QUANTIFICATION METHODOLOGY FOR NEXT GEN GAS VERSION 2.4

August 2024

Abstract

This document details Context Labs methodology for emissions quantification of natural gas, in support of Next Gen natural gas attestation.

Preface

Context Labs is an enterprise technology company dedicated to sourcing, organizing, contextualizing, and securing the world's climate information. The company enables trust in data, which can be utilized to inform markets. We synthesize disparate, disconnected data from all available data sources — including satellites, aerial flyovers, ground sensors, and other operational assets — to establish a more holistic understanding of ground truth carbon intensity for industrial operations. Data is ingested, contextualized, interconnected, and secured immutably using a combination of advanced graph analytics, artificial intelligence, and blockchain technologies—making climate disclosures fully auditable and impossible to manipulate.

Recognizing the critical importance of eliminating anthropogenic methane emissions, this quantification methodology was developed using several years of R&D and has been tested in the market. This trusted emissions data supports the production of trusted environmental attributes with provenance direct to the source. Our near-real time emissions quantification is being used by leaders in the natural gas industry to support their decarbonization efforts. Context Labs' intent is to inspire the development of other emissions quantification methodologies that could also be applied using their AI-enabled data fabric platform for at-scale decarbonization of industrial operations.

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1 Introduction

A key challenge to managing greenhouse gas (GHG) emissions is accurately understanding the specific quantity and distribution of emissions of methane and other GHGs into the atmosphere. Methane emissions at a natural gas facility occur during normal operations (e.g., continuous bleeds from pneumatic devices) or planned maintenance (e.g., depressurizing a piece of equipment for maintenance), or can also result from abnormal events (e.g., leaks, equipment malfunctions, system upsets, or damage caused by third parties). These emissions (notably those from unplanned events) can be particularly challenging to quantify as the onset of an emissions event and the methane release rate are often undetectable using traditional process and safety monitoring instrumentation found in common operating facilities. Uncertainty regarding the duration, frequency, and release rates results in uncertainty in the total quantity of methane released.

Context Labs' mission is to improve the reliability of greenhouse emissions detection, quantification, and reporting of emissions and emissions intensity to enable better-informed decision-making. This enables oil & gas operators to deploy capital more effectively to reduce GHG emissions. Improving the reliability of greenhouse emissions detection, quantification, and reporting simultaneously enables external stakeholders to make more informed decisions related to their energy supply and investment portfolios.

Although many methods for methane emissions estimation exist, conventional approaches rely heavily on laboratory-developed heuristic models, sometimes referred to as 'emissions factor models.' While these emissions factor models have the advantage of being simple for all companies to apply consistently, they fail to account for site-specific factors that can have significant effects on actual emissions—such as the equipment manufacturer and model, commissioning practices, time in operation, or maintenance programs. Many of the emissions factors defined within the U.S. EPA Greenhouse Gas Reporting Program (GHGRP) originate from dated studies, some almost three decades ago through a study by the Gas Research Institute released in 1996. According to a more recent publication by the National Academies of Science, Engineering & Medicine, in many cases, these emissions factors do not represent the current population of emissions sources, facility designs, or work practices in place today.[1]

Recent technological advances have greatly improved methane sensing instrumentation, but there remains no single sensor with both the high sensitivity to detect low-rate fugitive emissions and the broad swath to continuously monitor all possible leak points across a large, distributed system. Context Labs' data fabric approach ingests and integrates disparate data from multiple measurement sources to deliver a more comprehensive and accurate view of methane emissions based on the best available measurement for the facility. The Context Labs emissions quantification methodology improves on previous (especially emissions factor) approaches by integrating:

- Multiple conventional and advanced sensing and quantification devices for comprehensive and cost-effective emissions identification and measurement
- Direct measurement-informed quantification
- Rigorous data-driven analyses
- Robust and holistic emissions monitoring, mitigation, and reporting programs for natural gas companies and stakeholders

The basic shared approach of current greenhouse gas emissions estimation methods involves the identification of potential GHG-emitting sources at a facility. These sources include continuous emission sources, as well as discontinuous or intermittent sources and events. With appropriate source-level measurements, routine emissions from these common sources can be reasonably determined using engineering calculations combined with periodic measurements combined with site operating data. Common GHG emissions sources located at a natural gas facility include:

- Combustion Engines and Turbines
- Reciprocating Compressor Vents
- Centrifugal Compressor Vents
- Blowdowns
- Atmospheric Storage Tanks
- Equipment Leaks and Other Sources of Fugitive Emissions
- Gas-Driven Pneumatic Devices
- Glycol Dehydrators
- Desiccant Dehydrators
- Well Liquid Unloading
- Casinghead or Annulus Vent
- Control devices (e.g., flares, thermal oxidizers, and combustors)
- Gas starters
- Reciprocating Engine Crank Case Venting
- Acid-Gas Removal Units
- Electricity Usage

Several studies have demonstrated that a significant fraction of methane emissions at a facility can originate from a small fraction of sources.[1] High-emitting sources generally fall into three categories:

- Chronic high-emitting sources:
  - Do not vary over time and persistently emit at higher rates compared to similar sources
  - Typically caused by poor design or operational practice
- Episodic high-emitting sources:
  - Often associated with known, intentional releases such as blowdowns, equipment evacuation for maintenance, or liquids unloading
  - Produce very high methane emissions rates, potentially over very short periods of time (e.g., minutes)
- Malfunctioning high-emitting sources:
  - May be intermittent or prolonged
  - Examples include malfunctioning pneumatic devices, stuck-open dump valves allowing gas blowby to a downstream low-pressure tank, and leaking compressor isolation and blowdown valves.

The use of advanced detection and measurement technologies within this methodology helps to more rapidly identify the presence of high-emitting sources and unexpected events in order to perform timely remediation. In addition, these technologies assist in more accurately quantifying reconciled whole-site emissions and improving confidence in reported emissions values.

2 Referenced Protocols

The approach to emissions quantification set forth in this methodology has been developed based on the guidelines outlined in industry-leading protocols, including the the Oil and Gas Methane Partnerships (OGMP) Methane Emissions Reporting Framework Version 2.0 and the Gas Technology Institute (GTI) Veritas Protocol Version 2.0. In accordance with the GTI Veritas Protocol, this methodology considers the minimum detection threshold and uncertainty of sensing technology to leverage advanced measurement technology while ensuring comprehensive coverage and works to reconcile top-down and bottom-up emissions methods. In accordance with OGMP 2.0, in addition to the features listed above, this method implements emissions reported by detailed source type and specific emissions and activity factors based on source-level measurement (Level 4), with >90% of the expected methane emissions sources from each site meeting Level 4 requirements for source-level testing. Site-level measurements with risk-based facility revisit frequency (Level 5) is currently being performed at least semi-annually.

Gas Technology Institute (GTI) Veritas Protocol

- Emissions intensity protocol
- Measurement & reconciliation protocol for Upstream
- Measurement & reconciliation protocol for Midstream
- Audit and assurance protocol

Oil and Gas Methane Partnerships (OGMP) 2.0

- Benchmarking
- Emission reduction approaches
- Technology advancement
- Policy development
- Specific, measurement-based emissions and activity factors (Level 4) for source-level emissions estimation
- Top-down, site-level measurement (Level 5)

API Compendium of Methane Emission Estimation Techniques

US EPA's Greenhouse Gas Reporting Program (GHGRP)

- Established, objectively defined engineering calculations for bottom-up emissions estimation
- Combined with higher-frequency, unit/site-specific measurement-based emissions and activity factors

Natural Gas Sustainability Initiative's Methane Emissions Intensity Protocol

- Emissions intensity calculations
- Allocation of methane emissions to gas and liquid hydrocarbon product streams

3 Summary Description of the Methodology

In this document, Context Labs, B.V. puts forth a new method to enhance the accuracy of quantification of methane and total greenhouse gas emissions. To support a holistic and comprehensive approach to emissions quantification, this methodology incorporates external emissions measurement and monitoring from a variety of conventional (OGI cameras, Hi-Flow Samplers, exhaust stack testing) and advanced (Hyper/multi-spectral cloud imaging or LDAR-based near-Continuous Emissions Monitoring Systems, and LiDAR-equipped aerial flyover surveys) methane sensing devices for direct measurement-informed quantification of emissions across the full supply chain. Advanced methane detection satellite technologies are scheduled for launch beginning 2023+ and may over time provide an alternative for top-down measurement with more frequent repass, pending successful launch and performance validation. Measured emissions data are combined with real-time operational data from process control systems and operators' logbooks to quantify emissions on an ongoing basis.

Built on Asset-Grade Data (AGD), data veracity and data confidentiality are at the core of Context Labs' data management technology. Asset-Grade Data is data that has an immutable, auditable, end-to-end provenance to irrefutably prove the data has never been falsely represented, manipulated, or otherwise corrupted. At each point where data is created, transformed, combined, analyzed, or accessed, a 'Digital Proof' is created and published immutably to a distributed ledger (i.e., blockchain) to track and immutably preserve data pedigree and provenance for audit or verification purposes. Recognized third-party verifiers and subject matter experts act as 'Digital Notaries' submitting digitally signed statements attesting to the origin, integrity, and accuracy of raw data inputs or analytics outputs. This approach ensures the highest possible degree of trust, security, useability, and accountability related to emissions performance data.

The methodology can be broken down into three parts, which are detailed further in Sections 7-12.

Section 7: Data Inputs and Uses

- Facility Operational Data
- Emissions Monitoring Data

Section 8: Data Management

- Asset-Grade Data
- The Immutably™ Data Platform: A Contextual Data Fabric
- Immutable Provenance: Distributed Ledger, Identity, and Accountability

Section 9: Data Quality Levels & Exception Reporting

- Increasing reliance on measurement to reduce uncertainty
- Transparent disclosure of data quality level and any identified exceptions
- Incentivize continuous improvement, noting practical challenges of real-world operations

Section 10: Bottom-Up Source-Level Emissions Calculations

- Pre-deployment review of site equipment configuration and emissions inventories
- Higher frequency measurement of unit or site-specific emissions rates going beyond compliance requirements
- Measurement-informed engineering calculations using specific emissions factors and activity factors aligned with OGMP 2.0 Level 4

Section 11: Top-Down, Site-Level Measurements and Site Emissions Reconciliation

- Semi-annual aerial flyover surveys for top-down, site-level measurement aligned with OGMP 2.0 Level 5
- Reconciliation of bottom-up emissions and site-level measurements

Section 12: Supply Chain Emissions Allocation

- Allocate methane emissions with gas and liquid hydrocarbon product streams
- Associate emissions with specific product shipments
- Adjust for system-wide emissions
- Trace emissions end-to-end across the supply chain

Section 13: Verification

- Rigorous standards for emissions attestation, based on 3rd-party review

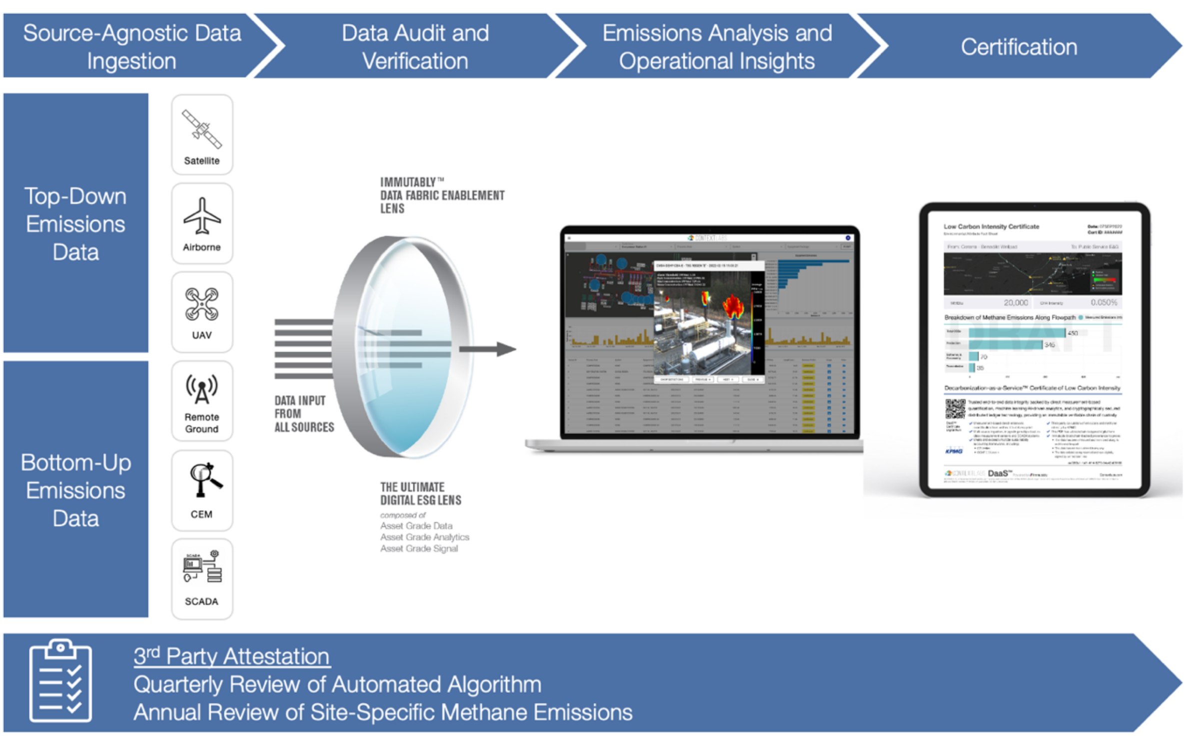


Figure 1. Illustrative overview of the Context Labs emissions quantification methodology

4 Definitions

Asset Hierarchy
A hierarchically organized list of all identifiable components (e.g., a valve, instrument, transmitter, etc.), equipment (e.g., a compressor), equipment groups (e.g., dehydration unit), facilities (e.g., a plant site), and groups of facilities (e.g., an operating division or region).

Asset Grade Data (AGD)
Data which has full provenance and veracity established.

Asset / Operating Unit
A logical business or operating unit as defined by the company (e.g. producing basins, regional assets, pipeline networks, gathering facilities, etc.). An asset may be comprised of one or more sites / facilities.

Emissions Source
A piece of equipment, device, or component within a process system that releases greenhouse emissions to the atmosphere.

Data Fabric
A data fabric platform provides a centrally managed means for integrating disparate data sources intelligently and securely, providing a consistent means to secure and access, as well as a unified semantic data layer to support business use cases.

Engine Stack Test
These are periodic tests performed on combustion engines per EPA procedures to ensure that the engines meet emissions performance standards for common pollutants (CO, CO_2, NOx, CH_4).

Emissions Factors
A representative value that attempts to relate the quantity of a compound released to the atmosphere with an activity associated with the release of that compound. Emissions factors are developed from source test data, material balances and engineering estimates of acceptable quality and are assumed to be representative of long-term averages for all facilities in the source category.

Emissions Inputs
Data inputs required to calculate emissions. Examples of emissions inputs are volume of natural gas throughput, equipment run-time, and mole fraction of GHG gas. Emissions inputs are used in emissions calculations, such as those found in EPA's 40 CFR 98 Mandatory GHG Reporting Rule.

Flyover
Aerial gas-imaging LiDAR methane plume detection and emissions rate estimation.

Geographical Information System (GIS)
A system that connects facility and equipment data to a map.

Leak Detection and Repair (LDAR)

LDAR is a system of procedures to locate and repair leaking components. Examples of data include the dates that leaks were identified, types of equipment leaking, and repair confirmation dates.

Light Detection and Ranging (LiDAR)

LiDAR scans a scene with lasers and measures the reflection or absorption patterns of light to determine the distance of an object or concentration of a target gas. The term LiDAR in this method refers to plane-mounted Gas Mapping LiDAR that detects and maps out methane leaks from the air.

Machine Learning

Application of mathematical and programming techniques to data, refining processes such that the system improves over time based on the data available.

Near-Continuous Emissions Monitoring System (Near-CEMS)

The U.S Environmental Protection Agency defines continuous emission monitoring systems (CEMS) as, "the total equipment necessary for the determination of a gas or particulate matter concentration or emission rate using pollutant analyzer measurements and a conversion equation, graph, or computer program to produce results in units of the applicable emission limitation or standard." Within this method, the use of the term Near-Continuous Emissions Monitoring System (Near-CEMS) refers specifically to methane emissions sensors installed on a permanent (or semi-permanent) basis for low-latency detection of elevated emissions. Certain tower-mounted laser or hyper/multi-spectral optical Gas Cloud Imaging (GCI) cameras may offer quantification capabilities and can potentially be used to locate methane emissions to a specific equipment source. Other advanced near-continuous monitoring technologies may also be incorporated in the future.

Next Generation Gas (NextGen Gas)

Natural gas with full end-to-end emissions traced from the point of origin through the supply chain to an end user that meets customer environmental, social, and/or governance standards.

Site / Facility

A collection of sources with some relation to one another within a process system. Typically, found within a contiguous piece of property at a discrete geographical location or physical address.

Supervisory Control and Data Acquisition (SCADA)

SCADA data allows companies to monitor and control equipment to improve operating efficiency. Examples of SCADA data include pressure, temperature, flow volume, and emissions (if available).

5 Applicability Conditions

This emissions quantification methodology applies to vented and fugitive greenhouse emissions for natural gas production, gathering, transportation, and processing facilities. Emissions are calculated on an equipment basis and are then aggregated to provide a site-, region-, and company-wide view for a particular operator. An emissions allocation methodology is provided for tracking and quantifying end-to-end supply chain emissions from the wellhead to the final delivery location.

6 Project Boundary

This methodology calculates greenhouse gas emissions for natural gas production, transportation, and processing facilities. At this time, this methodology addresses Total Scope 1 GHG emissions, including carbon dioxide and nitrous oxide emissions, and Scope 2 (indirect) GHG emissions. At this time, operational greenhouse gas emissions (post-commissioning) are included. Emissions from construction and development activities are not included at this time, but may be added as a future update. Emissions are quantified from all sources at a facility—from normal day-to-day operations to unplanned and unintentional leaks. Emissions from pipelines and pipeline blowdowns are also addressed. For end-to-end emissions tracking across the supply chain, a flow path must consist only of assets that have been evaluated following this method.

7 Data Inputs and Uses

To support a holistic and comprehensive approach to emissions quantification, this methodology incorporates real-time facility operational data and emissions monitoring from a variety of conventional (OGI cameras, Hi-Flow samplers, and exhaust stack testing) and advanced (e.g., Gas Cloud Imaging CEMS cameras, tower-mounted lasers, or LiDAR equipped airplanes, etc.) methane sensing devices. Advanced methane detection satellite technologies are scheduled for launch throughout 2023 and may be added as an alternative for top-down measurement with more frequent repass, pending successful performance validation. Facility data provides context to emissions measurements, which helps inform operators of equipment or facility conditions that may lead to different emissions patterns. Emissions measurements are then combined with real-time operational data from process control systems & operators' logbooks to quantify emissions on an ongoing basis.

7.1 Facility Operational Data

Detailed, real-time facility data are critical for understanding how fluctuations in day-to-day operations impact emissions. Operations data include site-wide performance data as well as equipment-specific data and can be sourced from multiple operations data systems:

- SCADA readings
  - e.g., Operating temperatures
  - Operating pressures
  - Process flow rates, fuel gas flow rates
  - Run times, etc.

- Equipment design specification sheets
    - e.g., Equipment manufacturer
    - Model number
    - Rated horsepower
    - Design throughput, etc.
- Operator logs
    - e.g., Compressor blowdown log, etc.

Operations data are also important for proactively identifying and distinguishing between different types of operating conditions, such as:

- Normal operations
- Planned maintenance or routine shutdowns (e.g., equipment depressurization, venting, etc.)
- Unplanned events (e.g., process upsets, equipment malfunctions, leaks, etc.)

7.2 Emissions Monitoring Data

In alignment with OGMP 2.0, this methodology quantifies emissions using bottom-up methods, which are compared and reconciled against top-down, site-level emissions. Site-level measurements attempt to discover unexpected or high-emitting sources not captured using bottom-up methods to assist in more accurately quantifying emissions and improving confidence in reported values. Based on the facility type, configuration, and expected emissions distribution, measurement method(s) are selected to provide comprehensive and cost-effective coverage of site emissions. Detection limits and confidence intervals for each data source are discussed with the technology vendors and quantified where possible.

- Bottom-up data
    - LDAR
        - Survey equipment components (valves, PRVs, open-ended lines, flanges, and threaded connectors), gas-driven pneumatic devices, and atmospheric storage tank vents using OGI camera or EPA Method 21 Survey
        - Identify methane leaks/sources of leaks visually using OGI camera or based on methane concentration readings using Method 21 survey
    - Direct measurement of methane emissions mass rate for certain sources
        - Hi-Flow Sampler testing performed concurrently with LDAR surveys, direct measurement of methane emissions mass rate for the following sources:
            - Centrifugal compressor wet seal and dry seal gas vents
            - Reciprocating compressor rod packing seal vent
            - Blowdown vent through-valve leakage
            - Fugitive emissions detected during LDAR survey from equipment components, malfunctioning pneumatic devices, etc.
    - Stack Testing
        - Testing content of methane, carbon dioxide, and other contaminants in the exhaust gas from compressor engines and turbines.
        - Testing of destruction and removal efficiency (DRE) for thermal oxidizers and other enclosed emissions control equipment.

- Top-down data
    - Aerial / flyover data
        - Semi-annual aerial surveys to capture top-down, site-level measurements
        - Screen for changes to baseline conditions throughout the year
    - Near-CEMS (rapid detection, with potential use as top-down measurement tool)
        - Near-Continuous Emissions Monitoring Systems (near-CEMS) for low-latency emissions detection. Field trials are in progress to evaluate the effectiveness of using certain near-CEMS technologies with quantification capabilities as a high-frequency top-down measurement source.
    - Satellite data (potential future top-down detection or measurement tool)
        - Advanced methane detection satellites are scheduled for launch beginning 2023+ and may be added as an additional source for top-down emissions detection or measurement with more frequent repass, pending successful performance validation.

8 Data Management

8.1 Asset-Grade Data

Enhancing trust in data is at the heart of Context Labs technology. All data used to measure, model, or report on emissions or emissions intensity is supported by data surety processes to be considered "Asset-Grade Data" ("AGD"). Asset-grade data is data that has an immutable, auditable, end-to-end lineage to irrefutably prove the data has never been manipulated or otherwise corrupted. AGD is validated through the reconciliation of multiple sources, with accuracy attested by recognized third-party verifiers or subject matter experts.

Context Labs accomplishes this using several advanced methods.

- Contextual Data Fabric Technology: integrating and reconciling operational (SCADA) data and emissions data from multiple sources, including flyover, satellite, near-continuous emissions monitoring systems, and periodic leak and vent surveys (as available) to produce a more accurate representation of ground truth
- 'Digital Notaries': incorporating recognized third-party verifiers and subject matter experts that submit digitally signed statements attesting to the origin, integrity, and/or accuracy of a raw data input or analytics results
- Immutable Provenance: at each point where data is created, transformed, combined, analyzed, or accessed, a 'Digital Proof' is created and published to a distributed ledger (i.e., blockchain) for tracking and to immutably preserve data provenance and lineage throughout the full data lifecycle

8.2 Contextual Data Fabric

A contextual data fabric (CDF) is a centrally managed means for integrating disparate data sources intelligently and securely as a unified semantic data layer. The software architecture consists of a set of data services that provide consistent means to secure and access data integrated from a variety of discrete sources across multiple cloud environments. Advantages include:

- Data discovery and metadata-driven insights
- Data access and control
- Data privacy and security (protection)
- Data veracity (provenance and 3rd party attestations See Fig. 3).

A CDF is a data fabric system that uses extensive metadata to contextualize each data element. This metadata includes the pedigree and provenance (who, what, where, when) of the underlying data payload as well as contributions from other (often 3rd party) sources adding related information (facts) or attesting to the veracity of the underlying data. These additional facts (truths) can be used to analyze patterns of behavior, produce advanced analytics, or quantify the degree to which data can be trusted. At the heart of these capabilities lies graph analytics, which is used to infer relationships (connect data to other data) and structure (understand the relatedness or interdependencies between data, allowing the synthesis of new data).

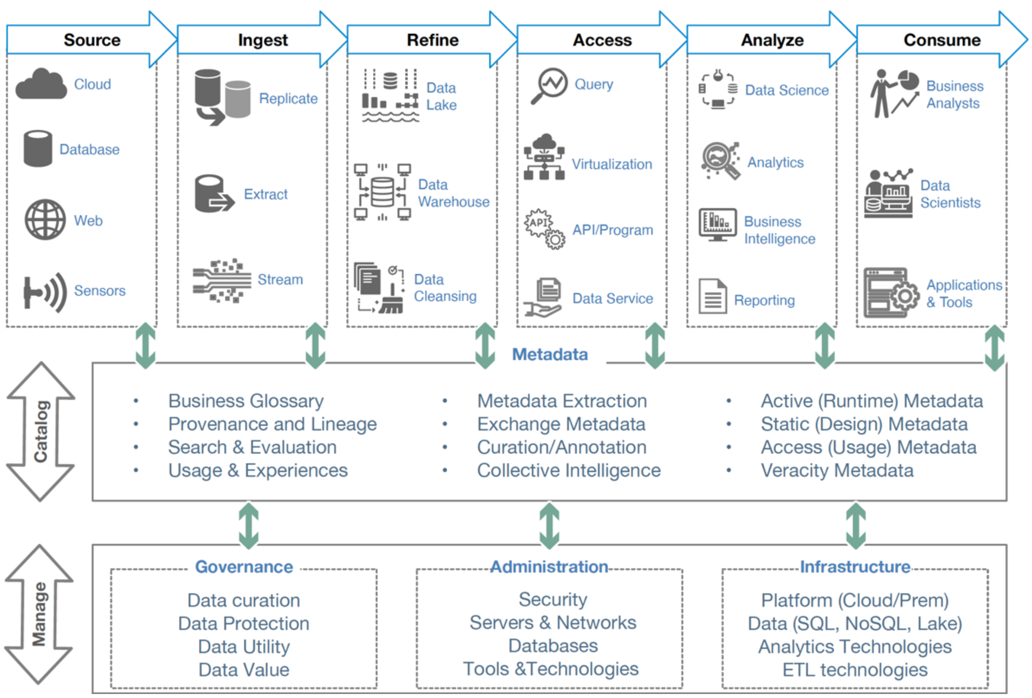


Figure 2. Contextual Data Fabric – Core Components and Features

The CDF used in this application ingests direct measurements from multiple best-in-class detection sources (see Sections 10 and 11) to deliver the most accurate digital representation of ground truth asset operations performance and their ambient environmental impact.

8.3 Immutably Data Platform

The Immutably™ Data Platform is a CDF that specializes in multi-source ingestion and digital processing. The system can manage an arbitrary number of oracles that augment the data payload by submitting additional metadata facts to describe the context, as well as notaries that consist of qualified third parties and subject matter experts ("SME") that can attest to the veracity of the data payload through digitally signed statements. The Immutably™ Data Platform creates an infrastructure that provides the ability to trace acquired data (traceability) back to the point of origination. To ensure complete auditability, all data within Immutably is recorded to a distributed ledger (blockchain).

As previously mentioned, verification of data is performed through Digital Notaries. A Digital Notary is an entity, individual, or group of individuals with relevant expertise and purview to attest to the quality of data generated. In the context of environmental/emissions monitoring and measurement, Digital Notaries could include (not limited to):

- Emissions Performance Testing Vendors
- LDAR Technicians
- Satellite Data Analysts
- External 3rd Party Verifiers

Notaries are responsible for providing artifacts that support the validity and integrity of the acquired data/measurements. It is possible to apply additional algorithms to "weight" the efficacy of each data feed based on established criteria surrounding each data point. For example – if a Notary cannot attest to the validity of a certain set of data points, then the resulting data points could be down-weighted—or disposed of altogether if the measurements are unreliable. Digital Notarization can be performed by human beings or algorithmically through executable programs, depending on the specific application.

8.4 Distributed Ledger and Identity

At the heart of the CDF is the notion of a trusted identity. All data and entities within the system must be assigned a unique, unforgeable identity used as the basis for linkage, but also non-repudiation via digital signatures. Traditionally, Public Key Infrastructure (PKI) has relied upon unsafe propagation of certificates and identities, but in Immutably, this is done using distributed ledger technology.

9 Data Quality Levels & Exception Reporting

9.1 Data Quality Levels

To incentivize continuous improvement in emissions monitoring and quantification processes while recognizing the practical challenges of real-world operations, facilities and companies may progress along the following Next Gen Gas methodology levels as they acquire additional data. These current categorizations reflected below are *qualitative* at this time, though in the future it is intended to develop *quantitative* confidence intervals to indicate the uncertainty of the emissions reflected on the certificates.

- **Basic:** emissions sources quantified using generic emissions factors from recognized industry publications, generally guided by 40 CFR 98 Subparts C & W and OneFuture. Analogous to OGMP 2.0 Level 3.

- **Good:** emissions sources quantified following Next Gen Gas Methodology Section 10 below, including site- and equipment-specific emissions and activity factors leveraging periodic site measurement and other approved methods. Analogous to OGMP 2.0 Level 4.

- **Better:** emissions sources quantified following Next Gen Gas methodology, including periodic top-down/ bottom-up reconciliation analyses following Next Gen Gas Methodology Sections 10 & 11. Includes site- and equipment-specific emissions and activity factors leveraging site measurements and other approved methods, combined with top-down, site-level emissions reconciliation. Analogous to OGMP 2.0 Level 5.

- **Best:** emissions sources quantified following Next Gen Gas methodology, with near-continuous monitoring system deployed onsite for Primary Emitting Facilities (defined in Section 10.1), allowing for rapid detection of abnormal conditions with potential for frequent automated top-down/ bottom-up reconciliation. This builds on and exceeds the requirements of OGMP 2.0 Level 5.

9.2 Exception Reporting

The categorizations mentioned above consider the materiality of different emissions sources for each facility. Meeting OGMP 2.0 Level 4 requires Level 4 measurements to be performed for sources that account for a target 90% of site emissions, with a minimum threshold of 70% with a justification for why 90% was not reached.

In some instances, companies or individual facilities may not have the ability to complete the detailed source-level monitoring outlined in Section 10 for certain material emissions sources. This may be due to the lack of available data or suitable measurement technology, or impractically high cost associated with measurement. Where measurements can be performed on sources that account for 70% of site emissions but cannot meet the 90% target, the sources without source-level measurement will be disclosed on the environmental attribute certificate for transparency. The emissions for these sources will be estimated using best-available data, which could include industry-wide or company-specific emission factors.

10 Bottom-Up Source-Level Emissions Calculations

The basic shared approach of methane emissions calculation methods is to categorize all known types of methane emissions and provide breakdowns by source type. The sources include continuous emission sources, as well as discontinuous or intermittent sources and events. With appropriate source-level measurements, routine methane emissions from many sources can be reasonably determined using engineering calculations based on periodic measurements combined with site operating data. Bottom-up source-level calculations described in this section will be

supported by top-down site-level measurements described in Section 11, which can identify the presence of unexpected or high-emitting sources not captured in the bottom-up calculations.
To satisfy measurement requirements defined by OGMP 2.0 and the GTI Veritas Protocol, source-level testing meeting OGMP 2.0 Level 4 is performed on sources expected to account for a target of >90% of site methane emissions (>70% minimum with acceptable written justification why >90% cannot be met—see Section 9.2). In order to ensure this target is met on an ongoing basis, at least annually the measurement results at each facility will be evaluated to determine whether new emissions sources have been identified and to assess whether a change in measurement technology or frequency is warranted to better capture and quantify site emissions.

10.1 Primary Emitting Facilities

Certain types of locations with more complex process operations and larger counts of potential emissions sources have been identified as primary emitting facilities. All primary emitting facilities of the following types will have rigorous measurement-informed bottom-up source-level emissions calculations described below, combined with top-down measurement technology described in Section 11:

- Wellpads
- Upstream Central Delivery & Processing Sites
- Compressor Stations
- Gas Treating Facilities
- Gas Processing Facilities
- LNG & Underground Storage Facilities

Common greenhouse gas emissions sources at natural gas facilities include:

- Combustion Engines and Turbines
- Reciprocating & Centrifugal Compressor Vents
- Reciprocating Engine Crank Case Venting
- Gas Starters
- Atmospheric Storage Tanks
- Gas-Driven Pneumatic Devices
- Desiccant Dehydrators
- Glycol Dehydrators
- Acid Gas Removal
- Well Liquid Unloading
- Casinghead or Annulus Vent
- Component Leaks
- Blowdowns
- Control devices (e.g., flares, thermal oxidizers, and combustors)
- Electricity Usage

Standard source-level calculations are enhanced through higher frequency measurement of unit or site-specific emissions rates. Bottom-up measurements will be conducted using the following methods:

For Upstream & Compressor Stations:

- Screening for leaks (Quarterly)
    - Screening could be performed using OGI surveys or Method 21 surveys
- Methane emissions mass rate measurement for certain sources (Quarterly)
    - Hi-Flow Sampler testing performed concurrently with LDAR surveys
    - Direct measurement of methane emissions mass rate for several sources:
        - Centrifugal compressor wet seal and dry seal gas vents
        - Reciprocating compressor rod packing seal vent
        - Blowdown vent through-valve leakage
        - Fugitive emissions detected during LDAR survey from equipment components, malfunctioning pneumatic devices, etc.
- Exhaust gas stack testing (Annually)

For Gas Processing Plants

- Screening for leaks
    - Complete annual survey. If results show that emissions from equipment leaks >5% of the overall site emissions, increase frequency and conduct semi-annual surveys for at least one year. If results show that emissions from equipment leaks >10% of the overall emissions, increase frequency and conduct quarterly surveys for at least one year.
    - Screening could be performed using OGI surveys or Method 21 surveys
- Methane emissions mass rate measurement for certain sources (concurrent with leak survey)
    - Hi-Flow Sampler performed concurrently with leak surveys
    - Direct measurement of methane emissions mass rate for several sources:
        - Centrifugal compressor wet seal and dry seal gas vents
        - Reciprocating compressor rod packing seal vent
        - Blowdown vent through-valve leakage
        - Fugitive emissions detected during LDAR survey from equipment components, malfunctioning pneumatic devices, etc.
- Exhaust gas stack testing (Annually)

Within this method, bottom-up source-level emissions estimates are calculated using well-established engineering relationship found in 40 CFR Part 98 Subparts C and W, and recognized industry methodologies, as detailed below and in Table 1. Until first quarter emissions measurements are made, historic facility measurements, company-based emissions factors, or industry-based generic emissions factors may be used as best available data.

1. <u>Combustion Exhaust</u>:
    - Monitoring methodology:
        - Conduct annual stack test, with methane analysis, for each operating engine. For turbines and fired heaters, conduct stack test where feasible, otherwise use emission factors in AP-42 Compilation of Air Pollution Emissions Factors.
        - Until first stack test is conducted, use stack test from same engine or turbine model at same facility; or
        - If stack test results are unavailable for the facility, use default methane emission factors in AP-42 - Compilation of Air Pollution Emissions Factors.
        - Measure monthly fuel use if possible, or calculate using run hours x heat rate

- Methane Calculation methodology:
  - Stack test result (lb CH_4/MMBtu) x mt/lb x fuel use (MMBtu/month).
- CO_2 Calculation methodology:
  - Stack test result (lb CO_2/MMBtu) x mt/lb x fuel use (MMBtu/month).
  - If stack test is unavailable, for pipeline quality fuel:
    - 40 CFR 98.33(a) Equation C-1, C-1a, or C-1b
  - If stack test is unavailable, for non-pipeline quality fuel:
    - Proposed 40 CFR Part 98.233(z) Equation-W-39A
- N_2O Calculation methodology:
  - For pipeline quality fuel
    - 40 CFR 98.33(c) Equation C-8 or C-8a
  - For non-pipeline quality fuel:
    - Proposed 40 CFR Part 98.233(z) Equation W-40

2. Compressor Vents:
   - Monitoring methodology:
     - Conduct quarterly compressor monitoring survey. For each compressor:
       - Record as-found operating mode; and
       - Measure vented flow rates with Hi-Flow Sampler for:
         - Dry seal gas vents (pressurized mode); and
         - Wet seal degassing vents (pressurized mode); and
         - Rod packing vents (pressurized mode); and
         - Blowdown vents (if through-valve leakage is found during LDAR survey).
     - For compressors with dry seal gas vents, engineering estimate of leak rate may also be used where sufficient data is available
     - For each compressor, measure monthly operating hours in each of three operating modes:
       - Operating-pressurized mode; and
       - Standby-pressurized mode; and
       - Not operating-depressurized mode.
   - Methane and CO_2 Calculation Methodology:
     - 40 CFR Part 98.233 (o)(6) Equations W-21, W-22, W-23 & W-24B
     - 40 CFR Part 98.233 (p)(6) Equations W-26, W-27, W-28, & W-29B
     - 40 CFR Part 98.233 (u) Equation W-35
     - 40 CFR Part 98.233 (v) Equation W-36

3. Reciprocating Engine Crankcase Venting:
   - Monitoring methodology:
     - Track the number of crankcase vents per engine
     - Where feasible, conduct measurement of crankcase vent rate & composition
   - Methane Calculation methodology:
     - If measurement is available
       - Measured vent rate x mol frac CH_4 x CH_4density (mt CH_4/scf) x operating hours

- If measurement is not available
  - Number of vents x 36 scfh CH_4 x CH_4 density (mt CH_4/scf) x operating hours
- CO_2 Calculation methodology:
  - Number of vents x Vent rate x mol frac CO_2 x CO_2 density (mt CO_2/scf) x operating hours

4. Engine Gas Starters:
   - Monitoring methodology:
     - Track the number of engine starts monthly
     - Option 1: Measure fuel consumption for each start using fuel gas meter
     - Option 2: Determine fuel consumption per start from vendor documentation OR engineering estimate, and use calculations below
   - Methane Calculation methodology:
     - # of starts x Fuel consumption/start x mol frac CH_4 x CH_4 density (mt CH_4/scf)
   - CO_2 Calculation methodology:
     - # of starts x Fuel consumption/start x mol frac CO_2 x CO_2 density (mt/scf)

5. Atmosphere Storage Tanks:
   - Monitoring methodology:
     - Monitor transmission storage tank vent with quarterly screening to detect upstream stuck-open dump valve(s);
     - Monitor gathering and processing storage tanks with regular screening or perform engineering estimate of vent emissions per 40 CFR Part 98.233 (j)
     - If continuous flow is detected, use Hi-Flow Sampler to measure leak rate.
   - Methane and CO_2 Calculation methodology:
     - 40 CFR Part 98.233 (k)(1) – (k)(4) and 40 CFR Part 98.233 (j)(1)-(j)(7)

6. Gas -Driven Pneumatic Devices:
   - Monitoring methodology:
     - Add gas-driven intermittent pneumatic devices to regular screening surveys for equipment components;
     - Use properly functioning EPA emission factor for intermittent devices with no leaks;
     - Use measured leak rate for malfunctioning devices where available, otherwise use malfunctioning EPA emission factor for intermittent devices with leaks;
     - Use EPA population emission factors for low-bleed and high-bleed continuous devices.
   - Methane and CO_2 Calculation methodology:
     - For intermittent devices:
       - Proposed 40 CFR Part 98.233 (a)(6) Equation W-1B (06/21/22)
     - For low-bleed and high-bleed continuous devices:
       - 40 CFR Part 98.233 (a) Equation W-1
       - 40 CFR Part 98.233 Table W-1A
       - 40 CFR Part 98.233 Table W-3B
       - 40 CFR Part 98.233 (u) Equation W-35
       - 40 CFR Part 98.233 (v) Equation W-36

7. Desiccant Dehydrators
    - Monitoring methodology:
        - Track the number of vessel openings monthly
        - For each vessel opening measure:
            - Gas pressure
            - Physical volume of desiccant dehydrator vessel
            - Void ratio of desiccant dehydrator vessel (i.e., % of packed vessel volume occupied by gas)
    - Methane and CO_2 Calculation methodology:
        - 40 CFR Part 98.233 (e)(3) Equation W-6

8. Glycol Dehydrators
    - Monitoring methodology:
        - Measure monthly operating hours; and
        - Measure annual representative inlet gas temperature, inlet gas pressure, inlet gas flowrate, and glycol circulation rate; and
        - Document glycol pump type (gas-driven or electric), use of flash tank separator, and controls on flash tank vent and regenerator vent.
    - Methane and CO_2 Calculation methodology:
        - Conduct annual emissions modeling using GRI-Glycalc or Promax or other acceptable software to obtain lb CH_4/hr and lb CO_2/hr from flash tank vent, and lb CH_4/hr and lb CO_2/hr from regenerator vent.
        - 40 CFR Part 98.233 (e)(1)

9. Acid Gas Removal Units:
    - Monitoring methodology:
        - Track the number of acid gas removal units per site
        - Conduct measurement of acid gas removal vent rate and concentration. Alternatively, perform engineering estimates using material balance or process simulation
    - Methane Calculation methodology:
        - Proposed 40 CFR 98.233 (d) Calculation Methods 2-4
        - If no measurement or process simulation is available, use emission factor of 42762.8817 kg CH_4/ AGR / year for uncontrolled AGR vents.
    - CO_2 Calculation methodology:
        - 40 CFR 98.233 (d) Calculation Methods 2-4

10. Well Liquid Unloading
    - Monitoring methodology:
        - Track the number of unloading events for each well monthly
        - Record time that well was left open to atmosphere
        - Method 1:
            - Measure vent gas flowrate by installing a recording flow meter on vent (measure wells with and without plunger lifts separately)
            - Performed annually, for at least one well per pad of each unique well tubing diameter group and pressure group (per 40 CFR 98.238).

- Method 2:
  - For wells without plunger lift:
    - Record shut-in pressure or surface pressure for wells with tubing production or casing pressure for wells without packers
  - For wells with plunger lift:
    - Record flow-line pressure based on engineering estimate
- Methane and CO_2 Calculation methodology:
  - Method 1:
    - 40 CFR Part 98.233 (f)(1) Equation W-7A and W-7B
  - Method 2:
    - 40 CFR Part 98.233 (f)(2) Equation W-8
    - 40 CFR Part 98.233 (f)(3) Equation W-9

11. Casinghead or Annulus Vent
- Monitoring methodology:
  - Record the number of monthly hours the annulus is vented to atmosphere
  - Measure and record annulus vent gas flowrate by installing flow meter on vent
- Methane Calculation methodology:
  - Vent rate (scf/hr) x mol frac CH_4 x CH_4 density (mt CH_4/scf) x vent hrs /month
- CO_2 Calculation methodology:
  - Vent rate (scf/hr) x mol frac CO_2 x CO_2 density (mt /scf) x vent hrs /month

12. Components (emissions from valves, PRVs, open-ended lines, flanges, threaded connectors)
- Monitoring methodology:
  - Conduct regular screening surveys to identify and repair leaks; and
  - Use Hi-Flow Sampler to measure leak rates in lieu of EPA emission factors. Hi-Flow Sampler device type should be known to inform if leak rate represents whole gas or methane only.
  - Leak duration will be calculated per the following approach:
    - If the start date of the leak is known, this date will be used. If the start date is unknown, the leak will be applied starting from the previous survey. The leak duration will end when it is confirmed to be repaired.
- Calculation Methodology for Devices that Measure Whole Gas Rate:
  - Methane Calculation methodology:
    - Leak rate (scf/hr) x mol frac CH_4 x CH_4 density (mt CH_4/scf) x leak hrs
  - CO_2 Calculation methodology:
  - Leak rate (scf/hr) x mol frac CO_2 x CO_2 density (mt /scf) x leak hrs
- Calculation Methodology for Devices that Measure Methane Rate:
  - Methane Calculation methodology:
    - Leak rate (scf/hr) x CH_4 density (mt CH_4/scf) x leak hrs
  - CO_2 Calculation methodology:
    - Leak rate (scf/hr) / mol frac CH_4 x mol frac CO_2 x CO_2 density (mt/scf) x leak hrs

13. Blowdowns at Primary Emitting Facilities:
    - Monitoring methodology:
        - Track blowdowns monthly; and
        - For each blowdown, measure:
            - Gas temperature; and
            - Gas pressure at beginning of blowdown; and
            - Gas pressure at end of blowdown; and
            - Physical volume of equipment being blown down.
    - Methane and CO_2 Calculation methodology:
        - 40 CFR Part 98.233 (i)(2) Equation W-14B OR Equation W-14A; and
        - 40 CFR Part 98.233 (u) Equation W-35; and
        - 40 CFR Part 98.233 (v) Equation W-36.

14. Control Devices (e.g., flares, thermal oxidizers, and combustors)
    - Monitoring methodology:
        - Where a flare or thermal oxidizer is unlit, a DRE of 0% shall be used
        - Where methane slip from flares or combustors is expected to constitute >2% of site methane emissions OR there is reasonable concern of low methane destruction efficiency, conduct initial stack test or process simulation to determine DRE within three (3) months if technically feasible AND repeat annually thereafter. Scenarios include:
            - Expected low DRE from process design or stack/tip specification
            - Known mechanical damage to stack/tip
            - High methane emissions identified using a site-level flyover
        - Where methane slip from flares is expected to constitute <2% of site methane emissions AND there is no cause to suspect low methane destruction efficiency, a methane DRE of 98% may be assumed;
        - Measure waste gas volume to flare or thermal oxidizer monthly. In cases where measured data is not available, engineering estimates will be used in the interim with an acceptable written justification and documented exception.
    - Methane Calculation methodology:
        - Gas vol (scf/month) x mol frac CH_4 x CH_4 density (mt CH_4/scf) x (1–DRE)
    - CO_2 Calculation methodology:
        - 40 CFR Part 98.233(n) Equation W-20
        - 40 CFR Part 98.233 (u) Equation W-35
        - 40 CFR Part 233 (v) Equation W-36
    - N_2O Calculation methodology:
        - Proposed 40 CFR Part 98.233(z) Equation W-40
        - 40 CFR Part 98.233 (u) Equation W-35
        - 40 CFR Part 233 (v) Equation W-36

15. Electrical Usage (Scope 2):
    - Monitoring methodology:
        - Track electricity usage per month
    - Methane Calculation methodology:
        - Electricity usage (MWh) x Grid-specific emission factor (lb CH_4 / MWh)
    - CO_2 Calculation methodology:
        - Electricity usage (MWh) x Grid-specific emission factor (lb CO_2 / MWh)
    - N_2O Calculation methodology:
        - Electricity usage (MWh) x Grid-specific emission factor (lb N_2O / MWh)

10.2 Minor Emitting Facilities

Emissions that occur outside of Primary Emitting Facilities must also be accounted for. Typically, these locations contain fewer, less complex process operations and relatively small counts of potential emissions sources. As a result, emissions of significant volumes of greenhouse gases are not expected during normal operating conditions. Nonetheless, emissions of minor amounts of greenhouse gases can occur during normal operations, and significant emissions can occur during abnormal conditions due to integrity-related issues or system maintenance, such as blowing down a segment of the pipeline prior to performing a repair or upgrade.

- Pipeline Segments
- Valve Sites
- Meter Stations
- Pig Launchers/Receivers

A similar approach is taken combining bottom-up source-level emissions calculations described with top-down measurement technology described in Section 11. However, as these sources account for low portions of total system emissions and are distributed across large land areas, rigorous source-level measurement and near-continuous emissions monitoring is not always feasible. As a result, company-based emissions factors or industry-based emissions factors are relied on as best available data for bottom-up source-level emissions calculations.

1. Pipeline Leaks
    - Monitoring methodology:
        - Obtain pipeline mileage by material type on a quarterly basis.
    - Calculation methodology:
    - 40 CFR Part 98.233 (r) Equation W-32A; and
    - Use pipeline material type emission factor(s) in 40 CFR Part 98.233 Table W-1A; and
    - 40 CFR Part 98.233 (u) Equation W-35; and
    - 40 CFR Part 98.233 (v) Equation W-36.

2. <u>Pipeline Stations (including Valve Sites and Meter Stations)</u>
    - Monitoring methodology:
        - Obtain count of pipeline stations by station type
        - For Valve Sites, develop engineering estimates of population emissions factors for similar sites using best-available data to estimate the counts of individual equipment components at each site
    - Calculation methodology:
        - 40 CFR 98.233 (r) Equation W-32A; or
        - 40 CFR 98.233 (r) Equation W-32B

3. <u>Blowdowns of Pipeline Segments & Pig Launcher/Receivers</u>
    - Monitoring methodology:
        - Track blowdowns monthly; and
        - For each blowdown, measure:
            - Gas temperature; and
            - Gas pressure at beginning of blowdown; and
            - Gas pressure at end of blowdown; and
            - Physical volume of equipment or piping being blown down.
    - Calculation methodology:
        - 40 CFR Part 98.233 (i)(2) Equation W-14B; and
        - 40 CFR Part 98.233 (u) Equation W-35; and
        - 40 CFR Part 98.233 (v) Equation W-36.

Methane Emissions Source	Calculation Methodology	Parameter Measured	Measurement Method / Instrument	Data & Measurement Frequency
Engine and Turbine Combustion Exhaust	Stack test result (lb CH_4/Btu) x fuel use (Btu/month) - preferred;	Fuel Use; Run-hours	Measured Fuel (scf), Calculated Fuel (scf), Run-hours - SCADA or Ops Logs	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as available
	Stack test result (lb CH_4/hr) x mt/lb x hrs/month - alternate	lb CH_4 / MMBtu of Fuel; lb CH_4 / hr	Stack Test - EPA Approved Method	Annually
Centrifugal Compressor Vents	40 CFR Part 98.233(o)(6) Equation W-21 & W-22	Run hours in Operating Pressurized Mode	Run Status Indicator, Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
		Run hours in Standby Pressurized Mode	Run Status Indicator, Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
		Run hours in Not-Operating Depressurized Mode	Run Status Indicator, Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
	40 CFR Part 98.233(v) Equation W-36	As-found Mode	Visual Observation during Compressor Monitoring Survey	Quarterly
		Uncontrolled Dry Seal Gas Vent Measurement	Hi-Flow Sampler or Portable Flowmeter during Compressor Monitoring Survey, or Flowmeter-SCADA if present	Near-real time SCADA feeds for Flowmeter (primary); Quarterly for Surveys (secondary)
		Uncontrolled Wet Seal Gas Vent Measurement	Hi-Flow Sampler or Portable Flowmeter during Compressor Monitoring Survey, or Flowmeter-SCADA if present	Near-real time SCADA feeds for Flowmeter (primary); Quarterly for Surveys (secondary)
		Uncontrolled Blowdown Vent Measurement (through-valve leakage)	Hi-Flow Sampler or Portable Flowmeter during Compressor Monitoring Survey, or Flowmeter-SCADA if present	Near-real time SCADA feeds for Flowmeter (primary); Quarterly for Surveys (secondary)
Reciprocating Compressor Vents	40 CFR Part 98.233(p)(6) Equation W-26 & W-27	Run hours in Operating Pressurized Mode	Run Status Indicator, Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
		Run hours in Standby Pressurized Mode	Run Status Indicator, Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
		Run hours in Not-Operating Depressurized Mode	Run Status Indicator, Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
	40 CFR Part 98.233(v) Equation W-36	As-found Mode	Visual Observation during Compressor Monitoring Survey	Quarterly
		Uncontrolled Rod Packing Vent Measurement	Hi-Flow Sampler or Portable Flowmeter during Compressor Monitoring Survey, or Flowmeter-SCADA if present	Near-real time SCADA feeds for Flowmeter (primary); Quarterly for Surveys (secondary)
		Uncontrolled Blowdown Vent Measurement (through-valve leakage)	Hi-Flow Sampler or Portable Flowmeter during Compressor Monitoring Survey, or Flowmeter-SCADA if present	Near-real time SCADA feeds for Operating Mode ; Quarterly for Surveys (secondary)
Reciprocating Engine Crank Case Venting	If measurement is available Measured vent rate x mol frac CH_4 x CH_4 density (mt CH_4/scf) x operating hours If measurement is not available Number of vents x 36 scfh CH_4 x CH_4 density (mt CH_4/scf) x operating hours	Vent rate and composition	Field surveys	Quarterly
Gas Starters	Number of starts x Fuel consumption per start x mol frac CH_4 x CH_4 density (mt CH_4/scf)	Number of starts, fuel consumption per start	Flowmeter if available; best available data and engineering calculations otherwise	Near-real time SCADA feeds (preferred); or monthly Engineering Calcs (alternate), as Available
Atmospheric Storage Tanks	40 CFR Part 98.233 (k)(1) - (k)(4) and 40 CFR Part 98.233 (j)(1)-(j)(7)	Non-Hydrocarbon Tanks (Gas Blowby from Stuck-open Dump Valves)	OGI Camera and Hi-Flow Sampler	Quarterly
		Hydrocarbon Liquid Tanks	Detailed Process Engineering Simulation	Monthly or Annually, based on Variability and Materiality
Gas-Driven Pneumatic Devices	For intermittent devices: Proposed 40 CFR Part 98.233 (a)(6) Equation W-1B (06/21/22)	Number of properly functioning pneumatic devices from quarterly OGI leak survey; and Number and leak rate of malfunctioning pneumatic devices from quarterly OGI leak survey	OGI Camera	Quarterly
	For low-bleed and high-bleed continuous devices: 40 CFR Part 98.233(a) Equation W-1; and 40 CFR Part 98.233 Table W-1A; and 40 CFR Part 98.233 Table W-3B: and 40 CFR Part 98(u) Equation W-35; and 40 CFR Part 98(v) Equation W-36	Count of Continuous Low Bleed Devices; and Count of Continuous High Bleed Devices	Manual Count from Operations; Monthly MOCs	Monthly
Desiccant Dehydrators	40 CFR Part 98.233 (e)(3)	Vessel opening count, gas pressure	Pressure Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
Glycol Dehydrators	40 CFR Part 98.233(e)(1)	Glycol Pump Run Hours	Glycol pump run status or Inlet Gas Flowrate - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
		Dehy vent gas flow rate and composition	Detailed Process Engineering Simulation	Annually
		Control on Flash Tank, Control on Regenerator Vent	Control Hours - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
		Glycol Pump Type, Use of Flash Tank Separator	Ops Log	Annually
Acid Gas Removal Units	Proposed 40 CFR 98.233 (d) Calculation Methods 2-4 If no measurement or process simulation is available, use emission factor of 42762.8817 kg CH_4 / AGR / year for uncontrolled AGR vents.	AGR vent rate and composition	Field surveys	Annually
Well Liquid Unloading	Method 1: o40 CFR Part 98.233 (f)(1) Equation W-7A and W-7B	Vent gas flow rate (Method 1)	Flow Meter	Near-real time SCADA feeds (preferred), or monthly Ops Logs for local flowmeter (alternate), as Available
	Method 2: o40 CFR Part 98.233 (f)(2) Equation W-8 o40 CFR Part 98.233 (f)(3) Equation W-9	Shut-in pressure or surface pressure for wells with tubing production or casing pressure for wells without packers (Method 2)	Field instrumentation	Near-real time SCADA feeds (preferred), or monthly Ops Logs for local meters (alternate), as Available
Casinghead or Annulus Vent	Vent rate (scf/hr) x mol frac CH_4 x CH_4 density (mt CH_4/scf) x vent hrs /month	Number of hours per month that venting occurred	Ops Log	Monthly
		Annulus vent flow rate	Flow Meter	Near-real time SCADA feeds (preferred), or monthly Ops Logs for local flowmeter (alternate), as Available
Equipment Components (Fugitive emissions from valves, PRVs, OELs, flanges, threaded connectors)	Leak rate (scf/hr) x mol frac CH_4 x CH_4 density (mt CH_4/scf) x hrs leaking / month	Number of leaking equipment components; and Leak rate (scf/hr) of each equipment component during quarterly leak survey	OGI Camera and Hi-Flow Sampler, Gas Chromatograph	Quarterly
		Number of hours per month that each equipment component leaked	Review of Leak Detection and Leak Repair Records in Leak Tracker Pro	Monthly
Blowdowns at Primary Emitting Facilities	40 CFR Part 98.233(i)(w) Equation W-14B; and 40 CFR Part 98.233(u) Equation W-35; and 40 CFR Part 98.233(v) Equation W-36	Blowdown Count, Beginning Pressure, Ending Pressure, Temperature, Physical Volume	Facilities: Pressure Indicator, Temperature Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available
Control Devices (e.g., flares, thermal oxidizers, and combustors)	Waste gas volume (scf/month) x mol frac CH_4 x CH_4 density (mt CH_4 / scf) x (1 - Destruction & Removal Efficiency (DRE))	Destruction and Removal Efficiency (DRE)	No measurement - 98 % DRE	Annual
		Run hours	Run Status	Near-real time SCADA feeds (preferred); or monthly Engineering Calcs (alternate), as Available
		Waste Gas Throughput (scf)	Flowmeter if available; best available data and engineering calculations otherwise	
Electrical Usage (Scope 2)	Electricity usage (MWh) x Grid-specific emission factor (lb CH_4 / MWh)	Monthly electrical usage	Company billing records	Monthly
Pipeline Leaks	40 CFR Part 98.233(r) Equation W-32A 40 CFR Part 98.233 Table W-1A 40 CFR Part 98.233 (u) Equation W-35 40 CFR Part 233 (v) Equation W-36	Pipeline mileage (mi) by Material Type	GIS Department Database	Quarterly
Pipeline Stations (including valve sites and meter stations)	40 CFR 98.233 (r) Equation W-32A; or 40 CFR 98.233 (r) Equation W-32B	Count of pipeline stations by type Valve sites - Engineering estimates of EF to estimate counts	GIS Department Database	Quarterly
Blowdowns of Pipeline Segments and Pig Launcher/Receivers	40 CFR Part 98.233(i)(2) Equation W-14B; and 40 CFR Part 98.233(u) Equation W-35; and 40 CFR Part 98.233(v) Equation W-36	Blowdown Count, Beginning Pressure, Ending Pressure, Temperature, Physical Volume	Pipelines: Pressure Indicator, Temperature Indicator - SCADA or Ops Log	Near-real time SCADA feeds (primary), or monthly Ops Logs (secondary), as Available

Table 1. Bottom-up methane emissions monitoring and quantification summary

10.3 Statistically Representative Sampling

Previous sections of this methodology specify measurement approaches to be completed in support of reliable, measurement-based emissions quantification. It is nonetheless recognized that performing these measurements on every individual emissions source or device may not be operationally or economically feasible, and may not produce an improved understanding of actual emissions profiles in all cases due to the law of large numbers. Where equipment or devices associated with emissions sources are sufficiently similar, statistical sampling may be utilized to enable the development of measurement-based equipment- or source-specific emissions factors. Groupings of equipment may consider equipment class/type, operating mode, manufacturer/model, time in operation, etc. Generally, groupings of similar equipment should be assessed for populations following similar design bases, typically an asset/operating unit, division, or segment level rather than a single-site or whole-company level.

To be representative, a minimum number of independent emissions source measurements must be captured. The population size listed in Table 2 below refers to the total population of individual devices or emissions sources of a given type. In general, measurement campaigns are likely to be coordinated and conducted on a site-by-site basis for cost and time efficiency. Enough sites should be included to ensure that the total number of emission sources sampled exceeds the sample size reflected in the table below as a percentage of the total population of devices. Note, within the Next Gen Gas Program, statistical sampling under this methodology is applied to bottom-up test methods and the deployment of near-continuous emissions monitoring devices only. Top-down, site-level flyovers should be performed for all covered facilities to screen for large, unexpected sources not included in the measurement-informed bottom-up emissions quantification.

Site selection for measurement campaigns should consider the risk of large or abnormal emissions. Risk factors could include facility age, history of emissions or large emissions events, unstable process operations, thermal cycling from frequent shut-down & restart, high operating pressure, high throughput, different operational modes, etc. While there is no prescriptive approach to determining which sites/equipment should be sampled, best effort should be made so that all sites/equipment are surveyed over multiple measurement cycles, though higher-risk facilities should be revisited more frequently. All applicable site/facility types (e.g. well sites, compressor stations, gas processing facilities, liquefaction plants, etc.) should be represented within a sampling campaign.

Year 1

When initiating a sampling program, company-specific statistical properties, such as the measurement mean and variance for each emissions source, may not be known. As a result, the sample size requirements will differ in year one in order to provide an initial sample set to estimate the company-specific measurement mean and variance to use for further refinement. The table below is modeled from Matrix 1 in OGMP 2.0 Reconciliation and Uncertainty Technical Guidance Practice[10] for high-materiality sources (noting that, following OGMP guidance, for source-level quantification, virtually all sources fall within 'Simple' category.)

Population Size	Sample Size
< 10	>20%
> 10	>15%
> 100	>10%
> 1,000	>5%

Table 2. Statistically Representative Sample Size Requirements (modelled from OGMP 2.0)

Year 2+

In subsequent years, when more is known about company-specific measurement distributions, the sample size should be calculated using established statistical methods to achieve a desired uncertainty and confidence in emissions quantification. As one example, for a lognormal distribution, the required sample size can be calculated using the equation below referenced from GTI Veritas Guidance for Uncertainty Calculations (v2.0, Mar 2024)[11].

$$n = \frac{2s_y^2 + s_y^4 + 2d + \sqrt{4s_y^4 + 4s_y^2(s_y^4 - 2d) + (s_y^4 + 2d)^2}}{4d}$$

Where,

$$d = \left(\frac{\ln(b+1)}{z_{1-\frac{\alpha}{2}}}\right)^2$$

s_y^2 = measurement sample variance
α = confidence level
b = uncertainty

At this time, reasonable ranges are permitted for confidence level (≥90%) and uncertainty (≤30%). Additional research is in progress to further refine and optimize statistically representative sampling and uncertainty in total emissions reporting to be included in future updates to this methodology.

11 Top-Down, Site-Level Measurements and Site Emissions Reconciliation

Several studies have demonstrated that a significant fraction of emissions originate from a relatively small fraction of sources with higher-than-expected emissions. The use of advanced top-down measurement technology within this methodology helps to more rapidly identify the presence of unexpected or high-emitting sources over and above those identified using bottom-up emissions covered in Section 10. This strategy will be implemented in order to perform timely remediation, to more accurately quantify resulting methane emissions, and to improve confidence in reported emissions values.

Top-down site-level monitoring is most commonly performed using aerial technologies to perform periodic surveys to measure whole-site methane emissions from planes or drones. Several vendors offer similar services, such as Bridger Technologies, Scientific Aviation, and LaSen, amidst many others. At a minimum, periodic top-down surveys must be performed semi-annually at Primary Emitting Facilities and Minor Emitting Facilities.

Sensing technology is evolving rapidly and may provide additional tools to increase the frequency or accuracy of top-down measurement supporting reconciled quantification of full-site emissions. Advanced satellite detection technologies are scheduled for launch beginning 2023+ and may provide an alternative for top-down measurement with more frequent repass, pending successful performance validation. Additionally, advanced near-continuous emissions monitoring systems (near-CEMS) provide a powerful tool for low-latency emissions detection. Field trials are currently in progress to evaluate the effectiveness of using certain near-CEMS technologies with quantification capabilities as a high-frequency top-down measurement source—including tower-mounted lasers and hyper/multi-spectral gas cloud imaging (GCI) cameras with quantification capabilities.

- Monitoring methodology:
  - Semi-annual aerial (airplane) surveys will be conducted to:
    - Detect significant methane emissions sources and events not captured by bottom-up methods at facilities and along pipelines in order to expeditiously address them; and
    - Screen for temporal changes by facility and pipeline segment; and
    - Reconcile against methane emissions quantification from bottom-up methods.
- Quantification methodology:
  - Accumulated aerial scanning data will be processed through the surveyor's proprietary algorithms and will be analyzed by the surveyor's data technicians.
    - Methane concentration, mass, and plume dimension information will be calculated and provided by the aerial surveyor in a report. The vendor shall also provide uncertainty bands and detection thresholds for all flyover measurements or near-CEMS measurement devices.
- Reconciliation of top-down site-level measurements with bottom-up source-level calculations will be conducted after each aerial survey as follows:
  - First, determine and document if any portion of top-down measured emissions originate from outside the monitored facility and should be excluded from analysis.
  - Top-down measurement devices generally have higher minimum detection thresholds and may not capture all sources, particularly those with small emissions rates. Measurement devices also have uncertainty bounds that must be factored into the reconciliation analysis and may vary based on environmental conditions and distance. Detection threshold and uncertainty bound information will be determined for the top-down measurement based on vendor input and/or industry references.
  - Compare top-down measurement (including uncertainty range) with measurement-informed bottom-up inventory. Bottom-up inventory should be time-matched to the period when the top-down measurement was taken.
  - If total measurement-informed, temporally-matched bottom-up emissions are within range of the site-level measurement (including measurement uncertainty ranges), use bottom-up emissions calculations.
  - If total measurement-informed, temporally-matched bottom-up emissions are outside the range of site-level measurement (including measurement uncertainty ranges), a root cause analysis should be performed to try to determine the source of the increased emissions. The root cause analysis will incorporate knowledge of

site operating conditions/ changes, engineering judgment, measurement uncertainty, and temporal effects.

- Using facility operating and maintenance records, determine and document if site-level survey captures routine episodic emissions with high instantaneous emissions rate included in bottom-up emissions (e.g., compressor blowdown).
- Using facility operating and maintenance records, determine and document if site-level survey captures routine episodic emissions with high instantaneous emissions rate *NOT* included in bottom-up emissions (e.g., depressurizing equipment for intrusive maintenance).
    - Calculate additional emissions either:
        - Using starting pressure, ending pressure, temperature, and equipment volume as described in 10.1.13 Blowdowns; or
        - Using facility operating and maintenance data, estimate the start and end time of the elevated emissions to calculate: [Elevated Emissions Rate (lb/hr) – Normal Emissions Rate (lb/hr)] x Duration of Event (hr)
    - Evaluate whether emissions source is likely to reoccur and should be added to known sources calculated in Section 10.
- Determine if site-level survey captures emissions from a correctable defect
    - Once malfunction has been corrected, using facility operating and maintenance data or prior emissions testing, estimate the start and end time of the elevated emissions to calculate: [Elevated Emissions Rate (lb/hr) – Normal Emissions Rate (lb/hr)] x Duration of Event (hr)
- If top-down measurement captures a new emissions source that is not included in bottom-up estimate, or measures a higher emissions rate for a known source, add the top-down measurement to the inventory.
- If significant uncertainty in the measurement estimates or source attributions is found to hinder root cause analysis, site-level measurement may be repeated to obtain a reliable sample to perform reconciliation or a change in the top-down measurement approach should be considered.

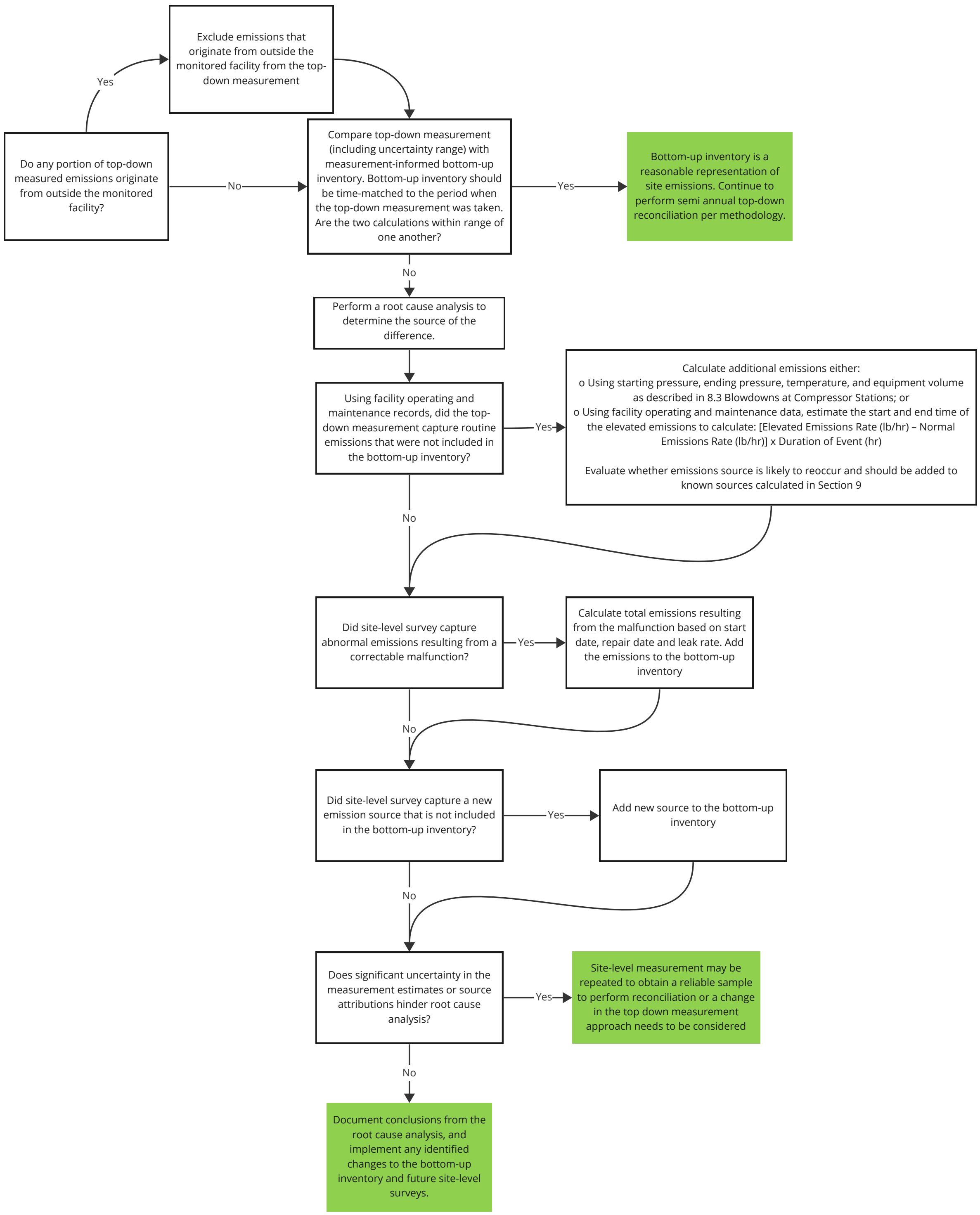


Figure 3. Reconciliation Process Flowchart

12 Emissions Allocation Method for End-to-End Emissions Tracking

For end-to-end emissions tracking from the wellhead to the final delivery point, the emissions associated with a specific oil or gas product shipment/delivery are added up for each emissions point across the supply chain. To accomplish this, the full flow path must be known from the point of origin (e.g., a well pad) to the final point of delivery (e.g., an industrial or utility offtaker, etc.).

Understanding emissions allocation at the well pad is relatively straightforward, as there is typically only one flow path out from the facility for the gas stream (wet or dry) and one for the liquid stream (if present). In this case, total methane emissions need only be allocated proportionately to the gas stream and liquid stream (if present). For the midstream, however, due to the nature of system operations, some additional analysis is required.

12.1 Production Segment

Where oil is produced simultaneously with gas, in accordance with the NGSI Methane Emissions Intensity Protocol V1.0 (2021), methane emissions should be allocated to each product stream proportional to the total energy produced in each stream. The following equations are reproduced from the NGSI Protocol:

The total energy produced (E_{ng}) in the gas stream is the product of the volume of gas produced (V_{ng}) multiplied by the energy content of the gas (EC_{ng}):

$$E_{ng} = V_{ng} * EC_{ng}$$

The total energy produced (E_{liq}) in the liquid stream is the product of the volume of liquids produced (V_{liq}) multiplied by the energy content of the hydrocarbon liquids (EC_{liq}):

$$E_{liq} = V_{liq} * EC_{liq}$$

The gas ratio is the total energy produced in the gas stream divided by the total energy of produced gas and liquids:

$$Gas\ Ratio\ (GR) = \frac{E_{ng}}{E_{ng} + E_{liq}}$$

The liquid ratio is the total energy produced in the liquid stream divided by the total energy of produced gas and liquids:

$$Liquid\ Ratio\ (LR) = \frac{E_{liq}}{E_{ng} + E_{liq}}$$

Methane emissions attributed to the gas stream and liquid streams are equal to the total methane emissions at the site multiplied by the gas ratio and liquid ratio, respectively:

$$Methane\ Emissions_{ng} = Total\ Methane\ Emissions * GR$$

$$Methane\ Emissions_{liq} = Total\ Methane\ Emissions * LR$$

Where the total gas or total liquid produced by a single well pad is sold to different customers, the same emissions intensity per unit is applied to all units produced. Methane emissions per unit for gas or liquid are simply the ratio of the emissions allocated to a product stream to the total production for that same product stream.

$$Methane\ Emissions\ per\ mt\ of\ Methane = \frac{Methane\ Emissions_{ng}}{Methane\ Production}$$

$$Methane\ Emissions\ per\ Bbl\ of\ Liquid\ Hydrocarbons = \frac{Methane\ Emissions_{liq}}{Liquids\ Production}$$

12.2 Midstream Segment

Because midstream facilities handle flows from many customers at a time, further analysis is required. For the midstream segment, once the total emissions at each operating facility are known, the total emissions from each facility need to be equitably allocated to a specific oil or gas product shipment/delivery. That is, the total emissions are subdivided and allocated proportionately to a unique ‘batch’ of oil or gas represented by an environmental attribute certificate.

It is important to note that due to mixing and fungibility across the oil & gas supply chain, the exact molecule of natural gas received from the wellhead may not be the same molecule of natural gas physically delivered to the consumer. Based on pipeline operations, tracking molecules is not possible. Nonetheless, a continuous flow path from a production source to a final delivery location with rights of ownership of the Environmental Attribute Certificates along the full path can be tracked relatively easily from end to end.

Across the midstream, emissions allocation occurs in four steps:

(1) Construct a network graph of the end-to-end system
(2) Identify the emitting facilities along the flow path
(3) Determine total throughput and emissions per unit for each emitting facility
(4) Determine total throughput and emissions per unit for pipeline segments

12.2.1 Construct a Network Graph of End-to-End System

The gas network consists of pipeline segments and locations. Locations are discrete points, and can be physical (e.g., a wellhead, a compressor station, etc.) or virtual (e.g., an administrative pooling location, etc., that exists only digitally with no physical counterpart). As an example, the Transco pipeline is comprised of over 1800 locations with pipeline segments connecting these locations. The position of a location can be identified using its pipeline milepost, i.e. the distance in miles from the origin of the pipeline.

By filtering the locations using the pipeline name and sorting them by milepost, a graph network of pipeline locations is generated by connecting each location to its adjacent neighbors.

Location ID	Short Name	Line Name	Milepost
9004065	WHARTON-TRES P M/L	TRANSCO MAINLINE	258.650
1003473	M4431 WH-VALERO XO	TRANSCO MAINLINE	265.910
1096690	GLEN FLORA (WHARTON)	TRANSCO MAINLINE	265.910
9006822	M3641 GLEN FLORA	TRANSCO MAINLINE	265.920
9009854	M4667 SPANISH CAMP XO	TRANSCO MAINLINE	271.200

Table 3. Sample locations for Transco Mainline sorted for Milepost

Receipt locations are points where gas enters the pipeline network, while delivery locations are points where gas exits the pipeline network. Some locations (e.g., wellheads, etc.) act only as receipt points, while some other locations (e.g., power generation facilities, etc.) act only as delivery points. Some locations (e.g., physical storage facilities, pipeline interconnects, etc.) can act as either a receipt or a delivery point, while other locations (e.g., compressor stations, gas treating facilities, etc.) support pipeline operations and are neither a receipt nor a delivery location—instead, all gas in the pipeline passes through.

Certain types of locations with more complex process operations and larger counts of potential emissions sources have been identified as primary emitting facilities. All primary emitting facilities of the following types will have bottom-up source-level emissions estimates, combined with top-down measurement technology, following the procedure described in Sections 8 and 9:

- Wellpads
- Compressor Stations
- Gas Treating Facilities
- Gas Processing Facilities
- Central Delivery Points

Note that primary emitting facilities are typically neither a receipt nor a delivery location. Note also that emissions between primary emitting facilities are not ignored, but rather measured or calculated and addressed as described in Section 10.2.

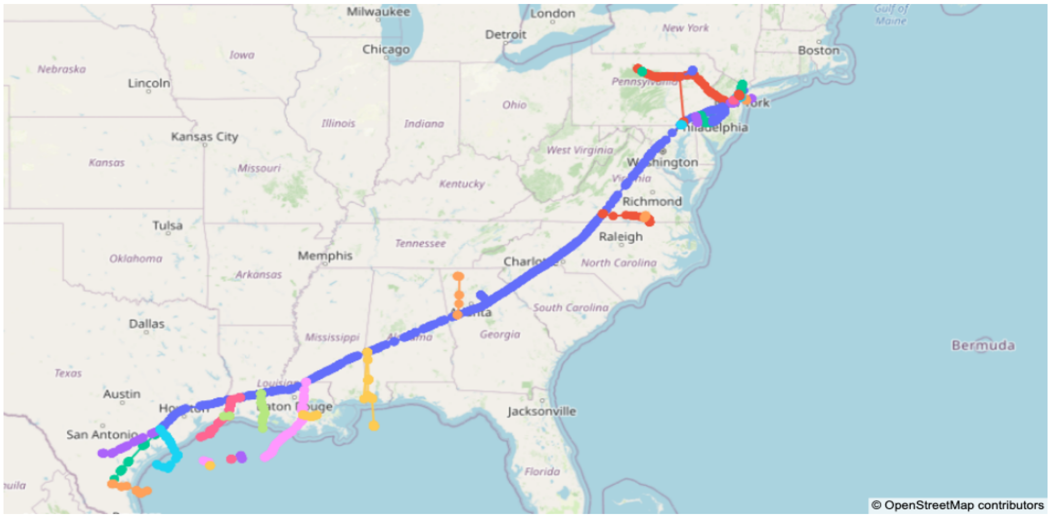


Figure 4. Map view of Transco pipeline network graph with >1800 locations connected by pipeline segment

12.2.2 Identify the Emitting Facilities Along Each Scheduled Flow Path

Once the network graph is constructed, after the flow day has occurred and allocations have been determined for each nomination, a list of primary emitting facilities along the flow path is tabulated for each nomination. First, the graph is traversed from the receipt point to the delivery point to identify the full list of locations along the flow path. Generally, it is assumed that the gas flows through the shortest path between the receipt location and the delivery location, unless a path route is specified (which could be driven by a nominated path, primary vs. secondary contract rights, etc.).

The full list of locations along the flow path is compared against the list of primary emitting facilities to determine the primary emitting facilities along the flow path.

12.2.3 Determine the Total Throughput and Emissions per Unit for Each Emitting Facility

Next, the total throughput at each emitting facility is determined and used to calculate the emissions per unit of throughput. Here, gathering & processing systems must be treated somewhat differently compared to transmission systems.

12.2.3.1 Gathering & Processing

In a gathering system, oil or gas production enters from many well pads, but predominately flows in only one direction towards a relatively small number of interconnects into transmission pipelines. It is therefore straightforward to determine total throughput through a facility by directly observing the reading of a physical flow meter (or flow meters) recording the total flow through the facility.

Gathering & processing facilities may receive wet gas streams which are separated into a dry gas stream and a condensate or natural gas liquids (NGL) stream. For gathering & processing facilities where liquids are separated from gas, in accordance with the NGSI Methane Emissions Intensity Protocol V1.0 (2021), methane emissions should be allocated to each product stream proportional to the total energy produced in each stream. The following equations are reproduced from the NGSI Protocol:

The total energy produced (E_{ng}) in the gas stream is the product of the volume of gas produced (V_{ng}) multiplied by the energy content of the gas (EC_{ng}):

$$E_{ng} = V_{ng} * EC_{ng}$$

The total energy produced (E_{liq}) in the liquid stream is the product of the volume of liquids produced (V_{liq}) multiplied by the energy content of the hydrocarbon liquids (EC_{liq}):

$$E_{liq} = V_{liq} * EC_{liq}$$

The gas ratio is the total energy produced in the gas stream divided by the total energy of produced gas and liquids:

$$Gas\ Ratio\ (GR) = \frac{E_{ng}}{E_{ng} + E_{liq}}$$

The liquid ratio is the total energy produced in the liquid stream divided by the total energy of produced gas and liquids:

$$Liquid\ Ratio\ (LR) = \frac{E_{liq}}{E_{ng} + E_{liq}}$$

Methane emissions attributed to the gas stream and liquid streams are equal to the total methane emissions at the site multiplied by the gas ratio and liquid ratio, respectively:

$$Methane\ Emissions_{ng} = Total\ Methane\ Emissions * GR$$

$$Methane\ Emissions_{liq} = Total\ Methane\ Emissions * LR$$

Methane emissions per unit for gas or liquid are simply the ratio of the emissions allocated to a product stream to the total production for that same product stream.

$$Methane\ Emissions\ per\ mt\ of\ Methane = \frac{Methane\ Emissions_{ng}}{Methane\ Received}$$

$$Methane\ Emissions\ per\ Bbl\ of\ Liquid\ Hydrocarbons = \frac{Methane\ Emissions_{liq}}{Liquids\ Received}$$

12.2.3.2 Transmission

In a transmission system, gas can enter and exit the pipeline at many points along the pipeline. Commercial customers can nominate to ship gas in opposing directions at the same time. In physical operations, gas cannot flow bi-directionally within a single pipe at the same point in time. Instead, the pipeline operator optimizes their pipeline asset to move the least physical gas possible, while at the same time satisfying all commercial commitments. This results in a divergence between the total volume recorded by a physical meter at a compressor station along the line, and the total commercial commitments that a pipeline operator makes with a flow path across that point in the system. For this reason, the measure of throughput for the Transmission sector is defined as the total *received volumes* allocated for nominations with flow paths crossing a given facility.

This is best illustrated with an example. For a hypothetical segment of pipe on a given flow day, consider the scenario depicted below:

- Customer #1: Nominates 360,000 dth from milepost 5 to milepost 100 (South to North)
- Customer #2: Nominates 1,000,000 dth from milepost 65 to milepost 20 (North to South)

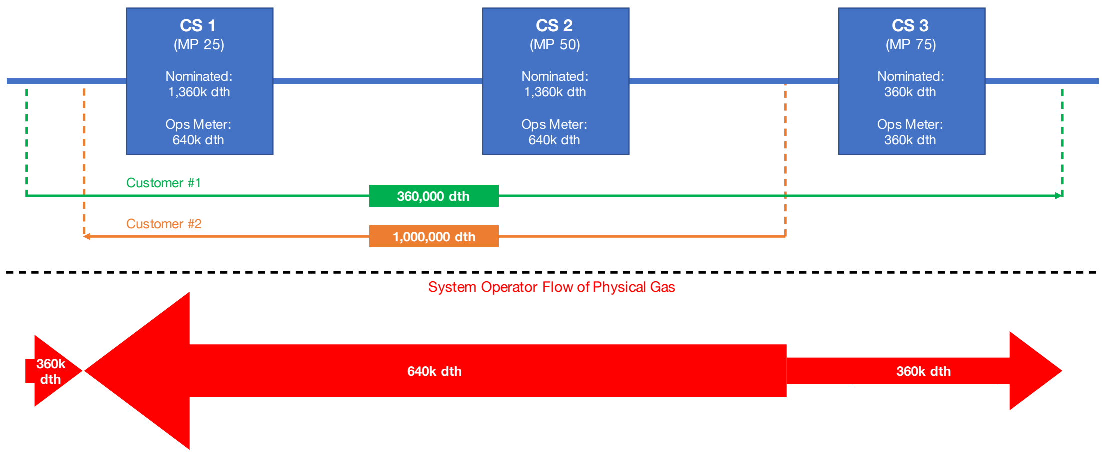


Figure 5. Commercial commitments vs. operational flow of physical gas

In this example, Customer #2 nominates to flow gas in the opposite direction compared to Customer #1. Physics will not allow flow in both directions at the same time, instead these opposing nominations result in *displacement*.

Assuming these are the only nominations on this day, in physical pipeline operations, Customer #1 will supply 360,000 dth at receipt point at milepost 5, which exits the pipeline at the delivery point for Customer #2 at milepost 20. Additionally, Customer #2 will supply 1,000,000 dth at the receipt point at milepost 65. This flow will be split, as shown, and delivered at milepost 20 (640k dth) and milepost 100 (360k dth). In this example, Customer #1 supplies 360,000 dth at milepost 5 and the same volume is delivered to the delivery point at milepost 100. Similarly, Customer #2 supplies 1,000,000 dth at milepost 65 and the same volume is delivered to the delivery point at milepost 20. However, an operational meter at Compressor Station #2 (milepost 50) will read only 640k dth, when the pipeline operator scheduled 1,360k dth of total commercial commitments to ship gas.

Due to the possibility of displacement described above, the measure of throughput for the Transmission sector is defined as the total *received volumes* allocated for nominations with flow paths across a given facility. (For illustrative purposes, using the example above, the throughput for Compressor Station #2 would be 1,360 dth.) This is done irrespective of whether a flow path is in the direction of net flow, or in the opposite direction. This method is preferred for several reasons:

1. Allows for proper overall mass balance for system emissions when all commercial shipments are certified
2. It more closely reflects the shipping choices made by customers using the pipeline system, rather than how the pipeline operator optimizes network flows
3. In the same way gas shipments can be scheduled in the direction of net flow and opposing net flow, it supports Certification both in the direction of net flow and opposing net flow
4. When taken system wide, it aligns with the NGSI Protocol, which defines total system throughput as the *total volume of gas received*

Gas transmission pipelines process only 'pipeline spec' (i.e., dry gas). Therefore, there is no allocation required for different gas and liquid product streams. Once the total throughput per facility is known, methane emissions per mt of methane is simply the ratio of the facility methane emissions to the total methane throughput for that facility.

$$Methane\ Emissions\ per\ mt\ of\ Methane = \frac{Methane\ Emissions}{Methane\ Received}$$

12.2.4 Determine Emissions per Unit for Pipeline Segments

Finally, emissions that occur outside of primary emitting facilities must also be accounted for. These emissions can occur due to integrity related issues or system maintenance, such as blowing down a segment of the pipeline prior to performing a repair or upgrade. This can also include emissions associated with valve sites and meter stations. Activities like blowing down a pipeline segment affect large portions of a midstream asset and are necessary to support the system as a whole. For that reason, throughput is defined as total natural gas received within an operating Zone. The total amount of monthly emissions from pipeline segments, valve sites, and meter stations within an operating Zone will be allocated evenly to all units of monthly gas throughput within that same Zone.

$$(Methane\ Emissions\ per\ mt\ of\ Methane)_{Pipeline} = \frac{(Methane\ Emissions)_{Zone}}{(Methane\ Received)_{Zone}}$$

12.3 Aggregate Emissions Across the Flow Path

Once the full flow path from the wellhead to the delivery point is known and emissions are normalized to a common unit of throughput, the methane emissions per metric ton (mt) of methane can be summed across the flow path. The total emissions associated with a specific oil or gas delivery are equal to the total emissions per metric ton (mt) of methane across the entire flow path, including the emissions from the pipeline, multiplied by the total delivered mass.

$$Total\ End-to-End\ Methane\ Emissions\ per\ mt\ of\ Gas\ Certified:$$

$$\left(\frac{Methane\ Emissions}{mt\ of\ Methane}\right)_{Total} = \left[\sum_{Emitting\ Facilities}\left(\frac{Methane\ Emissions}{mt\ of\ Methane}\right)\right] + \left(\frac{Methane\ Emissions}{mt\ of\ Methane}\right)_{Pipeline}$$

$$(Methane\ Emissions)_{Total} = \left(\frac{Methane\ Emissions}{mt\ of\ Methane}\right)_{Total} * mt\ of\ Methane\ Certified$$

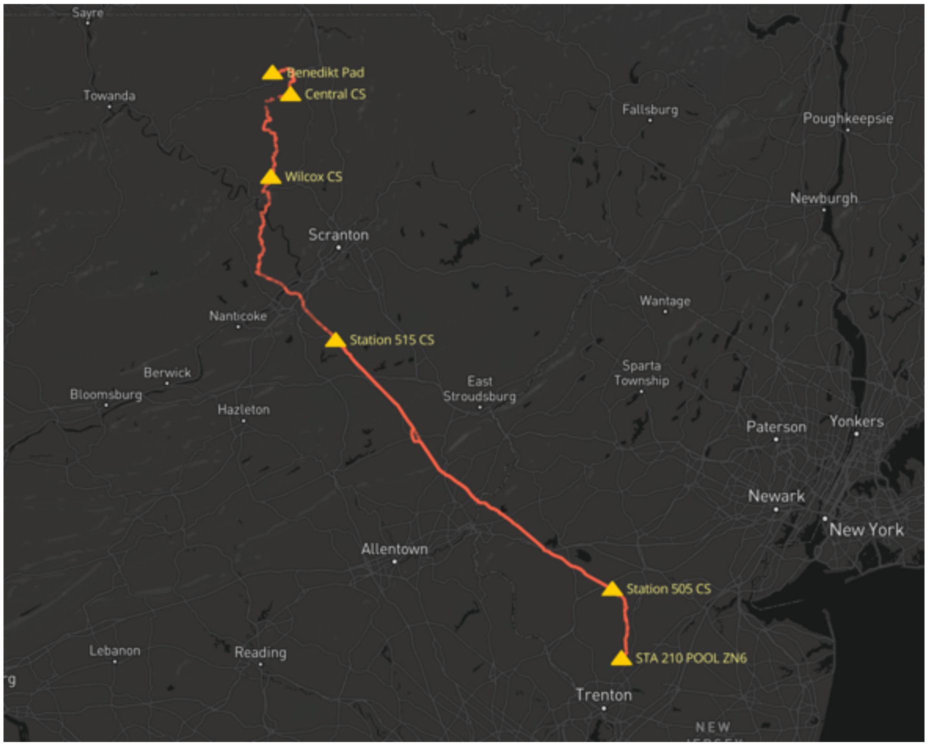


Figure 6. Emissions aggregation across the end-to-end flow path

13 Verification

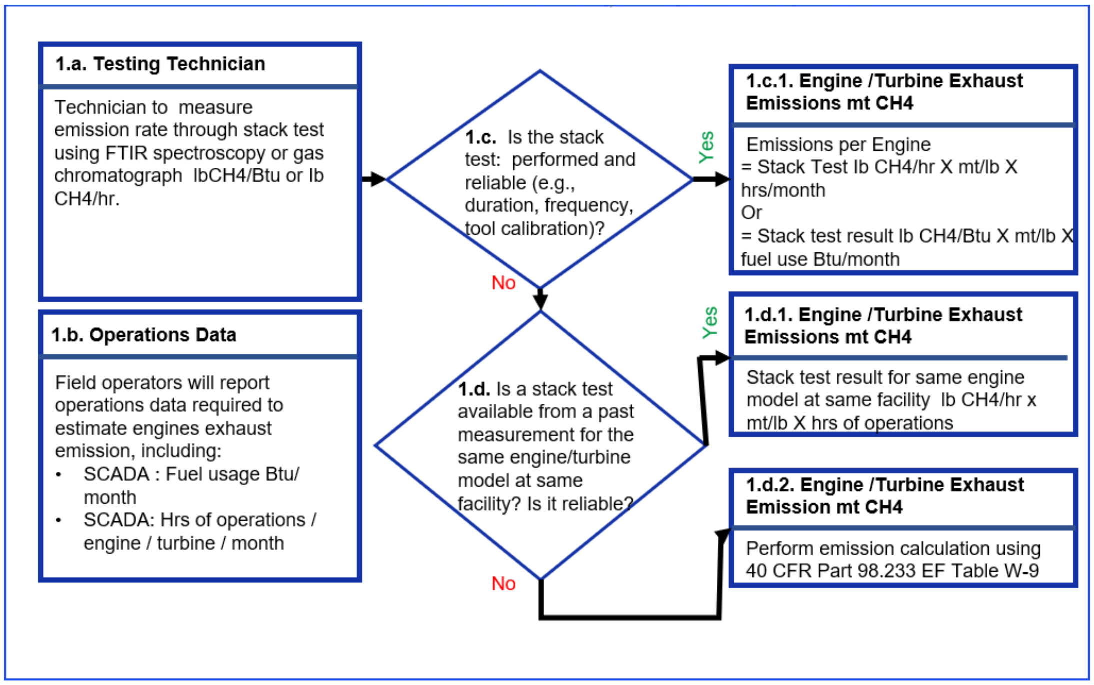
KPMG will perform a comprehensive 3rd party analysis to verify the integrity of data, its provenance, veracity, and calculations. As such, KPMG will thoroughly investigate the process by which emissions are generated, vet the approach to create measurement-based emissions inputs, and calculate aggregated emissions for verification purposes. The results of KPMG's calculation engine will allow for the preliminary screening of measurement-based emissions given historical data and relevant industry experience. With such context, baseline expectations will be set and outliers will be identified. KPMG has been assessed and authorized to perform verification in accordance with the procedures specified herein. Additional verifiers may be added in the future.

To assess and verify aggregate emissions and intensities along the flow path, KPMG will focus on: (1) understanding the approach used to create emissions inputs and site-wide emissions, (2) vetting measurement inputs, (3) and completing emissions calculations and associated screening / verification.

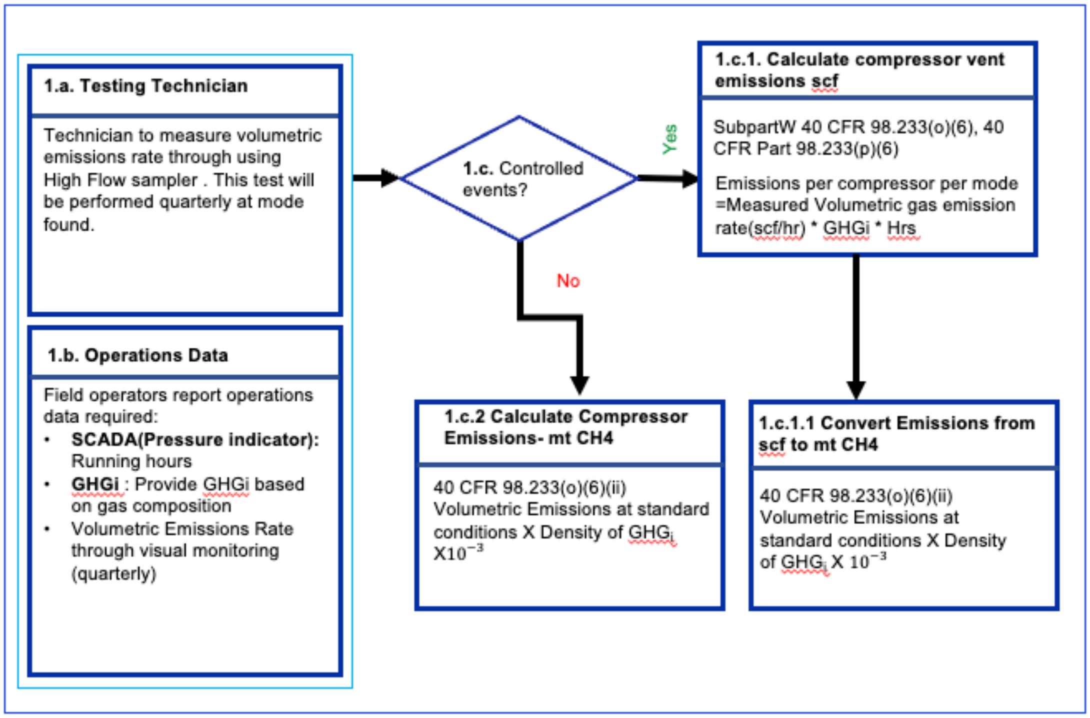
- Facility operator's approach to generate higher frequency measurement of unit or site-specific emissions rates span the following sources: (1) engine & turbine combustion exhaust, (2) reciprocating & centrifugal compressor vents, (3) gas starters, (4) reciprocating engine crank case venting, (5) atmosphere storage tanks, (6) gas-driven pneumatic devices, (7) dessicant dehydrators, (8) glycol dehydrators, (9) acid gas removal, (10) component leaks, (11) casinghead or annulus vent, (12) well liquid unloading, (13) blowdowns at emitting facilities, (14) control devices, (15) electricity consumption and (16) pipeline leaks, and (17) pipeline blowdowns.

1) The process flows outlined below, for the eleven emission sources highlighted, document the steps facility operators/Context Labs complete to translate on-site measurements and associated operational data into final emission values in metric tons.

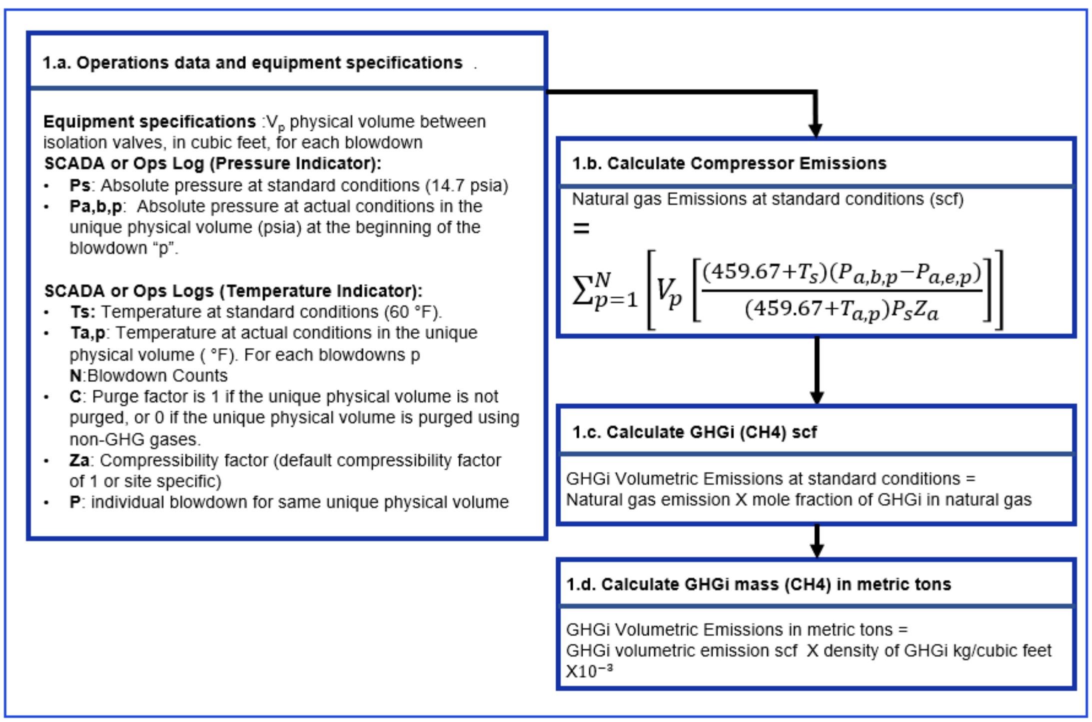
— 13.1.1.a. Engine and Turbine Combustion Exhaust



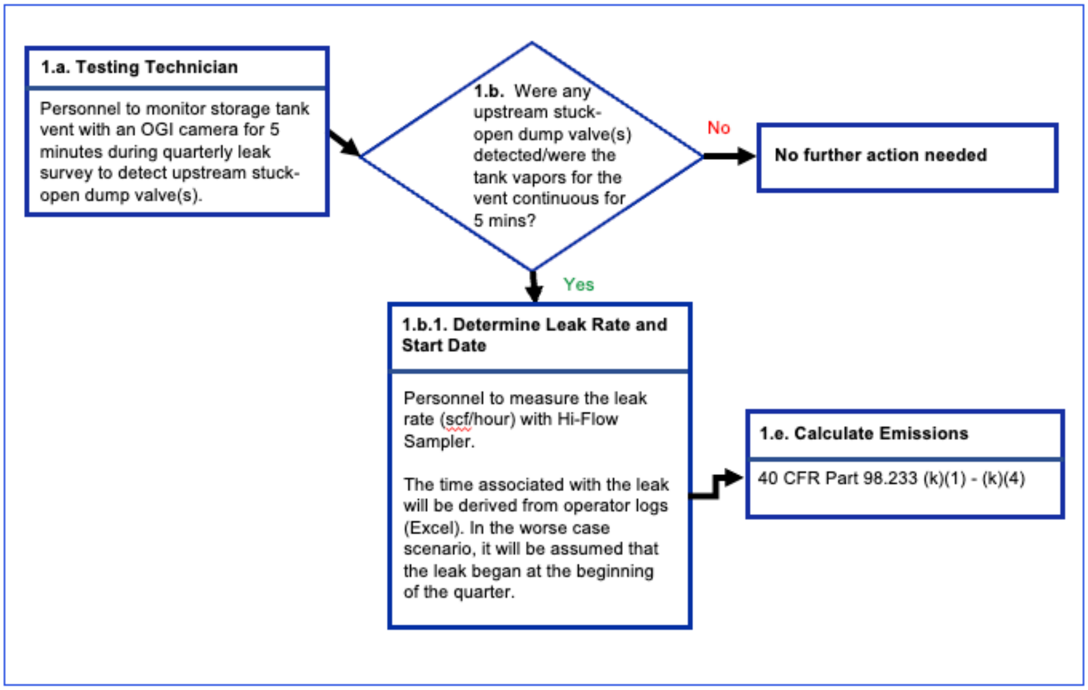
— 13.1.1.b. Compressor Vents



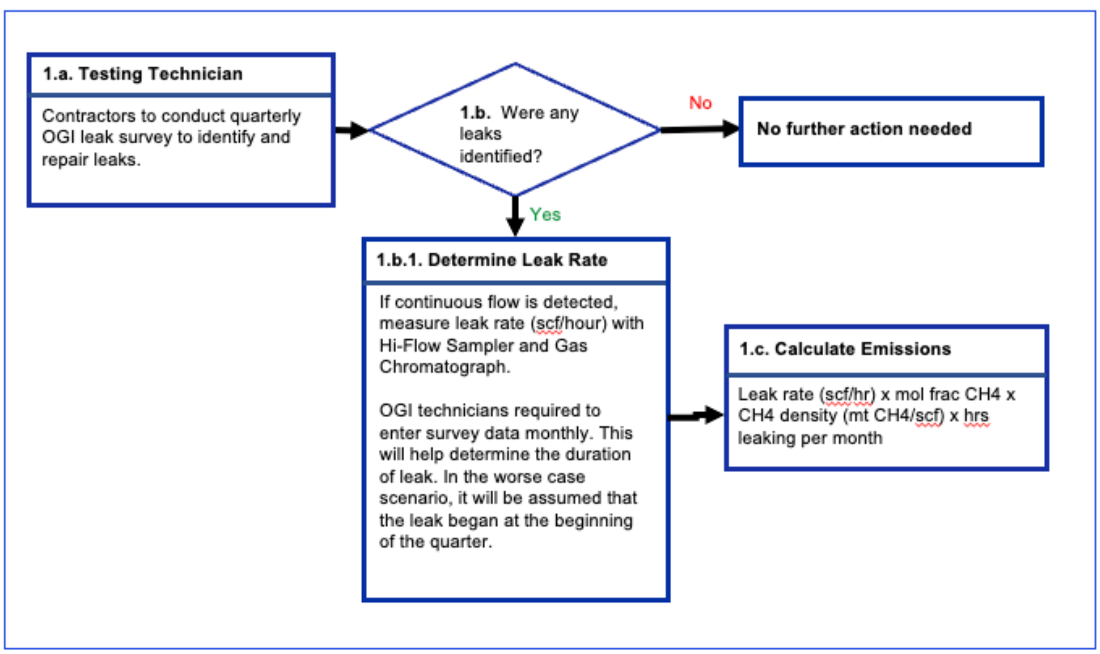
— 13.1.1.c. Blowdowns at Compressor Stations



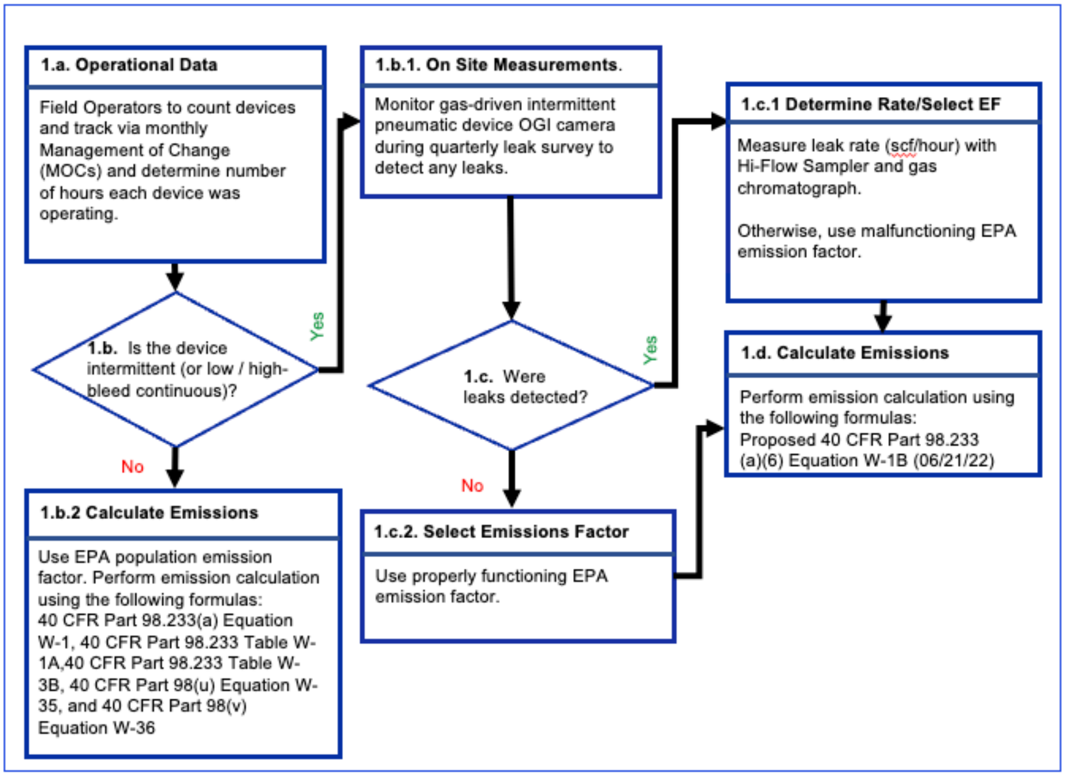
— 13.1.1.d. Atmospheric Storage Tanks (e.g., Stuck-Open Dump Valves)



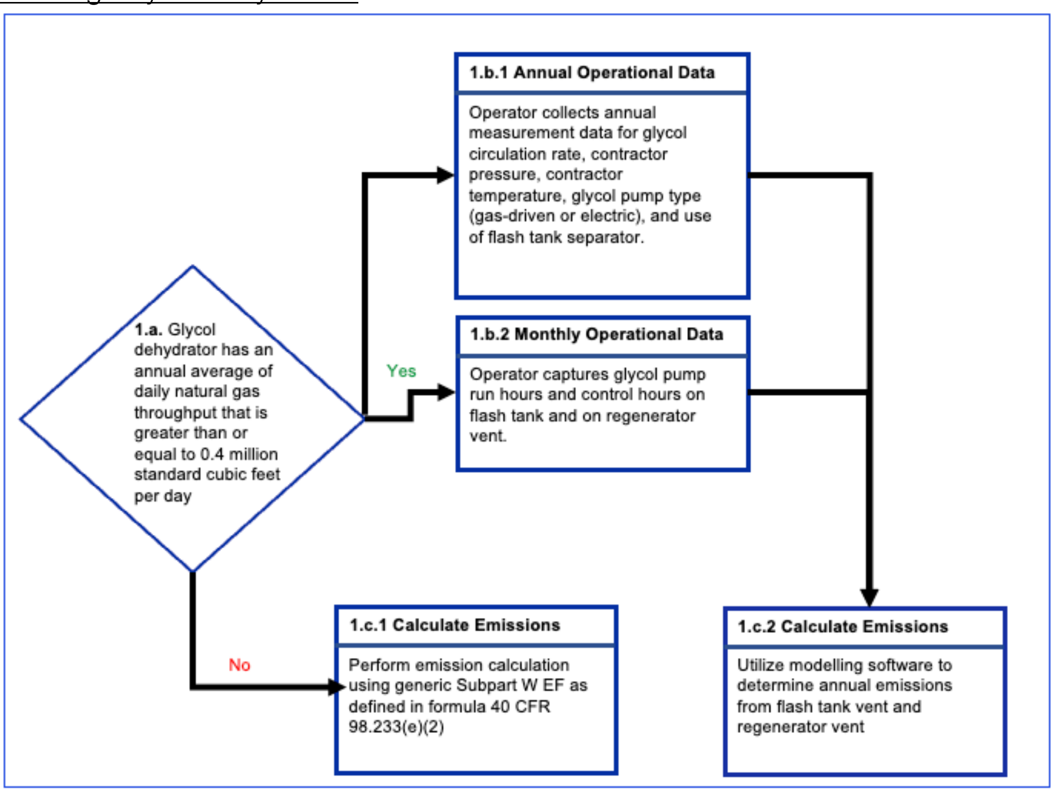
— 13.1.1.e. Equipment Components (Fugitive emissions from valves, PRVs, Open-ended lines, flanges, threaded connectors)



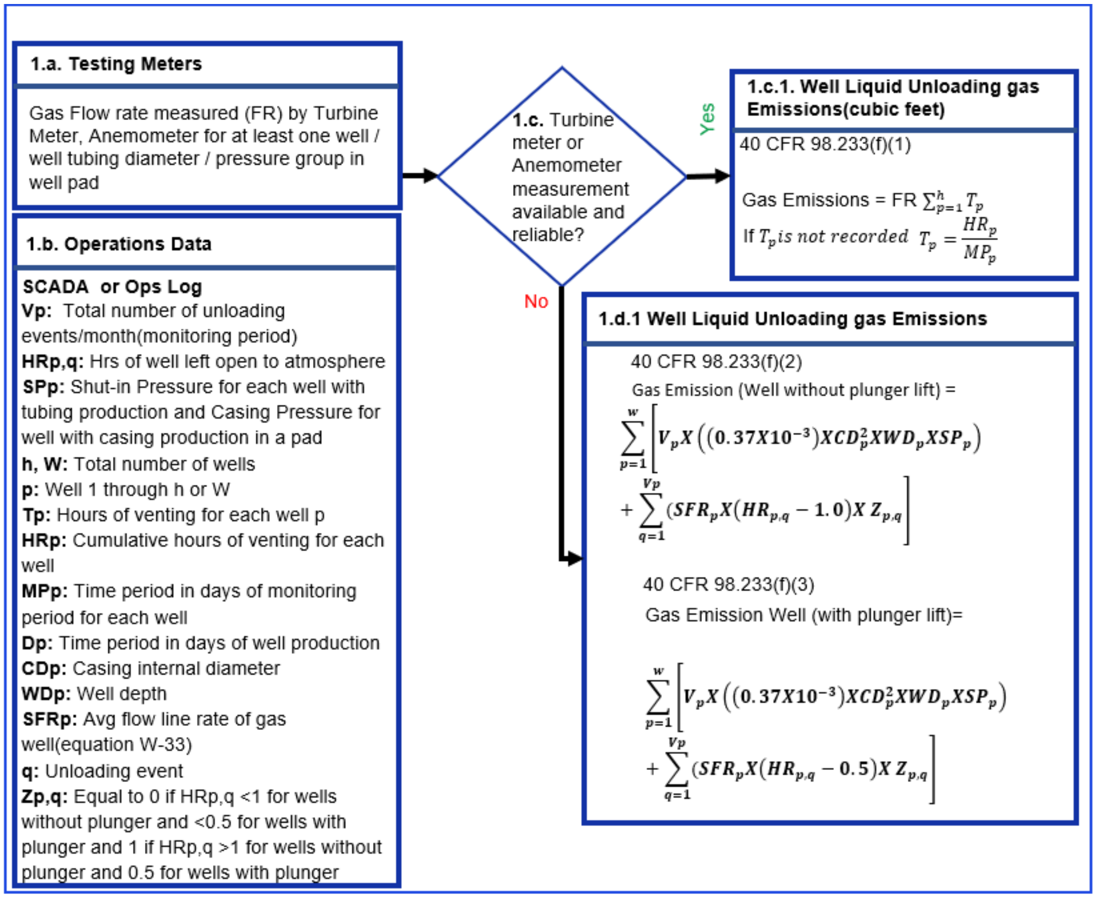
— 13.1.1.f. Gas-Driven Pneumatic Devices



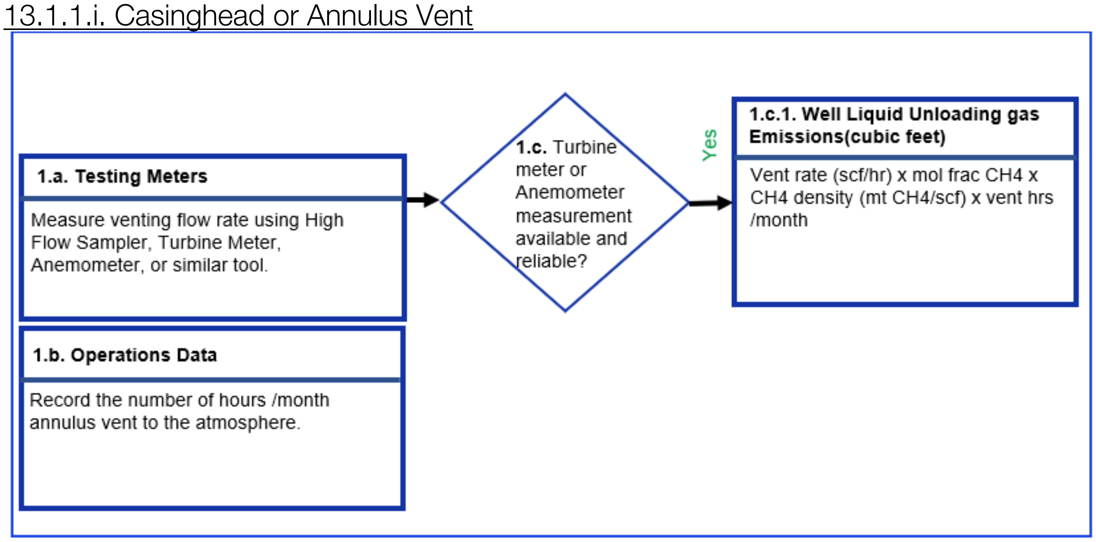
— 13.1.1.g. Glycol Dehydrators



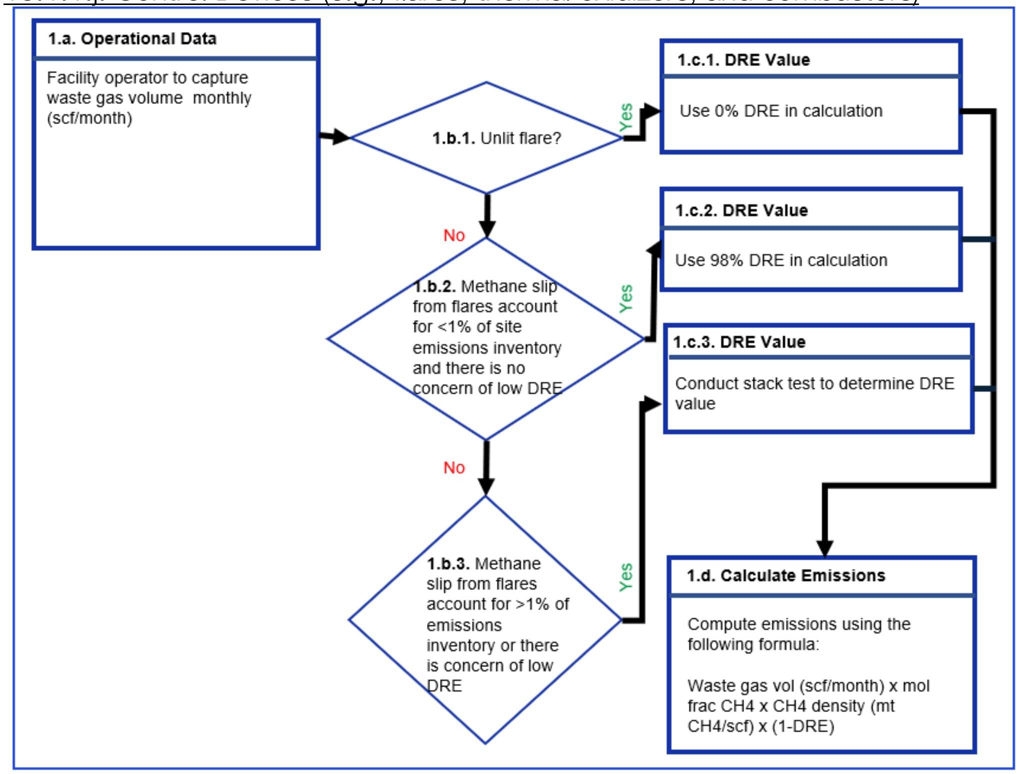
— 13.1.1.h. Well Liquid Unloading



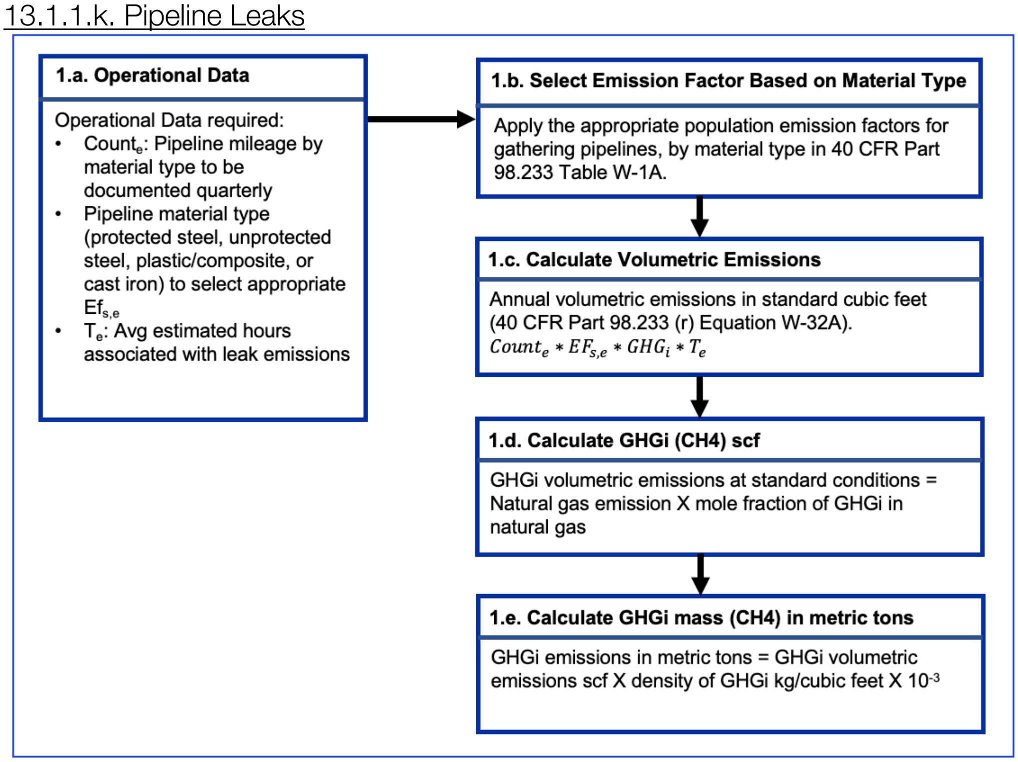
— 13.1.1.i. Casinghead or Annulus Vent



- 13.1.1.j. Control Devices (e.g., flares, thermal oxidizers, and combustors)



- 13.1.1.k. Pipeline Leaks



2) KPMG will vet the process of generating unit-specific or site-specific emission rates and values. KPMG will interview Context Labs' and facility operator's personnel to further understand the approach, as defined in section 10 of this methodology, to capture emission rates for all in scope source categories. Responses will help inform the completeness and accuracy of sampling, measurement techniques, and calculation methods as depicted in process flows for each source category in section 13.1.1. in this methodology. KPMG will utilize:
   - Original field measurements reports (e.g., Arktos RSG Surveys) to ensure data continuity from on-site measurements to calculation inputs.
   - EPA literature, equipment manufacturer manuals, and industry best practices as guidance. Questions to be asked during this process can be found below.

<u>Questions Applicable to Multiple Emission Source Categories</u>
- How will emissions testing personnel/contractors mitigate Bacharach High-Flow Sampler limitations/deficiencies (e.g., failure modes investigation, the need for regular calibration)? (Applicable to: 13.1.1.b, 13.1.1.d, 13.1.1.e, 13.1.1.f, 13.1.1.i)
- How will emissions testing personnel/contractors ensure that the instrument is capturing all the gas escaping from the component(s)? (Applicable to: 13.1.1.d, 13.1.1.e)
- How will the leak start, and end dates be appropriately deduced from the operator logs? (Applicable to: 13.1.1.d, 13.1.1.e, 13.1.1.f)
- How do you ensure that the stack test procedures align with EPA guidelines and testing requirements (e.g., taking the test at constant temperature and constant pressure)? (Applicable to: 13.1.1.a, 13.1.1.j)
- Review the calibration frequency under operation conditions as the site operation conditions. (Applicable to: 13.1.1.h, 13.1.1.i)
- Do you measure the gas flow rate annually using the turbine meter? Or do measure it more frequently and take the average annually? (Applicable to: 13.1.1.h, 13.1.1.i)

<u>Engine and Turbine Combustion Exhaust (13.1.1.a.)</u>
- Confirm that the facility operator is completing stack tests for all turbine/engines at facilities
- How long are stack tests run for?
- If stack test results are not available for every engine, will facility operator use the test results from another device at the same facility and apply it accordingly? Will the facility operator use test results for the same engine model or leverage a historic test result for the same engine? How will difference in operating conditions be accounted for?

<u>Compressor Vents (13.1.1.b.)</u>
- How does the facility operator account for different operating modes (operating-pressurized mode; and standby-pressurized mode; and not operating-depressurized mode) during quarterly compressor monitoring surveys?

Equipment Components (13.1.1.e.)

- What is the process for an OGI leak survey (are all components monitored, how are the components monitored)?

Gas-Driven Pneumatic Devices (13.1.1.f.)

- Will all pneumatic devices in all sites be monitored on sites or will a sample be leveraged for extrapolation (or rather defaulted to industry standard EF)?
- Confirmation of whether EPA emission factors or on-site measurements will be taken for intermittent pneumatic devices.
- Why are high-bleed and low-bleed continuous devices not being monitored via on-site measurements?
- Will the number of hours each device was operating be tracked or will these numbers need to be estimated?

Glycol Dehydrators (13.1.1.g.)

- Is operational input data collected for all glycol dehydrators on site or just a sample?
- Is the previous year's data used to determine whether annual average of daily natural gas throughput is greater than or equal to .4 million scf / day?

Casinghead or Annulus Vent (13.1.1.i.)

- If the measurement is deemed unreliable, what actions will be taken (e.g., will an industry average be leveraged)?

Control Devices (e.g., flares, thermal oxidizers, and combustors) (13.1.1.j.)

- Is waste gas volume captured via flowmeter or engineering calculations?
- How does facility operator determine if methane slip from flares account for <1% of site emissions inventory and there is no concern of low DRE?
- For thermal oxidizers that require stack testing, are stack tests conducted annually?

Pipeline Leaks (13.1.1.k.)

- How will the average estimated hours associated with leaks be deduced (measured or a default applied)?

3) KPMG's calculation engine will ingest, process, and validate measurement data. The engine outputs, calculated scope 1 methane emissions and average methane intensity for monthly batches of delivered gas, will be leveraged for the preliminary screening of the outputs/identification of outliers. As such, KPMG will:
   - Flag monthly data quality as well as submittal issues and collaborate with Context Labs to yield accurate calculation inputs.

- Verify executed calculations to ensure the translation of input measurements/operational data (e.g., equipment runtime, number of equipment, etc.) to yield intensities and aggregate emissions.
  - Verify equipment-level emissions calculation integrity by spot checking alignment with Subpart W formulas with Section 10 of this Methodology.
  - Calculate aggregate emissions and intensities along flow path segments and the entire flow path to confirm Immutably certificate output in alignment with the Veritas Protocol.
- Preliminarily screen processes to form baseline expectation by 1) analyzing historical standard Subpart W emission factor-based baseline values for 2021, 2020, and 2019 and 2) leveraging KPMG's existing relevant industry expertise.
  - Begin to investigate anomalies in the data to understand potential causes (e.g., to justify higher than historically observed emissions from specific equipment, or lower than expected throughputs or methane content, etc.) and discuss with the facility operator Engineering and/or Environmental personnel as needed.

14 References

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Appendix – Revision Log

Version Number	Date	Revisions	Made by
2.0	December 2022	• Issued for Use for initial Next Gen Gas Transaction	Matt Berchtold
2.1	February 2024	• CO_2 and Scope 2 calculation equations updated • For combustion sources, differentiated between survey requirements for engines, turbines, and fired heaters • Specified leak duration calculations for equipment leaks • Included comments to allow use of measured leak rates for malfunctioning pneumatics • Included comments around use of engineering estimates for flare calculations and dry seal vents • Added crankcase venting as an emissions source	Priya Germer
2.2	April 2024	• Added qualitative data quality indicators & exception reporting	Priya Germer
2.3	May 2024	• General clean-up on language, including eliminating references to specific sensor manufacturers	Matt Berchtold
2.4	August 2024	• Added statistically representative sampling	Jared Marshall