GUIDELINES FOR MANAGEMENT OF FUGITIVE METHANE AND GREENHOUSE GASES EMISSIONS IN THE UPSTREAM OIL AND GAS OPERATIONS IN NIGERIA

ISSUED BY

NIGERIAN UPSTREAM PETROLEUM REGULATORY COMMISSION

(NUPRC)

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ABBREVIATIONS

AVO	AUDIO VISUAL AND OLFACTORY
CATF	CLEAN AIR TASK FORCE
DCC	DEPARTMENT OF CLIMATE CHANGE
DRE	DESTRUCTION REMOVAL EFFICIENCY
EPA	ENVIRONMENTAL PROTECTION AGENCY
FDP	FIELD DEVELOPMENT PLAN
FEED	FRONT END ENGINEERING DESIGN
FMoE	FEDERAL MINISTRY OF ENVIRONMENT
GCOFR	GRAND COMMANDER OF THE ORDER OF THE FEDERAL REPUBLIC
GHG	GREENHOUSE GAS
HFC	HYDRO FLORO-CARBON
IPCC	INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE
LDAR	LEAK DETECTION AND REPAIR
NAP	NATIONAL ACTION PLAN
NDCs	NATIONALLY DETERMINED CONTRIBUTIONS
NERGP	NIGERIA'S ECONOMIC RECOVERY AND GROWTH PLAN
NUPRC	NIGERIAN UPSTREAM PETROLEUM REGULATORY COMMISSION
PPM	PARTS PER MILLION
PPMV	PARTS PER MILLION BY VOLUME
SLCP	SHORT-LIVED CLIMATE POLLUTANTS
TPY	TONNE PER YEAR
UNFCCC	UINITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE
VOC	VOLATILE ORGANIC COMPOUND

Definitions

a. *Breathing Losses:* Describes gas vapors that are released from an uncontrolled storage tank when the tank is subjected to a temperature rise, for example as a result of sunshine during a day.

b. *Centrifugal compressor*: Equipment that increases the pressure of natural gas by centrifugal action through an impeller. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

c. *Centrifugal compressor seal*: A wet or dry seal around the compressor shaft where the shaft exits the compressor case.

d. *Continuous bleed*: The continuous venting of natural gas from a gas-powered pneumatic device to the atmosphere. Continuous bleed pneumatic devices shall vent continuously in order to operate.

e. *Critical component*: Component that would require the shutdown of a critical process unit if the component was shut down or disabled. A critical process unit is a process unit that shall remain in service because the shutdown of the unit could affect the safety and/or reliability of the natural gas supply system.

f. *Commission*: Nigerian Upstream Petroleum Regulatory Commission (NUPRC)

g. *Facility*: Any building, structure, or installation to which this guideline applies, and which has the potential to emit methane. Facilities include all buildings, structures, or installations which:

i. Are under the same ownership or operation, or which are owned or operated by entities which are under common control.

ii. Are located on one or more contiguous or adjacent properties.

h. *Flash gas*: Gas dissolved in crude oil, condensate, or produced water under pressure which is released when the liquids are subject to a decrease in pressure, such as when the liquids are transferred from an underground reservoir to the earth's surface or from a pressure vessel to a storage tank maintained at atmospheric pressure.

i. *Fugitive emissions:* Optical gas imaging inspections means, any visible emission from a component observed using optical gas imaging. Any concentration of hydrocarbon above 500 ppm for any monitoring using approved quantitative instrument-based monitoring.

j. *Fugitive emissions component:* Any component that has the potential to emit fugitive emissions of methane or volatile organic compounds (VOC) including but not limited to a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum, valve, pipe, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive. .

k. *Global Warming Potential (GWP)*: is the cumulative radiative forcing of both direct and indirect effects, over a specified time horizon resulting from the emission of a unit mass of gas related to some reference gas. [CO_2: (IPCC 1996)]

l. *Intermittent bleed*: The intermittent venting of natural gas from a gas-powered pneumatic device to the atmosphere. Intermittent bleed pneumatic devices may vent all or a portion of their supply gas when control action is necessary but do not vent continuously.

m. *Large compressor station*: A compressor station where the total power of all compressors is three megawatts or greater.

n. *Liquefied Natural Gas Facility*: A facility with capability to liquefy, re-gasify, and/or facilitate the import or export of liquefied natural gas.

o. *Liquefied Petroleum Gas Facility*: A facility with the capability to process and refine hydrocarbons for the production of liquefied petroleum gas.

p. *Natural Gas Gathering Compressor Station*: A facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

q. *Natural Gas Transmission Compressor Station*: A facility, located downstream of natural gas processing plant, which contains one or more compressors designed to compress natural gas to allow it to move through a transmission pipeline system.

r. *Natural Gas Processing Plant*: Any processing site engaged in the extraction of natural gas liquids from field gas, conversion and/or fractionation of natural gas to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

s. *Operator*: Any entity, including an owner or contractor, having operational control of components or equipment, including leased, contracted, or rented components and equipment.

t. *Pneumatic device*: An automation device that uses natural gas, compressed air, or electricity to control a process.

u. *Pneumatic pump*: A device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.

v. *Reciprocating natural gas compressor*: Equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.

w. *Reciprocating natural gas compressor rod packing*: A seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that vents into the atmosphere. (55) "Reciprocating natural gas compressor seal" means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.

x. *Responsible official*: means one of the following:

   i. for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

   ii. for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

y. *Vapor recovery system*: Equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections, and flow-inducing devices used to collect and route emissions to a processing, sales gas, or fuel gas system; or to an underground injection well.

z. *Well Production Facility*: All equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

aa. *Working losses*: Gas vapors that are released from an uncontrolled storage tank when the liquid level rises in the tank, pushing the vapor in the headspace above the liquid out of the tank.

bb. *Green House Gases (GHG)*: Greenhouse gases are gases such as Carbon dioxide (CO_2), Methane (CH_4), and Nitrous oxide (N_2O) that absorb and trap heat leading to gradual increase in the atmosphere.

cc. Tier: a tier represents a level of methodological complexity. Usually, three tiers are provided.

Tier 1 is the basic method, that activity data and emission factor to determine emission

Tier 2 intermediate

Tier 3 most demanding in terms of complexity and data requirements.

Tiers 2 and 3 are sometimes referred to as higher tier methods and are generally considered to be more accurate.

FOREWORD

The President and Commander in Chief of the armed forces, Muhammadu Buhari, GCFR, signed on to the Paris Agreement on Climate Change on the 22nd of September 2016. Consequently, the country began the implementation of many ambitious initiatives aimed at reducing Green House Gases (GHG's) from all sectors of the Nigerian economy; Including the Implementation of the National Action Plan on reduction of Short-Lived Climate Pollutants (SLCP) as part of the effort to meet Nigerian's commitment on the Nationally Determined Contributions (NDCs).

As a critical sector of the economy, the Oil and Gas industry is pivotal in achieving the nation's Nationally Determined Contributions (NDCs), which is the instrument of our commitment to the agreement. Sequel to this, the Government has published the National Gas and Petroleum Policies in the official gazettes in December 2017, approved the National Gas Flare Commercialisation Programme, Flare Gas (Prevention of waste and pollution) regulation 2018 and associated Guidelines.

These policies and regulations led to the National Gas Flare Commercialisation Programme (NGFCP) and Climate change study initiatives by the NUPRC. Through this initiative arose the need to establish the estimated baseline emission from Oil & Gas to aid the revision of Nigeria's NDC, which is expected to include fugitive methane emissions. Consequently, these guidelines for the Management of GHG/Fugitive emission in the oil and gas industry are issued to achieve the NDC commitment and overall climate change mitigation in the Oil and Gas Industry.

Finally, we acknowledge the immense contribution of the Clean Air Task Force (CATF) for technical support and capacity building to the Commission and valuable input in development of these guidelines, as well as stakeholders and operators for inputs/review comments.

Engr. Gbenga Komolafe, *FNSE*
Commission Chief Executive

1.0 INTRODUCTION

1.1 Background

1.1.1 Overview of Climate Change

Climate change and its adverse effects on the human population and the environment has necessitated the need for sustainable use of natural resources globally. In the Nigerian Oil and Gas industry gas flaring and associated emissions from operations have caused significant environmental and health hazards and to a large extent, culminates in yearly loss of the Nation's revenue, health impact and depletion of environment resources. As a result of these incidents and attempt to mitigate the impact, government has initiated policies and regulations as well as ratified multi-lateral treaties to tackle the problem, the latest of such treaties is the 2016 Paris Climate Accord.

The objective of the agreement is to maintain the increase in global temperatures well below 2 degrees Celsius above pre-industrial levels, whilst making efforts to limit the increase to 1.5 degrees. Furthermore, the agreement addresses adaptation to climate change, financial and other support for developing countries, technology transfer and capacity building, as well as loss and damage. In contrast to the Kyoto Protocol, which commits only developed countries to specific reduction targets, the Paris Agreement requires all countries to prepare nationally determined contributions (NDCs), take measures to achieve their objectives, report on progress every two years and submit updated NDCs every five years.

1.1.2 Control of GHG Emission in Nigeria

Nigeria committed to reducing the emission of Short-Lived Climate Pollutants (SLCPs) emanating from activities and processes within its border, which has informed the preparation of National SLCP Actions Plan (NAP), purposely set for the mitigation of short-lived climate pollutants in the country. The process included the identification of the different sources of SLCPs emissions, their analysis, identification, and prioritization of measures targeted at reducing emissions from major SLCPs such as Black Carbon (BC), Methane (CH_4), as well as long-lived greenhouse gases such as Carbon Dioxide (CO_2).

Twenty-two (22) mitigation measures across eight sectors (Transport, Residential, Oil & Gas, Industry, Waste Management, Agriculture, Power/Energy) have been aligned with other national planning processes including the Nationally Determined Contributions (NDCs) to reduce GHG emissions, the HFC phasedown and Nigeria's Economic Recovery and Growth Plan (NERGP).

1.2 Purpose

The purpose of these guidelines is to establish the actions and mechanisms that operators shall adopt for the prevention and control of GHG/methane emissions from the Upstream Oil and Gas Operations. The provisions of these Guidelines shall be applicable to new and existing facilities within the upstream Nigerian Oil and Gas industry. The objectives include:

Reduction of the environmental and social impact caused by the emissions of components of natural gas including methane and other compounds.

i. Prevention of waste of natural resources.
ii. Protection of the environment.
iii. To achieve Nigeria's emission mitigation and reduction targets of the NDCs in the Oil and Gas, the key abatement measures and their targets are; elimination of routine gas flaring (100% of gas flaring eliminated by 2030) and fugitive emissions/leakages control (60% Methane Reduction by 2030). This notwithstanding, the exemption provisions of the sections 104 and 107 of the Petroleum Industry Act (PIA) 2021 shall apply.

1.3 Scope

The NUPRC is the lead agency mandated to ensure the mitigation targets are met for the Nigerian Upstream petroleum sector. These Guidelines covers the key abatement measures to achieve the targets for the elimination of routine gas flaring (100% of gas flaring eliminated by 2030) and fugitive emissions/leakages Control (60% Methane emission reduction by 2031). These guidelines are issued pursuant to the following:

i. Chapter 1 Part III, Sections 6(d, j), 7(c, e(iv), & r), 10(d) and Chapter 2 Part II, Sections 102 of Petroleum Industry Act 2021.
ii. Sections 25 and 36, Petroleum (Drilling and Production) Regulations 1969
iii. Flare Gas (Prevention of waste and pollution) Regulation 2018
iv. Mineral Oil Safety Regulation (MOSR) 1997

2.0 GHG AND FUGITIVE EMISSION MANAGEMENT

2.1 Emission Management Requirements

Methane (CH_4) and other GHG (CO_2 and Nitrous oxide (N_2O) emissions are gases with significant implications for climate change. In the upstream oil and gas industry, the operator/licensee shall ensure as follows at the minimum:

i. During design, installation, and modification of the facilities.
   a. The submission of GHG management plan as part of Field Development Plan (FDP), Concept and Front-End Engineering Design (FEED) application for approval and as may be requested by the Commission.
   b. Ensure the Installation and retrofitting of equipment to reduce emissions In line with section 3.0 of these Guidelines.

ii. Proper tracking of the key activities and operations that emit methane and fugitive emissions from operations such as gas flaring, venting, and fugitive emissions/leaks from the process equipment. Fugitive emission and leaks occur through process equipment such as:
   a. Compressors
   b. Pneumatics Controllers and Pumps
   c. Glycol Dehydrators
   d. Valves/Flanges
   e. Vent of Large Storage Tanks
   f. Cold Venting and Flares

iii. Put in place a system for identifying, classifying, and quantifying methane emissions from process equipment, components and other sources of emissions in their operations.

iv. Submission of fugitive emissions and GHG monitoring reports to the Commission on a quarterly basis.

2.2 Compliance Directive

To ensure the reduction of GHG and fugitive emissions, the following shall be carried out:

i. Operators shall within six (6) months from the effective date of these guidelines develop and submit a Green House Gases (GHG) Management plan for their facilities and operations for approval.

ii. The plan submitted by the operators shall include at the minimum the following:

   a. The scope of operation and emission sources.
   b. Methodologies of emissions quantification/accounting.
   c. Plan to reduce greenhouse gas emissions (yearly percentage reduction targets) and long-term strategies to attain net-zero.
   d. Set out timeline to replace single cycle steam turbines with combine cycle by 2030. This requirement shall be implemented immediately for new projects.
   e. Plans to achieve 2.5% per year reduction in Energy intensity (EI), which is reduction energy utilization/demand from the base year. The base year is 2020 in line with the NDCs. See appendix D for additional details.

iii. Submission of GHG inventory report shall comply with provisions of section 4.0.

3.0 METHANE AND GHG EMISSSION MITIGATION AND CONTROL REQUIRMENTS

3.1 Standard for Operations and Equipment leaks in Facilities

Monitoring of emissions from operations (venting and gas flaring) and leaks from equipment shall be applicable to all facilities, including well production facilities, natural gas gathering compressor stations, natural gas transmission compressor stations and natural gas processing plants.

3.2 Control Requirement

Inspection shall be conducted within 90 days after startup for new facilities, and within 90 days of enactment of this guideline for other facilities.

3.2.1 Instrument Leak Detection and Repair (LDAR)

Operators may choose one of the following options for compliance with inspection requirements, which shall be monitored by the Commission:

a. Conduct surveys in-house. This survey shall be subject to six (6) monthly verifications by a third-party service provider.
b. Contract inspection surveys to a third-party service provider.

The LDAR shall be conducted using optical gas imaging, laser beam technology or any other mature technology approved by the Commission.

The Commission shall issue certificate of confirmation to operator after monitoring the leak detection and repair (LDAR) exercise of the operator's facility(s).

3.2.2 Frequency of Inspection

1. Onshore Oil and Gas facilities:

i. In the first year after implementation of these guidelines, an operator shall conduct one inspection at each facility.

ii. In the second year after implementation of these guidelines, an operator shall conduct two inspections at each facility, with each inspection performed at least five months after the previous inspection.

iii. In the third and subsequent years after implementation of these guidelines, an operator shall conduct four inspections at each facility, with each inspection performed at least 2 months after the previous inspection.

iv. Notwithstanding the provisions of (i-iii), at the discretion of the Commission Chief Executive, operators with multiple facilities (more than 10) may be permitted to conduct a phase inspection that will cover 50% of their facilities within a two-year period.

2. Offshore Oil and Gas facilities:

i. Manned offshore platforms shall comply with same inspection frequency schedule as onshore facilities.

ii. Unmanned offshore platforms shall conduct LDAR inspections whenever on-site maintenance activities are planned, up to the frequency schedule outlined for onshore facilities.

iii. If planned maintenance occurs less frequently than once a year, the operator shall submit a waiver request to the Commission.

3.2.3 Inspection technical requirements

i. Ensure each inspection survey covers *fugitive emission components*.

ii. Inspections shall be in line with corporate-wide and site-specific fugitive emission inspection plans, as described in the recordkeeping section.

iii. Inspection shall include observation of flare stack. Notation on the state the flare stack:

a. Lit Flare – adequate combustion

A flare with adequate combustion is operated with no visible emissions, except for periods not exceeding a total of 5 minutes during any two (2) consecutive hours.

b. Lit – poor combustion (sputtering, smoking, etc.)

A flare with poor combustion is one that does not meet the requirements of **3.2.3(iii, a).**

c. Unlit flare with gas vent

d. Unlit flare with no gas vent

iv. If flare is found to be unlit with gas vent, repair (i.e., reignition) required within 48 hours. If the duration of repair is greater than 6 hours, operator is required to notify the Commission of delay.

v. If flare is sputtering or smoking, install a new flare tip, adding liquids knock-outs upstream of flare, or other appropriate interventions.

a. In first 2 years following implementation of these Guidelines, operators have 18 months to replace flare tip or conduct other interventions.

b. After an initial two (2) year period, sputtering/smoking flare shall be addressed within 60 days of detection.

vi. The above provisions (v, a-b) does not substitute for the annual flare control test required in **Section 3.3.2 (2).**

vii. In addition, conduct audio, visual, or olfactory inspections monthly, or daily for facilities that are visited daily and weekly for facilities that are not visited daily.

3.2.4 Repair Requirement

1. **First repair attempt shall be within the below timeframes:**

   i. Larger leaks (50,000 parts per million by volume (ppmv) shall be repaired within 5 working days of discovery.

   ii. Small leaks (5,000ppmv) shall be repaired within 14 days of discovery.

   iii. If the component is a critical component that cannot be repaired without shutdown, operators shall minimize the leak within one day of detection and repair the leak by the end of the next planned process shutdown or within one year, whichever is sooner.

iv. Consider that a fugitive emission component is repaired when:

a. Infra-red camera or any other detection technology does not detect emissions.

b. EPA Method 21 does not detect emissions or detects a concentration of hydrocarbons below 500 ppm. See appendix C for technical details.

2. Re-monitoring

Each repaired or replaced component shall be resurveyed as soon as practicable to ensure there is no leak, but no later than 15 days after leak repairs.

3. Record Keeping

i. Operators shall submit within six (6) months from effective date of these guidelines a company-wide fugitive emission inspection plan that shall include the following elements:

a. Manufacturer and model number of fugitive emission detection equipment to be used.

b. Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emission are detected, including timeframes for fugitive emission components that are unsafe to repair.

c. Procedures and timeframes for verifying fugitive emission component repairs.

d. Verification of optical gas imaging camera:

i. Verification shall be performed by the operator, the manufacturer, or a third-party.

ii. Initial verification includes confirmation that the camera is capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions and capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60 g/hr from a quarter inch diameter orifice.

iii. Daily verification check:

1. Shall be conducted prior to the commencement of inspection on any day when leak detection surveys will be performed.

2. Shall be based on the manufacturer's specifications of the instrument being used, and include:

    a. Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

    b. Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

iv. Procedures for conducting surveys, including:

a. How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

b. How the operator will deal with adverse monitoring conditions, such as wind.

c. How the operator will deal with interferences (e.g., steam).

v. Training and experience needed prior to performing surveys.

vi. Procedures for calibration and maintenance shall comply with those recommended by the manufacturer.

ii. Operators shall submit a site-specific fugitive emissions inspection plan that demonstrates that all fugitive emissions components are being monitored during each survey. This plan may include the following elements, but other plan components are acceptable based site-specific requirements:

a. Deviations from corporate-wide plan.

b. Sitemap.

c. Defined walking path. The walking path shall ensure that all fugitive emission components are within sight of the path and shall account for interferences.

iii. Establish that records for each monitoring survey shall contain, at a minimum:

a. Date of the survey.

b. Duration of the survey.

c. Name of operator(s) performing survey, the training and experience of the operator.

d. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

e. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

f. Documentation of the state of each flare flame observed.

g. The date of successful repair of the fugitive emissions components.

h. The instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

4. Reporting

i. Submit annual report within the first quarter of the new year, which shall include total number of facilities inspected, total number of inspections, total number of leaks identified, by component and type of facility, total number of leaks repaired, and total number of leaks on delayed repair list, accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official.

ii. Reporting shall include flare notation for each flare at the site.

3.3 Standard for Operations

3.3.1 Cold Venting

1. Applicability

In line with provisions of the Flare Gas (Prevention of waste and pollution) Regulation 2018 and EGASPIN 2018 Cold venting is prohibited in the Nigerian Oil & Gas. However, if an operator is granted waiver to vent natural gas due operational exigencies the control requirement in 2 shall apply.

2. Control Requirement

i. Operator shall address the root cause of gas being sent to a cold vent stack, including taking steps to minimize equipment venting from operations pursuant to **Sections 3.4.1 - 3.4.6** of this guideline and minimizing fugitive emissions pursuant to Section 4 of this guideline.

ii. Any remaining venting shall be routed to a flare, unless one of the following situations exist:

a. The gas mixture is not flammable.

b. The gas volume/pressure is too small/low for the flare design and thus the flame is not stable.

3. Record-keeping

Operator shall keep records of all equipment that contributes emissions to each vent and flare stack.

4. **Reporting**

   Submit annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

3.3.2 Flare Efficiency

1. **Operational requirements**

   i. All flared gas shall be combusted with an auto-igniter or continuous pilot light and a design destruction removal efficiency (DRE) of at least 98% for hydrocarbons and be operated within all parameters affecting DRE within the ranges required to achieve a DRE of 98%.

   ii. Calculation of 98% DRE shall not include the time flare is unlit for maintenance.

2. **Monitoring**

   i. Annual test of auto-igniter to ensure auto-igniter is operational or annual observation continuous pilot light to ensure pilot light is independently lit.

   ii. LDAR inspection shall also note whether flare is lit at the time of inspection. **See section 3.2.3 (iii, a-d).**

3. **Record-keeping**

   i. Keep records of annual flare efficiency test.

ii. Keep records of any observed instance of unlit flare with venting gas.

4. **Reporting**

Submit records for annual test/observation and unlit flares not later than first quarter of the proceeding year.

3.4 Standard for Equipment

3.4.1 Pneumatic Controllers

1. **Control Requirement**

i. The following requirement applies to all compressor stations and processing plants. In addition, it applies to well production facilities with access to grid-electricity operators, and all new well production facilities constructed after the effective date of this rule:

Operator shall not use natural gas-driven pneumatic controllers, and they shall instead retrofit facilities with zero bleed controllers, including controllers powered by electricity or instrument air or emissions shall be routed to a *vapor recovery system* that captures the emissions. If it is not feasible to capture the emissions, operators may use a flare.

ii. The following applies to well production facilities that do not have access to grid-electricity operators:

5-year phase-in period:

a. Within one year of implementation of the present guidelines, an operator shall ensure that 25% of these pneumatic controllers are zero bleed controllers (as defined in previous section), and the remainder are low bleed (i.e., emit less than 0.17 standard cubic meters per hour of natural gas).

b. Within two years of implementation of present guidelines, operator shall ensure that 65% of these pneumatic controllers are zero bleed controllers (as defined in previous section), and the remainder are low bleed (i.e., emit less than 0.17 standard cubic meters per hour of natural gas).

c. Within three years of implementation of present guidelines, operator shall ensure that 75% of these pneumatic controllers are zero bleed controllers (as defined in previous section), and the remainder are low bleed (i.e., emit less than 0.17 standard cubic meters per hour of natural gas).

d. Within four years of implementation of present guidelines, operator shall ensure that 85% of these pneumatic controllers are zero bleed controllers (as defined in previous section), and the remainder are low bleed (i.e., emit less than 0.17 standard cubic meters per hour of natural gas).

e. Within five years of implementation of present guidelines, operator shall ensure that all pneumatic controllers are zero bleed controllers (as defined in previous section).

2. Monitoring

i. As long as an operator has gas-driven pneumatic controllers on site, they shall be tested annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument), and operator shall repair any device with a measured emissions flow rate greater than 0.17 standard cubic meters per hour within 14 days from the date of leak detection.

ii. Any gas-driven intermittent controllers venting to the atmosphere shall be monitored with instruments during any inspection conducted pursuant to the requirements of **Section 3.2** to ensure that no emissions occur between actuations. If emissions occur between actuations, the controller shall be fixed or replaced within 30 days.

3. Recordkeeping

Documentation of the natural gas bleed rate or, if bleed rate is zero, documentation of the type of pneumatic controller. Maintain records for at least 5 years.

4. Reporting

Annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

3.4.2 Pneumatic Pumps (Diaphram Pumps)

1. Control requirement

The following requirement applies to all compressor stations and processing plants. In addition, it applies to operators of new well production facilities and well production facilities with access to grid-electricity.

i. Operator shall not use pneumatic pumps with natural gas venting, and they shall instead retrofit facilities with electric pumps, or route emissions to vapor recovery system, except for pumps that are used less than 90 days/year.

ii. The following applies to operators of well production facilities that do not have access to grid-electricity:

a. Operator shall monitor any natural gas-driven pump, *vapor recovery system* and combustor as part of instrumental LDAR,

b. Facilities shall be retrofit to eliminate emissions from pneumatic pumps with a 5-year phase in period.

i. Within one year of implementation of present guidelines, operator shall ensure that 25% of these pneumatic pumps are non-emitting, using one of the control options listed in **3.4.2,1(i)**.

ii. Within two years of implementation of present guidelines, operator shall ensure that 65% of these pneumatic pumps are non-emitting, using one of the control options listed in **3.4.2, 1(i).**

iii. Within three years of implementation of present guidelines, operator shall ensure that 75% of these pneumatic pumps are non-emitting, using one of the control options listed in **3.4.2, 1(i).**

iv. Within four years of implementation of present guidelines, operator shall ensure that 85% of these pneumatic pumps are non-emitting, using one of the control options listed in **3.4.2, 1(i).**

v. Within five years of implementation of present guidelines, operator shall ensure that all pneumatic pumps are non-emitting, using one of the control options listed in **3.4.2, 1(i).**

2. Reporting

Annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

3.4.3 Centrifugal Compressor Seals

1. Control requirement

Centrifugal compressors with wet seals: Require operators to route oil degassing unit emissions either to a vapor recovery system (including routing the emissions to the inlet of the compressor) or a *combustion device*. Alternatively, operators can design/retrofit the compressor using dry seals.

2. Monitoring

Inspect compressor, wet seals, isolation valves, vapor recovery system or control device as part of instrumental LDAR.

3. Reporting

Annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

3.4.4 Reciprocating Compressor Rod-packing

1. Control requirement

Route emissions from compressor vents; control emissions using one of the following options:

a. Rod packing shall be replaced on or before the compressor has operated for 26,000 hours, or 36 months from the date of the most recent rod packing replacement whichever occurs first. While for new reciprocating compressors, rod packing shall be replaced 36 months from the date of the startup.

b. Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system.

2. **Monitoring**

Inspect compressor, compressor seals, rod-packing and vapor recovery system or control device as part of instrumental LDAR.

3. **Reporting**

Annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

3.4.5 Glycol Dehydrators

1. **Control requirement**

i. Still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis using a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

ii. Calculation of 98% destruction efficiency shall not include time that dehydrator is offline for maintenance of process upsets.

2. Monitoring

Inspect glycol dehydrator and vapor recovery system or control device as part of instrumental LDAR.

3. Reporting

Annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

3.4.6 Liquid Storage Tanks: Flash Gas, Working & Breathing Losses

1. Control requirements

i. For all fixed roof storage tanks with potential to emit more than 2 tons per year of volatile organic compounds due to flash gas, working losses, and breathing losses, operators shall route emissions, including all emissions of flash gas, and emissions due to working losses and breathing losses, either to a vapor recovery system or, in some cases, to a combustion device. Implemented using the following phase in schedule (except for case noted in **section 3.4.6, 1(ii)**)

   a. Tanks with VOC >12 tpy controlled within one year of implementation of present guidelines.

   b. Tanks with VOC 6-12 tpy controlled within two years of implementation of the present guidelines.

c. Tanks with VOC 2-6 tpy controlled within three years of implementation of the present guidelines.

ii. Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the NUPRC for an exemption from the control requirements of Section **3.4.6, 1(i).** Such request shall include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements.

iii. Prohibit venting of hydrocarbon emissions from hatches and other access points on tanks during normal operation.

a. Hatch may be opened for measurement purposes, but the hatch shall be closed immediately after sample is taken.

b. Alternatively, operator may use an auto-gauging system or spigot to sample hydrocarbons in tank without opening the hatch.

iv. Require operators of controlled tanks to evaluate their systems for controlling tank emissions and certify that each system as designed is large enough to capture all potential emissions (flash gas, working losses and *breathing losses*) from the tank.

2. Monitoring

i. Require at least quarterly visual and AVO inspections of floating roof and fixed roof storage tanks with emissions of more than 2 tpy and control devices to ensure emissions are being routed to control units and flares are operating as designed.

ii. Monitor storage vessels, access points and *vapor recovery systems* and combustors as part of instrumental LDAR.

iii. All tanks (with emission >2tpy) that do not employ a vapor recovery system shall conduct annual flash analysis testing for these tanks to estimate annual methane emissions from the tanks and evaluate whether the exemption in Section **3.4.6, 1(ii)** remains warranted.

3. Recordkeeping

Retain records of quarterly visual and AVO inspections.

4. Reporting

Annual report demonstrating compliance and recording any deviations accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official. This report shall be submitted not later than first quarter of the proceeding year.

4.0 GREENHOUSE GASES INVENTORY AND ACCOUNTING

4.1 Monitoring Requirement

i. Operators shall undertake measurement/estimation and quantification of GHG emissions from their operation and report to the Commission on a quarterly basis. The emission measurement/estimation shall cover; Carbon Dioxide (CO_2), Methane (CH_4) and Nitrous oxide (N_2O). The reporting is a mandatory requirement for the following facilities:
   a. Oil and Gas Production Facilities
   b. Oil and Gas Export Terminals
   c. Gas processing and gathering & Boosting Stations

ii. Any other facility e.g., incinerator, thermal desorption units, landfill etc., as may be determined by the Commission. GHG emissions from combustion and fugitive emissions shall be calculated/estimated using the following approaches or combination of both.
   a. Equipment counts and population emissions factor (EqC) – relevant emissions factors, prescribed by IPCC shall be applied to equipment counts for a specific type of equipment emission
   b. Leak surveys (LS) – this shall involve the use of leak detection with optical gas imaging, organic vapour analyzers or toxic vapour analyzers, infrared laser beam or acoustic leak detection instrument.
   c. Tier 1, 2 and 3 emission estimates in line with the requirements of UN Intergovernmental Panel on Climate Change (IPCC)

or other emissions estimation/quantification methodologies such as the API are subject to validation and approval by the Commission. The following shall also apply by adopting a tiered approach in estimating emissions.

i. As minimum, operators shall adopt at least tier 1 emission estimate approach within one year of effective date of this guideline.

ii. After one-year, tiers 2 and 3 approach shall be adopted.

d. The reporting of GHG emissions shall be in line with the IPCC standard and the data submitted shall be subject to quality control validation by multi-disciplinary team of the Commission and operators. A third-party verifier may be appointed to validate the data as may be determined by the Commission. See appendix E for tier1 data reporting template.

Appendix A: Reporting Requirements

This appendix compiles and summarizes the reporting requirements, which are presented in the corresponding section of the Guidelines.

Each operator shall submit a report to the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) within the first quarter of the proceeding year. The report shall demonstrate compliance and record any deviations from the present guidelines. It shall be accompanied by a certification of the truth, accuracy, and veracity of the report signed by a *Responsible official* of the company. For each section of these guidelines, the operator's report shall include a certification of compliance, and additional reporting requirements for each section (if any) are noted below:

1.0 Equipment Leaks

i. Shall submit annual report including total number of facilities inspected, total number of inspections, total number of leaks identified, by component and type of facility, total number of leaks repaired, and total number of leaks on delayed repair list, accompanied by certification of the truth, accuracy and veracity of the report signed by a responsible official.
   a. Pneumatic Controllers
   b. Pneumatic Pumps
   c. Centrifugal Compressor Seals
   d. Reciprocating Compressor Rod Packing
   e. Glycol Dehydrators

f. Liquid Storage Tanks: Flash Gas, Working & Breathing Losses

ii. Reporting shall include flare notation for each flare at the site, highlighting:

a. Flare Efficiency

b. Cold Venting

c. Records of annual test/observation and unlit flares annually.

In addition to this annual report, each operator is required to submit a company-level fugitive emissions inspection plan and a site-specific inspection plan, as specified in the Equipment Leaks section of these guidelines. These plans shall be submitted to the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) 6 months after the entry into force of the present guidelines.

Site-specific fugitive emissions inspection plan shall be submitted to the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) 6 months after the entry into force of the present guidelines or within 6 months for a new facility and updated not later than six (6) months after any major site modification or acquisition.

Appendix B: Regulatory References

National and sub-national jurisdictions across the United States (US), Canada, and Mexico have issued regulations, or committed to do so to meet methane reduction goals. Several additional US states are in the process of developing or strengthening regulations, and several other countries have started to look at polices that can reduce methane emissions, including the European Union, Colombia and Argentina. The strength of regulations varies from one jurisdiction to the next. Some regulate methane emissions directly, while others address VOCs, which reduce methane as a co-benefit, since the two pollutants are both present in natural gas.

1.0 United States

In June 2016, the U.S. Environmental Protection Agency (USEPA) issued a set of New Source Performance Standards (referred to by the English acronym "NSPS OOOOa") to reduce emissions of methane and smog-forming volatile organic compounds (VOCs) from new, reconstructed and modified oil and gas sources.[1] This rule is built from a rule issued in August 2012 (NSPS OOOO) that focused on emissions of VOCs from new and modified natural gas production and processing facilities.

2.0 Canada

On April 25th, 2018, the Canadian Environment and Climate Change Ministry finalized robust, nationwide standards designed to cut methane pollution from the oil and gas industry by roughly 40-45 percent. These standards are the culmination of two years of Canadian federal efforts that began with Canada's commitment to reduce methane emissions from both new and existing sources of pollution in the oil and gas sector, and Canada's signing of the North American Leaders Summit pledge with Mexico and the US to reduce emissions by 40-45% by 2025.

Canada was the first country to put in place regulations to reduce methane from the oil and gas sector, covering both new and existing sources. Importantly, these rules cover sites across the industry, including oil and gas well sites, plants that process natural gas, and gas pipeline compressor stations.

The new Canadian standards will reduce emissions by requiring oil and gas companies to find and fix leaks in their equipment, reduce pollution during completion of new wells that have been hydraulically fractured, and repair and/or upgrade equipment such as compressors, oil tanks, and natural gas-driven automatic valves. With these regulations, Environment and Climate Change Canada (ECCC) estimates that between 2018 and 2035, methane emissions will be reduced by roughly 10 million metric tons. The total climate benefits of those reductions are around 845 million metric tons of CO_2e over the next few decades, so this rule has climate benefits similar to closing twelve coal-fired power plants or taking ten million cars off the road. ECCC estimates the regulations would result in net benefits of CAN$8.9 billion.

Under Canadian law, provinces with significant oil and gas production (specifically British Columbia, Alberta, Manitoba and Saskatchewan) will need to either adopt the federal standards or develop their own regulations to achieve a similar level of emissions reduction. This is a process known as "equivalency". The major oil and gas provinces are currently proposing regulations to meet the federal standards, a process expected to go through early 2020.

3.0 Mexico

In November 2018, the Mexican Agency for Security, Energy, and Environment (ASEA) finalized Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbon Sector.[4] The regulation covers the whole hydrocarbons value chain (from exploration to distribution) and includes both existing and new sources.

The regulation initially established a period of 12 months after its publication for the development of a "Program for Prevention and Integrated Control of Methane Emissions" (PPCIEM for its Spanish acronym), which includes a diagnosis of the baseline emissions. As a result of the COVID-19 pandemic this period was extended. ASEA provides some flexibility for regulated companies by allowing them to choose one of the last 5 years as the base year for all targets.

The PPCIEM aims to lay out the schedule for the implementation of all measures included in Title III (or measures that are similar or superior-including a technical justification), which shall all be implemented within 6 years of the publication of the regulation. These measures include improvements in technology and/or practices in vapor recovery systems, pneumatic pumps, compressors, pneumatic controllers, glycol dehydrators, transport/distribution pipelines, (flash) tanks, well completions and stimulation, liquids unloading, and flaring. If the implementation of a measure is deemed not technically feasible, a detailed justification shall be included in an annex to the PPCIEM and shall be validated by a third-party verifier (see section on Compliance Evaluation). The PPCIEM also requires the inclusion of a Leak Detection and Repair (LDAR) program, which shall start when the PPCIEM is submitted; inspections are to be performed quarterly.

Existing facilities will include an emission target in their PPCIEM and maintain that level of emissions once it is reached, while new ones will be required to maintain the level of emissions of the base year, which will be defined in the PPCIEM.

Reporting on both LDAR and the measures included in the PPCIEM will be done annually and will have to be verified by certified third parties.

4.0 State/Provincial Regulations

The states of Colorado, Pennsylvania, Utah, Wyoming, California, Ohio and New Mexico in the US and the provinces of Alberta and British Columbia in Canada have issued regulations to reduce methane emissions. The first one to do so was Colorado in 2008.

In 2008, the state of Colorado issued its first regulations to reduce VOC emissions from oil and gas operations in areas of the state with poor air quality. These were the first modern regulations to address emissions in the oil and gas sector and served as a launching point for other states and the US federal government's efforts to address methane leakage. In 2014, Colorado strengthened these rules, including requiring operators to perform regular, comprehensive leak detection and repair inspections. The 2014 rulemaking also expanded the regulation of oil and gas air emissions to the entire state and targeted methane emissions, in addition to VOC. In 2017 and 2019, Colorado further strengthened its standards, particularly in the part of the state with air quality problems. And in 2020-2021, Colorado further strengthened its rules by prohibiting routine venting or flaring of associated gas, significantly tightening rules for pneumatic controllers, increasing stringency for capturing emissions from well completions and workovers, and tightening other aspects of the regulations.

In 2013, the Pennsylvania Department of Environmental Protection (PA DEP) updated a General Operating Permit for new and modified natural gas compressor stations and processing plants (GP-5). In June 2018, the PA DEP strengthened GP-5 and issued a new General Operating permit for new and modified unconventional natural gas well (i.e., shale gas wells) site operations (GP-5A).

In June 2014, the Utah Department of Environmental Quality issued a General Approval Order for new and modified oil and gas well sites and tank batteries.

The Wyoming Department of Environmental Quality (WYDEQ) initially issued permitting guidance for new and modified oil and gas wells in 1997, and this guidance was most recently updated in 2016. This guidance includes standards of varying stringency, and covering different sets of equipment types, in different parts of the state; the strongest and broadest rules apply in a core area with dense natural gas production sites and significant ground-level ozone air quality problems. In 2015 WYDEQ developed a regulation for new and existing sources specific to the core area, the Upper Green River Non-Attainment Area.

In March 2017, the California Air Resources Board (CARB) issued regulations establishing greenhouse gas emission standards for crude oil and natural gas facilities in the state.

In 2017 the Ohio Environmental Protection Agency issued General Operating Permits for new and modified natural gas compressor stations.

In December 2018 the Alberta Energy Regulator (AER) published an Update to Directive 060, covering Flaring, Incinerating, and Venting in the Upstream Petroleum Industry.

In December 2018 the British Columbia Oil and Gas Commission (BC OGC) finalized amendments to the Drilling and Production regulation to reduce methane emissions from upstream oil and gas operations.

In May 2021, the New Mexico Energy, Minerals and Natural Resources Department (EMNRD) Oil Conservation Division (OCD) issued rules prohibiting the routine venting or flaring of associated gas and further requiring oil and gas operators to limit venting and flaring for any cause to two percent of natural gas production by the end of 2026.

In December 2018 the British Columbia Oil and Gas Commission (BC OGC) finalized amendments to the Drilling and Production regulation to reduce methane emissions from upstream oil and gas operations.

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Appendix C: Technical Descriptions

EPA Method 21:

METHOD 21 - DETERMINATION OF VOLATILE ORGANIC COMPOUND LEAKS

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.
Volatile Organic Compounds (VOC)	No CAS number assigned.

1.2 Scope. This method is applicable for the determination of VOC leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it shall meet the specifications and performance criteria contained in **section 6.0.** A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only and is not to be used as a direct measure of mass emission rate from individual sources.

3.0 Definitions

3.1 *Calibration gas* means the VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

3.2 *Calibration precision* means the degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

3.3 *Leak definition concentration* means the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

3.4 *No detectable emission* means a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 percent of the specified leak definition concentration. that indicates that a VOC emission (leak) is not present.

3.5 *Reference compound* means the VOC species selected as the instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition concentration is 10,000 ppm and the reference compound is methane.)

3.6 *Response factor* means the ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

3.7 *Response time* means the time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Hazardous Pollutants. Several of the compounds, leaks of which may be determined by this method, may be irritating or corrosive to tissues (*e.g.*, heptane) or may be toxic (*e.g.*, benzene, methyl alcohol). Nearly all are fire hazards. Compounds in emissions shall be determine through familiarity with the source. Appropriate precautions can be found in reference documents, such as reference No. 4 in section 16.0.

6.0 Equipment and Supplies

A VOC monitoring instrument meeting the following specifications is required:

6.1 The VOC instrument detector shall respond to the compounds being processed. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

6.2 The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

6.3 The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration.

6.4 The instrument shall be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 l/min (0.004 to 0.1 ft 3/min) when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.

6.5 The instrument shall be equipped with a probe or probe extension or sampling not to exceed 6.4 mm (1/4 in) in outside diameter, with a single end opening for admission of sample.

6.6 The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the example code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

7.0 Reagents and Standards

7.1 Two gas mixtures are required for instrument calibration and performance evaluation:

7.1.1 Zero Gas. Air, less than 10 parts per million by volume (ppmv) VOC.

7.1.2 Calibration Gas. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration approximately equal to the applicable leak definition specified in the regulation.

7.2 Cylinder Gases. If cylinder calibration gas mixtures are used, they shall be analyzed and certified by the manufacturer to be within 2 percent accuracy, and a shelf life shall be specified. Cylinder standards shall be either reanalyzed or replaced at the end of the specified shelf life.

7.3 Prepared Gases. Calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within 2 percent. Prepared standards shall be replaced each day of use unless it is demonstrated that degradation does not occur during storage.

7.4 Mixtures with non-Reference Compound Gases. Calibrations may be performed using a compound other than the reference compound. In this case, a conversion factor shall be determined for the alternative compound such that the resulting meter readings during source surveys can be converted to reference compound results.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Instrument Performance Evaluation. Assemble and start up the instrument according to the manufacturer's instructions for recommended warmup period and preliminary adjustments.

8.1.1 Response Factor. A response factor shall be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

8.1.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. Introduce the calibration gas mixture to the analyzer and record the observed meter reading. Introduce zero gas until a stable reading is obtained. Make a total of three measurements by alternating between the calibration gas and zero gas. Calculate the response factor for each repetition and the average response factor.

8.1.1.2 The instrument response factors for each of the individual VOC to be measured shall be less than 10 unless otherwise specified in the applicable regulation. When no instrument is available that meets this specification when calibrated with the reference VOC specified in the applicable regulation, the available instrument may be calibrated with one of the VOC to be measured, or any other VOC, so long as the instrument then has a response factor of less than 10 for each of the individual VOC to be measured.

8.1.1.3 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in References 1-3 of section 17.0.

8.1.2 Calibration Precision. The calibration precision test shall be completed prior to placing the analyzer into service and at subsequent 3-month intervals or at the next use, whichever is later.

8.1.2.1 Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

8.1.2.2 The calibration precision shall be equal to or less than 10 percent of the calibration gas value.

8.1.3 Response Time. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

8.1.3.1 Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. After switching, measure the time required to attain 90 percent of the final stable reading. Perform this test sequence three times and record the results. Calculate the average response time.

8.1.3.2 The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter that will be used during testing shall all be in place during the response time determination.

8.2 Instrument Calibration. Calibrate the VOC monitoring instrument according to section 10.0.

8.3 Individual Source Surveys.

8.3.1 Type I - Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

8.3.1.1 Valves. The most common source of leaks from valves is the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

8.3.1.2 Flanges and Other Connections. For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

8.3.1.3 Pumps and Compressors. Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

8.3.1.4 Pressure Relief Devices. The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

8.3.1.5 Process Drains. For open drains, place the probe inlet at approximately the center of the area open to the atmosphere. For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse.

8.3.1.6 Open-ended Lines or Valves. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.7 Seal System Degassing Vents and Accumulator Vents. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.8 Access door seals. Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse.

8.3.2 Type II - "No Detectable Emission". Determine the local ambient VOC concentration around the source by moving the probe randomly upwind and downwind at a distance of one to two meters from the source. If an interference exists with this determination due to a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source, but in no case shall the distance be less than 25 centimeters. Then move the probe inlet to the surface of the source and determine the concentration as outlined in section 8.3.1. The difference between these concentrations determines whether there are no detectable emissions. Record and report the results as specified by the regulation. For those cases where the regulation requires a specific device installation, or that specified vents be ducted or piped to a control device, the existence of these conditions shall be visually confirmed. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are:

8.3.2.1 Pump or Compressor Seals. If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described in section 8.3.2.

8.3.2.2 Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices. If applicable, observe whether or not the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur upstream of the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere upstream of the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in section 8.3.2 shall be used to determine if detectable emissions exist.

8.3.3 Alternative Screening Procedure.

8.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present shall be surveyed using the instrument technique of section 8.3.1 or 8.3.2.

8.3.3.2 Spray a soap solution over all potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of section 8.3.1 or 8.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

9.0 Quality Control

Section	Quality control measure	Effect
8.1.2	Instrument calibration precision check	Ensure precision and accuracy, respectively, of instrument response to standard.
10.0	Instrument calibration	

10.0 Calibration and Standardization

10.1 Calibrate the VOC monitoring instrument as follows. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

NOTE:

If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated, and corrective actions are necessary before use.

Appendix D: Energy Intensity Calculations

Energy intensity can be defined as:

$$\frac{CO_2e \text{ metric tons}}{\text{MBOE}}$$

CO_2e metric tons = CO_2 metric tons + (CH_4 metric tons * 82.5)

MBOE = Million barrel of oil equivalent = Oil MBOE + Gas MBOE

(82.5 is the 20-yr GWP of methane for methane from fossil sources as published in the latest IPCC report, AR6).

Appendix E: Templates for Reporting of GHG

Sector	**Energy**
Category	**Oil and natural gas**
Category Code	**1.B.2**
Sheet	**1 of 2 (Oil and Natural Gas)**

				CO_2		CH_4		N_2O	
IPCC Code	**Sector Name**	**Subcategory**	**A Activity Data**	**B Emission Factor**	**C Emissions (Gg)**	**D Emission Factor**	**E Emissions (Gg)**	**F Emission Factor**	**G Emissions (Gg)**
					C=A*B		E=A*D		G=A*F
1.B.2	Oil and Natural Gas								
1.B.2.a	Oil								
1.B.2.a.i	Exploration								
1.B.2.a.ii	Production and Upgrading								
1.B.2.a.iii	Transport								
1.B.2.a.iv	Refining								
1.B.2.a.v	Distribution of Oil Products								
1.B.2.a.vi	Other								
1.B.2.a.vii	Abandoned Oil Wells								
				TOTAL		TOTAL		TOTAL	

Sector	**Energy**
Category	**Oil and natural gas**
Category Code	**1.B.2**
Sheet	**2 of 2 (Oil and Natural Gas)**

				CO_2		CH_4		N_2O	
IPCC Code	**Sector Name**	**Subcategory**	**A Activity Data**	**B Emission Factor**	**C Emissions (Gg)**	**D Emission Factor**	**E Emissions (Gg)**	**F Emission Factor**	**G Emissions (Gg)**
					C=A*B		E=A*D		G=A*F
1.B.2.b	Natural Gas								
1.B.2.b.i	Exploration								
1.B.2.b.ii	Production and Gathering								
1.B.2.b.iii	Processing								
1.B.2.b.iv	Transmission and Storage								
1.B.2.b.v	Distribution								
1.B.2.b.vi	Gas Post-Meter								
1.B.2.b.vii	Other								
1.B.2.b.viii	Abandoned Gas Wells								
				TOTAL		TOTAL		TOTAL	
1.B.3	Other emissions from Energy Production								

Appendix F: Sanctions

This guideline provides the minimum requirements for management of GHG and fugitive methane emission.

Non-compliance with the requirements shall be deemed as violations to relevant sections of the Petroleum Industry Act, 2021, Petroleum (Drilling and Production) Regulations, 1969 & subsequent amendments, Mineral Oils (Safety) Regulation, 1963, 1997, EGASPIN 2018 and subsequent amendments. These violations may summarily lead to fines to operators/facility owner(s) or personnel and/or temporary or permanent revocation of License and/or permit and temporary or permanent withdrawal or non-approval of necessary Oil and Gas Industry Service Permit (OGISP) and/or imposition of applicable penalties (that shall be defined in the Nigeria Upstream Fees and Rents Regulations to be issued by the Commission) for permit holders by the Commission Chief Executive.

This guideline shall be subject to review from time to time to reflect changes in international best practices, Government policies, Industry events or as may be deemed necessary by the Commission Chief Executive.

APPROVAL

Approved by		
Engr. Gbenga Komolafe, *FNSE* (Commission Chief Executive, Nigerian Upstream Petroleum Regulatory Commission)		
	Date	November 5,2022

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