October 11, 2022

Re: Environmental Defense Fund Comments on Potential Changes to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (Oil and Gas Methane Regulation)

Dear Mr. Lanfitt and Mr. Nyarady:

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF") on the California Air Resources Board ("CARB") September 20th presentation regarding greenhouse gas emissions from oil and gas facilities.

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.

CARB has been a leader with respect to actions to reduce greenhouse gas emissions from multiple sectors, including the oil and gas sector. We appreciate CARB's continued commitment to reducing methane emissions from upstream and midstream oil and gas facilities and support enhancements to its methane rule contained in 17 Cal. Code Regs. § 95669 ("methane rule"). We offer the following suggestions to achieve additional reductions from this sector, pursuant to CARB's request for comment:

1. Allow operators to use alternative approved technologies and methods for conducting leak detection and repair ("LDAR") inspections
2. Require operators to inspect for and repair leaks detected with remote sensing technologies deployed by CARB
3. Prohibit venting from pneumatic controllers
4. Prohibit routine flaring and venting, and limit flaring and venting of associated gas
5. Require operators to use direct measurement approaches when reporting GHG emissions.

While the recommendations below are focused on the upstream and midstream stationary sources covered by CARB's methane rule, we encourage CARB to undergo a similar review of its pipeline rules to identify opportunities to reduce leaks and venting from its pipeline transport network as well.

I. Allow Alternative LDAR Approaches

We urge CARB to consider adding a provision to its methane rule that allows operators to seek approval for an alternative LDAR approach to the current quarterly Method 21 inspection requirement. Advanced technologies offer a promising pathway to more frequent and cost-effective screening to detect large emission events. According to the most recent inventory we have, large emission events caused by malfunctioning or improperly operated equipment were responsible for 61,980 tons of methane in California in 2019.[1] Frequent screening with advanced technologies paired with at least an annual Method 21 or OGI inspection can cost effectively detect both large and small leaks. Continuous monitors also provide an effective method to detect leaks and should also be allowed under an alternative LDAR approach. In the following section, we discuss the costs and availability of advanced monitoring technologies, how such a standard may be structured in the regulations, and how continuous monitoring can be incorporated.

A. Costs and Availability of Advanced Technologies

Advanced monitoring technologies are already widely available and in use by leading operators.[2] Many of these technologies are highly effective and inexpensive. And many companies providing advanced methane mitigation services are domestic and provide well-paying jobs in geographies across the country. These technologies are particularly capable and efficient at screening large areas for emissions, although layered approaches utilizing multiple techniques may be most appropriate for finding and fixing smaller (but collectively significant) leaks. Operator experience, scientific use and testing, and simulation modeling provide estimates of the cost and effectiveness of different approaches that can inform regulatory approaches.

A recent comprehensive survey from Datu Research shows that advanced leak detection services are widely available. Datu's survey of service firms offering advanced methane monitoring reveals their abilities and plans to scale up in response to new federal methane regulations.[3] Firms offering advanced monitoring services have nearly doubled in the past four years alone, and more than a quarter are already capable of surveying over 300 well sites per day. More than half of firms surveyed said they could survey at least 100 or more well sites per day over what they currently serve by 2023. Nearly half (47%) said they could scale up to serve more than 500 well sites per

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[1] EDF Synthesis Inventory (2019), Ex. 1. Note this inventory uses site-level emission factors collected in 2013-2014 that are assumed to still be representative of current emission rates. Because CA has passed fairly significant regulations in the interim, this inventory may not reflect reductions due to those regulations. As EDF transitions to using satellite data over the next couple years, we expect our inventories to better reflect regulatory and operational changes.

[2] *See* Datu Research, *Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry* (2021); EPA, *Methane Detection Technology Workshops*, https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.

[3] Marcy Lowe, *Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up*, Datu Research (July 22, 2021), http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_Datu-Research_8-10-2021.pdf.

day; these respondents comprised those using fixed sensors, airplanes, satellites, or a combination of these technologies. Eighty-nine percent of the firms surveyed can detect emissions at the equipment level, while 53% can detect emissions at the component level. The firms also operate broadly across major oil and gas basins, with at least 32% having a presence in every basin. Datu's findings underscore that advanced methane detection technologies are already widely available to operators and can easily be incorporated into regulatory standards.

EPA's Methane Detection Technology Workshop held in August 2021 further confirmed the availability of advanced technologies and included information on their effectiveness, while providing useful cost estimates.[4] Key takeaways from the workshops are summarized below:

- **Layered approaches are needed.**[5] The data now available suggests that, in their current form, advanced technologies should be used to supplement—not replace—OGI or Method 21 monitoring. Advanced technologies can quickly and cost-effectively detect super-emitters, achieving significant reductions. But traditional approaches with lower detection limits, like OGI or Method 21, are still necessary to detect and mitigate widespread smaller leaks that cumulatively represent a large portion of the sector's total emissions. In recognition of this fact, we recommend that CARB require companies using approved advanced technologies also complete at least an annual Method 21 or OGI survey of their affected facilities. Less sensitive advanced technologies may need to be paired with even more frequent Method 21 or OGI surveys to achieve equivalent emission reductions.

- **Advanced technologies are cost-effective and significantly reduce emissions.**[6] Advanced technologies are widely used by leading operators, small and large, to improve operations and reduce emissions to achieve company-set goals, even without regulatory requirements. Operators described conducting advanced monitoring voluntarily on top of OGI regulatory requirements based on the cost-effective improvements secured in operations. Exxon represented that semiannual aerial surveying was essentially equivalent to semiannual OGI; its modeling showed semiannual aerial reductions just below 60%.[7] Exxon also encouraged EPA

[4] EPA Methane Detection Technology Workshops (August 23 and 24, 2021), audio: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0183; transcripts: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
video: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop
Day 1 Video Link: https://www.youtube.com/watch?v=KfY50npQ0sM
Day 2 Video Link: https://www.youtube.com/watch?v=lQcUhMG24X0

[5] *See id.* (presentations by: David Lyon, Erin Tullos, Matt Johnson, Triple Crown, Jonah, Project Astra, Project Falcon, BPX, Conoco, and Exxon).

[6] *See id.* (presentations by: Triple Crown, TRP, Jonah, BPX, Conoco, and Exxon.)

[7] EPA, Methane Tech Workshop Transcript Day Two at 53, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181.

to pursue strong regulations incorporating advanced technologies.[8] Triple Crown Resources said that it "saw a 90% decrease in emission volumes in comparison to the first [aerial] survey after just eight months and three surveys."[9] Learning from the surveys, Triple Crown said it was able to take preventative steps, like re-weighting thief hatches and conducting routine flare checks.[10] Triple Crown also found that the "first survey paid for itself in approximately five days. Over the next four months, detecting and repairing those emission sources generated $400,000 of profit."[11] Further, "fly[ing] over all of Triple Crown's 23,000 acres, survey[ing] over 200 assets including pipelines, deploy[ing] a follow-up OGI camera crew, and roustabout crew to verify and repair every leak that was detected by Kairos" cost Triple Crown "less than $25,000."[12]

- **Comprehensive coverage is already deployed by leading operators.**[13] Triple Crown indicated that it was able to survey across its facilities, not just those subject to federal LDAR requirements, using advanced screening approaches.[14] Jonah Energy stated that increasing the frequency of its surveys to monthly and using continuous monitoring significantly reduced emissions and led Jonah to conduct monthly surveys at all its sites.[15] BPX has established a goal to install measurement technologies at all major oil and gas processing sites by 2023[16] and that it began using drones across all its operations in 2019.[17] Exxon said it can survey 30-65 facilities per day using aerial surveys,[18] which allow for near pinpointing of sources and immediate deployment of repair technicians.[19]

- **Workshop cost estimates:** OGI – $600/site/inspection[20]
  Aerial – $100-300/site, quarterly for $1,600/facility[21]
  Drone – $2,700-3,500/annually[22]

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[8] *Id*.
[9] EPA, Methane Tech Workshop Transcript Day One - Part 1 at 39, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
[10] *Id.*
[11] *Id.* at 40.
[12] *Id.*
[13] *See* presentations by: Triple Crown, Jonah, BPX, Conoco, and Exxon.
[14] EPA, Methane Tech Workshop Transcript Day One - Part 1 at 40, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
[15] *Id*. at 62.
[16] EPA, Methane Tech Workshop Transcript Day Two at 38, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181.
[17] *Id.* at 41.
[18] *Id.* at 59.
[19] *Id.* at 50.
[20] *Id.* (Erin Tullos and Arvind Ravikumar).
[21] *Id.* (Erin Tullos, Arvind Ravikumar, and Matt Johnson (TRP $1,600/facility/quarterly)).
[22] *Id.* (TRP).

Continuous – $1,000-5,000 annually[23]

B. Overview of Advanced Technologies

A broad range of advanced methane monitoring technologies are available and can be utilized by operators to detect, pinpoint, and quantify fugitive emissions. Over the past decade, rapid innovation has led to a diverse array of advanced methods: there are now at least 100 distinct methane measurement technologies that are commercially available for leak monitoring in the oil and gas industry.[24] Widespread adoption and deployment of emerging technologies—even in the absence of regulatory requirements—demonstrates their cost-effectiveness and the opportunity to incorporate these methods into a regulatory scheme.

Methane monitoring technologies can be classified in several ways. Generally, technologies can be grouped into screening (i.e., aerial) and close-range (i.e., OGI and Method 21). Most close-range methods are handheld instruments that can diagnose individual leaks at the component scale. Screening technologies are those that can quickly find abnormally emitting facilities for follow-up with close-range methods. Detection capabilities vary greatly and typically increase with proximity to the emission source. However, technologies that monitor from farther away, like aircraft and satellites, are usually much faster and can cover broad geographic areas frequently.[25]

A comprehensive monitoring program that utilizes both screening and close-range technologies is likely to be highly effective.[26] In this type of program, screening technologies are used to monitor across broad geographic areas frequently to quickly detect the largest emission sources, which can represent 50% or more of total emissions. Close-range methods are used for both directed follow-up to pinpoint emission sources detected during screening and to routinely monitor sites for smaller leaks that would not be detected by screening methods.

The use of screening technologies has grown rapidly across the oil and gas sector in the last few years.[27] Screening frequently for large leaks can be more effective than less frequent, close-range inspections. Typically, screening surveys cannot identify leaks at the component level nor distinguish permissible, vented emissions from fugitive and abnormal emissions. To diagnose and repair leaks, most screening methods must be paired with close-range systems. Differentiating between leaks and venting requires planning and recordkeeping to match detected emissions to planned venting events.

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[23] *Id.* (Erin Tullos and TRP.)
[24] Highwood Emission Management, *Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines (2022), https://highwoodemissions.com/wp-content/uploads/2022/04/Highwood_Pipeline_Leak_Detection_2022.pdf.* [hereinafter "Highwood 2022"].
[25] *Id.*
[26] Fox et al., *A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas*, 14 Env. Res. Letters 53002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3.
[27] *See* Highwood 2022, supra note 24; Datu, Find, Measure, Fix, supra note 2; *see also* Scientific Aviation, *Major Energy Companies Join Forces to Battle Methane Emissions* (March 2021), http://www.scientificaviation.com/major-energy-companies-join-forces-to-battle-methane-emissions/.

In general, detection sensitivity declines with spatial scale of measurement, meaning those farthest from the source will be less able to detect smaller emissions. However, there is typically a trade-off between sensitivity and survey speed, and the cost of deployment tends to decline as speed increases. For example, aerial surveys with high detection limits are low cost and can quickly cover broad areas but will only detect the largest emission events, missing smaller leaks.

Figure 1: Temporal and Spatial Capabilities of Detection Technologies[28]

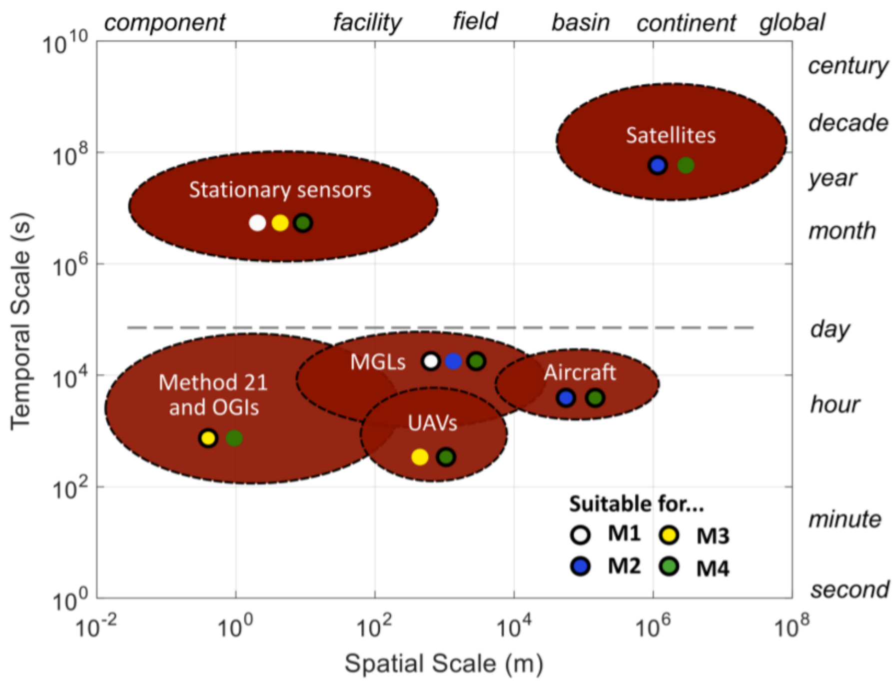

Figure 2. Technology classes categorized based on the spatial and temporal extent of coverage. Colored dots represent suitability for measurement motivations 1–4. Dots without black borders either show promise or may be useful in a limited capacity.

A major outstanding challenge for screening technologies is their inability to discern vented from fugitive emissions.[29] Under most regulations, including CARB's rule, venting is authorized in certain limited circumstances, creating potential problems for screening approaches. Detection of permissible high-emission events during screening could trigger follow-up ground surveys for events like liquids unloading or permissible tank flashing. Needless searching for these events may increase the cost of screening and disincentivize use of advanced technologies. Reducing instances of permissible emissions through other regulatory standards would alleviate much of this problem, as eliminating permissible venting would enable screening techniques to become more sensitive to the presence of fugitive emissions. Moving toward zero emission standards across the full range

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[28] Fox et al., *A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas*, 14 Env. Res. Lett. 053002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/pdf (Abbreviations: Method 21 and OGI = handheld IR methods; MGLs = vehicle-based monitoring; UAVs = unmanned aerial vehicles, or drones. Key: M1 - Develop and refine emissions factors to improve inventories, M2 - Estimate top-down emissions from a region with multiple sources, M3 - Conventional, close-range LDAR using handheld instruments, and M4 - Rapid screening for anomalous emissions.).

[29] *Id.*

of affected facilities, for example, phasing out gas-powered pneumatic controllers as we suggest below, could eventually eliminate this issue entirely. Rigorous reporting and notification of large events would also allow operators and regulators to know when a high emission event was planned and avoid sending follow-up ground crews if advanced screening detected planned emissions.

Methane detection methods differ not only in performance but also in the types of sources that can be identified and how these sources are characterized. For example, a recent study using aerial surveys identified far fewer–but much larger–sources than handheld surveys performed at the same time (39 vs 357 sources, respectively).[30] Many of the leaks found during the handheld survey were too small to be seen by aircraft, while many of the largest emission events occurred at a small number of sites and may have been missed during the ground inspection. This indicates that full coverage of a system is most effective with multiple technologies. Simulation studies have shown that a combination of technologies can be effective under the right circumstances.[31]

When considering the performance of an advanced monitoring approach, it is important to distinguish between technologies and methods. Technologies include deployment platforms and sensor types, while methods include the work practices and follow up procedures. Understanding the methods in combination with a technology is critical when evaluating performance.[32] For example, larger emissions detected during screening must be paired with shorter repair timelines to achieve substantial reductions. This is consistent with CARB's current regulations which require faster repair times for larger leak. For certain recurring or major emission events, engineering analysis might be required to diagnose and fix the underlying operational issues. Varying dispatch thresholds for follow-up is another work practice that can greatly influence the effectiveness of an approach. For example, if follow-up and repair is only required for the largest leaks, overall mitigation effectiveness will be lower than a work practice requiring follow-up on all detected leaks.

Technologies typically consist of sensors and deployment platforms. Sensing modes include point measurement of ambient mixing ratios, path integrated laser-based measurements (active imaging), and column-integrated passive imaging. Sensors can be broadly categorized as:

- **Point sensing** (in plume sensing) – Point sensors range from simple solid-state metal oxide detectors to complex cavity ringdown spectrometers (CRDS) and gas chromatographs. Point sensors can be deployed on any platform that passes through methane plumes.

- **Active imaging** (remote sensing) – Active imaging systems generate sources of light that traverse methane plumes, reflect off a remote surface, and return to a detector. Changes in the reflected light are used to infer methane concentrations along the path. A common example is Light Detection and Ranging (LiDAR).

[30] Tyner & Johnson, *Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data*, 55 Env. Sci. Tech. 9773 (2021), https://pubs.acs.org/doi/10.1021/acs.est.1c01572
[31] Fox et al., *A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas*, 14 Env. Res. Lett. 053002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/pdf.
[32] *See id.*

- **Passive imaging** (remote sensing) – Passive imaging systems use natural light to measure methane concentration in the atmosphere. They are used in all types of platforms, ranging from infrared (IR) cameras to satellite imagery.

- **Non-methane** – Many sensors infer the presence of leaks by measuring variability in pressure, temperature, vegetation growth, physical disturbance of equipment or the areas nearby, and other proxies.[33]

Deployment platforms can be broadly classified into the following categories:

- **Aircraft[34]** – Passenger aircraft, both planes and helicopters, can be equipped with various sensor technologies and used at different elevations and frequencies. These factors, along with the methodologies used, affect survey speed and detection capabilities. Some aerial technologies or methods may use remote sensing and fly higher and faster to achieve broad coverage more rapidly. Other aerial technologies and methodologies may call for lower and slower flights or use a technology with a higher sensitivity that detects more emission events but achieves less coverage in the same time period. Aircraft detection limits range from a few kilograms of methane per hour to tens of kilograms per hour. This technology is readily available and has undergone multiple, controlled release tests to verify performance metrics. Although aircraft systems are less sensitive than other systems, some aircraft are able to cover large geographic regions. This makes it possible to survey entire landscapes for large methane sources that may not otherwise be detected by targeted, site-specific inspections. The primary limiting factors for aerial methods are weather (high winds, precipitation, cloud cover), variable reflectivity from uneven snow cover, and flight permits.

- **Unmanned Aerial Vehicles (UAVs)[35]** – Also called drones, these can reach dangerous or hard-to-reach places and can fly very close to the source of plumes. They can be equipped with IR cameras and other relatively small, lightweight sensor devices and, like aircraft, can operate in three-dimensional space. Like manned aircraft, UAVs are not restricted to roads and can complement close-range methods by reaching dangerous or inaccessible places. Some UAV systems use point measurement technologies that directly measure methane concentrations. These point measurement UAVs are often more sensitive than aircraft techniques because of their ability to fly closer to the methane source. The primary limitations for this technology are weather, the distance from the operator, and the relatively short flight times of a few hours (at most). UAVs can typically detect and pinpoint smaller emission sources. This technology is readily available and has undergone multiple controlled release tests to verify performance metrics.

- **Mobile Ground Labs (MGLs)[36]** – Consisting of a vehicle with a global positioning system and a methane sensor, MGLs enable an operator to generate a map of methane concentrations along the vehicle's path. Because it is limited to the path (usually a road),

[33] Highwood 2022.
[34] *Id.*
[35] *Id.*
[36] *Id.*

this method collects data in a two-dimensional space. Typically, MGLs will also measure environmental conditions, especially wind speed, wind direction, temperature, and humidity. MGLs can take an active or passive approach to surveying. The active approach entails MGLs driving a predetermined route along the infrastructure to be monitored, while the passive approach entails mounting sensing equipment on vehicles performing unrelated tasks, like delivery trucks.[37]

- **Continuous Monitoring[38]** – These systems are unique in that they are stationary. Fixed sensors are installed at a facility—typically in high-risk areas—to provide continuous, real-time readings of methane concentration and will trigger an alarm if concentrations exceed certain limits. Fixed and continuous monitoring technologies can be divided into active and passive categories. Active continuous monitors regularly scan an entire site or use a laser detector to monitor a large area of the site for emissions. Tower-based systems provide even greater coverage and can scan broadly from a single location. Passive continuous monitors use point sensors to monitor a single location at the site. For passive sensors to detect a leak, the emission plume must be carried via the wind to the location of the sensor; therefore, these kinds of sensors must be deployed in larger numbers.

- **Satellites[39]** – Satellites equipped to measure methane concentrations can be combined with other data to identify large sources of emissions.[40] Many methane-sensing satellites currently exist, and still more are in development. These systems are diverse in form and function; some have very high minimum detection limits and therefore are better suited to detect large plumes, while others with improved sensitivity are capable of detecting smaller sources.[41] Minimum detection limits of satellites have been estimated to be between 1,000 and 7,100 kg CH_4/hr.[42] More recently, GHGSat has claimed facility-scale detection limits as low as 100 kg/h, but these have not yet been independently verified, and other point source imagers, such as PRISMA and EnMAP, report sensitivity in the 100-1,000 kg/h range.[43]

Over the past decade, there has been considerable innovation in advanced methane detection strategies. Significant advancements have occurred in technologies and deployment platforms, but also in the most effective methodologies and work practices. These advancements, which have largely occurred as the result of voluntary action by leading operators as well as researchers, can inform effective regulations.

C. Structure and Standard Design

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[37] *Id.*
[38] *Id.*
[39] *Id.*
[40] Datu 2021; Highwood 2022.
[41] *See, e.g.*, EDF, *MethaneSAT*, https://www.methanesat.org/; Daniel J. Jacob et al., *Quantifying Methane Emissions from the Global Scale Down to Point Sources Using Satellite Observations of Atmospheric Methane*, 22 Atmospheric Chemistry and Phys. 14 (2022), https://acp.copernicus.org/articles/22/9617/2022/acp-22-9617-2022-assets.html.
[42] Highwood 2022.
[43] *Id.*

We support CARB providing an alternative compliance pathway that allows frequent, broad-based monitoring using advanced technologies like aerial surveys or continuous monitoring. This approach represents an effective method for detecting large, potentially intermittent sources of emissions that may be missed during less frequent component-level ground surveys. Still, a large portion of emissions originate from smaller fugitive leaks that are currently best detected through ground-based monitoring, like OGI or Method 21. Regular close-range inspections and repairs are a proven method for reducing emissions and ensuring that sites are well maintained, reducing potential for super-emitters.[44] It is therefore imperative that advanced approaches are layered with component-level close-range inspections.[45]

By incorporating a flexible alternative—which may be more cost-effective for many operators and is likely to become less expensive over time—CARB can support innovative new approaches that will allow LDAR and methane mitigation markets to grow and become more efficient. CARB can also set parameters that achieve reductions equivalent to or greater than close range inspections in a manner that can further spur development of new technologies. Building in this flexibility will ensure that new technologies can qualify for regulatory use and will allow companies to innovate around clear parameters.

CARB should allow companies to use advanced monitoring technology as an alternative to Method 21 only when equivalent emission reductions can be demonstrated across a range of emission distributions. To do so, CARB could establish a framework that includes several pre-approved alternatives reflecting different combinations of detection threshold, frequency, regular OGI or M21 inspections, and OGI or M21 follow-up requirements. Critically, this framework should center on emission reductions. CARB could thus design frameworks that accommodate reasonably anticipated improvements in detection capabilities, rather than the limitations of currently in-use technologies.

With available methods for comparing emission reductions across different LDAR approaches, CARB need not foreclose the use of new and existing technologies that can effectively reduce emissions. However, CARB must only allow technologies that can be proven to satisfy rigorous parameters and achieve the same or greater emission reductions under a variety of scenarios. To

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[44] Wang et al., *Large-Scale Controlled Experiment Demonstrates Effectiveness of Methane Leak Detection and Repair Programs at Oil and Gas Facilities*, EarthArvXiv (2021) (non-peer reviewed preprint), https://eartharxiv.org/repository/view/2935/; Ravikumar et al., Repeated leak detection and repair surveys reduce methane emissions over scale of years, 15 Env. Research Letters 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf.

[45] EPA's fenceline monitoring requirements for refineries provide a useful example of a layered fugitive monitoring approach. Fenceline monitoring standards were adopted to augment traditional LDAR at refineries and improve the management of fugitive emissions. *See* Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, 80 Fed. Reg. 75,178 (Dec. 1, 2015) [hereinafter Refinery Standards]; *see also* EPA, *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries Background Information for Final Amendments: Summary of Public Comments and Responses* at 242 (Sept. 2015), https://www.epa.gov/sites/default/files/2018-07/documents/epa-hq-oar-2010-0682-0802.pdf [hereinafter Refineries RTC] ("The goal of the fenceline monitoring program is to improve the management of fugitive emissions by identifying emission sources quickly and reducing these emissions through early detection and repair."); *id.* at 168 ("Fenceline monitoring will . . . allow corrective action measures to occur more rapidly than would happen if a source relied solely on the traditional infrequent monitoring and inspection methods, such as those associated with periodic Method 21 LDAR requirements.").

ensure equivalent emission reductions, CARB could finalize multiple approved alternatives by evaluating monitoring frequency and detection capabilities—meaning that technologies with better detection capabilities could be used less frequently and those with higher detection limits could be used more frequently. Equivalence is discussed in more detail below.

For large emission events detected through screening, operators should be required to immediately report to a publicly-accessible database any detected emissions, and additionally, report when the repair is complete. Mitigating super-emitters, while extremely important, is the bare-minimum that CARB should seek to achieve through the LDAR program. If a super-emitter is detected, the operator should be required to submit supporting documentation and explain the likely cause. Operators who could prove the emissions resulted from a permissible event, like a scheduled blowdown, would not have to undertake additional action. However, where the cause of the emissions is unknown, or where multiple events have been detected at the same source or from the same operator, CARB should require a full engineering analysis.

D. Equivalence: Frequency and Detection Capability

To determine allowable alternatives, CARB should evaluate approaches by detection threshold and frequency to determine if these different technologies achieve equivalent emission reductions. There are readily available simulation models that CARB can use to generate a presumptive framework for allowable technologies, including ones that evaluate detection capabilities, required screening frequencies, and the necessary work practices when emissions are detected.[46]

The follow-up inspection and repair requirements that apply after emissions are detected are also a critical component of equivalence that should not be overlooked, especially since some new advanced technologies can actually quantify leaks. In general, CARB should require dispatch of repair or follow-up crews anytime emissions are detected with any technology. If a technology can pinpoint the emission source without follow-up, then a repair crew should be dispatched shortly after detection. Consistent with the current repair requirements in CARB's rule, CARB should also require shorter repair timelines for large emissions detected via aerial screenings. Most events detected by an aerial survey will be significant and should be stopped as quickly as possible. It should be noted that some technology companies, such as those deploying aerial approaches, require time for data processing between when a leak is detected and when information is sent to operators. This potential delay means that short repair times will likely be based on when operators are made aware of the emission source rather than the survey date.

Typically, LDAR effectiveness has been estimated with emissions simulation models such as the Fugitive Emissions Abatement Simulation Tool (FEAST). FEAST combines a stochastic model of methane emissions at upstream oil and gas facilities with a model of LDAR programs to estimate the efficacy and cost of methane mitigation.[47] Probabilistic models like FEAST simulate the generation, detection, and mitigation of emissions to compare the effectiveness of LDAR programs

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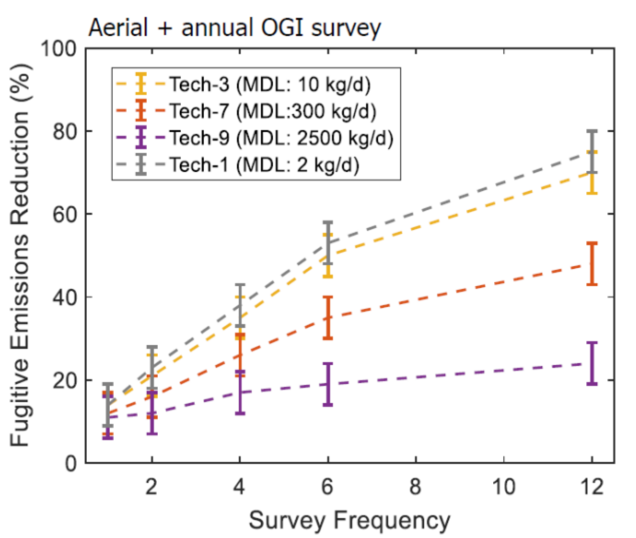
[46] Fugitive Emissions Abatement Simulation Tool (FEAST), https://arvindravikumar.com/feast/; LDAR-Sim, https://highwoodemissions.com/ldar-sim/.

[47] Kemp & Ravikumar, *New Technologies Can Cost Effectively Reduce Oil and Gas Methane Emissions, but Policies Will Require Careful Design to Establish Mitigation Equivalence*, 55 Env. Sci. Tech. 9140–9149 (2021), https://pubs.acs.org/doi/abs/10.1021/acs.est.1c03071.

with different technologies and work practices. For scientifically rigorous comparisons, models simulate emissions detection based on independent, controlled-release testing under diverse environmental conditions such as wind speed. These models are sensitive to assumptions such as emissions distributions and repair effectiveness, so it is critical that models use accurate assumptions that are representative and also test results against different likely emission distributions. CARB can and should use these models to accurately estimate percentage reductions from different technologies at different frequencies, which can inform the parameters CARB selects for permissible alternative approaches. Importantly, CARB should use an emission distribution in modeling that accurately represents actual conditions in California.

An example of this equivalency modeling is shown below, generated using FEAST. These equivalency estimates rely on a nationally averaged emission distribution and the effectiveness of each technology in terms of percentage reductions would likely be lower in California. We anticipate that a California-specific emission distribution would be more normalized and less heavy-tailed than the national average—meaning that a greater percentage of the total emissions are smaller component level leaks and a lesser percentage are super-emitters due to the existence of the state's robust quarterly LDAR requirement since 2017. By contrast, in a basin like the Permian, a large percentage of the total emissions are super-emitters. Less sensitive technologies (like Tech-7 and Tech-9 below) can readily detect super-emitters but cannot detect smaller leaks. These technologies therefore perform better in terms of percentage reductions in super-emitter heavy basins. It is likely that to achieve reductions equivalent to quarterly Method 21 or OGI in California, such technologies would need to be deployed frequently, and some may be incapable of achieving equivalent reductions unless paired with additional ground-based surveys (e.g., semiannual OGI).

Figure 2: Example Equivalence Framework Generated by FEAST



As shown in this figure, CARB can model the effectiveness of different detection thresholds at various frequencies to target a given level of emission reduction. These models are very sensitive to the underlying emission distribution that is used. Alternative approaches must be capable of achieving equivalent emission reductions across California basins. Some approaches might

achieve significant reductions in a basin where abnormal process emissions are common, but the same approach may not be effective in a basin characterized by smaller routine leaks.
CARB will also have to evaluate the follow-up work practices associated with detections to ensure a certain reduction target is met. For example, emissions detected by a screening technology that is only capable of 100 kg/hr will be very large, may require repair on short timelines to achieve significant reductions (and in many cases may not be able to show equivalency regardless of repair speed). In most screening approaches, there will also be challenges in determining fugitive emissions versus allowable high emission events and situations where emissions cannot be pinpointed or have disappeared since being detected by screening.

E. Continuous Monitoring

We urge CARB to adopt an alternative LDAR standard that allows for use of continuous monitoring. Continuous monitors, if operated in a rigorous manner with effective follow-up work-practices, have the potential to reduce emissions even further than periodic approaches.

Specifically, we recommend CARB allow for continuous monitoring approaches with detection limits as low as permissible screening approaches as long as equivalent emission reductions can be demonstrated. Most continuous monitoring approaches must also be paired with some degree of OGI or M21 follow-up. Operators should be required to perform a follow-up OGI or M21 survey if emissions are detected in excess of predicted, permitted emissions. To minimize false alarms, this would require quantitative measurement technology, continuous emissions modeling, and extensive recordkeeping.

CARB could also develop an alternative program for continuous monitoring that does not require follow-up OGI or M21 inspections so long as the alternative satisfies the equivalency requirement. The equivalent detection limit for continuous monitors could be estimated with FEAST or other similar approaches by modeling it as a very high-frequency discrete screening. The operator would need to continuously model the expected emission rate to determine when there are excess emissions, and operators would have a set time to repair detected excess emissions.

To ensure a continuous monitoring technology can reliably detect at a given threshold, CARB should consider at least five parameters: distance from the source, probability of detection, frequency of detection, wind speed, and temperature/atmospheric-stability class. CARB will also have to evaluate the follow-up work practices associated with detections to ensure a certain reduction target is met. For example, emissions detected by a screening technology that is only capable of 100 kg/hr will be very large, may require repair on short timelines to achieve significant reductions (and in many cases may not be able to show equivalency regardless of repair speed). In most screening approaches, there will also be challenges in determining fugitive emissions versus allowable high emission events and situations where emissions cannot be pinpointed or have disappeared since being detected by screening.

For continuous monitoring, CARB can slightly modify the same framework evaluating detection capabilities, frequency of screening, and follow-up work practices. To ensure equivalence, CARB can set minimum requirements for sensor placement, probability of detection, frequency of screening, and other operating parameters. To ensure a continuous monitoring technology can reliably detect at a given threshold, CARB should consider at least five parameters: distance from the source, probability of detection, frequency of detection, wind speed, and temperature/atmospheric-stability class.

Sensor placement is critical for ensuring that each emission source at the site can be reliably screened at the required detection threshold and frequency. Inadequate sensor placement or an insufficient number of sensors can lead to emissions being missed and going undetected. When considering the appropriate sensor placement, CARB should ensure that every possible source of fugitive emissions is within the reliable range of a sensor and screened the appropriate number of times. Placement of continuous sensors should be required so that the combination of factors above (especially wind and weather, detection probability, and distance) will allow emissions to be reliably detected from any equipment on the site for every period required at the given detection threshold. CARB can create a model for determining proper sensor placement. In most cases, we anticipate sensors would be placed close to the largest emission sources, but CARB should also ensure any equipment located farther away can be reliably screened. At larger sites, and depending on technology, this may require multiple sensors to ensure adequate coverage. By contrast, tower-based solutions may be able to reliably screen multiple sites with a single sensor. Sensors must not only be within a horizontal range of emission sources but must also be able to detect all emission sources vertically.

With continuous monitoring solutions, the follow-up work practices are extremely important. It is critical to clearly define which emissions will require follow-up and which will not. Otherwise, there is a significant risk that operators will be alerted to emissions but determine they do not need to be fixed or cannot be fixed. This problem also exists with other LDAR approaches as discussed above, but is more pronounced with continuous monitoring where emissions will be more frequently detected. With the potential to be alerted to a wide variety of emission events, absent rigorous protocols, operators may be more likely to avoid following up on each event and will be incentivized to view it as part of normal operations to avoid follow-up costs. CARB must therefore very clearly define the events that require inspection and repair. This might be done by clearly defining the range of the site's baseline emissions. Above the range, there would be a presumption of an abnormality and, unless the operator could prove with records that it resulted from a permissible event, the operator would be required to conduct a ground survey and repair.

II. Addressing Leaks Detected with Remote Monitoring Technologies

We support a revision to CARB's methane rule requiring operators inspect facilities and repair leaks if notified by CARB pursuant to the detection of leaks by remote monitoring technologies operated by CARB. As detailed above, a suite of remote monitoring technologies capable of detecting leaks reliably are available, and it is both appropriate and feasible to require operators to respond to remotely detected emissions once the operator has confirmed that such emissions are impermissible leaks or venting. As discussed above, we recommend operators be required to investigate all leaks detected with a remote monitoring technology. This could include, for example, a follow up inspection with OGI to screen for persistent leaks or venting and determine if such leaks or venting require repair. The follow up investigation could also include a review of the operations log, if any, for the date and time of the remote monitoring screening to determine if a large intermittent emission event coincided with a permissible temporary activity such as liquids unloading. CARB should require operators to fix all leaks detected with remote monitoring technologies unless the operator can demonstrate that the leak was permissible following an investigation. For large impermissible leaks, CARB should require an engineering root-cause analysis to ensure the same issue does not occur again.

Requiring operators to investigate emissions detected with remote monitoring technologies even where such emissions prove permissible is still highly useful as the information can inform CARB as to potential areas for further regulation and help operators optimize operations. For example, repeat detection of high emission events during maintenance activities, such as liquids unloading, could lead to future regulations where technologies exist to further cost effectively control such emissions. Similarly, operators may learn to optimize the efficiency of certain activities resulting in gas loss that otherwise could be captured and sent to sales.

CARB has authority to revise its regulations to require operators respond to data obtained by CARB using remote monitoring technologies. California Health and Safety Code provides broad authority to CARB to regulate in this manner. The Code authorizes CARB to "adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part."[48] Similarly, CARB is authorized to "do such acts as may be necessary for the proper execution of the powers and duties granted to, and imposed upon, the state board by this division and by any other provision of law."[49]

The Code gives CARB specific authority to adopt new technology, directing CARB to "rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section."[50] Moreover, CARB is required to gather the type of information remote monitoring would provide. CARB must:

> Inventory sources of air pollution within the air basins of the state and determine the kinds and quantity of air pollutants, including, but not necessarily limited to, the contribution of natural sources, mobile sources, and area sources of emissions, including a separate identification of those sources not subject to district permit requirements, to the extent feasible and necessary to carry out the purposes of this chapter.[51]

Finally, CARB is authorized to require owners and operators to comply with the rules adopted by CARB to determine emissions:

> the state board or the district, as the case may be, may adopt rules and regulations to require the owner or the operator of any air pollution emission source to take such action

[48] CA Health & Safety Code § 38560 (2021).
[49] CA Health & Safety Code § 39600 (2021).
[50] CA Health & Safety Code § 38562(e) (2021).
[51] CA Health & Safety Code § 39607(b) (2021).

> as the state board or the district may determine to be reasonable for the determination of the amount of such emission from such source.[52]

These provisions provide ample authority for CARB to use remote monitoring technologies to identify leaks.

III. Prohibit Venting from Pneumatic Controllers

We appreciate CARB's interest in prohibiting venting from intermittent vent pneumatic controllers and urge CARB to propose a rule banning venting from this source. We further recommend CARB expand the prohibition on venting to include continuous bleed controllers as well. According to our 2019 inventory, normally operating intermittent vent controllers were responsible for 3,991 tons of methane in 2019. Normally operating continuous bleed controllers were responsible for 4,594 tons of methane. Malfunctioning controllers were responsible for 8369 tons of methane. Several states have promulgated rules that prohibit venting from continuous and intermittent vent controllers, and EPA has proposed to do the same.

Colorado[53], New Mexico[54], and British Columbia[55] require operators to use zero bleed controllers in various applications. All of these jurisdictions require new pneumatic controllers to be zero emitting, with some exceptions where an emitting controller is necessary for safety or process purposes. These rules apply to intermittent and continuous bleed controllers.

In addition, Colorado and New Mexico recently promulgated a rule requiring operator to phase in a zero-emitting retrofit requirement for existing gas-powered continuous bleed and intermittent vent pneumatic controllers. Per the Colorado rule operators must first survey their operations to determine what percentage of their wells use emitting controllers, and then craft and implement a plan to transition these facilities to zero-emitting devices by May 2023.[56] This allows operators flexibility to determine the most cost-effective way to transition their existing facilities to zero-emitting devices. New Mexico recently finalized a retrofit requirement modeled on the Colorado rule that, like Colorado, requires retrofit their natural gas intermittent and continuous bleed pneumatic controllers to zero-bleed within specified timeframes.[57]

EPA also proposed to phase out all gas-powered pneumatic controllers, and to require all new pneumatic controllers to be zero bleed.[58] We anticipate EPA proposing a supplemental proposal shortly that will further flesh out these requirements. As CARB is aware, states must implement rules to conform to the requirements in EPA's final emission guidelines for existing sources. CARB could get a head start on compliance with EPA's emission guidelines, and jump start meaningful methane reductions, by incorporating zero bleed requirements into its near-term methane rule revisions based on the rules already adopted in New Mexico and Colorado.

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[52] CA Health & Safety Code § 41511 (2021).
[53] 5 C.C.R. 1001-9:D.III.C.4.a.
[54] NMAC 20.2.50.122.B.(4)(a).
[55] BC Rule 52.05(2) & (3).
[56] Colorado Reg. 7 § Pt.D.III.C.4.c.
[57] NMAC 20.2.50.122.B.(4)(a).
[58] EPA, Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Proposed Rule, 86 Fed. Reg. 63110 (Nov. 15, 2021).

Analysis prepared by Synapse Energy Economics, on behalf of EDF, found replacing gas-powered pneumatic controllers with non-emitting devices to be cost effective. Per Synpase, the costs for retrofitting high-bleed controllers with zero emitting devices is $7.89 per mcf of reduced methane and $410.14 per tonne of reduced methane. The unit cost of changing low-bleed pneumatic controllers to zero-bleed pneumatic controllers is $49.30 per mcf of reduced methane and $2,563.40 per tonne of reduced methane.[59]

Requiring all pneumatic controllers be zero-bleed not only reduces methane emissions stemming from the normal use of controllers, but importantly also reduces large emissions stemming from malfunctioning gas-powered controllers.

IV. Prohibit Venting from Associated Gas

We urge CARB to follow the lead of other states and ban venting of associated gas from wells, other than during upset conditions that are out of the control of the operator. Associated gas venting was responsible for 808 tons of methane in 2019 per EDF's inventory. Associated gas flaring was responsible for 1351 tons of methane. Doing so is consistent with regulations adopted in Colorado[60] and New Mexico[61] and proposed by the EPA. In addition, we urge CARB to take additional actions to reduce waste of associated gas including: (1) banning the routine flaring of associated gas; and (2) limiting the instances when flaring during maintenance activities is allowed.

There is precedent for a complete ban on venting of associated gas during completions. Colorado prohibits venting during oil and gas well completions.[62] Colorado requires operators capture natural gas during completions, and only allows flaring during the initial flowback stage. During the separation flowback stage, operators may flare only with preapproval or pre-approval or during an upset condition.[63] Colorado defines an upset condition as "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction." COGCC R. 100. New Mexico also prohibits venting during completions.[64] New Mexico allows for flaring during completions only where capturing the gas poses a risk to safe operation or personnel safety or if the gas does not meet pipeline specifications, and then only for a period not to exceed 60 days.[65]

We support a complete ban on venting during completions, as New Mexico and Colorado have done. We further support a ban on flaring during completions, as Colorado has done, other than in upset conditions.

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[59] Synapse, Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico, p. 9 (Sept. 13, 2019), https://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf.
[60] COGCC R.903.d.(3).
[61] NMAC 19.15.27.8.(D).
[62] COGCC R.903.c.
[63] COGCC R.903.c.(3); 5 C.C.R. 1001-9:D.VI.D.(requiring control of natural gas during the initial flowback stage and capture of natural gas during the separation flowback stage).
[64] N.M.A.C. 20.2.50.127.B.(1),(2) (prohibiting venting to the atmosphere during flowback).
[65] N.M.A.C. 19.15.27.8.C.

During production, both states allow venting or flaring only during emergencies or upset conditions or in limited specified instances. Colorado allows venting or flaring during upset conditions, but only for a limited period (i.e., up to 24 hours).[66] Colorado also allows venting or flaring during "active and required maintenance and repair activity", a bradenhead test, liquids unloading, or during a production test, if previously approved.[67] New Mexico's rules are similar, although New Mexico limits further the instances when an operator may vent by requiring operators flare, rather than vent, except when flaring is technically infeasible or would pose a risk to safe operations or personnel safety, and venting is a safer alternative than flaring.[68]

Both states ban the pernicious practice of routine flaring and venting. We use the term routine flaring and venting to describe instances where operators flare or vent produced associated gas for prolonged periods of time due to the absence or unavailability of a sales line. Routine flaring or venting can thus be distinguished from temporary flaring or venting during specified activities such as proscribed maintenance activities. Per Colorado and New Mexico operators must either connect wells to a gathering line capable of transporting produced associated gas to sales or otherwise put the associated gas to beneficial use. In both jurisdictions, when applying to drill a new well operators must submit gas capture plans demonstrating they have plans to connect to a gathering line capable of transporting 100% of associated gas, or, if not, alternative plans to capture and put to beneficial use,100% of associated gas.[69] In no instances may operators routinely flare or vent associated gas due to the unavailability of a pipeline other than in emergencies or upsets or if a gathering line is temporarily unavailable. In the latter instance, Colorado operators must obtain permission to flare gas.[70] Both states allow operators to flare during production, even when a pipeline is available, under limited exceptions such as during specified maintenance activities.

Routine flaring is avoidable with proper planning and coordination between producers and midstream companies and, where pipeline infrastructure is not available, the use of onsite gas capture technologies. Current practices and technologies are available to capture associated gas, such as compression or liquefaction of natural gas, removal of natural gas liquids, or generation of electricity from gas.[71]

We urge CARB to follow the lead of Colorado and New Mexico and ban venting during production other than where necessary for safety; ban the unnecessary and dangerous practice of routine venting and flaring of associated gas during production; limit the instances when operators may temporarily flare to enumerated maintenance activities, and proscribe durational limits to temporary flaring where practicable.

V. Incorporate Direct Measurement Approaches

We urge CARB to consider revising its GHG inventory rules to incentivize or require operators to use direct measurement methods, rather than engineering calculations, to report CH4 emissions. To do this, we recommend CARB shift to a default reporting methodology based on

[66] COGCC R.903.d.(1).A.
[67] COGCC R.903.d.(1).B.-E.
[68] N.M.A.C. 19.15.27.8.A.
[69] COGCC R.903.(e); NMAC 19.15.27.9.(D).
[70] COGCC R.903.d.(3).
[71] 81 Fed. Reg. 83008, 83017 (Nov. 18, 2016).

site-level emission estimates. Operators would then be allowed to use the site-level factors provided by CARB or their own measurement data, subject to parameters set forth by CARB to ensure rigor and representativeness. CARB should repeat this exercise every few years since site-level emission factors are expected to change as operators reduce emissions.
Scientific studies conducted across the US and Canada have demonstrated that operators routinely underestimate emissions when using engineering calculations that rely on activity factors and emissions factors. EDF's extensive scientific work on emissions from oil and gas sources has demonstrated that measured emissions are magnitudes higher than operator estimates, in part due to the inadequacy of current emission factors to account for large emission events. EDF's Synthesis Study, which summarized results from multiple direct measurement studies in basins across the US, concluded that measured emissions are 60% higher than EPA's Greenhouse Gas Inventory.[72]

California's GHG reporting rule plays a crucial role in the development of the state's climate policy; it helps policymakers, stakeholders, and the public better understand greenhouse gas emissions and how those emissions contribute to climate change. Data collected through the reporting rule including the sources, magnitude, and distribution of greenhouse gas emissions across the state, inform decisions about how to address those emissions through legislation, regulation, and voluntary efforts. Understanding greenhouse gas pollution through high-quality, representative, and granular data is critical for developing effective policy solutions to abate this pollution. Our comments suggest improvements with the overarching goal of ensuring reported data accurately reflects real-world emissions

To do this, we recommend a three-step process that is described in more detail below. First, CARB should compile representative site-level measurement data by major production basin. Second, CARB, either alone or with other agencies, should develop independent, routine, top-down estimates of total emissions by major production basin. And third, CARB should reconcile the two data sets to generate default site-level emission estimates to be used by reporters. Reporters could also follow CARB-defined protocols for collecting and submitting their own measurement data to demonstrate emissions lower than the site-level defaults.

This multiscale approach will ensure GHG reporting is accurate by not only ensuring that site-level measurements are reconciled to match total regional emissions, but critically that the approach is able to capture changes in emissions over time. As the industry reduces emissions, those reductions will be captured in the state's inventory. Such an approach will also incentivize improved methane monitoring and the use of advanced technologies.

Several scientific studies[73] across the oil and gas supply chain have shown that emissions are seldom normally distributed—with a small fraction of sites having a disproportionately large

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[72] Ramon A. Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, 361 Sci. 186, 187 (July 13, 2018).

[73] Brandt et al., *Methane Leaks from Natural Gas Systems Follow Extreme Distributions* (2016), https://pubs.acs.org/doi/10.1021/acs.est.6b04303 ; Gorchov Negron et al., *Airborne Assessment of Methane Emissions from Offshore Platforms in the U.S. Gulf of Mexico* (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c00179; Marchese et al., *Methane Emissions from United States Natural Gas Gathering and Processing* (2015), https://pubs.acs.org/doi/10.1021/acs.est.5b02275; von Fischer et al., *Rapid, Vehicle-Based Identification of Location*

contribution to total emissions. This means that any statistical treatment will need to include sufficient data to accurately account for the characteristics of the "heavy-tailed" emission distribution. Previous studies have demonstrated how site-level measurements can be extrapolated to regional emissions with statistical methods and then reconciled with basin-level top-down data to provide insights into key sources of emissions not previously fully captured in estimates.[74] While these methods will not provide information on the emissions of a particular site at a given time, they do accurately characterize the emissions of a population of sites and so should be the basis for determining "facility" level emissions in the reporting rule.

Top-down measurement-based approaches are able to constrain total oil and gas emissions at the regional scale and are readily available for widespread deployment.[75] When performed routinely, they provide the necessary assurance that aggregated emissions are accurately capturing all sources of emissions and are also reflecting emissions changes over time. There are also well-established methods of excluding methane emissions from non-oil and gas sources, and deploying these will be important to meeting the criteria for accuracy at varying degrees depending on the oil and gas production basin.

Previous scientific studies have described how site-level data can be statistically aggregated and reconciled with basin-level top-down estimates.[76] Studies have also shown how this multi-scale reconciled data can then be used to assess completeness and improvements to source-level inventories.[77] Discrepancies between bottom-up and top-down estimates provide information

and Magnitude of Urban Natural Gas Pipeline Leaks (2017), https://pubs.acs.org/doi/full/10.1021/acs.est.6b06095; Zavala-Araiza et al., *Super-emitters in Natural Gas Infrastructure Are Caused by Abnormal Process Conditions*, 8 Nat. Comms. 14012—1421 (2017), https://www.nature.com/articles/ncomms14012 [hereinafter "Zavala-Araiza 2017"].

[74]Alvarez et al., *supra* note 72; Omara et al., *Methane emissions from US low production oil and natural gas well sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3; Robertson et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5—9 Times Higher than U.S. EPA Estimates*, 54 Env. Sci. Tech. 13926—13934 (2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927; Zavala-Araiza 2017, *supra* note 73.

[75] Barkley et al., *Quantifying methane emissions from natural gas production in north-eastern Pennsylvania* (2017) https://doi.org/10.5194/acp-17-13941-2017; Lyon et al., *Concurrent Variation in Oil and Gas Methane Emissions and Oil Price During the COVID-19 Pandemic* (2021), https://acp.copernicus.org/articles/21/6605/2021/; Lin et al., *Declining Methane Emissions and Steady, High Leakage Rates Observed over Multiple Years in a Western US oil/gas Production Basin* (2022), https://www.nature.com/articles/s41598-021-01721-5; Karion et al., *Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region* (2015), https://pubs.acs.org/doi/full/10.1021/acs.est.5b00217; Peischl et al., *Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions* (2015), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2014JD022697; Shen et al., *Satellite Quantification of Oil and Natural Gas Methane Emissions in the US and Canada Including Contributions from Individual Basins* (2022), https://acp.copernicus.org/articles/22/11203/2022/; Schwietzke et al., *Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements* (2017), https://pubs.acs.org/doi/10.1021/acs.est.7b01810.

[76]Alvarez et al., *supra* note 72; Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.

[77] Rutherford et al., Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas; Zavala-Araiza 2017., *supra* note 73.

about larger uncertainties in terms of magnitude and location of emissions and help identify key sources that require further characterization and attention.[78] This reconciliation is also integral to ensuring the data is accurate, not systematically skewed as is currently the case. Reconciliation is also necessary to ensure data is empirically-based to ensure that changes in emissions are rapidly reflected in the reported emissions, unlike the current case where shifts in emissions are largely not included.

To improve the accuracy of reporting, we recommend CARB develop site-level emission factors that would serve as the basis for reporting alongside CARB's existing source-based approach. To ensure these site-level estimates are both empirically based and accurately reflect total emissions, we recommend that CARB follow the three-step approach described above and included in more detail below:

1. **CARB should oversee the collection of site-level measurement-based estimates.** This measurement data must be stratified randomly within regions, industry segments, operator ownership, and types of sites to ensure representativeness. The number of samples should be sufficient to fully characterize—in the aggregate—the populations of emission sources. CARB must also define what high quality population-level empirical data it will accept. The site-level measurement data should then be used to develop probabilistic, population-based models that characterize the entire emission distribution and extrapolate data to aggregate regional emissions.

2. **Independently quantify total oil and gas emissions at the basin/sub-basin level.** CARB, either alone or with agencies (e.g., NOAA) should perform, coordinate, and oversee routine top-down measurements covering the state's oil and gas producing regions that account for the overwhelming majority of oil and gas production. Top-down approaches should be based on a set of previously peer-reviewed, scientifically robust approaches including aircraft,[79] towers,[80] and satellites.[81] Top-down approaches should incorporate robust attribution methods[82] that allow for separating emissions between oil and gas and other methane sources.

3. **Reconcile the site-level data from (1) with the quantified basin/sub-basin level data from (2).** The reconciled data provides new site-level emission factors used

[78] Alvarez et al., *supra* note 72; Neininger et al., *Coal Seam Gas Industry Methane Emissions in the Surat Basin, Australia: Comparing Airborne Measurements with Inventories* (2021), https://royalsocietypublishing.org/doi/10.1098/rsta.2020.0458; Shen et al., *Satellite Quantification of Oil and Natural Gas Methane Emissions in the US and Canada Including Contributions from Individual Basins* (2022), https://acp.copernicus.org/articles/22/11203/2022/.
[79] *See, e.g.*, Karion et al., *supra* note 75; Peischl et al., *supra* note 75; Schwietzke et al., *supra* note 75.
[80] *See, e.g.*, Monteiro et al., *Methane, carbon dioxide, hydrogen sulfide, and isotopic ratios of methane observations from the Permian Basin tower network* (2022), https://essd.copernicus.org/articles/14/2401/2022/.
[81] *See, e.g.*, Shen et al., *Unravelling a large methane emission discrepancy in Mexico using satellite observations* (2021), https://www.sciencedirect.com/science/article/pii/S0034425721001796?via%3Dihub.
[82] Smith et al., *Airborne Ethane Observations in the Barnett Shale: Quantification of Ethane Flux and Attribution of Methane Emissions* (2015), https://pubs.acs.org/doi/full/10.1021/acs.est.5b00219.

by reporters. Operators are able to submit their own site-level measurement-based data—subject to specific requirements about data quality and previous validation of measurement methods—to prove their company-level facility-based emissions are lower than the population average. Company-submitted data must be considered when the general basin level emission factor is calculated to ensure that there is alignment with the top-down estimates and basin-level accuracy is maintained. In other words, if emission factors for one group of facilities goes down the factors for other facilities must go up to ensure conservation of mass and thereby meet the accuracy requirement.

By adopting these recommendations, CARB can ensure reporting is empirically-based, accurate, and allows operators to submit empirical data. Doing so will also encourage operators to move toward direct measurement using advanced technologies in order to demonstrate better performance.

Our recommendations here also have implications for CARB's source-level estimates. For purposes such as rulemakings that require source-level data, CARB could eventually reconcile the empirical estimates of total emissions derived through the process outlined above with source-level estimates.[83] CARB can also improve source-level reporting by updating its GHG reporting rule. We recently submitted comments[84] to EPA detailing methods to update its source-level reporting in the EPA GHG Reporting Rule. We welcome the opportunity to discuss these recommendations with CARB.

A. The Significant Problem of Underestimation

Emission estimates derived from data reported through subpart W have traditionally lead to significant underestimation of total emissions from the oil and gas sector, with the greatest divergence in the production segment.[85] A large body of peer-reviewed literature has documented this failure to fully capture emissions over the past decade, primarily attributing the divergence to the GHGRP and Greenhouse Gas Inventory's (GHGI) failure to account for intermittent, large emission events. These emissions, often termed "super-emitters," are commonly caused by abnormal process conditions and equipment failures. Super-emitters lead to a heavy-tailed emission distribution, where the top 5-10% of sites or components are responsible for around 50% of total emissions. Below we summarize the literature documenting these emissions across the oil and gas sector.

Super-emitters are generally considered within the category of fugitive emissions, but they are distinct due to their root causes, large magnitude, and stochasticity. Fugitive emissions are

[83] To do this, CARB could compare estimates of total basin-level emissions based on the current approach of engineering calculations and source-level emission factors to empirically derived estimates. It could then use the empirically derived estimates described in (1) to (3) as the official value for total emissions and assign the difference in emission estimates to a generic source category (e.g., uncategorized). And finally, CARB could assess which source estimates are the likely cause of discrepancies using statistical methods and basin-level comparisons and update source-level methods to increase their accuracy.

[84] https://blogs.edf.org/energyexchange/files/2022/10/EDF-GHGRP-Comments-10.6.2022-Final.pdf

[85] *See, e.g.*, Alvarez et al., *supra* note 72; Rutherford et al., *supra* note 77.

emissions that are not intended as part of normal operations and can be broadly classified as leaks and unintentional vents. Sources of fugitive emissions include valves, flanges, connectors, thief hatches of controlled tanks, pump diaphragms, seals, and open-ended lines, and many others. Causes of these emissions include persistent issues, such as equipment malfunctions (e.g., unlit flare), as well as intermittent, short duration events (e.g., flashing from condensate tanks with malfunctioning controls).[86] Fugitive emissions can also result from devices that vent as part of normal operations, such as natural-gas driven pneumatic controllers, and control devices or equipment combusting natural gas, such as flares, when those devices are not operating as intended and have abnormally high emission rates. Fugitive emissions that result from abnormal operating conditions or equipment failures and result in large emission events are termed "super-emitters."

Super-emitters are often not well-represented (and may not be represented at all) in official estimates and inventories because they can be intermittent and are easily missed when taking equipment- or component-level measurements.[87] Because of this, emission factors derived from such measurements that do not otherwise account for super-emitters are not representative of total observed emissions. Bottom-up methods that estimate emissions using component or equipment counts and emission factors often fail to account for super-emitter events and result in artificially low overall emission estimates. Bottom-up methods often rely on measurements that capture only a snapshot of time; therefore, they may not be representative of emissions over longer timescales and are likely to miss intermittent emissions. Additionally, emission estimates that rely on engineering calculations often fail to account for super-emitters because the data inputs assume normal operations. Aerial detection methods and other top-down measurement and quantification techniques have documented the significance of large emission events and their large contribution to total emissions. This well-documented, heavy-tailed emission distribution means that 5-10% of sites are often responsible for 50% or more of total emissions.

Over the last decade, research by EDF and others has quantified the significance of methane emissions caused by oil and gas production and the persistent underestimation of fugitive and abnormal process emissions.[88] A large body of measurement-based studies has consistently found higher oil and gas methane emissions than are reflected in most inventories.[89] Bottom-up approaches like the EPA inventory and the subpart W reporting protocols greatly underestimate emissions because they are based on assumptions that do not account for large events caused by

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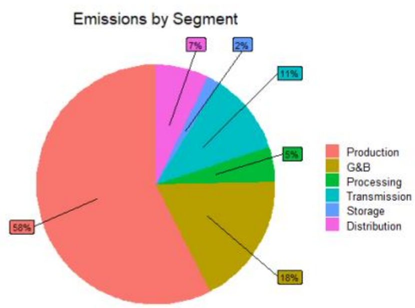
[86] Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.
[87] *See* IEA, *Methane Tracker Database* (Oct. 2021), https://www.iea.org/articles/methane-tracker-database (summary of inventory estimates).
[88] EDF, Methane Research Series: 16 Studies, https://www.edf.org/climate/methane-research-series-16-studies.
[89] Lyon et al., *Concurrent Variation, supra* note 75; Zavala-Araiza et al., *Reconciling Divergent Estimates of Oil and Gas Methane Emissions*, 112 Proc. Natl. Acad. Sci. 15597–15602 (2015), https://www.pnas.org/doi/abs/10.1073/pnas.1522126112; Zavala-Araiza 2017, *supra* note 73; Zimmerle et al., *Methane Emissions from the Natural Gas Transmission and Storage System in the United States*, 49 Env. Sci. Tech. 9374–9383 (2015),https://pubs.acs.org/doi/10.1021/acs.est.5b01669; Omara et al., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Region*, 50 Env. Sci. Tech. 2099—2107 (2016), https://pubs.acs.org/doi/10.1021/acs.est.5b05503; Peischl et al., *supra* note 75; Caulton et al., *Importance of Superemitter Natural Gas Well Pads in the Marcellus Shale*, 53 Env. Sci. Tech. 4747—4754 (2019), https://pubs.acs.org/doi/10.1021/acs.est.8b06965; Robertson et al., *supra* note 74; Zhang et al., *Quantifying Methane Emissions from the Largest Oil-producing Basin in the United States from Space*, 6 Sci. Adv. 5120 (2020), https://advances.sciencemag.org/content/6/17/eaaz5120/tab-pdf; Lyon et al., *Concurrent Variation*, *supra* note 75.

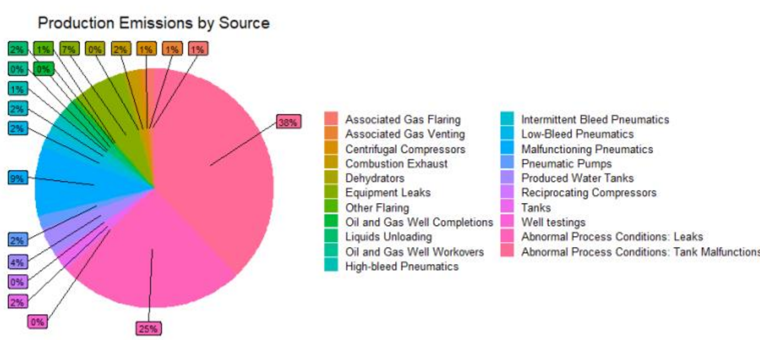
malfunctions and other abnormal conditions.[90] Accounting for these emission events can increase inventory estimates by 60-70%, underscoring the importance of accurate reporting protocols that capture such emissions.[91]

In 2012, EDF launched a series of research studies to quantify methane emissions from the U.S. oil and gas supply chain with diverse, measurement-based methodologies.[92] This collaborative work with over one hundred and forty experts from academia, industry, and government has resulted in more than forty peer-reviewed papers. In 2018, Alvarez et al., synthesized previous studies to estimate that U.S. oil and gas supply chain methane emissions were 13 million metric tons in 2015, equivalent to 2.3% of natural gas production and about 70% higher than estimated by EPA's current GHGI.[93] Numerous other studies have confirmed that bottom-up approaches like the GHGI and the subpart W reporting protocols greatly underestimate oil and gas methane emissions, largely capturing only component-level leaks and often missing the largest emission events.[94]

Emissions:

Total Emissions (Metric tons methane):	16,284,709
Formatted Total Emissions with Uncertainty (Million metric tons methane):	16 +/- 2
Methane Leak Rate (based on gross production):	2.4%
Methane Leak Rate (based on marketed production):	2.7%
Total VOC Emissions (Metric tons):	5,127,475





[90] Rutherford et al., *supra* note 77.
[91] Alvarez et al., *supra* note 72.
[92] *See* EDF, Methane research series: 16 studies, https://www.edf.org/climate/methane-research-series-16-studies.
[93] Alvarez et al., *supra* note 72.
[94] *See, e.g.*, Rutherford et al., *supra* note 77.

Figure 2: Alvarez Synthesis Model Inventory Estimates[95]

Recent research has found several common characteristics of oil and gas industry methane emissions. First, emissions occur across the value chain from well to end use, but are concentrated in the production and gathering segments, including well pads, tank batteries, and gathering compressor stations. EDF's emission inventory (shown above), derived from the Alvarez synthesis model and using more recent activity data,[96] estimates that production segment fugitive emissions represent nearly 50% of all oil and gas sector methane emissions. Second, all oil and gas facility types have a skewed distribution in which 5-10% of the highest emitting sites are responsible for about half of total emissions; however, the identity of these high-emitting sites can change with time and is difficult to predict.[97] Third, low production or marginal wells tend to have lower absolute emissions than high production wells, but much higher loss rates as a percentage of gas production. And because roughly three quarters of all wells are marginal, they cumulatively contribute a substantial fraction to total emissions–around 50% of production sector emissions according to a recent study.[98] Fourth, emissions can almost always be mitigated once detected, sometimes with a simple repair to stop a leak, and other times by implementing operational or equipment changes that improve a site's efficiency.

EDF's Permian Methane Analysis Project (PermianMAP) uses several peer-reviewed measurement approaches to quantify oil and gas methane emissions in the Permian Basin, the nation's largest oil field, and then posts the emissions data on the public website PermianMAP.org to facilitate mitigation. This project and other recent research in the Permian basin have generated several important findings, which we briefly summarize here.

Zhang et al. in a 2020 paper estimate the Permian Basin loss rate is 3.7% of gas production, substantially higher than the national average.[99] In 2021, Lyon et al., found a similar loss rate of 3.3% in the core production area of the Delaware sub-basin in March 2020 using aircraft and tower-based measurements. Lyon et al. report that the loss rate temporarily dropped to 1.9% in April 2020 when oil prices declined but recovered to prior levels by summer 2020.[100] They hypothesize that the Permian Basin typically has a high loss rate because wells are developed faster than the pipelines and compressor stations needed to transport the gas to market. This leads to both high rates of associated gas flaring and abnormal emissions due to gathering systems with inadequate capacity. The decline in well development during low oil prices likely temporarily relieved capacity issues and reduced emissions, bringing the leak rate closer to but still higher than

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[95] For an explanation of the methodology used to create this inventory, *see* EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate*, http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf.

[96] EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate*, http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf; *see also* IEA, *Methane Tracker Database* (Oct. 2021), https://www.iea.org/articles/methane-tracker-database (summarizing and comparing various inventory estimates).

[97] Lyon et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*, 50 Env. Sci. Tech. 4877 (2016), https://pubs.acs.org/doi/full/10.1021/acs.est.6b00705.

[98] Omara et al., *Methane Emissions from US Low Production Oil and Natural Gas Well Sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3; *see also* EDF, *Marginal Well Factsheet* (2021), https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf.

[99] Zhang et al., *supra* note 89.

[100] Lyon et al., *Concurrent Variation*, *supra* note 75.

EPA inventory estimates. This study suggests that permanent reductions could be achieved by ensuring adequate gathering infrastructure before permitting new well development.

Robertson et al. in a 2020 paper determined that New Mexico Permian well pad emissions were five to nine times higher than EPA inventory estimates; complex pads including tanks or compressors had about twenty times higher average emissions than simple pads with only a wellhead.[101] Finally, Cusworth et al. in 2021 used an aerial remote sensing approach to quantify over 1,100 large methane sources in the Permian.[102] In support of previous research, the paper found that both the gathering sector and flares are large sources of emissions. They also assess the intermittency of large sources and determine that, on average, large emission sources are emitting 26% of the time.

In addition to quantifying methane emissions, EDF scientists have assessed flare performance in the Permian with a series of helicopter-based infrared camera surveys. Based on over one thousand flare observations, approximately 5% of large flares are 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 to the atmosphere. On-the-ground flare combustion efficiency is thus much worse than EPA has assumed and than regulatory standards require. Flares are consequently one of the largest sources of methane in the Permian Basin, and the latest surveys have found even worse performance among smaller, intermittent flares. These findings suggest that reported flare emission estimates are likely far lower than actual emissions.

Studies examining emissions from low-producing or marginal wells—those that produce an average of less than 15 BOE/day—find even greater leak rates. And because there are hundreds of thousands of these sites nationwide, the cumulative emissions are very problematic and may represent more than half of total production-segment emissions.[103] In West Virginia, researchers found that wellhead methane emissions from marginal wells were 7.5 times larger than EPA's inventory estimate, with an average methane loss rate of 8.8% of production leaked at the wellhead.[104] In the Appalachian Basin, researchers reported that marginal well sites in Pennsylvania and West Virginia have enormously varied methane loss rates, ranging anywhere from 0.35% to 91% of their production.[105] For the very low production category of 0-1 BOE/day wells, which contribute just 0.2% and 0.4% of national oil and gas production, respectively, researchers in the Appalachian Basin estimated that wellhead methane emissions account for 11% of the production-related methane emissions in the EPA's inventory.[106] The same research observed that many marginal wells emit as much or more gas than they reported producing—in a region where natural gas is the primary product operators are aiming to sell.

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[101] Robertson et al., *supra* note 74.
[102] Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, Envtl. Sci. Tech. Letters __ (2021), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173.
[103] Omara et al., *Methane emissions from US low production oil and natural gas well sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3.
[104] Riddick et al., *Measuring Methane Emissions from Abandoned and Active Oil and Gas Wells in West Virginia*, 651, Sci. of the Total Env. 1849 (2019), https://doi.org/10.1016/j.scitotenv.2018.10.082.
[105] Omara et al., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin*, 50 Env. Sci. Tech. 2099 (2016), https://pubs.acs.org/doi/10.1021/acs.est.5b05503.
[106] Deighton et al., *Measurements Show that Marginal Wells are a Disproportionate Source of Methane Relative to Production*, 70 J. Air & Waste Mgmt. Assn. 1030 (2020), https://doi.org/10.1080/10962247.2020.1808115.

The scientific understanding of oil and gas methane emissions has expanded greatly over the last decade and can inform improved reporting requirements and effective regulations for reducing emissions, especially fugitive monitoring programs. The science shows that due to the skewed distribution of emission rates and the intermittency of some large emission events, emission factors that do not account for this using statistical methods or are not operationally verified with large-scale, frequent measurement efforts will greatly underestimate total emissions. These studies highlight the importance of updating reporting methodologies to bring reported and estimated emissions into better alignment with observed emissions.

VI. Conclusion

We appreciate CARB's consideration of these comments and welcome the opportunity to discuss them and answer questions at CARB's convenience.

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