ENVIRONMENTAL DEFENSE FUND'S COMMENTS ON DRAFT PROPOSED REGULATORY AMENDMENT TO STATEWIDE ORDER NO. 29-B

Environmental Defense Fund ("EDF") by and through the undersigned, greatly appreciates the opportunity to submit the following comment on the Louisiana Office of Conservation's draft proposed regulatory amendment to LAC 43:XIX. Subpart.I. Chapter 35.

EDF is a membership organization with more than 3 million members and activists worldwide and in the state of Louisiana, many of whom are deeply concerned about waste and pollution from oil and natural gas development and operations. EDF brings a strong commitment to sound science, collaboration, and market-based solutions to our most pressing environmental and public health challenges.

I. INTRODUCTION

EDF strongly supports and appreciates the efforts of the Engineering Regulatory Division of the Louisiana Office of Conservation ("Division") to amend the Division's rules related to the venting and flaring of natural gas.[1] The draft proposed rule is an important pillar of the state's commitment to achieving net zero greenhouse gas emissions by 2050 and fulfills one of the recommendations of the Governor's Climate Initiatives Task Force.

The venting and flaring of natural gas co-produced with oil ("associated gas") is a deeply wasteful and highly polluting practice that is easily avoidable, or significantly minimized, with existing technologies. These technologies are highly cost effective, in many instances resulting

[1] LA Dept. of Natural Resources, Office of Conservation, Potpourri, Public Comment Announcement, Statewide Order No. 29-B, 49 LA Register No. 3, p.622 (March 20, 2023).

in savings from the captured gas which is either sold, used onsite, or reinjected and stored for future use. [2]

Venting is especially damaging due to methane's very high potency as a greenhouse gas.[3] Flaring also produces a significant amount of greenhouse gas emissions,[4] both in the form of carbon dioxide from combustion and from methane, because even in ideal flaring conditions, not all methane is combusted.[5] In practice, many flares malfunction, with a significant methane slip rate, or are left unlit.[6]

Per EDF analysis, Louisiana upstream operators vented and flared a total of 5.2 BCF of natural gas in 2019.[7] Nearly all of this was due to (i.e., 5.1 BCF) flaring. This wasted gas released approximately 79,505 metric tons of methane ("CH4"), 22,084 metric tons of volatile organic compounds ("VOCs") and 837 metric tons of hazardous air pollutants ("HAPs").[8] Importantly, these numbers underestimate actual emissions since they do not account for emissions from malfunctioning flares.

Upstream venting and flaring generally has two causes: (1) routine flaring or venting that occurs in the absence of sufficient takeaway capacity for the associated gas; or (2) temporary flaring or venting during activities that are, by their nature, time-limited such as drilling and maintenance activities. The Division's rule proposes reasonable, cost-effective solutions that either

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[2] Rystad Energy, Cost of Flaring Abatement, at 11 (Jan. 31, 2022) [Hereinafter "Rystad"], Attachment A.

[3] EPA, Importance of Methane (Jun. 30, 2021), https://www.epa.gov/gmi/importance-methane (last accessed Apr. 17, 2023).

[4] EDF estimates that flaring releases 200,000 tons of methane into the atmosphere every year nationally. EDF, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last accessed Apr. 17, 2023).

[5] Most properly functioning flares are designed to operate at 95% efficiency, meaning that even in a best-case scenario, 5% of gas released is pure methane. *See, e.g.*, Björn Pieprzyk and Paula Rojas Hilje, *Flaring and Venting of Associated Gas*, ENERGY RESEARCH ARCHITECTURE, 12 n.3 (Dec. 2015).

[6] EDF, Permian Methane Analysis Project (2021), https://www.permianmap.org/ (last accessed Apr. 17, 2023).

[7] Synapse Energy Economics, Methane Waste and Pollution in Louisiana, https://www.edf.org/media/new-analysis-quantifies-natural-gas-waste-and-pollution-louisiana.

[8] EDF Analysis of 2019 vented and flared gas. Emissions calculated using EPA conversion factors.

eliminate, or significantly restrict, both types of venting and flaring. The proposed rule prohibits routine flaring and venting, other than for existing wells that may apply for a one-time extension to flare while they connect to a gathering line or find an alternative way to put associated gas to beneficial use.[9] Temporary flaring is permitted only during specific activities.[10]

We commend the Division on proposing a rule that eliminates the pernicious practice of routine flaring and venting and that significantly limits the instances when an operator may flare or vent during temporary activities. The draft rule comports with Louisiana's statutory prohibition on waste and will go a long way towards reducing harmful pollution that contributes to the climate crisis, threatens human health and disproportionately impacts vulnerable communities. Our comments below provide support for the draft rule, relying on examples of similar rules promulgated by other oil and gas producing states, and providing information demonstrating the cost effectiveness of technologies and practice that capture associated gas.

II. The Urgency of Reducing Methane Emissions

Methane is a dangerous and powerful greenhouse gas that is eighty-seven (87) times more potent than carbon dioxide on a molecule per molecule basis over a 20-year timeframe, and up to 36 times more potent over a 100-year time frame.[11] Methane is a short-lived greenhouse

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[9] Proposed La. Admin. Code tit. 43 § XIX-3507.A.4.

[10] *Id*. at §§ XIX-3507.A.2,3,4.a.-g.

[11] Wuebbles, Donald, et al., U.S. Glob. Change Research Program, Climate Science Special Report (CSSR) (fifth order draft) (final clearance June 28, 2017); https://s3.documentcloud.org/documents/3920195/Final-Draft-of-the-Climate-Science-Special-Report.pdf; Myhre, Gunnar, et al., 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, at ch. 8, https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf ("Myhre et al. 2013"); Bradbury, James et al., Dep't of Energy, Office of Energy Policy and Systems Analysis, Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology, at 10 (July 2015), https://www.energy.gov/sites/prod/files/2015/07/f24/QER%20Analysis%20-%20Fuel%20Use%20and%20GHG%20Emissions%20from%20the%20Natural%20Gas%20System%2C%20Sankey%20Diagram%20Methodology_0.pdf (explaining how the effects of oxidation increase the IPCC's global warming potential values for methane to 87 over a 20-year timeframe an 36 over a 100-year timeframe).

gas, lasting only approximately a decade.[12] This makes reducing methane emissions critical for achieving short-term greenhouse gas reductions ("GHG") and slowing the rate of climate change.[13]

In August 2020 Governor John Bel Edwards signed an Executive Order which established 2025, 2030 and 2050 GHG reduction goals for Louisiana.[14] Specifically, the Executive Order commits the state to reducing GHG emissions to 26-28% below 2005 levels by 2025, 40-50% below 2005 levels by 2030 and to achieving net zero GHG emissions by 2050.[15] The Executive Order also established the Governor's Climate Initiatives Task Force which was tasked with creating a state Climate Action Plan to develop strategies to meet the Governor's GHG reduction goals.[16] Strategies 7 and 8 of the Climate Action Plan recognize the critical role that methane reductions play in combating climate change, protecting public health and improving equity. A central recommendation of the Climate Action Plan is for Louisiana to "enact methane waste rules in line with rules of other states" noting that New Mexico and Colorado recently enacted strong methane waste rules.[17]

As the Climate Action Plan recognizes, climate change is already adversely impacting the health and welfare of many Louisianans, in particular those with the fewest resources, and harming sensitive and valuable environmental resources, in particular coastal resources.[18]

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[12] Atmospheric Lifetime and Global Warming Potential Defined, https://19january2017snapshot.epa.gov/climateleadership/atmospheric-lifetime-and-global-warming-potential-defined_.html.

[13] Smith, Kirk R., et al., U.S. Climate Change Science Programs Synthesis and Assessment Product 3.2, Climate Projections Based on Emissions Scenarios for Long-Lived and Short Lived Radiatively Active Gases and Aerosols at 64-65 (2008) https://www.globalchange.gov/sites/globalchange/files/sap3-2-draft3.pdf.

[14] Executive Order No. JBE 2020-18.

[15] *Id*.

[16] State of Louisiana, Climate Action Plan (Feb. 2022), https://gov.louisiana.gov/assets/docs/CCI-Task-force/CAP/Climate_Action_Plan_FINAL_3.pdf.

[17] Climate Action Plan, p.68.

[18] *Id.* at 19-31.

Immediate and deep reductions in GHGs, in particular of methane, are critically necessary. The contribution of Working Group III to the IPCC Assessment Reports highlights the importance of near-term methane reductions, finding with "*high confidence*" that "[d]ue to the short lifetime of [methane] in the atmosphere, projected deep reduction of [methane] emissions up until the time of net zero [carbon dioxide] in modeled mitigation pathways effectively reduces peak global warming."[19] Yet since 2007, atmospheric methane levels have been increasing at an accelerating pace, with the largest yearly rise in methane levels ever recorded occurring in 2020 and 2021 (15 and 18 ppb respectively).[20] A deep near-term reduction in methane pollution is therefore one of the most important actions to be taken in addressing the climate crisis.

The Division's draft rule represents an important step toward staving off the worst impacts of climate change as it will help reduce methane emissions caused by venting, flaring, and malfunctioning flares.

III. The Office of Conservation Has Clear Authority to Eliminate, or Significantly Limit, the Wasteful Practice of Venting and Flaring of Natural Gas.

30 Louisiana Revised Statutes § 2 prohibits waste of natural gas. The Act defines waste to include "physical waste" as that term is generally understood in the oil and gas industry[21] and "the producing of oil or gas from a pool in excess of transportation or marketing facilities ... or producing of an oil or gas well in a manner causing, or tending to cause, unnecessary or

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[19] Masson-Delmotte et al., Intergovernmental Panel on Climate Change, Summary for Policymakers in *Climate Change 2022: Mitigation of Climate Change: Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* at 24, C.2.3.

[20] World Meteorological Organization, *More bad news for the planet: greenhouse gas levels hit new highs*, Press Release Number: 26102022 (Oct. 26, 2022), https://public.wmo.int/en/media/press-release/more-bad-news-planet-greenhouse-gas-levels-hit-new-highs#:~:text=Since%202007%2C%20globally%2Daveraged%20atmospheric,systematic%20record%20began%20in%201983.

[21] LSA-R.S. § 30:3(16)

excessive surface loss or destruction of oil or gas."[22] The Act's capacious definition of waste unequivocally includes the venting and flaring of gas.

Physical waste in the oil and gas industry has long been understood to include the direct release of natural gas into the air, and the combustion of natural gas without putting it to beneficial use.[23] Venting constitutes the direct release of natural gas into the air. Flaring is a form of combustion. Thus, the Act's prohibition on waste applies to venting and flaring of natural gas.

The Act also defines waste to prohibit "the producing of oil or gas from a pool in excess of transportation or marketing facilities."[24] The production of natural gas from a well in the absence of takeaway capacity for the gas is a common cause of flaring. The Act's prohibition on producing gas from a pool in excess of transportation or marketing facilities further prohibits venting and flaring of natural gas.

Lastly, the Act defines waste to prohibit "producing of an oil or gas well in a manner causing, or tending to cause, unnecessary or excessive surface loss or destruction of oil or gas."[25] Surface loss is an express reference to venting; surface destruction applies to flaring. Thus, the Act's prohibition on producing oil or gas in a manner causing, or tending to cause, the

[22] LSA-R.S. § 30:3(16)(b).
[23] See Wm. & Meyers, Manual of Oil and Gas Terms 1046 (14th ed. 2009) (describing "physical waste" as "the loss of oil or gas that could have been recovered or put to use," including "flaring of gas"); see also, e.g., J. Howard Marshall & Norman L. Meyers, Legal Planning of Petroleum Production: Two Years of Proration, 42 Yale L.J. 702, 713 n.31 (1933) (discussing 1929 Texas statute that defined physical waste to include "escape into the open air of natural gas," and early efforts by courts to resolve questions of state authority to regulate economic waste in addition to physical waste); Cities Serv. Gas Co. v. Peerless Oil & Gas Co., 340 U.S. 179, 185 (1950) ("It is now undeniable that a state may adopt reasonable regulations to prevent economic and physical waste of natural gas."); R.R. Comm'n v. Shell Oil Co., 154 S.W.2d 507, 509 (Tex. Civ. App. 1941) (describing permissible regulation to prevent physical waste as including excess aboveground storage of oil or gas in open air tank).
[24] LSA-R.S. § 30:3(16)(a).
[25] *Id.* at (16)(b).

unnecessary or excessive surface loss or destruction of gas also prohibits venting and flaring of natural gas.

IV. Flaring and Venting Emit Emissions that Endanger Human Health and the Environment.

Venting and flaring releases methane and carbon dioxide —two greenhouse gases that contribute to climate change. Specifically, combustion of natural gas in flares produces carbon dioxide. Because no flares are 100% efficient in combusting natural gas, flaring also is a significant source of methane emissions. This is particularly the case when flares are operated improperly or allowed to extinguish, as discussed below.

A series of studies on flare performance in the Permian Basin in New Mexico and Texas demonstrate flares routinely malfunction, releasing significant amounts of climate altering pollution into the atmosphere. Using helicopter-based infrared camera surveys EDF scientists determined approximately 5% of large flares were unlit and venting gas at any given time, and another 5% have visible slip of methane or other hydrocarbons–meaning the flare is only partially combusting the methane and the rest is escaping into the atmosphere.[26] This determination was based on observing over 1,000 flares. These findings indicate that malfunctioning flares are a recurring and persistent problem.[27]

Flaring also contributes to black carbon—another driver of climate change.[28] Black carbon is a major component of airborne particles that are commonly referred to as "soot." Black carbon is a product of incomplete combustion of fossil fuels and biomass, and its

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[26] Permian MAP, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last visited Apr. 17, 2023)
[27] *Id*.
[28] Schwartz, et al., Black Carbon Emissions from the Bakken Oil and Gas Development Region, *Environ. Sci. Technol. Lett.* 2015, 2, 10, 281-285 (Sept. 3, 2015), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.5b00225

absorption properties make it a warming influence on climate. It is also harmful to human health when inhaled.[29]

A. Flaring and venting contribute to ozone pollution

Flaring emits oxides of nitrogen ("NOx") and volatile organic compounds ("VOCs") that contribute to ground-level ozone and cause adverse health impacts. Ground-level ozone is a dangerous air pollutant. Exposure to elevated concentrations of ozone lead to serious, adverse health effects, including asthma, increased emergency room visits, and premature death - impacts that are particularly severe in sensitive populations, like children and the elderly.[30] Ozone also causes direct harm to the environment by impeding plant growth and vitality and decreasing crop yield.[31] Increasing temperatures caused by climate change exacerbates ozone pollution.[32]

B. Emissions from flaring and venting are detrimental to human health and fall inequitably on disadvantaged communities.

Studies demonstrate that emissions from flaring and venting cause severe health burdens on communities, especially disadvantaged communities like low-income populations, people of color, the elderly, and children.

A 2023 study by Boston University's School of Public Health, The University of North Carolina, and Environmental Defense Fund analyzed the impacts of onshore oil and gas flaring and venting on air quality and health.[33] Prior studies have indicated that oil and gas activity is associated with increased risk of adverse health events, but there was limited quantification of

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[29] CIRES, Emissions of Black Carbon from Flaring in the Bakken Oil and Gas Fields (Sept. 9, 2015).
[30] 80 Fed. Reg. 65292, 65322 (Oct. 26, 2015).
[31] *Id*. at 65369, 65370.
[32] EPA, Climate Change Impacts on Air Quality, https://www.epa.gov/climateimpacts/climate-change-impacts-air-quality#:~:text=Climate%20change%20can%20affect%20air,level%20ozone%20in%20some%20areas.&text=Ground%2Dlevel%20ozone%20is%20also,trapping%20heat%20in%20the%20atmosphere.
[33] *See* Huy Tran et al., *Onshore Oil and Gas Flaring and Venting Activities in the United States and their Impacts on Air Quality and Health* (pre-publication slides) (Feb. 2023) (Attachment B).

the health impacts that resulted from air pollution from flaring and venting activities specifically. This study sought to fill this gap by quantifying ozone, PM2.5 and NO2 emissions from venting and flaring and attributing those emissions to particular health outcomes. Using a hybrid VIIRS and National Emissions Inventory based emissions inventory and applying EPA's community multiscale air quality modeling and EPA's environmental benefits mapping and analysis program-community edition to assess air quality health impacts, the study found that in 2017, flaring and venting emissions from oil and gas operations nationally resulted in 710 premature deaths, 73,000 asthma exacerbations among children, 210 instances of ozone NAAQS exceedances, and over $7.4 billion in health damages.[34] Critically, the study found that these health impacts disproportionately burden disadvantaged populations. The study also found that ozone (O3) pollution from flaring and venting contributes to 230 deaths, 9,700 asthma exacerbations, and 110 respiratory hospitalizations annually.[35]

The 2023 study results complement previously published literature, including a 2022 study by Rice University and Clean Air Task Force, which looked at the health impacts related to black carbon emissions from flaring in the U.S.[36] This study used satellite flaring data from VIIRS and three separate reduced form models to assess flaring health impacts. It estimated that national flaring from oil and gas operations emitted nearly 16,000 tons of black carbon in 2019, leading to 26-53 premature deaths that were directly attributable to air quality associated with flares.

These results comport with previous findings, including a 2021 study by researchers at UCLA and USC that found that more than half a million people in the U.S. live within a half

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[34] *Id*. at 4–5.
[35] *Id*. at 31.
[36] Chen Chen et al., *Black Carbon Emissions and Associated Health Impacts of Gas Flaring in the United States*, 13 Atmosphere 385 (Feb. 2022), https://www.mdpi.com/2073-4433/13/3/385/htm.

mile of significant oil and gas flaring.[37] Of these people, the study found 210,000 live near more than 100 flares, including a disproportionate number of black and indigenous people and other people of color.[38]

These studies show the significant health impacts of flaring and the disproportionate impact it has on vulnerable communities. They also highlight the critical need to address emissions from venting and flaring, as proposed by the Division.

V. Routine Flaring is An Outdated, Unnecessary and Wasteful Practice

As the Division's draft rule implicitly recognizes, routine flaring is an outdated practice that is never warranted. Actions of leading companies, several oil and gas producing states, and expert reports provided to US EPA by EDF, provide support for the Division's strong draft rule:

- ***Oil and Gas Industry Commitments***. Numerous leading companies, and consortiums of companies, have agreed to eliminate routine flaring. The World Bank's Zero Routine Flaring by 2030 Initiative "brings together governments, oil companies, and development institutions who recognize [routine flaring] is unsustainable from a resource management and environmental perspective, and who agree to cooperate to eliminate routine flaring no later than 2030."[39] As of 2022, there are 54 oil companies representing almost 60 percent of total global gas flaring that have committed under the Initiative to avoid routine flaring at

[37] Lara J. Cushing et al., *Up in smoke: characterizing the population exposed to flaring from conventional oil and gas development in the contiguous US*, 16 Env't Rsch. Letters 034032 (Feb. 2021), https://iopscience.iop.org/article/10.1088/1748-9326/abd3d4.
[38] *Id*.
[39] The World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/initiative-text

new fields and end ongoing routine flaring by 2030.[40] Another industry group, the Texas Methane and Flaring Coalition, consisting of seven state trade associations and over 40 Texas operators, has stated that "The Coalition agrees we should strive to end routine flaring…."[41] Exxon has halted all routine flaring in the Permian Basin.[42]

- ***State Rules.*** Several major oil and gas producing states–New Mexico, Colorado, and Alaska–have recognized that routine flaring is no longer either acceptable or necessary and have adopted regulations that effectively prohibit the practice. In 2020, Colorado adopted regulations that prohibit venting and flaring during oil and gas production except as allowed by specified exemptions for temporary activities such as upset conditions and pursuant to a one-time, time-limited advance approval by the regulator under specified conditions.[43] New Mexico adopted regulations in March 2021 that similarly prohibit routine venting and flaring during production other than during specific temporary exemptions.[44] In addition, Alaska has severely restricted routine flaring for decades through regulations that treat as waste venting or flaring that continues after one hour, absent regulatory approval.[45]

[40] The World Bank, Global Initiative to Reduce Gas Flaring: "Zero Routine Flaring by 2030" List, https://thedocs.worldbank.org/en/doc/a903b5e6456991faf3b5e079bba0391a-0400072021/related/ZRF-Initiative-text-list-map-104.pdf

[41] Texas Methane and Flaring Coalition, Flaring Recommendations and Best Practices, 2 (June 16, 2020), https://texasmethaneflaringcoalition.org/wp-content/uploads/2020/06/6-16-20-TMFC-Flaring-Recommendations-Best-Practices-Report.pdf.

[42] Sabrina Valle, *Exclusive: Exxon halts routine gas flaring in the Permian, wants others to follow* (Jan. 24, 2023), https://www.reuters.com/business/energy/exxon-halts-routine-gas-flaring-permian-wants-others-follow-2023-01-24/.

[43] 2 Colo. Code Regs. 404-1 § 903d.

[44] New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A).

[45] Alaska Administrative Code, 20 AAC § 25.235.

- ***EPA Proposal***. The U.S. EPA recently proposed to prohibit routine flaring other than in circumstances where operators can demonstrate that flaring is not technically feasible or safe, based on a certified demonstration signed by an engineer.[46] The EPA proposal prohibits venting other than where necessary for safety.
- ***Expert reports.*** Reports prepared by independent consulting entities demonstrate that routine flaring is avoidable. Rystad Energy conducted an in-depth study of flaring practices and flaring abatement costs in states with detailed publicly available information regarding flaring: North Dakota, Texas, New Mexico, Colorado and Wyoming.[47] The Rystad report notes that most operators in Texas, North Dakota, New Mexico, Wyoming, and Colorado report low flaring volumes.[48] Those operators that have reduced flaring have done so through "a change in mindset from viewing flaring as a part of normal operations to viewing flaring as a constraint on operations."[49] Similarly, a former Southwestern Energy Vice President, Thomas Alexander, submitted an expert report to EPA in support of strong rules that prohibit routine flaring.[50] Mr. Alexander's report demonstrates that routine flaring can be prevented, or eliminated, using available technologies and proper planning.

Routine flaring is readily preventable at new wells with proper planning and coordination between upstream and midstream operators.[51] The Rystad report makes clear that the main

[46] 87 Fed. Reg. 74702 (Dec. 6, 2022).
[47] Rystad, *supra* note 2.
[48] *Id*. at 100
[49] *Id.* at 80.
[50] Thomas Alexander, Alexander Engineering, *Expert Report of Thomas Alexander* 2 (2023) [hereinafter, *Expert Report of Thomas Alexander*] (Attachment C).
[51] *Id.*

drivers of flaring are timing of well hookups and infrastructure capacity.[52] An operator has complete control over decisions regarding where and when to drill a new well and when to complete or put such a well into production. As such, operators of new wells have the ability to address both timing and infrastructure capacity challenges.

Routine flaring from existing wells is also avoidable or preventable.[53] In the event an existing well is not currently connected to a gathering line, cost-effective options are available, including converting the associated gas to compressed natural gas (CNG), using it to replace a different fuel source for onsite fuel purposes, converting the gas to electricity, reinjection, or connecting to a gathering line.[54] Prudent operators are prepared for events that can result in loss of takeaway capacity such as midstream and downstream interruptions, changes in gas composition requirements, and changes in line pressure.[55] Such operators can quickly employ one of the alternative abatement options the Division proposes here.[56] The draft rule nevertheless affords existing operators who are not connected to a gathering line one year to make arrangements to capture, rather than vent or flare, associated gas. Colorado has a similar provision.[57]

In the event an operator loses its connection to a gathering line without warning due to events outside its control, a limited exception for flaring during the upset condition can address an operator's need to flare temporarily.[58] Operators can also temporarily shut in wells if time is needed to restore access to a pipeline or make arrangements for alternative gas recovery.

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[52] Rystad, *supra* note 2, at 8 (noting that infrastructure capacity constraints account for 84% of flaring in North Dakota and 62% of flaring in Texas).
[53] *Expert Report of Thomas Alexander*, *supra* note 50, at 4.
[54] *Id.* at 4; Rystad, *supra* note 2, at 8, 10-11.
[55] *Id.*
[56] *Id*.
[57] 2 Colo. Code Regs. 404-1 § 903d(3).
[58] *Expert Report of Thomas Alexander*, *supra* note 50, at 4–5.

Shutting in wells does not necessarily harm the productivity of a well and may, in some instances, enhance performance.[59] Both New Mexico and Colorado allow operators to vent or flare for a limited period of time in the event of loss of a connection to a gathering line. Colorado allows for venting or flaring up to 24 cumulative hours pursuant to its Upset Condition exception.[60] New Mexico allows for venting or flaring up to 8 hours pursuant to its Emergency exception.[61] The Division's draft rule includes an exception for upset conditions which similarly could allow for time-limited venting or flaring in the event of temporary loss of connection to a gathering line.[62]

VI. Cost Effective Solutions Exist to Eliminate Routine Flaring and Venting, and Significantly Reduce Temporary Venting and Flaring

Capturing gas by eliminating or minimizing flaring results in significant economic benefits in the form of higher royalty payments and taxes on captured and sold natural gas. In 2019, Louisiana saw $16 million of gas wasted through venting and flaring alone, enough gas to meet the needs of nearly every household in New Orleans for a year.[63] The wasted gas also represents lost potential revenue in the form of royalties to mineral owners and taxes. In 2019, the state lost out on $710,000 in tax revenue due to vented and flared gas.[64] Compliance with the draft rule's prohibition on flaring or venting associated gas will result in tax revenue for Louisiana and royalties for mineral owners, as well as savings for operators.

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[59] *Id.* at 3.
[60] Colo. Oil & Gas Conservation Comm., Statement of Basis, Specific Statutory Authority, and Purpose: New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 800/900/1200 Mission Change Rulemaking at 76, (Dkt. No. 200600115), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/800-900-1200MissionChangeDraftSBP.pdf [hereinafter "Colo. 800/900/1200 SBP"].
[61] N.M. Code R. §§ 19.15.27.7.H.(4).
[62] Proposed La. Admin. Code tit. 43 § XIX-3507.A.4.a.
[63] Synapse Energy Economics, et al., *supra* note 7.
[64] *Id*.

A suite of cost-effective technologies exist to recover, rather than waste, associated gas. We discuss these technologies below.

Routing to a sales line. The Rystad report shows that connecting wells to gathering infrastructure is not only highly cost-effective but profitable for operators, with an average net profit to operators of $3.10 per thousand cubic feet (kcf) and average negative cost of $162 per metric ton of methane flaring avoided.[65] Operators will pay between $0.40 and $1.20 per kcf handled by third party processing and gathering, netting profit after gas sales of $2.70 to $3.50 per kcf.[66] This corresponds to a range of negative $141-183 per metric ton of methane abated.[67] Gathering is an effective and available option for sites flaring any amount of gas.[68]

Truck Transport. In cases where existing well sites lack adequate existing gathering system infrastructure, or where gathering systems are at capacity on a temporary or ongoing basis, well operators may choose to forego construction of additional gathering capacity or coordination with third-party gatherers and instead convert associated gas onsite into CNG[69] and transport it by road in specialized tanker trucks.[70] The trucks would transport the gas to processing plants, where the gas is prepared to meet pipeline requirements.[71] Trucking can be both a long-term option for existing wells lacking adequate gathering line infrastructure or capacity, and a short-term solution in cases of low capacity due to outages, maintenance activities, or temporary system overload—either at the processing plant (in which case trucks

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[65] Rystad *supra* note 2, at 11.
[66] *Id*. at 45.
[67] *Id.*
[68] *Id.* at 40.
[69] As discussed in the Rystad report, *supra* note 2, at 10–11. LNG trucking is another option for gas transport. However, at this time we lack adequate data on overall emissions associated with LNG trucking to determine whether this would be an appropriate approach to emissions mitigation.
[70] *See* Anders Pederstad, Martin Gallardo, and Stephanie Saunier, Improving Utilization of Associated Gas in US Tight Oil Fields, Carbon Limits AS (Prepared for Clean Air Task Force) (Oct. 2015), https://www.catf.us/wp-content/uploads/2015/04/CATF_Pub_PuttingOuttheFire.pdf at 33 [hereinafter Carbon Limits].
[71] *See id.*

could transfer the gas to an alternative plant) or on the gathering system (in which case the trucks can bypass the initial pipelines and transfer the gas directly to the plant).[72]

A report from the New Mexico state Methane Advisory Panel, specifically examining CNG trucking, found that CNG trucking is a "portable, scalable and low or negative cost" approach to gas capture.[73] Indeed, as noted above, in many cases truck transport ultimately presents little or no additional cost to well operators because operators will incur only minimal net costs or achieve net benefits by reselling the gas. Various factors play into the total expense of a trucking operation, including distance traveled. The New Mexico report, for instance, found that trucking is most efficient when well sites are within 20-25 miles of a processing plant.[74] For CNG, operators must purchase an onsite compressor, the total one-time cost of which can be approximated at $200,000 for the equipment and $50,000 for the installation.[75] Operators will also need to pay the truck drivers, and may need to lease the appropriate trucking assembly.[76]

Analysis by ICF International reports that the quantities of gas transport needed for CNG trucking to break even as a method of gas capture—considering the costs of the onsite compressor, equipment lifetime, truck fuel, driver salary, and several other factors—range from 134 mcf to 345 mcf of captured gas per day, depending on gas prices.[77] Importantly, this total volume need not be collected from a single well: instead, operators may capture gas from multiple wells in the same

[72] *Id.* at 33.
[73] *See* New Mexico Environment Department & New Mexico Energy, Minerals and Natural Resources Department: Methane Advisory Panel (2019), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/OCD-Exhibit6-NMENRDNMED-MethaneAdvisoryPanel-Technical-Report.pdf [hereinafter Methane Advisory Panel] at 178. In March of 2021, the state of New Mexico joined Colorado in implementing regulations which banned flaring except in limited circumstances. *See generally* New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A) (accessible at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Part27-FinalRule3.25.21a.pdf).
[74] *See* Methane Advisory Panel at 173, 178.
[75] ICF INTERNATIONAL, Breakeven Analysis for Four Flare Gas Capture Options, 4 (Apr. 22, 2016) [hereinafter ICF].
[76] *See id.*
[77] ICF, at 9.

vicinity.[78] For particularly high producing wells, then, CNG trucking will constitute a net benefit for operators. And overall, the net costs are reasonable in terms of methane emissions abatement: Rystad's report finds that on average, CNG trucking will cost operators \$1.8/kcf, or \$94 per MT of methane flaring avoided.[79]

Reinjection. In some circumstances, well operators may prefer to reinject associated gas. Reinjection is used widely in Alaska, where 90% of associated gas is injected into oil-bearing formations.[80] Reinjection as a method of gas capture has significant emissions reduction benefits, because it largely eliminates emissions of methane and other pollutants.[81] Operators choosing to reinject associated gas may do so either by drilling a new injection well or by reappropriating an existing inactive production well.[82] Shale reservoirs are particularly well suited to injection because of their large storage capacity: "nanopores" in the rock formation can trap and store greenhouse gasses in an absorbed state.[83] Associated gas may also be injected and stored in natural aquifers, which may be suitable for gas storage when the sedimentary rock formation is overlaid with impermeable "cap" rock,[84] or in salt caverns.[85] Reinjection costs vary depending on various

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[78] *See id.*

[79] Rystad, *supra* note 2, at 39. Rystad further finds that LNG trucking will cost \$5.6/mcf, or \$292 per MT of methane flaring avoided. *Id.*

[80] *See* EIA, *Natural Gas Weekly Update: Alaska Natural Gas Infrastructure* (May 27, 2021), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/05_27/ (last accessed Apr. 18, 2023).

[81] *See* Fengshuang Du and Bahareh Nojabaei, *A Review of Gas Injection in Shale Reservoirs: Enhanced Oil/Gas Recovery Approaches and Greenhouse Gas Control*, MDPI: ENERGIES (June 19, 2018), https://www.mdpi.com/1996-1073/12/12/2355 at 25.

[82] See Sadiq J. Zarrouk & Katie Mclean, "Geothermal Wells", Geothermal Well Test Analysis, 39-61, 54 (2019) ("Geothermal reinjection wells [including gas reinjection wells] are generally designed and drilled to the same standards as production wells. In some fields, reinjection wells have been converted to production wells and vice versa.")

[83] Fengshuang Du & Bahareh Nojabaei, A Review of Gas Injection in Shale Reservoirs: Enhanced Oil/Gas Recovery Approaches and Greenhouse Gas Control, 25 (2019) https://www.mdpi.com/1996-1073/12/12/2355. *See also* Yuan Chi , Changzhong Zhao, Junchen Lv, Jiafei Zhao and Yi Zhang, Thermodynamics and Kinetics of CO2/CH4 Adsorption on Shale from China: Measurements and Modeling, MDPI: ENERGIES (Mar. 13, 2019) at 1, https://www.mdpi.com/1996-1073/12/6/978.

[84] *See* EIA, The Basics of Underground Natural Gas Storage (Nov. 16, 2015), https://www.eia.gov/naturalgas/storage/basics/ (last accessed Apr. 18, 2023).

[85] *See id.*

factors, but Rystad finds that on average, costs are $3.4/mcf, and $177 per MT of methane flaring avoided.[86]

Use Onsite as a Fuel Source or Gas-to-Wire. In addition to the various methods of gas capture and redirection explored above, well operators can use associated gas for power needs on site, and implement a gas-to-power system for local loads.[87] For wells that are not yet connected to the power grid, on-site gas-to-power technology can replace the diesel generators that would otherwise be used to power operations.[88] This is very beneficial from an emissions perspective, since diesel is a highly polluting fuel with elevated levels of nitrogen oxides, particulate matter and toxic pollutant outputs.[89] It can also provide significant cost saving, because purchasing and transporting fuel from offsite carries a significant cost. As a result, Rystad reports that fully displacing diesel with associated gas for power demand at the well amounts to $7-$10/mcf saved– subtracting the cost of power generator and treatment and assuming 50 mcf per day of power used.[90]

Thus, operators can significantly reduce both costs and emissions by utilizing available associated gas to meet well pad energy needs. And they can make a profit while doing so: Rystad estimates that on average, on-site use of gas nets a profit of $8.60/mcf.[91] This makes it a compelling alternative to routine flaring.

Another option is to use the associated gas to power a small electricity generation plant that sends power to the grid.[92] This approach depends on an ongoing supply of a relatively large

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[86] Rystad, *supra* note 2, at 69.
[87] Pederstad et al., *supra* note 70, at 38.
[88] *Id.* at 36. *See also* Rystad, supra note 2, at 51.
[89] *See* EPA, About Diesel Fuels (last accessed April 14, 2023), https://www.epa.gov/diesel-fuel-standards/about-diesel-fuels.
[90] Rystad, supra note 2, at 51.
[91] *Id.* at 11.
[92] *Id.* at 72.

quantity of gas to make the necessary investments worthwhile, so it is not suitable for every application.[93] But where the gas volumes and grid access are available, it can also be a net negative cost option.[94]

VII. Conclusion

We appreciate the Division's efforts to revise its venting and flaring rules. The Division's draft rule reflects best practices implemented by leading operators and required by other oil and gas producing states. We urge the Division to propose a Notice of Intent to amend its rules and finalize these amendments expeditiously to minimize the waste of natural resources and protect against the harmful emissions associated with venting and flaring that contribute to the climate crisis and threaten public health.

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[93] *See id.*
[94] *See id.*

RYSTAD ENERGY

COST OF FLARING ABATEMENT

FINAL REPORT

JANUARY 31, 2022

EDF ENVIRONMENTAL DEFENSE FUND®
Finding the ways that work

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Project parameters and purpose

Mandate and purpose

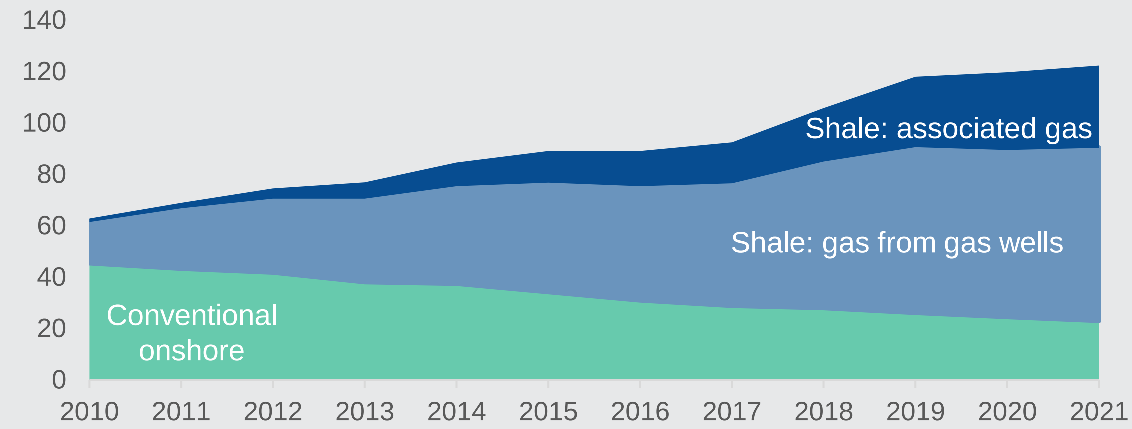
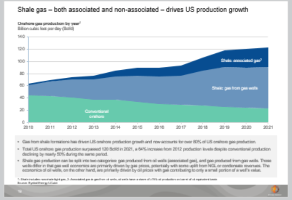
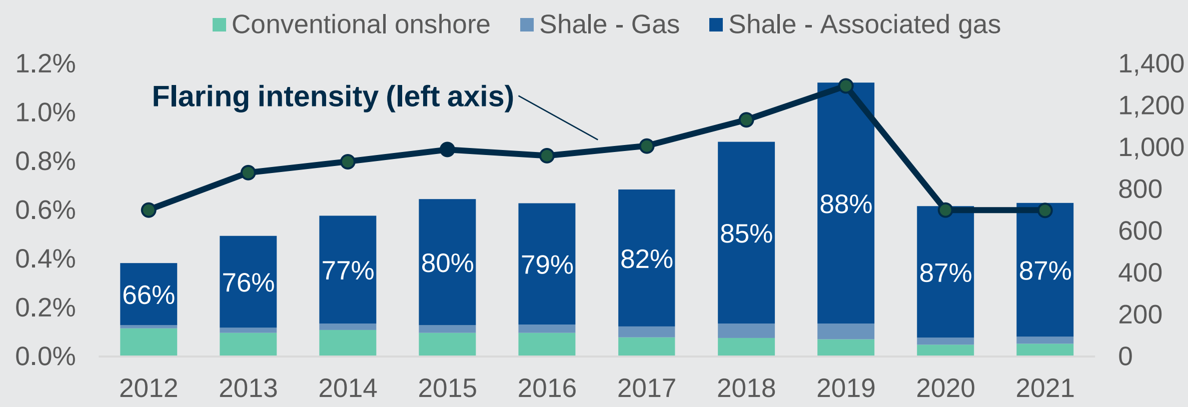
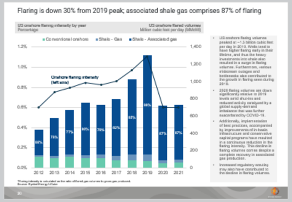
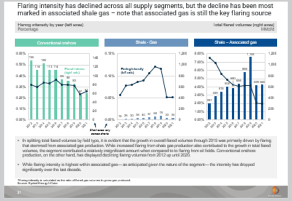
- The Environmental Defense Fund has engaged Rystad Energy to assess the cost of various flaring abatement measures for basins across the onshore US.
- The purpose of the report is to provide a fact-based overview of the cost and applicability of flaring reduction measures, enabling a better understanding of the addressability of flaring.
- The work is divided into three main sections:
  - Understanding upstream flaring – key topics include the size of flares, the timeline of flaring, the key drivers of flaring (e.g. lack of infrastructure).
  - Evaluating the cost of flaring reduction measures – explaining the key components and applicability of flaring reduction measures, describing the cost of such measures, and uncertainty.
  - Impact and net cost of flaring measures – combining the findings of previous sections to describe the impact of flaring reduction measures depending on costs, volume and geography.

Methodology, data and qualifications

- Rystad Energy has deep knowledge about both the US upstream sector and flaring. This report builds extensively on our proprietary databases, covering historical production, costs, activity and flaring in the upstream sector. We believe this data to be of high quality.
- For specific flaring abatement solutions, we combine proprietary data with industry experience to arrive at cost levels we believe to be representative. There are however a number of well and site-specific factors that influence cost levels. High CO2 content or presence of H2S are examples of such factors.
- Assumptions have also been made on the processes, scales, distances and uptime of such equipment.
- It's worth noting that certain flaring abatement measures would involve additional upfront efforts. E.g. finding a suitable reservoir for gas injection or finding offtake for CNG/LNG.

Source: Rystad Energy research and analysis

Associated gas production accounts for 87% of upstream flaring

Observation	Illustrations	Key slides
US gas production has surged in recent years – driven by shale.	**Onshore gas production by year** Billion cubic feet per day (Bcf/d) 	 *Page 19*
Flaring has also surged over the last decade with 87% now stemming from associated gas. **Flaring declined 30% in 2020 with lower production and alleviated constraints.**	**US onshore flaring intensity by year** Percentage **US onshore flared volumes** Million cubic feet per day (MMcf/d) 	 *Page 20*  *Page 21*

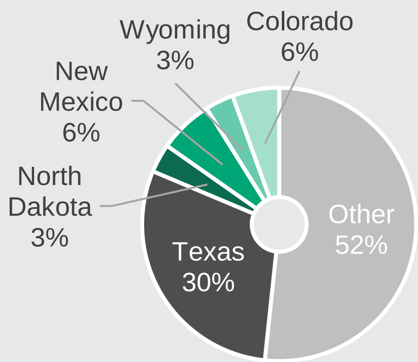
Note: US onshore upstream flaring only
Source: Rystad Energy research and analysis

A few states account for ~90% of the flared volumes – North Dakota with highest intensity

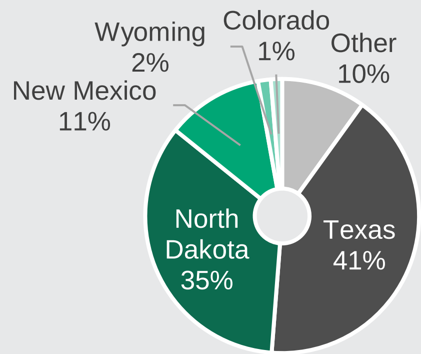
Observation	Illustrations	Key slides

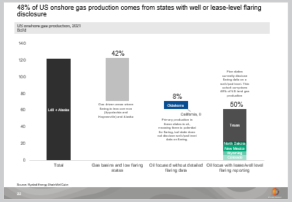
Five US states have detailed flaring disclosure. These states account for ~50% of onshore gas production but ~90% of total flaring.

US onshore gas production
*2021 distribution**



US onshore flaring
*2021 distribution**





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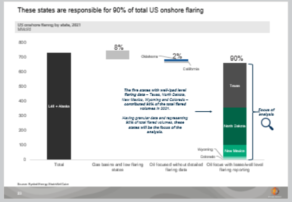

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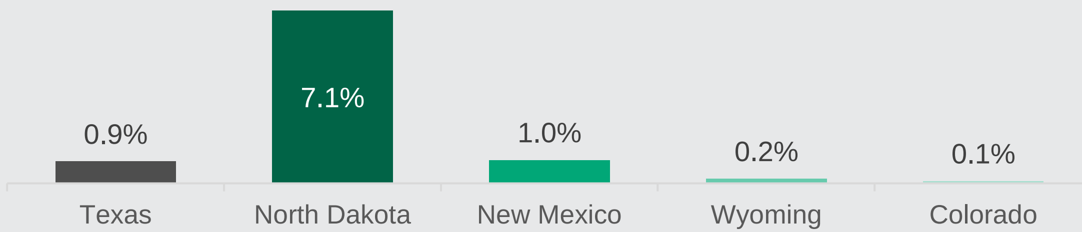
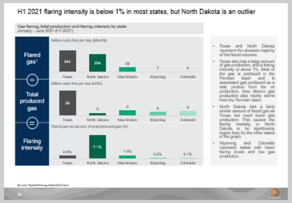
The different states have different flaring intensities.

While the flaring intensity is below 1% in most states, North Dakota is an outlier with a flaring intensity of more than 7%.

Flared gas as percent of total produced gas (flaring intensity)
Percentage





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*Distributions for volumes stemming from both gas and associated gas production. Associated gas alone exhibits a very similar distribution.
Source: Rystad Energy research and analysis

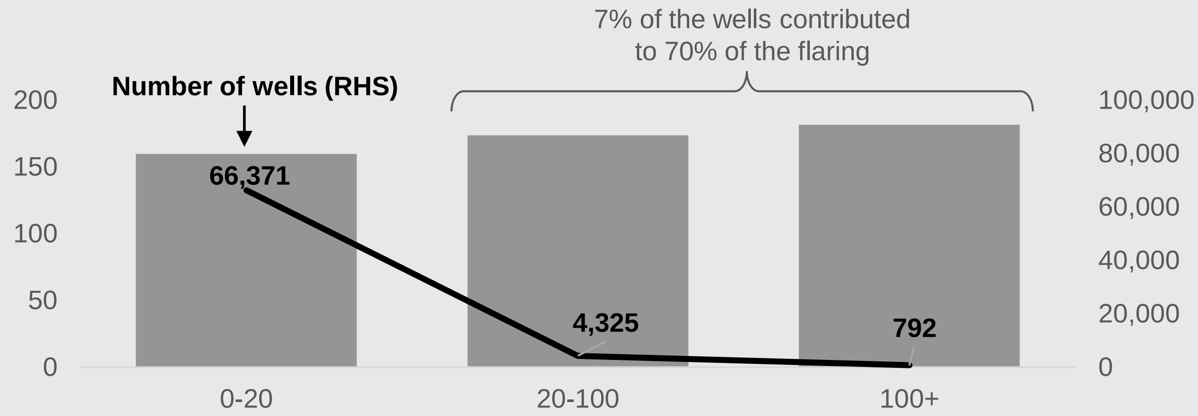
7% of the wells contributed to 70% of the flaring – new wells are the most flaring intensive

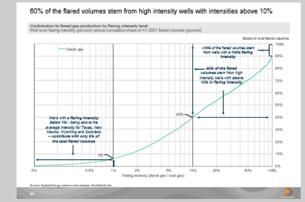
Observation	Illustrations	Key slides

Observation: Just 7% of flaring wells contributed to 70% of the flared volumes.

Natural gas flared in H12021 for the five focus states split by well level amount of gas flared per day
MMcf/d

Number of wells
#





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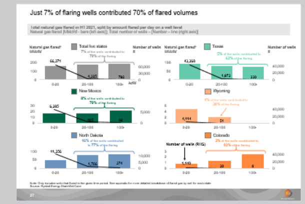

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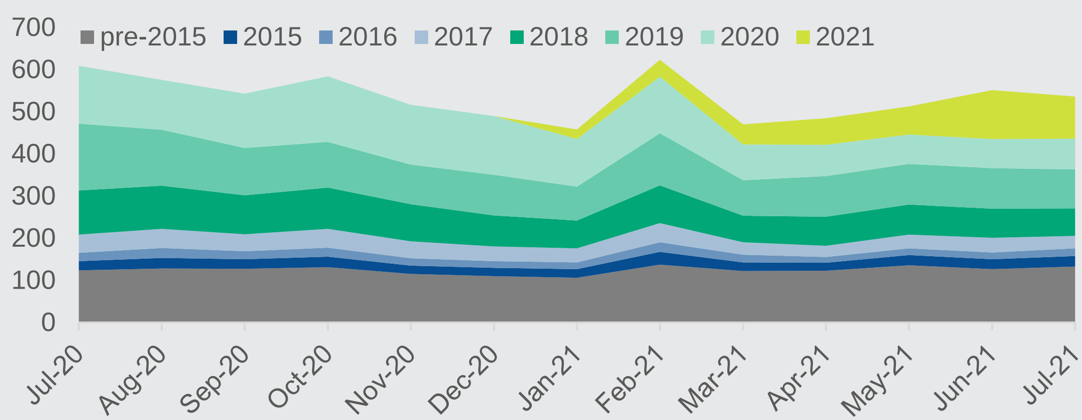
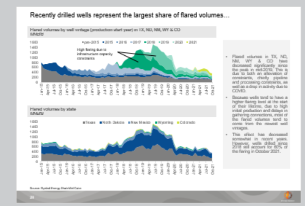
Observation: New wells represent the largest share of flaring due to high initial production and delays in gathering connections.

Flared volumes by well vintage TX, ND, NM, WY and CO
MMcf/d





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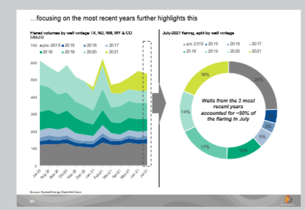

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*Upper chart show distributions for volumes stemming from both gas and associated gas production. Associated gas alone exhibits a very similar distribution.
Source: Rystad Energy research and analysis

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Infrastructure timing and capacity are the main issues, not infrastructure access

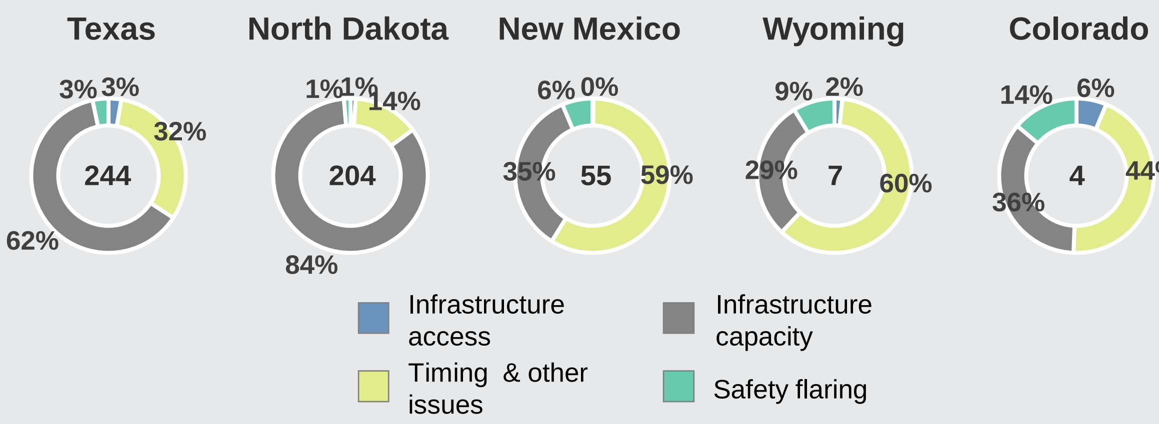
Observation	Illustrations	Key slides

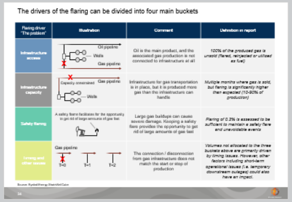
Timing of well hookups and capacity of infrastructure account for a large share flaring.

In the states with the highest flaring volumes, infrastructure capacity is the key problem.

Flaring driver "The problem"

First 12 months of production for 2020 completed wells – H1 2021 production inside pie [MMcf/d]





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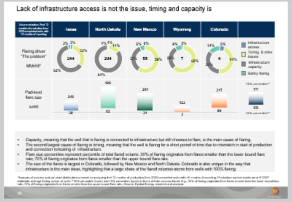

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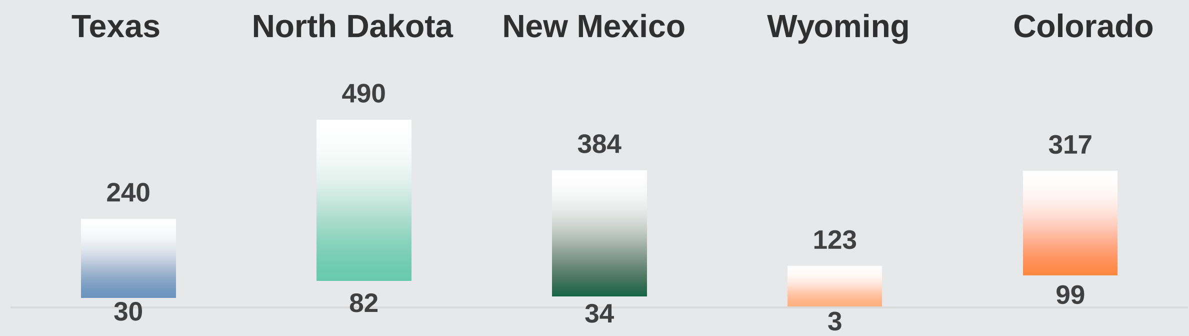
The majority of the flared volumes stem from well pads that flare around 250 kcf/d.

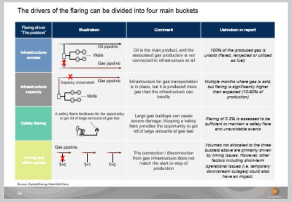
Pad level flare size

kcf/d



Upper boundary represents the level where 70% of the flaring stems from pads below this size

Lower boundary represents the level where 30% of the flaring stems from pads below this size



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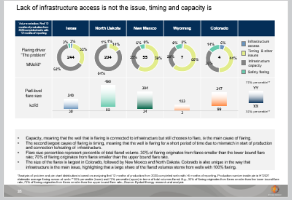

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Source: Rystad Energy research and analysis

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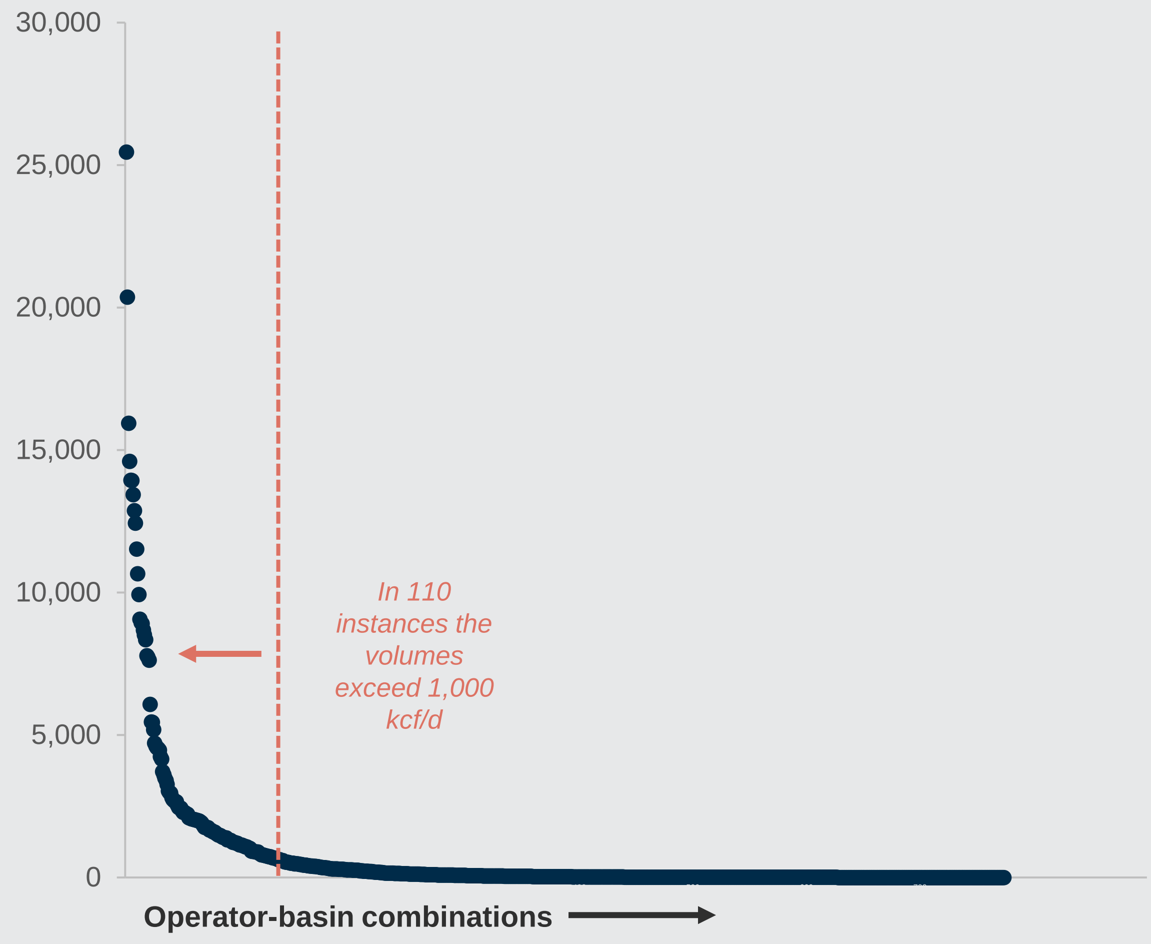
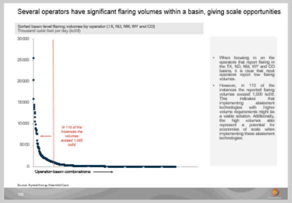
Some operators have significant flaring volumes within a basin – giving scale opportunities

Observation	Illustrations	Key slides
While flaring on a pad level is in the magnitude of ~250 kcf/d, several operators have significant flaring volumes within a basin. **Having scale creates opportunities for flaring abatement measures that might not be as feasible to apply to small flaring volumes.**	**Sorted basin level flaring volumes by operator (TX, ND, NM, WY and CO)** *Thousand cubic feet per day (kcf/d)* 	 *Page 100*

Source: Rystad Energy research and analysis

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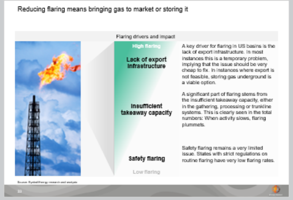
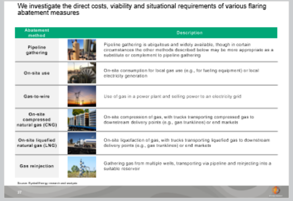
Various methods can be utilized to abate flaring

Observation	Illustrations			Key slides
Reducing flaring means utilizing the gas for other purposes on-site, bringing the gas to the market or storing it. **Several abatement methods can be utilized to achieve this.**		**Pipeline gathering**	Connecting wells to gas gathering systems to facilitate for transportation and marketing of the gas is the primary method of abating flaring.	
		**On-site use**	On-site consumption for local gas use (e.g. for fueling equipment) or local electricity generation.	 *Page 33*
		**Gas-to-wire**	Use of gas in a power plant and selling power to an electricity grid.	
		**On-site compressed natural gas (CNG)**	On-site compression of gas with trucks transporting compressed gas to downstream delivery points (e.g. gas trunklines) or end markets.	 *Page 37*
		**On-site liquefied natural gas (LNG)**	On-site liquefaction of gas with trucks transporting liquified gas to downstream delivery points (e.g. gas trunklines) or end markets.	
		**Gas reinjection**	Gathering gas, transporting via pipeline and reinjecting into a suitable reservoir.	

Source: Rystad Energy research and analysis

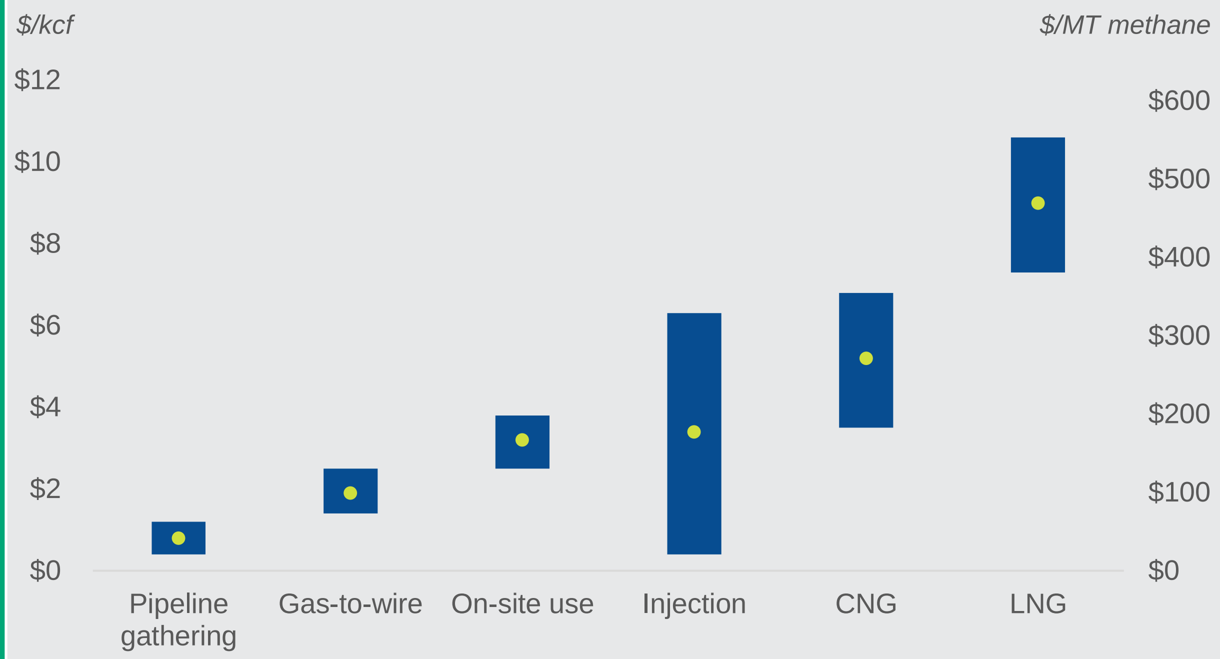
The different methods vary in cost – gas gathering and on-site use with net profit

Observation	Illustrations	Key slides

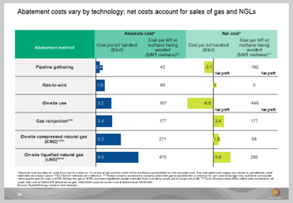
The different abatement options come at differing costs. Absolute costs represent the cost before revenues from any sales of gas and NGLs.

From a net cost perspective, accounting for gas and NGL sales, gas gathering and on-site use can generate a net profit.

Absolute cost range by method (pre-revenue from gas sales)



	Pipeline gathering	Gas-to-wire	On-site use	Injection	CNG	LNG
Net cost / profit *($/kcf)*	$3.1	$0	$8.6	$3.4*	$1.8	$5.6
Net cost / profit *($/MT CH4)*	$162	$0	$449	$177*	$94	$292



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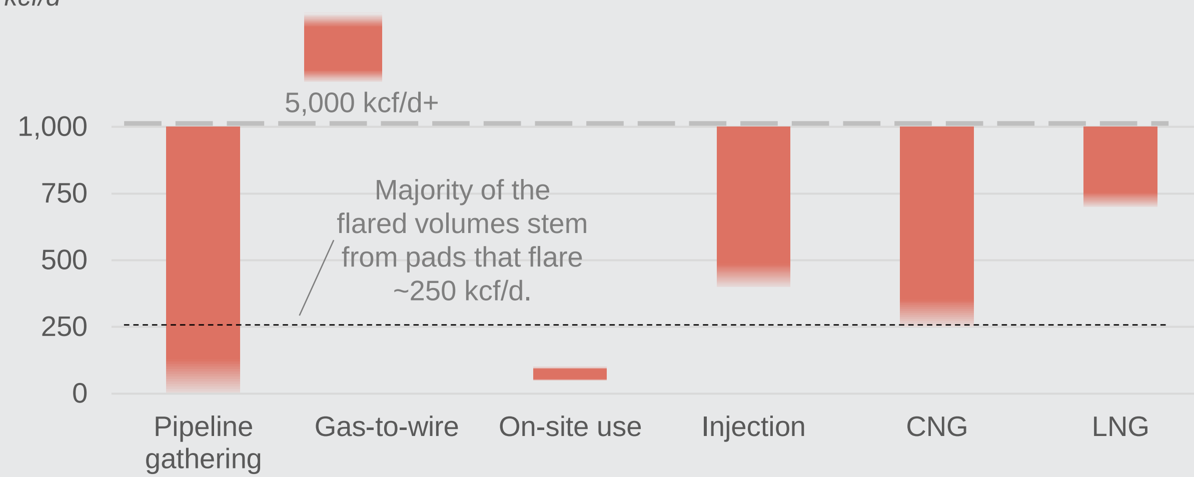
*The number represents a scenario where the gas is disposed into a reservoir for storage only and does not include retrieving the gas for re-sale or EOR. Re-sale or EOR represents upside potential.
Source: Rystad Energy research and analysis

But each method has different economically optimal volumes and situational requirements

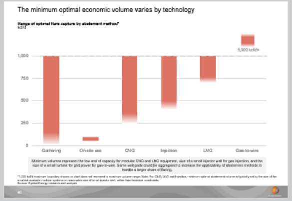
Observation	Illustrations	Key slides
The economically optimal abatement volume also varies by technology. **While gas gathering is applicable from very small volumes, other technologies require larger volumes. On-site use is typically too small compared to flared volumes**	See chart below	Page 40
Situational considerations also affect the feasibility of an abatement method	See table below	Page 41

Range of optimal flare capture by abatement method*
kcf/d



○ = *other considerations*

	Distance to infrastructure	***Downstream constraints***	***Local demand***	***Requires gathering and/or storage***
Pipeline gathering	○	○		○
Gas-to-wire	○	○		○
On-site use			○	
Injection	○			○
CNG			○	
LNG			○	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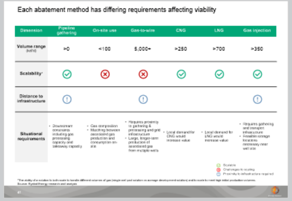
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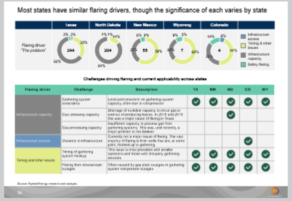
*1,000 kcf/d axis limit does not represent an upper limit for flaring abatement methods. Note: Minimum economically optimal abatement volume is typically set by the low end of capacity for equipment (such as a modular compressor) or the reasonable size of a small injector well, rather than technical constraints. Underutilizing capacity would result in higher costs.
Source: Rystad Energy research and analysis

Although with different relative importance, the states face similar challenges

Observation	Illustrations	Key slides

Most states face similar challenges that lead to flaring, though importance varies by state.

Flaring driver	Challenge	TX	NM	ND	CO	WY
Infrastructure capacity	Gathering system constraints	✓	✓	✓	✓	✓
	Gas takeaway capacity			✓		
	Gas processing capacity					
Infrastructure access	Distance to infrastructure				✓	
Timing and other issues	Timing of gathering system hookup	✓	✓	✓	✓	✓
	Flaring from downstream outages	✓	✓	✓	✓	✓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Each challenge has different operational and commercial facets.

Reducing flaring requires a broad-based approach addressing both operational and commercial issues.

Broad-based solutions to flaring reduction

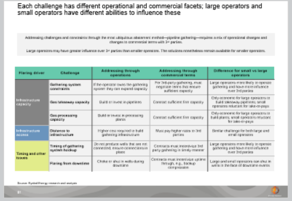
No single solution—must address both technical and commercial constraints

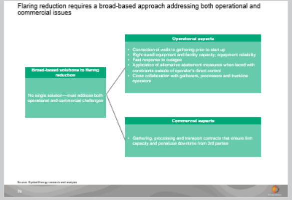
Operational aspects

- Right-sized equipment and facility capacity
- Equipment reliability
- Fast response to outages
- Application of alternative abatement measures when faced with constraints outside of operator's control

Commercial aspects

- Gathering, processing and transport contracts that ensure firm capacity and penalizes downtime from 3rd parties


Page 81


Page 79

Source: Rystad Energy research and analysis

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Gathering, CNG and injection most broadly capable of addressing the flaring challenges

Observation	Illustrations	Key slides

Gathering, CNG and injection are the most relevant technologies given costs, scalability and applicability across a variety of situations

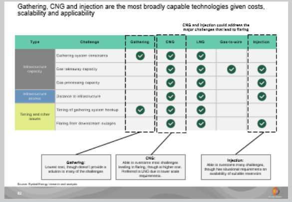
CNG and injection could address the major challenges that lead to flaring

Type	Challenge	Gathe - ring	CNG	LNG	Gas-to-wire	Injection
Infrastructure capacity	Gathering system constraints	✓	✓	✓		
Infrastructure capacity	Gas takeaway capacity		✓	✓	✓	✓
Infrastructure capacity	Gas processing capacity		✓	✓		✓
Infrastructure access	Distance to infrastructure		✓	✓		✓
Timing and other issues	Timing of gathering system hookup	✓	✓	✓		
Timing and other issues	Flaring from downstream outages		✓	✓		✓

Gathering:
Lowest cost, though doesn't provide a solution to many of the challenges

CNG:
Able to overcome most challenges leading to flaring, though at higher cost. Preferred to LNG due to lower scale requirements.

Injection:
Able to overcome many challenges, though has situational requirements on availability of suitable reservoirs



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Source: Rystad Energy research and analysis

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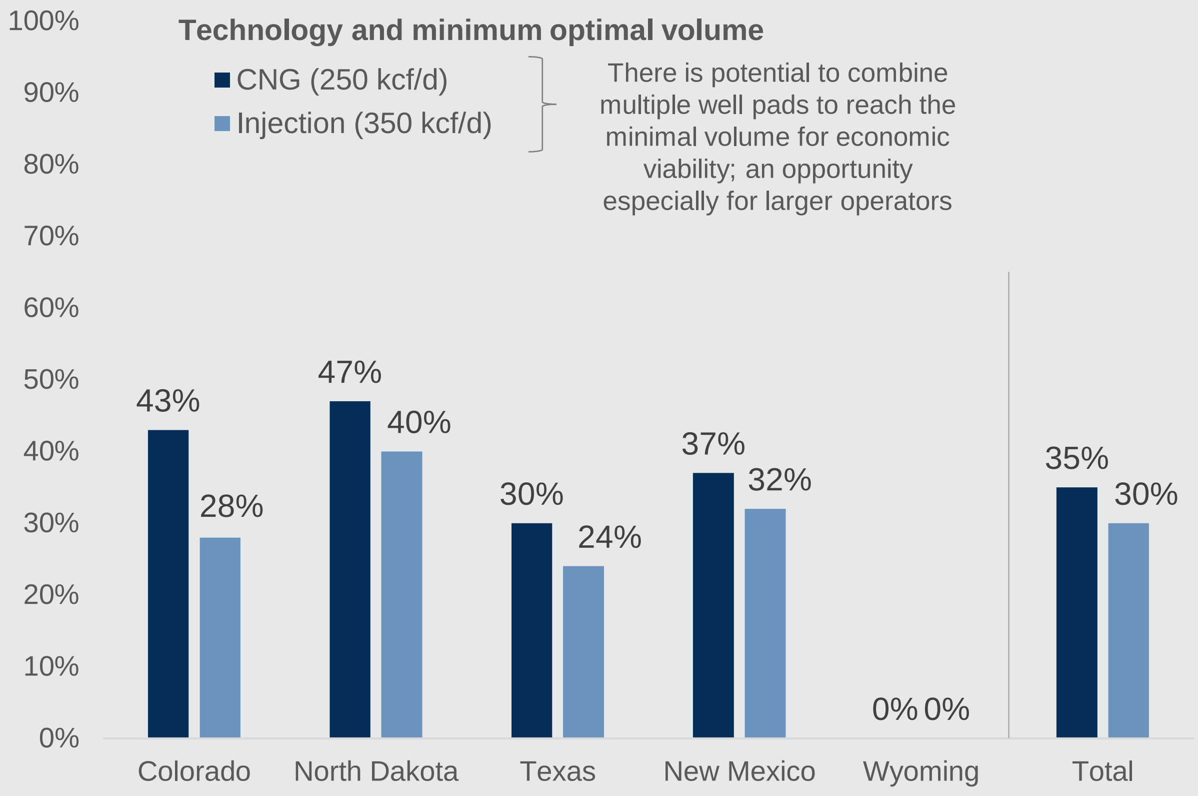
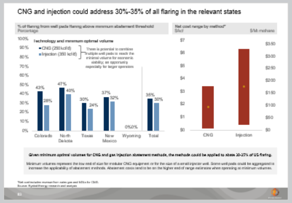
CNG and injection alone could address 30%-35% of flaring

Observation	Illustrations	Key slides
Given the minimum optimal volumes for CNG and gas injection abatement methods, the methods could be applied to abate 30-35% of US flaring.	**% of flaring from well pads flaring above minimum abatement threshold for CNG and injection** *Percentage* 	 *Page 83*

Source: Rystad Energy research and analysis

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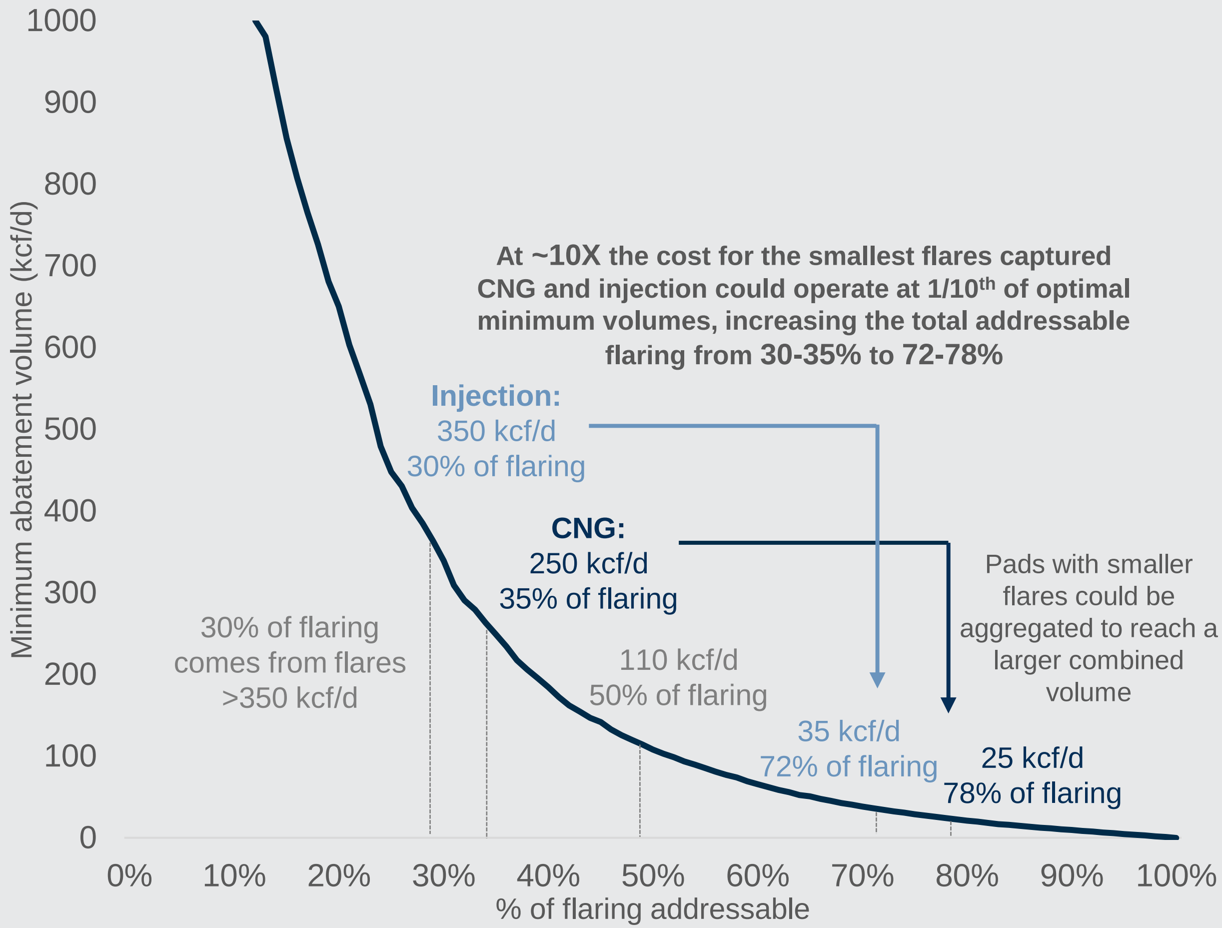
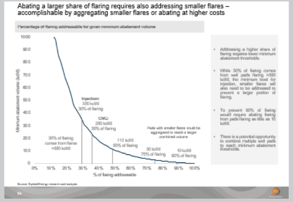
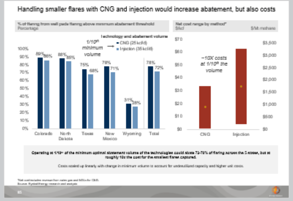
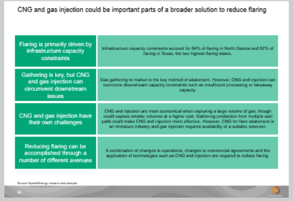
Technologies technically capable of reducing majority of flaring – but at a higher cost

Observation	Illustrations	Key slides
To abate a higher share of the flaring requires addressing smaller flares. **Injection and CNG could be utilized to capture smaller flares and to abate 72-78% of total flaring volume, but at ~10X the cost for capturing the smallest flares.**	**% of flaring addressable for given minimum abatement volume** *Percentage* 	 *Page 84*  *Page 85*

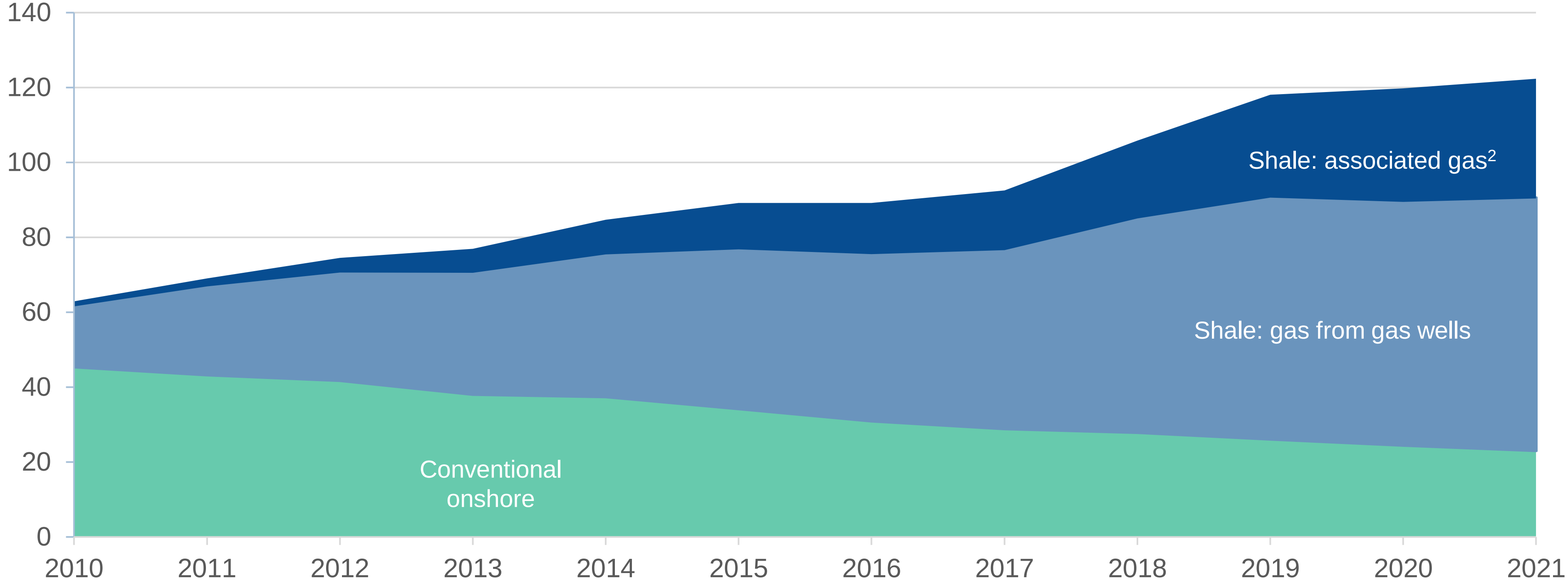
Source: Rystad Energy research and analysis

CNG and gas injection could be important parts of a broader solution to reduce flaring

Observation	Illustrations		Key slides
Flaring is primarily driven by infrastructure capacity constraints. Gathering is the key method of abatement, but CNG and gas injection can overcome downstream issues.	Flaring is primarily driven by infrastructure capacity constraints	Infrastructure capacity constraints account for 84% of flaring in North Dakota and 62% of flaring in Texas, the two highest-flaring states.	 *Page 86*
	Gathering is key, but CNG and gas injection can circumvent downstream issues	Gas gathering is the key method of abatement. However, CNG and injection can overcome downstream capacity constraints such as insufficient processing or takeaway capacity.	
	CNG and gas injection have their own challenges	CNG and injection are most economical when capturing a large volume of gas, though could capture smaller volumes at a higher cost. Gathering production from multiple well pads could make CNG and injection more cost effective. However, CNG for flare abatement is an immature industry and gas injection requires availability of a suitable reservoir.	
	Reducing flaring can be accomplished through a number of different avenues	A combination of changes to operations, changes to commercial agreements and the application of technologies such as CNG and injection are required to reduce flaring.	

Shale gas – both associated and non-associated – drives US production growth

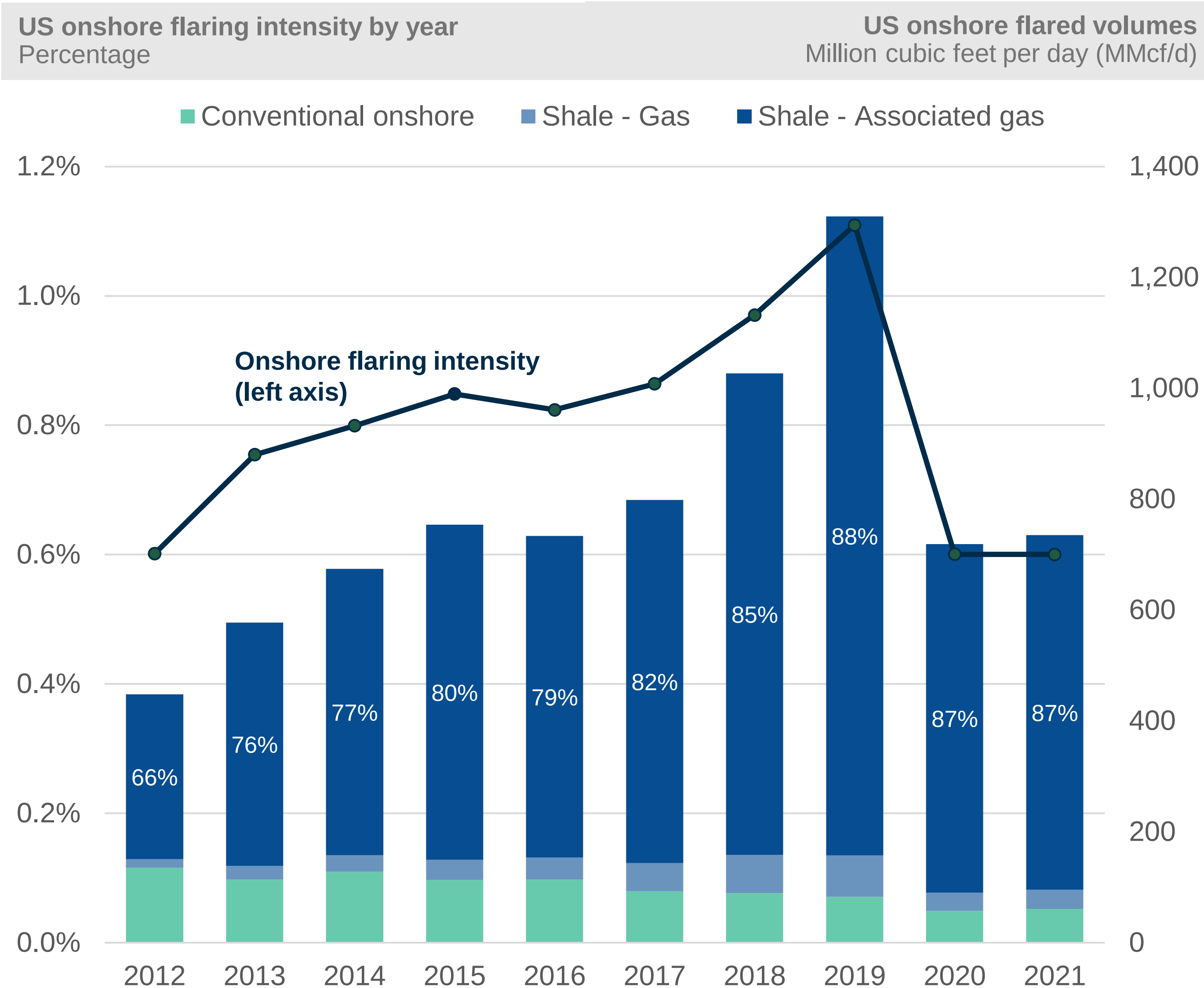
Onshore gas production by year[1]
Billion cubic feet per day (Bcf/d)



- Gas from shale formations has driven US onshore production growth and now accounts for over 80% of US onshore gas production.
- Total US onshore gas production surpassed 120 Bcf/d in 2021, a 64% increase from 2012 production levels despite conventional production declining by nearly 50% during the same period.
- Shale gas production can be split into two categories: gas produced from oil wells (associated gas), and gas produced from gas wells. These wells differ in that gas well economics are primarily driven by gas prices, potentially with some uplift from NGL or condensate revenues. The economics of oil wells, on the other hand, are primarily driven by oil prices with gas contributing to only a small portion of a well's value.

1: Shale includes non-shale tight gas, 2: Associated gas is gas from oil wells; oil wells have a share of ≥75% oil production on barrel of oil equivalent basis
Source: Rystad Energy UCube

Flaring is down 30% from 2019 peak; associated shale gas comprises 87% of flaring



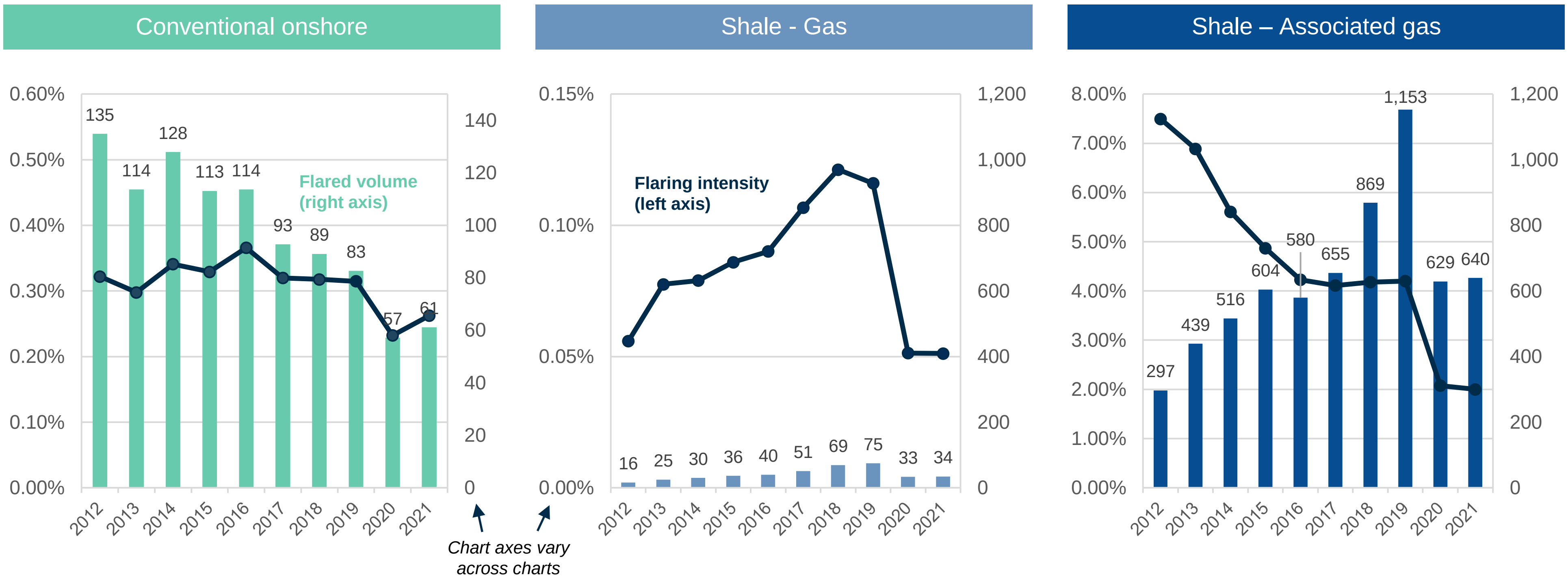
- US onshore flaring volumes peaked at ~1.3 billion cubic feet per day in 2019. Wells tend to have higher flaring early in their lifetime, and thus the heavy investments into shale also resulted in a surge in flaring volumes. Furthermore, various midstream outages and bottlenecks also contributed to the growth in flaring seen during 2019.
- 2020 flaring volumes are down significantly relative to 2019 levels amid shut-ins and reduced activity catalyzed by a global supply-demand imbalance that was further exacerbated by COVID-19.
- Additionally, implementation of best practices, accompanied by improvements of in-basin infrastructure and conservative capital programs have resulted in a continuous reduction in the flaring intensity. This decline in flaring volumes comes despite a complete recovery in associated gas production.
- Increased regulatory scrutiny may also have contributed to the decline in flaring volumes.

*Flaring intensity is calculated as the ratio of flared gas volumes to gross gas produced.
Source: Rystad Energy UCube

Flaring intensity has declined across all supply segments, but the decline has been most marked in associated shale gas – note that associated gas is still the key flaring source

Flaring intensity by year (left axes)
Percentage

Total flared volumes (right axes)
MMcf/d

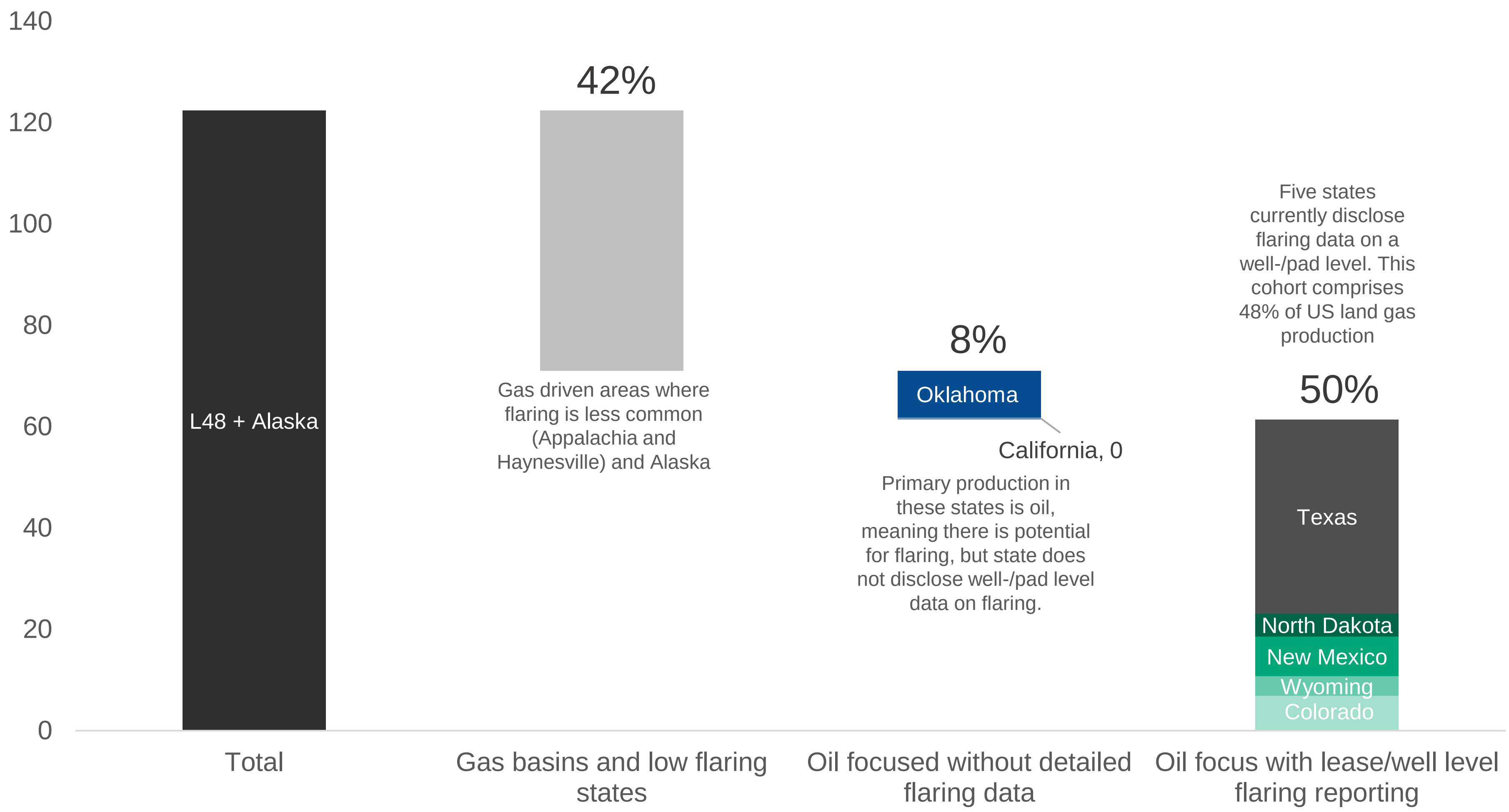


- In splitting total flared volumes by field type, it is evident that the growth in overall flared volumes through 2019 was primarily driven by flaring that stemmed from associated gas production. While increased flaring from shale gas production also contributed to the growth in total flared volumes, the segment contributed a relatively insignificant amount when compared to to flaring from oil fields. Conventional onshore production, on the other hand, has displayed declining flaring volumes from 2012 up until 2020.
- While flaring intensity is highest within associated gas— as anticipated given the nature of the segment— the intensity has dropped significantly over the last decade.

*Flaring intensity is calculated as the ratio of flared gas volumes to gross gas produced.
Source: Rystad Energy UCube

48% of US onshore gas production comes from states with well or lease-level flaring disclosure

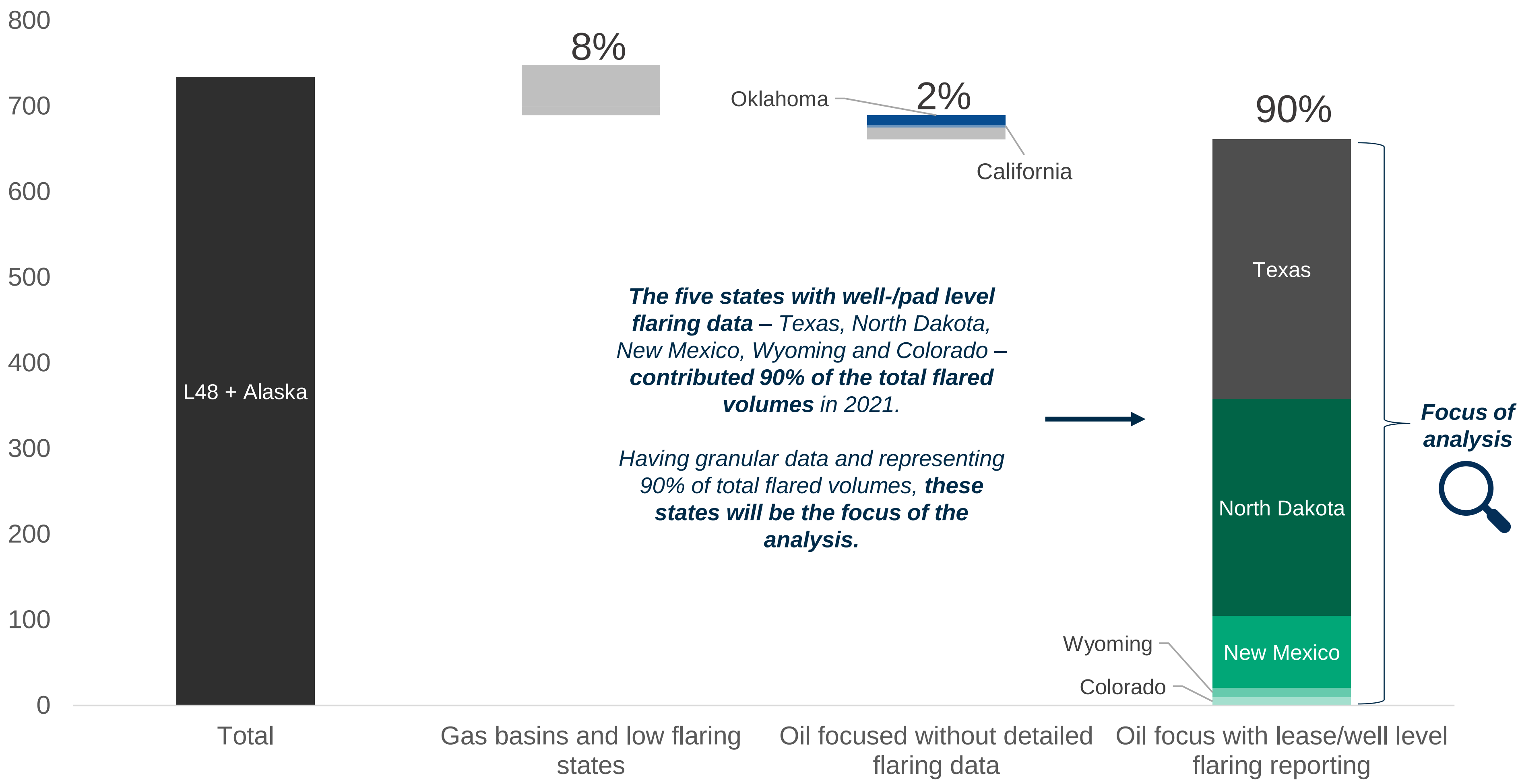
US onshore gas production, 2021
Bcf/d



Source: Rystad Energy ShaleWellCube

These states are responsible for 90% of total US onshore flaring

US onshore flaring by state, 2021
MMcf/d



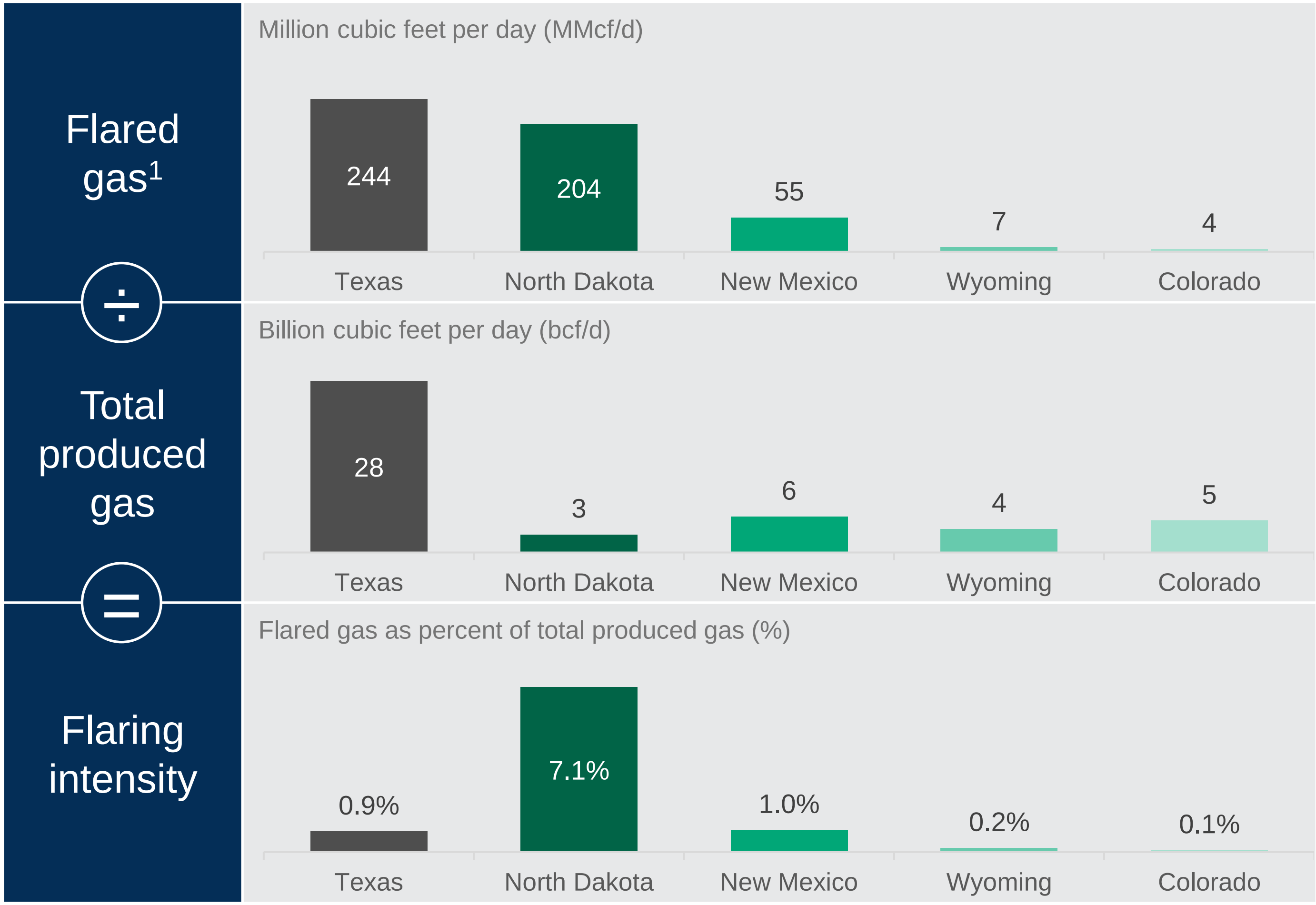
***The five states with well-/pad level flaring data** – Texas, North Dakota, New Mexico, Wyoming and Colorado – **contributed 90% of the total flared volumes** in 2021.*

*Having granular data and representing 90% of total flared volumes, **these states will be the focus of the analysis.***

Source: Rystad Energy ShaleWellCube

H1 2021 flaring intensity is below 1% in most states, but North Dakota is an outlier

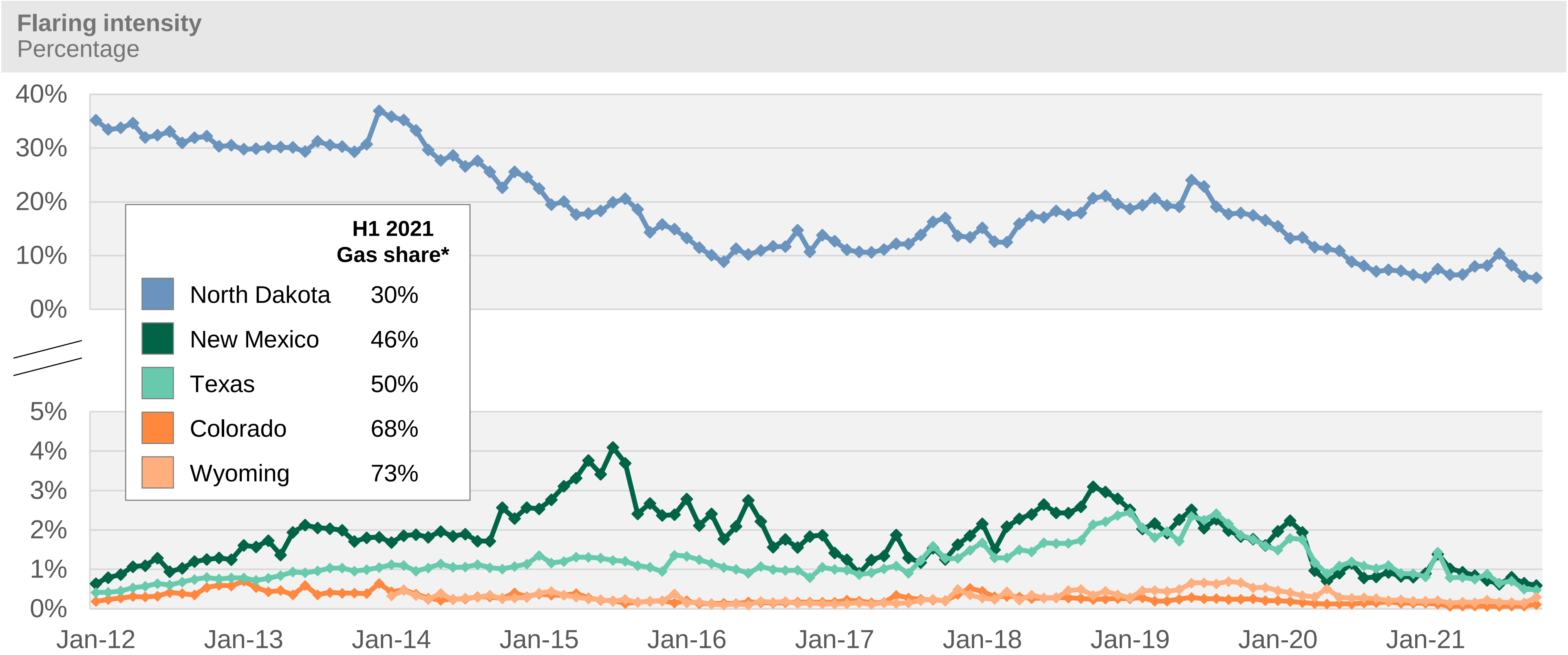
Gas flaring, total production and flaring intensity by state
January - June 2021 (H1 2021)



- Texas and North Dakota represent the absolute majority of the flared volumes.
- Texas also has a large amount of gas production, and a flaring intensity of about 1%. Most of the gas is produced in the Permian basin and is associated gas produced as a side product from the oil production. New Mexico gas production also mainly stems from the Permian basin.
- North Dakota has a fairly similar amount of flared gas as Texas, but much lower gas production. This causes the flaring intensity in North Dakota to be significantly higher than for the other states in the graph.
- Wyoming and Colorado represent states with lower flaring levels and low gas production.

Source: Rystad Energy ShaleWellCube

The states with highest gas production share* have historically had lowest flaring intensity

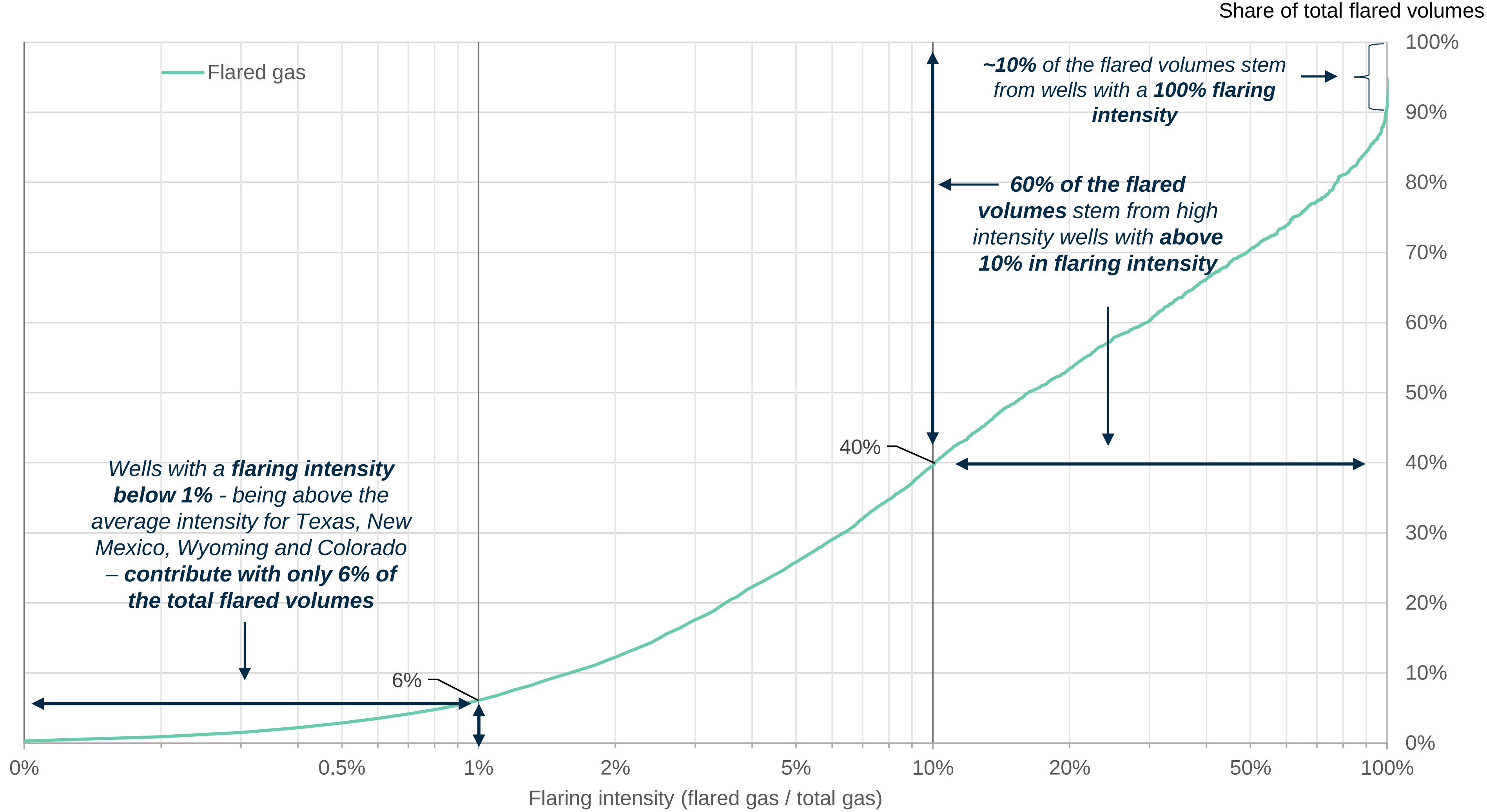


- North Dakota flaring intensity has decreased since 2012 but is still significantly higher than the four other states. The gas share of production in North Dakota is also significantly smaller than the other states in this graph.
- New Mexico & Texas gas share of production was in the same range in the first half of 2021. The historical flaring intensity of these states have also been at the same order of magnitude historically.
- Colorado & Wyoming are primarily producing gas and therefore have the highest gas share of production. These are also the states with the lowest flaring intensity.

Note: Wyoming data for 2012-2013 is not presented in the graph as it is not available.
*Gas share = Gas production / (Gas + light oil production). Source: Rystad Energy ShaleWellCube

60% of the flared volumes stem from high intensity wells with intensities above 10%

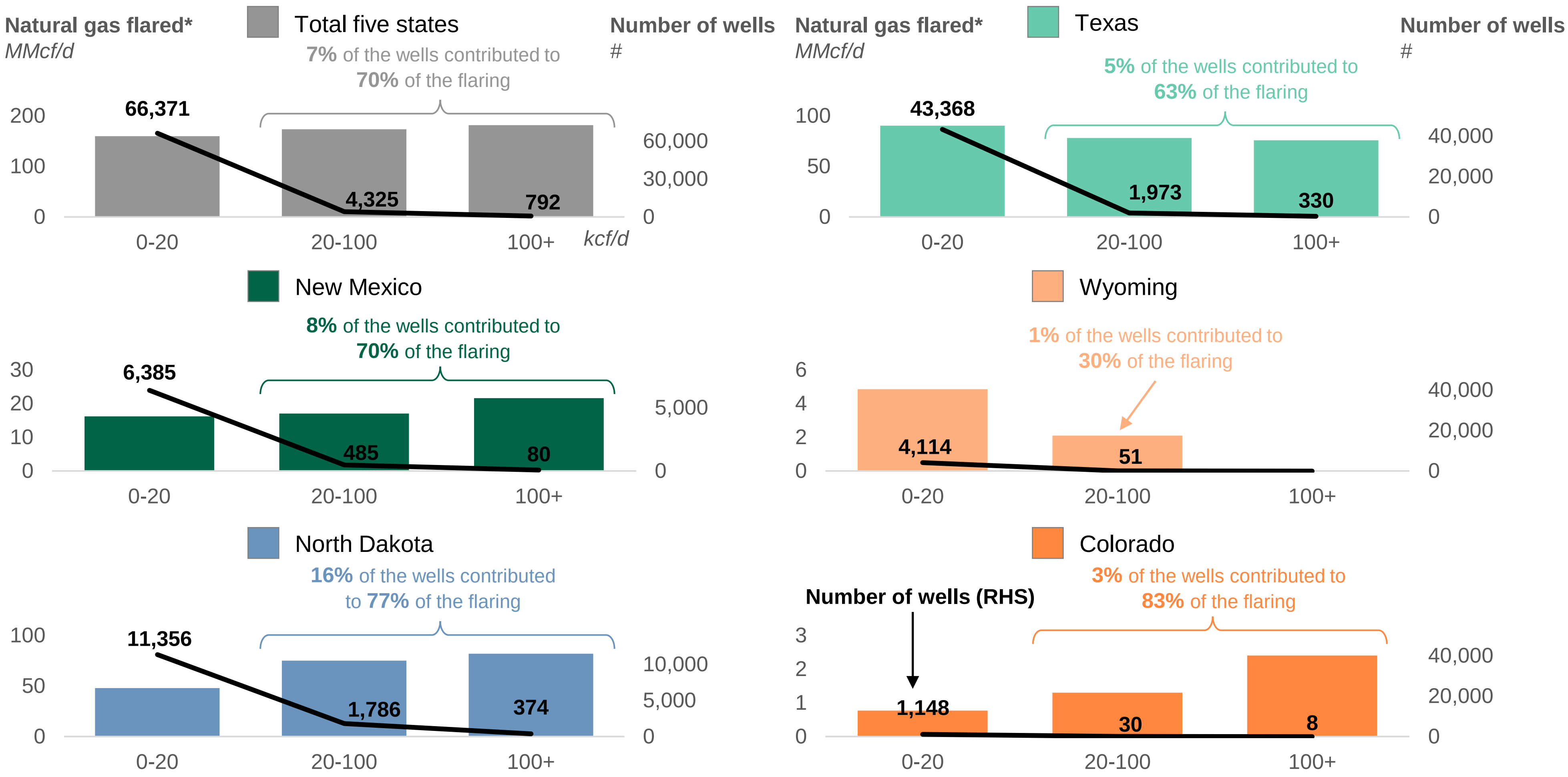
Contribution to flared gas production by flaring intensity level
Well level flaring intensity (percent) versus cumulative share of H1 2021 flared volumes (percent)



Source: Rystad Energy research and analysis; ShaleWellCube

Just 7% of flaring wells contributed 70% of flared volumes

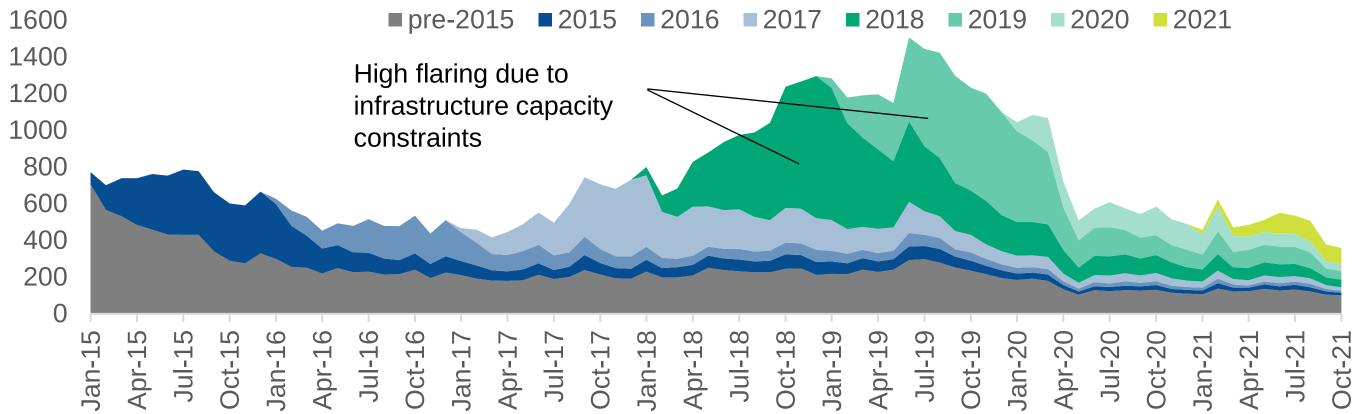
Total natural gas flared in H1 2021, split by amount flared per day on a well level
Natural gas flared [MMcf/d - bars (left axis)]; Total number of wells – [Number – line (right axis)]



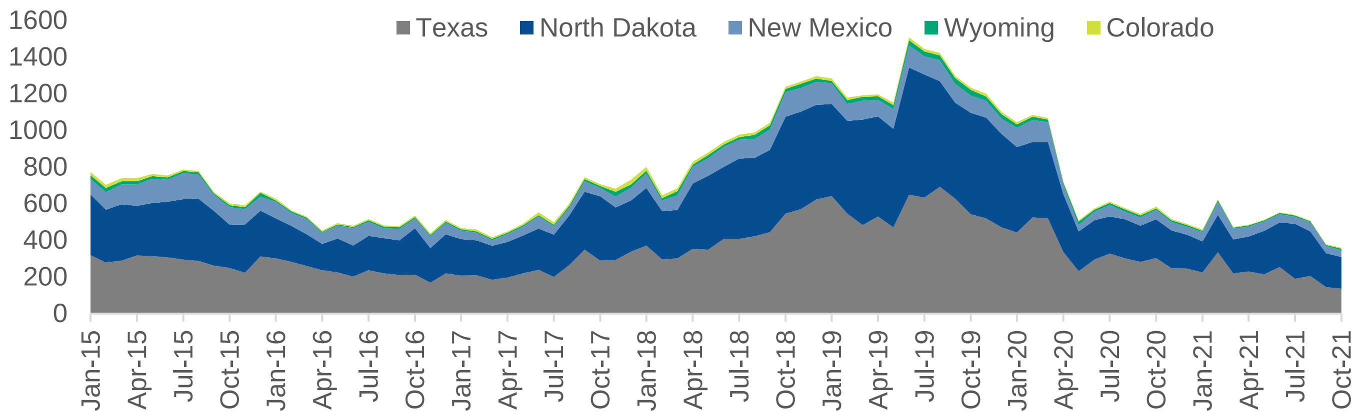
Note: Only includes wells that flared in the given time period. See appendix for more detailed breakdown of flared gas by well for each state
Source: Rystad Energy ShaleWellCube

Recently drilled wells represent the largest share of flared volumes…

Flared volumes by well vintage (production start year) in TX, ND, NM, WY & CO
MMcf/d



Flared volumes by state
MMcf/d

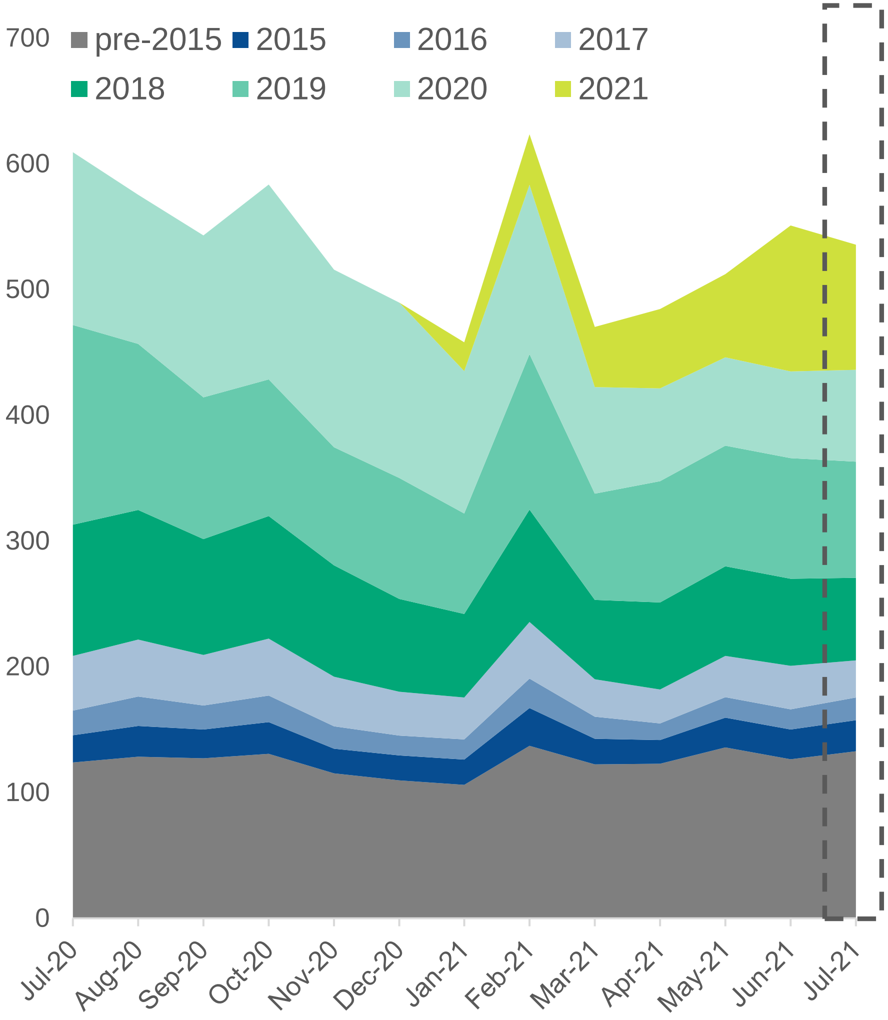


- Flared volumes in TX, ND, NM, WY & CO have decreased significantly since the peak in mid-2019. This is due to both an alleviation of constraints, chiefly pipeline and processing constraints, as well as a drop in activity due to COVID.
- Because wells tend to have a higher flaring level at the start of their lifetime, due to high initial production and delays in gathering connections, most of the flared volumes tend to come from the newest well vintages.
- This effect has decreased somewhat in recent years. However, wells drilled since 2018 still account for 60% of the flaring in October 2021.

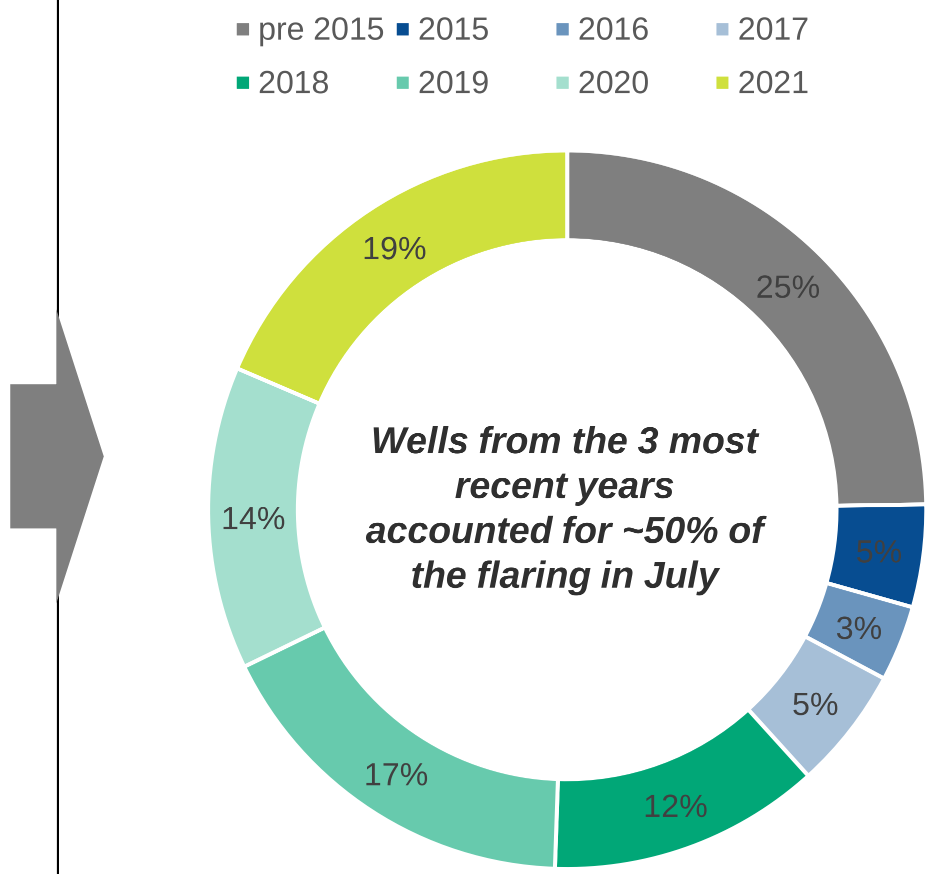
Source: Rystad Energy ShaleWellCube

…focusing on the most recent years further highlights this

Flared volumes by well vintage TX, ND, NM, WY & CO
MMcf/d



July-2021 flaring, split by well vintage



Source: Rystad Energy ShaleWellCube

Flaring intensity in North Dakota is significantly higher than in other states

Average flaring intensity per production month by completion year
Percentage

Single well leases only[1]

*Month 1 is the first full month of production; 1: Data shown based on leases with one well drilled to date, indicative of well-level flaring and flaring intensity
Source: Rystad Energy ShaleWellCube

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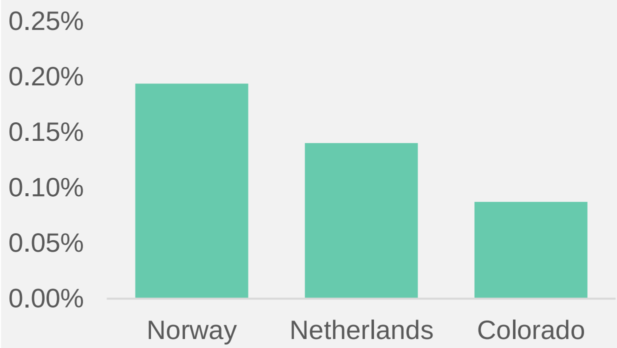
Flaring above 0.2% appears excessive based on observed flaring in US and elsewhere

Oil and gas operations means some flaring is needed

The term safety flaring encompasses a wide range of issues that result in the operator choosing to flare gas to reduce operational risk. At a minimum, operators need to maintain a pilot flame to enable them to get rid of the gas in case of emergency. In addition to this small volume of continuous flaring, safety events will drive flaring volumes. That is not to say that these events cannot be avoided.

But states and countries with strict regulations show that the level is low

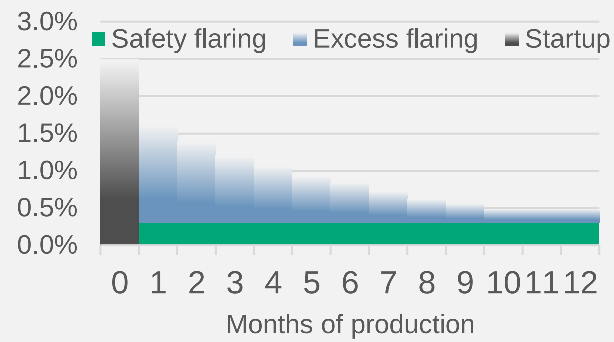
Flared gas as percent of production*



Certain geographies have implemented regulations seeking to reduce flaring. Colorado, Norway and the Netherlands have all banned routine flaring. This has resulted in a very low flaring intensity (flared volume as percentage of total produced volume). These examples imply that it's practically feasible to reduce flaring to such levels on a country/state level.

Key companies prove low flaring rates is feasible

Flared gas as percent of production

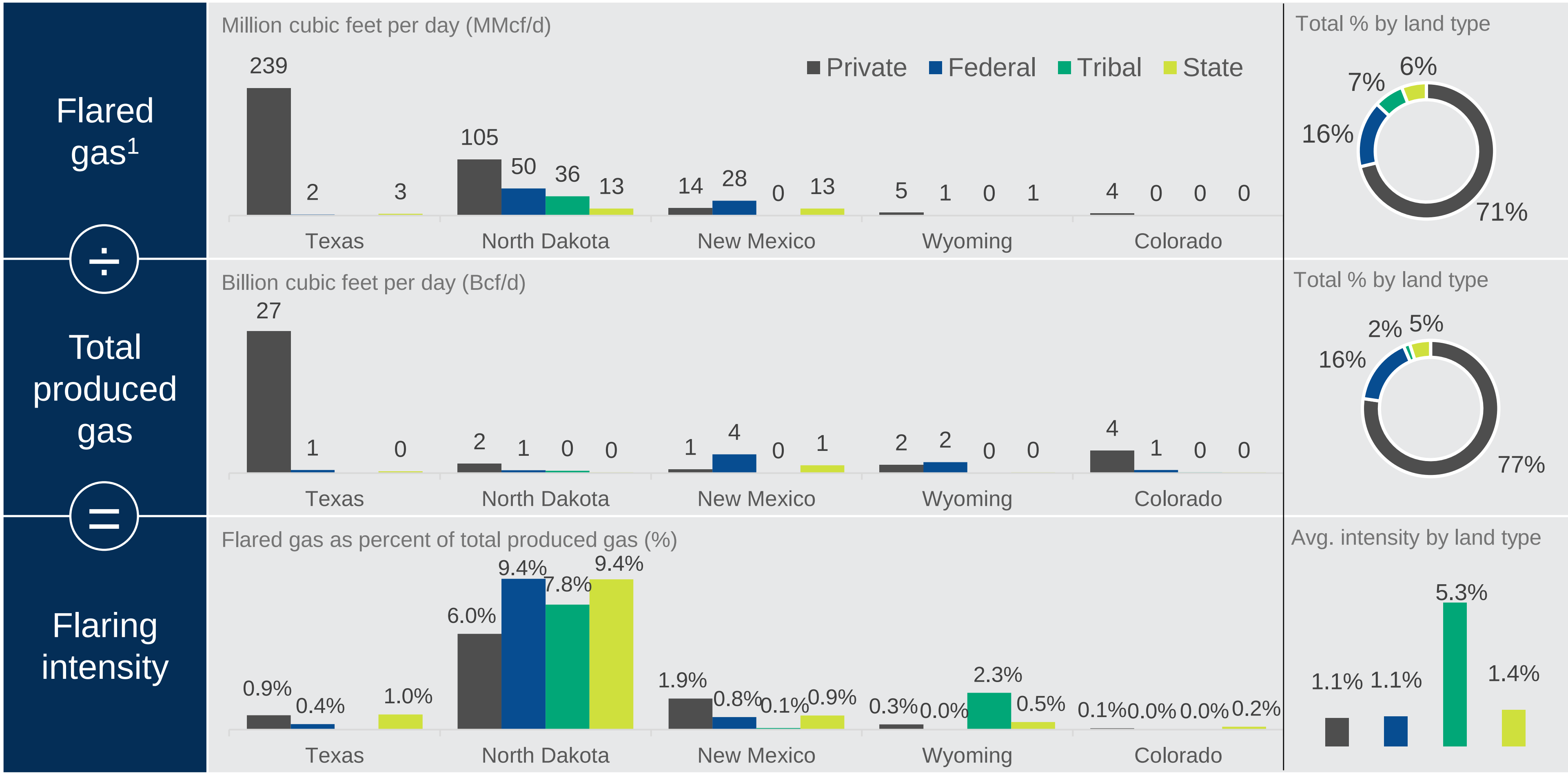


Flaring rates are in most basins significantly higher than what's seen in Colorado. However, the performance amongst operators varies greatly. Using the Permian as an example, key companies such as ExxonMobil, Chevron and Shell all had flaring intensities of 0.5% or lower in 2021. During the production phase, this implies that flaring above 0.2% would be excess (leaving some room for safety related flaring). The startup phase is also a key contributor, but the driver here is less the field setup and more the completion process.

Note: Upstream flaring only
*Colorado is H1 2021, Norway and Netherlands 2020 average.
Source: Rystad Energy research and analysis

70% of flaring, and 77% of production, occurs on private land

Gas flaring, total production and flaring intensity by state and type of land
January - June 2021 (H1 2021)



1: Wellhead gas flared only (excludes gas flared in midstream operations)
Source: Rystad Energy ShaleWellCube

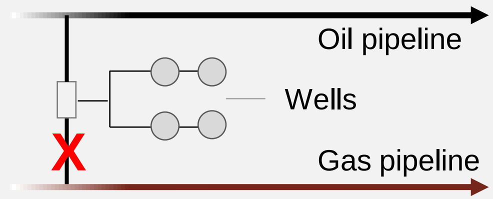
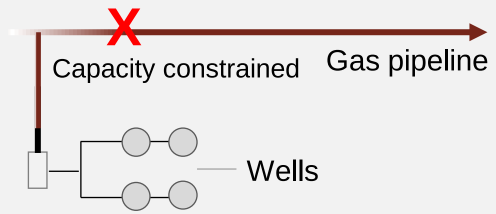
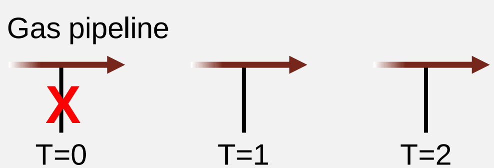
Reducing flaring means bringing gas to market or storing it

Flaring drivers and impact

High flaring	
Lack of export infrastructure	A key driver for flaring in US basins is the lack of export infrastructure. In most instances this is a temporary problem, implying that the issue should be very cheap to fix. In instances where export is not feasible, storing gas underground is a viable option.
Insufficient takeaway capacity	A significant part of flaring stems from the insufficient takeaway capacity, either in the gathering, processing or trunkline systems. This is clearly seen in the total numbers: When activity slows, flaring plummets.
Safety flaring	Safety flaring remains a very limited issue. States with strict regulations on routine flaring have very low flaring rates.
Low flaring	

Source: Rystad Energy research and analysis

The drivers of the flaring can be divided into four main buckets

Flaring driver "The problem"	Illustration	Comment	Definition in report
Infrastructure access		Oil is the main product, and the associated gas production is not connected to infrastructure at all	*100% of the produced gas is unsold (flared, reinjected or utilized as fuel)*
Infrastructure capacity		Infrastructure for gas transportation is in place, but it is produced more gas than the infrastructure can handle	*Multiple months where gas is sold, but flaring is significantly higher than expected (10-90% of production)*
Safety flaring	A safety flame facilitates for the opportunity to get rid of large amounts of gas fast 	Large gas buildups can cause severe damage. Keeping a safety flare provides the opportunity to get rid of large amounts of gas fast	*Flaring of 0.2% is assessed to be sufficient to maintain a safety flare and unavoidable events*
Timing and other issues		The connection / disconnection from gas infrastructure does not match the start or stop of production	*Volumes not allocated to the three buckets above are primarily driven by timing issues. However, other factors including short-term operational issues (i.e. temporary downstream outages) could also have an impact.*

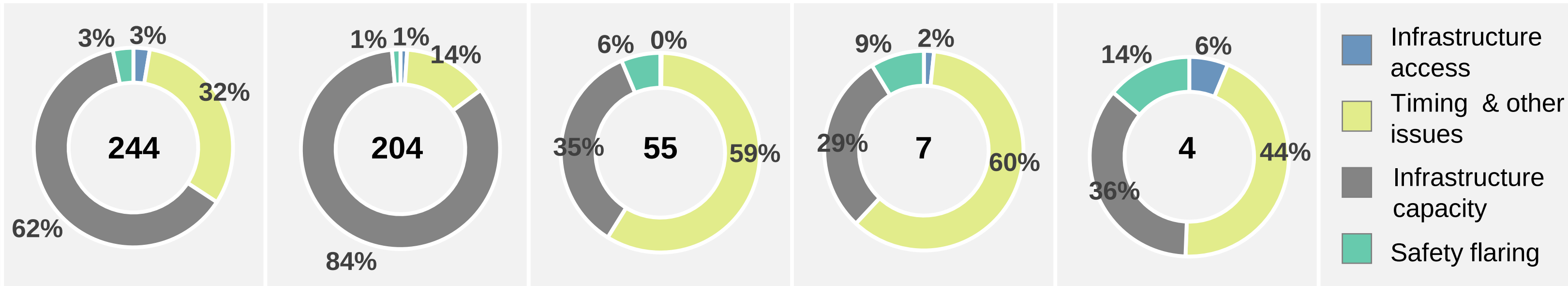
Source: Rystad Energy ShaleWellCube

Lack of infrastructure access is not the issue, timing and capacity is

Volume selection: First 12 months of production from 2020-completed wells with 12 months of reporting	Texas	North Dakota	New Mexico	Wyoming	Colorado	

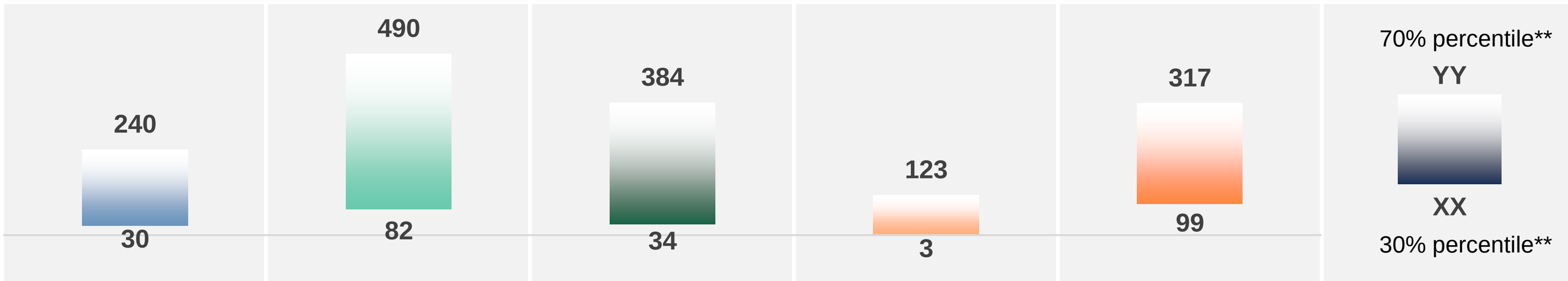
Flaring driver
“The problem”

MMcf/d*



Pad-level
flare size

kcf/d



- Capacity, meaning that the well that is flaring is connected to infrastructure but still chooses to flare, is the main cause of flaring.
- The second largest cause of flaring is timing, meaning that the well is flaring for a short period of time due to mismatch in start of production and connection to/scaling of infrastructure.
- Flare size percentiles represent percentile of total flared volume. 30% of flaring originates from flares smaller than the lower bound flare rate; 70% of flaring originates from flares smaller than the upper bound flare rate.
- The size of the flares is largest in Colorado, followed by New Mexico and North Dakota. Colorado is also unique in the way that infrastructure is the main issue, highlighting that a large share of the flared volumes stems from wells with 100% flaring.

*Analysis of problem and pie chart distribution is based on analyzing first 12 months of production from 2020-completed wells with >6 months of reporting. Production number inside pie is H12021 statewide average flaring across all wells **30% percentile (lower) and 70% percentile (upper) in terms of total volumes flared. E.g., 30% of flaring originates from flares smaller than the lower bound flare rate; 70% of flaring originates from flares smaller than the upper bound flare rate.; Source: Rystad Energy research and analysis

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We investigate the direct costs, viability and situational requirements of various flaring abatement measures

Abatement method		Description
Pipeline gathering		Pipeline gathering is ubiquitous and widely available, though in certain circumstances the other methods described below may be more appropriate as a substitute or complement to pipeline gathering
On-site use		On-site consumption for local gas use (e.g., for fueling equipment) or local electricity generation
Gas-to-wire		Use of gas in a power plant and selling power to an electricity grid
On-site compressed natural gas (CNG)		On-site compression of gas, with trucks transporting compressed gas to downstream delivery points (e.g., gas trunklines) or end markets
On-site liquefied natural gas (LNG)		On-site liquefaction of gas, with trucks transporting liquefied gas to downstream delivery points (e.g., gas trunklines) or end markets
Gas reinjection		Gathering gas from multiple wells, transporting via pipeline and reinjecting into a suitable reservoir

Source: Rystad Energy research and analysis

We assess the viability of these abatement alternatives across four dimensions

Dimension	Explanation
Optimal volume range	The volume of gas needed to support the optimal use of an abatement method. For example, the optimal volume range of gas that would be needed to support the application of gas reinjection or LNG, volumes below which would leave infrastructure underutilized.
Distance to infrastructure	Some methods may require proximity to existing infrastructure, while others may be viable even when well pads are isolated or remote.
Scalability	The ability of a solution to both scale to handle different volumes of gas (single well pad solution vs acreage development solution) and to scale to meet high initial production volumes.
Situational requirements	Each abatement method has its own situational requirements. Gas reinjection requires the availability of a suitable reservoir, while pipeline gathering for flaring abatement necessitates that there are not downstream constraints.

Source: Rystad Energy research and analysis

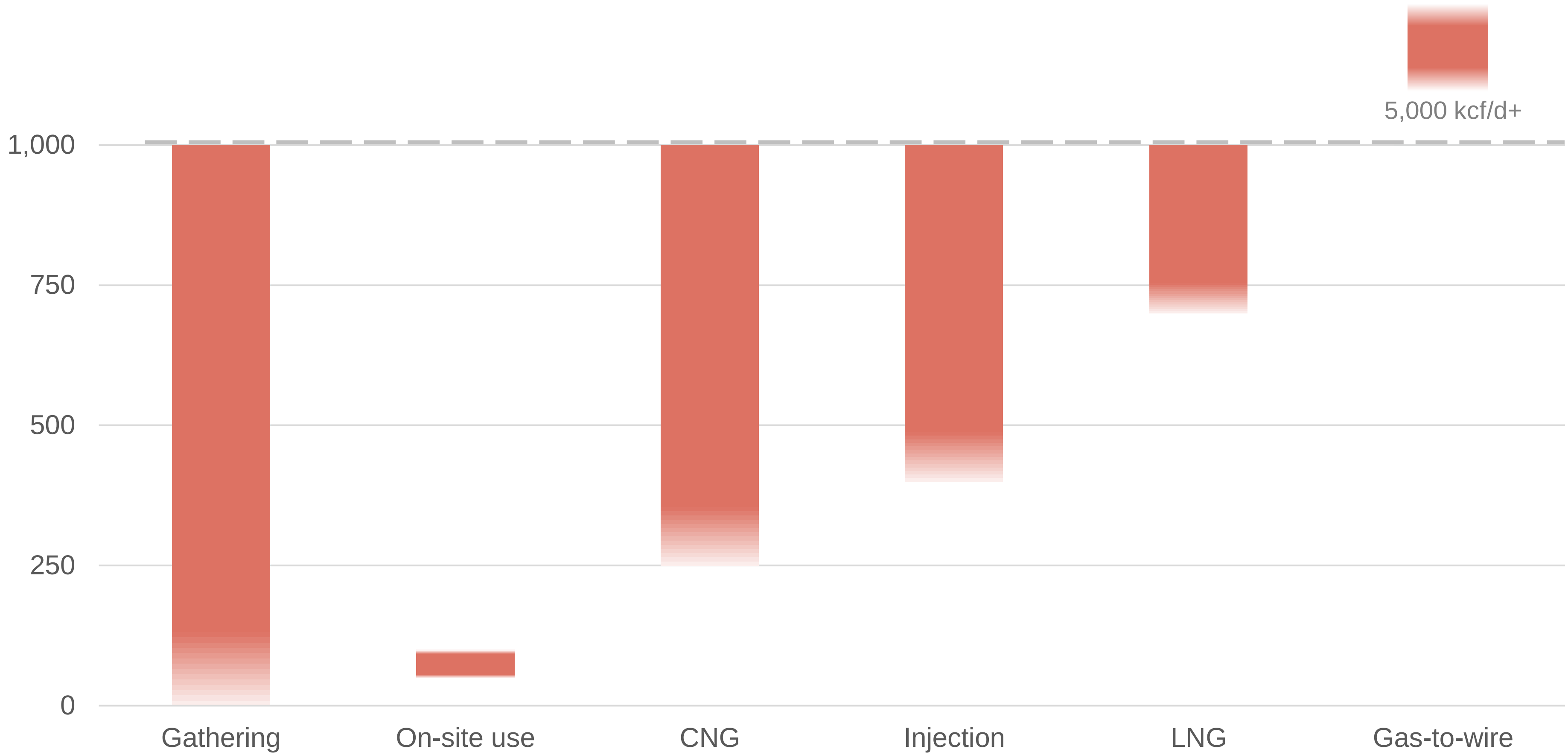
Abatement costs vary by technology; net costs account for sales of gas and NGLs

Abatement method	Absolute cost*		Net cost*	
	Cost per kcf handled ($/kcf)	Cost per MT of methane flaring avoided ($/MT methane)**	Cost per kcf handled ($/kcf)	Cost per MT of methane flaring avoided ($/MT methane)**
Pipeline gathering	0.8	42	-3.1 *Net profit*	-162 *Net profit*
Gas-to-wire	1.9	99	0	0
On-site use	3.2	167	-8.6 *Net profit*	-449 *Net profit*
Gas reinjection***	3.4	177	3.4	177
On-site compressed natural gas (CNG)****	5.2	271	1.8	94
On-site liquefied natural gas (LNG)****	9.0	470	5.6	292

*Absolute cost includes all costs from well to customer. To arrive at net cost the value of the product is subtracted from the absolute cost. The estimated cost ranges are shown in parenthesis, point estimates are shown above **52.2 kcf of methane per metric ton ***These numbers represent a scenario where the gas is injected into a reservoir for permanent storage only and does not include retrieving the gas for sale or EOR. Selling the gas or EOR represent significant upside potential that most likely would yield a large net profit. ****Cost of transporting NGLs with trucks included in net costs. Net cost of CNG/LNG delivered as gas, CNG/LNG could be worth more if delivered as CNG/LNG.
Source: Rystad Energy research and analysis

The minimum optimal economic volume varies by technology

Range of optimal flare capture by abatement method*
kcf/d



Minimum volumes represent the low end of capacity for modular CNG and LNG equipment, size of a small injector well for gas injection, and the size of a small turbine for grid power for gas-to-wire. Some well pads could be aggregated to increase the applicability of abatement methods to handle a larger share of flaring.

*1,000 kcf/d maximum boundary shown on chart does not represent a maximum volume range. Note: For CNG, LNG and Injection, minimum optimal abatement volume is typically set by the size of the smallest available modular systems or reasonable size of small injector well, rather than technical constraints.
Source: Rystad Energy research and analysis

Each abatement method has differing requirements affecting viability

Dimension	Pipeline gathering	On-site use	Gas-to-wire	CNG	LNG	Gas injection
Volume range (kcf/d)	>0	<100	5,000+	>250	>700	>350
Scalability*	✓	✗	✗	✓	✓	✓
Distance to infrastructure	!		!			!
Situational requirements	• Downstream constraints including gas processing capacity and takeaway capacity	• Gas composition • Matching between associated gas production and consumption on-site	• Requires proximity to gathering & processing and grid infrastructure • Large, longer-term production of associated gas from multiple wells	• Local demand for CNG would increase value	• Local demand for LNG would increase value	• Requires gathering and transport infrastructure • Feasible storage locations necessary near well site

✓ Scalable
✗ Challenges to scaling
! Proximity to infrastructure required

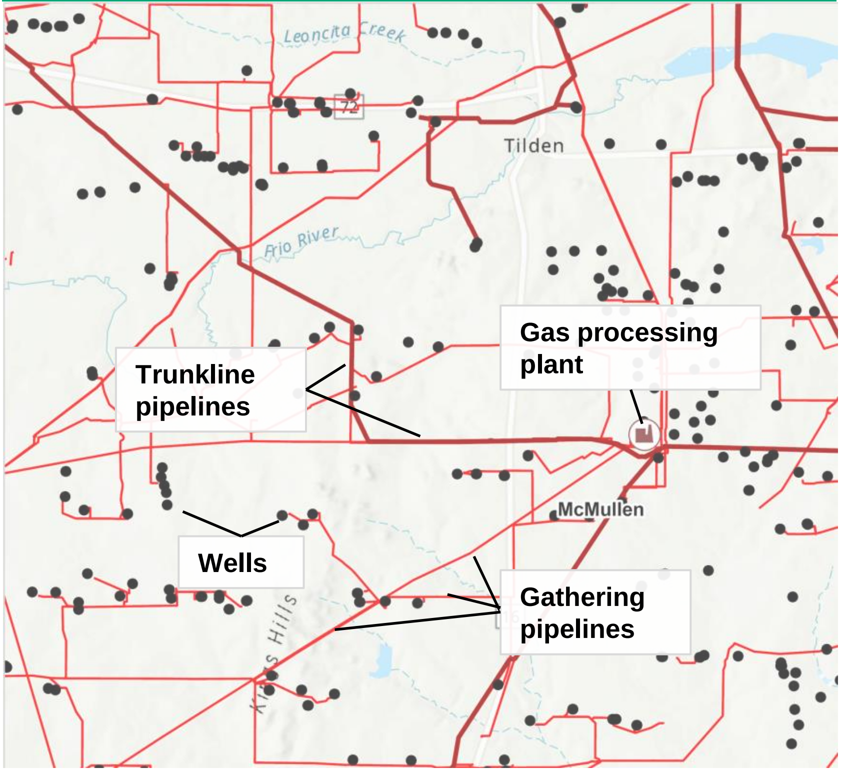
*The ability of a solution to both scale to handle different volumes of gas (single well pad solution vs acreage development solution) and to scale to meet high initial production volumes.
Source: Rystad Energy research and analysis

Gas pipeline gathering systems are main method of abatement, though employing gas gathering is challenging in some situations

Overview

Connecting wells to gas gathering systems is the primary method of abating flaring. Gas gathering systems bring wells to gas processing plants and subsequently trunklines. Operators that wish to limit capex can make agreements with 3rd-party gas gatherers for fee-based gathering, while others invest in and operate their own gathering systems.

Gathering system illustration



Advantages

- **Proven, ubiquitous**
  - The ubiquitous method of abatement, the industry and technology for midstream gas gathering is highly mature.
- **Scalable**
  - Gas gathering systems are the most effective way to capture gas from a large number of wells.
- **Often quick to deploy**
  - When wells are drilled in vicinity to existing gathering systems new wells can be quickly and cheaply connected.

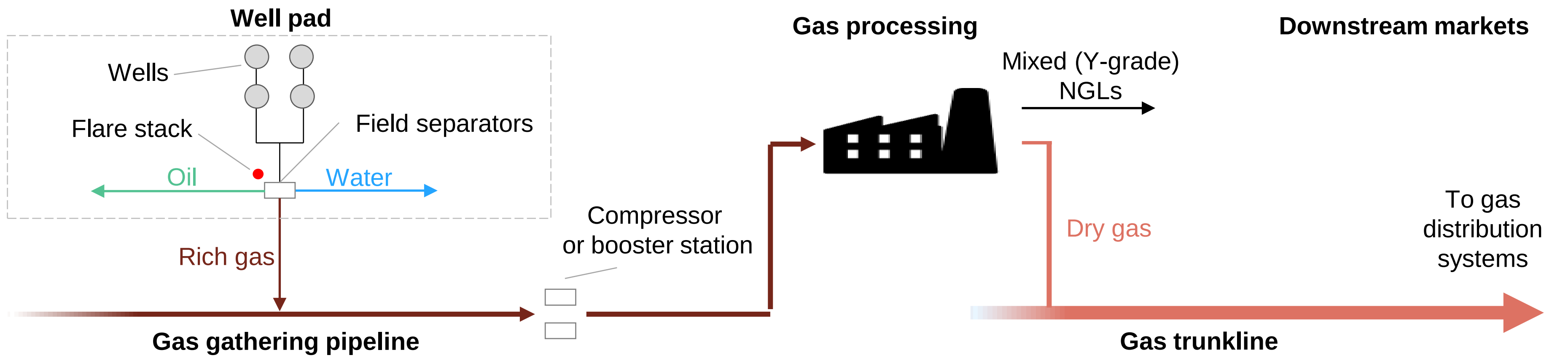
Challenges

- **Timing of connection**
  - Well completion must be timed with connection to gas gathering. There is often a delay due to planning, especially when operators utilize 3rd party gatherers.
- **Operational challenges**
  - Connecting new wells to gas gathering systems can cause operational issues due to high initial production rates and pipeline operating pressures. Due to this, connections are sometimes intentionally delayed.
- **Isolated wells**
  - Wells or well pads that are distant from existing infrastructure could require high capex to reach with gas gathering pipelines.
- **Downstream constraints**
  - Even if pipeline connections are feasible, constraints could exist downstream (e.g., at processing plants or on trunklines).

Source: Rystad Energy research and analysis

Gathering as an abatement method also relies on processing and trunkline capacity

Typical path of gas molecules from wellhead to market



Well pads

Summary:
Well pads typically consist of 2-6 wells in close vicinity sharing facilities such as separators, flares and tanks.

Potential constraints:
- Flaring often occurs when wells are not hooked into gas gathering systems prior to start up
- Wells that are distant from existing gathering systems could be expensive to connect to infrastructure

Gas gathering

Summary:
Gas gathering systems bring gas from many well pads to centralized processing facilities. Gas gathering systems often require “booster stations” to add gas compression.

Potential constraints:
- Flaring can occur at well pads if there is a lack of compression on gas gathering systems

Gas processing

Summary:
Gas processing plants are centralized plants that typically process 200-400 MMcf/d of gas, removing impurities and separating dry gas from NGLs. Dry gas is sent to gas trunklines, while NGLs are sent to NGL trunklines for further processing.

Potential constraints:
- Lack of processing capacity serving a gathering system can lead to flaring

Gas trunkline pipelines

Summary:
Gas trunklines are typically large (20”-42”) pipelines that take gas from multiple gas plants to end markets, such as natural gas distribution systems for residential, commercial or industrial consumption.

Potential constraints:
- Lack of trunkline capacity, often called takeaway capacity, can lead to flaring

Source: Rystad Energy research and analysis

Gathering is typically the most cost-effective method of preventing flaring

Pipeline gathering

Method of gathering	Explanation	Advantages/ disadvantages	Cost range* per kcf handled ($/kcf)	Cost range* per MT of methane flaring avoided ($/MT methane)**
3rd-party and processing gathering	Operators make arrangements with 3rd-party midstream operators, most often in the form of acreage dedications, paying a fixed fee for each unit of gas gathered.*** The same party usually offers gathering and processing.	**Advantages:** - No capex, leaving capital available for drilling and completions **Disadvantages:** - Requires coordination with gatherer to ensure timely well connections and reduce flaring -Requires negotiating appropriate commercial terms (e.g., sufficient firm capacity)	$0.80 ($0.40 - $1.20)	$42 ($21 - $63)
Net cost after gas sales	Value of rich gas stream = 3.9 $/kcf		*Net profit* $3.1 *Net profit* ($2.7 - $3.5)	*Net profit* $162 *Net profit* ($141 - $183)

*The estimated cost ranges are shown in parenthesis, point estimates are shown above.
**52.2 kcf of methane per metric ton.
***Many forms of midstream gathering-and-processing contracts exist. The most common form is an acreage dedication, whereby an operator commits to pay the midstream gatherer to gather all production on specified acreage. Operators typically pay a fixed fee for gathering and processing, often with an additional "percent of proceeds" clause whereby the processor retains a portion of extracted NGLs, giving the processor commodity price upside.
Source: Rystad Energy research and analysis

Rather than paying a fee to 3rd-parties, operators can instead invest the capital to build their own gathering systems

Method of gathering	Explanation	Advantages/ disadvantages	Capex range* per kcf/d capacity ($/kcf/d)	Capex range* per MT of methane flaring avoided ($/MT/d methane)**
Operator-building gathering and processing	Operator spends the capex to construct their own gathering system, and then operates the system themselves. Operators typically still pay for 3rd-party processing rather than operating their own processing plants.	**Advantages:** - Allows full control of gathering system design and timing of well connections - No need to provide a margin to 3rd party **Disadvantages:** - Requires significant capital as well as mid stream expertize	\$450 per kcf/d of gathering capacity \$500 per kcf/d of processing capacity	\$23,500 per MT methane/day of gathering capacity \$26,000 per MT methane/day of processing capacity

*All costs are gross.
**52.2 kcf of methane per metric ton.
Source: Rystad Energy research and analysis

Gas gathering is a viable and scalable solution in most circumstances, but still subject to downstream constraints

Dimension	Assessment
Volume range	• Gas pipeline gathering can be used for any volume of production--from single wells to thousands of wells. If distant from existing infrastructure, larger volumes may be required to be economic.
Distance to infrastructure	• Gathering systems are cheapest when wells are located near processing plants and in close proximity to eachother. When wells are far from existing infrastructure other abatement methods may be more appropriate.
Scalability	• Gas gathering systems can be sized to handle any volume of production. Equipment must be sized for initial production, but compressor stations, one of the most expensive components of gas gathering systems, can serve many wells.
Situational requirements	• The ability for pipeline gathering to abate flaring depends on whether or not there are downstream constraints, such as gas processing or trunkline takeaway constraints. • Having the right commercial terms can reduce flaring, such as sufficient uninterruptible capacity at processing plants and on trunklines

Source: Rystad Energy research and development

On-site use offers potential to reduce some flaring but is not a scalable abatement option

Overview

Associated gas can be used on-site for operations—directly in operations for heat or as a replacement for other fuel and as an input for electricity generation. Using gas in-basin has minimal barriers and the potential for increased use. However, while on-site use can help reduce flaring by utilizing some of the associated gas, it is a difficult option to scale given wide fluctuations in production and variability in demand for both gas and power at the well.

Uses for associated gas on-site

Direct use

- Heat
- Field gas to replace diesel for equipment

On-site power

- Power for gas separators
- Electric pressure pumping fleet
- Other electrical equipment

Advantages

- **Cost savings**
  - Operators can save from fuel switching including substituting field gas for other fuels like diesel and from utilizing gas as a low-cost, independent power source.
- **Less dependent on infrastructure**
  - Using associated gas on-site does not require access to other pipeline infrastructure to facilitate local use.
- **Minimal barriers to implement**
  - Any operator can theoretically use some associated gas on-site without major investments in infrastructure or significant coordination with 3rd parties.

Challenges

- **Supply demand matching**
  - Inconsistent volumes of associated gas production poses challenges over the life of the well— Demand at the well may fall significantly below production requiring additional abatement strategies on top of on-site use. Alternatively, if demand exceeds supply operators will still need to access to alternative power supply and fuels regardless of on-site use.
- **Gas composition limitations**
  - Use of associated gas may still rely on gas conditioning and processing.
- **Requires solution for remaining associated gas**
  - Due to the mismatch in supply for gas on-site and availability, an alternative abatement option is likely required in addition to on-site use highlighting the scalability issues of local consumption– a key consideration in allowing the strategy to be a true, large-scale abatement method.

Source: Rystad Energy research and analysis

Use of fuel on-site requires investment in gas treatment and power generation facilities

On-site use

Dimension	Explanation	Advantages/ disadvantages	Cost range* per kcf handled ($/kcf)	Cost range* per MT of methane flaring avoided ($/MT methane)**
Cost of small on-site power generator	A small turbine or other form of power generator can be used to help utilize the associated gas and create a source of on-site power. The cost of a small gas turbine without any fuel subsitition amounts to approximately $2/kcf.***	**Advantages:** - Independent supply of power using zero-cost fuel **Disadvantages:** - Limited on-site demand for heat and power compared to levels of associated gas production	$2.1 ($1.9 - $2.2)	$110 ($99 - $115)
Gas treatment	Processing of associated gas. Separate H2S and other impurities as well as recover NGLs.		$1.2 ($0.6 - $1.7)	$63 ($31 - $89)
Total cost	On-site treatment and power generation.		$3.2 ($2.5 - $3.8)	$167 ($131 - $198)

*The estimated cost ranges are shown in parenthesis, point estimates are shown above. All costs are gross.
**52.2 kcf of methane per metric ton.
***Cost ranges assumes 5-year life of power generator, generator CAPEX of $1,000/kW, and 50 kcf/d of potential gas use for on-site power and diesel displacement.
Source: Rystad Energy research and analysis

Use of gas on-site can offset costs of other fuels and power with potential for negative abatement costs though this is contingent on utilization and supply-demand matching

Dimension	Explanation	Advantages/ disadvantages	Net profit* per kcf handled ($/kcf)	Net profit* per MT of methane flaring avoided ($/MT methane)**
Net costs from fuel switching	Using field gas as a replacement for other fuels like diesel can offer significant cost savings. The cost savings of fully displacing diesel with associated gas for power demand at the well amounts to $7 - $10/kcf when subtracting the cost of the power generator and treatment. However, this figure represents the maximum savings possible assuming 50 kcf/d of power used and full diesel replacement (perfect gas supply-demand matching). Thus, while there is potentional for negative abatment costs, realizing a negative figure relies heavily on utilizatiion.	**Advantages:** - Significant potential cost savings from using field gas versus purchasing diesel **Disadvantages:** - 100% fuel substitution is unlikley and dependent on factors including type of pressure pumping fleet	*Net profit* $8.6 ($7.7 - $9.4)	*Net profit* $449 ($402 - $491)

Note: Cost ranges assumes 5-year life of power generator, generator CAPEX of $1,000/kW, and 50 kcf/d of potential gas use for on-site power and diesel displacement.
*The estimated ranges are shown in parenthesis, point estimates are shown above.
** 52.2 kcf of methane per metric ton.
Source: Rystad Energy research and analysis

On-site use offers potential for flaring reductions in certain circumstances

Dimension	Assessment
Volume range	• During production, power demand is estimated to range from 0.25 - 0.4 MW for a multi-well pad,[1] translating to approximately 50 - 100 kcf/d. • Consuming 50 - 100 kcf/d on-site would help reduce flaring but would not fully elimate all associated gas at most pads. **50 - 100 kcf/d** typically required for production related power generation for a multi-well pad
Distance to infrastructure	• Access to takeaway infrastructure is not required for on-site use. In lieu of pipelines, some on-site gas conditioning and processing may be required to use the associated gas. However, given the variability in production, access to grid power may still be necessary in somes cases to ensure operations can run uninterrupted.
Scalability	• While on-site gas use has relatively low barriers for operators to incorporate into well site operations, the option is difficult to scale given equipment and usage are specific to individual wells and power and fuel needs will also fluctuate over the life of the well.
Situational requirements	• On-site use depends heavily on gas compostion to determine conditioning and processing needs before using at the well. On-site use also relies on matching consumption with available volumes.

1: Carbon Limits Improving utilization of associated gas in US tight oil field
Source: Rystad Energy research and development

CNG is a possible solution to monetize associated gas from wells isolated from pipeline infrastructure or facing pipeline constraints

Overview

CNG is a potential solution to collect, transport and monetize associated gas that would otherwise be flared at locations without gas transportation infrastructure or constrained infrastructure capacity. The natural gas market is already established and commercial CNG solutions are available. Cost levels depend on volumes and transportation distances, as well as the quality of the gas. CNG are more suited for smaller volumes and shorter distances compared to LNG.

CNG illustration

Advantages

- **Available technology**
  - Compression technology for CNG is already in use.
- **Less need for infrastructure**
  - Does not need gas pipeline infrastructure connected to the well site.
- **Availability of associated gas**
  - Associated gas that would otherwise be flared can be sold and create value.
- **Scalable and moveable**
  - The systems that make up the CNG value chain are both scalable and transportable. Gas treatment units and compression systems can be modular and easy to transport between sites.

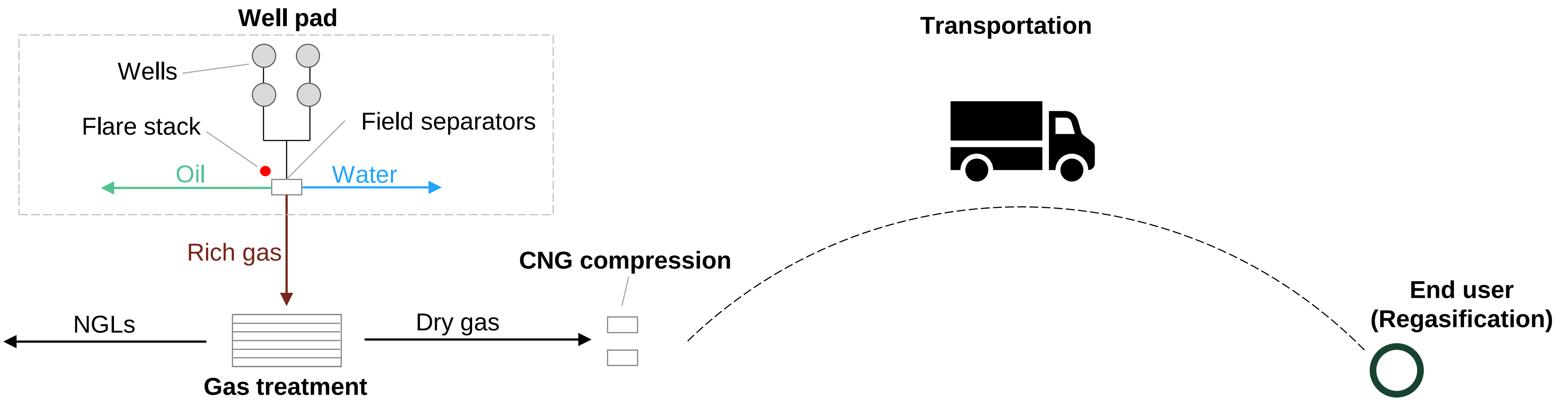
Challenges

- **Unproven at scale**
  - Has not been used in large scale in US shale production.
- **Variable volumes**
  - A typical shale well produces more associated gas in the first months, scaling abatement capacity to match flared volumes is a challenge.
- **Distance to market**
  - The cost of delivering CNG increases significantly when distance to infrastructure or end-users increase.
- **Logistics**
  - If volumes are large, many trucks are needed for transportation. This may create logistical challenges.
- **Market size**
  - Local CNG demand could be limited compared to associated gas volumes.

Source: Rystad Energy research and analysis

A CNG value chain can operate independently of gas transportation infrastructure

Typical path of gas molecules from wellhead to market



Feed gas treatment

Summary:
Associated gas are first treated in order to remove H_2S, CO_2 and other impurities, as well as separating heavier hydrocarbons (NGL) that can be sold separately as liquids. The cleaned gas are then ready for further processing.

Different combinations of treatment and compression could be possible, depending on point of delivery.

Potential constraints:
⬣ The quality of the feed gas affects the necessary amount of treatment.

CNG processing

Summary:
Cleaned gas are compressed and stored.

Different compression systems have different requirements for feed gas quality, some systems require previous treatment of the gas. Some multistage compressor systems can also separate heavier hydrocarbons (NGL).

Potential constraints:
⬣ Insufficient capacity of treatment and compression systems can lead to incomplete flaring abatement.

Truck transportation

Summary:
Transported in pressurized containers.

CNG is typically stored and transported at pressures of approximately 100-250 bar. Higher than pipeline pressure.

Potential constraints:
⬣ Large number of trucks needed for large volumes and/or distance to market due to low volumetric density.

Delivery to pipeline or end-use

Summary:
Delivered as CNG for vehicle fuel or depressurized for other consumption or input to pipeline grid.

Potential constraints:
⬣ Offloading equipment is necessary to receive CNG.

Source: Rystad Energy research and analysis; World Bank Global Gas Flaring Reduction Partnership

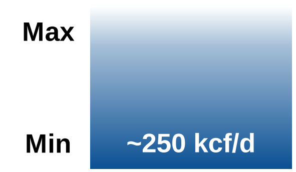
Transportation by truck represents the majority of CNG value chain costs

Part of value chain	Explanation	Key assumptions*	Cost range** per kcf handled ($/kcf)	Cost range** per MT of methane flaring avoided ($/MT methane)***
Gas treatment	Processing of associated gas to separate H2S and other impurities as well as recover NGLs. Gas treatment cost depends on the quality of the associated gas.	250 kcf/d capacity	$1.2 ($0.6 - $1.7)	$63 ($31 - $89)
Compression	Compressing gas to CNG before transportation.	250 kcf/d capacity	$0.7 ($0.3 - $1)	$37 ($16 - $52)
Transportation & offloading	Transportation of CNG and delivery to customer. CNG trucking is more expensive than typical cargo trucking.	250 kcf/d capacity 200 miles transportation	$3.3 ($2.6 - $4.1)	$172 ($136 - $214)
Total cost			$5.2 ($3.5 - $6.8)	$271 ($183 - $355)
Net cost after gas sales** **		Value of rich gas stream = 3.4 $/kcf	$1.8 ($0.1 - $3.4)	$94 ($5 - $177)

*Important factors affecting the cost level are transportation distance, volumes, gas quality and more. 10-year lifetime and 80% utilization are used for cost calculations.
**The estimated cost ranges are shown in parenthesis, point estimates are shown above.
52.2 kcf of methane per metric ton.*Cost of transporting NGLs with trucks included in net costs. Net cost of CNG delivered as gas, CNG could be worth more if delivered as CNG.
Source: Rystad Energy research and analysis; World Bank Global Gas Flaring Reduction Partnership; Carbon Limits

CNG is modular and scalable over time, but minimum optimal capacity is ~250 kcf/d

CNG

Dimension	Assessment	
Volume range	• CNG requires wells or wellpads of a sufficient size in order to make economics favorable. The cost per kcf of gas processed and transported increases quite rapidly as volumes decrease. Too large of volumes could also cause logistical challenges as a large number of trucks would be needed.	
Distance to infrastructure	• Connection to infrastructure is not necessary for CNG. The gas is transported in trucks instead of pipelines. Transportation accounts for the largest part of the cost of a CNG value chain. Transportation costs would be smaller for shorter distances, which could be relevant to bridge a pipeline gap, but the cost would decrease less than linearly for shorter distances. Long distances to the customer would be expensive but could yield better prices. For longer distances transportation cost scales quite linearly with distance.	200 miles used for calculations. In remote locations, distance to market could be very far.
Scalability	• The systems making up the CNG value chain is modular, scalable and transportable. The capacity can be scaled to the appropriate size as flare volumes change over time. The smallest modules can have too much capacity for smaller wells.	
Situational requirements	• Local demand of CNG is necessary to create the most value from the gas. • CNG could also be delivered as gas to a pipeline or to other customers demanding methane in gaseous state, but CNG would be more valuable if delivered as CNG.	

Source: Rystad Energy research and development

RYSTAD ENERGY

LNG is a solution to monetize associated gas from isolated wells, but LNG is primarily competitive against CNG for larger volumes and longer transportation distances

Overview

LNG is a quite similar solution as CNG in many ways and can be used to monetize associated gas at locations without gas transportation infrastructure or constrained infrastructure capacity. Micro scale LNG systems are operational and available in the market. The LNG liquefaction process is more costly than the CNG compression process and requires a larger upfront investment. The costs of LNG transportation is lower than CNG transportation at sufficiently large volumes and distances. Because of higher Capex and lower Opex, LNG is more suited for larger volumes and longer distances than CNG.

LNG illustration

Advantages

- **Available technology**
  - Liquefaction technology for micro scale LNG is already in use.
- **Less need for infrastructure**
  - Does not need gas pipeline infrastructure connected to the well site.
- **Availability of associated gas**
  - Associated gas that would otherwise be flared can be sold and create value.
- **Scalable and moveable**
  - The systems that make up the LNG value chain are both scalable and transportable. Liquefaction systems can be modular but are probably a bit harder to move than CNG compression systems.

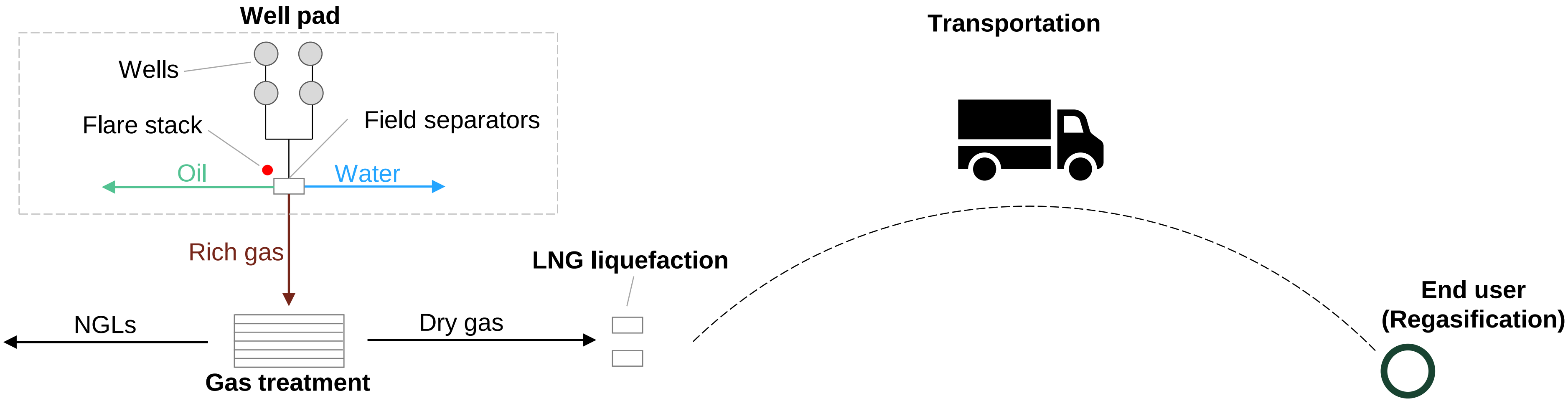
Challenges

- **Unproven at scale**
  - Has not been used in large scale in US shale production.
- **Profitability**
  - The necessary scale of LNG systems is larger than for CNG. The smallest liquefaction units also have higher capacity than the smallest CNG compressors.
- **Variable volumes**
  - A typical shale well produces more associated gas in the first months, scaling abatement capacity to match flared volumes is a challenge.
- **Distance to market**
  - The cost of delivering LNG increases significantly when distance to infrastructure or end-users increase.
- **Logistics**
  - Many trucks would be necessary for large volumes of LNG (but fewer than CNG)
- **Market size**
  - Local LNG demand could be limited compared to associated gas volumes.

Source: Rystad Energy research and analysis

The LNG value chain can transport gas over long distances using trucks

Typical path of gas molecules from wellhead to market



Feed gas treatment

Summary:
Associated gas are first treated in order to remove H2S, CO2 and other impurities, as well as separating heavier hydrocarbons (NGL) that can be sold separately as liquids. The cleaned gas are then ready for further processing.

The LNG liquefaction process have more strict quality requirements for the feed gas than CNG compression.

Potential constraints:
⬣ The quality of the feed gas affects the necessary amount of treatment.

LNG processing

Summary:
Cleaned gas are liquefied and stored at cryogenic temperatures.

Potential constraints:
⬣ Insufficient capacity of treatment and liquefaction systems can lead to incomplete flaring abatement.

Truck transportation

Summary:
Transported in vacuum-insulated containers.

LNG is transported at low temperatures and nearly ambient pressure. The energy density of LNG is higher than CNG, more energy can therefore be transported per truck.

Potential constraints:
⬣ Large number of trucks needed for large volumes and/or distance to market.

Delivery to pipeline or end-use

Summary:
Delivered as LNG for fueling or vaporized for delivery in gaseous form for other consumption or input to pipeline grid.

Potential constraints:
⬣ Special infrastructure is often necessary to turn LNG into a gaseous form. Turning LNG into gas is more expensive than turning CNG into gas.

Source: Rystad Energy research and analysis; World Bank Global Gas Flaring Reduction Partnership

LNG liquefaction costs are significantly higher than CNG compression costs

LNG

Part of value chain	Explanation	Key assumptions*	Cost range** per kcf handled ($/kcf)	Cost range** per MT of methane flaring avoided ($/MT methane)***
Gas treatment	Processing of associated gas to separate H2S and other impurities as well as recover NGLs. Gas treatment cost depends on the quality of the associated gas.	700 kcf/d capacity	$1.2 ($0.6 - $1.7)	$63 ($31 - $89)
Liquefaction	Liquefaction of gas before transportation.	700 kcf/d capacity	$4.5 ($4 - $5)	$235 ($209 - $261)
Transportation & offloading	Transportation of LNG with trucks and regasification at delivery. LNG trucking is more expensive than typical cargo trucking. LNG trucking is cheaper than CNG, but regasifiaction increases cost.	700 kcf/d capacity 200 miles transportation	$3.3 ($2.7 - $3.9)	$172 ($141 - $204)
Total cost			$9 ($7.3 - $10.6)	$470 ($381 - $553)
Net cost after gas sales** **		Value of rich gas stream = 3.4 $/kcf	$5.6 ($3.9 - $7.2)	$292 ($204 - $376)

*Important factors affecting the cost level are transportation distance, volumes, gas quality and more. 10-year lifetime and 80% utilization are used for cost calculations.
**The estimated cost ranges are shown in parenthesis, point estimates are shown above.
52.2 kcf of methane per metric ton. *: Cost of transporting NGLs with trucks included in net costs. Net cost of LNG delivered as gas, LNG could be worth more if delivered as LNG.
Source: Rystad Energy research and analysis; World Bank Global Gas Flaring Reduction Partnership; Carbon Limits

LNG is most competitive against CNG for large volumes and distances

Dimension	Assessment	
Volume range	• The economically feasible volume of LNG is higher than that of CNG due to larger upfront investments required to establish a LNG value chain. The cost per unit of LNG processed decreases as the scale increases and with sufficiently large volumes and transportation distances, LNG could be cheaper than CNG. • The gas volumes and transportation distances must be higher than the assumptions used here for LNG to be more attractive than CNG.	**Max** **Min** **~700 kcf/d**
Distance to infrastructure	• Connection to infrastructure is not necessary for LNG. The gas is transported in trucks instead of pipelines. Transportation costs for LNG is lower than for CNG, but still account for a significant amount of the costs and scales with transportation distance.	200 miles used for calculations. In remote locations, distance to market could be very far.
Scalability	• The systems making up the LNG value chain are modular, scalable and transportable. The capacity can be scaled to appropriate size as flare volumes change over time. The smallest LNG units are larger than the smallest CNG modules and can have too much capacity for smaller wells.	
Situational requirements	• LNG would have largest value if delivered as LNG beacuse of the significant costs associated with liquefying natural gas. Local demand of LNG would therefore increase the value of the gas. • LNG is usually consumed in gaseous form, but is more efficiently stored as a liquid.	

Source: Rystad Energy research and analysis

Gas injection most promising in areas with nearby storage capacity as well as gathering and transport infrastructure

Overview

Routine flaring can be reduced by installing gas processing facilities and infrastructure such that the gas can reinjected. Natural gas produced from oil and gas fields can be injected into nearby depleted reservoirs, saline aquifers or salt caverns as a form of storage. Stored gas can be withdrawn and sold in the future when capacity becomes available. Additionally, gas injection can be utilized in an effort to enhance oil recovery (EOR) by boosting depleted pressure in a formation.

EOR illustration

Advantages

- **Gas injection is proven and mature industry**
  - Gas injection for EOR purposes is widespread within conventional production, indicating that injection of gas into reservoirs is a highly mature industry.
- **Low abatement cost**
  - The abatement cost of reinjecting gas onshore is generally quite low and can even be negative if reinjecting the associated gas increases the recovery rate.
- **Cheap to deploy**
  - When storage availability, gathering and transportation infrastructure is in place, the vertical and simple nature of injection wells make them cheap to deploy.

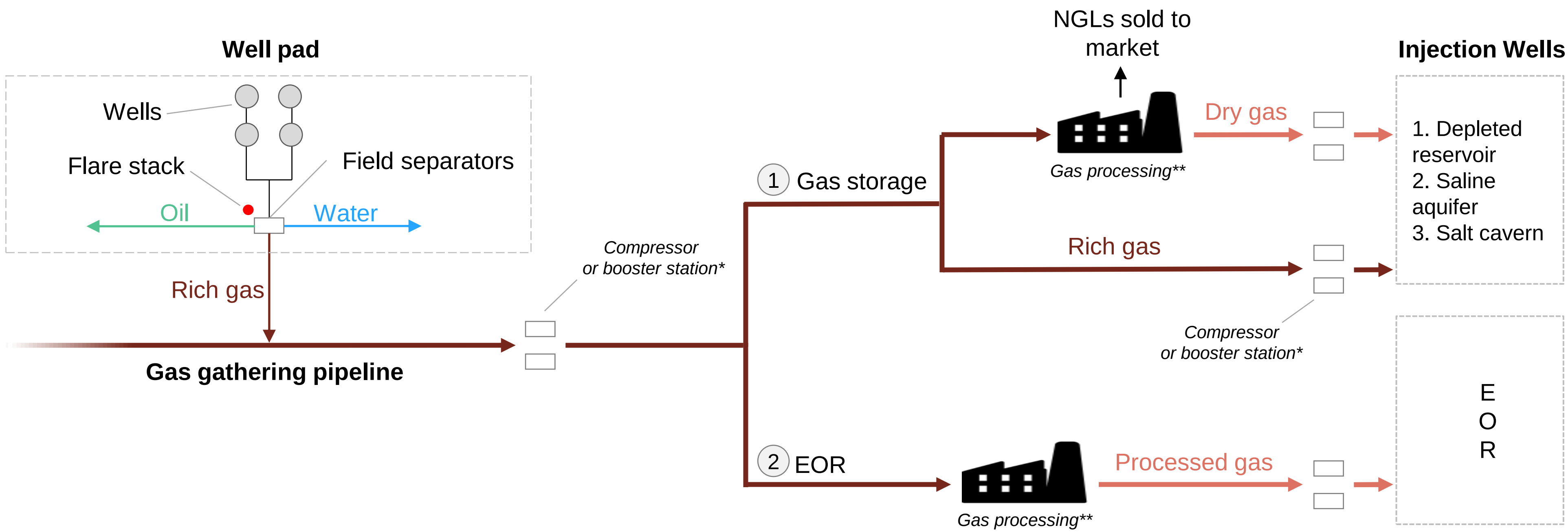
Challenges

- **Availability of injection wells**
  - For practical reasons, drilling injection wells is not possible on all fields, and hence, reinjecting gas is thus not always an option.
- **Availability of storage capacity**
  - Injection for storage purposes places high demands on the availability of nearby storage capacity, as well as gas gathering and transport infrastructure.
- **Efficiency uncertainties**
  - For EOR purposes there are always significant uncertainties regarding efficiency and added recovery of oil. In addition, EOR is uncommon for unconventional formations.
- **Challenges related to gas gathering**
  - As gas injection relies on gas gathering methods, aforementioned issues related to gas gathering implicitly affects gas injection opportunities.

Source: Rystad Energy research and analysis, American Petroleum Institute

After excess gas is gathered it can either be stored or used for EOR purposes

Typical path of gas molecules from wellhead to injection well



1	Gas storage

Summary:
Produced rich gas is either injected as is or stripped of its natural gas liquids, before it is compressed and pumped into an injection well. The gas is then re-injected into either depleted reservoirs, saline aquifers or salt caverns as form of storage. Stored gas can be withdrawn and sold when capacity becomes available.

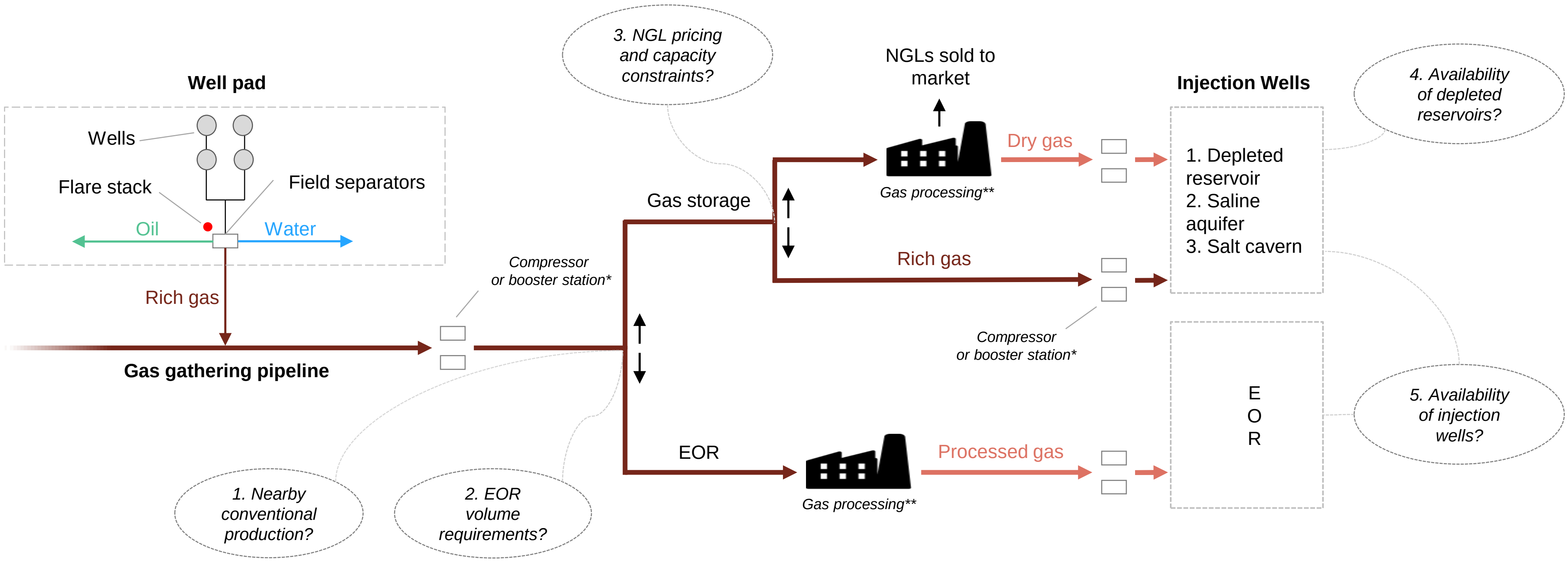
2	Enhanced oil recovery

Summary:
EOR is a technique that uses the gas to improve the recovery factor of an oil field. Processed gas is compressed and injected into the reservoir (and stored) to increase reservoir pressure, which helps oil recovery. It is a two-step process where the gas is first utilized and then stored. Gas withdrawal and sale is also possible for EOR.

Source: Rystad Energy research and analysis
*The need for compressors along the pathway from wellhead to processing plant depend on various factors such as well pressure and transportation distance. **Processing characteristics vary depending on use case.

Given potential constraints, gas reinjection is most suitable in certain circumstances

Various factors affecting which injection options are most beneficial



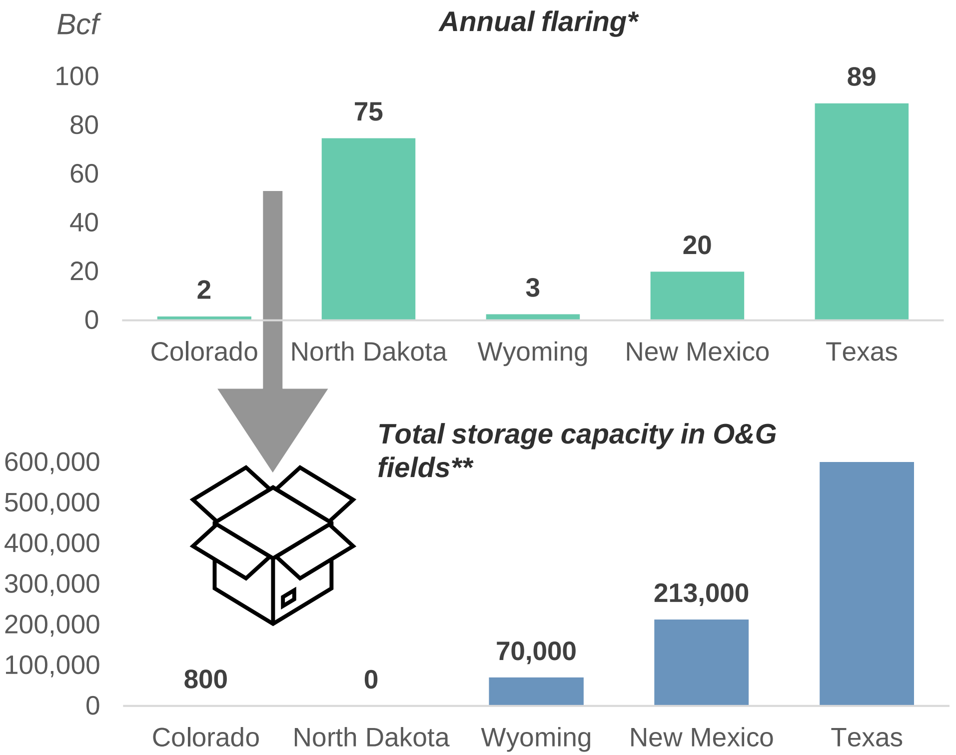
1 Nearby conventional production	2 EOR volume requirements	3 NGL pricing and capacity constraints	4 Availability of depleted reservoirs	5 Availability of injection wells
As EOR methods are mostly used for boosting conventional oil production, lack of nearby conventional production makes gas storage the preferable option.	In order to achieve EOR efficiency certain volume requirements must be met. If the excess gas at hand fails to meet these requirements, EOR will not be realizable.	High NGL prices incentivize gas processing before storage as NGLs can be very valuable by-products. However, processing plant and trunkline constraints may limit this option.	Depleted reservoirs are the cheapest storage type to develop, operate, and maintain. In regions without depleted reservoirs, one of the other two storage options is required.	For practical reasons, drilling injection wells is not possible on all fields, and thus, reinjecting gas for either storage or EOR purposes is not always an option.

Source: Rystad Energy research and analysis
*The need for compressors along the pathway from wellhead to processing plant depend on various factors such as well pressure and transportation distance. **Processing characteristics vary depending on use case.

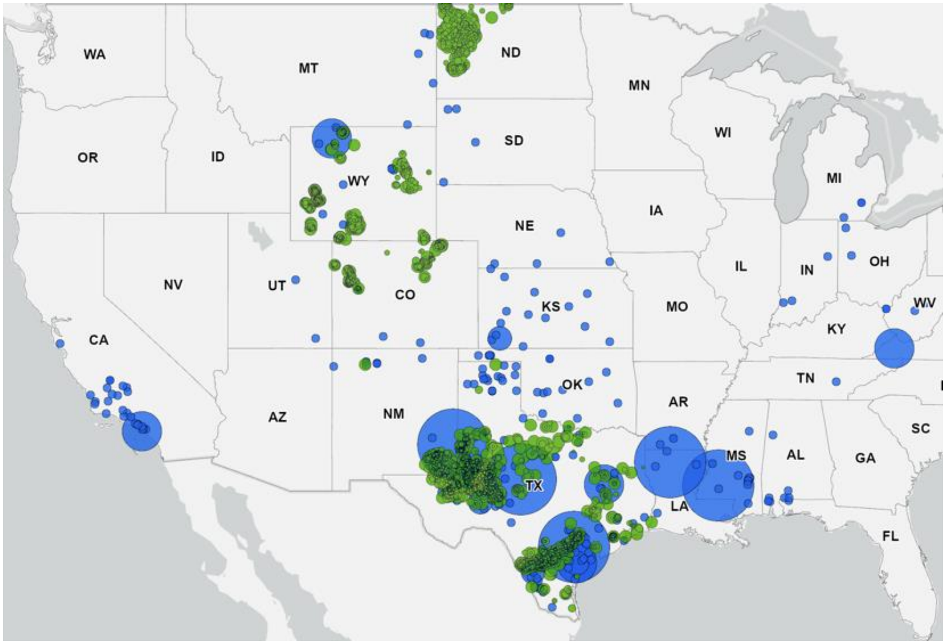
All states except North Dakota have significant storage capacity in oil and gas fields

Gas injection

Annual* flared volumes and total storage capacity by state



Flare site locations vs. location of O&G storage sites**



= flaring sites*** = Storage locations in O&G fields***

- The left chart above displays annual flared volumes (top) relative to total storage potential in oil and gas storage sites (bottom). As displayed, there is a huge storage potential in each state relative to the annual flared volumes except for North Dakota. This highlights that storage capacity is not an issue. While lacking storage sites in oil and gas fields, North Dakota has significant storage potential in saline aquifers.
- The map to the left displays the distribution of storage sites relative to the flaring sites. This map highlights how there are many potential storage sites near key flaring regions in Texas.

*Annualized H12021 flared volumes **EOR and/or dedicated storage ***Size of bubbles on flare sites vs. storage capacity are not on same scale. Chart to the left displays annual flaring vs total storage capacity by state, highlighting the significant storage potential relative to flared volumes; Source: Rystad Energy research and analysis

While ND lacks O&G storage there is huge potential in saline aquifers – pilots ongoing

Gas injection

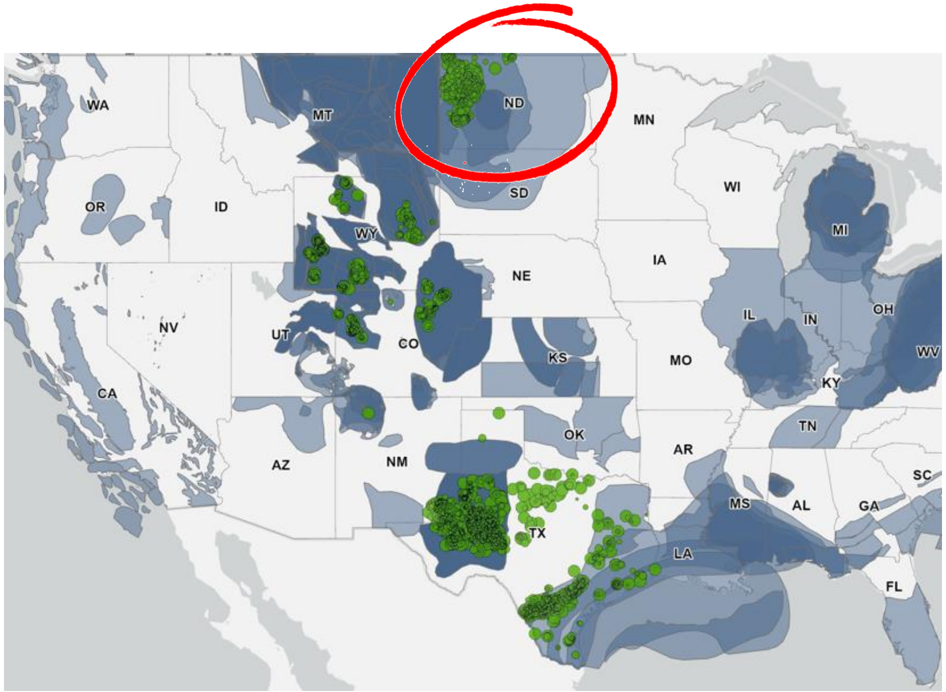
Project Tundra has pivoted its approach to utilize saline formations

INNOVATION STARTS HERE

Project Tundra is a bold initiative to build the world's largest carbon capture facility in North Dakota.

Innovative technologies are being designed to capture 90% of the CO2 produced from either generator at the Milton R. Young Station. This capture rate amounts to about 4 million metric tons per year, which is the equivalent to taking 800,000 gasoline-fueled vehicles off the road. North Dakota-based Minnkota Power Cooperative is leading the project, along with research support from the Energy & Environmental Research Center at the University of North Dakota.

Flare site locations vs. location of saline aquifers



= flaring sites = Saline aquifers

- Project Tundra is Minnkota Power Cooperative's ambitious initiative to install the world's largest carbon capture and storage facility in North Dakota.
- Minnkota originally planned to use captured CO2 in enhanced oil recovery operations, but as the EOR markets in North Dakota have not developed as expected, Minnkota has pivoted its approach to utilize saline formation storage as the primary means of storing CO2, while retaining the enhanced oil recovery as a secondary option if/when the markets are ready. The Federal Government's significant continued funding through the Department of Energy's (DOE) CarbonSAFE program to research and develop saline formation storage for CO2, supports this new focus on saline formations.
- Although certain reservoirs characteristics and regulatory authorities differ for natural gas and CO2 storage, project development and operation of the two types reflect great similarity. This indicates that saline aquifers in North Dakota may represent huge potential for natural gas storage as well.

Source: Rystad Energy research and analysis, Minnkota Power Cooperative webpages, Project Tundra webpages

The total cost of gas injection depends on both gathering and storage costs

Part of value chain	Explanation	Cost range* per kcf handled ($/kcf)	Cost range* per MT of methane flaring avoided ($/MT methane)**
Gas gathering	The gas gathering component relates to gathering and transportation of the gas from the well site to the storage site. This can be conduted either through utilizing third parties or it can be operator built. The cost range is stated for 3rd party gathering. A key factor affecting the total cost is the distance of the trasportation needed.	$0.4 ($0.2 - $0.6)	$21 ($10 - $31)
Storage	The storage component relates to receiving, compressing and injecting the gas at the storage site as well as opex components such as energy and monitoring associated with running the site. The factors with the most significant effect on cost are lifetime of the storage site / depreciation of the capex as well as the size of the opex (dependent on energy utilized for e.g. compression and energy prices).	$3 ($0.2 - $5.7)	$157 ($10 - $298)
Total cost	Total cost of gas injection is assessed to be in the $0.4-$2/kcf range. The lower range represents short distances with minimal opex and long depreciation of the equipment. The upper range represents scenarios where the gas is transported over longer distances, the gas is injected over a short period of time and the opex being in the higher range.	$3.4 ($0.4 - $6.3)	$177 ($20 - $329)

Note: There is potential for revenue generation from gas injection by later extracting and selling injected gas, or by using injection for enhanced oil recovery (EOR), which could offset costs. This upside is not analyzed here.
*The estimated cost ranges are shown in parenthesis, point estimates are shown above.
**52.2 kcf of methane per metric ton.
Source: Rystad Energy research and analysis, Energy & Environmental Research Center (EERC)

Gas injection is highly scalable, but requires nearby infrastructure and storage capacity

Dimension	Assessment
Volume range	• Gas injection can in theory be used for all volumes, however, longer distances from wellpad to injection site increase total cost of reinjection. Small volumes will also make the storage part very expensive, and volumes of a certain size are required in order to bring the cost down. However, the volumes stored could come from a number of wells from different locations, adding to the total volumes. 
Distance to infrastructure	• Gas injection is cheapest when wells are located near the storage site. When the wells are far from existing infrastructure other abatement methods may be more appropriate.
Scalability	• With sufficient gathering, transport and storage capacity, gas injection can be scaled in order to handle any volume of production.
Situational requirements	• For gas injection to be feasible, it is necessary to have gathering and transport infrastructure in addition to feasible storage locations in proximity to the well site.

Source: Rystad Energy research and development

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Gas-to-wire is technically viable but highly dependent on available infrastructure and requires significant CAPEX

Overview

Gas-to-wire refers to using associated gas as a feedstock in power generation that is exported to the grid. This method creates an end-use for gas that would otherwise be flared but requires access to both gathering and processing infrastructure along with access to transmission and grid infrastructure. Given the more sizeable CAPEX investments required for even a small power plant, the quantity of gas would need to be significant and available for several years to make gas-to-wire economically feasible.

Illustration

Advantages

- **Revenue from electricity sales**
  - Using gas to generate power for export can add to revenue through electricity sales.
- **Can account for significant volumes of associated gas**
  - Due to connection to larger plants and to a nearby electrical grid, a higher volume of gas can be used to generate electricity that can be exported and sold.

Challenges

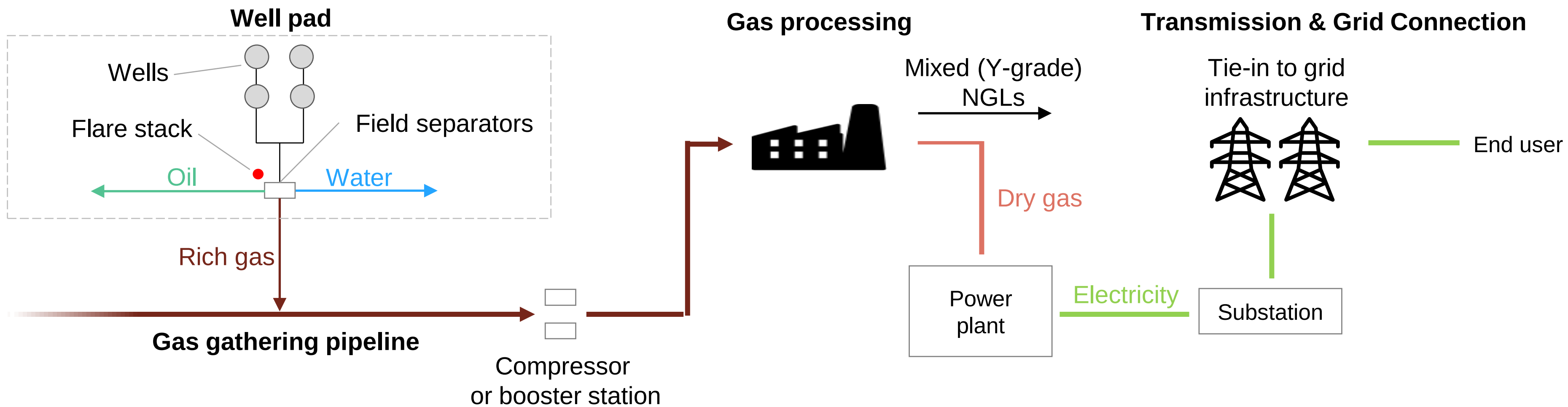
- **Requires access to grid**
  - Gas-to-wire relies heavily on access to existing grid infrastructure making it a challenging abatement option for more isolated wells.
- **Grid related infrastructure costs**
  - If there is not sufficient transmission infrastructure, investments are required here in addition to plant CAPEX.
- **Volume dependent**
  - Gas-to-wire is a more appropriate abatement option for wells or a group of wells with flaring above 5 million cubic feet per day, ideally over the long-term.
- **Still requires access to gathering and processing infrastructure**
  - Due to conditioning and processing needs, wells will also need access to gathering and processing infrastructure in addition to grid access, making Gas-to-wire more of a secondary takeaway solution.

Source: Rystad Energy research and analysis

Connecting to the grid requires access to power generation and transmission infrastructure in addition to gathering and processing systems

Gas-to-wire

Typical path of gas molecules from wellhead to market



Gas gathering and processing	Power generation	Grid connection
Summary: Gas gathering systems bring gas from many well pads to centralized processing facilities. Gas gathering systems often require “booster stations” to add gas compression. Gas processing plants are centralized plants that typically process 200-400 MMcf/d of gas, removing impurities and separating dry gas from NGLs. Dry gas is sent to gas trunklines or power plants, while NGLs are sent to NGL trunklines for further processing.	**Summary:** Dry gas would be sent to a power generation facility to convert the gas into electricity. Gas plants vary in size with combined cycle gas turbine plants generally reaching 300 – 400 MW in capacity. However, smaller alternatives range from 5 – 50 MW and can serve the smaller supply of associated gas from individual wells with significant flaring.	**Summary:** Electricity would be transformed and sent to grid connected transmission lines to travel to nearby demand centers or designated off-takers.
Potential constraints: Flaring can occur at well pads if there is a lack of compression on gas gathering systems or a lack of processing capacity serving the gathering system	**Potential constraints:** Flaring can occur at well pads if there is a lack of capacity available at connected power generation facilities downstream.	**Potential constraints:** Lack of nearby substations or other transmission infrastructure to connect generated power to grid

Source: Rystad Energy research and analysis

The cost of gas-to-wire is driven by investments in power generation in addition to gathering and processing costs

Gas-to-wire

Dimension	Explanation	Cost range* per kcf handled ($/kcf)	Cost range* per MT of methane flaring avoided ($/MT methane)[2]
Power generation facilities	Operators could invest in builiding local power generation facilities as a method of using the processed associated gas. This method would require access to grid infrastructure to transport the electricity to demand centers.	$1.10 ($1.00 - $1.25)***	$57 ($52 - $65)
Gathering and processing	Operators must contract with a 3rd party or build gathering and processing facilities to transport and treat associated gas.	$0.80 ($0.40 - $1.20)	$42 ($21 - $63)
Total cost	Total cost of power generation facilities and gathering and processing costs.	$1.90 ($1.40 - $2.45)	$99 ($72 - $128)

*The estimated cost ranges are shown in parenthesis, point estimates are shown above.
**52.2 kcf of methane per metric ton.
***Cost ranges assumes 10-year life of power generator, generator CAPEX of $1,000/kW, and 5000 kcf/d of gas use.
Source: Rystad Energy research and analysis

The costs of gas-to-wire can be partially offset by power sales over time

Dimension	Explanation	Cost range* per kcf handled ($/kcf)	Cost range* per MT of methane flaring avoided ($/MT methane)**
Total cost	Total cost of power generation facilities and gathering and processing costs.	$1.90 ($1.40 - $2.45)	$99 ($72 - $128)
Electricity sales	Power sales would help offset the costs of power generation facilties.	$1.95 ($1.75 - $2.20)***	$102 ($91 - $115)
Net cost savings due to electricity sales	Net cost savings of gathering and processing and power generation with electricity sales (assumes no investment in other transmission infrastructure necessary).	$0.05 (-$0.70 - +$0.80)	$3 (-$37 - +$42)

*The estimated cost ranges are shown in parenthesis, point estimates are shown above.
**52.2 kcf of methane per metric ton.
***Using 2020 weighted average wholesale power prices in United States.
Note: Cost ranges assumes 10-year life of power generator, generator CAPEX of $1,000/kW, and 5000 kcf/d of gas use.
Source: Rystad Energy research and analysis

Gas-to-wire has several situational and volume requirements that make it best suited for deployment in specific circumstances

Dimension	Assessment	
Volume range	• To be a feasible option, flaring levels for a well or group of wells must surpass 5 million cubic feet per day[1] which would still result in a smaller scale plant ~ 20-30 MW. • During the first half of 2021, approximately 20% of wells that flared had a significant enough volume to meet this criteria.	> 5 million cubic feet per day
Distance to infrastructure	• Wells must have access to infrastucture so that the associated gas can be conditioned and processed before being used as a feedstock for power generation. • Additionally, there must be sufficient transmission infrastructure and grid access for power to be exported.	
Scalability	• Given the need for both gathering and processing infrastructure in addtion to grid access and approval and a longer-term stream of associated gas above a certain threshold, gas-to-wire may be more costly and difficult to scale than other abatement options.	
Situational requirements	• Multiple situational requirements pose challenges to gas-to-wire as an abatement option. The method is highly dependent on transmission and other grid infrastructure. It also may rely on contiguous acreage or a large portfolio of wells so that volumes of associated gas are sufficient over several years to run a power plant and export electricity. Additionally, there may be limitations or requirements to sell power into the grid-- the approval process for grid access may be extended, limiting the viability of gas-to-wire.	

1: Best Available Techniques Economically Achievable to Address Black Carbon from Gas Flaring
Source: Rystad Energy research and development

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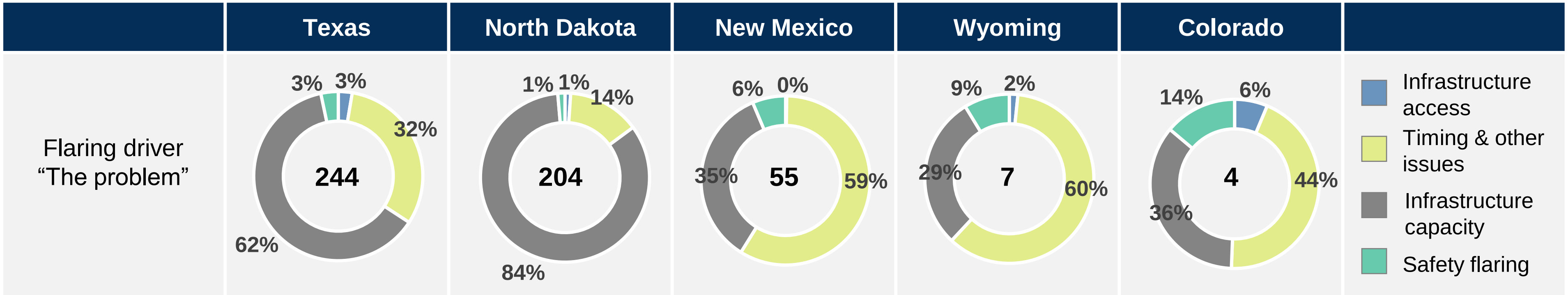
Most states have similar flaring drivers, though the significance of each varies by state

Flaring driver
“The problem”



Challenges driving flaring and current applicability across states

Flaring driver	Challenge	Description	TX	NM	ND	CO	WY
Infrastructure capacity	Gathering system constraints	Localized constraint on gathering system capacity, often due to compression	✓	✓	✓	✓	✓
	Gas takeaway capacity	Shortage of trunkline capacity to move gas in and out of producing basins. In 2018 and 2019 this was a major cause of flaring in Texas			✓		
	Gas processing capacity	Insufficient capacity to process gas from gathering systems. This was, until recently, a major problem in the Bakken					
Infrastructure access	Distance to infrastructure	Currently not a major cause of flaring. The vast majority of flaring is from wells that are, at some point, hooked up to gathering				✓	
Timing and other issues	Timing of gathering system hookup	This issue is most prevalent with smaller operators and those with 3rd-party gathering services	✓	✓	✓	✓	✓
	Flaring from downstream outages	Often caused by gas plant outages or gathering system compressor outages	✓	✓	✓	✓	✓

Source: Rystad Energy research and analysis

Flaring reduction requires a broad-based approach addressing both operational and commercial issues

Broad-based solutions to flaring reduction

No single solution—must address both operational and commercial challenges

Operational aspects

- Connection of wells to gathering prior to start up
- Right-sized equipment and facility capacity; equipment reliability
- Fast response to outages
- Application of alternative abatement measures when faced with constraints outside of operator's direct control
- Close collaboration with gatherers, processors and trunkline operators

Commercial aspects

- Gathering, processing and transport contracts that ensure firm capacity and penalizes downtime from 3rd parties

Source: Rystad Energy research and analysis

The operators most successful at reducing flaring have adjusted both operations and commercial agreements

The operators most successful at reducing flaring have achieved success through a change in mindset from viewing flaring as a part of normal operations to viewing flaring as a *constraint* on operations. Treating flaring as a constraint that must be avoided has brought about a variety of changes to how companies operate and structure agreements with gatherers, processors and pipeline operators.

Examples from conversations with operators

Dimension	Details
Operational changes to reduce flaring	• Requiring that wells *must* be connected to gas gathering prior to start up. • Choking or shutting in wells in the face of issues downstream (such as compressor failure or gas plant outage). Shutting in temporarily has been observed to have little effect on future well productivity or NPV. • Regularly coordinating with 3rd parties and off-takers to ensure alignement and prevent constraints before they occur. • Measure and record flaring data in a way that allows operators to identify and address issues.
Commercial agreement changes to reduce flaring	• Negotiate terms with midstream gatherers and processors that incentivizes higher uptime and penalizes constraints that lead to flaring. This has led midstream gatherers to improve reliability by, for example, adding spare compression capacity to gathering systems. • Ensure that contracted capacity on trunkline pipelines matches development plans.

Source: Rystad Energy research and analysis

Each challenge has different operational and commercial facets; large operators and small operators have different abilities to influence these

Addressing challenges and constraints through the most ubiquitous abatement method—pipeline gathering—requires a mix of operational changes and changes to commercial terms with 3rd parties.

Large operators may have greater influence over 3rd parties than smaller operators. The solutions nonetheless remain available for smaller operators.

Flaring driver	Challenge	Addressing through operations	Addressing through commercial terms	Difference for small vs large operators
Infrastructure capacity	**Gathering system constraints**	If the operator owns the gathering system they can expand capacity	For 3rd-party gathering, must negotiate terms that ensure sufficient capacity	Large operators more likely to operate gathering and have more influence over 3rd parties
	Gas takeaway capacity	Build or invest in pipelines	Contract sufficient firm capacity	Only economic for large operators to build takeaway pipelines; small operators reluctant for take-or-pays
	Gas processing capacity	Build or invest in processing plants	Contract sufficient firm capacity	Only economic for large operators to build plants; small operators reluctant for take-or-pays
Infrastructure access	**Distance to infrastructure**	Higher cost required to build gathering infrastructure	Must pay higher rates to 3rd parties	Similar challenge for both large and small operators
Timing and other issues	**Timing of gathering system hookup**	Do not produce wells that are not connected; ensure connections in place	Contracts must incentivize 3rd party gathering in timely manner	Large operators more likely to operate gathering and have more influence over 3rd parties
	Flaring from downtime	Choke or shut in wells during downtime	Contracts must incentivize uptime through, e.g., backup compression	Large and small operators can shut in wells in the face of downtime events

Source: Rystad Energy research and analysis

Gathering, CNG and injection are the most broadly capable technologies given costs, scalability and applicability

CNG and injection could address the major challenges that lead to flaring

Type	Challenge	Gathering	CNG	LNG	Gas-to-wire	Injection
Infrastructure capacity	Gathering system constraints	✓	✓	✓		
	Gas takeaway capacity		✓	✓	✓	✓
	Gas processing capacity		✓	✓		✓
Infrastructure access	Distance to infrastructure		✓	✓		✓
Timing and other issues	Timing of gathering system hookup	✓	✓	✓		
	Flaring from downstream outages		✓	✓		✓

Gathering:
Lowest cost, though doesn't provide a solution to many of the challenges

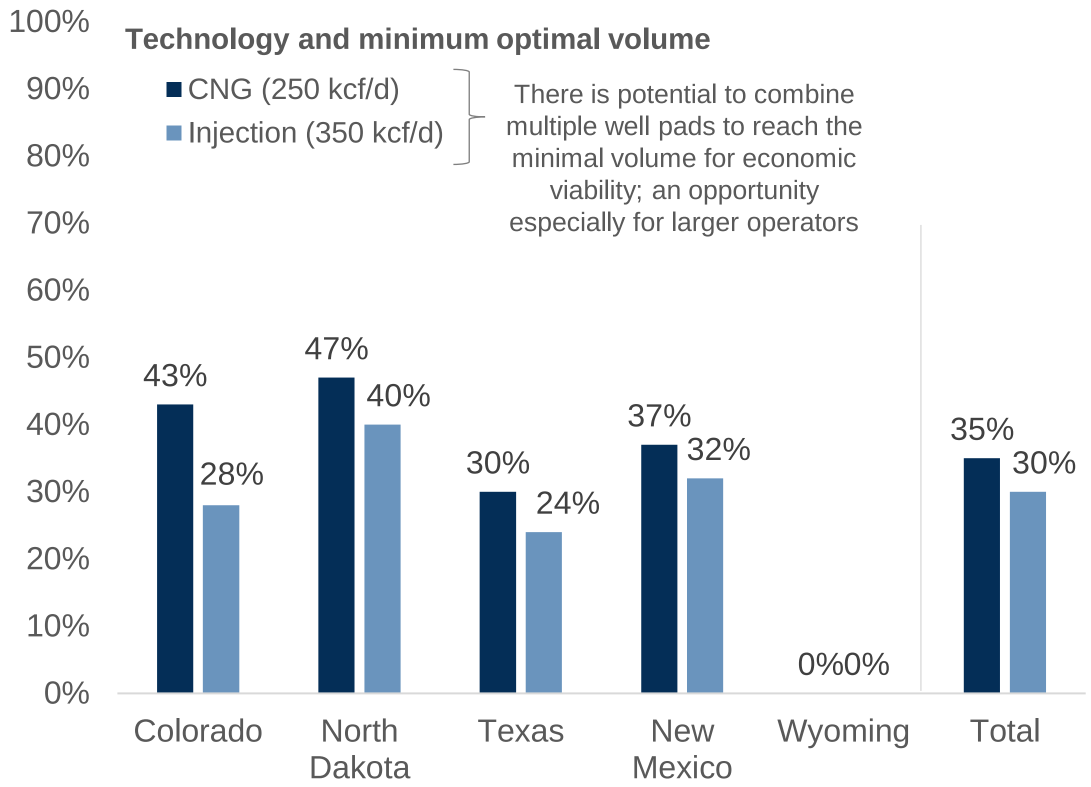
CNG:
Able to overcome most challenges leading to flaring, though at higher cost. Preferred to LNG due to lower scale requirements.

Injection:
Able to overcome many challenges, though has situational requirements on availability of suitable reservoirs

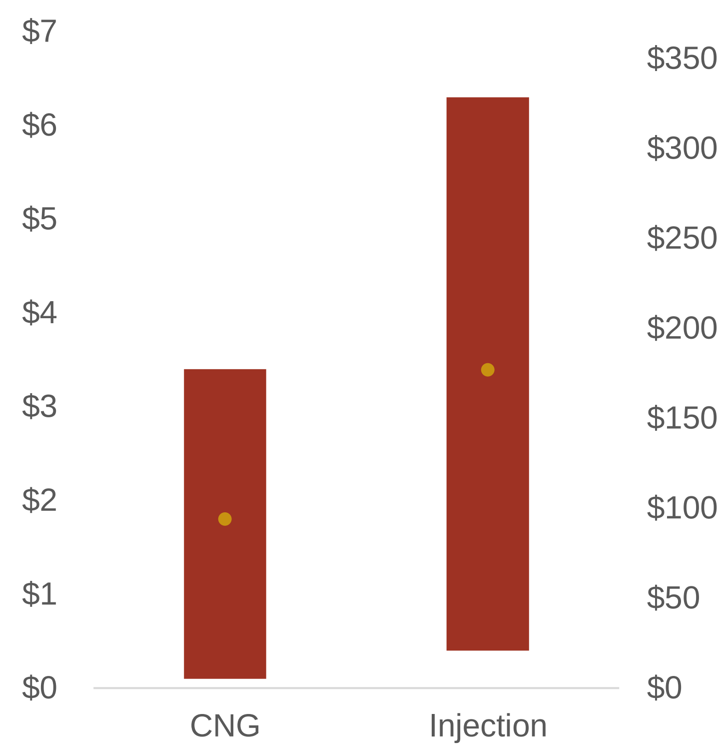
Source: Rystad Energy research and analysis

CNG and injection could address 30%-35% of all flaring in the relevant states

% of flaring from well pads flaring above minimum abatement threshold
Percentage



Net cost range by method*
$/kcf
$/Mt methane



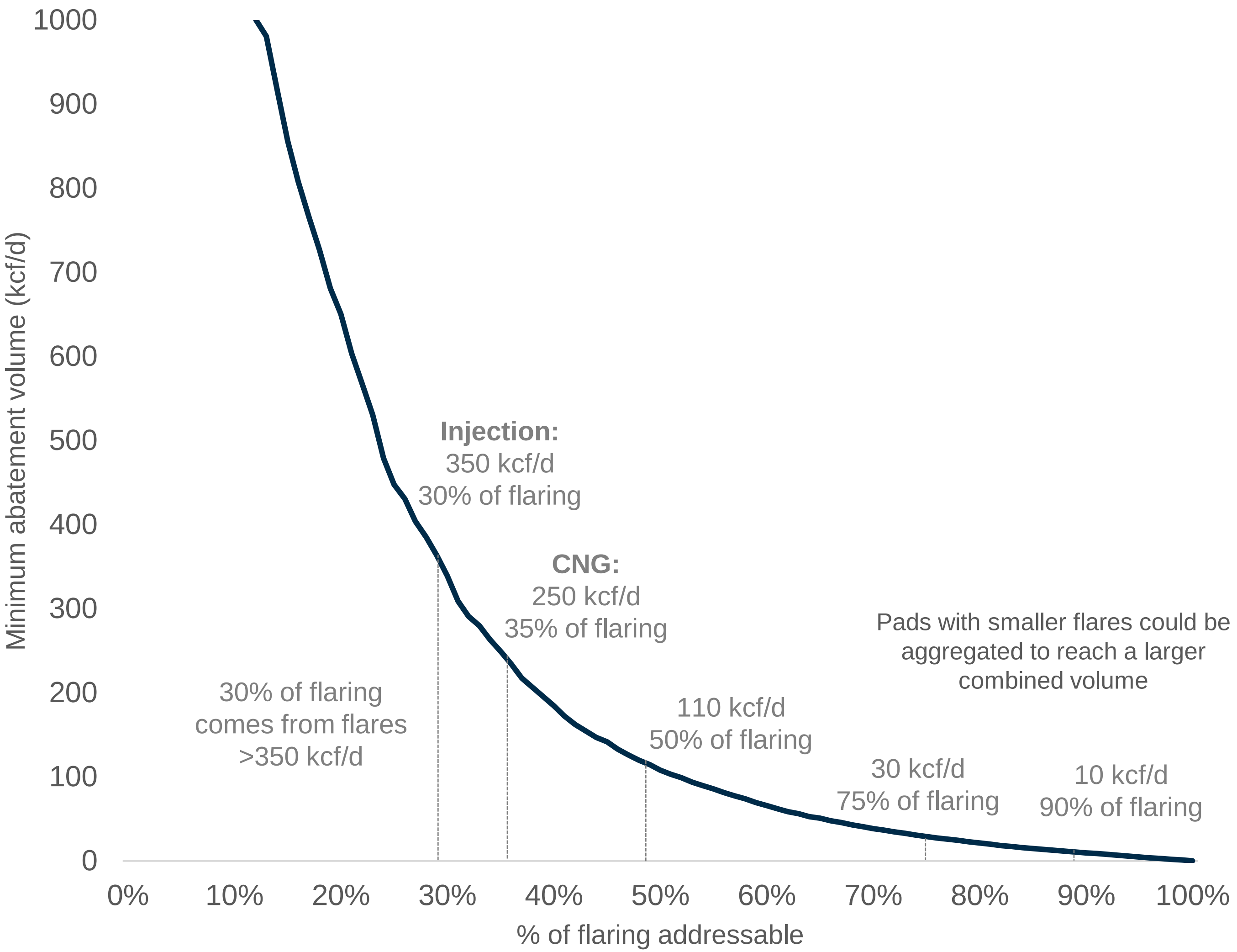
Given minimum optimal volumes for CNG and gas injection abatement methods, the methods could be applied to abate 30-35% of US flaring.

Minimum volumes represent the low end of size for modular CNG equipment or for the size of a small injector well. Some well pads could be aggregated to increase the applicability of abatement methods. Abatement costs tend to be on the higher end of range estimates when operating at minimum volumes.

*Net cost includes revenue from sales gas and NGLs for CNG.
Source: Rystad Energy research and analysis

Abating a larger share of flaring requires also addressing smaller flares – accomplishable by aggregating smaller flares or abating at higher costs

Percentage of flaring addressable for given minimum abatement volume

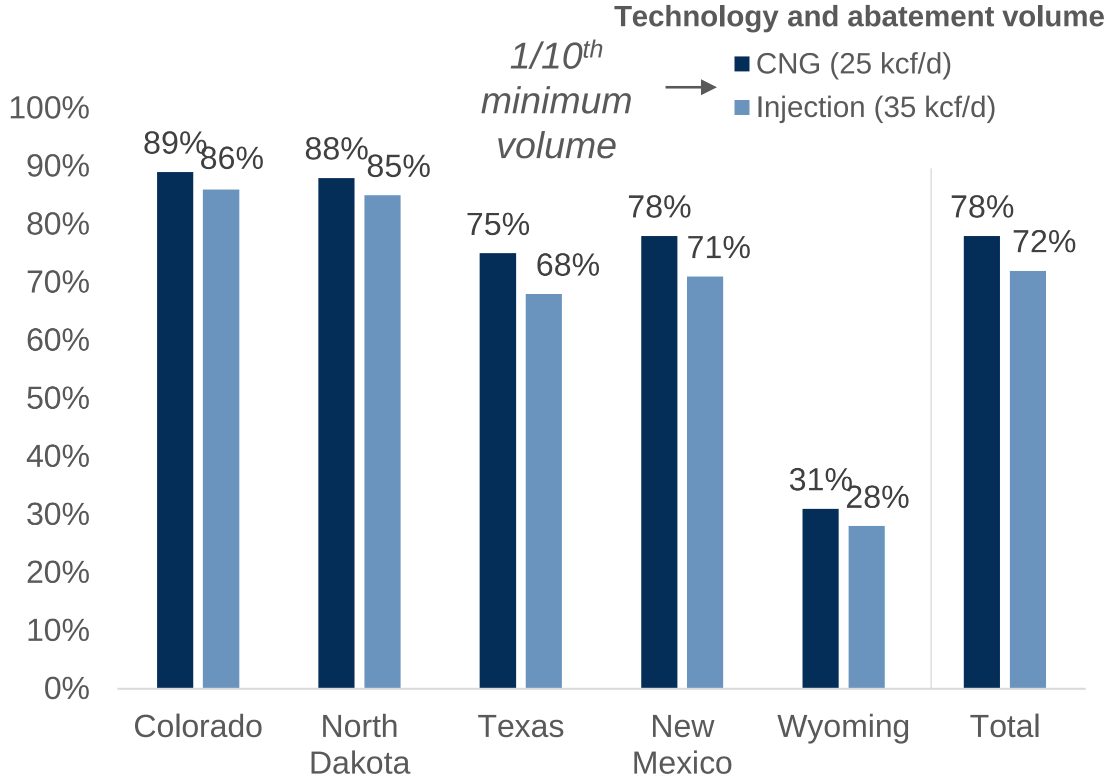


- Addressing a higher share of flaring requires lower minimum abatement thresholds.
- While 30% of flaring comes from well pads flaring >350 kcf/d, the minimum level for injection, smaller flares will also need to be addressed to prevent a larger portion of flaring.
- To prevent 90% of flaring would require abating flaring from pads flaring as little as 10 kcf/d.
- There is a potential opportunity to combine multiple well pads to reach minimum abatement thresholds.

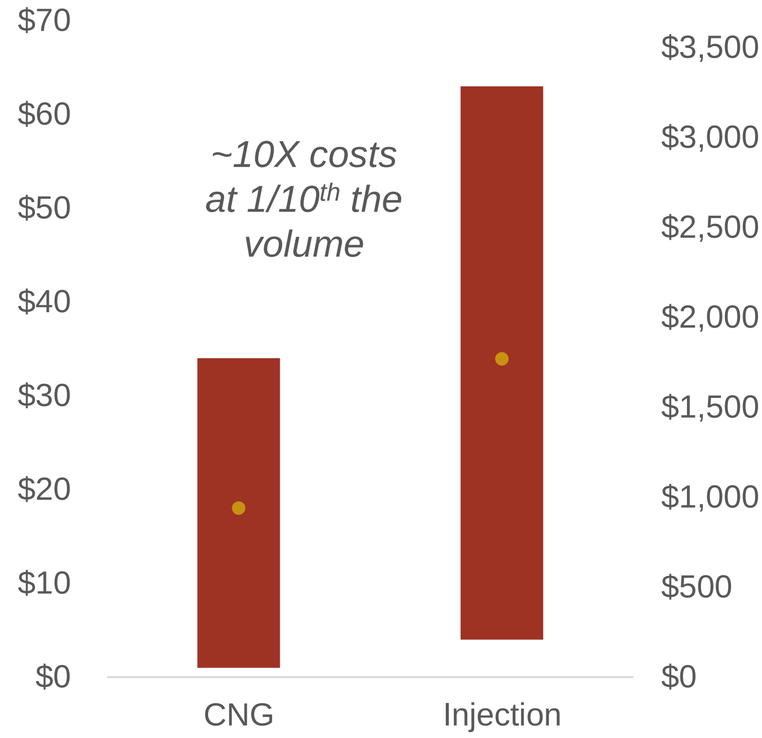
Source: Rystad Energy research and analysis

Handling smaller flares with CNG and injection would increase abatement, but also costs

% of flaring from well pads flaring above minimum abatement threshold
Percentage



Net cost range by method*
$/kcf
$/Mt methane



Operating at 1/10th of the minimum optimal abatement volume of the technologies could abate 72-78% of flaring across the 5 states, but at roughly 10x the cost for the smallest flares captured.

Costs scaled up linearly with change in minimum volume to account for underutilized capacity and higher unit costs.

*Net cost includes revenue from sales gas and NGLs for CNG.
Source: Rystad Energy research and analysis

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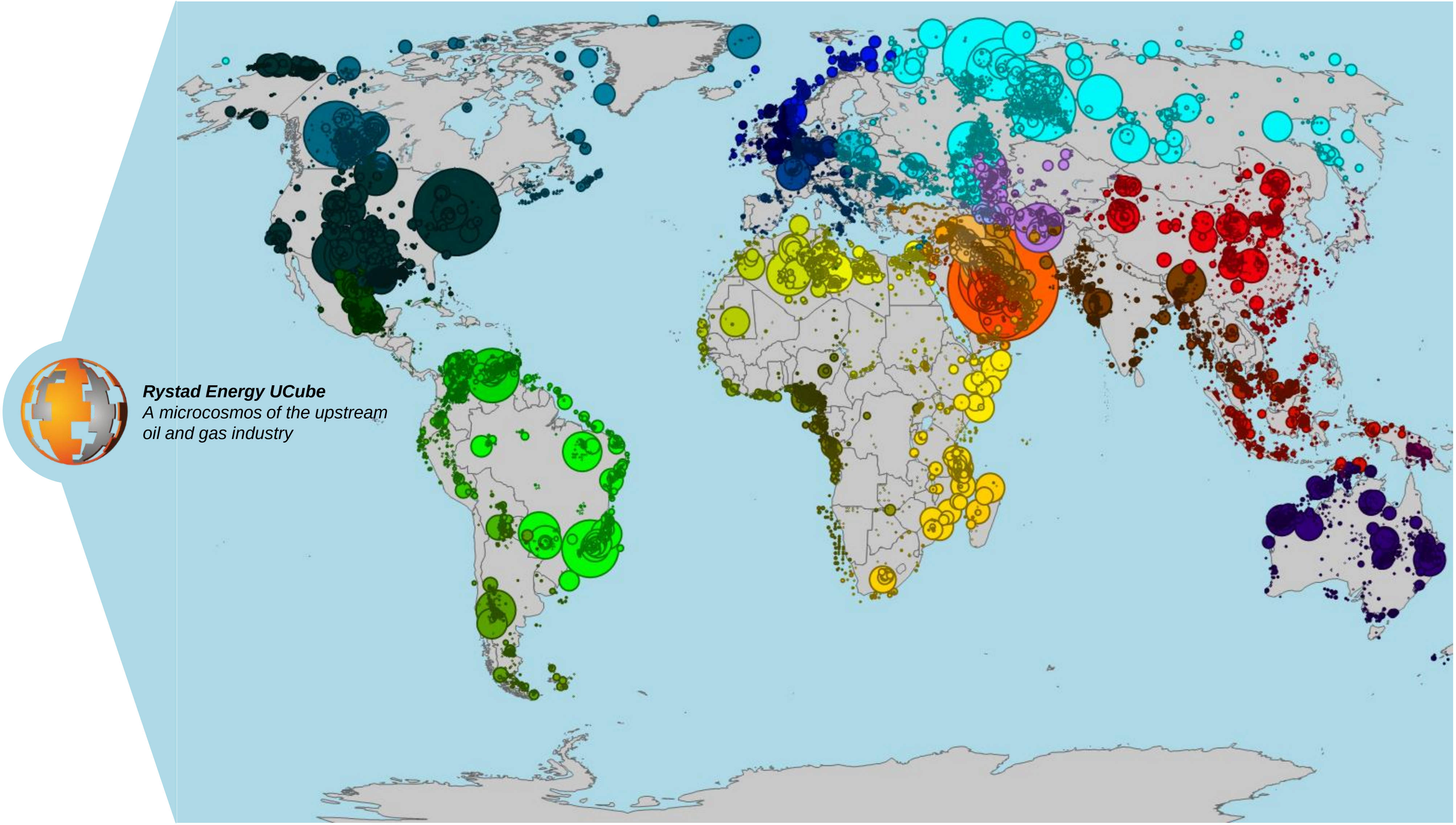
CNG and gas injection could be important parts of a broader solution to reduce flaring

Flaring is primarily driven by infrastructure capacity constraints	Infrastructure capacity constraints account for 84% of flaring in North Dakota and 62% of flaring in Texas, the two highest flaring states.
Gathering is key, but CNG and gas injection can circumvent downstream issues	Gas gathering to market is the key method of abatement. However, CNG and injection can overcome downstream capacity constraints such as insufficient processing or takeaway capacity.
CNG and gas injection have their own challenges	CNG and injection are most economical when capturing a large volume of gas, though could capture smaller volumes at a higher cost. Gathering production from multiple well pads could make CNG and injection more effective. However, CNG for flare abatement is an immature industry and gas injection requires availability of a suitable reservoir.
Reducing flaring can be accomplished through a number of different avenues	A combination of changes to operations, changes to commercial agreements and the application of technologies such as CNG and injection are required to reduce flaring.

Source: Rystad Energy research and analysis

Approach: Oil and gas emissions analyzed by using Rystad Energy UCube – A complete, bottom-up upstream database covering more than 65,000 upstream projects

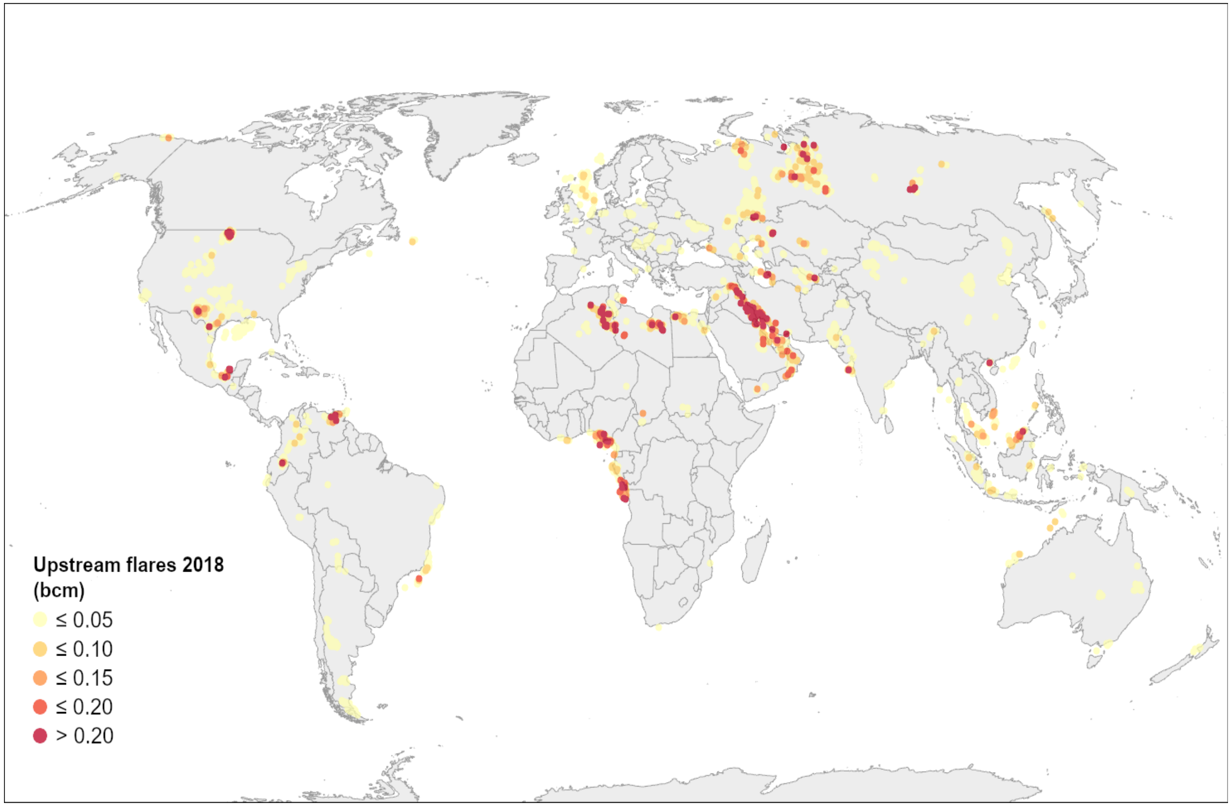


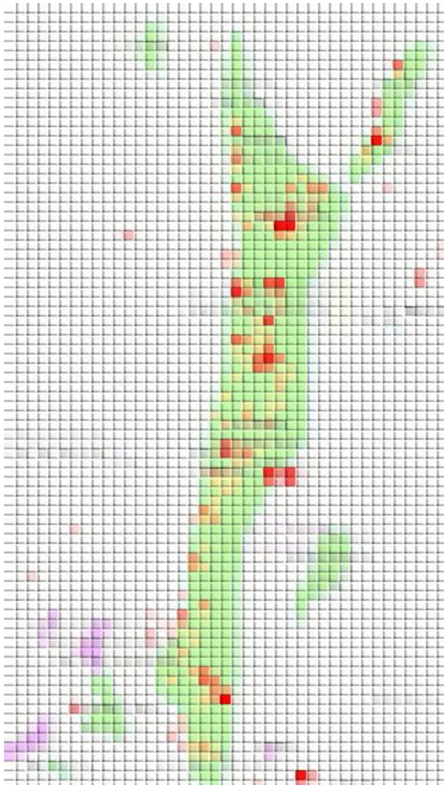
* Map shows global remaining oil and gas resources (2020), split by location of projects. Circle size indicates amount of resources. Source: Rystad Energy research and analysis

Satellite flaring data is also mapped to each asset by field shapes

Upstream flaring

Satellite flaring imagery



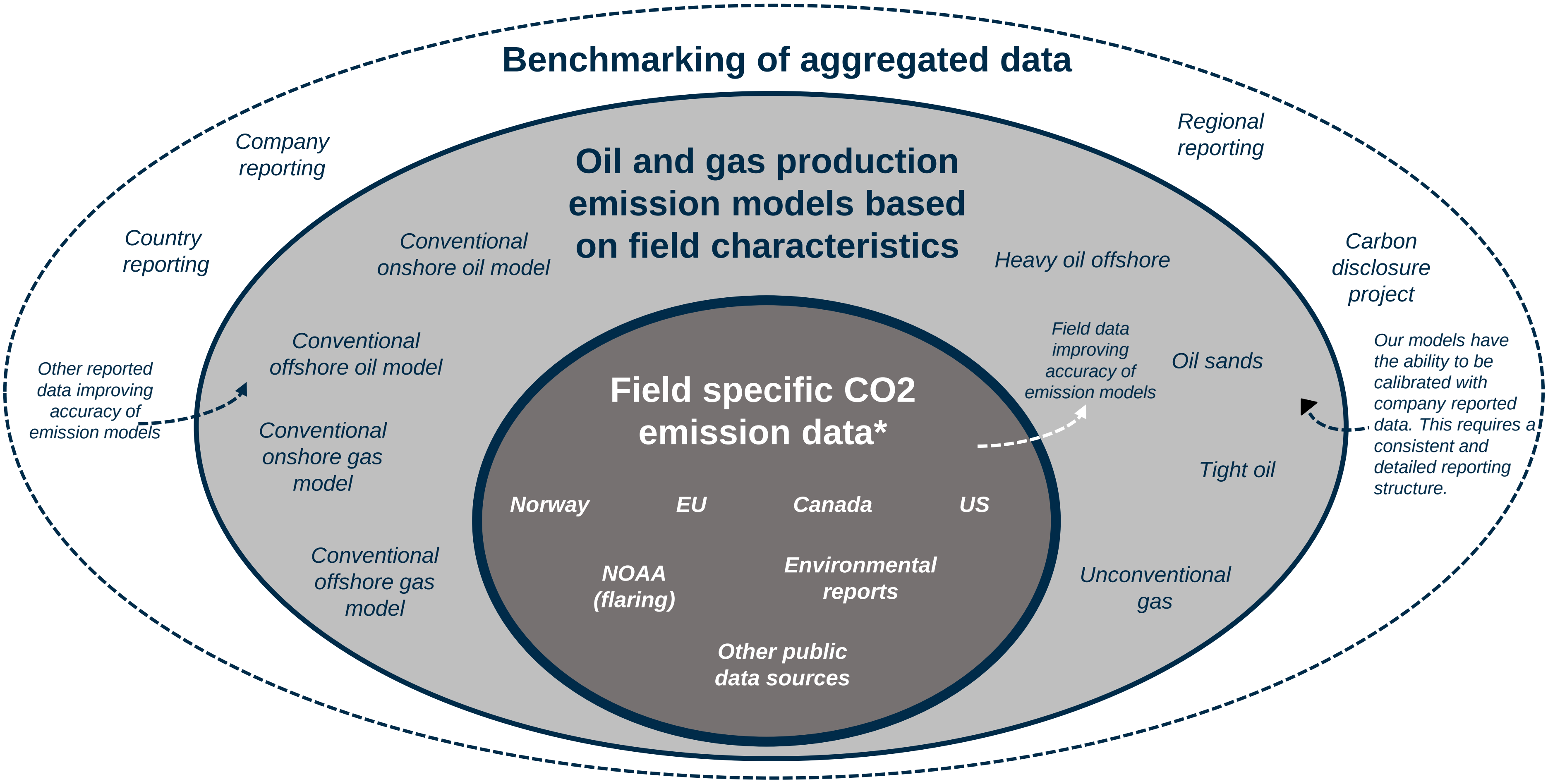


Description	**Flaring:** The flaring model is based on satellite data from the US National Oceanic and Atmospheric Administration (NOAA) and reported data by operators and governments. Based on infrared emissions, NOAA and its partners have estimated flaring volumes globally. Rystad Energy has via asset coordinates and field shapes/footprint mapped (GIS) these locations to UCube "assets", which has enabled modelling of flaring volumes for all fields globally based on "scouted"* data, this is matched with reported data (where available) to ensure accuracy.

*Reported field level data/matched satellite data. Source: Rystad Energy research and analysis; NOAA

Rystad Energy methodology complements and incorporates a wide range of sources

Upstream		Midstream			End-use combustion
Exploration	Production	Transport	Processing	Transport	



* Selected examples. Source: Rystad Energy research and analysis

Rystad uses alternate data sources to offset limitations and fill gaps in state-reported data

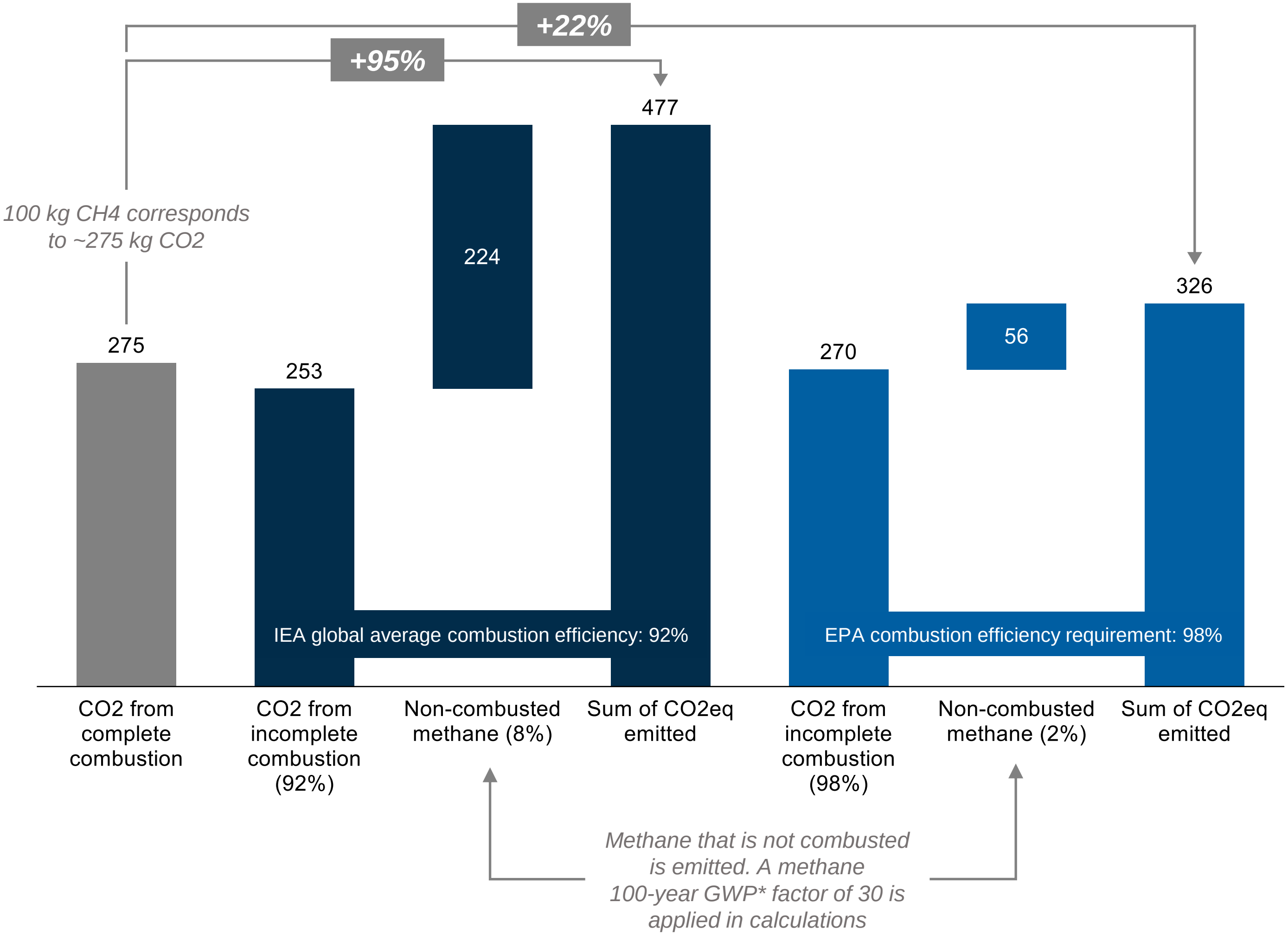
State	Source of flaring data
Colorado	Colorado Oil and Gas Conservation Commission
New Mexico	New Mexico Oil Conservation Division
North Dakota	North Dakota Industrial Commission
Texas	Railroad Commission of Texas
Wyoming	Wyoming Oil and Gas Conservation Commission

- Flaring data is reported in each state which provides a starting point for Rystad Energy's coverage of flared volumes.
- Reported volumes may be imperfect due to factors such as differing regulations on the state-level, potential grey area in reporting requirements, and even non-compliance in some cases.
- However, Rystad Energy performs detailed reviews of the reported data and then uses VIIRS[1] data and other modelling to help fill-in gaps in reporting such as non-complying producers.
- Methods used to identify reporting irregularities include, for example, applying Benford's law and comparing VIIRS data trends to reported values.

1: Visible Infrared Imaging Radiometer Suite
Source: Rystad Energy research and analysis

Flaring emissions increase drastically when adjusting for inefficient combustion

Comparing GHG emissions from complete combustion and incomplete combustion of 100 kg methane
Kg CO2 equivalents

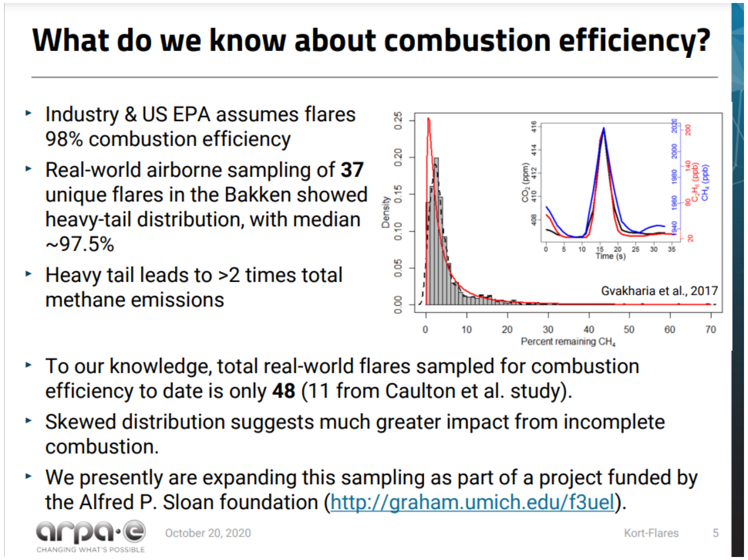


- Methane emissions play a significant role when considering emissions – as non-combusted methane impacts global warming notably
- The IEA has estimated a global average combustion efficiency of ~ 92%, when including both normally operating and extinguished flares. This would increase GHG emissions from flaring by +95%, measured in CO2 equivalents
- The EPA combustion efficiency requirement of 98%, assures better emission performance for methane with ~20% increase in total flaring GHG emissions
- Rule of thumb: A decrease of one % point in flare combustion efficiency corresponds to a ~10% increase in CO2eq emitted from flaring using a 100-year GWP. The impact over the next two decades (20-year GWP) is however 83, implying that flaring efficiency is of high importance.

*Global Warming Potential.
Source: Rystad Energy research and analysis; IEA; EPA, IPCC AR6

Efficiency of flares is often assumed at 98%, but real-life data is very limited

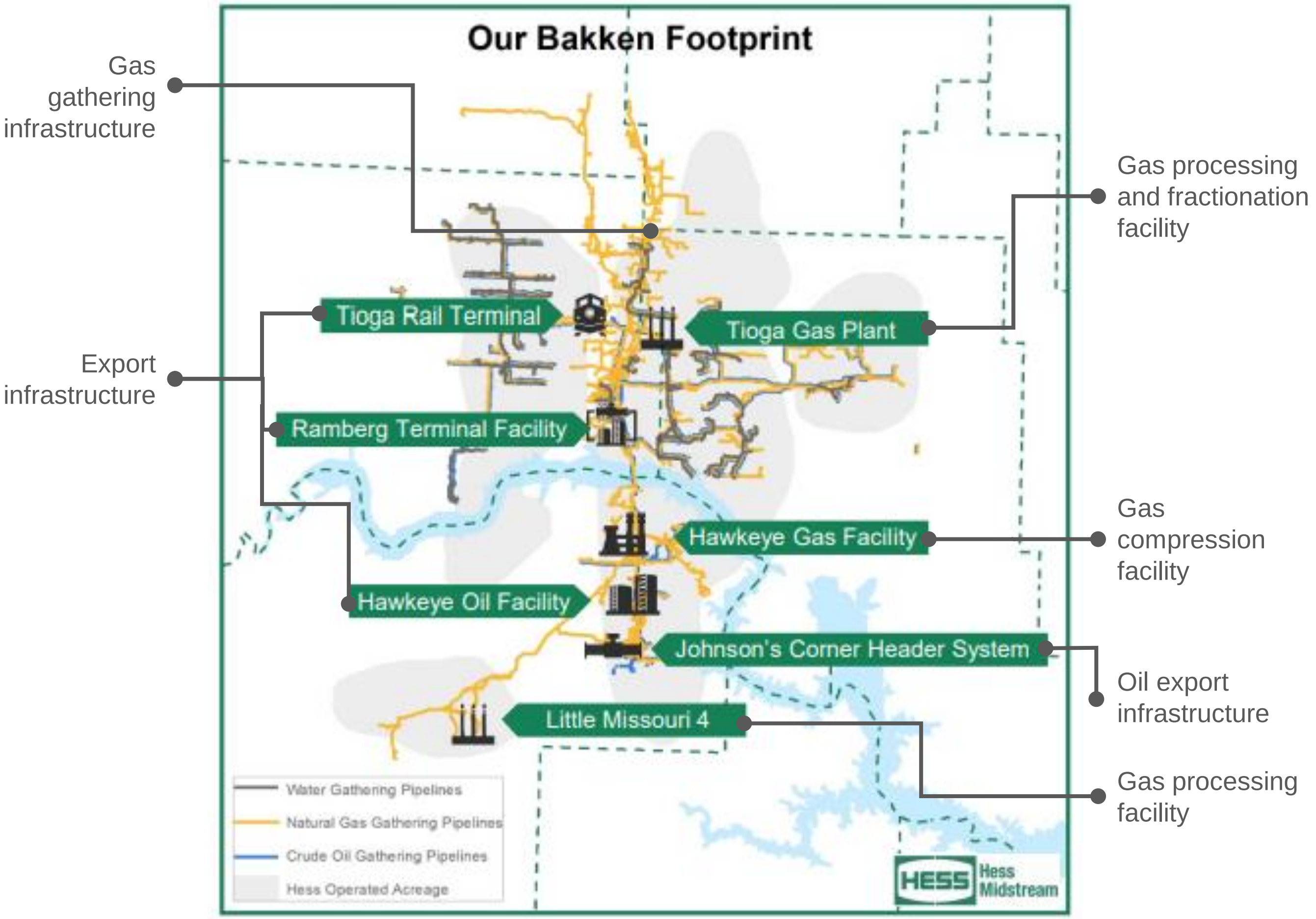
- Real-life flaring efficiency has a profound impact on the actual flaring GHG emissions.
- Flare monitoring is not common, meaning operational data on flares is scarce. Laboratory-testing implies that properly designed flares can achieve combustion efficiencies of around 98%.
- Real-life research based on a very limited sample implies that this figure is not unreasonable for lit flares. This does however not include the vented gas from unlit flares.
- Consequently, understanding the efficiency of flares is a key first step in addressing methane emissions from flares. The technology needed to measure flare combustion efficiency is available.



Source: Rystad Energy research and analysis, University of Michigan – Arpa-E - Kort, IEA, Baker Hughes, EPA, Environ. Sci. Technol. 2017, 51, 9, 5317–5325 ("Methane, Black Carbon, and Ethane Emissions from Natural Gas Flares in the Bakken Shale, North Dakota")

Integration across the value chain supports long-term reductions in flaring; Hess invested over $3bn in infrastructure to reduce flaring in ND between 2014-2021

Hess Bakken infrastructure footprint, January 2022



- Some operators have elected to invest in local infrastructure to reduce flaring.
- Hess has invested significant capital to expand gas gathering and processing capacity near the company's operated acreage in the Bakken over the last several years.
- Recent investments have included an expansion of the Tioga Gas plant from 250 MMcfd to 400 MMcfd and an added 140 MMcfd of gas compression capacity in North Dakota.
- Hess has announced plans to spend a further $235 million USD during 2022 on gathering and compression infrastructure in the Bakken.

Source: Rystad Energy research and analysis; Company reporting

State level incentives can bolster efforts to reduce flaring and test abatement methods; North Dakota has supported multiple projects to test gas injection and EOR

Project	Description	
EERC and XTO partned on gas injection and EOR pilot projects	EERC | UND UNIVERSITY OF NORTH DAKOTA	• EERC partnered with XTO on an EOR pilot in the Bakken to test the effects of produced gas on crude properties.[1] • EERC also partnered with XTO in Minnelusa on a gas storage pilot project with consideration of injection rates, gas conditioning and compression requirements, and permitting.[1]
EOG receives approval for EOR test project	**North Dakota Industrial Commission approves project aimed at reducing flaring**	• In January 2022, the North Dakota Industrial Commission (NDIC) approved a proposal by EOG to test on-site compression to inject associated gas underground as a method to reduce flaring.[2]

1: EERC and UND Report "Produced Gas injection as Mechanism to Reduce Flaring", June 2020
2: KYFR News "North Dakota Industrial Commission approves project aimed at reducing flaring", January 2022
Source: Rystad Energy research and analysis

Operator planning and efficiency key in reducing flaring—improving timing of production start and using associated gas on-site are useful reduction measures

Theme	Operator comments
Timing production with infrastructure availability helps avoid flaring	"We accomplished this by developing gas sales plans for each new well. Many times, we delayed production on new wells until pipeline infrastructure was in place and shut in wells where gas delivery became restricted. As a result of these efforts, Continental improved its companywide, volumetric gas capture percentage to 98.3%, up from 96.2% in 2019-- " -Continental Resources ESG Report, 2020
Using associated gas on-site helps to use volumes that would otherwise be flared	"In certain areas, we install electricity infrastructure to permit the use of electric-powered (versus fuel-powered) equipment." -EOG Sustainability Report, 2020

Source: Rystad Energy research and analysis; EOG Sustainability Report 2020; Continental Resources 2020 ESG Report

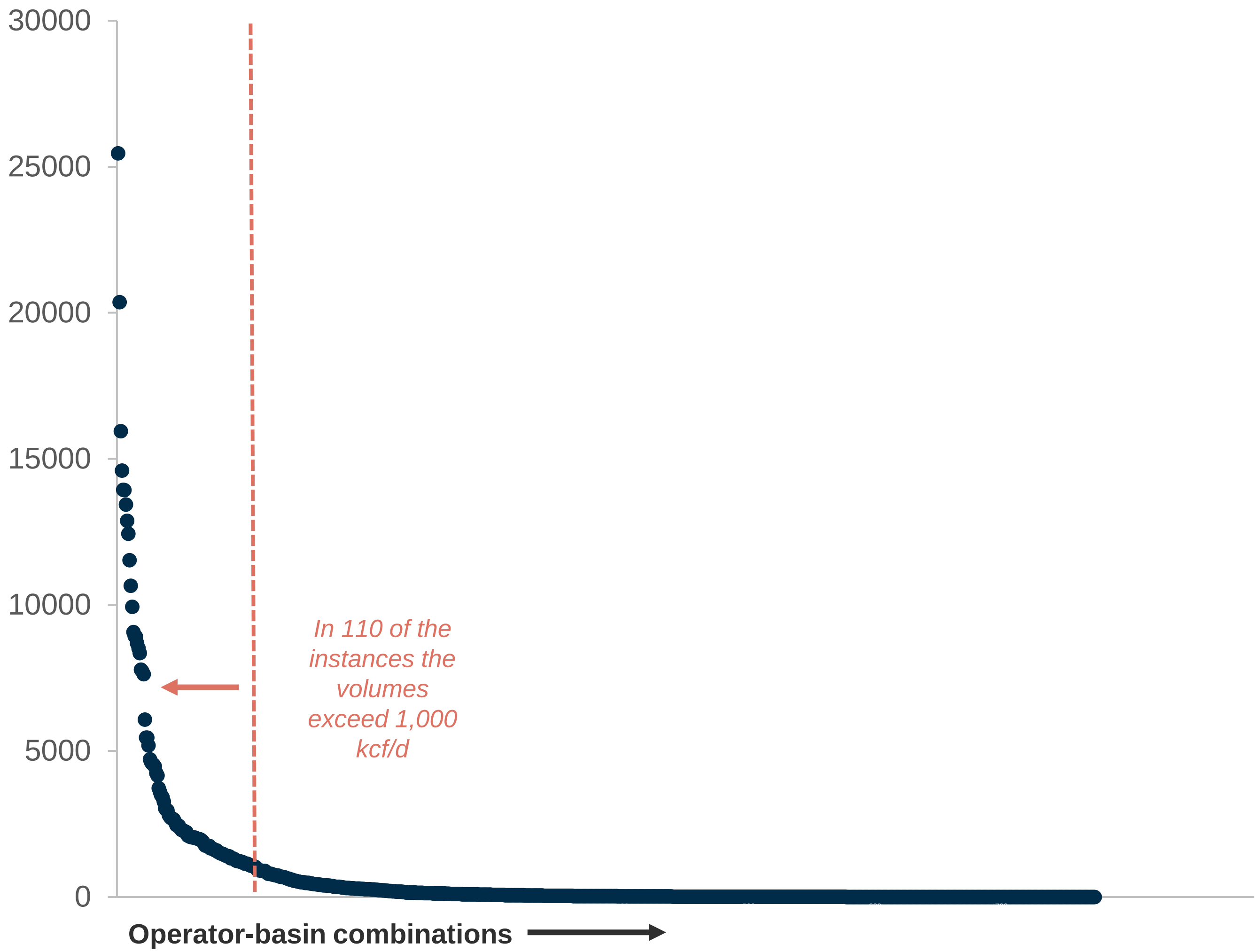
Value of rich gas streams varies by gas netback, NGL content and NGL netback

	NGL content (gal/kcf rich gas)	NGL netback price[1] ($/gal)	Dry gas content (dry gas/rich gas)	Local gas price[2] ($/kcf)	Value of rich gas stream ($/kcf)
Texas	3.9	0.46	80%	2.7	4
New Mexico	2.7	0.43	93%	2.7	3.7
North Dakota	6.1	0.25	89%	2.8	4
Colorado	3.1	0.28	93%	2.7	3.4
Wyoming	1.3	0.25	86%	2.7	2.6

1: NGL netback price assumptions are based on expected 2022-2025 average Mt. Belvieu NGL prices minus transportation costs and fractionation costs.
2: Gas price assumptions are based on expected 2022-2025 average Henry Hub natural gas prices and historical spreads to the Henry Hub price for each state
Note: Netbacks do not include processing costs, as those are captured by gathering & processing costs. NGL contents vary over time, the numbers presented here are from H1 2021.
Source: Rystad Energy research and analysis; Bloomberg

Several operators have significant flaring volumes within a basin, giving scale opportunities

Sorted basin level flaring volumes by operator (TX, ND, NM, WY and CO)
Thousand cubic feet per day (kcf/d)



- When focusing in on the operators that report flaring in the TX, ND, NM, WY and CO basins, it is clear that most operators report low flaring volumes.
- However, in 110 of the instances the reported flaring volumes exceed 1,000 kcf/d. This indicates that implementing abatement technologies with higher volume requirements might be a viable solution. Additionally, the high volumes also represent a potential for economies of scale when implementing these abatement technologies.

Source: Rystad Energy ShaleWellCube

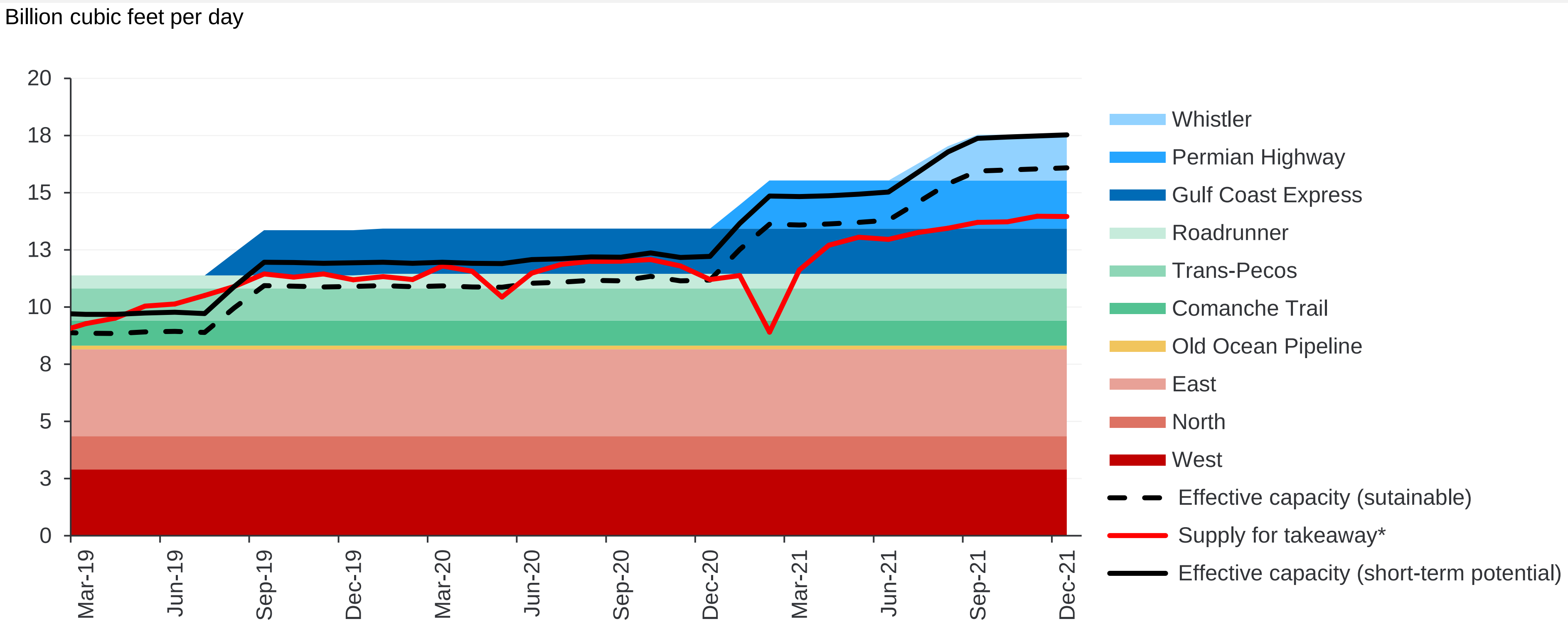
Overview of cost estimation methodology for each technology

Abatement method	Cost estimation approach	Reason for cost variation	External sources
Pipeline gathering	Costs based on known gathering and processing fees charged across US onshore basins.	Costs generally vary due to differences in the cost of infrastructure, which is driven by distance and density of wells, among other factors. Processing fees vary by processor, geography and contract terms.	• G&P company reporting • Known gathering rates from experience working with US midstream operators and investors
On-site use	Costs are estimated for a small turbine based on a conservative estimate for power requirements for a multi-well pad. 5-year lifetime assumed. Net savings is estimated based on maximum potential using 100% fuel switching.	The cost range varies to account for differences for on-site demand and and CAPEX costs per kW. Net savings ranges based on variables including the cost of alternative fuels.	• Carbon Limits Improving utilization of associated gas in US tight oil fields
Gas-to-wire	Costs are estimated based on the assumption of a 5 MMcf/d minimum flaring requirement for viability. 10-year lifetime assumed. Net savings factors in electricity sales which use 2020 weighted average wholesale power prices for US grids.	Variation is costs stems from varying plant capacities and efficiencies. Variation on savings depends on regional wholesale power prices.	• Best Available Techniques Economically Achievable to Address Black Carbon from Gas Flaring: EU Action on Black Carbon in the Arctic - Technical Report 3
On-site compressed natural gas (CNG)	Costs are estimated for the smallest system with 250 kcf/d capacity and 200 miles transportation. This gives an estimate of the highest unit cost for a small scale CNG system. Unit costs would decrease for larger systems. 10-year lifetime and 80% utilization assumed for modules.	There is a variation in the cost estimate to account for potential differences in quality of associated gas, varying end-user requirements or alternative systems.	• GGFR - Utilization of Small-Scale Associated Gas; GGFR - Comparison of Mini-Micro LNG and CNG for commercialization of small volumes of associated gas; and related papers. • Carbon Limits - Improving utilization of associated gas in US tight oil fields.
On-site liquefied natural gas (LNG)	Costs are estimated for the smallest system with 700 kcf/d capacity and 200 miles transportation. This gives an estimate of the highest unit cost for a small scale LNG system. Unit costs would decrease for larger systems. 10-year lifetime and 80% utilization assumed for modules.	There is a variation in the cost estimate to account for potential differences in quality of associated gas, varying end-user requirements or alternative systems.	• GGFR - Utilization of Small-Scale Associated Gas; GGFR - Comparison of Mini-Micro LNG and CNG for commercialization of small volumes of associated gas; and related papers. • Carbon Limits - Improving utilization of associated gas in US tight oil fields.
Gas injection	Costs are estimated for a single injection well assuming aggregated volumes from several production wells can be injected. They are based on a 350 kcf/d minimum flaring requirement for viability and a 10-year lifetime. Total costs include gathering costs.	The cost range reflects injection volumes ranging from the minimum abatement volume (350 kcf/d) up to the higher flaring volumes seen by operators* (~10,000 kcf/d).	• EERC - Produced gas injection as mehanism to reduce flaring

*Several operators flare at significant volumes within certain basins, the high volumes represent a potential for economies of scale.
Source: Rystad Energy research and analysis

Lower production means less strain on the export system

Permian dry gas production and takeaway capacity outlook

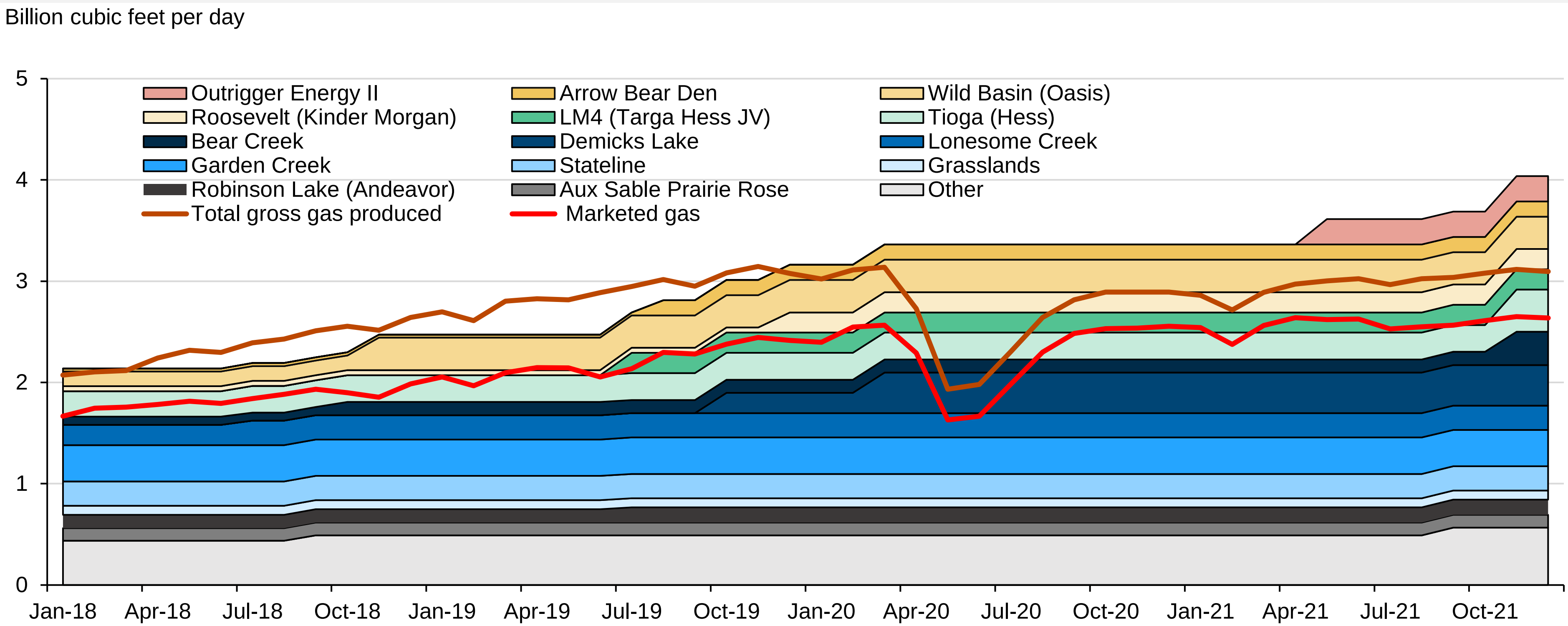


- Permian gas production has for a long time been limited by the available capacity in the export system. This has been a key reason why companies have flared, they simply were unable to find offtake for their gas.
- The drop in activity and subsequently production in 2020 (and 2021), allowed gas infrastructure to catch up with production.
- Currently, effective takeaway capacity is about 2 bcf/d above the production level.

*Difference between Permian dry gas output and regional gas consumption **Effective capacity assumes gradual build-up in West Texas to Mexico exports from 1.4-1.45 to 2 billion cfpd **Short-term potential for effective capacity assumes that all takeaway pipelines are flowing 10% above nameplate capacity levels, Source: Rystad Energy ShaleWellCube

North Dakota now has significantly more processing capacity than production

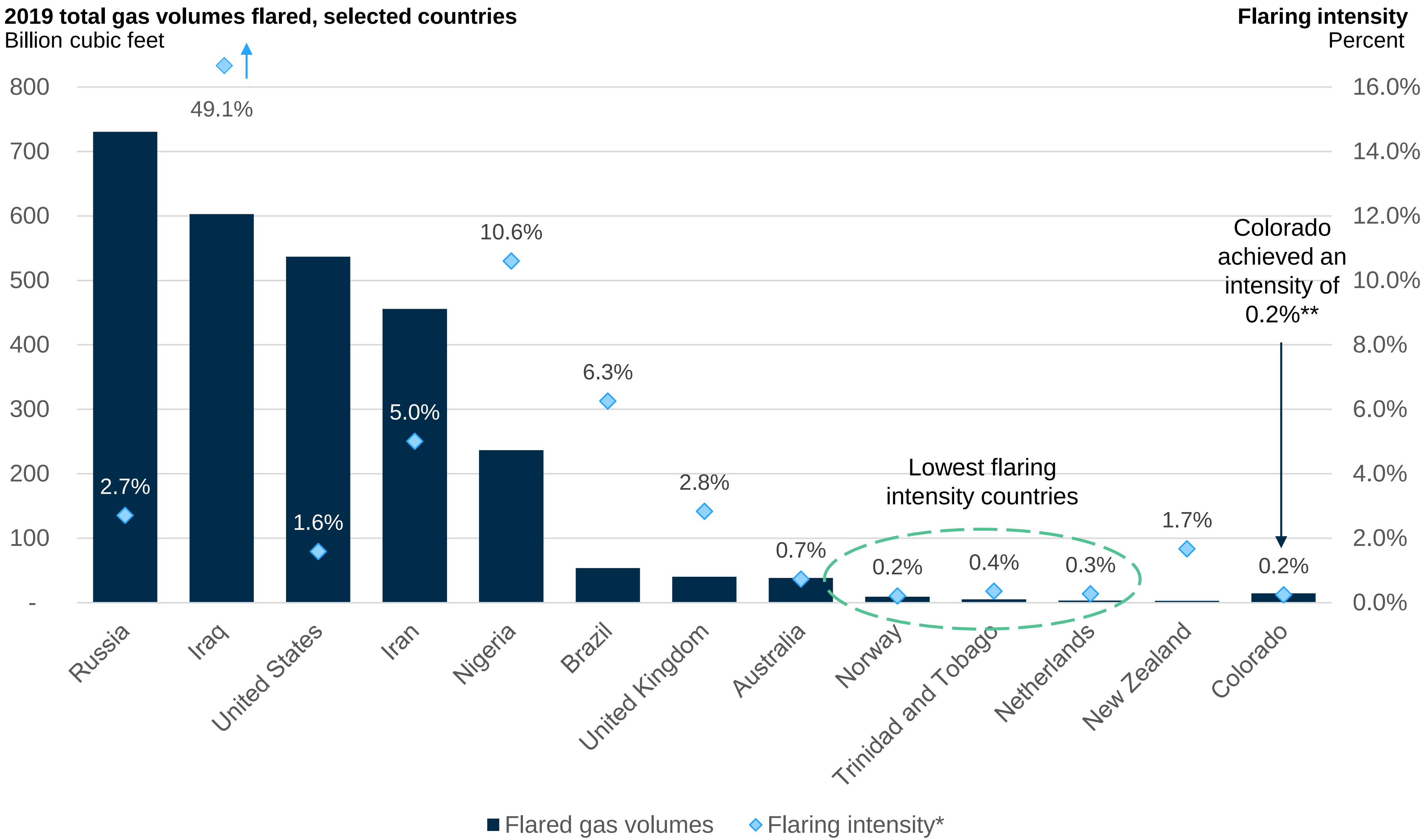
North Dakota natural gas processing capacity and production



- 2020 saw significant improvement in Bakken gas flaring intensity which resulted in marketed or sold gas output returning to pre-COVID peak levels faster than the gross gas output, which is yet to achieve such milestone. Following Outrigger's 250 million cfpd gas plant completion in early 2021, it appears that both ONEOK and Hess are on track to start commercial service on their recently completed expansion projects: Bear Creek and Tioga, respectively.
- We estimate that both projects will start providing significant contribution to the actual processed volumes in the state at some point in 4Q21.
- This brings total gas processing capacity in the state to 4 billion cfpd, though one needs to remember that due to variability in maintenance cycles, it is rarely the case that the entire capacity is available for processing at any given point of time. For example, in July 2021, summer maintenance on several independent plants was actually one of the factors contributing to unusual production drop in the states along with increased gas flaring levels.

*Includes base case estimates for 4Q21
Source: ND Pipeline Authority, Rystad Energy research and analysis, Rystad Energy ShaleWellCube

International examples, and results from Colorado, indicate that flaring intensities of 0.2-0.4% is possible

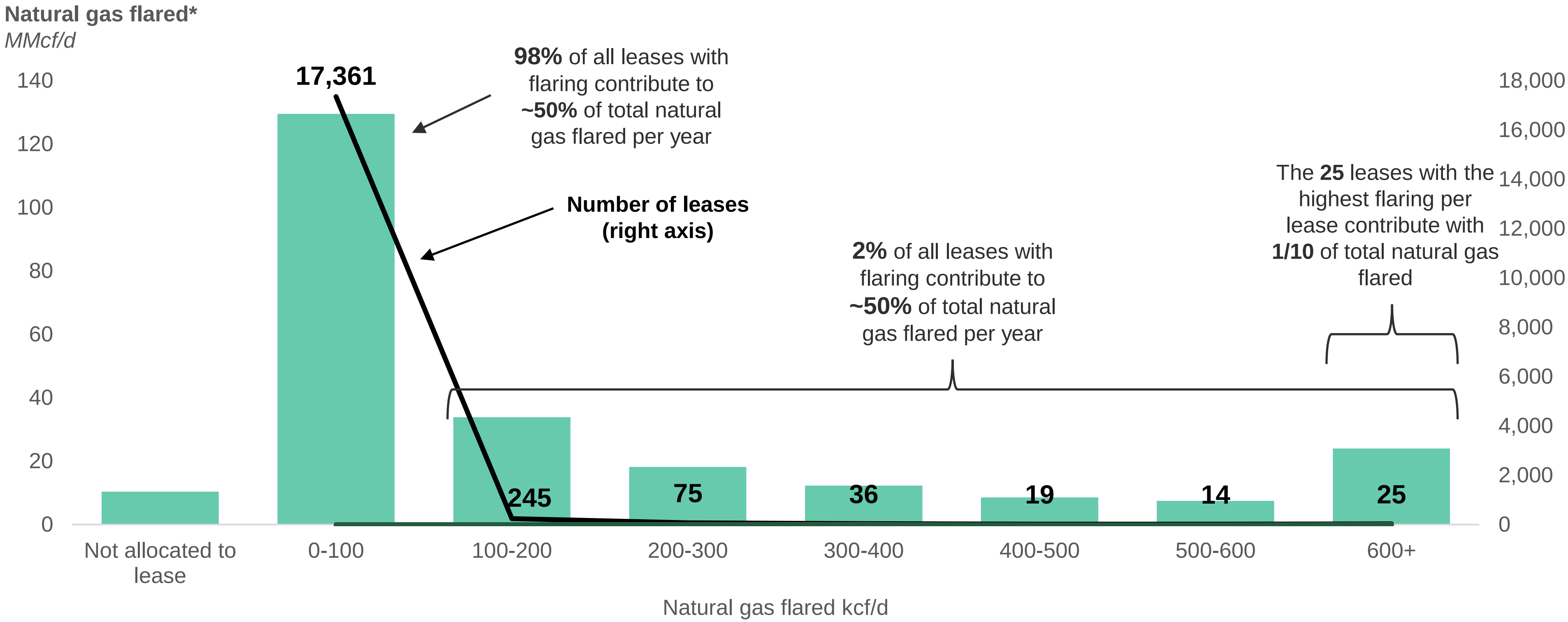


*Flared gas volumes divided by gross gas production; **Colorado's intensity reached 0.1% in 1H 2021
Source: Rystad Energy research and analysis, NOAA

2% of all leases with flaring contributed to ~50% of total natural gas flared

Texas

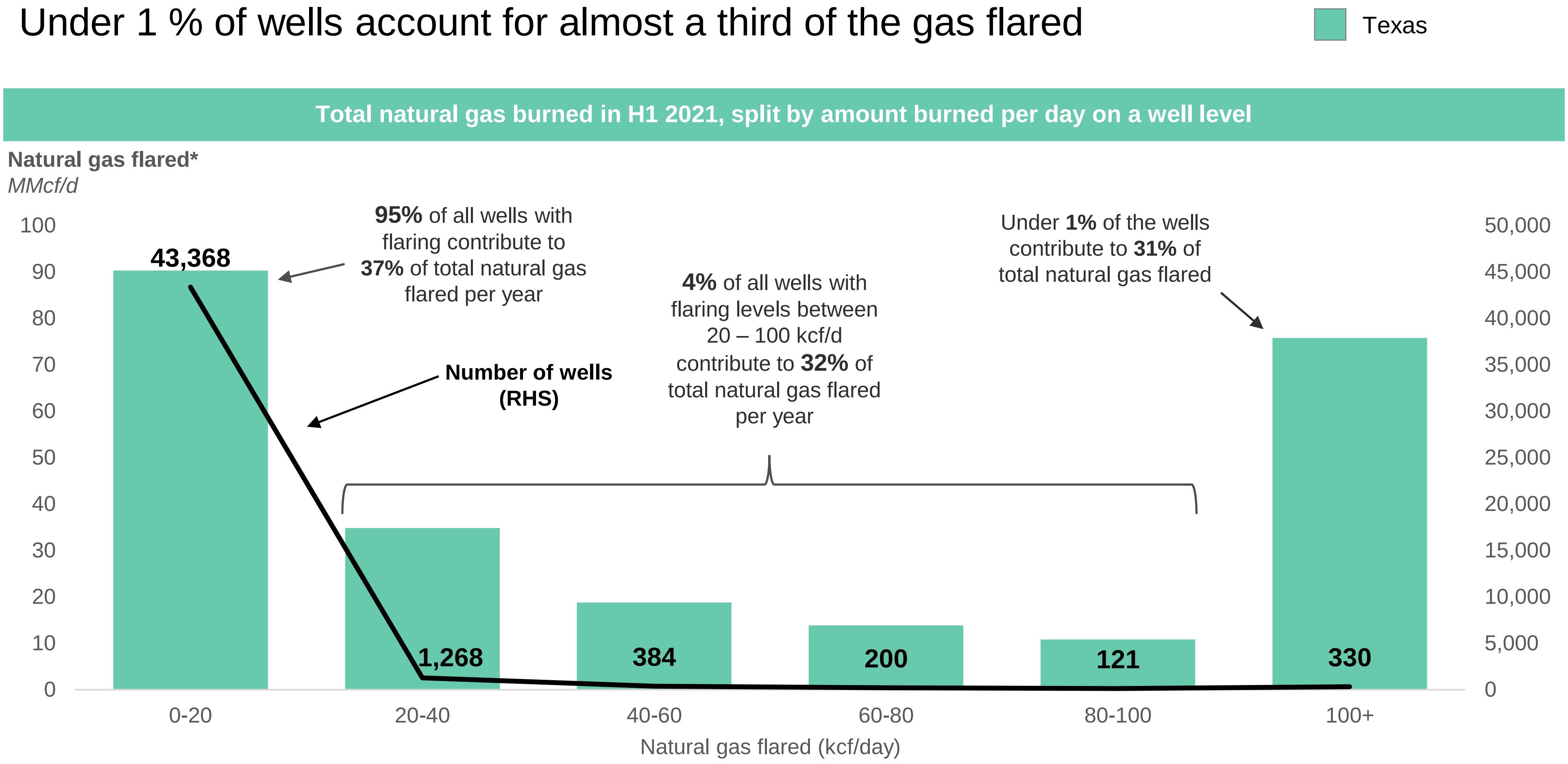
Total natural gas burned in H1 2021, split by amount burned per day on a lease level



- Looking at total natural gas flared in H1 2021 in Texas, most leases flare at low volumes between 0-100 kcf/d. In fact, approximately half of total natural gas flared per year stems from the 98% of leases flaring at these low volumes.
- To reduce flaring volumes, the focus should be on the remaining 2% of leases flaring at higher volumes. Especially the 25 leases flaring above 600 kcf/d.

*2021 amount.
Source: Rystad Energy ShaleWellCube

Under 1 % of wells account for almost a third of the gas flared

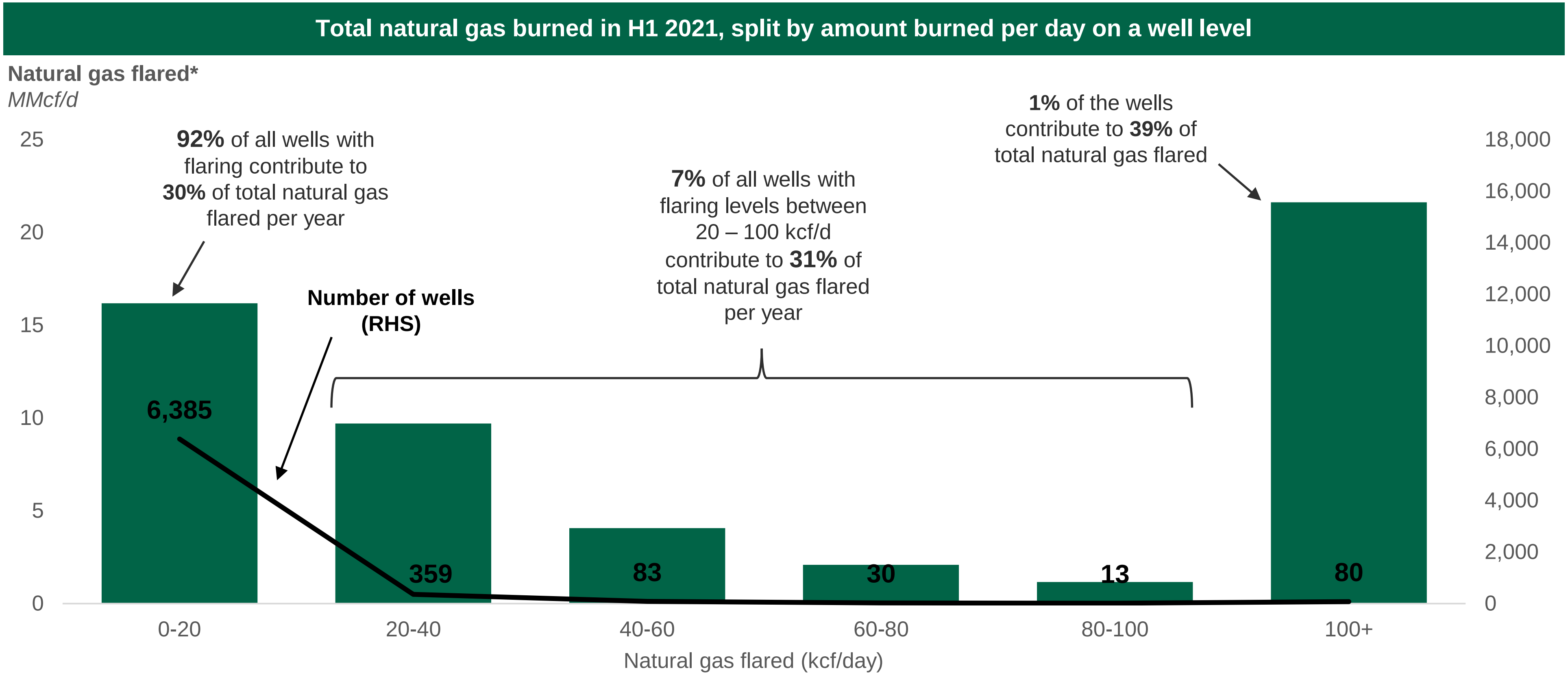


- In Texas, a majority of the wells flare at low volumes within 0-20 kcf/d. These wells account for 37% of total natural gas flared per year.
- 330 (under 1% of the total) wells flare at volumes above 100 kcf/d. With the aim of reducing flaring volumes in Texas, the focus should lay on these.

*2021 amount.
Source: Rystad Energy ShaleWellCube

39% of total natural gas flared stems from 1% of wells

New Mexico



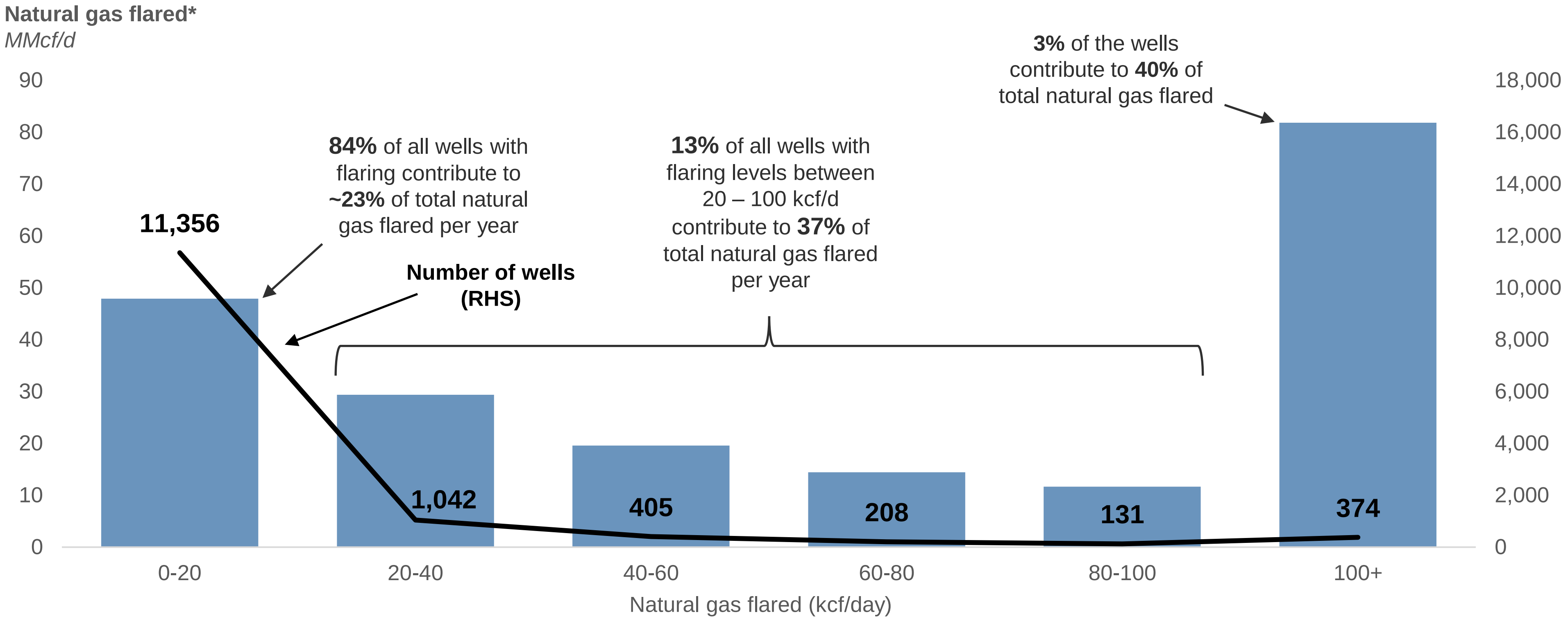
- In New Mexico, most wells flare at low volumes ranging from 0-20 kcf/d. 30% of total natural gas flared per year stems from these wells.
- In contrast to Texas, the wells with flaring levels above 100 kcf/d accounts for a bigger share of the total flaring volumes, than the wells flaring at the lowest volumes.

*2021 amount.
Source: Rystad Energy ShaleWellCube

3% of wells report 40% of flared volumes

North Dakota

Total natural gas burned in H1 2021, split by amount burned per day on a well level



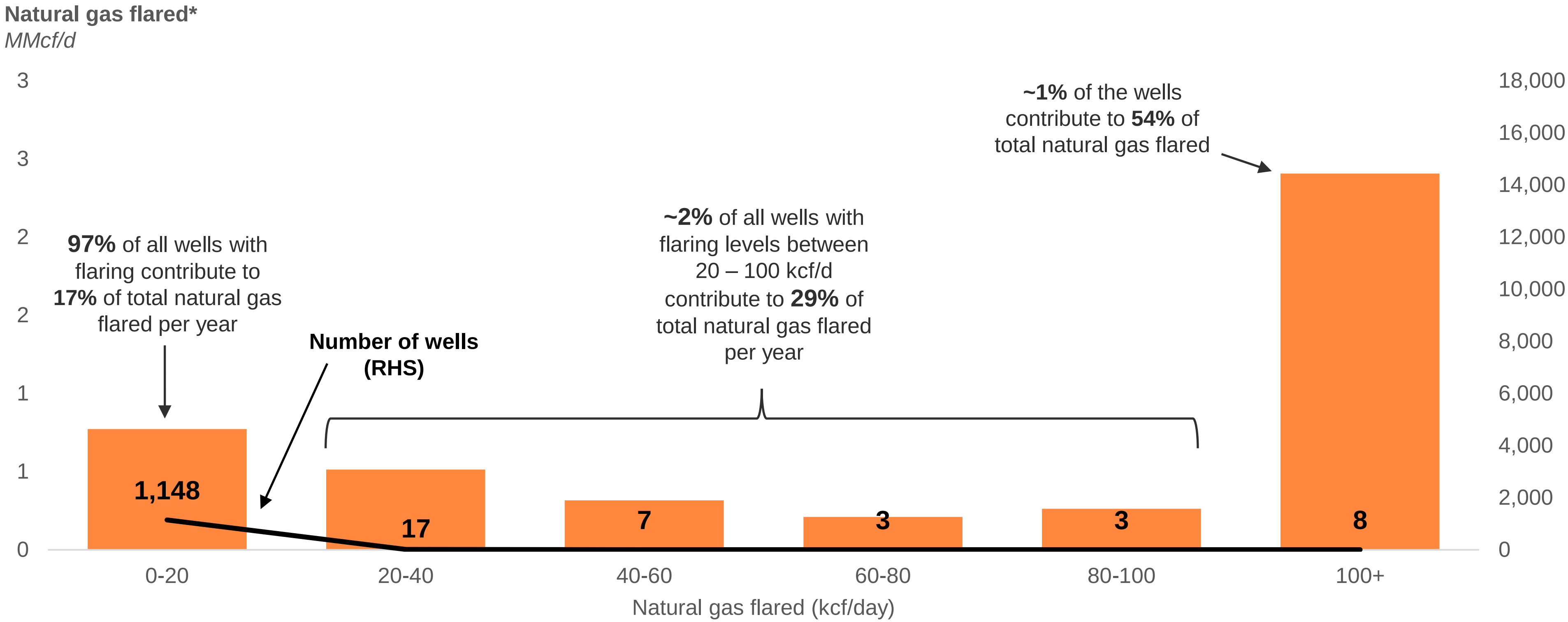
- The situation in North Dakota is relatively similar to New Mexico, meaning a minority of wells account for a majority of flaring volumes, although the flaring volumes from each category are significantly higher in North Dakota.
- In comparison to the other states, North Dakota has the highest percentage of wells with flaring volumes surpassing 100 kcf/d, indicating that flaring could be addressed in this state.

*2021 amount.
Source: Rystad Energy ShaleWellCube

Under 1% of wells report over half of flared volumes

Colorado

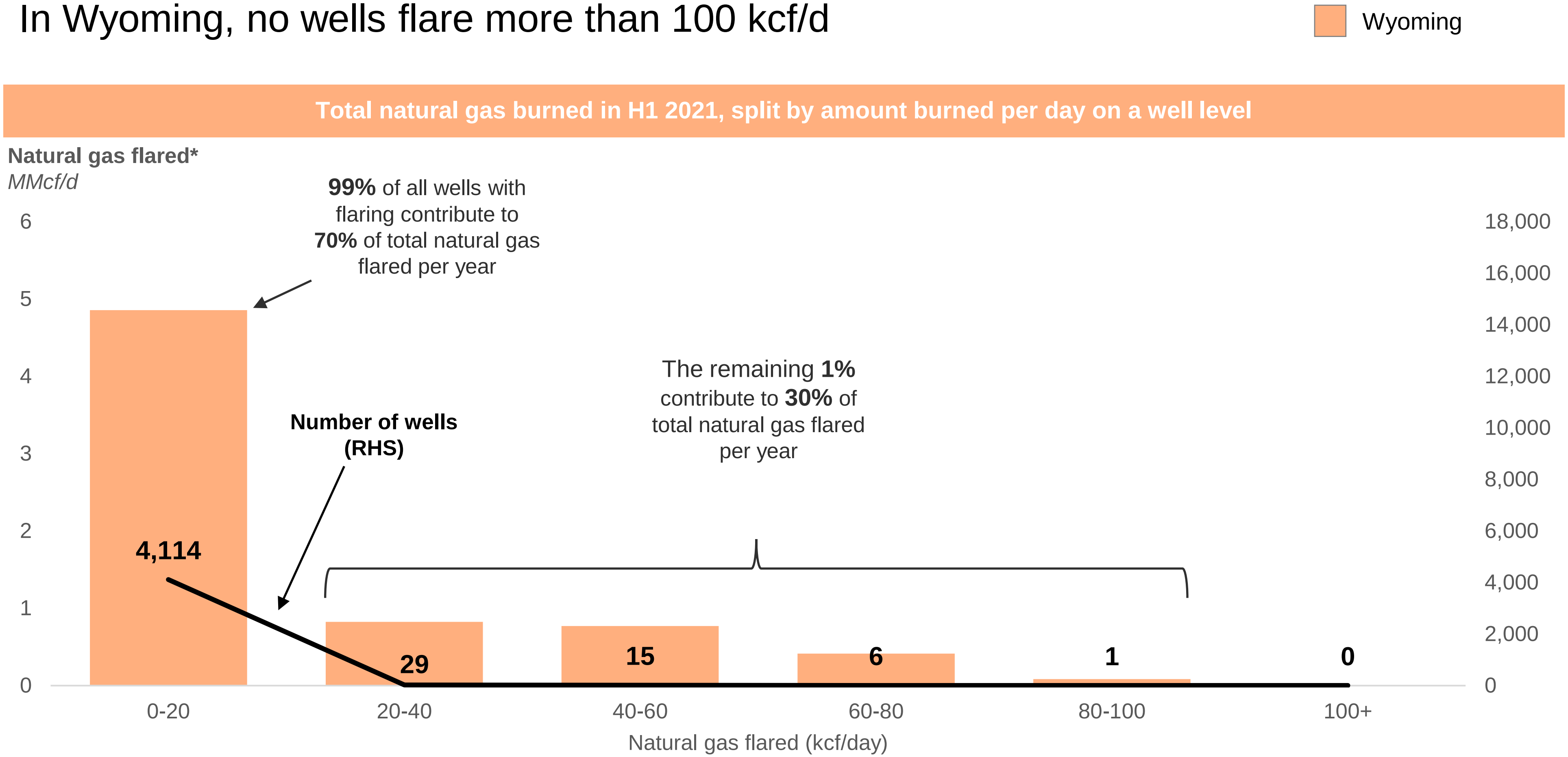
Total natural gas burned in H1 2021, split by amount burned per day on a well level



- Similar to what has been seen in Texas, New Mexico and North Dakota, a minority of the wells In Colorado contribute to a large share of the total gas flared. In Colorado, approximately 1% of the wells contribute to 54% of total flaring volumes, making it the only state where the wells flaring above 100 kcf/d account for over half of total gas flared.

*2021 amount.
Source: Rystad Energy ShaleWellCube

In Wyoming, no wells flare more than 100 kcf/d

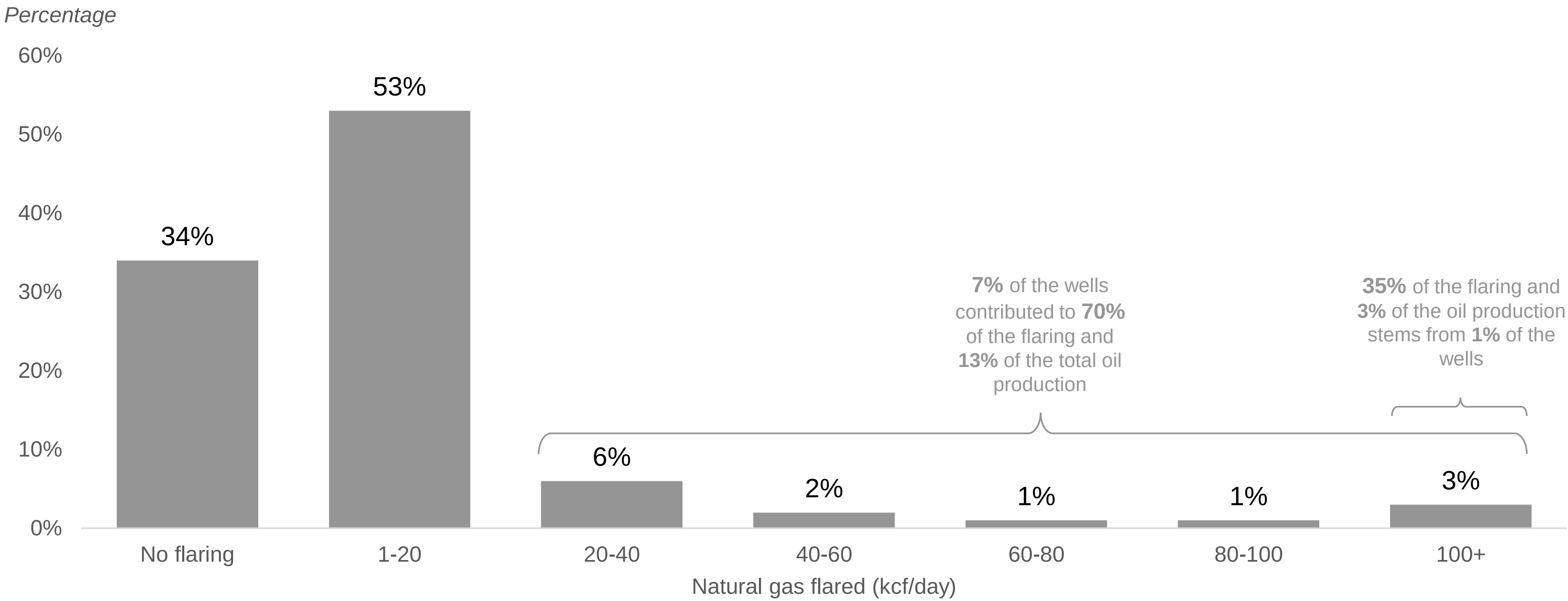


- Like in the other states, most wells in Wyoming flare at low volumes. Here the wells flaring at the lowest volumes makes up 99% of total wells, and account for 70% of total gas flared yearly.
- In contrast to the four other states, there are no wells in Wyoming with flaring levels exceeding 100 kcf/d.

*2021 amount.
Source: Rystad Energy ShaleWellCube

35% of flaring is associated with just 3% of oil production in the selected states

Share of oil production, split by volume flared per day on a well level*



- The chart shows how much of the aggregated oil production in Texas, New Mexico, North Dakota, Colorado and Wyoming that stems from wells flaring at different volumes.
- Wells that don't flare and flare at lower volumes account for a majority of the oil production in these states.

*2021 amount.
Source: Rystad Energy research and analysis

RYSTAD ENERGY

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Onshore Oil and Gas Flaring and Venting Activities in the United States and their Impacts on Air Quality and Health

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Environmental Defense Fund

Introduction

Flaring and venting in the oil and gas sector takes place when gas that is not being transported or sold is burned or released into the atmosphere.

This results in air pollutant emissions which forms air pollution (Ozone, $PM_{2.5}$ and NO_2) which can affect the health of communities.

Studies indicate that oil and gas activity is associated with increased risk of adverse health events (Cushing 2020, Rassmusen 2016, Currie 2017).

But there is limited quantification of the health impacts contributed due to air pollution from flaring and venting activities.

Further flared and vented gas volumes are often self-reported and inaccurate. Therefore, emissions, air quality and health impacts from flaring and venting could be underestimated.

Gas flare from well testing

Ref: U.S. DOE 2019, Cushing et al 2020, Rassmussen et al 2016, Currie et al 2017

Objectives

Using a hybrid VIIRs & NEI based emission inventory, apply CMAQ and BenMAP-R to assess the air quality health impacts of flaring and venting emissions on air pollution and health across the continental United States.

In this study we evaluate the contribution of flaring and venting to:

- Air pollution emissions (compare NEI estimates with our hybrid methods)
- Fine particulate matter, ozone and nitrogen dioxide levels and exceedances
- Air pollution-attributable mortality and morbidity

*Visible Infrared Imaging Radiometer Suite (VIIRS), National Emissions Inventory (NEI), The Community Multiscale Air Quality Modeling (CMAQ), Environmental Benefits Mapping and Analysis Program (BenMAP)

Key insights

Flaring and venting emissions contribute to ozone, $PM_{2.5}$ and NO_2 pollution and attributable adverse health impacts across the country.

- In 2017 it resulted in:
  - Over $7.4 billion in health damages
  - 710 premature deaths
  - 73,000 asthma exacerbations among children

Impacts are concentrated in disadvantaged populations. 1 in 3 of the cases are among low income populations and 1 in 5 cases in Native American populations.

- It also resulted 210 instances of ozone NAAQS exceedances.
- Impact of flaring and venting on O_3 conc. is significant and stronger in winter (up to 5 ppb; 18% in MDA8-O3) than in summer months (up to 2 ppb; 5%).
- **NEI 2017 underestimates emissions** from flaring and venting in the oil and gas sector (16X lower for $PM_{2.5}$ & 20% -240% lower for other precursors nationwide). This varies by state with highest underestimates in Texas.
- Many flares over these basins are only captured in VIIRS but not in NEI [e.g., North Dakota]. Denver basin often observes the highest impact on O_3 and $PM_{2.5}$

Policy implications

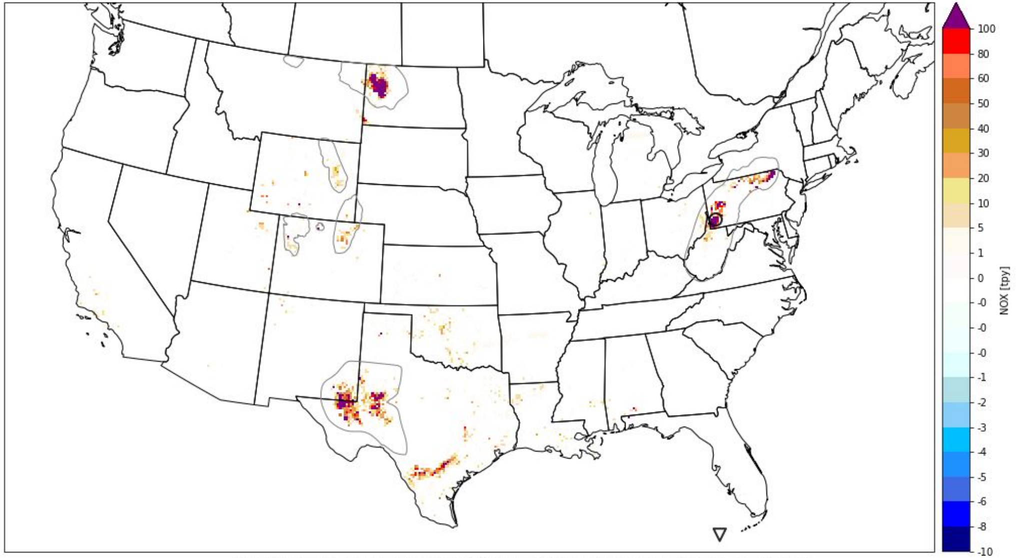
According to World Bank, 65% - 85% of flared gas volumes is routine flaring, which EDF encourages EPA to prevent. The following demonstrate the impacts of flaring and the potential benefits of mitigation:

- Our study finds that flaring and venting practices have significant impacts on air pollution and human health, including an estimated 700 premature deaths and 73,000 pediatric asthma exacerbations annually. In fact, flaring and venting account for ~10% of total estimated O&G air pollution impacts and the cost F&V health-related incidents is over $7.4 billion.

Flaring disproportionately effects disadvantaged populations.

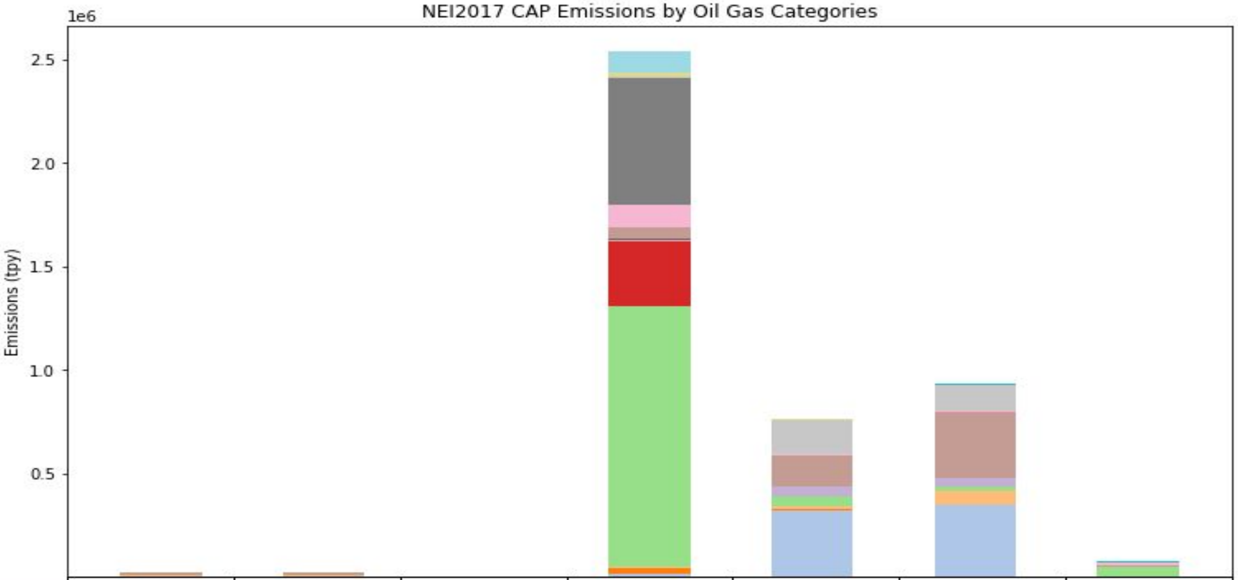
- The populations living within a ½ mile of flares across the US include higher than national average proportions of the following Census-designated groups: People of color, Hispanic/Latino, and Native American/American Indian.
- Of the air quality attributable to adult deaths and asthma exacerbations among children due to flaring and venting:
  - **1 in 5** are in communities home to **Native American** populations
  - **1 in 3** are among **low income** populations

Emissions from flaring and venting



CONUS: ○ Max = 2188.55 (FIPS: 42125), ▽ Min = 0.00 (FIPS: 12087), Mean=1.07

Emissions from flaring and venting in the NEI by pollutant



	PM10-PRI	PM25-PRI	NH3	VOC	CO	NOX	SO2
Waste_Disposal	1.25E+01	5.25E+00	0.00E+00	9.89E+04	3.71E+01	4.08E+01	2.39E+01
Turbine_Boiler	7.30E+02	7.27E+02	6.09E+01	4.88E+02	3.20E+03	5.56E+03	5.17E+03
Storage Tanks	3.00E+00	2.93E+00	0.00E+00	2.44E+04	1.32E+03	5.35E+02	3.73E+01
Pumpjack Engines	1.42E+03	1.39E+03	0.00E+00	5.26E+03	1.64E+05	1.21E+05	7.16E+01
Pneumatics	2.61E-01	2.61E-01	4.66E-03	6.14E+05	6.38E+01	1.94E+02	1.56E-02
Others	8.28E+02	7.03E+02	1.76E+03	1.08E+05	1.01E+04	8.96E+03	1.54E+04
Other_Engines	8.61E+03	8.51E+03	3.23E+02	5.32E+04	1.47E+05	3.18E+05	1.62E+03
Loading_Transport	8.34E+01	5.50E+01	3.20E-01	5.90E+03	1.66E+02	9.27E+01	1.51E+00
Heater_Separators	5.36E+03	5.32E+03	3.89E+01	4.36E+03	5.01E+04	4.21E+04	1.19E+03
GasPlant_Refinery_Others	5.77E-01	5.77E-01	0.00E+00	7.34E+02	6.83E+00	1.25E+00	2.94E-01
Fugitives	2.85E+01	1.55E+01	5.00E-12	3.11E+05	2.45E+02	1.42E+02	3.42E+02
Flares	3.06E+02	3.00E+02	1.84E-01	1.26E+06	4.79E+04	2.13E+04	4.88E+04
Drilling_Completion	1.87E+03	1.79E+03	6.55E+00	6.79E+03	1.40E+04	6.71E+04	4.32E+02
Dehydrators	6.67E+01	6.54E+01	1.23E-01	3.02E+04	1.16E+03	1.08E+03	1.46E+01
Compressor_Engines	2.98E+03	2.98E+03	0.00E+00	1.16E+04	3.24E+05	3.45E+05	1.16E+02

But, there are major uncertainties in the NEI estimates

- Emissions from flaring are not estimated separately at source but mixed in with emissions from associated sources: crude oil and condensate tanks, well heads, storage tank loading, gas venting, dehydrators

- Many states apply different Source Classification Codes (SCC) to characterize the same O&G source types, making if difficult to track flaring emissions from the NEI

- Inconsistency in estimating “flaring” emissions between NEI 2017 and other emission inventories

Comparing NEI with other inventories highlights uncertainties

Estimates are inconsistent across states

- Lower in Texas, North Dakota and New Mexico than other estimates. (~800 to 3000 tons/year lower; 10-85% lower)
- Significantly higher in Wyoming (12x) and Colorado (7x)

Comparison of NOx emissions (tpy) across different inventories

State	Rystad[1]	FOG[2]	NEI 2017
Texas	5,085	5,029	4,791
North Dakota	5,079	3,151	2,112
New Mexico	913	643	132
Wyoming	212	116	2,691
Colorado	119	48	868
Total	11,408	8,987	10,594

[1]*Rystad Energy, 2022*
[2]*Fuel-based O&G Emission Inventory (Francoeur et al., 2021)*

- *Rystad*: contains county-level flared gas volume based on state/local agencies' reports
- *FOG*: Fuel-based Oil & Gas emission inventory

Hybrid emission estimation (VIIRS, NEI and Rystad data) method to address uncertainties

Governing equation to estimate annual emissions (E) from flaring

$$E\left(\frac{tons}{yr}\right) = V\left(\frac{BCM}{yr}\right) \times \frac{10^9 m^3}{BCM} \times \frac{26700 \pm 114000\ BTU}{m^3} \times EF\left(\frac{lb}{BTU}\right) \times \frac{tons}{2000\ lbs}$$

V is flared gas volume from VIIRS in 2019; EF is emission factors of critical pollutants (NO_X, CO, SO_2, $PM_{2.5}$) based on literature reviews and Monte Carlo simulations to characterize their uncertainties

VOC emissions are taken directly from flare-associated sources from NEI 2017 and considered as venting

Examining VIIRS data with known flare locations revealed that not all flares were detected by VIIRS (could be filtered out by VIIRS Nightfire detecting algorithm)

Hybrid flare emissions = **VIIRS-based emissions (E)** +

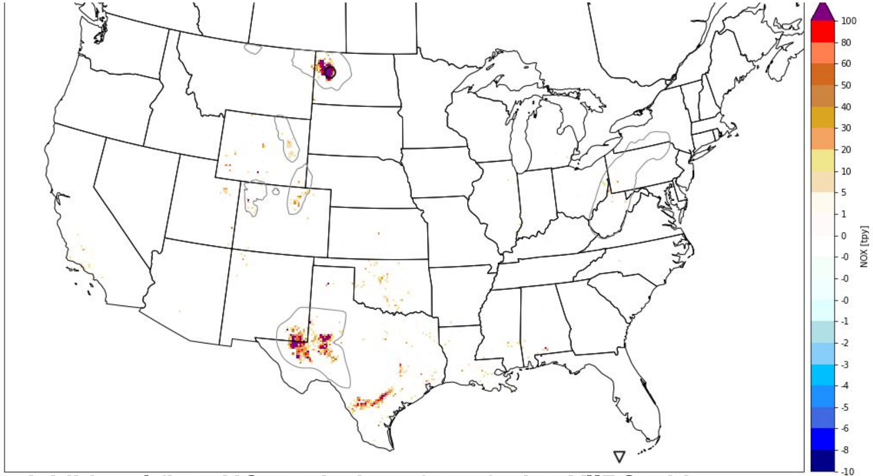
- **Excess emissions from flare volume-based emissions from Rystad*, or**
- **Excess emissions from flare-associated sources in NEI 2017**

*Rystad Energy, 2022. *Cost of Flaring Abatement Final Report*.

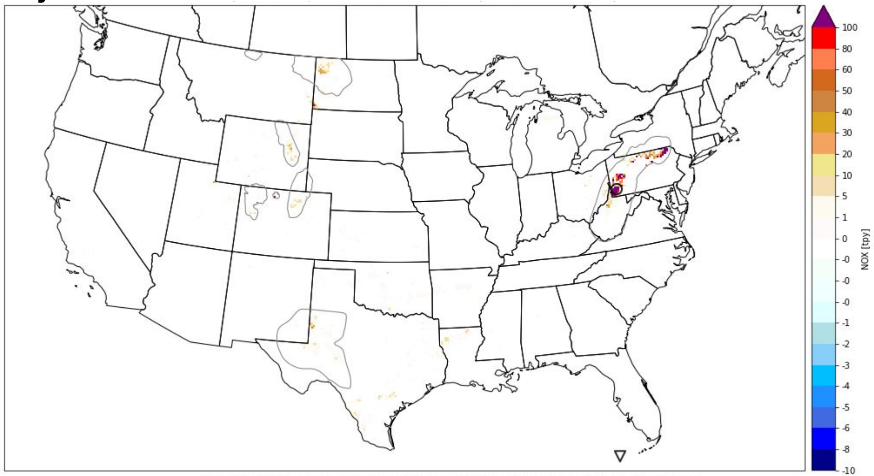
Use of “hybrid” approach that includes VIIRS, Rystad & NEI 2017 captures all possible ranges of flare emissions.

The NEI and Rystad inputs made the biggest contribution beyond the VIIRS estimates in Pennsylvania.

Flare NO_X emissions from VIIRS-based only



Additional flare NO_X emissions from fusing VIIRS with Rystad and NEI



CONUS: ○ Max = 2188.55 (FIPS: 42125), ▽ Min = 0.00 (FIPS: 12087), Mean=0.37

Annual emissions (tpy) from F&V over Pennsylvania

	$PM_{2.5}$	VOC	CO	NO_X	SO_2
VIIRS-based only	5.71E+00	3.13E+03	8.99E+01	1.89E+01	1.17E+02
Hybrid-VIIRS	1.71E+03	3.08E+05	2.69E+04	5.64E+03	3.59E+04
Differences	1.71E+03	3.05E+05	2.68E+04	5.62E+03	3.58E+04

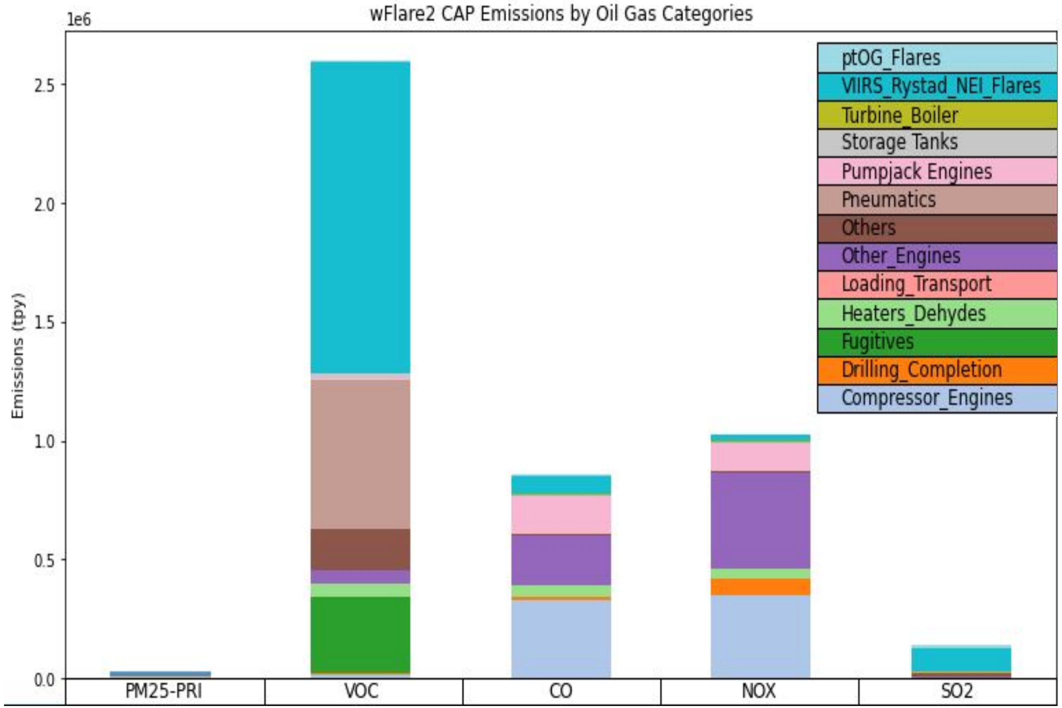
Emissions from flaring and venting (hybrid)

Flaring and venting are an important source of emissions in the oil and gas sector:

50% of VOC emissions
18% of PM2.5
82% of SO2
3% of NOx

Table 2. Annual emissions from F&V over CONUS

	$PM_{2.5}$	VOC	CO	NO_x	SO_2
Annual (tpy)	4,907	1,312,511	86,484	26,067	115,505
% of total O&G	18%	51%	10%	3%	82%



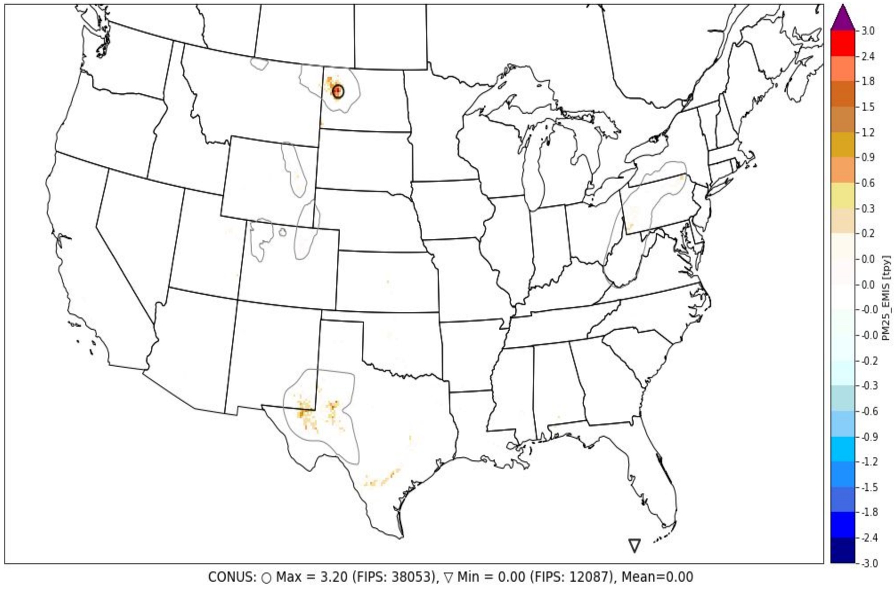
Emissions from Flaring and venting (Hybrid method)

Annual emissions from F&V over CONUS and top five states

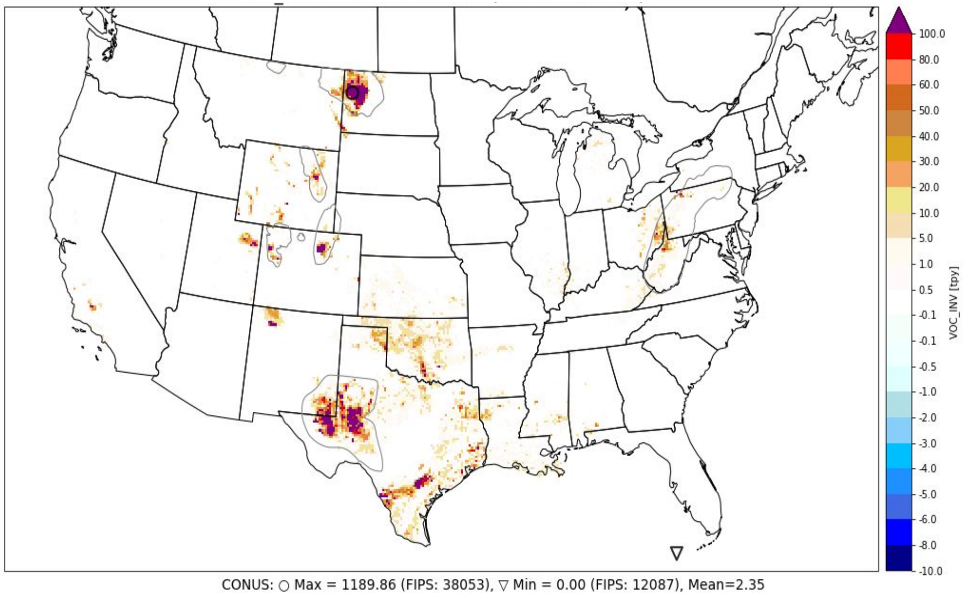
		$PM_{2.5}$	VOC	CO	NO_X	SO_2
Continental USA	*Annual tpy (% oil and gas emissions)*	4,907 (17.8%)	1,312,511 (50.5%)	86,484 (10.0%)	26,067 (2.5%)	115,505 (81.6%)
Texas	*Annual tpy (% state oil and gas emissions)*	2,244 (29.8%)	578,902 (63.1%)	38,112 (18.4%)	8,440 (3.0%)	53,336 (91.5%)
North Dakota	*Annual tpy (% state oil and gas emissions)*	1,713 (62.7%)	307,755 (84.6%)	26,886 (60.4%)	5,638 (22.0%)	35,900 (85.7%)
New Mexico	*Annual tpy (% state oil and gas emissions)*	370 (29.1%)	84,177 (52.0%)	6,189 (9.4%)	1,319 (2.4%)	10,019 (77.5%)
Colorado	*Annual tpy (% state oil and gas emissions)*	39 (6.5%)	83,672 (70.6%)	1,728 (5.7%)	491 (1.1%)	784 (69.6%)
Wyoming	*Annual tpy (% state oil and gas emissions)*	69 (4.8%)	55,964 (58.8%)	1,361 (9.4%)	479 (1.7%)	3,487 (61.0%)

VOC & $PM_{2.5}$ emissions from flaring and venting

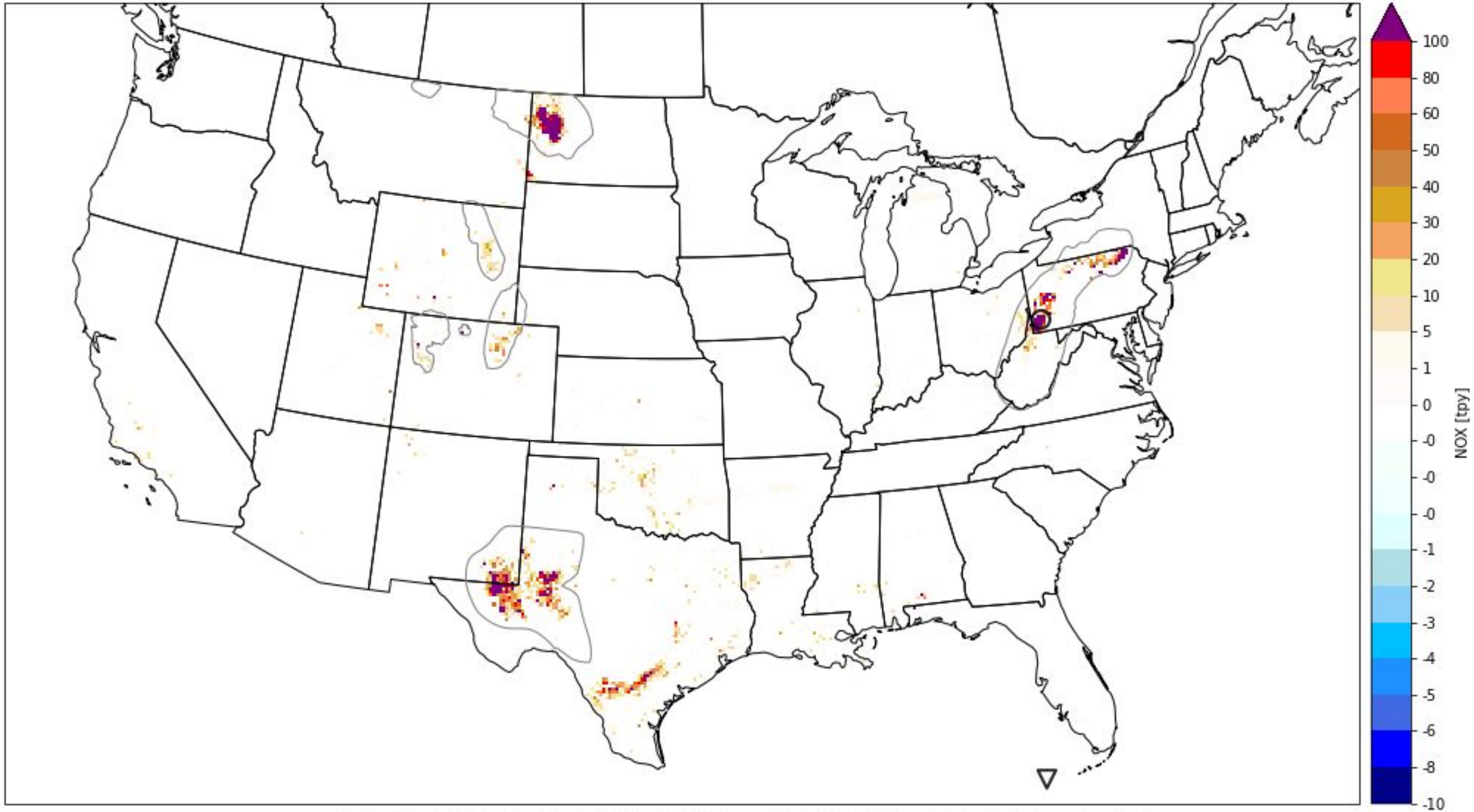
$PM_{2.5}$



VOC



NOx emissions from flaring and venting



CONUS: ○ Max = 2188.55 (FIPS: 42125), ▽ Min = 0.00 (FIPS: 12087), Mean=1.07

NEI 2017 underestimates flaring and venting emissions

Emissions (tpy)	$PM_{2.5}$	VOC*	CO	NO_X	SO_2	NH3
NEI 2017	3.00E+02	1.31E+06	4.78E+04	2.14E+04	4.90E+04	1.84E-01
Hybrid VIIRS	4.90E+03	1.31E+06	8.59E+04	2.60E+04	1.15E+05	1.84E-01
Ratio	16.3	1.0	2.4	1.8	1.2	1.0

**VOC emissions are taken directly from flare-associated sources from NEI 2017 and considered as venting*

Hybrid VIIRS estimates are 16X higher for $PM_{2.5}$ and 20% -240% higher for other precursors nationwide. Differences in VIIRS-based and NEI estimation methods are reason for the differences.

$PM_{2.5}$ emissions from flaring are not estimated in NEI due to discrepancies in emission factor (based on AP-42). Recent emission factors for $PM_{2.5}$ from flare are incorporated in VIIRS-based estimates which led to much higher $PM_{2.5}$ emission than NEI 2017.

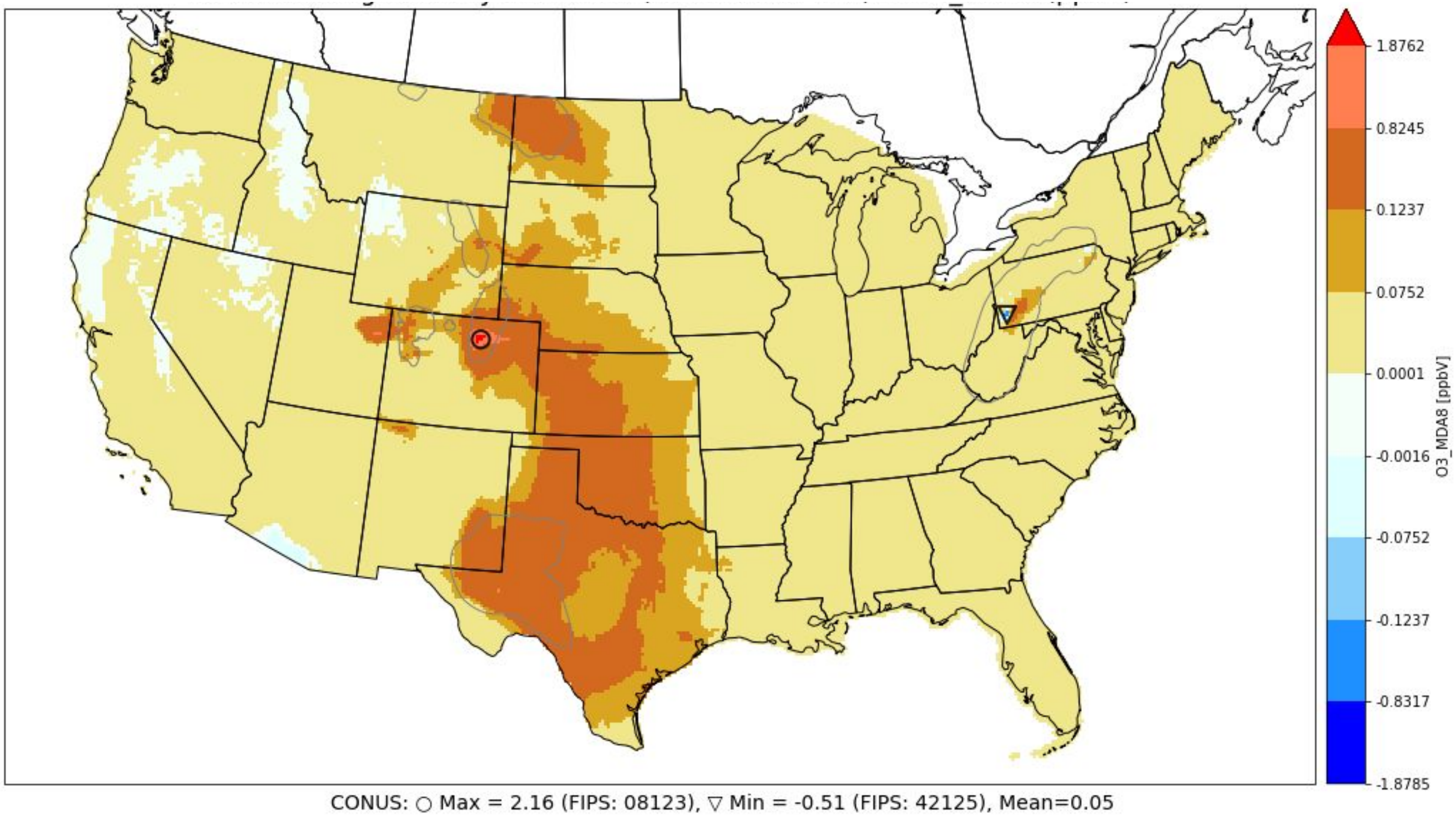
Differences between hybrid VIIRS-based estimated and NEI 2017 vary across states and pollutants (top five states shown)

State	Emissions (tpy)	$PM_{2.5}$	VOC*	CO	NO_X	SO_2
Texas	*NEI 2017*	9.35E+00	5.70E+05	2.34E+04	5.59E+03	3.01E+04
	Hybrid VIIRS	2.25E+03	5.70E+05	3.81E+04	8.44E+03	5.33E+04
	Ratio	**240.6**	1.0	**1.6**	**1.5**	**1.8**
North Dakota	*NEI 2017*	1.60E+00	3.08E+05	1.13E+04	2.14E+03	3.02E+03
	Hybrid VIIRS	1.71E+03	3.08E+05	2.69E+04	5.64E+03	3.59E+04
	Ratio	**1069.8**	1.0	**2.4**	**2.6**	**11.9**
New Mexico	*NEI 2017*	1.66E+00	8.42E+04	1.13E+03	2.46E+02	4.64E+03
	Hybrid VIIRS	3.70E+02	8.42E+04	6.19E+03	1.32E+03	1.00E+04
	Ratio	**223.2**	1.0	**5.5**	**5.4**	**2.2**
Wyoming	*NEI 2017*	3.71E+00	5.60E+04	9.90E+02	2.87E+03	2.19E+03
	Hybrid VIIRS	5.90E+01	5.60E+04	1.36E+03	4.80E+02	3.49E+03
	Ratio	**15.9**	1.0	**1.4**	**0.2**	**1.6**
Colorado	*NEI 2017*	1.32E+00	8.37E+04	1.15E+03	1.22E+03	2.29E+01
	Hybrid VIIRS	3.85E+01	8.37E+04	1.73E+03	4.91E+02	7.84E+02
	Ratio	**29.2**	1.0	**1.5**	**0.4**	**34.2**

Contribution of flaring and venting to air pollution

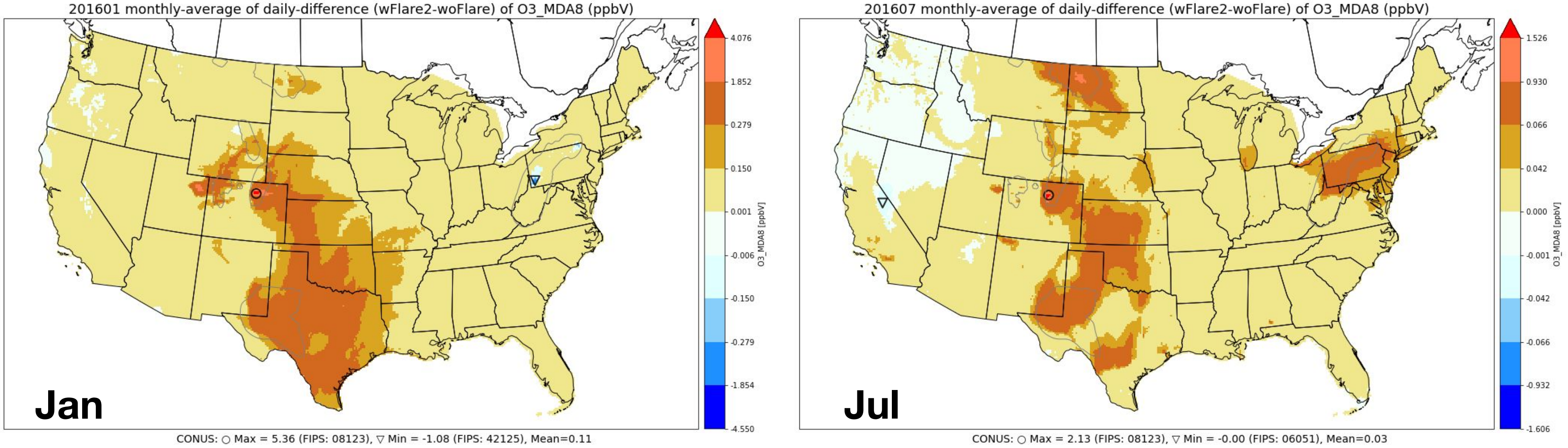
Credit: Pixabay/CC0 Public Domain

Distribution of flaring and venting emission impacts on MDA8* ozone (annual average)



*MDA8: Maximum daily 8 hour average

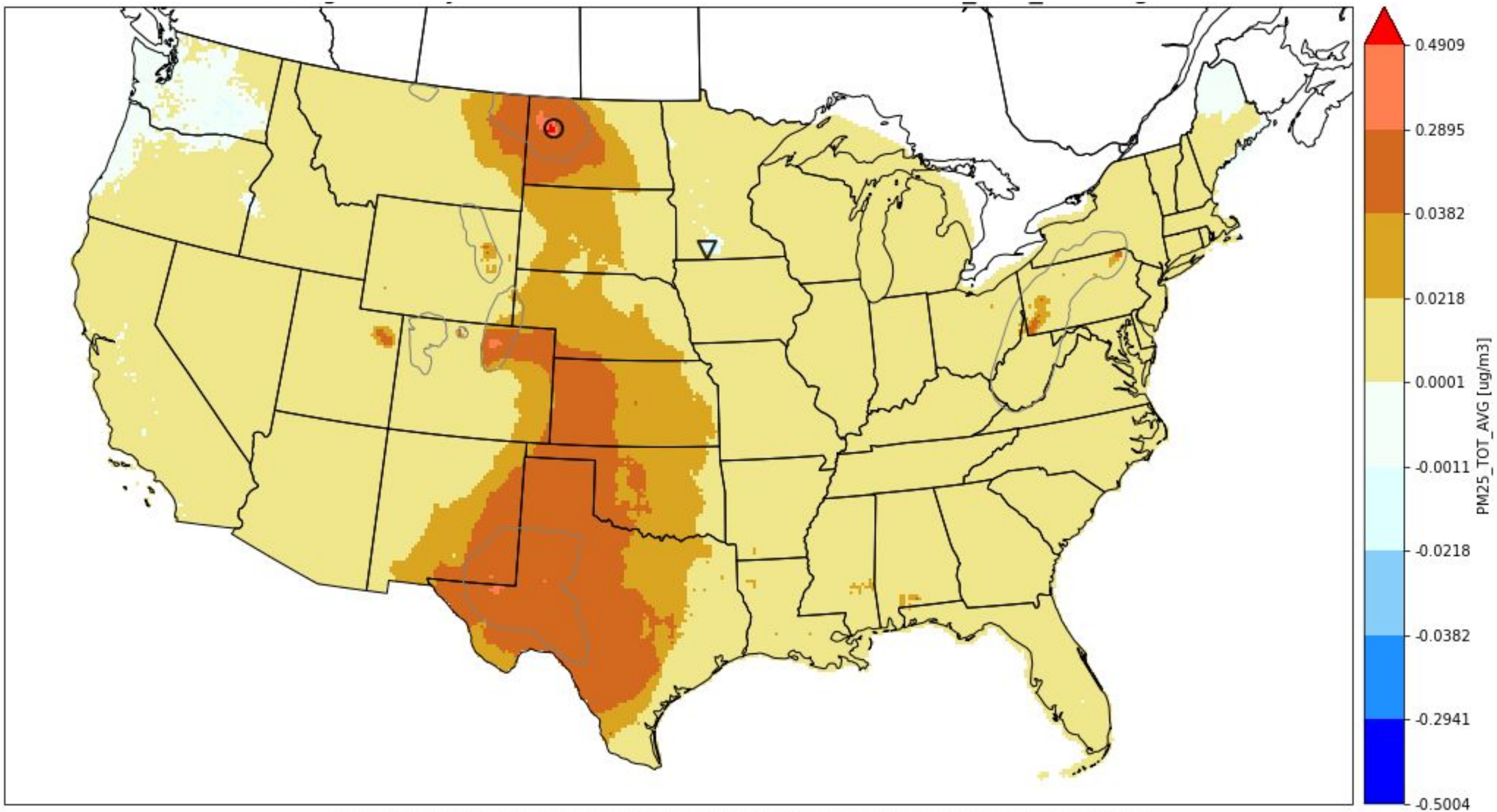
Flaring and venting contributes to winter ozone



Contribution to Average MDA8O3 (ppbV)

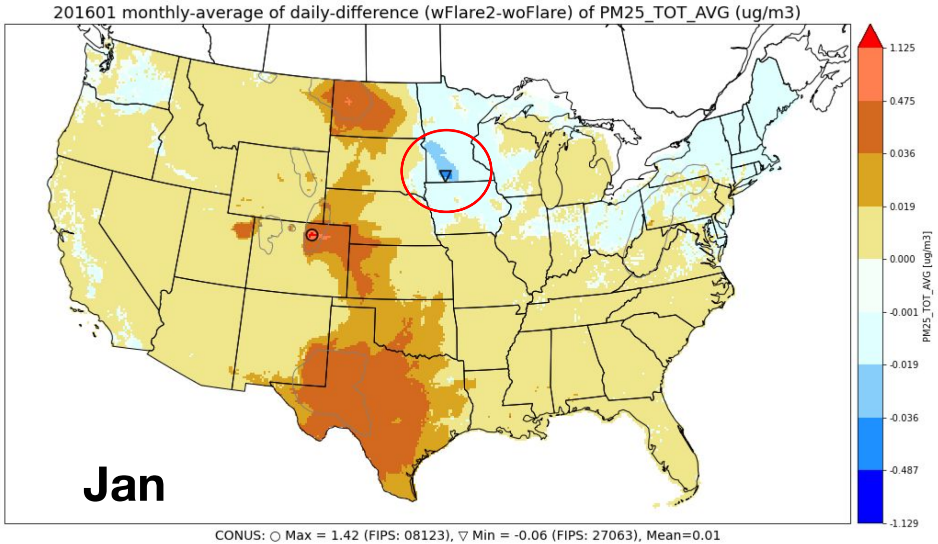
- Impact on O_3 is significant (up to 5 ppbV) and is 4x higher in winter than in summer months.
- Denver basin observes the highest impact in comparison to other O&G basins.
- Impacts seen in summer in North Dakota, where NEI underestimates flaring emissions.
- Large NO_X emission over Pennsylvania led to increased O_3 in summer months, but led to reductions in winter.

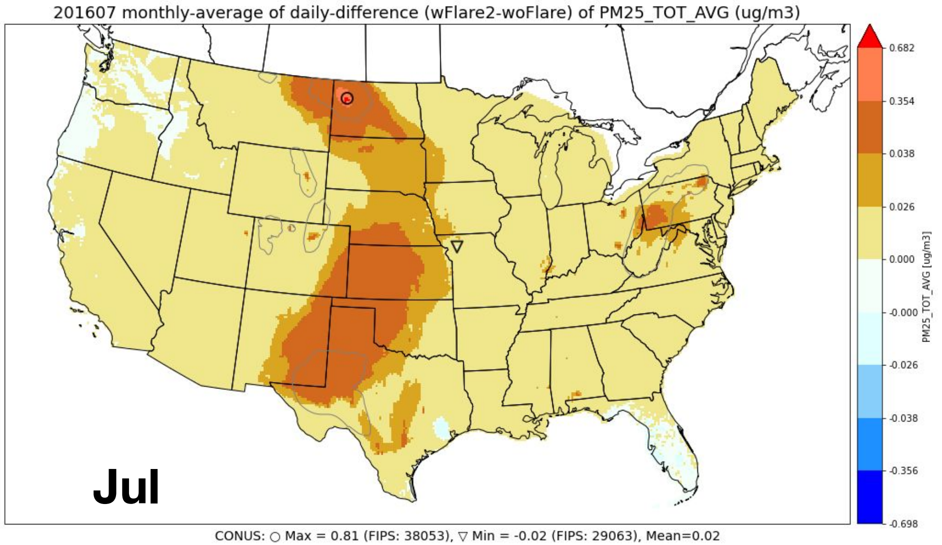
Distribution of flaring and venting emission impacts on 2017 $PM_{2.5}$ (annual average)



CONUS: ○ Max = 0.57 (FIPS: 38053), ▽ Min = -0.01 (FIPS: 27063), Mean=0.02

Flaring and Venting Impact on $PM_{2.5}$

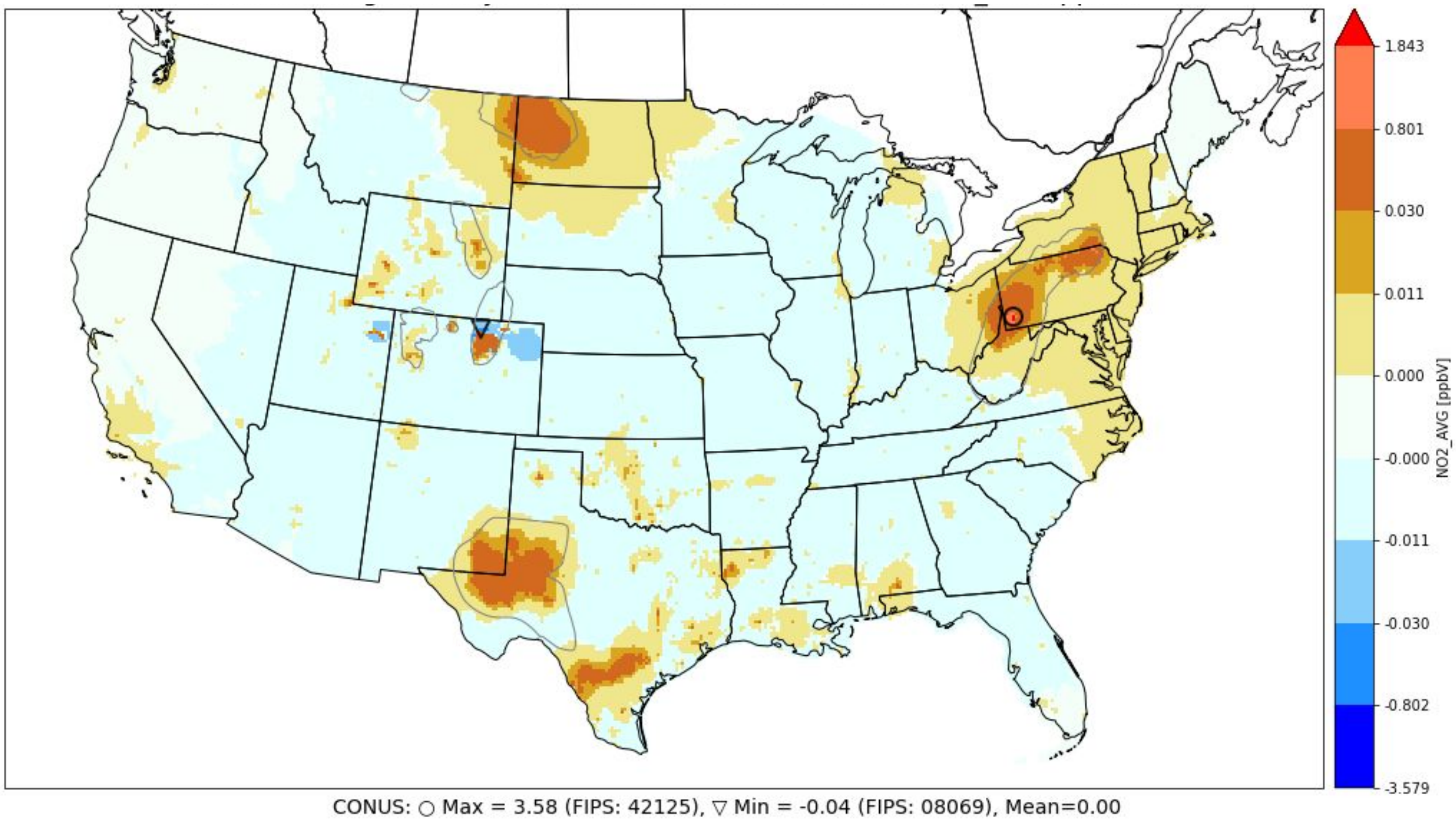




Contribution to Average $PM_{2.5}$ ($\mu g/m^3$)

- Similar to impact on MDA8O3, impact on $PM_{2.5}$ is stronger in winter than in summer (~2x), and up to 1.4 $\mu g/m^3$.
- Highest impact occurs in Denver basin in January and in Bakken basin in July.
- Small reduction of $PM_{2.5}$ in the Northeast and midwest regions due to decrease in NO_3 aerosol in winter

Distribution of flaring and venting emission impacts on NO_2 (annual average)



Contribution to NAAQS exceedances in 2017

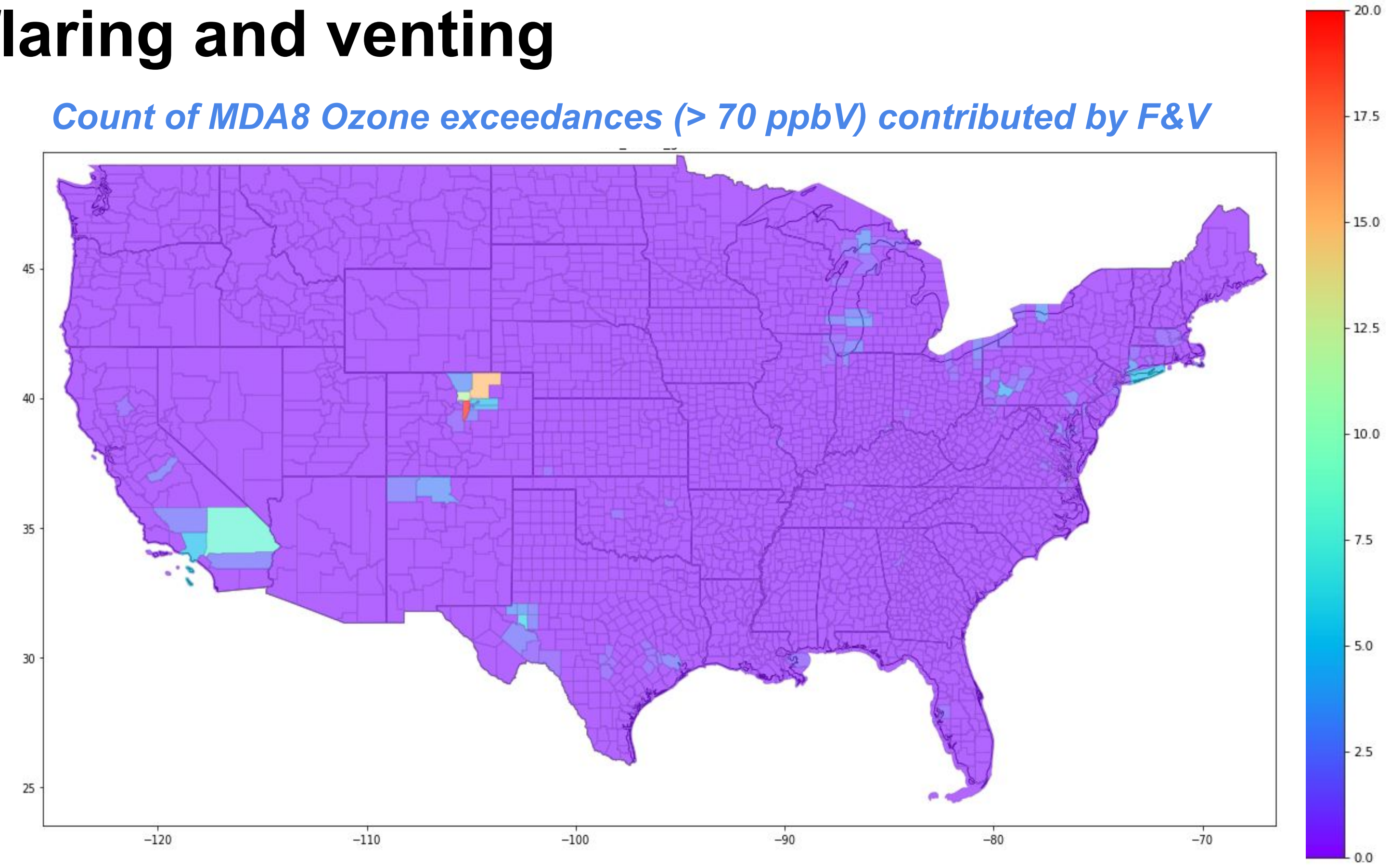
States	MDA8 O_3 > 70 ppbV	24 -hour $PM_{2.5}$ > *35 µg/m³*	Daily Max NO_2 > 60 ppbV*	Annual $PM_{2.5}$ > 10 *µg/m³* **
Colorado	65	0	9	0
Texas	31	0	0	0
California	20	0	0	0
Pennsylvania	17	1	0	3
Michigan	13	0	0	0
North Dakota	0	0	0	0
New Mexico	0	0	0	0
Wyoming	0	0	0	0

* No NO_2 exceedances with current national standard of 100 ppbV or until the threshold is lowered to 60 ppbV

** No $PM_{2.5}$ exceedances with current national annual standard of 15 *µg/m³* or until the threshold is lowered to 10 *µg/m³*

Based on 4 (JAJO) months of modeling. Daily exceedances are likely to be an underestimate.

Map of MDA8 ozone exceedances contributed by flaring and venting



Contribution to NAAQS exceedances in 2017

MDA8O3:

- Over 210 instances of exceedances (MDA8 Ozone > 70 ppbV) noted (over 4 simulated months)
- Exceedances largest in Colorado (Denver Basin)
- No MDA8O3 exceedances due to flaring and venting emissions in January
- Largest additional exceedances occurred in July

$PM_{2.5}$:

- Exceedance is small and additional exceedances occur in January only
- Decreases in nitrate and OC aerosols led to decrease in exceedances in some areas
- If $PM_{2.5}$ daily NAAQS were lowered to 30 ug/m^3, flaring and venting emission would contribute 10 instances of exceedances (over 4 simulated months)

NO_2:

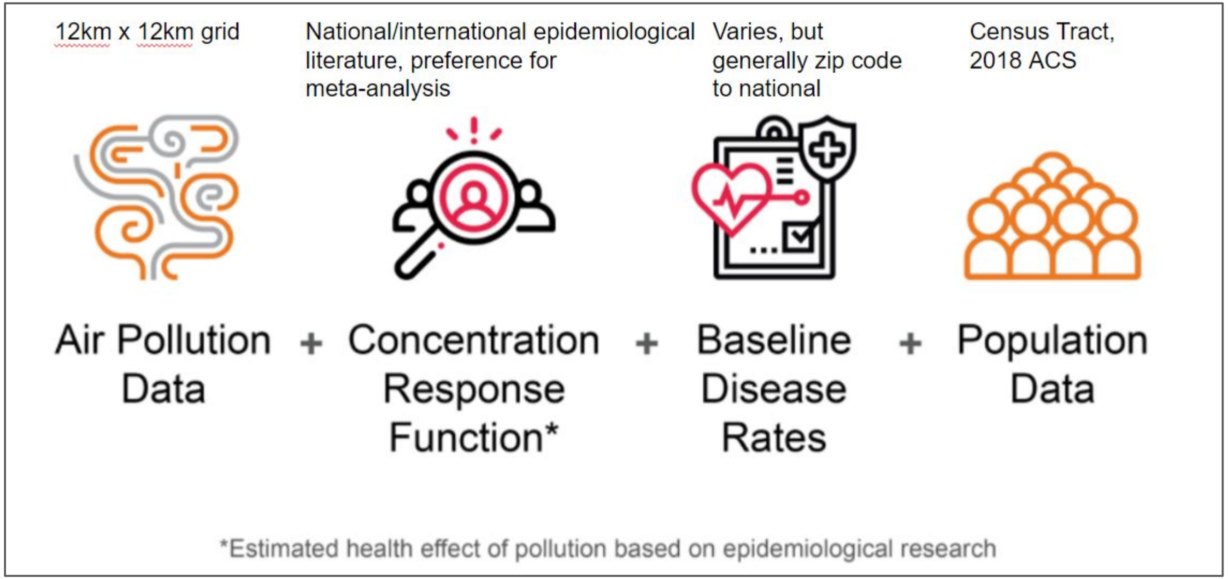
- Flaring and venting caused no additional NO_2 exceedances.
- If the 1-hour NO_2 standard were lowered to 60 ppbV then it would add 10 instances of exceedances.

Full Chain Air Pollution Health Impact Assessment

Flaring & venting activity (hybrid methodology) → Emission analysis → Air Quality modelling → Health analysis

Methods: assessment of health impacts

Using BenMAP-R, information from the published epidemiology literature on the relationship between incremental health risk associated with pollutant changes (concentration response function) and overlapping modelled air pollution contribution from flaring and venting, population distribution and baseline disease rates we estimate air pollution attributable health impacts.



Health impacts of flaring (2017) vs. total oil and gas (2016)

Health Impact	O&G Health Impacts (Buonocore et al., under review)		Flaring Health Impact Outcomes, based on Pollutant Type		% contribution of Flaring to Total O&G Sector (mid value estimates)
	Pollutant Type	Cases (95% CI)	Pollutant Type	Cases (95% CI)	F / O&G Cases * 100
Premature Deaths	All three	7,500 (4,500 - 12,000)	All three	710 (480 - 1,100)	9.5%
Asthma Incidence	$PM_{2.5}$ and NO_2 (Orellano)	2,200 (830 - 3,200)	$PM_{2.5}$ and NO_2	190 (66 - 300)	8.6%
Asthma Hospitalizations	$PM_{2.5}$ and NO_2 (Orellano)	53 (1.2 - 110)	$PM_{2.5}$ and NO_2 (Orellano)	3.2 (0.053 - 6.3)	6%
	-	-	All three (Alhanti*)	10 (6.4 - 15)	18%*
Asthma ED Visits	$PM_{2.5}$ and NO_2 (Orellano)	530 (12 - 1,100)	$PM_{2.5}$ and NO_2 (Orellano)	28 (0.43 – 56)	5.3%
	-	-	All three (Alhanti*)	92 (58 - 140)	17%*
Asthma Exacerbations	$PM_{2.5}$ and NO_2 (Orellano)	410,000 (9,200 - 810,000)	$PM_{2.5}$ and NO_2 (Orellano)	22,000 (340 - 43,000)	5.4%
	-	-	All three (Alhanti*)	73,000 (46,000 - 110,000)	18%*
Respiratory Hospitalizations	$PM_{2.5}$ and O_3	1,500 (550 - 2,400)	$PM_{2.5}$ and O_3	130 (50 - 210)	8.7%
Heart Attacks	$PM_{2.5}$ and NO_2	270 (150 - 390)	$PM_{2.5}$ and NO_2	23 (13 - 33)	8.5%

*The pollutants and epidemiology used for Alhanti asthma estimates are different than what was used in the 2016 health impacts assessment.

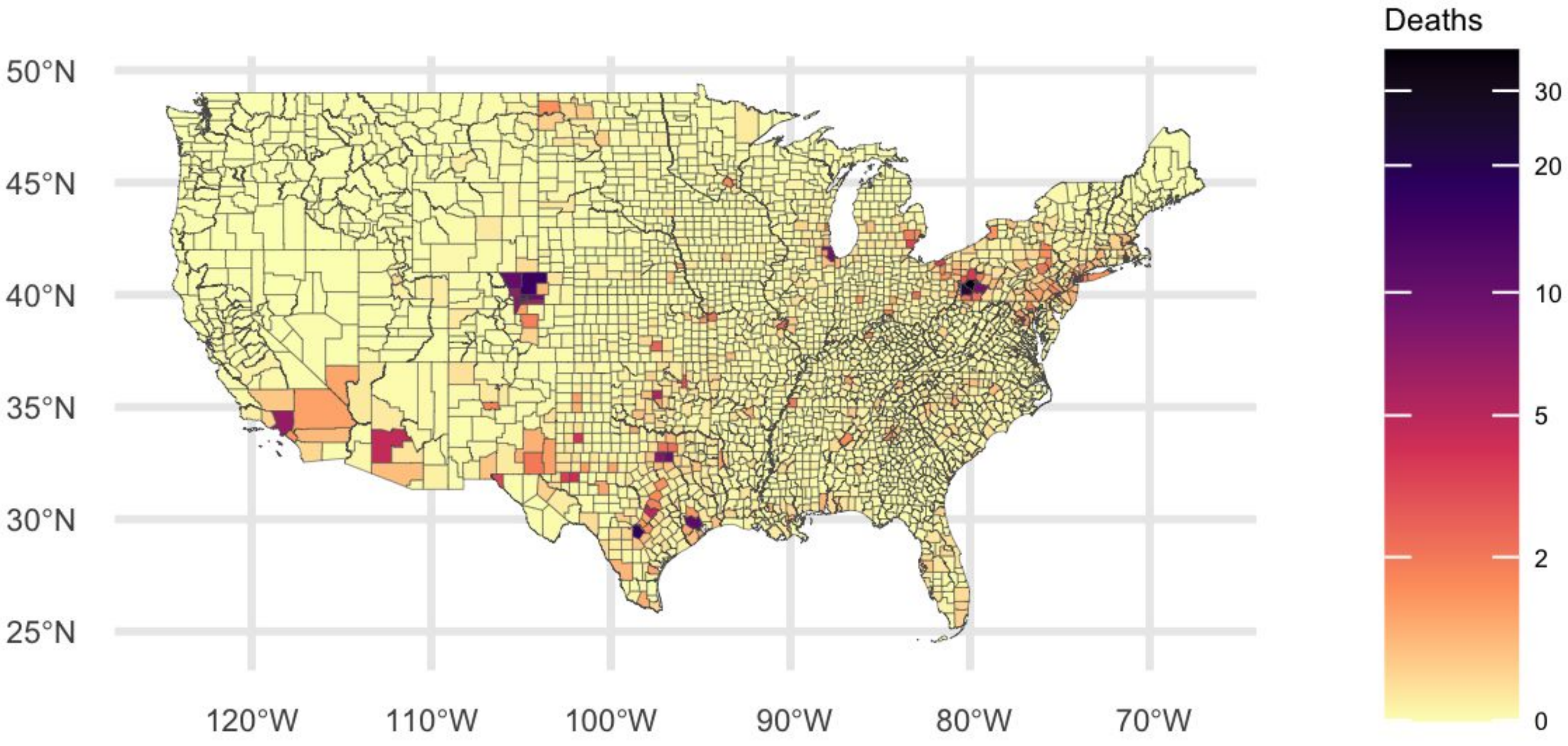
$7.4 billion in air pollution health damages due to flaring and venting in 2017

Health Impact	Flaring Health Impact Outcomes, based on Pollutant Type		Monetary Valuation of Health Impacts
	Pollutant Type	Cases (95% CI)	$ (mid value)
Premature Deaths	All Three	710	$7,300,000,000
Asthma Incidence, Heart Attacks	$PM_{2.5}$ and NO_2	210	$13,000,000
Respiratory Hospitalizations	$PM_{2.5}$ and Ozone	130	$4,000,000
Asthma Hospitalizations, Exacerbations, ED Visits (Alhanti)	All Three	73,000	$4,500,000
Sum Total	All pollutants	74,000	$7,400,000,000*

*Sums may not add up perfectly due to independent rounding. Summations of all individual health impacts (shown on the next slide), which include Alhanti asthma impacts and exclude Orellano asthma impacts, total to $7.4 billion.

Health Impact	O&G Health Impacts (Buonocore et al., under review)		Flaring Health Impact Outcomes, based on Pollutant Type		Monetary Valuation of Flaring Health Impacts
	Pollutant Type	Cases (95% CI)	Pollutant Type	Cases (95% CI)	$ (mid value)
Premature Deaths	-	-	PM2.5	360	$3,700,000,000
	-	-	O3	230	$2,400,000,000
	-	-	NO2	120	$1,300,000,000
	All Three	7,500 (4,500 - 12,000)	All Three	710 (480 - 1,100)	$7,300,000,000
Asthma Incidence	-	-	PM2.5	140	$8,200,000
	-	-	NO2	47	$2,800,000
	PM2.5 and NO2	2,200 (830 - 3,200)	PM2.5 and NO2	190 (66 - 300)	$11,000,000
Asthma Hospitalizations (Orellano)	-	-	PM2.5	1.1	$20,000
	-	-	O3	-	-
	-	-	NO2	2.1	$38,000
	PM2.5 and NO2	53 (1.2 - 110)	PM2.5 and NO2	3.2 (0.053 - 6.3)	$58,000
Asthma Exacerbations (Orellano)	-	-	PM2.5	8,500	$500,000
	-	-	O3	-	-
	-	-	NO2	13,000	$790,000
	PM2.5 and NO2	410,000 (9,200 - 810,000)	PM2.5 and NO2	22,000 (340 - 43,000)	$1,300,000
Asthma ED Visits (Orellano)	-	-	PM2.5	11	$5,000
	-	-	O3	-	-
	-	-	NO2	17	$7,700
	PM2.5 and NO2	530 (12 - 1,100)	PM2.5 and NO2	28 (0.43 - 56)	$13,000
Asthma Hospitalizations (Alhanti)	-	-	PM2.5	5.7	$100,000
	-	-	O3	1.3	$23,000
	-	-	NO2	3.2	$58,000
	-	-	All Three	10 (6.4 - 15)	$180,000
Asthma Exacerbations (Alhanti)	-	-	PM2.5	43,000	$2,500,000
	-	-	O3	9,700	$580,000
	-	-	NO2	21,000	$1,200,000
	-	-	All Three	73,000 (46,000 - 110,000)	$4,300,000
Asthma ED Visits (Alhanti)	-	-	PM2.5	54	$24,000
	-	-	O3	13	$5,700
	-	-	NO2	25	$11,000
	-	-	All Three	92 (58 - 140)	$42,000
Respiratory Hospitalizations	-	-	PM2.5	19	$570,000
	-	-	O3	110	$3,400,000
	PM2.5 and O3	1,500 (550 - 2,400)	PM2.5 and Ozone	130 (50 - 210)	$3,900,000
Heart Attacks	-	-	PM2.5	16	$1,100,000
	-	-	NO2	6.9	$480,000
	PM2.5 and NO2	270 (150 - 390)	PM2.5 and NO2	23 (13 - 33)	$1,600,000

Flaring and venting air pollution-attributable deaths in 2017



Flaring and venting impacts on disadvantaged populations

Justice 40 Category	Health outcome	Cases in Justice 40 category areas	All flaring and venting attributable cases	% of Health Impact Cases that belong to Justice 40 category.
Is low income (imputed and adjusted)? (FPL200S)	Premature deaths	220	710	31%
	Asthma Exacerbations (Alhanti)	22,000	73,000	30%
Greater than or equal to the 90th percentile for “American Indian/Alaska Native” as a percent of total reported population (quant_IA)	Premature deaths	130	710	18%
	Asthma Exacerbations (Alhanti)	14,000	73,000	19%
Greater than or equal to the 90th percentile for “Hispanic / Latino” as a percent of total reported population (quant_HL)	Premature deaths	70	710	10%
	Asthma Exacerbations (Alhanti)	10,000	73,000	14%

* 232 of the Justice 40 census tracts were dropped from the final health analysis dataset because their census tract data (GEOIDs) did not align perfectly between the two datasets. The Justice 40 dataset had 72571 unique GEOIDs, whereas the health dataset only had 72339.

- Of the air quality attributable deaths and pediatric asthma exacerbations due to flaring and venting:
    - **1 in 5** are in communities home to **Native American** populations
    - **1 in 3** are among **low income** populations

Distribution of impacts across states and counties in 2017 (top rankings by count and per capita impact)

Top 10 States, by health impact (deaths)	
State	**Total Deaths**
Texas	133.3
Pennsylvania	114.6
Colorado	75.9
Ohio	28.7
New York	28.0
Oklahoma	24.0
Illinois	22.2
Missouri	15.8
Michigan	14.8
North Carolina	14.3

Top 10 States, by per capita impact (deaths/100000)	
State	**Deaths per 100,000**
Texas	366.7
Kansas	110.9
Oklahoma	85.9
Pennsylvania	83.0
North Dakota	79.7
Nebraska	69.9
Colorado	58.0
Missouri	51.0
Kentucky	40.4
South Dakota	40.0

Top 10 Counties, by per capita impact (deaths/100000)		
State	**County**	**Deaths per 100,000**
Pennsylvania	Washington County	15.1
Colorado	Weld County	8.2
Pennsylvania	Greene County	8.1
North Dakota	Mountrail County	7.8
North Dakota	McKenzie County	7.6
Texas	Martin County	7.5
Texas	Loving County	7.3
North Dakota	Williams County	6.8
Texas	Winkler County	6.6
Texas	Ward County	6.1

Key insights

Flaring and venting emissions contribute to ozone, $PM_{2.5}$ and NO_2 pollution and attributable adverse health impacts across the country.

- In 2017 it resulted in:
  - Over $7.4 billion in health damages
  - 710 premature deaths
  - 73,000 asthma exacerbations among children
  - 1 in 3 of these impacts are among low income populations

- It also resulted 210 in instances of ozone NAAQS exceedances.
- Impact on O_3 conc. is significant and stronger in winter (up to 5 ppb; 18% in MDA8-O3) than in summer months (up to 2 ppb; 5%).
- **NEI 2017 underestimates emissions** from flaring venting in the oil and gas sector (16X lower for $PM_{2.5}$ & 20% -240% lower for other precursors nationwide). This varies by state with highest underestimates in Texas.
- Many flares over these basins are only captured in VIIRS but not in NEI [e.g., North Dakota]. Denver basin often observes the highest impact on O_3 and $PM_{2.5}$

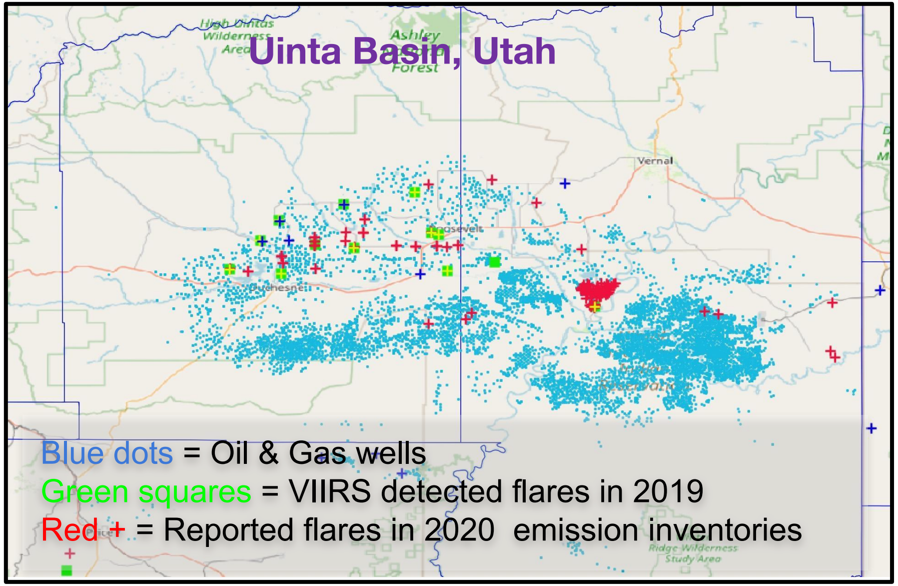
Additional details on methods

Emissions estimation methodology

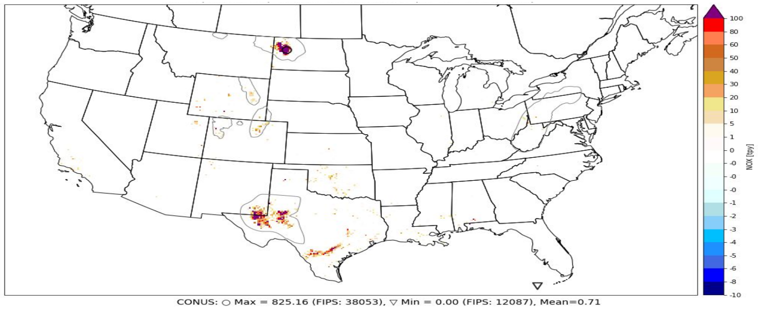
- See slides 10 and 11 for method of estimating flare emissions based on VIIRS's reported flared gas volume and hybrid VIIRS - Rystad - NEI estimations
- Hybrid VIIRS-based flare emissions are processed with SMOKE v4.6 with following treatments:
  - Emissions from 19 Oil & Gas source types (SCC) associated with flaring are replaced in NEI 2017 emission values with hybrid VIIRS estimations
  - Flare sources that are solely estimated from VIIRS are simulated as point sources with their stack parameters derived from empirical algorithms
  - EIA's reported monthly flare volumes are used to develop temporal profiles for allocating annual flare emissions to hourly value
  - Default VOC speciation profiles were applied for VOC emission from flaring and venting. Primary $PM_{2.5}$ from flaring and venting are attributed entirely to elemental carbon (EC).

Challenges in applying VIIRS-based flaring

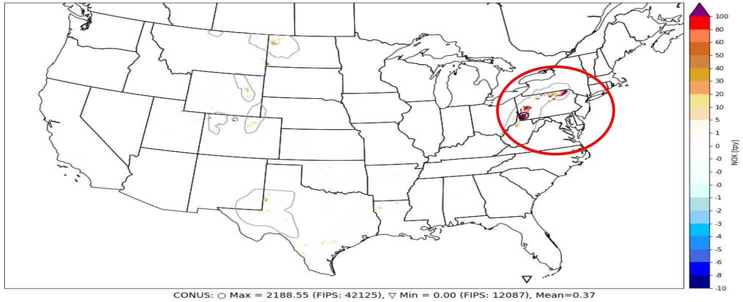
Not all flares are detected by VIIRS.



Use “hybrid” VIIRS & Rystad & NEI 2017 to capture all possible ranges of flare emissions.



Flare NO_x emissions from VIIRS-based only



Additional flare NO_x emissions from fusing VIIRS with Rystad and NEI

CMAQ Model Configurations

Model Configuration

- CONUS domain at 12km x 12km horizontal resolution, 35 vertical layers
- 2016 meteorology from WRFv4.7, 4 months modeled (January, April, July, October)
- Initial and boundary conditions from CMAQ-Hemi simulations for Northern Hemisphere
- CMAQ v5.2.1, Chemical mechanism: CB6r3 with aero6 and aqueous chemistry
- Disabled windblown dust, but included lightning emissions

Three modeling scenarios:

- Zero-out case (**woFlare**): including emissions from NEI 2016 for non-O&G and NEI 2017 O&G with flaring and venting emission excluded
- Base case (**wFlare2**): including emissions from *woFlare* and hybrid VIIRS-based flaring and venting emissions.
- Simulation results of wFlare2 are compared against woFlare to evaluate impact of emissions from flaring and venting on air quality (zero-out approach).

Methods: assessment of exceedances

- Exceedance counts are determined for each of woFlare and wFlare2 scenarios and then differences used to determine marginal impact of flaring and venting emissions on NAAQS threshold(s).
- An exceedance event is identified when concentration in any grid-cell for any pollutant exceeded its corresponding NAAQS for the relevant timescale
    - e.g., MDA8 Ozone at any grid-cell for any day exceeded 70 ppbV
- For this study, the model domain is 299 x 459 grid-cells and there are 123 simulation days in total. Thus there are up to 299 x 459 x 123 possibilities for MDA8 Ozone or Daily Ave $PM_{2.5}$ exceedances to occur.
- High number of exceedances does not necessarily lead to violation of NAAQS

Population & Background Health Data

Health Outcome	Population Group	Source(s)	Year	Spatial Resolution
Mortality	All Ages	U.S. Centers for Disease Control, Wide-Ranging Online Database for Epidemiological Research (CDC WONDER)	1999-2016	County
Respiratory Hospitalizations	≥65 years of age	BenMAP and Health Care Utilization Project (HCUP)	2011-2014, varies by outcome	State
Asthma Incidence	5-17 years of age	Winer et al., 2012	2006-2008	National
Asthma Exacerbations	5-17 years of age	State Prevalence: https://ephtracking.cdc.gov/DataExplorer/ National Prevalence: https://www.cdc.gov/asthma/nhis/2017/table4-1.htm Exacerbation Rate: Ostro et al., 2001	1993	State and National
Asthma ED visits and hospitalizations	5-17 years of age	BenMAP, CDC, and Health Care Utilization Project (HCUP)	2014-2018	State and National

Population data: U.S. Census American Community Survey 2018

Concentration response functions

Health Outcome	Population at Risk	Study	Pollutant	Metric	CRF central estimate (95% CI)
Mortality	Adults ≥ 25 years of age	Vodonos *et al.* 2018	$PM_{2.5}$	Annual Average ($\mu g/m^3$)	1.29% (95% CI: 1.09 - 1.5%)
Mortality	Adults ≥25 years of age	Faustini *et al.* 2014	NO_2	Annual Average ($\mu g/m^3$)	0.4% (95% CI: 0.2 - 0.6%)
Mortality	Adults ≥25 years of age	Turner *et al.* 2016	O_3	Annual Average of the 8hr maximum daily average (8hr MDA)	0.2% (95% CI: 0.1 - 0.4%)

Concentration response functions

Health Outcome	Population at Risk	Study	Pollutant	Metric	CRF central estimate (95% CI)
Asthma Incidence	Children between 5-17 years of age	Khreis *et al.* 2017	$PM_{2.5}$	Annual average ($\mu g/m^3$)	3.0% (1.0 - 4.9%)
Asthma Incidence	Children between 5-17 years of age	Khreis *et al.* 2017	NO_2	Annual average ($\mu g/m^3$)	1.2% (0.5 - 1.7%)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Orellano *et al.* 2017	$PM_{2.5}$	Annual average ($\mu g/m^3$)	0.22% (0 - 0.44%)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Orellano *et al.* 2017	NO_2	Annual average ($\mu g/m^3$)	0.39% (0.01 - 0.78%)

Concentration response functions

Health Outcome	Population at Risk	Study	Pollutant	Metric	CRF central estimate (95% CI)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Orellano *et al.* 2017	$PM_{2.5}$	Annual average ($\mu g/m^3$)	0.22% (0 - 0.44%)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Orellano *et al.* 2017	NO_2	Annual average ($\mu g/m^3$)	0.39% (0.01 - 0.78%)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Alhanti *et al.* 2016	$PM_{2.5}$	Annual Daily Average ($\mu g/m^3$)	0.25% (0.13 - 0.50%)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Alhanti *et al.* 2016	NO_2	Annual Average of the daily 1-hr max (ppb)	0.42% (0.33 - 0.58%)
Asthma Exacerbations, ED Visits, and Hospitalizations	Children between 5-17 years of age	Alhanti *et al.* 2016	O_3	Annual Average of the 8-hr max (ppb)	0.25% (0.14 - 0.36%)

Concentration response functions

Health Outcome	Population at Risk	Study	Pollutant	Metric	CRF central estimate (95% CI)
Respiratory Hospitalizations	Adults ≥ 65 years of age	Levy 2012 pooled with Zanobetti 2009	$PM_{2.5}$	Daily Average ($\mu g/m^3$)	0.11% (0.0016 - 0.00057)
Respiratory Hospitalizations	Adults ≥ 65 years of age	Ji *et al.* 2011	O_3	Annual Average of the 8-hr max (ppb)	0.16% (0.058 - 0.26%)
Heart Attacks	Adults ≥ 18 years of age	Mustafic et al., 2012	$PM_{2.5}$	Daily Average ($\mu g/m^3$)	0.25% (0.14 - 0.36%)
Heart Attacks	Adults ≥ 18 years of age	Mustafic et al., 2012	NO_2	Daily Average ($\mu g/m^3$)	0.11% (0.06 - 0.16%)

Details on Vodonos *et al.* 2018

- Meta-analysis of 53 epidemiological studies on air pollution
- 39 in North America, 8 in Europe, 6 from Asia
- All cause, respiratory, cardiovascular, cardiopulmonary, or lung cancer mortality
- All studies adjusted for numerous confounders
- 95% CI of CRF overlaps with LePeule *et al.* 2012 (1.4% (95% CI: 0.7%-2.2% per $\mu g/m^3$), which has used in EPA RIAs
- Found impacts below the NAAQS

Details on Faustini *et al.* 2014

- Meta-analysis including 23 separate studies that evaluated NO_2 and mortality
- Adjusted for $PM_{2.5}$ exposure
- All-cause, respiratory, and cardiovascular mortality
- All studies adjusted for numerous confounders
- 7 studies from United States, 2 from Canada, 4 from Asia, 10 from Europe

Details on Orellano *et al.* 2017

- Meta-analysis of moderate to severe asthma exacerbations with 22 studies
- 1-6 day lags between exposure and exacerbation
- 6 studies in United States, 5 in Canada, 6 in Europe, 4 in Asia, 1 in Australia
- Adjusted for multi-pollutant exposures
- Found statistically significant relationships in children for both NO_2 and $PM_{2.5}$

EXPERT REPORT OF THOMAS MICHAEL ALEXANDER, ALEXANDER ENGINEERING

2.9.2023

I. EDUCATION AND EXPERIENCE

I worked for Southwestern Energy (SWN) for 18 years (1998 – 2016) first as a consultant and then as a staff production and completion engineer. I was team leader for their Fayetteville Shale discovery team and Completion Manager. More recently, from late 2012 to 2016, I served as Vice President of Health, Safety & Environment for (SWN). I also worked for SWN's Canadian subsidiary, SWN Resources Canada in New Brunswick, Canada as the General Manager from mid-2010 through most of 2012. Prior to SWN I worked for New Prospect Company and Revere Corporation in Fort Smith, Arkansas, Habersham Energy Company in Englewood, Colorado, Southwest Operating, Incorporated and Altair Energy Corporation in Tyler, Texas and Schlumberger Offshore Services in Houston, Texas. From 1975 to 1981, I served in the United States Air Force as a B-52H Navigator and Radar Navigator.

I received a Bachelor of Arts in Psychology from Wake Forest University (1973). I did post-graduate work in chemistry and genetics at Duke University (1973). I received a Master of Science, Mining Engineering (1981) and a Bachelor of Science, Mining Engineering (1981) from South Dakota School of Mines and Technology. I completed the course work for Master of Arts, Environmental Policy, and Management at the University of Denver (1994).

I have been a consultant to EDF for over 6 years working on: underground gas storage, flaring, venting, and conventional and unconventional regulations for downhole activities and oil and gas well completions. Much of this work focused on eastern states, other than as follows. I assisted EDF in their advocacy before the New Mexico Oil Conservation Commission and Colorado Oil and Gas Conservation Commission when each adopted rules to prohibit routine flaring and venting and limit other instances of flaring and venting. I have also assisted EDF in its contributions to the Interstate Oil and Gas Compact Commission and Energy Resources, Research and Technology committee and two American Petroleum Institute work groups on risk management, health, safety and environment, security and training. These contributions lead to recently published revised and updated recommended practices on underground gas storage, API RP 1170 and API RP 1171.

II. INTRODUCTION

Over the past couple years, EPA, New Mexico, Colorado and a variety of interested parties (including EDF) have deliberated over proposed rules regarding the disposition of associated gas from oil wells. I consulted for EDF during the development and adoption of Colorado and New Mexico rules to prohibit routine venting and flaring. My report on EPA's proposed rules for associated gas builds on the opinions I provided to EDF during those state rulemaking processes. My opinions reflect my extensive experience as an oil and gas operator, familiarity with the New Mexico and Colorado rules, and review and analysis of the EPA proposal.

The EPA proposal requires owners and operators of oil wells to recover the associated gas from the separator and route the associated gas to a sales line or implement one of the following compliance options: (1) recover the gas from the separator and use the gas as an onsite fuel source; (2) recover the gas from the separator and use the gas for another useful purpose that a purchased fuel or raw material would serve; and (3) recover the gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well for enhanced oil recovery. Operators may flare or combust associated gas upon submission to EPA of a certified demonstration that all four of the compliance options are technically infeasible or unsafe.

I concur with EPA's proposal in so far as it requires owners and operators of oil wells to recover associated gas from the separator and route the gas to a sales line or one of the other abatement options EPA proposes which constitute a beneficial use of the associated gas. However, I have concerns with the technical infeasibility exemption. In my opinion, this exemption has the potential to be abused and may result in a significant loophole in the rule that significantly diminishes available, cost-effective emission reductions. A more protective approach would be for EPA to follow the lead of New Mexico and Colorado and require capture other than in narrowly tailored and specifically enumerated exemptions for temporary flaring or venting. My report discusses those instances when an operator must temporarily flare or vent for safety or technical reasons. I suggest EPA revise its rule to replace the technical infeasibility exemption with specific exemptions that allow for temporary flaring or venting modeled on the Colorado and New Mexico rules. As I discuss, these state rules are models for the nation and the provisions therein apply equally to operators and operations outside of these two states.

III. PRINCIPLES THAT GUIDE REPORT

The following discussion sets forth core principles that must guide EPA's consideration of the appropriate disposition of associated gas. First, there is no reason why oil and gas operators cannot plan well ahead of any drilling program to ensure they have the necessary infrastructure in place to avoid flaring and/or venting except in emergency situations and instances where the volume of gas and time needed to flare is minimal such as during bradenhead testing, routine equipment maintenance, packer leakage tests and maintenance events such as blowdowns of low pressure and low volume equipment. While the majority (90%) of my engineering and operational experience was with gas/condensate, dry gas, and low gas-to-oil (GOR) oil wells, the steps we took to ensure full utilization of the associated gas apply equally to steps oil producers can and should take. In all cases of my personal experience with oil production, the associated gas was deployed as an onsite fuel source. This is just one example of beneficial use of associated gas. I have never been personally involved with producing oil wells wherein the associated gas was vented or flared routinely. The gas/condensate and dry gas basins and their associated reservoirs required extensive prior planning internally as well as with all mid and downstream entities as it would be unacceptable to produce the wells in any fashion without adequate takeaway capacity. We must ask ourselves, why are operators with oil production any different than those with primarily gas production? I submit they are not except that one is forced to plan ahead while the other drills and produces their major product without proper regard for the associated gas.

The second principle has to do with basic economics. The EPA proposal contemplates four abatement alternatives to deal with associated gas from oil wells. While each alternative has its pros and cons, they are also necessarily based upon, to some extent, well and/or lease economics. The predominant methodology used by regulators, including EPA, and operators, is to evaluate these economic decisions on the gas production only and its prevailing pricing. In my opinion, the entire well/lease revenue stream-including revenue from oil- needs to be considered, especially if the decision to get to a sales line is the question. Considering gas revenue only actually promotes waste and negative environmental impact.

The third principle regards well shut ins. Operators have from time to time claimed that shutting in a well is damaging to the reservoir and thus the productivity of the well. The argument is also at times linked to the timing of shut ins. For example, some claim that shutting in during or just after a frac flowback can be detrimental to performance. This argument may be used to justify continuing to flow an oil well and venting or flaring the associated gas. While it's impossible to characterize every producing horizon, in my experience, it is rare that shutting in a well will adversely affect short to long-term performance. Conversely, in some cases, shutting in can enhance performance. We discovered that doing so in the Fayetteville Shale was often an advantage as it allowed the created fracture network to close on and better confine the proppant pack vs losing proppant in the high rate flowback which would create a pinch point at the fracture face, near wellbore. If the justification to flare is based upon this notion that shutting in will adversely impact a well, substantial, and significant evidence must be provided to support the claim.

IV. APPLICABILITY OF COLORADO AND NEW MEXICO RULES TO OTHER JURISDICTIONS

A. Routine Flaring from New Oil Wells is Always Avoidable

Rules and regulations were adopted in both Colorado and New Mexico that move toward the elimination of routine flaring. In some cases, operators in both jurisdictions were taking advantage of weak and unclear regulations to the point that year after year, natural gas was unnecessarily vented or flared. I supported the revisions of these rules and in my opinion the Colorado and New Mexico standards represent common-sense, technically feasible, cost-effective rules that can serve as models for EPA. These rules were adopted with input from multiple operators and trade associations, after many months of stakeholder input, and pursuant to a lengthy and robust rulemaking process.

I have operated in Colorado (i.e., Denver basin) and various basins (e.g., Arkoma, East Texas, Denver, and Appalachian) similar in nature to the Permian and San Juan basins in New Mexico. In total over my 35-year active career I operated in more than 7 other states (including Mississippi, Louisiana, Arkansas, Texas, Nebraska, Wyoming, and Oklahoma) and at least 11 other basins. All these basins have very similar reservoir drives, geological traps, pressures, temperatures, porosities, permeabilities, hydrocarbon maturity, drilling through production techniques, infrastructure, services, personnel, supplies, health, safety and environmental issues, risks and regulatory environments. There is nothing about the prohibition on routine flaring or the temporary flaring exemptions established by Colorado and New Mexico that would not be applicable and of use in these and other jurisdictions. The types of reservoir traps, reservoir drives, subsurface geology, structures, production technologies, infrastructure buildouts, availability of services and supplies are all very similar across producing areas. Even if new discoveries are made in areas largely devoid of infrastructure, adequate takeaway capacity for associated gas can be built out in coordination with well development to avoid routine flaring. An excellent example of this is the Fayetteville Shale in the eastern Arkoma basin with which I had extensive experience. The discovery necessitated extensive midstream and downstream infrastructure and establishment of new services and supplies located in proximity to wells and personnel, yet this was all done with intricate planning to capitalize on the economic recovery of many trillion cubic feet of natural gas. The example of the Fayetteville shale discovery and development can be an excellent model for all types of production, including oil. Therefore, I submit the Colorado and New Mexico approach, wherein operators of new wells must have adequate takeaway capacity for associated gas upon production can be deployed throughout all producing basins.

B. *Routine Flaring from Existing Wells Can be Avoided by a Combination of Temporary Shut-Ins and Installation of Equipment to Temporarily Capture and Put to Beneficial Use Associated Gas*

There are situations operators do or will face that negatively impact their ability to sell associated gas such as midstream or downstream interruptions (short to long term), gas composition requirements change, line pressure changes (upward), and takeaway capacity change downward. There may also be other situations operators will encounter. Whatever the issue, operators must be prepared to adjust in such a manner as to avoid anything but short-term flaring or worse, venting. Typical solutions that may be added include compression, compressing associated gas into CNG for transport and sale, expanded onsite use of associated gas, electrical generation for nearby use, and reinjection or injection. The typical resistance to these options involves the cost of additional measures to avoid flaring. I have two comments: First I have previously discussed the concept of utilizing the entire well revenue stream to justify measures to avoid flaring. This is an important concept not to be ignored. Second, there are always many risks associated with oil and gas exploration and production. A key risk is that operators always face the risk of low prices which is for all practical purposes the same as escalating costs of production. In the case of low prices, prudent operators will either use other measures to restore good economics, shut-in until conditions improve, or plug out the well(s). Changing economics to me is no reason to allow operators to waste a natural resource or pollute the environment.

C. *A Prohibition on Routine Flaring is Workable with Narrowly Tailored Exemptions that Allow Operators to Flare Temporarily*

The New Mexico and Colorado rules prohibit routine flaring and allow limited flaring or venting during specifically enumerated exemptions. I concur with this approach. I have reviewed the exemptions in the Colorado and New Mexico rules and find each reasonable, with some slight revisions discussed below. Moreover, I find each exemption applicable to basins outside of Colorado and New Mexico. In my opinion a federal rule that only permits venting and flaring in the specific exemptions I discuss below is reasonable and cost-effective.

I recommend EPA require gas capture and only allow venting and flaring associated gas from oil wells in the following circumstances, and subject to the temporal limitations discussed below:

1. Upset Condition. Operators should be allowed to flare during an upset condition defined as a sudden and unavoidable failure or breakdown of equipment or event beyond the reasonable control of the operator that significantly disrupts operations. This does not include failures caused by negligence or poor equipment maintenance on the part of the operator.

This also should not exceed 24 cumulative hours. In my experience, these situations do occur and it is reasonable for the operator to be allowed some flexibility for conditions beyond their control; however, there is no real reason why the flaring should extend beyond 24 cumulative hours even if that requires shutting the well in temporarily. Most of these situations can be remedied quickly and the interruption of cashflow will be minimal. In many cases, after a short shut-in, the well will have flush production that will make up for the lost production.

2. Pipeline, Equipment and Facilities Commissioning. Operators should be allowed to flare during pipeline, equipment and facilities commissioning, but only as long as necessary to purge introduced impurities. An operator may need to flare temporarily when it is first connecting to a pipeline that has just been constructed, for example, if the pipeline was cleaned out with substances that the midstream operator does not want in the gas. This is actually a perfect example of how proper coordination with midstream and/or downstream operations can substantially mitigate any lost production of oil and also avoid unnecessary flaring of associated gas. There simply is no reason to be allowed to flare associated gas for an extended amount of time in this case since it does not take long to clear impurities from equipment, facilities or pipelines. Flaring during this exemption will often be of very short duration.

3. Non-Pipeline Quality Gas. A third instance where operators may need to flare is where natural gas does not meet pipeline specifications. Depending on the circumstances, such as the type of play and composition of the fracking fluid, an operator may need to flare to rid the natural gas of non-pipeline quality components such as nitrogen or CO_2 for anywhere from two days to a week. New Mexico requires an operator to analyze the natural gas samples twice a week to determine if pipeline specifications have been achieved. Operators must route the natural gas into the gathering pipeline when pipeline specifications have been met. The New Mexico sampling requirement is very lenient. It's to the operator's advantage in all cases to discover that pipeline specifications have been achieved as soon as possible since they can then begin to send the gas to sales. In my experience, we increased the frequency of sampling as soon as possible after cleaning up the wells following hydraulic fracturing as we wanted to be selling product as soon as possible.

4. Active Repair and Maintenance. During active repair and maintenance an operator may need to vent or flare. Active repair and maintenance include blowing down and depressurizing production equipment, production tests, bradenhead monitoring and packer leakage tests. Operators should be required to flare, rather than vent, during active repair and maintenance other than during bradenhead monitoring and packer leakage tests, as discussed below. Temporary flaring can be limited to short duration with proper planning. All too often operators don't have good preventative maintenance programs and wind up being "surprised" by mechanical failures of various kinds. This is unacceptable. Under the proposed provision conditions, and in my experience, the operator should plan well ahead and arrive at the well with all the necessary equipment, parts, services and trained personnel to make the necessary repairs, preventive maintenance and tests in a very timely manner. I recommend EPA limit production test flaring to 24 hours yet allow operators to request pre-approval to flare for up to 60 days, based on the reservoir and depth of knowledge needed to understand whether the well will produce an attractive return on investment. For example, in

cases of low permeability reservoirs, operators may need longer test periods to ensure sufficient cost effective production.

D. *Venting is only Necessary for Safety or during Bradenhead and Packer Leakage Tests*

There are three times when temporary venting, rather than flaring, should be allowed. One is if venting is necessary to protect the safety of personnel. A second is during bradenhead monitoring. A third is during a packer leakage test. Venting can be limited to no more than 30 minutes during bradenhead monitoring and packer leakage testing. In my experience venting during these three circumstances is uncommon and with these proposed time limitations, will not lead to significant waste or emissions.

V. CONCENS WITH THE PROPOSED TECHNICAL INFEASIBILITY EXEMPTION

The EPA proposes that if there is no access to a sales line there are three acceptable alternatives that constitute beneficial use of the associated gas: use of the gas onsite for fuel; use of the gas for another useful purpose that a purchased fuel or raw material would serve; and injection or reinjection. If none of these three alternatives are deemed to be viable, the owner or operator must submit a certified demonstration by a professional engineer or other qualified individual in the first annual report for the affected facility indicating why these options are unsafe or not technically feasible. Each year the operator must report any circumstances that may have changed regarding the need to flare relative to the initial certification. As currently proposed, this has the potential to result in indefinite (i.e., routine) flaring. The EPA has rightly requested comment on how to avoid this situation.

I have the following concerns with the technical infeasibility demonstration, as proposed. First, it is not at all clear what the EPA will do with the submitted certification. How will it be reviewed and approved? What relationship will this professional engineer or qualified person have with the operator? Does the EPA have personnel qualified to test the submittals? Will the EPA challenge the submittal and potentially deny permission to flare? Does EPA have adequate personnel to review all the submittals. In my opinion, EPA may be inundated by submittals since operators must submit a demonstration any time they wish to flare, including instances of temporary flaring, which could be quite frequent. The idea that these submittals will be collected and filed away is unacceptable. The framework proposed by EPA will require significant agency time and resources to ensure that flaring is truly limited to instances where capture is technically infeasible or unsafe.

The framework adopted by New Mexico and Colorado, and recommended by EDF, is likely to result in significantly less flaring while also significantly decreasing the demand for limited agency resources. The operators that find themselves in the position of no sales line, limited onsite fuel use, injection or reinjection challenges or other useful purpose may only flare for short periods of time and only in narrowly tailored, explicitly enumerated instances. The framework will incent the pursuit and employment of methods and technologies that will require prior planning--planning that should have been done well before the operators find themselves in a position where they seek to flare, use of capital outside that generated by the associated gas, and more collaborative efforts with midstream, downstream, and other nearby operators.

In summary, there is no reason to pursue, on purpose, oil production with associated gas, knowing full well the typical economic solution for selling the gas vs flaring, is to use the revenue from the gas only to justify implementation of means to sell the gas. There should always be some use onsite or in the field, emerging technologies and methodologies (such as compressing to CNG), injection or reinjection (yes that will require capital), or delay drilling completion and production until solutions have been achieved.

VI. CONCLUSION

Allow me to summarize. I applaud EPA's commitment to address venting and routine flaring. It has gone on too long and operators have in far too many cases proceeded with operations unchecked, utilizing procedures that waste a natural resource and pollute the environment. It's obvious the first, and best, solution is to connect to a sales line to capture the associated gas and its value. In lieu of that option, EPA's three abatement options provide alternative means for gas capture.

Colorado and New Mexico have taken bold steps through highly collaborative efforts with operators, regulators and a whole host of interested stakeholders to further the cause to eliminate routine flaring. I was deeply involved with those efforts and through my 35+ years of oil and gas engineering and operating experience, there is nothing that unique about Colorado and New Mexico that would render these states' regulations concerning venting and flaring inapplicable in the remaining oil and gas producing jurisdictions, whatsoever.

By simply applying economics that incorporate the entire wellhead revenue stream and exercising detailed prior planning to ensure infrastructure availability, a significant amount of flaring will be avoided. I do understand there are instances wherein venting and flaring may be justified for safety reasons, but these cases are rare. Beyond this, by incorporating the very same measures now being deployed by Colorado and New Mexico, as discussed in detail above, to address upset conditions, pipeline and equipment commissioning, non-pipeline quality gas, active repair, and maintenance, bradenhead monitoring and packer leakage tests, occurrences of flaring not addressed by the three EPA proposed abatement measures will be substantially eliminated, which must be everyone's goal.