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Emissions from Landfill Renewable Natural Gas Plants in the Central USA

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Executive Summary

Onsite, direct measurements, downwind tracer flux, and other test method (OTM) measurements were made at 9 renewable natural gas (RNG) plants located in the central US states of Kansas, Oklahoma, and Texas between 8/17/2021 and 9/10/2021. CH_4 emissions originating between the inlet and outlet of each plant were quantified. Plant-level, throughput-normalized emissions (emission intensity) based on plant inlet CH_4 flows, emission factors developed from measurements and observations, coupled with estimates for emissions from flaring and waste gas streams range from 0.4% to 5.7%. RNG plants without direct venting all show emission intensities less than 1%, while those that vent some portion of waste streams directly to atmosphere show emission intensities of 4-6%. Concurrent downwind measurements at two plants employing direct venting support modeled results, but indicate slightly higher emission intensities of 5-7%.

In aggregate, the 1.8% CH_4 emission rate from the 9 plants, including the direct venting, is comparable to that of flaring (≈2%). If all 9 plants exhibited similar emissions as those without direct venting, CH_4 rates would be approximately reduce by $2/3^{rds}$, to ≈0.6%. Considering total equivalent carbon emissions, expressed as CO_2e, for the 9 plants studied, including direct venting at some of the plants, the RNG gas has approximately one half of the carbon intensity of natural gas. If direct venting of gas can be eliminated, resulting in a CH_4 emission rate of 0.6% of methane handled, RNG gas has approximately one third the carbon intensity of the equivalent amount of natural gas.

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AGRU acid gas removal unit

AVO auditory, visual, and olfactory

CNG compressed natural gas

CSU Colorado State University

EF emission factor

EPA U.S. Environmental Protection Agency

G&B gathering and boosting

GHG greenhouse gas

GHGI Greenhouse Gas Inventory

GHGRP Greenhouse Gas Reporting Program

HAP hazardous air pollutant

HEX heat exchanger

HP horsepower

LFG landfill gas

MC Monte Carlo

OGI optical gas imaging

OTM other test method

P&ID process and instrumentation diagram

RMLD remote, methane leak detector

RNG renewable natural gas

RNGC Coalition for Renewable Natural Gas

SCADA supervisory control and data acquisition

SLPM standard liters per minute

TEG tri-ethylene glycol

TOX thermal oxidation unit

VOC volatile organic compound

Chapter 1

Introduction

Renewable natural gas (RNG) refers to methane produced by biological processes, typically anaerobic digestion of long-chain hydrocarbons by bacteria. Common sources include bio-digesters at wastewater treatment plants and bio-digestions occurring naturally within landfills, manure management facilities, and composting centers. This study summarizes methane measurements made at RNG capture facilities located at landfills in the central US states of Kansas, Oklahoma and Texas.

In particular, the measurement campaign measured emissions from renewable natural gas processing plants located at the landfills. The work was sponsored by the Coalition for Renewable Natural Gas (RNGC), an industry association of RNG plant operators. Work was conducted in cooperation with the companies that owned and operated the plants who hosted measurement activities and provided plant overviews and data to the measurement team.

The objectives of this study were:

1. Performing site-wide screening and component-level emission measurements, categorized by major equipment.
2. Developing emission factors for major equipment based on measurements, ideally at the component/vent level.
3. Quantifying the emission intensity (CH_4 emitted, per CH_4 collected).
4. Comparing resulting emission factors to similar industry segments, as possible.

Chapter 2

Methods

2.1 Facility Selection and Sampling Strategy

A team from Colorado State University (CSU) visited nine RNG plants (sites) during a field measurement campaign that took place between 8/17/2021 to 9/10/2021. Sites were selected by the RNGC, who worked to recruit operators willing to participate in the project and provide site access for measurement. Site clusters were visited from north to south, along a driving route originating from Fort Collins, CO and ending outside of Galveston, TX. At each site, the CSU team met with site operators who gave a safety briefing and an overview of plant operations. Following the plant overview, the team was typically led to the plant control room to go over process flows and gas compositions in greater detail. The control room briefing was typically followed by a walking tour of the plant, where the CSU team became familiar with the physical equipment layout seen in plant overviews. This allowed the team to relate the physical equipment layout back to the process and instrumentation diagrams (P&ID's) and engineering drawings shown in the plant overviews, which aided in planning a daily measurement strategy. Facility screening and measurement times varied and were performed over the course of one to three days, depending on the size of the facility.

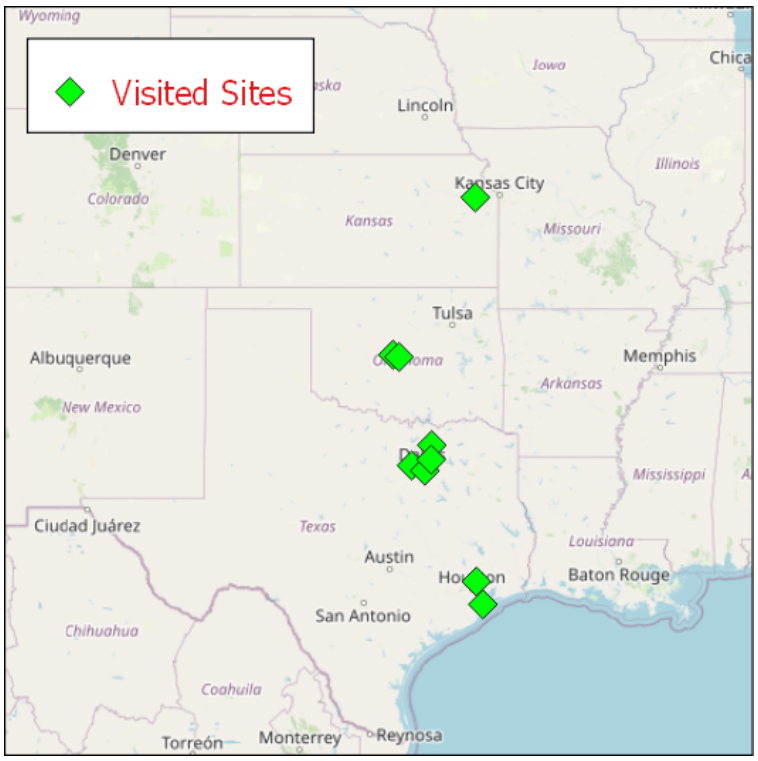

Figure 2.1: Nine RNG sites were visited in the central United States.

2.2 Site Screening and Component Emission Measurements

Screening was typically performed by a team of three people, working together to cover all equipment and components at the plant. The team typically followed the process flow, working through sections of the plant screening for emissions. The primary screening tool was an optical gas imaging (OGI) camera (Opgal, Eye-C-Gas), with assistance from a handheld, laser-based, remote, methane leak detector (RMLD) (Heath, RMLD-IS). All screening team members utilized auditory, visual, and olfactory (AVO) clues as well, and worked together using the screening tools to identify emission sources.

Figure 2.2: All components at the RNG plant were scanned using OGI and RMLD for methane gas detection. Identified emissions were cataloged by major equipment and component type prior to measurement.

Footage of all observed emissions were recorded with the OGI camera, in both infrared and normal modes. This provided a record of the emission source origination and a visual record of the approximate magnitude of the emission. Emission sources that were safely accessible and free of H_2S were quantified using a high-flow sampler (Bacharach, Hi-Flow Sampler). Observed emissions were categorized into "major equipment" categories, and component sub-types. Emissions that could not be measured were also recorded and categorized; the reason for not measuring was also noted. The most common reason for not measuring an observed source was "inaccessibility" which may have been for height, excessive heat, atmosphere, rotating equipment, or other safety hazards interfering with measurement. The next most common reason was the presence of H_2S. Leaks that were observed in the process prior to the completion of H_2S removal were not measured.

2.3 Downwind Emission Measurement

In addition to onsite screening and measurement, a mobile laboratory equipped with trace gas analyzers was used to perform downwind measurements at some facilities. Downwind measurements were performed using dual tracer flux [1], and other test method (OTM) 33A [2] methods. Briefly, in dual tracer flux measurements, tracer gases are released onsite through mass flow controllers at known flow rates. The mobile lab then attempts to capture both the source emission and tracer gas plumes by driving crosswind transects through the plumes downwind of the facility. The release points of tracer gases may be co-located with known emission points to ensure similar atmospheric dispersion and provide an indication that the intended source is being captured. Emission rates are inferred from the ratio of enhancements above background and the known tracer gas release rates. In OTM 33A measurements the mobile lab is parked downwind of the facility in a stationary

position within the emission plume. Emissions are monitored for 20-30 minutes and concentrations are binned by observed wind direction to recover a Gaussian plume shape. The emission rate is inferred from the average enhancement above background from the source, and the average wind speed during the measurement. Tracer gasses can also be used in OTM to aid in positioning, and may be toggled off and on during measurement to confirm the intended source plume is being captured. Additional details on each of these methods can be found in the associated protocol documents included in Appendix D.

Downwind measurements at RNG plants proved difficult for a variety of reasons. First, the CSU team was strictly forbidden from attempting downwind measurements at three of the nine RNG plants. This was due to concerns regarding relations with the adjacent landfills supplying the plants. Second, the siting of the RNG plants in close proximity to working landfills provided several confounding sources of both methane and tracer gases (acetylene (C_2H_2) and nitrous oxide (N_2O)). These included emissions from the landfills themselves, and from the ever-present equipment traffic at the landfill, which was often fueled with compressed natural gas (CNG). The RNG plants and associated landfills were typically located in industrial or agricultural districts which resulted in additional confounding sources. For example, an industrial composting facility located adjacent to one plant provided a confounding CH_4 source, while at another, a nearby fertilizer sales and distribution facility created a confounding source of N_2O which sometimes interfered with the tracer gas. Third, downwind methods in general are dependent on downwind road access and a prevailing wind speed and direction conducive to measurement. At one plant, where the team was authorized to make measurements, these conditions were not met and the team did not attempt to measure. Downwind measurements were attempted at five of nine RNG plants visited. Downwind measurements were considered successful at two sites, and unsuccessful at three sites. Unsuccessful attempts were hindered by insufficient winds, absence of roads for downwind access, and inability to differentiate plant emissions from landfill working face emissions due to wind direction on the day of measurement.

2.4 Plant Throughput

RNG plant flows were recorded during visits to each plant. Recorded flows included inlet, outlet (sales), TOX, flare, and vent flows. Gas flowrates were available from all facilities for the plant inlet and the plant outlet. Inlet gas compositions were available for 6 of 9 visited facilities and ranged from 54-55% CH_4 by volume. Outlet gas compositions were available for 7 of 9 facilities and varied from 95-96.4% CH_4 by volume. Site-specific, annual average inlet gas compositions reported to the Greenhouse Gas Reporting Program (GHGRP) were used to fill missing inlet gas composition values. Plants missing outlet gas composition values were assigned the average of the other sites as a best estimate since all plants must meet similar gas pipeline composition specifications. Gas flowrates and compositions for process streams routed to flares, thermal oxidation units (TOXs), and vents were known (measured) or estimated by plant operators at the time of the site visit for all but one facility. For this facility, values from a similarly constructed and operated "sister" facility were scaled by throughput and assigned.

Gas flowrates and compositions were used to calculate a CH_4 balance at each plant to understand the accuracy of measured plant flows, and the quality of estimates made for unmeasured flows. The CH_4 flowrate at the inlet was compared to the sum of of all other known CH_4 flows based on the

site-specific process configurations at each plant, which are generalized in Figure 2.3.

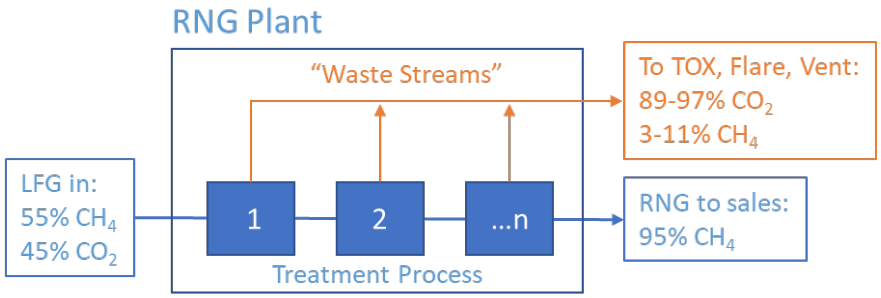

Figure 2.3: Simplified schematic of typical plant flows observed at RNG plants during the study. Landfill gas (LFG) enters the plant and undergoes numerous treatment process to strip CO_2 and other impurities. The resulting RNG is then suitable for sale at pipeline specifications. Various "waste streams" may be routed to some combination of flares, vents, and TOXs.

The CH_4 flow imbalance for each plant is shown in Figure 2.4 as a fraction of the plant inlet flow. At six of nine sites, plant flows are essentially balanced (within ±3%), for two they balance to within ±10% and for one they balance to within 17%. The reasons for these discrepancies were not identified and indicate there may be additional uncertainty in plant flows and gas compositions, which may impact emission estimates based on these data.

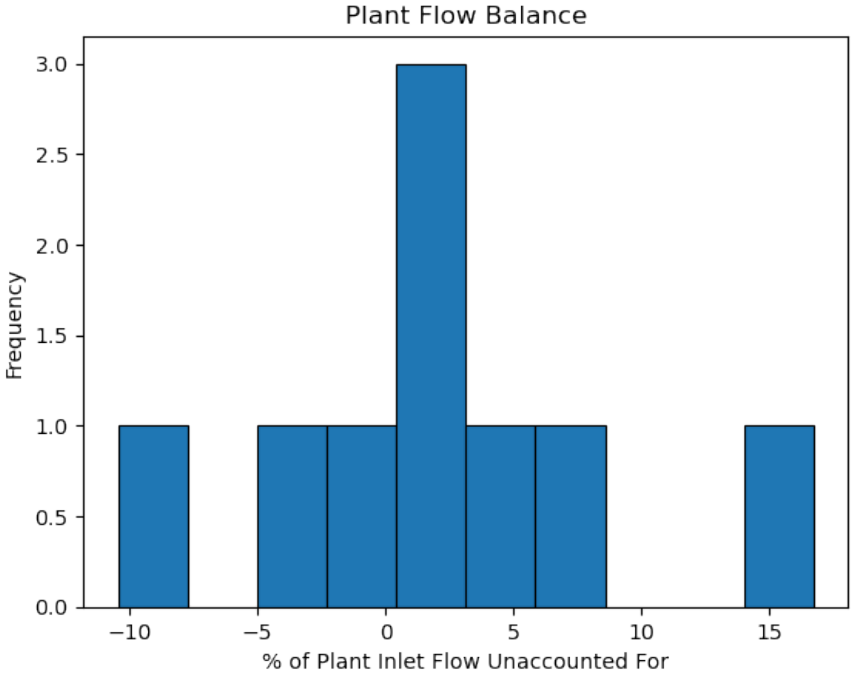

Figure 2.4: Plant flow balance at each of the nine RNG plants visited. Unaccounted for CH_4 flows are shown as a percentage of the known CH_4 plant inlet flow.

Additionally, plant inlet flows were compared to annual plant flows reported to the U.S. Environmental Protection Agency (EPA) GHGRP to understand how plant flows at the time of site visits compared to average annual plant flows. It appears that plant inlet flows during measurements

were typical of annual average site flows, as shown in Figure 2.5. We consider this an indication that the plants were operating typically during site measurements.

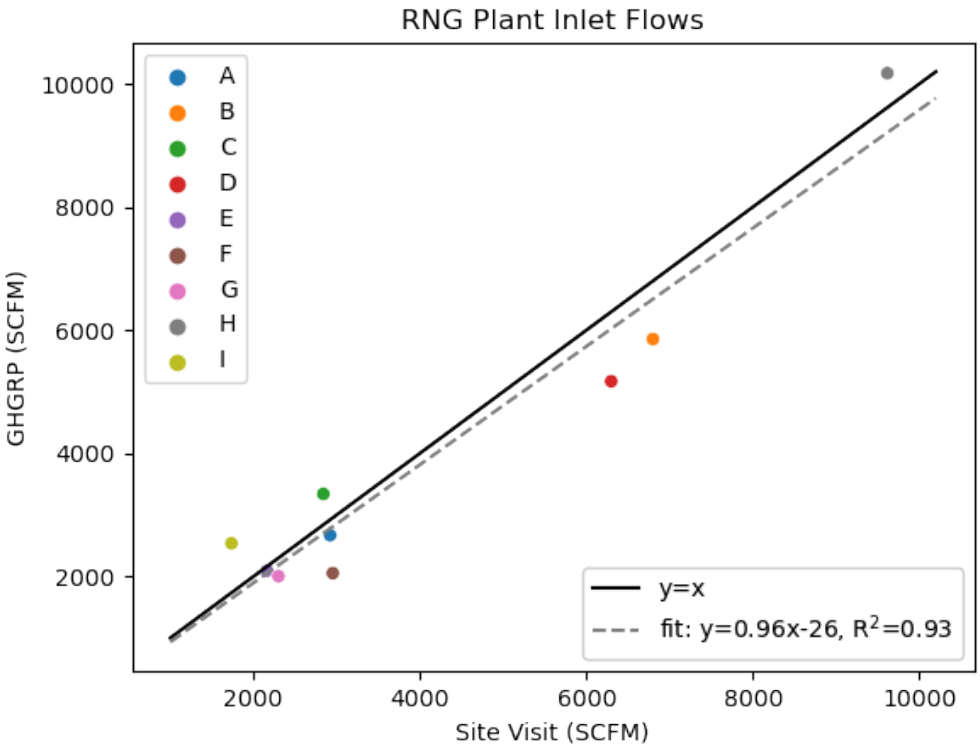

Figure 2.5: RNG plant inlet flows vs annual GHGRP-reported flows show good agreement by ordinary least squares regression, with a slope of 0.96 and an R^2 of 0.93

2.5 Vents, Flares, and Thermal Oxidizers

All visited facilities were equipped with one or more flare and TOX units. Three facilities utilized "cold vents", which vent some portion of the process gas directly to atmosphere as a normal part of LFG processing operations. Only one facility employed continuous flaring as part of its normal process; the gas composition and flowrate of the process stream routed to the flare were used to estimate emissions. Continuous process emissions from vents and TOXs were estimated assuming that the flowrates and compositions observed during site visits were reasonably accurate and typical of normal operations.

All facilities employed flares for "upset" conditions. The variety of site configurations and flaring strategies during these events makes the prediction of emissions during flaring events difficult. For example, one facility is shut in during upsets; all LFG is blocked at the plant inlet and routed to the flare. This facility provided summaries of active flaring times for the last several years, which ranged from 2-10% of the time, annually. At another facility, portions of the plant flow are routed to the flare and the inlet is never completely blocked; rather, the output is reduced during the time of flaring. Gas sent to flare may originate from various process stages, and can therefore vary in composition. This facility provided approximately 1 year of supervisory control and data acquisition (SCADA) data which included inlet, TOX, and flare flows at 15 minute intervals. These

data indicate that gas was routed to flare for 3% of the time (total elapsed time of 9 days in the 295 day log). Resampling from all "time-to-flare" data from the two sites gives a median time-to-flare of 4.8% (-2.0/+2.6%). Resampling from SCADA flowrate data (provided by one facility) indicates that 1.7% (±0.1%) of the CH_4 entering the plant was sent to flare, on average, for the data period provided. We assume that these flaring rates are applicable to the other facilities in this study, and use the median time-to-flare estimate for all facilities, based on their specific inlet flows, as a conservative estimate.

Both pilot gas for flares, and fuel gas for TOXs are excluded from this analysis. TOX fuel gas flows were only available at two of the visited facilities; there is no good way to estimate these flows without much more detailed knowledge of the waste stream flow rates and gas compositions. TOXs are usually operated to control for temperature, which is typically mandated to ensure destruction of pollutant species in the waste streams. Combustible species in the waste streams themselves may contribute to fueling the combustion process, reducing the need for additional fuel gas. In other cases, waste streams with lower heating values may require comparatively more fuel gas to maintain the desired operating temperatures within the TOX. For example, at one facility, the fuel flow to the TOX was 50% of the process CH_4 flow routed to the TOX; at another the fuel gas flow was more than two times the process gas flow. We assume a 98% CH_4 destruction efficiency by flares and TOXs.

2.6 Activity Data

"Activity Data" refers to the component or equipment inventory to which emission factors are applied to create an emissions estimate. For this study, component survey forms were provided to each host facility to capture their activity data for the study. The intent was to produce component-level emission factors, grouped by major equipment category. Due to resource limitations, only two of nine host facilities were able to provide comprehensive component counts. Similar resource limitations prevented the study team from performing component counts while onsite. All sites were able to provide major equipment inventories, or detailed P&ID's that the study team then used to create major equipment inventories which were reviewed by site operators. For the purpose of this study "major equipment" refers to functional units of equipment and co-located (attached, or very nearby) supporting equipment that perform dedicated process functions. For example, compressor units, and other skid mounted equipment purchased from a supplier, or similar functional groups "stick-built" onsite. The major equipment inventories are shown by site in Table 2.1.

2.6.1 Major Equipment Categories

Emission sources identified during onsite screening and measurement (both measured and unmeasured) were assigned to major equipment categories as outlined below. Each leak was also assigned a component-type as shown in Tables 2.1 and 3.2.

- **Combustors (Comb.)**: thermal destruction devices used continuously or intermittently in the RNG production process. Examples include candlestick flares "flares", and thermal oxidation units (TOX, TOU, etc.).

- **Compressors (Compr.)**: machinery used to raise the pressure of the process gas, providing the motive force needed to move gas through the process.
- **Dehydrators (Dehy.)**: Devices used to remove moisture from the process gas by means of solvent absorption, solid media adsorption, or refrigerant chilling.
- **Heat Exchangers (Hex)**: Devices used to cool process gas or auxiliary fluids for gas processing equipment. Generally air-to-air, fan/tube and fin coolers.
- **Instrumentation (Intsr.)**: Measurement instrumentation and associated vents and pipework. Includes online process analyzers, gas chromatographs, etc.
- **Separators (Sep.)**: Devices used to separate process fluid phases using passive, physical means such as filtration, impaction, coalescing, or settlement.
- **Tank**: Above-ground storage vessels used to handle and store process fluids or waste stream fluids. Distinct from sumps.
- **Treaters (Treat.)**: Treaters are the most common, most diverse, and most loosely defined major equipment category given the variety of treatment process needed at each individual facility.
- **Yard Piping**: Catch all for supporting piping and equipment not directly attached to treatment skids, vessels or equipment.

Table 2.1: Major equipment counts by site.

Maj. Equip. Site	Comb.	Compr.	Dehy.	Hex	Instr.	Sep.	Tank	Treat.	Yard Piping	Total
A	2	9	4	5	1	7	-	7	1	36
B	2	11	1	4	1	5	-	8	1	33
C	2	9	4	6	1	10	-	16	1	49
D	2	8	1	5	1	11	2	12	1	43
E	1	5	2	1	1	-	-	7	1	18
F	2	8	1	5	1	11	2	12	1	43
G	2	7	3	3	1	8	-	6	1	31
H	2	14	-	5	1	6	-	28	1	57
I	2	7	1	3	1	2	-	11	1	28
Total	17	78	17	37	9	60	4	107	9	338

Combustor emissions included in major equipment emissions include leaking *inputs* to the combustor, and not any unburned emissions *output*, which are considered separately. For example, fuel supply leaks, flow meter and analyzer leaks, etc. Compressors used most commonly in RNG service appear to be roots and centrifugal blowers, and oiled-screw compressors. Reciprocating compressors are typically only used at the exit of the RNG facility to boost the output pressure sufficiently for entrance into the gas sales line. All compressors observed in this study were powered by electric motors. No internal combustion engines were observed powering compressors. Dehydrators are commonly refrigerated liquid heat exchangers, and solid media (mol-sieve and

desiccant) adsorption vessels. Only one tri-ethylene glycol (TEG) dehydration unit (typical of natural gas gathering and processing) was observed in service during the study. Treaters, as used herein, are loosely defined and make no distinction between the variety of processes used to treat the landfill gas on its way to becoming renewable natural gas. Examples of treaters include membrane separation units, molecular sieves, pressure swing adsorption units, carbon polishers, oxygen and nitrogen removal units, selective solvent contactors, etc. Each facility was assigned one unit of Yard Piping, and one unit of Instrumentation. Yard piping includes the supporting piping connecting treaters or other pre-packaged skids, and inlet, sales, and other gas distribution piping onsite used for both process and fuel gas.

Chapter 3

Results and Discussion

3.1 Component Emission Measurements

Emissions identified during the site screening and component-level measurements are shown by major equipment category and component-type in Table 3.1. Counts of unmeasured emissions are also included and are shown in parenthesis. A total of 133 emissions were observed during facility screenings. Of those, 103 were quantified directly using the high flow sampler, while 30 could not be quantified directly. The most common reasons for not measuring an observed source were inaccessibility and the presence of H_2S. Leaks were considered inaccessible if a potentially unsafe scenario existed. This included heights inaccessible with man-lifts, active construction/demolition, hot surfaces, rotating equipment, standing water near electrical conduits, potentially asphyxiating atmospheres in the direct vicinity of the source, etc.

Table 3.1: Component leak count by major equipment type. Parenthesis indicate emission sources which were observed and logged during screening but were not able to be measured directly.

Maj. Equip. Cmpnt.	Comb.	Compr.	Dehy.	HEX	Instr.	Sep.	Tank	Treater	Yard Piping	Total
Conn.	3	6 (5)	2	(1)	1	(2)	-	15 (8)	7	34 (16)
Gauge	-	-	-	-	1	-	-	1	2	4
Meter	1	-	-	-	-	-	-	-	-	1
OEL	-	3	-	-	-	-	1	-	-	4
Other	(1)	8 (5)	-	(1)	1	(1)	(1)	2	-	11 (9)
PRV	-	-	-	1	-	-	-	1 (1)	(1)	2 (2)
Pneum.	-	1	-	-	-	-	-	-	-	1
Reg.	1	1	-	-	-	-	-	2	-	4
Sensor	-	-	-	-	-	-	-	2	1	3
Valve	2	4	-	2	-	-	-	6 (2)	1	15 (2)
Vent	1	2	1	-	18 (1)	-	-	1	1	24 (1)
Total	8 (1)	25 (10)	3	3 (2)	21 (1)	- (3)	1 (1)	30 (11)	12 (1)	103 (30)

Table 3.2: Measured leak rate by major equipment type and component sub-category in SLPM.

Maj. Equip. Cmpnt.	Comb.	Compr.	Dehy.	HEX	Instr.	Sep.	Tank	Treater	Yard Piping	Total
Conn.	2.3	58.2	1.0	0.0	0.4	0.0	-	76.7	9.8	148.5
Gauge	-	-	-	-	0.0	-	-	2.5	0.5	3.0
Meter	1.2	-	-	-	-	-	-	-	-	1.2
OEL	-	10.2	-	-	-	-	0.9	-	-	11.1
Other	0.0	183.4	-	0.0	0.9	0.0	0.0	6.3	-	190.7
PRV	-	-	-	3.5	-	-	-	9.1	0.0	12.6
Pneum.	-	1.4	-	-	-	-	-	-	-	1.4
Reg.	0.0	0.9	-	-	-	-	-	6.2	-	7.1
Sensor	-	-	-	-	-	-	-	5.6	0.4	5.9
Valve	42.1	15.3	-	76.9	-	-	-	19.0	6.3	159.7
Vent	0.6	203.3	10.6	-	63.5	-	-	13.0	2.2	293.2
Total	46.1	472.7	11.6	80.4	64.8	-	0.9	138.4	19.2	834.3

Emissions measured directly are shown in Table 3.2 by major equipment category and component type, and in Table 3.3 by major equipment category and site. The sparseness of observed emissions would make it impractical to summarize emissions at the component level. Describing emissions at the major equipment level is better supported by the data, though some categories still have relatively few measurements.

Categories with 0.0 standard liters per minute (SLPM) in Tables 3.2 and 3.3 correspond to categories that had only observed, but not measured sources (shown in parenthesis in Table 3.1). Compressors were the major equipment category with the largest emissions. This was mainly driven by reciprocating units. Emissions were observed on nearly all reciprocating compressors, and were large relative to those on blowers, oiled-screw, and centrifugal compressor units. It should be noted that the totals in Tables 3.2 and 3.3 are incomplete due to the missing contribution from the 30 observed, but not measured sources.

Table 3.3: Measured leak rate by major equipment type and site in SLPM.

Maj. Equip. Site	Comb.	Compr.	Dehy.	Hex	Instr.	Sep.	Tank	Treat.	Yard Piping	Total
A	0.0	15.2	10.6	76.9	0.0	0.0	-	28.2	-	130.9
B	-	74.3	-	0.0	6.6	-	-	5.6	6.3	92.8
C	-	21.6	-	-	8.0	-	-	0.9	0.5	31.0
D	1.2	305.5	-	-	-	0.0	0.0	9.3	-	315.9
E	1.2	4.6	1.0	0.0	0.0	-	-	3.5	0.4	10.8
F	41.7	51.5	-	-	1.0	0.0	-	6.7	4.7	105.7
G	0.5	-	-	3.5	8.4	-	-	-	7.2	19.6
H	1.6	0.0	-	-	39.2	-	0.9	75.2	0.0	116.9
I	-	0.0	-	-	1.5	-	-	9.1	-	10.5
Total	46.1	472.7	11.6	80.4	64.8	-	0.9	138.4	19.2	834.3

Two approaches were investigated to account for observed, but not measured sources. Both utilized Monte Carlo (MC) simulations of hypothetical site visits, where 10,000 realizations were computed by resampling. In each realization, the number of leaks per major equipment category was simulated by resampling from the number of leaks observed on each piece of major equipment during field screening, including zero counts for equipment observed not leaking. Emission rates for each leak were then drawn at random from the leak rates of measured sources in the corresponding major equipment categories. This provided a median emission factor, with uncertainty, across all facilities, for each major equipment category. The intent of this simulation is to account for observed, but not measured sources by resampling from the actual leaks measured within a given major equipment category. This simulation assumes, inherently, that the observed, but not measured leaks belong to the same underlying emission rate distribution of the observed, measured leaks. If this assumption were valid, measured leak rates would serve as valid substitutions for unmeasured leak rates and aggregate emission estimates would be equivalent. The results of this simulation are shown in Table A.1 by major equipment category and as applied to major equipment counts by site in Table A.2.

Based on field experience and review of the OGI camera footage, unmeasured sources often appeared larger than measured sources typical of the same major equipment category. Therefore, estimating the emission rate of unmeasured sources by substitution with measured sources is an inappropriate model which may lead to a low bias in aggregate emissions estimates. To better understand the magnitude of this potential bias, an additional simulation was performed where team members estimated the emission rate of unmeasured sources by reviewing the OGI camera footage. Measured emission rates were supplemented with the estimates and the simulation was repeated. The results of the simulation, with OGI estimates included, are shown in Table 3.4 by major equipment category, and as applied to major equipment counts, by site, in Table 3.5. The total emission rate shown in Table 3.5 (1649.0 (-558.9,+890.2)) is 48% greater than the simulation without OGI estimates (1113.1 (-472.3,+743.3) shown in Table A.2. However, the confidence interval of the result with OGI estimates included overlaps the median result without OGI estimates, indicating that the OGI observer estimates are not unreasonable. This method, while not ideal, may provide a more complete accounting of unmeasured sources for this particular study.

In Tables A.1 and 3.4 the simulated emission factor (EF) for Combustors, Instrumentation,

Table 3.4: Simulated EF by major equipment type (SLPM). Uncertainty bounds represent an empirical 95% confidence interval about the simulated median EF value given. The input data to this simulation includes observed, measured emission rate values, supplemented with estimates based on OGI footage of unmeasured sources, as discussed in the text.

Maj. Equip.	Sim EF (Measured + OGI estimated)
Comb.	5.99 (-5.81/+11.03)
Compr.	7.59 (-4.75/+7.59)
Dehy.	0.63 (-0.63/+1.87)
Hex	2.51 (-2.42/+4.69)
Instr.	7.73 (-5.77/+11.03)
Sep.	2.25 (-2.25/+4.75)
Tank	4.21 (-4.21/+12.50)
Treat.	5.66 (-3.44/+4.95)
Yard Piping	2.73 (-2.50/+4.33)

Tanks, Treaters, and Yard Piping went up, while the simulated EF for Compressors and Heat Exchangers, went down. The simulated EF for Dehydrators stayed the same since no estimation was required because there were no unmeasured sources in this category. The simulated EF for Separators is based entirely on estimates from OGI footage.

In both Tables A.2 and 3.5, emission factors developed from the simulations discussed above were applied to the component counts directly, without consideration for uncertainty in component counts. For each site, median estimates are shown for each major equipment category while site totals with uncertainty (computed by quadrature addition across major equipment categories) are shown in the "Total" column.

Table 3.5: Site level emissions computed from major equipment counts and emissions measured directly during the field campaign, inlcuding estimates for unmeasured sources.

Site	Comb.	Compr.	Dehy.	Hex	Instr.	Sep.	Tank	Treat.	Yard Piping	Total
A	12.0	68.3	2.5	12.5	7.7	15.8	-	39.6	2.7	161.2 (-54.6,+90.6)
B	12.0	83.5	0.6	10.0	7.7	11.2	-	45.3	2.7	173.1 (-62.3,+100.4)
C	12.0	68.3	2.5	15.1	7.7	22.5	-	90.6	2.7	221.4 (-75.9,+121.1)
D	12.0	60.7	0.6	12.5	7.7	24.8	8.4	67.9	2.7	197.4 (-64.4,+108.4)
E	6.0	38.0	1.3	2.5	7.7	-	-	39.6	2.7	97.8 (-35.0,+54.2)
F	12.0	60.7	0.6	12.5	7.7	24.8	8.4	67.9	2.7	197.4 (-64.4,+108.4)
G	12.0	53.1	1.9	7.5	7.7	18.0	-	34.0	2.7	136.9 (-45.7,+77.5)
H	12.0	106.3	-	12.5	7.7	13.5	-	158.5	2.7	313.2 (-119.2,+180.3)
I	12.0	53.1	0.6	7.5	7.7	4.5	-	62.3	2.7	150.5 (-52.8,+81.9)
Total	101.8	592.0	10.7	92.9	69.6	135.0	16.8	605.6	24.6	1649.0 (-558.9,+890.2)

3.2 Total Site Emissions and Emissions Intensity

Site-level emission rates and emission intensities (Emission Rate as % of Inlet) are shown in Table 3.6. Site flows and emissions rates by category are shown in SLPM of CH_4. Vents and Leaks are shown as direct CH_4 emissions to the atmosphere. Flaring and TOX flows are shown as emission rates to atmosphere assuming a nominal destruction efficiency of 98%; i.e., 2% of the CH_4 sent to the destruction device is emitted to atmosphere.

Emission intensity estimates varied greatly between sites that vented CH_4 directly to atmosphere as a part of normal operations and those that did not. All sites that did not vent waste streams directly were were found to emit less than 1% of the CH_4 taken in from the landfill for processing. In contrast, sites with direct venting emit an estimated 4-6% of CH_4 entering the plant for processing. Eliminating direct venting is the largest opportunity for immediate CH_4 emissions reduction at the sites visited in this study.

Table 3.6: Site CH_4 flows and emission rates (SLPM), and emission intensities (%). Flare and TOX emission rates assume a 98% CH_4 destruction efficiency.

Site	Inlet	Sales	Normal Flaring	Upset Flaring	TOXs	Vents	Leaks	Emission Rate	Emission Intensity (%)
A	46304	45017	0	44	122	0	161	328	0.7%
B	105809	87298	266	102	39	0	173	580	0.5%
C	43412	34932	0	42	143	0	221	406	0.9%
D	104524	96980	0	100	6	3964	197	4268	4.1%
E	33687	27843	0	32	27	1770	98	1927	5.7%
F	46827	43875	0	45	3	1776	197	2021	4.3%
G	36277	33222	0	35	67	0	137	238	0.7%
H	149779	119611	0	144	103	0	313	560	0.4%
I	26530	25502	0	25	40	0	150	216	0.8%

Summing inlet CH_4 flows and emissions across all 9 sites visited, we find an overall emissions intensity of 1.8%. Categorically, we find that normal flaring accounts for 2.5%, upset flaring 5.4%, TOXs 5.2%, vents 71% and fugitives 16% of the total emissions estimated in this study across the 9 sites. For plants without venting, the emission intensity was found to be 0.57%

To put these results into context, four scenarios are considered in Table 3.7. Without gas collection systems, we assume that the CH_4 emission rate equals the CH_4 inlet rate to the plants, i.e. if gas collection for the 9 plants ceased, an additional 212 kilo-tonnes of CH_4 would be emitted per year. As currently operated, with direct venting at some of the plants, the greenhouse gas (GHG) performance of the RNG plant is slightly better than if the LFG collection system were routed directly to flares operating at 98% efficiency. If venting were eliminated, and the average performance of non-venting plants in this study were achieved at all 9 plants, CH_4 emissions from RNG plants visited in this study could be reduced by roughly three times, from 3.8 kilo-tonnes CH_4 per year to 1.2 kilo-tonnes CH_4 per year. Therefore, as currently operating, CH_4 emissions are approximately equal to those from flaring; eliminate cold venting and the emissions would be substantially less.

Table 3.7: Annual CH_4 emissions in kilo-tonnes (10^6 kg) per year for the 9 plants visited for four scenarios.

	No LFG Collection	LFG Collection With Flaring	RNG with Venting	RNG without Venting
CH_4	212	4.2	3.8	1.2

Emissions intensity can also be viewed from the standpoint of total carbon intensity, often expressed as CO_2 equivalent emissions, or CO_2e emissions. To compare CO_2e emissions, we assume (a) that the gas processed by the RNG plant would be flared at the landfill and would need to be replaced by fossil natural gas; (b) the landfill flare destruction efficiency is 98% and combusted methane is fully converted to CO_2 and water vapor – i.e. no other combustion byproducts; (c) replacement natural gas has a methane emission rate of 2.3% of delivered methane, as per Alvarez, et al. [3], (d) a 30-year global warming potential of CH_4 of 86, and, (e) miscellaneous emissions from transport, processing, consumed electricity, etc. are similar for both RNG and fossil natural

gas. Calculation methodology is summarized in Appendix B and results are shown in Table 3.8.

Table 3.8: CO_2e emissions for RNG plants relative to flaring of the same LFG.

With Cold Venting		
	Plant	Flare
CH_4 Emission Rates	1.8%	2% + 2.3%
Relative CO2e Emission Rate	4.24	9.08
Ratio Plant to Flare		47%
Without Cold Venting		
	Plant	Flare
CH_4 Emission Rates	0.57%	2% + 2.3%
Relative CO2e Emission Rate	3.22	9.11
Ratio Plant to Flare		35%

For the 9 plants studied, including direct venting at some of the plants, the RNG gas has approximately one half of the carbon intensity of natural gas. If direct venting of gas can be eliminated, resulting in a CH_4 emission rate of 0.57% of methane handled, RNG gas has approximately one third the carbon intensity of the equivalent amount of natural gas.

3.3 Downwind Measurement Results

Downwind measurements were attempted at 5 of 9 RNG plants visited for measurement. Downwind measurements were considered successful at two sites, and unsuccessful at three. At site D, both OTM 33A and dual tracer flux measurements were performed successfully on two consecutive days. At site F, both OTM 33A and dual tracer flux measurements were successful on the single day they were attempted. Results of downwind measurements are shown in Table 3.9.

Table 3.9: Site CH_4 emission rates (SLPM) and intensities for modeled emissions and downwind measurements.

Site	Day	Model Emission Rate	OTM Emission Rate	Tracer Emission Rate	Model Intensity (%)	OTM Intensity (%)	Tracer Intensity (%)
D	1	4268	5320	5078 (-1155,+1616)	4.1%	5.1%	4.9% (-1.1,+1.5)
D	2	4268	5884	5574 (-698,+784)	4.1%	5.6%	5.3% (-0.7,+0.8)
F	1	2021	3230	3248 (-981,+1787)	4.3%	6.9%	6.9% (-2.1,+3.8)

At both sites D and F, downwind measurements predicted greater CH_4 emission rates than the model developed from onsite measurements and operational data provided by operators. At site D, emissions were of a similar magnitude, but slightly greater on day two by both the OTM 33A and dual tracer flux measurements. Tracer flux emission rates with uncertainties shown are given by the median, and a 95% confidence interval about the median by bootstrap averaging

the number of plumes that met acceptance criteria. On day one, only 3 dual tracer flux plumes passed all acceptance criteria, leading to a larger uncertainty bound. On day two, 7 dual tracer flux plumes passed acceptance criteria, leading to a lower uncertainty in the estimate. At site F, 3 single correlation plumes were used in the estimate due to a failure of the flow controller of one tracer gas. Uncertainty estimates on OTM measurements are not shown in Table 3.9, but have been given as $\pm 30\%$ (1σ) by Brantley [4] and Robertson [5], and $\pm 70\%$ (2σ) by Edie [6].

Concurrent OTM 33A measurements of tracer gases in this study generally fall within these uncertainty bounds based on the fraction of released tracer gas recovered during measurement. The general co-location of tracer gases and CH_4 emission sources onsite and the well-correlated tracer gas and CH_4 plumes recovered downwind indicate these uncertainty bounds should extend to CH_4 plumes under these circumstances. On day 2 at site D, we were able to precisely co-locate one tracer gas with the dominant emission source at the site, and concurrent OTM 33A measurements recovered 95% of the tracer gas. This may indicate a much lower uncertainty for this measurement.

3.4 Comparison to Other Sectors

The upgrading of LFG to RNG uses processes that are, in some ways, similar to those used in the natural gas industry. RNG plants serve a similar function to gathering and boosting (G&B) stations in that they collect field gas, upgrade it, and compress it into pipelines for transport and sales. The equipment used to perform these functions differs greatly; for example, a typical compressor at an RNG plant bears little resemblance to a typical natural gas compressor at a G&B station. The upgrading process at an RNG plant is typically more complex, and total plant output is lower. The throughput of a single, mega-Watt class compressor typical of U.S. onshore natural gas G&B operations is similar to the throughput of a single plant in this study. These differences make direct comparisons of emission factors difficult, and as such the following section attempts to identify and discuss the similarities and differences in the underlying equipment that produced the emission factors being compared.

Combustors, as used herein, refer to both thermal oxidation units and flares. Thermal oxidizers similar to those employed at RNG plants for control of volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions are not commonly used in natural gas G&B operations, but may be found at natural gas processing plants. Flaring is also used in production operations. An RNG emission factor was developed by applying the Simulated EF developed herein to each combustor (to account for leaks and fugitives), and then estimating CH_4 emissions from incomplete combustion based on plant-specific flows,compositions, and a 98% destruction efficiency to each combustor. Summing all normal flaring, upset flaring, TOX, and leak emissions and then dividing by the number of combustors yields 48.3 kg CH4/MMscf of CH_4 entering the plant. In comparison, "miscellaneous flaring" in onshore natural gas production operations in the 2020 EPA Greenhouse Gas Inventory (GHGI) reports 0.3, 0.03, 0.5, and 0.03 kg/MMScf in the Gulf Coast, Williston, Permian, and "Other" basins, respectively.

On a per-combustor basis, RNG combustors emit 29,637 kg/combustor of CH_4 per year compared to 1,871 kg/flare in G&B operations. Flaring activities at natural gas processing plants emitted 53,530 kg/plant in 2020, which is similar to the the per-plant total of 59,274 kg/plant for combustors (1 flare, 1 TOX per plant, typically) at RNG plants. This may indicate that flare/combustor

activities at RNG plants may be more similar to flaring activities at natural gas processing plants than those of production or G&B operations.

Compressors observed at the 9 RNG sites visited in this study were typically blowers, or oiled-screw compressors driven by electric motors, in the 100-400 horsepower (HP) class. This is in contrast to compressors in the gathering and boosting sectors which are typically much larger (≈1,000 HP) reciprocating compressors driven by internal combustion engines. Unburned fuel entrained in the exhaust of gas compression engines can be a significant source of CH_4, which is absent in the electric motors used for gas compression at RNG plants. The simulated EF for component leaks on compressors developed in this study was 7.59 (-4.75/+7.59) SLPM/unit compared to 45.1 SLPM/unit for gas compressors in service in G&B operations in the 2020 EPA GHGI. As mentioned previously, the throughput of compressors in each of these industry segments differs greatly and meaningful normalization is not possible with available data. Interestingly, the average emission rate for leaks observed on reciprocating compressors in this study was similar to G&B, at 39 SLPM vs 5 SLPM for blowers, oiled-screw, and centrifugal compressors.

Dehydrators in use at the 9 RNG plants visited in this study were most commonly refrigerant-chilled heat exchangers, which have little in common with the TEG units commonly used in natural gas operations. TEG units are more complicated and have additional emissions associated with process vents, pneumatic devices, etc. The simulated emission factor for dehydrators observed in this study was 0.63 (-0.63/+1.87) SLPM, compared to 1.39 SLPM for analogous component leaks on TEG units in G&B service.

Heat exchanger (HEX) and instrumentation do not have analogous emission factors available for direct comparison in other sectors, but the physical equipment is nearly identical. HEX emissions may be similar to those in other sectors but may be influenced by differences in, pressure, throughput, and maintenance activities. Instrumentation emissions should be very similar to other sectors on a per-unit basis, as very similar instrumentation setups are commonly used.

Separators, as used herein are most similar in purpose to standalone "Yard Separators" as used in natural gas G&B operations. The separators are distinct from those "built-in" to other process equipment; for example an inter-stage liquids knockout on a compressor skid would not be included here, while a standalone separator serving a site or stage of processing at a site would be. During this study, three leaks were observed on equipment classified as separators. Unfortunately, none of them were able to be measured directly; all estimates were based on OGI observations. These observation-based estimates resulted in a simulated EF of 2.25 (-2.25/+4.75) SLPM vs 0.26 L/min for those used in natural gas G&B operations.

Treaters, as used herein, refer to the various equipment used to treat and upgrade LFG to RNG such as CO_2, H_2S, N_2, H_2O, etc. For example a pre-built membrane separation skid, or a solvent contact-tower and associated supporting equipment attached or nearby would both be considered treaters. The simulated EF in this study for treaters is 5.66 (-3.44/+4.95) SLPM. A directly comparable class of equipment is not defined in the EPA GHGI, though some dehydration, smaller acid gas removal units (AGRUs), and fuel gas treatment skids are comparable in complexity.

Yard piping, as used herein, refers to various piping and equipment onsite not classified as a piece of major equipment. A similar category exists for natural gas G&B stations in the 2020 EPA GHGI. The simulated EF for RNG yard piping emissions is 2.73 (-2.50/+4.33) SLPM, compared to 35 SLPM for G&B operations, which likely have greater CH_4 throughput, on average, than the

plants visited in this study.

Overall, equipment emissions from operations at RNG facilities are generally not directly comparable those in other natural gas segments due to differences (or absences) in the process technology used, and in equipment scale and throughput. Emission factors for RNG plants should likely be developed separately from those in other natural gas segments.

Chapter 4

Summary Conclusions

Onsite, direct measurements and downwind tracer flux and OTM measurements were made at 9 RNG plants located in the central US states of Kansas, Oklahoma, and Texas between 8/17/2021 and 9/10/2021. The plants varied in throughput, and employed various upgrading processes. All equipment and components were screened using OGI, assisted by RMLD. 103 of 133 identified emission sources were measured directly with a high-flow sampler. Measured emission rates ranged from 0.05 to 187 SLPM. Emission factors were developed, using measurements and estimates by resampling from major equipment categories. Applying these emission factors to major equipment inventories at each plant resulted in plant-level, throughput-normalized emissions (emission intensities) ranging from from 0.4% to 5.7%. Downwind measurements were attempted at five plants, and were successful at two. Downwind measurement results generally confirmed modeled emission estimates, but were found to be slightly higher (see Table 3.9).

The overall CH_4 emission intensity for the 9 plants, in aggregate, was 1.8%. Among plants without direct venting, the aggregate emission intensity was 0.57%. Elimination of direct venting is the largest opportunity for immediate CH_4 emission reductions within the plant boundary and would reduce the CH_4 emission intensity at RNG plants by a factor of 3. The aggregate plant CH_4 emission intensity of 1.8% is better, but very similar to, what would result from flaring the collected CH_4, assuming the landfill flares were operating uniformly at a 98% destruction efficiency.

On a CO_2e basis, local GHG emissions are reduced by the RNG plant relative to flaring, and further, the heat content of the produced RNG is still available as a useful fuel for power generation, space heating, transportation, etc. For the 9 plants studied, including direct venting at some of the plants, the RNG gas has approximately one half of the carbon intensity of natural gas. If direct venting of gas can be eliminated, the RNG CH_4 emission intensity would drop to 0.57%, or approximately one third the carbon intensity of the equivalent amount of natural gas.

Measurements and analysis herein consider only CH_4 emitted during gas handling between plant inlets and outlets; emissions resulting from uncollected LFG (and the collection system itself) were outside the scope of the current study. The proportion of LFG that is collected and processed is an important consideration when evaluating the overall emission reductions enabled by RNG facilities. Collection of LFG at these 9 plants has reduced CH_4 emissions from the associated landfills by over 200 kilo-tonnes in 2021 alone, based strictly on recorded plant inlet flows. Ensuring that LFG collection and processing capacity are sufficient to match generation within the landfill may present

a larger opportunity for total emission reductions than improvements in emission intensity within the plants, among the plants studied.

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Appendix A

Simulated EF Excluding OGI Estimates

Table A.1: Simulated EF by major equipment type (SLPM). Uncertainty bounds represent an empirical 95% confidence interval about the simulated median EF value given. The input data to this simulation includes only actual measured values, as discussed in the text.

Maj. Equip.	Sim EF (Measured only)
Comb.	2.86 (-2.72/+7.51)
Compr.	8.15 (-5.48/+8.58)
Dehy.	0.63 (-0.63/+1.87)
Hex	4.16 (-4.15/+6.24)
Instr.	7.04 (-5.41/+10.68)
Sep.	-
Tank	0.05 (-0.05/+0.06)
Treat.	1.71 (-1.02/+1.45)
Yard Piping	1.96 (-1.80/+2.98)

Table A.2: Site level emissions computed from major equipment counts and emissions measured directly during the field campaign.

Site	Comb.	Compr.	Dehy.	Hex	Instr.	Sep.	Tank	Treat.	Yard Piping	Total
A	5.7	73.4	2.5	20.8	7.0	-	-	12.0	2.0	123.4 (-54.6,+86.3)
B	5.7	89.7	0.6	16.6	7.0	-	-	13.7	2.0	135.3 (-63.5,+100.1)
C	5.7	73.4	2.5	25.0	7.0	-	-	27.4	2.0	142.9 (-58.2,+91.1)
D	5.7	65.2	0.6	20.8	7.0	-	0.1	20.5	2.0	122.0 (-50.6,+79.6)
E	2.9	40.8	1.3	4.2	7.0	-	-	12.0	2.0	70.0 (-29.3,+46.6)
F	5.7	65.2	0.6	20.8	7.0	-	0.1	20.5	2.0	122.0 (-50.6,+79.6)
G	5.7	57.1	1.9	12.5	7.0	-	-	10.3	2.0	96.4 (-41.6,+66.4)
H	5.7	114.1	-	20.8	7.0	-	-	47.9	2.0	197.5 (-84.8,+131.9)
I	5.7	57.1	0.6	12.5	7.0	-	-	18.8	2.0	103.7 (-42.6,+67.6)
Total	48.6	635.7	10.7	153.9	63.4	-	0.2	183.0	17.6	1113.1 (-472.3,+743.3)

Appendix B

Computation of CO_2e Comparison

The CO_2e comparison utilizes a simple methodology to compare RNG to flaring the same methane at a landfill. The RNG plants have a fractional CH_4 emission rate of c_r, and the resulting produced gas $(1 - c_r)$ is productively consumed in end use. Had the plant not produced the gas, the LFG gas would be flared at the landfill, resulting in methane emissions of c_f, and the market gas would need to be replaced by fossil natural gas, which has a methane emission rate of c_n. Therefore, the RNG gas has a methane emission rate of c_r compared to a methane emission rate of $c_f + c_n$ for flaring at the landfill. Further, the methane flared at the landfill is converted to CO_2 and H_2O. During combustion, each kg of CH_4 produces 2.74 kg of CO_2.

Assuming a global warming potential of CH_4 of $G = 86$, the CO_2e of RNG gas is:

$$E_r = 86 \cdot c_r + 2.74 \cdot (1 - c_r) \tag{B.1}$$

while the CO_2e of the replacement gas is:

$$E_n = 86 \cdot (c_n + c_f) + 2.74 \cdot (1 - c_f) + 2.74 \cdot (1 - c_r) \tag{B.2}$$

Appendix C

Summary Data Tables

Data associated with equipment screening and measurement can be found in the file 'Screening and HiFlow.csv'. Picture and video files listed in columns 'PicFile', and 'VidFile' can be found in the archive 'OGI Screening.zip'. Column headers and data description are as follows:

- SiteID - Randomly ordered site identifier from 'A' to 'F'
- Date - mm/dd/yyyy
- Day - sequential number for day of measurement at each site.
- LeakNum - sequential leak number assigned to each observed emission per site.
- PicFile - picture file in 'OGI Screening.zip'.
- VidFile - video file in 'OGI Screening.zip'.
- MajorEquipmentType - one of the major equipment categories outlined in this report.
- MajorEquipmentDescription - free form description of the major equipment.
- ComponentType - type of componenet on the major equipment. 'Connector/Gauge/Meter/OEL/Other/Pneum Controller/PRV/Regulator/Sensor/Valve/Vent'
- ComponentSubtype - applies only to 'Connector' (Threaded/Flanged/Other) and 'Valve' (Large/Small) component types. Large valves are on pipes $\geq$ 2 in. Small valves are on pipes $<$ than 2 in.
- Location Description - free form notes of emission location from screening team
- Exceptions - 'yes/no/maybe' issues with measurement
- ExceptionDescription - description of exception
- OGI HiFlow OGI Estimate (SLPM) - OGI operator-estimated leakrate in SLPM
- OGI Estimate Notes - notes on OGI operator estimate
- HFLeak_SLPM - Hi-Flow measured leak rate in SLPM

Appendix D

Auxiliary Documents

The following additional documents are attached to this report.

- Optical gas imaging (OGI) protocol
- High flow protocol
- OTM measurement protocol
- Tracer flux protocol

Protocol

Emission Screening: Optical Gas Imaging (OGI)

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1 Overview

This document provides the on-site protocol for performing optical gas imaging (OGI) surveys at natural gas facilities.

2 General Approach

OGI will be used as the primary screening method at all sites selected for measurement. Screening will be performed using the high sensitivity mode of the OGI camera, though regular modes may be using following initial location of an emission source, or during video recording. All emissions identified will be recorded, described, and documented prior to measurement. Documentation should include a photo of the emission source with an equipment identification tag applied (e.g. masking tape or hang-tag), where practicable. Photos can be taken with the field data collection tablet computer, or the snapshot feature of the OGI camera. Recordings should be made such that the emission source is clearly discernible, and context is provided. For example, switching camera modes during recording, pointing a finger within the video frame, and zooming out to capture adjacent equipment can aid in pinpointing leak locations and properly categorizing leak sources.

An OGI sensitivity test will be performed on each camera, on each day, prior to screening. During the sensitivity test, a representative gas blend will be released from a gas cylinder at 1-2 slpm while the camera operator observes the gas plume. Alternatively, since the camera operates by detecting differential absorption of infrared radiation in the C-H stretch region between the emission plume and the surrounding, an unlit propane torch or unlit butane lighter could be used to perform the check. The distance between the camera operator and potential emission sources during screening should not exceed the observation distance used in the daily sensitivity check, if possible (e.g. 5-10 ft for initial scanning).

All equipment at the facility will be scanned and all emissions observed will be recorded in field data sheets or software. Identified emissions will be measured using appropriate methods, where possible. The choice of appropriate measurement method is driven by consideration of safety, process interruptions, and likely measurement outcomes.

Figure 1: Optical gas imaging (OGI) will be used as the primary emission screening tool.

In addition to screening for emissions, the OGI camera may also be used during other measurements. For example, to guide the operator and ensure complete emission capture during high-flow measurements, or to ensure that the sample inlet is aligned with a plume centerline during OTM measurements.

3 Capabilities and Limitations

The OGI camera is capable of viewing emission plumes of methane and other hydrocarbons/VOC's with absorption features within the spectral range of the camera's detector. The plumes appear as white or black "smoke" in the scene observed. OGI camera performance can be affected by several factors:

- Pollutant species observed
- Concentration of pollutant species observed
- Detector spectral range
- Detector sensitivity (i.e. type and cooled vs un-cooled)
- Ambient conditions
- The background against which the plume is viewed

The high-sensitivity, cooled Mercury-Cadmium-Telluride (MCT) detector used in the OPGAL EyeCGas® 2.0 is appropriate for natural gas leak screening. Camera operators can maximize its efficacy by not employing the camera during periods of high winds, dense fog, or precipitation. Camera operators should attempt to view each component being screened from several angles and with several backgrounds whenever possible. A cross-wind plume with a high-contrast background (i.e. plume-to-background temperature differential) will be more readily detected than a down-wind plume with a low-contrast background.

4 Procedure

The following procedure is specific to the OPGAL EyeCGas® 2.0 which will be used during the field campaign. Similar procedures will be followed in accordance with best-practices and manufacturer recommendations if other OGI cameras are used (e.g. FLIR® GF3xx, etc.)

1. Insert a fully charged battery and allow the camera to cool-down **with the lens cap on**
    - A non-uniform correction NUC will be performed by the camera software once the detector has cooled down. The lens cap must be on during the NUC.
2. Verify that NUC was successful before removing the lens cap. Perform manual NUC if required.
3. Verify that the date and time on the camera match the actual date and time. Correct if needed.
4. Perform daily camera function check
    - Setup a small (∼1 slpm) hydrocarbon leak in a safe area
    - Observe the leak from a distance similar to that used for initial screening in survey (4-10 ft)
    - The plume should be clearly visible. Switch between camera modes (Normal/Enhanced, WH/BH) if needed.
    - Record a short video (∼5-10 s)

- Note the video file name on the daily field sheet.

5. Begin screening all on-site equipment for emissions
    - Do - screen from a distance less than or equal to that used in the daily function check
    - Do - view equipment/components from several angles, with several backgrounds
    - Do - switch between camera modes (Normal/Enhanced, WH/BH) as needed
    - Don't - screen in sustained winds above 15 mph, or if screening is impaired by wind
    - Don't - screen in dense fog or light precipitation if screening is impaired
    - Don't - screen in rain. The camera is not waterproof
    - Don't - ascend catwalks on tank batteries
    - Do - screen tank vents/headers/thief hatches from ground-level
    - Don't - ascend unprotected elevated platforms without appropriate fall protection
    - Don't - enter confined/classified areas
    - Do - treat the camera as non-intrinsically-safe
    - Don't - open enclosures while operating the camera
    - Do - open enclosures prior to screening if needed/safe/allowed
6. Record any observed emissions
    - Mark the emission source and equipment ID with a tag/masking tape/card
    - Record emission source and equipment ID in field data sheets or software
    - Characterize emission source in field data sheets or software (see Field Data Collection)
    - Take a still image of the emission source in visible mode (with OGI or tablet)
    - Record a short (~10-20 s) video of the emission. Switch modes as needed during recording
    - Record the video file name in field data sheets or software
    - Determine an appropriate measurement method considering safety and likelihood of success
    - Perform measurement immediately if high-flow or calibrated bags are appropriate
    - Monitor high-flow/calibrated bag measurements. Ensure complete capture
    - Perform measurement following screening if downwind methods are to be used
7. Shutdown camera, replace lens cap, exchange battery if needed, return to case
    - Don't - replace the battery near onsite equipment
    - Do - replace the battery inside the mobile lab or at a safe distance from onsite equipment
    - Do - place the used battery on the charger inside the mobile lab immediately

5 Technical Specifications

Table 1: Technical specifications[1] for the OPGAL EyeCGas® 2.0

Gases Detected	Methane, Acetic acid, Benzene, Butadiene, Butene, Butane, Dimethyl-Benzene, Ethane, Ethylene, Ethyl benzene, Ethylene oxide, Hexane, Heptane, Isobutylene, Isopropyl alcohol, Isoprene, Methanol, MEK Methyl Ethyl Ketone, Octane, Pentene, Propane, Propanal, Propanol, Propylene, Propylene oxide, Styrene, Toluene, Xylene
Detector Type	Cooled, high-sensitivity MCT, 320x240 pixels
Spectral Range	Default for VOC 3.2μm to 3.4μm Optional for heavier alkanes 3.3μm to 3.5μm
Optics	18.5°x13.6° with 30mm lens, F# 1.1, manual focus
Imaging Modes	Normal IR, Enhanced IR, Thermography, and Visible Spectrum
Thermography	Spot temperature measurement, 6 color palettes
Connectivity	WiFi (2.4 GHz), Bluetooth, and Ethernet over USB
Size	230mm x 110mm x 130mm (9" x 4.3" x 5.1")
Weight	2.3kg (5lbs) w/o battery
Batteries	Field replaceable, 12V Li-ion, 4.5+ continuous operating hours

References

[1] OPGAL, "EyeCGas-2.0-User-Manual-181204.pdf,"
http://eyecgas.com/wp-content/uploads/2018/12/EyeCGas-2.0-User-Manual-181204.pdf, 2018.

Protocol

Direct Component Measurements: High-flow Sampler, etc.

Timothy Vaughn[1] and Daniel Zimmerle[1]

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1 Overview

This document provides the on-site protocol for performing direct component measurements at natural gas facilities.

2 General Approach

High-flow samplers (HI FLOW, Bacharach Inc.[1] and/or other devices with similar operating principals) will be the primary method for direct measurement of emissions. Alternately, calibrated, anti-static bags or temporary stacks with anemometers, turbine flow meters, or other suitable flow measurement devices may be used. High-flow devices measure emission rates directly, while other devices may require specific engineering calculations. For all emissions measured, it is desirable to note the gas composition of the emission source, and the ambient temperature and pressure at the location of the emission. This will allow the standardization of measured emission rates.

The high-flow sampler is typically equipped with a 6 ft long sampling hose and several end attachments suitable for capturing a variety of leak sources. Most commonly used is the bag, as shown in Figure 1. The bag is easily adaptable to leaks with complicated geometry. In practice, the bag is draped loosely around the emission point, such that excess air is easily drawn in through the opening in the bag while none of the emission escapes. Sufficient excess air flow can be ensured by monitoring for a constant blower flowrate reading on the sampler. Complete emission capture can be confirmed by a helper using an optical gas imaging (OGI) camera. Other attachments include flange straps and crevice tools which can aid in measuring emissions from large flanges.

Figure 1: Easily accessible high-flow measurement using bag attachment.

When leaks are elevated above arms-reach, or present other challenges to direct access, extension hoses and poles can be used with the high-flow sampler, as shown in Figure 2. For example, hot surfaces or rotating equipment may prevent measurement personnel from approaching emission points directly.

The high-flow sampler will be calibrated at the beginning of the field campaign, and re-calibrated anytime that daily calibration checks deviate by more than 10% from the initial calibration. Daily

Figure 2: Using an adapter pole to enable high-flow measurement of a hard-to-reach elevated vent above hot, rotating equipment.

calibration checks will be performed prior to measurement each day as specified in the high-flow user manual. An additional check will also be performed to validate the high flow measurements using a calibration gas with a composition of 35% CH_4 by volume.

Measurement teams will record the ambient temperature and atmospheric pressure (from on-board instruments or the local weather report) to convert direct measurements to selected standard conditions. Each emission point will be measured with the high-flow sampler at 2 blower speeds. The (blower) Speed, Flow (lpm), Back(ground) (%), Leak (%), and Leak (lpm) will be recorded at each speed (see Figure 3).

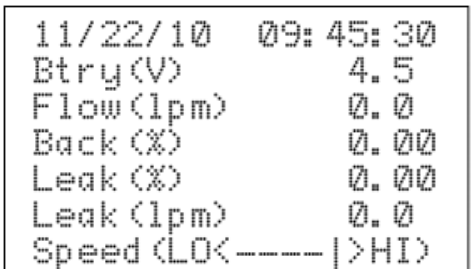

Figure 3: High-Flow measurement screen readout, from Ref. [1]. Each emission point identified will be measured at 2 blower speeds. All other indicated data will be recorded on field log sheets.

When leaks exceed the measurable range of the high-flow (~8 scfm, or 226 lpm) by a small amount (less than a factor of 2) other means of quantification may be used, for example calibrated vent bags [2], or temporary vent stacks equipped with anemometers or flow meters. Emission rates shown or estimated to be greater than this will be measured using downwind techniques.

3 Capabilities and Limitations

The high-flow sampler works on the principal of total capture. Ambient air is drawn in to the sample hose along with gas from the emission sources. Typically an operator draws in an initial sample at the highest

flow rate the high-flow is capable of achieving and takes a measurement. The operator then reduces the sampling flow rate to ∼75% of the initial sampling flow rate and makes another measurement. If the measurements are within 10% of each other than a complete capture is assumed. This technique will be employed during the field campaign, and supplemented by a second operator equipped with an OGI camera. The camera operator will observe all high-flow measurements and will assist the high-flow operator to achieve a complete capture of observed emissions, or inform the high-flow operator that an incomplete capture is occurring.

4 Procedure

The following procedure outlines the approach to be used when performing high-flow measurements during the field campaign.

1. Insert a fully charged battery and allow the high-flow to warm up
2. Perform a daily calibration in accordance with the user manual
    - Calibrate on 100% methane
    - Calibrate on 2.5% methane in air
    - Check intermediate calibration gas - confirm reading is within 10% of intermediate value. If not, recalibrate on 100% and 2.5% and reconfirm
    - Record the calibration activities on the daily field sheet.
3. Measure all suitable emissions identified by OGI (or other) screening activities
    - Do - attach grounding strap to grounded equipment when making a measurement
    - Do - choose the appropriate sampling attachment for the emission source
    - Do - approach emission slowly while sampling surrounding air to avoid saturating the sensors and possibly invoking a sensor transition failure
    - Do - Perform measurements in LPM readout
    - Do - record results with explicit decimal precision as shown on the readout (e.g. 1.0, or 1.00). 1.0 indicates measurement in TCD mode, while 1.00 indicates measurement in Cat Ox mode.
    - Don't - measure excessively wet streams (combustors, still column vents) or streams containing lead, silicones, or sulfur compounds. Think: pipeline quality gas streams are optimal/upstream gas compositions are acceptable.
4. Measure the emission at max speed, record results
5. Measure the emission at 75% of max speed record results
    - Do - work with camera operator to ensure complete capture of the emission source
    - Do - measure each emission for a reasonable time to allow a "steady state" (∼ 1 min) reading. Only record results once steady.
    - Do - note emission characteristics (steady, varying, intermittent). Record min and max values if not constant.
6. Shutdown high-flow, exchange battery if needed
    - Don't - replace the battery near onsite equipment
    - Do - replace the battery inside the mobile lab or at a safe distance from onsite equipment
    - Do - place the used battery on the charger inside the mobile lab immediately

5 Technical Specifications

Table 1: Key technical specifications[1] for the high-flow sampler (HI FLOW, Bacharach Inc.)

Measurable Leak Rate	0.05 to 8.00 SCFM (1.42 to 226 LPM) 0.05 to 6.00 SCFM (1.42 to 170 LPM)
Accuracy	Calculated Leak Rate: ±10% of reading by volume methane
Operating Temperature	0 to 50 °C (32 to 122 °F)
Storage Temperature	–40 to 60 °C (–40 to 140 °F)
Humidity	5 to 95% RH (non-condensing)
Sampling Flow Rate (Max)	10.5 SCFM (297 LPM) at full battery charge
Sampling Flow Rate (Initial)	10 SCFM (283 LPM)
Sampling Flow Rate (Second)	8 SCFM (226 LPM)
Sampling Flow Rate Method	differential pressure across orifice plate
Sampling Flow Rate Accuracy	±5% of reading
Natural Gas Sensor Type	Catalytic Oxidation/Thermal Conductivity
Natural Gas Sensor Range	Catalytic oxidation: 0 to 5% by volume methane
Natural Gas Sensor Range	Thermal conductivity:5 to 100% by volume methane
Natural Gas Sensor Accuracy	Greater of ±5% of reading or 0.02 % methane
Dimensions	18L x 12W x 7H inches (457 x 305 x178 mm)
Weight	20 lbs (0.9 kg)

References

[1] Bacharach, Inc., "HI FLOW® Sampler For Natural Gas Leak Rate Measurement," Jul. 2015.

[2] Heath Consultants Inc., "3.0 Cubic Feet Calibrated Vent Bag Verification Test," 2009.

Protocol

Downwind Measurements: OTM 33 A/B

Timothy Vaughn[1] and Daniel Zimmerle[1]

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1 Overview

This document provides the protocol for performing Other Test Method 33A (OTM33A) at natural gas facilities. OTM33A will be used in this study to quantify emissions from sources unsuitable for direct measurement by high-flow sampler. For example, sources shown or suspected to exceed the measurement range of the high-flow sampler, elevated or difficult-to-access sources, and sources which pose other safety risks may be quantified using OTM33A.

OTM33A is test method which has not yet been subject to federal rule making, but has been shown to be useful to the emission measurement community. Development of the method was performed under the United States Environmental Protection Agency's (EPA) Geospatial Measurement of Air Pollution (GMAP) program. GMAP systems employ global position systems (GPS) and fast response instrumentation to locate, characterize, and/or quantify emission sources. During OTM33A emission quantification (EQ) measurements, the time-averaged emission plumes for the species of interest are approximated as Gaussian plumes whose widths correspond to the stability class indicated by the observed winds. By assuming a point source emission and measuring the downwind distance between the source and the observation location, the mass emission rate of the source can be calculated. This inversion technique is known as Point Source Gaussian (PSG) and will be used in this study. The PSG procedure and example implementations are described in detail in Thoma et al.[1], and Brantley et al.[2].

2 General Approach

The Colorado State University (CSU) mobile lab (van) is equipped with a high precision GPS (Hemisphere R330), 2-D sonic anemometer (Gill Windsonic), and several fast response trace gas analyzers. An Aerodyne Research, Inc. TILDAS-CS trace gas monitor (TLDS) will be used for continuous, fast detection of CH_4, N_2O, C_2H_2, and H_2O during OTM33A measurements. The fast-response wind speed, wind direction, geo-location, and pollutant concentration data will be combined to estimate mass emission rates of methane (EQ measurement). This instrumentation will also be used to aid in detection of emission plumes, though the primary detection method will be optical gas imaging (OGI). The OGI camera will also be used to identify the approximate centerline and extent of the emissions plume during OTM33A measurements. OGI observations and apparent wind speed and direction will be used to direct the location of the van and sampling inlet prior to measurement. By aligning the sample port inlet with the centerline of the emission plume via observation with OGI, confidence in both total plume capture and the validity of the point source assumption are enhanced.

The sample inlet and anemometer are located atop a telescoping mast whose height (and angle, if needed) can be adjusted from ∼3—20 ft above ground level, which may provide easier access to elevated plumes at close distances. The mast can also be detached from the van and setup on a tripod up to 25 ft away from the front of the van. However, since the GPS receiver antenna is located on top of the van and not on the mast, careful measurement of sample inlet location is required when detached. This can be achieved with a tape rule, laser range finder, or by marking the inlet location using GPS, or differential GPS between the van antenna and the Handheld field tablet.

Ambient air is drawn into to the sample inlet tubing (3/8" OD x 14" ID ALTAFLUOR 2E0 Enviro Series FEP) through an inline, high-efficiency particulate air (HEPA) filter by a dry-scroll vacuum pump (Agilent IDP-7) and delivered to TLDS. The sample flow rate and cell pressure are set using manual valves. The flow is set to provide a sample cell turnover time $\leq$ 1 s to coincide with the 1 Hz (or other, as suitable) data acquisition rate. The flow is verified using a BIOS Defender Dry-Cal volumetric prover. Sample line delays are obtained by spiking an analyte at the sample inlet and noting the delay before the TLDS (or other instrument) registers the spike. Sample line delays should be obtained every time the flow is verified (∼daily). The sample delay time is entered into the software to coordinate the

real-time wind and location data with the real-time (but delayed) concentration measurements.

All instruments in the van are connected to a central workstation running a custom data acquisition software developed in house. Data acquired from each instrument are simultaneously displayed in real-time on a workstation operated by the passenger and saved to an archive on the workstation. Data is generally acquired at 1 Hz, but can be acquired at higher rates from instruments with higher data rates. Data are available for immediate analysis, and if no post-corrections or auxiliary data (e.g. lab analyses) are required, analysis can be performed in real-time from the passenger seat. Instruments with built-in computers can be accessed remotely from the central workstation for calibration, configuration, monitoring extended instrument parameters and alarms, etc. Data from the central workstation will be backed-up to an operators laptop daily, and uploaded over a virtual private network (VPN) to a secure server at CSU when a suitable internet connection is available. Several instruments have internal data storage capabilities which provide a built-in backup of test data.

OTM33A measurements will be made from a stationary position downwind of the identified emission source. It is generally intended that the method will be used to quantify an individual source, or several sources which are co-located and can be reasonably be characterized as a point source. For example, a single well head with multiple emissions, or tank vent(s) measured from the edge of a well pad. Facility-level measurements which aim to capture all emission sources identified at a facility will be performed using downwind, tracer flux measurements. Measurements will performed as outlined in the method, using the provided OTM33A software, or derived software using identical principals that integrates directly with the data acquisition software in the van. A measurement consists of locating the sample inlet within the emission source plume, and recording the wind speed, wind direction, and atmospheric enhancement of methane recorded by the TLDS for ∼20 minutes. The long measurement duration is required to build a statistical representation of the emission plume and the atmospheric conditions influencing it.

Wind speed and direction data are used to determine the atmospheric stability class during measurement, as described in the method. The average and standard deviation of both wind speed (WS) and direction (WD) are computed over the measurement period. A first stability class is obtained based on the standard deviation of the wind direction (Std WD). A second stability class is determined from turbulent intensity, defined as TI = Std WS/WS. The average of these two stability classes, pgi, is used as the stability class for the measurement, as shown in Table 1.

Table 1: Determination of atmospheric stability class.

Stability Class	Std WD	TI	pgi
1	Std WD>27.5°	TI>0.205	pgi<1.5
2	23.5°<Std WD≤27.5°	0.180<TI≤0.205	1.5≤pgi<2.5
3	19.5°<Std WD≤23.5°	0.155<TI≤0.180	2.5≤pgi<3.5
4	15.5°<Std WD≤19.5°	0.130<TI≤0.155	3.5≤pgi<4.5
5	11.5°<Std WD≤15.5°	0.105<TI≤0.130	4.5≤pgi<5.5
6	7.5°<Std WD≤11.5°	0.08<TI≤0.105	5.5≤pgi<6.5
7	Std WD≤7.5°	TI≤0.08	1.5≤pgi<6.5

The local stability class is then used to determine dispersion coefficients in the horizontal (σ_y) and vertical coordinates (σ_z), which correspond to the coordinate axes shown in Figure 1. Dispersion values are tabulated in OTM33A Appendix F for both σ_y and σ_z, by distance from the source (from 1 to 200 m), for each stability class. These parameters are interpolated directly from the table based on the calculated stability class and the distance from the source to the sample inlet.

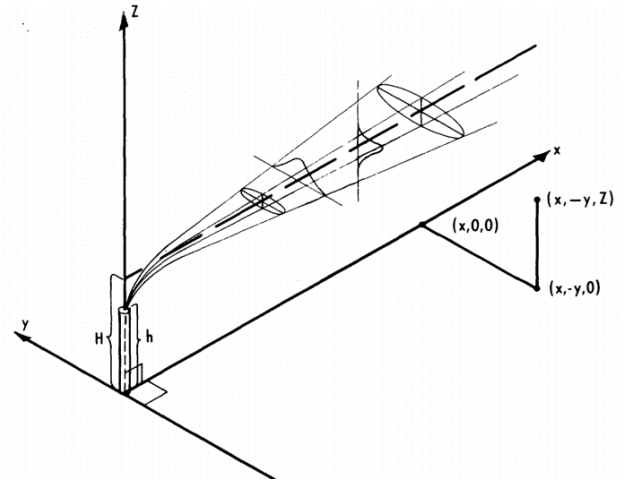

Figure 1: Example Gaussian Plume (from Turner[3]).

The next steps in the analysis involve fitting the observed concentration and wind data to a Gaussian function, and finally calculating a mass emission rate. The typical algorithm works as follows:

1. Determine the background concentration
2. Sort the measured concentration data into 5° bins based on azimuthal wind direction
3. Fit the binned data to a Gaussian function
4. Determine the peak methane concentration from the peak of the Gaussian fit
5. Multiply the plane-integrated methane concentration by the average wind speed during the measurement

Background concentration is obtained by averaging the lowest 5% of methane concentration values during the measurement. Wind direction bins with data points totaling less than 2% of the total number of data points during the measurement are eliminated prior to Gaussian fitting. The peak methane concentration is determined by fitting the observed data to the ideal Gaussian and finding the peak of the Gaussian fit, as shown in Figure 2. The plane-integrated methane concentration (in g/m^3) is obtained as shown in Equation 1, which is then multiplied by the average wind speed during the measurement to obtain the average mass emission rate of methane during the measurement, as shown in Equation 2.

$$G(y,z) = a1 \iint exp{-}(\frac{y^2}{2\sigma_y^2} + \frac{z^2}{2\sigma_z^2}) = 2\pi * a1 * \sigma_y * \sigma_z \tag{1}$$

$$\dot{m}_{CH_4} = G(y,z) * WS \tag{2}$$

Alternately, OTM33B may be employed since the van will be equipped with tracer gas release equipment. In this variation of the OTM method a tracer gas is co-released with the emission source at a known flowrate; the source emission rate can then be determined by ratio.

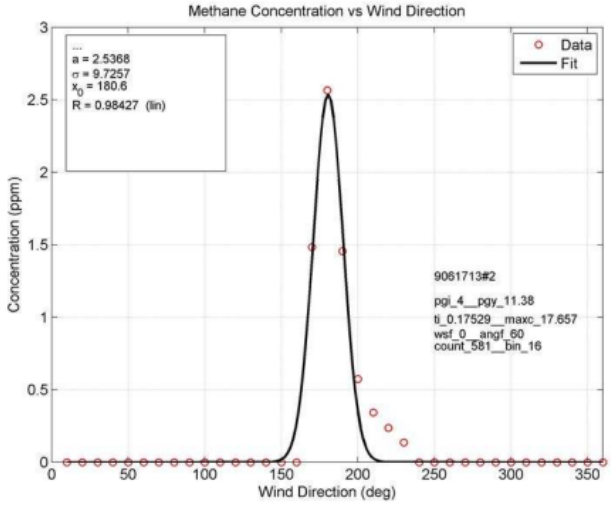

Figure 2: Example Gaussian Plume (from ref [4], Appendix F1). The peak methane concentration during OTM33A measurements is taken as the peak value of a Gaussian function fit to experimental data.

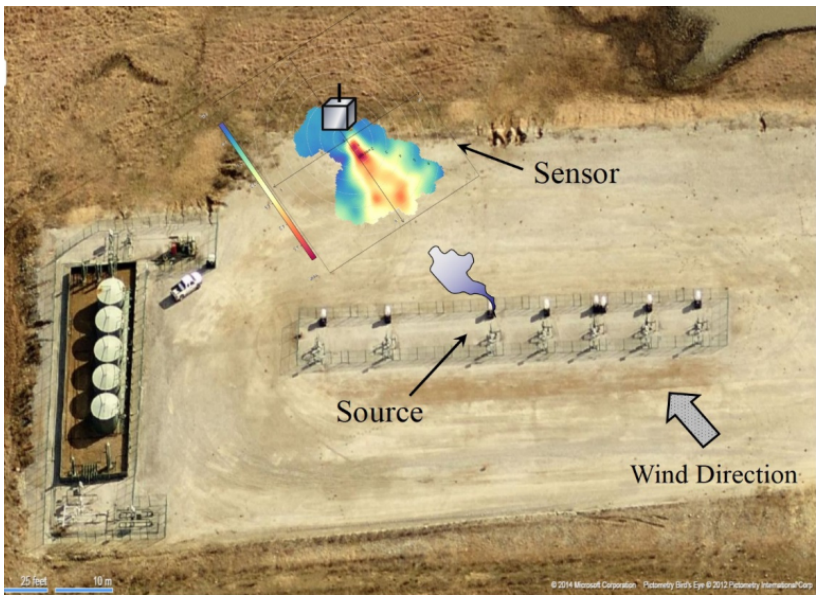

Figure 3: Example OTM33A setup (from Thoma et al.[1]). The sensor will be located on the van, which will be parked downwind from the source. It may also be possible to co-release tracer gas nearby identified sources(OTM33B), since the van will have tracer gas equipment available.

3 Capabilities and Limitations

Under ideal conditions, past work on quantifying emission rates from controlled releases has shown the accuracy of OTM33A to be as good as $\sim \pm 15\%$. Under field conditions, this level of accuracy is possible but is often more difficult to achieve for practical reasons. Wind speeds must be sufficient and from a direction which allows downwind access for sampling at an appropriate distance. Both of these needs can be hindered by the local topography and physical equipment layout encountered on sites (see Figures 4-1 and 4-3 in reference [4]). Near-field obstructions can introduce eddies, re-circulation, or channeling which invalidate the assumed Gaussian plume model. Measurements can be made between 20 and 200 m downwind of an identified source with wind speeds between 1 and 7 m/s [1].

4 Procedure

The following procedure outlines the approach to be used when performing OTM33A measurements during the field campaign.

1. Perform a daily calibrations for all instruments used, in accordance with their user manuals and/or established protocols
2. Position the sample inlet downwind of the source pointing towards it and begin measurement
   - Note Figures 4-1 and 4-3 in reference [4] for proper sample inlet placement
   - Ensure there is no upwind interference
   - If upwind interference is suspected, perform a background measurement to quantify it
   - Document the measurement setup with photographs and OGI videos
3. Monitor data quality indicators (DQIs) during measurement
   - Is the wind speed within range?
   - Is a time-varying methane signal present?
   - Is the methane signal correlated with a wind speed and direction?
   - Are there periods of little or no methane enhancement (for background corrections)?
   - Are the data streams for required inputs being read, and do they make sense?
   - If DQIs look problematic, attempt to correct, or abandon measurement if corrections are not possible. Note the unmeasured source and the reasons why a successful measurement was not possible.
4. If DQIs look good throughout the measurement, continue acquiring data for $\sim$20 minutes and perform post processing to determine an average methane emission rate.

5 Technical Specifications

Equipment and instrumentation options employed during OTM measurements may include the following:

- Picarro G2210-I (CH_4, C_2H_6, H_2O)
- Aerodyne mini-TLDS (CH_4, C_2H_6, N_2O, H_2O)
- Licor 850A (CO_2, H_2O)
- Hemisphere GPS
- 2-D sonic anemometers (2 portable (Airmar 150WX), 1 on van (Gill Windsonic)
- Alicat mass flow controllers (MCP-50SLPM-D-MODTCPIP)
- Opgal Eye-C-Gas infrared optical gas imaging camera

Detailed technical specifications can be found in the respective user and technical manuals. Key technical specifications for key instrumentation used in OTM33A measurements are listed in the following sections.

5.1 Methane Concentration-TLDS

Table 2: Technical specifications for the Aerodyne TLDS trace gas monitor.

Gas Species	N_2O	H_2O	C_2H_2	CH_4
1 s precision	0.06 ppb	10 ppm	100 ppt	0.3 ppb
100 s precision	0.02 ppb	5 ppm	30 ppt	0.1 ppb
Range	30 ppm	30%	30 ppm	200 ppm

Calibrations:

- zero-air purge every 15-30 minutes during use
- Span with calibration gases for the relevant species weekly, or as needed

5.2 Wind Speed and Direction-Anemometer

Table 3: Technical specifications for the Gill Windsonic anemometer.

	Wind Speed	Wind Direction
Range	0-60 m/s	0-359°
Accuracy	±2% @ 12 m/s	±2° @ 12 m/s
Resolution	0.01 m/s	1°
Response	0.25 s	0.25 s
Threshold	0.01 m/s	-

Calibrations:

- none required, perform periodic function check

5.3 Location-GPS

Table 4: Technical specifications for the Hemisphere R330 GPS receiver.

Item	Specification
Receiver Type	Multi-Frequency GPS, GLONASS, BeiDou, Galileo, and Atlas
Signals Received	GPS, GLONASS, BeiDou, Galileo and Atlas
GPS Sensitivity	-142 dBm
Channels	227
SBAS Tracking	3-channel, parallel tracking
Update Rate	10 Hz standard, 20 Hz optional
Timing (1 PPS) accuracy	20 ns
Cold start time	60 s typical (no almanac or RTC)
Warm start time	30 s typical (almanac and RTC)
Hot start time	10 s typical (almanac, RTC, and position)
Antenna input impedance	50 ohms
Maximum speed	1850 kph (999 kts)
Maximum altitude	18,288 m (60,000 ft)

Calibrations:

- none required, perform periodic function check

References

[1] US EPA ORD, "OTM 33 Geospatial Measurement of Air Pollution, Remote Emissions Quantification (GMAP-REQ) and OTM33A Geospatial Measurement of Air Pollution-Remote Emissions Quantification-Direct Assessment (GMAP-REQ-DA)," https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=309632.

[2] H. L. Brantley, E. D. Thoma, W. C. Squier, B. B. Guven, and D. Lyon, "Assessment of Methane Emissions from Oil and Gas Production Pads using Mobile Measurements," *Environmental Science & Technology*, vol. 48, no. 24, pp. 14 508–14 515, Dec. 2014.

[3] D. B. Turner, *Workbook of Atmospheric Dispersion Estimates*, 1970.

[4] O. US EPA, "EMC Other Test Methods," https://www.epa.gov/emc/emc-other-test-methods, Jun. 2016.

Protocol

Downwind Measurements: Tracer Flux

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1 Overview

This document provides the protocol for performing tracer flux measurements (tracer) at natural gas facilities. Tracer may be used to quantify emissions from sources unsuitable for direct measurement. For example, tank venting emissions that appear to be above the range of the high flow sampler, or inaccessible emission points like elevated stacks. Tracer may be used to quantify emissions from an entire facility provided suitable winds and downwind road access are present.

2 General Approach

Tracer flux, or dual tracer flux (tracer) measurements may be used to quantify emissions from single point sources, or an entire facility. Similar to OTM 33B, tracer gas(es) are released adjacent to known emission sources. Source mass emission rates can be deduced from the ratio of atmospheric concentration enhancements measured downwind, and the known flowrate of the tracer gas(es) released on-site. The tracer technique has been used extensively in prior studies (see Subramanian et al.[1], or Yacovitch et al. [2]), and is described in detail in Roscioli et al. [3]. The approach used for this study will follow that outlined in Roscioli et al. without modification. A tracer gas release apparatus is placed on-site (or nearby) preferably in close proximity to observed emission sources. The tracer gases are released at known flowrates. The mobile lab then drives downwind of the site, making multiple transects through the combined emission source and tracer gas plumes (see Figure 1). The unknown source emission rate can be deduced from the concentration ratios of the emission and tracer plumes and the known emission rate of the tracer gases released, according to Equation 1.

$$\frac{\Delta CH_4}{\Delta tracer} = \frac{Flow_{CH_4}}{Flow_{tracer}} \tag{1}$$

By measuring the concentration enhancements of methane and the tracer gas(es) above background (ΔCH_4 and $\Delta tracer$), and knowing the flowrate of the tracer gas being released ($Flow_{tracer}$), the flow of methane from the site ($Flow_{CH_4}$) can be determined readily.

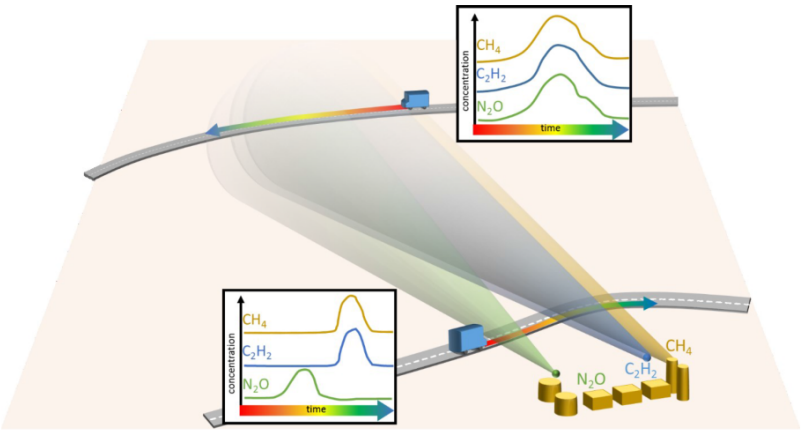

Figure 1: Dual tracer flux measurement setup from Roscioli et al.[3]. Tracer gases (N_2O and C_2H_2) are released on-site at known flow rates near suspected emission sources (CH_4). Mobile measurements of atmospheric enhancements of both the emission source and tracer gases are made downwind. The mass emission rate of the source can be deduced from the measured downwind enhancements and the known mass emission rates of the tracer gases.

The Colorado State University (CSU) mobile lab (van) is equipped with several fast response trace gas analyzers. An Aerodyne Research, Inc. TILDAS-CS trace gas monitor (TLDS) will be used for

continuous, fast detection of methane (CH_4), nitrous oxide (N_2O), acetylene (C_2H_2), and water (H_2O) during tracer measurements. Ambient air is drawn into to the sample inlet tubing (3/8" OD x 14" ID ALTAFLUOR 2E0 Enviro Series FEP) through an inline, high-efficiency particulate air (HEPA) filter by a dry-scroll vacuum pump (Agilent IDP-7) and delivered to TLDS. The sample flow rate and cell pressure are set using manual valves. The flow is set to provide a sample cell turnover time $\leq$ 1 s to coincide with the 1 Hz (or other, as suitable) data acquisition rate. The flow is verified using a BIOS Defender Dry-Cal volumetric prover. Sample line delays are obtained by spiking an analyte at the sample inlet and noting the delay before the TLDS (or other instrument) registers the spike. Sample line delays should be obtained every time the flow is verified ($\sim$daily). The sample delay time is entered into the software to coordinate the real-time wind and location data with the real-time (but delayed) concentration measurements.

All instruments in the van are connected to a central workstation running a custom data acquisition software developed in house. Data acquired from each instrument are simultaneously displayed in real-time on a workstation operated by the passenger and saved to an archive on the workstation. Data is generally acquired at 1 Hz, but can be acquired at higher rates from instruments with higher data rates. Data are available for immediate analysis, and if no post-corrections or auxiliary data (e.g. lab analyses) are required, analysis can be performed in real-time from the passenger seat. Instruments with built-in computers can be accessed remotely from the central workstation for calibration, configuration, monitoring extended instrument parameters and alarms, etc.

The van pulls a small (5 ft x 8 ft) enclosed trailer which houses the tracer gases and associated release equipment. The trailer will be decoupled from the van and left onsite (or nearby) during tracer measurements. Nitrous oxide and acetylene tracer gases are each metered through Alicat brand mass flow controllers (MCP-50SLPM-D-MODTCPIP) with custom spans of 0-60 SLPM, and 0-30 SLPM, respectively. Flow controllers will be checked prior to tracer measurements using a BIOS Defender Dry-Cal volumetric prover. Tracer gases are delivered through manual safety shut-off valves on the exterior of the trailer to their release locations through flexible 1/4 in tubing up to 200 ft in length. The trailer need not be adjacent to emission sources. Tracer gas flows will be set according to the needs of the measurement to achieve the needed down wind concentration enhancements, and are expected to typically be near the middle of the flow controller spans. Tracer gases will only be released in periods with average wind greater than 1 m/s second to avoid pooling and ensure sufficient dispersion for both safety and measurement activities. Acetylene has a lower flammability limit of 2% in air, and under typical test conditions (1.5 ms winds, 15 SLPM release rate) is diluted below the flammability limit within $\sim$3 ft of the release point.

Portable weather stations will be placed nearby (or coincident with) tracer gas release points and will log wind speed, wind direction, and GPS coordinates of the release locations. The trailer is equipped with a computer for data-logging and control of electronic mass flow controllers which deliver the tracer gases. This computer can be monitored and operated locally, or remotely from the van. Tracer measurements are estimated to take $\sim$1-3 hours to perform, but are only intended to be used in specific situations where other measurement methods are incapable. For example, total facility-level emission quantifications, or the quantification of "large" sources. Tracer is not intended to be used to quantify multiple "routine" emissions on a site. Past studies have shown repeatedly that "long-tail" emissions are not well characterized and often, emissions from these few, but "large" sources account for the bulk of emissions observed.

Data from the central workstation in the van and the auxiliary computer in the trailer will be backed-up to an operators laptop daily, and uploaded over a virtual private network (VPN) to a secure server at CSU when a suitable internet connection is available. Several instruments have internal data storage capabilities which provide a built-in backup of test data.

3 Capabilities and Limitations

For a successful tracer measurement, wind speeds must be appropriate ($1 \lesssim WS \lesssim 15$ m/s) and from a direction which allows downwind access for sampling transects at an appropriate distance. These needs can be hindered by the local topography and physical equipment layout encountered on sites. In practice measurements can be made between ~0.2 and 5 km down wind of a source or facility, though measurements are most commonly made between 0.5 and 1 km. Ideally, the sampling distance would chosen to be far enough for co-dispersion of tracer and source emissions while close enough to produce easily detectable concentration enhancements. However, the sampling distance is usually dictated by the location of nearby roads transecting the emission and tracer plumes. This can be a limitation of the method in certain circumstances.

In addition to tracer gas and emission source measurements, concurrent measurements of carbon dioxide (CO_2) and ethane (C_2H_6) will be made using online analyzers. Carbon dioxide measurement are used to discern methane associated with combustion sources or acid gas removal units (AGRs), while ethane measurements can be used to discern biogenic from thermogenic methane emissions. These auxiliary measurements can be useful for identifying interfering sources during transects such as self-sampling (vehicle exhaust), or interfering plumes from nearby landfills or livestock.

4 Procedure

The following procedure outlines the approach to be used when performing tracer measurements during the field campaign.

1. Perform a daily calibrations for all instruments used, in accordance with their user manuals and/or established protocols
2. Use the OGI camera to assist with tracer measurements.
    - Place the tracer release points near known emission sources
3. Place the portable weather stations at/near the tracer gas release points
    - Don't - place the tripods in a confined area, or a potentially hazardous area
4. Place the tracer release points on or near the weather stations
    - Don't - release tracer gases in areas where accumulation could occur, or in winds less than 1 m/s
5. Start the flow of tracer gases and begin downwind transects (measurements) with the van
    - Drive along the transect route at 10-20 mph with hazards lamps on, while ensuring it is safe to do so
6. Obtain ~5-10 downwind transects with good data quality indicators to best support source emission rate quantification
    - Attempt to capture dual tracer correlation plumes
        - Tracer gases and methane concentrations are well-correlated during plume transects ($R^2 > 0.5$ preferred)
        - Recovered tracer gas ratios reflect released tracer gas ratios

- Failing that, use other plume acceptance criteria in accordance with Figure S3 in reference [3] for other scenarios (Single Tracer, Dual Area, Single Tracer Correlation with Area Check, etc.)
- Use other information provided by instrumentation and knowledge of the measurement setup and surroundings
  - Recovered methane/ethane ratio align with the known or expected gas composition at the site (may not be useful for tanks, where composition may differ)
  - Ensure the wind direction is coming from the anticipated direction

7. Tracer measurements are estimated to take ∼1-3 hours from start to finish depending on the rate of attainment of plumes with valid data quality indicators. If no valid plumes are obtained within 1.5 hours after the start of measurement, the measurement may be stopped and documented as failed.

5 Technical Specifications

Equipment and instrumentation options employed during tracer measurements may include the following:

- Picarro G2210-I (CH_4, C_2H_6, H_2O)
- Aerodyne mini-TLDS (CH_4, C_2H_6, N_2O, H_2O)
- Licor 850A (CO_2, H_2O)
- Hemisphere GPS
- 2-D sonic anemometers (2 portable (Airmar 150WX), 1 on van (Gill Windsonic)
- Alicat mass flow controllers (MCP-50SLPM-D-MODTCPIP)
- Opgal Eye-C-Gas infrared optical gas imaging camera

Detailed technical specifications can be found in the respective user and technical manuals. Key technical specifications for key instrumentation used in tracer measurements are listed in the following sections.

5.1 Methane and Tracer Gas Concentrations-TLDS

Table 1: Technical specifications for the Aerodyne TLDS trace gas monitor.

Gas Species	N_2O	H_2O	C_2H_2	CH_4
1 s precision	0.06 ppb	10 ppm	100 ppt	0.3 ppb
100 s precision	0.02 ppb	5 ppm	30 ppt	0.1 ppb
Range	30 ppm	30%	30 ppm	200 ppm

Calibrations:

- zero-air purge every 15-30 minutes during use
- Span with calibration gases for the relevant species weekly, or as needed

5.2 Tracer Gas Release Rates - Alicat Mass Flow Controllers

Table 2: Technical specifications for the Alicat mass flow controllers.

Gas Species	N_2O	C_2H_2
Range	0-60 SLPM	0-30 SLPM
Inlet	15 psig	
Outlet	ambient	
Accuracy	±(0.8% of Reading + 0.2% of Full Scale)	
Repeatability	±0.2% of Full Scale	

Calibrations:

- Calibrate annually
- Check with Dry-cal at least daily

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[2] T. I. Yacovitch, C. Daube, T. L. Vaughn, C. S. Bell, J. R. Roscioli, W. B. Knighton, D. D. Nelson, D. Zimmerle, G. Pétron, and S. C. Herndon, "Natural gas facility methane emissions: Measurements by tracer flux ratio in two US natural gas producing basins," *Elem Sci Anth*, vol. 5, no. 0, Nov. 2017.

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