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Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector

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Abstract

Methane—a short-lived and potent greenhouse gas—presents a unique challenge: it is emitted from a large number of highly distributed and diffuse sources. In this regard, the United States' Environmental Protection Agency (EPA) has recommended periodic leak detection and repair surveys at oil and gas facilities using optical gas imaging technology. This regulation requires an operator to fix all detected leaks within a set time period. Whether such 'find-all-fix-all' policies are effective depends on significant uncertainties in the character of emissions. In this work, we systematically analyze the effect of facility-related and mitigation-related uncertainties on regulation effectiveness. Drawing from multiple publicly-available datasets, we find that: (1) highly-skewed leak-size distributions strongly influence emissions reduction potential; (2) variations in emissions estimates across facilities leads to large variability in mitigation effectiveness; (3) emissions reductions from optical gas imaging-based leak detection programs can range from 15% to over 70%; and (4) while implementation costs are uniformly lower than EPA estimates, benefits from saved gas are highly variable. Combining empirical evidence with model results, we propose four policy options for effective methane mitigation: performance-oriented targets for accelerated emission reductions, flexible policy mechanisms to account for regional variation, technology-agnostic regulations to encourage adoption of the most cost-effective measures, and coordination with other greenhouse gas mitigation policies to reduce unintended spillover effects.

1. Introduction

Global natural gas use is very likely to increase in coming decades [1]. Replacing coal with natural gas significantly reduces almost all air quality impacts, solving a profound challenge facing the rapidly growing megacities of Asia [2]. And in developed economies, natural gas could become more, not less, important because gas turbines readily support flexible power grids with large fractions of renewable power. These trends are strengthened by recent breakthroughs in unconventional gas production that promise decades of gas supply at affordable prices. However, increased use of natural gas has heightened climate concerns because leaked natural gas, which is comprised mainly of methane, is a potent greenhouse gas (GHG) [3, 4].

Globally, methane accounts for 16% of all GHGs in the atmosphere, second only to carbon dioxide [5]. A third of all methane emissions in the United States (US) come from the hydrocarbon (HC) sector (natural gas and petroleum systems) [6]. Recognizing this, the US aims to reduce HC sector methane emissions in 2025 to 40%−45% below 2012 levels [7]. More recently, Canada, US and Mexico agreed to jointly reduce methane emissions [8]. Concurrently, several important developments have brought public attention to the methane leakage issue. Recent incidents—like the Aliso Canyon blowout in California, [9] and deadly explosions in distribution systems in Taiwan [10] and Argentina [11] have increased public scrutiny of gas infrastructure.

However, reducing methane emissions from our HC system is a challenge. There are approximately 1 M oil and gas wells in the US, thousands of processing and handling facilities, and millions of km of transmission and distribution piping below our factories and cities [4]. Each well can contain hundreds of possible points of leakage, and facilities can contain thousands of components. Thus, mitigating methane from the HC sector requires a completely different approach than regulations based on monitoring a small number of large point sources (e.g. power plant CO_2 emissions).

In this context, the US EPA recently finalized updates to the 2012 New Source Performance Standards, henceforth called the *final rule*, to regulate methane emissions from the HC sector [12]. The *final rule* expects to mitigate about 0.46 million metric tons (Mt) of methane in 2025, and result in climate benefits worth 690 M$, at a cost of 530 M$. By comparison, total methane emissions from the oil and gas industry stood at 9.8 Mt ($-16\%/34\%$) in 2014 [6]. The *final rule* targets emissions across the natural gas supply chain, including production, processing, gathering and boosting, and transmission and storage sectors. It specifies equipment replacement and operational modifications, as well as periodic leak detection and repair (LDAR) surveys. EPA recommends the use of optical gas imaging (OGI) technology in LDAR surveys, as an alternative to the older standard 'Method-21' (M21), which relied on point-source concentration measurements. OGI technology relies on images and videos of methane leaks that are made visible using infrared imaging cameras. In the *final rule*, OGI-based LDAR is estimated to mitigate 60% or 80% of emissions for semiannual or quarterly surveys, respectively [12]. However, a recent analysis of OGI technologies showed that OGI performance varies significantly with environmental conditions, operator practices, and characteristics of the facility [13]. Therefore, further study is needed to understand whether OGI-based LDAR will result in expected emissions reductions.

Technology effectiveness aside, recent studies of methane emissions provide more cause for concern. For example, many studies have found 'super-emitting' leaks, which are few in number but can cause most of the emissions from a facility. There is also significant regional variation [4] in emissions. To illustrate, a recent study [14] found gathering and processing leakage rates varied from less than 0.2% to about 1% in different regions. Similarly, the Bakken region of North Dakota was found to be leaking up to 6% of produced gas [15, 16] while similar measurements made in Texas [17] show much lower emissions rates. In the face of this diversity, an important question arises: Will the new policies help achieve methane mitigation targets, and if not, are there effective alternative frameworks?

In this work, we analyze the effectiveness of the *final rule* and develop a framework to design improved policies for methane emissions reduction. Our findings are as follows:
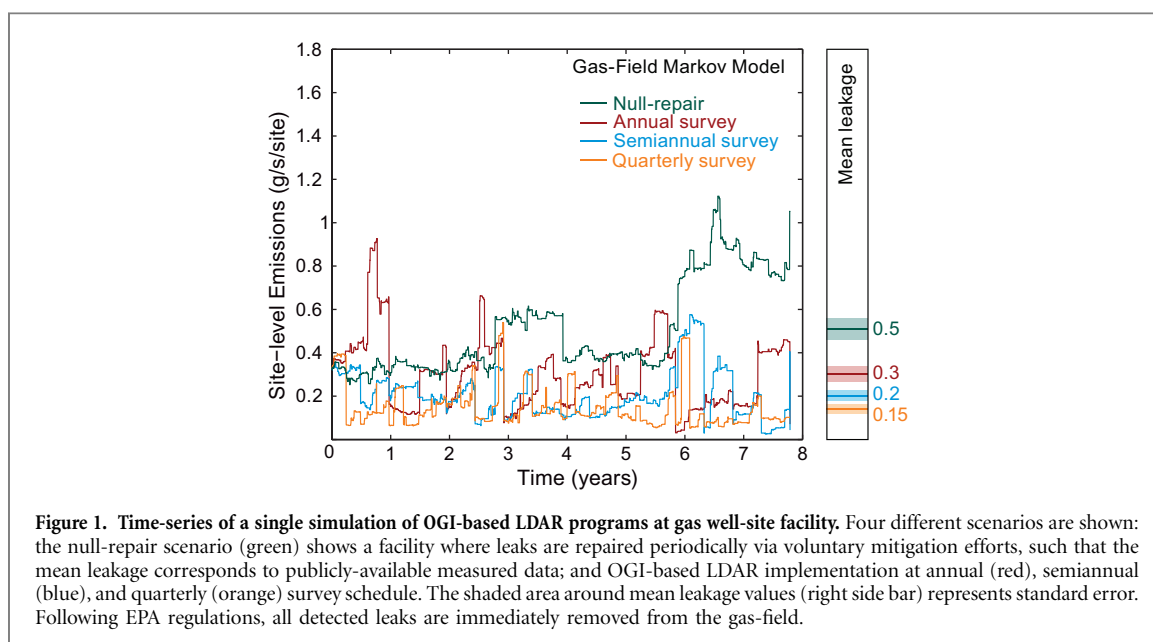
1. variation in the baseline emissions estimate between facilities leads to large variability in mitigation effectiveness

2. highly heterogeneous leak-sizes found in various empirical surveys strongly affect emissions reduction potential;

3. emissions reductions from OGI-based LDAR programs depend on a variety of facility-related and mitigation-related factors and can range from 15% to over 70%;

4. while implementation costs are 27% lower than EPA estimates, mitigation benefits can vary from one-third to three times EPA estimates;

5. a number of policy options will help reduce uncertainty, while providing significant flexibility to allow mitigation informed by local conditions.

To support these conclusions below, we first describe our simulation framework. Then we explore uncertainty arising from various facility-related, and mitigation-related factors. We discuss the implications of this uncertainty on the costs and benefits of regulation. Lastly, we develop recommendations that form a framework to effectively mitigate emissions from distributed sources.

2. Methods

General approach: We use an open-source model, the Fugitive Emissions Abatement Simulation Toolkit or FEAST [18], that simulates methane leakage from natural gas facilities at the component level with high time resolution. FEAST uses information about model-plant parameters, generates leaks from an empirical leak-population and applies OGI-based leak detection technology to evaluate mitigation effectiveness. Once 'detected' by the technology module, the leaks are removed from the field. New leaks are added over time in a stochastic manner. All simulations are conducted for a total time of 8 years, with capital costs distributed evenly at 7% interest, as per EPA calculations. At the end of every simulation, the per-site time-averaged leak rate is calculated and compared to the time-averaged no-LDAR leak rate to estimate the additional emission reductions due to policy intervention (see supplementary note 2.1 at stacks.iop.org/ERL/12/044023/mmedia).

OGI technology model: The OGI technology module in this work is modeled after FLIR's GasFind IR-320 camera used for methane leak detection. Images of plumes, as seen by the camera, are simulated using first-principles modeling of the infrared molecular absorption spectrum of methane and

Figure 1. **Time-series of a single simulation of OGI-based LDAR programs at gas well-site facility.** Four different scenarios are shown: the null-repair scenario (green) shows a facility where leaks are repaired periodically via voluntary mitigation efforts, such that the mean leakage corresponds to publicly-available measured data; and OGI-based LDAR implementation at annual (red), semiannual (blue), and quarterly (orange) survey schedule. The shaded area around mean leakage values (right side bar) represents standard error. Following EPA regulations, all detected leaks are immediately removed from the gas-field.

quantifying the influence of background thermal radiation [13]. Modeling of methane leaks is undertaken using a Gaussian plume dispersion model. We have previously shown that the effectiveness of using an IR camera for leak detection is strongly dependent on environmental conditions, operator practices, underlying leak-size distribution, and gas composition. We use this OGI technology module to evaluate emissions mitigation based on periodic LDAR surveys at natural gas well sites. To realistically model field conditions, we assume that the methane leaks are in thermal equilibrium with the surroundings at a temperature of 300 K, and the composite background emissivity is 0.5. More information on camera properties and other module parameters can be found in online supplementary note 2.2.

Data: Parameters for model plants of all facility-types are derived from the technical support documentation provided as part of EPA's *final rule* [19]. Some analysis also make use of EPA baseline emissions calculations for appropriate comparisons to our model. The population of ≈6000 leaks and the leak-size distribution are taken from various publicly available empirical datasets of natural gas systems in the production [20–22], gathering and boosting [23], and transmission and storage sectors [24]. Economic and policy parameters like capital costs, survey costs, repair and resurvey costs, and gas prices have been modeled after EPA's methodology [19] (also see supplementary note 3).
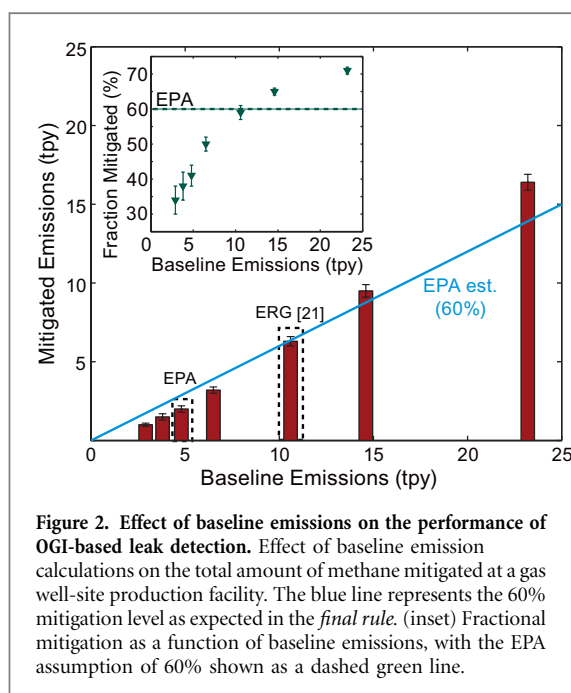
3. Simulation with an open-source model

FEAST simulates the evolution of leaks at gas facilities, using data from a variety of publicly available data-sets (see online supplementary note 3) to estimate methane emissions and model the effectiveness of LDAR programs. It uses components counts, site

characteristics, economic data, and LDAR designs from EPA's analysis [19] (see online supplementary note 4). FEAST also contains an OGI-technology simulation module which simulates the physics of infrared methane imaging cameras [13] (see online supplementary note 2). In FEAST, leaks evolve via a two-state Markov process: each component is in a 'leaking' or 'non-leaking' state with a finite probability of changing state at any given time. The probability that a leak will be found and fixed depends on the LDAR technology employed as well as properties unique to the gas field. Each simulation is run for a period of 8 years with one day time steps.

FEAST contains a 'null-repair' scenario where the total leak rate reaches steady state in the absence of any LDAR program or policy intervention. This is due to a null repair rate that finds and fixes leaks from the system. The null repair rate represents periodic repairs from operators undertaken through voluntary leak mitigation programs. FEAST can then compare this null-repair scenario results to various LDAR implementations. FEAST outputs results showing the time-series of leakage from a particular realization (see figure 1). In the 'null-repair' scenario with no-LDAR performed, the leakage averages 0.5 g s^{-1}/site, with variation due to the random leak generation process. Figure 1 shows the leakage from the same modeled facility under three different LDAR programs: annual, semiannual, and quarterly OGI surveys. We see that the mean leakage in these cases reduces (0.3 to 0.15 g s^{-1}/site) as survey frequency increases.

4. Testing the mitigation policy

Uncertainties in mitigation effectiveness of the *final rule* can be studied systematically under two broad classes: facility-related uncertainty and mitigation-related uncertainty. Facility-related uncertainties refer to effects

Figure 2. Effect of baseline emissions on the performance of OGI-based leak detection. Effect of baseline emission calculations on the total amount of methane mitigated at a gas well-site production facility. The blue line represents the 60% mitigation level as expected in the *final rule*. (inset) Fractional mitigation as a function of baseline emissions, with the EPA assumption of 60% shown as a dashed green line.

not related to the mitigation program: regional variation in leakage, facility-dependent emissions distributions, estimates of baseline emissions, or chemical composition of the gas resource. Mitigation-related uncertainties are driven by variation in detection technologies and their application in LDAR programs. These uncertainties include minimum detection limits of OGI-based cameras, the influence of environmental conditions during the survey, and sensitivity of OGI to non-methane emissions. We first examine facility-related uncertainties.

4.1. Baseline emissions: effects of voluntary mitigation

An important driver of mitigation effectiveness is the rate of baseline emissions. Baseline emissions are the steady-state leaks in a facility prior to the implementation of policy-mandated LDAR programs. They vary significantly across similar facilities because of regional differences, operator practices, and processing requirements. EPA calculates baseline emissions by multiplying emissions factors for each component at a given facility with the typical number of components at a 'model plant' [19]. Five different model plants with corresponding baseline emissions are specified in the *final rule*: gas well-sites (GW), oil well-sites (OW), gathering and boosting (G & B) stations, transmission (T), and storage (S). The assumed steady-state baseline emissions in a facility will strongly affect the benefits from an LDAR mandate. A higher baseline emissions rate would be associated with higher emission-reduction potential and larger potential cost recovery from saved gas.

To quantify the effect of variation in baseline emissions, we simulate a semiannual OGI-based LDAR survey at a GW site. The leak population and their size-distributions are derived from a survey

of ≈400 GW sites in Texas [20] (see online supplementary note 3). Different baseline emissions are modeled by varying the repair rate of the null repair process—a high null-repair rate represents significant voluntary emissions reductions and diligent repair, leading to lower baseline emissions (online supplementary note 5.1). Figure 2 shows the average emissions mitigated in metric tonnes per year (tpy) under different baseline emissions scenarios. The diagonal blue line represents 60% emissions mitigation as expected by the EPA for a semiannual survey. Emissions mitigation range from about 1.1 tpy for a baseline leak rate of 3 tpy to over 16 tpy at a baseline leak rate of ≈23 tpy. This corresponds to fractional emission reductions ranging from 37% to 71% (see inset of figure 4). OGI-based reduction fractions vary because of two related processes. While the null repair rate is assumed to repair leaks independent of its size, the OGI-based process removes only the largest leaks. Thus, using OGI-based leak detection technology in a facility with baseline emissions lower than ≈10 tpy tends to result in mitigation percentages that are smaller than the expected 60%.

4.2. Effect of skewed leak-size distribution

An even more important facility-related uncertainty is the variability in leak size distribution. Various studies have demonstrated that leak size distributions are highly heterogeneous, with a small fraction of 'super-emitters' contributing a large fraction of total emissions [25]. Because the minimum detection limit of a leak-detection technology is fixed, differing leak-size distributions will significantly affect mitigation even if the total volume of leakage remains constant. Figure 3(*a*) shows normalized cumulative share plots of five artificial leak-size distributions, A–E (see online supplementary note 5.2). The emissions contribution from the largest 10% of emitters varies from 30% in distribution A (least skewed) to 70% in distribution E (most skewed). All facilities exhibit a total emissions volume of ≈10 tpy. We now plot the fractional mitigation resulting from a semiannual OGI survey (figure 3(*b*)). We see that in Facility A, OGI only mitigates 16% of the emissions; while Facility E, with the most-skewed leak population, mitigation exceeds 50%. Clearly, estimates of expected emissions reductions are highly dependent on facility leak size distributions.

We next use six publicly-available component-level leak data-sets from five studies on production [20–22], gathering and boosting [23], transmission [24], and storage [24] facilities (figure 3(*c*)). We simulate OGI based monitoring at the EPA-recommended survey schedule for each facility. In order to directly compare simulation results with EPA-expected emissions reductions, we force each facility to have baseline emission values that corresponds to EPA estimates for that facility type (see online supplementary table S3 for details).
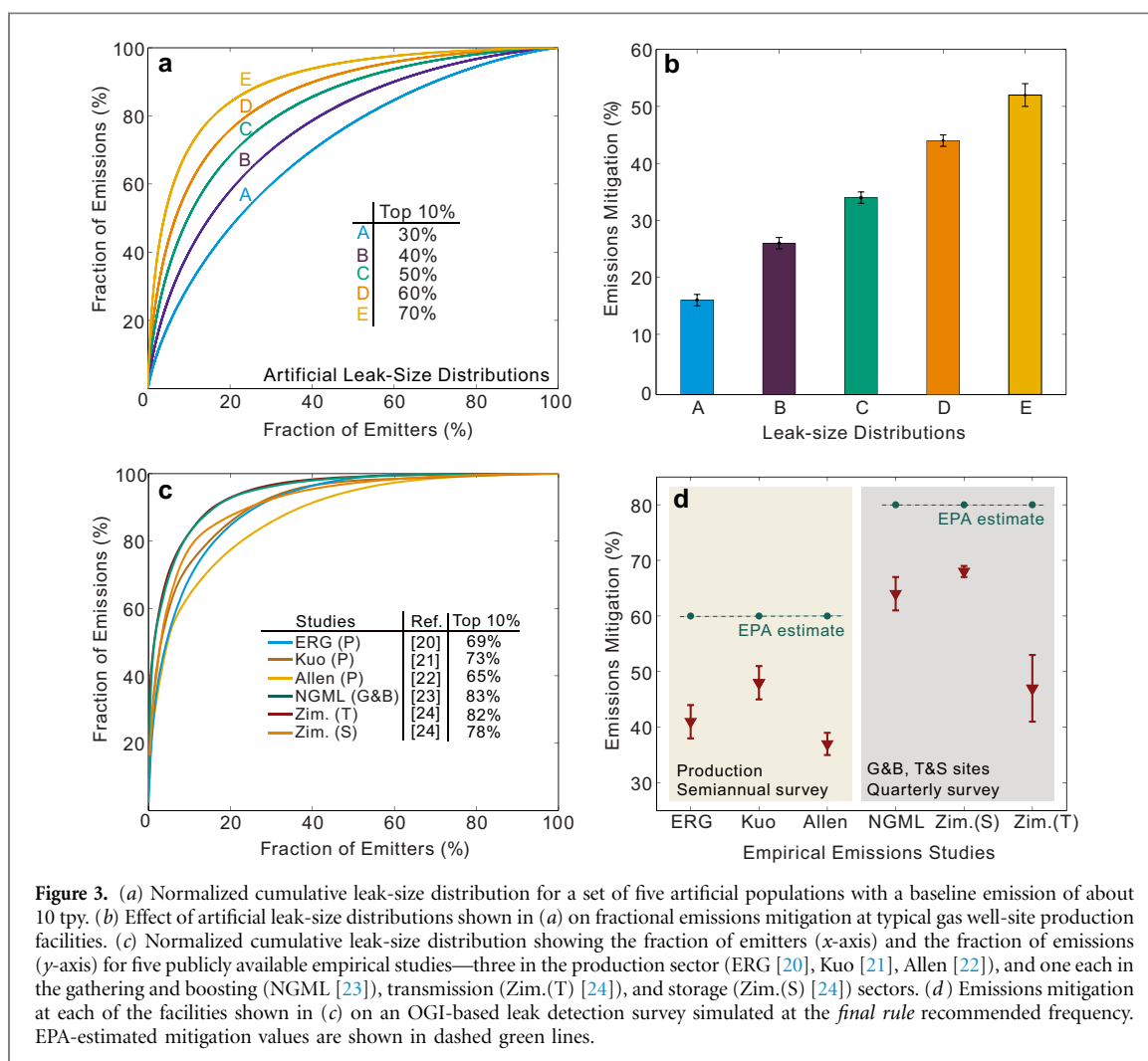
Figure 3. (*a*) Normalized cumulative leak-size distribution for a set of five artificial populations with a baseline emission of about 10 tpy. (*b*) Effect of artificial leak-size distributions shown in (*a*) on fractional emissions mitigation at typical gas well-site production facilities. (*c*) Normalized cumulative leak-size distribution showing the fraction of emitters (*x*-axis) and the fraction of emissions (*y*-axis) for five publicly available empirical studies—three in the production sector (ERG [20], Kuo [21], Allen [22]), and one each in the gathering and boosting (NGML [23]), transmission (Zim.(T) [24]), and storage (Zim.(S) [24]) sectors. (*d*) Emissions mitigation at each of the facilities shown in (*c*) on an OGI-based leak detection survey simulated at the *final rule* recommended frequency. EPA-estimated mitigation values are shown in dashed green lines.

Figure 3(*d*) shows the fractional mitigation for OGI-based leak detection surveys using these datasets with typical OGI survey conditions (see online supplementary note 2.2, but briefly: imaging distance of 5 m and ambient temperature of 300 K). In all cases, we find that simulated emissions mitigation falls short of the EPA-expected 60% (semiannual survey) or 80% (quarterly survey) mitigation levels (green dashed lines).

To explore the production sector cases in more detail: a semiannual LDAR survey only reduces emissions by 37%, 41%, and 48% in the facilities modeled using the Allen [22], ERG [20], and Kuo [21] distributions, respectively. These differences arise despite baseline emissions in all three analyses set equal to EPA-estimated 5 tpy. Variations observed, then, can be attributed to different leak-size distributions in the three studies considered. This shows that assuming a uniform baseline emissions volume for all facilities in a given industry segment is *not sufficient* to drive uniform mitigation benefits. The *final rule* does not model the direct relationship between leak volumes, leak size distributions, and leak detection effectiveness.

4.3. The role of technology and mitigation program
In addition to facility-related uncertainties explored above, mitigation-related uncertainties are also impor-

tant. Here, we explore the impacts of four mitigation-related uncertainties: imaging distance, detection criteria, ambient temperature, and ambient wind conditions. In all cases, we model GW sites, using a large dataset of leaks generated from peer-reviewed studies (see online supplementary note 5.3 for details).

Figure 4(*a*) shows emissions reductions as a function of imaging distance and survey frequency. Reductions can vary from about 15% (imaging annually at 50 m) to as high as 70% (imaging quarterly at 5 m). Compared to EPA's estimate of 60% reduction from a semiannual survey schedule, we see large variability in mitigation potential. Our results indicate that a 60% emissions reduction from semi-annual surveys is possible only when leaks are imaged at a distance less than 5 m from the leak source. Importantly, the *final rule* does not specify an acceptable survey distance. Furthermore, over 50% of total achievable mitigation at any imaging distance is realized from an annual survey schedule, leading to less variability with changing survey interval than might be imagined. Note that the *final rule* focuses on specifying the time interval of LDAR surveys, but does not specify a more impactful parameter, the survey distance.

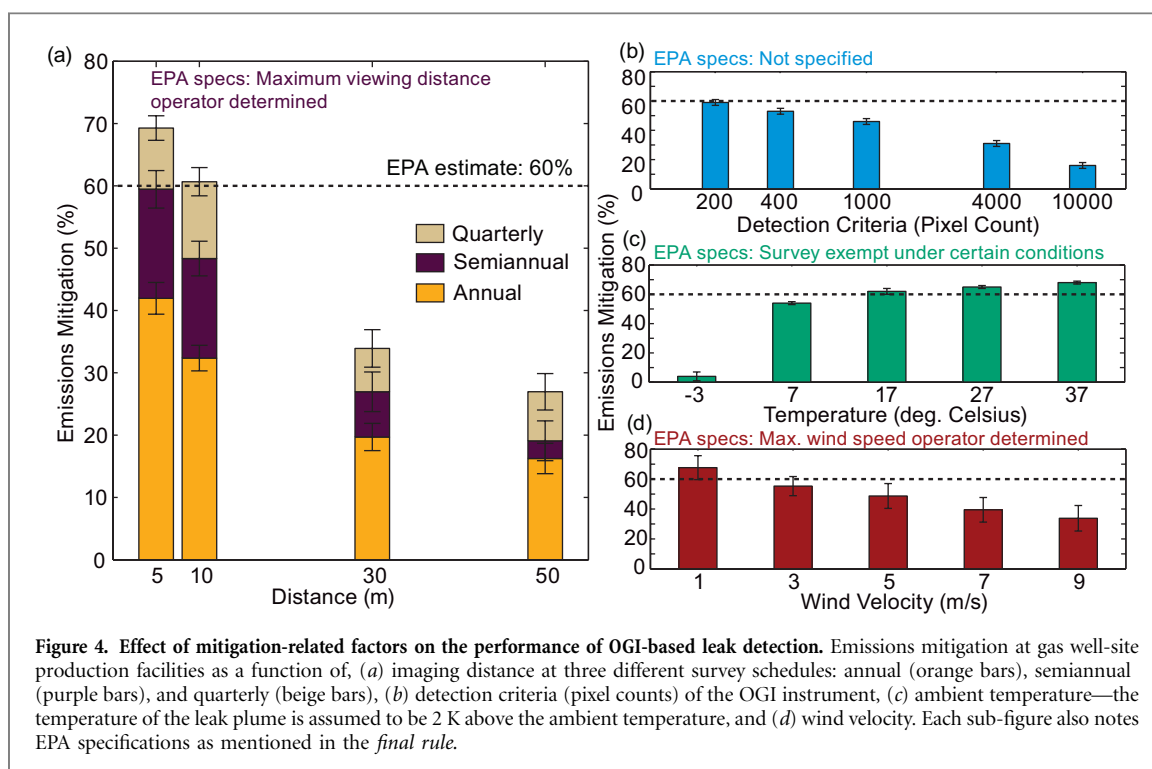Another mitigation-related uncertainty is the detection sensitivity. In OGI-based LDAR, detection

Figure 4. Effect of mitigation-related factors on the performance of OGI-based leak detection. Emissions mitigation at gas well-site production facilities as a function of, (*a*) imaging distance at three different survey schedules: annual (orange bars), semiannual (purple bars), and quarterly (beige bars), (*b*) detection criteria (pixel counts) of the OGI instrument, (*c*) ambient temperature—the temperature of the leak plume is assumed to be 2 K above the ambient temperature, and (*d*) wind velocity. Each sub-figure also notes EPA specifications as mentioned in the *final rule*.

depends on the visual acuity and experience of the operator. We model this factor by varying the minimum number of pixels affected in order for a plume to be detected. Figure 4(*b*), shows that emissions mitigation drops from ≈60% at a detection criterion of 200 pixels to 16% at a detection criterion of 10 000 pixels. In all simulations, a pixel 'registers' the plume if the signal-to-noise ratio (SNR) of the pixel is greater than or equal to 1. Specifying a higher SNR to reduce the occurrence of false positives will also reduce the detection effectiveness [13].

Environmental factors also affect OGI. The effects of temperature and wind velocity are shown in figures 4(*c*) and (*d*), respectively. Mitigation effectiveness abruptly drops near and below 270 K. This abrupt reduction indicates the temperature at which the temperature-emissivity contrast between the plume and its surroundings fall below the SNR of the camera modeled here. Any infrared imaging based detection system should account for significant reduction in detection effectiveness at low temperatures [13]. Wind velocity affects the dispersion of the plume in the atmosphere. Low wind-speeds are preferable to ensure that the plume body remains concentrated and therefore registers a high SNR on camera pixels. This is shown quantitatively in figure 5(*d*) where emissions mitigation reduced from 68% at calm atmospheric conditions with 1 m s^{-1} winds, to about 34% at winds of about 9 m s^{-1}.
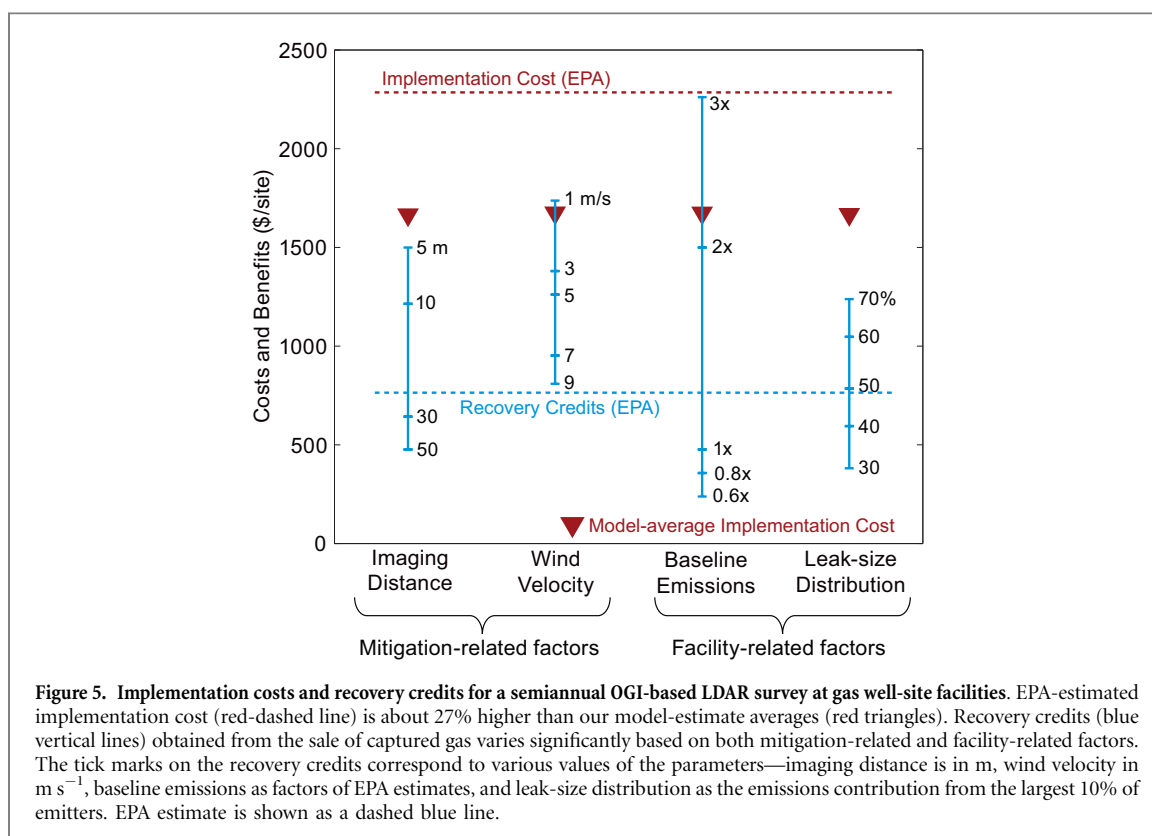
5. Fixed costs, variable benefits

The costs of mitigation associated with the *final rule* can be decomposed into three categories: (1) one-time costs to develop compliance plans and other capital expenditures, (2) annual recurring costs associated

with conducting LDAR surveys, and (3) costs of the repair and resurvey process. Because of the way the *final rule* is designed, the implementation costs do not vary considerably between similar facilities. On the other hand, the benefits from the expected sale of mitigated gas ('recovery credits'), are highly variable. Here, we analyze these costs and benefits at a GW site on a semiannual OGI-based LDAR schedule. A comparison of economic parameters between our model and that of EPA is summarized in table S6 (see supplementary note 4.5).

Figure 5 shows the implementation costs (red) and recovery credits (blue) at a site as a function of above-explored uncertainties. Two important results include: (1) implementation costs are fairly constant in both our model and EPA estimates, but costs in our model are 27% lower than EPA estimates; and (2) recovery credits vary significantly with mitigation-related and facility-related uncertainties explored above.

For semiannual LDAR monitoring, EPA estimates the implementation cost for all gas well-site production facilities to be $2285/site (figure 5, red dashed line). By comparison, we estimate a cost of about $1670 on average, a reduction of 27% from EPA estimates (figure 5, red triangles). The one-time costs and the annual recurring costs of OGI-based LDAR surveys are identical in both models. The difference arises because EPA has higher repair and resurvey costs compared to our model. This occurs because the EPA likely over-estimates the number of leaks found through an OGI-based LDAR survey, as discussed below. It should be noted that both models assume repair and resurvey costs are based on the number of leaks detected rather than the leak size—a reasonable assumption given that studies have shown no

Figure 5. **Implementation costs and recovery credits for a semiannual OGI-based LDAR survey at gas well-site facilities**. EPA-estimated implementation cost (red-dashed line) is about 27% higher than our model-estimate averages (red triangles). Recovery credits (blue vertical lines) obtained from the sale of captured gas varies significantly based on both mitigation-related and facility-related factors. The tick marks on the recovery credits correspond to various values of the parameters—imaging distance is in m, wind velocity in m s^{-1}, baseline emissions as factors of EPA estimates, and leak-size distribution as the emissions contribution from the largest 10% of emitters. EPA estimate is shown as a dashed blue line.

correlation between repair costs and leak size [23, 26] (also see online supplementary note S5.4).

In estimating repair and resurvey costs, EPA assumes that 1.18% of all components are found leaking using OGI technology [19]. However, this number is inferred from prior measurements of valves in petroleum refineries using an M21 device at the 10 000 ppm screening level [27]. M21 relies on a local concentration measurement (i.e. device returns a ppm CH$_4$ reading) and concentrations above a screening threshold (i.e. 10 000 ppm) are considered leaking. However, this M21 leak definition cannot be directly applied to natural gas well-sites on an OGI monitoring schedule because of significant differences in detection thresholds. For example, one study which surveyed and quantified thousands of leaks at production sites using both M21 and OGI [20] showed that only 0.175% of components were found leaking using OGI, while 1.07% were found leaking with M21. An earlier EPA study found 2.2% of components leaking with a M21 threshold screening value of 10 000 ppm [23, p. iii], while a recent study using OGI found 0.28% of components leaking [21]. Thus, available evidence suggests that the number of components found to be leaking will be an order of magnitude lower using OGI (0.1%−0.3%) rather than M21 (1%−2%). This difference translates to significantly lower repair and resurvey costs, and hence, lower LDAR implementation costs. In our model the total implementation costs are dominated by the cost of conducting semiannual LDAR surveys: about 80% of GW site

costs are from surveys. This results in a case where implementation costs are fairly constant, and independent of mitigation effectiveness.

However, the recovery credits from sale of captured gas vary significantly from EPA's estimates of $764/site. Here, we consider four different factors that affects the amount of emissions mitigated—imaging distance, wind velocity, baseline emissions, and leak size distribution. As imaging distance varies from 5–50 m, the recovery credits decrease from $1499/site to $214/site, respectively. This exemplifies an issue with the *final rule*—by varying an operator-controlled parameter such as imaging distance, the policy benefits vary widely. Similar dynamics are also at play with variations in wind velocity and other parameters. We also consider cases where baseline emissions range from 0.6–3 times the EPA estimate. For facilities with baseline emissions lower than the EPA estimate, the recovery credits available from a semiannual survey are lower than $500/site, covering less than a third of the implementation cost. On the other hand, facilities with high baseline emissions can accrue recovery credits that are higher than the implementation cost, resulting in a highly desirable net-negative cost of emissions control (see online supplementary note 6). Similarly, by varying leak-size distributions, we see that recovery credits vary from $381/site to about $1200/site with more heavy-tailed distribution. This indicates that 'super-emitters' greatly enhance the economics of OGI because the technology favors detection of the largest leaks.

6. Lessons for future mitigation policies

Combining our analysis with other recent findings, we propose improvements to methane mitigation regulation. First, an outcome-oriented policy with targets and an appropriate incentive structure will accelerate emissions mitigation. Second, a mechanism that accounts for regional variability can be more cost-effective. Third, technological flexibility can reduce costs and increase mitigation potential. And fourth, coordination with other emissions mitigation policies like the Clean Power Plan (CPP) [28] will be crucial to prevent unintended emissions spill-over effects. These four recommendations are discussed in further detail below.

Performance oriented targets for accelerated emissions reduction: First, performance based leakage targets based on either a mass-based (absolute emissions cap) or a rate-based (fraction of system throughput) will reduce the variability in mitigation effectiveness. This is because mitigation benefits can vary considerably based on technology, facility characteristics, and individual operator practices. At the same time, LDAR costs are directly proportional to the number of surveys. As we have seen, a poor survey implementation may result in highly sub-optimal emissions reduction. Such a standard perversely penalizes responsible operators with already low baseline emissions by forcing them to implement an LDAR program with minimal benefits. Also, the *final rule* only mandates that the behavior of LDAR is to be performed at some frequency. Such designs raise the possibility of not achieving mitigation goals if operators work to 'check the box' of the regulation requirements at lowest cost. A regulation that instead sets emission targets would allow operators to develop the most cost-effective means to achieve the target. Obviously, such targets would need to be enforced with periodic audits by regulatory agencies.

An outcome-oriented policy objective could have incentive structures that reward emissions mitigation that exceeds targets, while simultaneously penalizing non-compliance. This 'carrot-and-stick' approach can mitigate emissions at a rate faster than what conventional periodic LDAR surveys would allow. To illustrate, 'sticks' can take the form of fines or fees based on actual emission levels and a social cost of methane [29]; 'carrots' can include a system that rewards better-than-required performance (e.g. revenue recycling from fines or preferential permitting for excellent operators). Such target-based approaches would give operators the flexibility to choose mitigation technologies that are uniquely suited for their operations, improving cost-effectiveness.

Flexible policy mechanisms to account for regional variation: National emissions estimates, while important for accounting purposes, should not determine policy for all regions. There is growing evidence from a number of studies that methane emissions vary significantly based on basin characteristics and type of operation. For example, in a study of 114 gathering facilities across eight states, loss rates ranged from a low of about 0.2% to approximately 1% [14]. Measurements at production sites also show very different leak size distribution characteristics—the top 5% of emitters account for about 50% of total emissions in Barnett shale region [20], but over 90% in the Marcellus shale region [30]. Such differences in emission profiles will require different mitigation strategies. In this regard, states like Colorado have provided a template for effective regulation—in addition to LDAR programs at production and compressor facilities, Colorado instituted specific emissions management systems for storage tanks, where 'super-emitters' were more likely to occur. Estimates of expected emissions reductions should be tailored to reflect regional differences, and consequently, should also dictate the stringency and targets for mitigation programs.

Technology-agnostic regulations to improve cost-effectiveness: It would seem logical to specifically target and repair as quickly as possible the small number of super-emitters, resulting in large marginal abatement benefits. In this regard, OGI technology is ideally suited due to its ease in finding large leaks. However, as we saw in figure 4, the performance of this technology is sensitive to environmental conditions and 'detection' relies on the subjective judgment of the operator. Moreover, a semi-annual LDAR schedule could mean that large leaks go un-noticed for up to 6 months. When looking for super-emitters, continuous-monitoring technologies can trade-off sensitivity for lower cost, paving the way for real-time leak detection and mitigation. In addition to numerous technology start-ups, the Department of Energy's MONITOR program [31] is dedicated to developing cost-effective leak detection systems. However, it is unclear if and when such systems will be available on the market. Nevertheless, many other start-up companies promise to conduct leak detection surveys cost-effectively, with the main issue being the difficulty of demonstrating equivalence to EPA approved technologies. Policies should acknowledge future availability of newer and potentially cheaper technologies for leak detection and design regulations that allow for technological flexibility. Indeed, a mass or rate-based mitigation goal, as discussed previously, can be technology-agnostic, resulting in the flexibility that operators and states can use to great advantage, as long as mitigation targets are met and compliance is verified. Such technology-agnostic policies can have the dual advantage of giving operators choice in designing mitigation programs, while ensuring that a pre-determined methane mitigation goal is achieved in a cost-effective manner. As a spillover effect, such policies can establish a robust market for new technologies.

Coordination with other GHG mitigation policies to reduce unintended spillover effects: Finally, we stress

the importance of coordinating a methane mitigation policy into the broader context of reducing GHG emissions from different sectors of the economy. The CPP, relies to a large extent on switching high-emitting coal-based power plants with low-emitting natural gas plants. Such fuel-switching, coupled with the shale-gas boom, can significantly increase natural gas production, along with associated methane leakage. Studies have shown that increased methane leakage in the natural gas sector can potentially erode the benefits of the Clean Power Plan [32]. Policy coordination is essential to avoid unintended negative spill-over effects in GHG emissions.

Aside from an emissions perspective, there is also evidence that mitigating all GHGs simultaneously as opposed to focusing on just carbon dioxide will be more cost-effective. Modeling results [33, 34] show that costs are 20%−50% higher when carbon pricing is applied only to carbon dioxide rather than all GHGs, for the same cap on atmospheric CO_2-equivalent concentrations. These results suggest that there might be low-cost options to mitigate non-CO_2 GHGs, in addition to policies that target CO_2 emissions.

While the four policy options discussed here are not cumulative, one can recognize significant co-benefits in implementing these regulations simultaneously. Furthermore, we argue that lessons on effective methane mitigation as described here are widely applicable. Recent work by Kirschke *et al* [35] indicates that emissions from fossil fuels dominate the regional methane budgets in Europe, Middle-East and Russia. Despite global differences in gas composition and extraction systems, methane emissions sources from fossil fuel infrastructure are fairly comparable. Typically, leaks are highly distributed over multiple point sources that include thousands of components like valves, connectors, seals, etc or various points along the millions of km of transmission and distribution pipelines. Each of the components are prone to leaking to varying degrees and at unpredictable times. For this reason, any global effort to reduce fossil-based methane emissions would require mitigation policy that follows the broad recommendations discussed here.

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