that the program was critical to the abatement of methane emissions in New Mexico such that petitioning the EIB to codify the program in state regulation was the right path forward.

Over the past year and a half, the Department has conducted extensive research to understand the distribution and impacts of methane super-emitter events in New Mexico. With the support of Carbon Mapper, which provided New Mexico-specific data to the Air Quality Bureau Control Strategies Unit for analysis, the Department analyzed six years of methane emissions plume data to understand the methane abatement potential of a state-level Super-Emitter Program. The Department concluded, based on this emissions analysis, review of the scientific literature, and analysis of the federal rule, that a program designed to identify and address large, high-emitting leaks of methane was the best regulatory path for New Mexico to reduce statewide methane emissions at this time.

This proposed rule builds on and complements existing state regulations that directly and indirectly abate methane emissions. The Methane Waste Rules (19.15.27 and 19.15.28 NMAC), which reach full implementation in December 2026, will obviate one of the potential sources of super-emitter events by prohibiting routine venting and flaring of methane at well site operations. However, it is still possible that a malfunction could cause a large-scale venting or flaring event.

The Super-Emitter Program creates the regulatory infrastructure to catch this type of unintentional event and prevent it from persisting. In this way, the Super-Emitter Program complements the regulatory goal of the Methane Waste Rules of preventing waste of finite resources that serve as a foundation of the state's natural wealth. The Super-Emitter Program would also complement the Ozone Precursor Rule (20.2.50 NMAC), which abates methane

through the regulation of volatile organic compound (VOC) emissions (of which methane is a co-pollutant, such that when VOCs are reduced, methane is also reduced) and through requirements for routine leak detection and repair (LDAR). The purpose of routine LDAR is to identify leaks of pollutants so that they can be repaired. The challenge, highlighted by research on methane emissions from the oil and gas sector, is that large leaks of methane can occur at any time, and if they are between intervals of LDAR checks, they could persist for months before being identified and repaired.

Ideally, facilities would have constant monitoring, but this is cost-prohibitive for many operators in many cases. This is where government can step in and bear some of the costs associated with pollution mitigation. In the Department's proposed Super-Emitter Program, the Department would bear the cost of monitoring, alerting facilities to potential leaks on an ongoing basis. Facilities would bear the costs of investigation and repair, but, in many cases, the value of product saved will make up for and potentially exceed these costs. This regulatory approach to methane abatement is a win-win—it obviates the loss of a finite resource that produces value for private operators in the state and state revenue through taxation, and it provides environmental benefits that safeguard the people, ecosystem, economy, and lifeways of the state. Adoption of the Methane Abatement Rule would also further position New Mexico as a national climate leader, building on the state's innovation in adopting the aforementioned rules that abate methane (on which the EPA partially based its federal rule), passing the Energy Transition Act, and addressing mobile source emissions through the Clean Cars Rules and the Clean Transportation Fuel Program.

In modeling the proposed state-level Super-Emitter Program on the federal program, the Department elected to make several changes to tailor the program to state-specific needs.

Supported by both published research on methane emissions and analysis of methane emissions in New Mexico conducted by the Department, the Department made the decision to lower the threshold that defines super-emitter events from 100 kilograms per hour (kg/hr) in the federal rule to 50 kg/hr in the proposed rule, which brings more emission events under the scope of the program and therefore will result in additional leaks identified and repaired. The emissions abated by this state-specific threshold will put the state on a firmer path to achieving the reduction mandate set in E.O. 2019-003.

Initially, the Department sought to shorten the investigation and repair deadline from the deadline in the federal rule; however, the Department, after considering input from stakeholders, made the decision to change this deadline to 15 days, matching the federal rule. Finally, because the state is not bound by the specific regulatory architecture of the Clean Air Act when adopting state-level air quality regulations, and instead uses its authority under state statute—here, the Environmental Improvement Act and the Air Quality Control Act, of which it is a part—the proposed state-level Super-Emitter Program need not be bound to only the oil and gas sector. Instead, the program's scope applies to any entity capable of producing a large-scale methane emissions event, thereby abating methane emissions in a more comprehensive way than the federal rule. Because these methane events are able to be sensed ambiently only when they are geographically concentrated and emit over a certain threshold (due to limitations of remote-sensing equipment), only specific types of infrastructure can generate them (for example, methane emissions from enteric fermentation of ruminants, or, more commonly, cattle flatulence, would not be concentrated and high-emitting enough to generate a super-emitter event). Beyond oil and gas infrastructure, other sources that may generate methane super-emitter events are methane capture systems at dairies and landfills and leaks at coal mines. However, these sources

number very few in New Mexico: the only active coal mine under the Department's jurisdiction ceased operations in 2002; there are no methane capture systems installed at dairies in the state; and there are only five landfills in the state that have methane capture systems in place that are in the Department's jurisdiction (two of which have had methane detections by Carbon Mapper in the past that exceed the 50 kg/hr threshold, according to Department analysis). Captured methane is typically combusted on site for power generation, so a leak in this system leads to losses for the facility; notification of a leak is valuable because it allows the facility to quickly repair the leak to avert issues with power supply.

In conclusion, the Department is proposing this Super-Emitter Program to the Board for consideration based on its empirically-grounded belief that abating high-emitting methane leaks provides benefits for both the entities that extract, process, distribute, and sell oil and gas and the people, ecosystems, economy, and lifeways of New Mexico for which the state bears responsibility. This rule is proposed by the Department to fulfil its statutorily mandated role in ensuring an environment that in the greatest possible measure will confer optimum health, safety, comfort and economic and social well-being on its inhabitants, protecting this generation as well as those yet unborn from health threats posed by the environment, and maximizing the economic and cultural benefits of a healthy people. NMSA 1978, § 74-1-2. The Department urges the EIB to adopt this rule to fulfil its statutory mandate, as set forth in statute, to promulgate rules and standards in the area of air quality management as provided in the Air Quality Control Act, NMSA 1978, §§ 74-2-1 to -17. NMSA 1978, § 74-1-8(A)(4).

The rest of this testimony proceeds as follows. Section III provides a comprehensive overview of the scientific literature on methane emissions from the oil and gas sector. Section IV summarizes the Department's analysis of methane emissions in New Mexico. Section V provides

an overview of the design of the proposed state-level Super-Emitter Program. Section VI provides a discussion of benefits and costs. Section VII provides a walkthrough of the relevant provisions of the rule. Finally, Section VIII provides a conclusion.

III. OVERVIEW OF METHANE EMISSIONS FROM THE OIL AND GAS SECTOR AND THE IMPORTANCE OF SUPER-EMITTER EVENTS TO AGGREGATE EMISSIONS

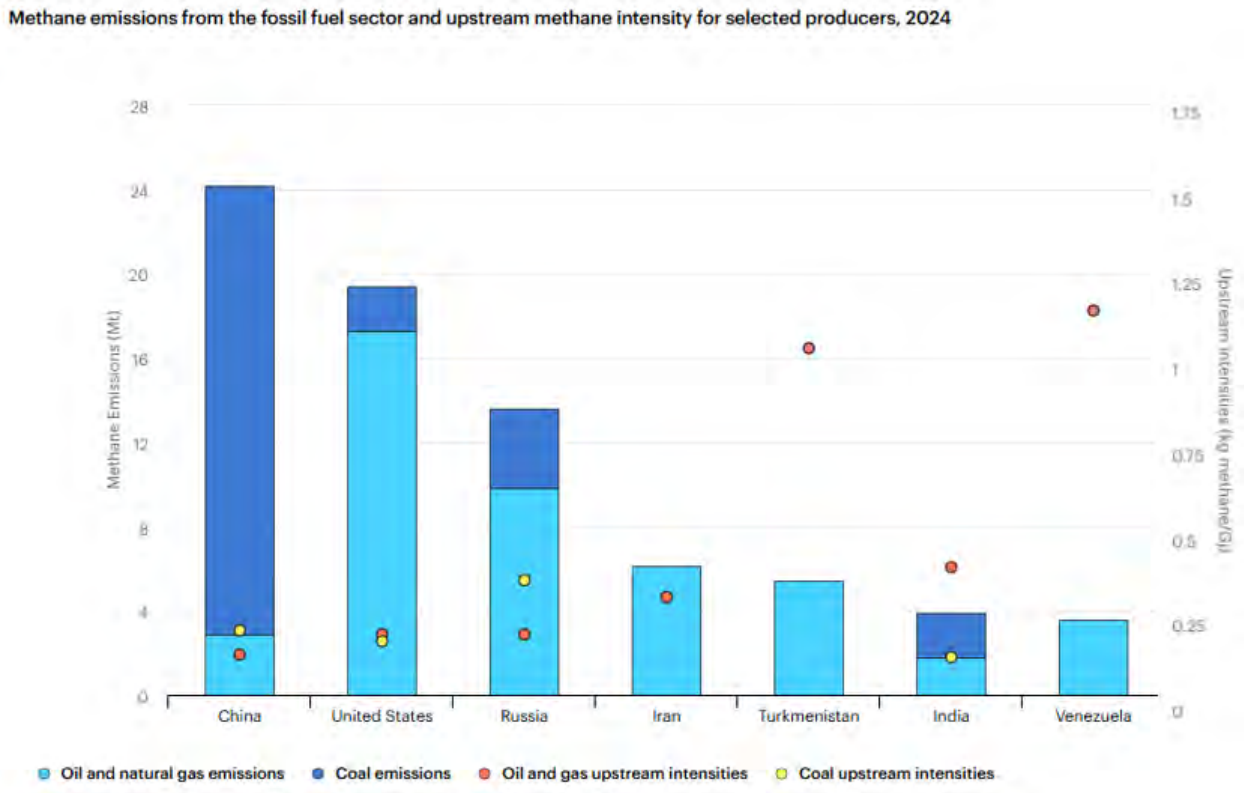
Substantial scientific research over the last 10 years has examined the impact of oil and gas sector methane emissions. This research is expansive, focusing on both domestic and international sources of methane emissions from oil and gas sectors around the globe. This analysis is in agreement that: (1) methane is a potent greenhouse gas with significantly more warming potential than carbon dioxide, particularly over short time horizons; (2) the oil and gas sector is a significant contributor to global and U.S. methane emissions; (3) there is a significant discrepancy between bottom-up and top-down estimates of methane emissions from the oil and gas sector, with geographically-focused research highlighting significant emissions from New Mexico oil- and gas-producing basins that are orders of magnitude larger than EPA estimates; (4) the distribution of emissions from the oil and gas sector does not follow a normal distribution, but rather has a "heavy tail" caused by the large impact of methane "super-emitter events"; and (5) because of the impact of these outlier emissions, there is significant abatement potential through regulation of "super-emitters." This section will discuss each of these findings in turn, with the exception of (1), which was covered in the testimony of Cindy Hollenberg.

(Finding #2) The oil and gas sector is a significant contributor to global and U.S. methane emissions.

The oil and gas sector accounts for a quarter of global methane emissions, emitting an estimated 78 million tons in 2023.[2] **NMED Exhibit 37a.** These emissions occur throughout the supply chain of the sector, from well to combustion and are the result of both intentional and unintentional releases. Emissions from leakage, venting, and incomplete combustion (mainly flaring and methane slip), account for 22%, 67.7%, and 10.3%, respectively, of global and gas methane emissions.[3] **NMED Exhibit 37a.** The U.S. is currently the largest global producer of methane emissions from the fossil fuel sector, according to the International Energy Agency (Figure 1). Domestically, emissions from the oil and gas sector make up the largest source of methane emissions at 28%, followed by enteric fermentation and landfills.[4]

[2] Lu, Hongfang, Donglai Xie, and Y. Frank Cheng. "Methane emissions from the oil and gas supply chain: Characteristics and mitigation." *Nexus* (2025).
[3] Ibid.
[4] https://www.epa.gov/natural-gas-star-program/about-methane-and-oil-and-gas-sector. All emission estimates are sourced from the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022.

Figure 1: Methane Emission from the fossil fuel sector and upstream methane intensity, 2024[5]

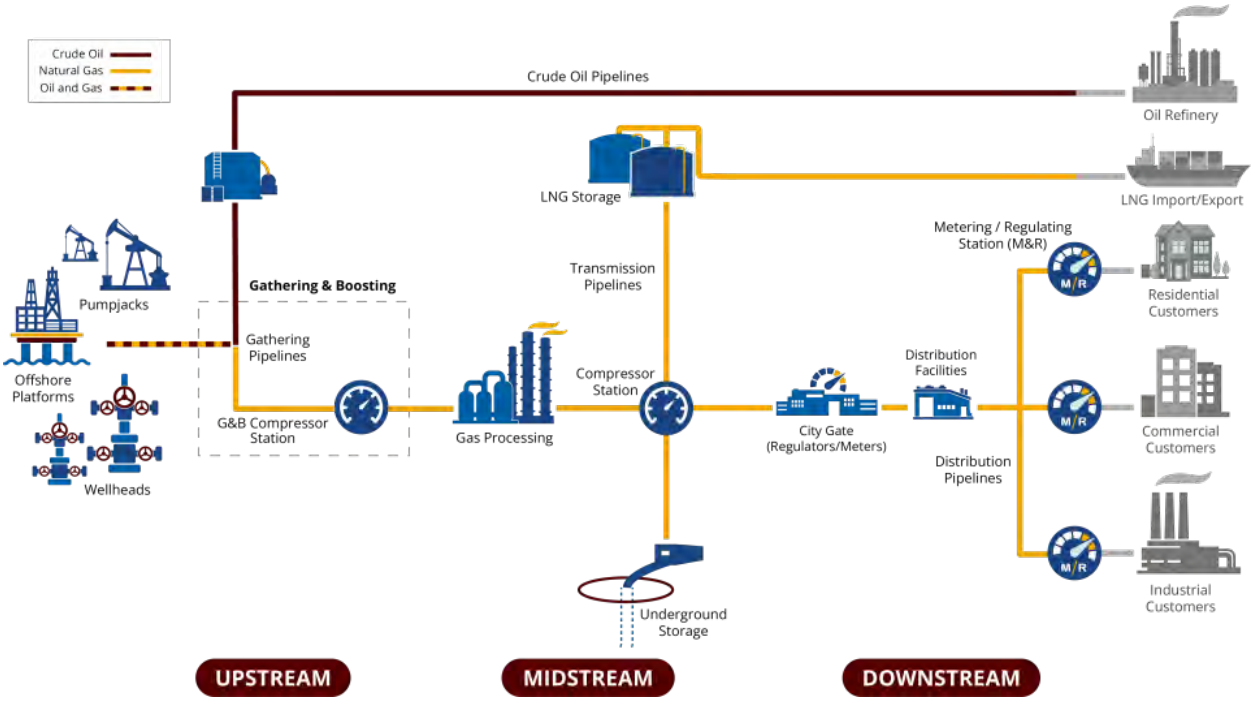


The remainder of this section will characterize methane emissions from the sector in general and then specifically in the U.S. and in New Mexico basins.

The oil and gas sector comprises a complex supply chain that spans multiple types of facilities and processes and thousands of miles from well to distribution. Below in Figure 1 is a schematic of this supply chain, showing the general steps that oil and gas go through as they travel through this supply chain.

[5] International Energy Agency, https://www.iea.org/reports/global-methane-tracker-2025/understanding-methane-emissions

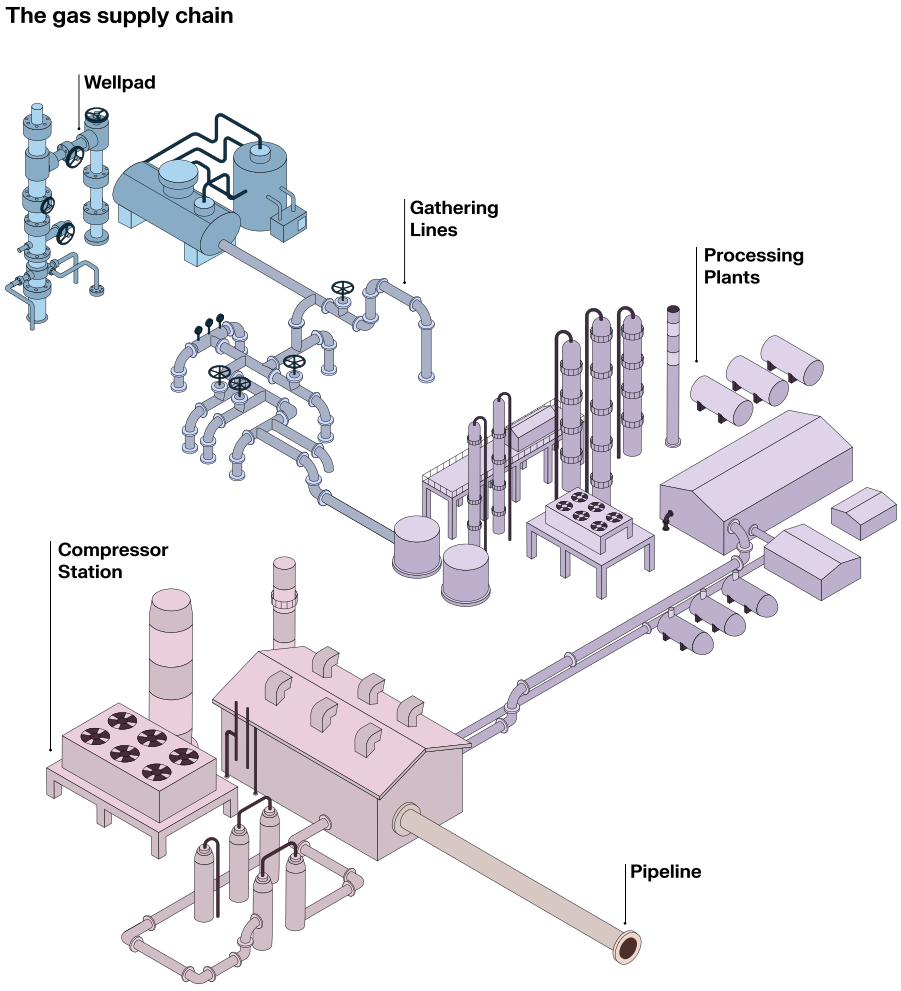
Figure 2: EPA schematic of the oil and gas supply chain[6]



Methane releases along this supply chain come from both intentional and unintentional releases (the latter are often called leaks or fugitive emissions). Routine processes in the sector generate ongoing methane emissions. Examples include liquid unloading, blowdowns, and venting from natural gas-fired process controllers. But, research has found that a significant share of methane emissions issues from unintentional releases, such as leaks caused by malfunctions, operator errors, and other non-standard functioning of equipment and processes. Examples of the latter include a thief hatch on a tank left open, a malfunctioning process controller, or a leak at a juncture between pieces of equipment. These unintentional releases can occur anywhere along the supply chain. The schematic below (Figure 3), which illustrates only the gas supply chain, though simplified, shows the many junctures and processes at which a methane leak can occur.

[6] https://www.epa.gov/natural-gas-star-program/about-methane-and-oil-and-gas-sector

Figure 3: The natural gas supply chain[7]

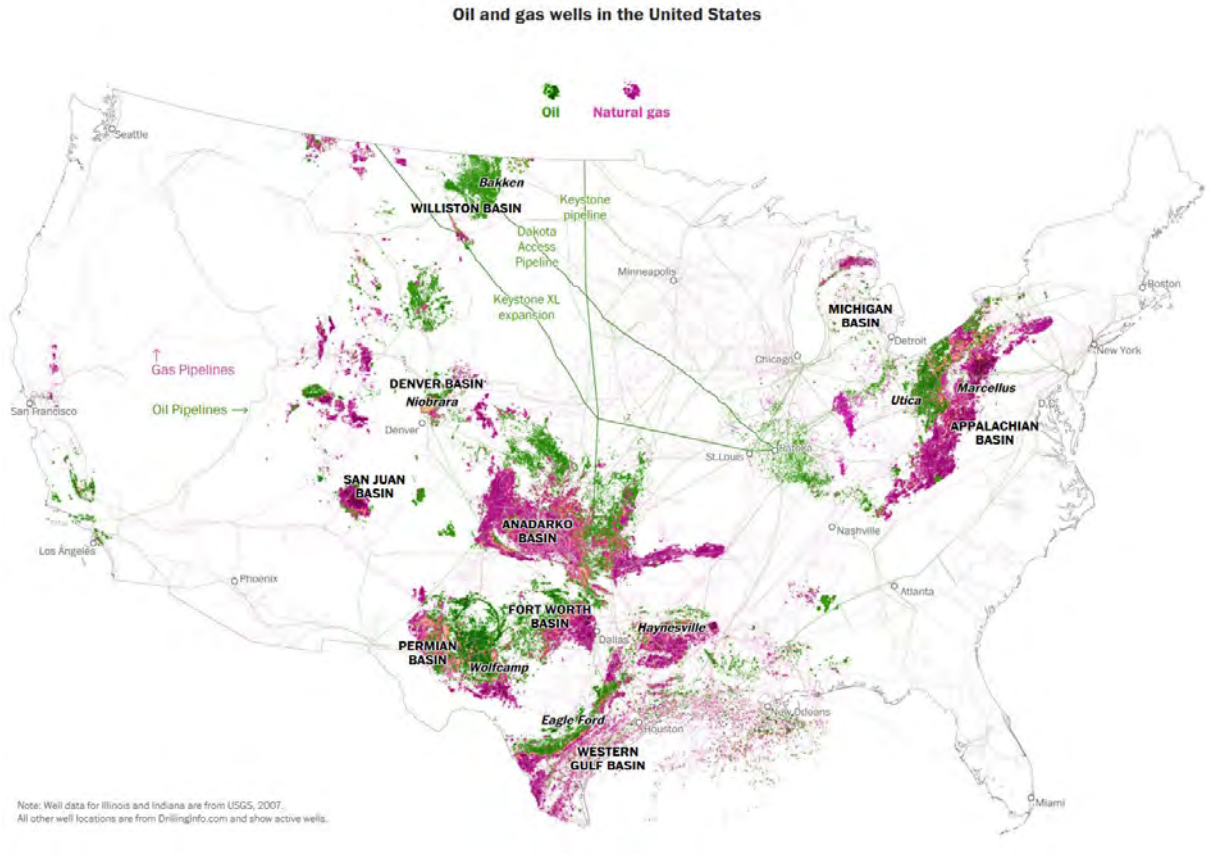


The policy solutions for abatement of methane emissions differ depending on whether the releases are routine and planned or unintentional. Elements of this proposed rule address both types—the process controller provisions address routine emissions from natural-gas fired process controllers by mandating the use of non-emitting controllers, and the Super-Emitter Program aims to abate unintentional large releases of methane.

[7] Image source: https://rmi.org/resources/unpacking-the-pipeline/

Oil and gas extraction in the U.S. follows oil and gas deposits and is therefore concentrated in specific geographic areas. The map below (Figure 4) shows the distribution of oil and gas wells in the United States, along with pipelines, in 2017.

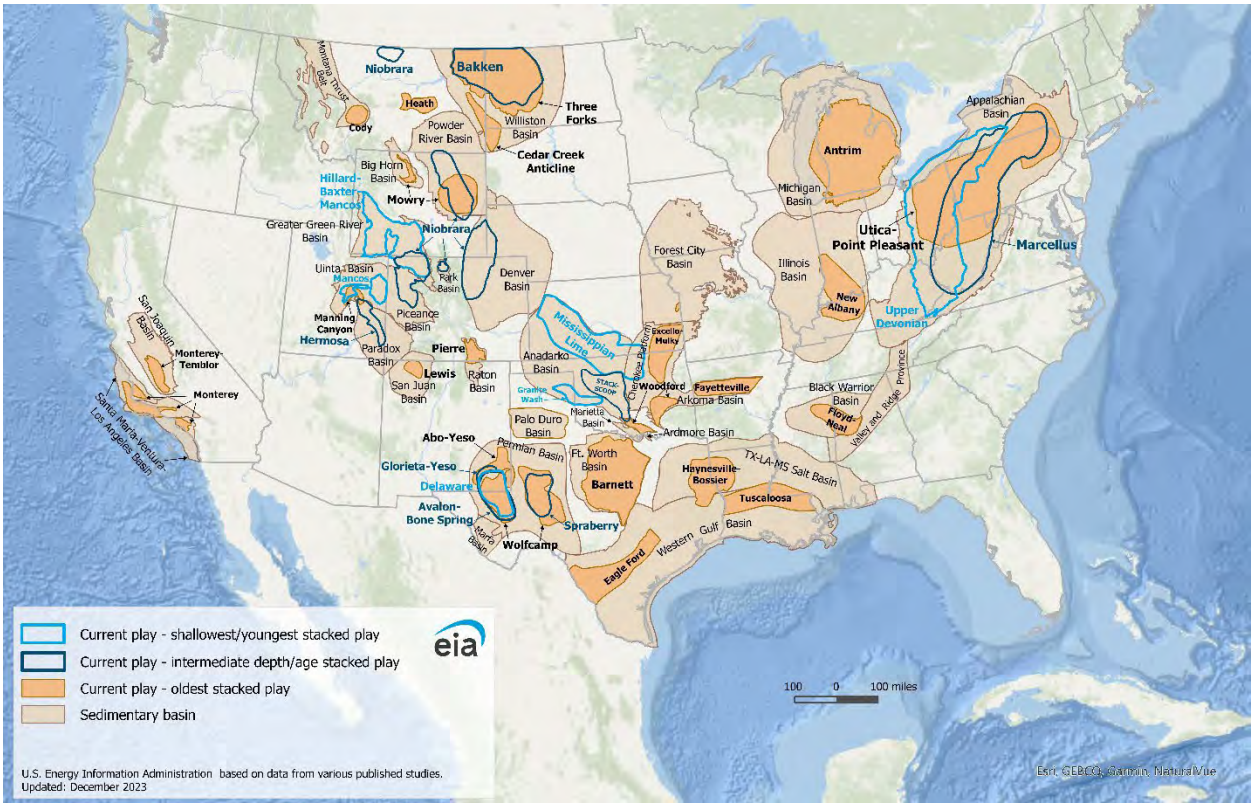
Figure 4: Oil and gas wells in the U.S.[8]



Focusing in on gas production, the map below (Figure 5) shows shale plays in the continental U.S.

[8] Meko, Tim, and Laris Karlis, "The United States of Oil and Gas," The Washington Post, February 14, 2017. https://www.washingtonpost.com/graphics/national/united-states-of-oil/

Figure 5: Shale Plays in the Lower 48 States[9]



Methane emissions from the oil and gas sector vary by oil/gas dominance, by production level, by basin, by segment, by facility, equipment, and process type, and as a result of regulatory intervention.

First, emissions differ by oil or gas dominance in extraction. In 2024, globally, oil operations were responsible for approximately 45 metric tons (Mt) of methane, natural gas operations for nearly 35 Mt, and abandoned wells for around 3 Mt.[10] The primary cause of methane emissions in oil development is associated gas—gas that is produced as a byproduct and often intentionally vented or flared when a site lacks infrastructure adequate to capture and

[9] U.S. Energy Information Administration, https://www.eia.gov/maps/images/lower-48/shale_gas_2023.jpg
[10] International Energy Agency, https://www.iea.org/reports/global-methane-tracker-2025/understanding-methane-emissions

process this gas. In addition, oil stored in tanks contained dissolved gas, which, as the pressure in the tanks drops, is "flashed" through vents into the atmosphere. Methane emissions from gas development issue primarily from leaks through the supply chain, venting from gas-driven process controllers, and intentional venting and flaring. Where oil and gas development co-occur, like in the Permian basin, methane emissions will be released from all of the aforementioned sources.

Research shows a multifaceted relationship between production level and emissions. It is common sense that emissions scale with production, and this is accurate for predictable emissions that issue routinely from equipment and processes (such as venting from gas-driven process controllers) and for the emission rates of leaks at higher production facilities. Zavala-Araiza et al. (2015) explain this phenomenon: "Because maximum potential CH_4 emissions from a site are limited by the total amount of gas produced at that site, absolute emissions tend to increase at sites with higher gas production rates."[11] **NMED Exhibit 37b at PDF 20.**

Particularly with methane leaks, higher production means more throughput at higher pressure, which increases the chances of leaks and potentially makes the leaks higher-emitting when they do occur. However, statistical research has only found a weak connection between production level and emissions. Emissions do not scale linearly with production. Instead, lower production sites (10-100 thousand standard cubic feet per day or Mcf/d) are almost twice as likely to be among the top 5% of emitters (which is the definition of super-emitter used by the authors) relative to sites with an order of magnitude higher rates of production (100-1000 Mcf/d)."[12] **NMED Exhibit 37b at PDF 20.** However, the highest producing sites—those over

[11] Zavala-Araiza, Daniel, David Lyon, Ramón A. Alvarez, Virginia Palacios, Robert Harriss, Xin Lan, Robert Talbot, and Steven P. Hamburg. "Toward a functional definition of methane super-emitters: Application to natural gas production sites." *Environmental science & technology* 49, no. 13 (2015): 8167-8174, page 8168.
[12] Ibid.

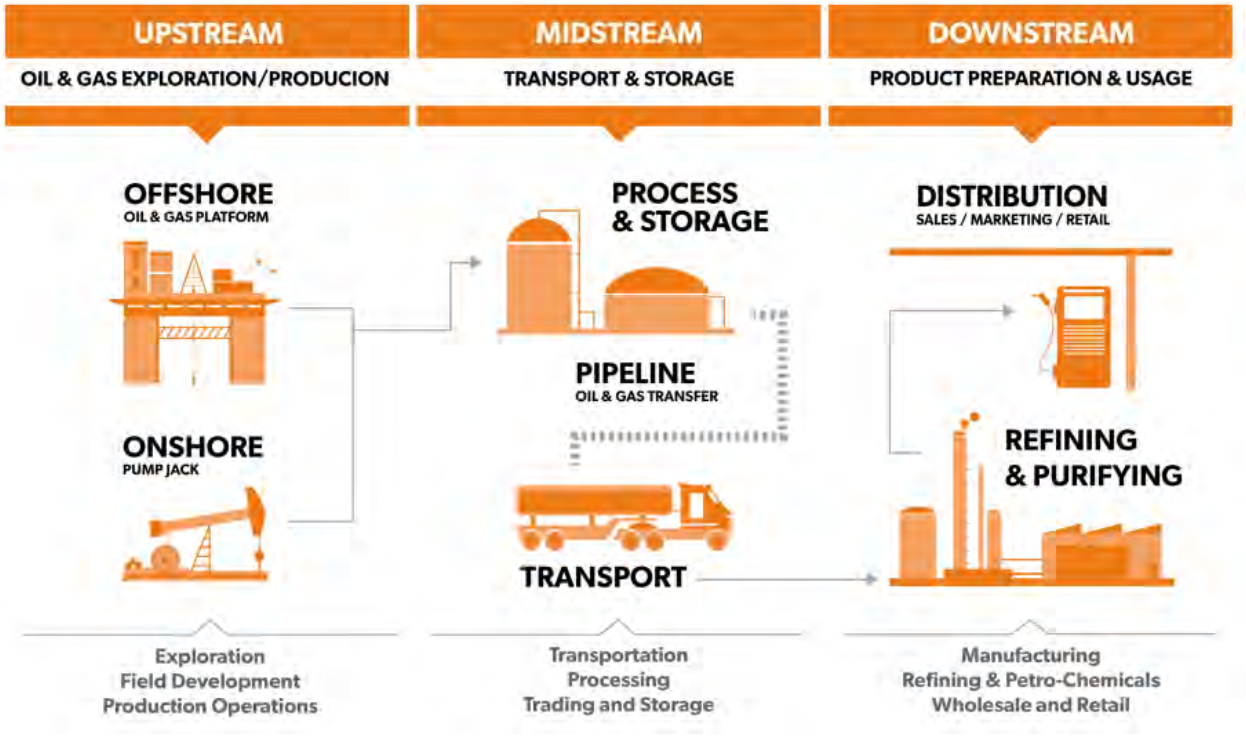
1000 Mcf/d—are 4 to 7 times more likely to be among the highest emitting sites.[13] **NMED Exhibit 37b at PDF 20.** The authors emphasize that unintentional leaks with high emission rates can occur at sites with any level of production and are likely the result of "abnormal or avoidable operating conditions," which could result in persistent leaks (such as equipment malfunction, e.g.. stuck open valve) or intermittent leaks (such as uncontrolled flashing form condensate tanks or well venting for liquids unloading).[14] **NMED Exhibit 37b at PDF 21.** Omara et al. (2018) build on this analysis and find that low production sites (<100 Mcfd), though they made up only 9.6% of production nationally in 2015, because of their relative site dominance (they make up 85% of all sites) contribute 63% of national methane emissions.[15] **NMED Exhibit 37c at PDF 34.** In other words, because there are so many low-producing sites relative to high-producing sites, their aggregate emissions form two-thirds of total emissions. Therefore, leaks from both low- and high-producing site are important—low-producing because they make up the bulk of the sector, and high-producing because when they leak, they have high emission rates and therefore high methane emissions.

Methane emissions also vary by oil and gas segment. Segments are divisions of the supply chain defined by function. The overarching tripartite segment scheme for the oil and gas sector is upstream, midstream, and downstream. The upstream segement includes exploration, drilling, wellhead operations, and extraction, and is often referred to collectively as production. The midstream segment includes processing, transportation, and storage. The downstream segment

[13] Ibid.
[14] Ibid., 8169.
[15] Omara, Mark, Naomi Zimmerman, Melissa R. Sullivan, Xiang Li, Aja Ellis, Rebecca Cesa, R. Subramanian, Albert A. Presto, and Allen L. Robinson. "Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate." *Environmental science & technology* 52, no. 21 (2018): 12915-12925, page 12922.

includes refinining (for petroleum), transmission, distribution, and marketing. Figure 6 shows a simplified schematic of these segments.

Figure 6: Oil and gas segments[16]



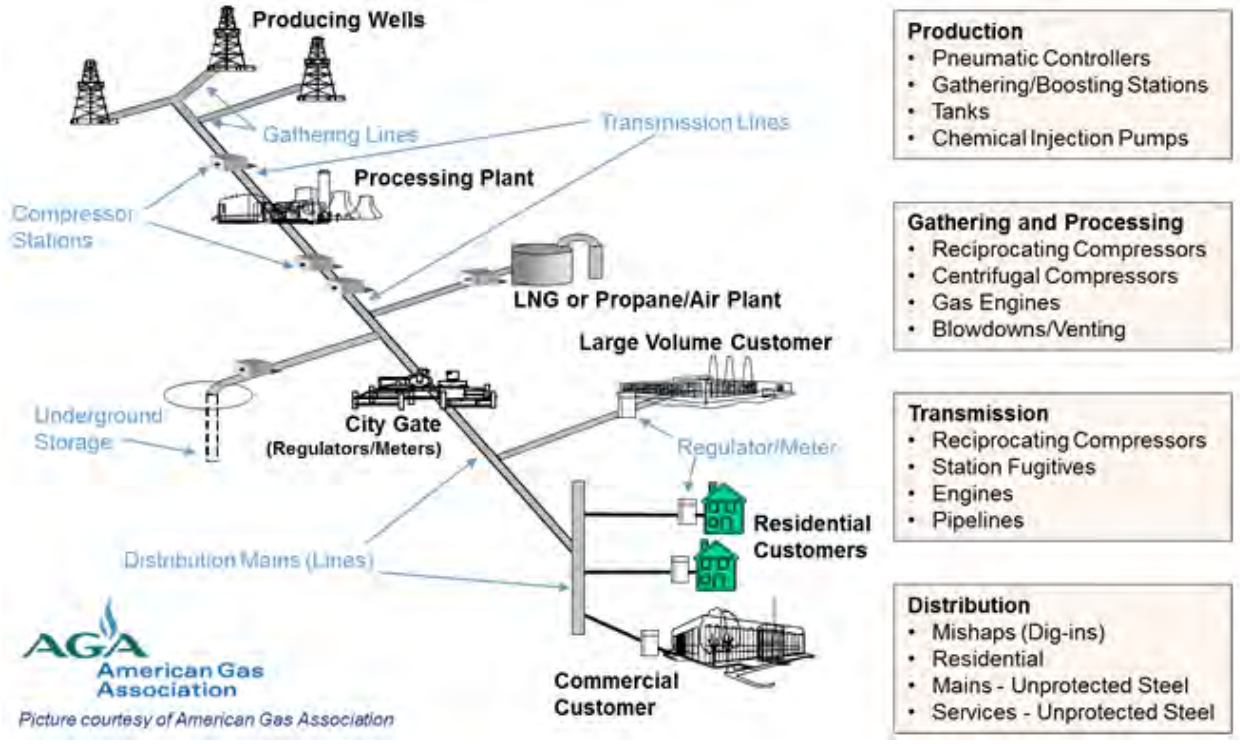
The gas sector is further broken down into production, gathering and boosting, processing, transmission, and distribution, however, the infrastructure within these categories can overlap and there is no universally-used delimitor between the segments, making precise calculation of emissions by segment challenging.

Production entails drilling and extraction of natural gas. Gathering and boosting are activities to adjust the pressure of the gas stream so that gas can be transported through the supply chain. Processing removes impurities, primarily hydrogen sulfides, carbon dioxide, and

[16] https://www.elandcables.com/the-cable-lab/faqs/faq-what-are-upstream-and-downstream-works-in-the-oil-gas-industry

water vapor, from the gas stream. Processing can also involve separating out heavier hydrocarbons, including ethane, propane, butane, isobutane, and pentanes, which can be mixed with methane. Transmission moves the gas to distribution points. The graphic below, displayed on an EPA website that provides an overview of emissions from the sector, collapses the gathering and boosting and processing segments.

Figure 7: Methane emissions sources by segment[17]



Research shows that methane emissions are highest in the production segment. Emissions in this segment primarily issue from equipment leaks, venting from gas-driven pneumatic controllers, storage tanks, produced water, and leaking wells; however, there is considerable variation between and within basins due to natural gas quality (determining the amount of processing required), production rates, operator practices, infrastructure development, and

[17] https://19january2021snapshot.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry_.html

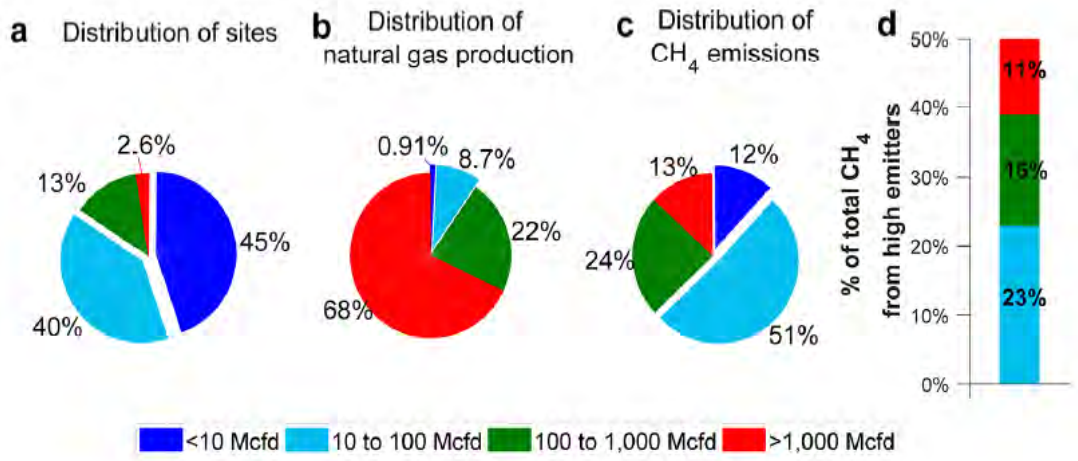
regulatory policies.[18] **NMED Exhibit 37c at PDF 33.** These emissions sources can be separated into intentional and unintentional emissions, with the latter grouped under the umbrella of "leaks." Intentional emissions are common in the following processes: venting from well completions and cleanouts, venting from gas-driven process controllers, maintenance blowdowns, and storage tank venting. Unintentional emissions are often the result of leaks in joints between equipment, malfunctioning equipment, open or leaking thief hatches on storage tanks, and blowouts (accidents).

Combining analysis of production sites and disaggregation by production level, Omara et al. (2018) analyzed emissions from over 1000 production sites across eight basins. As noted in the above discussion of the relationship between emissions and production level, the authors find significant emissions from a range of levels of production. Figure 8 below shows their findings. The first pie chart shows the breakdown of gas production sites (n=498,000) in 2015 by production level cohort. The second pie chart shows from which of these production level cohorts the gas supply issues, with 68% of total production coming from very high production (>1000 thousand cubic feet per day (Mcfd)) sites. The third pie chart shows the distribution of methane emissions by production level cohort, with 51% of emissions coming from sites that produce 10-100 Mcfd. Finally, the bar chart shows the percentage of total emissions that issues from high-emitting sites, defined as the top 5% of emitting sites in the cohort. The bar chart communicates the prevalence of super-emitters, defined as the top 5% of emitters, among each production cohort over 10 Mcfd. The authors estimate that high emitters in the 10-100 Mcfd cohort contribute 23% of total emissions, high emitters in the 100-1000 Mcfd cohort contribute

[18] Omara et al. (2018), 12922.

16%, and high emitters in the >1000 Mcfd cohort contribute 11%.[19] **NMED Exhibit 37c at PDF 35.**

Figure 8: Findings by Omara et al. of methane emissions by production level[20] **NMED Exhibit 37c at PDF 33.**



The takeaway from their emissions distribution analysis is that high emitters across production cohorts contribute a significant fraction of total emissions, suggesting that emissions could be significantly abated by reducing high-emitting events.

The gathering and boosting segment produces methane emissions primarily through gathering compressors, process controllers, pneumatic pumps, storage tanks, and leaks. Intentional emissions come from venting from gas-driven controllers and pumps, compressor and piping blowdowns, and storage tank venting. Unintentional leaks can occur through this infrastructure, including from compressor rod packing and seal wear, jammed controllers, gathering pipeline leaks, and open or faulty storage tank hatches.

[19] Ibid., 12923.
[20] Ibid., 12921.

Gas processing emits methane from compressors, acid gas units, blowdown systems and flares, and leaks. Intentional emissions come from plant maintenance blowdowns, acid gas removal venting, and routine flaring. Unintentional emissions can come from leaks, unlit or malfunctioning flares, and compressor wet seal degradation.

Researchers have estimated methane emissions from the gathering, boosting, and processing segments. Mitchell et al. (2015) measured methane emissions at 114 gathering facilities and 16 processing plants.[21] **NMED Exhibit 37d.** Observable emissions from leaks or venting were noted at 71 gathering facilities, including venting (flashing and off-gassing) from liquids storage tanks at 48 facilities, leaking or venting from compression equipment at 42 facilities, and gas pneumatics at 28 facilities.[22] **NMED Exhibit 37d at PDF 43.** A subset of these observed emitting sources were emitting excessively, which is reflected in the wide range and upper bound of emission rates measured at these facilities—0.7 to 700 kg/hr. Venting from liquid storage tanks was the most common non-combustion source observed onsite; of the 48 gathering facilities with observable venting from liquids storage tanks, substantial venting from tanks was observed at 23, and abnormal process conditions were identified at 6 of the 23 facilities.[23] **NMED Exhibit 37d at PDF 43.** Other sources of emissions observed were leaking valves and pipe unions, venting from the dehydrator, and compressor crank case/rod packing vents, stuck valves, and open thief hatches.

Zimmerle et al. (2020) analyzed methane emissions from gathering compressor stations, which include gas compression equipment, along with associated separators, tanks, piping, fuel

[21] Mitchell, Austin L., Daniel S. Tkacik, Joseph R. Roscioli, Scott C. Herndon, Tara I. Yacovitch, David M. Martinez, Timothy L. Vaughn et al. "Measurements of methane emissions from natural gas gathering facilities and processing plants: Measurement results." *Environmental science & technology* 49, no. 5 (2015): 3219-3227.
[22] Ibid., 3224.
[23] Ibid.

gas systems, and related equipment.[24] **NMED Exhibit 37e.** They found that combustion slip from engines that power compressors was the largest category of methane emissions at gathering stations in their study, contributing 38% [30−43%] of total methane emissions across all stations in the field campaign. At the 96% of stations powered by engines, combustion slip ranged from 0.21 to 92% of station emissions, and at 31% of those stations, combustion slip accounted for more than half of the methane emitted.[25] **NMED Exhibit 37e at PDF 52.** Fugitive and vented emissions from major equipment units (compressors, dehydrators, tanks, separators, and AGRUs) accounted for 21% [16−29%] of total emissions, while all remaining equipment was grouped into "yard piping," which was the source of 24% [15−38%] of total station emissions. For the 73% of stations that utilized gas-driven pneumatic controllers, these emissions were estimated using the EPA's Greenhouse Gas Reporting Program (GHGRP) emission factors and represent 11% [8.4−12%] of total emissions. Emissions from dehydrator still vents and flares made up the remaining 6.6% [3.2−12%] of emissions.[26] **NMED Exhibit 37e at PDF 53.**

In the transmission and distribution segments, the scale of pipeline infrastructure and distribution networks creates multiple potential conditions for leaks, which can occur at both pipelines and storage facilities. Transmission segment planned emissions can occur at storage facilities during maintenance or for pressure regulation, from compressor station blowdowns, and from process controllers and pneumatic pumps. Zimmerle et al. (2015) conducted an analysis of methane emissions from the transmission and storage sector, which they define as the "infrastructure between two custody transfer points—the receipt meter between the gathering

[24] Zimmerle, Daniel, Timothy Vaughn, Ben Luck, Terri Lauderdale, Kindal Keen, Matthew Harrison, Anthony Marchese, Laurie Williams, and David Allen. "Methane emissions from gathering compressor stations in the US." *Environmental Science & Technology* 54, no. 12 (2020): 7552-7561.
[25] Ibid., 7557.
[26] Ibid., 7558.

and processing sector and the transmission system, and the delivery meter between the transmission system and the distribution system (commonly called a "city gate") or industrial end user."[27] **NMED Exhibit 37f at PDF 58.** The segment includes compressor stations, pressurized pipeline networks, metering and regulation stations, and supporting equipment. Through modeling based on equipment measurements, they found that the largest emission sources were fugitive emissions and compressor-related equipment, specifically engines and pneumatic devices, at compressor stations associated with underground storage facilities. The largest source of fugitive emissions—approximately 50%—were from major compressor equipment, including seal vents, unit isolation and blowdown valves, and rod packing vents.[28] **NMED Exhibit 37f at PDF 61.**

Research has also described differences in emissions by facility, equipment, and process type. These, too, can be separated into intentional and unintentional emissions. Intentional emissions come from gas-driven process controllers and pneumatic pumps (which are designed to either continuously or intermittent vent methane), flashing from oil storage tanks, venting from glycol dehydrators, flaring, and venting during liquid unloading, maintenance blowdowns, and well completions. Leaks are common across all segments, facilities, equipment, and processes within the natural gas supply chain. Leaks can emerge at any juncture, joint, connector, or flange in equipment. They can be caused by mechanical wear, thermal stress, corrosion, inadequate maintenance, or operator error. Compressors leak methane in two ways: wet seal oil degassing in centrifugal compressors and leaks around rod packing rings in reciprocating compressors. Intentional emissions are predictable and therefore can be estimated using emission

[27] Ibid., 9375.
[28] Ibid., 9378.

factors specific to equipment/process multiplied by activity counts (number of pieces of equipment in the population), whereas unintentional leaks create challenges for emissions estimates because of their episodic nature and lack of knowledge about their emission rates and durations. However, leaks due to wear and tear can be prevented by conducting regular equipment maintenance, and leaks due to operator error can be avoided by following manufacturer guidance for equipment operation. In this sense, we can divide leaks into two categories: easily preventable and more difficult to avert.

Finally, methane emissions vary due to regulation. For example, New Mexico adopted the Methane Waste Rules in 2021, which prohibit routine venting and flaring of methane in the oil and gas sector. Colorado adopted rules that require the complete phaseout of gas-driven process controllers by 2029, in addition to a broader requirement that methane emissions be reduced 60% before 2005 levels by 2030.[29] Louisiana adopted rules that prohibit routine venting and flaring of natural gas in 2024.[30] California has a statewide mandate to reduce methane emissions by 40% by 2030 and regulations that requires oil and gas producers to address both fugitive and vented emissions of methane from new and existing oil and gas facilities through emission control plans, leak testing, and repair; and a remote sensing program to identify large leaks of natural gas.[31]

Empirical evidence shows that regulation of methane abates these emissions. Satellite data from both the New Mexico and Texas sides of the Permian Basin shows a divergent trajectory in methane emissions—over double the methane emissions per unit of production in

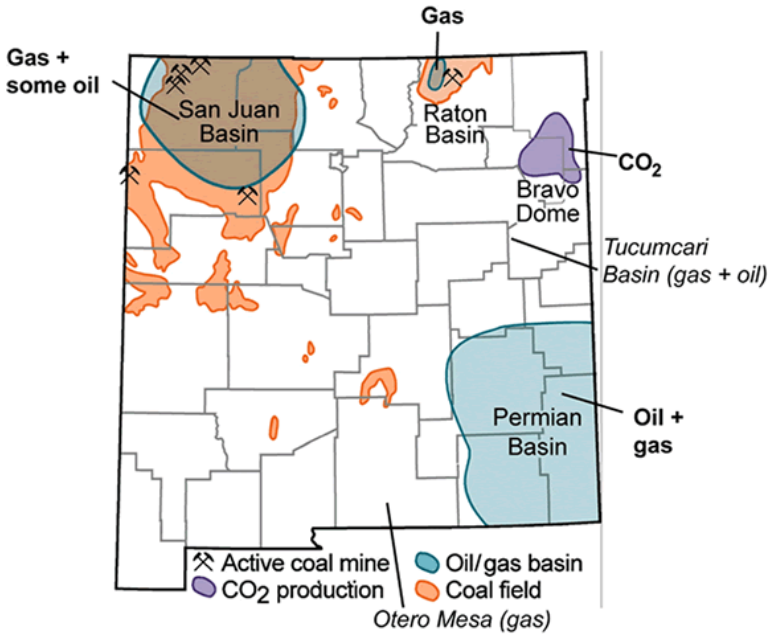
[29] https://www.climatepolicydashboard.org/policies/industry-materials-waste/oil-and-gas-methane#oil-and-gas-methane-regulations-by-state
[30] https://www.climatepolicydashboard.org/policies/industry-materials-waste/oil-and-gas-methane#oil-and-gas-methane-regulations-by-state
[31] https://modelclimatelaws.org/resources/california-oil-and-gas-sector-methane-emissions-regulation/

Texas despite doubling of production in New Mexico since 2020—that can be attributed to methane regulation only on the New Mexico side of the basin.[32]

Focusing in on New Mexico production and emissions

Oil and gas extraction in New Mexico is geographically focused in the Permian Basin in the southeast of the state and the San Juan Basin in the northwest of the state, with additional activity in the Raton Basin in the northeast of the state. The map below (Figure 9) shows the locations of these oil and gas development areas.

Figure 9: Locations of oil and gas development in New Mexico[33]



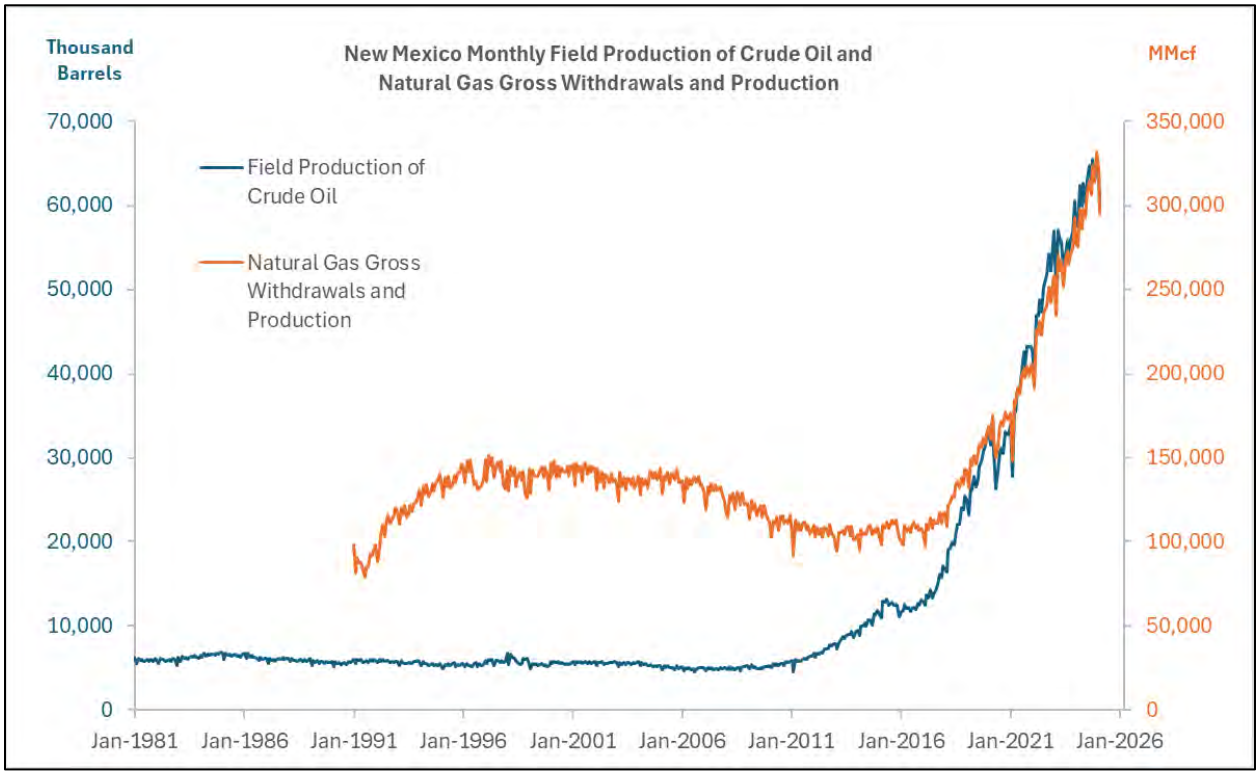
The San Juan basin is dominated by gas development, is a more mature development area, and has older infrastructure than the New Mexico portion of the Permian basin, which is

[32] https://blogs.edf.org/energyexchange/2025/12/03/texas-left-in-the-dust-as-new-mexico-slashes-methane-intensity-on-its-side-of-the-permian/
[33] New Mexico Bureau of Geology and Mineral Resources, https://geoinfo.nmt.edu/faq/energy/petroleum/home.html

dominated by both oil extraction and gas extraction via hydraulic fracturing in unconventional wells.

Oil and gas production in New Mexico has grown exponentially in the past 15 years, with most of the growth in the Permian Basin driven by increased oil extraction and the use of hydraulic fracturing to extract natural gas. The graph below (Figure 10) shows the trend in oil and gas development from 1981 to 2025. Between 2011 and 2024, oil production increased tenfold, and natural gas production more than doubled.

Figure 10: Oil and gas production in New Mexico, 2018-2025[34]



New Mexico is now the third-largest energy-producing state in the country, after Texas and Pennsylvania. It is the second-largest oil-producing state, after Texas, and, in 2024,

[34] Graph created using data from the U.S. Energy Information Administration.

accounted for 15% of the nation's total crude oil production and 14% of U.S. total proved crude oil reserves.[35] Crude oil production has increased significantly since 2010 and nearly doubled since 2020, the majority of which is extracted from the Permian Basin. In 2024, annual crude oil production reached an all-time high of just over 2 million barrels per day, nearly six times greater than it was a decade earlier, enabled by advanced drilling and oil recovery technologies that have increased production from the Basin's low-permeability shale formations.[36]

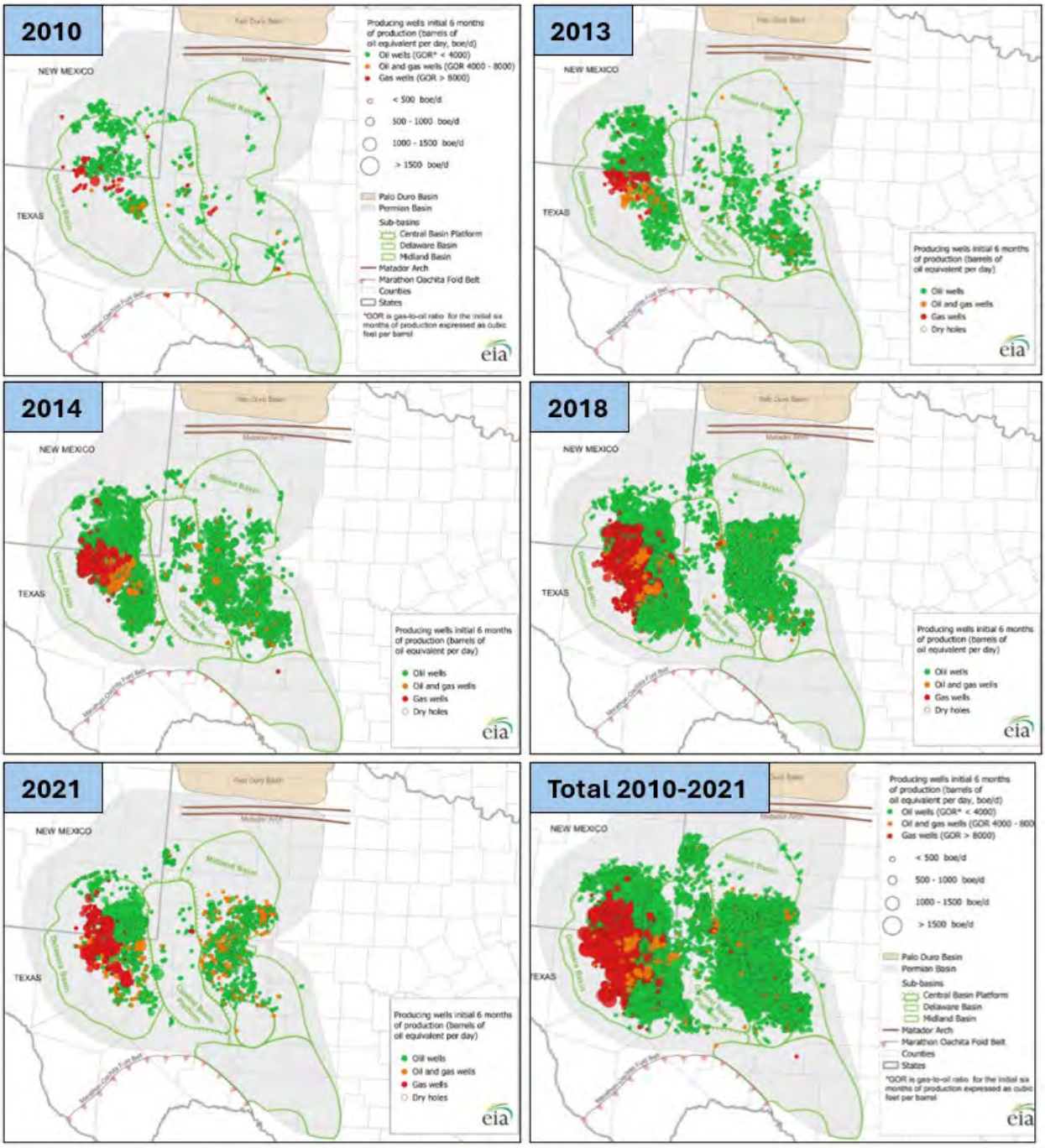
In 2024, New Mexico was the third-largest natural gas-producing state, after Texas and Pennsylvania, with annual natural gas gross withdrawals reaching a record 3.6 trillion cubic feet and accounting for 8% of the nation's total natural gas production.[37] The state produces 10 times more natural gas than it consumes, with the majority of the production transported to neighboring states via pipelines and a minority held in underground storage fields.[38]

Focusing in on the state's two major oil and gas basins, the Permian and San Juan differ in geological composition, type of development, and emissions. Due to differing geologies—the Permian has vertically deep, "stacked" deposits rich in both oil and gas, whereas the San Juan is dominated by coalbed gas in more geographically segregated and stratigraphically distinct pockets—the basins have very different production profiles. The San Juan is dominated by conventional, vertical gas wells, whereas the Permian is dominated by hydraulic fracturing of unconventional, horizontal gas that extract oil and gas simultaneously. Gas produced from oil wells is referred to as associated gas, which must be separated out from the oil for separate processing and transmission. The San Juan is an older gas development area, now considered

[35] U.S. Energy Information Administration, "New Mexico," https://www.eia.gov/states/NM/analysis
[36] U.S. Energy Information Administration, "New Mexico," https://www.eia.gov/states/NM/analysis
[37] U.S. Energy Information Administration, "New Mexico," https://www.eia.gov/states/NM/analysis
[38] U.S. Energy Information Administration, "New Mexico," https://www.eia.gov/states/NM/analysis

mature and declining compared to historic production highs in the latter half of the twentieth century to the early twenty-first century (production peaked around 2010), whereas the Permian has experienced exponential production growth over the past 15 years, largely due to hydraulic fracturing. The time series of Permian Basin maps below (Figure 11) shows the exponential growth of newly spudded wells from 2010-2021.

Figure 11: Times series of newly spudded unconventional wells in the Permian Basin, 2010-2021[39]



[39] U.S. Energy Information Administration, https://www.eia.gov/maps/oil-naturalgas.php

In the last 5 years, gas and oil production in the Permian has increased significantly, with gas production increasing faster than oil production, as shown in the graphs below (Figure 12). From 2021 to 2025, the Permian basin's natural gas production grew from 17.2 to 27.6 billion cubic feet per day, a 60% increase, while crude oil production grew by 39%, increasing from 4.7 to 6.6 million barrels per day.[40] The higher growth in natural gas production relative to oil production is the result of increasing gas-oil ratios due to gas being easier to produce at lower pressures, which occurs over time as oil and gas are extracted.

Figure 12: Oil and gas production in the Permian Basin, 2021-2026[41]

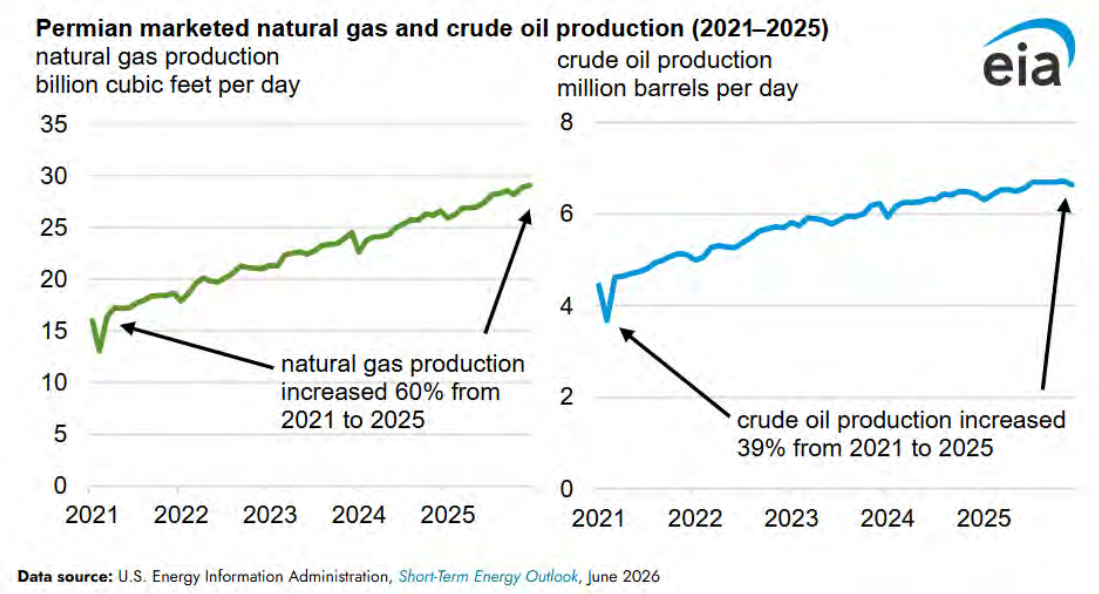
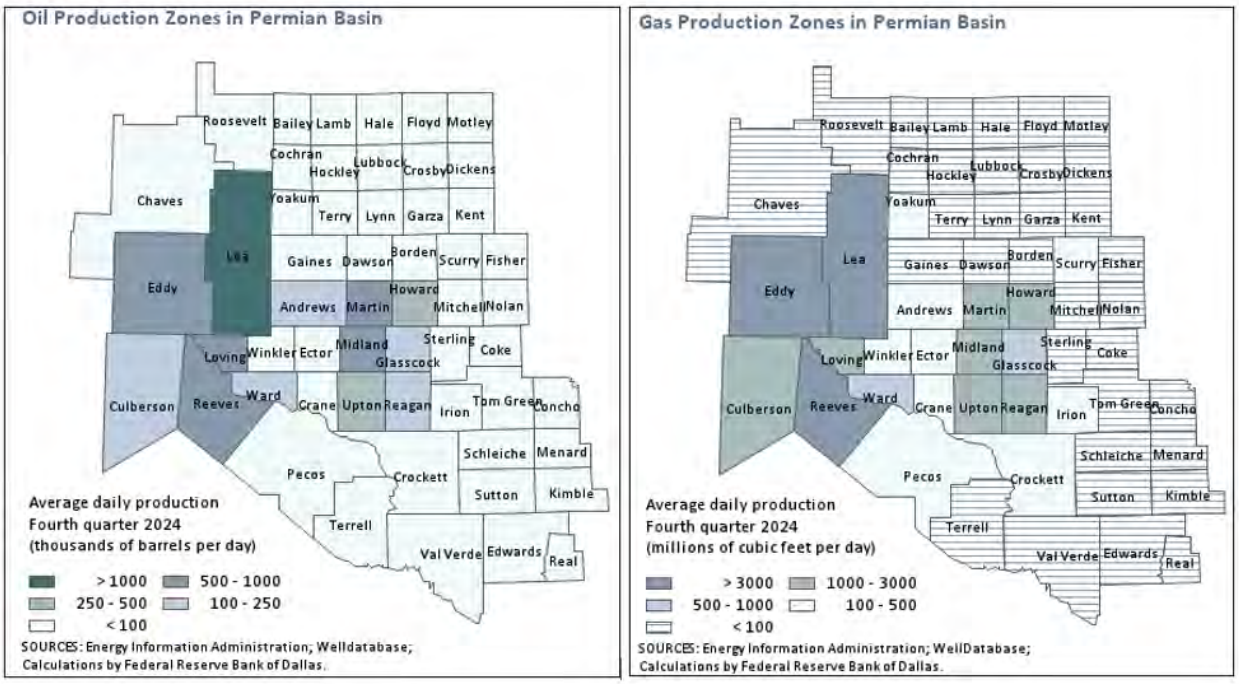


Figure 13 shows the concentration of production by county in the Permian Basin, with Eddy and Lea Counties in New Mexico topping production for both oil and gas in 2024.

[40] U.S. Energy Information Administration, "Permian natural gas production increased faster than crude oil," https://www.eia.gov/todayinenergy/detail.php?id=67785
[41] U.S. Energy Information Administration, "Permian natural gas production increased faster than crude oil," https://www.eia.gov/todayinenergy/detail.php?id=67785

Figure 13: Production levels by county in the Permian Basin, Fourth Quarter 2024[42]



Differences in emissions between the two basins reflect the differing deposits, ages of development, production dynamics, and technologies utilized. The San Juan Basin is a gas-dominant region that is mature (i.e., lower producing) with older infrastructure. As a gas-dominant region, it is less likely that methane emissions will occur from associated gas given the much smaller proportion of oil extraction. Lower levels of production means that leaks will likely have low emission rates, but because of the age of infrastructure, there may be more leaks from numerous sources that in aggregate generate significant methane emissions. This is particularly the case if infrastructure is not maintained and monitoring for leaks is infrequent. Conversely, the Permian Basin has seen a surge of new development over the last 15 years with high levels of both oil and gas production. When new oil wells are spudded, the amount of associated gas can exceed the ability to capture it, and it is vented as associated gas. The sheer

[42] Federal Reserve Bank of Dallas, https://www.dallasfed.org/research/energy11/permian

level of production also leads to high methane emissions because of the abundance of predictably emitting equipment (like gas-driven process controllers) and the high emission rates due to high production when there are unintentional leaks. However, relative to the San Juan, the infrastructure in the Permian is much newer and should be less likely to leak due to age.

Finally, the divergence in dependence on conventional versus unconventional wells leads to different emissions profiles for the two basins. The San Juan is dominated by conventional, vertical wells that are now operating at lower pressures due to age. These wells are more prone to continuous, low-volume leaks. The Permian is dominated by unconventional, horizontal wells associated with hydraulic fracturing, which are, in their early years, very high pressure. When leaks occur, the high pressure generates high emission rates and, potentially, super-emitter events. Several other factors related to well type influence emissions. Well completions produce less gas in conventional wells than in unconventional wells. Conventional wells, as they age, accumulate liquid, which chokes the gas flow and is addressed through blowdowns which vent methane from the well in order to blow out the liquid, whereas unconventional wells rely on artificial lift systems to manage fluid volumes, but which rely on local compressor infrastructure that can leak methane. Finally, unconventional wells have much more associated infrastructure on site, increasing the potential for leaks and the portion of methane slip from uncombusted methane powering equipment. Thus, for differing reasons, we see high methane emissions from both basins.

(Finding #3) There is a significant discrepancy between bottom-up and top-down analyses of methane emissions from the oil and gas sector, with geographically-focused research highlighting significant emissions from New Mexico oil and gas producing basins, orders of magnitude larger than EPA estimates.

Bottom-up emissions inventories estimate emissions using extrapolation from samples of infrastructure in the total population of the segment and emission factors that represent estimated

emissions per unit of a process, activity, or equipment. Top-down emissions inventories measure ambient methane emissions either at ground, air, or satellite levels using specialized sensors that can detect the signature of methane. Researchers have found that top-down inventories of methane are orders of magnitude larger than estimates of emissions from bottom-up inventories. In other words, bottom-up inventories underestimate methane emissions both globally and in the U.S.

Specifically focusing on U.S. methane emissions inventories, researchers have found that EPA Greenhouse Gas Inventories (GHGIs) of methane underestimate methane emissions by a factor of 1.5-2, meaning that actual methane emissions are 1.5-2x greater than estimated emissions.[43] **NMED Exhibit 37g.** There are several reasons for this underestimation. First, the samples of infrastructure on which the estimates are based are likely not representative of the larger population of infrastructure.[44] **NMED Exhibit 37h.** It is challenging to procure representative samples in such a large and diversified sector. Second, measurements for generating emission factors are expensive, which limits sample sizes, which, in turn, limit representativeness.[45] **NMED Exhibit 37h.** In addition, sample measurements are done with the consent of operators at particular sites, so there is reason to believe that these sites may not be representative of the total population.[46] **NMED Exhibit 37i.** As Alvarez et al. note, "[o]perators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are

[43] Rutherford, Jeffrey S., Evan D. Sherwin, Arvind P. Ravikumar, Garvin A. Heath, Jacob Englander, Daniel Cooley, David Lyon, Mark Omara, Quinn Langfitt, and Adam R. Brandt. "Closing the methane gap in US oil and natural gas production emissions inventories." *Nature Communications* 12, no. 1 (2021): 4715.
[44] Brandt, Adam R., Garvin A. Heath, E. A. Kort, Francis O'Sullivan, Gabrielle Pétron, Sarah M. Jordaan, P. Tans et al. "Methane leaks from North American natural gas systems." *Science* 343, no. 6172 (2014): 733-735.
[45] Ibid.
[46] Alvarez, Ramón A., Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis et al. "Assessment of methane emissions from the US oil and gas supply chain." *Science* 361, no. 6398 (2018): 186-188.

likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive."[47] **NMED Exhibit 37i at PDF 84.** Third, the population of infrastructure in the sector is not well known, so not knowing the totality of the sector that estimates are trying to accurately represent hinders effective sampling.[48] **NMED Exhibit 37h.** Emission factors (emissions per component or equipment per unit time) are multiplied by "activity factors" (counts of components per equipment and equipment per well). When activity factors are inaccurate, the estimated emissions will be inaccurate as well.

Finally, and most importantly for the present testimony, samples are likely to underrepresent high-consequence emissions sources, i.e., super-emitters. This is for several reasons. First, samples are unlikely to catch super-emitter events which are episodic and unpredictable in nature. This is compounded when sample sizes are small, which means the likelihood of catching a super-emitter when ground sampling is even smaller. In addition, as noted above, sampling occurs with the permission of operators, who are unlikely to allow access for sampling if they know they are experiencing high-emitting leaks, thereby biasing the sample to normal functioning equipment and processes. The consequence is that bottom-up inventories, and specifically the EPA GHGIs, are systematically biased in their lack of representation of episodic, high-emitting events, and therefore underestimate national methane emissions.

However, work by researchers has endeavored to produce more accurate bottom-up inventories using improved datasets and statistical approaches, such as the work of Alvarez et al. (2018) and Rutherford et al. (2021).[49] **NMED Exhibit 37g.** Alvarez et al. constructed a bottom-up inventory based on observed facility-level emissions, rather than a component-by-component

[47] Ibid., 187.
[48] Brandt et al. (2014).
[49] Rutherford et al. (2021).

approach, and compared this to top-down estimates.[50] **NMED Exhibit 37i.** Importantly, their approach includes the heavy tail distribution of emissions from super-emitter events. Their estimate is 63% higher than the 2015 EPA GHGI, largely due to a more than twofold increase in estimated emissions in the production segment, which they attribute to inclusion of high-emitting events caused by abnormal operating conditions. They narrow this difference to *unplanned* high-emitting events because the observed frequency of these events was too high to be attributed to routine operations, like liquid unloading. Subsequently, Rutherford et al. constructed a bottom-up inventory of the production segment based on "the most comprehensive public database of component-level activity and emissions measurements," which included approximately 3700 measurements from 6 studies across a 12-fold component classification scheme.[51] **NMED Exhibit 37g.** Rutherford et al.'s estimates are 1.8x the value of the GHGI for the production segment. The differential between the GHGI and Rutherford et al.'s estimate is equivalent to the latter's estimate of contributions from super-emitter events, defined as the top 5% of emission events. So, two different bottom-up estimates that factor in super-emitter events report that the underestimate by the GHGI is primarily due to its neglect of high-emitting events.

Because Rutherford et al. use a component-by-component approach, the same approach used by the EPA, they are able to determine the variation between the two inventories in a more fine-grained way. They conclude that the sources of underestimates in the GHGI are lower underlying equipment leak measurements and neglect of the contribution of unintentional emissions events at tanks (e.g., liquid hydrocarbon storage tank thief hatches).[52] **NMED Exhibit**

[50] Alvarez et al. (2018).
[51] Rutherford et al. (2021).
[52] Rutherford et al. (2021), 8.

37g at PDF 74. This reflects Alvarez et al.'s conclusion that not accounting for the emissions from unplanned leaks explains the gap between their estimate and that of the GHGI.

Researchers have also conducted analyses of discrepancies between EPA basin inventories and their own estimates for these basins. Multiple studies have focused analysis on the Permian basin given its rapid growth, high productivity, and importance to national methane emissions. Indeed, the Permian Basin is the largest oil-producing basin in the U.S., produces more oil than all but five countries in the world, and oil production has quadrupled and gas production has tripled in the past 15 years.[53] **NMED Exhibit 37j at PDF 87.** In 2018, the Permian Basin produced 3.5 million barrels of crude oil and 11 billion cubic feet of natural gas every day, equivalent to 30% and 10% of total U.S. withdrawals, respectively.[54] **NMED Exhibit 37k at PDF 94.**

Zhang et al. (2020) used satellite remote sensing data from the TROPOMI satellite over the period 2018-2019 to quantify methane emissions in the Permian Basin.[55] **NMED Exhibit 37k.** They estimated methane emissions at 2.9 [± 0.5] teragrams per year (Tg a^{-1}) (a teragram equals one trillion grams, which is equal to one million metric tons), which is more than a factor of 2 larger than the bottom-up estimate based on an extrapolation of EPA GHGI data.[56] **NMED Exhibit 37k at PDF 96.** Removing non-oil and gas sources from the total methane flux, oil and gas methane emissions are 2.7 Tg a^{-1}, which is significantly higher than estimated emissions for

[53] Chen, Yuanlei, Evan D. Sherwin, Elena SF Berman, Brian B. Jones, Matthew P. Gordon, Erin B. Wetherley, Eric A. Kort, and Adam R. Brandt. "Quantifying regional methane emissions in the New Mexico Permian Basin with a comprehensive aerial survey." *Environmental science & technology* 56, no. 7 (2022): 4317-4323, page 4317.
[54] Zhang, Yuzhong, Ritesh Gautam, Sudhanshu Pandey, Mark Omara, Joannes D. Maasakkers, Pankaj Sadavarte, David Lyon et al. "Quantifying methane emissions from the largest oil-producing basin in the United States from space." *Science advances* 6, no. 17 (2020): eaaz5120, 1.
[55] Ibid.
[56] Ibid., 3.

other U.S. basins and approximately one quarter of total emissions from all U.S. oil and gas production areas in 2015.[57] **[MED Exhibit 37k at PDF 97.**

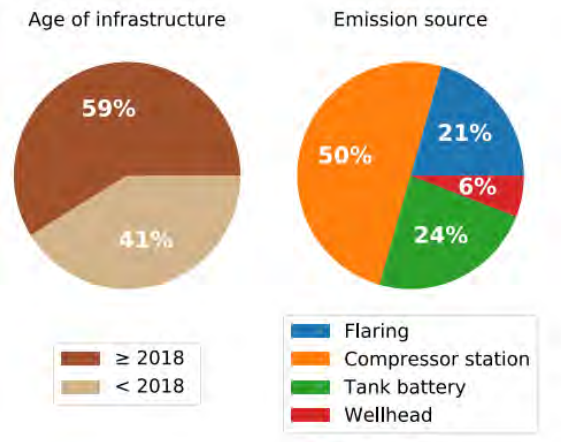
This amount of lost product represents wasted resources and significant warming—it is enough to supply 7 million households in the state of Texas and it results in the same radiative forcing as 260 Tg a^{-1} of carbon dioxide over a 20-year time horizon, which is roughly equivalent to annual carbon dioxide emissions from the entire U.S. residential sector.[58] **NMED Exhibit 37k at PDF 97.** The calculated methane leakage rate for the basin is 3.7% [± 0.7%], which is 60% higher than the U.S. average of 2.3% [± 0.3%] and over twice that of the GHGI (1.5%).[59] **NMED Exhibit 37k at PDF 97.** The leakage rather for the Delaware sub-basin, which overlaps the border of Texas and New Mexico is even higher at 4.1%. They attribute the high emissions in this basin to the high proportion of unconventional wells and infrastructure associated with these well, like gathering stations.[60] **NMED Exhibit 37k at PDF 97.** They conclude that the Permian Basin is an outlier among U.S. oil and gas producing basins due to its high oil production, high gas production, and high leakage rate.[61] **NMED Exhibit 37k at PDF 98.**

Irakulis-Loitxate et al. (2021) performed an analysis of point source emitters in the Permian Basin using a satellite-based large-scale and high-resolution survey over several days in 2019 and 2020, which allowed them to map individual methane plumes and attribute emissions to specific infrastructure.[62] **NMED Exhibit 37l.** The results of their sensing and analysis reveal that the Delaware sub-basin of the Permian contained the highest number of extreme point

[57] Ibid., 4.
[58] Ibid., 4.
[59] Ibid., 4.
[60] Ibid., 4.
[61] Ibid., 5.
[62] Irakulis-Loitxate, Itziar, Luis Guanter, Yin-Nian Liu, Daniel J. Varon, Joannes D. Maasakkers, Yuzhong Zhang, Apisada Chulakadabba et al. "Satellite-based survey of extreme methane emissions in the Permian basin." *Science Advances* 7, no. 27 (2021): eabf4507.

source emitters ever observed across an oil and gas basin, with 29 of the 37 detected plumes having an emission rate of over 1000 kg/hr.[63] **NMED Exhibit 37l at PDF 105.** The emission rate range was extremely high overall—500-6000 kg/hr—with one source emitting at a rate of 18,000 kg/hr.[64] **NMED Exhibit 37l at PDF 108.** Because of the high spatial resolution of their satellite data (30 meters), the authors were able to attribute detected plumes to specific infrastructure and draw conclusions about the relationship between infrastructure age and type and emissions. Figure 14 below shows their findings. Age analysis shows that 59% of emissions were from infrastructure that started production in or after 2018. Emissions source analysis shows the following breakdown: 50% of emissions from compressor stations, 24% from tank batteries, 21% from flaring, and 6% from wellheads.

Figure 14: Irakulis-Loitxate et al. breakdown of emissions[65] **NMED Exhibit 37l at PDF 107.**



The greater emissions from newer infrastructure is surprising given that wells spudded before 2018 made up 65% of active wells in the study area. Despite making up a smaller fraction of total wells, these new wells had extreme emissions 2.6 times more frequently than older wells

[63] Ibid., 2.
[64] Ibid., 5.
[65] Ibid., 4.

and produced twice the amount of methane emissions. The authors hypothesize that this is due to faster production of gas at new unconventional wells than the downstream storage and processing components can handle, which leads to a significant amount of inefficient flaring, but also note that exploratory drilling could contribute. Regarding source type, the authors note that the high emission rate from flaring indicates inefficient or malfunctioning flaring operations, but do not comment on the other source attributions they made.

Robertson et al. (2020) performed an analysis of methane emissions from well pads in the Permian Basin using a mobile laboratory detection system and found that their estimates were a factor of 5.5-9 times greater than the 2017 EPA National Emissions Inventory estimates for the region. This was the first study to report ground-based methane flux estimates in the Permian. They separated out emissions from the New Mexico portion of the basin and found that the Greenhouse Gas Reporting Program basin-level estimate is over an order of magnitude low for the New Mexico portion.[66] **NMED Exhibit 37m at PDF 118.** Further, "estimated basin-wide emissions from only well pads in just the NM portion of the basin (520,000-610,000 TPY CH4) exceed total basin-wide emissions (i.e., all O&G operations) estimated using aircraft mass balance techniques in almost every other O&G basin in the U.S.," with the exception of the Eagle Ford Shale region in Texas.[67] **NMED Exhibit 37m at PDF 118-119.**

Chen et al. (2022) conducted a basin-wide aerial survey of methane emissions in the Permian Basin capable of measuring emissions from nearly every asset in the basin and with

[66] Robertson, Anna M., Rachel Edie, Robert A. Field, David Lyon, Renee McVay, Mark Omara, Daniel Zavala-Araiza, and Shane M. Murphy. "New Mexico Permian Basin measured well pad methane emissions are a factor of 5–9 times higher than US EPA estimates." *Environmental Science & Technology* 54, no. 21 (2020): 13926-13934, page 13932.
[67] Ibid., 13932-13933.

resolution that enabled them to quantify and attribute medium-to-large point source emissions.[68] **NMED Exhibit 37j.** The aerial campaign detected 1985 methane plume observations from 958 distinct emissions sources, which the authors quantified at 153 [+71/-70, 95% confidence interval] metric tons per hour. Approximately half of these emissions were emitted from well sites (which include wells, gathering lines, storage tanks, and compressor stations), approximately 19% from pipelines (including underground gathering pipelines), 17% from compressor stations without a well on site, 6% from stand-alone storage tanks, 3% from gas processing plants, and the remainder from other sources.[69] **NMED Exhibit 37j at PDF 90.** The authors' emissions estimates are 6.5 [+2.4/-2.3] times larger than GHGI estimate aligned to the same study area and time period. **NMED Exhibit 37j at PDF 91.**[70]

Yu et al. (2022) conducted four aerial campaigns to estimate a basin-wide methane emission factor for natural gas gathering pipelines in the Permian Basin, a source that is more difficult to monitor on the ground than other infrastructure types.[71] **NMED Exhibit 37n.** Gathering pipelines transport natural gas from well sites to processing plants for treatment or to transmission systems (when the gas needs less processing). They emit methane either via leaks in the pipelines themselves, from leaks in the auxiliary equipment, or during intentional venting at auxiliary equipment, as in maintenance blowdowns. Using all measured sources, the authors derived the emission factor (EF)—a measure of the methane emission rate per unit of distance of pipeline—with a range from 2.7 [+1.9/−1.8] mega grams per year per kilometer (Mg $year^{-1}$ km^{-1}) for Fall 2021 to 10.0 [+6.4/−6.2] Mg $year^{-1}$ km^{-1} for Fall 2019, which is an order of magnitude

[68] Chen et al. (2022).
[69] Ibid., 4320.
[70] Ibid., 4321.
[71] Yu, Jevan, Benjamin Hmiel, David R. Lyon, Jack Warren, Daniel H. Cusworth, Riley M. Duren, Yuanlei Chen, Erin C. Murphy, and Adam R. Brandt. "Methane emissions from natural gas gathering pipelines in the permian basin." *Environmental science & technology letters* 9, no. 11 (2022): 969-974.

higher than the EPA's gathering pipeline EF of 0.19 Mg year^{-1} km^{-1} for the year 2020. They attribute this discrepancy to a small and non-representative sample for all basins used by the EPA.

Taken together, this research yields several salient conclusions. First, bottom-up emissions estimates have underestimated methane emissions primarily because they neglect the impact of high-emitting events. More accurate emissions estimates can be attained from top-down analyses and bottom-up estimates that include super-emitter events. This pattern holds true for oil and gas producing basins in New Mexico, for which EPA inventories have underestimated methane emissions at the extreme end by a factor of 9. The next section will focus on the impact of heavy-tail methane emissions.

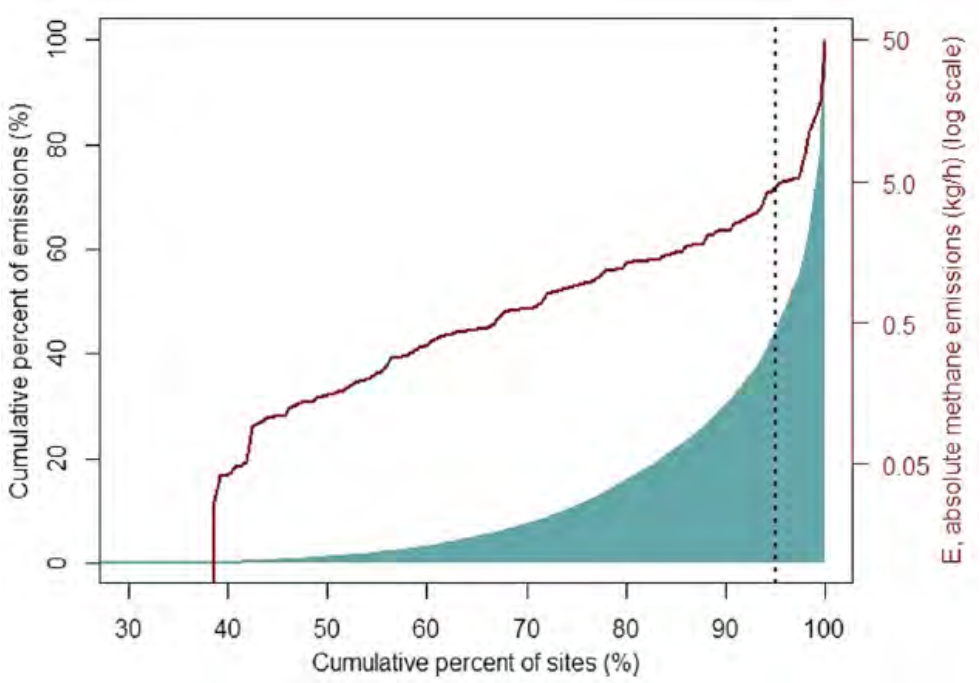
(Finding #4) The distribution of emissions from the sector does not follow a normal distribution, but rather has a "heavy tail" caused by the large impact of methane "super-emitter events."

The research on methane emissions from the oil and gas sector has conclusively found that emissions are dominated by a small fraction of high-emitting sources across the sector, including at well sites, gas processing plants, storage tanks, transmission compressor stations, and distribution systems. The skewed distribution of emissions has a "heavy tail" caused by a fraction of emitting sources with very high emissions. "Heavy tail" refers to the visual shape of the distribution. Rather than a normal distribution, which is shaped like a bell with the majority of data points in the middle rather than at the extremes, methane emissions from the oil and gas sector when plotted show very high emissions from a small number of sites. The graph below (Figure 15) shows the distribution of methane emissions from a study by Rella et al. (discussed below).[72] **NMED Exhibit b at PDF 20.** The blue area shows cumulative percent of methane

[72] This graph is from Zavala-Araiza et al. (2015), 8168.

emissions as a function of the cumulative percent of sites, plotted in rank order of increasing emissions. Sites to the right of the vertical dotted line are super-emitters using the definition of the top 5% of emitting sites.

Figure 15: Graph showing the heavy tail distribution of emissions



In a seminal study, Rella et al. in an analysis of oil and gas producing well pad facilities in the Barnett Shale in Texas found that the 6.6% highest emitting well pads were responsible for 50% of methane emissions, and the 22% highest emitting well pads were responsible for 80% of methane emissions.[73] **NMED Exhibit 37o.** Subsequent studies have found similar distribution skews. In a 2018 analysis of 1009 natural gas production sites spanning 8 basins in the U.S., Omara et al. (2018) found that the top 5% of high-emitting sites accounted for 57% of

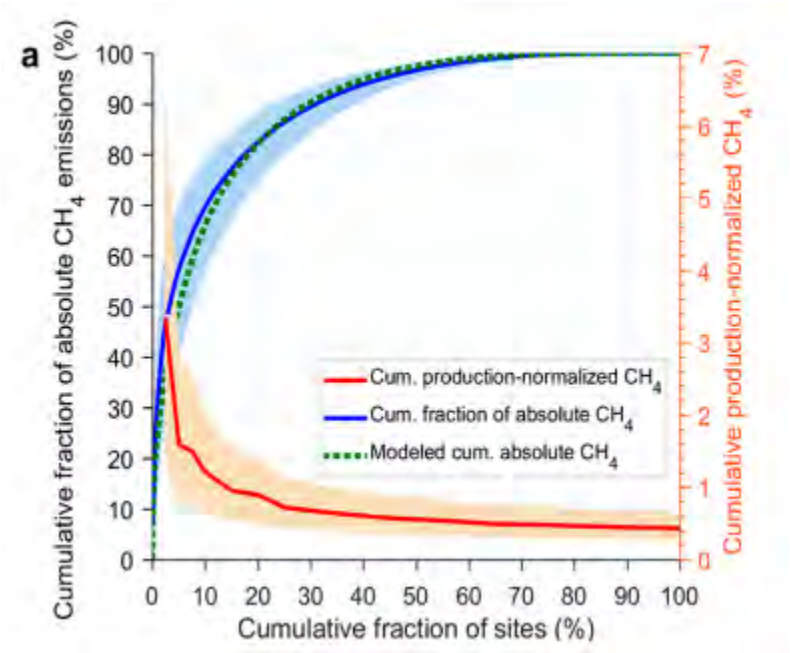
[73] Rella, Chris W., Tracy R. Tsai, Connor G. Botkin, Eric R. Crosson, and David Steele. "Measuring emissions from oil and natural gas well pads using the mobile flux plane technique." *Environmental science & technology* 49, no. 7 (2015): 4742-4748.

cumulative methane emissions.[74] **NMED Exhibit 37c.** An analysis of natural gas gathering facilities in the U.S. by Mitchell et al. (2015) found that more than 80% of emissions in their dataset issued from about 30% of gathering facilities.[75] **NMED Exhibit 37d.** One facility alone contributed 10% of total emissions.[76] **NMED Exhibit 37d.**

To investigate the nature of the "heavy tail" of methane emissions, researchers have developed a functional definition of super-emitters that can provide a threshold for analysis. Zavala-Araiza et al. (2015) set this threshold at the highest 5% of emitting sites.[77] **NMED Exhibit 37b.** Setting the threshold at percentage relative to total emissions allows for a standard definition of super-emitter across datasets. This threshold has become standard in subsequent analyses. The graph below (Figure 16) from Omara et al. illustrates this phenomenon.[78] **NMED Exhibit 37c at PDF 33.**

[74] Omara et al. (2018).
[75] Mitchell et al. (2015).
[76] Ibid.
[77] Zavala-Araiza et al. (2015).
[78] Omara et al. (2018), 12921.

Figure 16: *Figure 4 from Omara et al.*



In the graph above, site-level absolute CH4 emissions are plotted in descending rank-order. Focusing on the blue line on the lefthand side of the graph, you can see that the top 5% of sites contribute 57% of total absolute CH4 emissions.[79] The red line on the graph depicts the fraction of total production equivalent to these emissions—their cumulative methane emissions are equivalent to 1.6% of their total methane production. The dotted green line shows the modeled methane distribution for all 498,000 U.S. onshore natural gas production sites, with the top 5% of sites accounting for 50% of total CH4.

It is important to note that the super-emitter threshold chosen for research needs is different than that chosen for policy. There is a good reason for this. As noted above, setting the threshold for a super-emitter at a standard 5% of total emissions allows researchers to use this definition across datasets and create apples-to-apples comparisons. However, the threshold set

[79] The light blue and orange bands around the lines visually depict the 95% confidence intervals on the cumulative fraction of absolute and production-normalized CH4 emissions, respectively.

for policy serves a different function—to set a notification threshold for detected events in a super-emitter program. This will be discussed in more detail in the policy provisions section of this testimony.

Brandt et al. (2016) conducted a meta-analysis of approximately 150,000 measurements from 18 prior studies and found that heavy-tailed distributions are a pervasive characteristic of natural gas leak size distributions, natural gas leaks are more heavy-tailed than other natural and social phenomena, and the largest 5% of leaks are responsible for over 50% of the leaked methane from a given source category.[80] **NMED Exhibit 37p.** They conclude that these super-emitting sources represent "profitable 'low hanging fruit' for methane reduction efforts."[81] **NMED Exhibit 37p at PDF 135.** This skewed distribution holds true for all subsequent analysis of differing segments and basins reviewed below.

Frankenberg et al. (2016) conducted an analysis of methane emissions from oil and gas infrastructure in the San Juan Basin.[82] **NMED Exhibit 37q.** Using airborne sensing in a 2015 campaign, they detected more than 250 individual methane plumes and found that the top 10% of emitting sources contributed 49-66% of total methane emissions. They note that their analysis "shows that strong emitters dominate the regional budget, with presumably lower marginal cost for emission reductions."[83] **NMED Exhibit 37q at PDF 147.**

Zavala-Araiza et al. (2017), building on prior research that found the highest 1% and 10% of emitting sites in a survey of the Barnett Shale in Texas were responsible for approximately

[80] Brandt, Adam R., Garvin A. Heath, and Daniel Cooley. "Methane leaks from natural gas systems follow extreme distributions." *Environmental science & technology* 50, no. 22 (2016): 12512-12520.
[81] Ibid., 12513.
[82] Frankenberg, Christian, Andrew K. Thorpe, David R. Thompson, Glynn Hulley, Eric Adam Kort, Nick Vance, Jakob Borchardt et al. "Airborne methane remote measurements reveal heavy-tail flux distribution in Four Corners region." *Proceedings of the national academy of sciences* 113, no. 35 (2016): 9734-9739.
[83] Ibid., 9738.

44% and 80% of total methane emissions respectively, assessed whether the predicted distribution of component emissions could explain the previously observed heavy-tail distribution.[84] **NMED Exhibit 37r.** They found "an insufficient contribution from the components or operations that can produce high emission rates by design" and instead "this result is indicative of the existence of abnormal process conditions that create pathways for substantial unintended emissions of produced gas."[85] **NMED Exhibit 37r at PDF 150.** They conclude that "rather than looking to control emissions from a few sites, minimizing emissions requires monitoring approaches that enable efficient and timely responses to the unpredictable nature of when and where a super-emitter will be located."[86] **NMED Exhibit 37r at PDF 152.**

Chen et al. (2022), in their analysis of emissions from the New Mexico Permian Basin, found that 50% of measured emissions issued from 118, or 12%, of the 928 sources identified.[87] **NMED Exhibit 37j at PDF 90.** They further note that "the heavy tail gets even heavier for the largest emissions and contains a disproportionate number of midstream assets."[88] **NMED Exhibit 37j at PDF 90.** They, like other authors, draw the conclusion that these heavy-tailed emissions point to the "significant potential for mitigating methane emission by detecting and fixing these high-consequence sources."[89] **NMED Exhibit 37j at PDF 90.** Their analysis shows

[84] Zavala-Araiza, Daniel, Ramón A. Alvarez, David R. Lyon, David T. Allen, Anthony J. Marchese, Daniel J. Zimmerle, and Steven P. Hamburg. "Super-emitters in natural gas infrastructure are caused by abnormal process conditions." *Nature communications* 8, no. 1 (2017): 14012.
[85] Ibid., 2.
[86] Ibid., 4.
[87] Chen et al. (2022), 4320.
[88] Ibid.
[89] Ibid.

a high natural gas loss rate of 8.1% at the low end and 11% at the high end.[90] **NMED Exhibit 37j at PDF 90.**

Given the high emissions associated with the production sector, research has examined the distribution of methane emissions from oil and gas wells. Because oil and gas production declines substantially over the first few years of a well's life, new, high-producing wells make up a small percentage of active onshore wells, which number approximately 800,000 (in 2019). As a result, well production is highly skewed, with more than 90% of production coming from fewer than 20% of wells. Omara et al. (2022) focused analysis on emissions from low-producing oil and gas wells (defined as having average site-level production of ≤15 barrels of oil equivalent per day (boed)), which made up 6% of U.S. oil and gas output in 2019.[91] **NMED Exhibit 37s.** Both vertical and horizontal well production declines precipitously, with the former dropping from an approximately 25 boed/site maximum to below 15 boed within 1-2 years and the latter dropping from an approximately 150 boed/site maximum to below 15 boed within 3-5 years.[92] **NMED Exhibit 37s at PDF 160.** Working with a sample of 240 low-producing well sites across six U.S. oil and gas basins, the authors found that most low production sites have methane emissions of up to 5 kg/hr with a loss rate of 12%. They found a skew in the distribution of emissions with the top 5% of high-emitting sites responsible for approximately 50% of cumulative emissions.[93] **NMED Exhibit 37s at PDF 162.** They also found a dramatic skew in

[90] Ibid. This estimate is higher than Cusworth et al. (2026). They hypothesize that the time period may explain the divergence, with significant flaring occurring due to extremely high gas productively when many wells were being actively spudded in 2019. In contrast, Cusworth et al.'s study was conducted in 2024. Cusworth, Daniel H., Daniel M. Bon, Daniel J. Varon, Alana K. Ayasse, Gregory P. Asner, Joseph Heckler, Evan D. Sherwin, Sebastien C. Biraud, and Riley M. Duren. "Duration of super-emitting oil and gas methane sources." *Nature communications* 17, no. 1 (2026): 2011.
[91] Omara, Mark, Daniel Zavala-Araiza, David R. Lyon, Benjamin Hmiel, Katherine A. Roberts, and Steven P. Hamburg. "Methane emissions from US low production oil and natural gas well sites." *Nature Communications* 13, no. 1 (2022): 2085.
[92] Ibid., 2.
[93] Ibid., 4.

methane loss rate—the top 15% of sites based on methane loss rates emitted more than 32% of their product, and the top 5% of sites emitted more than 90% of their product. These percentages represent not only substantial emissions in aggregate, but extremely inefficient production. Overall, the authors affirm a tendency toward higher methane loss rates as site-level production declines, resulting in low-producing wells generating half of oil and gas production site methane emissions. They point to avoidable maintenance issues as the key driver of these emissions and assert that "routine emissions monitoring and repair has the potential to yield large emission reduction benefits."[94] **NMED Exhibit 37s at PDF 165.**

Yu et al. (2022), whose analysis of methane emissions from gathering pipelines was discussed in the prior section, note the same skewness generated by high-emitting sources. Across their four surveys, a small percentage—12.0% to 21.1%—of the highest-emitting sources account for more than 50% of total emissions.[95] **NMED Exhibit 37n at PDF 123.** The largest emitting gathering pipeline in their fall 2019 campaign was observed to be emitting at a rate of 4689 [±2297, 95% confidence interval] kg/hr of methane, roughly the same rate as the smallest 91 sources combined.[96] **NMED Exhibit 37n at PDF 123.**

Zimmerle et al. (2015) modeled methane emissions from the natural gas transmission and storage systems in the U.S. based on onsite measurement of individual emission sources.[97] **NMED Exhibit 37f.** They found that equipment-level emission data are highly skewed, with 5% of measurements accounting for at least 30% of total emissions in 13 of the 17 models, and

[94] Ibid., 7.
[95] Yu et al. (2022), 971.
[96] Ibid.
[97] Zimmerle, Daniel J., Laurie L. Williams, Timothy L. Vaughn, Casey Quinn, R. Subramanian, Gerald P. Duggan, Bryan Willson et al. "Methane emissions from the natural gas transmission and storage system in the United States." *Environmental science & technology* 49, no. 15 (2015): 9374-9383.

accounting for more than 50% of total emissions in 8 models.[98] **NMED Exhibit 37f at PDF 60.** The authors distinguish between long-tail fugitive emissions at the component level and super-emitter emissions at the facility level. They modeled "super-emitters" at the facility level, utilizing an emissions distribution developed from tracer flux measurements and a frequency model representing the probability of identifying a super-emitter, and found that super-emitting events account for 23% [9 to 39%] of modeled emissions and do not scale with equipment counts.[99] **NMED Exhibit 37f at PDF 65.** In their analysis of long-tail fugitive emissions at the component level, they found that the largest 5% of fugitive emissions, which they assert were likely due to equipment or control malfunctions, accounted for 40−75% of measured emissions in 11 of their 17 emission models. They note that "these emissions, and by extension a substantial proportion of total emissions, would likely be effectively reduced by reducing the frequency at which malfunctions occur and/or reducing the emission rate should a malfunction occur," and "[a]ssuming a conservative 40% of emissions in each of these categories could be identified and eliminated, total emissions would be reduced by 14−15%."[100] **NMED Exhibit 37f at PDF 65.**

Research has confirmed a pervasive skew in methane emissions for which a relatively small percentage of high-emitting sources are responsible. However, one of the challenges in analyzing these super-emitter events is deriving their aggregate emissions when duration is largely unknown. Aggregate methane emissions are calculated by multiplying the emission rate of the leak by the duration of the leak. Ground, aerial, and satellite sensing can all estimate emission rates, however, duration requires knowing the start and end of the leak, which is only

[98] Ibid., 9377.
[99] Ibid., 9382.
[100] Ibid.

attainable through continuous or near-continuous monitoring.[101] To address this challenge with available technologies and methods, Cusworth et al. (2026) conducted a focused aerial methane detection campaign on the New Mexico side of the Permian Basin between April 30-May 17, 2024, in order to estimate the intensity and duration of super-emitters across all infrastructure and supply chain categories therein. [102] **NMED Exhibit 37t.** The full region of the survey covered 12,000 km, including 67,000 wells, 98% of New Mexico Permian oil production, 98% of New Mexico Permian gas production, 295 compressor stations, and 45 gas processing plants.[103] **NMED Exhibit 37t at PDF 170.** They detected over 500 super-emitting sources, with super-emitter defined as having an emission rate of equal to or above 100 kg/hr, with 300 of these sources observed over multiple days.

Their analysis had two aims: to estimate basin-level emissions from super-emitters and to focus on high-production regions with multiple revisits over subsections of the basin to quantify the duration of super-emitter events. They estimated that observed super-emitters made up approximately 50% [37-73%] of total methane emissions. They estimated the durations of the observed super-emitter events by first categorizing them as "finite," meaning the events started and ended within the temporal interval of the campaign, "unbounded," meaning that the events emitted for the entirety of the campaign, or "mixed," meaning that the events were either ongoing when the campaign began but ended before the campaign concluded or started during the campaign and were ongoing when the campaign ended. Of the 369 super-emitter events identified, 174 were finite, 18 were unbounded, and 177 were mixed. They estimated super-emitter event durations from this data, finding that the median shortest and median longest

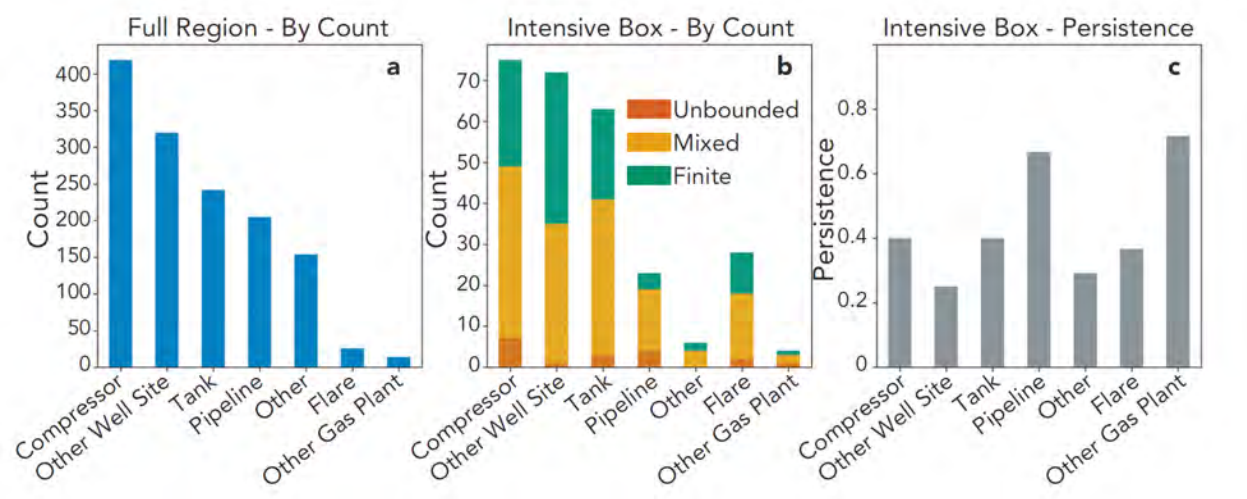
[101] Cusworth et al. (2026) note there are limiting in ground-level monitoring with regard to large plumes due to transport dynamics and the vertical structure of plumes.
[102] Cusworth et al. (2026).
[103] Ibid., 2.

duration for finite events are 2.4 to 145 hours, respectively; for mixed events, 0.14 to 129 hours, respectively; and for unbounded events, 387 to 411 hours, respectively.[104] **NMED Exhibit 37t at PDF 173.** They proceeded with a median duration of 2.4 hours based on observation revisit time, as only 2% of sources were observed more than three hours after the initial detection.[105] **NMED Exhibit 37t at PDF 174.** With both duration estimates and emission rates calculated, they were able to estimate aggregate emissions. Using the shortest duration, they estimated total emissions of 5.98 gigagrams (Gg) (1 Gg = 1000 metric tons), with 2.18 Gg (36%) from unbounded events, 2.44 Gg (41%) from mixed events, and 1.36 Gg (23%) from finite events. Using the longest durations results in higher total emissions (14.7Gg), with 2.33Gg (16%) from unbounded events, 5.21 Gg (35%) from mixed events, and 7.20 Gg (49%) from finite events.[106] **NMED Exhibit 37t at PDF 174.**

Using high-resolution visible imagery and geographic information system (GIS) datasets, they were able to attribute each event to specific infrastructure. Figure 17 below shows the categorized results of their analysis. Compressors made up 27% of super-emitter sources identified, and, along with pipelines, made up the majority—39%—of super-emitter sources identified, reflecting the importance of emissions from gathering and boosting activities in the Permian. The other most prevalent source categories were other well sites (24%), tanks (22%), pipelines (12%), flares (11%), and other gas plant sources (2%).

[104] Ibid., 5.
[105] Ibid., 6.
[106] Ibid.

Figure 17: Cusworth et al. infrastructure counts for detected sources during the campaign with associated source persistence[107] **NMED Exhibit 37t at PDF 175.**



Breaking down these sources by duration, for finite sources, other well site emissions were most prevalent (at 36%), followed by compressors (25%). For unbounded events, compressors (39%) were most prevalent, and other well sites only made up 6%. The authors inferred that other well site emissions were shorter-lived, and potentially associated with planned operations, due to their intermittency and high prevalence among finite-duration events. Tank sources, in contrast, were more persistent, suggesting that operational inefficiencies, for example open hatches or leaks, were responsible for the emissions, leading the authors to conclude that focused attention on these sources could potentially lead to significant emission reductions.[108] **NMED Exhibit 37t at PDF 174.**

In conclusion, research on methane emissions from the oil and gas sector has identified a pervasive skew in emissions distribution due to the presence of super-emitter events across the supply chain. These low-frequency events substantially contribute to high methane emissions

[107] Ibid., 7.
[108] Ibid., 6.

from the sector due to their high emission rates. The next section reviews the policy implications of the research on super-emitters.

(Finding #5) Because of the impact of these outlier emissions, there is significant abatement potential through regulation of "super-emitters."

Analysis of methane emissions from the oil and gas sector informs policy solutions to abate methane. As Brandt et al. (2016) articulated, and other researchers echo, addressing high-tail methane emissions represents "low hanging fruit" to abate a substantial amount of emissions. Because methane emissions come at the costs of lost product for sale, abating methane emissions also financially benefits producers. The remainder of this section draws out the policy implications of the research surveyed in the previous sections.

Alvarez et al., writing in *Science* in 2018, assert that the heavy-tail skew of methane emissions "has important implications for mitigation because it suggests that most sources—whether they represent whole facilities or individual pieces of equipment—can have lower emissions when they operate as designed." Further, "significant emissions reductions could be achieved by deploying well-designed emission detection and repair systems that are capable of identifying abnormally operating facilities or equipment."[109] **NMED Exhibit 37i at PDF 84.** They point to pneumatic controllers and equipment leaks as optimal targets for emission reduction—malfunctioning controllers account for 66% of pneumatic controller emissions and equipment leaks account, when properly estimated, are 60% higher than the GHGI.[110] **NMED Exhibit 37i at PDF 84.** These are precisely the areas that this proposed rule targets. This assessment echoes Brandt et al., who wrote in *Science* in 2014 that "[t]he heavy-tailed distribution of observed emissions rates presents an opportunity for large mitigation benefits if

[109] Alvarez et al. (2018), 187.
[110] Ibid.

scientists and engineers can develop reliable (possibly remote) methods to rapidly identify and fix the small fraction of high-emitting sources."[111] **NMED Exhibit 37h at PDF 81.**

Many of the studies summarized here do not include analysis of pipelines; Yu et al. (2022) fortunately does. In drawing conclusions from their analysis of methane emissions from natural gas gathering pipelines in the Permian Basin, they assert that their results "imply a need for increased pipeline-specific leak detection and repair (LDAR) programs that account for the heavy-tailed nature of the emissions distribution."[112] **NMED Exhibit 37n at PDF 124.** They highlight the "operational utility that aerial detection platforms provide by locating large emission sources from gathering pipelines, which conventional ground-based surveys are generally not well-equipped to do."[113] **NMED Exhibit 37n at PDF 124.**

Brandt et al. (2016) conclude that "[s]uperemitters are attractive as a mitigation target for achieving substantial emissions reductions at low marginal cost."[114] **NMED Exhibit 37p at PDF 140.** They assert that given millions of global natural gas infrastructure sites capable of generating leaks, "there is no substitute diligence: to reduce frequency of superemitters, formal leak detection and repair (LDAR) programs have been demonstrated to be effective" and "a regulatory approach mandating repeat checkups (as recently proposed in EPA regulation) could effectively reduce superemitter emissions."[115] **NMED Exhibit 37p at PDF 149.** Regulators should pursue a "two-tiered policy approach" that could include "LDAR programs to find and repair superemitting devices, coupled with empirically based emission limits or more rigorous

[111] Brandt et al (2014), 735.
[112] Yu et al. (2022), 972.
[113] Ibid.
[114] Brandt et al. (2016), 12518.
[115] Ibid.

and pro-active preventative maintenance schedules for devices that are known to be large emitters."[116] **NMED Exhibit 37p at PDF 149.**

Going a step further to understand the underlying characteristics behind super-emitter events so that they can point towards effective regulatory responses, Zavala-Araiza et al. (2015) analyze data on high-emitting events from the Barnett Shale by looking at the relationship between gas production, emission rates, and probability of being in the highest 5% of emitters.[117] **NMED Exhibit 37b.** They find that the probability of a site being among the highest 5% of measured emissions (in their dataset, the threshold is 4.6 kg/hr) does not increase uniformly with production. While greater production means that more gas is flowing through the segments and, consequently, when there is a leak it will have a higher emission rate due to higher flow, there are counteracting factors that constrain leaks from high producers. Instead, Zavala-Araiza et al. found that lower production sites (10-100 thousand standard cubic feet per day (Mcf/d) were almost twice as likely to be among the top 5% of emitters. The constraining conditions for leaks from high production sites were explored by Omara et al. (2018), who attribute the lower relative emissions to the fact that high production sites are generally newer facilities, so they are more likely to have optimally performing equipment and components and are likely subject to more frequent on-site inspection and maintenance than older sites.[118] **NMED Exhibit 37c at PDF 31.** In addition, because the flow rate is high at high-producing gas production sites, a leak is more likely to be audible and/or visible to workers on site, increasing the likelihood of detection and quick repair.[119] **NMED Exhibit 37c at PDF 31.** Therefore, the empirical trend of decreasing

[116] Ibid.
[117] Zavala-Araiza et al. (2015).
[118] Omara et al. (2018), 12919.
[119] Ibid.

methane intensity with increasing production can be explained by the age and productivity of the infrastructure.

In their analysis of gas gathering and processing facilities, Mitchell et al. (2015) note that the skew of the emissions is lower for processing facilities than for other gas facilities and explain this difference with reference to LDAR programs and facility staffing.[120] **NMED Exhibit 37d.** Active LDAR programs make it more likely that a high-emitting leak would be caught early. In addition, gas processing facilities tend to be staffed by an operator at all times, making it more likely that a worker would hear or see a high-emitting leak, given that gas processing plants have high throughput and a large leak would likely be audible and/or visible. Of the 25 facilities (both gathering and processing) with the lowest emission rates adjusted for production, 19 were staffed full time, whereas looking at only gathering facilities, whose emissions were much more skewed, only 14% were staffed full time.

Zavala-Araiza et al. (2017) conclude that "[f]requent or better yet continuous site-level monitoring of emission or process conditions would reduce the duration of super-emitting behavior," and, further, "such monitoring should produce accumulated learning, which in turn provides the knowledge to improve equipment, system design and operations that would reduce the frequency of large emission events."[121] **NMED Exhibit 37r at PDF 153.**

An analysis of the efficacy of required leak detection and repair (LDAR) at 36 gas facilities in Alberta, Canada by Ravikumar et al. (2020) found that total emissions were reduced by 44% after one LDAR survey, with over 90% of the leaks found in the initial survey when

[120] Mitchell et al. (2015).
[121] Zavala-Araiza et al. (2017), 5.

resurveyed were non-emitting, showing high repair effectiveness.[122] **NMED Exhibit 37u.** However, fugitive emissions were reduced by only 22% due to new leaks that occurred between the quarterly surveys, suggesting the need for "frequent, effective, and low-cost LDAR surveys to target new leaks."[123] **NMED Exhibit 37u.**

The research surveyed above demonstrates the opportunity for significant methane abatement by targeting regulatory intervention to super-emitting events. Because these events are relatively low frequency but high-emitting, a substantial proportion of methane emitted from the oil and gas sector can be avoided by catching leaks early and requiring their repair. A Super-Emitter Program complements requirements for routine LDAR by identifying leaks between routine LDAR surveys so that they do not persist for the duration between surveys.

IV. NEED FOR A STATE-LEVEL SUPER-EMITTER PROGRAM

The Department conducted a comprehensive analysis of methane emissions in New Mexico using Carbon Mapper's remote-sensing methane detection data.[124] This analysis complements and supplements the scientific literature on super-emitters reviewed in the prior section and demonstrates the need for a state-level Super-Emitter Program in New Mexico.

Department staff analyzed two methane datasets: an aggregate plume dataset downloaded from Carbon Mapper's public emissions data portal and a persistent source dataset provided by Carbon Mapper to the analysts by email.[125] When the analysts began work on methane regulatory development, one of the first resources that the team explored was an analysis by

[122] Ravikumar, Arvind P., Daniel Roda-Stuart, Ryan Liu, Alexander Bradley, Joule Bergerson, Yuhao Nie, Siduo Zhang, Xiaotao Bi, and Adam R. Brandt. "Repeated leak detection and repair surveys reduce methane emissions over scale of years." *Environmental Research Letters* 15, no. 3 (2020): 034029.
[123] Ibid.
[124] The full results of this analysis are in the Carbon Mapper Analysis Data Report. **NMED Exhibit 38.**
[125] https://carbonmapper.org/data

Carbon Mapper of the near-term mitigation opportunity of addressing methane super-emitter events using the Permian Basin as a case study. Carbon Mapper researchers conducted a focused remote-sensing campaign in the New Mexico side of the Permian Basin in April/May 2024, with the aim of estimating basin-level emissions of methane from super-emitters (defined as emitting >100 kg/hr) and to quantify the duration of super-emitter events. The results of this analysis were published as an article on their website on March 10, 2025 and as a scientific paper in *Nature Communications* in 2026.

As reported on their website, they: identified over 1,380 methane plumes in the surveyed region; attributed these plumes to about 529 unique facilities; through quantification analysis, estimated that most leaks ranged between 50-500 kg/hr with many exceeding the EPA super-emitter threshold of 100kg/hr; compared these identified super-emitter emissions to TROPOMI satellite data for this same portion of the Permian over the same period of time and found that super-emitter emissions likely made up 50% of total emissions from that area; and, finally, compared these results to airborne survey data dating back to 2019 to find that 18 of these facilities were ultra-persistent super-emitters, whose emissions, which taken together and extrapolated over 5 years, lost enough gas into the atmosphere to match the emissions from 1.7 million passenger vehicles.[126] This careful scientific analysis demonstrated to the Department that further investigation of methane emissions in New Mexico looking at a larger range of data was warranted.

The Department analysts began by downloading all New Mexico data from the Carbon Mapper public portal. Because the team had questions about the data, the team initiated contact

[126] Carbon Mapper, "The Near-Term Mitigation Opportunity of Super-Emitters - A Case Study in the Permian Basin," March 10, 2025, https://carbonmapper.org/articles/the-near-term-mitigation-opportunity-of-super-emitters

with Carbon Mapper and engaged in a series of virtual meetings in which they asked questions and Carbon Mapper staff provided answers. Through this process, the team learned that Carbon Mapper was able to provide a tailored dataset of what they identified as "persistent emitters"—the subject of their website article and scientific journal article—for the period April 30, 2024-Dec 10, 2025. Carbon Mapper defines a persistent source as a location where three or more methane plumes were detected across greater than 50% of observation opportunities at that site.[127]

Before analyzing the aggregate plume data, the analysis team assembled the data into Excel, then uploaded the data to ArcGIS, a web-based mapping software, to remove any residual plumes outside of New Mexico, then exported the culled data back into Excel to form a master dataset of 4,188 plumes. They then performed an exclusion analysis on the master dataset that consisted of removing plumes without quantified emission rates (in Carbon Mapper's dataset these plumes have a value of zero) and null detects, which are observations that have no methane detected. After this exclusion analysis, the master dataset contained 3,964 plumes, for a retention rate of 94.7%.

To analyze the emission rates of plumes in the dataset, the team needed to first understand the nature of the uncertainty attendant to the emission rates assigned by Carbon Mapper. Because plume observations are snapshots in time and space, Carbon Mapper must calculate an emission rate. When they do this, they take into account sources of uncertainty that affect the emission rate. These include wind speed and direction at the time of overflight, local atmospheric turbulence, sensor noise, background methane levels, and plume deformation due to

[127] Carbon Mapper Data FAQs: Carbon Mapper - Data

viewing geometry (which is the angle between the instrument, plume, and sun). Some of these uncertainty factors are calculated and attached to the estimated emission rate as a range, and others, primarily related to the instrumentation itself, cannot be factored into an uncertainty range. This produces an emission rate with a positive and negative range, e.g. 500 kg/hr [±100 kg/hr], which means that the true emission rate lies somewhere between 400 and 600 kg/hr. For each of the reported emissions rates for each plume, the team calculated the minimum and maximum rates based on the uncertainty range provided by Carbon Mapper. These plume emission rate values—minimum, reported, and maximum—were used in subsequent analysis.

To characterize the aggregate data set, the team first characterized the data by deriving the mean (average) and median of each of the three emission rate values for each year of data. The results are in Table 1 below. For all three emission rates—minimum, reported, and maximum—the mean is substantially above the median, meaning that the dataset is skewed towards a small number of very high values. Another way to say this is that the typical value in the dataset is lower than the average value in the dataset. This pattern is consistent with observed methane emissions in the oil and gas sector in scientific research—there is a "heavy-tail" skew indicating total emissions are dominated by high-emitting sources.

Table 1: Median emission rates across years for all plumes observed between 2019-2025

Year	Mean Emission Rates (kg CH_4/hr)			Median Emission Rates (kg CH_4/hr)		
	Minimum ER	Reported ER	Maximum ER	Minimum ER	Reported ER	Maximum ER
2019	278	438	597	177	292	400
2020	295	404	514	168	263	351
2021	289	416	543	162	252	338
2022	216	345	473	150	273	387
2023	391	602	813	204	386	550
2024	194	280	366	114	167	217

2025	438	628	819	286	405	512
All Years	**256**	**382**	**507**	**149**	**238**	**324**

The different emission rate thresholds are as follows: Minimum Emission Rate (ER) = ER – Emission Rate Uncertainty (ERU); Reported Emission Rate = ER; Maximum Emission Rate = ER + ERU.

To understand the prevalence of large-emitting events among the aggregate data, the team refined the analysis by emission rate thresholds. The team elected to analyze the data using two thresholds—50 kg/hr and 100/hr—in order to determine how much more emissions abatement would be achieved by lowering the emission rate threshold for super-emitter events for the purpose of the rule. Therefore, analysis from this point on includes plumes sorted by both those that are equal to or exceed 50 kg/hr and those that are equal to or exceed 100 kg/hr.

The first step in the threshold analysis was determining the maximum, reported, and minimum emission rates for the populations of plumes that fell into the two threshold categories. The results of this analysis are in Table 2 below. This table shows that even using the minimum emission rate, which is the most conservative emission rate value, a majority of plumes in the aggregate data set are large emitters—85% of plumes equal or exceed 50 kg/hr, and 66% of plumes equal or exceed 100 kg/hr. Using the reported emission rate, 95% of plumes equal or exceed 50 kg/hr, and 83% of plumes equal or exceed 100 kg/hr. And, using the maximum emission rate, 98% of plumes equal or exceed 50 kg/hr, and 90% of plumes equal or exceed 100 kg/hr.

Table 2: Percent of annual observed plumes by emission rate range and threshold

Year	Minimum Emission Rate		Reported Emission Rate		Maximum Emission Rate	
	Plumes with ER ≥ 50 kg/hr	**Plumes with ER ≥ 100 kg/hr**	**Plumes with ER ≥ 50 kg/hr**	**Plumes with ER ≥ 100 kg/hr**	**Plumes with ER ≥ 50 kg/hr**	**Plumes with ER ≥ 100 kg/hr**
2019	90%	73%	99%	92%	100%	97%
2020	85%	74%	96%	83%	98%	91%

2021	90%	70%	98%	87%	99%	94%
2022	87%	69%	99%	90%	100%	96%
2023	89%	72%	96%	88%	99%	94%
2024	79%	55%	90%	72%	95%	81%
2025	95%	89%	100%	100%	100%	100%
All	**85%**	**66%**	**95%**	**83%**	**98%**	**90%**

The different emission rate thresholds are as follows: Minimum Emission Rate (ER) = ER – Emission Rate Uncertainty (ERU); Reported Emission Rate = ER; Maximum Emission Rate = ER + ERU. Emission Rates are in kg CH_4/hr.

Part of the explanation for this pattern is explained by the detection limits of the imaging technology. As discussed in Cusworth et al. (2026), the detection limit is the threshold at which 90% of emissions are detected.[128] **NMED Exhibit 37t at PDF 170.** During the course of the aerial campaign for their study, the detection limit of their instrumentation was 70-150 kg/hr, from which the authors conclude that they have "near-full detection sensitivity to the super-emitter class," defined in their study as ≥100 kg/hr. Detection limit is influenced by conditions when conducting the sensing, so it needs to be calculated for each survey. In general, Carbon Mapper uses instrumentation on aircraft that can sense plumes as low as 5-10 kg/hr under moderate conditions (90% detection limits are closer to 30 kg/hr), and Tanager satellites are designed to detect methane plumes with emission rates as low as 70 kg/hr under moderate conditions (predicted 90% detection limit of about 100 kg/hr).[129] What this means is that there are more plumes that are below the limit of detection by instrumentation on aircraft and satellites that are not being detected, i.e., there are more anthropogenic methane emissions being produced than researchers are sensing. The presence of so many detected large emission events given the intermittency of the observation data suggests that there are many more large emission events

[128] Cusworth et al. (2026), 2.
[129] https://carbonmapper.org/work/science

occurring on an ongoing basis, in addition to the many smaller emission events that are unable to be confidently detected by instrumentation.

It is useful to return for a moment to the definition of super-emitter event used in much of the scientific literature and the distinction between this definition and that used by policymakers. Zavala-Araiza et al. (2015) advocated the use of the top 5% of emitting sites in a dataset to functionally define super-emitters. The advantage of this approach is that it allows researchers to use the same definition to characterize different datasets. This has allowed researchers to do comparative studies across segments of the oil and gas supply chain and conclude that the same heavy-tailed distribution is observed in each segment. In other words, each segment of the supply chain is characterized by a minority of emitters who disproportionately contribute to total emissions. This is a conclusion about the *distribution* of emissions. The disadvantage is that the emission rate threshold for what is deemed a super-emitter will change from study to study. This 5% is only determined retroactively to the observed events because it is a fraction of the dataset population. In some studies, the 5% threshold is quite low, at less than 10 kg/hr. But, remember that aggregate emissions are a product of emission rate multiplied by duration. So, even a low emitting source can have very high aggregate emissions if it is emitting for a long time. It is also not possible to use this proportional definition regulatorily because the threshold is variable. This is why the EPA selected a hard threshold for their Super-Emitter Program and some scholarly work (e.g., Cusworth et al. 2026) has adopted this same approach. A hard threshold allows a regulatory body to regulate a subset of emission rates, and therefore, emitters. In the Super-Emitter Program framework, only events over a chosen threshold are classified as super-emitter events and nearby sources notified, thereby triggering a requirement to investigate. To make a

Super-Emitter Program practicable, it is necessary to set a hard emission rate threshold for regulatory purposes.

Returning to the results displayed in Table 2, the fact that the population of observed plumes over 50kg/hr and over 100 kg/hr is so large indicates that methane super-emitter event emissions are a significant problem in New Mexico. But, how large a problem, in terms of aggregate emissions, is challenging to determine. As discussed in the scientific literature review section, aggregate methane emissions are calculated by multiplying the emission rate of the leak by the duration of the leak.

$$\boldsymbol{Aggregate\ emissions = emission\ rate\ x\ duration}$$

Carbon Mapper data provides estimated emission rates, but due to a lack of continuous remote sensing, there is very little concrete data on super-emitter event durations. Because calculating the potential reductions of methane through a Super-Emitter Program is essential to the policymaking process, Department analysts calculated a range of potential emissions reductions based on event durations that vary from 15 minutes to 3 months. The results are provided in Table 3 below.

Table 3: Estimated methane emission across various event durations in CO_2e (t)

Duration Threshold	Plumes with Emission Rates **≥ 50 kg CH_4/hr**			Plumes with Emission Rates **≥ 100 kg CH_4/hr**		
ER Range	**Min ER**	**Reported ER**	**Max ER**	**Min ER**	**Reported ER**	**Max ER**
Base Emission Rate (kg CH_4/hr)	178	253	334	234	291	366
15 minutes	3.7	5.2	6.9	4.8	6.0	7.6
30 minutes	7.3	10.5	13.8	9.7	12.0	15.1
1 hours	14.7	20.9	27.5	19.3	24.0	30.2
2 hours	29.4	41.7	55.1	38.6	48.0	60.4
3 hours	44.0	62.7	82.6	57.9	72.0	90.7
5 hours	73.4	105.0	138.0	96.5	120.0	151.0

12 hours	176.0	251.0	330.0	232.0	288.0	363.0
24 hours	352.0	502.0	660.0	463.0	576.0	725.0
48 hours	704.0	1,000.0	1,320.0	927.0	1,150.0	1,450.0
3 days	1,060.0	1,510.0	1,980.0	1,390.0	1,730.0	2,180.0
5 days	1,760.0	2,510.0	3,300.0	2,320.0	2,880.0	3,630.0
7 days	2,460.0	3,510.0	4,620.0	3,240.0	4,030.0	5,080.0
10 days	3,520.0	5,020.0	6,600.0	4,630.0	5,760.0	7,250.0
15 days	5,280.0	7,530.0	9,910.0	6,950.0	8,640.0	10,900.0
1 month	10,700.0	15,300.0	20,100.0	14,100.0	17,500.0	22,100.0
3 months	32,100.0	45,800.0	60,300.0	42,300.0	52,600.0	66,200.0

[1]Calculation = [Median plume emission rate x GWP-20 (82.5)) ÷ 1,000] x Duration (hours). The median emission rate is the 6-year overall value for each emission rate range. Note: Base emission rate units are in kg CH_4/hr

Three months was selected as the high-end of the duration range because a three-month leak is possible even with full compliance with the least restrictive LDAR requirements of the Ozone Precursor Rule (LDAR requirements in the rule vary with production level and infrastructure type). Cusworth et al. (2026), in their focused analysis of the duration of super-emitter events in the Permian Basin, estimated that the median event duration is 2.4 hours, which is why these lines of the table are highlighted.

Table 3 shows emissions in equivalent annual vehicle emissions *per leak*. The total plumes in the aggregate dataset after exclusion analysis and culling plumes whose emission rates fall below 50 kg/hr is 3768 across seven years, 2019-2025. Detections are a function of monitoring frequency (as discussed in the Carbon Mapper Analysis Data Report section 2.4), so this is likely an undercount of total plumes each year. **NMED Exhibit 38.** Divided by seven years, the average number of plumes per year is 538. Table 4 below shows the duration range estimates shown above multiplied by the average annual plumes that are equal to or exceed 50 kg/yr. This represents the *total possible emissions burden* of super-emitter events per year estimated based on observed data in both kilograms of methane and equivalent annual vehicle emissions.

Table 4: Aggregate methane emissions expressed as the equivalent number of passenger vehicles over time for a single event and for a yearly average of 538 events

Super-Emitter Duration	Single Event with Median Emission Rate 253 kg CH4/hr		538 Events with Median Emission Rate 253 kg CH4/hr	
	Aggregate Methane Emissions (kilograms)	Equivalent Annual Passenger Vehicles CO_2e) (Rounded	Total Aggregate Methane Emissions (kilograms)	Total Equivalent Annual Passenger Vehicles (CO_2e) (Rounded)
15 minutes	63	1	33,894	538
30 minutes	127	2	68,326	1,076
1 hour	253	5	136,114	2,690
2 hours	506	9	272,228	4,842
3 hours	760	14	408,880	7,532
5 hours	1,267	23	681,646	12,374
12 hours	3,042	55	1,636,596	29,590
24 hours	6,084	109	3,273,192	58,642
48 hours	12,167	218	6,545,846	117,284
3 days	18,251	327	9,819,038	175,926
5 days	30,418	546	16,364,884	293,748
7 days	42,586	764	22,911,268	411,032
10 days	60,837	1,091	32,730,306	586,958
15 days	91,255	1,637	49,095,190	880,706
1 month	185,046	3,319	99,554,748	1,785,622
3 months	555,137	9,956	298,663,706	5,356,328

[1]Median ER of 253 kg CH_4/hr converted to t CO_2e using GWP-20; 1 passenger vehicle = 4.6 t CO_2; 3,768 plumes with emission rates ≥ 50 kg/hr were used for this analysis. The total plumes detected between 2019 – 2025 (3,768) was divided by the number of years (7), resulting in an average of 538 plumes detected each year. The single event was multiplied by 538 to obtain the cumulative impact.

As Table 4 shows, 538 super-emitter events collectively produce emissions comparable to 2,690 passenger vehicles in one year. If these events persist for the estimated 2.4-hour duration determined by Cusworth et al. (2026), the emissions from one leak are equivalent to 11 passenger vehicles, with the cumulative impact increasing to 5,918 vehicles when accounting for an average of 538 events per year. This illustrates how even short-duration leaks can have significant contributions to statewide emissions. If the average event were to last for fifteen days, the total annual burden of methane emissions climbs dramatically, reaching the equivalent of

880,706 passenger vehicles, which is 40% of total number of passenger vehicles (2,179,765) registered in NM in 2026.

The emissions costs of delayed leak repair are readily apparent. Using the median emission rate of 253 kg/hr, a single three-day event produces emissions equivalent to about 327 passenger vehicles. If that same leak persists for five, seven, ten, or fifteen days, the emissions increase drastically, adding the equivalent of 218 to 1,309 additional vehicles compared to the three-day baseline. Table 5 demonstrates how rapidly the emission burden escalates when a single super-emitter event persists unmitigated.

Table 5: Additional emissions in passenger vehicle emission equivalents for 5-, 7-, 10-, and 15-days leaks

Equivalent Cars for a single 3-Day Event	Number of Additional Cars per Time Point			
	5 days	7 days	10 days	15 days
327	+218 cars	+436 cars	+764 cars	+1309 cars

Median ER of 253 kg CH_4/hr and GWP-20 used for calculations. 1 passenger vehicle = 4.6 t CO_2

Taken together, Tables 4 and 5 demonstrate both the cumulative burden of repeated super-emitter detections and the single-event consequences of delayed action. Table 4 quantifies how several thousand plumes, at the median emission rate, collectively generate the emissions equivalent of tens of thousands, and in some cases millions, of passenger vehicles across various duration intervals. Table 5 expands on this, showing how emissions from unmanaged super-emitter events can increase dramatically within twelve days.

This analysis demonstrates the need for a state-level Super-Emitter Program to abate methane emissions from large leaks. The Department's findings indicate that super-emitter emissions are a significant source of methane emissions in New Mexico. Analysis of aggregate

Carbon Mapper plume data for the years 2019-2026 shows that a majority of plumes detected are super-emitter events, using a 50 kg/hr threshold. Even using the most conservative emission rates, 85% of plumes exceed this threshold. While duration data is unavailable given the lack of continuous monitoring, we can estimate aggregate emissions across a range of possible durations. These estimates show that one super-emitter event, with a median emission rate of 253 kg/hr emits 63 kgs of methane in 15 minutes, 253 kgs in one hour, 6,084 kgs in one day, 42,586 kgs in 7 days, 185,046 kgs in one month, and 555,137 kgs in 3 months. In equivalent annual passenger vehicle emissions, these emissions equal 1 car, 5 cars, 109 cars, 764 cars, 3,319 cars, and 9,956 cars, respectively, showing how large the impact can be from a single large emission event. When multiplied by the average number of super-emitter events per year (538) based on Carbon Mapper data, the scale of super-emitter emissions becomes clear: if every leak lasted the median duration estimated by Cusworth et al. (2026), aggregate annual emissions would equal those of 5,918 vehicles. Research has shown that many leaks are ongoing, lasting months, and even years for infrastructure like old, low-producing wells. At the high end, a year's worth of super-emitter events emitting at 253 kg/hr produces the equivalent emissions of 5,356,328 vehicles, over double the number of total vehicles registered in New Mexico. These findings also reinforce the importance of rapid detection and prompt repair, as even short duration leaks can escalate into significant emission burdens if they are left unmitigated.

Additional Analysis of Super-Emitter Events in New Mexico by Facility and Infrastructure

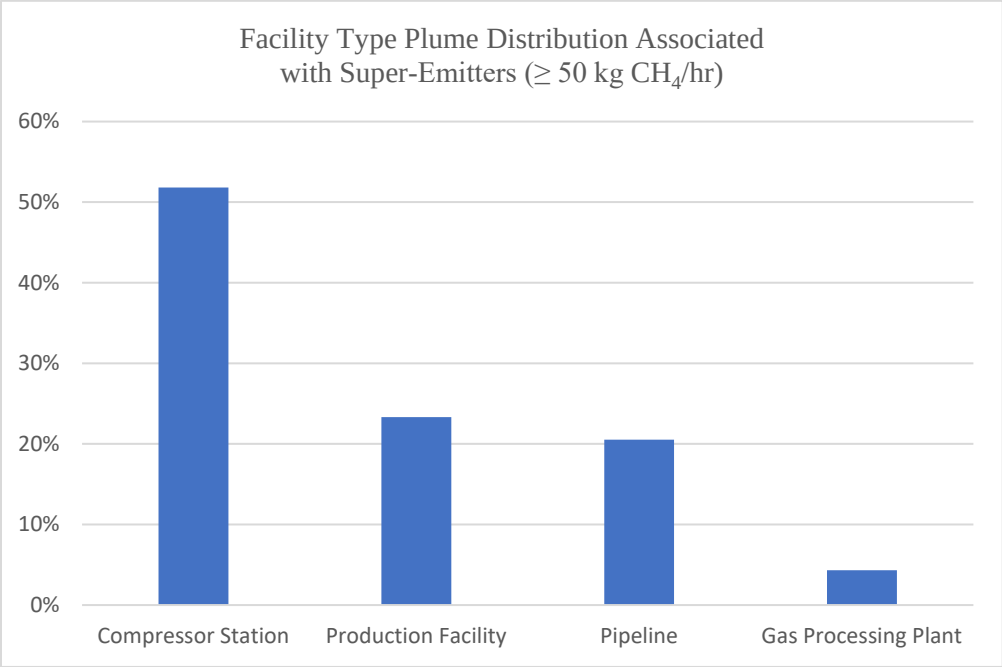
The Department performed additional analysis to characterize the persistent source dataset, consisting of 118 persistent sources, provided by Carbon Mapper in order to understand facility and equipment trends in super-emitter events in New Mexico. Carbon Mapper defines "persistent source" as a location where three or more methane plumes were detected across

greater than 50% of observation opportunities at that site.[130] Analysts disaggregated the plumes associated with these 118 sources for a total of 877 plumes.[131] **NMED Exhibit 38.** They then attributed these plumes to sources and identified the sources using data from the NMED Permitting Section, supplemented by data from Oil Conservation Division (OCD) well data, National Pipeline Mapping System (NPMS) pipeline data, and Rextag's Energy DataLink pipeline data. Finally, analysts attributed plumes to infrastructure within facilities. These analyses were done for the whole persistent source dataset and for the subset of the dataset comprising super-emitters (plumes with an emission rate equal to or exceeding 50 kg/hr), of which there were 716 plumes. All of this analysis was checked by multiple staff analysts for quality control.

Facility categories used in this analysis are Compressor Stations, Gas Processing Plants, Pipelines, and Production Facilities.[132] **NMED Exhibit 38.** Results of the analysis, presented in Figure 18, revealed that a majority of super-emitter plumes were associated with compressor stations, followed by production facilities and pipelines.

[130] Carbon Mapper Data FAQs: Carbon Mapper - Data
[131] A detailed explanation of how the Department disaggregated and analyzed this data can be found in the Carbon Mapper Analysis Data Report. **NMED Exhibit 38.**
[132] See the Carbon Mapper Analysis Data Report **NMED Exhibit 38** for explanations of these categories.

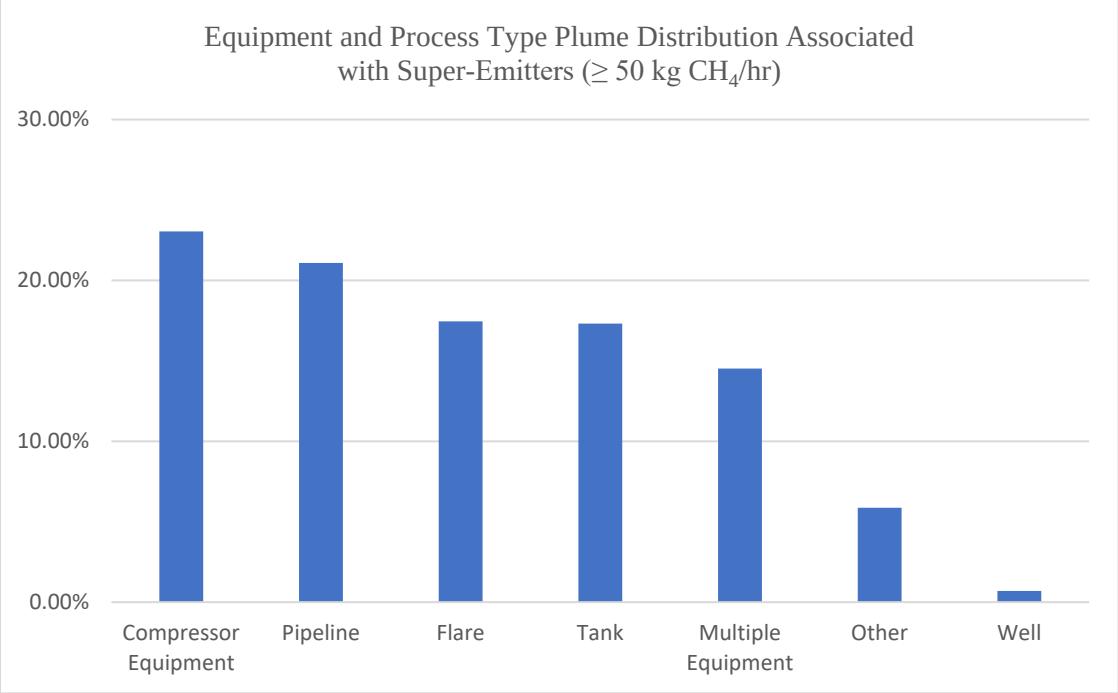
Figure 18: Facility type distribution for super-emitters as percent of dataset



Equipment/process sources and plumes were broken down into the following categories: Compressor Equipment, Flare, Multiple Equipment, Pipeline, Tank, Well, and Other.[133] **NMED Exhibit 38.** Results, presented in Figure 19, show that a majority of sources and plumes were associated with compressor equipment, followed closely by pipelines, flares, tanks, and multiple equipment.

[133] See the Carbon Mapper Analysis Data Report **NMED Exhibit 38** for explanations of these categories.

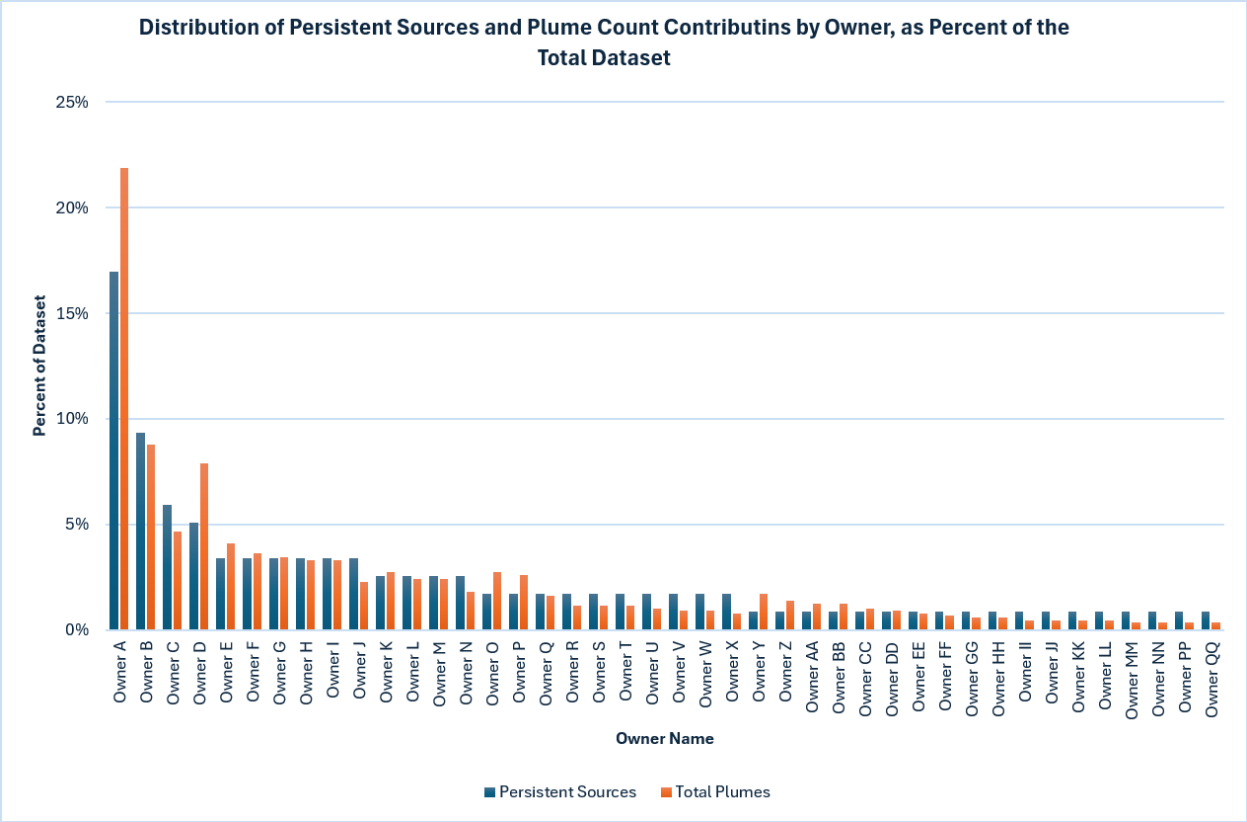
Figure 19: Equipment and process type distribution, as a percent of the dataset



The analysis team also broke the source and plume data down by facility owner. In the full persistent source dataset, 877 plumes across 118 sources originated from 99 unique facilities associated with 42 unique owners. After linking plumes to owners, the team found that the top emitting owners accounted for 66% of all plumes. The single largest emitting owner in the dataset accounted for 17% of the facilities and is responsible for 22% of plumes within the dataset.[134] Figure 20 below shows these results.

[134] See the Carbon Mapper Analysis Data Report **NMED Exhibit 38** for more detail about this analysis.

Figure 20: Distribution of persistent sources by owner



The implications for rule implementation are that a subpopulation of heavily-emitting facilities will be frequent notifyees of the Department, while the majority of owners will be much less touched by the Super-Emitter Program because their super-emitter events are infrequent.

To conclude this section, which provided an overview of the Department's analysis of Carbon Mapper methane emissions data, results of this internal analysis show that: 1) super-emitter events are a frequent occurrence in New Mexico, 2) the emissions from super-emitter events are significant and warrant regulatory intervention, and 3) according to an analysis of a smaller subset of persistent sources, the Super-Emitter Program will primarily address a few very-high emitting owners in the sector, who are disproportionately contributing to emissions.

The Department is pursuing codification of a state-level Super-Emitter Program because both scientific research and Department analysis reveal significant methane abatement potential of early identification and repair of methane super-emitter events, defined as those with emission rates equal to or exceeding 50 kg/hr. Because methane is a near-term potent greenhouse gas, abating methane emissions now has a strong mitigating effect on climate change. Abating methane emissions also reduces ozone formation, which is a significant problem in the Permian Basin, affecting the people, ecosystems, and economy in southeastern New Mexico. The Super-Emitter Program proposed in this rule offers a pathway to reduce statewide methane emissions that both obviates lost product and revenue for oil and gas operators and proactively protects the people, ecosystems, economy, and lifeways of New Mexico.

The next section reviews discrete choices the Department made in program design that are reflected in the rule.

V. SUPER-EMITTER PROGRAM DESIGN

The Department modeled its proposed Super-Emitter Program on the federal Super-Emitter Program, established by *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (89 FR 17043) promulgated by the EPA on March 8, 2024, but tailored the emission threshold for a super-emitter event and the program scope to capture a greater share of methane emissions under the program. The proposed rule contains the same division of responsibilities as the federal rule: a third-party certified by the Department will be responsible for monitoring and detecting super-emitter events and notifying the Department if an event is detected; the Department will notify sources within 50 meters of a detected super-emitter event;

and facility owners/operators will conduct an investigation, perform repairs, and compile and submit to the Department an investigation report.

Third party notifier certification

The Department retained the provisions allowing third-party entities to apply for certification and, if certified, use remote detection technologies to monitor for super-emitter events. Proposed rule 20.2.51 NMAC provides an overview of the requirements an interested party would need to meet to successfully apply for and be granted certified status. To demonstrate their ability to adequately monitor for and accurately detect super-emitter events, the Department will require both administrative and technological information related to the prospective notifier's operations to be submitted as part of the application, filled out by the prospective notifier, and subject to review and approval from the Department prior to the third-party being authorized to submit actionable data to the Department related to methane emissions.

Administratively, the prospective notifier would be required to submit the name, physical and mailing addresses, and email address for the applicant's designated point of contact. Technological submittals are going to be more detailed to meet the rigorous standards set by the Department to ensure data collected is accurate, verifiable, and transparent. The applicant would be required to submit a description of the technology they intend to use to detect methane emissions, a description of the detection methods that would be used, how the prospective notifier would perform data review and quality control to ensure the data collected is in compliance with the approved detection methods, a description of how the prospective notifier would accurately determine the geographic coordinates of the detected super-emitter event, and how they will maintain records in accordance with the rule. If approved, the Department would assign a unique identification number to the certified third-party notifier, and post the credentials

on the Department's website.

The Department would retain the ability to revoke the certification of any third-party notifier that engages in illegal activity to collect the data, changes their technology used to monitor for or detect methane emissions without notifying the Department of such change, or has demonstrated a pattern of submitting data that is not accurate and verifiable, or is erroneous in nature. A third-party who has previously had their certification revoked would be eligible for re-certification by submitting a new application to the Department for consideration.

Super-Emitter Event notification

Immediately upon receiving application approval from the Department, the certified third-party notifier will be able to begin monitoring for, detecting, and submitting notifications to the Department whenever a super-emitter event is detected. The rule defines a super-emitter event as any methane emissions that are detected using remote monitoring technologies, and have a verified emission rate that meets or exceeds 50kg/hr. When a certified third-party detects methane emissions that meet these criteria, a notification must be sent to the Department within seven calendar days of the date of detection. The notification must contain the certified third-party notifier's ID number, the date and time the super-emitter event was detected, the technology used to detect the super-emitter event, the quantified emissions rate of the super-emitter event in kg/hr along with the associated uncertainty rate, the location of the super-emitter event in latitude/longitude format and accurate to four decimal places, and imagery or other documentation that depicts the detected super-emitter event and the site where the event was located. If the certified third-party notifier is able to do so, they may also submit identification information for any sources that are located within 50 meters of the detected event. If the

certified third-party notifier is not able to identify all sources within the 50-meter radius of the super-emitter event, it will be incumbent on the Department to make these determinations.

NMED validation and source attribution

Upon receipt of a super-emitter event notification from a certified third-party notifier, the Department would be required to review the notification for completeness, accuracy, and reasonableness. If the notification meets the criteria for being complete and reasonable, the Department will perform a search for any potential source or sources that are located within 50 meters of the coordinates defined as the origin of the super-emitter event. This notification would then be posted on the website, and updated once the final super-emitter event report compiled by the facility owner/operator is submitted to the Department, and the Department's review determines the report findings are reasonable.

Owner/operator response

Once an owner or operator receives a notification of a super-emitter event from the Department, they must conduct a series of steps to investigate a potential source of the emissions and repair leaks that are identified. Investigation and repair must be completed within 15 days.

The Department anticipates that owners/operators will follow a series of steps in their leak investigations. The first step is checking maintenance records to see if there was scheduled maintenance or activities that were responsible for the detected emissions. Given that detections occur at a fixed point in time, contingent upon how often the certified third-party notifier is operating in that area, regularly scheduled maintenance or permitted activities (such as a scheduled blowdown) could potentially cause emissions that exceed the 50kg/hr threshold to be considered a super-emitter event. A review of records related to these activities could quickly identify the source of the super-emitter event for owners or operators conducting the

investigation. If this is the case, the person conducting the super-emitter investigation will document these activities in the investigation report and submit the report to the Department for review. The Department will review the report and, if the Department agrees with the presented evidence, will deem the investigation complete and no further actions will be required on the part of the owner/operator. The results of the investigation will then be posted on the Department website dedicated to super-emitter events.

If maintenance and activity records do not reveal the source of the super-emitter event, the next step in the investigatory process is to conduct a facility-wide screening using EPA Method 21, Optical Gas Imaging (OGI), or Audio, Visual, and Olfactory (AVO) methods. Super-emitter events are not always caused by a single large leak, but sometimes are a result of multiple leaks occurring in a given area that, when combined, exceed the emissions rate threshold of 50kg/hr and would be considered a super-emitter event. As such, screening the facility for leaking components in and around the given location of the super-emitter event is a reasonable approach to determining the potential source or sources of the event.

In the event that leaks are detected during the inspection, they must be repaired to stop the super-emitter event. The owner or operator has several options to pursue regarding the process of determining which leak repairs are required. If the owner/operator is able to quantify the emissions rate of the leak or leaks and determines that only a specific subset of the leaks detected are responsible for the super-emitter event, the owner/operator may choose to repair only the leak or leaks deemed responsible for the super-emitter event. If the owner/operator is able to quantify the emissions rate for leaks, an appropriate response may be to choose to repair all leaks that are found during the investigation. If an owner/operator is unable to quantify the emissions rate of the leak or leaks discovered during the investigation, then all of the leaks

discovered during the investigation must be repaired. The investigation and repair process must be completed within 15 calendar days of receiving the notification of a super-emitter event from the Department.

Recordkeeping and reporting requirements

Owners or operators are required to maintain records of all super-emitter event notifications received by the Department along with records of the investigation and repairs (if any) that were necessary to stop the super-emitter event. These records must be retained for a minimum of 5 years, may be requested at any time, and must be submitted to the Department within 3 calendar days of receiving a request for those records.

Key differences between the Super-Emitter Program in proposed rule 20.2.51 and the Super-Emitter Program in the federal rule

The proposed state-level Super-Emitter Program follows the design of the federal program in almost all ways. However, the Department determined that there were ways in which the program could be tailored to better abate methane emissions in New Mexico. The two salient differences are: the scope of facilities subject to the program and a narrowing of the threshold used to establish the definition of a super-emitter event.

Because of the sector-based structure of the Clean Air Act, the EPA designed the federal Super-Emitter Program to apply solely to the oil and gas sector. New Mexico's Environmental Improvement Act and Air Quality Control Act do not have the same constraints, and therefore an air quality regulation can apply to multiple sectors. The Department chose not to narrow the scope of the rule to only the oil and gas sector because super-emitter events can occur at facilities in other sectors, and these facilities should have the benefit of notifications of potential leaks. To aid in making this policy design decision, the Department analyzed methane emissions data to

determine if any non-oil and gas facilities would be subject to the program based on emissions observed by Carbon Mapper in the period 2019-2025.

Methane emissions come from a limited number of sources. The primary source of methane emissions in New Mexico is the oil and gas sector. Methane is also emitted by decomposition in landfills, by ruminants in beef and dairy operations, and by coal mining operations, which crack into methane seams during coal extraction.[135] Of these latter three sources, super-emitter events are only possible where there are enough concentrated methane emissions to generate a substantial ongoing leak. This precludes cattle and dairy operations from being the source of super-emitter events, with the exception of dairies that have methane capture systems, of which there are none currently in New Mexico. The same principle applies to landfills—only landfills with methane capture systems are capable of generating methane super-emitter events. The Department identified seven landfills that have active methane capture systems in the state.[136] One of these is under the jurisdiction of the City of Albuquerque and another is closed. Super-emitter events are possible at coal mines if there is a large methane seam that is exposed during mining.

To understand the likelihood of these non-oil and gas sources being subject to the rule, the Department analyzed Carbon Mapper plume data. Of the 4,212 New Mexico plumes in the dataset over the date range, 2019-2025, 9 were labeled by Carbon Mapper as emitting from the solid waste sector and 5 from the mining sector. Analysts then conducted source attribution using

[135] One additional potential source of a super-emitter event is the methane gas collection system attached to the wastewater treatment system at Southwest Cheese in Clovis, which is used to fuel on-site boilers.
[136] There are 5 active landfills with methane capture systems that hold Title V permits administered by NMED. In addition, there is one active landfill with a methane capture system outside of NMED jurisdiction (the Cerro Colorado in Bernalillo County) and a closed landfill with a methane capture system at Balloon Fiesta Park that is also outside of NMED jurisdiction.

the GIS coordinates and determined that all the mining plumes were from one coal mine (which exclusively served the San Juan Generating Station and shut down in September 2022) and the solid waste plumes were from two landfills with methane capture systems (see Table 5 below). Using a 50 kg/hr emission rate threshold, 100% (13 of 13) of the plumes would be super-emitter events, under the most conservative emission rate estimate. Note that the emission rate for one landfill plume was unable to be quantified by Carbon Mapper and is marked as "NA."

Table 5: Carbon Mapper data for non-oil and gas facilities with emission rates over 50 kg/hr

Sector	Facility	Owner	Plume Date	Minimum Emission Rate (kg/hr)	Plume Classified as Super-emitter? (≥ 50 kg/hr)
Solid Waste	Cerro Colorado Landfill	City of Albuquerque	2025-11-16	110	Yes
			2025-11-14	75	Yes
			2025-09-14	122	Yes
			2023-02-04	244	Yes
	Camino Real Landfill	Camino Real Environmental Centers Inc	2025-07-06	157	Yes
			2025-05-25	230	Yes
			2025-05-25	93	Yes
			2025-05-18	290	Yes
Coal Mining	San Juan Coal Company - San Juan Mine (ceased operation in September 2022)	Westmoreland Coal (was BHB Coal New Mexico)	2022-05-02	430	Yes
			2022-05-01	499	Yes
			2022-03-25	121	Yes
			2022-03-23	127	Yes
			2020-08-04	173	Yes

Setting the scope of the program to include all potential sources of super-emitter events allows the Department to notify these facilities of potential leaks so that they can be quickly investigated and repaired, thereby maximally abating emissions and saving these facilities lost methane that is typically used for on-site power.

To determine the emission rate threshold for a super-emitter event, the Control Strategies unit analyzed all observed methane plumes in New Mexico from Carbon Mapper data 2019-2025 that would be covered by the program if the minimum emission rate threshold were set at 50, 75, and 100 kg/hr, respectively. This comparison is shown below in Table 6.

Table 6: Comparison of plume coverage with super-emitter emission rate thresholds of 50, 75, and 100 kg/hr

Percentage of observed methane plumes classified as super-emitter events by threshold			
Year	**50 kg/hr**	**75 kg/hr**	**100 kg/hr**
2019	90%	82%	73%
2020	85%	77%	74%
2021	90%	80%	70%
2022	87%	77%	69%
2023	89%	81%	72%
2024	79%	66%	55%
2025	95%	92%	89%
All	**85%**	**75%**	**66%**

The Department made the decision to set the super-emitter emission rate threshold at 50 kg/hr to maximize the methane abatement accomplished by the rule. A threshold of 50 kg/hr would capture approximately 85% of observed methane plumes, whereas a threshold of 100 kg/hr would only capture approximately 66% of observed methane plumes. The more plumes that are subject to the rule, the more methane emissions will be reduced.

This decision is additionally supported by evidence from scientific literature on the distribution of methane emissions. In an analysis of production-scaled facility-level methane emissions from continental U.S. upstream and midstream operations for the year 2021, Williams et al. (2025) find that 60-86% of aggregate emission come from facilities emitting less than 100

kg/hr.[137] **NMED Exhibit 37v.** They estimate that 70% of regional methane emissions issue from production well sites, but of this population of well sites, numerous lower producing wells that only account for 10% of national production contributed 67-90% of total well site emissions. From this analysis, they caution that "while reducing emissions from high-emitting facilities is important, it is not sufficient for the overall mitigation of methane emissions from the oil and gas sector."[138] **NMED Exhibit 37v at PDF 188.** The fact that a relatively large number of lower producing sites generate the majority of emissions "implies that detection and mitigation strategies to reduce methane emissions from these [wells] and other low-emitting oil and gas infrastructure (e.g., abandoned oil-gas wells) would require alternative mitigation and detection approaches compared to those for the small number of super-emitting emission sources."[139] **NMED Exhibit 37v at PDF 201.** The table below is a recreation of a table in the Supplemental Information document associated with Williams et al. (page S14). Lowering the notification threshold to 50 kg/hr from the federal threshold of 100 kg/hr will capture additional emitting sources that Williams et al. show contribute to a majority of aggregate emissions.

Emission rate threshold range (kg/hr)	Percentage of total emissions
≤.01	0.2% (0.1-0.3%)
0.1-1	4.4% (4.1-4.8%)
1-10	25% (24-27%)
10-100	41% (39-42%)
100-1000	22% (21-23%)
>1000	7.2% (5.0-8.6%)

[137] Williams, James P., Mark Omara, Anthony Himmelberger, Daniel Zavala-Araiza, Katlyn MacKay, Joshua Benmergui, Maryann Sargent, Steven C. Wofsy, Steven P. Hamburg, and Ritesh Gautam. "Small emission sources in aggregate disproportionately account for a large majority of total methane emissions from the US oil and gas sector." *Atmospheric Chemistry and Physics* 25, no. 3 (2025): 1513-1532.
[138] Ibid., 1513.
[139] Ibid., 1526.

VI. DISCUSSION OF BENEFITS AND COSTS

The costs and benefits of reduction of super-emitter events are inherently very difficult to quantify given that we lack definitive knowledge about the phenomenon of super-emitter events. Estimating the benefits of a policy designed to reduce emissions requires estimating the quantity of emissions that will be reduced by the policy intervention. Similarly, estimating the costs of the policy requires knowing what government must do to implement the policy and what regulated entities must do to comply with the policy, not just conceptually, but in ways that can be translated into monetary costs. Estimates in this case are fundamentally limited because super-emitter events are so varied, unpredictable, and untracked.

The federal rule on which this proposed rule is based—*Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (89 FR 17043)—does not contain estimates of benefits and costs of the Super-Emitter Program provisions. Regulatory Impact Analysis, which entails estimating costs and benefits of regulatory action in monetary terms, is required as a part of federal rulemaking. However, the EPA only provided estimates for the whole rule rather than disaggregating to show benefits and costs for the Super-Emitter Program given the challenges of quantifying benefits of costs of these provisions. Of this challenge, the EPA states, “We do not attempt to quantify the impacts of the super-emitter response program per se due to the unpredictable nature of super-emission events, resulting in a lack of specific data on their frequency, intensity, and cost to mitigate. Moreover, there is a lack of specific information on how often third parties would conduct monitoring activities, what those activities would entail,

how often they would detect super-emitters, how often those detections would provide sufficient and timely information for companies to respond."[140]

As discussed in the previous section, estimating aggregate emissions from super-emitter events requires knowing both emission rates and duration of events. Duration of super-emitter events is almost entirely unknown because of the lack of continuous monitoring. Given this challenge, the best we can do is to estimate a range of durations using emission rates from observed super-emitter events in New Mexico. Section IV of this testimony provided this analysis, which is replicated below in Table 7 in abbreviated form.

Table 7: Annual aggregate methane emissions expressed as the equivalent number of passenger vehicles for a variety of possible durations

Super-Emitter Duration	Total Aggregate Methane Emissions (kilograms)	Total Equivalent Annual Passenger Vehicles (CO_2e) (Rounded)
15 minutes	33,894	538
30 minutes	68,326	1,076
1 hour	136,114	2,690
2 hours	272,228	4,842
3 hours	408,880	7,532
5 hours	681,646	12,374
12 hours	1,636,596	29,590
24 hours	3,273,192	58,642
48 hours	6,545,846	117,284
3 days	9,819,038	175,926
5 days	16,364,884	293,748
7 days	22,911,268	411,032
10 days	32,730,306	586,958
15 days	49,095,190	880,706
1 month	99,554,748	1,785,622
3 months	298,663,706	5,356,328

Median ER of 253 kg CH_4/hr converted to t CO_2e using GWP-20; 1 passenger vehicle = 4.6 t CO_2; 3,768 plumes with emission rates ≥ 50 kg/hr were used for this analysis. The total plumes detected between 2019 – 2025 (3,768) was divided by the number of years (7), resulting in an average of 538 plumes detected each year. The single event was multiplied by 538 to obtain the cumulative impact.

[140] EPA, "Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," December 2023, page 2-28. Available at: https://www.epa.gov/system/files/documents/2023-12/eo12866_oil-and-gas-nsps-eg-climate-review-2060-av16-ria-20231130.pdf

The Carbon Mapper aggregate dataset contains a wide variety of plumes whose emission rates vary from just above zero to over 5000 kg/hr. Cusworth et al. (2026) identified plumes in the Permian with durations between 0.14 hrs to 411 hrs (approximately 17 days).[141] Full compliance with the LDAR requirements of the Ozone Precursor Rule still permits a leak to persist for three months, and, given that compliance is never full, there are certainly leaks persisting beyond three months. These data points show how difficult it is to estimate aggregate emissions from super-emitter events without continuous monitoring, meaning that we cannot state with confidence where in the range of emissions provided in the table true emissions for any given year lie. However, because scientific research and Department research show that super-emitter events disproportionately contribute to methane emissions from the oil and gas sector in the state, we can confidently assert that abating super-emitter emissions will reduce significantly aggregate methane emissions in New Mexico.

VII. PROPOSED RULE SUPER-EMITTER PROGRAM PROVISIONS

20.2.51.101 – Methane Super-Emitter Program Overview

This section establishes the framework and requirements for the super-emitter program. For the purposes of this Part, a super-emitter event is defined as any methane emissions that are detected using remote detection technologies, and have a quantified emissions rate that meets or exceeds 50kg/hr. This section further describes the contents of 20.2.51.102 through 20.2.51.105 NMAC, as outlined below. **NMED Exhibit 1 at 3, lines 25-35.**

20.2.51.102 – Third Party Notifier Certification

[141] Cusworth et al. (2026), 5.

This section establishes the requirements that are necessary for an entity to apply for certification to become a third-party notifier. Subsection A specifies that any person, as defined by Subsection B of 20.2.2.7 NMAC, may apply to the Department for certification as a third-party notifier. Paragraphs (1) and (2) provide examples of approved remote detection technologies, and Paragraph (3) states that an applicant may provide a detection technology for their use outside the list described by the Department for review. If approved, the third-party may use that detection technology for the purposes of monitoring for super-emitter events. **NMED Exhibit 1 at 3, lines 39-44.**

Subsection B provides the list of documentation and information that an applicant is required to include as a part of their application package to become a certified third-party notifier. The details for the required information is outlined in paragraphs (1) through (5). **NMED Exhibit 1 at 3, lines 45-56; and 4, lines 1-8.** Section C states that the Department will either approve or disapprove an entity's application based on an evaluation of the reasonableness, completeness, and accuracy of the application within 30 business days of the application submittal. If approved, the Department will assign the applicant a unique identification number and the certified third-party may begin submitting notifications of detected super-emitter events upon receiving approval from the Department. **NMED Exhibit 1 at 4, lines 9-15.**

Subsection D specifies that any certified third-party notifier who intends to make a "significant change" to the process or procedures used to identify super-emitter events, such as a change in the technology used to identify the events, must submit a new application and request recertification from the Department. It also states that any notifications that are submitted by the third-party must be using the originally approved technology or procedures while the application

is under review. The third-party may begin submitting notifications under the new technology or procedures upon receiving approval from the Department. **NMED Exhibit 1 at 4, lines 16-21.**

Subsection E states that the Department retains the ability to revoke certification from a third-party notifier, and that any entity who has had their certification revoked may seek re-certification by submitting a new application to the Department for consideration. Paragraphs (1) through (3) provide a list of reasons that would be grounds for having certification revoked. **NMED Exhibit 1 at 4, lines 22-33.**

Subsection F states that the certified third-party notifier must retain records and submit them to the Department upon request. Paragraphs (1) through (3) contain the list of records that must be retained and submitted to the Department. **NMED Exhibit 1 at 4, lines 34-43.**

20.2.51.103 – Super-Emitter Event Notification Requirements

Section 103 establishes a list of required supporting documentation a certified third-party must submit to the Department as part of a super-emitter event notification. Subsection A states that only certified third-party notifiers are able to submit notifications of detected super-emitter events to the Department, and that the notification must be submitted via the means determined by the Department. This will be established in an implementation guidance document should the proposed rule be adopted. Paragraphs (1) through (7) contain the list of all required supporting documentation. **NMED Exhibit 1 at 4, lines 47-55 and 5, lines 1-6.** Subsection B states that the Department may request any additional information from the certified third-party notifier regarding the super-emitter event.

If a certified third-party notifier receives a request for additional information, they must provide the information within three business days of the Department's request. **NMED Exhibit 1 at 5, lines 7-10.** Subsection C states that the Department will review each notification for

completeness and accuracy. If the Department determines that the notification is complete and does not contain any information that is inaccurate to a reasonable degree of certainty, the Department will assign the notification a unique super-emitter event identification number. The Department will then perform a search for any source or sources that have a property boundary within 50 meters of the event coordinates and send a super-emitter event notification to any owner or operator identified by the search. Finally, the information contained in the super-emitter event notification would be made publicly available on the Department's website. **NMED Exhibit 1 at 5, lines 11-17.**

20.2.51.104 – Owner or Operator Notification and Response

This Section establishes the requirements that owners or operators must follow if they receive a notification of a super-emitter event from the Department. Subsection A states that an owner or operator must initiate a super-emitter event investigation upon the receipt of a notification of a super-emitter event that was detected near their source. It also states that the investigation must be completed in accordance with paragraphs (1) through (5) of the Section, and that repairs must be completed in accordance with Section B. Finally, it sets a requirement that all investigatory and repair processes must be completed within fifteen calendar days of receiving the super-emitter event notification from the Department, and that a report of the investigation describing the investigatory process and any repairs performed (if necessary) must be submitted to the Department for review. Owners and operators notified of a super-emitter event pursuant to this Section must maintain records of the super-emitter event investigation and findings in accordance with Sections 105 and 106 of the revised proposed rule. **NMED Exhibit 1 at 5, lines 20-27.**

Paragraph 1 states that the first step in the investigatory procedure is for the owner or operator to verify their source is located within 50 meters of the super-emitter event. If the owner or operator determine the super-emitter event is located more than 50 meters away from their property boundary, using a geographic information system or other similarly accurate geographic location system, the owner or operator will then submit this information in a demonstration showing the location of the super-emitter event and the distance from that event to the nearest property boundary is greater than a 50-meter distance. The Department will review this demonstration and, if the Department agrees with the contents and validates the demonstration, the investigation will be deemed complete and no further action would be necessary on the part of the owner or operator. **NMED Exhibit 1 at 5, lines 28-36.**

Paragraph 2 is an action plan that the owner or operator must undertake if they determine that a super-emitter event is within 50 meters of their property boundary. The requirements for the investigatory process include, but are not limited to, the contents of subparagraphs (a) through (d) and all of the items contained in subparagraph (d). Subparagraph (a) states that an investigator must review all maintenance and process activities occurring at the source, starting from t least 30 calendar days prior to the date the super-emitter event was detected, as noted in the Department's notification, to identify if monitoring data or process activities indicate a possible cause of the detected super-emitter event emissions. Subparagraph (b) states that the owner or operator must review all monitoring data from the source, subparagraph (c) requires a review of all fugitive emissions surveys conducted at the source, both in an effort to identify potential sources of the super-emitter event emissions. Subparagraph (d) states that if a review of the prior records does not indicate a potential source of the super-emitter event emissions, the owner or operator must survey the entire facility by using a method described in items (i)

through (iv), as applicable. Item (i) allows for use of US EPA Method 21 or Optical Gas Imaging (OGI), to identify leaking components. Item (ii) states that an investigator can also conduct a visual inspection for defects, such as cracks, holes, or gaps in piping or covers, loose connections, or other visually detectable defects. Item (iii) states that an audio investigation may be used to detect pressure or liquid leaks, and item (iv) states that an olfactory inspection may be used to detect strong odors that can indicate leaks. **NMED Exhibit 1 at 5, lines 37-56 and 6, lines 1-4.**

Paragraph (3) outlines requirements for use of US EPA Method 21 to detect leaks. Subparagraph (a) states that the detection instrument must be calibrated prior to each day of use, using the procedures outlined in US EPA Method 21 and the instrument's manufacturer, and subparagraph (b) states that a leak is detected if the instrument records a measurement of hydrocarbon emissions that meets or exceeds 500 parts per million (ppm) that is not associated with normal equipment operation. **NMED Exhibit 1 at 6, lines 5-7.**

Paragraph (4) outlines requirements that leak detection using OGI must meet. Subparagraph (a) states that the instrument must comply with specifications, daily instrument checks, and leak survey requirements that are found in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR §60.18. Subparagraph (b) states that a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation. **NMED Exhibit 1 at 6, lines 11-15.**

Paragraph (5) states that components that are deemed difficult, unsafe, or inaccessible to monitor are not required to be inspected until it becomes feasible to do so. Subparagraphs (a) through (c) provide this list. Subparagraph (a) states that if monitoring personnel must be lifted more than two meters above an unsupported surface, those components are determined to be

difficult to monitor. Subparagraph (b) states that a component is unsafe to monitor if it cannot be monitored without exposing personnel to immediate danger as a consequence of monitoring, and subparagraph (c) states that a component is inaccessible if it is buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel. **NMED Exhibit 1 at 6, lines 16-23.**

Subsection B sets the requirements for repair procedures an owner or operator must follow should a leak be identified during the investigation. If an owner or operator is able to accurately attribute the source of the super-emitter event by quantifying the emissions rate of the leak or leaks, then they may choose to repair only the leak or leaks deemed responsible for the super-emitter event emissions. If an owner or operator identifies a leak or leaks, and is not able to quantify the emissions rate of the leak or leaks identified, then they must repair all of the leaks identified during the investigation. Any repairs that are performed must be substantiated to ensure no further leaks are occurring by using either US EPA Method 21 or OGI. **NMED Exhibit 1 at 6, lines 24-29.**

20.2.51.105 – Super-Emitter Event Report

Section 105 lists the required components that are associated with a super-emitter event report. Paragraph A states that an owner or operator who receives a notification of a super-emitter event must conduct a super-emitter event investigation in accordance with the provisions found in 20.2.51.104 NMAC. This report must be submitted to the Department within 5 business days of completing the investigation and repair processes. It also states that, if a demonstrable error in the notification is found during the investigation, then the report must include documentation of the alleged error. **NMED Exhibit 1 at 6, lines 32-37.**

Paragraph B contains the list of required information to include in the super-emitter event report. Subparagraph (1) states that the notification must include the super-emitter event notification ID number assigned by the Department. Subparagraph (2) states that the report must contain the general identification information for the source, including the facility name, the owner or operator, physical address, and Agency Interest (AI) number, if applicable. Subparagraph (3) requires that a detailed account of the investigation be included in the report, including the steps that were taken to identify the source or sources of the super-emitter event emissions, a list of all leaks that were identified during the investigation, and the actions that were taken to repair the leaks. The report must also contain a list of any components that were not monitored due to being difficult, unsafe, or inaccessible. Subparagraph (4) is an attestation that the information contained in the super-emitter event report is true, accurate, and conducted in accordance with 20.2.51.104 and 105 NMAC. **NMED Exhibit 1 at 6, lines 38-54.**

Subsection C states that an addendum to the initial super-emitter event report must be submitted if any components were not monitored due to being difficult, unsafe, or inaccessible. This addendum must be submitted within three days of completing all outstanding inspections, and must include a description of any additional leaks that were identified and actions that were taken to repair the leaks. **NMED Exhibit 1 at 6, lines 55-56 and 7, lines 1-2.**

Subsection D states that the Department must review each submitted super-emitter event report, along with any addendum (if applicable) for completeness, reasonableness, and accuracy. **NMED Exhibit 1 at 7, lines 3-4.**

Subsection E states that the Department may request any additional supplemental information regarding the report from an owner or operator, and that the owner or operator must respond to the request within three business days. **NMED Exhibit 1 at 7, lines 5-7.**

Subsection F states that the Department will approve or disapprove the super-emitter event report, based on the review. If the Department disapproves the report, the Department may require the submittal of additional information, or the Department may take additional actions if necessary. **NMED Exhibit 1 at 7, lines 8-10.**

Subsection G states that the Department will update the initial notification that was posted to the website with the outcome of the super-emitter investigation once the report is finalized. This will include whether the super-emitter event was attributed to any notified source, and what repairs or resolution was necessary to end the super-emitter event. **NMED Exhibit 1 at 7, lines 11-14.**

20.2.51.106 – Super-emitter Recordkeeping Requirements

Section 106 contains Subsections A and B, both related to the recordkeeping requirements to comply with 20.2.51 NMAC. Subsection A states that owners or operators must retain the records of all super-emitter event notifications, investigations, and repairs for a minimum of five years. **NMED Exhibit 1 at 7, lines 17-19.** Subsection B states that these records may be requested by the Department, and an owner or operator must submit these records within three calendar days of receiving a request from the Department. **NMED Exhibit 1 at 7, lines 20-21.**

VIII. CONCLUSION

As this testimony and the testimony of Cindy Hollenberg make clear, reducing methane is a step toward mitigating climate change—a critical need for New Mexico, the United States, and the planet—and acting to address methane is firmly within the authority of the EIB and the Department as delegated by the State Legislature. Adoption of this rule will save industry revenue and protect the people, ecosystems, economy, and lifeways of New Mexico. This rule is a commonsense and economically efficient approach to reducing methane emissions without

unreasonably burdening the oil and gas sector, which is critical to the state's economy. For this reason, I urge the Environmental Improvement Board to adopt the revised proposed Part 51 as submitted on October 30, 2026.

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED ADOPTION OF
20.2.51 NMAC – *METHANE ABATEMENT*

No. EIB 26-78 (R)

New Mexico Environment Department,

***Petitioner*.**

NEW MEXICO ENVIRONMENT DEPARTMENT
TECHNICAL TESTIMONY OF KENNETH MILLER

I. INTRODUCTION AND QUALIFICATIONS

My name is Kenneth Miller, and I am an Environmental Analyst for the Air Quality Bureau ("Bureau") of the New Mexico Environment Department ("NMED" or "Department"). I have been employed by the Department for approximately 3.5 years and have been in my current position with the Bureau's Control Strategies unit for the duration of my tenure. In that position I develop and revise air quality regulations and plans for the State of New Mexico, including the New Mexico State Implementation Plan. Prior to joining the Department I was the Control Strategies Division Manager for the City of Albuquerque Environmental Health Department, where I oversaw the development of air quality regulations and plans for the City of Albuquerque and Bernalillo County. Previous to that I was clinical faculty at Washington University School of Law, serving as a Lecturer in Law and Environmental Scientist with the school's Interdisciplinary Environmental Clinic, and a hydrogeologist at Rapps Engineering & Applied Science, an environmental and civil engineering firm. I hold a B.A. degree in Classics and B.S. and M.S. degrees in Geology from Southern Illinois University and am a Licensed Professional Geologist in the State of Illinois (currently inactive).

My full educational and work background are set forth in my resume, which is marked as **NMED Exhibit 5**.

I present this written testimony on behalf of the Department in support of the Department's Petition for Regulatory Change to Adopt 20.2.51 NMAC – *Methane Abatement* (filed August 13, 2026). The purpose of my testimony is to describe process controllers used by the oil and natural gas industry, quantify methane emissions from these devices, explain existing state and federal regulations governing process controllers, provide an overview of the process controller provisions of proposed new rule 20.2.51 NMAC ("Part 51"), and discuss the rationale for these provisions along with their feasibility, costs, and benefits.

II. DESCRIPTION OF PROCESS CONTROLLERS

Process controllers are control devices used throughout the oil and natural gas industry to operate valves.[1] These valves, in turn, regulate process conditions such as liquid level, pressure, temperature, and flow. Functionally speaking, a process controller receives an input signal based on a sensed process parameter, compares it to a process set point, and then adjusts a control valve to maintain desired operating conditions. For example, a process controller may be used to maintain the liquid level in a separator.[2] When the liquid level in the separator reaches its high set point based on the setting of a level gauge, the controller responds by sending a signal to open the control valve between the separator and the tank, allowing liquid to flow from the separator to the tank. When the liquid level in the separator reaches its low set point, the

[1] Process controllers are not to be confused with emissions controls. Process controllers operate valves to regulate process conditions, whereas emissions controls reduce emissions of air pollutants by decreasing the amount of pollutants formed, removing them from exhaust air, or converting them into other, less harmful substances.
[2] A separator is a pressure vessel used to separate the fluids produced from a well into gaseous and liquid components.

controller sends a signal to close the control valve and stop the flow from the separator to the tank. **NMED Exhibit 39 at 8-9.**

Many process controllers used in the various segments of the oil and natural gas industry utilize pressurized natural gas to operate the valve. Natural gas-driven process controllers are a type of pneumatic controller and emit or "vent" natural gas, which contains methane and other pollutants such as volatile organic compounds ("VOCs"), to the atmosphere. **NMED Exhibit 40 at 2-1**. Pneumatic controllers driven by compressed air or nitrogen, and non-pneumatic controllers including mechanical and electric controllers, are not powered by natural gas and thus, by design, do not emit natural gas to the atmosphere. **Id. at 2-14**. The various types of process controllers are discussed further below.

Natural gas-driven process controllers are characterized primarily by their emission characteristics and are of three types. The first type, continuous bleed controllers, emit or "bleed" natural gas continuously and are subdivided into two types based on their bleed rate. Low-bleed controllers have a continuous bleed rate of less than or equal to 6 standard cubic feet per hour ("scfh"), while high-bleed controllers have a continuous bleed rate greater than 6 scfh. **NMED Exhibit 41 at 6-2**. The second type, intermittent bleed controllers, only emit natural gas during valve actuation and do not have a continuous bleed rate. Therefore, the emissions from an intermittent bleed controller are dependent on the amount of natural gas vented per actuation and the frequency of actuation. **Id. at 6-3**. Note that both continuous and intermittent bleed controllers can have higher emissions than they are designed to have due to improper operation or malfunction.[3] The third type, zero bleed controllers, do not emit natural gas at all. These are self-contained units that release the gas used to operate the valve to a downstream pipeline

[3] Examples include a low-bleed controller emitting natural gas at a higher rate than its design rate, and an intermittent bleed controller emitting natural gas continuously instead of only during valve actuation.

instead of to the atmosphere. **Id. at 6-2**. Figure 1 shows a schematic of a natural gas-driven process controller.

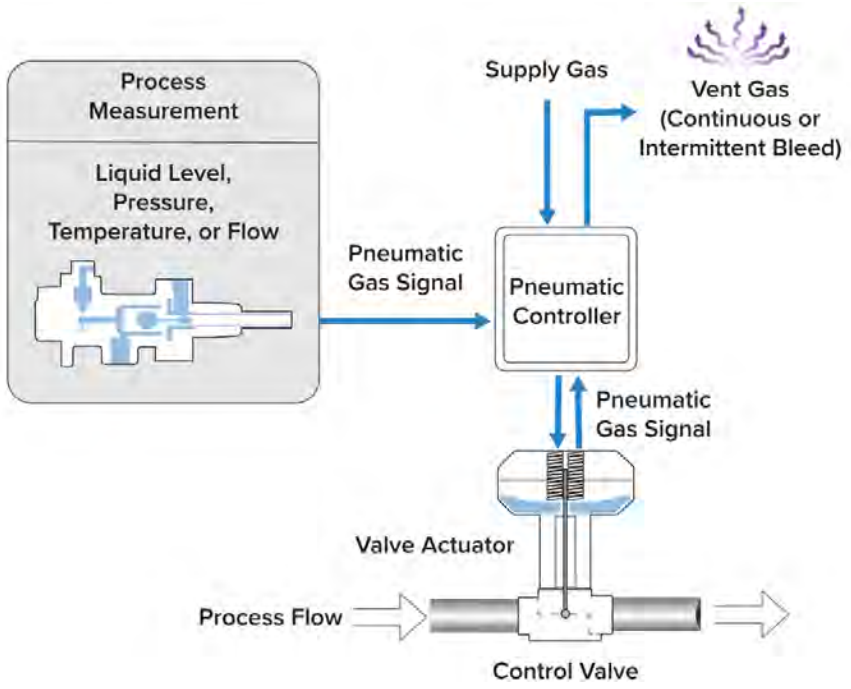


Figure 1. Natural gas-driven process controller schematic.[4]

Not all pneumatic controllers are driven by natural gas. Where electricity is available to run the necessary equipment, compressed air, often called "instrument air," can be substituted for natural gas to operate the valve. Alternatively, cryogenic nitrogen can be used. Nitrogen-powered systems rely on thermodynamics and do not require electricity to operate. **NMED Exhibit 40 at 2-14**. Pneumatic controllers operate the same way with instrument air (or nitrogen) as they do with natural gas, but only bleed air (or nitrogen) to the atmosphere, eliminating emissions of natural gas. **Id. at 2-24**. Figure 2 shows a schematic of a typical instrument air controller system.

[4] EPA, *Pneumatic Controllers*, https://www.epa.gov/natural-gas-star-program/pneumatic-controllers.

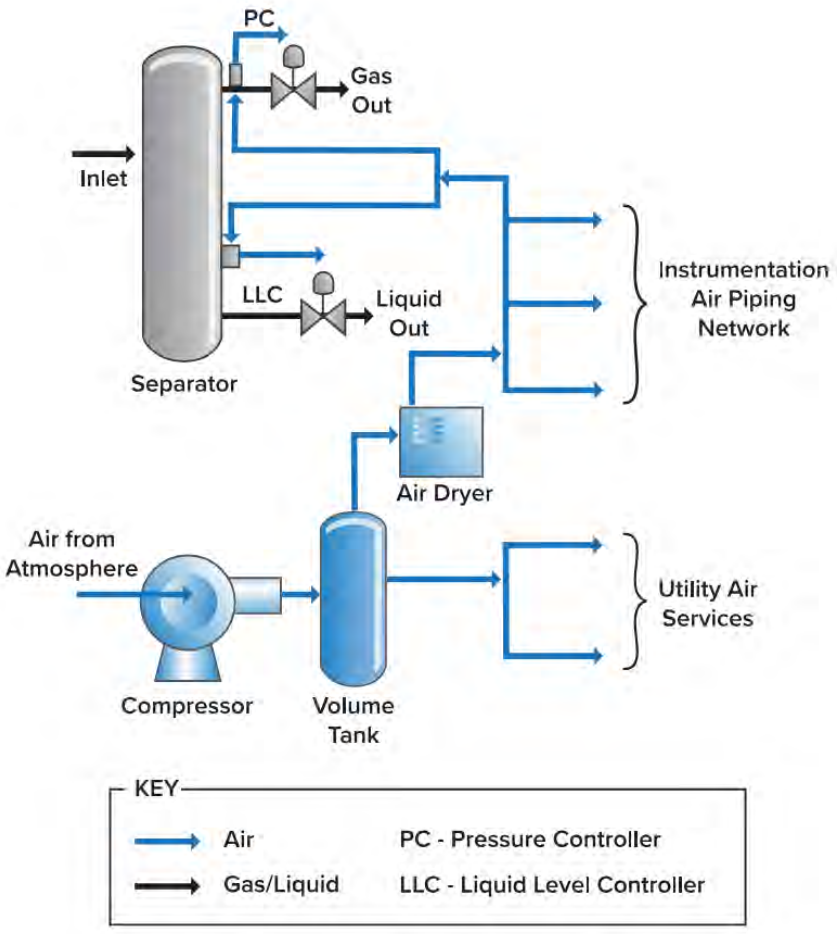


Figure 2. Typical instrument air controller system schematic.[5]

Mechanical and electric controllers work differently than pneumatic controllers. Instead of utilizing a pressurized gas (natural gas, instrument air, etc.) to operate the valve, a mechanical controller uses mechanical linkages to translate the position of a measurement device such as a liquid level float to the position of the valve,[6] whereas an electric controller sends a signal to an actuator powered by an electric motor to operate the valve. The power source for an electric controller can be the grid, solar panels and batteries, or on-site power generation. **Id. at 2-15**. Like pneumatic controllers driven by instrument air or nitrogen, mechanical and electric

[5] EPA, *Instrument Air Controllers*, https://www.epa.gov/natural-gas-star-program/instrument-air-controllers.
[6] EPA, *Mechanical Controllers*, https://www.epa.gov/natural-gas-star-program/mechanical-controllers.

controllers do not use any natural gas and therefore do not emit natural gas to the atmosphere. **Id. at 2-14**.

III. PROCESS CONTROLLER EMISSIONS

Methane emissions from individual natural gas-driven process controllers are relatively small. Individual unit emission factors used by the U.S. Environmental Protection Agency ("EPA") in its recent technical analysis for the final standards of performance for greenhouse gas ("GHG") emissions for new, modified, and reconstructed sources and emissions guidelines to limit GHG emissions from existing sources in the Crude Oil and Natural Gas source category, published in March 2024, range from 0.39 tons per year ("tpy") to 5.48 tpy depending on the industry segment and controller type. **Id. at 2-6**. These emission factors are summarized in Table 1.

Table 1. Individual Natural Gas-Driven Process Controller Emission Factors

Segment/Controller Type	Whole Gas Emissions (scf/hr)	Methane Emissions (tpy)
Production Segment		
High-Bleed Controllers	21	3.20
Low-Bleed Controllers	6.8	1.03
Intermittent Bleed Controllers	11.1	1.68
Transmission and Storage Segment		
High-Bleed Controllers	30	5.48
Low-Bleed Controllers	6.8	1.15
Intermittent Bleed Controllers	2.3	0.39

While individual natural gas-driven process controllers have relatively small emissions, collectively they are a significant source of methane emissions from the oil and gas industry due to their substantial number. Citing the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021 ("2023 GHGI"), the EPA stated in its technical analysis that there are an estimated

823,000 natural gas-driven process controllers located at U.S. oil production facilities and 694,000 located at U.S. natural gas production facilities. [7] **Id. at 2-2**. The 2023 GHGI further breaks these totals down by basin, indicating that there are 140,380 natural gas-driven process controllers located at oil production facilities and 28,647 located at natural gas production facilities in the Permian Basin, and 7,287 natural gas-driven process controllers located at oil production facilities and 110,939 located at natural gas production facilities in the San Juan Basin. **NMED Exhibit 42**. Together, the Permian and San Juan Basins account for nearly all oil and gas production in New Mexico. Table 2 summarizes 2023 GHGI natural gas-driven process controller counts for the U.S. and the Permian and San Juan Basins in more detail. The location and extent of the Permian and San Juan Basins in New Mexico are shown in Figure 3.

Table 2. 2023 GHGI Natural Gas-Driven Process Controller Counts

Controller Type	Petroleum Systems			Natural Gas Systems		
	U.S.	Permian Basin	San Juan Basin	U.S.	Permian Basin	San Juan Basin
High-Bleed	9,175	1,177	71	9,157	628	231
Low-Bleed	252,077	67,443	4,283	172,987	4,934	66,760
Intermittent Bleed	561,980	71,761	2,933	512,401	23,085	43,948
Total	**823,232**	**140,380**	**7,287**	**694,545**	**28,647**	**110,939**

[7] 2023 GHGI data are for the 2021 inventory year.

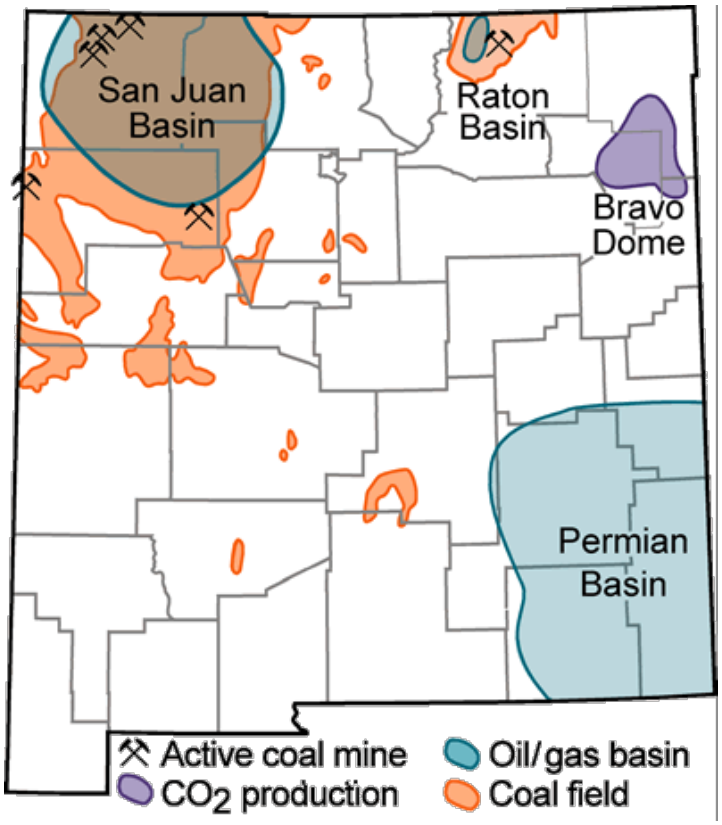


Figure 3. New Mexico oil and gas basins.[8]

As Table 2 shows, the Permian and San Juan Basins collectively account for approximately 18 percent of the natural gas-driven process controllers located at U.S. oil production facilities and approximately 20 percent of the natural gas-driven process controllers located at U.S. natural gas production facilities. Both basins extend into neighboring states so not all natural gas-driven process controllers in the Permian and San Juan Basins are located in New Mexico. However, the 2023 GHGI does not provide state-level data, and in the absence of such data, these numbers give a general indication of the high number of natural gas-driven process controllers located at oil and natural gas production facilities in New Mexico relative to most other states.

[8] New Mexico Bureau of Geology and Mineral Resources, *Oil & Gas Program*, https://geoinfo.nmt.edu/resources/petroleum/home.cfml.

EPA further stated in its technical analysis, again citing the 2023 GHGI, that annual methane emissions from natural gas-driven process controllers at oil and natural gas production facilities in the U.S. equal 1,015,000 metric tons and 1,002,000 metric tons, respectively. **NMED Exhibit 40 at 2-2**. These amounts represent 57 percent of total petroleum system methane emissions (65 percent when petroleum system segments not included in the oil and natural gas source category, i.e., crude oil transportation, refining, and offshore production operations, are excluded) and 15 percent of total natural gas system methane emissions (18 percent when natural gas system segments not included in the oil and natural gas source category, i.e., distribution and post-meter, are excluded). ***Id.* at 2-3**. The 2023 GHGI further breaks these totals down by basin, indicating that annual methane emissions from natural gas-driven process controllers at oil and natural gas production facilities in the Permian Basin equal 127,400 metric tons and 36,000 metric tons, respectively, while annual methane emissions from natural gas-driven process controllers at oil and natural gas production facilities in the San Juan Basin equal 5,900 metric tons and 66,100 metric tons, respectively. **NMED Exhibit 43**. Table 3 summarizes 2023 GHGI natural gas-driven process controller methane emissions for the U.S. and the Permian and San Juan Basins in more detail.

Table 3. 2023 GHGI Natural Gas-Driven Process Controller Methane Emissions (Metric Tons)

Controller Type	Petroleum Systems			Natural Gas Systems		
	U.S.	Permian Basin	San Juan Basin	U.S.	Permian Basin	San Juan Basin
High-Bleed	48,200	4,800	400	88,500	2,600	1,300
Low-Bleed	46,400	10,900	500	33,600	700	6,700
Intermittent Bleed	920,500	111,700	5,000	879,700	32,700	58,100
Total	**1,015,100**	**127,400**	**5,900**	**1,001,800**	**36,000**	**66,100**

As Table 3 shows, the Permian and San Juan Basins collectively account for approximately 13 percent of annual methane emissions from natural gas-driven process controllers at U.S. oil production facilities and 10 percent of annual methane emissions from natural gas-driven process controllers at U.S. natural gas production facilities. However, the basin-level data for natural gas systems in Table 3 is only for the production segment and excludes gathering and boosting, whereas the data for the U.S. is for all segments and includes gathering and boosting. Therefore, the Permian and San Juan Basins likely account for more than 10 percent of annual methane emissions from natural gas-driven process controllers at U.S. natural gas production facilities.

Although the 2023 GHGI does not provide state-level data, such data are available from NMED's periodic oil and gas GHG emissions inventories. These inventories have been completed for years 2005, 2020, and 2023 and provide estimates of oil and gas industry methane emissions by source – including natural gas-driven process controllers – for four industry segments (production, gathering and boosting, natural gas processing, and transmission and storage) as well as for inactive oil and gas wells. **NMED Exhibits 44, 45, and 46**. Table 4 summarizes these estimates.

Table 4: New Mexico Oil and Gas Industry Methane Emissions (Metric Tons)

Year and Segment	Emissions from Process Controllers	Emissions from All Sources	Share of Emissions from Process Controllers
2005			
Production	170,867	682,474	25%
Gathering & Boosting	11,453	126,398	9%
Natural Gas Processing	86	25,934	0.3%
Transmission & Storage	514	22,978	2%
Inactive Wells	---	---	---
Total	**182,920**	**857,784**	**21%**
2020			
Production	129,316	387,824	33%
Gathering & Boosting	9,834	126,013	8%
Natural Gas Processing	106	19,210	0.5%
Transmission & Storage	235	13,382	2%
Inactive Wells	---	784	0%
Total	**139,491**	**547,212**	**25%**
2023			
Production	89,901	208,120	43%
Gathering & Boosting	10,893	185,726	6%
Natural Gas Processing	96	11,238	1%
Transmission & Storage	128	14,848	1%
Inactive Wells	---	591	0%
Total	**101,019**	**420,523**	**24%**

As Table 4 shows, total New Mexico oil and gas industry methane emissions decreased by 51 percent and natural gas-driven process controller methane emissions decreased by 45 percent from 2005 to 2023, a laudable achievement given that crude oil production increased

approximately tenfold and natural gas production roughly doubled during the same period.[9,10] However, the industry is still responsible for 45 percent of economy-wide GHG emissions according to NMED's most recent (2023) economy-wide GHG emissions inventory, the most of any sector. **NMED Exhibit 13 at 18**. This is shown in Figure 4.

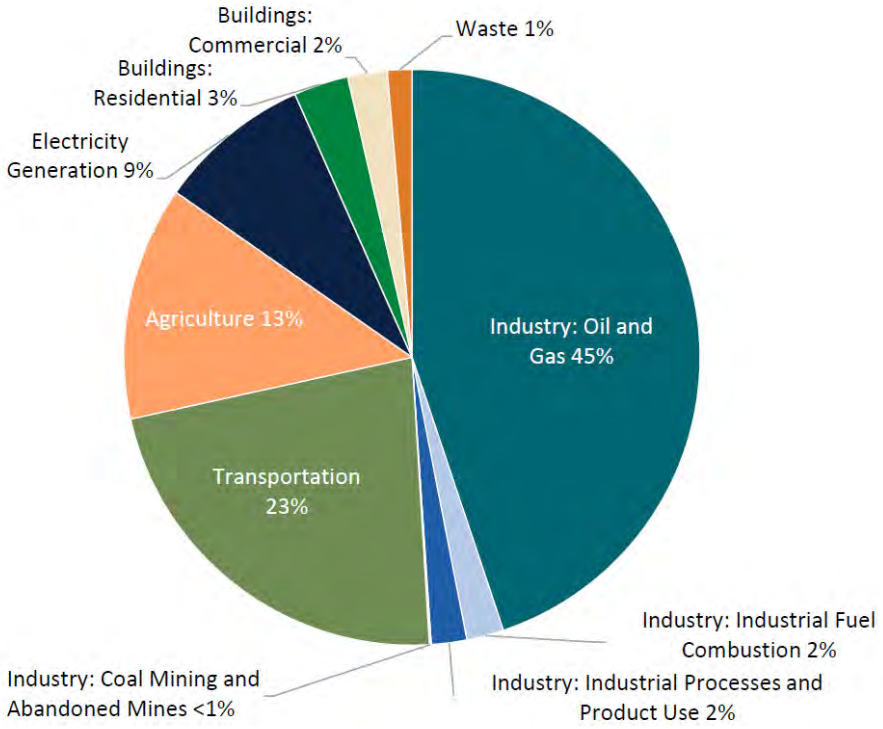


Figure 4. Economy-wide GHG Emissions for Year 2023 by Sector.

Furthermore, while both total New Mexico oil and gas industry methane emissions and natural gas-driven process controller methane emissions have decreased since 2005, the share of total oil and gas industry methane emissions from natural gas-driven process controllers has increased since 2005, from 21 to 24 percent. Additionally, NMED's most recent (2023) oil and

[9] U.S. Energy Information Administration, *Petroleum & Other Liquids: New Mexico Field Production of Crude Oil*, https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpnm1&f=a.
[10] U.S. Energy Information Administration, *Natural Gas: New Mexico Natural Gas Gross Withdrawals*, https://www.eia.gov/dnav/ng/hist/n9010nm2a.htm.

gas GHG emissions inventory shows that process controllers are the second largest source of oil and gas industry methane emissions, second only to combustion. **NMED Exhibit 46 at 48-49**. 2023 New Mexico oil and gas methane emissions by source are summarized in Table 5.

Table 5. 2023 New Mexico Oil and Gas Methane Emissions by Source (Metric Tons)

Emission Source	Annual Methane Emissions
Combustion	113,324
Process Controllers	101,019
Acid Gas Removal Units	0
Equipment Leaks	73,358
Miscellaneous Flaring	5,562
Reciprocating Compressors	37,487
Tanks	17,381
Associated Gas	4,883
Mud Degassing	14,768
Produced Water	14,678
Equipment Blowdowns	9,630
Pipeline Leaks	7,818
Pipeline Blowdowns	7,538
Completions	637
Dehydrators	530
Liquids Unloading	3,628
Centrifugal Compressors	3,553
Transmission Storage Tanks	1,791
Pneumatic Pumps	1,775
Inactive Wells	591
Tank Unloading	447
Workovers	93
Well Testing	4
Storage Wells	27
Total	**420,523**

IV. EXISTING STATE AND FEDERAL REGULATIONS GOVERNING PROCESS CONTROLLERS

Natural gas-driven process controllers in New Mexico are subject to requirements under 20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* ("Ozone Precursor Rule" or "Part 50").[11] In addition, EPA published final standards of performance for GHG emissions for new, modified, and reconstructed sources and emissions guidelines to limit GHG emissions from existing sources in the Crude Oil and Natural Gas source category in March 2024, which are codified at 40 CFR Part 60, Subparts OOOOb and OOOOc and include requirements for natural gas-driven process controllers.[12,13] These existing state and federal requirements are discussed further below.

A. OZONE PRECURSOR RULE

In June 2022 the Environmental Improvement Board ("EIB" or "Board") adopted the Ozone Precursor Rule. Part 50 requires oil and gas operators in designated areas of the state to reduce emissions of nitrogen oxides and VOCs, pollutants that contribute to ground-level ozone. To achieve the desired reductions, Part 50 establishes emissions standards for certain crude oil and natural gas production and processing equipment, including natural gas-driven process controllers.

Specifically, Part 50 requires new natural gas-driven process controllers to have an emission rate of zero upon startup. It further requires owners and operators to retrofit an increasing percentage of existing natural gas-driven process controllers with non-emitting controllers over time. The percentages are based on facility type and the historic percentage of non-emitting controllers at all of the owner or operator's affected facilities that commenced

[11] https://www.srca.nm.gov/parts/title20/20.002.0050.html.
[12] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOb.
[13] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOc.

construction before the effective date of Part 50. The retrofit schedule and required percentages of non-emitting controllers are shown in Tables 5 and 6 below.[14]

Table 5. Part 50 Retrofit Schedule for Existing Natural Gas-Driven Process Controllers at Well Sites, Standalone Tank Batteries, and Gathering and Boosting Stations

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
>75%	80%	85%	90%
> 60-75%	80%	85%	90%
> 40-60%	65%	70%	80%
> 20-40%	45%	70%	80%
0-20%	25%	65%	80%

Table 6. Part 50 Retrofit Schedule for Existing Natural Gas-Driven Process Controllers at Transmission Compressor Stations and Gas Processing Plants

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
75%	80%	95%	98%
> 60-75%	80%	95%	98%
> 40-60%	65%	95%	98%
> 20-40%	50%	95%	98%
0-20%	35%	95%	98%

Note that temporary natural gas-driven process controllers used for well abandonment activities, used prior to or through the end of flowback, or that are on-site for less than 90 days, and natural gas-driven process controllers used as emergency shutdown devices at well sites are not subject to the requirements of Part 50. In addition, owners or operators that met at least 75

[14] Tables 5 and 6 replicate Tables 1 and 2 in Subsection B of 20.2.50.122 NMAC.

percent non-emitting controllers by January 1, 2025, were not thereafter subject to the retrofit requirements shown in Tables 5 and 6 above. Owners or operators can also seek a waiver from further retrofit requirements if after January 1, 2027, their remaining natural gas-driven process controllers are not cost-effective to retrofit.

Part 50 also includes monitoring, recordkeeping, and reporting requirements for natural gas-driven process controllers. Monitoring requirements include, on a monthly basis, conducting an audio, visual, and olfactory ("AVO") or optical gas imaging ("OGI") inspection, physically inspecting the controller, performing necessary maintenance, and maintaining the controller according to manufacturer specifications to ensure VOC emissions are minimized. Recordkeeping requirements include, *inter alia*, maintaining a record of the total controller count (emitting and non-emitting) at all of the owner or operator's affected facilities, maintaining a record of the total count of natural gas-driven process controllers necessary for a safety or process purpose, and maintaining a record for each natural gas-driven process controller that contains the controller ID number, controller type and bleed rate or volume, time and date of any monitoring and the name of the person(s) conducting the inspection, AVO or OGI inspection results and level discrepancy in bleed rate or volume, and maintenance date and activity. Lastly, reporting requirements include responding to information requests from NMED within three business days. Absent a request from NMED, Part 50 does not require owners or operators to submit information or regular reports to the Department.

B. 40 CFR PART 60, SUBPARTS OOOOb and OOOOc

In March 2024, EPA promulgated a rule finalizing new standards of performance limiting GHG and VOC emissions from new, modified, and reconstructed sources in the Crude Oil and Natural Gas source category, and emission guidelines for states to follow in developing,

submitting, and implementing state plans to establish performance standards to limit GHG emissions from existing sources in the same source category.[15,16] The standards of performance for new, modified, and reconstructed sources are codified at 40 CFR Part 60, Subpart OOOOb ("NSPS OOOOb"), and the emission guidelines for existing sources are codified at 40 CFR Part 60, Subpart OOOOc ("EG OOOOc"). NSPS OOOOb and EG OOOOc both include GHG standards for natural gas-driven process controllers in the form of limitations on emissions of methane.[17]

Specifically, NSPS OOOOb requires that natural gas-driven process controllers at new facilities (those that commence construction, modification, or reconstruction after December 6, 2022) operate with zero methane emissions to the atmosphere beginning January 22, 2027, or upon startup, whichever is later. EG OOOOc contains a "model rule" " at 40 CFR §§ 60.5385c through 60.5430c that includes a presumptive standard for natural gas-driven process controllers at existing facilities (those that commenced construction, modification, or reconstruction on or before December 6, 2022) requiring that they operate with zero methane emissions to the atmosphere beginning January 22, 2030, three years after the deadline for states to submit plans

[15] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Final rule, 89 Fed. Reg. 16820 (March 8, 2024), available at https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for.

[16] EPA defines the Crude Oil and Natural Gas source category to mean: (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station, commonly referred to as the ''city-gate.''

[17] EPA released a pre-publication version of a proposed rule amending OOOOb and OOOOc on the evening of October 27, 2026. *See* Additional Reconsideration Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Proposed rule (Pre-publication version signed by EPA Administrator Lee Zeldin on October 27, 2026), available at https://www.epa.gov/system/files/documents/2026-10/san-12726-ong-reconsideration-2-nprm-preamble-20261015-clean.admin_disclaimer.pdf. The Department has not yet evaluated the proposed rule, which must be published in the Federal Register and go through notice and comment rulemaking prior to adoption.

for implementing the guidelines to EPA.[18] States are required to adopt standards that are at least as stringent as the model rule's presumptive standard unless they can demonstrate that facilities cannot reasonably achieve the presumptive standard.

NSPS OOOOb and EG OOOOc both exempt natural gas-driven process controllers that function as emergency shutdown devices from these requirements. They also establish monitoring requirements that differ from the requirements in Part 50 in that they are designed to demonstrate compliance with zero emissions standards, whereas the monitoring requirements in Part 50 are designed to ensure that emissions from emitting controllers are minimized (since Part 50 still allows 2-20 percent of an owner or operator's natural gas-driven process controllers to emit natural gas to the atmosphere once fully implemented). NSPS OOOOb and EG OOOOc also contain more robust reporting requirements than Part 50, requiring the submission of annual reports documenting compliance with applicable requirements.

V. OVERVIEW OF THE PROCESS CONTROLLER PROVISIONS OF PART 51

The process controller provisions of Part 51 build on the requirements of Part 50 and are designed to close the regulatory gap that will remain once Part 50 has been fully implemented. That gap consists of the 2 to 20 percent of an owner or operator's natural gas-driven process controllers that will still be allowed to emit natural gas, and therefore methane and other pollutants, to the atmosphere after January 1, 2030.[19] The process controller provisions of Part 51 are closely modeled after the EG OOOOc model rule's process controller provisions and

[18] The compliance deadline was originally March 9, 2029, but was later extended by EPA. *See* Extension of Deadlines in Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Final Rule, Interim final rule, 90 Fed. Reg. 35966 (July 31, 2025), available at https://www.federalregister.gov/documents/2025/07/31/2025-14531/extension-of-deadlines-in-standards-of-performance-for-new-reconstructed-and-modified-sources-and.

[19] The share of an owner or operator's natural gas-driven process controllers that will still be allowed to emit natural gas to the atmosphere after January 1, 2030, could be as high as 25 percent if the owner or operator takes advantage of the early action incentive in 20.2.50.122(B)(4)(v).

require all "process controller designated facilities" to emit zero methane to the atmosphere beginning January 1, 2031, either by routing the emissions to a process through a closed vent system or by using self-contained natural gas-driven process controllers.[20] Process controller designated facility is defined as the collection of natural-gas driven process controllers at a gathering and boosting station, natural gas processing plant, tank battery, transmission compressor station, or well site. Natural gas-driven process controllers that function as emergency shutdown devices and process controllers that are not driven by natural gas (e.g., instrument air-driven or electric controllers) are exempt from the designated facility and are not subject to the rule's requirements.

The process controller provisions of Part 51 also specify inspection requirements for closed vent systems and self-contained natural gas-driven process controllers, design and operating requirements for closed vent systems, and requirements for demonstrating initial and continuous compliance with the zero methane emissions standard for process controller designated facilities. They further require owners or operators to submit annual reports to the Department documenting compliance with the zero methane emissions standard and to maintain related records.

The process controller provisions of Part 51 are described in more detail below. The other provisions of the rule (those not specifically related to process controllers) are described in the testimonies of Cindy Hollenberg and Jessica Hejny. **NMED Exhibits 6 and 7**.

[20] "Route to a process" means to convey the emissions via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled, consumed, transformed into other materials, or recovered. NMED Exhibit 1 at 2, Lines 25-28.

20.2.51.201 – Methane Standards for Process Controllers

Section 201 contains the methane standards for process controller designated facilities and specifies the compliance methods owners or operators may use to meet them. It also requires owners or operators to demonstrate initial and continuous compliance with the standards and to perform required reporting and recordkeeping.

Subsection A requires all process controller designated facilities to be designed and operated with zero methane emissions to the atmosphere beginning January 1, 2031. This requirement applies to both new and existing natural gas-driven process controllers, although Part 50 has required new natural gas-driven process controllers to have an emission rate of zero since August 2022, so it only affects existing natural gas-driven process controllers, specifically those that are not retrofitted with non-emitting controllers before January 1, 2030, to meet the requirements of Part 50. Owners and operators can comply either by routing natural gas-driven process controller emissions to a process through a closed vent system or by using self-contained natural gas-driven process controllers designed and operated with no identifiable emissions. Compliance cannot be achieved by routing natural gas-driven process controller emissions to a control device, such as a flare.[21] **NMED Exhibit 1 at 7, Lines 29-37**.

[21] The EG OOOOc model rule, which, as discussed above, includes the presumptive standard for natural gas-driven process controllers at existing facilities, only allows routing emissions to a control device at sites in Alaska that do not have access to electrical power. At sites outside Alaska, and sites in Alaska with access to electrical power, emissions can only be routed to a process. This is because allowing emissions to be routed to a control device when there is a technically feasible option available to comply with the best system of emissions reduction ("BSER"), which EPA determined to be the use of controllers that have a methane emission rate of zero, would result in a less stringent standard than the BSER and allow more emissions. For more discussion of the BSER, see section VI.B below. In addition, although venting or flaring of natural gas during normal operation of a natural gas-driven process controller is technically allowed under the Energy, Minerals, and Natural Resources Department's Methane Waste Rules (19.17.27 NMAC and 19.15.28 NMAC), it would be contradictory to operators' "general duty to maximize the recovery of natural gas by minimizing the waste of natural gas through venting and flaring" pursuant to 19.15.27.8(A). The Methane Waste Rules are discussed further in the testimony of Cindy Hollenberg.

Importantly, Subsection A does not preclude the use of non-emitting process controllers, such as instrument air-driven or electric controllers. Because the zero methane emissions standard only applies to process controller designated facilities, which as noted above is defined as the collection of **natural gas-driven** process controllers at a subject facility, and the rule specifically exempts process controllers that are not driven by natural gas from the designated facility, switching to non-emitting process controllers would relieve an owner or operator from having to comply with the rule's requirements. Compliance is only necessary if an owner or operator chooses to continue using natural gas-driven process controllers after January 1, 2031, in which case they would have to use one of the compliance methods described above to meet the zero methane emissions standard.

Subsection B requires an owner or operator who complies with the requirements of Subsection A by routing natural gas-driven process controller emissions to a process to route the emissions through a closed vent system that meets the requirements of 20.2.51.203 NMAC, *Closed Vent System Design and Operating Requirements*. **NMED Exhibit 1 at 7, Lines 38-40**.

Subsections C and D require owners and operators to demonstrate initial and continuous compliance with the requirements of Subsection A as required by 20.2.51.204 NMAC, *Demonstrating Initial Compliance with the Methane Standards for Process Controller Designated Facilities*, and 20.2.51.205 NMAC, *Demonstrating Continuous Compliance with the Methane Standards for Process Controller Designated Facilities*. **NMED Exhibit 1 at 7, Lines 41-44**.

Finally, Subsection E requires owners and operators to submit reports and keep records as required by 20.2.51.206 NMAC, *Reporting Requirements for Process Controller Designated*

Facilities, and 20.2.51.207 NMAC, *Recordkeeping Requirements for Process Controller Designated Facilities*. **NMED Exhibit 1 at 7, Lines 45-46**.

20.2.51.202 – Inspection Requirements for Closed Vent Systems and Self-Contained Natural Gas-Driven Process Controllers

Section 202 contains the inspection requirements for closed vent systems and self-contained natural gas-driven process controllers. It further provides that owners or operators complying with the leak and fugitive emissions detection requirements of Part 50 through an approved alternative monitoring plan may comply with the inspection requirements of Section 202 through the same alternative monitoring plan provided the plan covers all of the owner or operator's closed vent systems and self-contained natural gas-driven process controllers subject to Part 51.

Subsection A requires owners or operators who route natural gas-driven process controller emissions to a process through a closed vent system to conduct an initial inspection of all system components within 30 days of startup and periodic inspections thereafter (according to the frequencies specified in Subsection B) of any components or connections that are not permanently or semi-permanently sealed to demonstrate that the system operates with no identifiable emissions; conduct annual visual inspections for defects that could result in air emissions; and conduct monthly AVO inspections. It also requires owners or operators to ensure that bypass devices do not divert the vent stream away from the process and to the atmosphere by setting the flow indicator to take readings at least once every 15 minutes and, if the bypass device valve is secured in the non-diverting position using a car-seal or lock-and-key configuration, visually inspecting the seal or closure mechanism at least once every month to ensure the valve is maintained in the non-diverting position. **NMED Exhibit 1 at 8, Lines 10-47**.

Subsection B specifies the test methods and procedures for demonstrating that closed vent systems and self-contained natural gas-driven process controllers operate with no identifiable emissions. These include conducting initial and, for closed vent system components or connections that are not permanently or semi-permanently sealed, quarterly OGI inspections,[22] except closed vent systems at natural gas processing plants must be inspected more frequently (bimonthly) after the initial inspection. Subsection B also provides specifications for OGI, AVO, and EPA Method 21 inspections, including what constitutes a deviation of the no identifiable emissions standard, and requires owners or operators to repair any closed vent system emissions or defects found as soon as practicable but no later than 30 days after the emissions or defect is detected, unless repair is technically infeasible without a shutdown or the emissions resulting from immediate repair would be greater than the emissions likely to result if repairs are delayed, in which case delay of repairs is allowed but must be completed by the end of the next shutdown. In addition, parts of closed vent systems that are deemed unsafe or difficult to inspect are exempt from routine inspection requirements and only need to be inspected during safe-to-inspect times or, in the case of difficult to inspect parts, at least once every five years. **NMED Exhibit 1 at 8, Lines 48-55, 9, Lines 1-56, and 10, Lines 1-38**.

20.2.51.203 – Design and Operating Requirements for Closed Vent Systems

Section 203 contains the design and operating requirements for closed vent systems used to route natural gas-driven process controller emissions to a process.

Subsection A requires owners or operators to design their closed vent systems to capture and route all gases, vapors, and fumes to a process and to operate such systems with no identifiable emissions. It also requires owners or operators to properly install, calibrate, maintain,

[22] As an alternative to OGI, EPA Method 21 may be used to inspect for no identifiable emissions.

and operate a flow indicator at the inlet to each bypass device that sounds an alarm or otherwise provides notification when the bypass device is open and the vent stream is, or could be, diverted away from the process and to the atmosphere. Alternatively, owners or operators can secure the bypass device valve in the non-diverting position using a car-seal or lock-and-key type configuration. **NMED Exhibit 1 at 10, Lines 44-56, and 11, Lines 1-7**.

Subsection B requires owners or operators to conduct an assessment that their closed vent system is of sufficient design and capacity to ensure all gases, vapors, and fumes from their process controller designated facility are routed to the process, and that the process is of sufficient design and capacity to accommodate all emissions from the designated facility. This assessment must be prepared by or under the supervision of a qualified professional engineer or in-house engineer with expertise on the design and operation of the closed vent system and certified by the engineer who prepares or oversees the assessment. **NMED Exhibit 1 at 11, Lines 8-22**.

20.2.51.204 – Demonstrating Initial Compliance with the Methane Standards for Process Controller Designated Facilities

Section 204 specifies how owners or operators must demonstrate initial compliance with the methane standards for process controller designated facilities in Section 201. It further provides that in the event an owner or operator changes compliance methods, they must demonstrate initial compliance again for the new method.

Subsection A requires owners or operators to demonstrate that their process controller designated facility does not emit any methane to the atmosphere. If the owner or operator complies with the standard by routing the emissions to a process through a closed vent system, initial compliance is demonstrated by meeting the requirements in Subsection B. If the owner or

operator complies with the standard by using self-contained natural gas-driven process controllers, initial compliance is demonstrated by conducting the initial no identifiable emissions inspection required by Section 202. **NMED Exhibit 1 at 11, Lines 33-40**.

Subsection B requires owners or operators to only install closed vent systems that meet the design and operating requirements of Section 203 and to conduct the initial inspections (of the closed vent system and bypasses) required by Section 202. **NMED Exhibit 1 at 11, Lines 41-45**.

Subsection C requires owners or operators to submit the initial annual report for their process controller designated facility required by Section 206. **NMED Exhibit 1 at 11, Lines 46-47**.

Finally, Subsection D requires owners or operators to maintain the records specified in Section 207 for their process controller designated facilities. **NMED Exhibit 1 at 11, Lines 48-49**.

20.2.51.205 – Demonstrating Continuous Compliance with the Methane Standards for Process Controller Designated Facilities

Section 205 specifies how owners or operators must demonstrate continuous compliance with the methane standards for process controller designated facilities in Section 201.

Subsection A requires owners or operators to demonstrate that their process controller designated facility does not emit any methane to the atmosphere. If the owner or operator complies with the standard by routing the emissions to a process through a closed vent system, Subsection A states that the owner or operator must comply with the closed vent system inspection and monitoring requirements of Section 202. If the owner or operator complies with the standard by using self-contained natural gas-driven process controllers, Subsection A states

that the owner or operator must conduct the no identifiable emissions inspections required by Section 202. **NMED Exhibit 1 at 12, Lines 1-7**.

Subsection B requires owners or operators to submit the annual reports for their process controller designated facility required by Section 206. **NMED Exhibit 1 at 12, Lines 8-9**.

Subsection C requires owners or operators to maintain the records specified in Section 207 for their process controller designated facilities. **NMED Exhibit 1 at 12, Lines 10-11**.

20.2.51.206 – Reporting Requirements for Process Controller Designated Facilities

Section 206 contains the reporting requirements for owners or operators of process controller designated facilities. It provides that the initial annual report is due no later than 90 days after the end of the initial compliance period, and subsequent annual reports are due no later than the same date each year as the initial annual report. It further provides that an owner or operator may submit one annual report for multiple process controller designated facilities and that annual reports may coincide with Title V reports as long as all required elements of the annual report are included.

Subsection A describes the general information required for all reports, including company name, facility site name, US well number or associated US well number (if applicable), and facility address or coordinates; identification of each process controller designated facility included in the report; beginning and ending dates of the reporting period; and a certification by a company official that the statements and information in the report are true, accurate, and complete. **NMED Exhibit 1 at 12, Lines 23-34**.

Subsection B describes the information required in the owner or operator's initial annual report and subsequent annual reports for process controller designated facilities that are constructed, modified, or reconstructed during the reporting period, including identification of

each existing natural gas-driven process controller and identification of which of these controllers are complying with the methane standards in Section 201 by routing the emissions to a process and which ones are complying by using a self-contained natural gas-driven process controller. Subsection B also describes, together with Subsection C, additional information (apart from the general information described above) required for each annual report, including identification of each natural gas-driven process controller which changes its method of compliance during the reporting period; dates of each inspection of a closed vent system or self-contained natural gas-driven process controller required under Section 202; each defect or leak identified during each inspection and the date of repair (or anticipated date of repair if the repair is delayed); and, for each natural gas-driven process controller that uses a closed vent system to route emissions to a process, the date and time of each bypass alarm or each instance the key is checked out and the engineer's certification required by Section 203. **NMED Exhibit 1 at 12, Lines 35-54, and 13, Lines 1-21**.

20.2.51.207 – Recordkeeping Requirements for Process Controller Designated Facilities

Section 207 contains the recordkeeping requirements for owners or operators of process controller designated facilities. It further provides that all required records must be maintained for at least five years.

Subsection A requires owners or operators to maintain records identifying all natural gas-driven process controllers that do not function as an emergency shutdown device; identifying all natural gas-driven process controllers for which the owner or operator collects and routes vapors to a process through a closed vent system; identifying all self-contained natural gas-driven process controllers, the dates of each inspection, each defect or leak identified during each inspection, and the date of repair or anticipated date of repair if repair is delayed; records of each

change in compliance method; and records of each deviation, including the date, time, and duration of the deviation. **NMED Exhibit 1 at 13, Lines 27-53**.

Subsection B requires owners or operators to maintain, for each closed vent system inspection, a record of the inspection or no identifiable emissions monitoring survey including the identification number for the closed vent system, date of the inspection, and method used; the location of each defect or emissions detected, description of the defect, maximum concentration reading (if using EPA Method 21) or indication of emissions (if using AVO), date of each detection, and date repairs were completed; if the repair is delayed, the reason for the delay and the date the owner or operator expects to complete the repair; and the reason any parts are designated as unsafe to inspect and a written plan for inspection of those parts. **NMED Exhibit 1 at 13, Lines 54-55, and 14, Lines 1-16**.

Subsection C requires owners or operators to maintain, for each bypass, readings from the flow meter; each inspection of the seal or closure mechanism; and the date and time of each instance the key is checked out or the alarm is sounded. **NMED Exhibit 1 at 14, Lines 17-20**.

Subsection D requires, for each closed vent system routing to a process, a copy of the design and capacity assessment and engineer's certification required by Section 203. **NMED Exhibit 1 at 14, Lines 21-26**.

VI. RATIONALE, FEASIBILITY, COSTS, AND BENEFITS

A. Rationale for the Process Controller Provisions of Part 51

As discussed in the testimony of Cindy Hollenberg, methane – owing to its high Global Warming Potential – has a potent short-term impact on climate change, which is already causing harm to the people, ecosystems, economy, and lifeways of New Mexico. Recognizing the urgency of the threats posed by climate change and the significant climate benefits of efforts to

reduce methane emissions throughout the state, Governor Michelle Lujan Grisham issued Executive Order 2019-003 in January 2019 requiring the State to reduce greenhouse gas emissions by 45% by 2030 as compared to 2005 levels. However, New Mexico GHG emissions inventories and forecasts show that the State will not meet this target without additional efforts to reduce methane emissions, and in particular methane emissions from the oil and gas sector, which made up 15.5 percent of total GHG emissions in the State in 2023. **NMED Exhibit 6 at 3-21**. Hence the need for additional timely action, including closing the regulatory gap that will remain after Part 50 has been fully implemented by requiring that 100 percent of existing natural gas-driven process controllers be non-emitting in order to completely abate emissions from what has historically been a significant source of methane emissions in the State.[23]

In addition, EG OOOOc requires states to adopt standards for process controllers that are at least as stringent as the model rule's presumptive standard, which requires that natural gas-driven process controllers at existing facilities (those that commenced construction, modification, or reconstruction on or before December 6, 2022) operate with zero methane emissions to the atmosphere beginning January 22, 2030. Part 50 partially fulfills this mandate but will still allow a share of an owner or operator's existing natural gas-driven process controllers to emit natural gas to the atmosphere after the rule has been fully implemented (i.e., after January 1, 2030). The Department considered Part 50's retrofit requirements for existing natural gas-driven process controllers when choosing a compliance date of January 1, 2031, for the process controller provisions of Part 51.

Finally, and most importantly, the EIB has a legislative mandate to "prevent or abate air pollution" per the Air Quality Control Act ("AQCA"). NMSA 1978, § 74-2-5(A). The AQCA

[23] As discussed above and shown in Table 5, process controllers were the second largest source of oil and gas industry methane emissions in New Mexico in 2023, second only to combustion.

defines air pollution as "the emission, except emission that occurs in nature, into the outdoor atmosphere of one or more air contaminants in quantities and of a duration that may with reasonable probability injure human health or animal or plant life or as may unreasonably interfere with the public welfare, visibility or the reasonable use of property." NMSA 1978, § 74-2-2(B). In making its rules, the Board "shall give weight it deems appropriate to all facts and circumstances, including: (1) character and degree of injury to or interference with health, welfare, visibility and property; (2) the public interest, including the social and economic value of the sources and subjects of air contaminants; and (3) technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved." NMSA 1978, § 74-2-5(F).

Furthermore, per the Environmental Improvement Act, the role of the Department is to "be responsible for environmental management and consumer protection in this state in order to ensure an environment that in the greatest possible measure will confer optimum health, safety, comfort and economic and social well-being on its inhabitants; will protect this generation as well as those yet unborn from health threats posed by the environment; and will maximize the economic and cultural benefits of a healthy people." NMSA 1978, § 74-1-2. The Department has proposed Part 51, including the process controller provisions discussed above, in response to the Board's mandate and in fulfillment of the Department's statutorily defined role.

B. Feasibility of the Zero Methane Emissions Standard

When the EIB adopted Part 50 in 2022, it found that there are "several ways to reduce emissions from [natural gas-driven process controllers], including . . . using instrument air rather than natural gas to drive controllers, and using non-gas-driven controllers such as mechanical or

electric controllers, including solar-powered controllers." **NMED Exhibit 47 at 222**. Thus, the Board determined that there were technically feasible, non-emitting alternatives to natural gas-driven process controllers that owners or operators could utilize to comply with the rule's requirement that all new process controllers have an emission rate of zero as well as to comply with the rule's retrofit requirements for existing process controllers. The same options exist today for compliance with the zero methane emissions standard in Part 51.

The EIB further rejected calls from community and environmental parties to increase the stringency of Part 50 by adopting changes that would shorten the deadlines for retrofitting existing natural gas-driven process controllers with non-emitting controllers and increase the number of existing natural gas-driven process controllers owners or operators were required to retrofit. The Board rejected these changes because New Mexico would be regulating process controllers for the first time under Part 50, as opposed to building on previous regulatory efforts, and it was concerned that more stringent requirements might not be technically or economically feasible given New Mexico's starting point (i.e., the number of controllers affected, the number of facilities required to comply, and the time needed to come into compliance) and then-current supply chain issues related to the COVID-19 pandemic. ***Id.* at 223-241**. While those concerns were valid with respect to Part 50 at the time, they are not valid with respect to Part 51 today.

First, whereas Part 50 did not build on previous regulatory efforts, Part 51 builds on Part 50, which, as discussed above, requires owners or operators to retrofit 80-98 percent of their existing natural gas-driven process controllers with non-emitting controllers by January 1, 2030. Therefore, the starting point for Part 51 is radically different than it was for Part 50. The number of controllers affected is much smaller owing to the significant progress that will have been made towards eliminating existing natural gas-driven process controllers once Part 50 has been fully

implemented and Part 51 takes over. Furthermore, the pandemic's impacts on supply chains are a thing of the past, and owners and operators will have had years of experience retrofitting existing natural gas-driven process controllers with non-emitting controllers when the time comes to close the regulatory gap that remains after Part 50 has been fully implemented. They will also have several years to plan for how they will close that gap, and then a full year beyond the January 1, 2030, compliance deadline in Part 50 to do so.

Second, there have been several significant regulatory developments since the Board adopted Part 50 that further demonstrate the feasibility of the zero methane emissions standard for existing process controllers in Part 51. As discussed above, EPA promulgated EG OOOOc in March 2024, which established a presumptive state standard for existing process controllers requiring that they operate with zero methane emissions to the atmosphere by January 22, 2030. The presumptive standard was determined through an evaluation of the best system of emission reduction ("BSER") for control of methane from existing natural gas-driven process controllers in the production, processing, and transmission and storage segments of the Crude Oil and Natural Gas source category. Based on this analysis, EPA concluded that process controller technologies not driven by natural gas are cost effective based on the range it considers reasonable for methane. EPA also concluded that process controller technologies not driven by natural gas are technically feasible in locations with and without electrical power and have minimal secondary impacts even when they result in increased electricity needs. Therefore, EPA concluded that BSER for existing natural gas-driven process controllers is the use of controllers that have a methane emission rate of zero. This option results in a 100 percent reduction of emissions of methane and still allows

owners or operators to use continuous or intermittent bleed natural gas-driven process controllers so long as they capture the emissions and route them to a process through a closed vent system.[24]

Furthermore, in February 2025 the Colorado Air Quality Control Commission adopted amendments to its Regulation Number 7, Control of Emissions from Oil and Gas Emissions Operations (5 CCR 1001-9), to align the rule with EG OOOOc. These amendments included a requirement that owners or operators of existing natural gas-driven process controllers at well production facilities, natural gas compressor stations upstream of natural gas processing plants, and natural gas processing plants design and operate their controllers with zero emissions by March 1, 2029 (earlier for facilities located in 8-hour Ozone Control Area comprising much of the Denver metropolitan area and north front range, or in northern Weld County). Therefore, New Mexico is not the first state to seek to implement state standards for existing natural gas-driven process controllers that are at least as stringent as the presumptive standard in the EG OOOOc model rule, as required by the federal Clean Air Act. Notably, industry largely supported the amended Regulation 7 after revisions were made to the initial proposal in response to discrete concerns, resulting in what the Colorado Department of Public Health and Environment's Air Pollution Control Division described as "a largely consensus rule."[25] The February 2025 amendments to Regulation 7 build on earlier amendments to Regulation 7 requiring a large share of existing natural gas-driven process controllers to be retrofit with non-emitting controllers by May 1, 2023. These requirements formed the basis for Part 50, which Part 51 builds on in identical fashion.

[24] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Supplemental notice of proposed rulemaking, 87 Fed. Reg. 74702 (December 6, 2022), 74768, available at https://www.federalregister.gov/documents/2022/12/06/2022-24675/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for.

[25] In the Matter of Proposed Revisions to Regulation Number 7, February 19-21, 2025 Hearing, Rebuttal Statement of the Colorado Department of Public Health and Environment, Air Pollution Control Division (February 3, 2025), at 3, available at https://drive.google.com/file/d/1Vlpyp-wvn9MCjUVyWQmx-u-pqq3oN97A/view?usp=drive_link.

C. Costs

Because the methane standards for process controller designated facilities in Part 51 are identical to the EG OOOOc model rule's presumptive standard for natural gas-driven process controllers at existing facilities, and because Part 51 is so closely modeled after the EG OOOOc model rule, EPA's cost analysis for EG OOOOc also supports Part 51. As discussed above, EPA concluded that process controller technologies not driven by natural gas are cost effective based on the range it considers reasonable for methane when it adopted EG OOOOc. This conclusion was based on a cost analysis that estimated the cost to replace all natural gas-driven process controllers at existing sites with non-emitting controllers.[26] Because the number of controllers requiring replacement – and thus total replacement costs – would vary depending on site type and size, EPA developed a series of "model" plants (based on the number of natural gas-driven controllers) representing small, medium, and large sites in the production, midstream, and transmission and storage segments and estimated net annual costs for various types of non-emitting process controllers for each model plant. These costs are highly conservative for Part 51 because they assume that 100 percent of the process controllers at a site emit methane and therefore require replacement. However, Part 50 already requires that 80 to 98 percent of an owner or operator's existing process controllers be non-emitting by January 1, 2030. Therefore, far less than 100 percent of the process controllers at any given site will need to be replaced in order to comply with Part 51, meaning site-wide costs will be considerably less than EPA's estimates for EG OOOOc.

[26] EPA's analysis also estimated the cost to install non-emitting process controllers in lieu of natural gas-driven process controllers at new sites. However, Part 50 has required all new process controllers to have an emission rate of zero since August 2022. Therefore, Part 51 imposes no new requirements on new sites. As a result, EPA's estimates of the cost to install non-emitting controllers at new sites are not discussed here.

For its analysis, EPA first estimated methane emissions for individual natural gas-driven process controllers of various types. These estimates are shown in Table 1 above. It then determined the number of controllers at each model plant based on available information and calculated the plant's baseline annual emissions, which represent the emissions eliminated by replacing all of the plant's natural gas-driven process controllers with non-emitting controllers. This information is summarized in Table 7 below.

Table 7. EPA Model Plant and Baseline Emissions Data for Existing Sites

Model Plant	# of Controllers			Methane Emissions (tpy)
	Continuous High Bleed	Continuous Low Bleed	Intermittent Bleed	
Production Segment				
Small	1	1	2	7.6
Medium	1	1	6	14.3
Large	1	4	15	32.5
Midstream Segment				
Small	1	4	15	32.5
Large	1	28	71	151.1
Transmission and Storage Segment				
Small	1	7	22	22.1
Large	1	13	36	34.5

Finally, EPA used costs for equipment, engineering, installation, and operation, principally based on those found in reviewed literature, to calculate the total capital cost of replacing each model plant's existing natural gas-driven process controllers with various types of non-emitting controllers. EPA then annualized these costs based on reasonable assumptions regarding annual interest rates and equipment life, added the annual operation and maintenance ("O&M") costs for the replacement controllers, and deducted the avoided O&M costs associated with the replaced natural gas-driven process controllers to determine the net annual cost of

installing and operating each type of non-emitting controller over the expected life of the equipment. This information is presented in full in **NMED Exhibit 48** and summarized in Table 8 below.

Table 8. EPA Annual Process Controller Cost Estimates for Existing Sites

Model Plant	Annual Capital Cost Range	Annual O&M Cost Range	Avoided Annual O&M Costs	Net Annual Cost Range
Production Segment				
Small	$3,225-$25,175	$336-$6,750	$1,252	$2,499-$31,926
Medium	$5,473-$25,175	$671-$6,750	$2,504	$4,021-$31,926
Large	$12,217-$46,155	$1,678-$8,714	$6,260	$8,586-$54,729
Midstream Segment				
Small	$12,217-$46,155	$1,678-$8,714	$6,260	$8,586-$54,729
Large	$57,174-$100,265	$8,392-$18,930	$31,300	$39,032-$102,610
Transportation and Storage Segment				
Small	$17,885-$46,155	$2,518-$18,930	$9,390	$12,457-$61,805
Large	$29,125-$86,960	$4,196-$18,930	$15,650	$20,066-$102,610

The non-emitting controller types for which EPA estimated costs include electric process controllers powered by the grid, solar power, and on-site generator(s), and instrument air-driven process controllers powered by the grid and on-site generator(s). EPA lacked sufficient information to estimate costs for instrument air-driven process controllers powered by solar power, nitrogen-powered process controllers, routing natural gas-driven process controller emissions to a process, or self-contained natural gas-driven process controllers.

As **NMED Exhibit 48** and Table 8 show, annual O&M costs are lower for some of the non-emitting process controller options than for natural gas-driven process controllers, offsetting some of the capital costs. In addition, EPA's cost estimates do not account for the value of the natural gas no longer emitted by the replaced natural gas-driven process controllers. According

to EPA, in some instances owners or operators could actually realize a net savings by switching to non-emitting process controllers when the value of the gas that is saved is considered.

D. Benefits

As shown in Table 4 above, there were 139,491 metric tons of methane emissions from natural gas-driven process controllers in New Mexico in 2020, before the adoption of Part 50. In 2023, shortly after Part 50 took effect, natural gas-driven process controller methane emissions dropped to 101,019 metric tons. This reflects the fact that after August 5, 2022 (the effective date of Part 50), new process controllers were required to have an emission rate of zero, and owners or operators were required to begin retrofitting their existing natural gas-driven process controllers with non-emitting controllers according to the schedule shown in Tables 5 and 6 above, with an initial compliance deadline of January 1, 2024.[27] In 2030, after Part 50 has been fully implemented, natural gas-driven process controller methane emissions are projected to drop to 22,167 metric tons. **NMED Exhibit 49**. By closing the regulatory gap that remains after Part 50 has been fully implemented, Part 51 will eliminate these 22,167 metric tons of methane emissions by January 1, 2031.[28] It will also reduce emissions of other pollutants contained in natural gas, including but not limited to VOCs, prevent waste of energy resources, and generate savings for owners and operators by allowing them to sell the natural gas that otherwise would have been vented to the atmosphere by their natural gas-driven process controllers.

VII. CONCLUSION

Action to address climate change is urgently needed owing to the harm it is causing to the people, ecosystems, economy, and lifeways of New Mexico. This prompted Governor Michelle

[27] 25 to 80 percent of an owner or operator's controllers were required to be non-emitting by this date.
[28] There could still be a de minimis amount of methane emissions after this date from natural gas-driven process controllers used as emergency shutdown devices, which are exempt from the requirements of Part 51.

Lujan Grisham to issue an executive order in 2019 requiring the State to reduce GHG emissions by 45% by 2030 as compared to 2005 levels. The State has made progress in the intervening years, but recent GHG inventories show additional action to reduce GHG emissions is necessary in order to meet this target. This includes action to address methane emissions from the oil and gas sector, which made up 15.5 percent of total GHG emissions in the State in 2023, owing to methane's potent short-term impact on climate change. Natural gas-driven process controllers have historically been a significant source of these emissions, accounting for almost 25 percent of industry-wide methane emissions in 2023. Part 51 builds on the requirements of existing Part 50 to completely eliminate these emissions, furthering New Mexico's climate goals while also complying with federal requirements for states to adopt standards for existing natural gas-driven process controllers that are at least as stringent as the zero methane emissions standard in the EG OOOOc model rule. For these reasons, the Department respectfully requests the Board adopt revised proposed Part 51.