Energy Research and Development Division

FINAL PROJECT REPORT

Multi-Tiered Greenhouse Gas Emissions Measurements of California's Natural Gas Powered Industrial and Fueling Infrastructure

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division manages the Natural Gas Research and Development Program, which supports energy-related research, development, and demonstration not adequately provided by competitive and regulated markets. These natural gas research investments spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

The Energy Research and Development Division conducts this public interest natural gas-related energy research by partnering with RD&D entities, including individuals, businesses, utilities and public and private research institutions. This program promotes greater natural gas reliability, lower costs and increases safety for Californians and is focused in these areas:

- Buildings End-Use Energy Efficiency.
- Industrial, Agriculture and Water Efficiency.
- Renewable Energy and Advanced Generation.
- Natural Gas Infrastructure Safety and Integrity.
- Energy-Related Environmental Research.
- Natural Gas-Related Transportation.

Multi-tiered GHG Emissions Measurements of California's Natural Gas Powered Industrial & Fueling Infrastructure is the final report for the Multi-tiered GHG Emissions Measurements of California's Natural Gas Powered Industrial & Fueling Infrastructure project (PIR-16-014) conducted by the Electric Power Research Institute. The information from this project contributes to the Energy Research and Development Division's Natural Gas Research and Development Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at 916-327-1551.

ABSTRACT

Major knowledge gaps exist for methane emissions occurring downstream of the customer meter, such as fugitive, vented and incomplete combustion emissions. This project used a suite of methane monitoring techniques at high throughput industrial natural gas customer sites (two power plants and one food processing facility) and 48 compressed natural gas fueling stations. Also measured were nitrous oxide emissions from the industrial combustion stacks. The multi-tiered monitoring approach used sensors installed on aircraft, ground-based vehicles, handheld devices, and stack sampling platforms, and was necessary to access, identify and integrate all emission sources across large facilities, while determining the best measurement method for each source.

Fugitive methane emissions at the industrial sites are such that a small fraction of emission sources make up most of the emissions. Total site fugitive emissions represented tiny fractions of natural gas throughput and stack combustion greenhouse gas emissions depended on plant operating mode.

Total emission rates from compressed natural gas fueling stations were also dominated by a small fraction of sites. Similarly, total emissions within natural gas fueling stations were dominated by a small fraction of components. Compressors had the highest emissions by equipment or component type; emissions were significantly impacted by operational mode. However, categorizing these as intentional releases versus leaks was not possible. A spatially explicit bottom-up estimate of non-combustion methane emissions from oil and natural gas production, transmission, processing, distribution, and post-meter consumption was also created that improves upon prior work.

Lessons learned from the site recruitment process, along with emissions results, will inform the design of future research. Results should not be used to create categorical emission factor assessments as the full range of operational conditions, and proportional sampling of site types across the state, were not possible to incorporate into the project design.

Keywords: Greenhouse gas, GHG, methane, power plant, compressed natural gas, CNG

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Introduction or Background

California’s progress toward reducing greenhouse gas emissions is supported by identifying and quantifying emissions sources, total emissions, and emissions trends. Despite a number of intensive measurement campaigns in recent years to locate and quantify greenhouse gas (GHG) emissions in California and elsewhere, significant uncertainty still exists in estimates of methane emissions that originate from human activities. Many of the previous campaigns focused on the extraction and transport phase of the natural gas fuel cycle, with minimal measurements at downstream industrial facilities, residences, and other beyond-the-meter end users.

California’s ambitious GHG reduction goals and reporting requirements create the need for more complete knowledge of the sources, magnitude, and distribution of methane emissions in the state. These policy goals include:

- Reduce statewide GHG emissions 40 percent below 1990 levels by 2030 under Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) and amended Assembly Bill 32 (Nunez, Chapter 488, Statutes of 2006).
- Ensure maintenance, repair and replacement of pipelines to minimize methane leaks while improving public safety and reducing GHGs under Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014).
- Reduce methane emissions by 40 percent from 2013 levels by 2030 under Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016).

To help provide a more complete understanding of methane emissions in California, this report provides results from an intensive measurement campaign held at multiple sites from 2018 to 2020.

Project Purpose

The researchers investigated emissions sources that had not previously been characterized with a multi-tiered measurement method, providing preliminary data to characterize methane and nitrous oxide emissions from these sites on the customer-side of the gas meter, which is referred to as downstream of the meter throughout this report. In addition to developing and applying a multi-tiered measurement method, the research team provided insights regarding the use of multi-tiered measurement approaches for characterizing emission sources that differ in geographic scale and temporal variation. The project also investigated nitrous oxide emissions from the combustion stacks of three industrial sites with high levels of natural gas combustion.

The multi-tiered measurement campaign focused on GHG emissions from several types of high throughput industrial natural gas customer sites, including natural gas power plants, and compressed natural gas fueling stations. The researchers (1) worked with industry and utility partners to identify and quantify emissions from poorly characterized sources for improved understanding and potential voluntary mitigation; (2) compared the ability of various measurement platforms to characterize on-site emissions; (3) determined isotopic signatures of emissions of natural gas and nitrous oxide to identify and quantify contributions to atmospheric plumes, (4) updated maps of spatially resolved major anthropogenic sector GHG emissions from California; and (5) compiled lessons learned regarding non-technical issues (such as from identifying and recruiting host sites for the emissions measurements) to inform future emissions measurement efforts.

Project Approach

This project developed and applied a multi-tiered monitoring approach to estimate methane emission rates from facilities, stacks, components (such as compressors), and pipes associated with several types of high throughput industrial natural gas customer sites (including two natural gas power plants and one natural gas-powered food processing facility) as well as compressed natural gas fueling stations. Multi-tiered refers to the use of a suite of different emission monitoring techniques relevant for use over small and large geographic scales. This approach is necessary to completely identify, analyze and integrate sources across a large industrial facility, which is comprised of numerous components and equipment with varying physical accessibility.

The multi-tiered measurement approach was used to screen for, and then quantify, GHG emissions at facilities of interest. Facility-wide GHG emissions estimates were obtained using aircraft-based and vehicle-based methods. Methane emissions from individual pieces of equipment were identified using handheld instruments, while stack GHG emissions were measured using specialized extractive probes and spectroscopic stack monitoring equipment. Isotopic analysis was performed on samples of methane gas where applicable, to analyze gas composition and to distinguish if the source was thermogenic (from natural gas) or biogenic (from livestock or wetlands). The various methods allow a full assessment of emissions from all equipment on site, make possible a comparison of top-down versus bottom-up approaches in calculating site-specific emissions, and facilitate assessment of the advantages and limitations of each approach. The authors believe this to be the first study applying such a wide suite of emission measurement technologies to behind-the-meter sources of methane.

Emissions from these facilities have not been studied extensively because of the difficulty of gaining site access and conducting ground level measurements to verify remote measurements from satellites or aircraft. Furthermore, these facilities may exhibit sporadic operating patterns, which adds a layer of complexity when deciding the timing of the measurements.

Selection of sites for intensive, on-site monitoring included consideration of facilities' designs and equipment, which are the main operational drivers of emissions. The information gathered for selection of facilities for on-site monitoring was also used to identify several dozen additional sites across the state that were candidates for aircraft sampling, although the on-site multi-tiered monitoring method was not used there. These included a mix of large natural gas end-users or potential confounding sources of methane: landfills, dairies, petroleum refineries, biomass power plants, natural gas-fired power plants, food processing facilities, and wastewater treatment plants.

A bottom-up inventory showing the spatial distribution of methane emissions for oil and natural gas production, transmission, processing, and distribution was developed. The residential, commercial, and industrial post-meter natural gas consumption sector—which was not accounted for in previous spatial inventories—was added to the spatially resolved methane inventory. Similarly, gridded natural gas-related carbon dioxide emissions were developed while generating gridded nitrous oxide emissions based on the US Environmental Protection Agency Greenhouse Gas Reporting Program.

Project Results

Project results are discussed in three sections: intensive measurement campaigns that demonstrate the use of a multi-tiered approach and provide important insights into emissions at large industrial facilities, monitoring of emissions at several dozen compressed natural gas fueling stations, and development of a spatially resolved, bottom-up GHG inventory for emissions associated with production, transmission, processing, distribution, and consumption of oil and natural gas in California.

Intensive multi-tiered measurement campaigns at industrial sites

Intensive measurement campaigns at three host facilities provided the opportunity to use the tiered measurement methods to detect and quantify GHG emissions. For the first combined cycle power plant visited on site and by aircraft in this study (Facility 1), aircraft measurements of carbon dioxide emissions were generally similar to stack measurements and were within 14 percent of the average annual values reported to Greenhouse Gas Reporting Program required by Environmental Protection Agency. Measured nitrous oxide stack emissions were 4.8 times larger than values reported to the Greenhouse Gas Reporting Program, but near and sometimes below measurement detection limits. Methane stack measurements were below detection limits at this site. For the food processing facility visited in this study (Facility 2), aircraft measurements of carbon dioxide emissions were consistent with boiler stack measurements. As the site visit occurred during the busy harvest season, these values were multiple times higher than Greenhouse Gas Reporting Program reported values, which represent average values over the course of a year. No methane or nitrous oxide emissions above the detection limits were observed at Facility 2 by aircraft or stack measurements. These results suggest it may be necessary to improve detection limits for extractive infrared spectroscopy to perform future methane or nitrous oxide field measurements at combustion stacks.

Due to the very low stack emissions of methane at the sites, fugitive methane emissions from equipment leaks at the two combined cycle power plants and the food processing plant were significant in comparison, although also only representing substantially lower than one percent of natural gas throughput at the sites. Along with operational differences during the campaigns as compared to annual average operations, this finding could help explain discrepancies between measured facility-wide methane emissions and the methane emissions reported to Greenhouse Gas Reporting Program which only requires combustion emissions. Additionally, fugitive methane emissions were dominated by a few large sources. Identifying and mitigating these sources early could be a particularly effective strategy to reduce emissions. The number of emission points (such as, individual locations of leaks or intentional emissions, not including combustion stacks) per site ranged from 18 to 37 (out of potentially thousands of components present).

Power plant combustion-related GHG emissions depended on the operating mode and capacity factor of the facility. Stack data from the power plants showed GHG emissions increased with instantaneous load factor. Highest carbon dioxide emissions were observed during steady high load operating modes. In some cases, very high methane emission rates were observed for periods of several minutes during startup operations due to transient combustion adjustments made as the generators and emission controls came online.

Isotopic sampling allowed for identification of methane gas origin by distinguishing if the observed methane was biogenic or thermogenic. In a particular instance, a significant plume of methane was detected by aircraft above the host facility even though handheld and vehicle-based measurements did not indicate any major emissions. Isotopic analysis suggested that the stable carbon isotopic signature ($\delta^{13}C$) of the methane plume was too low for it to originate from natural gas and provided support that confounding of the facility plume with a plume from nearby biogenic sources could be the cause of the aircraft detection of methane at levels much higher than could be accounted for by the ground-based and stack measurements. This also implies that aircraft measurements of whole-facility emission rates should be validated whenever possible to avoid inaccuracies due to confounding off-site emission sources.

Results from vehicle-mounted analyzer measurements show that the method can be useful for estimating facility-wide methane emissions and provide higher time efficiency compared to component-level emissions using handheld instruments at the cost of higher uncertainty. However, emission sources higher than the gas sampling inlet points, such as vent stacks, may not be fully captured by vehicle-mounted instruments. Spacing restricts how close to the emission points the vehicle can reach, which can also result in underestimated emissions.

Aircraft sampling of GHG emissions at 41 additional secondary sites in nearby regions demonstrated the method can be useful for screening large-emitting facilities to obtain an order of magnitude estimate of the emission rate. Compared to the vehicle-based method, aircraft sampling further adds time efficiency and is not subject to source height limitations. However, the technique has a significantly higher detection limit compared to handheld or vehicle-based techniques and was prone to interference from nearby confounding sources of emissions such as dairy farms. Carbon dioxide and methane emission rates estimated by aircraft sampling were usually higher than Greenhouse Gas Reporting Program reported values, to varying degrees. Of the 12 facility types visited by aircraft, refineries, oil depots, and combined cycle power plants were the top three emitting facilities for carbon dioxide emissions while landfills, dairies, and refineries were the top three facility categories for methane emissions. Greenhouse Gas Reporting Program values represent a yearly average while the aircraft sampling is a snapshot in time; thus, seasonal factors may also affect the comparison of observations to the inventory.

Key findings regarding the use of a multi-tiered approach include that:

- It is important to have a plurality of methods to characterize emissions sources that are intermittent and/or variable in time, span a range of sizes, and detection of which can be complicated by nearby sources (point and area sources). Each method used was found to be an important contributor to the overall project analyses.
- The on-site emissions measurements with hand-held instruments were able to reach the overwhelming abundance of individual emission points across all sites sampled (with a few exceptions, such as limited locations where equipment blocked access). These instruments also had a sufficiently low detection limit that dozens of emission points per

site were able to be quantitatively sampled. Thus, measurements from these instruments were used as the baseline method to estimate ground-based emissions.

- The ground-based mobile platform (the Mobile Plume Integrator) was used to confirm the identification and emission rates of emission sources located fewer than 12 feet above ground level. However, this was only possible at a limited number of emission points, because the car could not always closely approach the emission point due to physical barriers, site orientation or the need to be driving at a tangential direction to the flow of the emission plume for accurate emission rate estimation.
- The unmanned aerial vehicle platform was the only option for reaching elevated emission sources (for example, vents) that were not reachable by lift equipment, and was used to quantify emissions at several sources, also to demonstrate the distances downwind by which those plumes had dissipated into the background.
- The aircraft flights measured the whole-facility emission rates and served as a comparison point to the sum of fugitive and stack emissions. The aircraft flights also provided a large range of measurements from sites further afield that were not visited on the ground. These data provide broader context for the sectoral categories sampled (for example, power plants) and served as comparison points for the intensively measured sites. Isotopic analyses assisted with confirmation of the fossil vs. biogenic nature of the emissions sources when the sources were unclear.

Emissions monitoring at CNG fueling stations

The research team visited 48 unique CNG stations throughout the state of California and conducted intensive surveys with handheld equipment on 27 of the stations, in addition to performing surveys with a vehicle-mounted system on a subset of the stations. Compressed natural gas station level total emission rates were dominated by the top few emitting stations. Analysis of individual emission points within each compressed natural gas station revealed that the mean number of emission points per compressed natural gas station was 6.3 (out of potentially hundreds of components present), and the emission rate distribution within each station demonstrated that a small fraction of components was responsible for a large majority of the emissions. The compressor was found to be the largest source of emissions within a station and its emission rate seemed to be significantly impacted by the compressor mode, with a large increase observed in the initial periods of operation and a subsequent tapering off during and after operations. Due to the complexity of compressor design and operations, it was not possible to separate compressor emissions into vented and leaking emissions. Improved understanding of the transient nature of compressor emissions is needed to understand the role of these sites in behind-the-meter emission estimates.

Development of a bottom-up GHG emissions inventory

A separate emissions mapping task within this project developed a bottom-up inventory that shows the spatial distribution of GHG emissions for oil and natural gas production, transmission, processing, and distribution (Appendix E). That task estimated statewide non-combustion (that is, fugitive, vented, flared) 2016 carbon dioxide and methane emissions for the primary sectors (oil and natural gas production, transmission, processing, distribution) to be 1.42 (1.06 – 1.88 at 95 percent confidence) and 4.31 (3.58 – 5.08) teragram (Tg) carbon dioxide equivalent (CO_2 eq), respectively using a 100-yr global warming potential of 25 g CO_2 eq/g methane. However, when the residential, commercial and industrial post-meter consumption (including natural gas combustion) emissions are considered, the total carbon dioxide emissions (97.2 Tg CO_2) become substantially larger than those of methane (5.7 Tg CO_2eq), underscoring that reduction of combustion emissions remains an essential goal for climate change mitigation. This study's methane emission estimates for the primary sectors are approximately 50 percent lower than those from previous similar studies performed for California. This reduction is attributed to the revised emission factors from the Environmental Protection Agency's GHG inventory used in this study (Appendix E for details), as well as a recent (2016 vs. 2010) factor of three decrease in non-associated (dry) gas production.

The sampling performed in this project was not intended to result in a categorical assignment of emission factors for several reasons: (1) use of a limited sample set – two power plants and a single food processing plant, (2) the lack of sustained measurement campaigns designed to systematically characterize the average of transient emissions and the persistence of point sources, and (3) the distribution of compressed natural gas fueling stations sampled may not be representative of California's population of compressed natural gas fueling stations with regard to site characteristics or operational profiles, despite the larger number of sites sampled. Accordingly, the results are meant to offer an initial assessment of emissions to inform future studies and are not intended to be an exhaustive examination of emissions that would be required to establish emission factors.

Knowledge Transfer

Public dissemination of the preliminary results from this project was minimal because of site confidentiality. Broader dissemination will occur after the final report is released. The research team members plan to share detailed results with the global electric utility membership of Electric Power Research Institute (EPRI) at the semi-annual meetings, with the gas utility membership of the Gas Technology Institute, with stakeholder organizations in the energy and environment areas, and at technical conferences (for example, American Geophysical Union Annual Meetings, or Methane Connections). EPRI will provide individual briefings to any entity with interest.

Periodic updates regarding project progress, interim results, and lessons learned were provided to California Energy Commission staff and members of the Technical Advisory Committee, which included representatives from Southern California Gas Company, NGV America, and NASA's Jet Propulsion Laboratory. Technical Advisory Committee members performing research on related areas benefited from the opportunity to incorporate lessons learned from this project into their research activities.

An additional series of technical transfer activities was performed during the study period to assist one host company participating in the study as they communicated on the topic of methane and natural gas emissions with their local stakeholders. Results from each measurement campaign were also provided to the host sites as "Host-Specific Interim Measurement Reports" so they have a company-specific record of the findings from their sites, including details protected under confidentiality agreements.

Benefits to California

This research delivered scientific advancements that support climate policy by providing improved understanding of the quantity and distribution of GHG emissions. Specifically, the project results have improved scientific understanding of GHG emissions (from stack and fugitive sources) from two key types of high natural gas throughput industrial sites – power plants and food processing plants – and from compressed natural gas vehicle fueling stations. These results can be used as guidance to assist in developing relevant scope and scale of any future emissions studies performed in California or elsewhere. The work identified equipment types at these sites with the highest propensity to emit GHGs.

Further, this work provides benefits to ratepayers that accrue from leak detection and repair. The equipment and emission results, as well as lessons learned from use of multiple measurement platforms, are already being used to make company operations and maintenance and leak detection and repair programs more effective. This includes the companies involved with this study, as well as other companies (that is, electric utilities with EPRI membership who have been briefed on the results). As operators continue to mitigate methane emissions, one reasonable approach is to prioritize the highest emitters to bring about immediate, large abatement. Targeted leak detection and repair activities at power plants, food processing facilities and compressed natural gas fueling stations could identify emissions early and mitigate risks to system reliability. This in turn will lead to improved worker and public safety, reduced risk of damage to infrastructure, improved system efficiency, reduced natural resource loss and lower net costs to California ratepayers.

CHAPTER 1: Introduction

Motivation and Previous Work

Anthropogenic methane (CH_4) emissions originate from many different sources, each with varying degrees of uncertainty. Understanding the sources and magnitudes of greenhouse gas (GHG) emissions in California is important to properly mitigate and control those emissions. Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) requires California to reduce GHG emissions 40 percent below 1990 levels by the year 2030. Some GHGs have larger impacts on climate than carbon dioxide (CO_2) as indicated by larger global warming potentials (GWPs). Methane with a GWP ranging from 28 – 86 and nitrous oxide (N_2O) with a GWP of 264 – 298, depending on the time horizon used, both fall into this category. Additionally, Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014) requires that the maximum feasible effort must be made to estimate and reduce natural gas leaks from the natural gas infrastructure to ensure public safety and advance GHG goals (Senate Bill 1371 2014). Therefore, these GHGs are important to consider for safety and GHG emissions reduction purposes.

U.S. Energy Information Administration (EIA) reports 27 percent of the natural gas burned in California was used for electricity generation in 2019, with the balance in residential (22 percent), industrial (36 percent), and commercial (12 percent) sectors (U.S. Energy Information Administration 2021). Most research has focused on methane emissions from the natural gas industry upstream of the customer meter (Alvarez, et al. 2018) (Littlefield, et al. 2017) (Burns and Grubert 2021). The dearth of data on fugitive emissions from downstream source categories was highlighted as an important area for future research (Heath, et al. 2015). Detectable gas leaks in commercial or residential buildings are a priority for gas utility and public safety personnel. However, their goal is to immediately mitigate the leak for safety reasons, not to quantify GHG emissions. Improved techniques and protocols for quick and simple emissions quantification that could be deployed in this maintenance and repair context would be valuable developments.

Recent focus has begun to shift to emissions downstream of the customer meter [(Saint-Vincent and Pekney 2020); (M. L. Fischer, W. R. Chan, et al. 2018); and (von Fischer, et al. 2017)]. Methane can have different emission pathways at these sites, either as fugitive emissions (leaks), vented emissions (engineered emissions, usually intended to be periodic and not continuous), or as "slip" through incomplete combustion. Prior to the beginning of this study, what was known about downstream methane fugitive emissions derived from a series of mobile measurement campaigns across several metropolitan areas across the country with dense natural gas infrastructure. Those typically found a large number of small, previously undetected emission points [(von Fischer, et al. 2017), (Phillips, et al. 2013), (Weller, Roscioli, et al. 2018), (Weller, Hamburg and von Fischer 2020)]. Using a different approach, McKain et al. (McKain, et al. 2015) collected data from stationary monitoring sites in the Boston area and inferred a leak rate from downstream gas system components (including transmission, distribution, and use). Their result was a 2.7 percent leak rate, more than twice as high as the most applicable state inventory estimate. Additionally, the South Coast Air Quality Management District sponsored downstream field testing in 2015 (Mellqvist, et al. 2017) for fugitive volatile organic carbon emissions with long-path optical remote sensing. However, none of these techniques are amenable to finding specific emission or leak sites within high throughput natural gas industrial facilities (such as power plants) as they operate across larger geographic scales and reflect aggregated emissions from multiple individual emission points or sources (such as components or equipment). The need remained to get on site to localize, quantify and potentially mitigate the emissions from discrete leaks (M. L. Fischer, et al. 2017).

Several studies investigating post-meter methane emissions were undertaken in parallel with this study, both at residential and commercial sites. Lebel et al. measured 64 natural gas water heaters and found that roughly 0.4 percent of natural gas consumed by these appliances were emitted as leaks or as unburned methane (i.e., transient emissions or methane that passes through the combustion zone unburned) (Lebel, Lu and Speizer, et al. 2020). Additionally, despite having higher methane emissions (0.93 percent of gas consumed), tankless water heaters have lower overall GHG emissions because they use less energy to heat a unit of water. Merrin et al. found that appliance exhaust in homes typically exhibits a brief methane concentration spike during ignition and extinguishment, and relatively low concentrations during steady-state operations (Merrin and Francisco 2019). The research team projected that annually, 30 Gg of methane emissions can be attributed to residential natural gas appliances which account for ~0.1 percent of U.S. anthropogenic methane emissions. Fischer et al. measured post-meter methane emissions associated with residential natural gas consumption from 75 California homes and estimated the statewide mean value to be 35.7 Gg of methane per year or 2 percent of the state methane emissions in 2015 [(M. L. Fischer, W. Chan, et al. 2018), (M. L. Fischer, W. R. Chan, et al. 2018)]. Emissions from pilot lights were likely a major contributor to inactive emissions.

Sweeney et al. and Johnston et al. developed and demonstrated methods to measure methane emissions from natural gas appliances in commercial buildings. Both studies also found that fugitive methane emissions from commercial buildings were higher than those shown in current inventories, with the top 3 percent of emission sources accounting for more than 50 percent of total fugitive emissions, even as most gas piping and equipment in the sample of commercial buildings operated with low to no fugitive methane emissions. (Sweeney, et al. 2020) (Johnston, et al. 2020).

He et al. found that there are seasonal and nonseasonal contributions to methane emissions in the Los Angeles area. While the seasonal pattern is correlated with natural gas consumption from residential and commercial sectors, the nonseasonal component is consistent at 22.9 Gg methane/month. Comparing with throughput, this study suggests that roughly 1.4 percent ± 0.1 percent of commercial and residential consumption is released into the atmosphere in the Los Angeles area (He, et al. 2019).

Overall Project Scope and Objectives

The purpose of the project was to investigate sources that were hitherto uncharacterized with a multi-tiered measurement method, providing both preliminary data to characterize methane and nitrous oxide emissions from these sites downstream of the meter; and to provide insights regarding the use of multi-tiered measurement approaches for characterizing emission sources that varied in geographic scale and temporal variation. The project conducted a multi-tiered measurement campaign for methane and nitrous oxide emissions from several types of high throughput industrial natural gas customer sites (including two natural gas power plants and a natural gas-powered food processing facility) and compressed natural gas fueling stations. Nitrous oxide emissions from the combustion stacks of those industrial sites were also measured. The primary technical objectives were to (1) work with industry and utility partners to identify and quantify emissions from poorly characterized sources for improved understanding and potential voluntary mitigation; (2) compare the ability of various measurement platforms to characterize on-site emissions; (3) determine isotopic signatures of emissions of natural gas and nitrous oxide to identify and quantify contributions to atmospheric plumes, (4) update spatially resolved emission maps from current databases and inventories in a geographical information system (GIS) format for comparison against the anonymized and aggregated behind-the-meter emissions measurements; and (5) compile lessons learned and non-technical issues to inform future emissions measurement efforts.

The three categories of interest for this study were natural gas power plants, natural gas-powered industrial facilities, and compressed natural gas (CNG) vehicle fueling stations. Emissions from these facilities have not been studied extensively in part due to the difficulty in gaining site access and in conducting ground level measurements to verify remote measurements from satellites or aircraft. Furthermore, these facilities may exhibit sporadic operating patterns as part of their normal annual cycles, implying intentional or leak emissions measured at a certain point in time might be quite different than that from another time or an annual average value. For example, Duren et al., performed repeated sampling of large numbers of point sources in several industrial sectors over the span of several years, and demonstrated this variability (Duren, et al. 2019). Temporal variability in operations added a layer of complexity when deciding the timing of the measurements. However, the monitoring dates ended up being selected primarily on the availability of the host site technical experts, the research team, and to avoid major disruptions in host site service (such as outages, or periods of expected low activity), rather than to optimize a time or times for which the emission rate would be representative of long-term average conditions. As a result of the temporal effects, providing information to support emissions inventory development requires repeated sampling to illuminate the persistence of point sources. Smaller sites like CNG stations may not produce enough emissions to be detectable using airborne detection methods and require ground level measurements. Most industrial or commercial entities will not pay for leak or emissions testing unless it is a regulatory requirement, or if they have indications of substantial product loss with subsequent financial or operational management impacts. Quantitatively estimating those emissions through ratepayer support of the Public Interest Energy Research (PIER) program is highly valuable from a GHG emission, safety and cost standpoint. Site types that fall below thresholds for GHG reporting rules do not typically have labor or financial resources available for testing. Therefore, the research funding serves a very practical need to quickly screen dozens of facilities that otherwise would not be tested. It is likely that in many cases leak mitigation can be performed relatively quickly and cost-effectively once identified, thus improving facility operations while helping the state meet GHG emission reduction goals

Natural gas power plants generate electricity by burning natural gas and consequently release GHG (carbon dioxide, methane) and criteria air pollutants (carbon monoxide, nitrogen oxides, and particulate matter) as byproducts. California electric utilities own a mix of older boilers and newer gas turbines, which may be set up as "peaker" simple-cycle units, or as combined-cycle plants.

Industrial boilers are often much smaller than utility boilers and may use the generated steam for heating industrial processes or power generation. They are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-pressure and high-temperature steam for producing electricity. Natural gas is combusted, and the hot combustion gases are passed to a series of heat exchangers to heat water. Like natural gas power plants, emissions from industrial boilers include GHG and criteria pollutants.

Nitrous oxide is primarily associated with combustion, and not fugitive and vented emissions, at high natural gas throughput industrial facilities. Formation of nitrous oxide is minimized when combustion temperatures are kept high (above 1475^{o} F) and excess oxygen is kept to a minimum (<1%). Little information exists, however, on how much how much nitrous oxide is emitted from the facility types of interest and the factors that may lead to its formation.

CNG vehicle fueling stations serve the needs of vehicles from fleet trucks to light duty passenger cars. The majority of the approximate 208 CNG/LNG fueling stations in California (Duren, et al. 2019) are centralized fleet sites or public stations similar to gas stations. CNG station components which could emit fugitive methane emissions include compressor, dispenser, dryer, storage tank, and priority panel for controlling compressor sequencing. Compressors at CNG stations may vent natural gas by design during startup and depressurization, and these are classified as vented, not fugitive, emissions.

Building upon previous studies, this study also undertook an emissions mapping task to provide an updated spatially explicit bottom-up estimate of methane emissions from primary sectors (oil and natural gas production, transmission, processing, distribution) and residential, commercial and industrial post-meter natural gas consumption (that is, both fugitive and combusted; see Appendix E). Using unified methods and recent datasets, this study also develops gridded natural gas-related CO_2 emissions while generating gridded nitrous oxide emissions based on EPA's Greenhouse Gas Reporting Program (GHGRP). This work improves the spatial representation of the distribution and consumption sectors by developing a high-resolution natural gas consumption map across California, whereas previous work (for example, Jeong et al., 2014) used population density as a proxy for natural gas consumption (Jeong, Millstein and Fischer 2014). A full reporting of the methods and results from this project task can be found in Appendix E, with result highlights in the Conclusion and Executive Summary.

CHAPTER 2: Project Approach

Project Team and Roles

EPRI served as the lead institution for the team with substantial expertise brought to the measurements by other collaborating organizations. The Gas Technology Institute (GTI) was responsible for all hand-held/component level leak identification and quantification. Two groups at Lawrence Berkeley National Laboratory were responsible for 1) vehicle-based mobile plume integration (MPI) measurements and 2) isotopic analysis of gas samples. Scientific Aviation conducted aircraft and unmanned aerial vehicle measurements, while Montrose Environmental performed in stack measurements at natural gas power plants and the industrial facility. Additionally, TAC members (mentioned in the Acknowledgments section) provided valuable insight on desired and actual facility types along with operations during site selection process; broad knowledge of natural gas infrastructure emissions; and assistance with data interpretation.

The broad backgrounds and expertise of the project team and TAC allowed for the successful completion of three intensive field campaigns at two natural gas fired power plants and one industrial facility with multiple measurement platforms applied for each. The campaigns involved measurements made with handheld instruments, MPI, in-stack probes, airborne platforms (aircraft or UAV). The team was also able to visit several dozen compressed natural gas vehicle fueling stations to perform handheld, MPI, and collect samples for isotopic analysis.

Site Selection and Recruitment Process

The largest project barrier was the non-technical task of identifying and recruiting host sites for the emissions measurements. Several years passed from project initiation until completion of the final of six separate site access agreements. Recruitment and the measurement campaigns were performed on a rolling basis to accommodate the needs of varying access agreement negotiation processes. More potential hosts were pursued than needed, to provide a range of viable candidates that suited the technical needs of the project.

The first project task was to use (1) available inventories (for example, CARB GHG Inventory Mapping Tool (CARB 2018), U.S. EPA Greenhouse Gas Report Program (U.S. EPA 2021), U.S. EPA Air Markets Program Data (AMPD) (U.S. EPA 2018), and U.S. EIA Form 860/923 (U.S. Energy Information Administration 2021), (2) facility design and operational patterns, (3) natural gas throughput, (4) aerial imagery of target facilities and nearby emission sources, (5) proximity to restricted airspace, and (6) prior GHG emissions monitoring study results to create a target list of sites at which the methane fugitive and nitrous oxide stack emissions measurements could be conducted.

With only three intensive sampling campaigns incorporating the ground-level measurements at large facilities, data gathered are insufficient to improve categorical emission factors even if the facility characteristics are quite similar. Further, the potentially transient or variable nature of emissions (that is, lack of emissions persistence) at facilities in many industrial sectors

(Duren, et al. 2019) means that repeated, targeted measurement campaigns must be conducted to obtain enough information to amend inventories. Therefore, the goal was to represent varied facility designs to explore a range of equipment and operational drivers of emissions. The full listing of relevant California sites in the categories of interest (for example, power plants, industrial facilities, compressed natural gas fueling stations) was reduced to a smaller set which was targeted through discussions with site owners and operators.

Site Recruitment Process

The screening process results were used to open dialogue with potential partners and facility owner/operators. Outreach began through professional contacts and distribution of a recruitment flyer with email (Figure A-1). These materials were also distributed to a large number and variety of industrial facilities through Investor Owned Utilities (IOUs), the California Council on Environmental and Economic Balance (CCEEB), and the industrial research partners of several local air quality management districts. The team obtained interest from more sites than were possible to analyze. Three site access agreements were made for week-long intensive central site monitoring campaigns, and three agreements with different owners/operators of CNG fueling stations. The information gathered for site selection was also used to identify several dozen secondary sites across the state for aircraft sampling. These include a mix of large natural gas end-users or potential confounding sources of methane: landfills, dairies, petroleum refineries, biomass power plants, natural gas-fired power plants, food processing facilities, and wastewater treatment plants.

Site Recruitment Lessons Learned

The site recruitment process provided experience and lessons learned on the value statements and approaches used to communicate with potential host sites. Compelling value statements for host company participation were necessary to counteract the three primary concerns and perceived risks, which were preserving anonymity, sharing of detailed information on facility operations, and the actual costs of substantial in-kind labor and effort to coordinate with the research team.

Anonymity of the host company and facility, as well as detailed operational protocols, were key concerns requiring special project management arrangements to address. The hosts and monitoring sites were kept anonymous from CEC staff, the Technical Advisory Committee (TAC), and each other, and site descriptions in project reporting were generalized. The TAC reviewed a detailed site selection process, which was documented in a report, but not the sites themselves. However, some potential hosts were still concerned that unusual plant operational activity or research team visits as part of the study might be misinterpreted by agencies or neighbors. Potential hosts considered informing neighbors and/or regulatory entities that control electric grid loading and local air districts to be absolutely certain there were no safety or compliance concerns; each made their own decisions on the matter. Maintaining anonymity also required special contractual terms with the CEC to ensure that cost reimbursement (for example, travel receipts) would not allow for unintentional deduction of project participants. These factors led to difficulties with maintaining anonymity of host sites despite efforts by all involved parties.

The in-kind efforts involved preparations, staff escorts while on property, and assistance with data interpretation. This all requires substantial time to accommodate planning, internal and external communications, and the escorts and data interpretation. Some companies considering participation felt this actual labor cost was too high for them to support and chose not to participate.

Three major benefits to prospective facility owner/operators were emphasized to help overcome recruitment challenges: 1) increased safety, (2) facilitation of cost-effective leak detection and repair programs, and 3) reduced exposure to regulatory risk and compliance costs (that is, lower GHG compliance costs under California's AB 32 cap-and-trade program).

Many industrial entities are not willing and/or able to pay for leak or emissions testing unless it is a regulatory requirement, or if they already have indications of substantial product loss with subsequent financial or operational management impacts. Several public estimates to date have demonstrated that for some oil and gas companies the cost to implement a leak detection and repair (LDAR) program is substantially larger that the value of methane recovered from sites such as well pads (George 2018). However, large facilities have numerous locations where leaks could occur, and due to the volume of gas throughput, the aggregated impact could be large. Therefore, participation provided a host facility the opportunity to understand their emissions more accurately, but for only a relatively small in-kind cost as compared to paying for the full independent analysis on their own. Participation in this study would also allow previously monitored sites to compare against any prior work they have done (monitoring or paper calculations), or to see if any changes occurred since last estimates, as emissions can be intermittent and transient. Finally, some of the strategies deployed in this study, such as mobile methane mapping technologies, are a strategic approach to leak detection summarized in the Summary of Best Practices Working Group Activities document. (Scheehle, Setiawan and Magee 2016) For entities that are proactively investigating natural gas or methane emissions from their facilities, participation provided a low-cost opportunity to gain experience with several novel research-grade monitoring instruments and approaches.

Other value to the potential host sites varied depending on the type of site. For example, food processing facilities are large natural gas users that fall under cap and trade requirements for GHG emissions in 2020. However, there is a lack of new, more energy efficient technologies available to help reduce these burdens and retain cost-effective operations. A better understanding of the potential emissions reductions from leak mitigation at an anonymous food processing facility may be of high value to the industry.

Other important considerations included the following:

- Consideration of issues that could hamper measurements at potential host sites was made during the recruitment process. This included maintenance outages, facility updates and ownership changes. Site orientation/layout, equipment spacing, and wind patterns throughout the facility (which could affect use of the vehicle-mounted flux measurement technique) were considered. The latter three factors were particularly impactful for CNG station selection to allow for vehicle access and consider plume directionality.
- The long time for site access negotiations meant company business changes (for example, mergers, closures) impacted ongoing discussions and previous agreements. This necessitated moving to alternate host companies in some instances.

- Working with well-known measurement partners, who in some cases already had relationships with host companies, reduced the perceived risk of participating in a research project not required for regulatory compliance.

Measurement Methodologies

This section describes the nature of each measurement as well as the basic data processing procedures and rationale that was applied.

Hand-Held Component-Level Measurements

Emission Point Indications

Hand-held component level scans were performed by GTI to determine whether components had an emission and/or were "leaking." Emission point indications in this report are defined as emissions that were above a specific predefined concentration threshold of 500ppm and were located on components such as, but not limited to, threaded connections, valve bodies, compressor vents, flanges and gauges. Two sensors were used to determine the presence of an emission indication, a GF320 Optical Gas Imaging Camera (OGI; FLIR Systems, Inc; Wilsonville, OR), infrared camera and a Gold G2 (Sensit Technologies; Valparaiso, IN) combustible gas indicator (CGI).

Criterion for Emission Rate Quantification

Conducting a survey with a Sensit Gold G2 (Sensit Technologies 2019) component-by-component is a sensitive technique for identifying emissions point indications, including those with very small emission rates. To streamline site visits, the research team quantified only emission point indications that were visible with the FLIR GF320 in high sensitivity mode (HSM).

According to a 2018 field study by Ravikumar et al., at 1 meter away, the GF320 optical imaging camera has a 90% probability of detecting a 0.0019 kg/hr [or 0.1 standard cubic feet per hour (scfh)] emission and a 50% probability to detect a 5.7×10^{-4} kg/hr [or 0.03 scfh emission] (Ravikumar, et al. 2018). One meter is a good approximation of the distance from emission sources when the FLIR camera was used in this study. The findings of Ravikumar et al. 2018 are well-aligned with the results of this study – the smallest leak indication detected with the FLIR camera during the study had an emission rate of 0.0015 kg/hr (or 0.08 scfh). Consequently, 0.0015 kg/hr (or 0.08 scfh) was the quantification limit of the method and emission point indications that were not able to be detected with the FLIR camera, and subsequently not quantified, were likely smaller than 0.0015 kg/hr (or 0.08 scfh).

Emission Rate Quantification

Bagging/Enclosure Technique

A dynamic enclosure technique was used to quantify emissions from components (Moore, Stuver and Wiley 2019). Briefly, ambient air was drawn through a well-mixed enclosure (in this case, an anti-static bag) at a constant, measured rate.

Methane emitted from the emission point mixed into the enclosure air and was sampled in the exhaust of the pump. The *methane* emission rate (E_{rate}) was calculated from the measured air flow rate through the enclosure ($Flow_{sample}$) and the measured inlet ($Conc_{Background}$) and exhaust ($Conc_{Sample}$) *methane* concentrations.

$$E_{rate}\left(\frac{kg}{hr}\right)=\frac{\left(Conc_{Sample}\ (ppm)-Conc_{Background}\ (ppm)\right)}{1000000}xFlow_{Sample}\left(\frac{sL}{hr}\right)x\frac{0.00067\ kg\ CH_4}{L\ CH_4\ @standard\ \ conditions}$$

Providence Photonics QL320

The Providence Photonics QL320 was used in an attempt to quantify emissions that were not easily accessible with the enclosure method. The QL320 is an accessory for the FLIR GF320 Optical Gas Imager which under specific circumstances could allow the user to derive quantitative methane emission rates after the emission point is detected with the FLIR camera. The QL320, unlike the bagging technique described earlier, does not require close contact with the gas to measure emission rates, making it potentially usable in cases where the leaks are beyond reach, inaccessible, or unsafe to approach.

There are several limitations of this technology, however, that reduced the applicability for this study. For instance, the emissions must be able to be seen with the FLIR GF320 in "Auto" or "Manual" mode, not just "High Sensitivity Mode" (HSM). Most of the vents and leaks encountered in this study were only able to be seen in HSM. Another limitation of the technology was the need for a large temperature difference between the emitted gas and the background. This temperature difference was often difficult to obtain on the equipment that was scanned during this project. The QL320 does work well for larger emissions that can meet the temperature differential requirements.

Mobile Plume Integrator

The Lawrence Berkeley National Laboratory LBNL's Mobile Plume Integrator (MPI) system has been described in detail in other publications (M. Fischer, et al. 2016) (Lebel, Lu and Vielstadte, et al. 2020) (Fischer, Lebel and Jackson 2020). Briefly, the LBNL Mobile Plume Integrator (MPI) system provides continuous roadway measurement of the vertical distribution of methane plumes and associated meteorological variables necessary to integrate the wind-borne advective flux of methane across the path of motion to estimate total emissions within multiple plumes over large travel distances. The highest sampling location on the vehicle mast is 12′, indicating this method is most appropriate for plumes that do not rise above the highest inlet. The detection limit of the MPI system was evaluated as part of a previous CEC project and found to be approximately 1 g methane/hr for a small ground level source measured under steady winds in unobstructed, level terrain (Fischer, Lebel and Jackson 2020) (Lebel, Lu and Vielstadte, et al. 2020). With the caveat that some of the sites in the current study may include obstructions, the authors expect that detection limits near 1 g methane/hr might similarly be expected for the cases where the methane sources are well below top of the 4 meters (m) high MPI sampling mast.

Stack Emissions Monitoring

Continuous flue gas concentration measurements were performed by the Montrose Air Quality Services LLC at the stack using an extractive Fourier transform infrared (FTIR) spectrometer following the guidelines of EPA Method 320 and CARB Method MLD 136 adapted as appropriate for stationary sources. EPA Method 320 is a promulgated method of continuous measurements based on infrared absorption spectroscopy that may be used at combustion stacks that do not have in-stack direct measurements, or during an independent Relative Accuracy Test Audit (RATA) test to validate CEMS performance. The FTIR analyzer was the widely used MKS 2030 Multi-Gas FTIR with liquid nitrogen cooled MCT Detector. Analytes included nitrous oxide, CO_2, methane and H_2O. When multiple stacks were present on-site, probes were inserted into each, and the flow to the FTIR was switched between stacks (for example, alternating hours) for various periods of time that depended on the plant operational cycle.

Calibration gas mixtures with certified concentrations are used for initial calibration of the analyzer and for on-site dynamic spikes. Detection limits were determined by measuring analytical algorithm response of blank samples containing similar levels of moisture and carbon dioxide, but not targeted compounds, following Annex A2 of ASTM D6348-12 (ASTM D6348-12(2020) 2020). Lower detection limits were approximately 0.5 kg/hr for both methane and nitrous oxide. FTIR diagnostics were performed daily to ensure the instrument met all required health checks, which was true for all testing performed.

Aerial Measurements

Fixed-Wing Aircraft Measurements

Scientific Aviation conducted aerial measurements using a Mooney aircraft equipped with Picarro instruments to quantify methane emissions from individual facilities. The aircraft also collected data at other sources near the host sites during the measurement campaigns. This information has been aggregated across all campaigns in this project. A closed loop flight pattern was used to sample gases and horizontal winds over a control volume surrounding the facilities of interest to produce a measurement technique with a lower detection limit of approximately 10kg/hr, which is discussed in detail elsewhere (Conley, et al. 2017).

Unmanned Aerial Vehicle

In addition to fixed wing aircraft, Scientific Aviation used an unmanned aerial vehicle (UAV) platform to measure emissions from target sources in areas where measurements were otherwise inaccessible. The UAV was a DJI Matrice 210, with an Aeris Pico methane sensor installed on the camera mount. methane concentration, speed, position, altitude, and horizontal winds are measured directly in real time. Flights were made at a variety of altitudes to identify and localize areas of high methane concentration. Once an emission source was identified, multiple laps were flown in a raster pattern downwind of a source at increasing altitudes to fully sample the vertical extent of the emissions plume. Downwind distance was usually within 25m of the source. Upwind flights were performed to obtain the background concentration, which was subtracted from the downwind concentrations before the emission rates were estimated in post-processing. It has been found in the past that 5-15 laps are an appropriate range for all sites. UAV flights were limited to 100’ above ground level (AGL) due to FAA restrictions at the time of measurement; this precluded the ability to measure the stack plumes. The detection limit for methane under steady wind conditions is 10 g/hr.

Stable Isotope Measurements

Samples were taken at the point of natural gas emissions at several of the sites for isotopic analyses of hydrocarbons. The purpose of these analyses was to test the use of stable isotopic compositions for identifying sources of the natural gas. In many cases, there may be several potential sources of natural gas besides emissions from the fueling stations (for example, power plants, refineries, landfills, wetlands, and agricultural sources). The carbon and hydrogen isotopic compositions of these sources can be different and useful for distinguishing which source(s) may be contributing to the identified emissions. Isotopic compositions vary depending on factors including the substrate from which the compounds are produced, the process by which they were produced (for example, thermal or microbial cracking of the compounds) and the temperature at which they were produced. These differences allow us to distinguish between the different possible sources. This technique has been used successfully for a broader study of natural gas anomalies in southern California (Townsend-Small, et al. 2012). The compounds of interest in gas samples were separated using gas chromatography, then either converted to CO_2 by combustion for mass spectrometry carbon isotopic analyses or reduced to H_2 for mass spectrometry hydrogen isotopic analyses. The isotopic ratios (δD for hydrogen and $\delta^{13}C$ for carbon) are given using the δ notation in part per thousand differences from internationally accepted standards (VSMOW for hydrogen and VPDF for carbon). Based on repeated analyses of in-house standards, the standard deviation for the $\delta^{13}C$ of hydrocarbon compounds is ±0.5‰ (1 sigma) and for the δD is ±5‰ (1 sigma).

Natural Gas Power Plant/Commercial Facility Specific Methodologies

Emission point indications were recorded, and emission rates quantified, only for emission point that were visible through the FLIR camera in HSM. This methodology was chosen *a priori* due to the size of the facilities and locations of piping within the facility to maximize the chances of finding and quantifying as many emissions as methodologically possible. The focus of the facility visits was in determining the overall total emissions from the facility, as well the range of emitting components. Overall emissions have been shown to be driven by a few large sources (so called "fat-tailed" emissions) from any facility or category of component. Therefore, it was important to identify and quantify the largest sources that were likely driving the overall emissions from the facilities.

Compressed Natural Gas Vehicle Fueling Station Specific Methods

Quick Scan Method

Quick scans of stations were conducted using the FLIR GF320 optical gas imaging (OGI) camera to quickly identify major emissions sources on site without performing time-intensive emission rate measurements. The use of optical imaging camera for leak detection is aligned with United States Environmental Protection Agency (US EPA) Alternative Work Practice (AWP) guidance released in 2008 which allows facility operators the option of performing leak surveys with an OGI instrument instead of a conventional handheld gas sensor prescribed in EPA Method 21 (U.S. EPA 2008) (U.S. EPA 2017). No specific leak survey requirements exist for CNG fueling stations to the knowledge of the researchers, but it was determined OGI and Method 21 are reasonable starting points for unregulated source categories. During station quick scans, any emission that was visible with the OGI camera was recorded.

The EPA AWP guidance describes how the OGI camera is comparable to EPA Method 21 for leak screening. When EPA Method 21 is used, the definition of a leak depends on a defined leak threshold specified between 500 to 10,000 parts per million (ppm) in existing LDAR rules (U.S. EPA 2008). An emission is considered a leak only if it registers a concentration reading above the leak threshold specified in a specific rule. Simulation studies performed by EPA indicated that an OGI camera could detect emissions that Method 21 at the most stringent limit (500 ppm), making it a comparable method for instrument leak screening (U.S. EPA 2008).

All quick scans were performed from the external side of the station perimeter fence. The quick scan measurements provided a simple count of the number of emission sources on site. While data from the quick scans were not suitable for in-depth quantitative analysis, it provided the research team with knowledge of whether an emission source existed at the station at a level high enough to be seen with the OGI camera. It was not capable of determining whether no emission sources existed at a station, since not all potential points of origin for emissions were visible (that is, could be scanned with the OGI camera). Three of the sites that were quick scanned were re-surveyed using the intensive scan methodology to collect additional emission rate measurements (discussed in the next section). Note that the remainder of the chapter refers to the specific OGI camera used (the FLIR) rather than the general technique (OGI).

Intensive Scan Method

Intensive scans of sites involved a first screening of all accessible components with a Sensit Gold G2 and recording all indications of concentration above a threshold of 500 ppm as an emission source. Gas indications refer to instances when the CGI identified concentrations higher than the threshold whereas emission sources are indications that have been confirmed as natural gas emissions. The 500 ppm threshold was selected as it is the most stringent limit in existing federal LDAR rules (U.S. EPA 2008). This ensures a comprehensive evaluation of facilities that were intensively surveyed. After emission sources were identified, every source that was visible with the OGI camera (second screening) and was safely accessible was enclosed and had its emission flow rate quantified using the enclosure technique described above. (Ravikumar, et al. 2018) (Bacharach 2015) (Sensit Technologies 2019) (Helsel 2009) (Bolks, DeWire and Harcum 2014)

MPI-Only Scan Method

Several CNG vehicle fueling stations were visited with the MPI system only. These stations were not able to be visited by the quick scan/intensive scan crews due to timing and are indicated separately in the analysis.

CHAPTER 3: Project Results

Natural Gas Power Plants/Commercial Facilities

The site recruitment efforts resulted in the engagement of three host facilities for the multi-tiered emission rate measurements including two combined-cycle power plants (Facility 1 and 3) and a food processing plant (Facility 2).

Facility 1

The first facility visited for intensive on-site measurements was a large several hundred MW natural gas-fired combined cycle power plant. The plant was configured with two gas turbines, a heat recovery steam generator, a steam turbine, as well as NO_x control methods (selective catalytic reduction). The two gas turbine units had similar nameplate capacities. During the preparations and the campaign, it was requested that the plant load be kept at a high instantaneous load factor and substantial ramping be avoided, but to otherwise continue normal activity as much as possible. This was intended to generally represent the activity and emissions of a baseload facility. The instantaneous load factor throughout the three days of campaign averaged 91% with a standard deviation of 7%. Emissions resulting from effects of SCR are captured in the stack emissions.

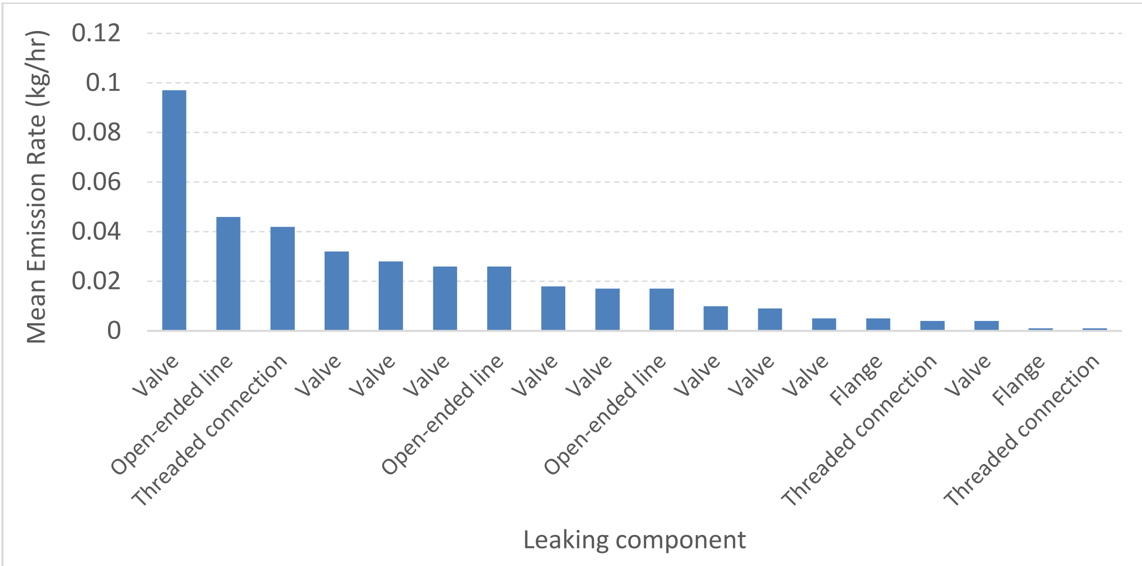
Facility 1 Component-Level Measurements using Handheld Instruments

A handheld FLIR infrared camera was used to scan all major natural gas components at the power plant to identify emission points on the first day of the campaign. This included scans of the gas inlet to the plant where fuel enters the property from the distribution pipeline, and all the piping runs up to the point of the combustion turbine enclosures, including fuel conditioning skids. Potential emission sources up to this point that were out of reach (for example, elevated vents) were surveyed with the help of a manlift. Typical combined cycle plant designs incorporate a heat recovery steam generator after the turbine, followed by a selective catalytic reduction (SCR) system (for NO_x emissions reduction) before the stack. It is not possible to sample these systems at the piping level while the plant was operating. However, the flue gas travels through them to the combustion stack, at which emissions were measured. A summary of the 18 emission points and vents identified in Facility 1 is provided in Figure 1 and Table B-1. Once identified, the CGI and Hi-Flow instruments were used to quantify the emissions. The median rate for quantifiable emissions was 0.017 kg/hr (0.90 ft^3/hour), which is fewer than 0.0001% of average hourly natural gas fuel use at this site in 2016. The aggregated emission rate of 0.39 kg/hr (20.2 ft^3/hour) is ~0.0007% of average hourly natural gas fuel use in 2016. The top 5 largest emission points found were on valves, a vent on a conditioning skid, and a vent from a gas chromatograph.

Facility 1 Mobile Plume Integrator

The Mobile Plume Integrator (MPI) completed multiple circuits on perimeter roadways outside the facility fence line, and multiple circuits within the host facility on access roads and between major components (that is, turbine power blocks). Background methane concentrations measured upwind of the host facility were 1.94 – 1.97 ppm, consistent with typical ambient levels (Figure 3). Background concentrations were also consistent across the different inlet heights on the MPI mast, suggesting that potential nearby sources did not exist or were not impacting the measurements.

Figure 1: Leaks Quantified at Facility 1, Sorted by Emission Rate

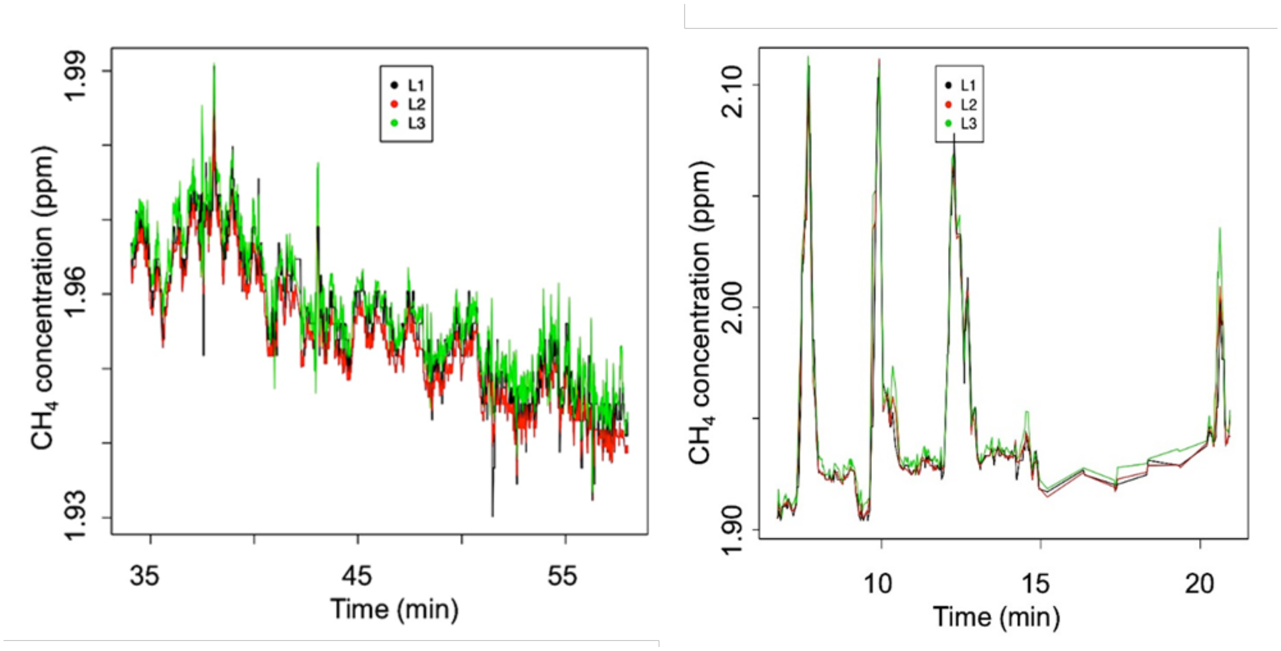


Source: EPRI

Measurements taken during laps driven within the host facility on day 2 and 3 showed very small methane enhancements above background that would not affect facility-level estimates from the aircraft, though they were clearly detectable by the MPI. For example, a plume with enhancements of ~0.2 ppm was observed at 1-4 meters AGL in the center of the facility. Some mixing occurred above the MPI mast, and full plume integration was not possible. This plume may have been derived from emissions from a vent (approximately 45-50 ft AGL) which were detected with the handheld instruments from a manlift. This area of the plant was also densely structured, and higher turbulence there could have affected the plume dispersion. The Figure 2 right panel illustrates the plume detection as the MPI was driven past emission sources. In other locations, small concentration enhancements were also observed at the lowest level of the mast near the gas inlet to the plant. These were fully captured vertically by the MPI instruments with methane enhancements of ~0.1 ppm or less.

Aggregating the multiple plumes detected within the host facility and adjoining meter station on days 2 and 3 yielded a total emission rate of 0.01 ± 0.0015 kg/hr, substantially lower than the aggregated emission rate of sources identified by handheld sensors 0.39 kg/hr). With the highest inlet point on top of the mast, the MPI is constrained to capture plumes lower than 3.5 meters AGL. Mild wind conditions and high ambient temperature during the measurements, in addition to the lower density of methane versus air, may have caused the natural gas plumes to rise upwards quickly instead of drifting laterally. As there were limited roadways in the facility, the vehicle was constrained from getting closer to the emission sources in some cases. This could have been a source of limitation in the MPI's ability to detect and quantify the plumes.

Figure 2: MPI Methane Measurements Upwind and Within Facility 1



MPI Methane Measurements Upwind (left) and Within Facility 1 (right)

Source: EPRI

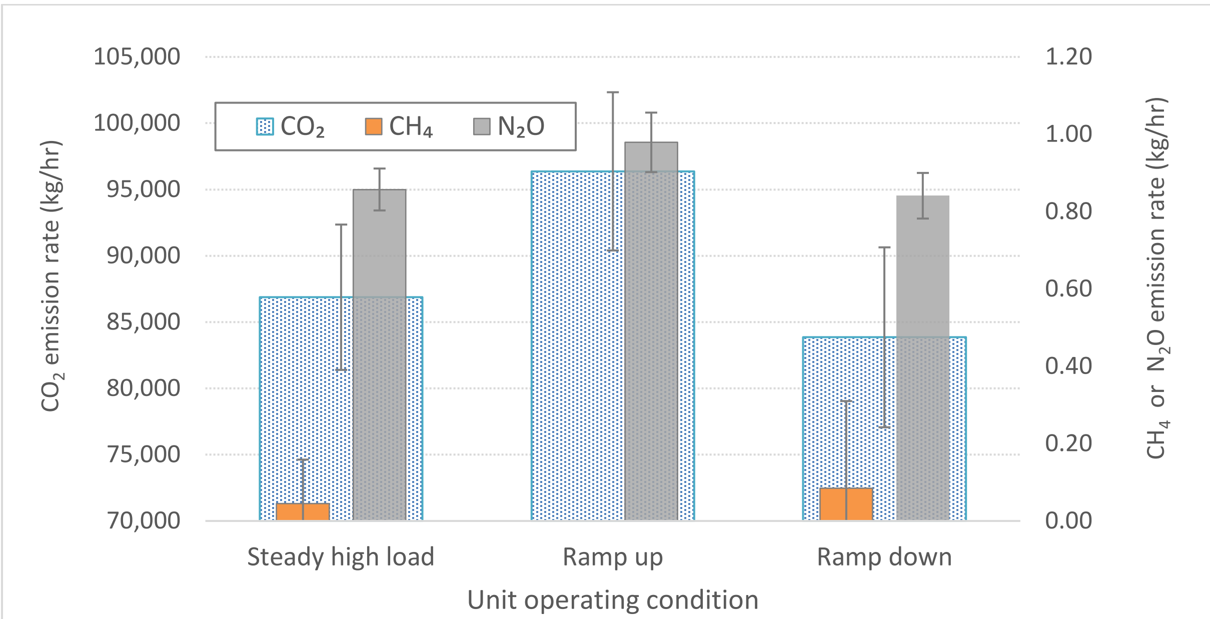
Facility 1 Stack Emissions

The FTIR stack testing equipment collected measurements over three days during 24 separate time windows. CO_2, methane, and nitrous oxide were the gaseous species analyzed. Separate stack probes were inserted in each of the two gas turbine stacks, and the flow to the detector was switched from one probe/stack to the other at intervals (for example, 60 minutes). FTIR diagnostics were performed prior to measurements to ensure the instrument met all required health checks. Both units at the plant operated at stable loads throughout the campaign. The standard deviation of the load within each sampling interval in both stacks (for example several hour period during which one unit's stack was sampled, before switching to the second unit) ranged from 0.2 to 9.2 percent. The average value of those interval standard deviations was 2.4 percent. GHG emissions were similarly stable. Figure B-1 depicts an example of uncorrected nitrous oxide flue gas concentrations for several time periods of unit switching.

Methane stack emissions were consistently low and close to or below the lower detection limit of 0.5 kg/hr. Only 3 out of the 24 time windows across both turbine units and both sampling days had more than 3 individual data points of methane concentration above the detection limits. Nitrous oxide stack emissions consistently ranged from 1.5 to 2.0 kg/hr during the measurement periods which were low and close to the lower detection limit. CO_2 emissions from one stack averaged 86,874 ± 6,187 kg/hr.

While the plant was mostly operating at a high steady load, there were several instances of the units ramping up and down. There were approximately 10.5 hours of stack measurements in high steady load versus 1.5 hours in each ramp up and ramp down conditions. On average, the facility instantaneous capacity factor was 81 percent under high steady load, versus 92 percent during ramp up, and 82 percent during ramp down. Figure 3 shows a comparison of the average emissions during the three operating conditions. CO_2 and nitrous oxide emissions registered noticeable increases during ramp up conditions but no discernable changes between steady load and ramp down conditions. On the other hand, methane emissions decreased during ramp up mode and went up during ramp down. Emission changes are expected during transient loads as combustion, equipment (for example, SCR) and fuel slip conditions are variable. A detailed understanding of the reasons behind the magnitude and direction of these changes is unknown. A hypothesis could be that as the system ramps up, any fuel (and thus methane) available would be combusted more completely, with less slip (that is, emission). During a ramping down, excess fuel would be available that was not needed by the turbine and slip could increase.

Figure 3: Facility 1 Unit-level Stack Emissions at Different Operating Conditions



There are two units at this site.

Source: EPRI

Facility 1 Aircraft Measurements

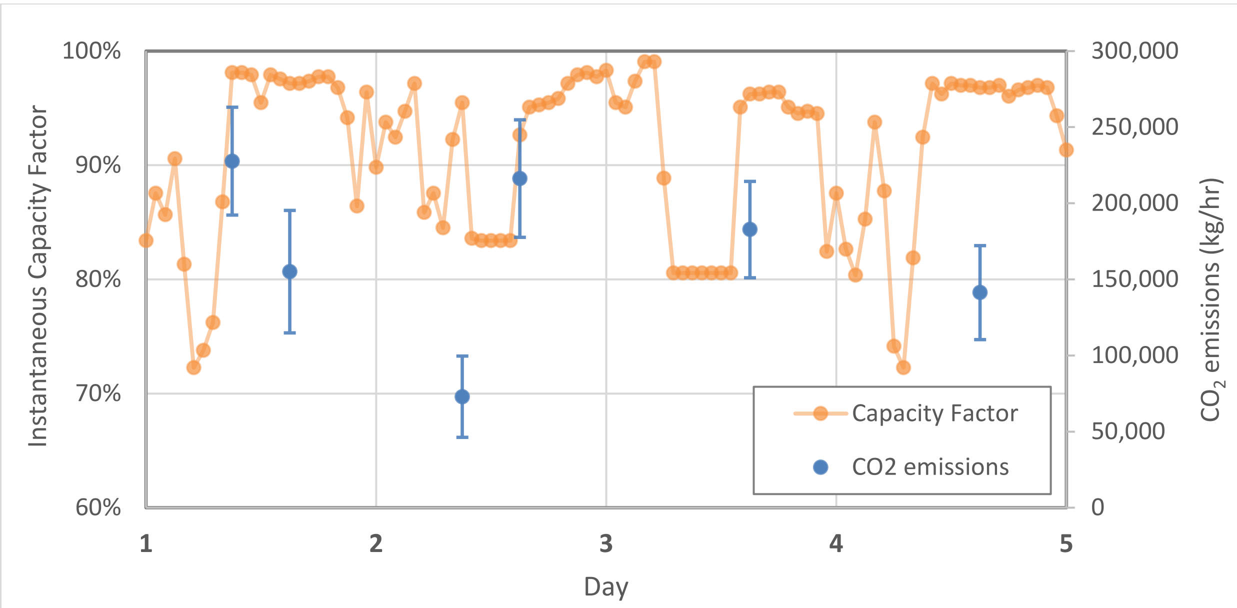
Fixed-wing aircraft measurements were collected over the facility on six occasions over 4 days (Table B-2). The flights typically did not detect methane enhancements above the aircraft method detection limit of ~10 kg/hr, although CO_2 was clearly present and defined the facility plumes. CO_2 emission rates ranged from 155,000-227,000 kg/hr over all six flights. The aircraft only detected methane emissions during two out of six flights at rates of 12 ± 6 kg/hr (624 ± 312 scfh) and 49 ± 18 kg/hr (2,548 ± 936 scfh).

The plant's output was typically higher in the afternoon than morning (Figure 4); there was no clear correlation between whole facility CO_2 emissions as measured by the aircraft. For example, CO_2 emissions dipped by more than 30 percent in the afternoon of Day 1 compared to that morning even though capacity factor remained consistently high above 95 percent. The two time periods when aircraft measurements detected methane emissions also did not consistently correspond to higher loads. Similarly, times with high instantaneous capacity factors often did not record detectable methane emissions. Other factors such as atmospheric conditions and the episodic nature of the emissions might have caused the variation in methane emissions, but the cause is most likely confounding from nearby sources.

Weather data could not explain why methane emissions were detected during two flights. There was no drastic difference in wind direction for the two time periods compared to other days. The trend in wind speed was similar across all three measurement days with higher speed observed in the afternoon (9 mph) versus the morning (5 mph). Temperature was relatively similar across the three days at 60°F in the morning and 90°F in mid-afternoon. On the other hand, there were potential sources of methane from the surrounding area, including a neighboring dairy farm, which could have contributed. Positions of livestock could have an impact on the measurements but are not verifiable.

Methane stack measurement data did not indicate anomalous enhancements during the flights in question. Lack of evidence of sudden elevated plant emissions suggests the hypothesis of extraneous sources is the most plausible explanation.

Figure 4: Instantaneous Capacity Factor and Aircraft CO_2 Emissions Measurements of Facility 1 During the Site Visit Days



Source: EPRI

Facility 1 Comparison of Aircraft Versus Other Measurements

Aircraft emission estimates are also compared with data from EPA's Air Markets Program Data (AMPD) and GHGRP as shown in Table B-3. EPA requires that facilities report hourly averaged CO_2 emissions as described in Title 42 of the U.S. Code of Federal Regulations (U.S. EPA 2018) (U.S. Office of the Federal Register 2017). Since AMPD data are available with hourly granularity, the hourly average CO_2 emissions per survey day can be obtained. On the other hand, GHGRP is a reporting program for greenhouse gas point sources that includes CO_2, methane and nitrous oxide emissions. GHGRP only requires reporting of combustion related methane emissions from the stacks and do not include fugitive methane emissions from leaks. GHGRP data is available as annual values, thus were divided by 8760 hours to arrive at an hourly rate. For the same reason, GHGRP data do not change across days of the same year.

Relative to power plant methane emission rates from other peer-reviewed studies, Facility 1 methane emissions is on the low end. In 2015, Lavoie et al. measured an average methane emission rate of 140 ± 70 kg/h from 3 combined cycle power plants using an aircraft-based flux curtain mass balance approach, or 21-120 times higher than facility-reported estimates for those sites (Lavoie, Shepson and Cambaliza, et al. 2015). Lavoie et al. (Lavoie, Shepson and Gore, et al. 2017) acknowledged that their measurements were performed during peak operating hours which could have contributed to the high values. In 2019, Hajny et al. (Hajny, et al. 2019) reported average methane emission rates of 8 ± 5 to 135 ± 27 kg/h from 14 combined cycle power plants. Hajny et al. found that most of the methane emissions were from uncombusted natural gas from the stack rather than fugitive sources. These findings from Facility 1 shows that stack methane emissions (~0.5 kg/hr) are of comparable magnitude to fugitive methane emissions (0.39 kg/hr).

Handheld and mobile survey methods produced emission rate measurements that can be combined with stack measurements to obtain facility-wide emission rates and compared with the aircraft estimates. Table 1 shows the comparison of methane estimates among the different methods.

Table 1: Facility 1 Comparison of Methane Measurement Methods

Measure-ment method	Whole-facility methane emission rate (kg/hr)	Uncer-tainty in methane emission rate (kg/hr)
Aircraft	BDL to 12*	± 6
Vehicle	0.01	± 0.002
Handheld	0.39	N.A.
Stack	0.30	± 0.15

***BDL = Below Detection Limit. Only Day 2 and 3 values shown since vehicle surveys were done on Day 2 and 3.**

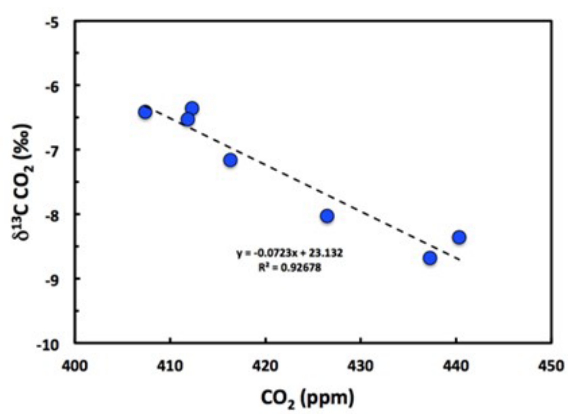
Source: EPRI

There were significant differences among methane estimates from the four methods. Only aircraft data from Day 2 and 3 were used for comparison as the vehicle and stack methods were also deployed on these two days. The three ground-based methods captured emission rates that are three orders of magnitude lower than the maximum observed by aircraft method. Handheld methods discovered 18 emission sources which generated a total emission rate of 0.39 kg/hr. The MPI surveyed the main facility and the adjoining meter station on separate days and the aggregated emission rates from both areas amounted to 0.01 ± 0.002 kg/hr, a negligible value. The MPI's limitation to not drive close to the emission sources, coupled with its reliance on stable meteorological conditions and maximum sampling height of 12' AGL, made it likely to underestimate emissions produced by this facility. For example, natural gas emitted from elevated vent stacks was likely not captured by the MPI. Stack measurements can be combined with vehicle and handheld measurements to produce facility-wide emission estimates comparable to aircraft measurements (Appendix B Table B-3); the sum of stack and ground-based fall far short of aircraft measurements. The difference is likely caused by nearby off-facility confounding methane sources detected by aircraft measurements.

Facility 1 Stable Isotope Measurements

A variety of gaseous samples ranging from 30-150 mL were collected during the campaign (Table B-4, Appendix B). The two background upwind samples taken from the aircraft had CO_2 concentrations of ~420 ppm, slightly above average background atmospheric levels of 412 ± 4 ppm (monthly average at Mauna Loa; https://www.esrl.noaa.gov/gmd/dv/data/), and had average stable carbon isotopic composition ($\delta^{13}C$) of -6.6‰. Seven samples collected from the aircraft while in the facility plume had CO_2 concentrations ranging from 407-440 ppm. The $\delta^{13}C$-CO_2 values of the downwind plume samples collected by the aircraft indicated that $\delta^{13}C$ was an accurate tracer for the plume (Figure 5). Methane was observed in five of the seven downwind (that is, facility plume) samples collected by the aircraft. The methane $\delta^{13}C$ ranged from -48‰ to -55‰. Considering that atmospheric methane has a $\delta^{13}C$ value of -48‰, and the isotopic $\delta^{13}C$ of the supply natural gas to the power plant was -42‰, it seems unlikely that the methane observed in the airborne downwind samples was derived from the power plant. This finding provides further support that nearby sources of methane including livestock could have contributed to the elevated methane concentration above the power plant which was not observed by the MPI and handheld instruments.

Figure 5: Facility 1 Plume Isotope Signatures



Source: EPRI

Five samples taken across both stack sampling lines over two days had CO_2 concentrations of 4.1 percent with average $\delta^{13}C$ of -37.3‰.

Three samples taken from the upstream natural gas fuel supply showed an average methane $\delta^{13}C$ of -42.3‰ which falls within the field of thermogenic methane. (Whiticar 1999) The methane $\delta^{13}C$ in the four samples taken from leaks identified with handheld instruments (for beyond the scope of this project.

Facility 2

A food processing facility was chosen as one of the industrial sites for intensive monitoring because it is one of several sectors in California with large consumption of natural gas, and has the potential for conversion of processing equipment (through electrification) to improve energy efficiency and costs. Little information on natural gas leakage was available at the project start, but if large, could be an additional motivating factor for equipment exchanges, or participation in programs such as the Food Production Investment Program funded by (Assembly Bill 109 2017) (Ting, Chapter 249, Statutes of 2017). Previously unknown leaks would change the baseline facility emissions rate from which GHG emission reductions would be calculated. Additionally, secondary goal of the overall project was to explore the potential for stack emissions of nitrous oxide. Thus, a facility with a potentially different suite of prime mover (boiler vs. turbine), emission control devices, and operational cycles as compared to electricity generation units was desired.

The facility covered ~1.7 mi^2 with three large natural gas-fired boilers, each with their own stack, that provide steam for the nearby processing lines. Several large warehouses were also located at the facility that utilized large, ceiling mounted Rezner units for space heating. The main boiler at over 100,000 lb/hr and two smaller secondary boilers have ammonia-based post-combustion NO_x emission controls. During the preparations and the campaign, the plant staff were instructed by the research team to continue nomal activity and operations.

Facility 2 Component-Level Measurements

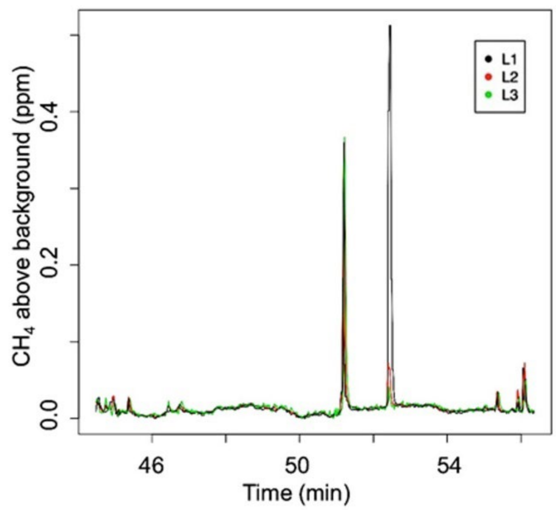
A FLIR infrared camera was used to scan all major natural gas components at the host facility to identify emission points on the first day of the campaign. This included the main gas supply where fuel enters the property, and piping runs to the boiler room enclosure. Scans were also conducted at an ancillary boiler, and multiple ceiling-mounted Rezner space heaters in food storage warehouse buildings. A summary of the emission points identified during the campaign is provided in Table B-5; all were determined to be fugitive leaks and not intentional equipment venting. Once identified by visualization on the FLIR camera, the CGI and Hi-Flow were used to quantify methane emissions. The median leak rate, including the imputed values of those below the detection limit of the FLIR camera, was 0.0013 kg/hr (see Appendix B). The aggregated rate across all the leaks (34 total), including imputed values for leaks below the detection limit of the FLIR camera, was 0.27 kg/hr. A single leaking regulator at 0.19 kg/hr was by far the dominant individual source. The sum of emission rates of all the leaks was approximately 0.008 percent of the facility's natural gas throughput for the month of visit.

Facility 2 Mobile Plume Integrator

Measurements in Area Outside Facility

Methane was measured with the Mobile Plume Integration (MPI) system on a road encircling the facility (approximately 1 km away). An example ring observation made near midday is shown in Figure 6. Measurements were made at heights of 1.5 (L1, black), 2.5 (L2, red), and 3.5 (L3, green) meters above the roadway. In general, measurements were consistent with that expected for air representing the regional background of approximately 1.9 ppm. Mixing ratio enhancements were generally <0.05 ppm. However, there were two exceptions with methane measurement peaks near 0.4 ppm and 0.5 ppm above background. One of these was located ~1 km north of the food processing facility and directly downwind of another facility known to consume natural gas. The second was located ~1.2 km northwest of the facility and possibly due to a leaking underground pipeline. This suggests that background methane is sufficiently stable across the landscape that it will not influence or interfere with plume integration measurements for sources located within the host site's fence line.

Figure 6: MPI Methane Measurements on Roads Outside Facility 2



Source: EPRI

Onsite Measurements Near Main Boiler Units

Measurements were also made inside the host site by repeatedly driving back and forth along a path just south of the two main boiler buildings. Measured methane plumes were clearly observed, with enhancements of up to 8 ppm. From the proximity of the plume locations (not shown), one might associate the emissions with two distinct sources, each with an emission rate of slightly fewer than 1 liter per minute (lpm) or 0.03 kg/hr. However, because the wind was generally blowing down a roadway from one building to the next, the research team could not uniquely determine whether there were distinct plumes, or if the plumes detected at the second building originated from a single source at the upwind building. Figure 7 shows estimated emissions from repeated measurements of leaks identified within the facility near the two main boiler buildings on Day 1 (left) and Day 2 (right). Filled circles denote captured plumes, which refers to those where the peak vertical concentration was below the top-most inlet level (3.5 meters above ground level). The solid and dashed lines represent the average and standard deviation of repeated measurements.

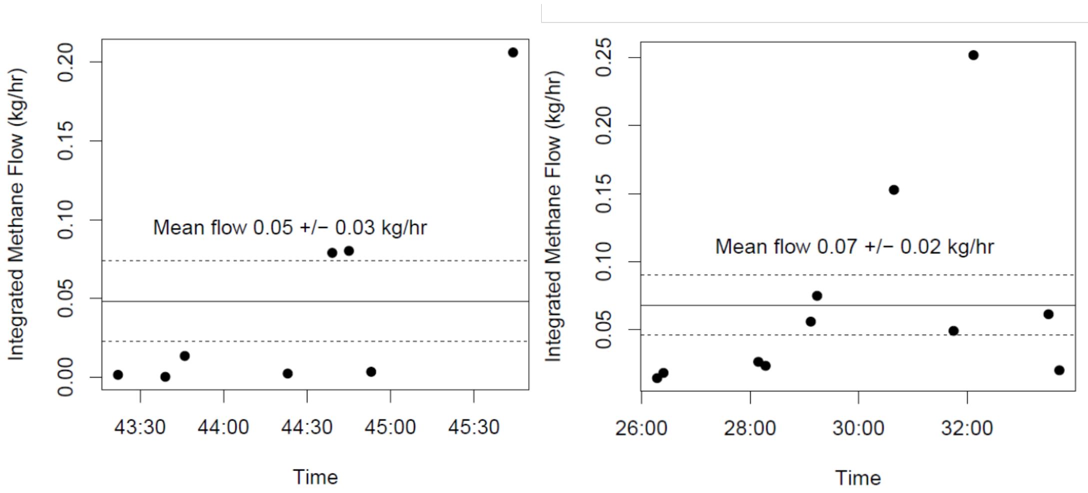
Measurements at the Natural Gas Metering Station

Methane and wind speed/direction were measured directly adjacent to the natural gas metering station (located within 1m of the ground) serving as the main facility fuel supply. The plume was fully captured on several days, at 0.3 +/- 0.1 lpm ($1.9e^{-4}$ +/- $0.6e^{-4}$ kg/hr). Figure 8 illustrates a cross section of methane enhancements above background levels that was measured downwind of the natural gas metering station. The plume was strongest near the ground, indicating that cross-wind integration yielded a reasonably accurate estimate of methane emissions.

Facility 2 Stack Emissions

The FTIR stack testing equipment collected measurements over two full days. Separate stack probes were inserted in each of the three gas boiler stacks, and the flow to the detector was switched from one stack to the other at typical intervals of 60 minutes. FTIR diagnostics were performed prior to measurements to ensure the instrument met all required health checks. The measured concentrations for methane and nitrous oxide were all below the detection limit of the method, at approximately 0.5 kg/hr.

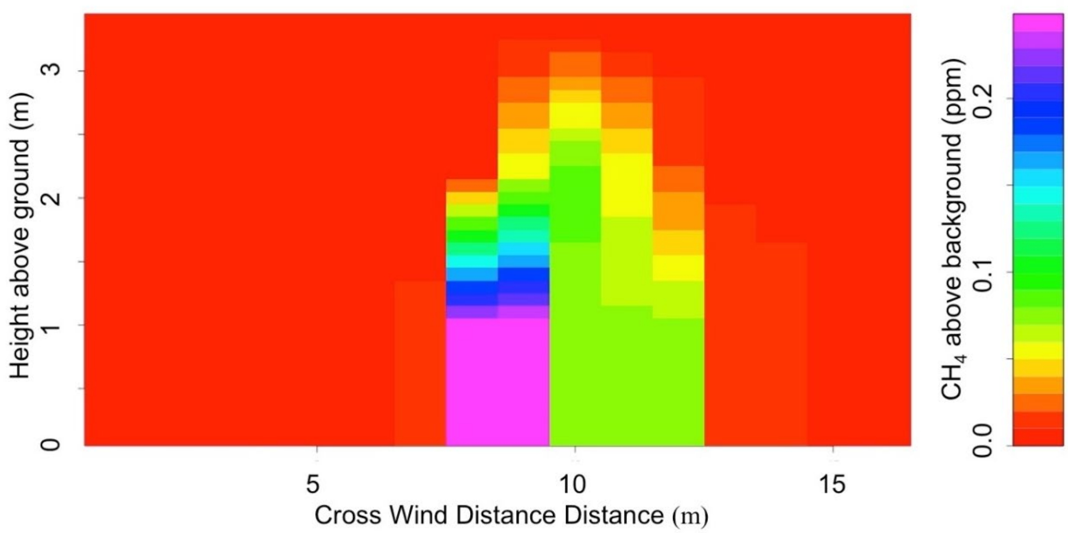
Figure 7: MPI Methane Measurements on Access Roads Inside Facility 2



The solid and dashed lines represent the average and standard deviation of the repeated measurements.

Source: EPRI

Figure 8: Cross Section of Methane Plume Downwind of Natural Gas Metering Station



Cross wind distance origin is at an arbitrary position approximately 10 m before the methane plume crossed the measurement plane defined by the vehicle motion.

Source: EPRI

Facility 2 Aircraft Measurements

A total of four aerial measurements were collected over the facility on various days; none detected any methane emissions above the detection limit of ~10 kg/hour, and in fact some were estimated as negative values. That is, the downwind concentrations were less than the upwind ones, indicating the presence of other methane sources near, but off-site of, the facility. On the other hand, CO_2 was clearly present. Emission rates averaged 14,308 ± 8,086 kg/hour and ranged from 5,611 to 21,548 kg/hour (5.6 - 21.5 metric tons/hour), likely depending on a combination of facility operations and meteorological conditions (Table 8).

Facility 2 Comparison of Aircraft Versus Other Measurements

Relative to annual CO_2 emissions data from GHGRP, the aircraft measurements reported a 1-6x higher CO_2 emission rate from the facility (Table 2; Table B-6). During the campaign, the facility was amid a busy harvest season. Based on communication with the site operators, the facility was utilized at a higher capacity relative to other times of the year. In fact, 30% of the boiler natural gas usage for the entire prior year was consumed during the month of the site visit. That month's consumption was about 3.5x the average monthly consumption for the prior year, explaining the comparatively high (factor of 1-6x) CO_2 emissions relative to the monthly average. The monthly site capacity, defined as the ratio of actual to theoretical maximum monthly gas consumption, was much higher than average and is shown in Figure 9 below.

Total boiler CO_2 emissions, for the two days when the boiler and aircraft measurements were conducted, were stable (± 5%) and within the uncertainty of aircraft measurements. Facility 2 reported low methane emissions (<0.2 kg/hr) to the GHGRP, in alignment with aircraft measurements which yielded undetectable values. However, since the aircraft lower detection limit for methane was roughly 10 kg/hr, it was unable to be verified more accurately.

Only one boiler stack was measured at any given time and since aircraft measurements lasted for less than an hour, boiler stack measurements within five hours of aircraft flights were averaged for comparison with aircraft data. The wide time window is justified by the stable boiler stack emission rates during the entire measurement period. To aggregate boiler emissions, an assumption was made that all three boilers were continuously operating at a

Table 2: Facility 2 Aircraft, Stack Measurements and Reported Emissions

Date	Aircraft CO_2 measurements (kg/hr)	% difference aircraft and GHGRP CO_2 data†	Boilers CO_2 measurements ** (kg/hr)	Aircraft methane measurements (kg/hr)	Boilers methane measurements** (kg/hr)	Boilers nitrous oxide measurements** (kg/hr)
Day 1 (morning)	21,648 ± 4,377	668%	NA	BDL ± 35	NA	NA
Day 1 (afternoon)	5,611 ± 8,391	99%	11,801 ± 437	BDL ± 19	BDL	BDL
Day 2 (afternoon)	12,957 ± 2,717	360%	11,536 ± 418	BDL ± 18	BDL	BDL
Day 4 (afternoon)	17,016 ± 4,109	504%	NA	BDL ± 6	NA	NA
Average	14,308 ± 8,086	408%	11,931 ± 526	BDL ± 20	BDL	BDL

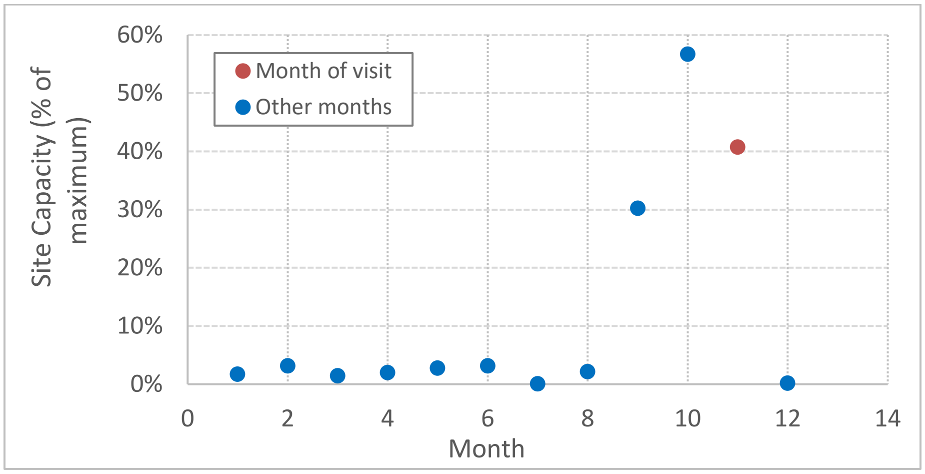
***BDL = Below Detection Limit**

****Assume that all boilers were operating at 40% capacity factor which was the average during the month of visit**

† See text for discussion on high site activity during the month of the visit as compared to average monthly activity

Source: EPRI

Figure 9: Facility 2 Site Capacity During the Month of Visit Compared to Prior Months



Source: EPRI

steady site capacity of 40 percent, which was the average for the month of visit. This assumption is in line with the hourly boiler natural gas input data provided by the facility operators for the measurement period (that is, all three boilers were running continuously).

Unlike Facility 1, there was better agreement among the estimated facility wide methane emission rates produced by all four measurement methods (Table 3). Vehicle-based surveys and handheld surveys were both conducted on Day 1 – 3. As observed with Facility 1, the vehicle-based estimate was lower compared to the handheld method; likely due to site accessibility issues due to proximity limitations and the fact many handheld measurements (12 percent of total quantifiable emissions) were made indoors.

Table 3: Facility 2 Comparison of Methane Measurement Methods

Measurement method	Whole-facility methane emission rate (kg/hr)	Uncertainty in methane emission rate (kg/hr)
Aircraft	BDL	± 20
Vehicle	0.08	± 0.02
Handheld	0.24	N.A.
Boiler stacks	0.03	± 0.00

Source: EPRI

The difference between handheld and MPI measurements was not as significant as compared to Facility 1 because the largest observed emissions identified by the handheld devices was outdoor at an approximate elevation of 3 feet above ground level, well within the mast height of the MPI. Boiler stack measurements registered negligible readings implying negligible methane from the boilers.

Similarly, all of the aircraft-based methane measurements were below the system's detection limit of 10 kg/hr. The uncertainty of the aircraft results was considerably high at 20 kg/hr and Scientific Aviation attributed this to other unidentified source of methane emissions in the area resulting in negative methane flux measurements as the plumes transited through the flight loops. Considering that the detection limit of the aircraft method was 10 kg/hr, it is not possible to ascertain if the emission rate was as low as what the ground level methods predicted.

Boiler stack methane emissions were low compared to total fugitive methane emissions captured using component-level measurements. It can be deduced that the boilers at this facility was efficient in combusting natural gas. However, methane emission rate during boiler startup and shutdown was not characterized in this study and could possibly contribute a notable increase for brief periods of time.

Facility 2 Isotopic Analyses

Isotopic analyses were performed for leak samples, airborne samples, stack emissions and background (Table B-4 in the Appendix). Unfortunately, natural gas feed samples were unobtainable for this facility as there was no pre-existing access point. However, it was likely in the same range as the natural gas feed from Facility 1 (-42‰ for the $\delta^{13}C$ of methane). Measurements were made of the $\delta^{13}C$ of methane for eight airborne samples (four upwind and four from the plume). The $\delta^{13}C$ values ranged from -41‰ to -48‰. As discussed earlier, atmospheric methane averages -48‰. Unlike the data from Facility 1, there appears to be some contribution from natural gas, however, the samples with the higher values were not restricted to the downwind plume samples. In addition, the $\delta^{13}C$ of methane in the two upwind samples taken at ground level were -43‰. Based on these data, it does not seem that emissions from Facility 2 are the source of this higher $\delta^{13}C$ methane.

Facility 3

The third intensive measurement campaign was held at a large several hundred MW combined cycle natural gas-fired power plant with post-combustion NO_x emissions controls (selective catalytic reduction). Measurements were conducted on a combined cycle train (two units in line with a heat recovery steam generator and steam turbine), as well as an independent simple cycle gas-fired turbine. Additionally, the campaign measured emissions from a large, two-train fuel gas compressor system, with known leaks due to damaged packings. The aircraft and MPI vehicle measurements systems were not used at this facility; an unmanned aerial vehicle (UAV) was used instead.

During the preparations and the campaign, the plant staff managed the plant through a mix of operational states, beginning with a hot start. The plant compressors, gas turbines, and steam turbine were off but still at elevated temperature above ambient for a full day before the campaign. Other conditions included ramping up or down, steady state operation at high or low loads and use of duct burners at high loads. An *a priori* operational plan was created as a guide and approved by dispatchers, though subject to cancellation or modification if urgent electricity system needs arose. The exact operations during the campaign were somewhat modified from plan, but the campaign goals were successfully accomplished.

Facility 3 Component-Level Measurements

A FLIR infrared camera was used to scan all major natural gas components to identify leak locations on the first day of the campaign. These included scans of the gas yard where fuel enters the property from the distribution pipeline, compressor stations, fuel conditioning skids located directly before fuel is fed into combustion turbines, and flanges and valves along pipeline runs that connect these components. Once visualized on the camera, methane emission rates of individual sources were quantified using CGI and Hi-Flow.

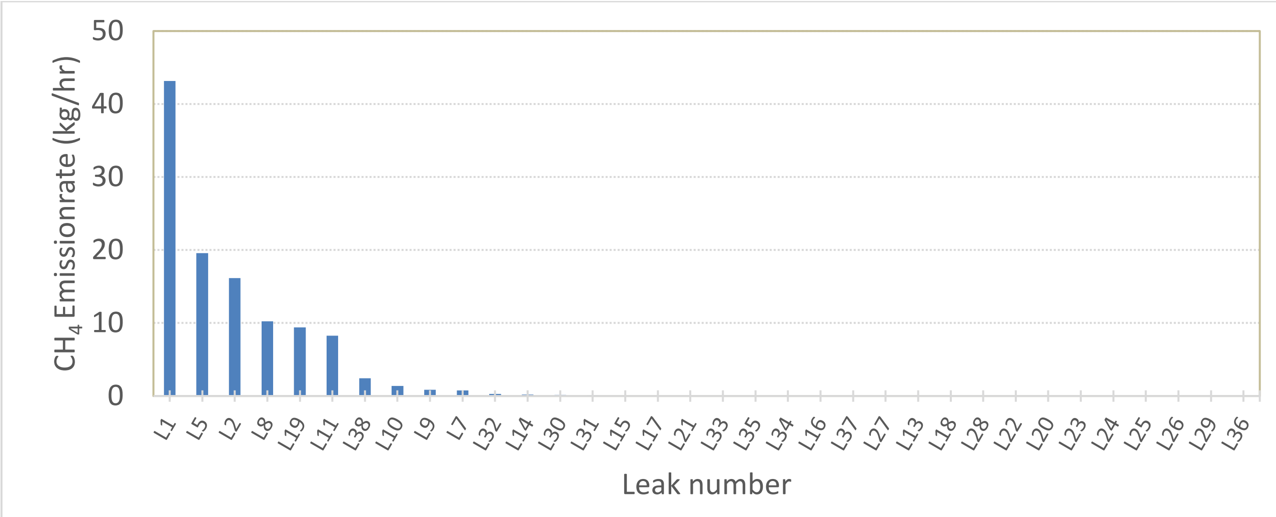
Several emission sources were inaccessible or unsafe to be quantified using Hi-Flow. For these cases, the Providence QL320 add-on to the FLIR was used to estimate methane emission rate. However, as noted in previously, QL320 only works for larger emissions. A mini experiment was performed on two large sources onsite to evaluate accuracy of the QL320 versus the Hi-Flow where the QL320 estimated emission rate was within 20% of the Hi-Flow sampler in both cases. Specifically, QL320 estimated 450 scfh for both leaks whereas Hi-Flow measured 546 scfh and 528 scfh respectively.

A summary of the 38 sequentially numbered individual emission points identified during the campaign is provided in Figure 10 and Table B-8 in the Appendix. Seven of these emission points were quantified using the QL320 due to accessibility issues or safety concerns (such as not entering enclosed spaces). The emission sources were relatively evenly distributed across different major locations with the plant. Compressor train A had four, compressor train B eight, the metering station three, the filtering station four, two on turbine unit A and associated duct burner, four on turbine unit B and associated duct burner, four on the peaker compressor train A, five on peaker compressor train B, and three on the peaker unit strainer/filter.

The compressor system had previously known leaks due to damaged cylinder packings. These were detected in the 1A and 1B compressor trains and accounted for the overwhelming abundance (89 percent) of the total facility non-stack emission rate. The emissions bled off through the vents, drain lines and crank case of the compressor trains. Due to part and resource availability, packing repairs were not performed prior to the study.

The detectable emission rates, excluding emissions below detection limit (BDL), individually ranged from 0.04 (or 0.0006 kg/hr) to 2,750 scfh (or 43.2 kg/hr). The aggregated total emission rate was 7,221 scfh (113.3 kg/hr). This was comprised of 100.5 kg/hr from the compressor station, 0.3 kg/hr from the metering station, 9.5 kg/hr from the filtering station, and 3.1 kg/hr from the peaker unit. In total, these emissions were a fraction of the estimated natural gas throughput of the combined cycle system (0.21-0.49 percent), with the exact value depending on whether they were assumed to occur only during the sampling period or over the entire day, and whether the maximum or minimum value of the rates were used when the same emission point was measured under different conditions (such as compressor on or off). methane emissions for the peaker unit averaged 0.05 percent of natural gas throughput at the facility.

Figure 10: Distribution of Quantified Methane Leaks and Vents at Facility 3



The median representative emission rate for all quantified sources was 0.04 kg/hr (or 2.7 scfh).

Source: EPRI

Compressor Leaks

The largest leaks observed at the host facility were in the two largest compressor trains, both of which are rated near 4,000 HP. One had been refurbished 2.5 years prior to the campaign, and the other five years prior. It is important to note that not all power plants require a large compressor onsite to support their natural gas supply as this one does. At most plants, analogous compressors are upstream of the facility and managed by the gas distribution company.

The leaks were known to the facility before the team's arrival and planned for repair. Plant personnel had independently quantified these leaks through line isolation and orifice flowmeters for several supply line fuel gas pressure. They found average leak rates of 2,670 scfh for train 1A and 2,010 scfh for train B; these were similar to or smaller than the campaign measurement of 2,750 scfh across both trains. The facility plans to replace the relevant packing and seals as soon as feasible, however scheduling this major maintenance has been a challenge due to both access to the replacement materials and the need for continued plant operations.

Certain types of compressors are known to be more susceptible to leaks than other types (for example reciprocating compressors vs. centrifugal compressors; (Subramanian, et al. 2015)). The site results can be compared with prior published data for additional context. Nathan et al. (Nathan, et al. 2015) used a model aircraft for 22 flights on a single mid-stream compressor station over a 1-week period and found an average of 14±8 g methane/s (or 2,780 scfh). Subramanian et al. (Subramanian, et al. 2015) measured emissions at reciprocating compressors. Six of 15 measured compressors with a total power rating of <10,000HP had leaks (not including combustion exhaust) larger than 2,000 scfh.

Facility 3 Unmanned Aerial Vehicle Based Mobile Measurements

Four main locations were monitored with the UAV: the main compressor for the combined cycle units, the compressor for the peaker unit, vents atop the turbine units, and an area representing ambient background. The results are shown in Table 4.

Compressor

Multiple flights were made over two consecutive days around the main compressor system, which was bounded with walls on three sides. These included upwind and downwind flights, and a flight near an oil drain vent just outside of the compressor area. Repeated measurements of between 450 and 500 ppm methane were observed at this vent.

For emission quantification on campaign Day 3, the UAV flew a total of 9 passes approximately 5 meters downwind of the walls, at altitudes from 3 to 11m AGL. Winds averaged 1.6 m/s. Total methane and ethane emissions are estimated at 82 ± 19 kg/hr and 8 ± 3 kg/hr, respectively. On Day 4, 13 laps were flown at altitudes ranging from 2 to 17m AGL. Winds were steady at an average speed of 2.3 m/s. Total methane and ethane emissions were 211 ± 33 kg/hr and 23 ± 6 kg/hr, respectively. A half hour later a final measurement was taken, with 10 laps flown at 1 to 11m AGL. Winds were steady at an average of 2.4 m/s. Total methane and ethane emissions are estimated at 179 ± 33 kg/hr and 29 ± 8 kg/hr. A point measurement of 52 ppm was taken from oil drain vent. Upwind concentrations on this flight were 2.2-2.3ppm.

Peaker Compressor

UAV flights over the peaker compressor area targeted four vertical vent pipes, two on each compressor enclosure. One of these had larger emissions than the others; 30 ppm methane was detected within 1 m of this vent. The UAV could not approach closer due to structures present on the rooftops and requirements for line-of-sight flying. A total of 16 raster laps were flown at altitudes ranging from 1 to 7 m AGL on the downwind side of the structure. Winds were steady at an average speed of 2.5 m/s. Total methane and ethane emissions were each estimated at 0 kg/hr, signifying the emission plume had been sufficiently dispersed to be below detection limits at the point of measurement about 10m downwind.

Local Background/Open Field

Measurements were also made in an area of the facility property with an open field, dirt and gravel. No power plant operations or petroleum storage equipment were upwind of this area; just other industrial facilities further off property (~ 0.25 mi away). A total of 13 laps were flown from 1 m AGL to 10 m AGL; winds were steady at 2.1 m/s. No significant enhancements were observed, with consistent concentrations of 2.03 ppm as compared to typical regional background of about 1.9 ppm. This suggests that the local background methane is sufficiently stable across the landscape that it did not influence or interfere with plume integration measurements for sources located within the host site fence line.

Turbine Vents

Two flights attempted to measure plumes from vents atop the gas turbine units. Upon startup at ground level, about 20-30 ft from the base of the unit, the UAV displayed a compass calibration error. After restart, calibration, and confirmation of flight readiness, a pass was performed above the vent of interest. Mid-flight communications weakened leading the pilot to abort the flight. The source of this interference is likely electromagnetic. It was not advised to attempt further flights in this area of the facility, which contains metal scaffolding, building enclosures, and 100ft high poles. Similar limitations may exist for the use of this UAV platform at other facilities with dense infrastructure.

Table 4: Emission Measurements From the UAV Platform

Site	Campaign Day	Methane Emissions (kg/hr)	Ethane Emissions (kg/hr)
Compressor	Day 3	82 ± 19	8 ± 3
Compressor	Day 4	211 ± 33	23 ± 6
Compressor	Day 4	179 ± 33	19 ± 8
Peaker Compressor	Day 4	0	0
Open Field Flight	Day 4	0	0

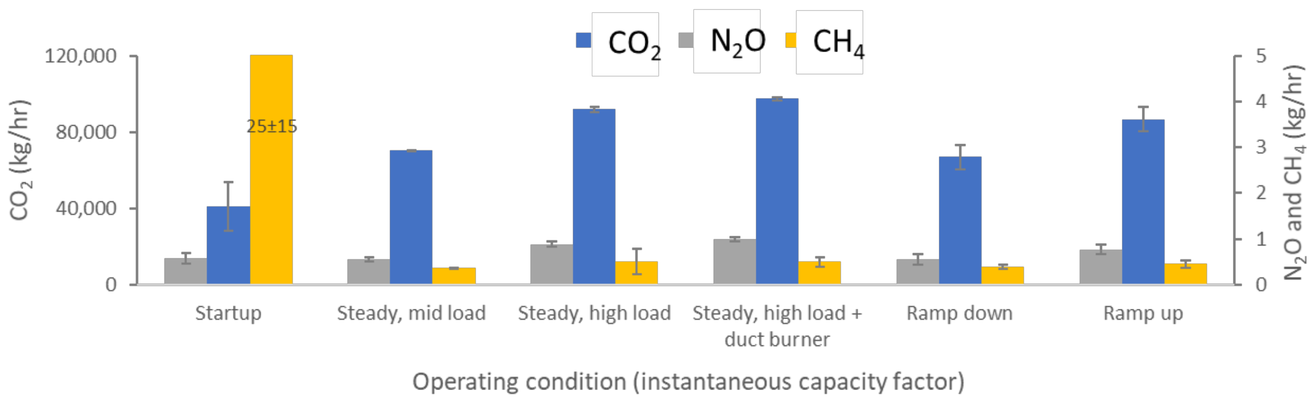
Source: EPRI

Facility 3 Stack Emissions

Stack testing by FTIR spectrometry was performed for CO_2, methane, and nitrous oxide during startup, ramping, and steady state operations of the combined cycle system and the peaker unit over a period of three days. When the combined cycle system was sampled, separate stack probes were inserted in each of the two stacks, and the flow to the detector was switched from one stack to the other at intervals relevant to unit operations.

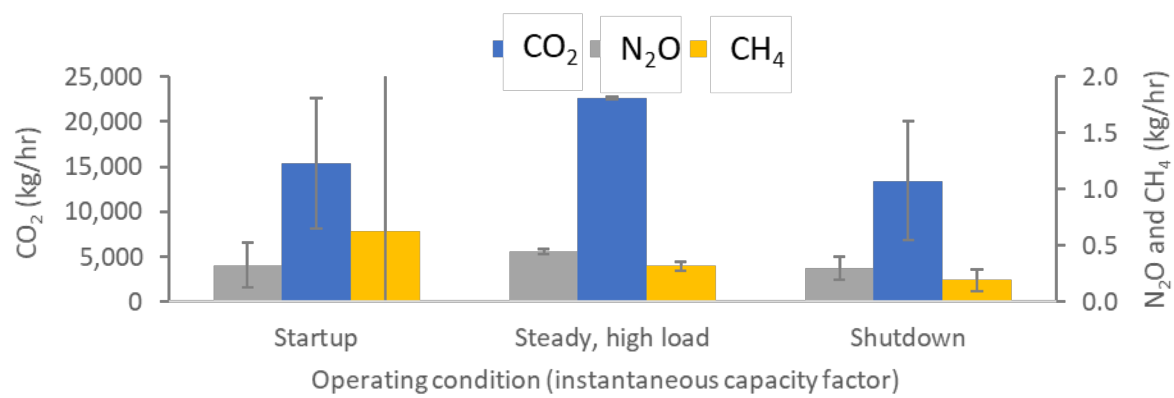
Figure 11 to Figure 14 provide a summary of GHG measurements for the combined cycle units and peaker unit at various operating modes. The two combined cycle units were categorized into six operating modes. For each mode, the load was calculated as the ratio of the turbine, heat recovery steam generator and duct burner's combined load to the nameplate capacity (percent of nameplate capacity). On average across the entire intervals, startup mode refers to 18 percent of nameplate capacity, steady mid load 58 percent, steady high load 82 percent, while ramp up and ramp down were 73 percent and 70 percent respectively.

Figure 11: Facility 3 Combined Cycle Units Stack Emissions as a Function of Operating Mode



Source: EPRI

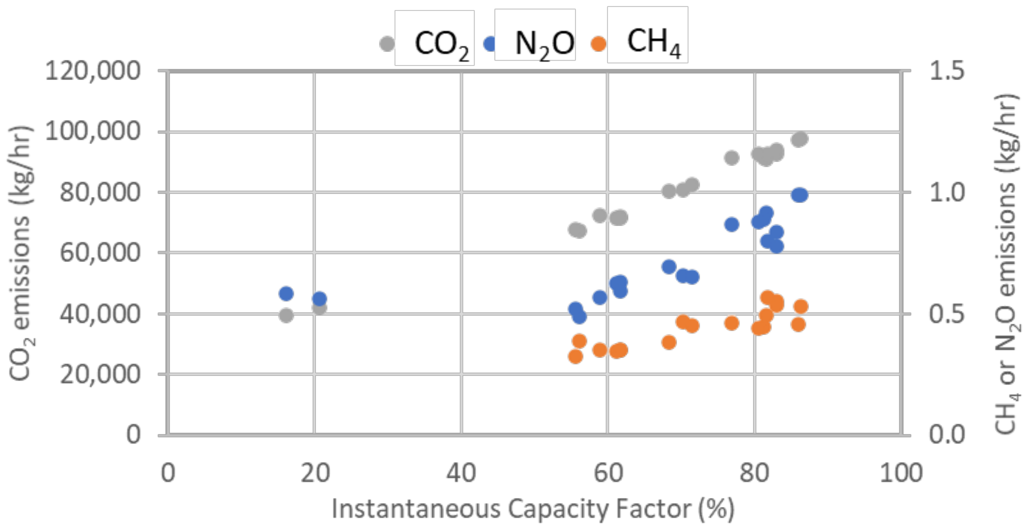
Figure 12: Facility 3 Peaker Unit Stack Emissions as a Function of Operating Mode



Source: EPRI

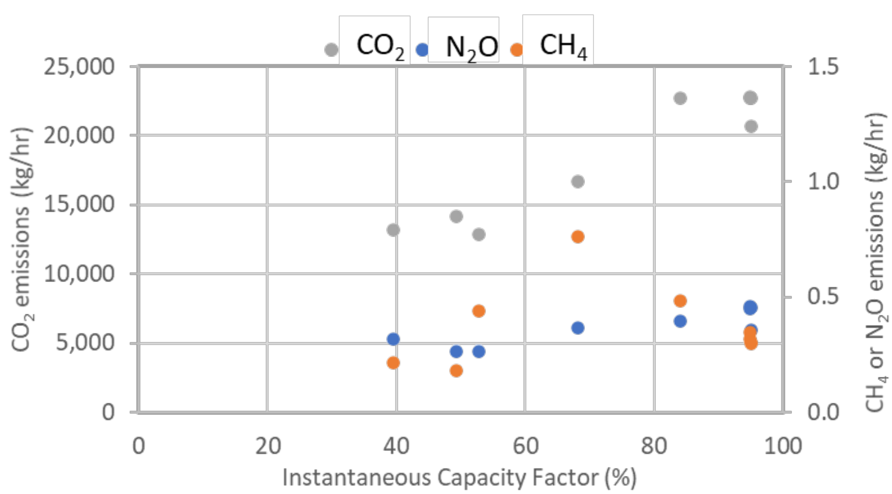
For the combined cycle and peaker units, CO_2 and nitrous oxide emissions showed an increasing trend as the load increased from startup to mid-load to high load (Figure 13 and Figure 14). Emissions decreased as the units ramped down or entered shutdown mode. On the other hand, methane emissions recorded very high values in startup mode, an order of magnitude larger for combined cycle units and 2-3 times higher for peaker unit. These methane emissions are due to uncombusted natural gas as the units are warming up. During this mode, the variability of the methane readings was also very large. Startup mode lasted for roughly 10-20 minutes during the measurements. Thus, generation units could release more methane than usual for a brief amount of time after starting up. The relationship between emissions and load is not as clear for the peaker unit as it was for the combined cycle system. For both charts, the methane data points corresponding to the startup mode are purposely excluded.

Figure 13: Facility 3 Combined Cycle Units Stack Emissions as a Function of Instantaneous Capacity Factor



Source: EPRI

Figure 14: Facility 3 Peaker Unit Stack Emissions as a Function of Instantaneous Capacity Factor



Source: EPRI

Facility 3 Comparison of Measurement Methods

In Table 5, the handheld and stack measurements are compared with emissions reported by the facility to GHGRP and measurements from other studies. Component level methane emissions are summed together and reached 12.8 kg/hr for fugitives from the non-compressor components. Compressor related methane emissions contributed an additional 100.5 kg/hr, or 89 percent, of the total fugitive emissions rate of 113.3 kg/hr. Weighted average stack emission rates from each generation unit are combined, and added to the fugitive emissions, to form facility-wide total estimates of 119.1 kg/hr. The assumption used is that both combined cycle units are in operating mode and the peaker unit runs for 5 percent of the time. Since GHGRP values are yearly, they would be impacted by any seasonality in the site operations. NASA JPL (Duren, et al. 2019) measured facility-wide methane emissions from Facility 3 using an aircraft-mounted imaging spectrometer and recorded a value that is within 20 percent of this project's facility-wide emission rate measurements (fugitive plus stack emissions). For comparison purposes, facility-wide emissions measurements from Lavoie et al.'s study (Lavoie, Shepson and Gore, et al. 2017) on three combined cycle power plants and Hajny's et al.'s study (Hajny, et al. 2019) on 14 combined cycle power plants, neither necessarily inclusive of Facility 3, are also included in the table.

Table 5: Facility 3 Measured Emissions From Various Sources

Measurement method / Study	Description	Average CO_2 emission rate (kg/hr)	Average methane emission rate (kg/hr)
Handheld	Fugitive non-compressor emissions	N.A.	12.8
Handheld	Compressor emissions	N.A.	100.5
Stack measurements	Combustion emissions*	158,444 ± 6,439	5.8 ± 6.5
Total facility measurements	Facility-wide emissions	158,444 ± 6,439	119.1
GHGRP	Combustion emissions	less than 50% of stack measurements	less than 25% of stack measurements
NASA JPL (2019)	Facility-wide emissions	N.A.	within 20% of total facility measurements
Lavoie et al. 2017	Facility-wide emissions	160,920 ± 80,460**	140 ± 70
Hajny et al. 2019	Facility-wide emissions	N.A.***	8 ± 5 to 135 ± 27

***Stack emissions assume that both combined cycle units are running and the peaker unit is operating for 5 percent of the time.**

****Assuming an average CH_4:CO_2 (kg/kg) EF of (8.7E-4).**

***** Hajny study reports CH_4 to CO_2 ratio but the variability is very large**

Source: EPRI

CO_2 stack emissions are comparable with the average facility-wide CO_2 emissions extrapolated from the Lavoie 2017 study (Lavoie, Shepson and Gore, et al. 2017). Lavoie's reported methane emissions rate was converted to CO_2 emissions using the provided average CH_4:CO_2 (kg/kg) ratio were similar to this facilities total emissions. However, the CO_2 stack emissions measured in this study were approximately 2 times higher than the values the facility reported to GHGRP. Since GHGRP values are yearly total, they do not account for the cyclical nature of the facility capacity factor. The month of visit also happened to be a high-capacity factor season which could explain the difference between stack CO_2 measurements and average monthly CO_2 emissions reported to GHGRP.

The portion of Facility 3's fugitive methane emissions that not associated with the compressor are 2.2 times larger than uncombusted methane emissions from the stacks is also shown. The larger previously known leaks at the compressor units were 20x those of the stack emissions. This is in line with findings from the Lavoie 2017 study which reported that fugitive methane emissions in the three combined cycle power plants that they measured were roughly three times larger than stack emissions. Thus, at power plants fugitive methane emissions may be larger than combustion-related emissions. The observation that the majority of this power plant's emissions are from fugitive or non-combustion-related equipment would support the discrepancies observed between the facility-wide methane emission rate and that reported by the facility to GHGRP, which only requires reporting of combustion-related methane emissions.

Secondary Aircraft Measurements

Flight measurements were also conducted at 41 additional sources across the state of California. These other sources were identified via review of economic sectors of interest, emissions databases, and site locations prior to the measurement campaign. The facilities visited are categorized into 12 types which include landfill, wastewater treatment plant, oil depot (tank farm), and combined cycle natural gas power plant. The definition of each facility type is shown in the appendices Table C-1, and Table C-2 shows the date, meteorological condition, and confidence level of each set of flight measurements at individual facilities.

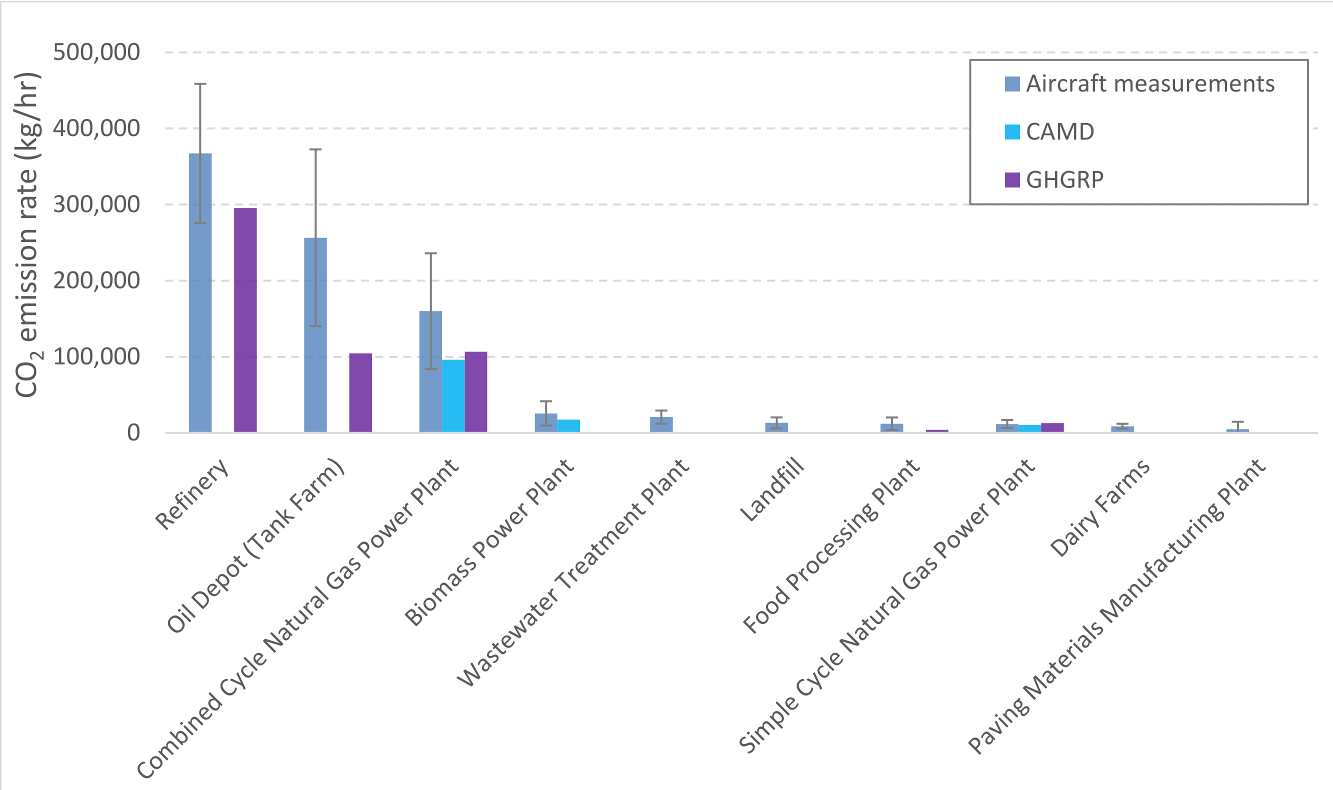
In Table C-3, facility-level CO_2 emissions measured by the aircraft are compared with values reported to EPA AMPD and GHGRP programs, while methane emissions measurements are compared to GHGRP values and estimates from recent NASA Jet Propulsion Laboratory aircraft methane measurements in California (Duren, et al. 2019). While aircraft measurements estimate facility-wide emissions, AMPD and GHGRP programs only include combustion related emissions from generation unit stacks. Only certain facilities with yearly emissions more or equal to 25,000 metric tons of CO_2 equivalent must disclose their emissions. In addition, AMPD only tabulates data for electric generation units. When data is not available, they are omitted from Figure 15, Figure 16, Figure 17, Figure 18 and Table C-3. NASA JPL only visited a subset of California facilities in their methane measurement study. For example, the JPL survey did not encompass dairies, wastewater treatment plants, and food processing facilities. NASA JPL methane data were collected on multiple days at different times and thus deviations from these aircraft measurements are expected. Facility-reported GHGRP data is a yearly total and is not specific to the measurement day unlike AMPD data which has hourly granularity.

Table C-3 shows the breakdown of CO_2 and methane emissions by facility type and compares the estimates and reported values. For facility types with more than one facility count, the AMPD and GHGRP emission rates are the average (statistical mean) emission rates of facilities in that category. Since emissions may be dependent on facilities' operating conditions, the number of sites that were operating during aircraft measurement is shown for simple cycle and combined cycle power plants facility types as their hourly operating data is reported to AMPD. The other facility types do not have high resolution operating data readily available.

Several CO_2 measurements are marked as *"bdl"* or below detection limit. A subset of these were negative, presumably due to additional unidentified CO_2 sources nearby that were transiting the flight loops and led to increased uncertainty. For methane measurements, NASA JPL employed an airborne imaging spectrometer with a lower detection limit of 2-10 kg/hr of methane, comparable to the lower detection limit of 10 kg/hr achieved by the Scientific Aviation aircraft method. In most cases, JPL visited each site multiple times during their survey period and the measurements (only those above detection limits) were averaged to provide the values in Table C-3 in the appendix. Imputations were not performed on CO_2 and methane measurements below the respective detection limits. As such, values shown on the table are not meant to be representative of population averages but was an initial assessment of relative emission magnitudes and as comparison points to the individual sites that were intensively measured on the ground and at the stack as part of this project.

Average CO_2 emissions for each facility type ranged from 150,000 – 370,000 kg/h as visualized in the bar chart on Figure 15. Refineries, tank farms, and combined cycle natural gas power plants were the three facility types with the highest CO_2 emissions. All the combined cycle power plants were operating during measurement. The other facility types had CO_2 emissions that were one or two orders of magnitude lower than the top three.

Figure 15: Average CO_2 Emissions of Different Facility Types Measured by Aircraft



CAMD data only available for power plants. Vertical error bars represent standards deviation in aircraft measurements. Cogen power plant is excluded because measurement was below detection limit.

Source: EPRI

Aircraft CO_2 measurements tended to be higher than the values reported to AMPD and GHGRP for these sites. For the 3 facility types that had both average aircraft measurements and average AMPD data, aircraft measurements were 42 percent higher than AMPD data on average. For the five facility types with aircraft CO_2 measurements and GHGRP CO_2 data, aircraft CO_2 measurements were, on average, 83 percent higher than GHGRP data. For example, food processing facilities showed 200 percent higher aircraft measurements compared to GHGRP data followed by oil depot with 145 percent higher aircraft measurements. No site-specific data exists to help explain the result, but it is possible the site was visited during a busy period, which the GHGRP is an average of operations over a year.

Aircraft methane measurements were significantly higher than values reported to GHGRP programs, with two of the seven facility categories two orders of magnitude larger, three of the categories about 20x larger and two categories 2-3x larger. One explanation for this discrepancy could be that the specific operating conditions on the day of aircraft sampling were not representative of average annual operations as reflected in GHGRP reporting data. This was found to be the case at the food processing site that was visited on the ground in this study. Another possible explanation for this discrepancy could be that fugitive emissions from component leaks are not reported to GHGRP. Food processing facilities had the biggest discrepancy having aircraft methane measurements that was 382 times higher than GHGRP values. Simple cycle natural gas power plant category was in second place with aircraft measurements being 112 times higher than GHGRP data. However, only two out of the six visited facilities were operating at the time, as they are peaker plants operated only when there is high demand for electricity. Thus, the GHGRP data reported likely reflect non-operational conditions, while the measurements incorporate operational periods.

Landfill, dairy, refinery, wastewater treatment plant, and tank farms were the top five largest emitting facility types for methane.

Methane emissions measurements from dairy farms were comparable with findings from a recent case study by Arndt et al. (Arnd, et al. 2018). Arndt et al. employed aircraft-based mass balance approach to measure methane emissions from two dairy farms with cattle counts of 7,379 and 3,433 and found whole-facility methane emissions to be approximately 1.1 kg/h per cattle. In comparison, this study obtained an average methane emission rate of 734 ± 174 kg/h from six dairy farms of unknown cattle count. Considering that the average cattle size of a dairy farm in California is around 1,000 cattle, these methane measurements can be approximated to 0.7 kg/h per cattle which is slightly lower than Arndt et al.'s findings (University of California Agriculture and Natural Resources 2019). It is important to note that methane emissions from dairy farms are dependent on many factors not limited to cattle count, time of year, manure management practices, type of animal housing; factors which were not considered in this study.

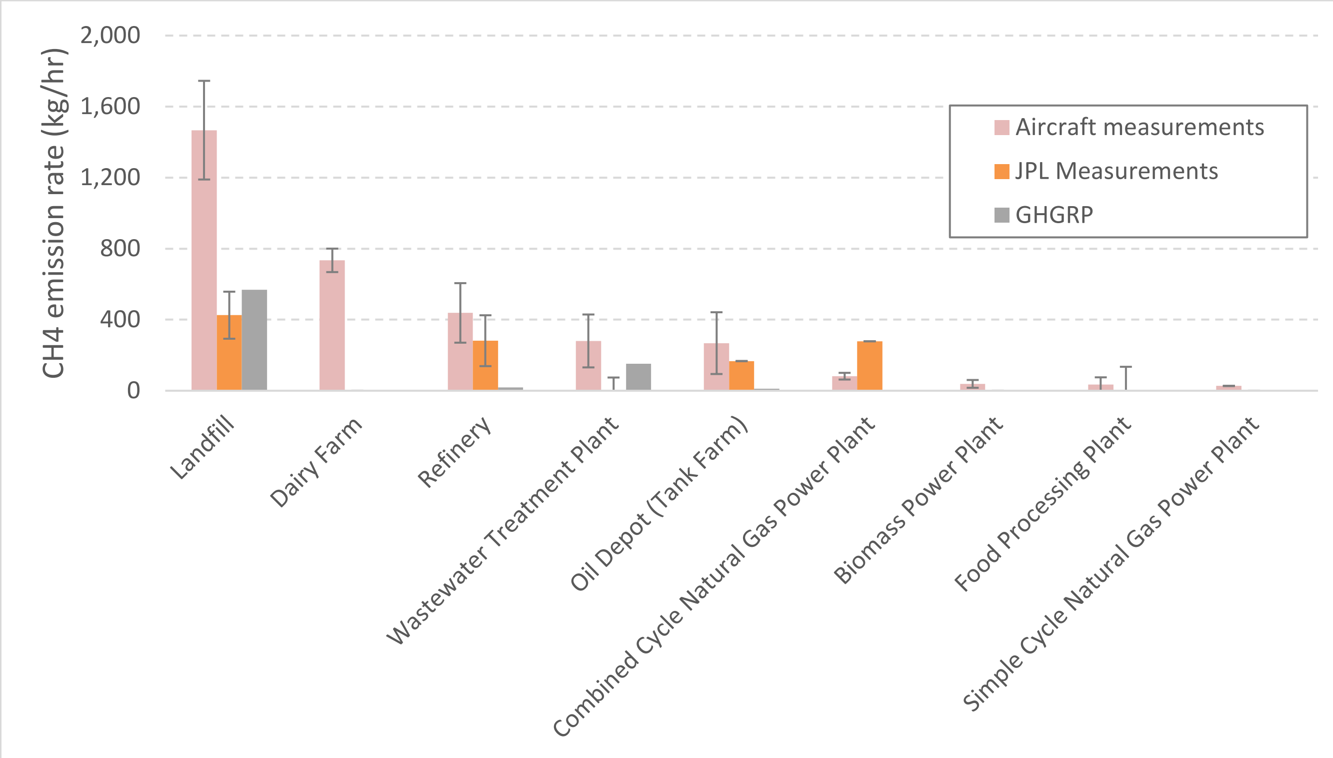
Average methane emissions from combined cycle power plants were 82 ± 40 kg/h, 20 times higher than facility-reported estimates for GHGRP. The four combined cycle power plants visited were operating during measurement which might give a positive bias to the result. In comparison, in 2015, Lavoie et al. measured an average methane emission rate of 140 ± 70 kg/h from three combined cycle power plants using a similar aircraft-based mass balance approach as this study which were 21-120 times higher than facility-reported estimates (Lavoie, Shepson and Gore, et al. 2017). Lavoie et al. acknowledged that their measurements were performed during peak operating hours which could have contributed to the high values. They also suggested that the primary source of methane emissions at the power plants were from non-combustion sources, which could explain why inventory estimates appear biased low as the 2018 GHGRP only requires reporting of combustion-related methane emissions (Lavoie, Shepson and Gore, et al. 2017). The observations from two intensively monitored power plants in this study (Facility 1 and Facility 3) also demonstrated that fugitive methane emissions were comparable or higher than methane emissions from the stack. On the other hand, in a 2019 study, Hajny et al. found that observed methane emissions from 14 natural gas-fired mostly combined cycle power plants measured using aircraft techniques were mostly uncombusted natural gas from the stack rather than fugitive sources (Hajny, et al. 2019). In alignment with these findings, Hajny et al. reported average methane emission rates of 8 ± 5 to 135 ± 27 kg/h from five of 14 power plants. The remaining plants had zero methane emissions detected. This range is on same order of magnitude as the higher range of these findings, which had a low end of <1 kg/h. Hajny's values reflected stack emissions only; they found no evidence of fugitive emissions at their monitored sites. Power plants may have highly variable emissions during different operations. For example, startup and shutdown emissions could possibly range up to several orders of magnitude higher than continuous operation emissions, but for short time periods [8]. Another combined cycle power plant, Facility 3, was visited in this study to characterize stack emissions during startup and shutdown phases. The results show that methane emissions increased significantly by an order of magnitude for 10-20-minute period during startup, while CO_2 emissions were lower during startup and shutdown. Thus, aircraft measurements on power plants are dependent on the operating modes of the generation units.

Measured methane emissions from refineries were comparable to what Lavoie et al. found in their 2017 study. Lavoie measured methane emissions from three refineries and obtained an average of 580 ± 220 kg/h, slightly higher than this project's average of 438 ± 168 kg/h (Lavoie, Shepson and Gore, et al. 2017). In comparison, NASA JPL measured 282 ± 143 kg/h methane emissions from refineries on average (Duren, et al. 2019).

Aerial emissions data were collected at six food processing facilities. Measurements of methane at three of the six food processing facilities were above the aircraft's detection limit, ranging from 22.8-39.0 kg/hr. Compared to other food processing facilities, the intensively monitored Facility 2 had similar CO_2 emission rate but much lower methane emission rate as shown in Figure 18. These emissions rates were orders of magnitude lower than those observed at a landfill (775 kg/hr) and four dairies (227-955 kg/hr).

This study's aircraft methane measurements tended to be higher than JPL measurements, 73 percent higher on average, for the four facility types with both datasets. These aircraft measurements for landfills and oil depots were 245 percent and 61 percent higher than JPL data respectively. However, combined cycle power plant aircraft measurements were 71 percent fewer than JPL measurements. Differences are not unexpected and seem within reasonable ranges as the measurements were taken at different times of the year and could have captured different combinations of venting and fugitive emissions as driven by differing facility operations.

Figure 16: Average Methane Emissions of Different Facility Types Measured by Aircraft



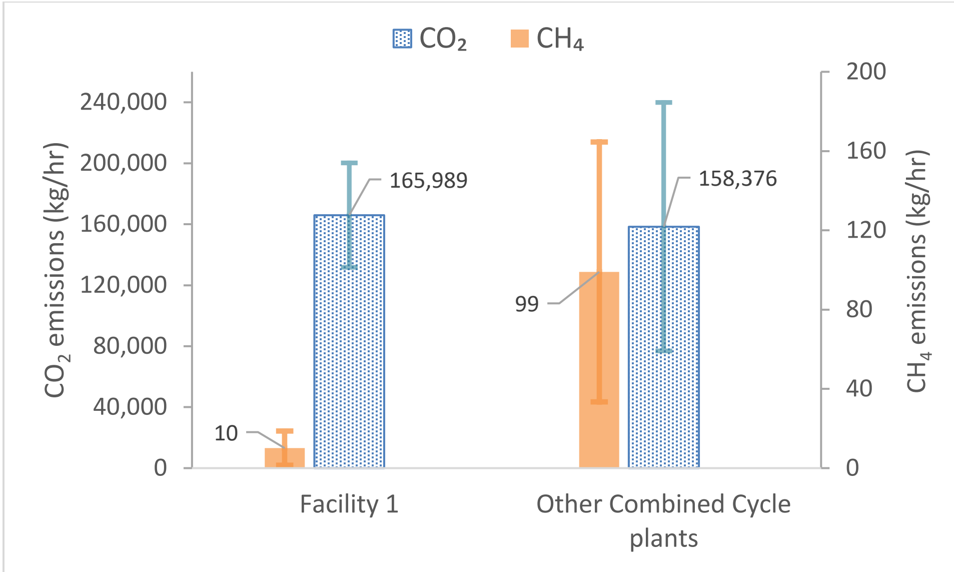
Vertical error bars represent measurement standard deviation across individual sites in the category. Cogen power plant and paving materials manufacturing plant are excluded because measurement data were below detection limit.

Source: EPRI

Regional aircraft measurements by facility category can be compared with the researcher's findings for the intensively monitored Facility 1 and Facility 2. As shown in Figure 17, aircraft CO_2 emissions measurements for Facility 1 were similar in magnitude to emissions of other combined cycle power plants. However, methane emissions of other combined cycle power plants tended higher than Facility 1. All combined cycle power plants measured in this campaign were operating during the measurement period. For Facility 2, aircraft measurements for CO_2 emissions were not far from other food processing plants', as shown in Figure 18. Similar to Facility

1, methane emissions for Facility 2 was much lower compared to the other facilities of the same type that were measured during the study.

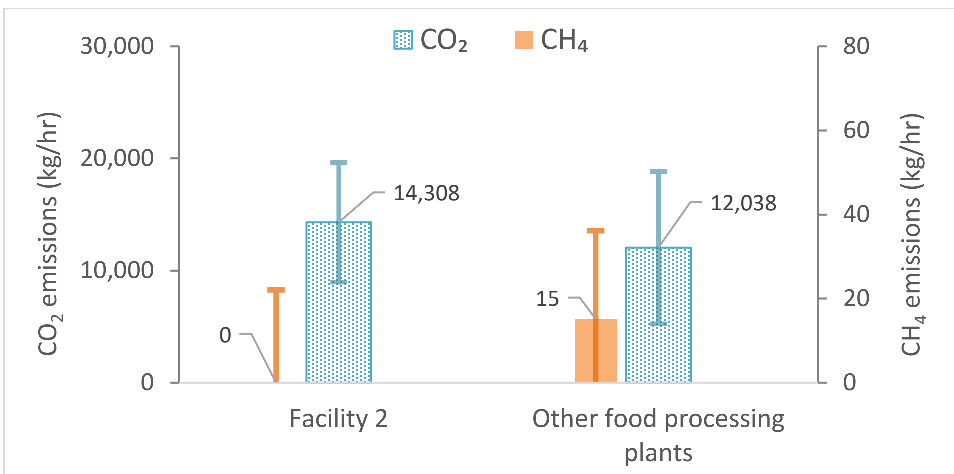
Figure 17: Aircraft Measurements of Facility 1 Compared to Other Combined Cycle Power Plants



Vertical error bars represent measurement standard deviation.

Source: EPRI

Figure 18: Aircraft Measurements of Facility 2 Compared to Other Food Processing Plants



Vertical error bars represent measurement standard deviation.

Source: EPRI

Aircraft data can be very useful to provide a preliminary assessment of site emissions but have the potential for much larger error than the on-site measurements (that is, handheld + stack data). Thus, it should not be assumed that aircraft measurements are accurate without some ground-truthing or validation.

Compressed Natural Gas Vehicle Fueling Stations

The purpose of the compressed natural gas (CNG) vehicle fueling station sampling was to provide a first in-depth examination of the potential for methane emissions from this category of facility. The study design was created first to determine whether these stations were emitting methane, and second to provide initial data on the emissions from a sample of CNG stations. The results of the testing are meant to be an initial/preliminary assessment of emissions to inform the development of future studies and are not an exhaustive examination or creation of emission factors that would be required to establish categorical emission factors (should that be deemed as needed). For example, the mix of sites sampled may not reflect the real proportionality of site type, site characteristics or operational profiles present in the state of California.

Between 2018 and 2020, the research team surveyed 48 unique CNG vehicle fueling stations throughout the state of California with three of the stations visited twice for a total of 51 measurement visits. There are roughly 309 CNG stations in California thus the stations visited represent roughly 15 percent of the statewide total (California Energy Commission 2019). The stations visited primarily serviced public buses, refuse trucks, delivery trucks, and other fleets as well as small personal vehicles. A subset of the stations was accessible by the public while others were only used to service internal fleets (no public access).

Stations were sampled using three methods, quick scan, intensive scan, and Mobile Plume Integrator (MPI). In addition, a limited number of samples were taken for isotopic analyses of natural gas components in the samples.

The objective of the quick scan, intensive scan and MPI methods was to identify emission sources and quantify the emission rates of those sources when detailed criteria were met. Therefore, the definition used throughout this report for an emission source is any area where a concentration of gas registers above a specific concentration threshold. The threshold is discussed in the following sections. Throughout the CNG station section, emission rates are reported in standard cubic feet per hour (scfh) instead of kilograms per hour (kg/hr) because scfh is more commonly used in literature when characterizing CNG stations. This choice will also improve readability of the numbers. For example, emission rates measured at the CNG stations range from 0.04 to 25.81 scfh (0.00076 to 0.493 kg/hr).

Overview of CNG Station Surveys

Quick scans were performed at 19 CNG vehicle fueling stations, intensive scans were performed at 27 stations, and five stations were exclusively visited with the MPI system, resulting in a total of 51 station visits. 3 CNG stations were visited twice, first with the quick scan methodology followed up with the intensive scan. The CNG stations surveyed consisted of common equipment such as a natural gas customer meter at the gas utility connection point, dehydrators to remove excess moisture from inlet gas, and compressor units to increase gas pressure to the appropriate vehicle fuel tank pressure. Other prevalent equipment included filters to remove foreign particles in the natural gas, storage vessels to store high pressure gas, priority panels to direct flow of gas from the compressor to storage vessels, and fuel dispensers that deliver compressed gas to vehicles. A series of tubing or piping, valves, and fittings connected these various pieces of equipment.

Compressor units at the visited CNG stations were typically housed in well-ventilated enclosures or under canopies or shelters for weather protection with a vent stack on the rooftop to allow emitted gas to safely vent to atmosphere. At most stations, there was a standby compressor unit, usually located next to the primary unit, for load distribution and to operate as a redundant system.

As shown in Table 6, 19 stations were surveyed with the quick-scan approach representing 12 different station operators. Station operators are organizations in charge of station maintenance and upkeep and may include private or public (government) institutions such as municipalities. Out of the 19 stations, 11 had at least one emission source identifiable with the OGI camera. In addition, five of the 11 stations were also surveyed with the MPI system and in all five cases the MPI system detected methane emissions from the station.

Table 6: Summary of CNG Station Quick Scans

Summary of stations visited with quick scans	Count
CNG stations that were quick-scanned	19
Number of station operators represented	12
Stations with emission indication(s) visible with FLIR	11
Stations quick-scanned and surveyed with MPI	5

Source: EPRI

Intensive scans were performed on 27 stations representing four different station operators (Table 7). The researchers found 171 emission indications from all the intensive survey visits which translated to a mean of 6.3 indications per station, with each station having a minimum of two emission sources. Due to time limitations, only indications that were visible with the OGI camera were quantified. Of all indications, 50 (29 percent) were detectable with the OGI camera and were quantified, the remaining 71 percent of the indications were below the OGI detection limit. Additionally, nine of the 27 stations visited with intensive surveys were also surveyed with the MPI, providing an additional aggregate emission rate measurement for comparison.

Table 7. Summary of CNG Stations that were surveyed intensively

Summary of stations visited with intensive surveys	Count
CNG stations surveyed intensively	27
Number of operators represented	4
Stations visited with intensive survey and MPI	9
Emission point indications found	171
Ave. number of emission point indications per station	6.3
Emission point indications quantified	50

Source: EPRI

The intensive surveys produced a subset of emission sources that met the emission source threshold (500 ppm on the CGI) but were not visible with the OGI camera and were labeled as below quantifiable limits. These emission sources were assumed to have an emission rate upper limit of 0.08 scfh (0.0015 kg/hr), which was the smallest measured quantifiable emission rate from the campaign that was also visible with OGI camera. This value was close to the 0.1 scfh (0.0015 kg/hr) OGI camera lower detection limit (at 90 percent probability) at 1 meter from the emission source reported by (Ravikumar, et al. 2018). The 0.08 scfh (0.0015 kg/hr) limit was used in the robust Regression on Order Statistics (ROS) algorithm to impute the censored data (data below quantifiable limit).

Several components were located beyond the reach of the handheld detectors and, in these cases, the OGI camera was used to scan for emission indications. Since the quantification method relied on direct physical access to components, when an emission was detected on inaccessible components, quantification was not performed and instead a value of 0.57 scfh (0.01 kg/hr), the OGI camera lower detection limit (with 90 percent probability) at 3 meters from an emission source was assumed as the upper limit for these sources during the imputation process for the robust ROS method (Ravikumar, et al. 2018). There were five such emission sources found during the intensive surveys and all of them were at vent stacks on compressor enclosures.

Compressor Type and Characteristics

All stations visited were equipped with reciprocating compressors. CNG stations typically do not have a large enough throughput to warrant the use of centrifugal compressors which have much larger compression capacity than the reciprocating variety. Without vapor recovery systems, reciprocating compressors emit natural gas during normal operation due to the inherent design of the piston rod packing systems (U.S. EPA 2016). The packing, which consists of flexible rings, is used to maintain a tight seal around the piston rod, preventing gas compressed in the compressor cylinder from venting to the atmosphere while allowing the rod to move freely. The amount of emission from a reciprocating compressor depends on cylinder pressure, fitting and alignment of the packing parts, and amount of wear on the rings and rod shaft. As the system ages, the emission rates may increase from wear on the packing rings and piston rod. In addition to fugitive emissions, natural gas may be vented during startup and depressurization process (for example, blowdowns). These emissions are categorized under vented emissions due to their intentional and non-continuous nature. Without continuous measurements at the compressors, it is difficult to discern between continuous fugitive emissions and vented emissions that occur during system startup and shutdown.

While individual compressor designs can be different, vented, or leaked emissions from compressor systems are routed primarily through two outlets: crankcase vent(s) and rooftop vent stack(s). Compressor emissions, purposeful and fugitive, from the piston rod packing, and from the distance piece go through a compressor vent stack, although individual crank case vents may also be combined into a header going to the same vent stack depending on design. There could be multiple vent stacks to the atmosphere; for example, the main one is for the rod packing sections, distance pieces and crank cases while an additional one routes emissions from pressure relief valves.

All visited CNG compressors operated on electric power; none of the compressors utilized a natural gas engine. Electric compressors are known to be compact and create less oxides of nitrogen (NOx) and carbon dioxide emissions compared to compressors with natural gas engines or turbines making them suitable for use in urban and suburban areas (Greenblatt J. B. 2015). Further, the locations of the CNG stations often had convenient access to electricity which could be another factor in the decision to use electric motors.

Compressors come in many varieties and during construction of the stations the selection of compressor type was based on the unique operational need of the station. Within the 42 compressors visited at the 27 intensive scan sites, there were 14 makes and models. Across the 27 intensive sites, the compressor installation date, or the date since the rod packing and seal were replaced, ranged from several months to almost thirty years. The compressor rated horsepower spanned from 40 to 400 hp, suction pressure from 5 to 265 psig, compression capacity from 24 to 504 scfm, and storage capacity from 10,000 to 80,000 scf at varying pressures. The daily throughput of stations ranged from approximately 1,300 to approximately 833,000 scf based on throughput data provided for a subset of stations, highlighting the large variation in volume of gas delivered per station. Stations with heavy-duty vehicles fueling operation have throughputs in the upper end of the range.

Continuous and Episodic Emissions

Fugitive emissions occur from leaks in various parts of infrastructure, especially from components such as valves and threaded connections in piping and other equipment, while vented emissions arise from releases from equipment blowdowns, pressure relief safety devices, maintenance/turnaround activities, and emergency shut-down processes (U.S. EPA 1996) (Heath, et al. 2015) (URS Corporation 2009). Fugitive emissions tend to be continuous with steady rates while vented emissions are typically episodic and highly variable in emission rate.

Being highly variable, episodic emissions are difficult to detect and quantify during leak survey visits. To detect and quantify an episodic emission, the surveying team would have had to have the methane sensor and flow rate measurement device on the emission source's vent. Episodic emissions are not easy to predict, so this strategy was impractical for the purposes of this study. Further, capturing infrequent vented emissions may not be a good representation of the mean emission rate over time. A better option to capture episodic emissions for a future study would be to deploy remote emission rate measurement methods with high temporal resolution at equipment known to have periodic emissions (such as blowdown stacks or pressure relief devices) to accurately detect the frequency of the emissions and quantify the mean emission rate.

It is important to distinguish between continuous and episodic emissions because emissions volume from a continuous source can be estimated using its known emission rate multiplied with duration whereas an episodic emission source is more complex as the duration and emission rate of its releases are more variable. In this report, attempts were made to separate emissions that would be considered continuous versus the ones that could be classified as episodic.

For the CNG station visits, emission sources identified were considered continuous if they exhibited steady behavior during the duration of the station visit unless otherwise noted. In a later section of this report, the authors discuss how compressor emissions taper off after switching from operating to non-operating mode. As it was not possible to rule out that the emissions measured in non-operating mode were obtained during or after the tapering off period, which could vary across compressors, a conservative assumption was made that emissions measured in non-operating mode were continuous. Discussions with several compressor engineers about typical operations indicated that a continuous emission is possible if there is no vapor recovery system, regardless of whether the emitted gas is an intentional or a fugitive leak. For the entire study, no emission was found occurring on pressure relief devices, dehydrator vents, storage vessel vents or pneumatic controllers. Thus, the only component type that could have a combination of continuous and/or episodic emissions was the station compressors. It is important to note that the emissions measured during the sites visits remained at similar levels for the visit duration (roughly two hours).

Episodic emissions from compressors occurred during system start-up and shutdown (blowdown) and were emitted through compressor vent stacks. At the same time, based on discussion with compressor engineers about typical operations, compressors may have continuous emissions in the form of fugitive leaks or engineered vents from the rod packing seals. These are generally released from the crank case vent. As some of the compressors were measured in operating mode or shortly after a shut down, emissions from compressors were unable to be clearly distinguished into continuous or episodic emissions. More details on compressor operating conditions, startup and shutdown times would be required to classify which emissions were purely continuous or a mixture of continuous and episodic. To fully separate continuous and episodic emissions, multiple temporally dense measurements during different compressor operating modes are needed to obtain the baseline continuous component of the compressor emissions. This project was able to make short and preliminary emissions measurements from compressor crank case vents after shifts in operating mode (that is, off to on, on to off). Details of these measurements are included later in the report. Compressor emissions are separated from continuous fugitive emissions in the following sections to avoid any potential mis-categorization of emissions.

The research team recommends that future research projects deploy continuous methane monitors at select equipment over extended periods (few hours to several days) to obtain a better understanding of episodic emission behavior.

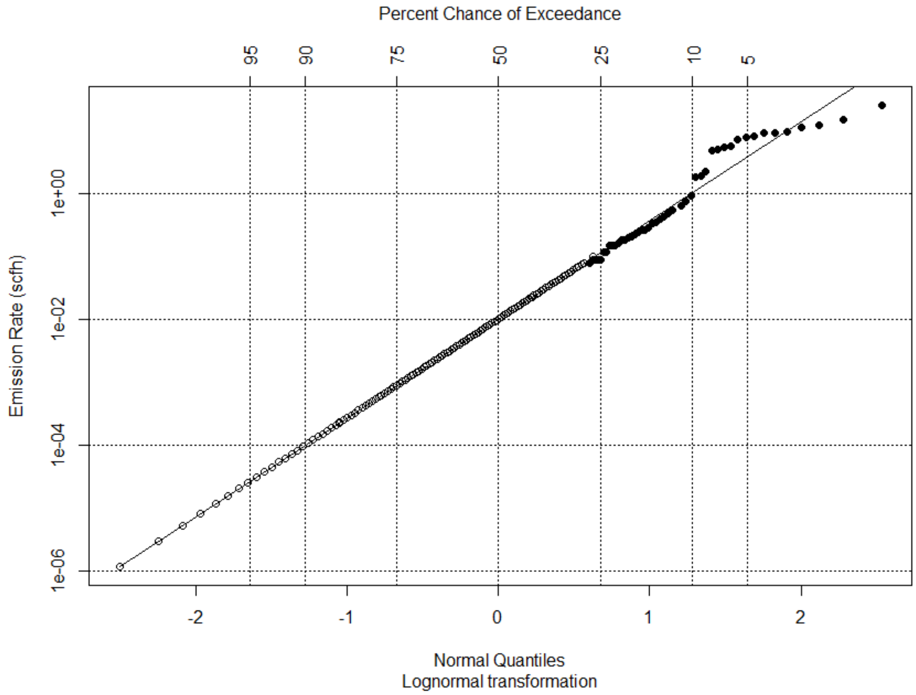
Distribution of Emission Rates

Station level emission rates are reported as an aggregate of all point source indications above the 500 ppm CGI measurement threshold found at a station, with emission points below the quantifiable limit being modeled using the robust ROS method (discussed above). Station level emission rates include both compressor and non-compressor emissions thus including both continuous and episodic emissions. For compressor emissions, if measurements were made when a compressor was in operating and non-operating modes, then the overall emissions for that compressor was conservatively assumed to be 0.1 × operating emissions + 0.9 × non-operating emissions. In other words, an assumption that a compressor is operating for 2.5 hours every day was made, as this information is currently not collected by site operators. This assumption is a balance between the observation that at some site visits the compressor was not operating at all, and for others multiple events occurred during the approximately two hour visits (and were expected to continue triggering at a similar rate for additional hours over the full day). Given that most sites visited did not have a high rate of compressor operation (based on a review of the daily throughput ranges), it is reasonable to assume the bulk of time would be assigned to the non-operating condition. For comparison, a 2014 EPA review document reported that the percent of time in a year a transmission reciprocating compressor stayed in pressurized mode was approximately 79 percent (U.S. EPA 2014). Ideally, future measurements would be taken in a continuous manner over several days, so operational cycles can be determined and a time-weighted average by operational state can be calculated.

All the 27 CNG stations visited with the intensive scan methodology had at least two emission sources each (above the 500 ppm CGI threshold) and 21 stations had at least one source that was larger than the quantification threshold (identifiable with the OGI camera). A total of 171 sources were found during the study, 50 of which were visible with OGI camera and were quantified using the Hi-Flow Sampler.

The robust ROS method used to impute values assumed that the observations followed a continuous log normal probability distribution and used uncensored observations to fit the distribution [(Bolks, DeWire and Harcum 2014) (Helsel 2009)]. Censored observations were imputed, and new summary statistics such as mean, and median were computed. Figure 19 shows the robust ROS technique applied to the individual point source indication data including the data from the compressors. These individually modeled points were aggregated to calculate station-level emissions. In the remaining sections of this report, all charts and summary statistics include the imputed data (censored) from the robust ROS process unless otherwise stated.

Figure 19: Normal Probability Plot Produced by the ROS Method



The ROS method showing the detects/measured component emission rates as black circles and the imputed non-detects/unquantified emissions as the empty circles.

Source: EPRI

Additional details about Figure 19 are as follows. The underlying assumption in the robust ROS method is the dataset follows a lognormal distribution. The solid line represents the lognormal distribution. The lognormal parameters are fitted using the quantified emission rates ("detects"), shown by the solid circles, while emissions that were below quantifiable limit ("censored"), shown by the hollow circles, are imputed by extrapolating them along the lognormal line. The adjusted R-squared value of the line is 0.93 which indicates a good fit. With the estimated values for non-detects, a new statistical mean can be computed.

After imputing the below quantifiable limit (that is, censored) data using the robust ROS procedure, a new statistical mean was computed for both individual emission sources and station emission rates. Close to 71 percent of emission indications were censored as they were below the quantification threshold, leaving a total of 50 indications that were quantified. Table 8 shows the comparison of statistical means of individual source and station emission rates with and without the rates below the quantifiable limit.

Table 8: Comparison of Statistical Means With and Without Non-detect Data

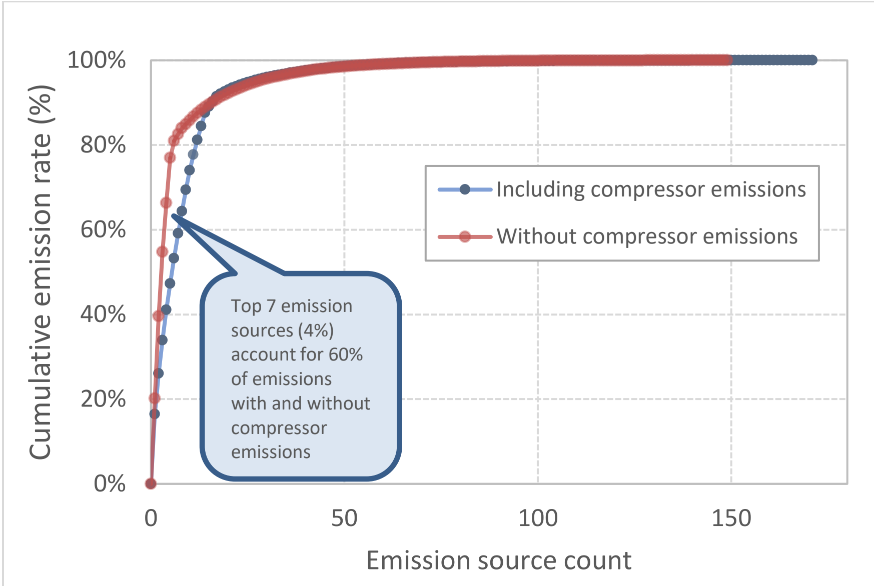
	Mean emission rate per emission source (scfh) including compressors	Mean emission rate per station (scfh) including compressors	Mean emission rate per emission source (scfh) excluding compressor emissions	Mean emission rate per station (scfh) excluding compressor emissions
Excluding data below quantifiable limit	3.29 ± 0.35	7.23 ± 0.84	1.27 ± 0.03	2.53 ± 0.07
Including data imputed using robust ROS	0.92 (0.49 – 1.41)*	5.80 (2.37 – 10.15)*	0.32 (0.12 – 0.57)*	1.94 (0.42 – 4.05)*

***95th percentile confidence interval based on 10,000 bootstrap replicates.**

Source: EPRI

Cumulative distributions of individual component emission rates and station emission rates sorted from largest to smallest including data points imputed with the robust ROS method are shown in Figure 20 and Figure 21. In these charts, the vertical axis is the cumulative emission rate as a percentage of sum of total emissions and the horizontal axis is the count of emission sources (Figure 20) and stations (Figure 21). Emission rates are arranged in descending order, such that the higher emission rate appears on the left. The charts highlight the contribution of several highest emitters to the overall emissions measured in this study.

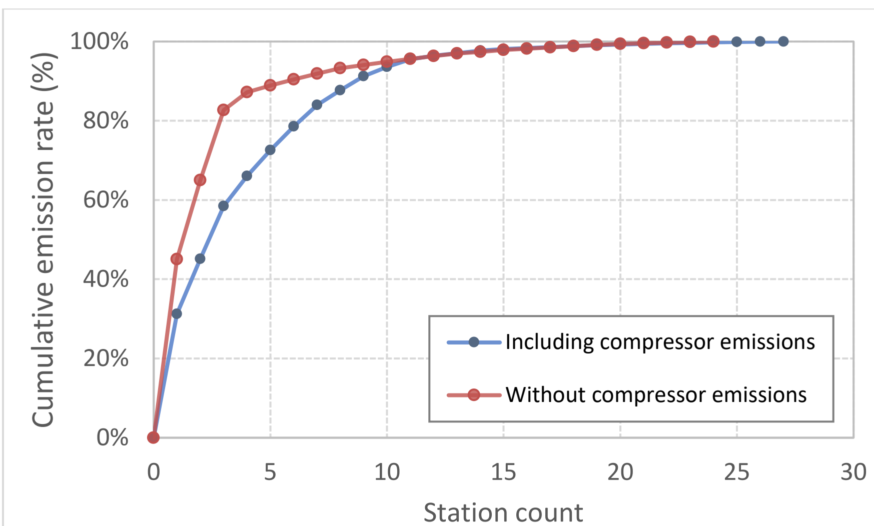
Figure 20: Cumulative Distribution of Emission Rates for Individual Emission Sources



Rates are for intensively scanned stations (Count = 171 and 149).

Source: EPRI

Figure 21: Cumulative Distribution of Station Emission Rates for Intensively Scanned Stations



(Count = 27 and 24)

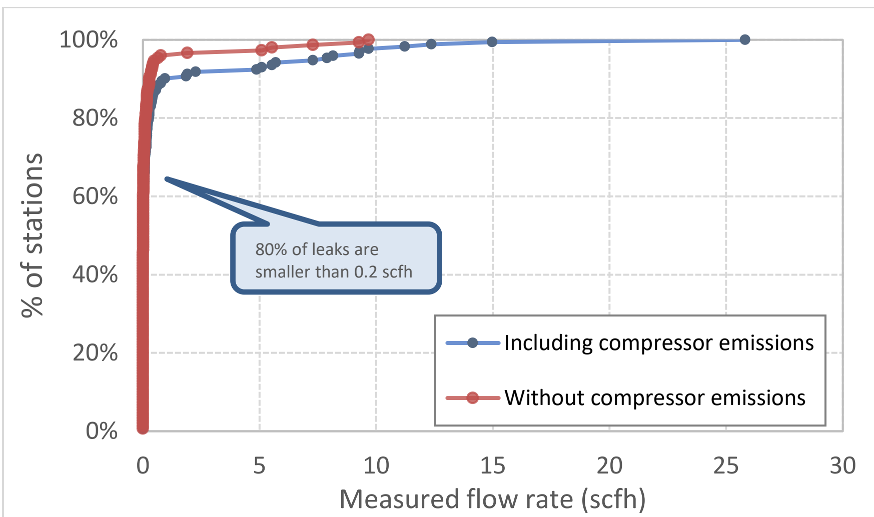
Source: EPRI

The shapes of the two distribution curves are similar and indicate that a large majority of emissions were contributed by a small number of sources while the remainder of the sources only made up a small percentage of the emissions. This is called a heavy-tailed, or fat-tailed, distribution due to its strong skewness. The highest-emitting three out of 27 stations (11 percent) accounted for roughly 60 percent of the overall emission rate while the top 7 out of 171 emission indications (4 percent) accounted for 60 percent of the emissions.

Figure 20 also displays the cumulative distribution of emission rates without compressor sources. With compressor emissions omitted, some of the higher emissions were excluded and as a result, the distribution has a thinner tail. Notably, the underlying pattern that a few emission points contributed a large percentage of emissions is still consistent with the observation when compressor sources are included. The findings are aligned with several studies which investigated methane emission sources across the natural gas supply chain and consistently found that in many segments, emission sources follow a tail-heavy distribution implying that a few sources – whole facilities or individual pieces of equipment - dominated the emissions [(Brandt, Heath and Cooley 2016) (Alvarez, et al. 2018)].

Figure 22 and Figure 23 further demonstrate the heavy tails for both distributions and provide a clearer picture of emission rates of individual emission sources and stations, respectively. In Figure 22, 80 percent of emission indications were smaller than 0.2 scfh but the largest four were all above 10 scfh. Figure 23 shows that 80 percent of stations had emission rates fewer than 10 scfh but the remaining 20 percent have substantially higher emission rates. The findings imply that substantial emissions could potentially be abated by focusing mitigation efforts on a small subset of the emission sources.

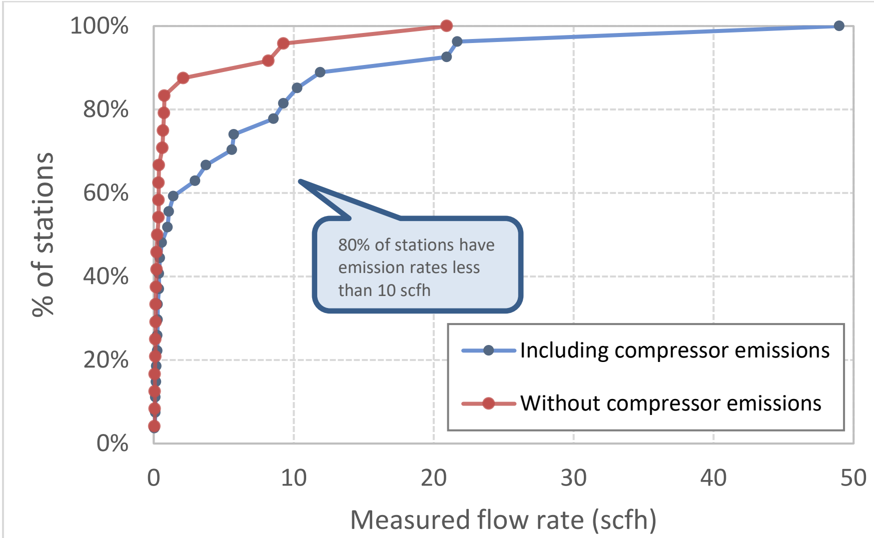
Figure 22: Distribution of Emission Rates of Individual Emission Sources



(Count = 171 and 149)

Source: EPRI

Figure 23: Distribution of Station Emission Rates



(Count=27 and 24)

Source: EPRI

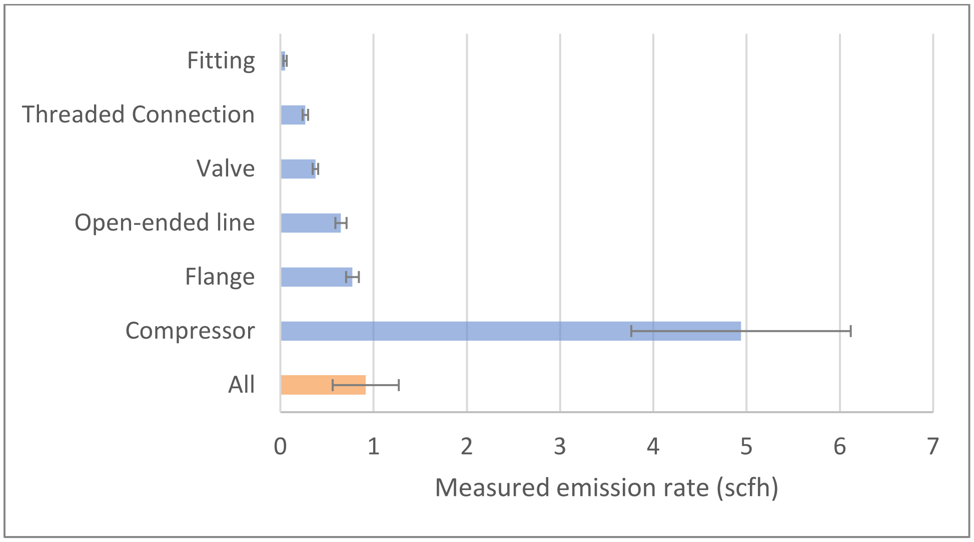
Component Level Emissions

Throughout the study, intensive surveys were completed on 42 compressor units, 19 had at least one emission source, resulting in a total of 22 emission source indications. Fourteen of the 22 indications were larger than the quantification criterion (that is, visible with the OGI camera).

The equipment types present at CNG fueling stations included meters, compressors, dehydrators, filters, automated gas priority panels, high-pressure storage vessels, and dispensers. In this study, the equipment type was further sub-categorized into six component categories namely fittings, open-ended lines, threaded connections, valves, flanges, and compressors. The classification was aligned with guidance provided by EPA in the CARB regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities as all the component types were subsets of the categories listed by the regulation (CARB 2017). The compressor component type covers compressor rod packing emissions, crank case vent(s) and/or other compressor vent stack(s) depending on compressor design. Other parts on the compressor unit were placed in their respective categories (fittings, open-ended lines, threaded connections, valves, and flanges). All the emission source indications discovered at the stations were assigned one of the six categories. As previously discussed, emission rates of sources below the quantification threshold were estimated using the robust ROS method.

The mean component level emission rate for all source categories including compressors was 0.92 scfh with a 95th percentile confidence interval of (0.49 - 1.41) scfh based on 10,000 bootstrap replicates within the robust ROS method (Bolks, DeWire and Harcum 2014) for additional detail on the method and terms. When compressor emissions were excluded, the mean component level emission rate was 0.32 scfh with a 95th confidence interval of (0.12 – 0.57) scfh. Figure 24 displays the mean emission rate of sources of each component type. The compressor component type had the largest mean emission rate at 4.94 (± 1.18) scfh per individual source and was likely due to a combination of continuous and episodic emissions as described earlier. Fittings had the lowest mean emission rate at 0.05 (± 0.02) scfh. On average, compressor vent emissions were about 14 times higher than non-compressor component emissions.

Figure 24: Mean Emission Rate of Emitting Components by Component Type

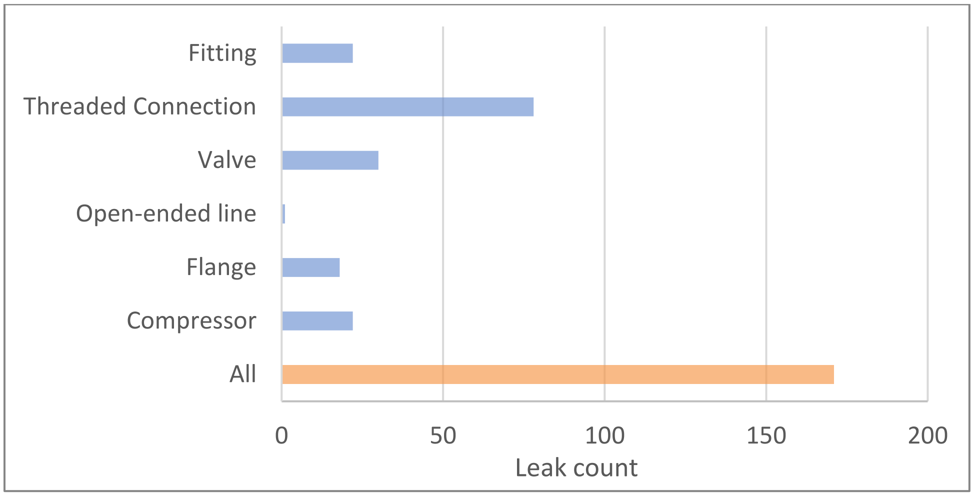


Source: EPRI

Figure 25 shows the number of emission sources for each component type. Threaded connections had the highest number of emission sources which may be due to the presence of many threaded connections per station (total per station was not collected). The component with the second highest number of emission sources was valves while compressor was tied for third with fitting. On average, there were 0.8 compressor emission indications and 5.5 non-compressor indications per station intensively sampled. It is of note that as there are likely hundreds of components at a station, an average of 6.3 component leak per station is very low by count. If only indications above the quantification threshold were considered, there were 0.5

compressor and 1.3 non-compressor indications per station. Given that mean compressor emissions were larger than the mean component emission and that the frequency of compressor vent emissions per intensively sampled station was not trivial, compressors could be an important initial target for innovation to reduce methane emissions.

Figure 25: Count of Emitting Components by Component Type



Source: EPRI

Emission Rate as a Function of Compressor Operating Mode

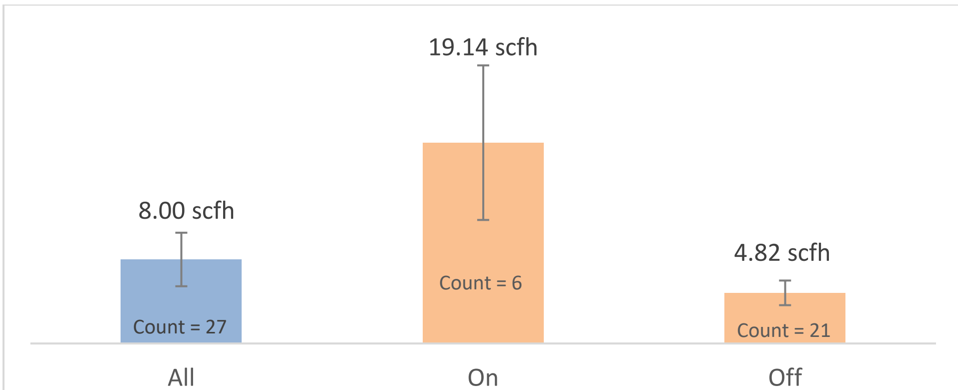
For the various equipment present at a CNG vehicle fueling station, the compressor could be one of the higher emitting components (U.S. EPA 2016). In this section the mean emission rate of compressors at different operating modes is evaluated. Operating compressors were only sampled opportunistically as it was difficult to predict whether a compressor would begin operation, the total operating time and duration ahead of arrival, even with general site usage information provided by the operators.

Of the 42 compressors visited at the 27 intensively surveyed CNG stations, five were operating while the remaining 37 compressors were non-operating. All five of the operating compressors had detectable emissions while only 14 of the 37 (38 percent) non-operating compressors showed emissions. Thus, a significant portion of the non-operating compressors had no emissions. However, emissions from non-operating compressors were unable to be clearly distinguished into continuous fugitive emissions or episodic emissions from shutdown operations. This is because the research team had no knowledge of the compressor operations before arrival, to determine if emissions were in a temporary period of tapering off after the compressor stopped operating or were more reflective of a continuous state of emission. Additional studies with continuous measurements would be needed to determine if non-operating emissions stabilize or taper off over longer periods.

The mean emission rates of compressors in different operating modes are shown in Figure 26. Emission rates were aggregated at the compressor level - if there were multiple emission indications per compressor, the emission rates were summed together to represent each compressor. The chart is based on 27 compressor measurements, including six when the compressor was operating and 21 when the compressor was non-operating. Note that this number is higher than the 22 emission source indications on compressor units mentioned previously because five compressors were measured during both operating modes.

Indications smaller than the quantification threshold were imputed using the robust ROS method and are included in the means. There was roughly a four times difference in emission rate when a compressor was operating, denoted as "On", compared to when a compressor was not operating, denoted as "Off". It is important to note that based on the limited number of data points collected in this study, conclusive statements cannot be made regarding the trend between the operating modes of the compressor but the results indicate that an operating compressor may be more emission-intensive than a non-operating unit. In a later section of this report, the temporal change in compressor emission rate during the transition from operating to non-operating modes is explored further.

Figure 26: Mean Compressor Emission Rate by Operating Mode



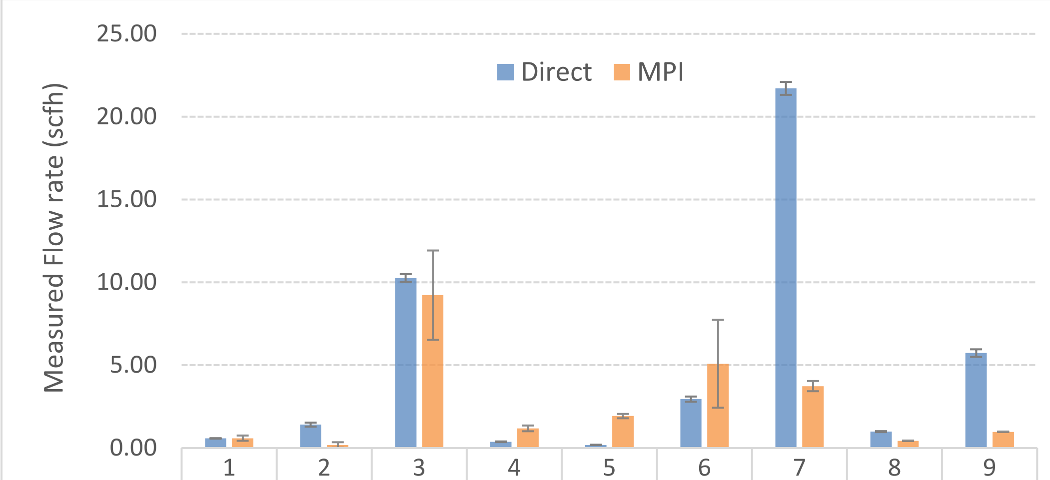
Source: EPRI

Comparison of Handheld and MPI Measurements

A total of nine intensively surveyed stations were also surveyed with the Mobile Plume Integrator (MPI). Considering that the MPI system captures the facility/station level emission rate, the individual emission sources of each station were aggregated to arrive at a value that could be compared with the MPI data. A previous study suggested that emission rate measurements from mobile systems are prone to a higher level of uncertainty compared to direct enclosure measurements due to unknown distance between the emission source and vehicle among other factors (Weller, Roscioli, et al. 2018). However, the study also demonstrates that mobile platforms were able to categorize and discriminate between relative leak sizes (for example, small, medium, and large).

Figure 27 displays the station level emission rates measured with the handheld equipment and the MPI for all nine stations with both sets of data. In ideal conditions, the MPI was expected to measure a value higher than the handheld measurements since there could be emissions beyond the reach of handheld equipment that could contribute to the methane plume observed by the MPI downwind of the facility. Additionally, in cases where the MPI was not able to access a roadway upwind of the site to obtain background methane concentration, the MPI measurements may have been susceptible to overestimation due to high background methane, though the MPI does incorporate algorithms to filter out datasets with poor quality.

Figure 27: Comparison of Station Emission Rates Measured by Direct (Handheld) and MPI Methods



	1	2	3	4	5	6	7	8	9
Direct	0.58	1.41	10.26	0.38	0.19	2.95	21.71	0.99	5.73
MPI	0.60	0.18	9.23	1.19	1.93	5.09	3.74	0.44	0.98

Source: EPRI

Six out of the nine MPI emission rates measurements were similar to or slightly higher than the emission rates measured with the handheld instruments. However, there were three instances where the handheld measurements exceeded the MPI measurements by a large margin (that is, stations 2, 7 and 9). Upon closer analysis, one of the stations (number 7) had obstructions in the form of a brick wall on the downwind side of the compressor station that prevented the gas plumes from the compressor enclosures from reaching the mobile system. Additionally, MPI measurements for station 2 and 9 were affected by low wind speed which limited lateral movement of gas plumes and reduced the likelihood of the vehicle transecting the plume. There is an inherent uncertainty in the MPI aggregated measurements that is not included in the error bars of the figure, which represent standard deviation. That inherent uncertainty has been independently determined to translate to a standard error of 70 percent of measured values; standard error refers to the mean dispersion around the mean of repeat measurements.

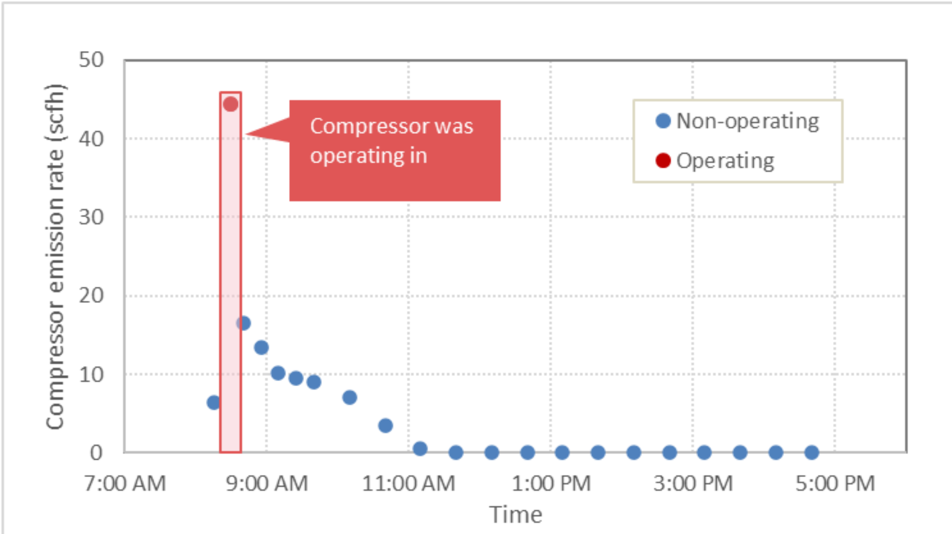
The handheld and MPI measurement methods each have specific strengths and weaknesses. MPI can provide a fast estimate of the facility level emission rate while having relatively higher uncertainty and being reliant on wind conditions and site design to obtain meaningful data. Handheld measurements, on the other hand, can provide more precise emission rate measurement compared to MPI but requires significantly longer time to sniff for leaks and conduct Hi-Flow enclosure measurements on a component by component basis. In certain cases, and with the ideal wind conditions, MPI survey could be done outside of the facility fence line and does not require site access. Depending on the objective and accessibility of roadways around the facility of interest, each type of measurement method can be successfully employed.

Temporal Analysis of Compressor Emission Rate

During intensive survey visits to three CNG sites, the research team was onsite long enough to conduct multiple measurements on four compressor units, more specifically the crank case vents, as they transitioned from operating to non-operating modes and vice-versa. As a result, an opportunistic temporal analysis of the emission profiles could be conducted on these compressors. Past studies have indicated that there is a large temporal variability in emission rates of natural gas facilities with compressor units [(Thorpe, A. K. et al 2019) (Subramanian, et al. 2015) (GSI Environmental Inc. 2019)].

At site 1, the research team collected 21 Hi-Flow sampler measurements on the single compressor unit for nine hours (Figure 28). Each Hi-Flow measurement takes roughly two minutes, so the measurement represents the mean emission rate during the period. Figure 28 shows the emission rate time series of the compressor. The measurement location was fixed at the crank case vent of the compressor unit which was by far the biggest source of emissions from this unit. The compressor was triggered to operate briefly from 8:25 to 8:35 AM and one measurement was taken during this period. The emission rate experienced a significant increase when the compressor unit was operating compared to non-operating mode. This observation is in line with the estimate by EPA Natural Gas Star that the best-case scenario emission rate for a reciprocating compressor packing system is no fewer than 11.5 scfh (U.S. EPA 2016). Since only one 2-minute measurement was taken in the 10-minute window, the peak emission rate might not have been captured. Higher frequency measurements would be needed to fully understand the emission behavior and the integrated emission rate over the operating period. Once the compressor switched to non-operating mode, the emission rate gradually tapered off over a period of two hours before getting close to non-detectable levels. It can be hypothesized that high pressure gas built up in the rod packing crank case and required time to slowly vent off until residual gas pressure was relieved. The emission rate for the first data point in the time series indicates that the compressor had likely operated during the two hours prior to beginning the measurement, therefore had not yet completely reached the low levels experienced later in the day. Pressure data from the time window was not obtained from the operator to verify the rise and decline in system pressure.

Figure 28: Emission Rate Temporal Analysis of a Compressor at Site 1

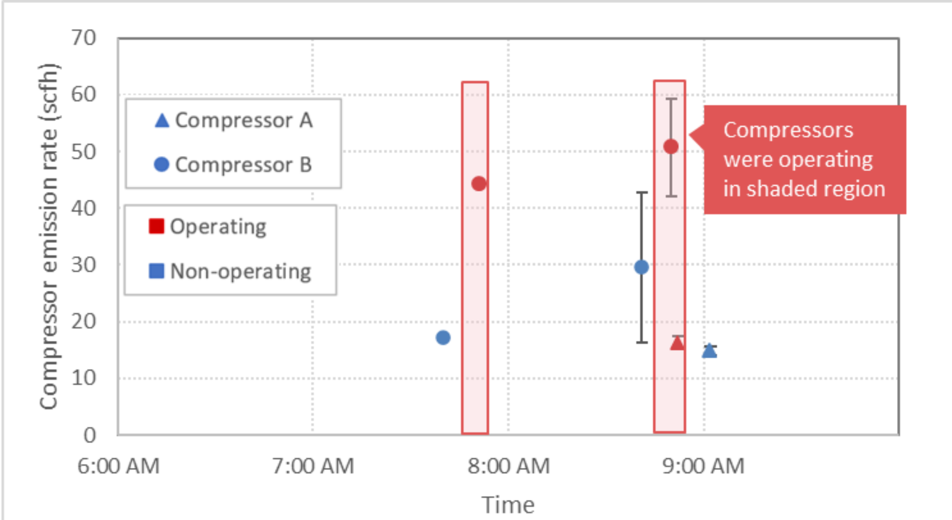


The red shaded box delineates the time period that the compressor was operating. Red markers indicate measurements whilst the compressor was operating, while blue markers indicate measurements on a non-operating compressor.

Source: EPRI

At site 2, the team was able to collect multiple data points on two compressor units (referred to as compressor A and compressor B) which were both operating for brief periods during the intensive survey process (Figure 29). In contrast with site 1 which had numerous measurements, only 6 measurements were taken over a period of fewer than two hours for site 2 so there was less information available to establish a trend in the emission rate. Similar to site 1, the compressor B emission rate increased during compressor operation and quickly came back down when the unit stopped running as observed in Figure 29. The decrease in emission rate was not as drastic as site 1 as the compressor may not have blown down all the pressure in the crank case before the unit was triggered to run again. The measurement for compressor A was likely taken at the tail end of the operating period hence there was no clear difference between the blue and red points.

Figure 29: Emission Rate Temporal Analysis of Two Compressors at Site 2

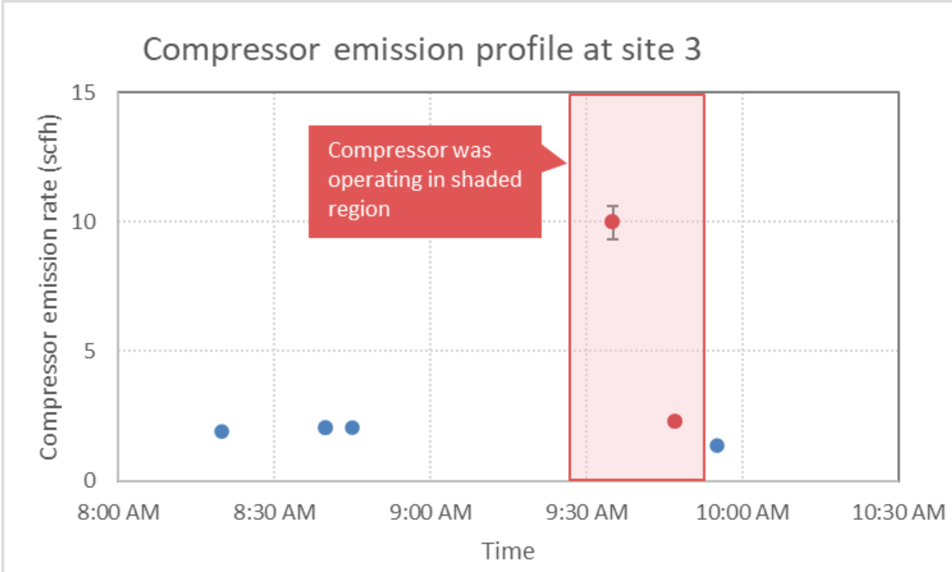


The red shaded box delineates the time period that the compressor was operating. Measurements on compressor A and B are shown as triangles and circles respectively. Red markers indicate measurements whilst the compressor was operating, while blue markers indicate measurements on a non-operating compressor.

Source: EPRI

At site 3, the same observation at the first two sites can be made as the emission rate increased during compressor operation. The difference here was that the compressor unit was operating for a longer period, close to 30 minutes, compared to the first two sites and the team was able to complete two measurements during this time. The second measurement, shown as the second red point on Figure 30, indicates that the emission rate had dropped even when the compressor was still operating suggesting that the spike may not extend for the entire period of operation. A higher frequency and continuous methane monitoring system would be needed to verify this observation.

Figure 30: Emission Rate Temporal Analysis of a Compressor at Site 3



Red shaded box denotes period during which compressor was operating. Red markers indicate measurements whilst the compressor was operating, while blue markers indicate measurements on non-operating compressor.

Source: EPRI

Given the limited amount of data in the temporal analysis, it is difficult to draw a definitive conclusion, but the implication of this finding is that the number of times a compressor switched from non-operating to operating could have an impact in the overall compressor emission rate. Other factors such as the size, pressure of the storage vessels, and station throughput volume could affect the compressor operating instances as well.

Given the short duration of the operating modes and associated rapid change in emission profile observed in this study, a possible topic for future study is to install systematic and persistent high-frequency methane monitoring systems at compressor units.

Compressor Emission as a Function of Compressor Characteristics

Previous studies have suggested that emissions at CNG stations will largely be associated with the compressor systems and three factors largely govern leak and vent presence and quantity at these type of sites– the type of compressor system, compressor age and how often it operates. Maintenance history may also play a role. Compressor characteristics data on a subset of the visited compressors were obtained from the operators and a simple linear regression analysis was performed to determine if relationships existed between these variables and emission rate.

The characteristics considered for the regression analysis includes time since last compressor rebuild (compressor age), compressor horsepower, suction pressure, and throughput volume. The type of compressor system was uniform for all the compressors visited and frequency of compressor operation was not easily determined when the team was not on site and was excluded from the analysis. The operating mode of the compressors during measurements is used to further stratify the dataset since operating mode is believed to have a major impact on emission rate. In the regression charts below, each point represents a single compressor unit.

However, since some of the compressors were measured in both operating and non-operating modes, some of the points could refer to the same compressor unit.

Only 19 of the 42 compressors visited showed emissions and could be included in the regression. And for only one out of the 19 stations, the research team was not able to retrieve pertinent compressor information from the operator. The emission rates shown in the charts include imputed values for emissions that were below the quantification limit but were detectable.

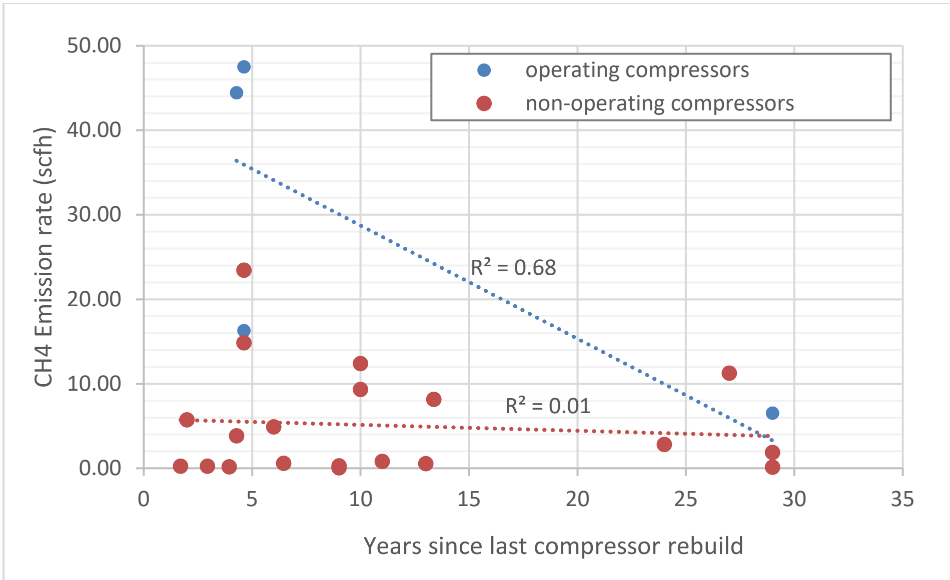
Figure 31, Figure 32, and Figure 33 display the relationship between the individual parameters with the compressor emission rate stratified by operating mode. No strong correlation was observed between emission rate and time since last rebuild (compressor age) and horsepower for compressors in non-operating modes as shown by the low R-squared values on Figure 31 and Figure 32. On the other hand, operating compressors' emission rates exhibited a negative correlation with time since last rebuild and horsepower; though the time since rebuild relationship was strongly driven by only a single point. The trends observed for the two regression charts are slightly negative which was counter-intuitive and could be due to scatter in the data and low number of data points. Intuitively, the longer the period between the last compressor rod packing ring and piston rods replacement (and thus potential for breakage or degradation due to high use) and the greater the horsepower, the higher the expected compressor emission rate. Operating horsepower is linked with the amount of gas delivered at fixed pressure and thus could impact methane emissions. Due to the small number of data points, the research team did not have a high degree of confidence in the slope of the regression lines for operating compressors.

Slightly positive correlations were observed for the regressions between emission rates and suction pressure in both compressor operating modes as shown in Figure 33. Suction pressure is the initial pressure in the compressor's cylinder and is typically lower than the pipeline supply pressure as gas undergoes filtration before entering the compressor. The authors hypothesize that higher suction pressure may lead to a higher-pressure gradient between the rod packing and the ambient atmospheric pressure, which in turn could lead to increased fugitive emissions per unit time due to the movement of gas from areas of higher pressure to areas of lower pressure.

At the same time, higher suction pressure could reduce the time a compressor needs to bring gas to the desired discharge pressure. With shorter operating duration, the overall operating emissions are expected to decrease. This relationship is not shown since continuous measurement is needed in order to characterize the overall operating emissions of compressors.

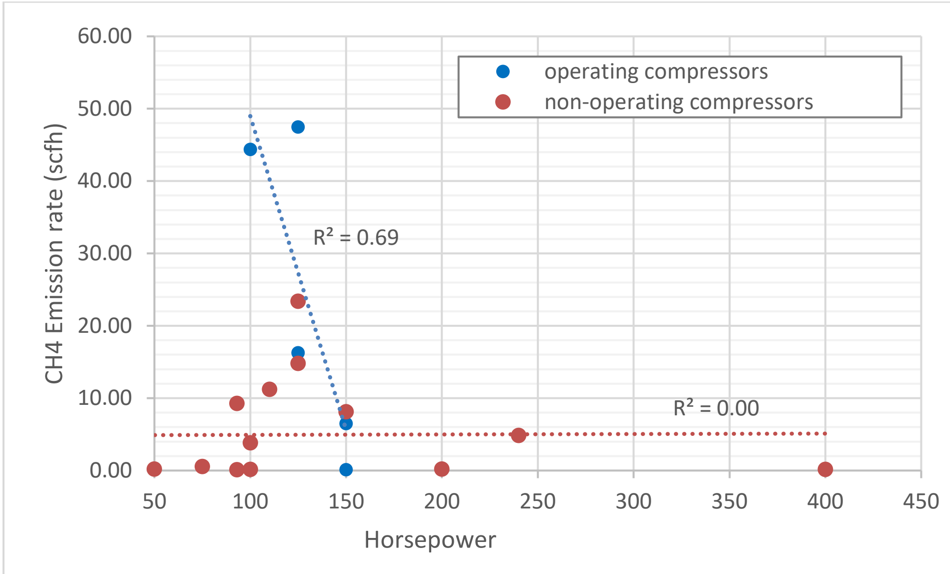
The scatter observed in the data in Figure 33 could be attributed to several reasons. First, compressor operating characteristics such as discharge pressure and temperature were not known, and they could have a larger effect on the compressors' operating emissions compared to suction pressure. Additionally, for non-operating emissions, the duration from the last operating mode was not known. Rod packing emissions may only reach a steady state hours after transitioning from operating to non-operating mode and this could add to the variability in the data observed. Mean monthly and daily station throughput volume data was obtained for a subset of the stations visited and was correlated with station compressor emission rates. Daily station throughput is more specific to these measurements as it is the approximate throughput for the day of station visit whereas monthly throughput volume is throughput for the month of visit.

Figure 31: Compressor Emission Rate as a Function of Time Since Last Compressor Rebuild



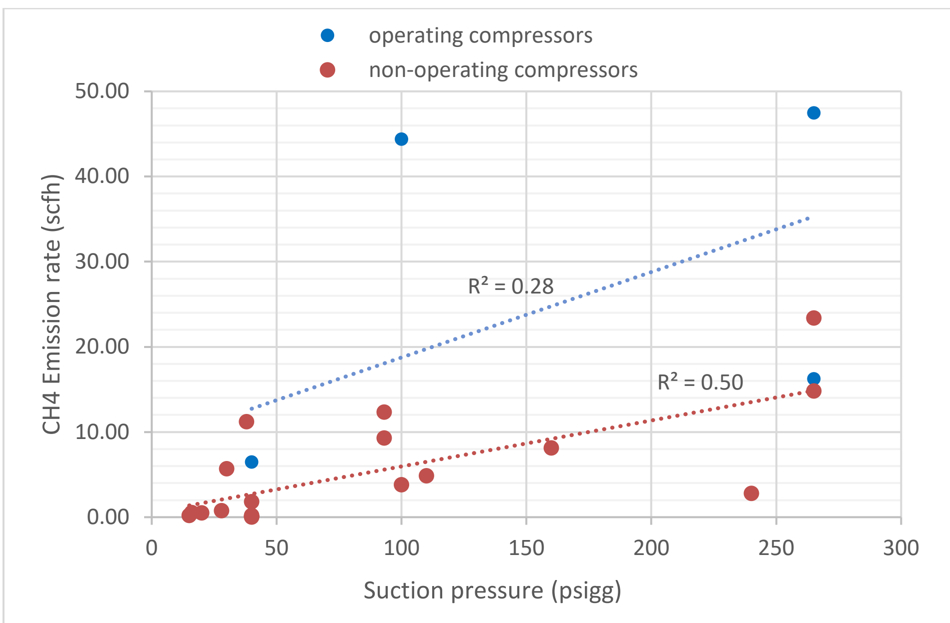
Source: EPRI

Figure 32: Compressor Operating Emission Rate as a Function of Compressor Horsepower



Source: EPRI

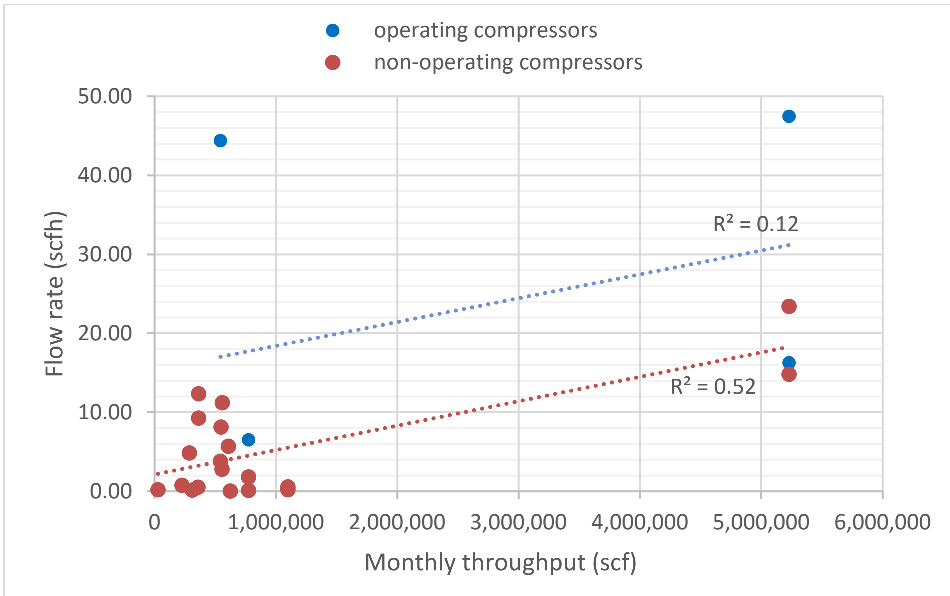
Figure 33: Compressor Emission Rate as a Function of Compressor Suction Pressure



Source: EPRI

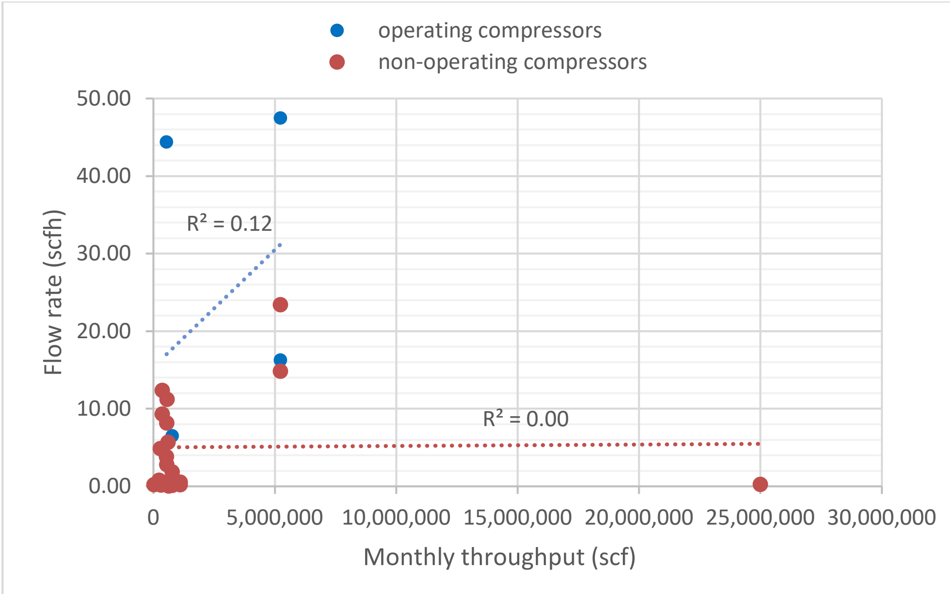
Considering that compressor operating time is directly related to station throughput volume, higher station throughput is expected to increase emissions both when the compressors are operating and non-operating. When a compressor operates longer to deliver the required volume of gas, the rod packing system spends more time at higher pressure, leading to a higher amount of gas lost. Secondly, longer compressor operation may lead to higher wear and tear on compressor components, potentially compromising its ability to seal in gas and resulting in higher emission rate even when the compressor is non-operating. The regression charts in Figure 34 and Figure 36 support the hypothesized positive relationship between throughput volume and compressor emission rate in operating mode. When data from a high throughput station is included (Figure 35 and Figure 37), there is no correlation between compressor emission rate in non-operating mode and throughput volume, presumably because other factors such as equipment age and maintenance practices could also impact emission rate. No significant difference is observed between the regressions with monthly and daily throughputs.

Figure 34: Compressor Emission Rate as a Function of Monthly Station Throughput Volume Without Throughput Station



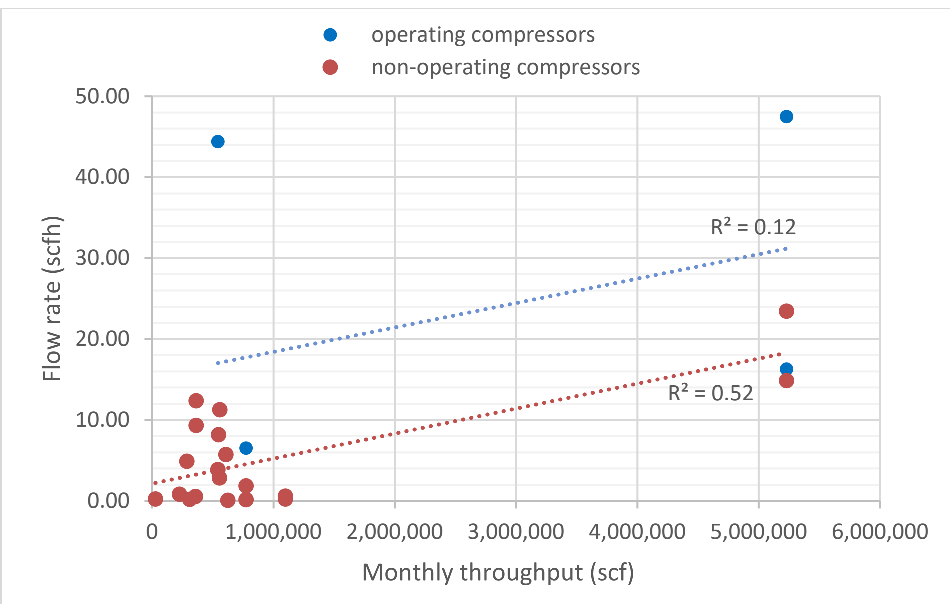
Source: EPRI

Figure 35: Compressor Emission Rate as a Function of Monthly Station Throughput Volume



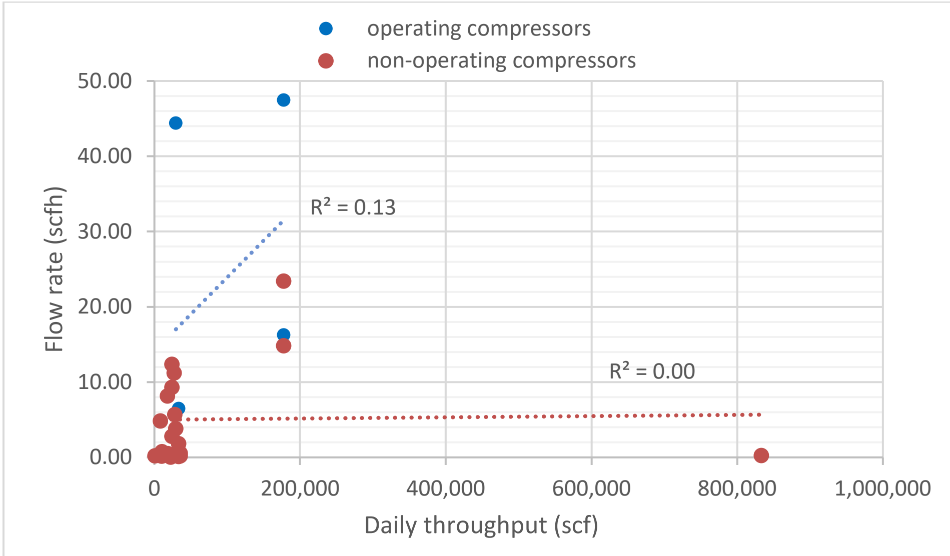
Source: EPRI

Figure 36: Compressor Emission Rate as a Function of Daily Station Throughput Volume (Without High Throughput Station)



Source: EPRI

Figure 37: Compressor Emission Rate as a Function of Daily Station Throughput Volume



Source: EPRI

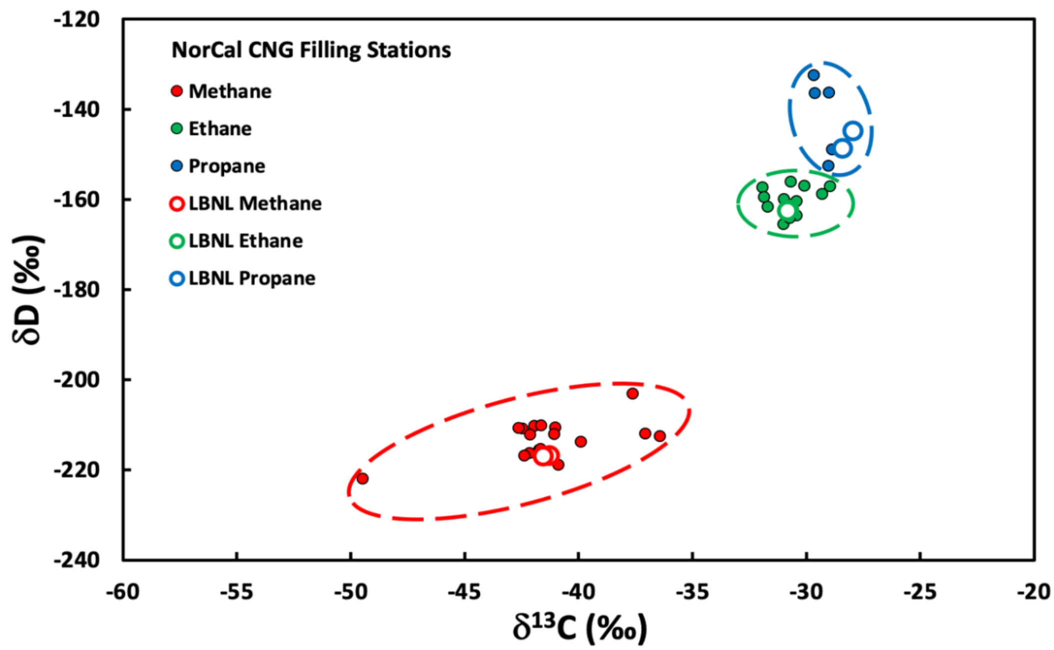
Stable Isotopic Composition of Emissions

A total of 43 emission point samples was collected for stable isotopic analyses including eight from stations in southern California and 35 from stations in northern California. Stable isotopic analysis provides confirmation that the natural gas measured was thermogenic (that is, from the natural gas supply) as opposed to biogenic. The isotope data for all samples with measurable concentrations of methane, ethane and propane (~1000 ppm for the analytical technique used) are included along with the concentrations of the different components of the natural gas.

The data for samples from Southern California are listed in Table D-2 in Appendix D. Only the isotopic composition of methane in the samples were analyzed. The individual results are variable beyond the analytical uncertainty (±10‰ for δD and ±1‰ for δ13C). The average and standard deviations across all 8 samples for δD were -176.8±5.4‰, and for δ^{13}C were -43.3±9.7‰. The research team has observed similar variability in leaks from other types of facilities (a power plant and a food processing plant) during this project. The authors believe this variability is caused by isotopic fractionation related to the high-pressure gas flowing through small leak points on the equipment and/or the field sampling method which used negative pressure to draw gas from the emission points which were not fully enclosed by the sampling tube. All of the emissions from these sites were classified as leaks, as defined earlier in this chapter.

Nineteen (19) of the 35 samples collected from northern California had measurable concentrations of hydrocarbons and the results for those samples are given in Table D-3. In Appendix D. The individual results were again variable beyond the analytical uncertainty; though the methane average and standard deviations across all 19 samples for δD were -213.9±4.1‰, and for δ^{13}C were -41.3±2.6‰. Data for two samples of the natural gas supply to the isotope lab at LBNL's facility in Berkeley, California, that were taken during the same week as the northern California samples from the natural gas stations, are also included in the table. It is assumed here that the LBNL natural gas represents a reasonable baseline for the natural gas supply at the fueling stations. The data for the fueling stations and the LBNL natural gas are plotted on Figure 38. As with the emission samples from the southern California fueling stations, the data for the isotope data are variable, especially for the $\delta^{13}C$ values of methane. However, they do cluster around the isotopic values of the LBNL natural gas, suggesting that the emissions compositions can likely confirm that they are derived from the natural gas supply to the CNG facilities. This suite of samples was classified as a mix of leaks and compressor emissions. The isotope signatures for the methane leak values can be summarized as -213±5‰ for δD and -41±4‰ for $\delta^{13}C$; for the compressor values, -214±3‰ for δD and - 41±2‰ for $\delta^{13}C$. One observation of note occurred at Site D, where one sample was taken from the crankcase vent of a compressor with the compressor off, then two more once the compressor was running. The isotopic signatures were essentially the same, although the methane concentration dropped after operation began.

Figure 38: Isotopic Compositions of Natural Gas Emissions from Northern California Fueling Stations



These fueling stations are with the compositions of natural gas from LBNL taken during the same time period. Ellipses encompass the clustered ranges of measured isotopic composition.

Source: EPRI

CHAPTER 4: Knowledge Transfer Activities

Project results are disseminated through the final report, a final presentation that covered both a high-level summary for a wide audience as well as technical detail, and the creation of executive summaries of the results for publication in EPRI document(s).

Public dissemination of the preliminary results throughout the course of the research was limited due to the nature of site confidentiality needs. It was required that project results were reviewed by project site partners to confirm no confidential material remained before dissemination to other parties. However, additional dissemination will occur as soon as the final report is released.

Key Stakeholders

The primary stakeholders for the project include natural gas and electric utilities, large industrial end users of natural gas, energy sector regulators at the state or air quality management district level, and research organizations investigating fugitive methane emissions. These entities are able to access the final reporting materials, and EPRI is willing to provide briefings to any entity with interest.

In particular, investor-owned (for example Pacific Gas and Electric Company, San Diego Gas & Electric, Southern California Edison), municipal (for example Sacramento Municipal Utility District, Los Angeles Department of Water and Power), and other utility companies have the option of obtaining findings through the publicly available documents or through their EPRI membership participation in meetings and briefings. Individual meetings can also be established.

Type of Activities

Over the course of this research, a number of meetings occurred with the six host companies that participated in the monitoring study. These included real-time updates during the campaigns and discussions throughout the project, in-person meetings, conference calls and webcast presentations. The range of information provided included measurement approaches and instrument details, results from other independent research in this topical area that are relevant to the campaigns and data interpretation, and data analysis techniques relevant to the project topic, for example. An additional series of technical transfer activities was performed to assist one host company participating in the study as they communicated on the topic of methane and natural gas emissions with their local stakeholders. Results from each measurement campaign were also provided to the host sites in the form of "Host-Specific Interim Measurement Reports" so they have a company-specific record of the findings from their sites, including details protected under confidentiality agreements.

Regular interim updates were provided to CEC staff and members of the technical advisory committee (TAC), which includes Southern California Gas Company (SCG), NGV America, and NASA's Jet Propulsion Laboratory (JPL). TAC members performing their own research on related areas considered incorporating lessons learned from this project into their own activities, some ongoing in parallel. EPRI also participated in an interview with a reporter from the Los Angeles Times, in support of public newspaper reporting on the topic of methane emissions from energy and electricity systems.

EPRI and the research team presented or plan to present results from this project at technical conferences (for example, American Geophysical Union Annual Meetings, Air and Waste Management Conference, or methane Connections). EPRI also hosts international, national, state, and regional conferences and symposia that range from highly technical to broader overviews and implications of scientific research in the policy and market arenas. These events offer another opportunity for the project results to be shared with a broad audience. Stakeholders that will be targeted include academic and national laboratory researchers (for example the University of California), consultants such as monitoring instrument vendors), government entities (for example the California Public Utilities Commission), and non-governmental organizations.

Use

Results from this project will improve scientific understanding of GHG emissions (from stack and fugitive sources) from large industrial end users, such as power plants, food processing plants, and compressed natural gas (CNG) vehicle fueling stations, that can be used as guidance by researchers, government agencies or funding agencies for relevant scope and scale of any future studies. The emission results and lessons learned from use of multiple measurement platforms can be used to improve the effectiveness of company operations and maintenance and LDAR programs.

Sharing the results outside of California benefits the state through increased visibility of CEC and state agency efforts. Broader dissemination of the potential for emission monitoring improvements to be implemented will also occur, which will further improve emissions estimates and subsequently reduce GHG impacts, which do not stay within state borders.

CHAPTER 5: Conclusions/Recommendations

This project used a multi-tiered measurement approach to screen for, and then quantify, methane emission rates from two types of high throughput industrial natural gas customers (power plants and a food processing plant) and compressed natural gas fueling stations across the state of California. The multi-tiered approach at the high natural-gas throughput sites included aircraft-based estimates of facility-scale emissions, on-site measurements at the point of specific emissions or leak points with handheld monitors and an unmanned aerial vehicle, on-site measurements with a ground-based vehicle to span the spatial scale between individual emission points and whole-facility emissions, and combustion stack measurements with extractive spectroscopy. Nitrous oxide emissions were also measured at the combustion stacks. Multi-tiered measurements at the compressed natural gas (CNG) fueling stations included monitoring by handheld devices and a ground-based mobile platform. Aircraft sampling at the fueling stations was not possible due to uncleared airspace, the need for very low flight altitudes, and the comparatively lower emission rates. In addition, a series of GIS-based maps of total emissions from primary sectors (that is, oil and gas production, processing, transmission, and distribution), as well as emission estimates for post-meter consumption, across the state were created across the state of California.

The results provide a preliminary assessment of emissions to inform future studies and do not provide sufficient information to enable a categorical assignment of emissions factors. This is due to several reasons, including a limited sample for the high throughput industrial sites (two power plants and a food processing plant). Further, the mix of CNG sites sampled may not reflect the real proportionality of site type, site characteristics or operational profiles present in the state of California, despite the larger number of sites in that category. The data also do not characterize persistence of transient emissions, or the temporal average of sporadic emissions. However, these results are very useful for:

- depicting the range of emission types, magnitudes and drivers that may exist at these facility types, as based on very detailed site surveys;
- determining which emissions monitoring technologies are most useful for each of the emission point types (for example, fitting and flange leaks (components), equipment emissions (for example, compressors), stacks);
- providing on-site data to compare against remotely sensed or estimated data, which can inform the potential limitations of remotely-sensed data;
- and informing the design of future research studies, from specific knowledge gaps on emissions from various site types and how to best measure those, to ways to improve host site recruitment, contractual requirements and other metrics to increase participation of industrial sites in CEC research projects.

Power Plant/Food Processing Facility Conclusions

For the combined cycle power plant visited on site and by aircraft in this study (Facility 1), aircraft measurements of CO_2 emissions were generally similar to stack measurements and within 14 percent of the values reported to GHGRP. Measured methane and nitrous oxide stack emissions were larger than values reported to GHGRP. However, methane stack emissions from this site were closer to GHGRP values than was observed for methane emissions from other power plants in recent studies. Total facility methane emissions were estimated at <1 kg/hr. For the food processing facility in this study (Facility 2), aircraft measurements of CO_2 emissions were consistent with boiler stack measurements but were one to six times higher than GHGRP reported values due to the site visit being scheduled during a busy operational season. No methane emissions above the detection limits were observed by aircraft or through stack measurements. Total Facility 2 methane emissions were estimated at <1 kg/hr.

Combustion-related GHG emissions from both power plants in this study depended on the operating mode and instantaneous capacity factor of the facility. Stack data from the two power plants showed methane, CO_2 and nitrous oxide emissions generally increased with load, and higher rates of methane were observed for short periods during startup versus other modes.

Ground-based vehicle measurements can be useful for estimating fractions of facility-wide methane emissions (for example, aggregated from individual emission points, and/or at the equipment scale) and provide higher time efficiency compared to component-level emissions using handheld instruments at the cost of higher uncertainty. However, emission sources located higher than the gas sampling inlet points on the vehicle, such as vent stacks, are likely not captured. Aircraft measurements provided facility-scale emissions estimate and are highly efficient but are prone to higher uncertainty and are more susceptible to interference from nearby confounding sources of methane such as dairy farms or landfill.

Due to the very low stack emissions of methane at the sites, fugitive methane emissions from component leaks at the two combined cycle power plants and the food processing plant were significant in comparison. Along with operational differences during the campaigns as compared to annual averages, this finding could help explain discrepancies between measured facility-wide methane emissions and the methane emissions reported to GHGRP which only requires combustion emissions.

Fugitive methane emissions at all the sites monitored in this study were dominated by a few large sources (heavy-tailed distribution). Identifying and mitigating these emissions early could be particularly effective. The number of emission points per site ranged from 18-37 (out of potentially thousands of components present).

Most individual leaks or emission points at the three intensive sites were very small. In total at a given site, the emissions represented substantially less than 1 percent of natural gas throughput at the sites (for example ~0.0007 percent of average hourly fuel use across the entirety of a recent prior year for Facility 1; and 0.008 percent of the facility's natural gas throughput for the month of visit for Facility 2). Many of these emission points were easily fixable, and occasionally the hosts were able to do so while the team was on site, despite no requirement to mitigate. Several of the observed leaks across all sites were at locations that would require shutting the facilities if mitigation was found to be necessary. If such an action was pursued without other reasons (such as during annual maintenance downtime), this could result in substantial loss of revenue, reduced grid stability and increased loss of methane as the piping across the plants was vented. As a result, the host facilities for which this was observed developed corrective work orders to address any observed leaks, even if very small, in the next planned outage in an abundance of precaution.

CNG Station Conclusions

As the number of natural gas vehicles in California increases to meet GHG emission reduction targets and clean vehicle standards, it is important to gain a more complete understanding of methane emissions from CNG fueling stations. In this study, the research team visited 48 unique CNG stations throughout the state of California and conducted intensive surveys with handheld equipment on 27 of the stations, in addition to performing surveys with a ground-based vehicle-mounted analyzer on a subset of the stations. Station level total emission rates followed a heavy-tailed distribution, suggesting that the top few emitting stations were responsible for a large majority of the emissions. Based on discussions with compressor engineers, the station level emission rates include an assumption that emissions quantified in non-operating compressor modes reflected a continuous emission rate, which is a conservative approach and may overestimate emission rates.

Analysis of individual emission point locations within each of the stations reveals that the mean number per CNG station was 6.3 (out of potentially hundreds of components present), and the emission rate distribution within each station also followed a heavy-tailed distribution. As operators continue to mitigate methane emissions, one reasonable approach is to prioritize the highest emitters to bring about immediate large abatement. The compressor was found to be the largest source of emission within a station and its emission rate was significantly impacted by the compressor mode, with a large increase observed in the initial periods of operation and a subsequent tapering off during and after operation. Improved understanding of the role of intentional (for example, vents designed in the compressor) vs. unintentional emissions (that is, leaks) from compressors as they vary across compressor design would be valuable. Future studies could focus on collecting high-frequency methane monitoring data during the compressor transition period to enhance understanding of its emission profile and provide a robust time-weighted mean of compressor emissions according to operational mode.

Emissions Mapping Conclusions

Building upon previous studies, this study also provided updated spatially explicit bottom-up estimates of non-combustion (that is, fugitive, vented, flared) methane emissions from non-combustion primary sectors (oil and natural gas production, transmission, processing, distribution) and post-meter natural gas consumption (both combustion and non-combustion activities) in California. This study also developed gridded natural gas-related non-combustion CO_2 emissions and nitrous oxide emissions based on EPA GHGRP. This work improves the spatial representation of the distribution and consumption sectors by developing a high-resolution natural gas consumption map across California for use in emissions estimation, whereas previous work used population density as a proxy for natural gas consumption. This study's methane emission estimates for the primary sectors are ~50 percent lower than those from previous similar studies. This change is attributed to the revised emission factors from the EPA's GHG inventory used in this study, as well as a recent factor of three decrease in non-associated (dry) gas production. A full reporting of the methods and results from this project task can be found in Appendix E.

CHAPTER 6: Benefits to Ratepayers

This research delivered scientific advancements that support climate policy by providing improved understanding of the quantity and distribution of GHG emissions. Specifically, this research investigated specific site types and sectoral source categories that have previously been under-sampled. Results provide detailed surveys of emission points, magnitudes, and potential drivers from a variety of component and equipment types across several high throughput facilities and compressed natural gas fueling stations in California. The results from the regional aircraft sampling also provide some insight into the emissions from, and relative importance of, the monitored source categories, as based on multiple sites monitored within each category. The diversity of measurement instrument platforms used in this project provides greater context and detail on the emission profiles for each site as compared with previous studies that have relied on one measurement platform (that is, aircraft). Project results have improved scientific understanding of GHG emissions (derived from stack and fugitive sources) from high natural gas throughput facilities (two power plants and a food processing plant) and compressed natural gas (CNG) vehicle fueling stations, that can be used as guidance for relevant scope and scale of any future studies.

Further, this work provides benefits to ratepayers that accrue from leak detection and repair. The emission results and lessons learned from use of multiple measurement platforms were conveyed to the host sites and a broader range of electric utilities to make company operations and maintenance and LDAR programs more effective. Resulting changes will be implemented over future years. Additionally, the leak survey and quantification activities performed by the research team alerted facility operators to several needed equipment repairs of which they were not previously aware; a combination of immediate and scheduled repairs were undertaken.

Identifying and repairing natural gas leaks can improve facility reliability by reducing the risk of unexpected fuel supply interruptions, equipment failures (that is, regulators, valves, meters, flanges, and so on), or explosions. None of the emission points identified during the research team's three measurement campaigns thus far have presented a major risk to safety or operational continuity, but targeted LDAR activities at other industrial facilities based on the insights determined in this project could identify and mitigate potential risks to system reliability. This in turn will lead to further reduced GHG emissions, improved worker and public safety, reduced risk of damage to infrastructure, improved system efficiency, reduced natural resource loss, and lower net costs to California ratepayers.

LIST OF ACRONYMS AND ABBREVIATIONS

Term	Definition
AGL	Above ground level
AMPD	Air Markets Program Data
AWP	Alternative work practice
BDL	Below detection limit
C_2H_8	Ethane gas
CARB	California Air Resources Board
CCEEB	California Council on Environmental and Economic Balance
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring System
CGI	Combustible gas indicator
CH_4	Methane gas
CNG	Compressed natural gas
CO_2	Carbon Dioxide
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
FAA	Federal Aviation Administration
FLIR	Forward looking infrared
FTIR	Fourier transform infrared
GC	Gas chromatograph
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Report Program
GIS	Geographical Information System
GTI	Gas Technology Institute
GWP	Global warming potentials
HP	Horsepower

Term	Definition
hr	Hour
HSM	High sensitivity mode
IOU	Investor-owned utilities
kg	Kilogram
Lb	Pounds
LBNL	Lawrence Berkeley National Laboratory
LDAR	Leak detection and repair
LNG	Liquefied natural gas
M	Meters
MCT	Mercury cadmium Telluride
MLE	Maximum likelihood estimation
MMBtu	One-million British Thermal Unit
MPI	Mobile plume integrator
NASA JPL	National Aeronautics and Space Administration Jet Propulsion Laboratory
NOx	Nitric oxides
N_2O	Nitrous oxide
OGI	Optical gas imaging
PPM	Parts per million
PPMV	Parts per million volume
PSIG	Pounds per square inch – gauge
REF	References
ROS	Regression on order statistics
SB	Senate Bill
SCFH	Standard cubic feet per hour
SCR	Selective catalytic reduction
SCG	Southern California Gas Company
TAC	Technical advisory committee
UAV	Unmanned aerial vehicle
VPDF	Vapor pressured deficit
VSMOW	Vienna Standard Mean Ocean Water

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SITE RECRUITMENT FLYER

Figure A-1. Site Recruitment Flyer

ELECTRIC POWER RESEARCH INSTITUTE (EPRI) - PROJECT PARTNERSHIP NOTICE

GREENHOUSE GAS (GHG) EMISSIONS MEASUREMENTS AT CALIFORNIA INDUSTRIAL FACILITIES USING NATURAL GAS

EXECUTIVE SUMMARY

The Electric Power Research Institute (EPRI) has received funding from the California Energy Commission (CEC) to help industrial end users of natural gas identify and quantify methane leaks with a multi-tiered measurement approach. EPRI is seeking facility owners/operators who are interested in participating to obtain actionable data on leak detection and potential repair/mitigation strategies. Your participation in this project will contribute to a more complete understanding of GHG emissions in California and support efforts to achieve corporate sustainability objectives.

HOW WILL THIS PROJECT BENEFIT YOU?	▪ **Identification and mitigation of gas leaks will reduce fuel losses, resulting in cost savings and improved operational efficiencies.** ▪ **Improved safety of workers and the public living near your facility** ▪ **Demonstrate commitment and progress toward achieving corporate sustainability objectives** ▪ **Reducing gas leaks and other sources of GHG emissions will reduce compliance costs under California's carbon trading program and will provide more accurate data than formula-based GHG data** ▪ **The lessons learned during the leak detection process will be used to refine and improve future emission reduction programs.** ▪ **Work with a team of experienced methane researchers *(Gas Technology Institute, Montrose Air Quality Services, Scientific Aviation, Lawrence Berkeley National Laboratory, Electric Power Research Institute)***
WHAT ARE THE MAIN OBJECTIVES AND TASKS?	• Collect facility-level emissions data from aircraft-based measurements • Collect "fence line" emissions data from a mobile laboratory built into a car • Collect equipment and sub-equipment level emissions data using hand-held instruments like infrared cameras and combustible gas indicator • Collect stack emissions samples for methane and nitrous oxide (N_2O) • Obtain facility natural gas usage data, emissions reporting data, and facility equipment information to provide context for and interpret the emissions
WHAT DOES PARTICIPATION COST?	▪ There is **<u>no cost</u>** to participate in emissions monitoring campaigns ▪ Facility data collected during field measurement campaigns will be made available to the owner/operator free of charge ▪ Depending on the terms of site access agreements (i.e., need for full-time supervision) some on-site staff time may be needed to provide researchers with safety instructions, supervision, orientation and pre/post-visit coordination
WILL THE FACILITY REMAIN ANONYMOUS?	YES – The solicitation explicitly states that the data collected from surveyed facilities will be presented in a way that ensures the identity of participating facilities will remain anonymous. Emissions data will be made available to facility owners/operators to inform internal decisions on detection and repair. Any mitigation would be voluntary and does not need to be reported.
CONTACT	For more information about this project please contact EPRI's research team: ▪ Stephanie Shaw, Principal Technical Leader, Energy & Environment 650.855.2353 | sshaw@epri.com ▪ Ben Kaldunski, Engineer Scientist III, Energy & Environment 650.855.8526 | bkaldunski@epri.com

ELECTRIC POWER RESEARCH INSTITUTE

Additional Details of Intensive Central Site Monitoring Stations

Facility 1

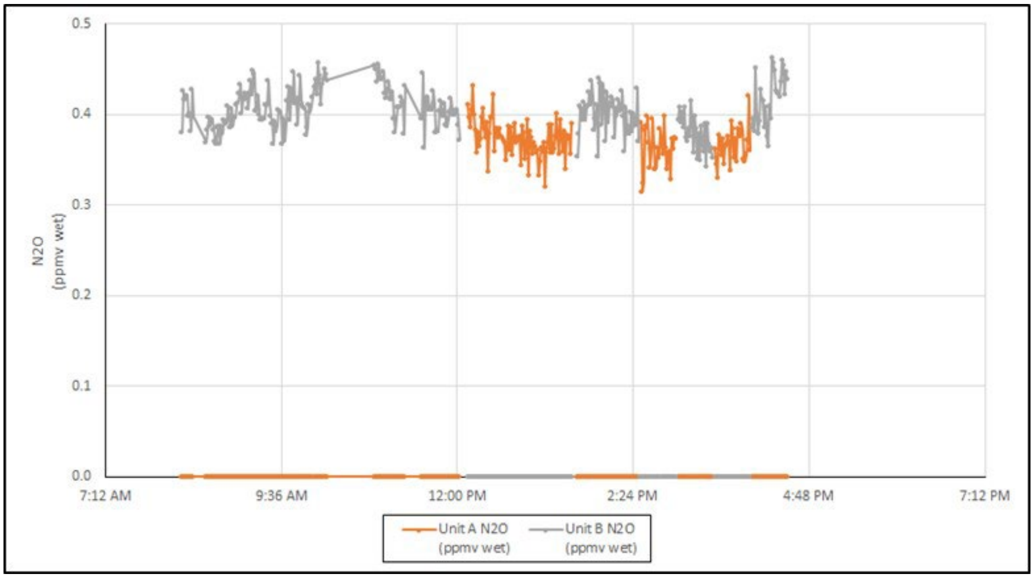
Table B-1. Leaks Identified and Quantified at Facility 1

Leak #	Leak Component	Location/Description	Mean Emission Rate (kg/hr)	Mean Emission Rate (scfh)
1	Open-ended line	Gas inlet	0.026	1.34
2	Open-ended line	Gas inlet	0.017	0.87
3	Valve	Gauge	0.004	0.19
4	Valve	Ball valve	0.018	0.92
5	Valve	Plug	0.097	5.07
6	Valve	Conditioning skid	0.028	1.46
7	Valve	Conditioning skid	0.005	0.24
8	Valve	Heater	0.032	1.68
9	Flange	Conditioning skid	0.005	0.24
10	Valve	Near conditioning skid	0.026	1.38
11	Valve	Near conditioning skid	0.017	0.88
12	Flange	Conditioning skid	0.001*	0.08*
13	Threaded connection	Plug	0.042	2.18
14	Threaded connection	Conditioning skid	0.001*	0.08*
15	Threaded connection	Conditioning skid	0.004	0.21
16	Valve	Heater	0.009	0.46
17	Valve	Heater	0.010	0.53
18	Open-ended line	Vent, conditioning skid	0.046	2.40
Total			0.389	**20.21**

***Emission sources below the FLIR detection limit are assigned a value of 0.08 scfh or 0.001 kg/hr**

Source: EPRI

Figure B-1. Example of Facility 1 Raw Stack N_2O Measurements



Source: EPRI

Since stack measurements have higher granularity compared to aircraft data, stack measurements were aggregated based on the two time windows that aircraft flights were performed: between 8 am to 11 am (morning) and between 12 am to 3 pm (afternoon), whenever data was available. Considering that aircraft measurements usually lasted for 40 to 60 minutes, this approach assumes that stack emission rates did not change drastically during the 3-hour time window. Additionally, since only one stack could be measured at any time, results from individual stacks were extrapolated to the facility level by assuming that the other unit was operating at a similar load and emission intensity (emission rate per instantaneous load factor) as the unit being measured. This is a reasonable assumption since the facility has two main generating units with identical maximum capacities and both units generated similar CO_2 emission rates (± 3%) when normalized.

Table B-2. Summary of Aircraft Measurements Above Facility 1

Date	CO_2 Emission (kg/hour)	CH_4 Emission (kg/hour)	Laps	Wind Speed (m/s)	Min/Max Altitude (m)	Confidence
Day 1 (morning)	227,684 ± 35,430	49 ± 18	20	2.5	94 – 702	medium
Day 1 (afternoon)	155,075 ± 40,328	BDL	15	5.4	115 – 747	medium
Day 2 (morning)	72,916 ± 26,702	BDL	19	1.5	91 – 706	medium
Day 2 (afternoon)	216,241 ± 38,604	BDL	23	3.2	91 – 920	medium
Day 3 (afternoon)	182,716 ± 31,665	12 ± 6	19	4.5	100 – 729	high
Day 4 (afternoon)	141,300 ± 30,882	BDL	21	1.5	98 - 719	medium

Source: EPRI

Table B-3. Facility 1 measured and reported emissions

Time	Instantane-ous load factor	Aircraft CO_2 measurements (kg/hr)	% difference between aircraft and AMPD CO_2 data	% difference aircraft and GHGRP CO_2 data	Stack CO_2 emissions (kg/hr)**	Aircraft CH_4 measurements (kg/hr)	% difference aircraft and GHGRP CH_4 data	Stack CH_4 measurements (kg/hr)	Stack N_2O emissions (kg/hr)	% difference stack and GHGRP N_2O data
Day 1 (morning)	89%	227,684 ± 35,430	26%	56%	NA	49 ± 18	1600%	NA	NA	NA
Day 1 (afternoon)	97%	155,075 ± 40,328	-15%	6%	NA	BDL	NA	NA	NA	NA
Day 2 (morning)	92%	72,916 ± 26,702	-60%	-50%	195,479 ± 6,847	BDL	NA	0 ± 0	1.99 ± 0.10	563%
Day 2 (afternoon)	83%	216,241 ± 38,604	19%	48%	178,784 ± 434	BDL	NA	0 ± 0	1.65 ± 0.05	450%
Day 3 (afternoon)	79%	182,716 ± 31,665	2%	25%	167,783 ± 213	12 ± 6	317%	0.02 ± 0.08	1.72 ± 0.05	473%
Day 4 (afternoon)	95%	141,300 ± 30,882	-21%	-3%	NA	BDL	NA	NA	NA	NA
Average	88%	165,989 ± 34,257	-8%	14%	176,261 ± 8,750	BDL	NA	0.30 ± 0.15*	1.75 ± 0.10	483%

BDL = Below Detection Limit

NA = Not available

***The average in the last row refers to the mean of all stack data, including the times not covered by the specific times of aircraft measurement flights listed in the table.**

****Stack measurements at individual generating units are aggregated by the three-hour time window that defines morning (8-11 am) and afternoon (12-3 pm), and then extrapolated by assuming that the other unit was operating at the same capacity and emission intensity (emission per capacity factor) to arrive facility-level stack emissions.**

Source: EPRI

Table B-4. Facility 1 isotope data

Sample	Date Sampled	CO_2 $d^{13}C_{PDB}$ (‰)	CO_2 $d^{18}O_{PBD}$ (‰)	CH_4 $d^{13}C_{PDB}$ (‰)	CH_4 d^2H_{SMOW} (‰)	C_2H_6 $d^{13}C_{PDB}$ (‰)	C_2H_6 d^2H_{SMOW} (‰)
Natural Gas Supply							
Supply 1	Day 1			-42.3	-203	-30.5	-176
Supply 2	Day 1			-42.1	-202	-30.8	-176
Supply 3	Day 1			-42.4	-202	-30.7	-179
Leak Samples							
Leak 1	Day 3			-46.9	-200	-32.9	-183
Leak 2	Day 3			-38.6	-196	-29.6	-178
Leak 3	Day 3			-40.0	-200	-29.8	-178
Leak 4	Day 3			-42.4	-203	-30.6	-176
Airborne Samples							
Upwind 1	Day 2	-8.4	8.0	-55.3	bd		
Upwind 2	Day 2	-8.7	7.9	-49.8	bd		
Downwind/ plume1	Day 2	-6.4	9.8				
Downwind/ plume 2	Day 2	-6.5	10.1	-47.7	bd		
Downwind/ plume 3	Day 2	-8.0	8.3	-53.0	bd		
Downwind/ plume 4	Day 3	-6.7	6.6	-55.1	bd		
Downwind/ plume 5	Day 3	-6.5	9.9				
Downwind/ plume 6	Day 3	-7.2	9.0				

Upwind Background			
Ground level 1	Day 2	-6.4	7.2
Ground level 2	Day 3	-6.8	7.7
Stack Samples			
Stack A.1	Day 4	-37.3	37.3
Stack A.2	Day 4	-37.2	36.6
Stack B.1	Day 4	-37.3	36.0
Stack B.2	Day 4	-37.3	36.6
Stack B.3	Day 4	-37.4	37.3

Source: EPRI

Facility 2

Table B-5. Leaks Identified and Quantified at Facility 2

Leak #	Component Type	Location/ Description	Mean Emission Rate (kg/hr)	Mean Emission Rate (scfh)
1	Valve	Filter Skid	0.0199	1.04
2	Valve	Filter Skid	0.0013*	0.08*
3	Valve	Filter Skid -- valve packing	0.0013*	0.08*
4	Valve	Filter Skid -- valve body	0.0013*	0.08*
5	Valve	Filter Skid	0.0013*	0.08*
6	Meter	Boiler meter- strainer	0.0013*	0.08*
7	Fitting	Boiler meter– tee	0.0013*	0.08*
8	Valve	Boiler Meter	0.0026	0.13
9	Flange	Boiler Meter-- flange on valve	0.0030	0.15
10	Valve	Boiler Meter	0.0013*	0.08*
11	Threaded Connection	Boiler Meter- spacer 1	0.0013*	0.08*
12	Valve	Boiler A	0.0021	0.11
13	Threaded Connection	Boiler A – plug	0.0021	0.11
14	Regulator	Boiler A	0.0013*	0.08*
15	Valve	Boiler A	0.0013*	0.08*
16	Valve	Boiler A	0.0013	0.08
17	Fitting	Boiler A – coupling	0.0013*	0.08*
18	Fitting	Boiler A – elbow	0.0019	0.10
19	Flange	Boiler A	0.0053	0.28
20	Threaded connection	Boiler B – strainer	0.0013*	0.08*
21	Flange	Boiler B	0.0013*	0.08*
22	Fitting	Boiler B	0.0013*	0.08*
23	Threaded Connection	Boiler B – plug	0.0018	0.09

Leak #	Component Type	Location/ Description	Mean Emission Rate (kg/hr)	Mean Emission Rate (scfh)
24	Flange	Boiler C	0.0013*	0.08*
25	Fitting	Boiler C – coupling	0.0013*	0.08*
26	Fitting	Boiler C – coupling	0.0115	0.60
27	Fitting	Heater -- coupling	0.0013*	0.08*
28	Valve	Heater -- valve	0.0013*	0.08*
29	Valve	Heater -- valve	0.0013*	0.08*
30	Threaded Connection	Heater -- flex hose connection	0.0013*	0.08*
31	Threaded Connection	Heater -- flex hose connection	0.0013*	0.08*
32	Threaded Connection	Heater -- flex hose connection	0.0013*	0.08*
33	Fitting	Heater – roof	0.0013*	0.08*
34	Regulator	Ancillary boiler – regulator	0.19	9.69
Total			**0.271**	**14.22**

***Emission sources below the FLIR detection limit are assigned a value of 0.08 scfh or 0.0013 kg/hr.**

Source: EPRI

Table B-6. Summary of Aircraft Measurements Above Facility 2

Date	CO_2 Emission (kg/hr)	CH_4 Emission (kg/hr)	Laps	Wind Speed ($m\ s^{-1}$)	Min/Max Altitude (m)	Confidence
Day 1	21,648 ± 4,377	BDL ± 35	20	2.9	62 – 544	medium
Day 1	5,611 ± 8,391	BDL ± 19	23	2.8	77 – 763	medium
Day 2	12,957 ± 2,717	BDL ± 18	26	2.9	86 – 695	high
Day 4	17,016 ± 4,109	BDL ± 6	22	2.5	79 – 870	medium

Source: EPRI

Table B-7. Facility 2 Isotope Data

Sample	Date Sampled	CO_2 $d^{13}C_{PDB}$ (‰)	CO_2 $d^{18}O_{PDB}$ (‰)	CH_4 $d^{13}C_{PDB}$ (‰)	CH_4 d^2H_{SMOW} (‰)	C_2H_6 $d^{13}C_{PDB}$ (‰)	C_2H_6 d^2H_{SMOW} (‰)
Leak Samples							
Leak A	Day 2	10.5	3.5	-42.5	-183	-33.2	-155
Leak A	Day 3	-9.3	3.2	-50.2	-183	-34.7	bd
Leak B	Day 2	-23.0	4.7	-43.6	-189	-33.0	bd
Leak B	Day 3	-27.0	4.4	-39.6	-189	-32.0	bd
Leak C	Day 2	-11.2	3.0	-45.6	-189	-34.7	-158
Leak C	Day 3	-5.4	3.3	-45.0	-189	-34.6	-159
Airborne Samples							
Background/ upwind 1	Day 3	-7.7	7.8	-48.4	bd*		
Background/ upwind 2	Day 3	-7.0	11.6	-44.2	bd		
Background/ upwind 3	Day 4	-7.8	7.4	-49.3	bd		
Background/ upwind 4	Day 4	-7.6	6.1	-42.5	bd		
Plume/ downwind 1	Day 2	-8.0	7.6	-43.0	bd		
Plume/ downwind 2	Day 3	-8.2	7.1	-48.2	bd		
Plume/ downwind 3	Day 4	-8.4	6.6	-45.9	bd		
Plume/ downwind 4	Day 4	-7.8	7.0	-40.9	bd		
Upwind Background							
Ground level background1	Day 2	-7.5	7.7	-42.9	bd		
Ground level background2	Day 2	-7.6	6.2	-43.0	bd		
Stack Samples							
Stack 1.1	Day 2	-41.9	0.7				
Stack 1.2	Day 2	-41.8	0.4				
Stack 1.3	Day 2	-42.2	3.1				
Stack 1.4	Day 3	-41.8	3.0				
Stack 1.5	Day 3	-41.5	-0.3				
Stack 2.1	Day 2	-41.6	0.9				
Stack 2.2	Day 2	-41.8	-0.1				
Stack 2.3	Day 2	-42.2	0.5				
Stack 2.4	Day 3	-41.5	-0.9				
Stack 3.1	Day 1	-41.6	3.0				
Stack 3.2	Day 1	-41.3	-0.3				
Stack 3.3	Day 2	-41.0	2.5				

***bd = Below detection limit**

Source: EPRI

Facility 3

Table B-8. Identified and Quantified Leaks and Vents at the Host Facility 3

Leak #	Component type	Location	Compressor status	Representative flow rate (scfh)	Representative flow rate (kg/hr)
L1	Open-ended line	Compressor vent	Off	2750	43.16
L1	Open-ended line	Compressor vent	On	1300	20.40
L2	Open-ended line	Compressor drain vent	Off	1030	16.17
L2	Open-ended line	Compressor drain vent	On	970	15.22
L3	Open-ended line	Compressor crank case vent	Off	NA	NA
L4	Open-ended line	Compressor crank case vent	Off	NA	NA
L5	Open-ended line	Compressor vent	Off	995	15.62
L5	Open-ended line	Compressor vent	Off	1500	23.54
L6	Open-ended line	Compressor crank case vent	Off	NA	NA
L7	Open-ended line	Compressor crank case vent	Off	50.3	0.79
L8	Open-ended line	Compressor drain vent	Off	460	7.22
L8	Open-ended line	Compressor drain vent	Off	546	8.57
L8	Open-ended line	Compressor drain vent	Off	950	14.91
L9	Flange	Compressor outlet	Off	55	0.86
L10	Flange	Compressor outlet	Off	88	1.38
L11	Open-ended line	Compressor drain vent	Off	528	8.29
L12	Compressor	Compressor head	Off	NA	NA
L13	Fitting	Meter - elbow	On	0.25	0.004
L14	Open-ended line	Pneumatic controller	On	13	0.20
L15	Open-ended line	Pneumatic controller	On	5.4	0.08
L16	Valve	Filter station	On	0.77	0.01
L17	Fitting	Pneumatic controller	On	2.88	0.05
L18	Valve	Filter station	On	0.175	0.003
L19	Open-ended line	Drain tank vent	On	600	9.4
L20	Open-ended line	Fuel gas vent	On	0.08**	0.001**
L21	Open-ended line	Duct burner piping		2.525	0.04

Leak #	Component type	Location	Compressor status	Representative flow rate (scfh)	Representative flow rate (kg/hr)
L22	Pipe	Duct burner piping		0.11	0.002
L23	Threaded connection	Duct burner piping		0.08**	0.001**
L24	Fitting	Duct burner filter		0.08**	0.001**
L25	Threaded connection	Duct burner piping		0.08**	0.001**
L26	Open-ended line	Compressor drain vent	Off	0.08**	0.001**
L27	Open-ended line	Compressor building vent	Off	0.08**	0.001**
L27	Open-ended line	Compressor building vent	On	0.41	0.006
L28	Flange	Compressor building	Off	0.12	0.002
L29	Threaded connection	Compressor building	Off	0.08**	0.001**
L30	Open-ended line	Compressor building vent	Off	8.9	0.14
L31	Open-ended line	Compressor building drain vent	Off	7.5	0.12
L32	Open-ended line	Compressor building vent	On	17.1	0.27
L33	Open-ended line	Compressor crank case vent	Off	2.08	0.03
L34	Compressor	Compressor unit	Off	0.96	0.02
L35	Valve	Strainer valve	On	1.62	0.03
L35	Valve	Strainer valve	Off	0.12	0.002
L36	Threaded connection	Strainer area - elbow	On	0.08**	0.001**
L36	Threaded connection	Strainer area - elbow	Off	0.08**	0.001**
L37	Threaded connection	Strainer area - reducer	On	0.77	0.01
L37	Threaded connection	Strainer area - reducer	Off	0.2	0.003
L38*	Open-ended line	Compressor building exhaust	On	155	2.43
Total of quantified leaks†				**7220.7**	**113.3**

“NA” is “not available as the leak was not quantified due to safety concerns, lack of accessibility

****Leaks below the detection limit of FLIR was assigned a value of 0.08 scfh or .001 kg/hr**

Gas yard emissions halved and attributed to both combined cycle and peaker systems.

Leak #	Component type	Location	Compressor status	Representative flow rate (scfh)	Representative flow rate (kg/hr)

*** Total building leak; supersedes L28 and L29.**

†Including L38, without L28+L29. Means used for replicates. Used only the maximum value if a leak was measured multiple times under different conditions (e.g., compressor on and off). If the minimum value of a leak was used for leaks measured under different conditions, the cumulative leak sum was 89.6 kg/hr.

Source: EPRI

Pressure-Related Changes in Emissions

Several of the emission points across the facility were measured when the relevant equipment and compressors were both operating and not operating (Table B-9). The leaks in one site (strainer area) demonstrated a clear increase in emission rate when the line pressure increased. A second site (compressor A) appears to have similar behavior, however it was not possible to quantify the exact same leaks for the compressor on and off conditions. Table B-8 shows the large L38 in the 'compressor on' condition accounts for the difference. This measurement was made from the exhaust fan of the entire compressor building and aggregates all the leaks inside. This measurement was made because when the compressor turned on, a widespread diffuse background methane signal was detected in the building that was not present during the compressor off condition, making it difficult to detect individual leaks. An analogous measurement at the exhaust fan was not made during the off condition for a direct comparison. However, the only quantified leaks during the off condition were L28 and L29, and they were individually very small in comparison.

The third site (compressor 1A) demonstrated a different pattern. When the compressor turned on, the leak rate dropped. The single L10 was not quantified during the "compressor on" condition but is small in comparison to the difference between the off and on conditions. Based on discussions with facility personnel, the design of this compressor is such that pockets exist internally where gas can collect and build up pressure through slow leaks from the gas inlet. Turning the compressor on acts to move the natural gas through the system, reducing that build up, lowering leak rates. It is also possible that the presence of oil during operations helps to improve the seal, reducing leaks. (Subramanian, et al. 2015) also observed that operating reciprocating compressors had higher emission rates than compressors on standby.

Table B-9. Change in CH_4 Leak Rates with Line Pressure Changes

Site	Compressor Status	Leaks in site	Leaks measured	Total flow rate (scfh)	Notes
Compressor 1A	Compressor 1A Off	L1, L2, L3, L4, L10	L1, L2, L10	3868.0	L10 was 88scfh
Compressor 1A	Compressor 1A On	L1, L2, L3, L4, L10	L1, L2	2270.0	
Compressor	Compressor A Off	L26, L27, L28, L29, L32	L28, L29	0.19	
Compressor	Compressor A On	L26, L27, L32, L38	L27, L32, L38	172.51	
Strainer area	Compressor A and B Off	L35, L36, L37	L35, L36, L37	0.36	Line pressure 100 psi
Strainer area	Compressor A On	L35, L36, L37	L35, L36, L37	2.43	Line pressure 660psi

***Note that not all identified leaks were quantified due to safety concerns, lack of accessibility, or being below detection limits.**

Source: EPRI

The pipelines throughout the power plant facility maintain at least "street" pipeline pressure (pressure at the point of entry to the facility; varies from roughly 200-475 psig). This occurs from the entrance to the plant to the stop valve at the gas module on the combustion units, whether the turbines are running or not. The pressures are boosted to at least 450 psig (several hundred additional psig at the peaker unit) before entry into the turbines. Many sections of these lines, often split by valves or equipment, have pressure gauges and others do not. For most pipelines pressure is maintained even when the combustion units are not running. Thus, a facility-wide cold-start would be needed to reach zero pressures; it was not feasible to construct this scenario for testing. If the street pressure was on the low end of the 200-475 psig range, it might have been possible to find additional leaks experiencing a range in pressures during the campaign. However, the pressure was at the high end of the rangeduring this entire campaign. Thus, the authors have minimal examples of how changes in pressure may change leak rates. Based on the existing results, it is feasible to assume that in general leak rates from piping will increase with increasing pressure. The required pressure thresholds for such a change are not known.

Additional Detail from Regional Aircraft Measurements

Facility Descriptions

Table C-1. Facility type descriptions

Facility	*Description*
Landfill	A landfill site for disposal of waste materials
Wastewater	A facility that treats wastewater or sewage and remove pollutants
Refinery	A facility where oil is refined
Oil Depot (Tank Farm)	A facility where oil, petroleum, and petrochemical products are stored
Dairy	A farm where livestock are raised for milk
Food Processing	An establishment that is a commercial operation that processes food
Simple Cycle Natural Gas Power Plant	A type of natural gas power plant which operates by propelling hot gas through a turbine, to generate electricity. Typically used to provide peaking power and are not run for very long throughout the year
Combined Cycle Natural Gas Power Plant	A natural gas power plant that uses both gas and steam turbines to produce electricity
Cogen Power Plant	A power plant which simultaneously produce heat and electricity
Biomass Power Plant	A power plant which burns biomass such as wood waste or other waste as feedstock to produce steam that runs a turbine to make electricity
Paving Materials Manufacturing	A facility that manufactures materials for paving such as asphalt, concrete, stones, and bricks

Source: EPRI

Flight Quality Assessment

Due to limited survey time at each facility (often due to FAA limitations), a smaller number of flight loops were performed at each site that was further afield as compared to the flights at Facility 1 and Facility 2. A deeper review of the flight measurement data was performed to ensure data quality (Table C-2). Individual lap data was filtered out if there were insufficient wind speed or sharp changes in wind direction with altitude during the loop. At low wind speed, CH_4 plumes would rise vertically and might not transect the flight path leading to underestimation. Shifting wind direction, especially if in the direction opposite to the predominant wind direction, generated high measurement uncertainty because measured emissions and background data would be flipped and without knowing the duration that the plume took to travel from the source to the airplane it would be complex to correct the output, thus such flight laps were excluded from the analysis. Approximately 19% (29 out of 152) of flight laps were excluded due to low wind speed or shifting wind conditions.

Data from the remaining flight laps were processed to generate facility-wide emission estimates for the sites visited along with a three-level confidence rating to describe the level of certainty in the estimates (low, medium, high). Sites with large amount of upwind contamination were given a "low" confidence rating as these extraneous sources could overwhelm and mask emissions from the facility of interest, making isolating the site emissions nearly intractable. Additionally, a subset of sites had limited lap numbers at lower altitude and, in some cases, limited number of laps at higher altitudes which added uncertainty of whether the full vertical extent of the plume was captured. Only sites where the full vertical extent of the plume was captured were given "high" confidence rating. Shifting winds and variable meteorological conditions increased both the quantitative and qualitative uncertainty estimates reported.

Table C-1. Flight quality of individual site measurements during the regional aircraft measurements

Month of flight	Facility type	Laps	Wind Direction	Wind Speed (m/s)	Min/Max Altitude (m)	Confidence	CO_2 Emission (kg/hr)	CO_2 Uncertainty (kg/hr)	CH_4 Emission (kg/hr)	CH_4 Uncertainty (kg/hr)
Jun-18	Landfill	20	W	3	161 - 819	high	**10,296**	6613	1637	316
Jun-18	Wastewater	22	W	3.5	106 - 797	high	**40,819**	8,086	386	80
Jun-18	Biomass Power Plant	8	W	3.9	117 - 370	medium	**13,827**	4,928	BDL	BDL
Jun-18	Refinery	15	W	5.2	126 - 536	high	**596,153**	137,019	554	98
Jun-18	Refinery	14	SW	2.1	171 - 510	high	**595,741**	74,571	1,388	283
Jun-18	Refinery	13	W	4.5	162 - 574	high	**185,977**	21,067	136	25
Jun-18	Biomass Power Plant	20	N	2.1	77 - 665	high	**21,014**	8,066	16	18
Jun-18	Biomass Power Plant	16	SE	2.4	53 - 333	medium	**45,924**	10,260	6	10
Jun-18	Wastewater	16	SW	5.6	109 - 576	high	**4,278**	13,860	325	50
Jun-18	Landfill	17	SW	4.1	96 - 600	high	**17,897**	7,441	1,991	348
Jun-18	Biomass Power Plant	18	S	3.5	105 - 484	high	**44,235**	8,844	33	8
Jun-18	Refinery	14	W	3	134 - 574	medium	**257,400**	86,743	128	90
Sep-18	Food Processing	17	NW	2.4	97 - 591	medium	**4,197**	1,956	BDL	BDL
Sep-18	Food Processing	18	NW	2.2	152 – 653	low	**4,562**	2,563	BDL	BDL
Sep-18	Food Processing	22	NW	2.2	90 - 723	medium	**28,108**	13,328	40	34
Sep-18	Peaker Natural Gas Power Plant	12	NW	3.7	78 – 343	medium	**1,846**	1,048	BDL	BDL
Sep-18	Wastewater	19	NW	2.5	74 - 661	high	**16,957**	4,076	130	45
Sep-18	Food Processing	8	NW	3.2	94 – 283	medium	**1,955**	4,296	BDL	BDL
Sep-18	Food Processing	19	NE	2.5	95 – 591	medium	**21,442**	7,300	43	8
Sep-18	Peaker Natural Gas Power Plant	17	N	4.9	113 – 557	medium	**3,180**	1,416	17	22
Sep-18	Dairy	23	NW	3.6	78 – 1123	high	**3,077**	4,894	900	184

Month of flight	Facility type	Laps	Wind Direction	Wind Speed (m/s)	Min/Max Altitude (m)	Confidence	CO_2 Emission (kg/hr)	CO_2 Uncertainty (kg/hr)	CH_4 Emission (kg/hr)	CH_4 Uncertainty (kg/hr)
Sep-18	Dairy	23	NW	3.3	69 – 786	high	**BDL**	BDL	813	187
Sep-18	Landfill and Dairy	22	NW	3.5	69 – 978	high	**11,074**	6,727	774	155
Sep-18	Peaker Natural Gas Power Plant	21	NNW	10.1	115 – 656	medium	**BDL**	BDL	15	12
Sep-18	Meat Processing	15	NW	3.3	198 – 568	medium	**9,697**	1,990	23	13
Sep-18	Peaker Natural Gas Power Plant	21	NW	2.5	84 – 810	medium	**BDL**	BDL	BDL	BDL
Sep-18	Dairy	18	NW	3.6	66 – 624	high	**2,105**	4,325	1,007	283
Sep-18	Peaker Natural Gas Power Plant	18	N	3.2	99 – 653	high	**29,984**	10,355	49	17
Sep-18	Dairy	19	N	2.8	81 – 767	high	**13,605**	2,818	227	61
Sep-18	Dairy	19	NW	3.3	69 – 786	high	**15,761**	3,423	724	145
Sep-19	Biomass Power Plant	17	NW	2.1	282 – 930	medium	**2,997**	5,854	99	151
Sep-19	Natural Gas Power Plant	12	NW	3.5	170 – 898	medium	**369,559**	140,017	164	90
Sep-19	Natural Gas Power Plant	6	NNW	4.2	192 – 519	medium	**118,748**	61,620	121	69
Sep-19	Refinery	9	NW	1.9	138 – 601	high	**BDL**	BDL	384	119
Sep-19	Combined Cycle Natural Gas Power Plant	10	N	1.5	103 – 453	medium	**128,839**	54,690	BDL	BDL
Sep-19	Cogen	12	W	4.3	120 – 935	low	**BDL**	BDL	BDL	BDL
Sep-19	Combined Cycle Natural Gas Power Plant	14	SW	3.9	204 – 573	high	**16,359**	13,634	12	6
Sep-19	Refinery	10	SW	2.5	345 – 517	low	**200,683**	88,469	39	28
Sep-19	Tank Farm	7	S	3.1	315 – 424	low	**256,445**	116,163	268	149
Sep-19	Tank Farm	7	S	3.4	317 – 439	high	**BDL**	BDL	BDL	BDL
Sep-19	Tank Farm	8	S	3.4	296 – 436	high	**BDL**	BDL	BDL	BDL

Month of flight	Facility type	Laps	Wind Direction	Wind Speed (m/s)	Min/Max Altitude (m)	Confidence	CO_2 Emission (kg/hr)	CO_2 Uncertainty (kg/hr)	CH_4 Emission (kg/hr)	CH_4 Uncertainty (kg/hr)
Sep-19	Paving Materials	7	SW	2	294 – 418	high	**4,846**	9,698	BDL	BDL
Sep-19	Simple Cycle Natural Gas Power Plant	7	SW	2.7	250 – 379	low	**BDL**	BDL	BDL	BDL

BDL = Below Detection Limit

Source: EPRI

Table C-2. CO_2 and CH_4 measurements from various sources grouped by facility type

			CO_2 Emissions				CH_4 Emissions				
Facility Type	Count	Number of Sites that were Operating during visit*	Average Aircraft CO_2 Emission (kg/hour/facility)	CO_2 Uncertainty (kg/hour)	AMPD hourly average for day of survey (kg/hour/facility)	GHGRP hourly average 2018 CO_2 emissions (kg/hour)	Average Aircraft CH_4 Emission (kg/hour/facility)	CH_4 Uncertainty (kg/hour)	GHGRP hourly average 2018 CH_4 emissions (kg/hour)	JPL average CH_4 emissions (kg/hour/facility)	JPL CH_4 stdev (kg/hour)
Landfill	3	NA	13,089	7,267	NA	NA	1,467	278	569	425	132
Wastewater	3	NA	20,685	8,674	NA	NA	280	66	151	NA	NA
Refinery	6	NA	367,191	91,513	NA	295,345	438	168	19	282	143
Oil Depot (Tank Farm)	3	NA	256,445	116,163	NA	104,670	268	149	12	167	74
Dairy	5	NA	8,637	3,262	NA	NA	734	174	NA	NA	NA
Food Processing	7	NA	12,038	8,225	NA	3,953	35	19	0.1	NA	NA
Simple Cycle Natural Gas Power Plant	6	2	11,670	5,284	10,218	12,911	27	22	0.2	BDL	BDL
Combined Cycle Natural Gas Power Plant	5	5	159,899	76,143	95,965	106,677	82	40	4	278	135
Cogen Power Plant	1	NA	BDL	BDL	NA	NA	NA	BDL	NA	NA	NA

Biomass Power Plant	5	NA	25,599	15,958	17,565	NA	39	44	NA	BDL	BDL
Paving Materials Manufacturing	1	NA	4,846	9,698	NA	NA	BDL	BDL	NA	NA	NA

***Site operating condition is determined using hourly Air Markets Program Data (AMPD). Combined cycle and simply cycle natural gas power plants report CO_2 emissions to AMPD**

Source: EPRI

Additional Details of Compressed Natural Gas Fueling Station Measurements

Modeling of Data Below Detection

There were numerous emission sources found during the CNG measurement campaign that did not get their emission rates measured because these sources were not visible with the FLIR camera or were below the quantification threshold. As a result, a large portion (73 percent) of these emission rates data is left-censored. This was because the 500 ppm emission source identification threshold was substantially lower than the quantification threshold (detection with the FLIR camera). Advanced and well documented statistical methods were used to impute emission rates below the quantifiable limit (Bolks, DeWire and Harcum 2014) (Helsel 2009) .

In particular, the robust regression on order statistics (ROS) method, available in the R statistical software 'NADA' package, was chosen to estimate summary statistics from the censored data or data below the quantifiable limit. The robust ROS method is specifically applicable to smaller data sets (n < 50) with up to 80% censored data, compared to another accepted method of estimating censored data, the maximum likelihood estimation (MLE) method. With approximately 73% of the emission sources in the CNG station dataset being below the quantifiable limit and fewer than 50 quantified sources, the robust ROS method was selected to compute the summary statistics. The method produces a new statistical mean which accounts for non-detects, and a probability plot to visualize the goodness of fit of the data to the lognormal model. This procedure provides a statistically robust method to obtain a representative mean from the censored dataset. Table D-1 shows the recommended methods for various scenarios (Bolks, DeWire and Harcum 2014).

Table D-1. Methods for treating non-detects

Sample Size	Percent of Data Censored		
	<50%	50-80%	>80%
n < 50	Robust ROS	Robust ROS	Censoring too high to compute summary statistics (for example, mean)
n ≥ 50	Robust ROS	MLE	Censoring too high to compute summary statistics (for example, mean)

Source: EPRI

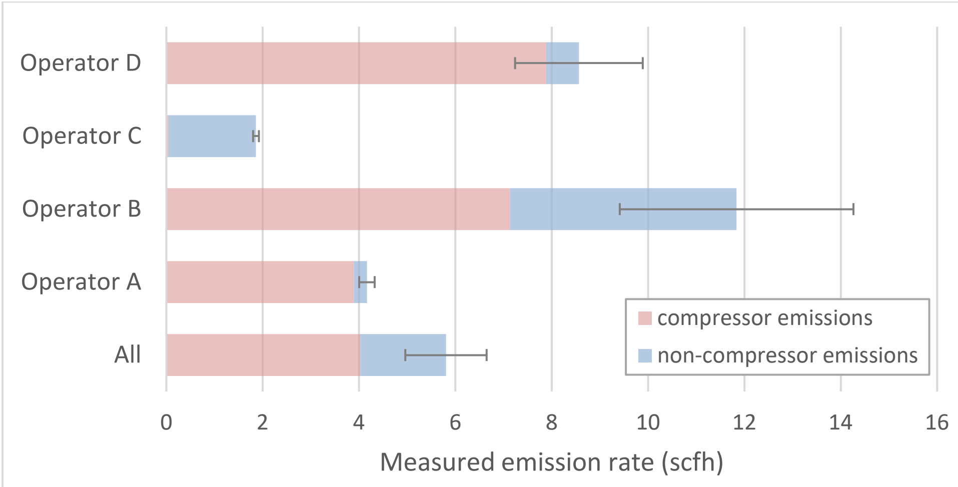
The robust ROS method assumes that the uncensored and censored data are derived from the same underlying population distribution. A lognormal distribution is a reasonable starting assumption for natural gas emissions data; however, other distributions such as log-logistic could be considered if the uncensored data exhibits a heavy tail. Robust ROS is based on regressing raw or transformed uncensored data on a normal probability plot. The censored observations are imputed based on the regression coefficients and an assumed upper limit. If transformations such as a logarithmic function were used, the imputed values are back transformed. Summary statistics are then calculated from the combination of uncensored data and imputed values. The robust ROS method provides a metric (R-squared value) to measure the goodness of fit of the selected distribution to the dataset.

Fueling Station Emission Rate by Operator

The 48 unique stations visited by the research team were geographically distributed across California and were run by a total of 12 different organizations. They represent roughly 15% of California's 300+ CNG fueling stations. The subset of stations that were intensively surveyed, 27 stations in total, were operated by 4 entities. Figure D-1 below shows the mean total emission rate of each station grouped by operator. Emission rates of stations with emission indications smaller than the quantification threshold were imputed using the robust ROS method.

The mean station emission rate including non-detects was 5.80 (± 0.84) scfh, and 7.23 (±0.84) scfh for the quantifiable values only. The mean emission rate includes emissions from compressor units which may incorporate both continuous and episodic emissions. Due to potential differences in how continuous and episodic emissions are estimated, compressor emissions have been differentiated from non-compressor emissions in Figure 41 below. As a reminder, the goal of this study is not to create operator-specific emission factor but to establish an initial screening for CNG stations. That said, there were variances observed in station emission rates of different operators in 4 of 5 cases that were larger than the error bars on each operator's mean rates. Mean emission rates by operator vary from 2 to 12 scfh per station. It is possible that some factors such as station throughput, compressor operating time, maintenance protocol, and leak detection and repair (LDAR) practices, have an impact on overall emission rates. Station throughput and compressor operating time have direct impacts on emissions from operating compressors. Maintenance protocol and LDAR practices, in theory, influence the quantity and emission rates of continuous fugitive leaks at the station as leaks appear and can change with time (for example, ongoing degradation of rod-packing can increase emission rates as the systems age). To illustrate, emission rates from reciprocating compressor units are highly dependent on the condition of packing rings and piston rods which are replaceable (U.S. EPA 2016). On the other hand, leak survey and repair practices would determine the duration that a leak would remain unrepaired. The higher the frequency of survey and the faster the repair, the less chance a leak would continue for an extended time period.

Figure D-1. Mean station emission rates grouped by operator (station count per operator ranges from 1 to 21)



Source: EPRI

Two of the four operators allowing site access provided their maintenance protocols and LDAR procedure with the research team. There are several commonalities in practices as both operators perform leak surveys using the traditional soap solution methods and repair leaks immediately after they are identified. Leak survey frequency of the two operators differs but the operator with the higher survey frequency surprisingly has a greater mean station emission rate. Survey frequency may not be the most impactful factor affecting station emission rates. Another important factor is station throughput volume. Linear regression of station emission rates versus throughput volume for the two operators that provided throughput data, shown in a later section of the report, shows a relatively strong positive relationship indicating the importance of throughput volume as a factor in leak rate. It is important to note that each visit is only a snapshot in time – emissions might change over time during the day or night depending on site operations.

CNG Sample Isotopic Composition

Table D-1. Isotopic Composition of Samples Taken at Southern California Sites

Sample name	Day of Campaign	CH_4 (ppm)	CH_4 d^2H (‰)	CH_4 $d^{13}C$ (‰)
Site A, Sample 1*	Day 1	187000	-180	-41.6
Site A, Sample 2	Day 1	134000	-182	-45.6
Site B, Sample 1	Day 2	45000	-168	-27.7
Site B, Sample 2	Day 2	10000	-179	-51.3
Site B, Sample 3	Day 2	5000	-184	-60.5
Site C, Sample 1	Day 4	4000	-172	-41.6
Site C, Sample 2	Day 4	221000	-174	-39.0
Site C, Sample 3	Day 4	278000	-174	-39.0

Source: EPRI

Table D-2. Isotopic Composition of Samples Taken at Northern California Sites

Sample name	Day of Campaign	CH_4 (ppm)	CH_4 d^2H (‰)	CH_4 $d^{13}C$ (‰)	C_2H_6 (ppm)	C_2H_6 d^2H (‰)	C_2H_6 $d^{13}C$ (‰)	C_3H_8 (ppm)	C_3H_8 d^2H (‰)	C_3H_8 $d^{13}C$ (‰)
Site A, Point 1	1	336490	-211	-42.5	16319	-157	-31.9	902	-132	-29.7
Site A, 1m downwind Point 1	1	1205	-203	-37.6	bdl	Bdl	bdl	bdl	bdl	bdl
Site A, Point 2	1	85927	-210	-41.9	4314	-159	-31.9	151	bdl	-29.5
Site B, Point 1	1	3693	-210	-41.6	bdl	Bdl	bdl	bdl	bdl	bdl
Site C, Point 1 *, Sample 1	2	160602	-211	-42.6	6546	-162	-31.7	345	-136	-29.6
Site C, Point 1*, Sample 2	2	162838	-211	-41.0	7832	-156	-30.7	412	-136	-29.0
Site D, Point 1*, Sample 1	2	100475	-216	-41.7	5653	-164	-30.4	238	bdl	-29.0
Site D, Point 1*, Sample 2	2	69330	-216	-42.1	3614	-166	-31.0	174	bdl	-28.7
Site D, Point 1*, Sample 3	2	74788	-215	-41.7	3816	-164	-30.7	147	bdl	-28.8
Site D, Point 2, Sample 1	2	31616	-213	-36.4	1504	-157	-29.0	81	bdl	-27.9
Site E, Point 1*, Sample 1	3	55098	-219	-40.9	3052	-160	-30.4	162	bdl	-28.4
Site E, Point 1*, Sample 2	3	2358	-217	-42.4	bdl	Bdl	bdl	bdl	bdl	bdl

Sample name	Day of Campaign	CH_4 (ppm)	CH_4 d^2H (‰)	CH_4 $d^{13}C$ (‰)	C_2H_6 (ppm)	C_2H_6 d^2H (‰)	C_2H_6 $d^{13}C$ (‰)	C_3H_8 (ppm)	C_3H_8 d^2H (‰)	C_3H_8 $d^{13}C$ (‰)
Site E, Point 1*, Sample 3	3	87636	-212	-37.1	5052	-159	-29.3	252	bdl	-28.0
Site F, Point 1*, Sample 1	4	123863	-212	-41.1	5738	-163	-30.9	462	-153	-29.0
Site F, Point 1*, Sample 2	4	452008	-212	-42.1	25253	-162	-30.8	2026	-149	-28.9
Site G, Point 1, Sample 1	4	32838	-216	-41.3	1618	-161	-30.9	93	bdl	-28.8
Site G, Point 1, Sample 2	4	24506	-218	-41.7	1138	-160	-31.0	20	bdl	bd
Site G, Point 2, Sample 3	4	32046	-214	-39.9	1617	-157	-30.1	96	bdl	-28.6
Site G, Point 2, Sample 4	4	26201	-222	-49.5	956	-162	-34.5	48	bdl	-31.1
LBNL Natural Gas	-6		-217	-41.3		-162	-30.8		-145	-27.9
LBNL Natural Gas	10		-217	-41.5		-163	-30.8		-149	-28.4

***At each site, the individual samples are replicates of the same emission points.**
Emission points, as well as replicate samples at individual emission points, are labelled. "bdl" denotes values below detection limit. "*" denote samples from the crankcase vents of compressor.

Source: EPRI

SPATIAL INVENTORY OF GREENHOUSE GAS EMISSIONS FROM CALIFORNIA NATURAL GAS INFRASTRUCTURE

Appendix E can be accessed here.