November 14, 2024
Via Email

Re: Environmental Defense Fund Comments on Potential Amendments to the Oil and Gas Methane Regulation to Implement U.S. EPA's Emissions Guidelines

Dear Ms. Yonn and Mr. Nyarady:

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF") on potential revisions to the California Air Resources Board's ("CARB") Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities ("Oil and Gas Methane Regulation") to implement EPA's Emissions Guidelines for Oil and Gas Sources.

EDF is an international membership organization with more than 3 million members and activists worldwide and almost half a million in the state of California, many of whom are deeply concerned about the pollution emitted 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.

We strongly support CARB's intention to revise its existing Oil and Gas Methane Regulation to align with EPA's final standards for designated facilities set forth in 40 C.F.R. § OOOOc. We agree with CARB that many of the requirements in the Oil and Gas Methane Regulation already are as protective as the EPA requirements for designated facilities covered by the EPA emissions guidelines and thus that minimal revisions to existing requirements are necessary.[1] We also agree with CARB regarding the revisions to existing rules and additional rules that CARB is contemplating to implement the emissions guidelines. We offer below our supportive comments for the revisions CARB proposes. In addition, we provide our independent analysis of EPA's cost estimates for the OOOOc requirements generally, as well as an independent analysis prepared by Rystad Energy regarding abatement options to eliminate methane emissions from oil wells that produce associated gas.

We urge CARB to finalize the contemplated revisions to its existing methane rule and submit its CAA Section 111(d) state implementation plan ("Section 111(d) SIP") as expeditiously as practicable in order to secure critically needed methane reductions from the oil and gas sector.

[1] See CARB, Potential Amendments to the Oil and Gas Methane Regulation to Implement U.S. EPA's Emissions Guidelines, slide 15, Aug. 15, 2024.

I. Introduction

A. Overview of EPA's Emissions Guidelines

On March 8, 2024 EPA finalized the first ever federal standards of performance to address methane pollution from existing sources.[2] Existing sources (so called "designated facilities") are sources constructed on or December 6, 2022. According to EPA, implementation of standards of performance for designated facilities will avoid the release of 35 million tons of methane to the atmosphere between 2024 and 2028.[3] The rules will also result in the reduction of harmful co-pollutants that contribute to direct public health impacts and regional ozone. EPA estimates that standards of performance for designated facilities will reduce 8.6 million tons of VOCs that contribute to ground-level ozone[4] and approximately 333 million tons of hazardous air pollutants, including benzene, that threaten public health, between 2024 and 2028.[5] Implementation of EPA's standards of performance for designated facilities will also result in gas savings that lead to increased profit, royalties and taxes. Per EPA's Regulatory Impact Analysis, by 2033, the increased recovery of gas will offset $1.4 billion per year of compliance costs.[6]

B. Swift and Deep Reductions of Methane Are Critically Necessary

Climate change poses an existential threat to humanity and to all the living beings on our planet. Scientific evidence overwhelmingly demonstrates that climate change is already causing immediate, devastating impacts on communities, and that these harms will worsen dramatically as greenhouse gas pollution continues to rise. Immediate and deep reductions in greenhouse gases, particularly of methane, are critical. The contribution of Working Group III to the IPCC Assessment Reports highlights the importance of near-term methane reductions, finding with "high confidence" that "[a]s methane has a short lifetime but is a potent GHG, strong, rapid and sustained reductions in methane emissions can limit near-term warming and improve air quality by reducing global surface ozone."[7] 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).[8] A deep near-term reduction in methane pollution is therefore one of the most important actions needed to address the climate crisis.

C. California's Role in Implementation of EPA's Emissions Guidelines

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[2] 89 Fed. Reg. 16820 (March 8, 2024).
[3] EPA, Regulatory Impact Analysis (hereinafter "RIA"), Table 1-3.
[4] *Id*.
[5] *Id*.
[6] Id. at Table 1-4.
[7] IPCC, 2023: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland, 184 pp., doi: 10.59327/IPCC/AR6-9789291691647.
[8] 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.

Section 111(d) of the Clean Air Act ("CAA") authorizes states to play a central role in the elimination or reduction of greenhouse gases such as methane from existing sources. For certain pollutants, including greenhouse gases, Section 111(d) of the CAA requires EPA to issue emissions guidelines for sources of pollution for which EPA has promulgated New Source Performance Standards ("NSPS") pursuant to Section 111(b) of the CAA. Emissions guidelines provide information to states to guide them in establishing, implementing, and enforcing standards of performance for existing sources for certain air pollutants, including greenhouse gases, to which an NSPS would apply if the source were a new source. EPA has issued general regulations to implement Section 111(d) of the CAA,[9] as well as specific emissions guidelines for select sources of pollution for which EPA has promulgated NSPS. EPA's regulations implementing Section 111(d) of the CAA sets forth procedural and substantive requirements that states implementing EPA emissions guidelines must comply with when preparing state plans. The emissions guidelines for oil and gas sources include presumptive standards of performance for designated facilities that states may rely on when preparing a Section 111(d) SIP as well as revisions to the procedures contained in the general regulations.

Under EPA's general implementing regulations for Section 111(d) and the OOOOc emissions guidelines for oil and gas sources, states such as California that are home to designated facilities must submit a SIP establishing standards of performance for designated facilities to EPA for approval within two year's of EPA's publication of the final Methane Rule in the Federal Register. State SIPs must meet the following certain criteria:

(1) Standards of performance for designated facilities must be at least as protective as the federal standards.[10] States may adopt more stringent standards for designated facilities than those finalized by EPA provided the state has authority to do so.[11]

(2) Define the regulated emissions sources in a manner that is the same or substantially similar to EPA's defined designated facilities.

(3) Regulate the same designated pollutant, which in the case of the Oil and Gas Methane Rule, is methane or a surrogate for methane such as total hydrocarbons.

(4) Use the same format for each standard of performance that EPA uses (i.e., numerical or work practice standard).

(5) Contain adequate monitoring, recordkeeping and reporting provisions to ensure continued compliance with the standards and projected emissions reductions

[9] 40 C.F.R § 60.20a et seq.

[10] States may propose a less stringent standard for a facility in certain circumstances based on the facility's remaining useful life ("RULOF"). States must demonstrate the basis for any less protective standard of performance according to strict criteria EPA sets forth in the final emissions guidelines. See EPA's discussion of RULOF at 89 Fed. Reg. 16820 at 17,002.

[11] 40 C.F.R § 60.24a.(i)(1)("Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing, as part of the plan: (1) Standards of performance more stringent than emission guidelines specified in this part.")

II. Revisions Required to CARB's Existing Oil and Gas Methane Rule

CARB has been a leader with respect to reducing methane pollution from oil and gas sources since it promulgated its methane rule in 2017. That rule established many requirements that are as protective, if not more protective, than the federal standards of performance for existing sources finalized by EPA this year. For example, CARB requires quarterly instrument inspections for production facilities and compressor stations, prohibited the use of pneumatic controllers, other than those installed prior to January 1, 2016, requires routine monitoring of emissions from compressors, and as of last year, requires owners and operators to investigate, and repair as appropriate, notices from CARB of the satellite detection of large leaks at oil and gas facilities.[12]

Because of the strength of CARB's existing oil and gas methane rule, CARB need only revise certain requirements in its existing methane rule. CARB has flagged the following for potential revision as part of California's development of its CAA Section 111(d) SIP:

(1) Expand zero emitting pneumatics requirements
(2) Ban associated gas venting
(3) Lower LDAR leak concentration to 500 ppm
(4) Allow alternative LDAR approaches that achieve equivalent or better emissions reductions
(5) Ban or minimize emissions from liquids unloading
(6) Limit emissions from centrifugal dry seals
(7) Expand AVO
(8) Require well closure plans as well as other compliance plans and notifications of compliance
(9) Address SEP
(10) Reconsider heavy oil exemption for LDAR.

We agree with CARB that these revisions are likely necessary to ensure that CAA's Section 111(d) SIP meets EPA approval criteria. We support CARB's making these revisions to its methane rule and urge CARB to do so as expeditiously as practicable in order to secure near-term reductions of methane from unregulated sources such as oil wells that produce associated gas.

A. Independent Cost Estimates or Vendor Data

In response to CARB's request for data on "cost considerations" we include below EDF's independent analysis of EPA's estimate of compliance costs, as well as analysis prepared by third-party consultants.[13] These analyses demonstrate that EPA's cost estimates for OOOOc (and OOOOb) is reasonable and well supported, confirming EPA's conclusion that new requirements for new and existing sources will impose minimal costs on the oil and gas industry.

[12] 17 C.C.R. § 95665 et seq.
[13] CARB, Potential Amendments to the Oil and Gas Methane Regulation to Implement U.S. EPA's Emissions Guidelines, Slide 20, Aug. 15, 2024.

1. *EDF Analysis*

EDF economists and third-party experts retained by EDF to evaluate EPA's cost estimates and analysis conclude that "EPA's analysis and conclusions are reasonable and well supported..."[14] These experts reviewed the Methane Rule (both the requirements for new sources and existing sources), Technical Support Document and Regulatory Impact Analysis. They also reviewed information regarding the production levels of new and existing wells, industry profits in 2021, 2022 and 2023, and EPA's estimate of total annualized compliance costs for the Methane Rule. Their review and analysis confirmed the reasonableness of EPA's estimate that the Methane Rule's total annualized compliance costs for new and existing owners and operators are estimated to represent just 0.5% of industry revenue:[15]

> EPA's compliance cost projections are derived from reasonable cost estimates associated with each standard multiplied by the estimated number of sources that will be subject to those standards. In determining the costs of each standard, EPA relied on numerous data sources, including data from past federal and state rulemakings and, in many cases, industry supplied data.[16]

EDF's experts also agree that EPA's analysis of the costs of LDAR inspections and associated gas flaring rules "are reasonable and are based on reliable data from state regulators and industry."[17] Indeed, EDF estimates that "costs may be lower in reality than assumed by EPA,"[18] due in part to studies documenting that "compliance costs decline over time as operators learn how to comply at lower costs and as manufacturers ramp up production of equipment and devices."[19]

EDF's experts also agree with EPA that operators of existing wells will be able to absorb compliance costs. Based on an analysis of revenue and ownership profiles, EDF estimates that operators of these wells generated $608 billion in 2022, with a per operator average revenue of $53 million. In 2019 and 2021, the average per operator revenue for operators of existing sources was $24 million and $32 million, respectively.[20] EPA estimates that the total annualized compliance costs for the NSPS and Emissions Guidelines represent 0.5% of industry revenue,[21] accounting for gas savings. EPA does not separately evaluate compliance costs for the emissions guidelines. Nevertheless, the significant average revenues generated by owners of existing sources (nearly half a billion in the most recent year evaluated) indicates that the majority of them will be able to absorb compliance costs that represent less than 1% of their revenue. In addition, many marginal wells are existing wells. A separate EDF analysis of the ownership of marginal wells reveals that the majority of such wells (three quarters) are owned and operated by

[14] Decl. of Lucija Muehlenbachs, Lauren Beatty, and Maureen Lackner at 2, Opp. of Environmental and Health Respondent-Intervenors to industry Petitioners' Motion for Stay, Attachment A, starting at p.34.
[15] Id. at 3.
[16] Id. at 5.
[17] Id. at 6.
[18] Id. at 7.
[19] Id. at 9.
[20] Id. at 13
[21] 89 Fed. Reg. at 16,866.

companies who also own larger producing (and thus more profitable) wells.[22] This analysis further demonstrates that existing well operators will be able to absorb the compliance costs associated with implementation of standards of performance for designated facilities.

2. *Rystad Report*

EPA's finalized two separate presumptive standards for oil wells that produce associated gas. EPA determined that the best systems of emission reduction for higher emitting wells-those that emit CH4 emissions from associated gas venting of 40 tpy or greater-is to route associated gas to a sales line. Alternatively, operators may utilize one of three abatement options that prevents emissions. These options are using the gas as an onsite source of fuel, using the gas for another useful purpose that a purchased fuel or raw material would serve, or injecting the gas into the well or another well. If it is not technically feasible to capture the gas and route it to sales or utilize the gas for one of the beneficial purposes noted above, operators may flare the gas using a device that achieves a 95% reduction in methane emissions.[23]

EPA determined that routing associated gas to a sales line is also the best systems of emission reduction for lower emitting wells-those with 40 tpy of CH4 emissions from associated gas venting. These wells may also utilize one of the three abatement options noted above or flare the gas using a device that achieves a 95% reduction in methane emissions.[24]

EPA estimated the cost of routing associated gas to a sales line or to a flare. For a flare, EPA estimated a capital cost of $100,579 and annual operating costs of $36,044.[25] EPA estimated the cost of routing associated gas from a new well or an existing well where the associated gas is vented using information provided by The INGAA Foundation and ICF representatives. This information provided different cost estimates depending on the diameter of the natural gas pipeline, the distance between an oil well and the pipeline, and compressor station construction costs. EPA also considered savings from routing the associated gas to sales. The annual costs, considering savings, for routing associated gas to a sales line of a new well ranged from $26,130 (assuming a 4" diameter pipeline and 3 miles between the well and the pipeline) to $1,043,568 (assuming a 6" diameter pipeline and 50 miles between the well and the pipeline). Table 4-2, TSD 4-10. Routing associated gas to a sales line located 1 mile from the wellhead, and using a 4" diameter pipeline, results in net savings. Id.

For existing wells, EPA estimated the incremental cost of routing the associated gas to a flare and routing it to sales line. EPA conducted two analysis for this scenario: In one analysis it assumed that the operator is venting gas from the existing well. In the second analysis, EPA assumed the operator is flaring the gas. EPA's estimated annual incremental costs under the first scenario ranged from net savings to a cost of $40,064, depending on the diameter of the pipeline and the distance between the well and the sales line. EPA's estimated annual incremental costs

[22] https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2021/11/MarginalWellFactsheet2021v2.pdf
[23] 89 Fed. Reg. at 16,835, Table 4.
[24] *Id.*
[25] EPA Background Technical Support Document for the Final New Source Performance Standards and Emissions Guidelines, at 4-12 (November 2023).

under the first scenario ranged from net savings to a cost of $76,108, depending on the diameter of the pipeline and the distance between the well and the sales line. 4-13.

An independent report prepared by Rystad provides different cost estimates for routing associated gas to sales and also provides cost estimates for the three alternative abatement options EPA allows, but did not analyze. Per the report, routing associated gas to sales and using associated gas on-site are options that result in net savings to the operator. slide 11. Specifically, Rystad estimates that connecting wells to gathering infrastructure results in an average net profit to operators of $3.10 per thousand cubic feet (kcf) and average *negative* costs of $162 per metric ton of methane flaring avoided.[26] Operators will pay between $0.40 and $0.80 per kcf handled by third party processing and gathering, netting profit after gas sales of $2.70 to $3.50 per kcf.[27] This corresponds to a range of *negative $141-183 per metric ton of methane abated*.[28]

Rystad estimates that using associated gas onsite as a source of fuel also results in a net profit of $8.60/kcf and $449 per MT of methane flaring avoided, after accounting for cost savings from fuel switching.[29] For a site producing 50 kcf per day of associated gas, costs associated with onsite power generation include between $1.90 to $2.20 per kcf for a small power generator and between $0.60 to $1.70 per kcf for gas treatment, netting between $7.70 to $9.40 in profit per kcf.[30] This corresponds to a range of *negative $402-491 per metric ton of methane abated*.[31] Onsite use is an effective option for sites flaring a relatively small amount of gas (less than 100 kcf/day).[32]

Operators may also convert associated gas to compressed natural gas and truck the gas offsite. This option is effective for sites flaring more than 250 kcf/day of gas.[33] Rystad finds that on average, compressed natural gas (CNG) trucking will cost operators $1.8/kcf, or $94 per metric ton of methane flaring avoided.[34] At a site producing 250 kcf per day of associated gas, costs associated with CNG include between $0.60 to $1.70 per kcf for gas treatment, $0.30 to $1.00 per kcf for compression, and $2.60 to $4.10 per for 200 miles of transportation, for a net cost after gas sales of between $0.10 to $3.40 per kcf.[35] This corresponds to a range of *$5 to $177 per metric ton of methane abated*.[36]

Lastly, Rystad analyzed the cost of injecting associated gas into underground storage wells. injection costs. Injection costs vary depending on various factors, but Rystad finds that

[26] Rystad, at 11. Additional detail on Rystad's analysis illustrating how Rystad derived cost ranges is included in Rystad Energy, *Flaring Abatement Input Costs*, Attachment B.
[27] *Id*. at 45.
[28] *Id*.
[29] *Id*. at 11.
[30] *Id*. at 50–51.
[31] *Id*. at 51.
[32] *Id*. at 40.
[33] *Id*. at 40–41.
[34] *Id*. at 11.
[35] *Id*. at 56.
[36] *Id*.

on average, costs are $3.4/kcf, and $177 per metric ton of methane flaring avoided.[37] Costs associated with reinjection include between $0.20 and $0.60 per kcf for gathering and between $0.20 and $5.70 per kcf for storage, for a total cost between $0.40 to $6.30 per kcf.[38] This corresponds to a range of *$20 to $329 per metric ton of methane abated*. Reinjection is an effective option for sites flaring more than 350 kcf/day of gas.[39]

The information provided by Rystad demonstrates that there are multiple cost effective options to capture associated gas, including in circumstances where connection to a sales line is not technically or economically feasible.

III. Conclusion

We appreciate CARB's consideration of these comments and welcome the opportunity to discuss them and answer questions at CARB's convenience. As the State of California and EDF are making great strides to provide more actionable data through our MethaneSAT and Carbon Mapper satellite projects, we strongly believe that these efforts will help CARB implement and enforce strong oil and gas methane requirements while also helping industry and the public identify and address pollution problems expeditiously. We look forward to continued coordination with CARB on this rulemaking as well as further opportunities to look at issues like methane performance standards and methane monitoring, reporting and verification (MMRV) as states like Colorado have begun to establish.

Respectfully submitted,

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[37] *Id*. at 11.
[38] *Id*. at 69.
[39] *Id*. at 40.