THESIS

METHANE EMISSIONS FROM GATHERING PIPELINE NETWORKS, DISTRIBUTION SYSTEMS, AGRICULTURE, WASTE MANAGEMENT AND NATURAL SOURCES

Submitted by

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ABSTRACT

METHANE EMISSIONS FROM GATHERING PIPELINE NETWORKS, DISTRIBUTION SYSTEMS, AGRICULTURE, WASTE MANAGEMENT AND NATURAL SOURCES

Climate change has influenced United States policymakers and industry professionals alike to minimize greenhouse gas emissions; including methane, the second most abundant greenhouse gas. The recent focus on quantifying methane emissions is not only motivated by its abundance but also the high global warming potential of the gas, which is 86 times greater than that of carbon dioxide on a 20-year timescale. Techniques to quantify methane emissions can be broken into three categories: component level, facility level, and basin level. In this study component level measurements and published emission estimates were used in Monte Carlo models to estimate regional methane emissions from three different source categories: natural gas gathering pipeline networks, natural gas distributions systems, and non-oil and gas sources such as: agriculture, waste management, lakes, ponds, rivers, wetlands and geological seepage. These estimates are designed to support a regional estimate including all methane sources for comparison against top-down emission estimates from aircraft measurements in the same region.

Gathering pipeline networks are a sector of the natural gas supply chain for which little methane emissions data are available. In this study leak detection was performed on 96 kilometers of underground plastic pipeline and above-ground components including 56 pigging facilities and 39 block valves. Only one leak was located on an underground pipeline, however, it accounted for 83% of total measured emissions. Methane emissions estimated using a Monte-Carlo model for the 4684 km of gathering pipeline in the study area were 400 [+214%/-87%] kg/h (95% CI). This estimate is statistically similar to estimates based on emission factors from EPA's 2015 Greenhouse Gas Reporting Program and is approximately 1% [0.1% to 3.2%] of the 39 Mg/h estimated in a prior aircraft measurement of the study region. The wide uncertainty range is due to two factors: one, the small sample size relative to the total gathering system in the study area and two, the presence of only one underground pipeline leak to characterize a range of

possible emissions. The study also investigates what fraction of gathering pipelines in a basin must be measured to understand the maximum probable impact gathering line emissions could have on a basin level emission estimate.

Distribution systems are a sector of the natural gas supply chain that has been analyzed and measured in recent years due to the attention they received in a 1992 study showing that they contribute approximately 25% of total methane emissions from the natural gas supply chain. The only distribution company in the study region provided data and access to their system for measurement during this study. During the field campaign, 129 of 239 metering and regulating stations were visited and 34 of 87 documented leaks from PHMSA surveys were visited. When scaling measured emissions to the eight counties in the study region, pneumatic emissions dominate, accounting for 2.8 [+37%/-31%] kg/h (95% CI) or 53% [42%-64%] of total emissions from measured sources. When including customer meters, the total distribution system in the 8 county study region contributes approximately 0.05% [0.02% to 0.12%] of the 39 Mg/h found in a prior aircraft measurement of the study region. While this study shows that the distribution system measurements are not a major contributor of emissions in this basin, it does not imply emissions are negligible on a national scale, since the rural regions in the study area had relatively little distribution infrastructure, and other distribution systems that may be older or constructed with materials that have higher leak rates, such as cast iron or unprotected steel.

A detailed emission estimate from non-oil and gas sources was performed including poultry, cattle, swine, rice cultivation, landfills, wastewater treatment, wetlands, rivers, ponds and lakes, and geological seepage. This analysis supported emission estimates of previous work suggesting that cattle are the largest source of biogenic methane in this region. This analysis also indicates the importance of understanding geological seepage due to the large contribution that it may have to methane emissions from non-oil and gas sources.

This analysis concludes that methane emissions from gathering pipeline networks, distributions systems, agricultural practices, waste management systems and natural sources contribute a small, but non-negligible, fraction of total methane emissions for this particular region which includes large-scale natural gas production. While methane emissions from the analyzed sources are proportionally low in the study region they are not necessarily proportionally small on a state, national or global scale.

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 1. INTRODUCTION

1.1 Incentive for Methane Research

From 1880 to 2012 the earth's mean global surface temperature has risen by nearly 1°C, which has caused global mean sea levels to rise 0.19 meters [1]. Increased concentrations of greenhouse gases such as CO_2, CH_4, N_2O and H_2O cause this warming effect. The increased prevalence of greenhouse gases is largely the byproduct of anthropogenic activity. Methane is a potent greenhouse gas with a global warming potential that is up to 86 times greater than CO_2 on a 20-year timescale[2]. Decreasing emissions of methane could help maintain current global temperature and prevent dramatic climate change. Emissions of natural gas, of which methane is the primary component, is the single largest source of anthropogenic methane emissions[3]. Methane emissions in the natural gas industry can be reduced by preventing and fixing unintentional leaks, also known as fugitive emissions, and re-designing systems and components, such as process controllers, to emit less gas or route the gas to emission control units for combustion.

Due to the cost effective nature of shale gas extraction by horizontal drilling and hydraulic fracturing, the natural gas industry has been growing for the past ten years and is projected to grow at a similar rate for the next 25 years [4]. Reduced natural gas prices have allowed electricity generation from natural gas to surpass coal for annual electricity generation in 2016 for the first time in history [5]. With the increased prevalence of natural gas in the energy sector, it is important to understand natural gas emissions and to have a clear understanding of emissions from the natural gas sector. It is also important to characterize methane emissions from non-oil & gas sources to understand the total impact of methane on global warming and where opportunities for emission reduction exist.

1.2 The Natural Gas Industry

The natural gas system spans from the extraction of thermogenic gas from beneath the earth's crust to combustion in end use. The different stages of the natural gas sector can be broken into exploration and production, gathering and processing, transmission and storage, and distribution. A diagram of the industry is displayed in Figure 1.

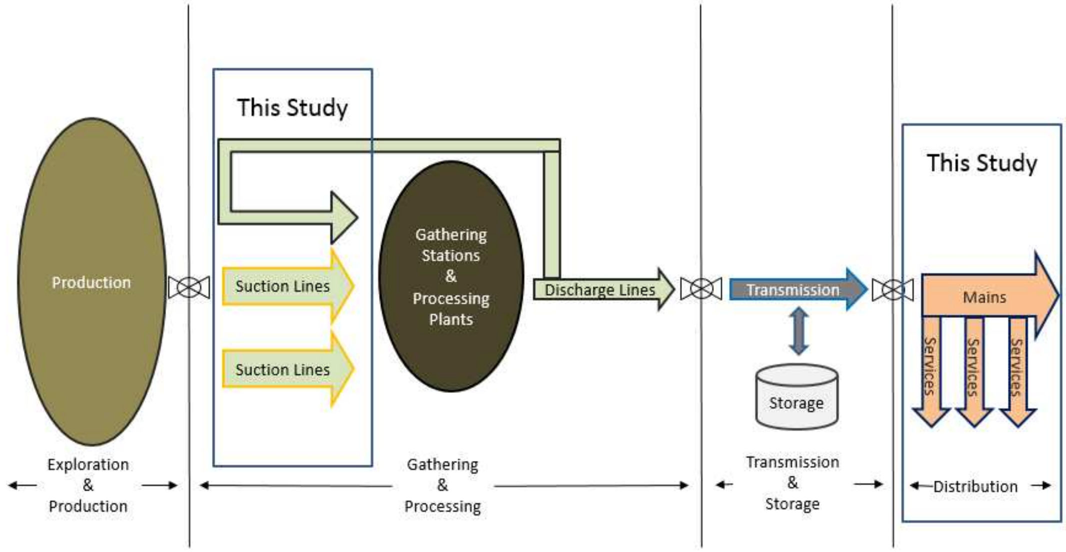

Figure 1 Schematic of natural gas industry sectors. Sectors are separated by lines, gas flow is indicated by arrows. This study is focused on gathering lines their auxiliary equipment and total emissions from each sector along with emissions from distribution systems and their associated components and facilities.

Exploration and production is the process by which natural gas is found and extracted from beneath the earth's surface. Natural gas is extracted from the earth at well pads, often using the earth's own internal pressure to push the natural gas through well bores to the surface. When well bores fill up with water, intervention is required in order to get the well to produce natural gas at the wells maximum capacity once more. Methods to remove water and debris from the well can be done as follows: injecting soap down into the well, installing mechanical automatic plungers, artificially pressurizing the well with compressors, and simply opening the valve up to atmosphere to allow the decrease in back pressure to lift water out of the well bore in an increase flow of natural gas. Natural gas well pads are outfitted with the necessary equipment to assist in the extraction of the natural gas and provide initial water and debris separation. Water is stored in produced water tanks while the natural gas is sent through meters to gathering pipelines. A typical well pad set up can be seen in Figure 2.

Figure 2 Production well pad, no compressor or plunger present on the well tree to assist in gas lift. Glycol and foamer tanks present at the left of the image, vertical separator highlighted with a red oval. Produced water tank at the right side of the image.

Once the gas has left the well it is then transported through gathering pipelines or "suction lines". These lines traverse a variety of landscapes through rights of way (ROW) or easements that belong to different land owners and are leased by gas companies. The pipelines are equipped with block valves to stop or reroute gas flow and pig launchers and receivers which are used to clean water and debris out of the pipelines that can accumulate over time. A standard ROW and block valve can be seen in Figure 3. The pipelines deliver the natural gas to gathering and boosting stations.

Figure 3 Gathering pipeline right of way(ROW) and block valve.

The gathering and boosting station compress low-pressure gas from the surrounding gas wells to a much higher pressure after additional water separation (dehydration) has occurred. Depending on the region, additional processing may be needed to remove excess CO2 and toxic H2S to meet quality standards for transmission companies to purchase the gas. Additional dehydration of gas is performed at sites after compression. A typical gathering site can be seen in Figure 4

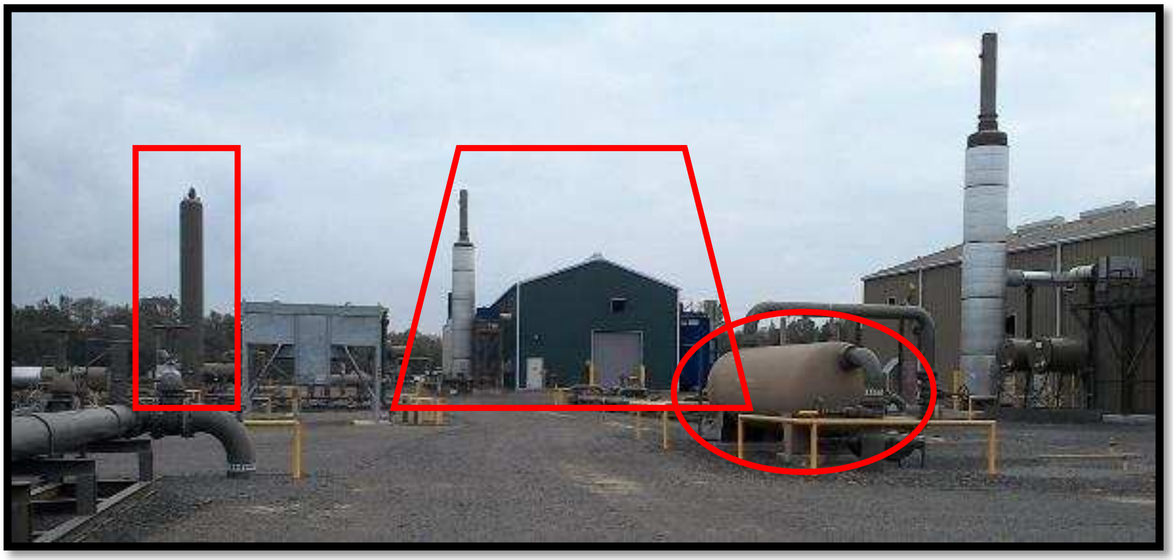

Figure 4 Typical gathering and boosting station, where red rectangle highlights dehydrator still column, red trapezoid highlights compressor house where compressors are located. Red oval highlights the inlet separator that removes liquid water from the gas before compression.

Once the natural gas is at an acceptable quality the transmission companies transport the gas to customers that are potentially across the country. Transmission stations, similarly to gathering stations, combust natural gas in order to drive the compressors that boost and maintain pressures of the gas passing through the station. A network of national transmission lines can be seen in Figure 5.

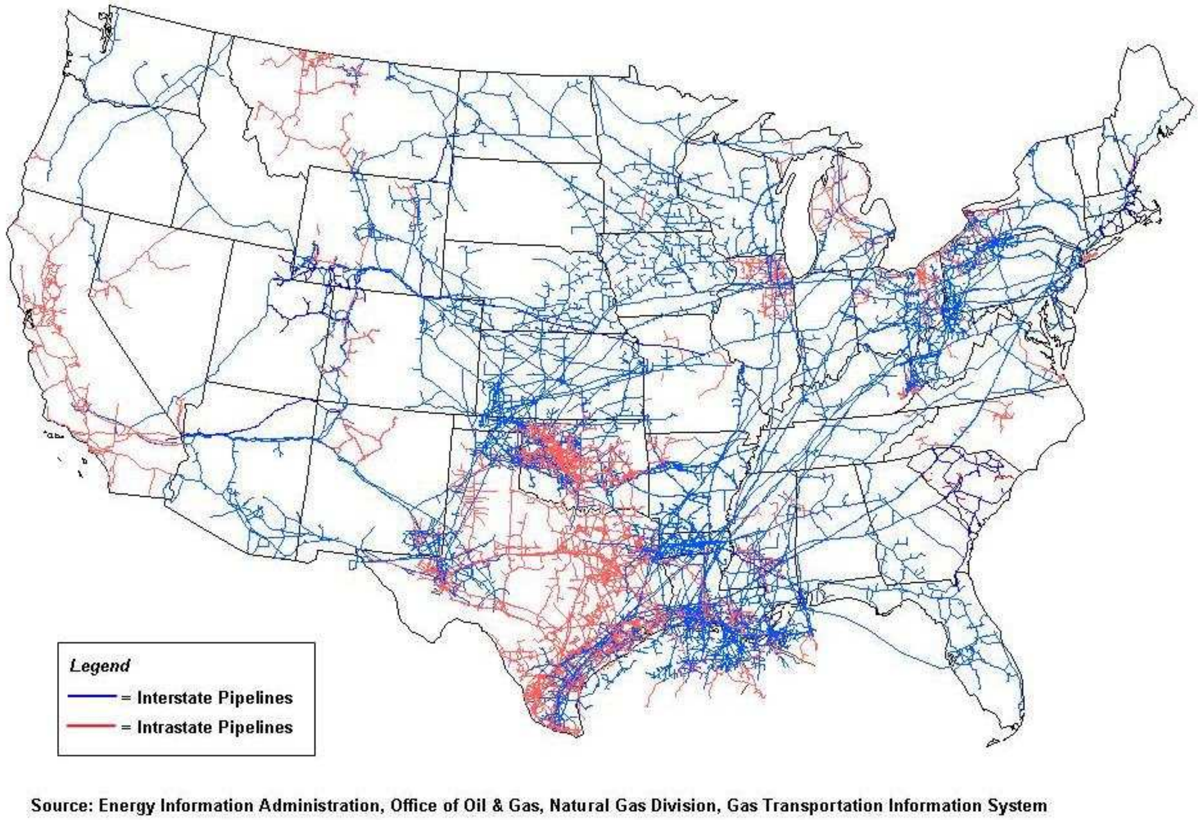

Figure 5 Display of natural gas pipeline network provided by US Energy Information Agency [6]. This graphic illustrates the scale of the natural gas sector and highlights the importance of understanding potential emissions from such a large industry.

Since production rates are relatively steady over time while gas consumption varies substantially with seasons, weather, and other factors, storage facilities store produced gas, allowing natural gas to be extracted when demand is high and injected when demand is low. Storage facilities are often utilize depleted oil and gas wells, underground salt mines or other structures that have minimal contaminates to help minimize additional processing when it is time to retrieve the gas from the well and send it down the line once more. Transmission companies sell gas directly to power plants, manufacturing companies or other large operations that require large quantities of natural gas delivered at high pressures. The remainder of the gas is sold to distribution companies that lower the pressure in the lines and distribute it to consumers such as businesses to residential houses for heating or compressed natural gas filling stations for vehicles.

An image of a customer meter and distribution systems in the Fayetteville shale play region can be seen in Figure 6.

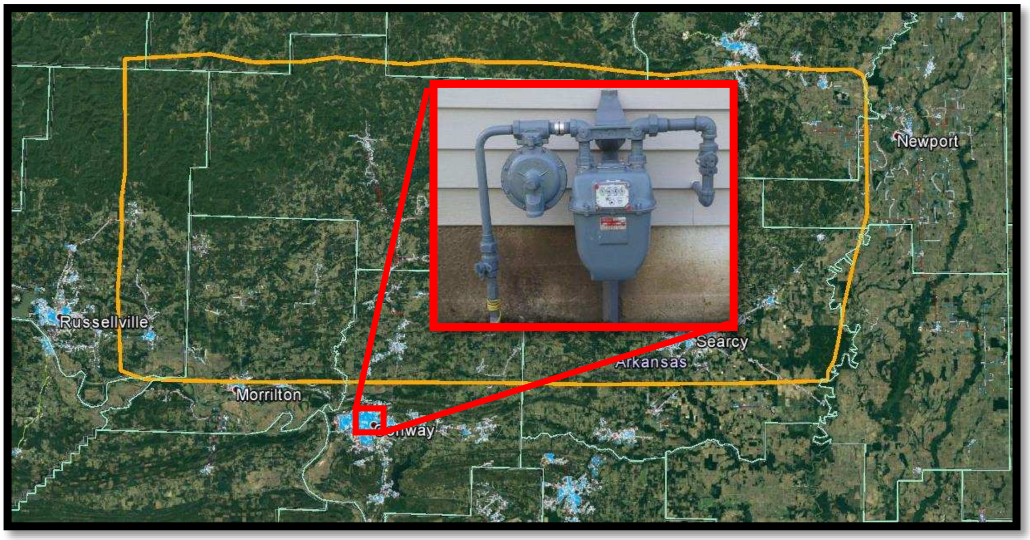

Figure 6 Distribution company display of meters and pipeline with an image of a customer meter.

This analysis ends at the customer meter and does not estimate emissions from pipelines within households or industrial or commercial facilities, or from uncombusted methane in exhaust gas. Distribution leaks are more odorized with the addition of mercaptan to make it easier to detect low concentrations of natural gas in the atmosphere.

1.3 Non-Oil & Gas Sector

Methane is not exclusively emitted by the natural gas sector. Methane is also generated from anthropogenic sources such as agriculture and waste management and from non-anthropogenic sources, such as wetlands and geological seepage. Understanding the origin of methane emissions provides guidance for where methane mitigation may be most effective. Measurement technologies are designed to accomplish a variety of task such as detection, quantification, and source attribution. Source attribution is the process by which the origin of the methane can be attributed. Biogenic methane, unlike thermogenic methane, does not produce ethane and the presence or absence of ethane in the atmosphere proportionally to methane can be used to identify whether the methane originated from biogenic sources. Geological seepage is the only form of natural methane emissions that has ethane present because it originates from the same gas reserves as natural gas sector that is anthropogenically extracted. For this reason, separate measurement data is required to estimate geological seepage emission rates since ethane ratios cannot be utilized for source attribution.

Several measurement techniques are utilized to measure the methane emissions from different emission rates and from different emission locations.

1.4 Overview of Measurement Technologies

In order to better understand methane emissions from the natural gas supply sector, as well as others, several different types of methane measurement techniques have been developed. The measurement technologies utilized in this campaign range from component measurements to sub-basin measurements. Component measurements were made using both Bacharach and Indaco high-flow samplers. Facility level measurements were made using downwind methods such as OTM33A, Dual Tracer Flux Release, and Aircraft spiral. Sub-basin measurements were performed using aircraft mass balance techniques. Each measurement technique will be described below.

Figure 7 Bacharach high flow setup using an inherently safe enclosure placed over the leaking device to obtain a complete capture of emitted methane. The flow is routed and analyzed in the operator's backpack and then recorded by the operator.

For both Bacharach and Indaco high flow measurement devices, the same method of quantification is utilized. The high flow mechanically isolates the leaking component by wrapping a loose fitting barrier around the leak. This is to ensure that all the methane that is being emitted travels it into the high flow to be measured while still allowing air to flow through to get an accurate emission rate estimate. Before the leak is isolated the high flow is turned on. The high flow works by pulling a suction and measuring the volumetric flow rate of air through the device. While it is pulling air through, a separate sensor measures methane concentration. Methane emission rate is then calculated from the volumetric flow and methane concentration. For high flows devices that are not calibrated before the measurement is taken, the measured concentration is then subtracted from the background concentration for real time calibration. The difference between measured and background concentrations is then multiplied by the volumetric flow rate to obtain a leak rate[7]. This can be done at two different flow rates in order to ensure proper quantification. A field operator using a high flow can be seen in Figure 7.

High flow measurements can be summed at a facility and combined with engineering estimates from unmeasured sources to generate a Study Onsite Estimate (SOE) which can then be compared against facility level emission measurement techniques Other Test Method 33a (OTM33a) and dual TRACER flux release (TRACER).

Figure 8 Other Test Method 33a (OTM33a) Transect on standard well pad equipped with well trees, tanks separators, and sales data collection[8].

OTM33A is a measurement technique that is still being developed and proven. The method uses inverse Gaussian dispersion modeling to calculate leak rates based upon methane concentrations in the air.

The method is typically performed in this order: A vehicle outfitted with a sensitive methane concentration instrument and an anemometer will drive around a facility looking for peaks in methane concentrations. If an increased concentration is found the measurement vehicle will park downwind from the site in an area where the elevated methane concentration was detected. It will then measure the methane plume for at least twenty minutes until a Gaussian distribution of measurements has been formed by the wind sweeping the plume back and forth over the vehicle. Based upon the approximate distance from the source, wind speed, and concentrations an emission rate is estimated[9]. On large pads, OTM33a can isolate single sources and attempt estimates for a particular portion of the well pad.

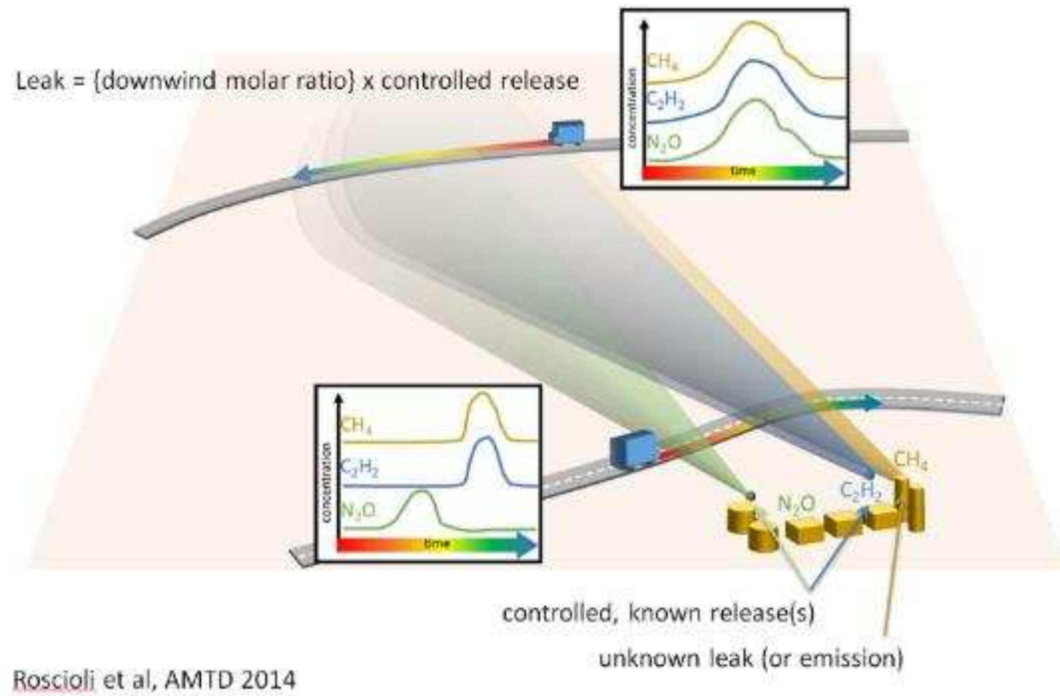

Figure 9 Tracer transect showing that at different distances from the facility tracer and methane plumes may be spatially correlated or uncorrelated. Uncorrelated plumes can, under the right conditions, be utilized to determine the position within a facility where a methane emission is originating.[10]

TRACER is a more established method of facility level measurements. The measurement technique compares the downwind concentration of one or more tracer gasses to the downwind concentration of methane to estimate a facility level methane emission rate. Dual tracer utilizes two distinct tracer gasses released near methane emissions points at a known rate – nitrous oxide and acetylene in this study – as shown in Figure 9. The measurement vehicle will then drive transects downwind from the facility and collect measurement concentrations of methane and the two trace gasses. By comparing the downwind concentration of the known trace gas emission rates to simultaneously-collected concentration of methane, the methane emission rate can be estimated.

Facility level emission estimates can then be total for an entire region and compared against sub-basin aircraft measurements.

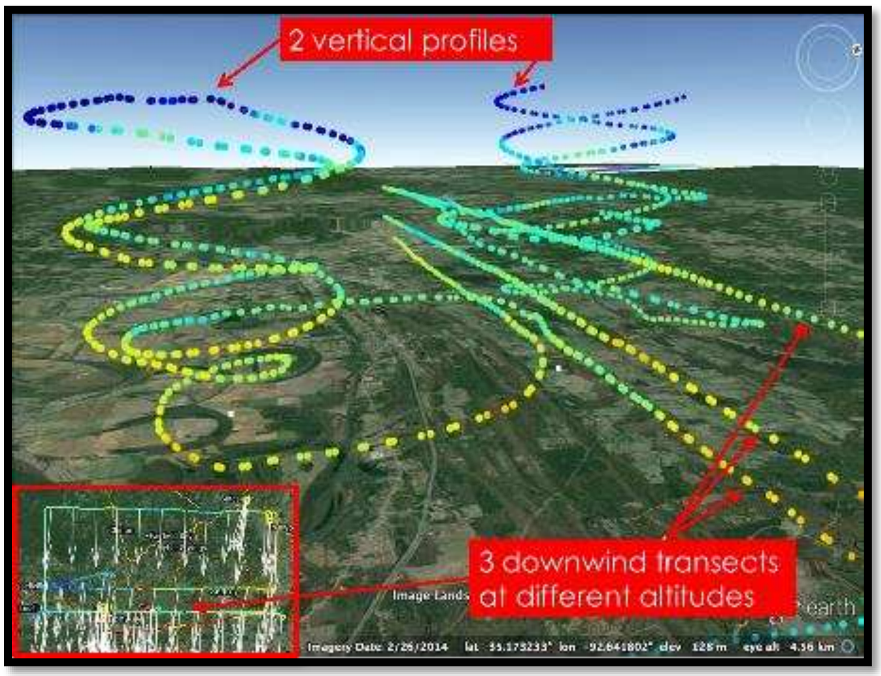

Figure 10 Aircraft spiral flight and transect flights with methane concentration displayed by color, where yellow has greater concentrations and blue has lower concentrations. Aircraft transects were performed at three altitudes to capture all emissions passing through the transect line. Spiral flights are not directly related to transect flights and can be used to estimate facility level emissions.

Aircraft-based measurements were performed at the facility level using spiral flights and the sub-basin level using a combination of raster and mass balance flights. The method for estimating facility level emissions and basin level emission methods are similar. The aircraft flies around the area being analyzed, it measures methane concentration upwind from the facility and methane concentrations downwind from the facility. The method then uses wind speed and the difference in background concentration to determine the emission rate inside the encircled perimeter. For facility level flights a spiral is flown around the facility starting low and circling upward to capture the entire plume from the facility. The basin level mass balance is performed by making one transect upwind of the basin, flying a perimeter around the basin, and then flying at three different levels at the downwind end of the basin. The three levels of varying height help confirm complete mixing and that methane concentrations are not different at varying altitudes. Raster flights can also be performed where a gridded pattern is flown over the basin detecting methane enhancements to develop a spatial understanding methane emissions. In ideal conditions a raster flight can be used to perform a mass balance[11].

1.5 Measurement Discrepancies

Prior to this study the most recent attempt to compare top-down measurements with bottom-up measurements was performed in the Barnett Shale region[12]. A spatially resolved model was constructed with 18 source categories. Facility emissions were estimated at the facility level; no individual component measurements were made. The study estimated emissions to be greater than other estimation methods, including the Greenhouse Gas Inventory (GHGI) and the Greenhouse Gas Reporting Program (GHGRP) thus showing a discrepancy in basin level emission estimates.

The discrepancy was thought to be due to fat tail emissions or “super emitters”. Ground-level measurements were made in October while the top town aircraft measurements were made in March. For this reason the study cannot be viewed as contemporaneous and a direct comparison of measurement techniques is not made and the measurements are compared to established EPA GHGI emission factors.

Another study published in 2014 used satellite imagining to find regions in the united states where there were peaks in methane concentration[13]. It was reported that the Four Corners region in the US southwest was emitting nearly 1.8 times more methane than what the GHGRP reported for the region and 3.5 times the EDGARv4.2 estimates. This study shows that there is a large gap between top-down estimates and bottom-up estimates. The report also indicates that satellite imaging is a valid method for estimating methane emissions in a particular region.

A study using 7710 and 4984 observed methane concentration measurements from aircraft and towers respectively, constructed atmospheric transport model to estimate the spatial distribution of methane emissions in the United States[14]. Results from the study show that their top-down estimates is approximately 1.5 and 1.7 times larger than emission estimates from the EPA and the emissions database for global atmospheric research respectively. They concluded that methane emissions from fossil fuels and livestock are larger than previously predicted.

Similar to the national estimate performed with towers and aircraft measurements, a more localized study conducted in the Denver-Julesburg basin used aircraft measurements to perform a mass balance to determine total methane emissions from the region [15]. This estimate was compared against an inventory for the region. The comparison shows that top-down estimates are nearly 3 times larger than the bottom-up estimate. The study concludes that inventories for volatile organic compounds are under-predicting actual emissions by a factor of 2 during the period when the mass balance occurred.

In contrast to the previously discussed studies, another top-down measurement campaign using aircraft-based measurements to perform mass balances determined that top-down measurements were lower than what earlier studies predicted[16]. The study concluded that the national average of fugitive methane emissions was lower than estimates performed by previous studies. One of the regions scanned in this study was the Fayetteville shale play with very similar boundaries used in the field campaign reported in this study.

The analysis presented in this thesis is part of a larger study to compare, and potentially reconcile, emissions using top-down and bottom-up methods where data was simultaneously collected for both methods. The analysis presented here includes a more comprehensive analysis of methane emissions for the Fayetteville study area than has previously been completed. Methods of analysis used here are not novel and have been used in similar studies. This study was guided by previous work in some instances, such as measurement protocol and statistical model construction, but is a first of its kind in the level of detail in multiple source categories, and in the spatial resolution and temporal resolution of the emission estimates.

1.6 This Study and the Bottom-Up Estimate

During the fall of 2015, a 4-week field campaign was conducted in the Fayetteville shale play in the Arkoma basin in Arkansas. The campaign mission was focused on reconciling the disparity in emission estimates using top-down and bottom-up methods. In order to reconcile this difference, contemporaneous measurements were performed to minimize temporal differences that could bias emission estimates. Comparisons of emissions estimates from OTM33a[8], Tracer[10], and SOE were performed on well pads[17] and Tracer[10], Spiral Flight, and SOE were performed on gathering stations[18].It addition to contemporaneous measurements, the study team had access to the vast majority of natural gas assets in the study region to generate the most complete comparison to date for both facility level comparisons [17] [18] and sub-basin comparisons between ground level estimates[19] and aircraft basin level estimates [11]. Production well pads and gathering stations contribute the majority of gas system emissions, and facility-level comparisons were focused on these sectors. The goal for comparing the different measurement techniques was to reconcile and understand different emission rate estimates. The sub-basin ground level estimates were composed of emission estimates from the natural gas sector composed of production well pads, gathering pipelines, gathering stations, transmission lines, distributions systems in the study area and non-oil and gas emission sources such as agriculture, waste management, and natural sources.

1.7 This Report

The research presented in this thesis fits into the sub-basin level comparison where each sector of the natural gas supply chain was modeled to generate a ground level area estimate which was compared against the aircraft mass balance that was performed in the region across multiple days. The categories described in this report include gathering pipeline networks, distribution systems, agricultural practices, waste management and natural sources. The ground level area estimate and the aircraft mass balance are compared spatially and temporally. For this reason, locations of emission sources were used to generate an appropriate spatial comparison. Where GPS coordinates were not available county boundaries were used to separate some non-oil and gas emission categories. This is the first study to measure gathering pipelines in order to update emission factors that had previously been derived from measurements of distribution mains.

The analysis that was performed on natural gas methane emissions from gathering pipeline networks is found in Chapter 2, measurements performed on distributions systems and statistical estimates are found in Chapter 3, agricultural practices, waste management systems and natural sources and associated methane emissions are found in Chapter 4 and a discussion on the comparison of emission sources and how the contribute to the bottom-up estimate is found Chapter 5. Each category was assessed to provide a complete ground level estimate for the comparison to the aircraft measurements. A thorough analysis was developed to provide the most accurate possible bottom-up estimate of emission both in and out of the natural gas industry.

CHAPTER 2. GATHERING PIPELINE NETWORKS

Disclaimer: This chapter has been submitted for publication and is waiting on approval.

2.1 Introduction

U.S. dry natural gas production increased from 18 trillion cubic feet in 2005 to 27 trillion cubic feet in 2015 [20] . Use of natural gas offers potential climate benefits compared to coal or oil [21], but those benefits depend on the emissions of methane, the primary component of natural gas and a potent greenhouse gas, across the entire supply chain. This study is part of a larger, 5-week field study designed to compare, and possibly reconcile, estimates of methane emissions based upon on-site, device-level, measurements; downwind techniques estimating methane emissions for entire facilities; and aircraft-based mass-balance estimates to estimate emissions for a sub-basin study area. Measurements at all three scales were performed contemporaneously to minimize the uncertainty caused by temporal variability and the use of data from other studies or measurement periods.

Gathering pipelines refer to the pipelines that connect wells to gathering compressor stations or processing plants, and connect those facilities to transmission pipelines or distribution systems. Inlet pressures of gathering systems range from 30 to 7,720 kPa [22], but the majority of gathering pipelines operate at the low end of that pressure range. Gathering pipeline systems consist of buried pipelines and auxiliary surface components for operation of the pipelines including pig launchers and receivers, blocking valves, and a variety of other, less common, components (e.g. "knock out bottles" used to remove liquids from pipelines on older systems). Pig launchers/receivers are used to insert/remove cleaning plugs, called "pigs", into gathering lines to remove water and debris from the pipeline. Block valves are used to isolate sections of pipeline or reroute the flow of natural gas. (SI-7.1.1).

Gathering pipeline network methane emissions originate from three sources:

1) *Emissions from pipelines* between auxiliary equipment. Pipelines are typically underground, although some older systems utilize above-ground pipelines. Underlying causes of pipeline

emissions include corrosion, failed joints, and structural stresses caused by settling earth or the traversal of heavy equipment. Pipelines may also be damaged by accidental contact by outside parties.

2) *Emissions from auxiliary equipment*, such as emissions from valve packing or seals on pig launcher doors. Auxiliary equipment is often called “above ground” equipment.

3) *Episodic emission from pipeline operations*. Episodic emissions are releases of gas that occur for defined, typically short, periods. While gas may be released due to emergency situations arising from mishaps , the two most common planned episodic emissions for gathering pipelines are the blowdown of lines for maintenance and the blowdown and purging of pig launchers and receivers during pigging operations.

This study measured the first two types of emissions –underground pipelines and auxiliary equipment – and performed an engineering estimation of planned episodic emissions.

The authors are unaware of any recently published studies of gathering pipeline emissions, and as a result, emission factors are unknown for this sector [23]. EPA’s greenhouse gas inventory (GHGI) uses emission factors based upon measurements of distribution mains from a 1996 GRI/EPA study [24] to approximate emissions for gathering pipelines. The majority of gathering pipelines are not regulated by the US Pipeline and Hazardous Material Administration (PHMSA) because they do not cross state boundaries and are in rural areas that fall below population proximity rules [25]. Recent studies have characterized emissions for gathering and processing plants [26], [27] and well pads [28]–[30], but none of these studies performed measurements on gathering pipeline infrastructure. Several recent studies have evaluated regional methane emissions using aircraft measurements (e.g. [31]; [32]; [16]), but the methods utilized did not support attribution to specific portions of the gathering infrastructure. Other ground-based measurement campaigns did not measure gathering pipelines (e.g. [33]; [34];[35]; [36]). Recent ground-based pipeline studies have focused on distribution pipelines between the city gate and the consumer’s meter [37], and have shown a correlation between leak frequency and either pipeline age or material. In summary, since no recent study has systematically measured methane emissions from gathering pipelines, the GHGI estimates emissions using aggregate emission factors based upon distribution pipeline measurements.

This study represents the first, albeit limited in scope, attempt to characterize gathering pipeline methane emissions, and details measurements made during an 8-county study in the eastern portion of the Fayetteville shale play in Arkansas, USA. (SI-S2-7.1.2) While the data is not sufficiently representative to provide methane emission factors at the regional or national level, the study provides initial information about the mix of emission sources and guidance to design future gathering pipeline studies.

2.2 Methods

Measurement Campaign. Natural gas produced in the study area is “sweet and dry,” produces no natural gas liquids, and requires minimal upgrading to achieve pipeline quality. There are no gas processing facilities in the study area. Water is separated from the gas at the well pads utilizing gravity-type separators, and gas further dehydrated at the gathering compressor station using glycol dehydrators. The pipelines measured for this study were operated by two study partners. For their systems, the suction side of the gathering compressors operates between 100 and 325 kPa (15-50 psia). Due to the low suction pressures, gathering pipelines between wells and gathering compressor stations typically range between 4 and 20 inches in diameter and utilize “poly” (plastic) material. Non-study-partner lines vary in configuration, with at least one company operating their well-compressor pipelines at 1-2.8 MPa (150-400 psia), using smaller diameter steel lines. Considering the entire study area, 67% of well-compressor gathering pipelines pipeline utilizes “poly” (plastic) material, and all measurements were made on this type of pipeline. Compressor-transmission lines, which were not measured in this study, are constructed of steel and operate between 6 and 8 MPa (850-1150 psia).

Gathering pipelines are installed in rights of way (ROW), defined by an easement allowing the operator to access and maintain their pipelines. A ROW segment may contain more than one pipeline, but all ROWs measured in this study contain a single pipeline from a single operator. All active producing wells and the associated pipelines in the study area were completed no earlier than 2004, and 79% of all active wells went on line after 2008 [38].

Study partners operate 98% of gathering pipeline length in the study area, this level of precision for activity data is unique to this study. However, not all of these ROWs were practical for measurement. Exclusion criteria included: ROWs too steep to traverse with the measurement equipment, ROWs covered with un-harvested crops, ROWs that had access restricted by the landowner, or ROWs that were covered with vegetation growth too dense to traverse with the available screening equipment (SI-S37.2). One partner company cuts brush on ROWs every two years, and during the study period, only the western half of the study area was sufficiently cleared for measurement.

During the measurement campaign, a random section of pipeline ROW was selected each day for measurement from accessible ROWs, and days were allocated to each operator in proportion to the number of wells they operate (SI-S37.2). After specific ROWs to be measured were determined each day, the measurement team drove as much of the selected ROWs as possible. Measurements were made on 12 days traveling an average of 8 km per day with a minimum of 4 km in a day and a maximum of 15 km in a given day.

A vehicle-based measurement system (VMS) was utilized to detect methane concentrations above background levels to detect underground pipeline leaks. Measurement vehicles were outfitted with a gas collection manifold on the front bumper of the vehicle routed to a Los Gatos Research Ultraportable Greenhouse Gas Analyzer, with a detection threshold of 0.01 ppm over ambient methane levels (SI-7.2). While detection efficacy of the vehicle measurement system (VMS) could not be assessed with controlled studies in gathering pipeline conditions, similar methods have been utilized successfully by recent distribution pipeline studies [37]. For the single pipeline leak identified in this study (4 kg/h), the VMS noted a maximum methane mixing ratio of 11,160 ppm, in a clearly defined peak, and methane mixing ratios were above 10 ppm up to 37 meters away from the emission source, as seen in Figure 1A. To determine if the VMS would detect smaller emission rates, a qualitative assessment of the VMS was performed post campaign. The concentrations recorded by the VMS were reviewed for periods when the VMS was within 50 meters of identified emissions from auxiliary equipment. Since these sources were independently screened and measured, reviewing atmospheric concentrations seen by the VMS provides an independent check of the VMS's capabilities. Qualitatively, a review would expect to see a defined concentration peak – defined here as 3 ppm above background concentration of 1.9 ppm – when the VMS was near auxiliary equipment emissions. An example, shown in Figure 11b, indicates that the VMS detected an enhancement when 7 meters from a 0.087 kg/h emission source, and peaked at 36ppm when 1.2 meters away from the emission source. Additional examples are provided in SI-S37.2. This qualitative analysis indicates that the VMS would likely have identified pipeline methane emissions significantly smaller than the single pipeline emission detected during the study, assuming the gas arrived at the surface within the ROW and/or upwind of the VMS. Therefore, it is a reasonable assumption that either (a) the single emission detected here is the only underground pipeline leak in the ROWs measured during the study, *or*, (b) any undetected leaks were substantially smaller than 4 kg/h.

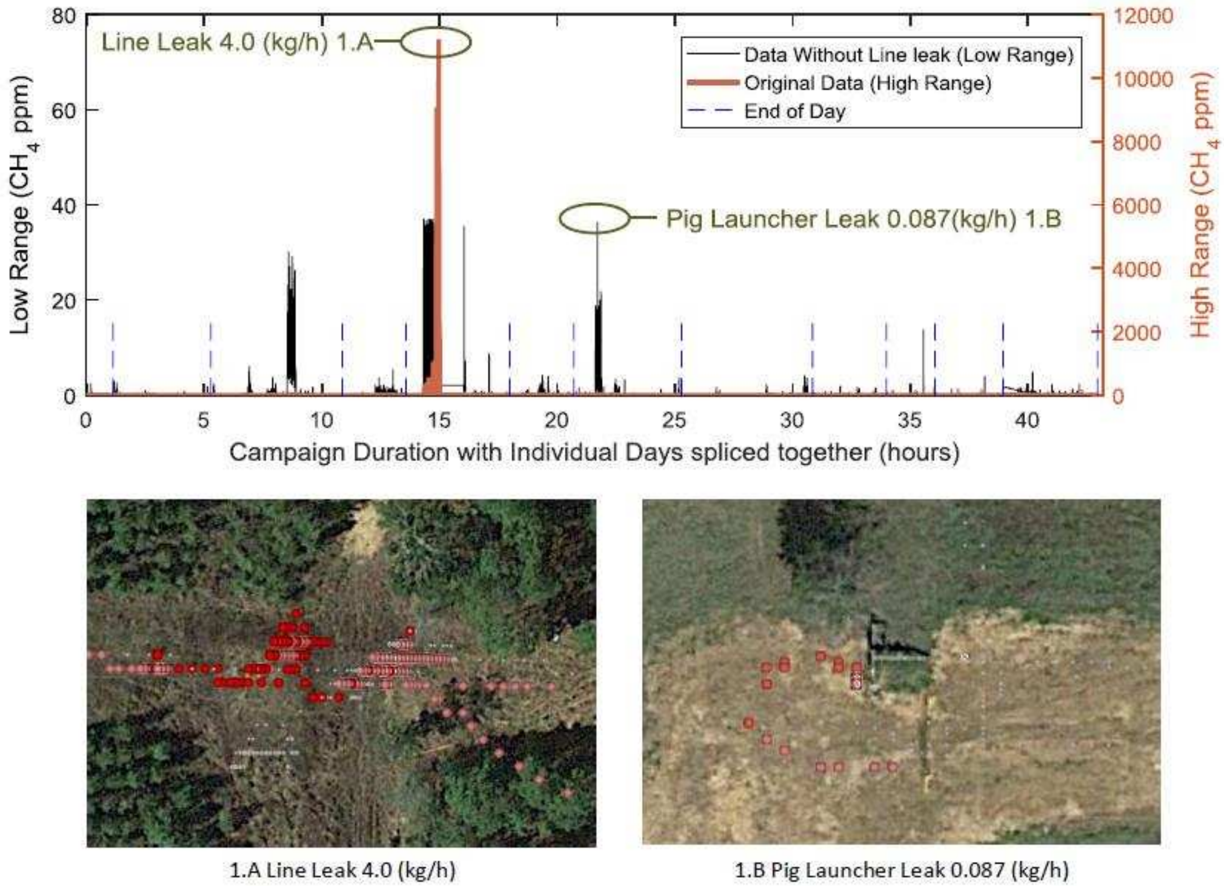

Figure 11 Vehicle measurement system efficacy tests. The plot shows methane mixing concentrations for measurement days, spliced into a single timeline. The high range (right axes) illustrates the size of the pipeline emission compared to the remainder of the measurements. The largest peaks do not register on the high range scale. The low range (left axes) illustrates how the vehicle-mounted measurement technique would detect smaller pipeline leak emissions with favorable ground and weather conditions. Map images of the circled peaks are illustrated in 1.A (underground pipeline leak) and 1.B (pig launcher facility). Methane mixing ratios in 1.A and 1.B are scaled from gray (low ppm) to dark red (high ppm).

While screening the ROWs, measurement vehicles would periodically arrive at auxiliary equipment (block valve and/or pig launcher) and measurement staff would survey the components with a laser emission detector and then use a high-flow instrument to quantify detected methane emissions sources (SI-S4.1).

Taking into account the scope of the study, measurement results presented here should not be construed as sufficient to develop emission factors for gathering pipelines in general. However, study measurements provide insight into the mix of emissions, and associated mathematical models can provide guidance on the requirements for developing nationally-applicable emission factors.

Study Area Estimates. Monte Carlo methods [39] were utilized to estimate total emissions for the study area. Field measurements were utilized to model emissions, and emission drivers – commonly called activity data – were developed from public data and non-public partner data (SI-S4.4). Activity data was provided by two study local companies who provided data and gave access to measure gathering lines called study partners and one data partner who gave information on company equipment but did not provide site access. Activity data is summarized in Table 1. Together these three companies operate 98% of the active gas wells in the study area. [38] All companies provided pipeline lengths and material type. Auxiliary equipment counts were available from one study partner and the non-partner company, and the study team estimated auxiliary equipment counts for the other study partners utilizing satellite imaging (SI-S4.4).

Table 1 Available activity data by operators in the study area. Partners 1 and 2 provided access to their gathering systems for measurement. The non-partner provided activity data but no access. Combined, the three companies operate 98% of the active gas wells in the study area.

	Partner 1	Partner 2	Non-Partner
Pipeline Length	✓	✓	✓
Pipeline Type	✓	✓	✓
Pig Launchers	✓	E	✓
Block Valves	E	E	✓

✓ = Reported, E = estimated via satellite imagery
Estimated data from partners was due to lack of available information, not due to lack of cooperation.

Two sources of uncertainty exist for emissions from pipeline leaks because only one pipeline leak was detected when screening a small portion (2.4%) of partners' study area mileage. First, it is unknown if the measured emission rate is representative of the mean emission rate of possible leaks within the study area. (Currently, gathering system operators are not required to perform leak surveys, and when leaks are found or surveys are conducted, the emission rate is not typically quantified.) Therefore, this emission rate is modeled using a triangular distribution with a mean at the estimate found in the field measurements (4.0 kg/h), a lower bound of 0 kg/h and an upper bound of 8 kg/h (SI-S4.37.4.1). Second, uncertainty also exists in the frequency at which leaks occur within the pipeline system. This uncertainty was modeled by analyzing the probability of finding one event (the observed leak) assuming a range of possible, but unknown, leak counts within the study population. For this study, we are interested in the probability of finding one pipeline leak while surveying 96 km of pipeline randomly selected from the total population of 3948 km of pipeline operated by the study partners. The resulting probability distribution, shown in Figure 12, has a mode matching the field campaign (96 km/leak), but has a significant upward skew, resulting in a mean probability of twice the field campaign (50 km/leak) and a wide, asymmetric, 95% confidence interval (CI) of 18 to 425 km/leak. This analysis provides an estimate of the uncertainty inherent in finding rare events given a limited sample size. This method is described in the SI-S4.3 and is utilized to analyze the coverage required in future pipeline studies to provide an upper bound on emissions from gathering line leaks.

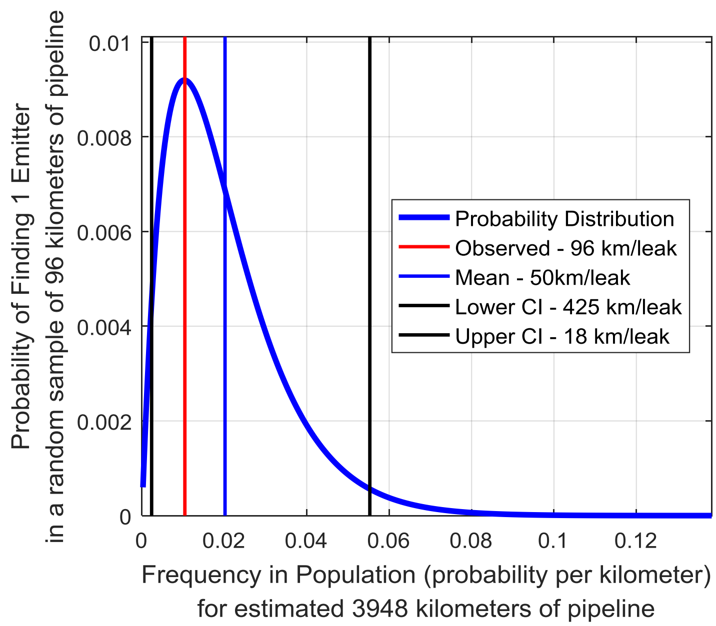

Figure 12 Uncertainty in Frequency of Underground Pipeline leaks. This figure displays the probability distribution of total leak count in the study area, based upon finding 1 pipeline leak in 96 kilometers of measured pipeline. This figure shows that the mean frequency of occurrence (50 km/leak) is almost double the frequency that was found.

In addition to steady state fugitive emissions from gathering lines and auxiliary equipment, planned episodic emissions from pig launchers and receivers were calculated. Emissions from each pig launch/receive event which occurred during the study period was calculated based on geometry of vessel, pressure before release, average ground temperature, and gas composition. Our analysis indicates that planned episodic emissions are small relative to other pipeline emission sources: There were 13 pigging operations during the three week campaign which contributed an estimated 31 kg of emitted methane, or 1.3 % of the 2430 kg (4.82 kg/h) of emitted methane due to the emission rate directly measured from pipelines and auxiliary equipment, scaled to the same period. Unplanned pipeline ruptures or pipeline blow downs did not occur during the field study. Therefore, to simplify the analysis presented here, planned episodic emissions are not included in the analysis discussion below but are reported in the SI-S4.5. Unplanned episodic emissions (e.g. accidental pipeline breach) were not analyzed in this study.

EPA's greenhouse gas inventory (GHGI), and greenhouse gas reporting program (GHGRP), as well as most recent studies updating emission factors for distribution mains, stratify pipelines by material (steel or plastic in this case). To match these methods, pipelines were also stratified for the study area, although all measurements in this study were made on plastic pipelines. None of these programs break out emissions from auxiliary equipment as a separate emissions source.

Finally, an empirical 95% confidence interval is utilized throughout, defined as the 2.5% / 97.5% percentiles for two-sided analyses, and 0% / 95% for when discussing pipeline screening guidelines for future studies.

2.3 Results & Discussion

Field measurements. We first consider measurement results for the field campaign, which are summarized in Table 2 and in SI data table 2. The field campaign surveyed 95 auxiliary equipment locations and detected 98 total leaks, of which 72% of which originated from valve packing. While the underlying cause of each leak is unknown, field operators report that valve packing most often loosened prior to operating a valve during pigging operations or to allow a blocking valve to be turned by hand, and it is possible the packing was not re-tightened sufficiently after the operation was complete, resulting in a fugitive emission. The remainder of detected leaks were from pig launcher doors (13%), flanges (12%), and gauges (2%). A total of 0.83 kg/h of emissions were measured, with valves contributing 49%, pig launcher doors 47%, flanges 3% and gauges 1%. There was no statistical difference in auxiliary equipment emissions between the two partner companies (SI-S5.1). This study did not detect any failures of auxiliary equipment releasing gas at high rates, nor did it estimate the frequency at which such failures may occur.

A single underground pipeline emission, measured at 4.0 kg CH_4/hr, was found while screening a total of 96 kilometers of pipeline.

Table 2 Summary of emission measurements. All auxiliary equipment on surveyed ROWs were screened with an RMLD to detect emission locations, and each detected location was measured utilizing a high-flow instrument.

Auxiliary equipment type	Locations screened[1]	Locations with detected methane enhancements		Locations with emissions above high-flow detection limit.		Measured Methane Emissions Rates (kg/h)	
		Count	Fraction	Count	Fraction	Mean	95% CI
Pigging facilities	56	42	75%	28	50%	0.014	-52% / +65%
Block valves	39	17	44%	6	15%	0.002	-56% / +74%
Pipeline leaks	96 km	1	NA	1	NA	4.0	NA[2]
Notes:							
1	Pigging facilities and blocking valves were screened utilizing an RMLD. Pipeline leaks were screened utilizing a vehicle-mounted methane concentration instrument.						
2	Since only one leak was detected, it is not possible to estimate a confidence interval on the leak rate.						

Estimated emissions for the study area. Table 3 summarizes the simulated methane emissions for the study area, termed the Study Model Estimate (SME), which was developed using the Monte Carlo methods described earlier. The SME predicts total study area methane emissions to be 400 kg CH_4/h [-87% / +214%]. Underground pipeline leaks dominate the SME, contributing 93% [83% to 98%] of mean estimated methane emissions. Uncertainty in leak frequency (i.e. the number of pipeline leaks per kilometer of pipeline) dominates the CI for the SME.

Table 3 Simulation results for the study area. Both total emissions and the confidence interval are dominated by the single underground pipeline emission detected during the field campaign.

Emission Component	Study Model Estimate		Mean Fraction of Emissions[4]	Range of Fraction of Emissions[3]
	Mean (kg/h)	95% Confidence Interval		
Pig Launchers[1]	15	14% / +15%	5%	2% to 14%
Block Valves[1]	4	-14% / +15%	1%	0.4% to 4%
Pipeline Leaks[2]	380	-92% / +225%	93%	83% to 98%
Study Area Total	400	-87% / +214%	100%	
Notes:				
	1) CI considers both range of emissions rates measured and uncertainty in the activity estimates.			
	2) CI considers uncertainty in the frequency of leak detection and assumes a triangular distribution for emission rate estimates.			
	3) Minimum and maximum source contribution to gathering pipeline network emissions			
	4) Reported percentages are rounded Independently and may not sum to 100%			

Due to the number of auxiliary components measured and the frequency of leak detections, the CI's for auxiliary equipment emissions are much tighter (±15% for block valves and pigging equipment). Auxiliary equipment contributes on average 6% of total emissions with at least 2%, and no more than 17%, of total emissions (95% CI). Most of the detected emissions on auxiliary equipment could be eliminated by screening for emissions after maintenance operations to detect valve packing or seal leaks that could be readily fixed by tightening packing bolts or seal latches on pig launchers. However, it should be emphasized that such control actions would eliminate only 5% of gathering pipeline emissions based upon current study results. Further, the low emission rate of auxiliary components, coupled with a moderate number of these components, produces emission rates for auxiliary equipment across the entire basin significantly below that of other infrastructure measured simultaneously during the larger study. For example, 1% of the 261 well pads [17] and 83% of the gathering compressor stations [18]measured in the larger study have estimated emissions of more than 20 kg/h, the estimated mean emissions from all auxiliary gathering pipeline equipment in the basin. Given that there are 3000 well pads and 120 compressor stations in the study area, and assuming that no auxiliary equipment components have undetected major malfunctions, measurements completed here indicate that auxiliary equipment emissions approach negligibility relative to other gathering emission sources.

In contrast, the estimated 380 kg/h [-92% / +225%] estimated for pipeline leaks is not negligible. Approximately 94% of the 261 well pads [17] measured in the larger study had estimated emissions smaller than the measured pipeline leak. The measured rate, 4 kg/h, also approaches the emission rate of the lowest-emitting gathering stations measured in the study [18] With due caution caused by the small sample size available here, pipeline leaks are likely *not negligible*, suggesting analysis and future measurement of gathering pipelines should focus on pipeline leak detection and measurement.

The study area estimate is compared to other studies in Figure 13 (see SI-S5.3 for calculation methods). The comparison utilizes activity data developed in this study and emission factors from the GHGRP [40], the 2015 GHGI [41], and recent emissions data for distribution mains [37]. Since all methods utilize the same activity data, comparisons between estimates focus only on differences in emission rates for the mix of pipeline equipment in the study area. Since GHGRP emission factors are provided without CI's, only the mean estimate is shown. The CI's for GHGI emission factors were estimated from 90% CI's listed in the [42] report.

The GHGI and GHGRP –based estimates for the study area fall within the CI of the study estimate, and given the uncertainty around both the size and frequency of pipeline leaks in the study estimate, this overlap is a strong indicator of statistical similarity. Therefore, this study provides no evidence of issues with the GHGI and GHGRP emission factors and supports the estimates. The comparison with the distribution is included because past revisions of the GHGI have utilized distribution mains as a source for gathering line emission factors. In this comparison, mean emissions estimated using emission data from Lamb's distribution study are 8% of the mean study estimate, and even though CIs overlap, measurements performed here indicate that these new distribution measurements should not be utilized to estimate gathering pipeline emissions as the one measured leak would account for 13% of the total emission estimates which would indicate a total of 8 leaks emitting at 4kg/h exist in the whole system which is out of the 95% CI estimate for leak frequency.

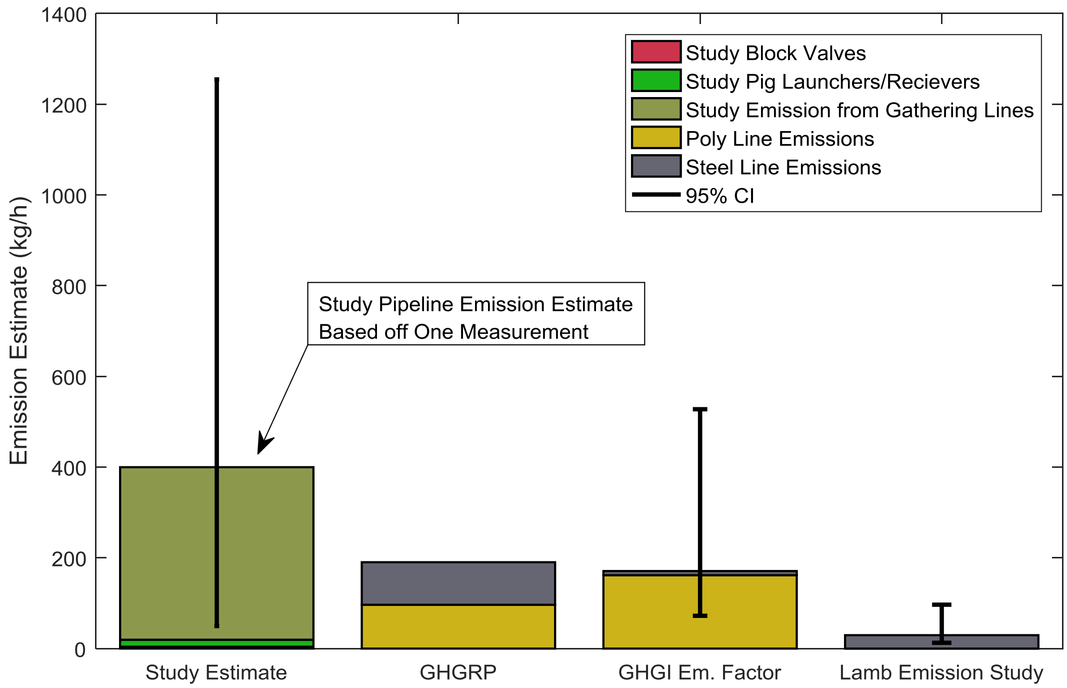

Figure 13 Comparison of the study estimate to other emission estimates. All estimates utilize emission factors from the referenced study and activity estimates developed in this study for the study area. Pipeline estimates are classified by pipeline material type. Both the GHGI and GHGRP are statistically similar to this study. While confidence intervals based upon emission factors from Lamb's distribution study overlap, the much lower mean estimates indicates that emission factors from distribution pipelines may not be appropriate for gathering pipelines.

2.4 Pipeline Screening Guidelines for Future Studies.

The current study indicates that pipeline leaks are rare events in this region. The uncertainty analysis presented above provides a conceptual model to understand how the frequency within a study population of these rare events contributes to uncertainty in the resulting emissions estimates. Using this conceptual model, it is possible to pose the question: What size of field campaign would be necessary to constrain estimates of pipeline leak emissions to a desired fraction of total basin emissions?

To exercise this conceptual model, it is first necessary to define a frequency range over which pipeline leaks *might* occur. Given that range, it is possible to explore the fraction of a basin that would need to be screened and measured to produce constrain emissions from gathering pipelines to a desired fraction of total basin emissions.

While there is little-published information about gathering pipeline leak frequency, leak surveys are occasionally completed for operators and produce unpublished counts of identified leaks for surveyed systems. The authors contacted a number of organizations which had done recent leak surveys, and, while not ideal, several agreed to provide data under the condition of confidentiality. In all cases, leaks were detected, but not measured. Anecdotal information provided was:

- A leak detection survey of 595 kilometers of an old gathering system in Pennsylvania indicated approximately 0.3 kilometers per leak, of which 10% were audible.
- A helicopter survey (with an unknown lower detection limit) of a variety of pipeline types found 16,000 leaks in 225,000 kilometers survey, or ≈14 kilometers per leak.
- An operator managing 790 kilometers of newer, low-pressure pipeline reports "less than 5 underground leaks" in two years. Assuming all leaks remained unreported for six months, this would translate into a leak frequency of ≈160 kilometers per leak.

From these qualitative data, reported leak frequencies range from 0.3 to 160 km/leak, with the current study's data of 96 km/leak somewhat centered within the reported range. The CI estimated here (18-425 km/leak) includes the low-frequency, but not the high-frequency end of the range. The pipelines with high leak frequencies occur in regions where pipelines are older and have not been constructed using plastic or protected steel lines. In these regions, corrosion and damage has had more opportunity to occur resulting in pipelines with more leaks. The majority of the pipeline analyzed in this study was installed in the last 10 years and for this reason, a direct comparison cannot be made.

Figure 14 shows simulation results for five leak frequencies for a study area similar in size to the study area in this campaign – approximately 4000 km of gathering pipeline. The simulation assumes a conservative (i.e. likely high) mean leak emission rate of 4kg/hr for all pipeline leaks. We also assume that total emissions from all sources in this hypothetical basin can be estimated using Peischl's [16] measurement of the eastern Fayetteville shale. The bounding question is: Assuming a leak frequency, how much of the study area gathering pipeline network must be measured to constrain any underestimate of pipeline leak emissions (upper 95% CI) to within 1 percent of the region's total emissions? (SI-S6)

Figure 14 illustrates the upper 95% CI on emissions, as a fraction of the Peischl estimate, for a range of leak frequencies. In areas where leaks occur less frequently than 1 leak per 100 km of pipeline, a field campaign measuring 5% of the basin pipeline would constrain any under-estimate of emissions from gathering pipelines to be less than one percent of total basin emissions. The current study measured 2.4% of the basin and found 1 leak in 96 km of pipeline. The uncertainty analysis indicates that measuring approximately twice the pipeline length (≈200 km), and finding no more than two pipeline leaks, the upper bound on emissions would be in error by no more than 1% of total study area emissions. For basins with higher leak frequencies, pipeline emissions account for a larger fraction of total emissions, and relatively more pipeline must be measured to reduce uncertainty in the total leak count. For example, for areas with leak frequencies of 1 leak in 2 km, 25% of the pipeline network must be measured to constrain uncertainty to within 1% of total basin emissions.

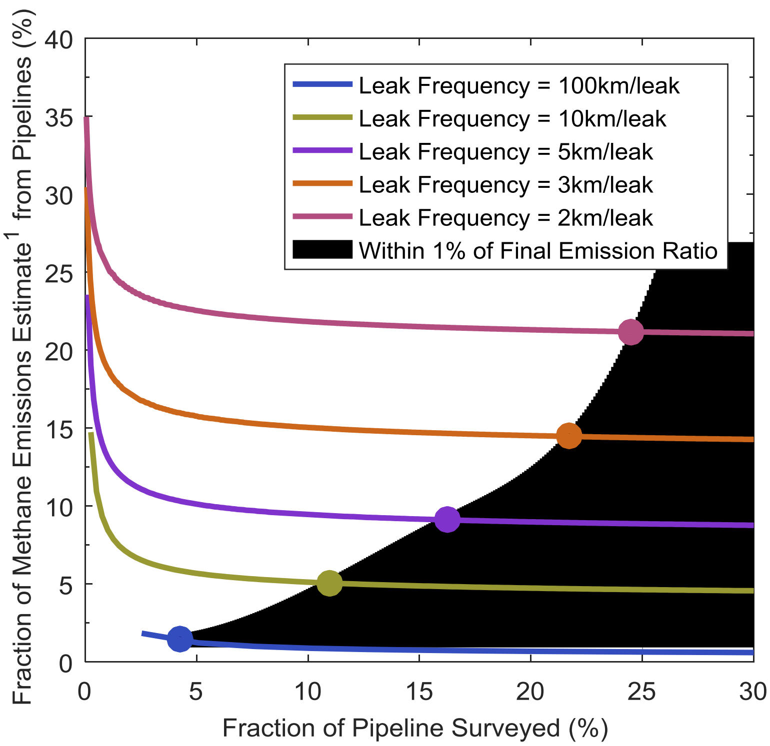

Figure 14: Required survey size to achieve a 95% confidence that any underestimate of emissions from gathering pipeline measurements is less than one percent total basin emissions. All pipeline leaks are conservatively assumed to be 4 kg/hr, as found in the study. Estimated emissions are normalized by Peischl et. al.'s estimate of 39 Mg/h from the eastern Fayetteville Shale. Black region indicates at what fraction of measured pipeline a study team will improve the estimate of total emissions by less than 1% of total basin emissions. The blue 100km/leak line appears to be cut off early because a point cannot be generated for the line until 100km have been traveled.

This analysis suggests that periodic, random, screening of small fractions of gathering pipeline systems could be utilized to (1) constrain leak frequency, and by extension total emissions from gathering pipelines, to within a well-understood fraction of total area emissions; and (2) that less pipeline length must be measured in basins where there is strong evidence of low leak counts in the region.

In conclusion gathering pipeline networks are a sector of the natural gas supply chain for which little-measured methane emissions data are available. For 12 days Leak detection was performed on 96 kilometers of underground poly pipeline, 56 pigging facilities and 39 block valves. Only one found underground pipeline leak emitting at 4.0kg/hr accounted for 83% of total measured emissions. Methane emissions estimated using a Monte-Carlo model for 4684km of gathering pipeline in the study area were 400 [+214%/-87%] kg/h (95% CI), or approximately 1% [0.1% to 3.2%] of the 39 Mg/h found in a prior aircraft measurement of the study region .This estimate is statistically similar to estimates based on emission factors from EPA's 2015 Greenhouse Gas Reporting program (200% [30% to 700%]) However, using emission factors from recent distribution studies to estimate emissions from gathering pipelines, as has been done in the past, would significantly underestimate emissions relative to current emission factors. The wide uncertainty range reflects the small sample size relative to the total gathering system in the study area. The study investigates what fraction of gathering pipelines in a basin must be measured to constrain any underestimate of pipeline leak emissions to within 1% of total basin emissions.

CHAPTER 3. DISTRIBUTION SYSTEMS

3.1 Background on Distribution Systems

This chapter describes distribution pipelines and auxiliary facilities in the context of the natural gas supply chain and their use in the study area. Distribution lines transport gas from transmission lines to customer meters. Distribution pipelines exist in two distinct groups

1) The natural gas infrastructure between the Transmission Distribution Transfer Stations (TDTS) and Regulating valves; these pipeline systems are called "service mains."
2) The infrastructure between regulating valves and customer meters called "services."

Distribution lines are typically constructed of plastic, steel, or cast iron. In the basin where this study was performed the pipeline mains and services are composed completely of cathodically-protected steel and plastic.

In addition to pipelines, three types of facilities are also installed on study partners' systems in the study area: Metering & Regulating facilities (M&R) as seen in Figure 15, TDTS as seen in Figure 16 and customer meters as seen in Figure 17.

Figure 15 A Metering & Regulating (M&R) Facility.

M&R facilities are usually small and designed to regulate natural gas flowing at a high pressure to lower pressures for delivery to customer meters. The majority of "M&R" sites in the study region are only comprised of regulators that regulate pressure; the entire distribution system is owned by one company, and additional metering is generally not required.

Figure 16 A Transmission Distribution Transfer Station (TDTS).

TDTS also commonly called Town Border Stations (TBS) or "city gates" and are much larger than a typical M&R facility. Gas from transmission lines is regulated from around 1000 psi to between 100-500 psi. All gas is metered by both companies at TDTS's. Each company has access to the others equipment but maintenance is only performed by each company on its own piping and valves. Piping is usually differentiated by paint color to know what components and pipe belong to what company.

Figure 17 A Residential Customer Meter.

Customer meters are the final sales point to the consumer. These meters regulate the pressure down to less than 0.25 psi [43] and meter all gas flow into the building. Most meters are also utilized for billing. The example displayed in Figure 17 is a residential customer meter. Commercial and industrial meters are larger and handle more gas flow. An industrial customer meter is shown in Figure 18. These types of larger meters exist at natural gas power plants, metal refining and processing plants, petroleum refining plants and other large gas consumers.

Figure 18 An Industrial Customer Meter [44].

Distribution systems are used to deliver natural gas to customers. Distribution systems exist in populated regions where it is profitable to operate natural gas distribution systems. Due to the nature of their systems being in populated areas, there have been several studies that look into the leak frequency and emission rate from distribution systems.

The type of pipeline material may drive distribution system leak frequencies, particularly when pipeline material is prone to corrosion, such as cast iron or unprotected steel pipe. A study performed in 1992 by the Gas Research institute and the EPA found that distributions systems accounted for 24.5% of total emissions from the natural gas supply chain, where 97% of total emissions from the distribution system are fugitive emissions. Fugitive emissions in the report were a result of underground pipeline leaks (54%), pressure regulating stations (36%) and customer meters (7.5%).

With the potential for a large fraction of emissions to be a result of distribution systems, several studies were launched to better characterize emission rate and leak frequency.

In one study in Boston all city roads were driven and scanned for methane enhancements[34]. During the study 3356 leaks were found with atmospheric enhancements that were greater than 2.5 ppm. In order to ensure the thermogenic origin of the gas, carbon isotopes were measured in the methane. This analysis indicated that a majority of methane emissions originated from oil and gas sources. It was found that neighborhoods with large amounts of cast iron pipe used for natural gas distribution also had more leaks than neighborhoods with little to no cast iron pipe, showing a correlation between the presence of cast iron pipes and leak frequency with $R^2 = 0.79$. Leak counts did not differ statistically by regions of differing income rates or poverty levels. Other pipeline materials did not have as strong of a correlation to leak frequency ($R^2 \leq 0.27$). These data suggests that cast iron pipes are a major contributor to distribution leaks.

A similar study was performed in Washington DC, 5893 leaks were found while driving 1500 road miles on city streets using a Picarro G2301 cavity ring down spectrometer [35]. Carbon isotopes and ethane were analyzed to ensure that methane enhancements were similar in composition to the natural gas in the distribution network. It is reported that Washington DC has the highest percentage of cast iron pipeline in the nation; 35% of the distribution mains are cast iron. They suggest that this high percentage of cast iron pipe contributes to the fact that Washington DC has an above-average "lost and unaccounted for" gas fraction, as well as a high number of leaks.

A multi-city study looked and leaks from distribution networks across Durham, NC, Cincinnati, OH, and Manhattan, NY where 132, 351, and 1050 leaks were found while scanning 595, 750, 247 road miles[36] respectively. The study reported that distribution networks have 90% fewer leaks where pipeline replacement programs have been implemented than distribution networks that have not had systematic pipeline replacement programs. Similar methods of scanning and source attribution were performed for this study as the Washington DC and Boston studies.

With the understanding that thousands of leaks have been detected in the previously mentioned studies, Lamb et. al. [37] conducted a national distribution system study to develop a better understanding of emission rates from distribution leaks. (Previously mentioned studies performed only leak detection and did not quantify leaks.) The study was performed on 13 local distribution companies' systems. The 13 sampled companies operate 19% of total pipeline mileage, 26% of total services and delivered 16% of total delivered natural gas in the United States in 2011. Comparing emission factors from the Lamb study with emission factors from the 1992 EPA/GRI study, emissions from distribution networks are approximately one fourth the emissions estimated in 1992.

Methods utilized in the Lamb study were also utilized in the study presented in this thesis. The author of [37] was present during this field campaign and spent time in the field with the measurement teams. The study performed here, like the Lamb study, performed both leak detection and leak quantification, allowing for emission factors to be generated for line types and metering and regulating stations by the single operating company in the study area.

It should be noted that the Lamb study did not perform measurements on distribution systems in the study region. The work presented here is the first to measure the distribution system servicing communities in and around the Fayetteville shale play.

Emissions from distributions systems have the potential to be a large source of emissions if the lines are primarily composed of cast iron and if leak detection and repair is not performed on a regular basis. In order to ensure that the methane emission from distribution system in the study area were accurately represented, measurements were performed on both local M&R and TDTS facilities as well as quantifying reported leaks in services and mains. These measurements were then statistically scaled and applied to the study region to generate a bottom-up estimate to compare to top-down emission estimates.

3.2 Measurements

A single distribution company services the study region. This company was partnered with the study team making 100% of distribution systems in the study area available for screening and measurement. While GIS information for locations of pipeline and services were not shared, complete leak lists and site counts were shared with the study team. Pipeline emission surveys were not completed during this field study. Reported leaks were randomly selected from a comprehensive leak list provided by the partner company. Counties with large areas in the study area were given preference to counties with little total area. Once counties were selected, sites were randomly measured to near completion. 100% of M&R facilities were measured in Faulkner, Van Buren, Conway, and Cleburne County. A description of facilities measured in each county can be seen in Table 6. The campaign ended while measuring sites in White county resulting in 44% completion of M&R sites. No measurements were made in Independence nor Jackson County. All sites were well maintained with easy access to the study team and could be measured in any order. There were no physical limitations or hazards that could prevent the study team from being able to measure a facility.

The only restrictions that existed in performing a survey were at TDTS sites, as they are split into two sides, Transmission and Distribution. At the onset of the field campaign, it was not clear that the study team had legal permission to measure the transmission side of the TDTS's. During the study, the local transmission company provided permission to measure the transmission side of the TDTS. For this reason, not all TDTS have measurements on both sides of the station.

Facility types were divided into Transmission/Distribution Transfer Stations (TDTS), metering and regulating (M&R) facilities and Customer Meters. The same method for screening and measurement applies to all facility types. Differences between facilities consist of use and size. TDTS have more components than M&R which in turn can have more components than customer meters. In addition to the difference in size, inlet pressures for each facility type also varies. TDTS have the highest pressure, as gas enters from transmission pipelines at around 1000psi and is regulated to approximately 300 psi before the gas leaves the TDTS in distribution mains. At M&R stations the pressure is further regulated to appropriate pressures for delivery to customer meters. The facilities are categorized by pressure in the following increments: greater than 300 psi, between 100 and 300 psi, between 40 and 100psi and less than 40 psi. The pressure aggregation matches that used in the Lamb study, however, it should be noted that no facilities measured in the region had recorded inlet pressures less than 40 psi. Customer meter upstream pressures are not reported and were not categorized by pressure in this analysis.

During the field campaign, customer meters were only measured if they had leaks. Four were measured during the campaign, three measurements were made at the lower detection limit of the high flow, (1.728 g ch4/h) and one had a leak of 93.54 g/h. Only customer meters with reported leaks were measured. Therefore, no data on the leak frequency of customer meters was available. Due to the small study size and small number of participating distribution systems, emission factors cannot be developed by this study.

The partner company had a list of underground pipeline leaks that was used to find and measure the emissions from the reported leaks. Sites were chosen at random. The leak list was primarily composed of class B and class C leaks with only one Class A leak. Leaks are classified using the Pipeline and Hazardous Material Safety Administration's (PHMSA) classification system. Class A leaks are repaired immediately as they pose a safety hazard, while class B and C leaks do not have to be repaired immediately. Emission rates from class A leaks are not necessarily larger than class B or C. Class A can be defined by proximity to human activity and associated risk. For this reason, no Class A leaks were measured during the campaign.

3.3 Measurement Platforms & Number of Locations Sampled

Distribution line leaks and auxiliary facilities were measured utilizing Heath Consultants RMLD to detect leak locations and an INDACO High-Flow analyzer to measure emission rate. Operators inspected each component at a facility with the RMLD and if a methane concentration above 20 ppm was detected, the component would be measured using the high-flow with either a plastic enclosure or cone to isolate the leak. Enclosure selection was dependent upon the shape of the component. Pneumatic controllers were measured whenever present at a facility using the high-flow. Measurements being taken with a high-flow and plastic bag attachment can be seen in Figure 19.

Figure 19 Operator performing a high-flow measurement of a leak emission at TDTS.

Measurements performed on underground pipeline leaks were found by using the leak list supplied by the partner company. In most cases, leaks had been marked by flags or tape by the partner company. However, if the tape or flag had been removed dead vegetation often indicated where the leak was located.

If leak location was not apparent or if the leak appeared to disperse wider than the enclosure, multiple measurements would be taken using the high flow and plastic enclosure in a gridded pattern. Figure 20 shows the underground leak plastic enclosure being used to capture methane, while the methane diffusion through the soil is depicted in Figure 21. In instances where the leak is larger than the enclosure, a gridded box pattern will be set up to capture all diffused methane. However, it should be noted that not all underground leaks required the large leak enclosure and the leak could be sampled in ways similar to other components as seen in Figure 22.

Figure 20 underground pipeline leak measurement enclosure. Placed over dead grass to capture leak diffusing through grass and along pipe that is connected to the above-ground pipe shown in the picture. Chain is used to provide a loose seal over the enclosure.

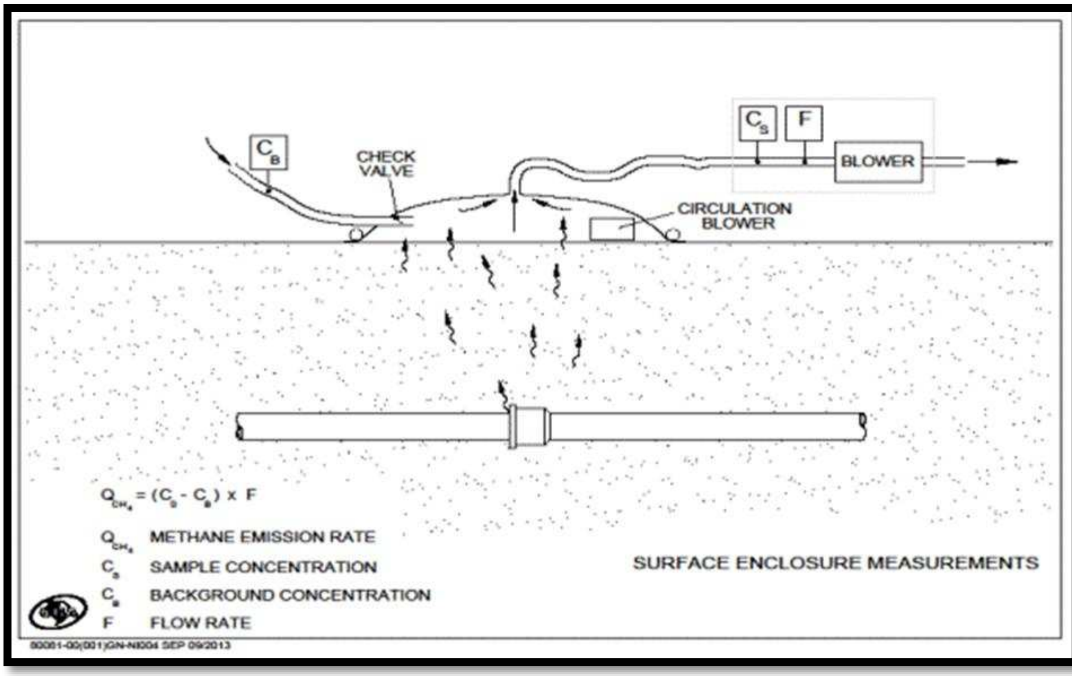

Figure 21 Depiction of underground pipeline leak. Methane can escape from a joint or crack and diffuse up through the soil to the surface. Methane emission can be assisted by natural faults or cracks in the dirt or nearby pathways that are formed by the presence of rocks or pipe that give the flow a more defined path to follow.[37]

Figure 22 Exposed underground pipeline leak being measured using the INDACO high flow and plastic bag enclosure.

During the field campaign counties with the most area in the study area were chosen to characterize the emissions from distribution pipelines and auxiliary facilities. The study area is defined by the orange box in Figure 23, and represents, the box flown by the aircraft when making mass-balance measurements of the study area. No GIS data for distribution pipelines is available. GPS coordinates were not taken by the study team during this campaign.

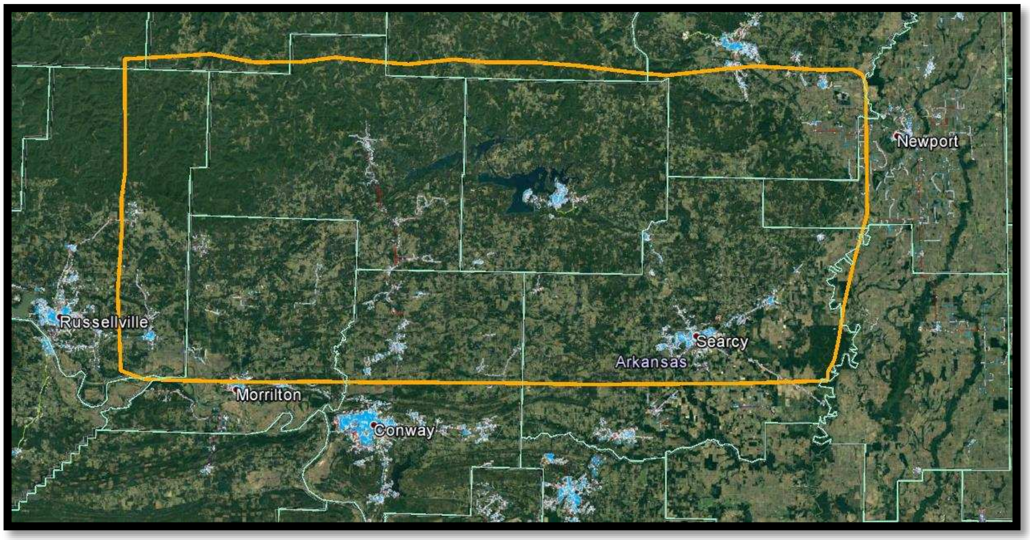

Figure 23 Study area Definition and approximate locations of Distribution systems.

During the field campaign, 34 reported leaks were measured. They were randomly selected from a leak list with 107 reported leaks. Upon selection of a leak, the study partner operators would guide the study team to the underground pipeline leak. Leaks were then measured using a specific enclosure designed to measure underground leaks in combination with an INDACO High-Flow as seen in Figure 20 and Figure 22.

Once the study team arrived at the facility all valves, gauges, flange, doors, hatches, joints and connectors were screened with a Heath Consultants RMLD. If upon screening a concentration of methane above background was detected a measurement would be attempted with the INDACO High-flow. The High-flow would be outfitted with either a plastic bag or cone shape enclose depending on the shape of the leaking object.

The same process applied to M&R facilities. All M&R facilities are in public areas and did not require additional permission from other companies to measure the facilities. Random sampling of M&R facilities was not required for the same reason that TDTS's did not receive random sampling.

The screening method is standard for the industry, and the measurement systems have been utilized in similar field campaigns. With experienced operators, it is a reliable method to detect and measure emissions on a facility. No form of facility level measurements were used in this campaign and total facilities are estimated by summing all known leaks found and quantified at a facility.

In the eight-county study region, there was a large number of facilities that could be measured, as seen in Table 4. Due to the extensive distribution measurement campaign performed on customer meters they were not randomly screened and measured to quantify emissions. This was the same approach used in the Lamb study to quantify emissions from customer meters. This assumption is described in greater detail in 3.4.

Table 4 Total operations in the eight-county study region. Services are counted and not measured by miles. All Commercial and Residential meters have a service line attached to them.

Pipelines		
Material	**Mains (miles)**	**Services (n)**
Protected Steel	599	16,440
Plastic	1,553	42,645
Cast Iron	0	0
Unprotected Steel	<1	0
Metering and Regulating		
Facility Type		**Facilities (n)**
Metering and Regulating Stations (M&R TDTS)		239
Commercial Meters		8,631
Residential Meters		50,352

Using the techniques described above, Table 5 shows the number and type of facilities screened and, if necessary, measured, during the campaign. Reported leaks are broken down by service and main.

Table 5 Sites visited during the campaign.

Source	Source Description	Number Screened
Transmission/Distribution Transfer Stations (TDTS)		
TDTS	Both sides of the facility	23
TDTS	Transmission side only	2
TDTS	Distribution side only	4
Distribution		
M&R	Metering and regulating facilities	100
Reported leaks	Company documented leaks	34

Onsite direct measurements were performed on 50% of all metering and regulating (M&R) and 69% of all transmission-distribution transfer stations (TDTS), as seen in Table 6.

Table 6 Facilities visited in each county and emission rate totals by county for screened and measured sites.

Screened and Measured Sites										
	M & R Sites			TDTS				Pneumatics		
County	Total	Visited	Total ($g\ CH_4/h$)	Total	Visited	Transmission side visited	Total ($g\ CH_4/h$)	Total	Total ($g\ CH_4/h$)	**Total County ($g\ CH_4/h$)**
WHITE	29	13	72.0	6	2	0	3.7	0	0.0	75.8
FAULKNER	37	30	15.5	11	9	9	54.5	5	981.7	1051.7
VANBUREN	27	27	4.9	1	1	0	1.7	0	0.0	6.7
CONWAY	10	10	1.7	8	7	6	0.0	0	55.5	57.2
POPE	15	15	5.3	5	4	4	156.2	2	480.3	641.7
CLEBURNE	5	5	0.0	6	6	6	381.9	1	133.9	515.8
INDEPENDENCE	47	0	NA	3	0	0	NA	NA	NA	NA
JACKSON	27	0	NA	2	0	0	NA	NA	NA	NA
TOTAL	197	100	99.5	42	29		598.0	8	1651.3	2348.8

In addition to the screened and measured sites, a list of screened and measured leaks can be seen in Table 7. Some counties did not have reported leaks. It can be seen that the majority of emissions are from pneumatics.

Table 7 Reported leaks visited in each county and emission rate totals by county for screened and measured sites. Reported leaks are assumed to be representative of the entire basin.

Screened and Measured Reported Pipeline Leaks									
	Services				Mains				
County	Known Leaks	Visited	Visited (%)	Measured (g/h)	Known Leaks	Visited	Visited (%)	Total (g/h)	Total Emissions (g CH_4/h)
WHITE	17	10	59%	168.5	23	11	48%	191.2	359.7
FAULKNER	11	5	45%	98.8	3	2	67%	1.7	100.5
VANBUREN	0	0		0.0	0	0		0.0	0.0
CONWAY	0	0		0.0	0	0		0.0	0.0
POPE	9	5	56%	75.8	4	1	25%	26.7	102.5
CLEBURNE	0	0		0.0	1	0		0.0	0.0
INDEPENDENCE	6	0		NA	5	0		NA	NA
JACKSON	1	0		NA	5	0		NA	NA
TOTALS	44	20	45%	343.1	41	14	34%	219.6	562.7

In addition to emission source, emission rate, and location; inlet pressures to the facility are also reported for M&R and TDTS facilities. No measured emission rate approached the upper measurement limit of the high-flow. All detected leaks were quantified. Of the 163 measurements performed 105 were zero and 31 were at the lower detection limit (1.73 g CH4/hr). Measurements were also performed on reported leaks which were categorized as either mains or services. Leaks were randomly selected from the leak list to be measured. Class A leaks were not measured in this campaign. Class A leaks are repaired as quickly as possible because of their potential safety hazards, but they are not necessarily larger than class B or C leaks. There was only one Class A leak in the leak list. Of the 34 leaks measured on the leaks list seven were zero 19 were at the lower detection limit (1.73 g CH4/hr).

All measurements were performed with the measurement devices listed in Table 8. All measurement equipment was calibrated each morning before measurements were performed.

Table 8 Measurement Equipment Used in field campaign for the distribution sector.

Manufacturer	*Instrument*	*Model Number*	*Use*	*Serial Number*
Heath Consultants	RMLD-IS	RMLD-IS	Underground pipeline leak delineation/detection	8.10E+09
Heath Consultants	DP-IR	DP-IR	Underground leak delineation	91013-40001
INDACO	High-Flow	BT-GCI-211 TSL- 8340	Underground pipeline leaks w/ enclosure	

3.4 The Model and Methods

The model was constructed for estimating emissions from the distribution network in the entire study area. The model utilized Monte Carlo methods[39] and follows the schematic plan in Figure 24. The remainder of this chapter will discuss how each block was determined and estimated.

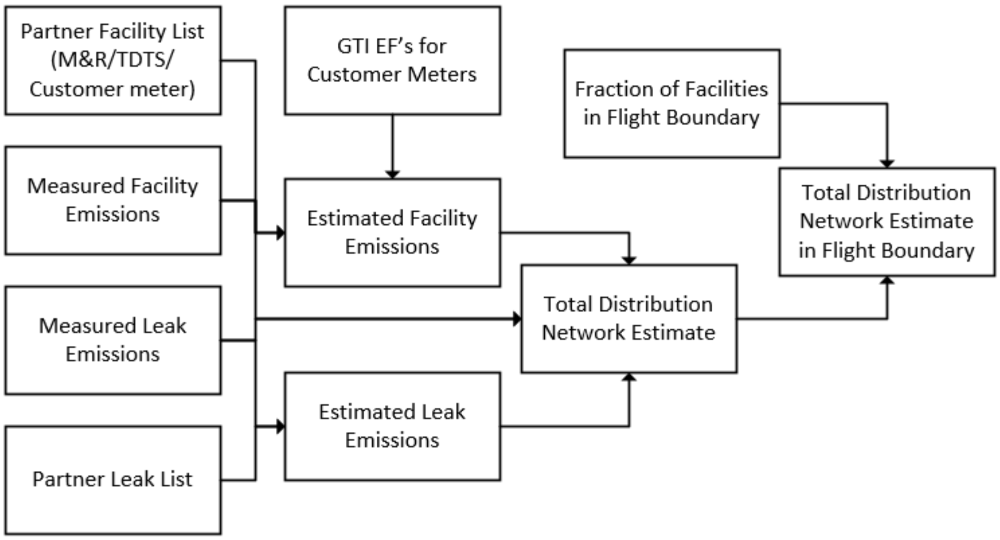

Figure 24 Model visualization for distribution system emission estimate. All information on the left boxes were supplied by the partner company or measured in the field campaign. GTI EF's represent the only external source of information in the estimate.

A study area estimate was generated using the information collected in the study. Emissions estimates for M&R and TDTS facilities utilized only emissions data collected in this study. Estimates from a Gas Technology Institute study[45] were used to provide a range of potential emission factors for both residential and commercial customer meters. The measurements taken at the lower detection limit of the high flow were not estimated but were taken as the reported value which is the lower detection limit. The Lamb study did help guide the model of this study, the same method to separate facilities by inlet pressure was used as well as distinguishing facilities by M&R TDTS, main, service and customer meters. Where the Lamb study is focused on annual emissions from distribution lines this study is focused on a two-day period of combined total emission rate to compare against aircraft measurements, because of this annual leaks are not considered, and the leak list provided by the partner company is assumed to be complete and representative of all leaks that exist in the system during the mass balance flights.

The model developed a study area estimate by breaking facilities down into measured and non-measured leaks and facilities. The facilities and leaks that had measurements performed on them used the measured values to simulate the emissions. Facilities and leaks that did not have an associated measurements had an emission rate randomly assigned to the facility in Monte Carlo Model[39] pulling emission rates from distributions of emission rate measurements for the same equipment category operating at a similar pressure. Unmeasured TDTS sites would randomly assign the presence of pneumatics to a facility based upon the fraction of observed TDTS sites that had pneumatics. If a facility was assigned to have pneumatics then an emission rate would be randomly selected from the range of possible emissions that were measured on pneumatic equipment. TDTS sites were simulated for both transmission side and distribution sides independently, to account for emissions when only the distribution side or the transmission side was measured. For each side, random measurements were pulled from distributions of emissions for that side of the TDTS.

Customer meters represent a different part of the distribution system that were not measured in this study. In 2009 a large measurement campaign performed by the Gas Technology Institute [45] surveyed 836 commercial meters and 2400 residential meters. Emission factors were established for seven commercial and six residential companies for each company's meters and can be seen in Table 9 and Table 10. This range of potential emission factors for each company provided the range of emission rates for distribution systems similar to those in the study region. Emission rates drawn from this distribution were multiplied by number of customer meters and residential meters in the study area to obtain and approximate emission rates for each county

Table 9 GTI Residential meter emission factor estimates provided from six different field surveys. Reorder from largest emission factor to smallest emission factor.

Field Survey	No. Fugitive Leaks Identified	No. Vented Emissions Identified	Total Natural Gas (ft3/year)	Total Methane Emissions (lb CH4/year)	No. Residential Meters Surveyed	Residential Meter Emission Factor (lb CH4/meter-yr)
Test D	27	0	72,927	2853	420	6.79
Test A	5	1	34,073	1,344	288	4.67
Test F	2	4	9,203	371	362	1.02
Test C	1	0	2,637	104	201	0.52
Test B	4	2	5,950	235	637	0.37
Test E	3	2	2,398	94	492	0.19
Total	42	9	127188	5001	2400	2.08

Table 10 GTI Commercial meter emission factor estimates provided from seven different company surveys. Reorder from largest emission factor to smallest emission factor.

Company	No. Fugitive Leaks Found	No. Vented Emissions Found	Total Natural Gas (ft3/year)	Total Methane Emissions (lb CH4/year)	No. Commercial Meters Surveyed	Commercial Meter Emission Factor (lb CH4/meter- yr)
D	11	1	162,519	6,413	91	70.47
G	6	28	265,700	10,485	440	23.83
B	1	3	12,658	499	65	7.68
F	1	5	9,626	388	64	6.15
A	5	0	2,397	94.61	36	2.63
C	1	0	995	39.3	77	0.51
E	0	1	448	19	63	0.30
Total	25	38	454,343	17,938	836	21.46

As seen in Figure 23 and Figure 25 not all distribution systems are in the flight boundary of the aircraft. For this reason, emissions from the study area had to be scaled accordingly to not overestimate emissions from the distribution system that would be seen by the aircraft. The distribution system operator provided a map of facility locations and the fraction of sites in the area was multiplied by total emissions to determine approximate emissions within the flight boundary on a county level. To estimate the amount of distribution system in each county, the total number of pixels in each county associated with distribution systems was counted along with the number of pixels inside the flight boundary for each county. This ratio of total pixels to pixels in the flight boundary was used to approximate the fraction of total emissions that would have been seen by the aircraft. The Monte Carlo model was iterated 100,000 times to produce results.

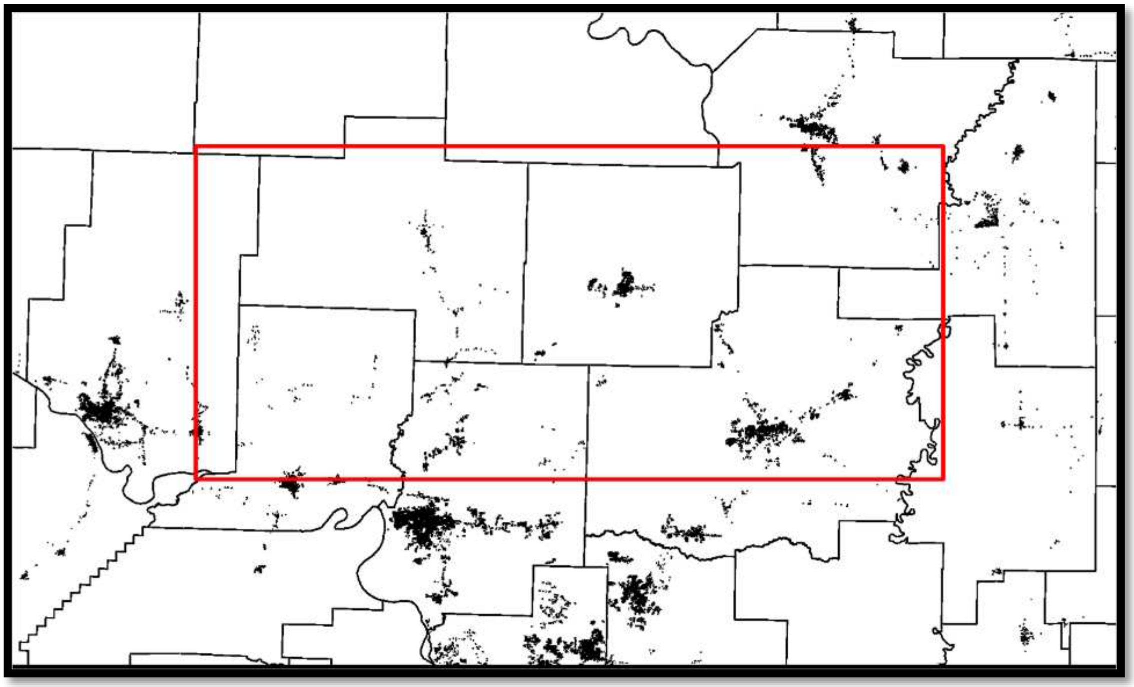

Figure 25 Monochrome graphic used to determine content within flight boundary in and out of each county.

3.5 Results & Discussion

Simulation results indicate that the majority of emissions from all TDTS, M&R sites, and line leaks in the eight-county area are a result of pneumatic releases, which account for 53% of total emissions. Reported leak emissions are second largest, accounting for 27% of all emissions. TDTS fugitive emissions, excluding pneumatic emissions, account for 14% of all emissions and M&R fugitive emissions account for 5% of emissions. County level emissions and uncertainties can be seen in Figure 26. Emissions shown in the figure have not been scaled to reflect the proportion of the total what was inside the flight boundary.

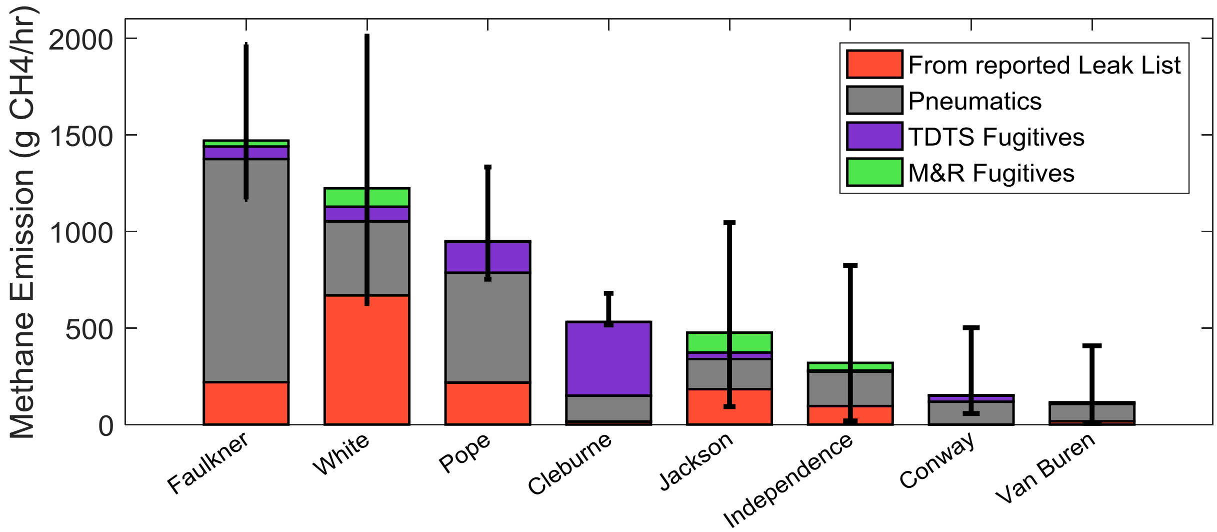

Figure 26 TDTS, M&R and line leak emissions sources by county, with uncertainty. Uncertainty is dominated by pneumatic emissions. White county has large uncertainty because it has more unmeasured reported leaks than any other county, Jackson, and Independence County also have large uncertainties because they had no measurements performed. Emissions shown in the figure have not been scaled to reflect the proportion of the total what was inside the flight boundary, and meters are not included in this analysis.

Adding emissions from residential and customer meters cause emission estimates to change on a county level, as seen in Figure 27. It can be seen that uncertainty for total emissions also changes significantly. This is due to the large variability in customer meter emissions that were reported in the GTI study. Emissions for residential meters range from 0.19 lb CH4/meter/year to 6.79 lb CH4/meter/year and emissions from commercial meters range from 0.30 lb CH4/meter/year to 70.47 lb CH4/meter/year. It should be noted that while there are nearly 7 times as many residential meters as there are commercial meters, the total emission rates are similar due to the large emission factors associated with commercial meters.

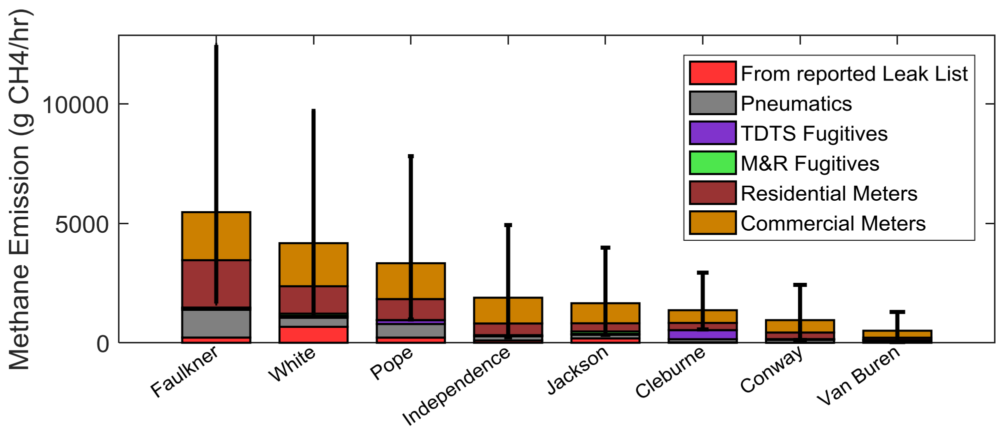

Figure 27 Emissions from all Distribution source categories in the eight-county region.

When including customer meters it can be seen that emissions are dominated by this category. In order to get an understanding of how emissions from the basin could change depending on what emission factors from the GTI study are used Figure 28 shows how the average emission factor and the uncertainty decrease when the largest emission factor for both residential and commercial meters are excluded.

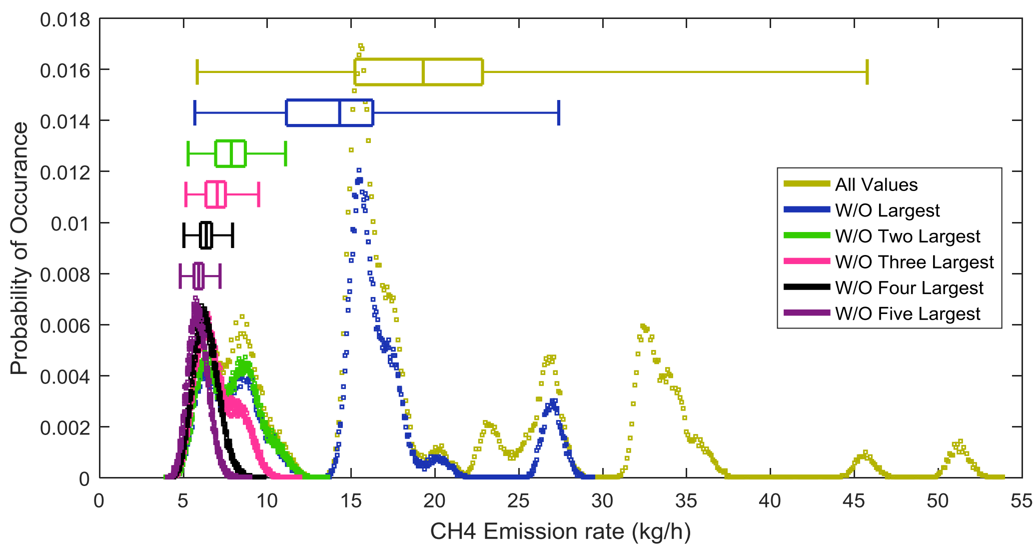

Figure 28 Total emissions from the distribution system Includes all potential emission sources. The gold distribution includes all reported customer meter emission estimates as seen in Table 9 and Table 10. Blue distribution excludes the largest reported customer meter emission estimates for both residential and customer meters. Green distribution excludes the largest two, pink excludes three largest, black excludes four largest and purple excludes five largest residential and commercial customer meter estimates. Box and whisker plots show mean, one standard deviation and two standard deviations for each distribution.

In order to preserve the worst case scenario of emissions and to include any rare event emission sources from customer meters all reported emission rates were used in the analysis. Figure 27 displays total emissions for the eight-county area, while Figure 29 shows the fraction of estimated emissions in each county which are inside the aircraft light boundary.

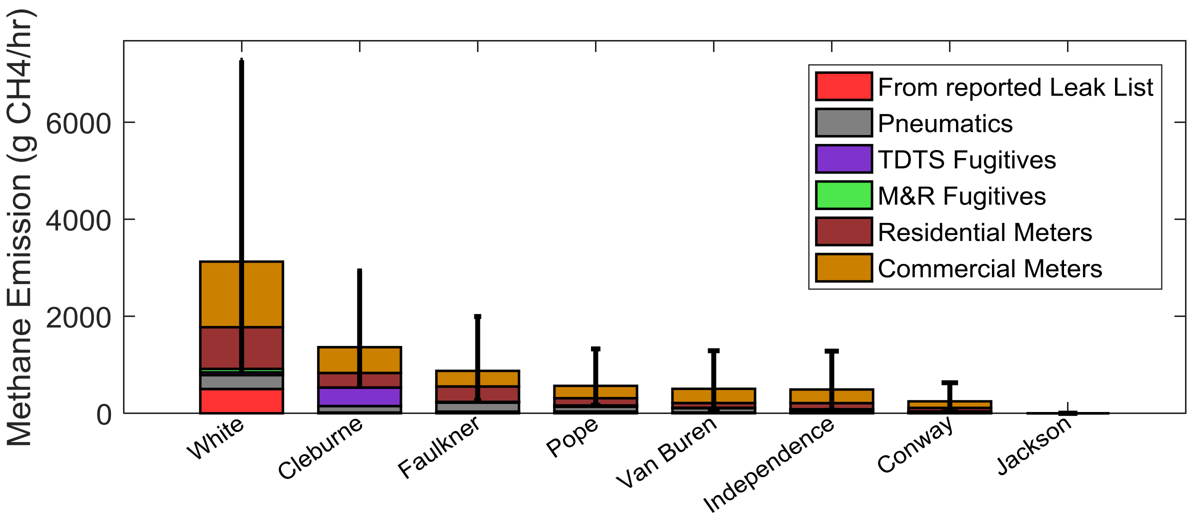

Figure 29 Scaled county level emissions by fraction of facilities in flight boundary.

When comparing the measurements performed in this study with emission rates found in the Lamb study it can be seen that emissions from reported leaks are statistically similar to the Lamb study. In contrast emissions from TDTS's and M&R's are significantly lower than in the Lamb study (Table 11).

Table 11 Study comparison with Lamb study shows the statistical similarity between reported leaks and statistical difference between facility emissions.

	EF Lamb (kg/h)	EF This Study (kg/h)			# of sites	Average Total Emissions(kg/h)	
Source Category	Mean	Mean	Low	High		Lamb	This Study
TDTS	0.35	0.08	0.06	0.11	42	14.76	3.53
M&R	0.24	0.00	0.00	0.00	197	46.33	0.28
Main	0.05	0.02	0.01	0.03	41	2.06	0.70
Service	0.01	0.02	0.01	0.03	45	0.35	0.72
Commercial Meter	0.0011				7728	9	9
Residential Meter	0.0001				50822	5.48	5.48
Total Emission Estimate						77.57	19.29
Total Emission Estimate Scaled by area						28.8	7.2
Measured source Emission Estimate Scalled by Area						63.50	2.1

These data indicate that the local distribution operator has lower methane emissions than the national average. It can also be seen that by scaling by proportional area in and out of each county the total estimated emissions that the aircraft would see is significantly reduced from 19.29 (kg/h) to 7.2 (kg/h). Finally, attention needs to be drawn to the size of proportional emissions from customer meters which were not measured in this study. While including them in the study would have reduced the time available to measure other sources it could have provided a superior estimate of emission from the operator. Future studies could randomly measure customer meters develop emission factors comparable to the GTI study. This could reduce uncertainty in this emission category and improve the understanding of actual emissions from the distribution network being measured.

CHAPTER 4. NON-OIL & GAS EMISSION SOURCES

4.1 Non-Oil & Gas Emissions Sector

Methane emissions occur from a variety of sources and to properly attribute the emissions to the natural gas sector an understanding of where potential emissions can occur is imperative. This section analyzes methane emission sources that are not directly related to the natural gas supply chain, including biogenic and natural thermogenic sources.

The second largest source of methane generation in the U.S. is from enteric fermentation (Figure 31). Enteric fermentation is a process that occurs in ruminant animals, or animals with multiple stomachs that use bacteria located in the rumen (fore-stomach) to digest material that monogastric animals cannot, usually grass or hay. The bacteria ferments the rough plant matter and allows for further digestion. In this process methane is emitted. [46] In the US, enteric fermentation emissions are dominated by cattle.

Other sources of methane emissions such as manure management, wetlands, ponds, lakes, rivers, landfills, wastewater treatment and rice fields, all occur due to anaerobic digestion. Anaerobic digestion is the process by which bacteria break down organic matter into methane, CO_2, and other trace gasses[47]. The reaction occurs in environments that do not contain dissolved oxygen, usually underwater or underground. Anaerobic digestion can take place over a wide range of temperatures and be completed by a wide range of bacteria species, causing variation in the production of methane from the same source material. Methane production through anaerobic digestion is lower at ambient temperatures than at higher temperatures. [48] An image of a wetland preserve area found near the study region is shown in Figure 30.

Figure 30 Wetland near study area in Arkansas. A typical example of a source where anaerobic methane emissions could occur.

The non-oil & gas methane emissions analysis developed for this study consist of three categories of sources: (a) naturally-occurring thermogenic methane emissions– i.e. thermogenic gas that is not released from oil and gas industry operations; (b) biogenic methane from anthropogenic activities, and (c) biogenic methane from naturally-occurring processes.

One naturally-occurring source of thermogenic methane emissions is geological seepage. Geological seepage is natural gas from gas-bearing formations that passes through geological features such as cracks, fissures, or even permeable soil and made its way to the surface. Thermogenic methane can be identified by the presence of carbon isotopes that differ from carbon isotopes present in biogenic methane[49] or the presence of ethane in conjunction with the methane. Geological seepage has been reported to be a large emission category on the global scale and was also analyzed to determine potential emissions from the region.

Anthropogenic methane is released from sources other than oil and gas operations. The analysis in this study was guided by the Greenhouse Gas Inventory's (GHGI)[50] methods to understand the other major sources of anthropogenic methane emissions. Figure 31 illustrates the large impact of other emission categories on total methane emissions and emphasizes the importance of estimating methane emissions from all potential sources, both anthropogenic and natural.

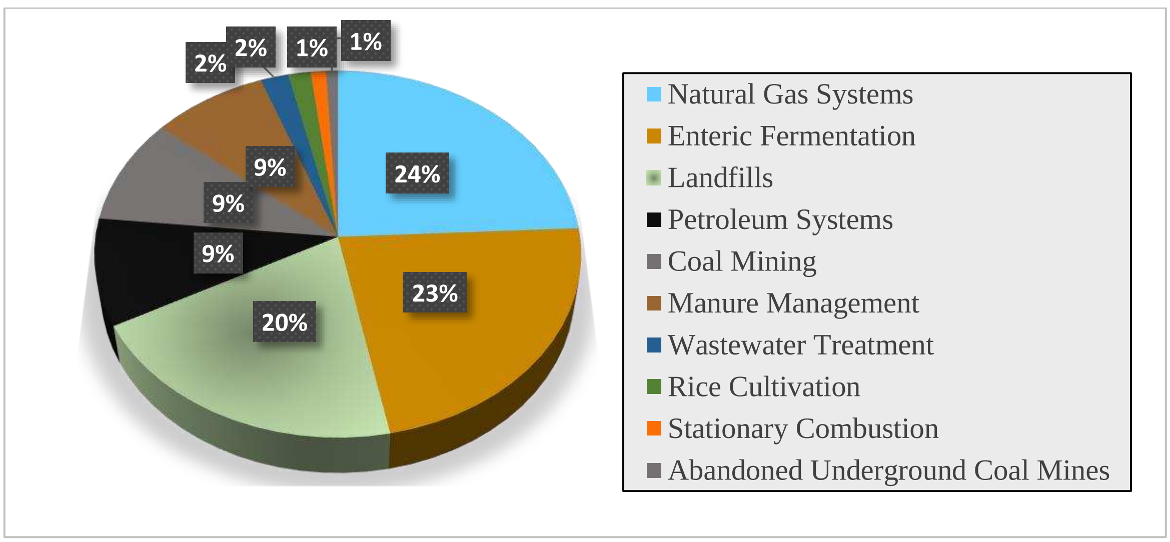

Figure 31 Non-Oil & Gas emissions from anthropogenic sources in the study region

The GHGI does not include emissions estimates from naturally-occurring biogenic sources, such as wetlands, rivers, ponds, and lakes, but these emissions are included in this analysis. Emissions from natural sources were guided by available activity data such as wetland, river, pond, and lake, locations and areas were provided by U.S. Fish & Wildlife service[51]. A report on emissions from natural sources [52], shows that wetlands dominate in total natural source emissions, followed by lakes. The wetland areas provided by [51] were known locations that had the potential to generate methane through anaerobic digestion. Once the largest natural emission source as reported by [52] were estimated other categories of potential methane emissions were reviewed.

Finally, all other unknown sources of methane generation were examined using GHGRP FLIGHT[53] to see if other unknown facilities in the region could be emitting methane. A coal-fired power plant was found in the northeast region of the basin. Numbers provided by FLIGHT were used to estimate emissions from the source and were not estimated in this analysis.

Combined anthropogenic methane emissions from non-oil and gas sources are larger than emissions from oil and gas sources on a national level as seen in Figure 31. The GHGI supplies extensive information on each source category of anthropogenic methane emissions and was used as the literature review for agriculture, landfills, waste water, and stationary combustion. Similarly to better understand methane emissions from natural gas systems and other anthropogenic sources there has been a push to understand methane emissions from all possible sources. The influence of wetland methane emission has been documented for over 25 years[54], but there has been a recent push in better understanding methane emissions from sources that aren't as well characterized, including, rivers, ponds, reservoirs, and geological seepage.

Rivers have historically been viewed as having minimal potential for methane production and emission due to the aerated environment that prevents anaerobic digestion. However, there has been an increased understanding of the pervasiveness of methane within rivers and streams, and it is now estimated that rivers emit 26.8 Tg CH4 annually which is 15-40% of wetland emissions.[55]

Ponds, similarly to rivers, have not been estimated in many previous greenhouse gas inventories, driven in part by the lack of information on the quantity and size of the small ponds. Recent improvements in satellite imaging along with measurement campaigns of small ponds has provided better estimates of pond count and area. Methane diffusion rates in small ponds have been reported to contribute 40.6% of diffusive CH4 emissions from freshwater lakes and ponds even though they only comprise 8.6% of total area of lakes and ponds globally. This higher flux rate from smaller ponds thus increases the contribution of small ponds to the global methane inventory more than previously anticipated and represent and important inland water source of methane [56].

Reservoirs have been measured in recent history but detailed correlations between methane emissions and reservoir nutrient content, average temperature, and latitude have not been made. The relationship between methane emissions and chlorophyll-a in the water has the strongest correlation with $R^2 = 0.5$. This correlation predicts methane emissions better than latitude or temperature. It is reported that global methane emissions from reservoirs can be as large as 52.5 Tg per year and that previous studies that ignore methane emissions from bubbling or ebullition are likely to underpredict total methane emissions.

Geological seepage as mentioned earlier, releases thermogenically produced methane, unlike other biogenic natural sources that generate methane through anaerobic digestion. Geological seepage of methane occurs in 75% of all petroliferous basins and is enhanced by the presence of faults and fractures in rocks. Geological seepage is the process by which methane will follow faults up through the earth's crust towards the surface. In some instances, the cracks connect subsurface reservoirs directly to the surface resulting in macro-seeps that are easily detectable. If the cracks or fissures don't continue to the surface but stop in upper soil layers, methane can still disperse through the soil resulting in micro-seeps. Micro-seeps have been largely unreported and are now starting to receive more attention due to the global impact they could present. Recent estimates put global microseepage at greater than 10 Tg/year[57]. The occurrence of geological seepage in the study region was corroborated by water quality studies performed in 2012[58]. Measurements were performed on drinking water wells where dissolved CH4 was found in 32 out of 51 wells. Thermogenic methane was only found in single well showing that geological seepage is possible in the basin but it is not widespread affecting all water wells in the basin.

Beyond the gas operations analyzed in the larger study, there are no other petroleum operations in the study area and there are three abandoned or partially filled hand dug coal mines in the study region as reported by [59] Due to the small quantity they are not estimated in this analysis.

The analysis presented here covered a similar region as the non-oil and gas estimate made for the Peischl et. al. study [16], but there are differences in both analysis methods and results. Peischl estimated enteric fermentation using similar methods as this study, but used a mean average emission factor for all cattle types, while this study used average emission factors for each cattle type in the study region – primarily beef cattle and calves, and dairy cattle. The Peischl study also used estimates provided by NREL for emissions from manure management. This service provides potential emission estimates and not actual emission estimates, the analysis presented in this work is estimated using emission factors reported by the GHGI and uncertainties for emission factors from IPCC. This study also includes an emission estimate for other agricultural operations such as rice cultivation, and waste management. Based upon the time of year for the Peischl study, emissions from rice cultivation and wetlands should also have been included in the study, since it occurred during the wet season. Scaling county level reported animal counts was done in a similar fashion using the percent of the county in the flight boundary to approximate a similar ratio of livestock being present in the flight boundary. The study model is described in detail in the following section.

4.2 Data Model and Methods

Disclaimer: This section has been submitted for publication and is waiting on approval.

Non-oil and gas CH_4 emissions were estimated from (i) anthropogenic sources such as enteric fermentation, landfills, coal mining, manure management, wastewater treatment, rice cultivation, stationary combustion and abandoned underground coal mines as guided by [41], (ii) natural sources such as wetlands and geological seepage (using [51] and [57]), and (iii) other methane sources in the study area such as large landfills or power plants [53] that are not accounted for in (i) and (ii).While absolute CH_4 emissions were reported for (iii), emissions for (i) and (ii) were estimated using Eq. 1, where EF_{Source} are source-specific emission factors, AD_{Source} are the associated activity data, and FA_{County} is the spatial fraction of the county in the study area.

Equation 1

$$Total\ Emissions = \sum EF_{\mathrm{Source}} * \mathrm{AD}_{\mathrm{Source}} * FA_{County}$$

Activity Data represent the count of potential emission sources (livestock, stationary combustion, and wastewater) or aerial extent for potential area sources (geological seepage, wetlands, landfills, and rice fields). All study activity data and literature sources are shown in Table 12. All activity data, with the exception of wetlands, ponds, lakes, and rivers, are multiplied by the surface area fraction of the county within the study area. Wetland activity data locations based on [51] are shown in Figure 32. Only wetlands within the red box were included, which represents the approximate flight path during the mass balance. Only permanently flooded wetland types were used in the analysis. Temporarily and seasonally flooded wetland types were not included in the activity data because the mass balance flights occurred during the dry season. The description of seasonally, temporarily and permanently flooded wetland types is provided in [51]. Agricultural activity data is available at the county level [60].

Table 12 Study area activity data reported by county. NA signifies that the actual number is not disclosed to avoid revealing an individual's personal operation and assets. For this analysis NA is assumed to be zero if supplemental information could not be found. The* denotes information was provided by the 2007 Census data. Category source references can be found bellow. White text denotes values were provided on a county level basis. Black text represents data found with geospatial coordinates and is assumed to be representative of actual locations. Red text belonging to geological seepage resents values with the largest uncertainty as no geological seep studies have been performed and there is no information on fault line, cracks or fissures that could facilitate in the emission from geological seepage.

Categories	Cleburne	Conway	Faulkner	Independence	Jackson	Pope	Van Buren	White	Total
Beef Cattle[A]	34,276	37,436	30,168	36,053	4,458	29,870	18,736	41,951	232,948
Dairy Cattle[A]	0	1130*	886	0	0	0	790*	401	2,262
Broilers (10^3)[A]	1,722	6,889	0	2,711	0	4,871	489	806	17,489
Layers (10^3)[A]	390	63	3	75	0	156	1	NA	687
Swine[A]	140	12,512	129	104	0	9,380	3103*	408	22,673
Rice Fields (km^2)[A]	0	5	10	38	355	15	0	41	463
Emergent Wetlands (km^2)[B]	0	7	3	1	0	3	0	4	18
Forested Wetlands (km^2)[B]	1	0	0	3	3	0	0	42	48
Ponds (km^2)[B]	7	8	7	5	1	3	7	14	52
Lakes (km^2)[B]	90	12	0	1	0	4	37	6	150
Rivers (km^2)[B]	9	2	2	10	2	4	4	24	57
Stationary Combustion[C]	0	0	0	1	0	0	0	0	1
Wastewater (People*10^3)[D]	25	21	122	37	17	63	17	79	371
Septic/Sewer[E]	0.70	0.60	0.51	0.65	0.36	0.49	0.74	0.49	0.54
Landfills (km^2)[F]	0.04	0	0	0	0	0	0	0	0.04
Geologic Seep (km^2)[D]	1,434	1,430	1,678	1,979	1,642	2,104	1,834	2,681	14,782
In Study Area[F]	100%	87%	59%	40%	13%	40%	100%	79%	64%

Notes: Published estimates of geologic CH_4 seepage do not yet exist in the study area. Globally, more than 75% of all petroliferous basins on the global level contain macro-seepage (with microseepage also present; [57]). We calculated total non-oil and gas CH_4 emissions in the study area for two cases: geologic seepage (i) is not present, and (ii) is present in the entire study area considering the published global geologic seepage flux distribution described below.

References for Table 12 as follow: A) 2012 Census data [60]; B) U.S. Fish & Wildlife Service: Wetland and Wildlife Wetland Mapper [51] ; C) GHGRP FLIGHT [53] ;D) U.S. Census Bureau QuickFacts [61] E) Arkansas Department of Health [62]; F) Estimated Areas Using Google Earth [63]

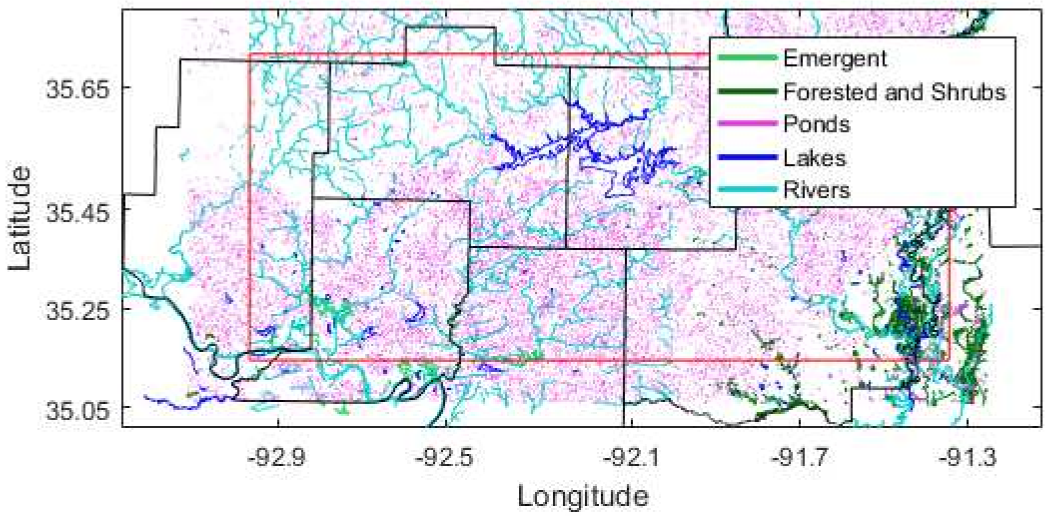

Figure 32 Activity data for wetlands, rivers, ponds and lakes provided by the U.S. Fish and Wildlife service [51]. Wetland types are provided with codes that describe if wetlands are seasonally, temporarily or permanently flooded. Only permanently flooded wetlands were used in this analysis as the field campaign took place during the dry season and mass balance flights occurred during dry sunny days without temporary flooding. Only permanently flooded areas are shown in the figure.

Figure 33 provides a summary of the total area by wetland type in each county. Line width in Figure 32 appears to show greater prevalence of ponds than is representative of the actual area. While there is a large quantity of small ponds their overall total area is not substantial as seen in Figure 33.

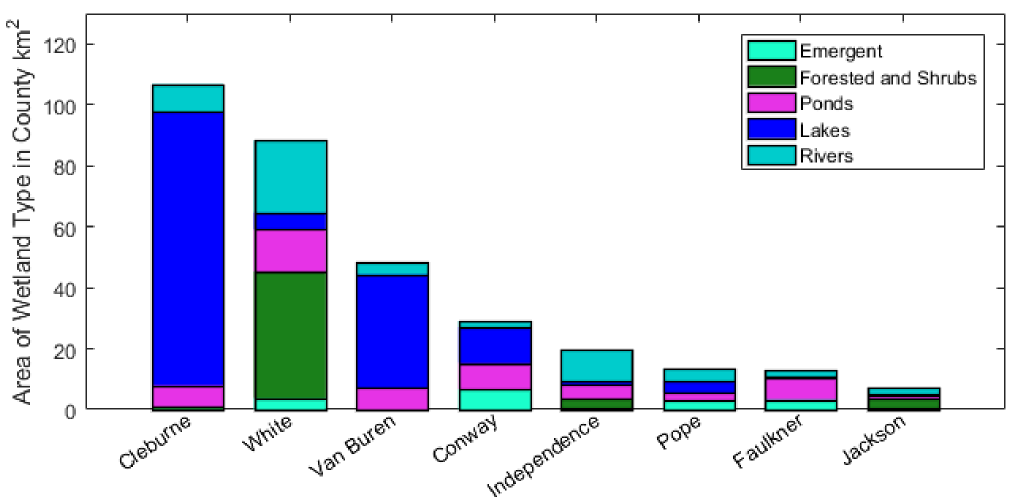

Figure 33 Comparison of wetland area types in the 8 county study region Wet land size has been adjusted to aircraft flight boundary showing total areas of what the aircraft would see.

Emission Factors represent estimated (see details below) or reported CH_4 emissions per area, count, or population. We assume triangular distributions based on the reported mean values and confidence intervals listed in Table 13.

Table 13 Emission Factors and Confidence Intervals Used in Analysis.

Emission Categories	EF	95% CI	Source
Beef Cattle (g CH4/(h*head)) [P]	8.4	±50%	GHGI/IPCC
Beef Cattle Manure Management (g CH4/(h*head)) [P]	0.2	±30%	GHGI/IPCC
Dairy Cattle Enteric (g CH4/(h*head)) [P]	13.5	±50%	GHGI/IPCC
Dairy Cattle Manure Management (g CH4/(h*head)) [P]	0.2	±30%	GHGI/IPCC
Broilers Manure Management (g CH4/(h*head))[P]	0.01	±30%	GHGI/IPCC
Layers Manure Management (g CH4/(h*head))[P]	0.01	±30%	GHGI/IPCC
Swine Enteric Fermentation (g CH4/(h*head)) [P]	0.2	±50%	GHGI/IPCC
Swine Manure Management (g CH4/(h*head))[P]	1.6	±30%	GHGI/IPCC
Rice Fields (kg CH4/(h*km^2) [E]	0.1	-35% / +41%	GHGI/IPCC
Emergent Wetlands kg CH4/(h*km^2)[E]	7.25	-32% / +38%	Bartlett (1990)
Forested Wetlands kg CH4/(h*km^2)[E]	4.05	-45% / +50%	Bartlett (1990)
Ponds kg CH4/(h*km^2)[E]	0.75	-46% / +46%	Holgerson (2016)
Lakes kg CH4/(h*km^2)[E]	2.25	-53% / +83%	Deemer (2016)
Rivers kg CH4/(h*km^2)[E]	0.6	-290% / +290%	Bastviken (2011)
Stationary Combustion (kg/hr)[P]	136	0% / +0%	GHGRP
Wastewater Sewer (kg CH4/(h*capita))[E]	0.05	NA	GHGI
Wastewater Septic (kg CH4/(h*capita))[P]	0.4	-30% / +30%	Leverenz
County Landfill (kg CH4/(h*km^2)) [E]	801	-56% / +61%	GHGRP FLIGHT
Geologic Seep kg CH4/(h*km^2)[E]	0.1	-162% / +217%	Etiope & Klusman(2010)
Notes	P = Published Value		
	E= Estimated for this analysis		

Estimated values were calculated as follows:

Geological Seepage:

Geologic seep CH_4 emission estimates in the study area are based on reported global geologic seep flux measurements [57], which are categorized into three seep intensity levels (level 1 = 210 mg CH_4/m^2/day, level 2 = 14.5 mg CH_4/m^2/day, and level 3 = 1.4 mg CH_4/m^2/day). We assume only level 3 flux rates in our study are for two reasons. First, level 1 and level 2 flux rates are most commonly found in regions with macro-seeps [57], and macro-seeps are not reported in the study area. Second, only 2% of water wells in the study area include thermogenic CH_4 [58] compared to 5% in the Denver-Jules basin [64], which has reported CH_4 fluxes for both levels 2 and 3 [57]. Based on reported level 3 flux statistics [57], a triangular emission distribution was generated with a peak of 1.4 mg CH_4/m^2/day, a minimum of 0 mg CH_4/m^2/day, and a maximum of 5 mg CH_4/m^2/day.

Wetlands: Global CH_4 emission estimates were found in Methane and Nitrous Oxide Emissions from Natural Sources [52]. Emission factors from the most recent global estimate [54] published in [52] were used in this analysis. Descriptions of wetlands in the study area provided by [51] and were used to apply the appropriate emission factors published in [54]. An average emission flux within a set range for **forested wetlands** is provided in [54]. Using the reported emissions flux rates a triangular distribution was generated for this analysis. The reported emission flux is based off a seasonal average. This seasonal emission factor was applied to the study area during the field campaign which was during the dry season, the seasonal variation is accounted for in the activity data and not in the emission factor. **Emergent wetlands** and bogs also have a reported average emission factor along with a provided range, these values were also used to create a triangular distribution for potential emissions from emergent wetlands. Emission range values are provided in [54]. It should be noted that the reported mean is different than the mean emission factor used in the analysis due to the nature of the triangular distribution not accurately representing the true distribution of measurements.

Table 14 Calculated emission factors for mid-latitude wetlands based on Bartlett et al. Modified to a seasonal emission factor on a per hour basis instead of a seasonal emission factor on a daily basis. Due to the shape of the triangular distribution, the median emission values is not the mean of the distribution. This allows for a high biased conservative estimate of emissions from wetlands.

Source and Units	Minimum	Reported Mean	Maximum
Bartlett Emergent EF (kg CH4/km^2/h)	4.25	6.7	10.8
Bartlett Forested EF (kg CH4/km^2/h)	1.7	3.75	6.7

Ponds in the study region were estimated using estimates for small ponds found in [56]. In their analysis, they measured 50 ponds less than 0.001 km^2, 20 ponds between 0.001 km^2 and 0.01km^2 and 239 ponds greater than 0.01km^2. The emission factors published in the report for each range of pond sizes were then applied to ponds that matched the selection criteria and can be seen in Table 15. The size of ponds in the study area was provided by [51] and allowed the appropriate emission factor to be applied to each pond size.

Table 15 Ponds in Study area and applied Emission Factors based on pond size.

Flux Rate (mg/m2/h)	reported values	Fraction in study area that meets selection critera	# of Ponds	Selection Criteria
1.5	mean	31%	9533	<.001 km^2
0.3	std			
0.43	mean	65%	20318	0.001-0.01 km^2
0.11	std			
0.2	mean	4%	1241	>0.01 km^2
0.0	std			

Lakes and Reservoirs in the study region were estimated using emission factors from [65]. A range of possible emission factors is provided ranging from 1kg/km^2/h to 4.7 kg/km^2/h without a reported mean for hydroelectric reservoirs. In order to better determine a probabilistic mean, chlorophyll-a was used to create an estimate. In the report, it is found that methane emissions from lakes have a correlation to chlorophyll-a with $R^2 = 0.5$ and a correlation to dissolved inorganic phosphorus with $R^2 = 0.18$. Chlorophyll-a content is reported in [66] for 1999, 1994, and 1989 for upper, middle, and lower stations in the Greer's Ferry, the largest lake in the study region. Averaging reported values of chlorophyll-a content spread across the lake results is an average chlorophyll-a concentration of at 2μg/l this can be compared against average chlorophyll-a content found in lakes reported in [66] with a minimum value of 0.2 μg/l and average of 12.77μg/l and a maximum of 137.5 μg/l. Because the average chlorophyll-a content for Greer's Ferry is at the low end of the range a triangular distribution is generated to best accommodate this finding. To provide a more accurate mean emission estimate comparable triangles were used where the range for chlorophyll-a was used to generate a similar triangular distribution for methane flux's to more accurately predict mean methane emissions from the reservoir. In this analysis, the range of potential emissions is preserved while increasing the accuracy of the mean emission rate. This can be seen in Figure 34.

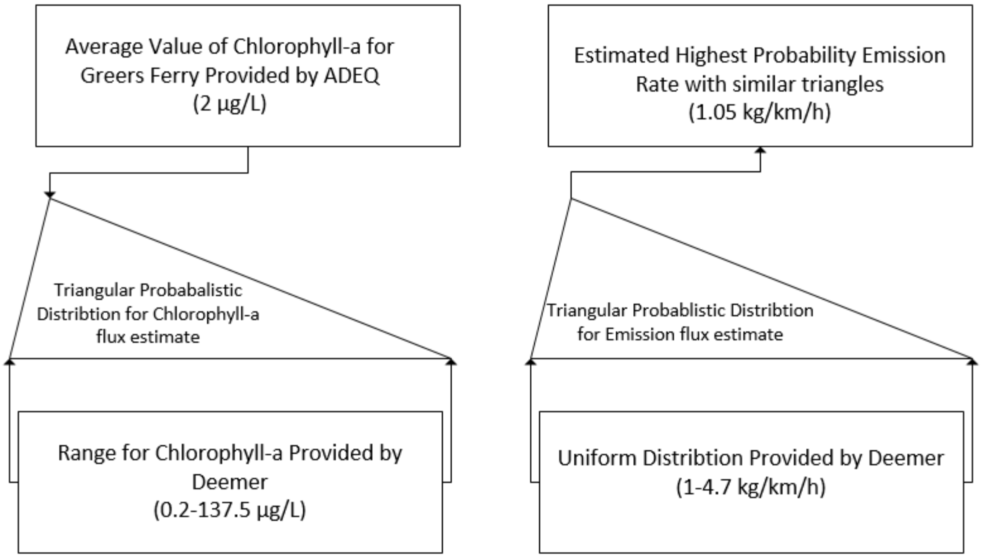

Figure 34 Probabilistic lake emission rate generation process. A probabilistic triangular distribution was generated to represent Greer's ferry emission in the range of possible chlorophyll-a concentrations. This triangular distribution was used to generate a similar triangle for emission rates. This provides a mean emission estimate for generating reservoirs that are not reported.

Greer's Ferry is reportedly one of the cleanest lakes in the country, for this reason, it should be expected that it would have lower emissions than lakes with large amounts of chlorophyll-a. However, there have been reports of large amounts of ebullition that occur in the lake. For this reason, the maximum level of recorded emissions is still included in the distribution shown in Figure 34. Documented ebullition[67] can be seen in Figure 35.

Figure 35 Documented Ebullition in Greer's Ferry Reservoir.

Rivers in the study region were estimated using methods described in [55]. A rivers emission factor was created by taking total reported annual emissions and the total area of rivers between 25° and 54°

latitude and dividing annual emissions by total area to produce units of kg CH4/km^2/h. Since the standard deviation is given, it was utilized to create a normal distribution to estimate emission factors.

Wastewater Sewer: We assume reported U.S. average centralized sewer system emission factors (based on waste management systems and diets) on a per capita basis, but uncertainties are not reported [41]. The resulting emissions are dominated by emissions from septic tanks. In the study area, 54% of the inhabitants use septic systems and 91% of methane emissions come from septic tanks [68].

Table 16 Reported Emissions from septic systems and sewer systems in the United States with calculated emission factors.

	Total E co2 eq	kg CH4/year	% U.S. pop	Total U.S. Population	EF (g CH4/day/person)
SEPTIC	5,900,000,000	236,000,000	19%	60,427,486	10.7
CENTRAL	3,100,000,000	124,000,000	81%	262,572,514	1.3

County Landfill: The size of the only landfill in the study area is below the GHGRP reporting threshold. We bootstrapped emission factors on a per area basis from five GHGRP reporting landfills located just outside of the study area as shown in Table 17.

Table 17Reported methane generation from landfills by GHGRP FLIGHT with estimated emissions factors of landfills found by dividing reported methane generation by reported area. Landfills with gas collection would emit more methane than those without. The reported generation does not include methane capture.

	GHGRP FLIGHT Reported Emission Generation (kg/h)	Reported Surface Area (km^2)	Emission Factor (kg ch4/Km^2)	Methane Capture Efficiency
Two Pine [Y]	1761	0.6	3186	60%
Little Rock City [Y]	281	0.2	1402	33%
Saline Landfill [N]	697	0.2	2996	NA
Conway County [N]	138	0.3	518	NA
Modelfill [Y]	828	0.5	1763	60%
Notes :	Y : Landfill has gas collection			
	N: Landfill does not have gas collection			

Rice Fields: The majority of CH_4 emissions from rice occur during the growing season while the crop is submerged [69], which took place before the mass balance flights during the field campaign [70]. Because only 2% of CH_4 emissions from rice cultivation occur after the growing season [71], we multiplied the reported emission factors by 0.02.

4.3 Results

Total CH_4 emission rate estimates for each source category are summarized in Figure 36, which includes total emission rates and fluxes from each county (see inset of Figure 36). The cumulative distribution functions of all emission categories are shown in Figure 37 with geological seeps included (purple) and excluded (brown). Geologic seeps represent almost one-third of total non-natural gas industry CH_4 emissions in the study area (with a substantial contribution to total uncertainty). In this paper, we estimate total natural gas industry CH_4 emissions as aircraft mass balance CH_4 emission estimates minus total non-natural gas CH_4 estimates (including geologic seepage). While geologic seeps co-emit CH_4 and ethane, other non-natural gas CH_4 emission sources do not emit ethane. We report here also non-natural gas CH_4 estimates excluding geologic seepage as a reference for our companion paper (Mielke-Maday *et al*.), which uses measured atmospheric ethane-CH_4 ratios as an alternative approach to distinguish natural gas industry CH_4 emissions from non-natural gas sources.

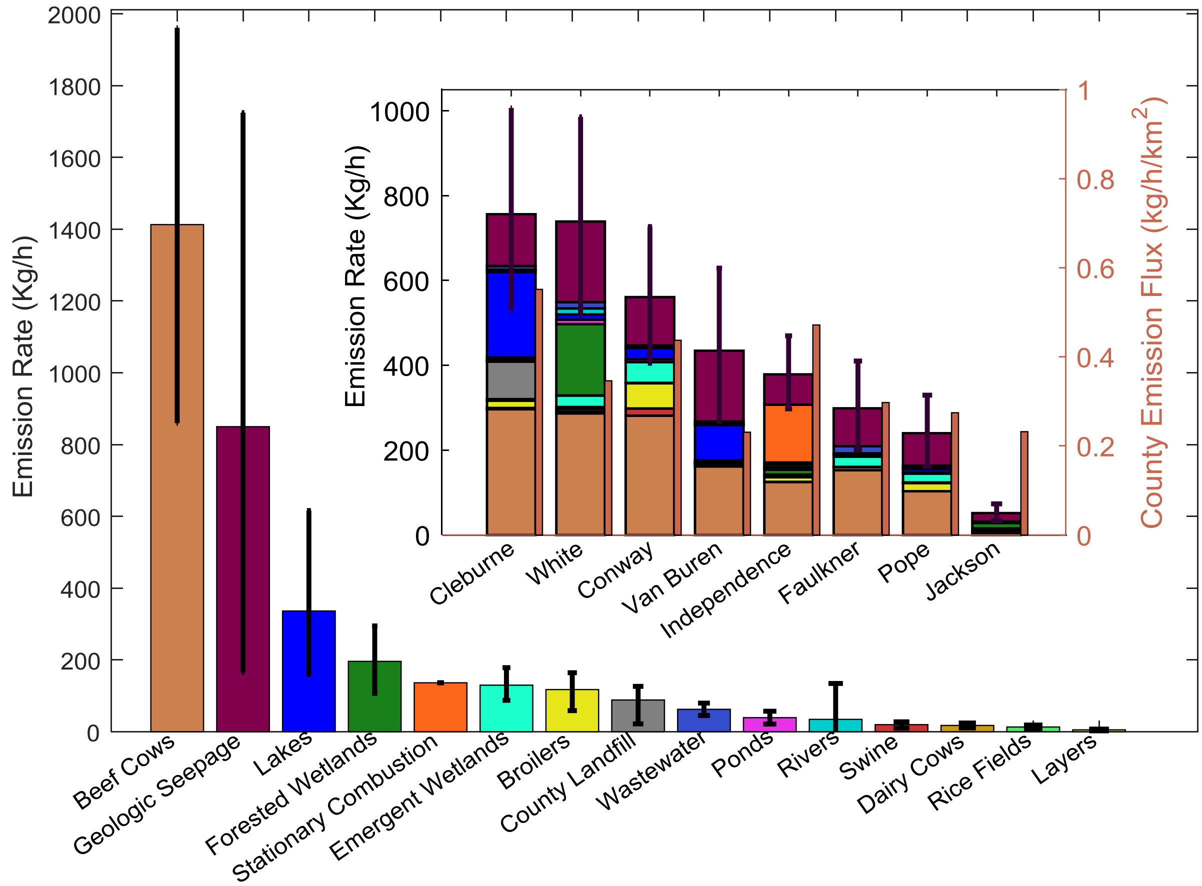

Figure 36 Total CH_4 emission estimates by source category and by county. Not all counties have the same amount of area present in the study area, a flux estimate (i.e., on a per area basis) is also provided. The stacked bar color-code in the inset is consistent with the colors in the main graph.

When comparing the results of this study against previous work from the Peischl study it can be seen that the estimate proposed in this study encompasses the result from the Peischl study. CDF's are used in the comparison to show that the Peischl study did not incorporate uncertainty in their emission estimate and they are lower than the mean emission prediction found in this estimate.

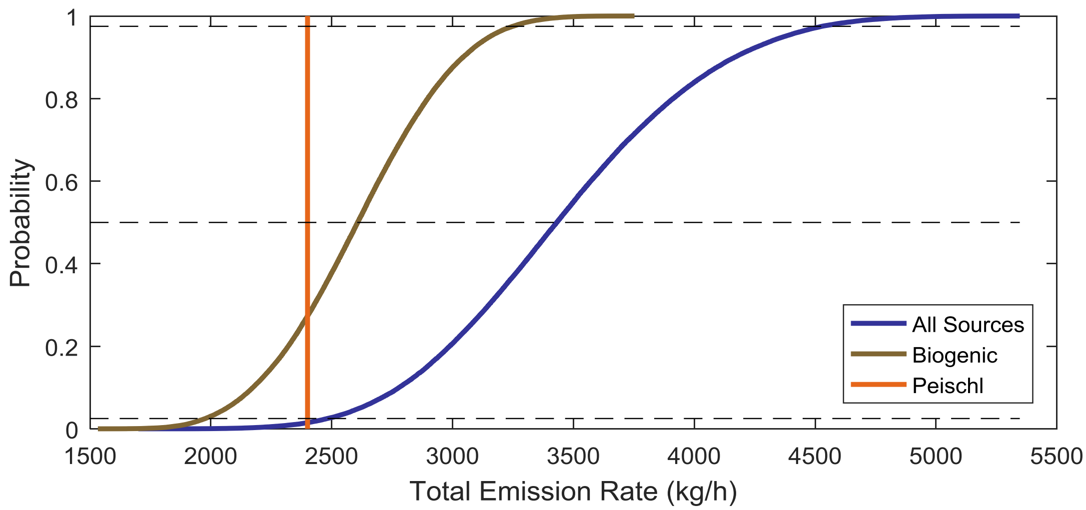

Figure 37 Emission cumulative distribution function for all CH_4 sources excluding geologic seepage (i.e, ethane is not co-emitted) and including geologic seepage (i.e., ethane is co-emitted). Dashed lines represent the median of the distribution and upper and lower 95% CI. Peischl study estimates emissions from enteric fermentation and manure management only for biogenic sources that exist in the flight boundary for this study.

Figure 38 shows CH_4 emission rates and flux rates spatially resolved at the county-level assuming an even distribution across the surface area of each county. County-level is the highest available resolution for the majority of inventory data described in this section. In particular, activity data locations for agriculture are not provided by state or federal agencies. Cleburne and White County dominate in total CH_4 emissions (Figure 38, upper panel) due to large cattle populations and wetland areas (see Figure 36) as well as county size present in the flight boundary. The flux rates (Figure 38, lower panel) indicate a relatively even CH_4 emission distribution across most of the study area, yet with higher rates towards the East. However, considering the CH_4 emission magnitudes of non-natural gas sources (2–4 t CH_4/hr) compared to total estimated study area sources (23-39 t CH_4/hr), these spatial differences are minor when interpreting the spatial patterns of all emission sources in [Figure 4 in main article].

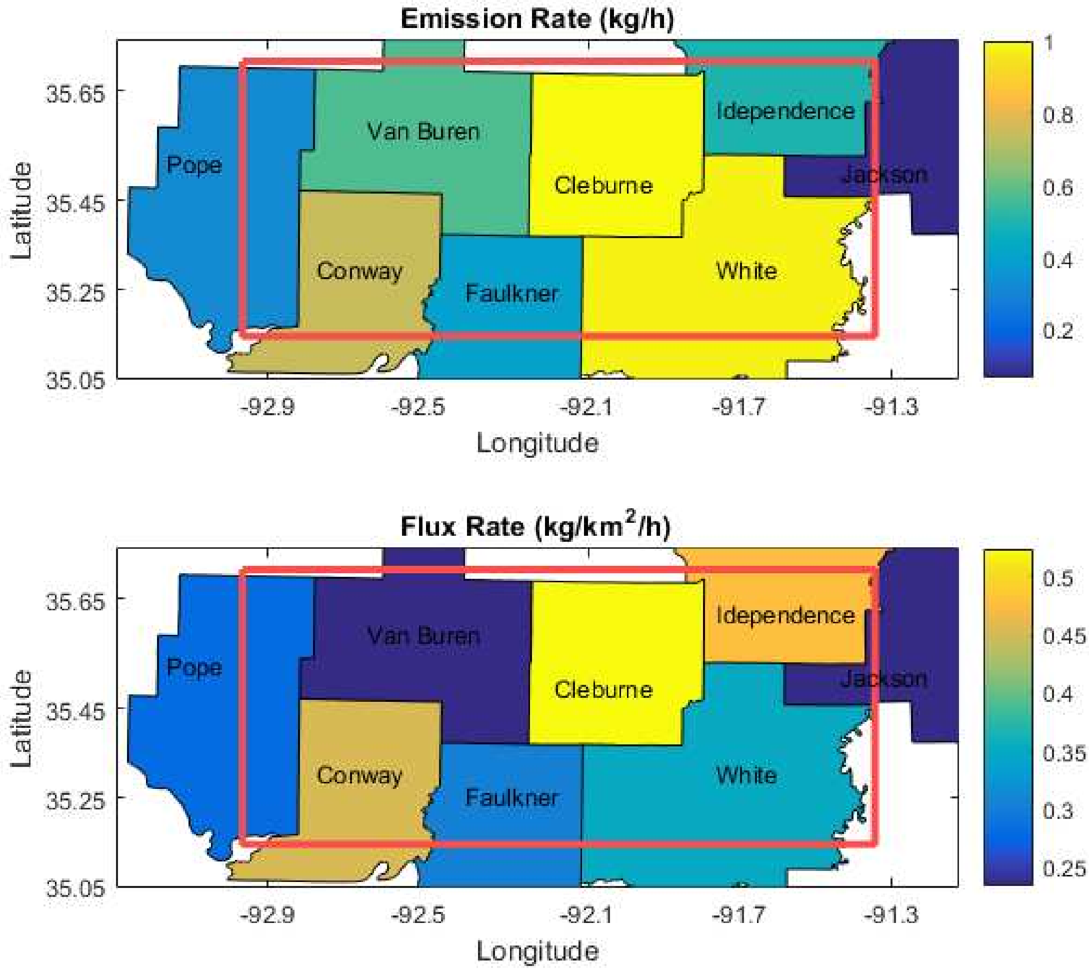

Figure 38 Spatially resolved methane emission rates and fluxes on a county basis. The red box represents the approximate flight boundary performed during the field campaign. Latitude and Longitude was estimated from shape file and not provided by GIS.

When comparing the non-oil and gas emissions performed in this analysis with [16] it can be seen that this analysis is more extensive with more emission categories and can provide a range for uncertainty. However, while the analysis is more extensive, the additional source categories, including geological seepage contribute an additional 44% to total emissions, illustrating that emissions are dominated by livestock, and in particular, cattle.

CHAPTER 5. CONCLUSIONS

5.1 Study Comparison and Contribution to Bottom-Up Estimate

For the 8 county study region, distribution networks emit approximately 20 kg CH_4 /h on average. In comparison, the largest dairy, with 1200 head (as reported by ADEQ in 2007), generates 16.4 CH_4kg/hr [±50%] based on emission factors used in this study.

Surrounding the study region there are two landfills that generate 147 and 678 kg CH4/h respectively, as seen in Table 17. Other landfills have reported methane captures systems with efficiencies as high as 60%. If 60% of methane was captured from Saline landfill, 418 kg/h would be captured, on an average annual basis, which is comparable with estimates from gathering pipeline networks. These data indicate the importance of understanding the full range of potential emission sources – both biogenic and anthropogenic.

In the 1996 EPA/GRI study, emission factors from distribution mains were utilized to estimate methane emissions from gathering pipeline networks. This study finds that emission rates from gathering lines are similar to those from the 1996 study. In contrast, recently measured emission factors from distribution mains (e.g. Lamb study) are one-twelfth (8%) of the study estimate. These data indicate that emission rates from distribution lines have fallen significantly since 1996. No statements can be made regarding gathering lines, as these were not measured in 1996.

This study also finds that national emission factors from the Lamb study are approximately twice as large as measurements taken during this study. These data indicate that emissions from distribution mains in this region are statistically smaller than those from the national study.

Methane emissions from the sources characterized in this thesis (gathering pipelines, distribution systems, agriculture, waste management and natural sources) can be seen in Figure 39 and are augmented with estimates for bottom-up emissions estimates for O&G operations in the study region during the flight period [19]. The agriculture category is composed of all emissions from cattle, chickens, swine, and rice fields. The natural sources category is composed of emissions from emergent wetlands, forested wetlands, ponds, lakes, and rivers. The waste management category is composed of emissions from wastewater and landfills. All bottom-up emission estimates are assumed to be occurring within the flight boundary as depicted in Figure 23. Together, the sources estimated in this work account for ≈19% of the total bottom-up estimate of emissions from the study area. The remaining 81% of emissions are from O&G operations in the study area, including production, gathering, transmission and a limited amount of exploration and well maintenance operations. It is also important to note that the estimate of O&G operations are time-resolved and represent emissions estimates when aircraft mass balance flights were completed.

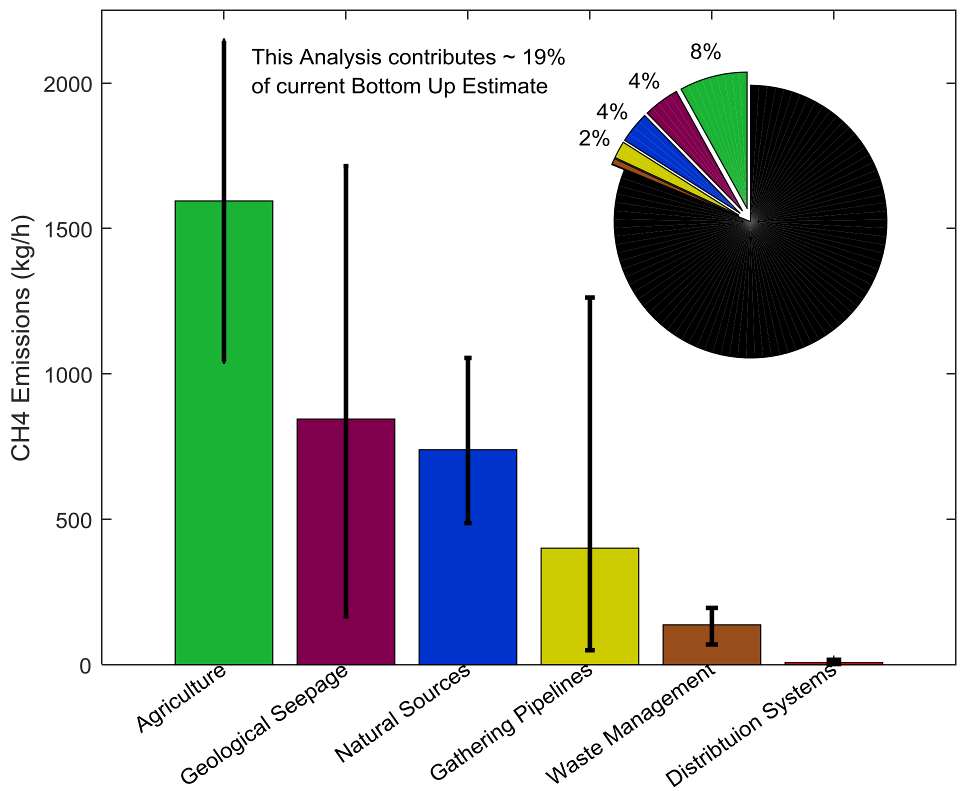

Figure 39 Comparison of emissions from: gathering pipelines, distribution systems, agriculture, waste management and natural sources to the total bottom-up study estimate. Distribution system does not appear visually in the pie chart due to small fractional contribution. Black Section represented by other sources in the bottom-up estimate not covered in this analysis but included to emphasize the contribution of this analysis.

For the categories analyzed here, agriculture represents the largest emissions source that was analyzed. Distribution systems are significantly lower than all other emission categories. In comparing to previous basin level emission estimates all modeled sources generate approximately 3,860 (kg/h) or 10% of total basin emissions as estimated by Peischl, et. al. [16]. The 95% confidence interval indicates that that methane emissions from all sources analyzed are less than 5168 kg/h as seen in Figure 40.This analysis provides insight into the sizes and ranges of unmeasured methane sources in the study region and sources that have not been measured in the past. All estimates are utilized in a larger model that combines emissions from all sources including gathering stations, production well pads, and transmission lines. The analysis performed here represents a comprehensive analysis of non-O&G emission sources for the study area, and to the author's knowledge, no substantial source of emissions was omitted from the estimate.

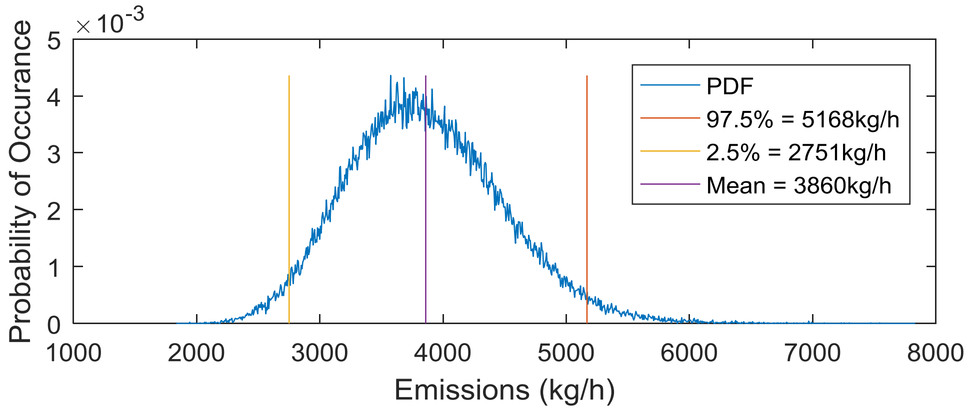

Figure 40 PDF of all simulated emissions.

Comparison and reconciliation of estimates at the basin or facility-level are beyond the scope of this thesis and are not included herein. These analyses are included in [19].

5.2 Future Work

Spatial resolution of non-O&G emissions would be greatly enhanced if geographical coordinates for emission categories were available. While lakes, ponds, wetlands, landfills and waste water treatment plants do have coordinates the largest emission sources in the region do not. Cattle ranches and geological seepage contribute the largest amount of methane and their locations are unknown. Confined Animal Feeding Operations(CAFOS) have been used in other studies to determine where large-scale dairies are to assist in the spatial resolution[12], in Arkansas, the majority of cattle operations are open ranching and do not require confined animal permits. There are only 37 CAFO permits with estimated livestock counts in the 8 county region, this includes eight dairy locations, one chicken layer house, 27 hog houses and one Fish Hatchery. With only eight known dairy operations this does not assist in assigning geographical locations to beef cattle that graze in fields. If ranchers were required to track how many cattle they had on a particular range at a given time, or if ground images were taken by the aircraft during measurements, increased spatial resolution for emissions from cattle would be possible to produce a more accurate comparison of bottom-up estimates to aircraft estimates. In addition, if ranchers recorded the types of fields that cattle graze, emission factor uncertainty could also be reduced, since enteric fermentation is dependent upon food quality of the cattle.

In addition to animal emission locations, geological seepage locations are completely unknown. In order to better understand geological emissions, maps of fault lines could be used to guide future measurement campaigns to generate a spatial distribution of emissions. To generate this kind of information an extensive campaign that would require detailed geological surveys and emission measurement teams to quantify emissions throughout the study area mapping emissions in a gridded fashion. These types of studies are usually performed in regions where macro-seeps exist, however with the continual focus on methane emissions across all emission sectors, a campaign focused in this region could be performed to assist in reconciliation with less uncertainty. In addition, since geologic seepage is a slow process, estimates made in the next 1-2 years could be back-annotated into this analysis, improving its accuracy *ex post facto.*

In addition to decreased methane emission uncertainty in the non-oil and gas sector, there is still room for improvement in emission estimates from the O&G industry. Uncertainty in gathering pipeline emissions could be reduced by surveying more pipeline as described in 2.4, with measurements focused on pipeline leaks rather than on auxiliary equipment emissions, to better characterize the size of pipeline leaks found in this campaign.

Finally, uncertainty for the smallest category of total emissions, distribution systems, could be reduced by measuring customer meters and providing GPS coordinates for all facilities in the study area. However, it is important to note that decreasing uncertainty in this category would likely have little impact on the total uncertainty due to the small total emission rate from distribution systems.

While basin level measurements allow for rapid quantification of emissions from a total region it cannot give insight into the source of emissions within the natural gas industry. Facility- and device-level measurements provide additional value by measuring components and facilities to identify specific leak locations. However, scaling these measurements to the basin level requires extensive analysis, performed here and in [19], to produce accurate basin-level estimates. Detailed measurements also help identify ideal candidates for emission mitigation efforts. For example, some sectors, such as distribution, *in this basin*, contribute very little methane emissions. Emissions mitigation should be focused on other areas in order to have a substantive impact on emissions for this region.

A complete techno-economic assessment of methane mitigation could assist it directing future methane mitigation programs. This analysis provides the base framework to begin the TEA showing that some natural gas companies could focus on methane mitigation in other sectors that would eliminate as much methane as they are currently estimated to be emitting. A more detailed analysis of methane capture systems and leak detection and repair programs needs to be made before any definitive conclusions can be made on cost effectiveness for methane mitigation across an array of industries. This could be done to make the largest impact on methane emissions in hopes of reducing greenhouse gasses and slowing the global warming process.

CHAPTER 6. REFERENCES

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CHAPTER 7. APPENDICES

Disclaimer: This appendix has been submitted as an SI for CHAPTER 2 and is waiting for approval.

7.1 Gathering Line Paper SI

7.1.1 Description of Gathering Lines and Auxiliary Equipment

This chapter describes gathering lines and auxiliary equipment in the context of the natural gas supply chain, their use, and variation between basins. Gathering lines transport gas from the natural gas production pads to transmission or distribution systems. Gathering lines exist in two distinct groups (see Figure 41):

1) The natural gas infrastructure between the exit meter at the production well pads and the entrance valve or piping at the gathering station(s).

2) The infrastructure between gathering stations and downstream processing plant or transmission or distribution system.

Gathering lines are typically constructed of plastic and/or steel. In the study area, the lines between the well pads and gathering stations are predominantly plastic, and those between gathering stations and downstream sales points are steel.

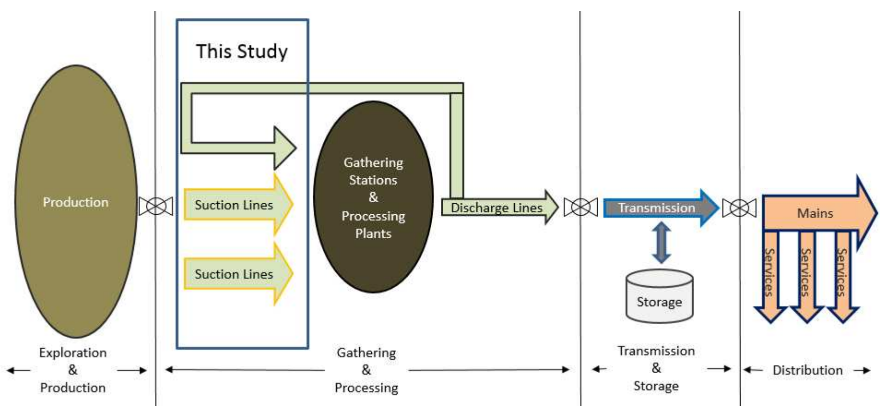

Figure 41 Schematic of natural gas industry sectors. Sectors are separated by lines, gas flow is indicated by arrows. This study is focused on gathering lines their auxiliary equipment and total emissions from the sector, some gathering lines transport natural gas to processing plants as depicted in the return loop around gathering stations.

In addition to pipelines, two types of auxiliary equipment are also installed on study partners' systems in the study area – pig launchers or receivers and block valves. Pig launchers and pig receivers (Figure 2) are nearly identical components but installed in different orientations to launch or receive the pig. For simplicity, both types are called pig launchers in this study.

Figure 42 A typical pig launcher/receiver from the study area. Door or hatch to the pig launcher can be seen on the left side of the image.

Operators pig lines when flow rates decrease or pressures change in the line or in nearby connected facilities. A "pig" is a cleaning plug pushed through the pipeline by the gas flow in the pipeline. To insert a pig, or to remove a pig and any debris cleaned from the line, operators must depressurize the pig launcher, releasing gas to the atmosphere. At times the pig doesn't travel the intended route, and operators may have to open and check several launchers and receivers to locate the pig. Since transmission systems handle market-quality gas and very high pressures, operators purge pigging equipment extensively to prevent air contamination. In contrast, gathering gas has not been upgraded, and operators release relatively less to purge pigging equipment.

Block valves are used to stop the flow of gas in a pipeline or change the direction of flow. Figure 44 shows a block valve. In general, block valves are simpler than pig launchers, with fewer gauges, flanges, and valves, reducing potential sources of fugitive emissions.

Both block valves and pig launchers have multiple flanges, gauges, and valves that have the potential to be sources of fugitive methane emissions. Pig launchers also have doors/hatches that are used to insert the pig. Emissions can be found at any of these interfaces, and multiple leaks may be detected at a given auxiliary equipment location.

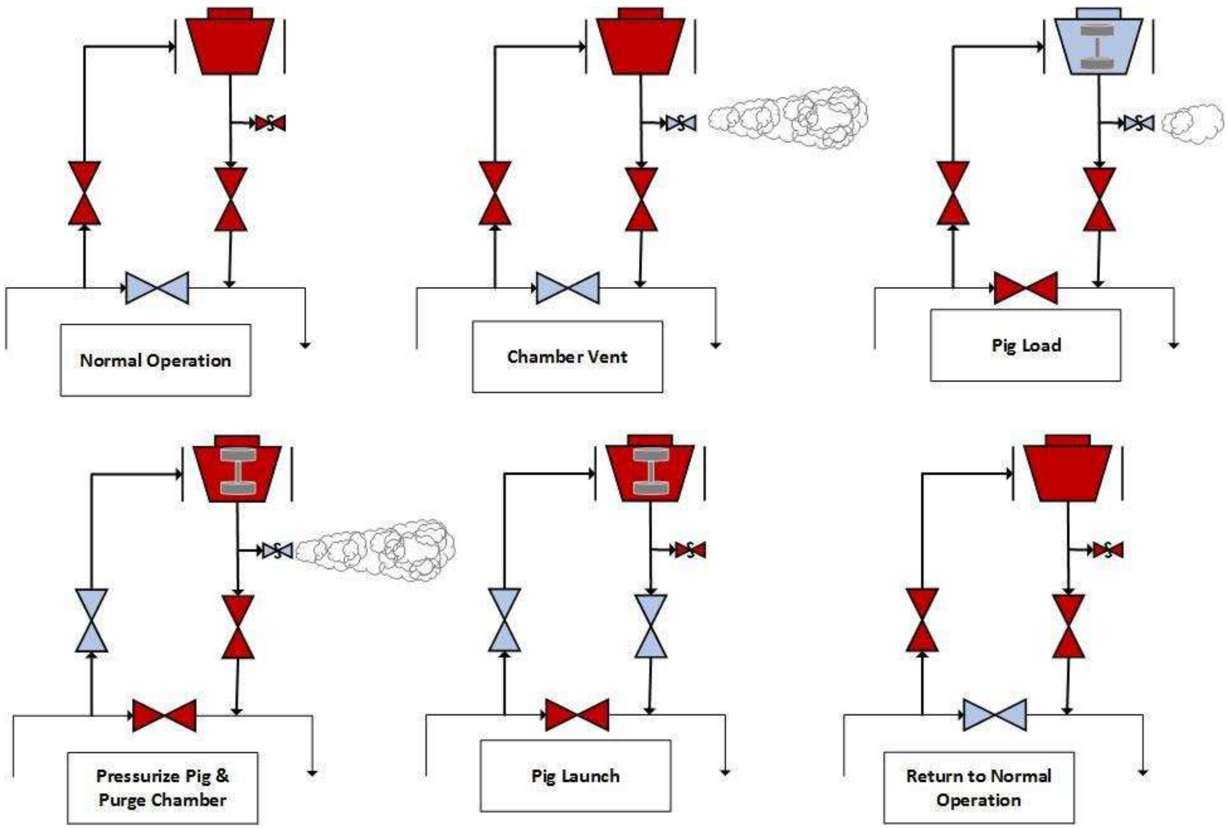

Figure 43 Pigging procedure: Schematics describe the gas flows during normal operation, loading and launching a cleaning pig. Gas releases occur to vent the launcher/receiver chamber and are largely determined by the pipeline pressure and the size of the pigging equipment. Light blue indicates open valve with gas flowing through it, red indicates closed valve that is preventing gas flow.

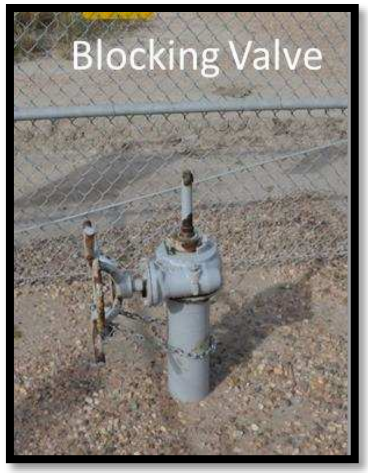

Figure 44 Example is a small block valve typical of those found in gas gathering systems. (Photo not from study area).

7.1.2 Study Area Definition and Pipeline Selection

During the field campaign, different sections of gathering line were randomly chosen to characterize the emissions from gathering lines. The study area is defined by the orange box in Figure 45 and represents the path flown by measurement aircraft when making mass-balance measurements of the study area on October 1, 2015. Figure 45 shows that production wells are more densely populated in the western half of the Fayetteville shale play which suggests that there is more gathering pipeline in the western half of the study area. Prior to the field campaign one partner company had only mowed ROW in the western half of the basin at the time of the study. For that reason, the field campaign was partially restricted to the western half of the study area for that partner. Qualitatively, the pipeline in the eastern and the western halves of the study area are configured similarly, and there is no evidence that emissions behavior would be statistically different. Gathering pipelines measured in the field campaign are marked in white. All pipelines measured were combined into a single timeline traced to create Figure 1 of the main paper.

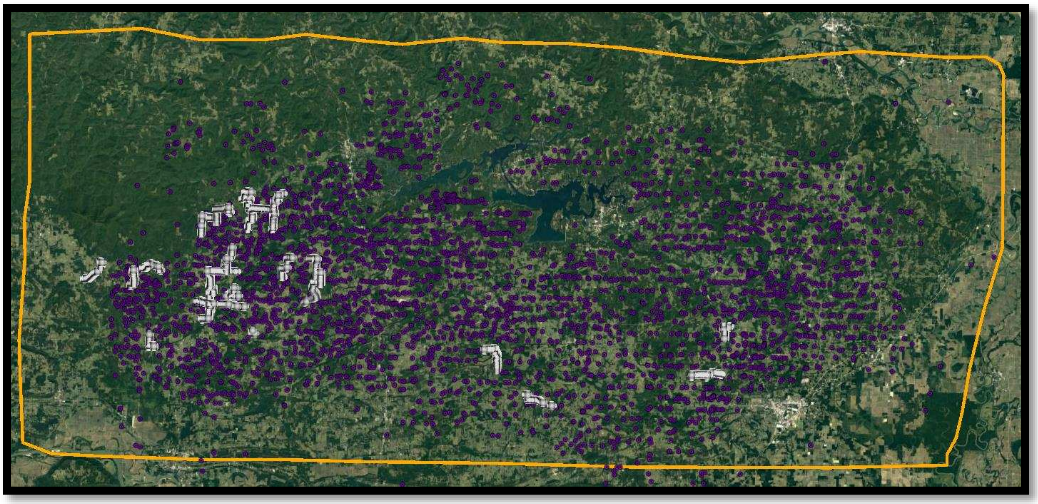

Figure 45 Sections of gathering pipeline surveyed during the field campaign. Measurements were biased toward the western half of the study area because one partner had mowed only ROWs in that area. Grey marks are driven ROWs. Purple dots are individual well pads, the orange line is the flight boundary for October 1st mass balance. Image from Google Earth™.

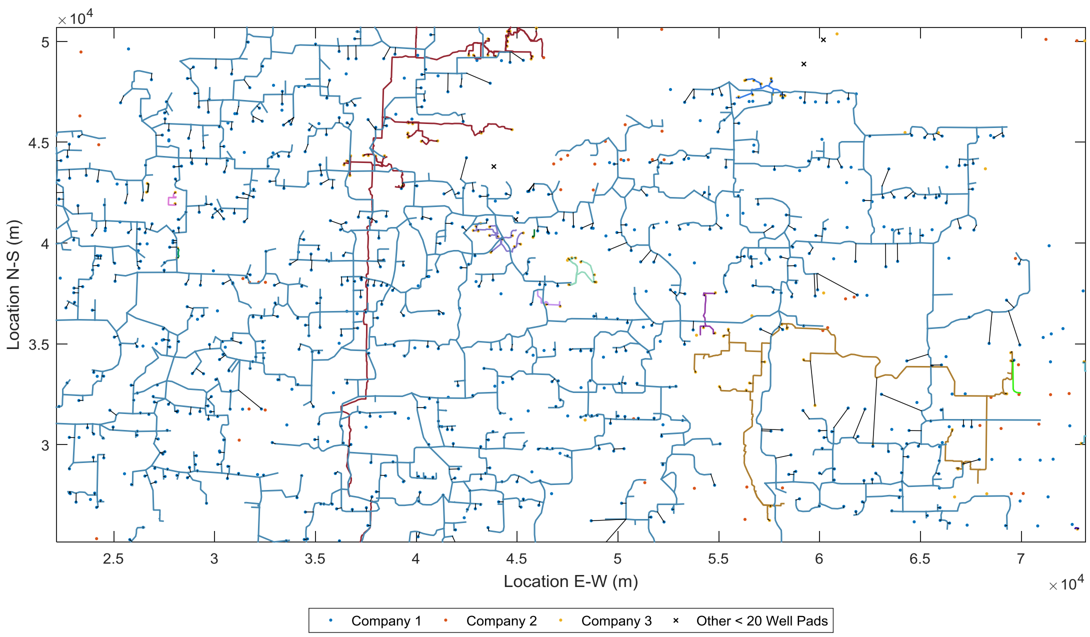

Figure 46 Gathering system equipment including well locations and representative gathering pipelines from MapSearch™ data and partner GIS data. Pipelines have been colored randomly to maintain the privacy of partner and non-partner companies. Not all wells are connected to gathering pipelines due to incomplete gathering pipeline information.

7.1.3 Measuring ROWs

Determining which ROW to scan was guided by both experimental guidelines and physical limitations. Experimental guidelines were implemented to achieve an adequate characterization of the basin. The pipeline was randomly sampled across the study area and includes ROWs that were both near towns and rural. However, random sampling was conditioned by the accessibility of the ROWs, including the following physical limitations:

- Grade of ROW was too steep to traverse safely and effectively
- ROW was covered with un-harvested crops
- Access restricted by landowner
- Vegetation covering the ROW was too dense to traverse
- Access to the ROW was had water or mud that made it impossible to traverse safely

Figure 47 & Figure 48 illustrate the range of vegetation on typical ROWs in the study area. In consultation with study partners, the study team selected sections of ROW to traverse each morning to best implement the study plan while accommodating local conditions. To maximize ROW traversed, areas were selected with 2-3 segments of traversable ROW each day. Operators would provide options for drivable ROWs and measurement contractor randomly selected which ROWs to traverse to reduce sampling bias.

Figure 47 ROW with a steep slope, but mowed and relatively accessible.

Figure 48 ROW with dense vegetation. The photo illustrates the challenges that exist when attempting to traverse overgrown ROWs. Rocks, ditches, fallen trees and other obstacles exist but are not apparent in the photo.

7.2 Measurement Equipment Used in Study

All measurements were performed by Gutteridge Haskins and Davey (GHD) using measurement devices owned by GHD and calibrated by GHD employees. The complete list of equipment provided by GHD can be found in Table 18.

Table 18 List of instrumentation used throughout the measurement campaign

Manufacturer	*Instrument*	*Model Number*	*Use*	*Serial Number*
Heath Consultants	RMLD-IS	RMLD-IS	Underground pipeline leak delineation/detection	8101311001
Heath Consultants	DP-IR	DP-IR	Underground Leak Delineation	91013-40001
Bascom-Turner	Gas Sentry	CGI-211	High Flow Gas Concentrations Aboveground / Underground leak measurements	0302-014091 9935-011256 9614-007683 9614-006789 9532-5118
TSL	VelociCheck	8340	High Flow Gas Flow Rate Aboveground / Underground leak measurements	96030356 95040139 96030360
INDACO	High-Flow	BT-GCI-211 TSL- 8340	Underground pipeline leaks w/ enclosure	-
Los Gatos Instruments	Ultra-Portable GHG Analyzer CH4/CO2/H2O	915-0011	Gathering pipeline leak screening (mobile ambient measurements)	-
Geneq Inc.	GPS	Sx Blue	Ambient Monitor Position	-

GHD’s vehicle measurement system (VMS) was designed to detect methane enhancements low to the ground using bumper-mounted air intakes with four inlets (see Figure 49). The four inlets were joined together and routed to the Los Gatos analyzer.

Figure 49 Front Bumper of GHD's Measurement Rig. Mounted with 4 intake hoses that are flexible and designed to ride low to the ground.

The analyzer was paired with the Geneq GPS to track location, as shown in Figure 45. Equipment was calibrated on a regular basis.

7.2.1 VMS Efficacy

The validation for the VMS was performed by confirming that the observed concentration of methane in proximity to known leaks was elevated an observable amount above background methane concentrations. Figure 53 Shows GIS images overlaid with plots of methane enhancements, defined as concentration observed after subtracting background methane concentration of 1.9 ppm CH_4. When the study team identified an elevated methane concentration, the team sought to identify the source, often driving the VMS near the source. Figure 50 shows the concentrations detected near the single underground pipeline leak (4.0 kg/h), while Figure 51 through Figure 53 illustrate elevated concentrations near the much smaller emissions typical of auxiliary equipment. Note that measured concentrations do not correspond directly to release rates, but each facility shows clearly elevated concentrations detectable by the VMS, showing that the VMS was capable of identifying concentrations corresponding to far smaller leaks than seen in the detected pipeline leak.

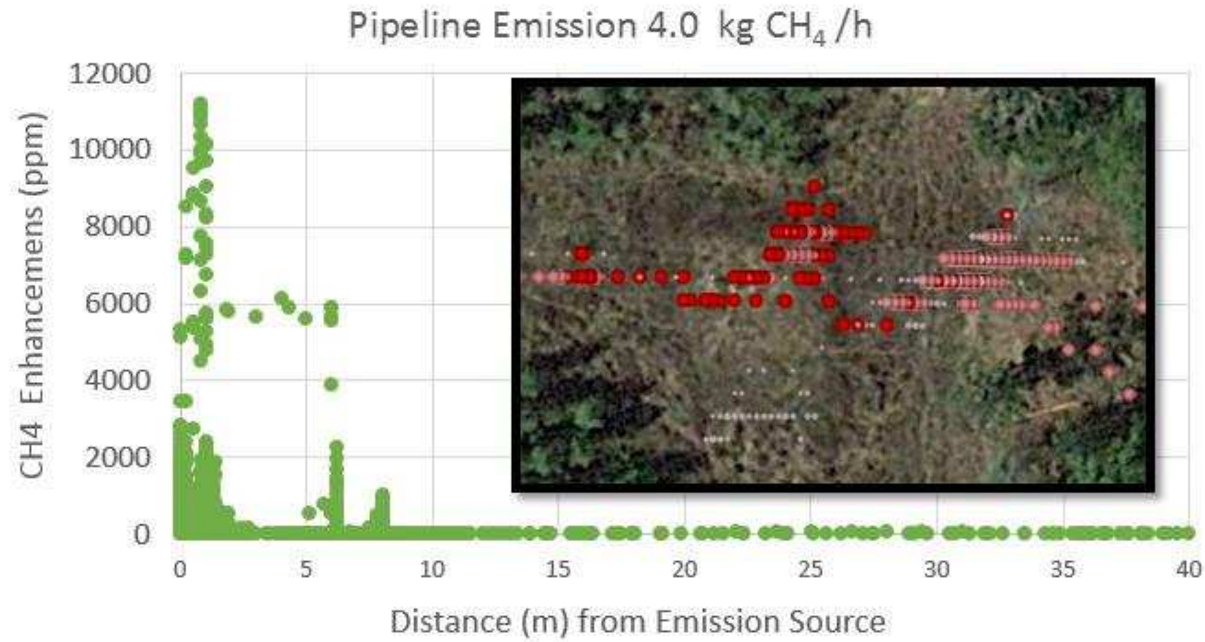

Figure 50 Methane concentration near the underground pipeline leak

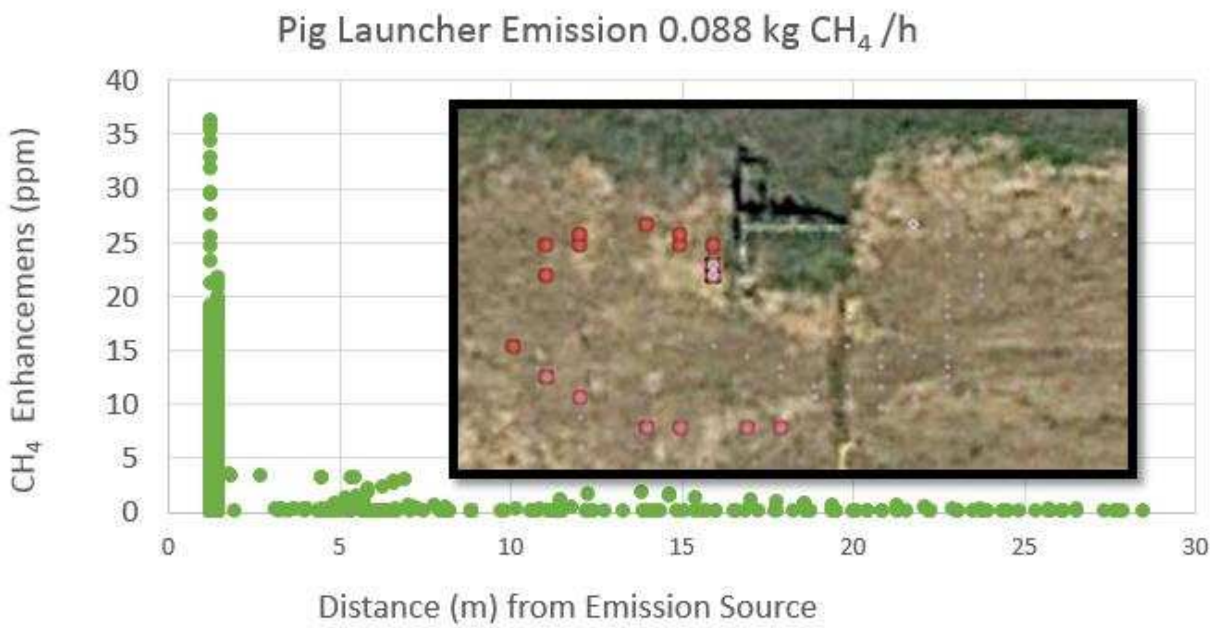

Figure 51 VMS data near a pig launcher emitting 88 g CH_4/hr.

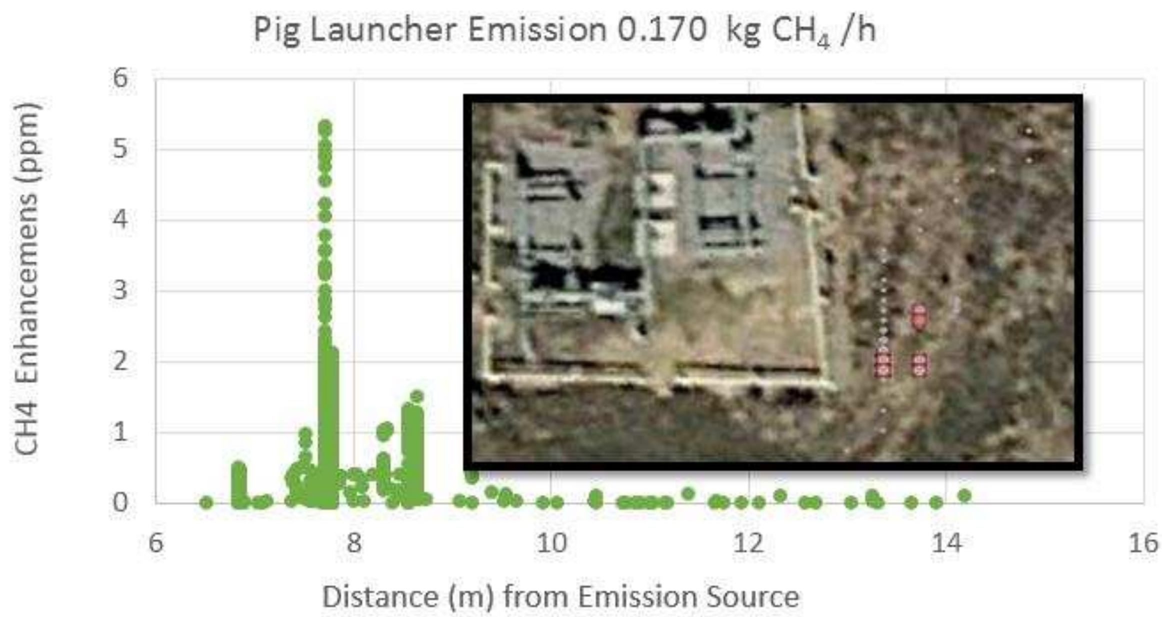

Figure 52 VMS data near a pig launcher emitting 170 g CH_4/h.

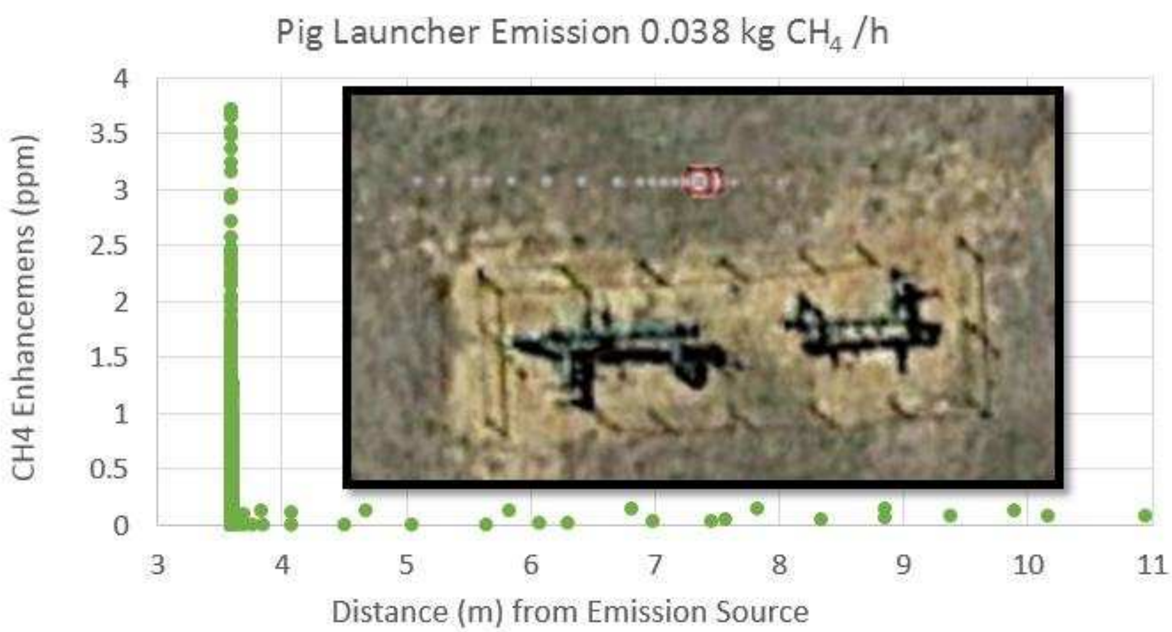

Figure 53 VMS data near a pig launcher emitting 38 g CH_4/h.

All gathering pipeline is buried in the study area. This requires the removal of rock that creates small voids through which methane can migrate away from the emission source. During burial operations, trenches are typically filled with soil of consistent origin. This removes rocks, creating a more uniform overfill, which minimizes methane migration. For this reason, it is likely that that methane emissions from buried pipelines would likely surface somewhere inside the ROW.

During the campaign, wind direction was not monitored which would assist in positioning the VMS downwind of the trench centerline whenever possible. However, winds were light at ground level during the field campaign, reducing dilution or movement of the surface methane plume. The qualitative tests discussed above indicate that the VMS can detect methane enhancements over 7 meters away from a source of 170 g/h for the local wind conditions at that day which were not recorded by the measurement team. Considering the trench width, VMS intake width (2 meters), detection sensitivity and ROW width (typically 20 meters), the VMS driving the centerline of the ROW effectively covered approximately 95% of the ROW, where leaking natural gas would likely reach the surface. From this qualitative analysis, we conclude that it is highly likely, but not conclusive, that all underground pipeline leaks in excess of 200 g/h were identified by the screening method.

7.3 Measurement Techniques

When the auxiliary equipment was encountered on the ROW, the study team screened the equipment using an RMLD® to locate and isolate emissions from joints or valves. After determining which component exhibited a methane emission the measurement contractor would use the high-flow instrument to measure the emission. High-flow measurements were performed using either a bag or cone enclosure to capture all emissions. Operators also collected background methane concentration, methane concentration going through the instrument, and total mass flow through the instrument. These measurements were utilized to calculate the methane emission rate from the emission source.

The underground emission was first isolated utilizing the RMLD and the methane analyzer. The team then placed an enclosure (commonly called a flux chamber) over the emission source (a hole in the ground) and measured the emission rate utilizing the high-flow instrument. After measurement, the operator immediately initiated efforts to repair the leak.

7.4 Model Methods

Monte Carlo methods were utilized to estimate study area emissions from gathering pipelines, following the schematic plan in Figure 54, which will be discussed, block-by-block, in the remainder of this chapter.

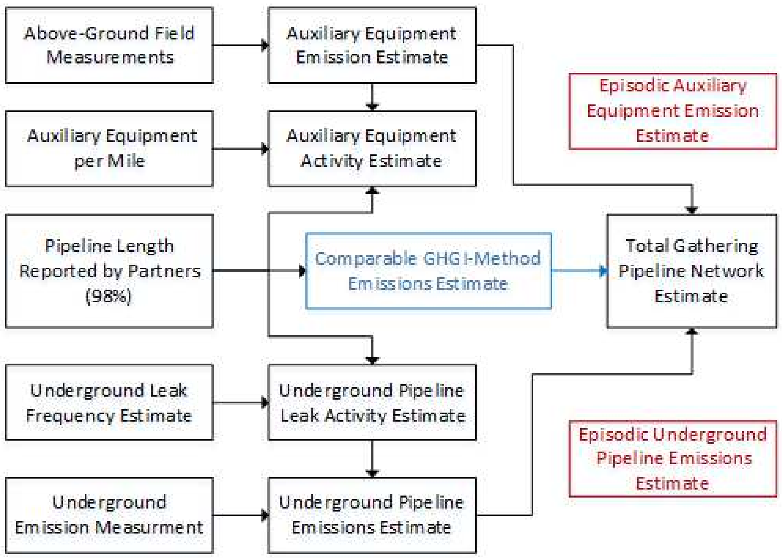

Figure 54 Model Visualization: How to create a gathering pipeline estimate

Field measurements and component counts were used to populate total emission estimates for the study region. Mean emission factors can be multiplied by complete activity counts to get mean methane emissions from the study area. Monte Carlo simulation was utilized to propagate both variability and uncertainty through calculations, and uncertainty was determined empirically from the result distributions.

7.4.1 Gathering Pipeline Emissions

Total emissions from gathering pipelines depend on three variables, the total length of pipe, emission rate (stratified by material) and leak frequency (not stratified by material). This section will discuss how line length was estimated, how leak frequency was approximated and how emission range was determined.

7.4.2 Pipeline Activity Count

Pipeline lengths and material type were provided by partner and non-partner companies in the basin. The line data that was provided accounts for pipeline attached to 98% of active producing wells in the study area. Since these three companies all operate gathering systems, and smaller companies do not appear to operate gathering systems, it is likely that the pipeline reported by these companies represents a similar percentage of gathering line in the basin. Therefore, in our analysis, we assume that reported pipeline length represent all pipelines in the study area. The authors know of no prior study where the precise lengths of 98% of the study area gathering pipeline systems were known.

7.4.3 Modeling Emission Rate from Underground Pipeline Leaks

Pipeline emissions factors were based directly upon the single measured pipeline emission in table SI X2. In order to approximate uncertainty associated with the emission rate, a triangular distribution was utilized. Previous studies measuring similar line types in distribution networks have found multiple pipeline leaks, but all of them are smaller than the pipeline leak found in this campaign. From this observation, we hypothesize that many leaks may be significantly lower than the leak measured here, and set the lower bound of the triangular distribution to 0 kg/h. To maintain the same mean value as measured here, the upper bound was then set to 8.0kg/h, which also allows for leaks – potentially from higher pressure lines – which are up to twice the emission rate of the observed leak. The triangular distribution is shown in Figure 55.

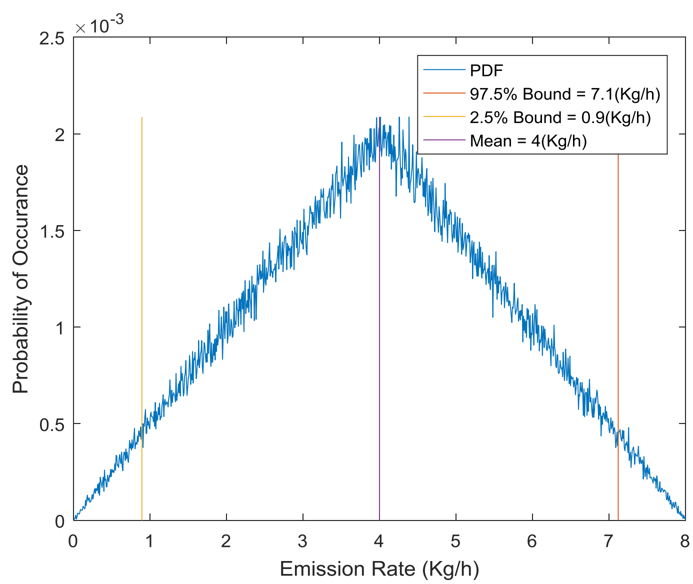

Figure 55 Triangular distribution for emission rate from underground pipeline leaks. Data shown is the result of simulating with 100,000 iterations.

7.4.4 Modeling the Frequency of Underground Pipeline Leaks

We now consider the probable density, or frequency, of pipeline leaks which may exist in the study area, based upon the field study result which discovered one pipeline leak while measuring 96 kilometers of gathering pipeline randomly sampled from 3948 kilometers of pipeline operated by study partners. The probability of finding k events when drawing n samples from a total population of N that contains K total events, is represented by a hypergeometric distribution:

$$P(K) = \frac{\binom{K}{k}\binom{N-K}{n-k}}{\binom{N}{n}} = \frac{\frac{K!}{k!\,(K-k)!} * \frac{(N-K)!}{(n-k)!\,((N-K)-(n-k)!}}{\frac{N!}{n!\,(N-n)!}}$$

Where

- $P(K)$ is the probability of finding $k = 1$ events if the study partner's pipelines contained K total events.
- $N = 3948\ km$ is the pipeline length operated by the study partners.
- $n = 96\ km$ is the amount of pipeline measured during the field campaign.

By assuming a range for K – the unknown number of leaks within the study population (in this case, the study partner's gathering pipelines that could be randomly sampled) – it is possible to calculate the probability of the result seen in the field study for all possible true leak populations. If we assume pipeline is measured in steps of one kilometer (this assumption converts a continuous problem into a discrete approximation), and calculate the probability for $K = 1 \ldots 550$ leaks in the study partner's pipelines, we arrive at the probability distribution shown in Figure 56. Note that this analysis is similar to that of the Wilson score interval with a known, finite population size.

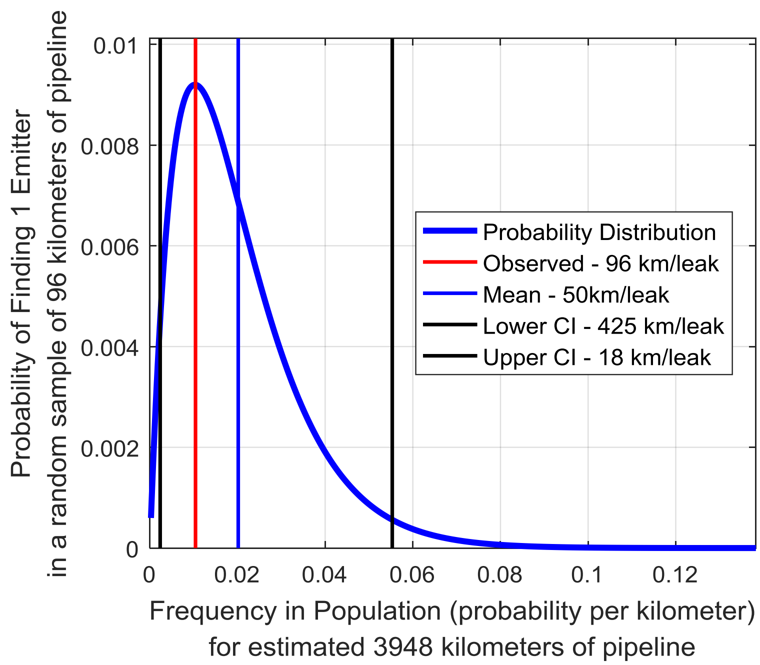

Figure 56 Probability distribution for the frequency of underground pipeline leaks

Results of this analysis indicate a mean of 50 km/leak with a 95% confidence interval of 18-425 km/leak, or a leak frequency of 0.02 leaks/km [+178%/-88%]. The mode of the distribution matches the frequency observed in the field campaign (96 km/leak), but the mean frequency of 50 km/leak indicates that assuming true leak populations of 1-550 leaks are equally probable, the mean frequency is ≈2X that observed in the field campaign. This distribution was utilized in the Monte Carlo simulation to estimate total underground pipeline leaks within the study area. The same probabilistic method was also utilized to estimate the fraction of a basin's pipeline system to measure.

7.4.5 Auxiliary Equipment Counts and Emission Rates

Available data for the auxiliary equipment counts is summarized in Table 1 of the main paper. Where missing, Monte Carlo methods were utilized estimate facility counts. Auxiliary equipment was estimated by using satellite imagery to identify pig launchers or block valves along randomly selected sections of ROW, as shown in Figure 58. Scanning was performed for 9 pipeline sections including 3 belonging to the partner who reported component counts. Sections varied in length from 32 to 48 km. [63] . Counts from the 9 sections were bootstrapped to create a probability distribution of for counts of auxiliary equipment for partners and non-partners. The resulting distribution is provided in the accompanying data tables, in the worksheet "Sheet2 Activity Data." The density of pig launchers and block valves were essentially ($R^2 > 0.89$) uniformly distributed, with block valves ranging from 0.06 to 0.38 locations per kilometer of pipeline, and pig launchers from 0.15 to 0.64 locations per kilometer of pipeline. (Figure 57)

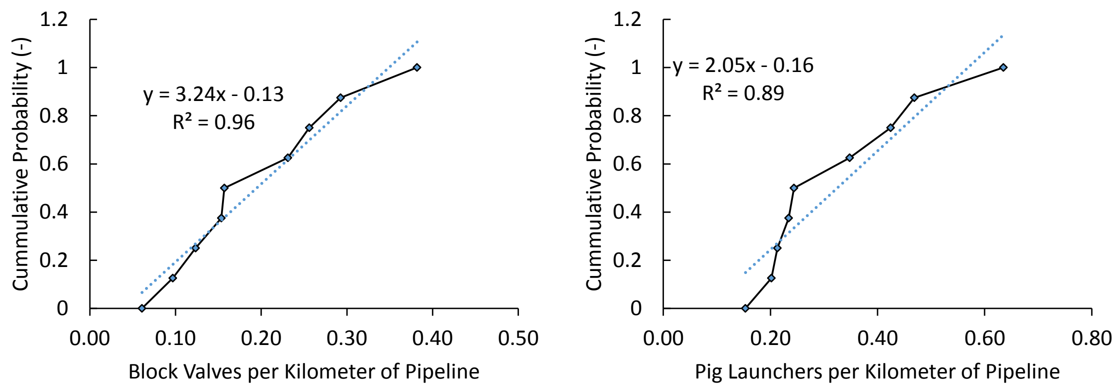

Figure 57: Cumulative distribution functions for block valves and pig launcher locations

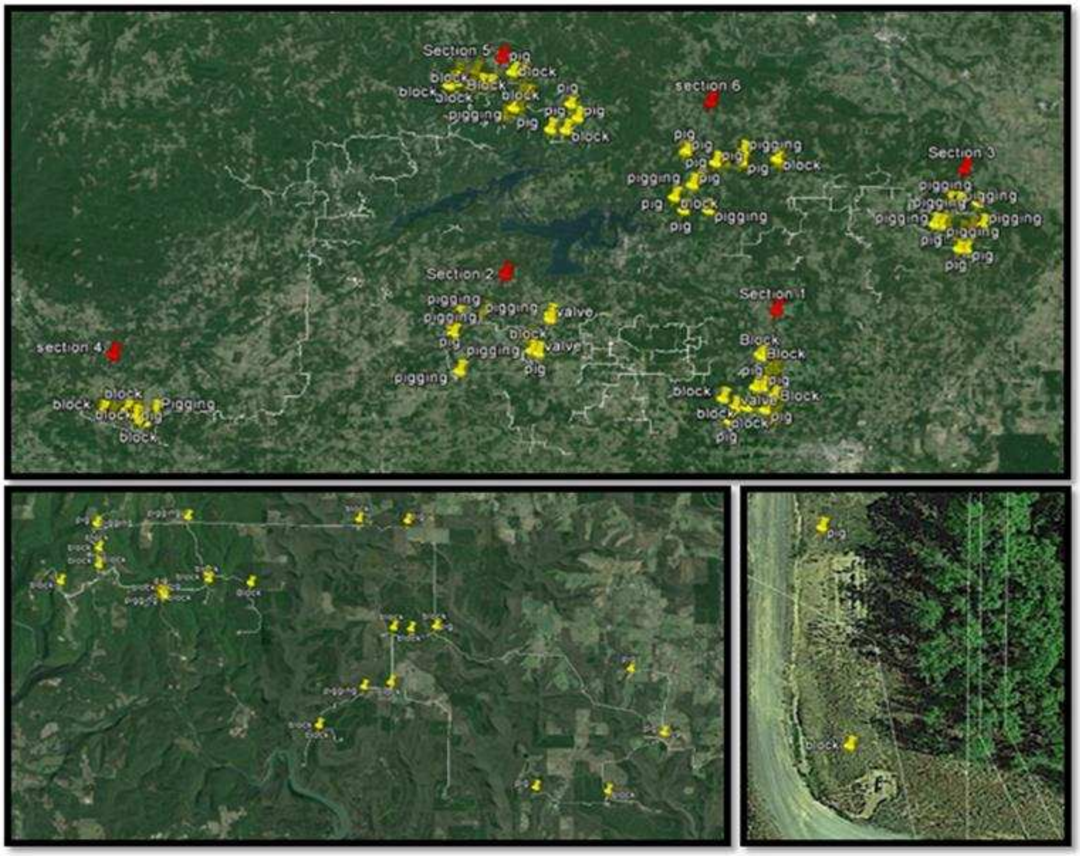

Figure 58 Satellite image surveys to determine auxiliary equipment counts. Top image displays 6 sections of viewed pipeline, bottom left shows zoomed in image of section 6 and the bottom right shows what pig launchers and block valves look like in satellite imaging.

Emission rates for the auxiliary equipment were randomly drawn exclusively from data measured in the field campaign. All emissions from each auxiliary equipment location in the field study were summed to create a distribution of emissions *by location type*. Data is in “Gathering Pipeline Emission Data.xlsx”.

7.4.6 Planned Episodic Emissions

No pipelines were blown down (or ruptured) during the study period. Therefore, planned episodic emissions in this study are only composed of pig launching and receiving. During the field campaign, there were 13 pigging operations. Dimensions of vessels and pressures were provided by partner companies. Calculating the total mass of methane released was performed using the following method.

$$V = B_L\left(\frac{\pi B_D^2}{4}\right) + b_L\left(\frac{\pi b_D^2}{4}\right)$$

$$G = K_{CH4}\frac{P * V}{r * T}$$

Where

- V = volume of pig launcher/receiver
  - B_L = Barrel length
  - B_D= Barrel Diameter
  - b_L = Bypass length
  - b_D= Bypass Diameter
- G = mass of methane in the pig launcher or receiver when pressurized, in grams
  - P = Pressure provided by partner before Purge
  - r = Gas constant, 8.3145 $m^3*PA*K^{-1}*mol^{-1}$
  - T = Temperature of gas at release
  - K_{CH4} Conversion from moles to mass. $K_{CH4} = 16.04\ g/mol$ for methane.

Emissions from pig launch & recovery are small relative to other emission sources, as indicated by the calculations in Table 19, and observing that the single pipeline leak of 96 kg/day is an order of magnitude higher than the total emissions from pigging operations on any given day.

Figure 59 Venting of Pig Launcher Chamber

Table 19 Dates and Sizes of Pig Launcher Emissions

Location	Date	Mass Released (kg CH4)	Total Mass Realsed (kg CH_4)
Pig Facility 1	10/6/2015	1.6	9.3
Pig Facility 2		2.1	
Pig Facility 3		3.2	
Pig Facility 4		2.3	
Pig Facility 5	10/7/2015	2.6	9.1
Pig Facility 6		3.9	
Pig Facility 7		2.6	
Pig Facility 8	10/13/2015	1.1	2.0
Pig Facility 9		0.9	
Pig Facility 10	10/14/2015	2.5	10.5
Pig Facility 11		2.9	
Pig Facility 12		2.2	
Pig Facility 13		2.8	

7.5 Results & Study Comparisons

The study area model utilized only measurements and activity data from the field campaign. The model was compared against emission estimates for the same study area based upon emissions factors from other sources/studies combined with activity estimates developed for this model. Therefore, comparisons with other methods compare emission rate estimates scaled to the study area without comparing different methods of estimating activity that may have been used in other studies. Model results include emissions for pipeline leaks and auxiliary equipment, and *do not* include planned episodic emission since these were not incorporated into the emission factors from other sources.

7.5.1 Field Campaign Measurements for Auxiliary Equipment

Cumulative distribution functions (CDF) of pig launchers and block valves are shown in Figure 60, and complete data is included in the SI data table “Gathering Pipeline Emission Data.xlsx”. Lower Detection Limit (LDL) of high-flow is shown in plots.

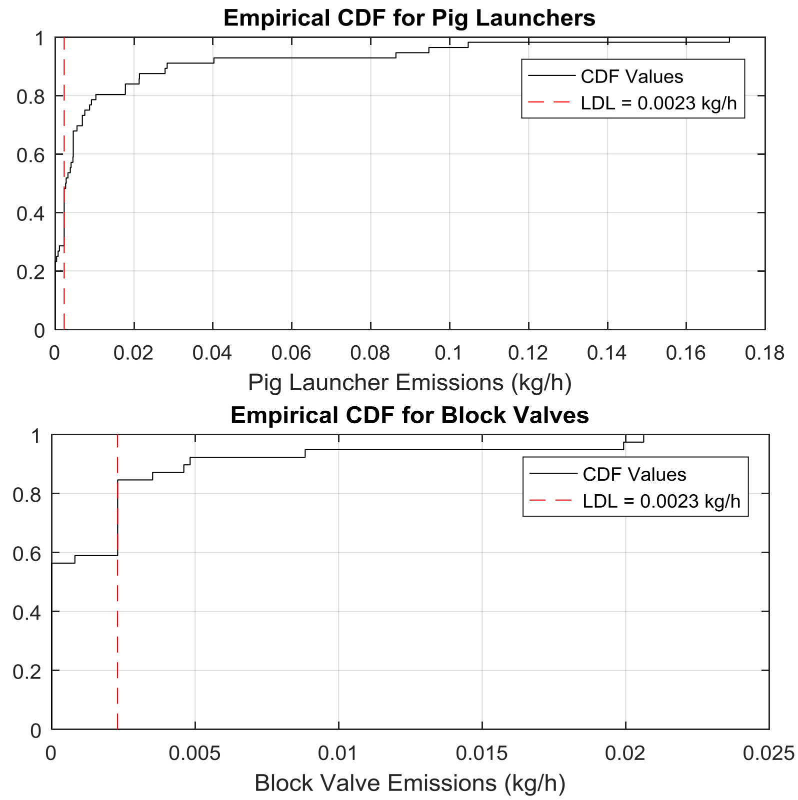

Figure 60 CDF's for Pig Launcher & Block Valve Emissions

Zero's in the CDFs represent measurements of rates below the minimum detection limit (MDL) of the high-flow instrument. There are some non-zero measurements below the MDL because the study team was able to reduce the MDL by reducing the flow rate of the high-flow instrument under some conditions. The methane sensor has an MDL of 0.05% concentration by mass, and slowing air throughput increases methane concentration, allowing methane quantification at lower leak rates. The study team made the decision to restrict airflow on a case-by-case basis, based upon prior experience. Quality control after the field campaign determined if the restricted airflow measurements could be utilized. A table of measured emission values for Pig Launchers, Blocks valves, and the single line pipeline emission can be seen in SI Data Table x2.

Using a both a two-sided Kolmogorov-Smirnov test and a student-t test there is no statistical difference between emissions from the two partner companies. Measurements from both companies were combined and also utilized to estimate emissions from non-partner auxiliary equipment.

7.5.2 Study Results

The study model estimate (SME) of emissions from the study area was developed utilizing Monte Carlo methods with 100,000 iterations. Both activity and emission models were varied during each iteration. Results for the SME and comparable results using emission factors from three other sources are illustrated in Figure 61. A comparison of CDF's can be made to view the nature of the emission profile distributions. It can be seen that the GHGI emission estimate has a large tail to encase a large maximum possible emission while the low end of the distribution is small due to the nature of the log-normal distribution that the estimate is generated from. It can also be seen that the study model estimate and GHGI and GHGRP estimate all cross each other in the figure suggesting that the emission estimates are statistically similar. The Lamb emission estimate does not cross any of the other estimates suggesting that its emission estimates are from a different population of emission sources.

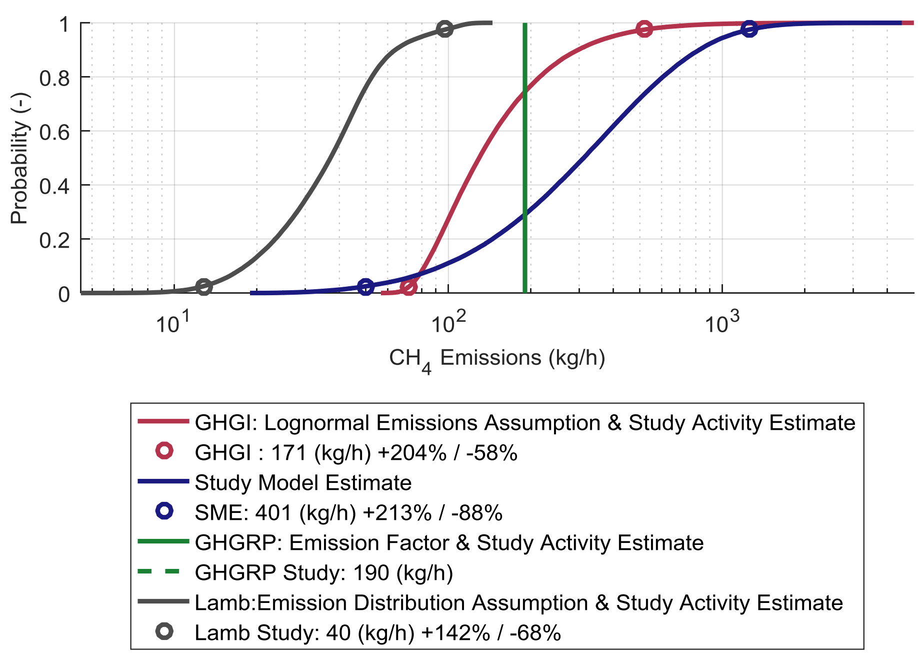

Figure 61 Study area emission estimates. The Study Model Estimate (SME) is compared against estimates based upon study activity estimates and emission factors from the greenhouse gas inventory (GHGI), greenhouse gas reporting program (GHGRP), and emission factors from the recent Lamb et. al. study of distribution mains. Circles indicate the empirical 95% confidence intervals for all studies where variability could be estimated from available data.

7.5.3 Study Comparison

This study was compared against emission estimates based on emission factors and activity factors provided by the Greenhouse Gas Inventory (GHGI), Greenhouse Gas Reporting Program (GHGRP), and Lamb distribution study. This section discusses how emission factors and associated distributions were calculated from each of the studies.

7.5.4 GHGI Estimates

The 2015 GHGI sinks and sources report, released in 2016 [41], uses emission factors that were measured and calculated in a 1992 field campaign and reported in 1996 [24]. The GRI/EPA study generated emission factor and activity factor estimates for gathering pipelines for different pipeline types based upon measurements performed on distribution network pipelines. Figure 62 was pulled directly from the GRI/EPA report[24] and provides emission factors, activity factors and 90% CI's for different line types.

TABLE 9-4. SUMMARY OF METHANE EMISSIONS ESTIMATE FROM UNDERGROUND PRODUCTION PIPELINES[a]

Pipe Material	Average Emission Factor, (scf/leak-yr)	Average Activity Factor, (equivalent leaks)	Methane Emissions Estimate, (Bscf)	90% Confidence Interval of Emissions Estimate,[b] (Bscf)
Protected Steel	17,102	53,657	0.9	1.2
Unprotected Steel	43,705	114,655	5.0	7.0
Plastic	84,237	6,467	0.6	1.2
Cast Iron	201,418[c]	856[d]	0.2	0.1
Total			6.6	7.2

Figure 62 1992 Emission Values and 90% CI for GHGI data series

The report indicated that the emission distributions were log-normal, but did not provide standard deviation, and original data could not be acquired. The model values were estimated by assuming a log-normal distribution, and estimating parameters of the distribution using Nelder-Mead optimization (MatLab™) determine the standard deviation that would produce a similar 90% CI. Figure 63 provides an example of the reconstructed lognormal distribution for plastic pipeline emissions.

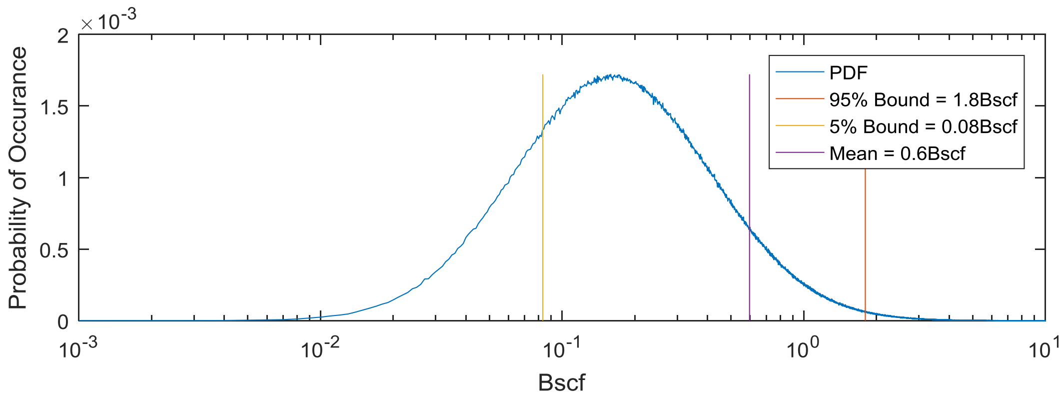

Figure 63 Estimated lognormal distribution of emission rates from plastic pipelines from the 1996 EPA/GRI study [24]. Simulation results illustrate the resulting probability distribution utilizing a mean of 0.6 Bscf and matching a stated 90% CI of 1.2 Bscf.

7.5.5 GHGRP Estimates

The Greenhouse Gas Reporting Program provided Emission factors for pipelines on a per mile basis as seen in Figure 64. The GHGRP does not supply CI's, standard deviations or supporting data to put uncertainty bounds on their estimates.

Population Emission Factors—Gathering Pipelines by Material Type [7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emission Factor is in units of "scf/hour/device."
[3] Emission Factor is in units of "scf/hour/pump."
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."
[7] Emission factors are in units of "scf/hour/mile of pipeline."

Figure 64 GHGRP Table 1-wa: Emission Factors for Gathering Pipeline

7.5.6 Lamb study Estimates

The Lamb study provided national estimates for emission factors from distribution pipeline mains, 95% confidence intervals from bootstrap and identifies the best distributions to characterize the data. These values were used to generate similar distributions with the same mean and upper 95% CI. Emission factors per mile of pipe were estimated by dividing the total national emissions for each pipeline type by national pipeline lengths for each line type. See Lamb study SI table S4.6 for U.S. pipeline mileage, see table S3.4 for emission distribution types and Lamb study table 4 for overall emission inventory for us natural gas distribution systems.

Emission data was downloaded from Lamb SI to populate potential emissions from individual pipeline leaks. Leak frequency was held constant in the comparison and was found by using Lamb's national estimate for equivalent leaks and dividing by Lamb's estimate for total distribution main pipeline lengths.

Total line lengths were found by determining the total number leaks per partner and then randomly selecting that many emission sources from the distribution. The values were then summed which created the study area estimate for the Lamb study.

The distribution data is included in this study because past revisions of the GHGI and GHGRP utilized emission factors from distribution mains when measurements of gathering pipelines were not available. While gathering and distribution pipelines are constructed of similar materials, they are operated differently due to differences in gas quality, safety regulations, and proximity to human population. This study suggests that, due to the, or other, differences, emission measurements from distribution mains are not a good surrogate for emissions in gathering pipelines.

7.5.7 Statistical Similarity

The GHGI and Lamb study distributions were found to be statistically different from the SME using a two-sided Kolmogorov-Smirnov Test with $\alpha = 0.05$. The SME and the GHGRP-based estimate were compared by determining if GHGRP value was contained by the CI of the SME.

7.6 Estimating Required Size of Gathering Pipeline Measurement Campaigns

The uncertainty in the SME is largely driven by the unknown frequency of underground pipeline leaks. We estimate this uncertainty following the method of Section 7.4.4, above, for a range of possible leak frequencies in a study area of similar size to this study area.

The method utilized for Figure 5 in the paper is as follows:

1. Select a leak frequency for the study area. While unknown before the field campaign, a range of estimates should be possible.
2. Assume a fraction of the basin surveyed to detect leaks.

3. Using (1) and (2), calculate the upper confidence interval using the method in Section 7.4.4, and shown in Figure 56. For this analysis, we are interested in only the upper confidence bound, to focus on the probability of underestimating emissions from pipeline leaks. We, therefore, utilize a 0/95% confidence interval, which provides a 95% confidence that the real emission rate is less than or equal to the estimated emission rate.
4. Repeat (1)-(3) for the full range of leak frequencies and survey fractions.

The result is a curve for each assumed leak frequency which estimates the 95% upper bound on estimated emissions for any given field campaign, as shown in Figure 65. As indicated in the figure, a larger portion of basins (study areas) with low leak frequencies must be surveyed to produce the same *relative* upper confidence bound as basins with high leak frequencies.

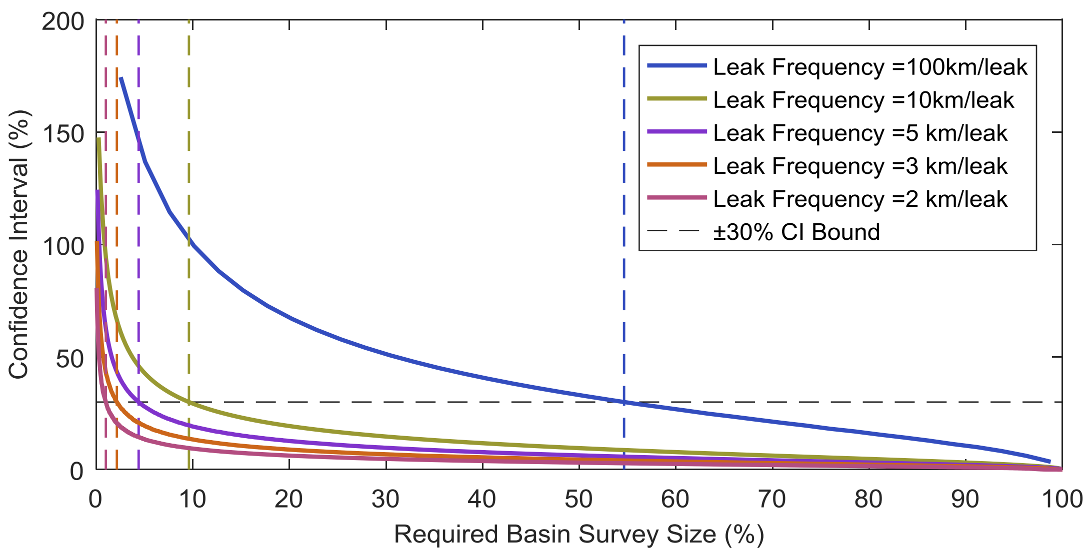

Figure 65 Relationship between survey size and upper confidence bound in a basin similar in size to the study area. Estimates consider only the impact of leak frequency within the basin. The fraction of the basin which must be surveyed increases as leaks become less frequent, ranging from ≈1% of the basin for 1 km/leak to 65% of the basin for 160 km/leak.

However, a more relevant metric to design a leak measurement campaign is to look at pipeline emissions uncertainty relative to total emissions in the basin. To do this analysis, we assume that total emissions in the study area will be similar to Peischl's [16] measurement of the eastern Fayetteville shale, and ask the question: How much of the basin need we measure before we can bound the pipeline emissions to be within estimated with an error ≤1% of total basin emissions? The 1% bound was chosen as it represents a low fraction of total basin emissions. It was arbitrarily chosen and the analysis could be done with a different cut off percentage.

This analysis is completed by the following algorithm for each leak rate l:

1) Compute the upper bound on pipeline emissions, U_l, for the basin using the number of leaks computed from the curves in Figure 65 and assuming a conservative (i.e. likely high) emission rate of 4 kg/h per leak. Note that U_l is a function of the measured fraction of the basin, f, i.e. $U_l = U_l(f)$.
2) Compute the "assumed real" total pipeline emissions, R_l, for the basin by multiplying the assumed emission rate (4 kg/h) by the assumed total number of leaks in the basin (e.g. $(4000\, km)/(100\, km/leak) = 40\, leaks$)
3) Determining the fraction of the basin which must be measured for $\frac{U_l}{R_l} - 1 \leq 0.01$. This area is shaded black in Figure 5 of the main paper.