Translating Satellite Data into Abatement: A Technical Explanation for Satellite Insights on Global Methane Super-Emitters

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Introduction

1.1 Methane emissions globally

Methane (CH_4) is a potent greenhouse gas (GHG) with a Global Warming Potential (GWP) of 29.8[1] over 100 years. **Anthropogenic methane emissions** come from different sectors (Figure 1), including oil, natural gas, coal, waste, and agriculture, and represent about 19.25%[2] of global GHG emissions.

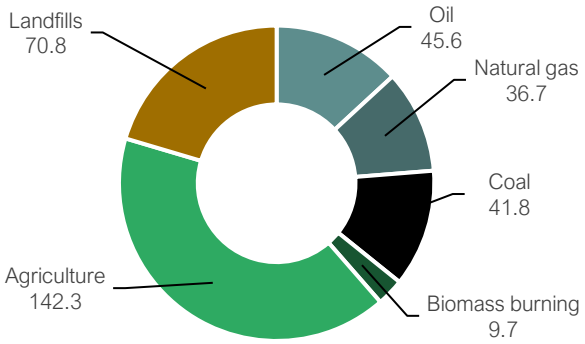

Figure 1. Anthropogenic methane emissions by sector in 2022 ($MtCH_4$). In 2022, the energy sector accounted for 40% (135 million tons - Mt) of global anthropogenic methane emissions. Source: IEA Global Methane Tracker[3]

Oil and gas - Natural gas, predominantly composed of methane, is extracted from gas fields and can be a byproduct of oil production. Methane is therefore emitted along the oil and gas value chain, from production to distribution. The emission sources are various, including unintentional sources such as leaks and malfunctions, and intentional sources such as through vents, incomplete combustion, and flaring.

Landfills (e.g., Municipal Solid Waste Landfills) - Methane is produced during the decomposition of organic waste by bacteria in anaerobic conditions. Methane is emitted diffusely through the landfill site but can also come from specific emission points. These emissions can occur for different reasons, ranging from site management (e.g., absence of landfill cap or cover, which is typically the case for the active face of the landfill where a lot of emissions occur), an inefficient flare, or a malfunctioning gas collection system.

Agriculture – Methane is mainly emitted through enteric fermentation and manure management.

Coal – Methane is mainly emitted during coal extraction activities from active underground mines, commonly from degasification and ventilation systems used for safety reasons. To a lesser extent, emissions will also arise from surface, closed, or abandoned mines.[4]

[1] IPCC Sixth Assessment Report (AR6, Table 7.15) at Climate Change 2021: The Physical Science Basis (ipcc.ch)
[2] Jones et al. (2023) – with major processing by Our World in Data. "Methane (CH_4)" [dataset]. Jones et al., "National contributions to climate change" [original data]. Retrieved from: Greenhouse gas emissions - Our World in Data, in February 2024.
[3] IEA (2023). *Global Methane Tracker 2023.* Retrieved from: Global Methane Tracker 2023 – Analysis - IEA, in January 2024.
[4] EPA (2023) – *About Coal Mine Methane.* Retrieved from: About Coal Mine Methane | US EPA, in February 2024.

1.2 Reducing methane emissions from super-emitters

Significant reductions in methane emissions are necessary to meet mitigation targets and address the pressing issue of climate change.

Globally, **super-emitters**[5] – the small fraction of emitting sources that contribute a disproportionately large fraction of total methane emissions[6] – represent a large abatement potential of methane emissions. Recent work has focused on identifying these super-emitters and quantifying their total impact[7,8]. However, even though methane hot spots seen from space have become regular topics in international news articles, a systematic analysis of the sources that cause them and of the total costs related to their abatement is still missing.

There is a large focus globally on super-emitters from the energy sector. Methane from the **oil and gas** sector offers low-hanging fruit options for GHG mitigation in terms of emission reduction potential and abatement cost. According to the Global Methane Tracker, **70%** of methane emissions from the oil and gas sector can be mitigated with existing technologies, and **40%** can be mitigated at **no net cost**. The IEA has examined sources of financing to accelerate methane emissions reductions in the oil and gas sector.[9] They believe that to achieve the IEA's Net Zero Emissions (NZE) by 2050 Scenario, "around USD 55 billion is needed in upstream oil and gas facilities and just over USD 20 billion in downstream operations". However, upstream oil and gas offers some of the cheapest options to reduce methane emissions across sectors (less than USD 5/tCO_2eq) with a potential revenue from the sale of captured methane around USD 45 billion, based on the gas price trajectory of the NZE Scenario.[10]

Meanwhile, there is a growing awareness of methane emissions from the **landfill sector** for which significant reductions could also be achievable. However, there is not as much focus on, or knowledge about, these end-of-life emissions as for the oil and gas sector. Gas collection systems to capture landfill methane are generally only put in place due to regulations, and there is limited revenue from such projects to incentivize their implementation or to maintain their proper operation. There are many operational barriers in place and unless there is external financing, then properly operating these systems is prohibitively expensive (at least in the global South) and time consuming. These systems are also quite susceptible to operational failure or physical damage that renders them less effective. It is also important to note that changes further up the waste value chain would have more impact, but these are harder to implement – i.e. one of the best ways to mitigate emissions is to reduce food waste/divert organics, which requires a lot of public education and operational changes.

1.3 Scope and objectives of the study

This white paper will be targeted at the oil and gas and waste management (landfill) sectors, which constitute two of the world's three largest anthropogenic sources of methane emissions.

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[5] In this white paper, the term "super-emitter" is defined as an emission observation by GHGSat, commonly aligning with a minimum emission rate of 100 kgCH_4/h.

[6] Daniel Zavala-Araiza, David Lyon, Ramón A. Alvarez, Virginia Palacios, Robert Harriss, Xin Lan, Robert Talbot, and Steven P. Hamburg. (2015) *Toward a functional definition of methane super-emitters: application to natural gas production sites.* Environmental Science & Technology 49 (13), 8167-8174. DOI: 10.1021/acs.est.5b00133. Retrieved from: Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites | Environmental Science & Technology (acs.org), in February 2024.

[7] Itziar Irakulis-Loitxate, Luis Guanter, Joannes D. Maasakkers, Daniel Zavala-Araiza, and Ilse Aben. Environmental Science & Technology 2022 56 (4), 2143-2152. DOI: 10.1021/acs.est.1c04873

[8] Cusworth, Daniel H., et al. "Strong Methane Point Sources Contribute a Disproportionate Fraction of Total Emissions across Multiple Basins in the United States." Proceedings of the National Academy of Sciences, vol. 119, no. 38, 2022, https://doi.org/10.1073/pnas.2202338119.

[9] IEA (2023). *Financing reductions in oil and gas methane emissions*. Retrieved from: Financing reductions in oil and gas methane emissions – Analysis - IEA, in February 2024.

[10] IEA (2023). *Financing reductions in oil and gas methane emissions*. Retrieved from: Financing reductions in oil and gas methane emissions – Analysis - IEA, in February 2024.

To perform this analysis, high-quality satellite data from GHGSat is used to identify emission sources of methane super-emitters, quantify the impact of methane mitigation from super-emitters, provide cost estimates to inform decision-makers on financing and provide insights into methane emissions in a global context.

The results will both complement and expand on existing analysis by directly linking super-emitting events with emission reduction opportunities.

GHGSat[11] operates a constellation of commercial satellites that monitor greenhouse gases (methane CH_4 and carbon dioxide CO_2) with a high resolution of 25 meters, enabling emissions to be attributed to individual facilities. GHGSat can target known sources and monitor facilities from different industries.

Emission observations between January 1st, 2021, and December 31, 2022 (Figure 2) cover 37 countries[12] and include methane emission rate, relative error rate, observation date and time, and coordinates.

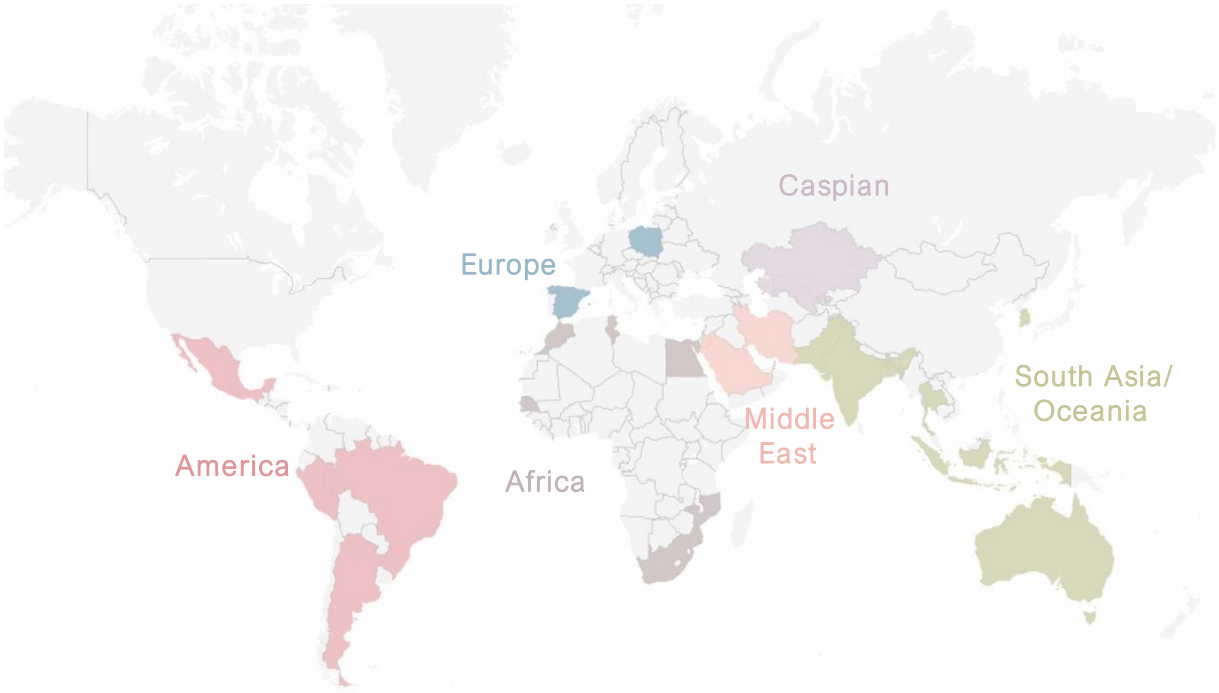


Figure 2. Countries with observations from 01/01/2021 to 31/12/2022. Source: Carbon Limits based on GHGSat data.

The results of the study are presented in three white papers[13,14,15] and can be useful for a broad range of stakeholders – from policy makers to potential funders of mitigation actions – to eliminate these emissions. Results can provide information to decision-makers on available solutions and financing needs for the most common causes of super-emitters and help make available satellite data even more actionable.

The analysis presented here draws on a subset of GHGSat satellite detections of methane plumes from oil and gas and waste sectors. The sample is limited to only some sectors and countries and only to regions/areas that the satellites have targeted (only specific areas or facilities are covered). GHGSat satellite constellation has a quoted detection threshold of 100 kg/hr, meaning that smaller emissions may not be captured in this study.

[11] GHGSat. Greenhouse Gas Emissions Monitoring Service - GHGSat
[12] Algeria, Argentina, Australia, Azerbaijan, Bahrain, Bangladesh, Brazil, Egypt, India, Indonesia, Iran, Iraq, Jordan, Kazakhstan, Kuwait, Libya, Mexico, Morocco, Mozambique, Oman, Pakistan, Peru, Poland, Qatar, Saudi Arabia, Senegal, South Korea, South Africa, Spain, Sudan, Syria, Thailand, Turkmenistan, Tunisia, United Arab Emirates, Uzbekistan, Yemen
[13] Carbon Limits. High Opportunity, Low Cost: Optimizing Landfill Operations for Methane Mitigation. 2024.
[14] Carbon Limits. Perspectives on Methane Super-Emitters: Determining Emission Sources using Satellite Detections. 2024.
[15] Carbon Limits. Low Cost, High Impact: Satellite Insights on Global Methane Super-Emitters. 2024.

Shortlisting of countries

Aim: draw up a list of relevant countries to be studied further

A comparison of countries was made based on the observational dataset. Countries were selected where:

i. Basemap (optical) satellite imagery (e.g., Google Maps, Google Earth, Bing Maps) is of high quality, taking into account the local geography.
ii. At least two emissions points have been detected by GHGSat over the observation period.
iii. Carbon Limits has extensive information on current oil and gas practices based on previous experience.

Countries across six regions were included in the analysis of super-emitters (Table 1). This corresponds to approximately 3900 observations.

Table 1. Selected emission points by region. Source: Carbon Limits based on GHGSat's satellite detections

Region	Number of observed emissions
Africa	598
Americas	272
Caspian	2092
Europe	83
Middle East	289
South Asia/Oceania	535

Emission source identification

Aim: based on satellite data analysis, attribute plume observations to sector, facility type, and emission source types.

To attribute plume observations to specific pieces of equipment or activities, Carbon Limits followed the decision tree presented in Figure 3. The decision tree presents a subjective assessment by several reviewers which is explained in further detail below.

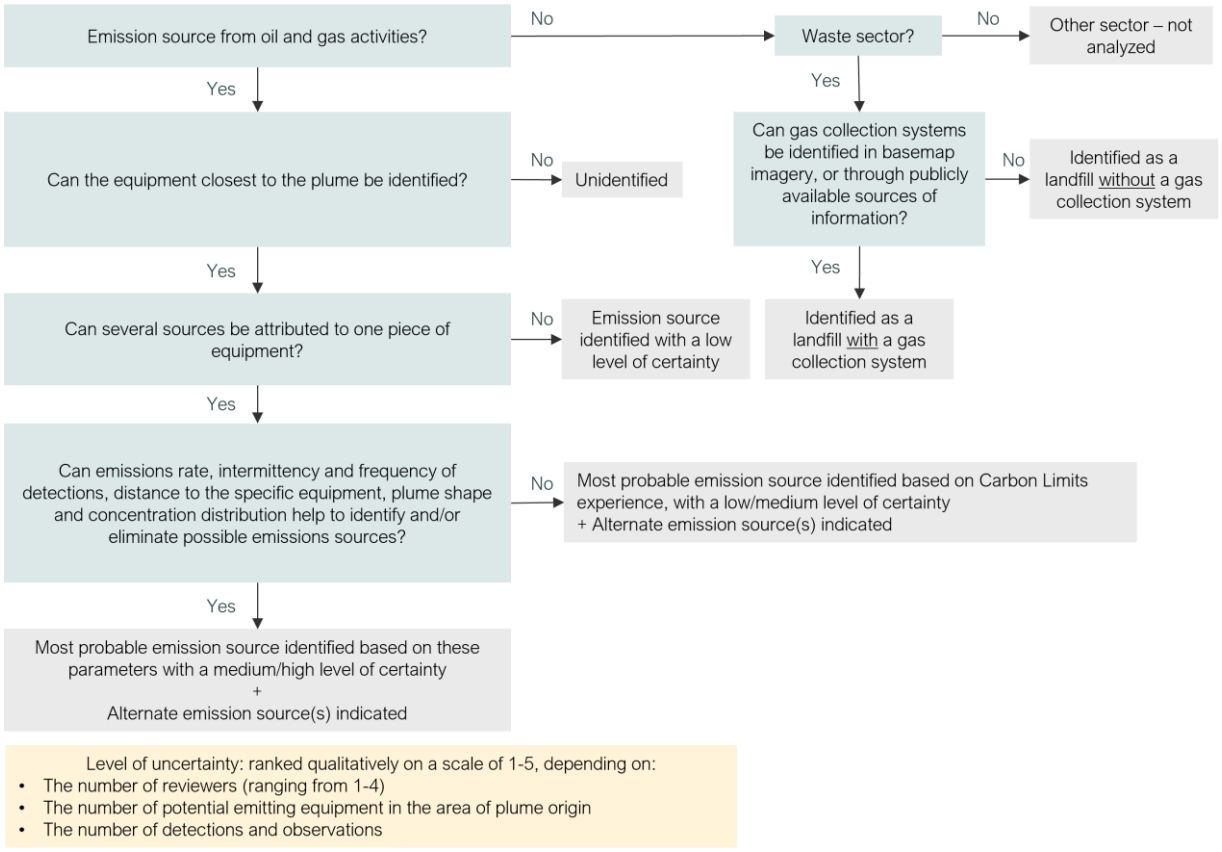


Figure 3. Decision tree for emission source identification. Source: Carbon Limits

The sector is first identified by comparing the coordinates of identified plume locations (determined by GHGSat) and plume shapes to publicly available satellite basemap layers.[16,17]

1.4 Oil and Gas Sector

For emissions from the **oil and gas sector**, further analysis is performed using basemap layers, in addition to satellite imagery datasets such as the Oil and Gas Infrastructure Mapping (OGIM) database,[18] and Carbon Limits' previous experience and expertise.[19] The type of facility and possible emission sources are identified.

Figure 5 a-k shows several facility types and emission sources in the oil and gas sector. If more than one piece of equipment can be attributed to the plume, the emission rates, the intermittency and the frequency of detections, the distance between the emission coordinates to specific equipment, date, plume shape, and concentration distribution help prioritize and/or eliminate some possible emissions sources. For example, the probability of liquid unloading is higher in winter than in summer, emissions from burning pits are usually not continuous, etc. It is important to note that equipment sources may not be identifiable in all circumstances.

For each source, the level of certainty in identifying the emission source depends on the quality of the basemap (optical) imagery (e.g., Google Earth, Google Maps, Bing Maps), the number of potential emission sources, and the relative distances between emission sources and plume locations. The attribution of emissions to specific sources is highly dependent on the **quality and date of basemap (optical) satellite imagery**. In addition, some emission sources will not be identifiable, regardless of image quality (e.g., no

[16] Google Earth: https://earth.google.com/web/
[17] Bing Maps: Bing Maps - Directions, trip planning, traffic cameras & more
[18] https://essd.copernicus.org/articles/15/3761/2023/
[19] Carbon Limits: Projects (carbonlimits.no)

identifiable emission sources, or too many potential emission sources). This case leads to the "unidentified" category in the analysis. Only further work with operators to "ground-truth" emission sources can further identify emission sources.

Figure 5a-k shows several typical satellite imageries from the non-oil and gas sectors.

Figure 4 presents the average level of certainty of all analysed emission sources from the oil and gas sector and included in the analysis. Flares and tanks had the highest level of certainty, while unidentified emission sources were understandably less certain.

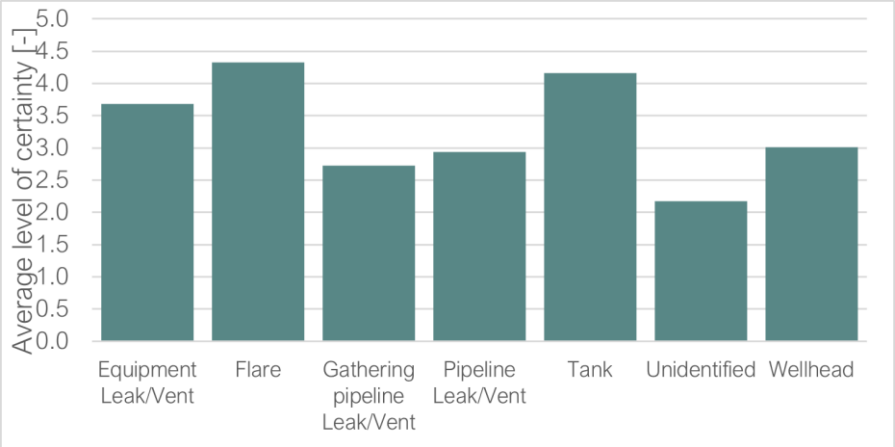


Figure 4 Level of Certainty of identified emission sources

1.5 Landfills/Waste sector

As methane emissions from landfill sites are essentially diffuse, this analysis followed a simplified approach. Landfill areas were estimated using Google Earth; a combination of satellite imagery and site information gathered from company websites (identified using Google Maps) were used to identify the presence or absence of gas extraction systems at the landfills. There is inherent uncertainty in this process due to assumptions made solely based on satellite imagery, including:

- Sites identified as having gas collection systems infrastructure are actually performing gas collection;
- Gas collection infrastructure is in operation;
- Gas collection infrastructure is not being properly maintained and/or operated;
- Super-emitters are stemming from gas collection infrastructure, rather than other site infrastructure, the active face of landfills, or some other source. Methane emissions from landfills are not as well understood as those from other sources;[20]
- Landfill extents determined using satellite imagery are the same extents that would require gas collection.

Figure 5l-p shows several typical satellite imageries from the non-oil and gas sectors. Figure 5q-r show typical satellite imagery from the coal sector, which have not been analysed in this study.

[20] Carbon Mapper. (2024, March 28). *Study finds landfill point source emissions have an outsized impact and opportunity to tackle U.S. waste methane.* Carbon Mapper. https://carbonmapper.org/articles/studyfinds-landfill

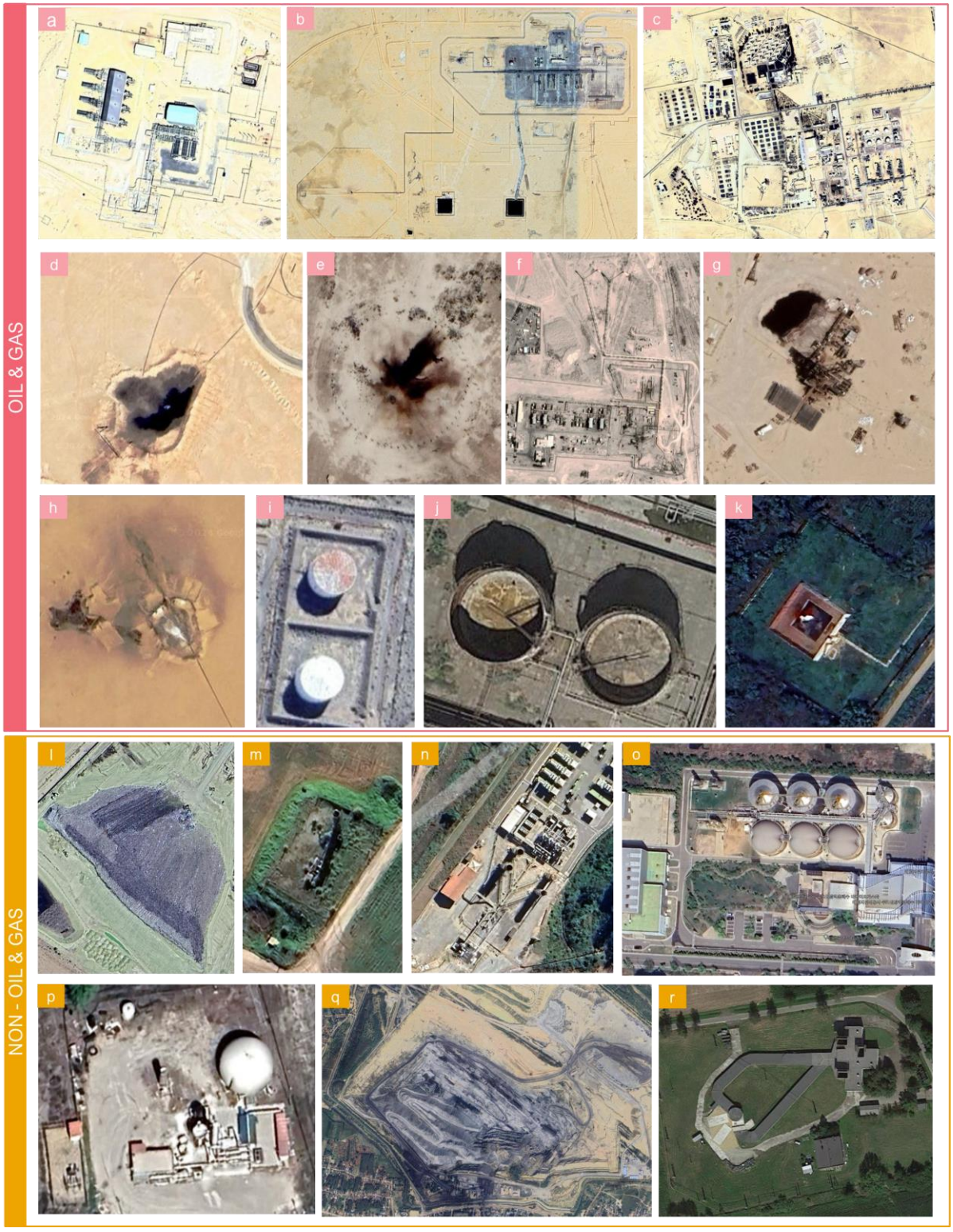


Figure 5. Example of facility types and emissions sources. a. Compressor station; b. Grouping unit; c. Processing facility; d. Liquid dumping; e. Elevated flare at well site; f. Elevated flare at compressor station; g. Well drilling; h. Burning pit; i. Fixed-roof tanks; j. Floating-roof tanks; k. Ground flare; l. Landfill; m, n, o, p. Landfill gas extraction systems; q. Coal mine; r. Ventilation shaft for underground coal mine. Source: Google Maps, Carbon Limits

Annual emissions estimation

The following approach is based on Chen et al (2022).[21]

Aim: for each emission source, use emission observations to estimate an annual emission rate using a Monte Carlo-based approach.

Emission sources may have one or many attributed plumes. For emission sources with multiple plumes, these are assumed to represent snapshots of this emission source over time.

For each emission source, the intermittency must be determined. This corresponds to how often an emission source is emitting or not, and therefore corresponds to the probability of emitting. To determine the intermittency of an emission source, P_i, the number of observed plumes and the number of overflights are used as follows:

$$P_i = \frac{J_i}{C_i} \qquad \text{(Eq. 1)}$$

Where:

- J_i = number of plumes for this emission source i
- C_i =number of observations for this emission source i

When there are few observations (low values of C_i), P_i might be overestimated. Thus, average intermittency of the emission source in the region is used in such cases (see Section 1.7).

All emission sources have an intermittency in the range $0<P_i\leq1$. For example, an emission source with one plume and one observation has $P_i = 1$ and is assumed to be emitting 100% of the time. Conversely, an emission source with three plumes and 19 observations has $P_i = 3/19$ and is assumed to be emitting 16% of the time. The assumption of intermittency follows the ergodic hypothesis, such that intermittency is stationary over time (cf. Section 1.7).

To determine a representative estimate of mean annual emissions, a bootstrap method using Monte Carlo analysis is performed. This Monte Carlo approach leverages a finite number of observations to create a synthetic dataset that simulates a satellite performing many repeated observations of an emission source. By repeating the process many times, a more representative estimate can be used to turn individual emission observations into an annual emission estimate. In the present analysis, 10,000 iterations are performed. For each emission source, a finite number of plumes (J_i) are identified. For each iteration x, one of the observed J plumes is selected using a uniform distribution. Then, an emission rate L_x is randomly selected using a normal distribution with the mean μ estimated by GHGSat for this plume J_i and the standard deviation ε is derived based on the error rate determined by GHGSat. Then, a Bernoulli distribution is used with probability P_i to determine whether an emission was observed (a value of 1), or not observed (corresponding to a value of 0)[22]. L_x is then multiplied by this probability to determine the observed emission rate of iteration x.

An average of the 10,000 iteration outputs is calculated using the mean as an approximation of the annual emission rate for emission source i. This average value is used for the analysis. This process is then repeated for each emission source.

This intensive process is conducted on RStudio. Figure 6 summarizes inputs and outputs of this calculation step and Figure 7 provides a visualization of the process.

[21] Chen et al. (2022). *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey.* Retrieved from https://pubs.acs.org/doi/10.1021/acs.est.1c06458 in September 2023.

[22] **Bernoulli distribution**:
Emission: P(Bx = 1) = Pi
No emission: P(Bx = 0) = 1 – Pi
Where Pi is the intermittency.

INPUT

	Plume *1*	Plume *i*	Plume *j*
Emission ID	1234567-1111	...	1234567-1112
Source ID	XXX-01	XXX-01	XXX-01
Rate (kg/h)	1250	...	303
Error rate (%)	58%	...	56%
Latitude	XX.XXXX	...	XX.XXXX
Longitude	YY.YYYY	...	YY.YYYY
Country	Country Z	Country Z	Country Z
Emission sector	Oil and gas	Oil and gas	Oil and gas
Facility Type	LNG plant	LNG plant	LNG plant
Emission source	Tank	Tank	Tank
Number of observations	J	J	J

OUTPUT

Source ID	XXX-01
Intermittency	0.40
Mean - Rate (kg/h)	900
Latitude	XX.XXXX
Longitude	YY.YYYY
Country	Country Z
Emission sector	Oil and gas
Facility Type	LNG Plant
Emission source	Tank

Figure 6. Tabular description of inputs and outputs for determining emission source characteristics. Source: Carbon Limits

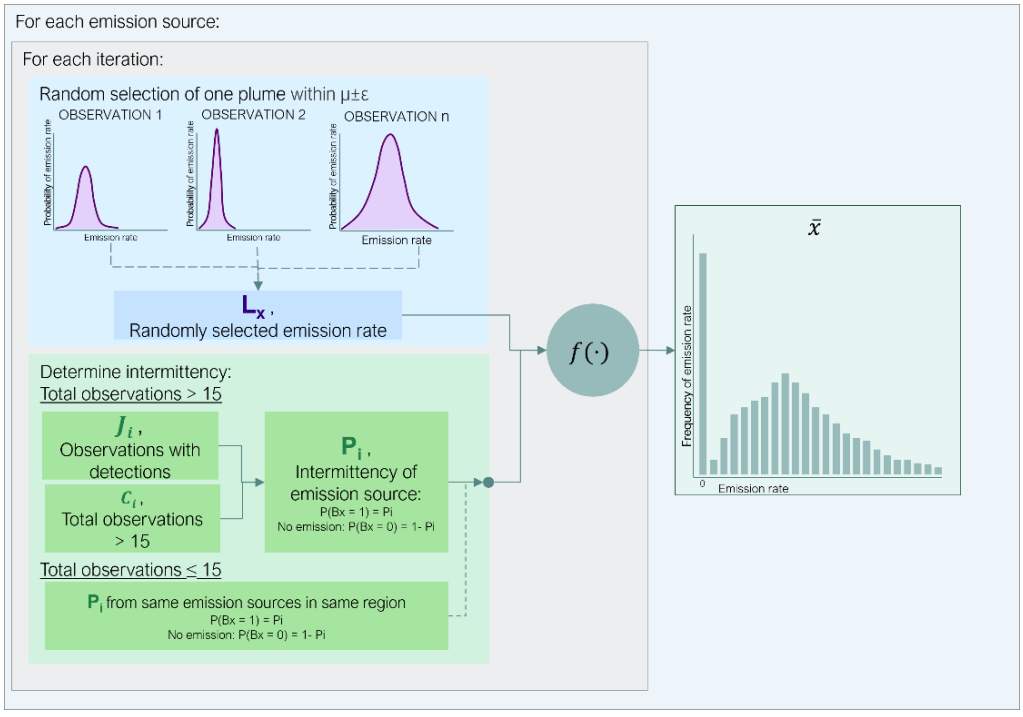


Figure 7 Visualization of annual emission rate estimate for each emission source. Source: Carbon Limits

1.6 Comparison with global inventories

Global annual emissions from the oil and gas sector

As presented in Figure 1, IEA estimates that the oil and gas sector was responsible for 82.3 $MtCH_4$ in 2023. However, this accounts for all sources of emissions, in all countries and regions. Most of these emissions are not realistically detectable by satellite. The 2022 IEA Methane tracker assumes that super-emitting events detected by satellites accounted for 3.5 $MtCH_4$ in 15 countries in 2021.[23]. In the 2023 version of the Global Methane Tracker, large leaks detected by satellites were estimated to emit 3 $MtCH_4$ from oil and gas operations in 20 countries in 2022[24]. The emissions observed in the dataset for this analysis represent approximately 1/3rd of data (1.01 $MtCH_4$/y) from the Global Methane Tracker reports.

This analysis does not aim to present a global inventory of methane super-emitters, but to identify emission sources in specific regions and attempt to estimate both annual emissions and the potential investment required to address these.

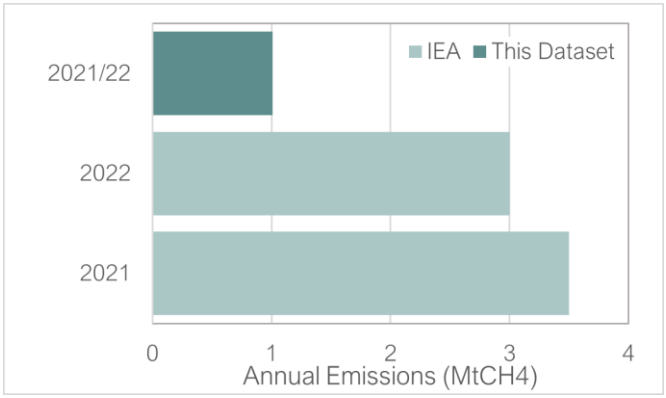


Figure 8 Comparison of emissions from the oil and gas sector in this analysis vs. IEA Methane Tracker

Note on flares

Amongst all the emission sources, for flares there is an advantage that global satellite datasets based on Visible Infrared Imaging Radiometer Suite (VIIRS) exist, providing the possibility of comparing observations. In the analysis of methane super-emitters in the oil and gas sector, 285 flares were identified. This is 13% of the approximately 2100 flares observed in the analysed regions using VIIRS flaring data. Complete country coverage ranged from 1->100% (not plotted), yet regional coverage ranged from 1-~50% for the five analyzed regions as can be seen in Figure 9.

[23] IEA. 2022 Global Methane Tracker. https://www.iea.org/reports/global-methane-tracker-2022/estimating-methane-emissions
[24] IEA. 2023 Global Methane Tracker. https://www.iea.org/reports/global-methane-tracker-2023/understanding-methane-emissions

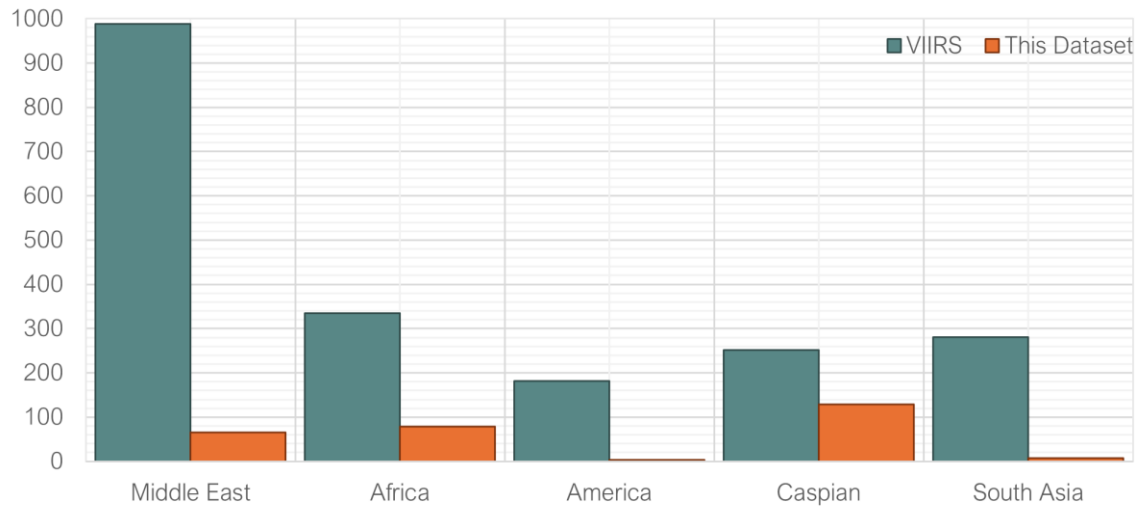


Figure 9 Comparison of flares included in the 2021/2022 VIIRS datasets compared to flares analysed in this white paper

Global annual emissions from landfills

As discussed in the white paper on methane super-emitters from landfills,[25] the total methane emissions from the 89 super-emitting landfill sites analysed was 1.01 Mt CH_4/yr. To provide a comparison of this with global methane emissions from landfill super-emitters, methane emissions data from solid waste disposal sites in 2022 from Carbon Trace[26] are also presented. The global emissions from Carbon Trace's dataset are 36.6 Mt CH_4/yr[27]. When only considering countries similar to those assessed in this analysis, emissions from the Carbon Trace dataset are 11.6 Mt CH_4/yr, or 11.5 times higher than emissions analysed in this dataset. Additionally, the dataset used in this analysis is concentrated in landfills with average annual rates higher than 1300 kgCH4/h, whereas the dataset from Carbon Trace includes non-super-emitter points and therefore accounts for many sources with lower emission rates (Figure 10). The sample size of this study is also much smaller (89 sites compared to 3,990 sites in matching countries in the Carbon Trace dataset), while the Carbon Trace dataset is based on a variety of datasets, including from satellite- and aircraft-based measurements, the United States Environmental Protection Agency Greenhouse Gas Reporting Program (EPA GHGRP) the Canadian Greenhouse Gas Reporting Program (GHG-RP), the European Pollutant Release and Transfer Register (E-PRTR). Therefore, it is important to note that the emissions presented in this white paper are not meant to provide a global, regional or country-level inventory estimate of total emissions. Rather, the goal is to assess a sample of super-emitting landfills to evaluate the potential costs of abatement of methane super-emitters.

[25] Carbon Limits. High Opportunity, Low Cost: Optimizing Landfill Operations for Methane Mitigation. 2024.
[26] Carbon Trace Data Explorer. https://climatetrace.org/explore
[27] 2022 data retrieved from https://downloads.climatetrace.org/v02/sector_packages/waste.zip

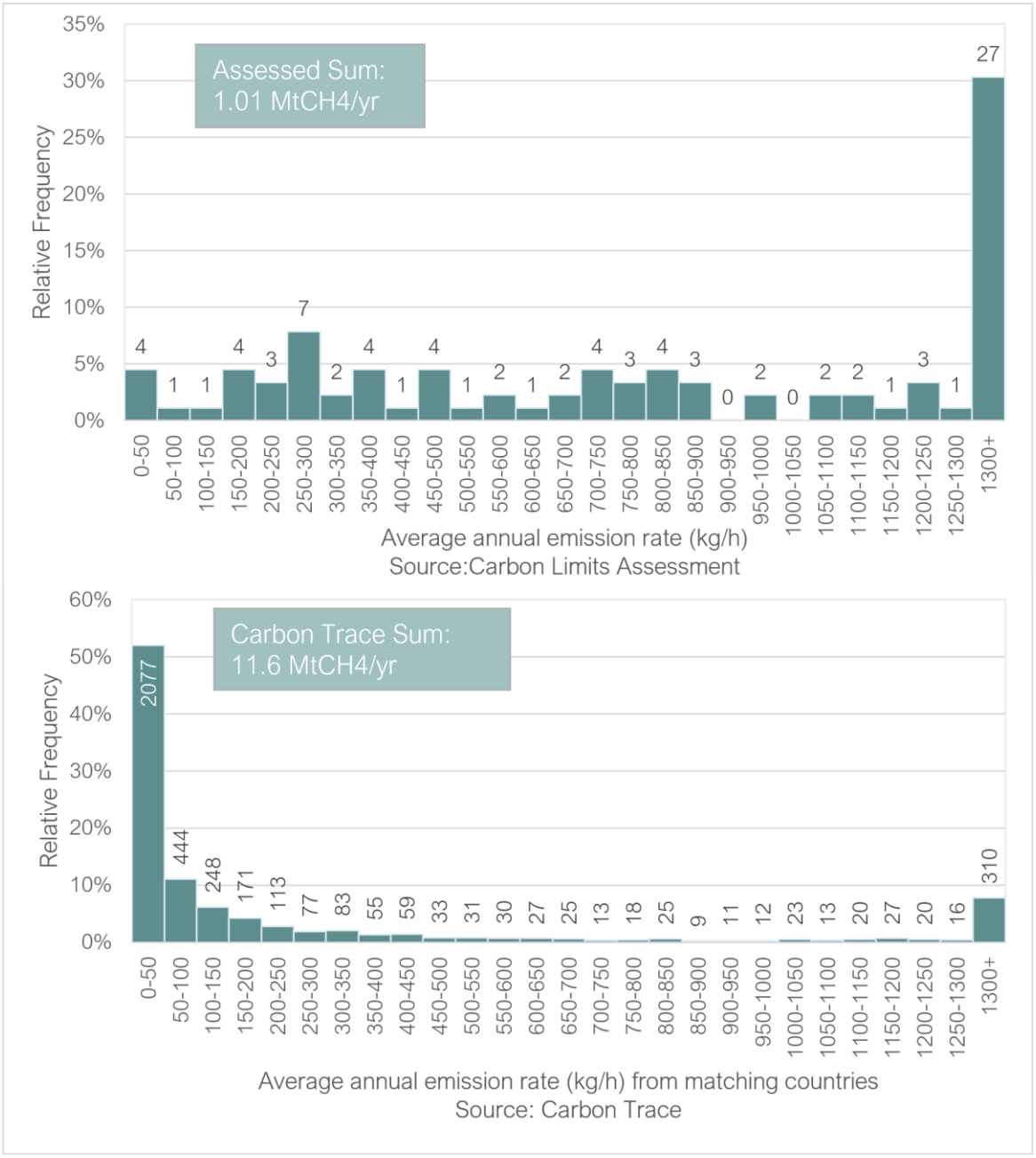


Figure 10 Comparison of average annual emission rates between landfills (Source: Carbon Limits Assessment) and solid waste disposal sites (Source: Carbon Trace). Note difference in y-axis limits.

Other considerations

This study is based on analysis of specific GHGSat targets within 37 countries of interest. Therefore, the study does not cover all GHGSat observations of methane super-emitting emission sources in relevant countries or regions. In addition, within each of the 37 countries, only targeted sites are analysed, which might not be representative of the entire country.

In addition, most satellites typically utilise a sun-synchronous orbit, which is subject to time limitations and enables the detection of emissions only between 8.30 am and 2.30 pm. Measurements are typically conducted at a fixed time each day, a design feature that is intended to capitalise on optimal light conditions for methane detection.

While the term “super-emitter” is commonly associated with emissions greater than 100 kg CH_4/hour, emissions lower than this may be detected under favourable environmental conditions. For example,

emissions observations as low as 44.8 kg CH_4/h were included in the analysis. Common impacting environmental conditions include weather, clouds and surface albedo.

Conventional satellite measurements over water are limited due to the low reflectivity. In the oil and gas sector, 28% of global oil and gas production is attributed to offshore operations.[28] In recent years, satellite methods to detect offshore methane plumes from oil and gas equipment have been developed using sun-glint observation modes described by Irakulis-Loitxate et al. (2022)[29] , and more recently by MacLean et al. (2023)[30] using the GHGSat constellation. Offshore observations can now be made by GHGSat satellites, but the detection threshold is variable and dependent on latitude and time of year. Regardless, emissions from offshore sources of methane super-emitters are not included as part of this analysis.

1.7 Accounting for low-observation count emission sources

GHGSat measurements are targeted, which means that the screening is **not continuous** over time and only covers **specific areas** or facilities. Thus, different sources are monitored at different frequencies. To estimate annual methane emissions, it is assumed that the emission sources have ergodic behaviours, and that the intermittency does not depend on the time between two observations and is **constant** over time. While this assumption does not occur in practice, the dataset includes two years of historical data (2021-2022), covering sufficient time and number of observations so that the snapshot samples are representative of the period.

Of all analysed emission sources from the oil and gas sector, over 30% were observed less than 15 times (or approximately once every two months over the two years of analysis), while over 50% of emission sources had less than 30 observations (Figure 11). As mentioned above, emission sources with low numbers of observations could create complicating assumptions that emissions are more intermittent or less intermittent than in reality due to the low temporal coverage.

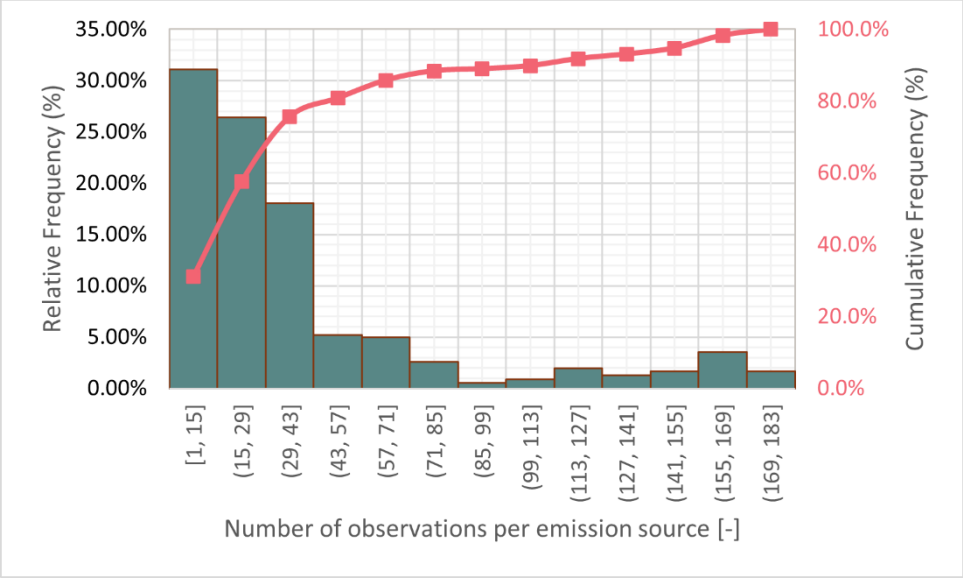


Figure 11 Number of observations per emission source in 2021 and 2022

To mitigate this, the intermittencies of emission sources with fewer than 15 observations were replaced with average intermittencies from similar emission sources within the same region, to increase sample sizes.

[28] Statista (2024). *Distribution of onshore and offshore crude oil production worldwide from 2005 to 2025*. Retrieved from: Global crude oil onshore and offshore production distribution 2025 | Statista, in February 2024.
[29] Irakulis-Loitxate, I., Gorroño, J., Zavala-Araiza, D., Guanter, L. (2022). *Satellites detect a methane ultra-emission event from an offshore platform in the Gulf of Mexico*. Retrieved from: Satellites Detect a Methane Ultra-emission Event from an Offshore Platform in the Gulf of Mexico (acs.org), in February 2024.
[30] W. MacLean, J.P., Girard, M., Jervis, D., Marshall, D., McKeever, J., Strupler, M., Ramier, A., Tarrant, E., Young, D. (2023). *Offshore methane detection and quantification from space using sun glint measurements with the GHGSat constellation.* Retrieved from: egusphere-2023-1772.pdf (copernicus.org), in February 2024.

Figure 12 shows the comparison of total emissions estimates using true vs. representative intermittencies. Implications for this are that annual emission estimates using small sample sizes have a higher uncertainty and may not be representative of annual averages.

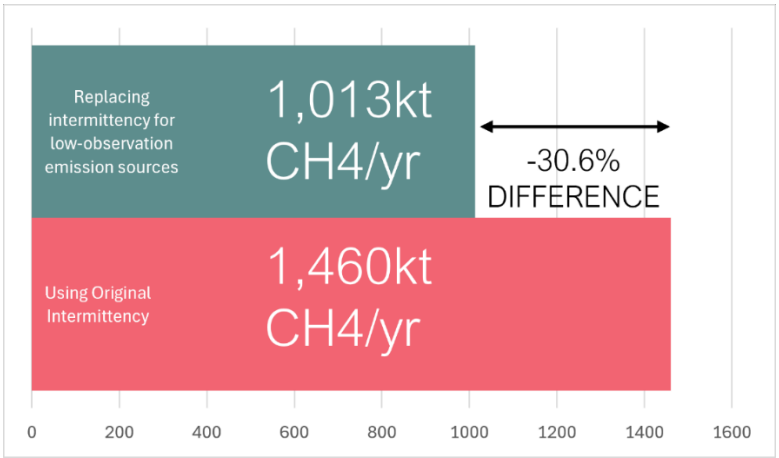


Figure 12 Comparison of global methane super-emitters when using either observed intermittencies or representative intermittencies for emission sources with low observation counts

Cost Estimations

Aim: for each emission source, identify the more relevant abatement option and estimate the total investment cost for mitigating the super-emitter source

1.8 Identify abatement option per emission source

Carbon Limits has identified potential abatement options to reduce methane emissions from super-emitters (Table 2). Not all abatement options may be applicable to each specific source, particularly given ground-truthing of emission sources was outside the scope of this study. Therefore, a range of abatement options and associated costs are considered, as discussed below in Section 1.9.

Table 2 List of abatement options for identified sources

	Emission Source		Abatement Activity
Oil and Gas	Wellhead	Liquid Unloading	Rerouting to an existing gas system
			Installing plunger lift systems, routing flow to separators, artificial lift and foaming agent, and velocity and foaming agent
			Routing flow to separators, artificial lift and foaming agent, and velocity and foaming agent
			Artificial lift and foaming agent
			Velocity and foaming agent
		Well Casinghead Gas Venting/Blowdown	Casinghead Vent Gas Recovery with a Compressor
		Well Testing/Completion	Reduced Emissions Completion
	Gathering Pipeline Leak/Vent	Blowdown/Venting	Transferring vented gas to low pressure systems
			Flaring
			Inline compression
			Mobile compression
			Stopples
			In-line compression with flaring
			Mobile compression with flaring
		Leak	Leak Repair
		Vent/Blowdown	Flaring

	Pipeline Leak/Vent		Inline compression
			Mobile compression
			Stopples
			In-line compression with flaring
			Mobile compression with flaring
		Leak	Leak Repair
	Equipment Leak/Vent	Leak	Leak Repair
		Vent	Gas Capture
	Emission Source		Mitigation Option
Landfill	Landfill with gas extraction system		Improved management of gas collection and flaring system
	Landfill without gas extraction system		Installation of gas collection and flaring system

1.9 Estimate CAPEX for mitigation

Oil and Gas

To determine a representative estimate of costs, a bootstrap method using Monte Carlo analysis is performed. A Monte Carlo approach is used to leverage a finite number of observations to create a synthetic dataset that simulates the uncertainty and the variety of abatement costs of an emission source. By repeating the process many times, a more accurate estimate can be used to turn cost ranges into individual abatement costs. 50,000 iterations are performed in this analysis.

For each emission source i, a 2.5, 50 and 97.5 percentile are estimated (summarized in Table 5). For each iteration x, a mitigation cost is randomly selected using the specified distribution with the estimated mean, μ, and the estimated standard deviation, ε, based on estimated 2.5th, 50th and 97.5th percentiles. An average and maximum of the 50,000 iteration outputs is calculated using the mean as an approximation of the mitigation costs for each emission source.

This process is then repeated for each emission source. This intensive process is conducted on RStudio.

The final assessment of capital expenditure (CAPEX) is based on a variety of publicly available data sources, tools and interviews with service providers.

1. Flares

Identified mitigation options for flares are investments in improved flaring equipment (new flares) or further gas use instead of flaring.

Replace the flare

Capital and annualized costs for installing and operating elevated flares are based on the US EPA Flare Costing Toolkit.[31] This tool considers a typical flare system including "(1) a gas collection header and transport piping for collecting and conveying gases from process units to the flare, (2) a knockout drum (disentrainment drum) to remove and store condensable and entrained liquids, (3) a seal or purge gas supply to prevent flash-back, (4) a single- or multiple-burner unit and stack, (5) gas pilots and an ignitor to ignite the mixture of waste gas and air, and (6) steam injection or forced air for smokeless flaring. Natural gas, fuel gas, inert gas, or nitrogen can be used as purge gas."

Gas utilisation project

[31] Cost Reports and Guidance for Air Pollution Regulations | US EPA

Typical cost ranges are estimated from two common gas utilisation projects (Table 3):

- Mini Gas Plant Processing-Natural Gas Liquids (GPP-NGL) recovery-dry gas export
- Microturbine

Costs for these two options were taken from the report *Small-Scale Technologies for Utilization of Associated Gas*.[32]

Table 3. Description of utilisation options evaluated

Gas utilisation project	Description	Costs included
Mini GPP and NGL recovery, dry gas export	Small scale gas processing unit NGL recovery to produce NGL mix (LPG & condensate mix of C_3, C_4 and C_5+). The dry gas (which has lower methane number compared to "full fractionation" option) is assumed to be exported.	Cost of mini-GPP plant (including pre-conditioning of the gas), and dry gas preparation / compression. Product transport costs (NGLs and dry gas) are excluded.
Microturbines	The main product is electricity. Typically, little pretreatment is required, but if the gas has too high fraction of heavy components and NGL removal is required, the NGLs are assumed to be sold.	Cost of microturbine(s) and gas pretreatment unit(s) (as applicable to the gas composition being assessed). Electricity transmission costs are excluded and transport costs for NGLs (as a product of pretreatment) are excluded.

Source: Carbon Limits and VYGON Consulting (2021). *Report on Small-scale Technologies for Utilization of Associated Gas*[32]

For each project, capital costs (CAPEX) and Net Present Value (NPV) are estimated based on the region, the average annual emission rate and the maximum annual emission rate. An economy of scale factor is considered based on the technology, the rate and the region.

2. Tanks

A unique mitigation solution is considered for tanks: Vapor Recovery Units (VRU).

VRU

In an effort to account for variability, Carbon Limits contacted multiple service providers to obtain CAPEX estimates for this mitigation option. Most providers are based in North America but provide services globally. However, only a few of them shared CAPEX. ZEECO[33] provided costs for different options (three pressures with three flow rates) for the gas composition presented in Table 4.

Table 4. Gas composition used to estimate costs

Gas	Percentage	Gas	Percentage
CH_4	17%	C_2H_6	10%
H_2	0%	C_3H_8	11%
He	0%	C_4H_{10}	7%
CO_2	2%	C_5H_{12}	2%
O_2	10%	C_6^+	3%
N_2	37%	H_2S	0%

These costs include the tank vapor recovery system (liquid ring systems or ejector-based systems) and do not include field assembly or erection, commissioning and start-up, interconnecting pipework, wiring, shipping to site, flow measurement systems, gas drying equipment, etc. Costs increase with the pressure and flowrate. For each pressure, an extrapolation between the three flowrates is performed (Figure 13).

[32] Carbon Limits and Vygon Consulting (2021). *Report on Small-scale Technologies for Utilization of Associated Gas*. World Bank. https://documents1.worldbank.org/curated/en/305891644478108245/pdf/Report-on-Small-scale-Technologies-for-Utilization-of-Associated-Gas.pdf

[33] Zeeco | Redefining Combustion

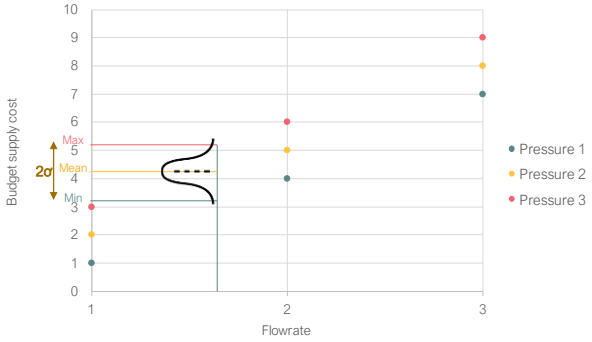


Figure 13. Estimation of VRU cost. Source: Carbon Limits based on information provided by Zeeco.

For each identified emitting tank, a normal distribution is assumed based on maximum and annual emission rate (see Section *0. Annual emissions estimation*) (Figure 13) and a Monte Carlo analysis is performed with 50,000 iterations per tank.

3. Wellhead

Emissions from the wellhead can occur for a variety of reasons. Emissions may be short in duration and occur during initial well drilling,[34,35] testing, and completion.[36] Similarly, well workovers or liquid unloading[37] present a similar, episodic event for super-emitting events. Emissions may also occur during casinghead gas venting.[38] There is potential that a leak may also be the cause of the super-emitting events. Through analysis of each individual wellhead, including the persistence and time of year of emissions, the cause of emissions at the wellhead were theorized, and an abatement cost from public information was assigned. If the cause of emissions was not adequately clear, the source remained as Wellhead – unidentified and the maximum cost of abatement was assigned. The mitigation options considered are presented in Table 2.

4. Gathering and Transportation Pipelines

Emissions from gathering and transportation pipelines were broken up into three values, and costs assigned from publicly available sources. If emissions came from a pipeline vent that had visible venting infrastructure (stacks, maintenance points, etc.), the emission source was assigned as a pipeline blowdown/vent.[39] If the emission source had a short duration without visible infrastructure suggesting intentional emissions, it was attributed to a leak.[40] Leaks may occur due to line integrity issues, and mitigation costs vary depending on the nature of the leak, diameter, location (above or below ground, requiring potential excavation), type of repair needed and labour time for repair. Therefore, this cost is considered as an average, but may be much higher for individual scenarios. If emissions from gathering and transportation pipelines were not attributable to a leak or a vent, the emission source was labelled as an unidentified pipeline leak or vent, and the maximum cost was assigned.

For mitigation costs of methane emissions from gathering pipelines, a unique source of information is used[41] and it is assumed that the costs follow a log normal distribution ($percentile_{2.5}$ = 1 008$, mean = 14 422$, $percentile_{97.5}$ = 73 737$).

5. Equipment Leak/Vent

[34] CL assumption based on similar techniques used for well completion (Reduced Emissions completion methane capture): Flareless Completions - Earthworks
[35] Costs assumed similar to rerouting to existing vent capture system: Producer Price Index by Commodity: Machinery and Equipment: Oil Field and Gas Field Machinery (WPU1191) | FRED | St. Louis Fed (stlouisfed.org)
[36] Based on IPIECA, 2014, assuming completions emit at a constant rate over 4 days, the average duration from Allen et al. (2013): https://www.ipieca.org/resources/energy-efficiency-database/green-completions-2014
[37] Adapted from Natural gas star program, Installing Plunger lift systems in gas wells, 2011
[38] https://www.ccacoalition.org/sites/default/files/resources//2017_OGMP-TGD9-Casinghead-venting_CCAC.pdf
[39] BVS › Trans Adriatic Pipeline (TAP) (tap-ag.com)
[40] Preliminary Regulatory Impact Analysis, Pipeline Safety: Gas Leak Detection and Repair Proposed Rule PHMSA: https://downloads.regulations.gov/PHMSA-2021-0039-0019/attachment_1.pdf
[41] BVS › Trans Adriatic Pipeline (TAP) (tap-ag.com)

In the case of emissions coming from equipment leaks or vents, it is assumed that high emissions rates (exceeding 100 kg/hour) are more likely to result from venting, whereas low emission rates are assumed to be attributable to leaks. Mitigation costs are applied to the vent and leak, respectively.

It is assumed that the leak repair costs follow a normal distribution ($percentile_{2.5}$ = 3 362$, mean = 6 724$, $percentile_{97.5}$ = 13 448$). It is assumed that the mitigation costs for vents follow a log normal distribution ($percentile_{2.5}$ = 1 008$, mean = 14 422$, $percentile_{97.5}$ = 73 737$).

6. Unidentified

Where the emission source is not identified, a conservative estimate is used. Mitigation costs of equipment leak/vent, gathering and transportation pipelines, wellhead, tank and flare are estimated as described in the previous sections and the maximum cost is considered.

Table 5 summarizes cost inputs for emission sources attributed to wellheads, gathering pipeline leaks and vents, pipeline leaks and vents and equipment leaks and vents. Costs were obtained from the identified sources and converted to 2023 prices in USD using the Producer Price Index for Oil and Gas Field machinery and Equipment Manufacturing from the Federal Reserve Bank of St Louis.[42]

Table 5 Summary of Cost Assumptions

Wellhead			
Liquid Unloading			
Percentile	Mitigation Activity	Cost (USD)	Source
2.5	Rerouting to an existing gas system	$6,159	Connect Casing to Vapor Recovery Unit: US EPA Natural Gas Star Program
50	Average of: Installing plunger lift systems Routing flow to separators Artificial lift and foaming agent Velocity and foaming agent	$33,661	Installing plunger lift systems: US EPA Natural Gas Star Program
97.5	Installing artificial lift and foaming agents	$66,593	Installing plunger lift systems: US EPA Natural Gas Star Program
Distribution: Lognormal			
Well Casinghead Gas Venting/Blowdown			
Percentile	Mitigation Activity	Cost (USD)	Source
2.5	Casinghead Vent Gas Recovery with a Compressor	$19,775	OGMP 1.0 TGD 9
50	Casinghead Vent Gas Recovery with a Compressor	$39,550	OGMP 1.0 TGD 9
97.5	Casinghead Vent Gas Recovery with a Compressor	$59,325	OGMP 1.0 TGD 9
Distribution: Normal			
Well Testing/Completion			
Percentile	Mitigation Activity	Cost (USD)	Source
2.5	1 Reduced Emissions Completion events per year	$14,926	Ipieca: Green Completions
50	4 Reduced Emissions Completion events per year	$59,702	Ipieca: Green Completions
97.5	8 Reduced Emissions Completion events per year	$119,404	Ipieca: Green Completions
Distribution: Lognormal			
Gathering Pipeline Leak/Vent			
Percentile	Mitigation Activity	Cost (USD)	Source

[42] https://fred.stlouisfed.org/

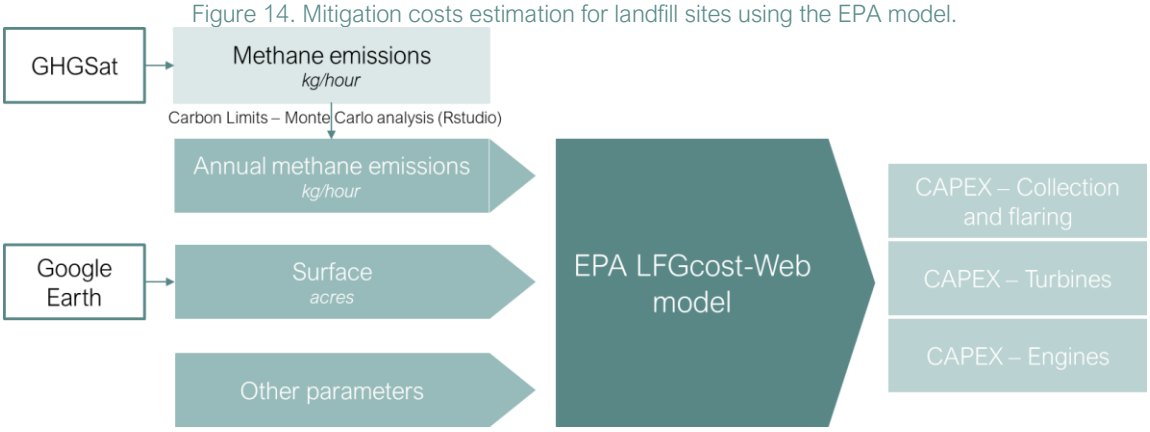
2.5	Transferring vented gas to low pressure systems	$1,008	Pipeline Blowdown Emissions and Mitigation Options: MJB&A
50	average cost of blowdown mitigation analysis for 20km of gathering and boosting pipelines	$14,422	Preliminary Regulatory Impact Analysis: US Department of Transportation.
97.5	Installing stopples	$73,737	Pipeline Blowdown Emissions and Mitigation Options: MJB&A
Distribution: Lognormal			
Pipeline Leak/Vent			
Pipeline Blowdown/Vent			
Percentile	Mitigation Activity	Cost (USD)	Source
2.5	Transferring vented gas to low pressure systems	$1,008	Pipeline Blowdown Emissions and Mitigation Options: MJB&A
50	average cost of blowdown mitigation analysis for 20km of gathering and boosting pipelines	$14,422	Preliminary Regulatory Impact Analysis: US Department of Transportation.
97.5	Installing stopples	$73,737	Preliminary Regulatory Impact Analysis: US Department of Transportation.
Distribution: Lognormal			
Pipeline Leak			
Percentile	Mitigation Activity	Cost (USD)	Source
2.5	Leak Repair	$3,362	Pipeline Blowdown Emissions and Mitigation Options: MJB&A
50	Leak Repair	$6,724	Preliminary Regulatory Impact Analysis: US Department of Transportation.
97.5	Leak Repair	$13,448	Pipeline Blowdown Emissions and Mitigation Options: MJB&A
Distribution: Lognormal			
Equipment Leak/Vent			
Equipment Leak Vent Annual emission rate <100kg/h			
Percentile	Mitigation Activity	Cost (USD)	Source
2.5	Leak Repair	$3,362	50% of average cost
50	Leak Repair	$6,724	Methane Abatement Costs: Alberta. Delphi Group
97.5	Leak Repair	$13,448	200% of average cost
Distribution: Normal			
Equipment Leak Vent Annual emission rate >100kg/h			
Percentile	Mitigation Activity	Cost (USD)	
2.5	Leak Repair	$1,008	Cost assumed similar to Pipeline Blowdown/Vent
50	Leak Repair	$14,422	Cost assumed similar to Pipeline Blowdown/Vent
97.5	Leak Repair	$73,737	Cost assumed similar to Pipeline Blowdown/Vent
Distribution: Lognormal			

Landfills/Waste Sector

Carbon Limits interviewed researchers and service providers to obtain background information and estimates of CAPEX and OPEX mitigation costs.

In addition, Carbon Limits conducted a literature review of mitigation costs. Limited data is available; the LFGcost-Web model version 3.6[43] developed by EPA was used to estimate the costs of gas collection, flaring and electricity generation using turbines and engines. This model uses typical project designs and landfill situations. The different assumptions made are presented in Figure 14. Parameters are assumed to be identical from one landfill site to another. Landfill areas were determined by basemap imagery analysis, methane emissions were used to determine design flow rates of landfill gas extraction systems, and 2023 electricity and labour prices were determined by country. The model does not account for whether a landfill site is already currently managed or not. Therefore, it is important to note that a simply adding a gas collection system on a dumpsite (unmanaged landfill) will not fix the issue by itself. Mitigation of such sites would require higher investment costs and operational costs to facilitate proper operation of the gas collection system. For the OPEX of collection and flaring systems, the costs for monthly wellhead monitoring for gas quality are included.

Figure 14. Mitigation costs estimation for landfill sites using the EPA model.



Source: Carbon Limits, based on the LFGcost-Web model version 3.6[43]

To determine the validity of the model, several real-world examples with available cost information were used and compared to modelled CAPEX for collection and flaring,[44] electricity generation using turbines (not including flare systems)[45] and electricity generation and collection and flaring systems.[46] Table 6 presents summarized CAPEX costs, which range from -29 – 67% difference from actual costs using an inflation rate of 2%, and from 19 – 180% using an inflation rate of 8%. While the CAPEX considers the cost of electricity generation using engines and collection system, it is unclear if the CAPEX considers the cost of a flaring system, and may be less comparable.

Table 6 Summary of Cost comparison from real-world examples with modelled costs using LFGcost

[43] EPA (2023). *LFGcost – Web – Landfill Gas Energy Cost Model*. Retrieved from: LFGcost-Web — Landfill Gas Energy Cost Model | US EPA, in January 2024.
[44] The World Bank. Financing Landfill Gas Projects in Developing Countries. Urban Development Series Knowledge Papers,no. 23. https://openknowledge.worldbank.org/entities/publication/e8c294be-126e-5d17-910d-87b185c07cba
[45] Landfill Gas Utilization Economic Evaluation for Anchorage Regional Landfill. https://www.muni.org/Departments/SWS/Documents/ARL_LFG%20Utilization%20Economic%20Evaluation.pdf
[46] Project: 0008 Brazil NovaGerar Landfill Gas to Energy Project - Crediting Period Renewal Request. https://cdm.unfccc.int/Projects/DB/DNV-CUK1095236970.6/view

Project	Project CAPEX – (2023, USD)	CAPEX - this tool (2023, USD)		% Difference	
		2% inflation	8% inflation	2% inflation	8% inflation
Collection and flaring systems	$20,825,275	$15,163,121	$25,363,013	-27%	22%
Electricity generation using engines, and collection system (unclear if includes flaring system)	$5,817,417	$9,728,491	$16,272,678	67%	180%
Electricity generation using engines, collection and flaring systems	$6,965,492	$4,947,854.00	$8,276,164.00	-29%	19%

1.10 Investment Cost calculation

Oil and Gas

Investment Cost is calculated by dividing the CAPEX by the Emission rate as:

$$Investment\ Cost = \frac{Capital\ Expenditure\ (CAPEX)}{Emissions\ (ktCH_4/y)}$$

Since analysis of all emission sources does not include operational expenditures (OPEX), potential gas savings or other costs or savings, the investment cost calculation is not comparable to an abatement cost such as those presented in the IEA Methane Tracker[47].

NPV calculation

Oil and Gas

NPV calculations were limited to flare emission sources in the oil and gas sector. First, both CAPEX and OPEX data were not readily available for other sources. Similarly, regional differences, gas prices, existing infrastructure, current operational and maintenance practices, and market availability varied significantly such that any estimates would provide little added value to the analysis of other sources. Coupled together, the decision was made to only perform NPV calculations on flare emission sources where a slightly higher level of certainty was available for cost information.

NPVs were calculated using a 10% discount rate. CAPEX and OPEX values were obtained from the US EPA Flare Cost However, they were limited to flare emission sources due to lack of data availability on both CAPEX and OPEX for certain possible for all emission sources identified in the oil and gas sector.

Landfill/Waste Sector

NPV calculations for the landfill and waste sector were calculated using a 9% discount rate (default value in the US EPA landfill model, and a project lifetime of 15 years. Total landfill gas was assumed to be 50% of methane (taken as the maximum observed emission rate from each of the individual landfills). The landfill gas area was estimated from the size of the active area of the landfill using basemap imagery from Google Earth. CAPEX and OPEX values were taken from the US EPA landfill model.

[47] IEA (2024), *Global Methane Tracker 2024*, IEA, Paris https://www.iea.org/reports/global-methane-tracker-2024, Licence: CC BY 4.0

Appendix A: Abbreviations

CAPEX	Capital Expenditure
CH_4	Methane
CO_2	Carbon dioxide
EPA GHGRP	United States Environmental Protection Agency Greenhouse Gas Reporting Program
E-PRTR	European Pollutant Release and Transfer Register
GHG	Greenhouse Gas
GPP-NGL	Mini Gas Plant Processing-Natural Gas Liquids
GWP	Global Warming Potential
IEA	International Energy Agency
LFG	Landfill Gas
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
Mt	Million tons
NGL	Natural Gas Liquids
NPV	Net Present Value
NZE	Net Zero Emissions
O&G	Oil and gas
OGIM	Oil and Gas Infrastructure Mapping
OPEX	Operating Expense
REC	Reduced emissions completion
USA	United States of America
USD	US Dollars
VIIRS	Visible Infrared Imaging Radiometer Suite
VRU	Vapor Recovery Unit

Appendix B: Lists of emission sectors, facilities and emission sources considered and identified

Table 7 List of Sectors

Sector
Oil and Gas
Landfill
Other (Agriculture, Coal, Other, Unknown)

Table 8 Facility Type (Oil and Gas Sector)

Facility Type
Compressor station
Gathering Pipeline
Grouping unit
LNG facility
Midstream Facility
Power plant
Processing plant
Oil Refinery
Tank farm
Well site
Unidentified

Table 9 Emission Source Type (Oil and Gas Sector)

Emission Source	Refined Emission Source/Cause
Flare	Elevated Flare without observed flaring
	Burning Pit/Ground flare without observed flaring
	Elevated Flare with observed flaring
	Burning Pit/Ground flare with observed flaring
Tank	Fixed Roof
	Floating Roof
Wellhead	Liquid Unloading
	Well Casinghead Gas Venting/Blowdown
	Well Testing/Completion
	Wellhead - Unidentified
Gathering Pipeline Leak/Vent	Gas lift system
	Leak
	Liquids Dumping
	Gathering Pipeline - Unidentified
Pipeline Leak/Vent	Vent/Blowdown
	Leak
	Pipeline - Unidentified
Equipment Leak/Vent	Separator
	Oil Heater
	Vessel
	Equipment – Unidentified