Methane Abatement in the Oil and Gas Sector

Costs and Opportunities for Key African and Latin American Countries

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Carbon Limits works with public authorities, private companies, finance institutions and non-governmental organizations to reduce greenhouse gas emissions from a range of sectors. Our team supports clients in the identification, development, and financing of projects that mitigate climate change and generate economic value, in addition to providing advice on the design and implementation of climate and energy policies and regulations.

Disclaimer

This report provides an indicative assessment of methane abatement potential and costs based on publicly available data, country-level assumptions, and representative technology characteristics. It reflects market conditions, gas prices, and financing assumptions at the time of the study and does not account for subsequent changes, including the increase in gas prices starting in the first quarter of 2026 due to the global geopolitical situation. Results should be interpreted as national averages; actual costs may vary significantly across operators and sites, depending on asset characteristics, operational practices, and access to infrastructure and financing.

This report is intended for informational purposes only and should not be relied upon as the sole basis for investment, operational, or policy decisions. Regulators are invited to reach out to CATF for further discussions on understanding the assumptions underlying the costs and for guidance on the adoption and implementation of methane regulation.

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Abbreviations

ABEGÁS	Brazilian Association of Piped Gas Distributing Companies
ANP	Brazilian National Agency for Petroleum, Natural Gas and Biofuels
ANPG	National Agency for Oil, Gas and Biofuels
CAPEX	Capital expenditure
CATF	Clean Air Task Force
CBE	Central Bank of Egypt
CCS	Carbon Capture and Storage
CH_4	Methane
CO_2e	Carbon dioxide equivalent
COMAT	Country Methane Abatement Tracker
DRE	Destruction Removal Efficiency
ESG	Environmental, Social and Governance
EU	European Union
GHG(s)	Greenhouse Gas(es)
GWP	Global Warming Potential
GWP 100	Global Warming Potential over 100 years
IAPG	Argentinian Institute of Oil and Gas
IBAMA	Brazilian Institute of the Environment and Renewable Natural Resources
IEA	International Energy Agency
IMF	International Monetary Fund
IOC(s)	International Oil Company(ies)
kt	Kilo metric tons
LDAR	Leak Detection and Repair
LNG	Liquefied Natural Gas
MACC(s)	Marginal Abatement Cost Curve(s)
Mbtu	Thousand British thermal units
MMBtu	Million British thermal units
MRV	Measurement, reporting and verification
Mt	Mega metric ton
NUPRC	Nigerian Upstream Petroleum Regulatory Commission
NOC(s)	National Oil Company(ies)
NPV	Net Present Value
OGCI	Oil and Gas Climate Initiative
OGDC	Oil & Gas Decarbonization Charter
OGI	Optical Gas Imaging
OGMP	Oil & Gas Methane Partnership
OPEX	Operational expenditure
PEMEX	Petróleos Mexicanos (Mexican National Oil Company)
t	Metric tons
TTF	Title Transfer Facility
USD	United States Dollar
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit

1 Introduction

Methane emissions from the oil and gas sector represent a significant and highly addressable source of greenhouse gas emissions globally. A range of established mitigation technologies and practices are available and are often considered cost-effective in aggregate. Yet the costs actually faced by operators vary considerably across countries, shaped by differences in infrastructure, market conditions, regulatory frameworks, and access to financing. This study responds to the need for a more granular understanding of these cost drivers. It builds on existing global analyses by providing a complementary, country-specific perspective on the financial and structural factors shaping the deployment of methane mitigation measures.

The report assesses methane abatement costs across nine major producing countries in Africa (Algeria, Angola, Egypt, Ghana, Libya and Nigeria) and Latin America (Argentina, Brazil and Mexico). It focuses on four mitigation options: leak detection and repair (LDAR), vapor recovery units (VRUs), improved flaring practices, and the replacement of gas-driven pneumatic equipment. The analysis applies a bottom-up marginal abatement cost curve (MACC) approach to compare options in terms of emissions reduction potential and cost. Estimates reflect country-specific conditions, including gas prices, infrastructure availability, and financing constraints. Costs presented reflect mitigation measures implemented at existing facilities; mitigation costs at new facilities can be expected to be lower in nearly all cases, as the sites can include mitigation technology from the outset rather than needing to retrofit.

The findings are intended to inform policy design. By identifying the cost drivers specific to each country, the study highlights where emissions reductions can be achieved at relatively low cost and where additional policy support or enabling conditions will be needed to accelerate deployment.

The report opens with the analytical framework and key assumptions, before moving to country-level assessments covering emissions profiles, abatement costs and potentials, and tailored policy recommendations. Dedicated sections examine each of the four mitigation technologies, addressing implementation considerations alongside cost estimates.

2 Methodology

2.1 Overview

This study assesses the costs and financial implications of methane abatement measures in the oil and gas sector across nine major producing countries in Africa (Algeria, Angola, Egypt, Ghana, Libya and Nigeria) and Latin America (Argentina, Brazil and Mexico). The objective is to support policymakers in designing effective incentives and prioritizing mitigation actions.

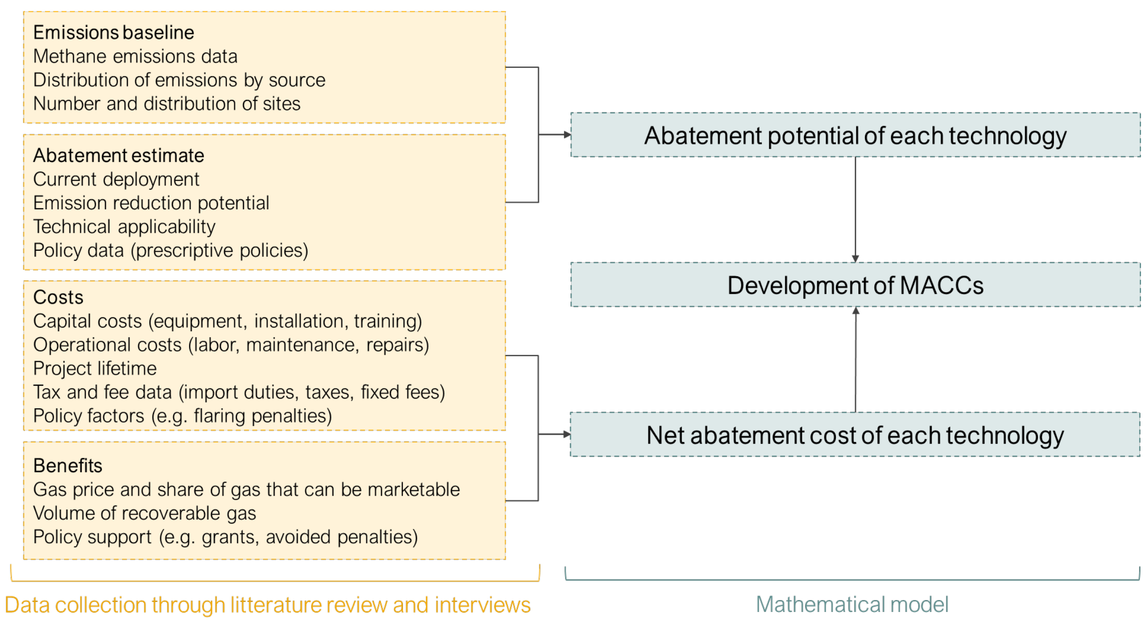
A bottom-up marginal abatement cost curve (MACC) approach is used to estimate abatement potential and costs. MACCs are developed for each country using three main inputs: baseline methane emissions, mitigation option characteristics, and the potential for monetizing recovered gas. Estimates are produced at the country level and aimed to reflect prevailing operational practices, policy frameworks, and deployment constraints.

The analysis covers four main methane emission sources: flaring (incomplete combustion and unlit flaring), leaks, tanks, and natural gas-driven pneumatic equipment. For each source, at least one mitigation option is assessed. These include leak detection and repair (LDAR) programs, installation of vapor recovery units (VRUs), replacement of gas-driven pneumatics with electric or air-driven alternatives, elimination of unlit flaring and improvements to flaring performance.

The analysis is based on a combination of stakeholder consultation and literature review. A total of 35 interviews were conducted with government agencies, oil and gas operators, and technology and service providers.[1] These inputs were complemented by published studies and technical reports. Where data was not available, assumptions were developed to address the gaps.

Figure 1 provides a visual overview of the key inputs and sequential steps involved in the process.

Figure 1. Methodological framework for Methane Abatement Cost Curves (MACCs) development



[1] The interview templates are provided in Appendix 1, Appendix 2 and Appendix 3.

The following sections describe the key components of the analysis, covering methane emission estimates, abatement potential and costs calculations, MACC development, and the limitations of the study.

2.2 Abatement potential

Methane emission estimates

To construct the MACCs presented in this report, the first step was to estimate methane emissions per assessed emission sources for each of the countries. This was done through assessing total methane emissions from the oil and gas sector for each country, as well as the distribution of these emissions across the different emission sources.

For this purpose, multiple independent datasets reporting total methane emissions from oil and gas sector were compared, including academic studies (Chen et al., 2023[2]; Crippa et al., 2023[3]; Gütschow et al., 2025[4]; Hancock et al., 2025[5]; Höglund-Isaksson, 2017[6]; Janardanan et al., 2024[7]; Maasakkers et al., 2019[8]; O'Rourke et al., 2017[9]; Shen et al., 2023[10]), the International Energy Agency (IEA) Methane Tracker[11], and the Clean Air Task Force's Country Methane Abatement Tracker (COMAT)[12]. Emission estimates show reasonable agreement for some countries but diverge substantially for others. Brazil, Argentina, Libya and Nigeria exhibit particularly large discrepancies, with estimates varying by up to an order of magnitude between different studies. These variations reflect differences in measurement methodologies (bottom-up inventories versus top-down atmospheric inversions), temporal coverage, and emission factor assumptions, as well as various limitations depending on the selected approach.

The IEA estimates (2024 data) were chosen as the baseline reference for country-level methane emissions due to: (i) regular annual updates incorporating recent production data, (ii) methodological transparency, (iii) broad geographical coverage, and (iv) a tendency to fall near the median of available estimates, providing a central reference point relative to other available estimates.

To disaggregate country-level emissions across source categories, available datasets and studies were reviewed and compared, including the IEA Methane Tracker, COMAT and Höglund-Isaksson. Höglund-Isaksson offers estimates disaggregated by source type across all assessed countries, covering flaring, leaks, and venting, but does not disaggregate all emission categories required for this study (particularly

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[2] Zichong Chen et al. (2023). *Satellite quantification of methane emissions and oil–gas methane intensities from individual countries in the Middle East and North Africa: implications for climate action*. Atmospheric Chemistry and Physics 23: 5945–5967. Available at: https://doi.org/10.5194/acp-23-5945-2023

[3] Crippa, Monica et al. (2023). *GHG emissions of all world countries*. European Union: JRC134504. Available at: https://doi.org/10.2760/953322

[4] Gütschow, Johannes et al. (2025). *The PRIMAP-hist national historical emissions time series (1750-2023).* v2.6.1. Zenodo. Available at: https://doi.org/10.5281/zenodo.15016289

[5] Sarah E. Hancock et al. (2025). *Satellite quantification of methane emissions from South American countries: a high-resolution inversion of TROPOMI and GOSAT observations*. Atmospheric Chemistry and Physics: 797–817. Available at: https://doi.org/10.5194/acp-25-797-2025

[6] Lena Höglund-Isaksson. (2017). *Bottom-up simulations of methane and ethane emissions from global oil and gas systems 1980 to 2012*. Environmental Research Letters 12: 024007. Available at: https://doi.org/10.1088/1748-9326/aa583e

[7] Rajesh Janardanan et al. (2024). *Country-level methane emissions and their sectoral trends during 2009–2020 estimated by high-resolution inversion of GOSAT and surface observations*. Environmental Research Letters 19: 034007. Available at: https://doi.org/10.1088/1748-9326/ad2436

[8] Joannes D. Maasakkers et al. (2019). *Global distribution of methane emissions, emission trends, and OH concentrations and trends inferred from an inversion of GOSAT satellite data for 2010–2015*. Atmospheric Chemistry and Physics 19: 7859–7881. Available at: https://doi.org/10.5194/acp-19-7859-2019

[9] Rachel M. Hoesly et al. (2018). *Historical (1750–2014) anthropogenic emissions of reactive gases and aerosols from the Community Emissions Data System (CEDS)*. Geoscientific Model Development 11: 369–408. Available at: https://doi.org/10.5194/gmd-11-369-2018

[10] Lu Shen et al. (2023*). National quantifications of methane emissions from fuel exploitation using high resolution inversions of satellite observations*. Nat Communications 14: 4948. Available at: https://doi.org/10.1038/s41467-023-40671-6

[11] International Energy Agency (IEA). (2025). *Methane Tracker Database*. Available at: https://www.iea.org/data-and-statistics/data-tools/methane-tracker-data-explorer

[12] Clean Air Task Force (CATF). (2025). *Country Methane Abatement Tracker (COMAT)*. Available at: https://www.catf.us/comat/

tanks and natural gas-driven pneumatic equipment). The most granular publicly available datasets are the ones of the IEA Methane Tracker, which disaggregates emissions into 119 sub-categories, and COMAT. Taken together, this review highlighted that source-level emission distributions are considerably less documented than country-level totals, with the IEA Methane Tracker providing the most comprehensive and consistent basis for this analysis.

Based on these findings, this study uses IEA estimates as the primary source for defining emission volumes across the selected categories. The analysis focuses on flaring sources (from incomplete combustion and unlit flaring), leaks, tanks, and natural gas-driven pneumatic equipment, as these were identified as the four highest-emitting sources across the nine assessed countries.

The correspondence between IEA Methane Tracker source categories and the terminology adopted in this report is presented in Table 1, along with the segment associated with each source.

Table 1. Correspondence between IEA Methane Tracker emission source categories and study terminology

IEA Methane Tracker emission source	Segment	Terminology used in this study
Incomplete flare	Upstream	Flaring sources
LDAR Offshore	Upstream	Leaks
LDAR Transmission	Midstream	Leaks
LDAR Wells	Upstream	Leaks
Large Tanks w/o Control	Upstream	Tanks
Large Tanks w/VRU	Upstream	Tanks
Produced Water	Upstream	Tanks
Small Tanks w/o Flares	Upstream	Tanks
Storage Tanks	Upstream	Tanks
Tanks	Upstream	Tanks
Chemical Injection Pumps	Upstream	Natural gas-driven pneumatic equipment
Kimray Pumps	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Device Vents (High Bleed)	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Device Vents (Intermittent Bleed)	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Device Vents (Low Bleed)	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices (High Bleed)	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices (Intermittent Bleed)	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices (Low Bleed)	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices High Bleed	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices Int Bleed	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Devices Low Bleed	Upstream	Natural gas-driven pneumatic equipment
Pneumatic Pump	Upstream	Natural gas-driven pneumatic equipment

Sources: IEA[13], Carbon Limits

[13] IEA. *Methane Tracker Database*. (see footnote 11)

While other mitigation options are only considered for the upstream segment in this study, LDAR is applied to both upstream and midstream assets, given that fugitive leaks constitute a major source of methane emissions across both segments.

For three of the four categories (flaring sources, leaks, and tanks), IEA emission volumes were adopted directly. For natural gas-driven pneumatic equipment, consultations with local companies and regulators on sector practices and device utilization rates, combined with Carbon Limits' field experience working with local operators, suggested that available estimates overstate actual emissions in several countries. Emission volumes for this category were therefore adjusted to better reflect conditions on the ground, using country-level shares of natural gas-driven pneumatic devices. These shares are reported in Appendix 4.

Overall, Table 2 presents the share of emissions analyzed for each country, based on adjusted IEA data.

Table 2. Share of emissions analyzed for each country

Country	Coverage
Algeria	58%
Angola	42%
Argentina	52%
Brazil	36%
Egypt	52%
Ghana	50%
Libya	79%
Mexico	53%
Nigeria	48%

Sources: IEA[14] data adjusted based on Carbon Limits' experience and interviews with local stakeholders.

Methane emission estimates

This study assessed methane mitigation options across four emission sources: flaring sources, leaks, tanks, and natural gas-driven pneumatic equipment. For each source, at least one abatement measure was evaluated. The full list of mitigation options incorporated into the MACCs is presented in Table 3. Where multiple mitigation options apply to a single source, distribution factors were defined on a country-specific basis to reflect the share of emissions from that source addressed by each mitigation option.

Table 3. Emission sources and mitigation options

Emission source	Mitigation option[15]
Flaring sources	Improve flaring destruction efficiency
Flaring sources	Remove unlit flaring
Leaks	Leak Detection and Repair (LDAR) – Annual
Leaks	LDAR – Biannual
Leaks	LDAR – Quarterly
Tanks	Install Vapor Recovery Units
Natural gas-driven pneumatic equipment	Replace with electric equipment

[14] IEA. *Methane Tracker Database*. (see footnote 11)
[15] The definition of each mitigation option is available in Appendix 6.

Emission source	Mitigation option[15]
Natural gas-driven pneumatic equipment	Replace with instrument air equipment

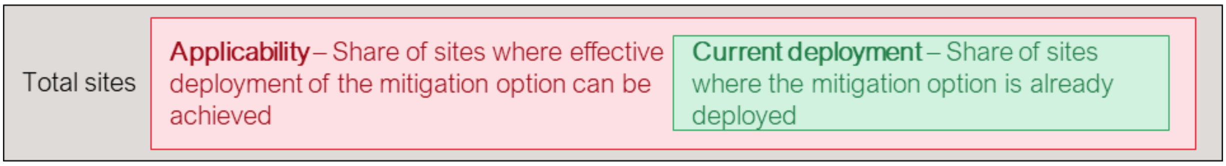
The abatement potential of each mitigation option was determined by four parameters: current deployment, applicability, emission reduction potential, and the use of the recovered gas.

The current deployment of each mitigation option reflects the extent to which it has already been adopted within the country. This is expressed as the share of sites where the mitigation option is already in place. Country-specific current deployment factors are presented in Appendix 5.

The applicability of each measure denotes the proportion of sites within a country where effective deployment can be achieved, accounting for the share of sites where the measure is already in place. Applicability factors are consistent across all countries and are presented in Table 4.

Figure 2 illustrates the concepts of *applicability* and *current deployment*.

Figure 2. Current deployment versus applicability of each mitigation option



Applicability may differ between onshore and offshore settings due to specific constraints. For example, offshore, space limitations and safety requirements can restrict the deployment of certain technologies (e.g. VRUs).

Table 4. Applicability of the mitigation options assessed

Mitigation option	Applicability	
	Onshore	Offshore
Leak Detection and Repair	95%	95%
Improve flaring destruction efficiency	70%	90%
Remove unlit flaring	95%	100%
Install Vapor Recovery Units	80%	40%
Replace with Electric Equipment	100%	100%
Replace with Instrument Air Equipment	100%	100%

Sources: Interviews with technology and service providers, Carbon Limits expertise

The emission reduction potential of each measure reflects its effectiveness in reducing emissions relative to the baseline level. A consistent set of values is applied across all countries for LDAR programs, VRUs, and replacement of natural gas-driven pneumatic, as reported in Table 5.

For flaring measures, methane emissions are not fully eliminated due to incomplete combustion. Residual emissions are therefore accounted for using country-specific flare destruction and removal efficiency (DRE), defined as the share of hydrocarbons that are effectively combusted and converted during flaring.

Accordingly, the mitigation potential is country-specific and depends on the baseline DRE assumed for each country: lower baseline efficiencies imply higher residual emissions and, therefore, greater potential for improvement through enhanced flaring performance. These DRE values were estimated using country-specific data where available. In the absence of such data, DRE values were derived from the literature and conservatively assumed at 95.2%, with unlit flares (assumed to represent 4.1% of cases) excluded. The DRE assumptions applied by country are presented in Appendix 7.[16]

The reduction potential of the flare improvement option also depends on the assumed achievable DRE, set at 99% and applied consistently across all countries.

Table 5. Emission reduction potential of the mitigation options assessed

Mitigation option	Emission reduction potential
Leak Detection and Repair (LDAR) – Annual	40%
LDAR – Biannual	60%
LDAR – Quarterly	80%
Improve flaring destruction efficiency	Country-specific factor, based on the DRE
Remove unlit flaring	Country-specific factor, based on the DRE
Install Vapor Recovery Units	95%
Replace with Electric Equipment	100%
Replace with Instrument Air Equipment	100%

Sources: United States Environmental Protection Agency (US EPA)[17] [18] [19], interviews with technology and service providers, Carbon Limits expertise

Finally, the net abatement achieved is influenced by how captured gas is handled following recovery. Three disposal options are considered: sale through existing infrastructure (e.g., gas transmission pipelines, natural gas power plant or Liquefied Natural Gas (LNG) infrastructure next to the producing field), flaring, and reinjection. The share of captured gas that can be marketed is determined by country-specific average conditions for onshore and offshore operations (e.g., gas management practices, pipeline and LNG plant capacity), as reported in Appendix 7; the remainder is assumed to be flared or reinjected. Flaring does not fully eliminate methane emissions, as combustion is incomplete; residual emissions are accounted for through the application of country-level flare destruction efficiencies. Methane emissions from reinjection are assumed to be low; for modelling purposes and to remain conservative, the same reduction potential as flaring is applied.

2.3 Net abatement costs

The abatement cost of each technology is calculated as its actual capital and operating costs minus the benefits generated by its implementation.

Costs

The cost of each abatement measure was estimated based on two components: capital expenditure (CAPEX) and operational expenditure (OPEX). CAPEX represents one-time expenditure covering equipment procurement and installation, and where applicable, employee training. Baseline costs are assumed to reflect installation at existing sites, which is typically more expensive, and therefore more conservative, than implementation at new sites. These costs are annually amortized over the expected

[16] Genevieve Plant et al. (2022). *Inefficient and unlit natural gas flares both emit large quantities of methane.* Available at: https://www.science.org/doi/10.1126/science.abq0385

[17] United States Environmental Protection Agency (US EPA). (2015). *Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities*. Available at: https://gaftp.epa.gov/air/nei/2017/doc/supporting_data/nonpoint/EPA_2015b_NSPS%20OOOOa%20TSD%20August%202015.pdf

[18] United States Environmental Protection Agency (US EPA). (2026). *Vapor Recovery Units*. Available at: https://www.epa.gov/natural-gas-star-program/vapor-recovery-units

[19] United States Environmental Protection Agency (US EPA). (2026). *Instrument Air Controllers*. Available at: https://www.epa.gov/natural-gas-star-program/instrument-air-controllers

lifespan of each measure, as reported in Appendix 9. OPEX encompass all recurring annual expenditures for labor, maintenance, and related expenses.

Baseline costs for each abatement measure were primarily derived from interviews with equipment suppliers and service providers in North America and Europe, supplemented by publicly available data. Where available, country-specific cost data from interviews with local service or technology providers were used in place of global values.

These baseline costs were then adjusted to reflect local market conditions using country-specific factors that account for procurement costs, deployment constraints, and import procedures where equipment is not manufactured locally. Import duties and taxes were applied to such equipment based on the applicable tariffs, taxes, and regulations in each country.[20] Finally, local labor rates were used for operational costs to reflect regional wage structures (see Appendix 10). Where recovered gas is flared rather than sold, applicable flaring penalties were also incorporated into the analysis.

Benefits

Methane abatement measures may generate economic benefits through several channels: the sale of recovered gas, avoided costs under carbon pricing mechanisms, the avoidance of regulatory penalties, and access to grant or climate finance programs. These various options were assessed for applicability across countries, emission sources, and mitigation options examined in this study.

Gas sales revenue

This analysis considers two scenarios for captured gas: sale through existing infrastructure, or disposal through flaring or reinjection.

Where methane is captured rather than vented, the recovered gas may generate revenue if it can be sold or utilized. New on-site utilization options (such as power generation) were excluded, as they may require additional capital investment beyond the scope of this assessment. An assessment of the prevalence of sites with pre-existing on-site power generation was also beyond the scope of this assessment.

The share of captured gas that can be monetized varies by country and depends on several factors: the existence of local gas markets, the availability of export infrastructure such as cross-border pipelines or LNG terminals, the connection of individual facilities to transport networks, and the current capacity of processing and transmission systems. For each country, the marketable gas fraction was estimated using available public data on national gas balances (including volumes produced, flared, vented, reinjected, used for on-site power generation, and sold locally or exported). Where public data was unavailable, assumptions were developed through stakeholder consultations with government agencies and oil and gas companies operating in the assessed countries. Country-level marketable gas fractions are reported in Appendix 8. For the midstream segment, it is assumed that all gas (100%) is marketable, reflecting the presence of sufficient gas transport and processing infrastructure.

The revenue associated with gas sales was estimated based on publicly available local gas prices. Where local pricing data were unavailable, gas prices were derived from international market benchmarks, adjusted to reflect the netback value at the point of sale. The upstream gas price was set at 35% of the relevant import price reference, and the midstream price at 70%, reflecting deductions for transport, liquefaction, shipping, taxes, and applicable fees. The benchmarks applied are presented in Table 6; country-level gas prices are reported in Appendix 11.

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[20] World Trade Organization. (2026). *Tariff and import notifications (IDB).* Available at: https://ttd.wto.org/en/data/idb

Table 6. Upstream and midstream gas prices derived from international benchmarks

Export market	Gas price (United States Dollar/Million British thermal units, or USD/MMBtu)			Import gas price reference
	Upstream	Midstream	Import[21]	
Europe	5.1	10.2	14.60	Title Transfer Facility (TTF)
United States	1.2	2.4	3.45	Henry Hub

Sources: [Upstream and Midstream] Carbon Limits assumptions; [Import] Energy Institute[22]

Benefits from reinjection were excluded from the analysis. Reinjection of captured gas may generate value through enhanced oil recovery, extended field life, and eventual monetization of the reinjected gas when gathering infrastructure is established. These various benefits are highly site-specific and contingent on reservoir characteristics, pressure management requirements, and operator strategy, and are thus not incorporated into the analysis.

Flared gas does not generate direct economic revenue.

Other benefits

Beyond gas sales, methane abatement can generate additional economic and financial benefits. These include financial benefits arising from carbon pricing mechanisms, the avoidance of regulatory penalties in jurisdictions with binding methane emission limits, potential access to climate finance or grant funding under international methane reduction programs, and reputational or market access benefits linked to Environmental, Social and Governance (ESG) performance and emerging low-carbon gas certification schemes. However, none of these additional benefit streams were found to be applicable across the mitigation options and countries assessed in this study.

Overall, this study conservatively treats gas sales as the sole monetizable benefit, with the understanding that actual project economics may be more favorable in specific contexts where additional benefit streams apply.

Calculation of net abatement costs

For each abatement measure, net costs - reflecting both costs and benefits – are estimated and expressed as Net Present Value (NPV). The NPV is calculated using country-specific discount rates derived from publicly available data, as reported in Appendix 12. The discount rate reflects the cost of capital or the return on alternative investments in the country and is used to determine the present value of future cash flows associated with each measure over its lifetime.

2.4 Development of marginal abatement cost curves (MACCs)

Finally, country-specific MACCs were constructed to assess the economic performance and emissions impact of each mitigation option. The curves were generated based on the emission abatement potential of each measure by country, expressed in ktCH_4 (Section 2.2), and the net costs associated with each measure, encompassing both expenditures and revenues, expressed in USD (Section 2.3).

The net costs were divided by the volume of emissions reduced to yield a marginal abatement cost expressed in USD per tCH_4. Country-level results are presented in Appendix 14 to Appendix 22.

A distinct methodology was used for LDAR programs to account for the availability of multiple inspection frequencies (annual, biannual, and quarterly). To avoid double counting of emission reductions, the net costs

[21] Import gas prices based on average values over the period 2020–2024.
[22] Energy Institute. (2025). *Statistical Review of World Energy (74th edition).* Available at: https://www.energyinst.org/statistical-review.

and the volume of emissions reduced were calculated incrementally. The biannual LDAR option reflects the additional cost and emission reduction beyond those achieved through annual inspections. Similarly, the quarterly option reflects the incremental cost and emission reduction relative to biannual inspections. Each segment of the MACC therefore represents the marginal benefit of increasing inspection frequency, rather than cumulative totals. However, for a regulator seeking to understand the cost implications of a regulatory LDAR requirement, the absolute costs of these LDAR options are more relevant than the marginal costs. The absolute costs for each LDAR frequency in each country are presented in Appendix 23.

2.5 Interpretation and analysis

The MACCs were analyzed at both country- and technology-levels (see sections 0 and 5 for the country and technology fact sheets), combining quantitative estimates of abatement potential (tCH_4) and costs (USD/tCH_4).

Country fact sheets

Each country fact sheet provides a concise overview of methane emissions, abatement opportunities, and policy context in the oil and gas sector. The key elements presented in each fact sheet are as follows.

Key figures

Each fact sheet begins with a set of headline indicators. These include:

- **Estimated annual emissions**, defined as the total methane emissions from the country's oil and gas sector. This estimate is based on the IEA Methane Tracker Database (2023), as adjusted by Carbon Limits and the Clean Air Task Force (CATF), as described in section 2.2.
- **Emissions analyzed**, defined as the share of total methane emissions covered by this study (the emission sources assessed as presented in Table 2).
- **Technical abatement possible from analyzed technologies**, defined as the share of estimated annual emissions that can be reduced through the implementation of the selected mitigation options (as presented in Table 3). This is based on applicability factors (i.e., the share of sites where each technology can be effectively deployed). Non-technically abatable emissions include (i) sources where deployment is not feasible due to technical or operational constraints, (ii) residual emissions due to less-than-100% reduction efficiencies, and (iii) emission sources that fall outside the scope of the technologies and segments considered in this study.
- **Low-cost abatement potential from analyzed technologies**, defined as the share of estimated annual emissions that can be reduced at low cost through the implementation of the selected mitigation options (as presented in Table 3). In this study, the low-cost threshold is set at 596 USD/tCH_4, equivalent to 20 USD/tCO_2e using a 100-year GWP. This value is used as a pragmatic, policy-relevant reference point to identify economically attractive abatement opportunities. It remains well below observed carbon prices,[23] policy instruments,[24] and estimates of the social cost of methane,[25] supporting its use as a conservative threshold. In addition, it is also below the cost typically associated with other decarbonization measures in the oil and gas sector, such as carbon capture and storage (CCS) and electrification.[26]

[23] Trading Economics. (2026). *EU Carbon Permits.* Available at: https://tradingeconomics.com/commodity/carbon
[24] Congressional Research Service. (2025). *Inflation Reduction Act Methane Emissions Charge: Overview and Developments.* Available at: https://www.congress.gov/crs_external_products/R/PDF/R48475/R48475.2.pdf
[25] United States Environmental Protection Agency (US EPA). (2023). *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Available at: https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf
[26] International Energy Agency (IEA). (2023). *Emissions from Oil and Gas Operations in Net Zero Transitions*. Available at: https://iea.blob.core.windows.net/assets/2f65984e-73ee-40ba-a4d5-bb2e2c94cecb/EmissionsfromOilandGasOperationinNetZeroTransitions.pdf

Current policies and practices

This section outlines the methane regulatory framework, the gas infrastructure and market conditions, and key barriers to implementing mitigation options.

Marginal Abatement Cost Curve

Each fact sheet includes a country-specific marginal abatement cost curve illustrating the abatement potential of each mitigation measure (kt CH_4/year) and the associated marginal cost (USD/tCH_4). The curve is followed by a brief interpretation of the results, focusing on the key drivers of abatement costs. It also provides an overview of the total technical abatement potential at the country level and the associated costs under different assumptions regarding the monetization of recovered gas.

Summary of analyzed mitigation technologies

This section summarizes the four mitigation technologies analyzed in the study (e.g., LDAR, vapor recovery units for storage tanks, improved flaring practices, and natural gas-driven equipment replacement). For each technology, the fact sheets present:

- **Abatement potential** (kt CH_4 abatable)
- **Marginal abatement cost** (USD/tCH_4)
- **Current practices**, defined as the extent to which a given mitigation option is already implemented in each country, including existing operational approaches, technologies in use, and adoption rates across relevant assets or operators; and
- **Ease of deployment**, defined as the feasibility of scaling up each mitigation option, considering key barriers and enablers such as operational complexity, import needs, cost and access to finance, regulatory frameworks, and institutional capacity.

This section combines quantitative metrics with qualitative insights on regulatory requirements, operational practices, and deployment barriers.

Policy recommendations

Each fact sheet concludes with tailored policy recommendations, structured across short-, medium-, and long-term priorities.

Technology fact sheets

Each technology fact sheet provides a concise overview of a specific methane abatement measure, including its technical characteristics, cost implications, and key deployment considerations. The key elements presented in each fact sheet are as follows.

Description of the abatement option

Each fact sheet begins with a description of the mitigation technology, including its operating principles, the emission sources it targets, and the performance assumptions.

Cost ranges

The fact sheets present indicative cost ranges associated with the implementation of the technology, distinguishing between CAPEX and OPEX. Costs are typically expressed on a per-equipment basis. However, for LDAR programs, costs are structured differently. Given that LDAR involves a combination of equipment, personnel, and repeated survey campaigns rather than a single physical technology, costs are expressed on a per-team (i.e., per equipment set) basis. These costs reflect both in-house implementation (including CAPEX for equipment and training, and OPEX for detection and repair) and outsourced detection models, with repairs assumed to be carried out internally.

For all technologies, these estimates are derived from literature, industry inputs, and expert judgment, and should be interpreted as indicative values that may vary significantly depending on site-specific conditions, local market dynamics, regulatory requirements, and project characteristics.

Current policies and practices

This section summarizes the regulatory framework and level of adoption of the mitigation technology across the countries included in the study. It provides an overview of whether specific regulations are in place and assesses the extent to which the technology is currently implemented (low, medium, high adoption).

Marginal Abatement Cost Curve

Each fact sheet includes a common MACC presenting the cost-effectiveness of the mitigation technologies across countries. Abatement costs are aggregated at the country-technology level using weighted averages based on abatement potential, combining different segments (upstream and midstream) and locations (onshore and offshore). The mitigation option covered in the fact sheet is highlighted in color, while all other measures appear in grey. The curve is followed by a brief interpretation of the results. It highlights the key drivers of abatement costs and explains variations across countries, including factors such as emission volumes, infrastructure availability, and the ability to monetize recovered gas.

Challenges and barriers to wider deployment

This section outlines the main technical, economic, and operational barriers limiting the deployment of the mitigation option.

2.6 Sensitivity analysis

MACC are highly sensitive key input parameters, particularly gas prices, the ability to market recovered gas depending on infrastructure availability, costs assumptions, and methane emission estimates. Given the uncertainties associated with these parameters, sensitivity analyses were conducted to assess how variations influence both abatement costs and mitigation potential across countries and mitigation options.

Sensitivity to gas prices

This analysis examines how gas prices influence marginal abatement costs. The results are presented at the country level, under current assumptions regarding the ability to market recovered gas. In practice, sites with access to infrastructure that enables gas sales are likely to face significantly lower abatement costs.

Results indicate that, for most countries, LDAR can generate negative marginal abatement costs (i.e. net benefits) when gas prices exceed approximately 5.5-6 USD/MMBtu. In contrast, VRUs are the most capital-intensive measure and require significantly higher gas prices to become cost-effective, generally above 14 USD/MMBtu, and in more favorable cases around 9 USD/MMBtu, which is not met in the vast majority of countries assessed. Replacement of natural gas-driven pneumatic devices falls in between, requiring moderate gas prices levels, typically above 6-8 USD/MMBtu, to generate net benefits over the project lifetime. Improved flaring is insensitive to variation in gas price, as the recovered gas is not monetized under this mitigation option.

Overall, these findings highlight the critical role of gas price in determining the economic viability of methane mitigation measures.

Sensitivity to gas infrastructure availability

This analysis examines how the ability to monetize recovered gas affects marginal abatement costs. Results indicate that if all sites were able to bring to market 100% of the recovered gas, abatement costs would decrease substantially. In some cases, costs could be reduced by up to a factor of eight, and many measures would shift from positive to negative abatement costs, as additional revenues from gas sales would exceed mitigation expenses.

In contrast, this parameter does not influence the abatement costs of eliminating unlit flaring or improving flare efficiency, as these measures do not involve gas recovery and therefore do not generate additional revenue. However, improved access to gas markets can still enhance their overall impact, as it increases the feasibility of implementing flare gas recovery solutions, enabling operators to capture and monetize gas that would otherwise be flared. The economics of flare gas recovery as a mitigation option strongly depend on site conditions and has therefore not been assessed as part of this study.

Overall, these findings highlight the critical role of infrastructure access in determining the economic viability of methane mitigation options. Limited access to pipelines, or processing facilities can significantly constrain cost-effectiveness, while improved infrastructure access can substantially enhance the economic attractiveness of mitigation measures.

Sensitivity to cost assumptions

This analysis evaluates how change in capital and operational costs affect marginal abatement costs. A 25% decrease in operational costs results in a significant decreases in marginal abatement costs for most mitigation options, with a more pronounced effect for LDAR programs due to their high operational intensity. The impact is relatively limited for LDAR programs, but much more pronounced for capital-intensive measures such as VRUs. Conversely, a 25% decrease in capital costs reduces abatement costs by up to a factor of five. In some cases, regulators can have the possibility influence this by facilitating access to and deployment of relevant technologies, for example by streamlining import procedures and reducing barriers to implementation.

Changes in operational costs exhibit a different pattern. A 25% decrease in operational costs results in abatement cost decreases of up to a factor of three for most mitigation options, with a more pronounced effect for LDAR programs due to their high operational intensity. In some cases, this is sufficient to shift LDAR from positive to negative abatement costs, increasing their economic attractiveness. Conversely, a 25% increase in operational costs leads to a comparable increase in abatement costs and, in some cases, can shift LDAR from negative to positive costs, thereby reducing their economic viability.

The contrasting sensitivities observed across mitigation options reflect fundamental differences in their cost structures. LDAR programs are predominantly driven by operational costs, including inspection, repair, labor, and training activities, while other mitigation measures, such as the VRUs, are more capital-intensive, with costs largely associated with equipment and installation.

Sensitivity to methane emission estimates

Methane emissions are often underestimated,[27] [28] [29] [30] and this study does not explicitly account for super-emitters. It is therefore important to assess how uncertainty in emission estimates may influence marginal abatement costs. A 25% increase in baseline emissions leads to a decrease in marginal abatement costs, ranging from negligible changes for some mitigation options and countries to reductions of up to a factor of five, with extreme cases reaching up to twelvefold decreases. This trend is primarily driven by higher volumes of recoverable gas, while associated costs remain largely unchanged, thereby enhancing the

[27] Oil and Gas Climate Initiative (OGCI). (2021). *Methane emissions from upstream oil and gas production in Canada are underestimated.* Available at: https://www.ogci.com/methane-library-item/methane-emissions-from-upstream-oil-and-gas-production-in-canada-are-underestimated/

[28] Clean Air Task Force (CATF). (2022). *The IEA's Methane Tracker shows massive underestimation of methane emissions in national inventories.* Available at: https://www.catf.us/2022/04/ieas-methane-tracker-shows-massive-underestimation-methane-emissions-national-inventories/

[29] Riddick et al. (2024). *Potential Underestimate in Reported Bottom-up Methane Emissions from Oil and Gas Operations in the Delaware Basin.* Available at: https://www.mdpi.com/2073-4433/15/2/202

[30] MethaneSAT. (2026). *First Look at a System Wide View.* Available at: https://www.methanesat.org/project-updates/first-look-system-wide-view

economic performance of mitigation measures through increased potential revenues. Conversely, a 25% decrease in baseline emissions results in higher marginal abatement costs, ranging from minimal increases to up to a fivefold rise. In cases where baseline abatement costs are negative, they generally remain negative under both scenarios.

Overall, these results highlight the strong sensitivity of MACC outcomes to underlying emission estimates and underscore the importance of robust methane inventories to reliably assess the cost-effectiveness of mitigation options in a given context.

2.7 Limitations of the study

The results of this study are subject to a number of limitations that should be considered when interpreting the findings. These relate to the scope of the analysis, the quality of underlying data, and the assumptions required where data were unavailable.

Scope of the analysis

The abatement options assessed in this study represent a selected set of technologies and measures identified as relevant across the countries and emission sources examined. Additional technologies, operational practices, and regulatory approaches can further drive emission reductions but fall outside the scope of this assessment. The results should therefore not be interpreted as representing the full abatement potential available to the oil and gas sector in each country assessed. The percent of total methane emissions from the four sources we considered varies per country, depending on assumptions about the distribution of source-level emissions (see Table 2). Some of the largest emission sources are not covered in this study, including gas engines and heaters, and associated gas venting.

In addition, this study only focuses on estimating abatement costs. As such, the results should be interpreted as a conservative assessment of the value of methane mitigation options. A more comprehensive assessment would require integrating a broader set of impacts beyond direct project economics, including system-wide, environmental, and societal dimensions, as well as the interaction with evolving regulatory frameworks and market conditions (e.g., carbon pricing). These aspects are not explicitly monetized in the analysis but are critical to fully characterize the overall rational for implementation.

Data quality and key uncertainties

The findings depend heavily on the quality of available data and the assumptions made in their absence. Where country-specific data were available, they were used as the primary basis for the analysis; in their absence, international standards and default assumptions were applied. The quality of these data directly affects the three main parameters driving abatement economics: baseline emission volumes, the fraction of captured gas that can be marketed, and the capital and operational costs associated with each mitigation option. Each of these parameters is subject to uncertainty, and changes in their values can produce material variations in results. Given these uncertainties, the results should be interpreted as indicative of general trends rather than precise predictions.

It should also be noted that satellite-detected emissions were not included in the baseline emissions, as attribution of emissions to specific sources remains challenging and would require additional analysis beyond the scope of this study. Additionally, the mitigation cost structures of super-emitting events can differ from standard operations.[31] On-the-ground LDAR campaigns can work in combination with satellite detection programs to pinpoint and repair large emission sources, and thus this study may be underestimating the potential mitigation opportunity from LDAR.

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[31] Carbon Limits. (2025). *Methane Super Emitters*. Available at: https://www.carbonlimits.no/projects/methane-super-emitters-kizd1

Interpretation of results

The MACCs presented in this study reflect national-average abatement costs and potentials and are intended to provide a comparative overview of mitigation options within each country assessed and strong variations can exist between sites or projects. This analysis is intended for informational purposes only and should not be relied upon as the sole basis for investment, operational, or policy decisions. Regulators are invited to reach out to CATF for further discussions on understanding the assumptions underlying the cost curves and for guidance on the adoption and implementation of methane regulations.

It is important to note that abatement costs can vary significantly even within countries, driven by differences in regional conditions and operator characteristics. Variations in gas prices, infrastructure availability, and operating environments can materially affect both the cost and overall economics of mitigation measures. Operator type also plays a key role. National Oil Companies (NOCs) may face higher borrowing costs or budget constraints but can, in some cases, benefit from government support or preferential access to imported mitigation technologies.[32] By contrast, International Oil Companies (IOCs), are often able to leverage economies of scale and prior experience, enabling them to standardize and replicate mitigation practices across their global portfolios, typically resulting in lower unit costs. Smaller or local operators may face capacity and knowledge gaps that can limit deployment; however, industry initiatives such as the Oil and Gas Climate Initiative (OGCI), the Oil & Gas Decarbonization Charter (OGDC) and the Oil & Gas Methane Partnership (OGMP 2.0) are increasingly helping to address these barriers through capacity building, technology transfer, and the dissemination of best practices. As a result, the cost-effectiveness and scalability of mitigation options can differ substantially across operators within the same country, a factor that should be explicitly recognized by regulators and other stakeholders when designing and implementing methane mitigation strategies.

In addition, operating companies are encouraged to develop their own facility-level MACCs reflecting site-specific emissions profiles, operational constraints, and local cost structures, which may differ materially from the national averages presented here. In particular, the analysis estimates baseline costs based on installation at existing sites. New sites will often face lower costs since the economics of methane mitigation can differ substantially between the two. New facilities can typically integrate mitigation options during design and construction at lower incremental cost, while retrofitting existing infrastructure may involve higher marginal costs, operational constraints, and technical limitations (particularly in offshore installations).

[32] Methane Finance Working Group. (2025). *Guidance for Including Methane Abatement in Oil and Gas Debt Structuring*. Available at: https://www.edf.org/sites/default/files/2025-06/Guidance%20for%20Including%20Methane%20Abatement%20in%20Oil%20and%20Gas%20Debt%20Structuring_0.pdf

3 Understanding a Marginal Abatement Cost Curve (MACC)

What is a Marginal Abatement Cost Curve (MACC)?

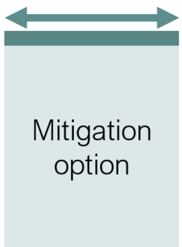
A Marginal Abatement Cost Curve (MACC) is a graphical representation of a set of greenhouse gas mitigation options, where each option is shown as a block combining its abatement potential and its cost per unit of emissions reduced. It enables comparison of options by ranking them from the cheapest to the costliest. As an analytical tool, a MACC supports the identification of cost-effective mitigation options and the prioritization of actions. For policymakers, it provides a structured basis to inform climate strategies, resource allocation, and the design of policy and financing mechanisms.

How a MACC is built

For each mitigation option, its abatement potential and its marginal abatement cost are calculated. These two elements serve as the basis of the MACC.

1. **Calculate the abatement potential (tCH_4)**

$$Abatement\ potential\ (tCH_4) = Baseline\ emissions\ (tCH_4) * \ Estimated\ fraction\ of\ emission\ reduced\ (\%)$$



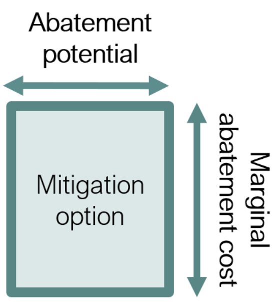
- What is the mitigation option adoption rate in the baseline scenario?
- What are the emissions in the baseline scenario?
- What are the emissions with the mitigation option in place?
- What are the emissions that can still be reduced with the mitigation option, considering mitigation potential by technology, current level of technology deployment, technical applicability, and regulations?

2. **Calculate the marginal abatement cost (USD/tCH_4)**

$$Marginal\ abatement\ cost\ (USD/tCH_4) = \frac{Net\ Present\ Value\ (USD)}{Abatement\ potential\ (tCH_4)}$$

- What are the total and incremental CAPEX and OPEX in the baseline scenario?
- What are the total and incremental CAPEX and OPEX to implement the option?
- What are the revenues generated by the implementation of the option?
- What is the lifetime of the option?
- What is the discount rate?

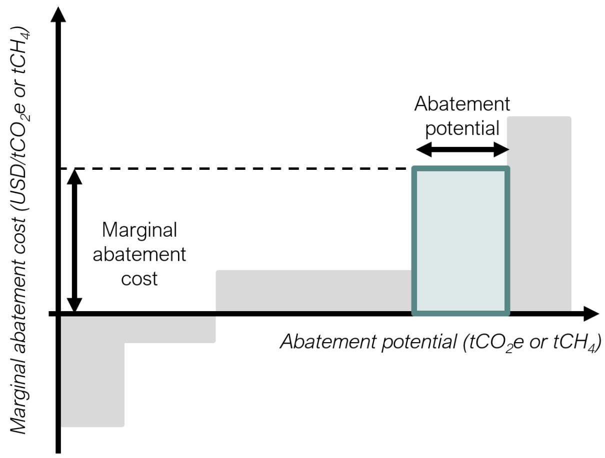
3. **Draw the element of the mitigation option**



Once both metrics have been established, each option can then be visualized as a box, where the height indicates its marginal abatement cost and the width reflects its abatement potential.

4. Draw the MACC to visualize the results

Plot all boxes of each mitigation options on a line sorted by increasing marginal abatement cost.

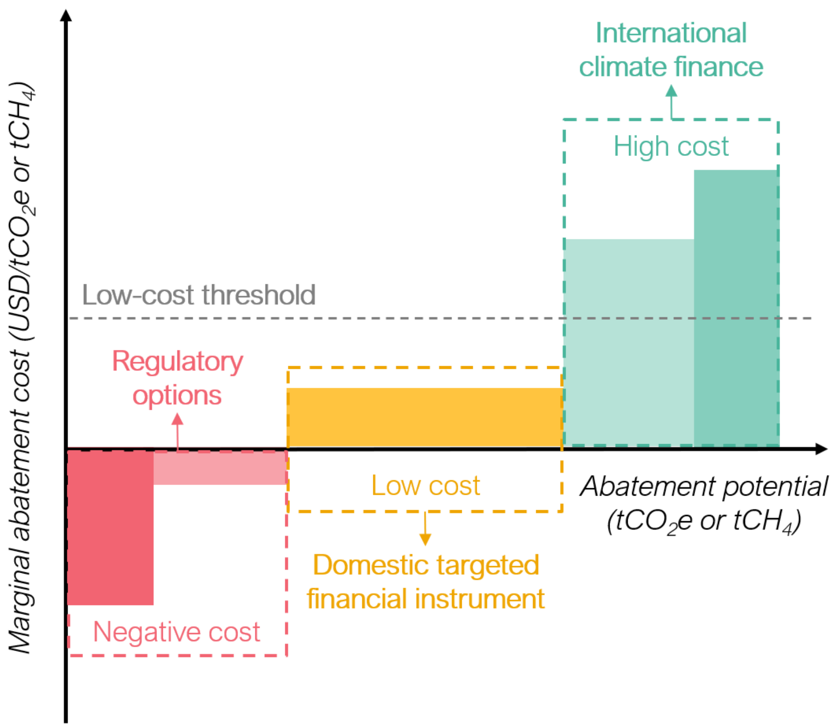


How to interpret a MACC for policy markers

A MACC provides a comparative view of mitigation options, showing how much emissions reduction each option can deliver and at what abatement cost. Options with negative abatement costs represent net economic savings over their lifetime, meaning they provide a positive return on investment, while those with positive costs require additional financial resources.

Figure 3 presents a conceptual MACC, illustrating how methane mitigation options can be grouped by cost level and linked to different types of policy and financing approaches.

Figure 3. Conceptual marginal abatement cost curve and associated policy levers



Options with negative abatement costs may be facilitated through regulatory options, targeted incentives, or by options addressing non-financial barriers. In addition to regulations, options with low abatement costs may be supported through targeted financial instruments, such as carbon pricing, concessional financing, fiscal incentives, or public investment. In addition to domestic targeted financial instruments, higher-cost options may require additional support through international climate finance, which can provide higher-value financing for emission reductions.

The threshold used to define "low-cost" options should be tailored to the scope of the project to reflect its specific conditions.

Estimated abatement costs are impacted by several factors, such as technology availability, economics or operational barriers and incentives, interest rates and import taxes.

By linking cost levels to potential policy and financing approaches, MACCs help structure discussions on how mitigation options could be enabled in practice. However, they do not prescribe specific decisions. MACCs should be understood as decision-support tools that provide a simplified and comparative view of options under a defined set of assumptions, and their interpretation should be adapted to broader policy, institutional, and economic contexts.

Limits and points of caution

MACCs have several limitations that must be considered when interpreting results.

Interactions between options not accounted. MACCs present the abatement potential of each option independently, without accounting for possible interactions between measures. In practice, it means that the actual abatement potential of one option may be impacted by the deployment of another, meaning that their actual combined effect cannot be obtained by simply adding individual estimated potentials. As a result, aggregating options in a MACC can lead to a misestimation of the total achievable emissions reductions.

Co-benefits or broader costs excluded. MACCs focus on direct economic costs and do not include broader costs and benefits, such as transaction costs, behavioral factors, or co-benefits related to health, environment, or employment. As a result, some options may appear less favorable than they are from a societal perspective.

Static and average representation. MACCs provide a static representation of mitigation options and do not reflect technological progress, cost reductions over time, or changing market conditions. In addition, results rely on national average values and assumptions, which does not reflect variability among different types of operators or regions within a country. Therefore, the actual abatement costs for individual projects might be different.

Significant upfront CAPEX not intuitively remarkable. Marginal abatement cost reflects both CAPEX and OPEX. However, looking at a MACC doesn't allow to tell which mitigation option requires significant upfront investment or ongoing operating expenses. This distinction is important, as it can strongly influence the feasibility, financing, and prioritization of mitigation measures in practice

Assumptions lead to uncertainties. The analysis is sensitive to input data and key assumptions, such as discount rates, energy prices, and emission factors, which introduces uncertainty. For these reasons, MACCs should be complemented with additional quantitative and qualitative analyses and used as one input among others in policy decision-making.

4 Country fact sheets

4.1 Algeria

Key figures

Estimated annual emissions[33]	Technical abatement possible from analyzed technologies
2,304 kt CH_4 (68.7 Mt CO_2e)	41% of estimated emissions
Emissions analyzed[34]	**Low-cost abatement potential from analyzed technologies[35]**
1,345 kt CH_4 (58% of estimated emissions)	41% of estimated emissions

Current policies and practices

Algeria does not have a dedicated methane regulatory framework for the oil and gas sector. Methane control is addressed indirectly through general hydrocarbons laws, notably **restrictions on flaring**.[36] [37] Routine flaring is generally prohibited, subject to authorization, quantitative limits, and a flaring tax, with several exemptions for exploration, start-up, or lack of gas recovery or evacuation infrastructure.[38] In practice, however, exemptions granted based on insufficient infrastructure can weaken the effectiveness of the regulation. By allowing flaring to continue under these conditions, the framework may reduce the incentive for operators to invest in gas capture and transportation infrastructure, thereby limiting the implementation of methane mitigation measures.

Algeria is a **major gas producer and exporter**, with natural gas dominating domestic energy use and power generation.[39] The national oil company, Sonatrach, operates an extensive transmission system, including two export pipelines to Europe and two LNG terminals, although installed capacity is not fully utilized. Persistent flaring occurs in some regions due to **insufficient gas gathering, processing, and compression infrastructure**. At the domestic level, **heavily subsidized gas prices**, well below cost-recovery levels, can weaken incentives to capture and utilize flared gas.[40]

Methane mitigation in Algeria is constrained by several technical and operational barriers, including **infrastructure gaps** that restrict gas monetization and **relatively low domestic gas prices**. At the same time, **external market pressures could become an important driver for mitigation efforts**. The European Union (EU), the largest destination for Algerian gas exports[41], has strengthened international cooperation with

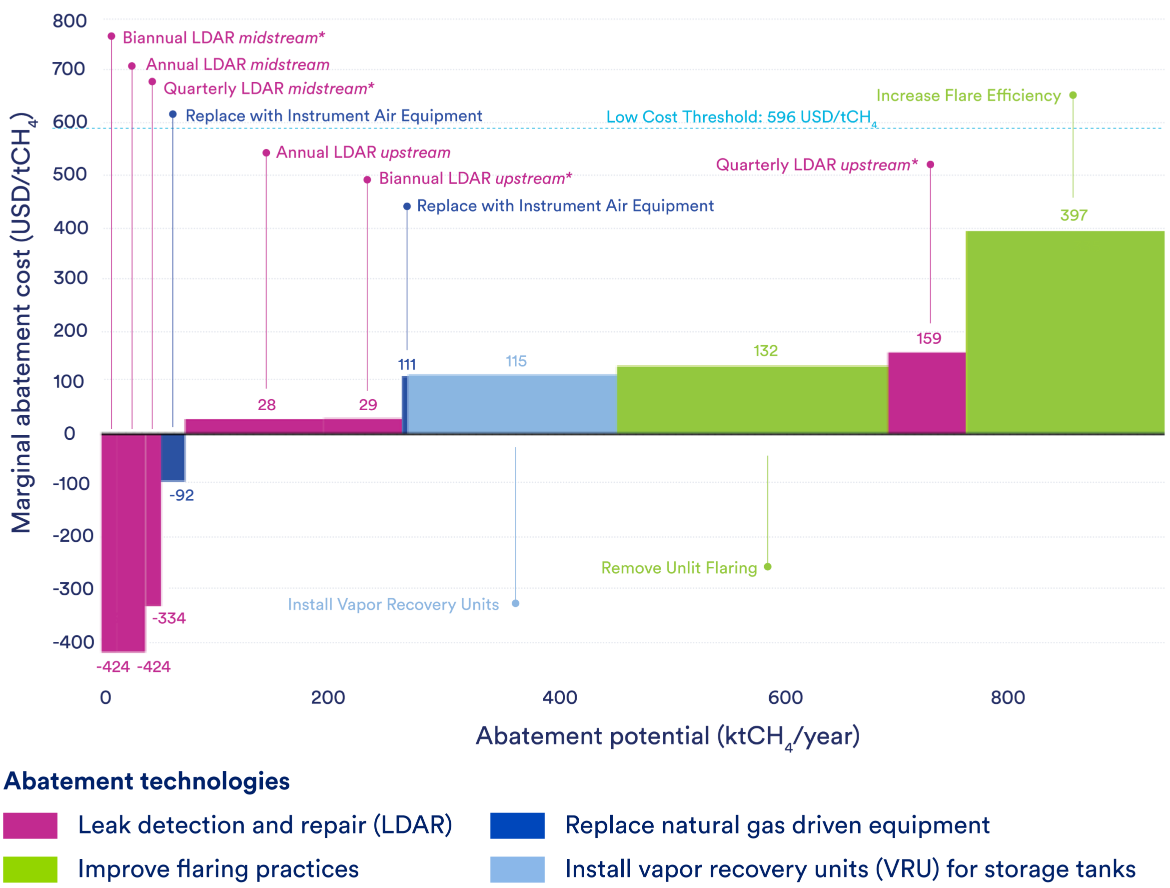
[33] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[34] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[35] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[36] People's Democratic Republic of Algeria. (2005). *Law No. 05-07 – Law concerning hydrocarbons.* Available at: https://www.arh.gov.dz/media/file/114/loi_n005_07_hydrocarbures_62e7e3759ec966.16641299.pdf
[37] People's Democratic Republic of Algeria. (2019). *Law No. 19-13 – Law governing hydrocarbon activities.* Available at: https://www.joradp.dz/FTP/JO-FRANCAIS/2019/F2019079.pdf
[38] People's Democratic Republic of Algeria. (2021). *Executive Decree No. 21-330 of 25 August 2021 establishing the conditions for granting exceptional authorizations for gas flaring.* Available at: https://www.arh.gov.dz/media/file/44/de_n0_21_330_du_25_aout_2021_fixant_les_conditions_doctroi_de_lautorisation_exceptionnelle_de_torchage_de_gaz_62a73ed006ca37.99240929.pdf
[39] International Energy Agency (IEA). (2023). *Algeria – Natural gas*. Available at: https://www.iea.org/countries/algeria/natural-gas
[40] Columbia Center on Sustainable Investment & Capterio. (2025). *Igniting Action to Reduce Gas Flaring – Country Case Study: People's Democratic Republic of Algeria*. Available at: https://ccsi.columbia.edu/sites/ccsi.columbia.edu/files/content/docs/publications/CCSI-Capterio-Flaring-Case-Study-Algeria-June-2025.pdf
[41] European Commission. (2026). *Union for the Mediterranean.* Available at: https://energy.ec.europa.eu/topics/international-cooperation/key-partner-countries-and-regions/union-mediterranean_en

Algeria on methane reduction within its energy partnership, partly to support alignment with the EU Methane Regulation.[42]

Marginal Abatement Cost Curve

Figure 4 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Algeria's oil and gas sector. The results are also provided in tabular form in Appendix 14.

Figure 4. Algeria Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR campaigns in the midstream segment and the replacement of natural gas-driven equipment with instrument air alternatives, show negative abatement costs, as recovered gas generates net savings. These savings rely on assumptions regarding gas marketability and prices. In this analysis, it is assumed that 100% of recovered gas in the midstream segment can currently be brought to market at 10 USD/MMBtu, while 70% of recovered gas in upstream operations

[42] Directorate-General for Energy, European Commission. (2026). *Strategic partnership between the People's Democratic Republic of Algeria and the European Union in the field of energy: High-Level Annual Meeting.* Available at: https://energy.ec.europa.eu/news/strategic-partnership-between-peoples-democratic-republic-algeria-and-european-union-field-energy-2026-02-12_en

can currently be brought to market at 5 USD/MMBtu.[43] Under these assumptions, all mitigation measures assessed fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Within this MACC, the elimination of unlit flaring delivers the largest single abatement potential, with approximately 238 kt of methane emissions reductions per year at a marginal cost of approximately 132 USD/tCH_4. Other measures, such as upstream LDAR programs, replacement of pneumatic devices with electric systems, and installation of VRUs, also remain well below the low-cost threshold. Replacing natural gas-driven equipment with air- or electric-driven alternatives shows a relatively low abatement potential, as these technologies are assumed to already be widely adopted by operators.

Higher marginal costs are associated with upgrades to flaring infrastructure, since this measure involves additional investment while gas continues to be flared and does not generate any economic value. Nevertheless, given the significant volumes of gas flared in Algeria, these upgrades still offer substantial emissions reductions at costs that remain below the low-cost threshold. While gas utilization options could present significant additional abatement opportunities in the country, given the scale of flared volumes, they were not assessed in this analysis.

Overall, deploying the full portfolio of considered abatement measures could result in 935 kt of methane emissions reductions per year at a net cost of around USD 116 million/year. *If all recovered upstream gas were assumed to be saleable at 5 USD/MMBtu, net abatement costs could decline to around USD 78 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices *Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring*			
Ease of deployment	**Current practices**	**Abatement potential**	**Marginal abatement cost**
Intermediate	Low adoption	413 kt CH_4 abatable	290 USD/tCH_4

Algeria does not impose strict performance, monitoring, or repair requirements for flaring systems. Regulation is limited to restricting routine flaring under petroleum legislation, with flaring permitted mainly for exploration and start-up activities, operational safety, or in areas where gas recovery or evacuation infrastructure is unavailable or limited.

In this regulatory context, operators prioritize reducing flared volumes rather than optimizing flare performance, investing instead in gas utilization or monetization solutions. Several flare-capture projects have been commissioned in recent years, such as flare gas recovery projects at the Hassi Messaoud and Ohanet fields.[44]

Install Vapor Recovery Units *Installation of vapor recovery units (VRUs) on storage tanks*			
Ease of deployment	**Current practices**	**Abatement potential**	**Marginal abatement cost**
Intermediate	Low adoption	183 kt CH_4 abatable	115 USD/tCH_4

There are no regulatory requirements mandating the installation of VRUs on storage tanks. Deployment therefore depends on operator investment decisions and the availability of gas utilization pathways.

Adoption remains limited, with key barriers including high upfront capital costs, uncertain returns where gas cannot be readily monetized, and limited regulatory signals prioritizing tank emissions. Opportunities

[43] Assuming all marketable recovered gas is sold on export markets.
[44] Sonatrach. (2024). *Climate: a linchpin of our strategy*. Available at: https://sonatrach.com/wp-content/uploads/2025/06/Brochure_HSE_ENG_2024.pdf

are more favorable in fields located near gas processing or export infrastructure, where recovered gas can be economically utilized.

Leak Detection and Repair (LDAR) *Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	312 kt CH_4 abatable	-15 USD/tCH_4
Algeria does not have regulatory requirements mandating LDAR programs, leaving practices largely driven by operator actions. Some operators (notably through partnerships between international oil companies and domestic operators) have started implementing LDAR campaigns across pipelines and facilities, identifying leaks and initiating repairs. Longer-term plans aim to progressively expand LDAR coverage, increasingly supported by satellite-based methane monitoring to help identify and prioritize emission sources. Wider deployment is constrained by the absence of regulatory incentives, and competing investment priorities.			

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Easy	High adoption	26 kt CH_4 abatable	-52 USD/tCH_4
Algeria does not impose specific regulatory requirements targeting methane emissions from natural gas-driven pneumatic equipment, leaving technology choices to operators. In practice, natural gas driven equipment is not widely used in the oil and gas sector, with most assets already relying on electric or instrument-air alternatives.			

Policies recommendations

Algeria has not established a dedicated methane regulatory framework, with existing provisions largely limited to restrictions on routine flaring under petroleum legislation. This regulatory gap may create growing exposure as the EU Methane Regulation extends to imports from 2027 onward, directly impacting Algeria, whose gas exports are predominantly destined for the EU. Within this context, **near-term priorities could focus on introducing an initial regulatory framework** that targets the most cost-effective mitigation opportunities, while **aligning monitoring, reporting, and verification practices with EU methane requirements** to help safeguard continued market access. Several measures, notably LDAR and the elimination of unlit flaring, show large abatement potential at low or negative marginal costs. Establishing minimum LDAR standards alongside flaring control requirements to prevent unlit flaring would provide a high-impact entry point for methane regulation. **Effective implementation and enforcement** will then be essential to translate these provisions into tangible emissions reductions on the ground, which will require institutional and technical support.

Over the medium term, Algeria could expand methane regulation by introducing targeted requirements for additional mitigation measures, such as VRUs on storage tanks. **Targeted financial instruments**, such as concessional loans or fiscal incentives, could further support the deployment of more capital-intensive technologies, including improving flaring efficiency.

In the longer term, addressing structural barriers through **continued development of gas gathering, processing, and transmission infrastructure** would improve gas monetization opportunities and further strengthen the economics of methane mitigation. In parallel, **reviewing domestic gas pricing arrangements** could help improve the economic viability of certain methane mitigation options.

4.2 Angola

Key figures

Estimated annual emissions[45]	**Technical abatement possible from analyzed technologies**
796 kt CH_4 (23.7 Mt CO_2e)	25% of estimated emissions
Emissions analyzed[46]	**Low-cost abatement potential from analyzed technologies**[47]
336 kt CH_4 (42% of estimated emissions)	25% of estimated emissions

Current policies and practices

Angola does not have a dedicated methane regulatory framework, with existing provisions largely limited to restrictions on gas flaring under the Petroleum Activities Law.[48] [49] Flaring is generally prohibited, although exemptions may be granted, and authorized flaring may be subject to fees. However, there is limited publicly available evidence on enforcement, compliance rates, and effectiveness, making it difficult to assess real-world impact. In parallel, **discussions are ongoing within the government to develop a national methane mitigation plan**, which could lead to future measures in the oil and gas sector. As of May 2026, a draft of this methane mitigation plan has been developed and is awaiting formal review and approval, indicating progress toward a structured policy approach.

Angola's gas market is largely export-oriented, with nearly 80% of volumes exported, while domestic gas use remains limited.[50] Most natural gas production is associated with oil, and **infrastructure constraints combined with limited economic incentives prevent all produced gas from reaching the market.**[51] In 2024, 53% of gas was reinjected and 6% was flared.[52] These patterns reflect ongoing challenges in gas monetization and utilization, including the Angola liquefied natural gas (LNG) plant's historical operation below capacity. In response, **Angola has adopted the National Gas Master Plan**, outlining measures to address these constraints through expanded gas infrastructure and improved gas monetization over the period to 2050.[53]

Angola faces several methane mitigation technical and operational barriers, including offshore space and operational constraints, limited methane-specific technical expertise among domestic operators, few local service providers, some ageing facilities with legacy equipment that is not fully compatible with modern mitigation technologies, and insufficient infrastructure to reinject or commercialize captured gas.

Marginal Abatement Cost Curve

Figure 5 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Angola's oil and gas sector. The results are also provided in tabular form in Appendix 15.

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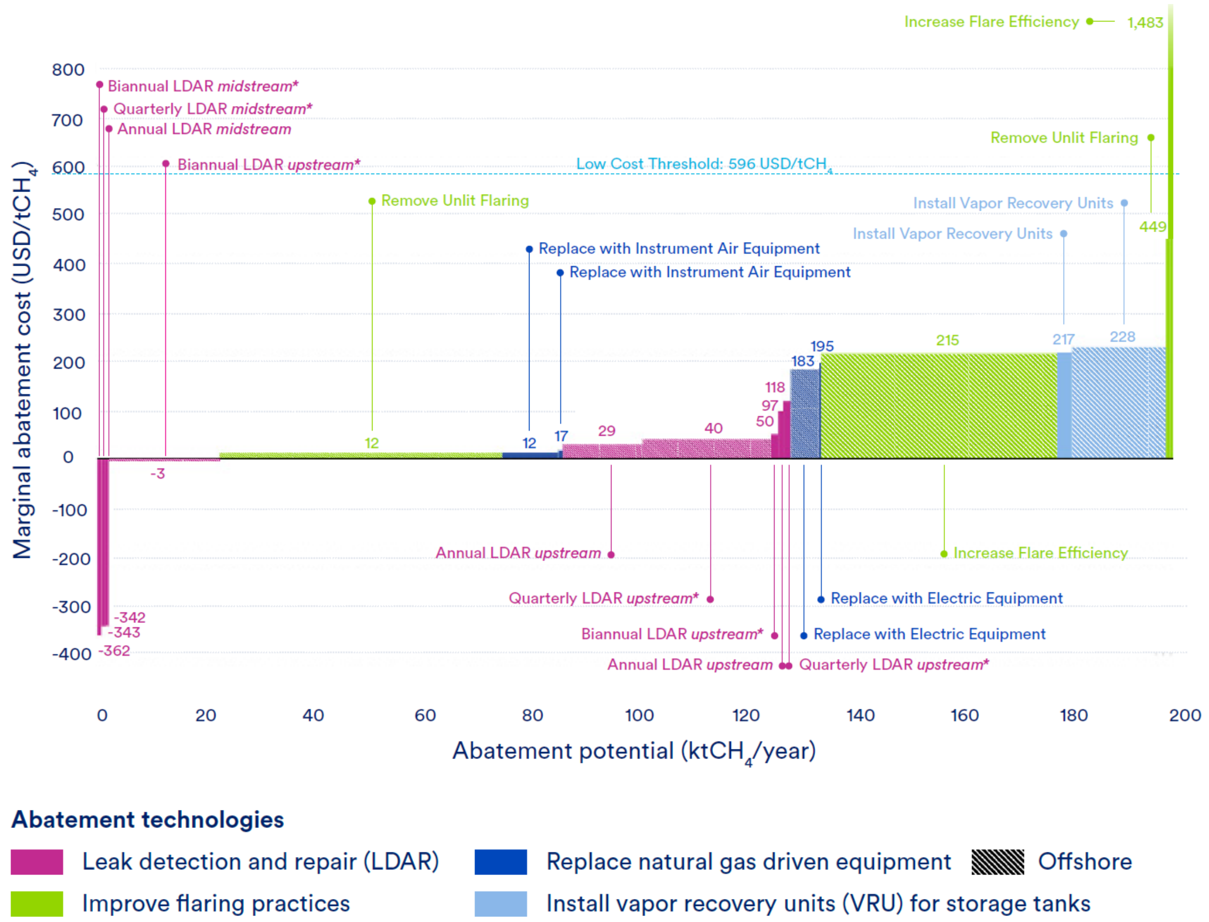
[45] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[46] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[47] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[48] Republic of Angola. (2004). *Petroleum Activities Law, Law No. 10/04*. Available at: https://faolex.fao.org/docs/pdf/ang81903e.pdf
[49] Republic of Angola. (2019). *Law No. 5/19 amending Law No. 10/04 on Petroleum Activities.* Available at: https://faolex.fao.org/docs/pdf/ang185279.pdf
[50] International Energy Agency (IEA). (2023). *Angola – Natural gas*. Available at: https://www.iea.org/countries/angola/natural-gas
[51] Surplus associated gas that is not utilized or commercialized by operators must be transferred free of charge to the Angola LNG plant.
[52] National Oil, Gas and Biofuels Agency (ANPG). (2025). *Annual Report 2024*. Available at: https://anpg.co.ao/wp-content/uploads/2025/06/Relatorio_de_Gestao_2024.pdf
[53] Republic of Angola. (2025). *Presidential Decree No. 72/25 approving the Natural Gas Master Plan*. Available at: https://faolex.fao.org/docs/pdf/ang234158.pdf

Figure 5. Angola Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*

Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR programs in the midstream segment, show negative abatement costs, as recovered gas generates net savings. These savings depend on assumptions regarding gas marketability and prices. In this analysis, 100% of recovered gas midstream is assumed to be currently brought to market at a price of 10 USD/MMBtu, while only 40% of recovered gas in upstream operations is assumed to be currently brought to market at a price of 5 USD/MMBtu. Under these assumptions, most mitigation measures assessed fall well below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Within this MACC, the elimination of unlit flaring offshore delivers the largest single abatement potential, with approximately 52 kt of methane emissions reductions per year at a marginal cost of around 12 USD/tCH_4. LDAR programs in the upstream segment and the replacement of pneumatic equipment with instrument air systems also remain well below the low-cost threshold. Higher marginal costs are associated with infrastructure upgrades, including improved flaring systems, installation of vapor recovery units, and replacement of pneumatic equipment with electric systems.

Overall, deploying the full portfolio of considered abatement measures could result in 198 kt of methane emissions reductions per year at a net cost of around USD 18 million/year. *If all recovered upstream gas were assumed to be saleable at 5 USD/MMBtu, net abatement costs could decline to around USD 6 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices *Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	97 kt CH_4 abatable	151 USD/tCH_4

Angola does not impose strict performance, monitoring, or repair requirements for flaring systems. Regulation is largely limited to restricting routine flaring under petroleum legislation, with flaring permitted mainly for testing or operational safety.

The main policy instrument is mainly focused on gas monetization.[54] This orientation is also mirrored in operator strategies, which prioritize reducing routine flaring volumes over improving flaring performance standards.

Install Vapor Recovery Units *Installation of vapor recovery units (VRUs) on storage tanks*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Difficult	Low adoption	20 kt CH_4 abatable	226 USD/tCH_4

There are no regulatory requirements mandating the deployment of VRUs in Angola, and their uptake currently relies on voluntary operator initiatives.

Adoption remains limited, reflecting high installation costs and the need for recovered gas to have on-site or market value for investments to be viable. Offshore space, weight, and safety constraints (particularly on older facilities) further complicate retrofitting. Wider deployment of VRUs depends on improved access to gas utilization routes, which could increase their attractiveness over time.

Leak Detection and Repair (LDAR) *Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	65 kt CH_4 abatable	14 USD/tCH_4

Angola does not have regulatory requirements mandating leak detection and repair (LDAR) programs, and current practices vary across operators. International oil companies typically conduct LDAR campaigns as part of their global methane management strategies. Local operators are only beginning to implement LDAR, generally through limited pilot campaigns at selected facilities.

Wider deployment is constrained by the absence of regulatory incentives and by limited local technical capacity, which often requires reliance on foreign service providers.

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	17 kt CH_4 abatable	70 USD/tCH_4

Angola does not impose regulatory restrictions on natural gas driven pneumatic equipment, leaving decisions on the use of pneumatic or electric pumps and controllers to operators.

[54] Republic of Angola. (2025). Presidential Decree No. 72/25 approving the Natural Gas Master Plan. Available at: https://faolex.fao.org/docs/pdf/ang234158.pdf

In practice, natural gas driven equipment continues to be used on older offshore platforms, while newer installations increasingly rely on electric or instrument air systems.

Policies recommendations

Angola has not established a dedicated methane regulatory framework, with existing provisions largely limited to restrictions on routine flaring under petroleum legislation. Current policy efforts instead address methane emissions indirectly through broader gas utilization and monetization objectives. **In the near term, introducing an initial regulatory framework could support cost-effective emissions reductions.** Several mitigation options, notably LDAR, replacement of natural-gas-driven pneumatic equipment, and elimination of unlit flaring, exhibit low or negative marginal abatement costs. Establishing minimum regulatory requirements, such as periodic LDAR surveys or restrictions on gas-driven equipment, could help scale deployment beyond voluntary operator initiatives. However, the effectiveness of such measures will depend on institutional capacity for monitoring, reporting and enforcement, as well as coordination between regulatory bodies, which may require targeted capacity-building support alongside regulatory development.

Over the medium term, targeted fiscal incentives or concessional financing could help address capital and capacity constraints, particularly for more capital-intensive technologies such as vapor recovery units. Such measures could complement regulatory requirements and improve uptake where commercial returns remain uncertain. At the same time, **continued development of gas infrastructure** would further support commercialization and progressively lower abatement costs by expanding monetization opportunities. In parallel, **improving the commercial terms for recovered gas**, for example delivered to the Angola LNG plant, could materially strengthen project economics and incentivize broader uptake of methane mitigation measures.

In the longer term, Angola could **focus on implementing higher-cost mitigation options**, **supported by international climate or carbon finance** where appropriate.

4.3 Argentina

Key figures

Estimated annual emissions[55]	**Technical abatement possible from analyzed technologies**
1,363 kt CH_4 (40.6 Mt CO_2e)	32% of estimated emissions
Emissions analyzed[56]	**Low-cost abatement potential from analyzed technologies**[57]
708 kt CH_4 (52% of estimated emissions)	30% of estimated emissions

Current policies and practices

Argentina's natural gas system is key to the national energy economy, supplying around half of primary energy demand and more than 50% of electricity generation.[58] Argentina's growth prospects depend on scaling up gas production and infrastructure to enhance energy security and exports, with the Vaca Muerta shale, one of the world's largest unconventional resources, expected to drive significant output growth. The system relies on an **extensive transmission network** that has historically faced some capacity constraints, combined with limited underground gas storage and strong seasonal demand variability. Recent pipeline expansions have improved gas transport capacity, but operational challenges remain.

Argentina's legal and regulatory framework for addressing methane emissions in the oil and gas sector is still **nascent and fragmented**. At the federal level, methane-specific regulations are currently limited to venting and flaring restrictions and provisions addressing evaporative losses for storage tanks.[59] [60] A National Program for the Measurement and Reduction of Fugitive Emissions from hydrocarbon exploration and production activities was established in 2023, but implementing regulations are still pending.[61] In 2024, a comprehensive draft federal law was proposed to establish minimum standards for methane emission measurement, reporting, and reduction across the value chain, but it has not yet been approved.[62] In parallel, **oil- and gas- producing provinces** of Chubut, Neuquen, and Mendoza **have started implementing their own regulatory frameworks**, including requirements for emissions management plans and LDAR programs.[63] [64] [65] [66]

Methane mitigation deployment is constrained by the high costs for advanced technologies, **a limited pool of local service providers, and economic instability**, which has limited the entry and expansion of foreign technology and service providers despite a recent easing of rules around equipment imports and providing

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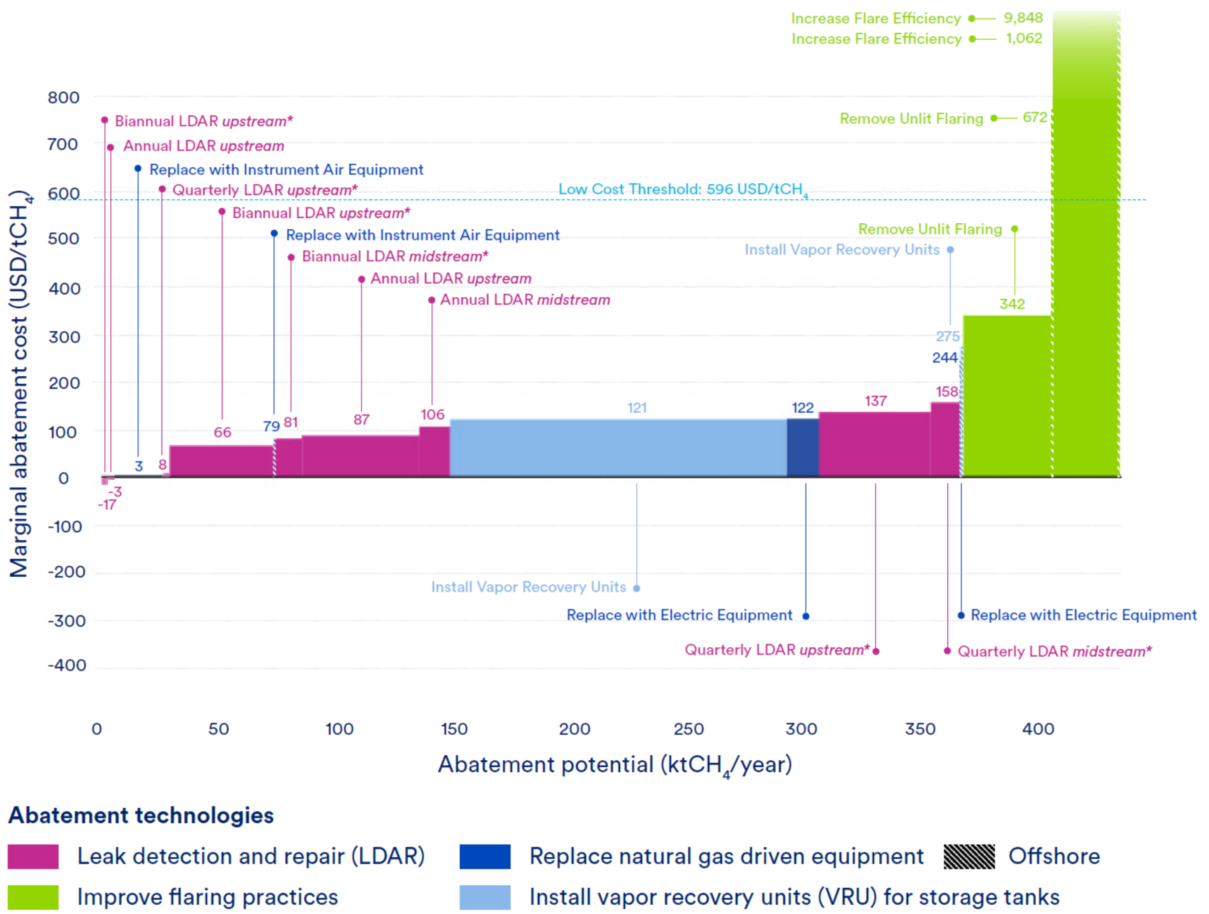
[55] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[56] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[57] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[58] International Energy Agency (IEA). (2024). *Argentina – Natural gas*. Available at: https://www.iea.org/countries/argentina/natural-gas
[59] Ministry of Energy, Argentina. (1998). *Resolution 143/1998 – Modification of Resolution No. 236/96, Approve the Rules and Regulations of Gas Venting*. Available at: https://www.argentina.gob.ar/normativa/nacional/resoluci%C3%B3n-143-1998-50476/texto
[60] Ministry of Energy, Argentina. (2005). *Energy Resolution 785/2005 - National Program for Control of Losses of Air Tanks for Storage of Hydrocarbons and their Derivatives.* Available at: https://www.argentina.gob.ar/normativa/nacional/resoluci%C3%B3n-785-2005-107289
[61] Ministry of the Economy, Argentina. (2023). *Resolution 970/2023 – National Program for the Measurement and Reduction of Fugitive Emissions from Hydrocarbon Exploration and Production Activities.* Available at: https://www.argentina.gob.ar/normativa/nacional/resoluci%C3%B3n-970-2023-394156/texto
[62] National Congress (Argentina). (2024). *Minimum Environmental Protection Standards for the Management of Methane Emissions in the Hydrocarbon Sector.* Available at: https://www4.hcdn.gob.ar/dependencias/dsecretaria/Periodo2024/PDF2024/TP2024/2898-D-2024.pdf
[63] Province of Chubut. (2024). *Resolution 58/2024 – Regulation of methane emissions from hydrocarbon activities.* Available: https://boletin.chubut.gov.ar/archivos/boletines/Octubre%203,%202024.pdf
[64] Province of Neuquén. (2025). *Resolution 258/2025 – Program for the Monitoring and Mitigation of Greenhouse Gas Emissions in the Hydrocarbon Sector.* Available at: https://ambiente.neuquen.gov.ar/wp-content/uploads/2025/04/resolucion-258-2025-1.pdf
[65] Province of Mendoza. (2025). *Decree 758/25 – Comprehensive Provincial Program on Greenhouse Gas Emissions.* Available at: https://boe.mendoza.gov.ar/publico/pdf_pedido/ccd75cbb905f651ff72ec0087dfcb253d291579748
[66] Province of Neuquén. (2025). *Official Gazette, Issue No. 4563*. Available at: https://boficial.neuquen.gov.ar/Boletines/boletin_4563.pdf

new tax incentives for the oil and gas industry. The absence of a carbon price and limited targeted incentives further complicate project economics, despite growing operator engagement and increasing deployment of mitigation measures.

Marginal Abatement Cost Curve

Figure 6 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Argentina's oil and gas sector. The results are also provided in tabular form in Appendix 16.

Figure 6. Argentina Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall; when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR programs in the offshore upstream segment, show negative abatement costs, as recovered gas generates net savings. These savings rely on assumptions regarding gas marketability and prices. In this analysis, 100% of recovered gas midstream and 85% of recovered gas upstream is assumed to be currently brought to market at a price of approximately 3 USD/MMBtu. Under these assumptions, most mitigation measures assessed fall well below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Within this MACC, the installation of VRUs on storage tanks in the onshore upstream segment delivers the largest single abatement potential, with approximately 144 kt of methane emissions reductions per year at a marginal abatement cost of around 121 USD/tCH_4. LDAR programs and the replacement of natural gas-driven pneumatic equipment also remain low- to moderate-cost range. Higher marginal costs are associated with the elimination of unlit flaring and the implementation of improved flaring systems, as flaring is distributed across a lot of sites, which increases costs of abatement as it requires individual investments for each flare. As a result, the emissions reductions achieved associated to improving flaring practices are limited compared with the level of capital investment required to implement these measures.

Overall, deploying the full portfolio of considered abatement measures could result in 436 kt of methane emissions reductions per year at a net cost of around USD 82 million/year. *If all recovered upstream gas were assumed to be saleable at 3 USD/MMBtu, net abatement costs could decline to around USD 79 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices *Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	67 kt CH_4 abatable	788 USD/tCH_4

Argentina does not impose strict performance, monitoring, or repair requirements for flaring systems. Regulation is largely limited to restrictions on venting volumes under petroleum legislation, with any gas authorized for disposal required to be combusted in accordance with appropriate operating procedures.[67]

Operationally, several operators prioritize reducing flare volume rather than optimizing flare performance and have taken steps to eliminate routine flaring. These efforts include investments in gas evacuation infrastructure, zero-routine-flaring facility design, and gas utilization or monetization solutions.

Leak Detection and Repair (LDAR) *Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	188 kt CH_4 abatable	96 USD/tCH_4

LDAR programs are not yet mandated nationwide in Argentina. However, the province of Chubut has recently introduced a requirement for operators to submit an annual LDAR plan; however, the inspection frequency remains at the operator's discretion.[68]

In practice, LDAR deployment is driven mainly by voluntary company commitments. Several international and domestic operators conduct periodic LDAR campaigns using a range of technologies, such as Optical Gas Imaging (OGI) cameras, ultrasonic chambers, and aerial detection tools. However, LDAR coverage and frequency across the sector remains uneven.

Wider deployment is constrained by a limited pool of specialized local service providers, higher costs due to reliance on imported equipment and expertise, and sometimes complex site access conditions.

[67] Ministry of Energy, Argentina. *Resolution 143/1998*. (see footnote 59)
[68] Province of Chubut. *Resolution 58/2024.* (see footnote 63)

Install Vapor Recovery Units *Installation of vapor recovery units (VRUs) on storage tanks*			
Ease of deployment Intermediate	Current practices Medium adoption	Abatement potential 145 kt CH_4 abatable	Marginal abatement cost 123 USD/tCH_4

There is currently no national regulation mandating the installation of VRUs in Argentina. As a result, VRU deployment remains operator-driven and uneven. Several international and domestic operators have deployed VRUs across both existing and new facilities. In some cases, performance issues have been reported, but operators are actively working to improve system reliability and equipment uptime.

Deployment remains sensitive to high installation costs, operational complexity, and uncertain economic returns, as recovered gas must generate sufficient value to ensure a reasonable payback period.

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment Easy	Current practices High adoption	Abatement potential 36 kt CH_4 abatable	Marginal abatement cost 53 USD/tCH_4

Argentina does not compel operators to phase out natural gas-driven pneumatic equipment, leaving decisions on the use of pneumatic or zero-emissions pumps and controllers to operators. Although instrument air and electric systems are already commonly adopted across the sector, natural-gas-driven pneumatics remain in use in some operations. However, conversion efforts are ongoing, with some domestic and international operators actively transitioning remaining pneumatic systems to instrument air or electric configurations.

Policies recommendations

Argentina currently lacks a dedicated federal methane regulatory framework, with current provisions limited to venting, flaring, and evaporative loss controls for storage tanks. A national fugitive emissions program was launched in 2023, but national implementation of LDAR campaign, improving flaring practices, installing VRUs and replacing natural gas-driven equipment is pending, while several provinces have begun introducing their own methane-related requirements. **In the near term, establishing or strengthening basic regulatory requirements** (such as periodic LDAR surveys or restrictions on natural gas-driven pneumatic equipment) could support wider uptake of low-cost mitigation options. Several measures, including LDAR, replacement of natural-gas-driven pneumatic devices, and installation of VRUs, exhibit low or even negative marginal abatement costs, yet adoption has so far been uneven and relied largely on voluntary operator initiatives. **Expanding provincial requirements** would allow regulators to **prioritize measures most relevant to local production characteristics and infrastructure constraints**, while a federal framework could enhance consistency across jurisdictions. In parallel, for provinces that have already started to introduce methane requirements, the key priority can be **effective implementation and enforcement** to translate regulatory provisions into measurable emissions reductions.

In the longer term, Argentina could **focus on implementing higher-cost mitigation options through regulation**, possibly **supported by international climate or carbon financing** where appropriate. While standalone improvements to flaring efficiency are not eligible for carbon finance, projects that reduce flared volumes through gas utilization, may be eligible.

4.4 Brazil

Key figures

Estimated annual emissions[69]	**Technical abatement possible from analyzed technologies**
1,073 kt CH_4 (32.0 Mt CO_2e)	19% of estimated emissions
Emissions analyzed[70]	**Low-cost abatement potential from analyzed technologies**[71]
383 kt CH_4 (36% of estimated emissions)	19% of estimated emissions

Current policies and practices

Brazil does not yet have a dedicated methane regulatory framework for the oil and gas sector. Methane control is addressed indirectly through petroleum and environmental regulations, with a strong focus on flaring and venting restrictions.[72] [73] [74] These include limits on total gas losses (generally around 3% of gas production), inclusion of flared gas in royalty calculations, and restrictions on routine flaring under certain circumstances. In parallel, **dedicated methane regulations are under preparation**, with a new framework **expected to be adopted by the end of 2026.**[75]

Brazil's gas market is undergoing gradual liberalization, with reforms promoting third-party access and new investments.[76] Gas production is largely associated with offshore oil, but around 54% of volumes are reinjected for reservoir pressure maintenance, and due to limited transport infrastructure and gas composition constraints requiring additional processing.[77] **Persistent infrastructure gaps, including limited pipeline coverage and processing capacity, continue to constrain gas monetization**, particularly in remote and offshore areas. As a result, domestic demand exceeds supply, leading to continued reliance on imports.

Methane mitigation in Brazil is constrained by several economic and technical barriers, including **high upfront costs, limited access to financing**, and a **small pool of local service providers**. **Offshore constraints** and **infrastructure gaps** can restrict the ability to capture and commercialize gas, while limited technical capacity and low awareness further hinder uptake among some operators. However, several low-cost abatement opportunities exist, and operators are required to **allocate a share of their revenues to research, development and innovation,** which could support research and pilot-scale demonstration of methane emissions reduction technologies.[78]

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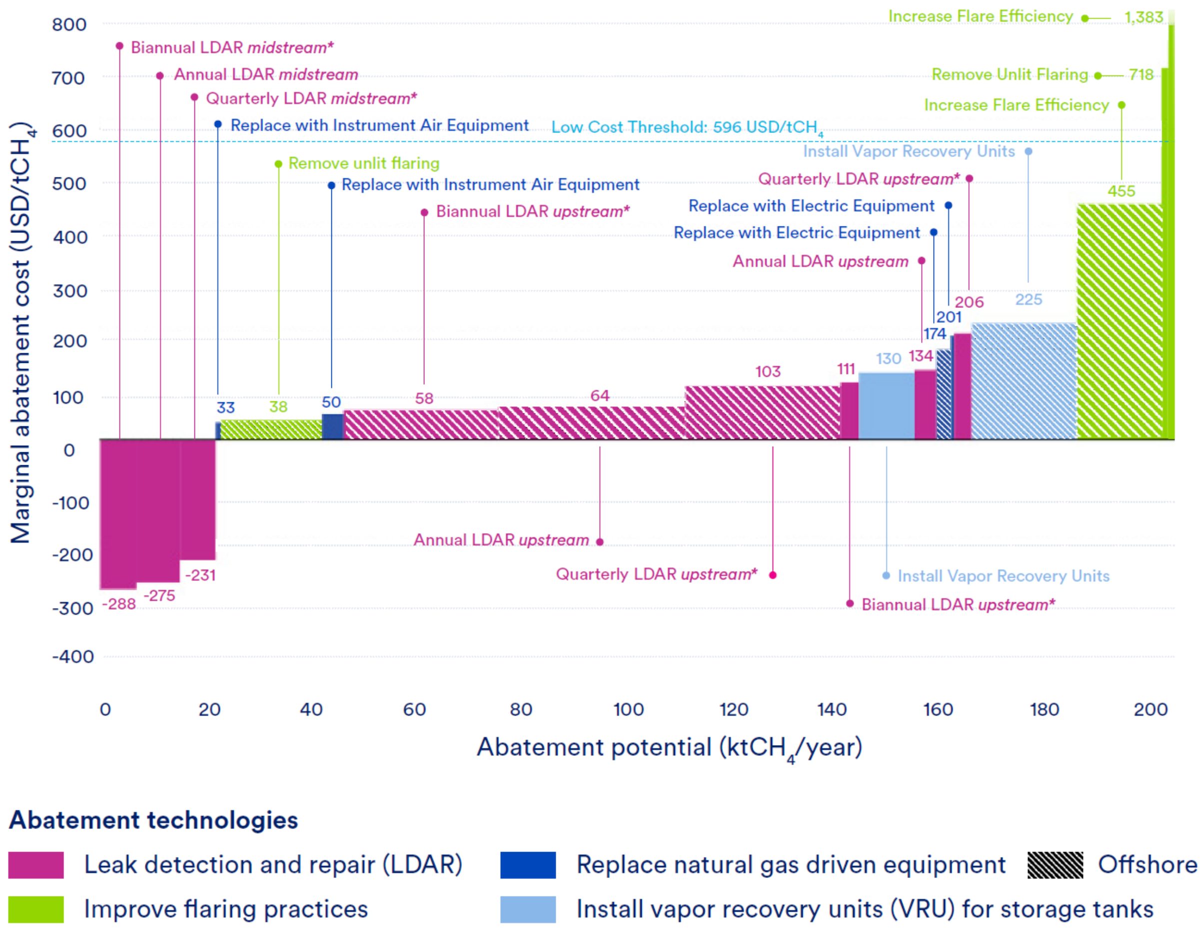
[69] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[70] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[71] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[72] Federative Republic of Brazil. (1997). *Law No. 9.478 - Dealing with national energy policy, oil monopoly activities, establishing the National Energy Policy Council and the National Petroleum Agency and making other arrangements.* Available at: https://www.gov.br/mme/pt-br/acesso-a-informacao/legislacao/leis/lei-n-9-478-1997.pdf/view
[73] Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP). (2020). *Resolution No 806 of 2020 from ANP*. Available at: https://atosoficiais.com.br/anp/resolucao-n-806-2020
[74] Brazilian Institute of the Environnement and Renewable Natural Resources (IBAMA). (2010). *IBAMA Normative Instruction No 12 of 2010*. Available at: https://www.mprs.mp.br/media/areas/gapp/arquivos/inst_norm_2_ibama_2010.pdf
[75] Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP). (2025). *ANP will conduct a prior consultation on a study concerning methane emissions*. Available at: https://www.gov.br/anp/pt-br/canais_atendimento/imprensa/noticias-comunicados/anp-fara-consulta-previa-sobre-estudo-relativo-a-emissoes-de-metano
[76] Federative Republic of Brazil. (2021). *Law No. 14.134.* Available at: https://www.planalto.gov.br/ccivil_03/_ato2019-2022/2021/lei/l14134.htm
[77] Brazilian National Agency for Petroleum, Natural Gas and Biofuels (ANP). (2026). *Oil and gas production.* Available at: *https://app.powerbi.com/view?r=eyJrIjoiNzVmNzI1MzQtNTY1NC00ZGVhLTk5N2ItNzBkMDNhY2IxZTIxIiwidCI6IjQ0OTlmNGZmLTI0YTYtNGI0Mi1iN2VmLTEyNGFmY2FkYzkxMyJ9*
[78] Brazilian National Agency for Petroleum, Natural Gas and Biofuels (ANP). (2023). *Resolution No 918 of 2023 from ANP*. Available at: https://atosoficiais.com.br/anp/resolucao-n-918-2023

Marginal Abatement Cost Curve

Figure 7 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Brazil's oil and gas sector. The results are also provided in tabular form in Appendix 17.

Figure 7. Brazil Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR programs in the midstream segment, show negative abatement costs, as recovered gas generates net savings. These savings depend on assumptions regarding gas marketability and prices. In this analysis, it is assumed that 100% of recovered gas in the midstream segment can be marketed at a price of 10 USD/MMBtu, while 72% of onshore upstream recovered gas and 26% of offshore upstream recovered gas can be marketed at a price of 2 USD/MMBtu. Under these assumptions, most mitigation measures assessed fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Within this cost range, the improvement of annual LDAR programs in the offshore upstream segment delivers the largest single abatement potential, with approximately 36 kt of methane emissions reductions per year at a low marginal abatement cost of around 64 USD/tCH_4. The installation of VRUs and the replacement of pneumatic equipment with electric or air-driven alternatives systems also remain below the low-cost threshold. Higher marginal costs are associated with the elimination of unlit flaring and the implementation of improved flaring systems. Given that flaring volumes are already relatively low due to site-level limits, the resulting emissions reductions are modest relative to the capital investment required.

Overall, deploying the full portfolio of considered abatement measures could result in 205 kt of methane emissions reductions per year at a net cost of around USD 20 million/year. *If all recovered upstream gas were assumed to be saleable at 2 USD/MMBtu, total abatement costs could decline to around USD 12 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices *Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	38 kt CH_4 abatable	349 USD/tCH_4

Brazil does not impose strict performance, monitoring, or repair requirements for flaring systems. Regulation is limited to controlling flaring and gas losses under petroleum legislation, with gas losses capped and flaring primarily allowed for safety-related or exceptional operational conditions.[79]

Operationally, several facilities rely on cameras and temperature sensors to continuously monitor flare status and ensure ignition is maintained, with regular maintenance supporting high destruction efficiency.

Install Vapor Recovery Units *Installation of vapor recovery units (VRUs) on storage tanks*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	31 kt CH_4 abatable	192 USD/tCH_4

There is currently no regulation mandating the installation of vapor recovery units (VRUs) in Brazil. As a result, VRU deployment remains operator-driven and uneven. Some operators have started implementing vapor recovery systems in newer facilities to capture tank vapors, while others are still assessing their feasibility.

However, deployment is not widespread: many older offshore installations continue to vent due to space, weight, and safety constraints that complicate retrofitting. Deployment also remains sensitive to high installation costs, and uncertain economic returns, as infrastructure gaps can limit the ability to transport or commercialize recovered gas.

Leak Detection and Repair (LDAR) *Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	128 kt CH_4 abatable	22 USD/tCH_4

Brazil does not have regulatory requirements mandating LDAR programs, and practices vary across operators. Some companies conduct periodic campaigns (e.g. annual or multi-year) using internal teams and external contractors, supported by ground-based surveys and drones. In some cases, these efforts are complemented by continuous monitoring systems. While many leaks are addressed promptly, others are deferred and prioritized during planned shutdowns.

Deployment remains constrained by cost and capacity. A limited number of local service providers reduces competition and drives up prices, compared to mature markets. Offshore campaigns are

[79] ANP. *Resolution 806/ 2020*. (see footnote 73)

especially complex and time-consuming, with logistics and permitting requirements increasing costs and limiting survey frequency.			
Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Easy	High adoption	8 kt CH_4 abatable	100 USD/tCH_4
Brazil does not impose specific regulatory requirements targeting methane emissions from natural gas driven pneumatic equipment, leaving technology choices to operators. In practice, such equipment is not widely used in the Brazilian oil and gas sector, with most assets already relying on electric or instrument air alternatives.			

Policies recommendations

Brazil is currently working on updates to its existing flaring regulation and is planning to propose a dedicated methane regulation. At the same time, several mitigation measures assessed in this study show substantial abatement potential at low or negative cost. **Thus, in the near term, priorities could focus on ensuring that the methane regulation expected by end of 2026**[80] **includes targeted measures addressing the most cost-effective mitigation opportunities** while the **revised flaring regulation incorporates requirements for flare efficiency and the prevention of unlit flares**. In particular, introducing minimum LDAR requirements in the methane regulation would provide a high-impact entry point, complemented by provisions covering additional measures such as vapor recovery units, replacement of natural gas-driven equipment, and others. Consideration could be given to phased implementation for more capital-intensive measures at existing facilities. Strong implementation and enforcement will then be essential to translate these provisions into measurable emissions reductions.

Over the medium term, Brazil could focus on **strengthening measurement, monitoring, reporting and verification systems** to improve emissions data and support effective compliance. **Targeted financial instruments** (such as concessional financing, expanded credit lines, and support for access to international climate finance) could help address remaining economic barriers, particularly for offshore assets. **Developing capacity strengthening initiatives** across the value chain could further support technology deployment and innovation.

In the longer term, addressing structural constraints will be essential**. Continued development of gas gathering, processing, and transport infrastructure** would improve gas monetization opportunities and strengthen the economics of methane mitigation.

[80] ANP. *Prior consultation on methane emissions study*. (see footnote 75)

4.5 Egypt

Key figures

Estimated annual emissions[81]	**Technical abatement possible from analyzed technologies**
596 kt CH_4 (17.8 Mt CO_2e)	35% of estimated emissions
Emissions analyzed[82]	**Low-cost abatement potential from analyzed technologies**[83]
308 kt CH_4 (52% of estimated emissions)	35% of estimated emissions

Current policies and practices

Egypt does not have a dedicated methane regulatory framework for the oil and gas sector. Methane control is addressed indirectly through petroleum and environmental regulation, including requirements for flaring and separation systems, vapor ventilation on storage tanks, and the safe disposal of associated gas that cannot be utilized.[84] Recent developments point to a potential shift, as Egypt has approved an agreement to develop a methane reduction roadmap, including possible regulatory measures.[85]

Egypt's gas sector is central to its energy system, supplying most electricity demand and supported by vast production, processing, and export infrastructure.[86] However, declining output and rising demand have tightened supply, leading to periodic LNG imports. At the same time, **infrastructure gaps** (particularly in older or remote oil fields) continue to result in flaring. In addition, **partially regulated gas prices** (remaining below international prices) and **restricted market access** weaken economic incentives for methane mitigation investments, although recent reforms aim to liberalize the sector.[87]

Methane mitigation in Egypt is constrained by several technical and operational barriers, including **high upfront capital costs**, **infrastructure gaps**, **restricted market access**, and **low domestic gas prices** that weaken investment incentives. However, several low-cost abatement opportunities exist, and some operators have begun to take up the issue of methane emissions and have started to implement solutions.

Marginal Abatement Cost Curve

Figure 8 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Egypt's oil and gas sector. The results are also provided in tabular form in Appendix 18.

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR programs in the midstream segment, show negative abatement costs, as recovered gas generates net savings. These savings rely on assumed marketable gas shares. In this analysis, 50% of recovered gas in upstream operations is assumed to be currently brought to market at a price of 2.8 USD/MMBtu, while 100% of recovered gas in the midstream segment is assumed to be currently brought to market at a price of 3.3 USD/MMBtu. Under these assumptions, all mitigation measures assessed fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

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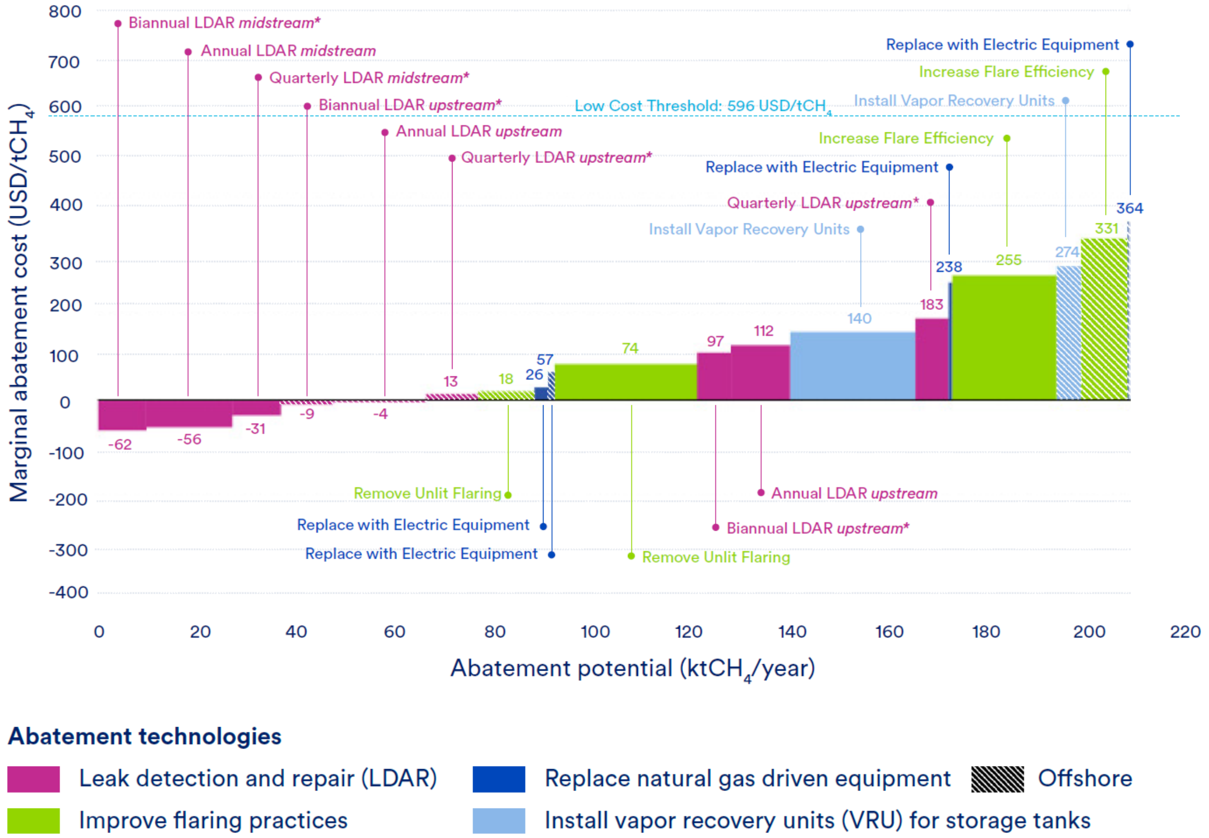
[81] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[82] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[83] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[84] Arab Republic of Egypt. (1995). *Prime Minister's Decree No. 338 of 1995 Issuing the Executive Regulations of the Environment Law 4/1994*. Available at: https://faolex.fao.org/docs/pdf/egy4986E.pdf
[85] Egypt Today. (2025). *President Sisi approves agreement for roadmap to reduce methane emissions in Egypt.* Available at: https://www.egypttoday.com/Article/1/141050/President-Sisi-approves-agreement-for-roadmap-to-reduce-methane-emissions
[86] International Energy Agency (IEA). (2023). *Egypt – Natural gas*. https://www.iea.org/countries/egypt/natural-gas
[87] Arab Republic of Egypt. (2017). *Law for Gas Market Activities Regulation*. Available at: https://www.gasreg.org.eg/law-for-gas-market-activities-regulation/

Figure 8. Egypt Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Within this MACC, the elimination of unlit flaring in the onshore upstream segment delivers the largest single abatement potential, with approximately 29 kt of methane emissions reductions per year at a marginal abatement cost of around 74 USD/tCH_4. LDAR programs in the upstream operations and the replacement of natural gas-driven pneumatic equipment with instrument air systems also remain well below the low-cost threshold. Higher marginal abatement costs are associated with infrastructure upgrades, including installation of VRUs, replacement of pneumatic equipment with electric systems, and improvement of flaring destruction efficiency. Despite these factors, these measures remain within the low-cost abatement range.

Overall, deploying the full portfolio of considered abatement measures could result in 209 kt of methane emissions reductions per year at a net cost of around USD 17 million/year. *If all recovered upstream gas were assumed to be marketable at 2.8 USD/MMBtu, net abatement costs could decline to around USD 12 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices

Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	71 kt CH_4 abatable	191 USD/tCH_4

Egypt does not impose detailed performance, monitoring, or maintenance requirements for flaring systems. Instead, the current regulation provides a general provision that associated gas which cannot be safely used or exploited must be disposed of in accordance with relevant international standards.[88]

In practice, operators prioritize reducing flared volumes rather than optimizing flare performance, investing instead in gas utilization or monetization solutions. Several flare-capture projects have been commissioned in recent years. Flare gas recovery supports reduction of methane emissions and GHGs more broadly, however, this analysis focuses on the opportunity to mitigate methane emissions through better efficiency and reduction of unlit flares at existing flare systems.

Install Vapor Recovery Units

Installation of vapor recovery units (VRUs) on storage tanks

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	30 kt CH_4 abatable	161 USD/tCH_4

The current regulation does not mandate the use of VRUs. Instead, it takes a performance-based approach, requiring storage tanks to be tightly sealed and any release of excess vapors to be managed in accordance with international standards.[89]

In practice, some operators have started implementing vapor recovery systems. However, wider deployment is constrained by high installation costs and uncertain economic returns, as infrastructure gaps and complex gas market conditions can limit the commercialization of recovered gas.

Leak Detection and Repair (LDAR)

Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	103 kt CH_4 abatable	12 USD/tCH_4

Egypt does not have regulatory requirements mandating LDAR programs, and current practices vary across operators. Some operators have begun implementing LDAR using OGI cameras, with campaigns carried out in-house, by contractors, or through partnerships between international and domestic companies. In some cases, these efforts are driven primarily by safety considerations rather than emissions reduction objectives. Wider deployment is constrained by the absence of regulatory incentives and the prioritization of capital toward other investments.

[88] Arab Republic of Egypt. *Decree 338/1995.* (see footnote 84)
[89] Arab Republic of Egypt. *Decree 338/1995.* (see footnote 84)

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Easy	High adoption	5 kt CH_4 abatable	84 USD/tCH_4
The current regulation requires operators to prioritize the use of compressed air instead of compressed natural gas for measuring and control equipment wherever technically feasible.[90] In practice, natural gas-driven equipment is not widely used in the Egyptian oil and gas sector, with most assets already relying on electric or instrument-air alternatives.			

Policies recommendations

Egypt has not yet established a dedicated methane regulatory framework, with existing provisions primarily embedded in broader environmental and petroleum regulations. However, recent steps toward developing a methane reduction roadmap signal growing policy momentum. **Priorities could focus on establishing a regulatory framework that targets the most cost-effective mitigation opportunities in the near term and phases in a broader set of mitigation measures in the medium term**. Near term measures can include LDAR programs and the elimination of unlit flaring, which show substantial abatement potential at low or negative cost. Introducing minimum LDAR requirements, alongside basic flaring monitoring obligations, would provide a high-impact entry point. **Measures that can be phased in can include** performance standards for flaring systems and the deployment of vapor recovery units on storage tanks.

Further liberalization of gas market access and pricing could help improve monetization opportunities and strengthen the economic case for methane mitigation. In parallel, **targeted financial instruments**, including concessional financing or fiscal incentives, could help address capital constraints and support the uptake of more capital-intensive technologies. **Strengthening technical capacity and awareness** among operators would also further support implementation.

In addition, **continued development of gas gathering, processing, and transport infrastructure** would further improve gas monetization prospects.

[90] Arab Republic of Egypt. *Decree 338/1995.* (see footnote 84)

4.6 Ghana

Key figures

Estimated annual emissions[91]	**Technical abatement possible from analyzed technologies**
96 kt CH_4 (2.9 Mt CO_2e)	29% of estimated emissions
Emissions analyzed[92]	**Low-cost abatement potential from analyzed technologies**[93]
48 kt CH_4 (50% of estimated emissions)	29% of estimated emissions

Current policies and practices

Until recently, Ghana had only limited methane-specific regulatory requirements, and most mitigation efforts depended on operators' own standards.[94] Existing requirements were limited to restrictions on flaring and venting, enforced through facility limits and penalties for unapproved flaring. **The new Environmental Protection (Petroleum) Regulations (2025) mark a shift toward a dedicated methane framework**, introducing clearer expectations for inspection, monitoring, and emissions control.[95] Supporting technical guidelines will translate these regulations into practical, enforceable procedures for inspections, repairs, and emissions reporting to the Environmental Protection Authority (EPA), with an implementation roadmap to guide effective rollout.[96]

Ghana's gas market and infrastructure shape methane outcomes in important ways. Most of the gas used for domestic electricity generation is produced locally, with smaller volumes supplemented through regional pipeline imports.[97] Yet, **infrastructure constraints limit the ability to bring all produced gas to the market**: in 2024, 44% of gas production was reinjected and 10% was flared.[98] These figures highlight **ongoing limits in processing capacity and transmission bottlenecks** that hinder Ghana's ability to capture and use its gas. To address these limitations, the country is advancing **major infrastructure projects** to strengthen energy security, increase domestic gas use, and reduce routine flaring.

Key barriers to methane mitigation in Ghana include **high upfront capital costs of mitigation technologies**, **limited commercial incentives** when gas volumes are small, **offshore logistical challenges**, as well as ongoing **gas infrastructure gaps**. Looking ahead, Ghana's emerging carbon-market framework may create new incentives for methane abatement projects that deliver verified reductions beyond regulatory baselines.[99]

Marginal Abatement Cost Curve

Figure 9 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Ghana's oil and gas sector. The results are also provided in tabular form in Appendix 19.

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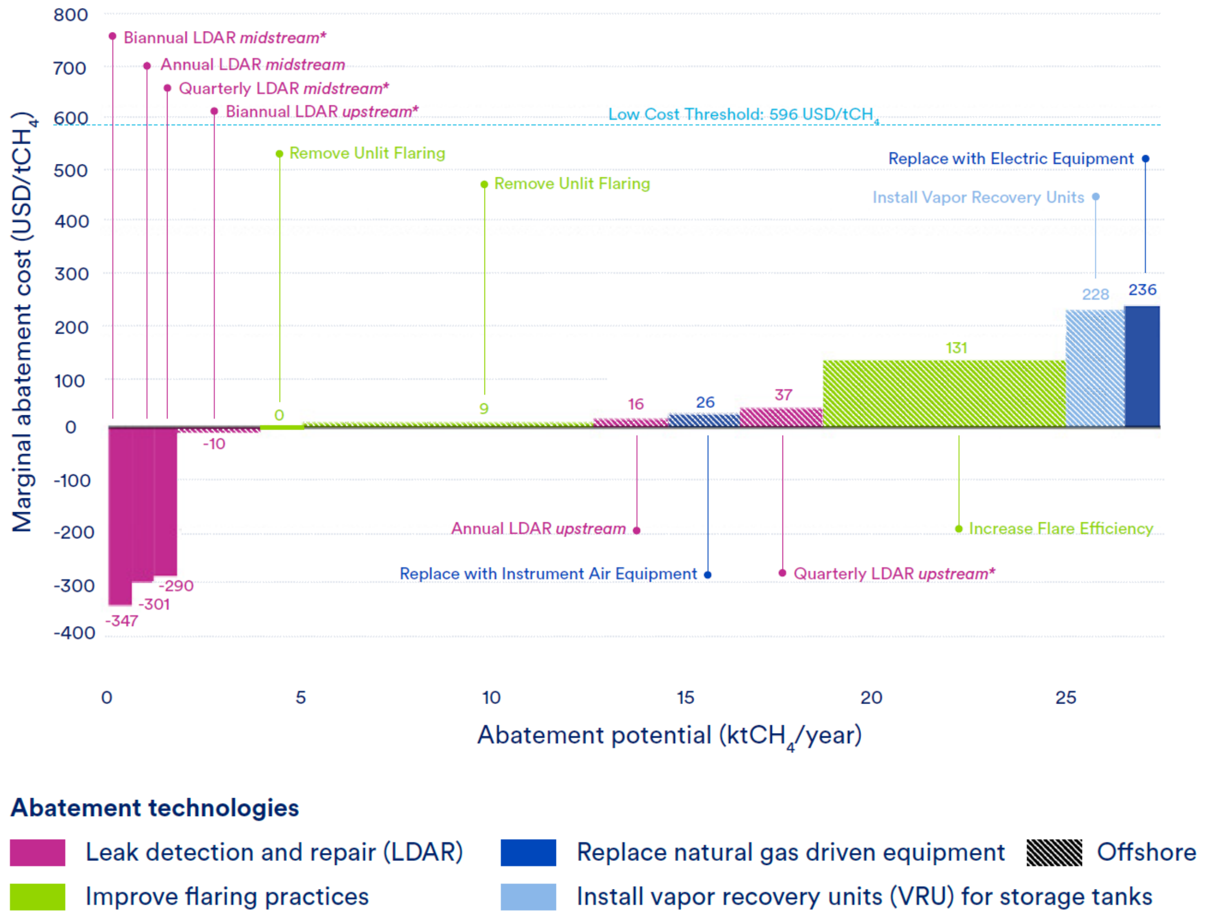
[91] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[92] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[93] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[94] Previous framework encompassed the Petroleum (Exploration and Production) Act, 2016 (Act 919) and the Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017.
[95] Republic of Ghana. (2025). *The Environmental Protection (Petroleum) Regulations.* To be released in 2026.
[96] Environmental Protection Authority (EPA). (2026). *Guidelines for Inspection, Monitoring and Reporting of Fugitives Methane Emissions from Oil and Gas Operations in Ghana.* Approved by the EPA and awaiting official unveiling.
[97] Energy Commission, Ghana. (2025). *2025 National Energy Statistical Bulletin*. Available at: https://energycom.gov.gh/planning/energy-statistics
[98] The Petroleum Commission, Ghana. (2025). *2024 Fields Production Data*. Available at: https://petrocom.gov.gh/production-volume/
[99] Republic of Ghana. (2025). *Environmental Protection Act, 2025*. Available at: https://epa.gov.gh/new/wp-content/uploads/2025/01/Environmental-Protection-Act-2025-Act-1124-2.pdf

Figure 9. Ghana Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR programs in the midstream segment, show negative abatement costs, as recovered gas generates net savings. These savings depend on assumptions regarding gas marketability and prices. In this analysis, 41 % of recovered gas in upstream operations is assumed to be currently brought to market at a price of 5 USD/MMBtu, while 100 % of recovered gas in the midstream segment is assumed to be currently brought to market at 10 USD/MMBtu. Under these assumptions, all mitigation measures assessed fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Within this cost range, the elimination of unlit flaring delivers the largest single abatement potential, with approximately 8 kt of methane emissions reductions per year at a low marginal abatement cost of around 9 USD/tCH_4. LDAR programs in the upstream segment and the replacement of pneumatic equipment with instrument air systems also remain well below the low-cost threshold. Higher marginal abatement costs are associated with infrastructure upgrades, including improved flaring systems, installation of vapor recovery units, and replacement of pneumatic equipment with electric systems, but these are still below the low-cost threshold.

Overall, deploying the full portfolio of considered abatement measures could result in 27 kt of methane emissions reductions per year at a net cost of around USD 1 million/year. *If all recovered upstream gas were assumed to be saleable at 5 USD/MMBtu, the aggregate cost of the abatement portfolio becomes negative, implying net cost savings of around USD 0.3 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices *Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	15 kt CH_4 abatable	79 USD/tCH_4

The recent regulations prohibit routine venting and limit flaring to clearly defined exceptional circumstances, such as emergency or safety-related events.[100] Flares must achieve a minimum destruction efficiency of 98% and be supported by technology to minimize periods when flare is unlit. Any flare that becomes unlit or operates below performance standards must be repaired or replaced within strict timelines.

Operationally, several offshore facilities rely on flare monitoring and alarm systems to detect flame outages, and some operators report upgrades (e.g., flare tip replacements) that can materially reduce methane emissions.

Install Vapor Recovery Units *Installation of vapor recovery units (VRUs) on storage tanks*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Difficult	Low adoption	2 kt CH_4 abatable	228 USD/tCH_4

The recent regulations require operators to minimize venting from tanks by capturing vapors (e.g., through vapor recovery units) or applying appropriate combustion controls.[101] The regulations discourage the use of "vent-by-design" equipment in new facilities, while requiring operators to plan the phased replacement of higher-emitting equipment in existing installations.

VRUs are used selectively in Ghana, but wider adoption is limited due to integration challenges with existing offshore systems and high installation costs, which require recovered gas to generate sufficient value to ensure a reasonable payback period.

Leak Detection and Repair (LDAR) *Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	8 kt CH_4 abatable	-58 USD/tCH_4

LDAR is one of the most cost-effective mitigation options for both offshore production facilities and onshore midstream facilities in Ghana. The recent regulations require operators to conduct regular inspections using technologies such as optical gas imaging (OGI) cameras, with inspection frequency increasing progressively over the first three years, and mandate prompt repair of all detected leaks.[102]

Current LDAR practices are largely operator-driven, with some companies using fixed gas detectors and OGI cameras to identify fugitive emissions. Leading operators, including Eni Ghana,[103] are also taking steps toward more advanced, quantitative LDAR approaches aligned with international reporting frameworks.

[100] Republic of Ghana. *The Environmental Protection (Petroleum) Regulations.* (see footnote 95)
[101] Republic of Ghana. *The Environmental Protection (Petroleum) Regulations.* (see footnote 95)
[102] Republic of Ghana. *The Environmental Protection (Petroleum) Regulations.* (see footnote 95)
[103] CATF. (2025). *Building partnerships and expertise to tackle methane emissions in Ghana*. Available at: https://www.catf.us/2024/12/building-partnerships-and-expertise-to-tackle-methane-emissions-in-ghana/

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	3 kt CH_4 abatable	96 USD/tCH_4
In practice, gas-driven pneumatic controllers and pumps are reportedly common across Ghana's oil and gas sector, while electrified and instrument air alternatives are not widely used. The recent regulations require minimization of venting from equipment, discourage venting designs in new builds, and promote replacement of gas-driven pneumatic devices with zero-emission alternatives where feasible.[104]			

Policies recommendations

Ghana has recently taken important steps toward establishing a dedicated methane regulatory framework through the adoption of the Environmental Protection (Petroleum) Regulations, which introduce clearer requirements for inspection, monitoring, and emissions control. With the regulatory foundations now in place, **near-term priorities can focus on effective implementation and enforcement** to translate these requirements into emissions reductions on the ground. Several mitigation options show low or negative marginal abatement costs, notably LDAR and elimination of unlit flaring, particularly where recovered gas can be monetized. For these low-cost measures, consistent enforcement of existing standards could support rapid uptake.

Over the medium term, targeted financial instruments, such as concessional loans or fiscal incentives, could **help address remaining deployment barriers, particularly for more capital-intensive technologies**, such as vapor recovery units or electrified equipment. Such instruments may be especially important where infrastructure constraints or market conditions limit commercial returns.

In the longer term, where marginal abatement costs remain higher due to limited gas market access, Ghana could prioritize further **development of gas processing and transmission infrastructure to expand gas monetization opportunities and progressively improve the economics of methane recovery**.

In parallel, **promoting the use of Ghana's carbon market framework** (particularly the eligibility of flaring reduction activities under the national carbon whitelist)[105] could help operators integrate potential carbon revenues into project economics. Developing projects to utilize previously flared gas and monetize it could indirectly reduce the abatement cost of other mitigation measures.

[104] Republic of Ghana. *The Environmental Protection (Petroleum) Regulations.* (see footnote 95)
[105] Ghana Carbon Market Office. (2023). *Pre-selected MO Activities.* Available at: https://gcr.epa.gov.gh/wp-content/uploads/2023/12/Whitelist_Preselected_.pdf

4.7 Libya

Key figures

Estimated annual emissions[106]	Technical abatement possible from analyzed technologies
1,221 kt CH_4 (36.4 Mt CO_2e)	55% of estimated emissions
Emissions analyzed[107]	**Low-cost abatement potential from analyzed technologies**[108]
962 kt CH_4 (79% of estimated emissions)	55% of estimated emissions

Current policies and practices

Libya currently lacks a dedicated methane regulatory framework for the oil and gas sector. Emissions are addressed indirectly through general environmental and petroleum laws, based on broad pollution control obligations and compliance with the sector's best practices.[109] [110] While earlier laws did not explicitly prohibit routine flaring or venting, a recent regulation marks a shift by classifying excessive flaring as a waste of national resources and restricting it to testing or emergency situations subject to approval.[111] Although implementation and enforcement remain at an early stage, this regulation represents a step toward stronger control of methane emissions from flaring.

Libya's gas sector is closely linked to oil production, with high volumes of associated gas. Most gas is consumed domestically, primarily for power generation, while a smaller share is exported. However, **export capacity is not fully utilized** due to declining production and rising local demand. At the same time, **aging and insufficient gas gathering, processing, and transport infrastructure** continue to limit gas utilization and contribute to flaring in some areas, despite recent efforts to expand capacity.

Methane mitigation in Libya faces **several technical and operational barriers**, including **high upfront capital costs**, **limited access to financing**, **security and logistical constraints**, **infrastructure gaps**, and **import restrictions** affecting specialized mitigation equipment.[112] At the same time, **external market pressures could become an important driver for mitigation efforts**, as the European Union (the largest destination for Libyan oil and gas exports)[113] implements the EU Methane Regulation.[114]

Marginal Abatement Cost Curve

Figure 10 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Libya's oil and gas sector. The results are also provided in tabular form in Appendix 20.

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, despite representing small volumes, show negative abatement costs, as recovered gas generates net savings. These savings rely on assumptions regarding gas marketability and prices. In this

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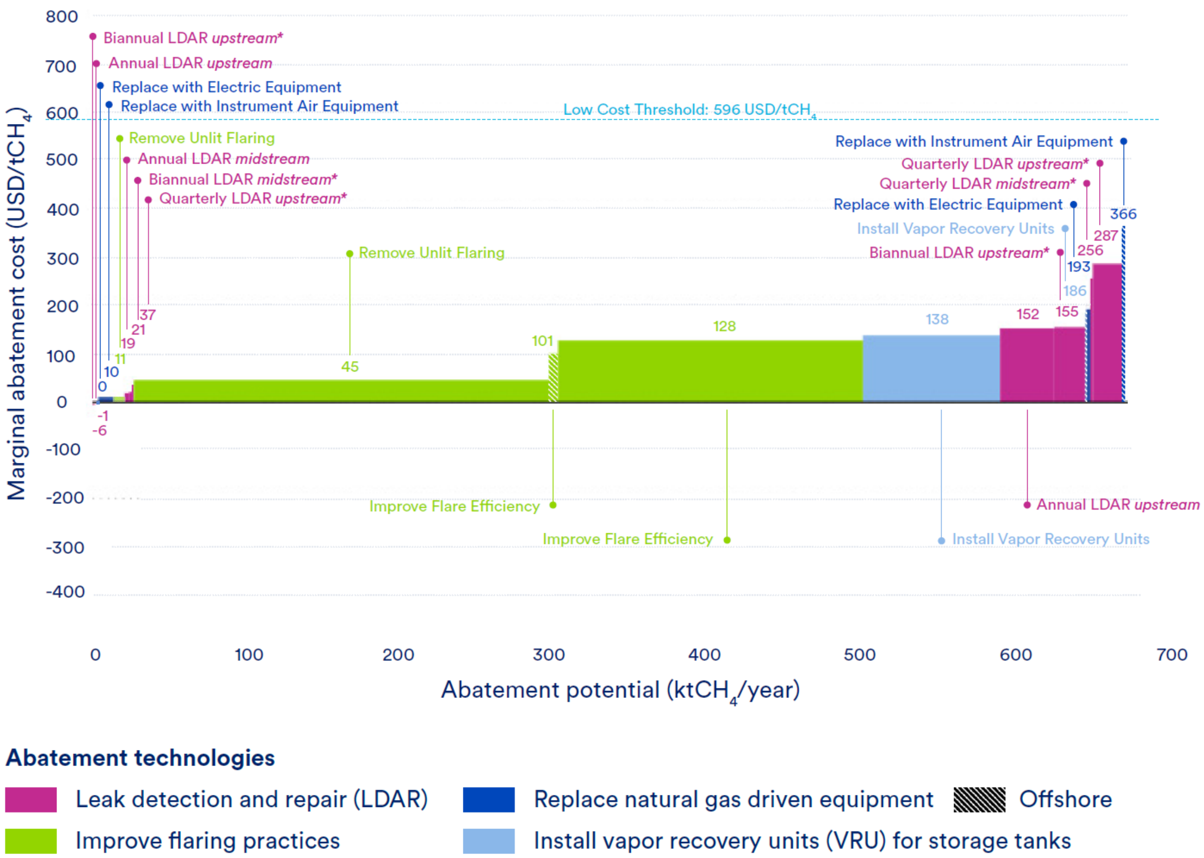
106 Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
107 Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
108 Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
109 State of Libya. (1955). *Petroleum Law No. 25 of 1955*. Available at: https://security-legislation.ly/latest-laws/law-no-25-of-1955-on-the-petroleum-law/
110 State of Libya. (2003). *Law No. 15 of 2003 on Protection and Improvement of the Environment*. Available at: https://environment.gov.ly/law-no-15/
111 Ministry of Oil and Gas (State of Libya). (2024). *Petroleum Regulation #10 For the Conservation of Oil & Gas Resources, Health, Safety & Environment*. Available at: https://ogm.gov.ly/ar/wp-content/uploads/2025/10/Petroleum-Regulation-10.pdf
112 State of Libya. (2010). *Law No. 10 of 2010 On Customs*. Available at: https://security-legislation.ly/latest-laws/law-no-10-of-2010-on-customs/
113 U.S. Energy Information Administration. (2024). *Libya Analysis*. Available at: https://www.eia.gov/international/analysis/country/LBY
114 European Union. (2024). *Regulation (EU) 2024/1781 on the reduction of methane emissions in the energy sector and amending Regulation (EU) 2019/942.* Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=OJ:L_202401787

analysis, it is assumed that 100% of recovered gas in the midstream segment can be brought to market at a price of 10 USD/MMBtu, while 40% of recovered gas upstream can be brought to market at a price of 5 USD/MMBtu. Under these assumptions, all mitigation measures assessed fall well below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Figure 10. Libya Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Within this MACC, the elimination of unlit flaring in the onshore upstream segment delivers the largest single abatement potential, with approximately 271 kt of methane emissions reductions per year at a marginal abatement cost of around 45 USD/tCH_4. Improvements in flaring destruction efficiency also remain below the low-cost threshold. Although these measures require additional investment and do not generate economic value as gas continues to be flared, the significant volumes flared in Libya mean that such upgrades can still deliver substantial emissions reductions at a relatively low cost. The installation of vapor recovery units provides a significant methane emissions reduction opportunity, reflecting their currently limited deployment, while remaining within the low-cost abatement range.

Overall, deploying the full portfolio of considered abatement measures could result in 672 kt of methane emissions reductions per year at a net cost of around USD 66 million/year. *If all recovered upstream gas were assumed to be saleable at 5 USD/MMBtu, net abatement costs could decline to around USD 48 million /year.*

Summary of analyzed mitigation technologies

Improve flaring practices

Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	482 kt CH_4 abatable	94 USD/tCH_4

Libya does not impose detailed performance, monitoring, or maintenance requirements for flaring systems. Regulation is limited to controlling flaring and gas losses under petroleum legislation, although implementation and enforcement remain at an early stage.[115]

In practice, operators prioritize reducing flared volumes rather than optimizing flare performance, investing instead in gas utilization or monetization solutions which also supports methane emissions reduction, but fall outside the scope of this analysis. Initiatives such as one of NOC's subsidiaries aiming near-zero flaring targets for 2030 provide strategic direction, but implementation is constrained by financing, infrastructure needs, and weak regulatory enforcement.

Install Vapor Recovery Units

Installation of vapor recovery units (VRUs) on storage tanks

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Difficult	Low adoption	90 kt CH_4 abatable	139 USD/tCH_4

There are no regulatory requirements mandating the installation of vapor recovery units (VRUs) on storage tanks, and deployment depends on operator investment decisions and available gas utilization pathways. In practice, VRUs have been applied selectively, mainly at light crude storage sites and newer facilities, with early projects demonstrating strong economic and emissions benefits. However, wider deployment remains constrained by upfront costs, aging infrastructure, and limited incentives. Opportunities primarily exist where recovered gas can be used on-site or integrated into nearby systems.

Leak Detection and Repair (LDAR)

Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Difficult	Low adoption	87 kt CH_4 abatable	170 USD/tCH_4

Libya currently has no regulations requiring LDAR programs or specifying inspection frequency, technologies, or reporting standards. LDAR deployment remains limited and uneven across operators, though some international joint ventures have conducted targeted measurement campaigns. Major gaps include limited access to equipment such as optical gas imaging cameras and drones and a limited number of trained personnel. Import approval procedures and security clearances further delay deployment. The combination of these factors makes LDAR deployment difficult.

[115] Ministry of Oil and Gas (State of Libya). *Petroleum Regulation #10.* (see footnote 111)

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	High adoption	13 kt CH_4 abatable	51 USD/tCH_4
Libya does not impose specific regulatory requirements targeting methane emissions from natural gas-driven pneumatic equipment, leaving technology choices to operators. In practice, such equipment is not widely used in the oil and gas sector, with most assets already relying on electric or instrument-air alternatives.			

Policies recommendations

Libya has not established a dedicated methane regulatory framework, with emissions addressed through broader environmental and petroleum provisions. This regulatory gap may create growing exposure as the EU Methane Regulation extends to imports from 2027 onward, directly impacting Libya, whose oil and gas exports are predominantly destined for the EU. **In the near term**, Libya could **introduce targeted regulations addressing the most cost-effective mitigation opportunities**, while progressively implementing its zero-flaring ambition for 2030. Establishing flaring performance standards, such as setting minimum efficiency thresholds or eliminating unlit flaring, would provide a high-impact entry point. These measures, alongside the deployment of VRUs where gas can be monetized, offer strong abatement potential at low costs.

Over the medium term, Libya could **expand its regulatory framework to include additional mitigation measures** such as LDAR programs and the replacement of gas-driven pneumatic systems, which could incentivize the conversion of remaining units to zero-emitting alternatives. **Targeted financial instruments**, such as concessional loans or fiscal incentives, could support investments in VRUs, particularly where infrastructure constraints limit returns. In parallel, **addressing import restrictions on key equipment** would also ease the deployment of mitigation technologies.

In the longer term, addressing structural constraints will be essential to sustain methane mitigation efforts. **Continued development of gas processing and transmission infrastructure** could improve the economics of methane recovery by expanding monetization opportunities. Projects that capture and utilize previously flared gas could further lower the effective cost of mitigation measures and support sustained emissions reductions over time.

4.8 Mexico

Key figures

Estimated annual emissions[116]	Technical abatement possible from analyzed technologies
1,169 kt CH_4 (34.8 Mt CO_2e)	34% of estimated emissions
Emissions analyzed[117]	**Low-cost abatement potential from analyzed technologies[118]**
616 kt CH_4 (53% of estimated emissions)	34% of estimated emissions

Current policies and practices

Mexico has established a **comprehensive legal and regulatory framework to control methane emissions across the oil and gas value chain**, including prescriptive requirements on equipment and operational practices (such as LDAR), restrictions on venting and flaring, high associated-gas utilization targets, and detailed obligations for monitoring, reporting, and verification.[119][120] The regulation requires facilities to establish a methane emissions prevention and control plan, with defined and self-imposed reduction objectives, as well as an implementation schedule, supported by annual reporting to the regulator and third-party review. While the framework is robust, **remaining challenges** relate primarily to **enforcement capacity and effective implementation**.

Domestic natural gas production in Mexico is central to the energy system, supplying around 45% of total primary energy demand and over 60% of electricity generation.[121] However, **domestic production meets only 37% of demand**, resulting in a strong reliance on imports, particularly from the United States of America. Mexico has an **established and expanding gas processing and transmission network**, but **regional infrastructure gaps persist**, limiting the full monetization of domestic gas resources in some areas. At the same time, national production is largely composed of associated gas from oil fields, including sour gas that requires significant investment to meet market specifications. Where processing capacity is insufficient, these constraints result in some gas being flared or reinjected.

Methane mitigation deployment in Mexico is constrained by economic and technical challenges, including **limited financial resources and technical expertise**, affecting both smaller and larger operators, and **insufficient gas gathering and processing infrastructure**, which limit reductions in venting and flaring.

Marginal Abatement Cost Curve

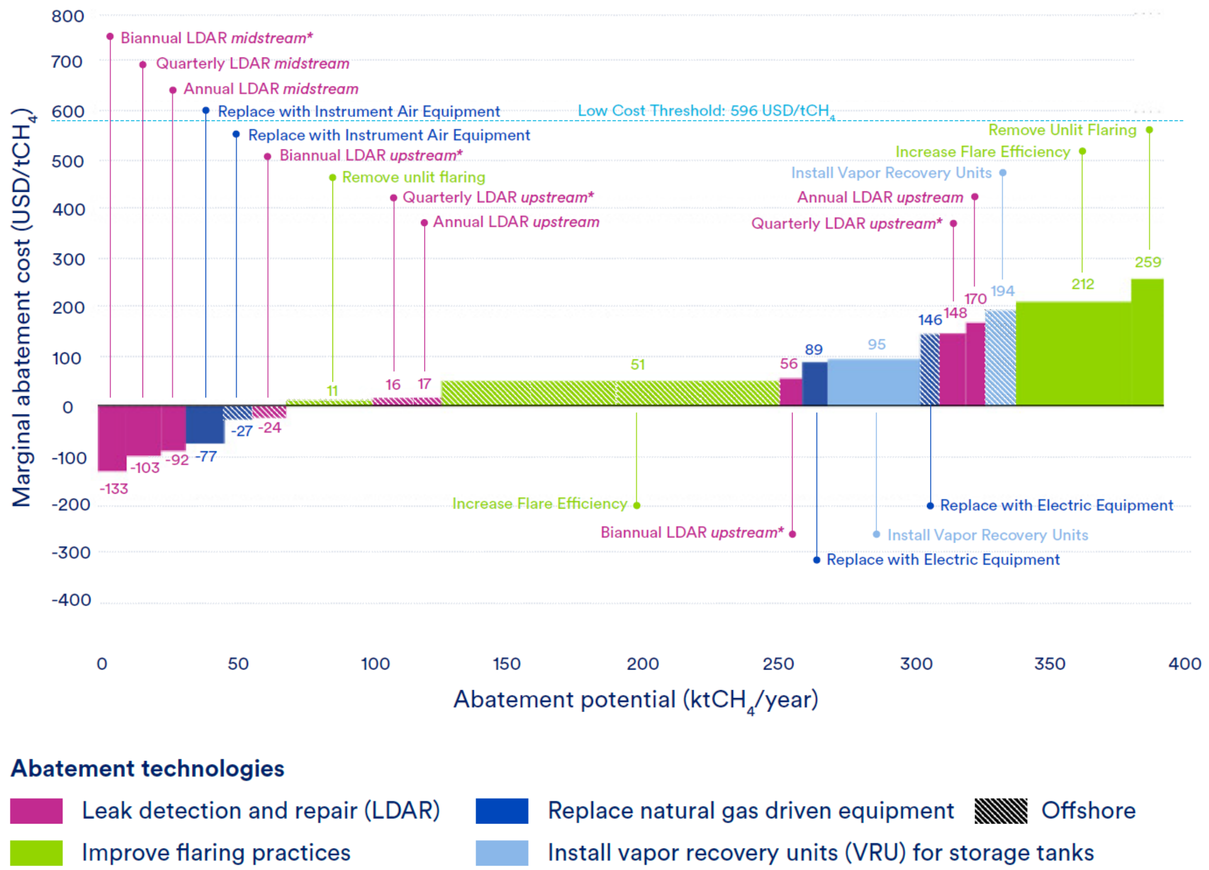
Figure 11 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Mexico's oil and gas sector. The results are also provided in tabular form in Appendix 21.

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, marginal abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as the implementation of LDAR programs in the midstream segment and the replacement of pneumatics equipment with instrument air systems, show negative abatement costs, as recovered gas generates net savings. These savings rely on assumed marketable gas shares. In this analysis, it is assumed that 100% of recovered gas in the midstream segment, 80% of onshore upstream recovered gas, and 55% of offshore upstream recovered gas can currently be brought to market at a price

[116] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[117] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[118] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[119] Government of Mexico. (2018). *Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector.* Available at: http://www.dof.gob.mx/nota_detalle.php?codigo=5543033&fecha=06/11/2018
[120] Government of Mexico. (2016). *Technical guidelines for the use of associated natural gas in exploration and production of hydrocarbons.* Available at: https://www.dof.gob.mx/nota_detalle.php?codigo=5422286&fecha=07/01/2016#gsc.tab=0
[121] International Energy Agency (IEA). (2024). *Mexico – Natural gas*. Available at: https://www.iea.org/countries/mexico/natural-gas

of 3 USD/MMBtu. Under these assumptions, all mitigation measures assessed fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Figure 11. Mexico Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Within this MACC, the improvement of flaring systems in the offshore upstream segment delivers the largest single abatement potential, with approximately 124 kt of methane emissions reductions per year at a low marginal abatement cost of around 51 USD/tCH_4. This reflects the large volumes of gas currently flared due to limited infrastructure to monetize associated gas. In addition, flaring efficiency is assumed to remain below optimized levels,[122] together creating substantial potential for emissions reduction at a low cost, even while capital investment and ongoing operational effort are required. LDAR programs in the offshore upstream segment also remain well below the low-cost threshold. Higher marginal abatement costs are associated with infrastructure upgrades, including installation of vapor recovery units, replacement of pneumatic equipment with electric systems, and improvement of flaring practices in the onshore upstream segment. LDAR implementation in the onshore upstream segment similarly shows higher costs, reflecting an assumed lower number of emission sources per site and relatively low gas prices. Despite these factors, these measures remain well within the low-cost abatement range.

Overall, deploying the full portfolio of considered abatement measures could result in 392 kt of methane emissions reductions per year at a net cost of around USD 24 million/year. *If all recovered upstream gas*

[122] The average destruction efficiency is assumed to be 84%, based on information reported by PEMEX (Mexican National Oil Company) in its sustainability report. PEMEX. (2024). *Sustainability Report 2024*. Available at: https://www.pemex.com/etica_y_transparencia/transparencia/informes/Documents/sustainability_report_2024_eng.pdf

were assumed to be saleable at 3 USD/MMBtu, total abatement costs could decline to around USD 14 million/year.

Summary of analyzed mitigation technologies

Improve flaring practices

Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	210 kt CH_4 abatable	90 USD/tCH_4

The current regulations set minimum flare combustion efficiency requirements of 90% for exploration and extraction activities and 98% across the rest of the value chain, alongside mandatory continuous ignition systems.[123]

In practice, flare combustion efficiency is assumed to be below regulatory thresholds in some companies. However, the deployment of high-efficiency enclosed flares, achieving methane destruction efficiencies above 98%, is being evaluated through pilot projects in selected fields.

Install Vapor Recovery Units

Installation of vapor recovery units (VRUs) on storage tanks

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	45 kt CH_4 abatable	120 USD/tCH_4

The current regulations require both new and existing facilities with storage tanks to control methane emissions using vapor recovery systems (VRUs) when annual emissions are estimated to be 10 tonnes of methane or more per facility.[124]

Some operators have already installed VRUs on stabilization and storage systems and reinject the recovered gas into process pipelines. However, wider deployment is constrained by economic and capital limitations, space and feasibility challenges for offshore assets, and insufficient associated-gas gathering and processing infrastructure that limits gas monetization.

Leak Detection and Repair (LDAR)

Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency

Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Easy	Medium adoption	96 kt CH_4 abatable	-3 USD/tCH_4

The current regulations mandate quarterly LDAR inspections using Optical Gas Imaging (OGI) cameras or equivalent methane-calibrated technologies, with prescriptive repair timelines depending on leak size.[125]

Many companies have started to implement LDAR programs to meet regulatory requirements, either through external service providers or by training in-house teams. However, deployment remains uneven across operators, and, in many cases, inspection frequency falls short of regulatory requirements.

Scaling quarterly LDAR implementation is constrained by limited financial and human resources, affecting both smaller operators and large companies, while offshore deployment is further hindered by logistical complexity.

[123] Government of Mexico. *Guidelines on methane emissions in the hydrocarbons sector.* (see footnote 119)
[124] Government of Mexico. *Guidelines on methane emissions in the hydrocarbons sector.* (see footnote 119)
[125] Government of Mexico. *Guidelines on methane emissions in the hydrocarbons sector.* (see footnote 119)

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Easy	Medium adoption	41 kt CH_4 abatable	11 USD/tCH_4
The current regulations mandate zero-bleed or gas-capture solutions for new facilities and progressive replacement options for existing assets, including electrification, instrument air, or routing gas to vapor recovery units or combustion systems.[126] In practice, some operators have begun replacing gas-driven pneumatics with instrument air or electric systems.			

Policies recommendations

Mexico has developed a regulatory framework covering all the methane mitigation technologies assessed and has now **transitioned from policy design to implementation**. While challenges remain, particularly in achieving consistent compliance with quarterly LDAR requirements, the marginal abatement cost curve (MACC) indicates that effective implementation and enforcement of existing regulations could deliver net economic benefits while addressing remaining adoption barriers.

In the near term, priorities could focus on **strengthening implementation and enforcement of low-cost mitigation measures**. All options assessed show low or negative marginal abatement costs, because, where gas can be captured and sold, the value of recovered gas is assumed to outweigh deployment costs. Regulatory action, including stricter enforcement of existing bans, equipment standards, and emissions limits, combined with targeted capacity-building programs for operators, could support rapid uptake of measures such as LDAR, pneumatic equipment replacement, and vapor recovery.

Over the medium term, **targeted policy instruments** such as concessional loans, tax incentives, or fiscal transfers could help address remaining financial barriers. **Continued development of gas processing and transport infrastructure** would further improve commercialization prospects and lower abatement costs.

[126] Government of Mexico. *Guidelines on methane emissions in the hydrocarbons sector.* (see footnote 119)

4.9 Nigeria

Key figures

Estimated annual emissions[127]	**Technical abatement possible from analyzed technologies**
1,794 kt CH_4 (53.5 Mt CO_2e)	30% of estimated emissions
Emissions analyzed[128]	**Low-cost abatement potential from analyzed technologies**[129]
865 kt CH_4 (48% of estimated emissions)	28% of estimated emissions

Current policies and practices

Nigeria has established a **regulatory framework to reduce methane emissions and routine flaring** through penalties, equipment prescriptions and practice bans, and strengthened monitoring requirements.[130] The upstream petroleum regulator (NUPRC) enforces a dynamic flare regulation system with progressively stricter thresholds targeting zero routine flaring by 2030, with penalties set to match or exceed market gas prices. While this framework provides a clear policy signal and **is increasingly reflected in operators' methane management strategies**, opportunities exist to strengthen and optimize its implementation.

In practice, progress remains uneven. While most onshore assets connect to the domestic pipeline network, many offshore facilities remain disconnected due to high infrastructure costs and regulated prices, resulting in continued flaring or reinjection. To address this, Nigeria is **expanding gas market opportunities through infrastructure development and investment-oriented government programs**, which are gradually improving conditions for gas capture, transport, and commercialization.[131] This policy direction is supporting the integration of methane abatement projects.

Deployment of technologies remains constrained by high equipment costs (mainly due to dependence on imported solutions), **limited technical capacity**, **competing priorities**, as well as ongoing gas infrastructure gaps. Since Nigeria encourages the use of local labor for methane mitigation services, international service providers will have to plan for this to deploy **methane mitigation technologies** in the country.

Marginal Abatement Cost Curve

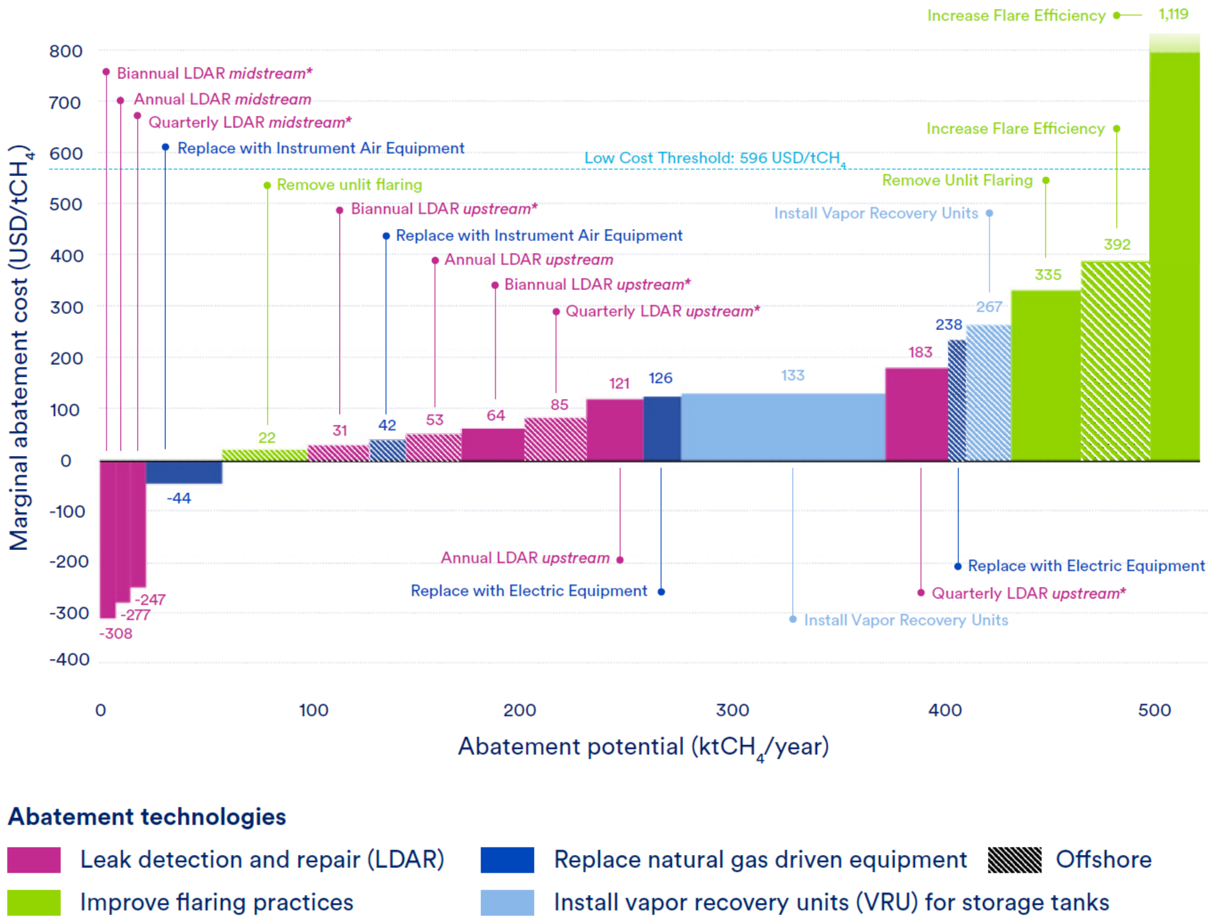
Figure 12 presents the Marginal Abatement Cost Curve (MACC) for the selected methane mitigation measures in Nigeria's oil and gas sector. The results are also provided in tabular form in Appendix 22.

Mitigation economics largely depends on whether recovered methane can be monetized: when gas can be sold, abatement costs fall, and when it is flared or reinjected, costs rise. This dynamic explains why some measures, such as replacing natural gas-driven equipment with electric or air-driven alternatives and implementing onshore midstream LDAR, show negative abatement costs, as recovered gas generates net savings. These savings depend on assumptions regarding gas marketability and prices. The ability to sell gas is especially important in Nigeria, where flared volumes may incur penalties, further weakening the economics of measures that do not enable commercialization. In this analysis, it is assumed that 100% of recovered gas in the midstream segment can currently be brought to market at a price of 10 USD/MMBtu, while 80% of onshore upstream recovered gas and 50% of offshore upstream recovered gas can currently

[127] Based on data from International Energy Agency (2025) *Methane Tracker Database* - IEA; as modified by Carbon Limits and CATF
[128] Emissions analyzed refer to the share of total methane emissions impacted by the abatement measures studied.
[129] Low cost refers to a cost less than 596 USD/tCH_4 (20 USD/tCO_2e using GWP 100)
[130] Nigerian Upstream Petroleum Regulatory Commission (NUPRC). (2022). *Guidelines For Management Of Fugitive Methane And Greenhouse Gases Emissions In The Upstream Oil And Gas Operations In Nigeria.* Available at: https://www.nuprc.gov.ng/wp-content/uploads/2022/11/METHANE-GUIDELINES-FINAL-NOVEMBER-10-2022.pdf
[131] The Nigerian Gas Flare Commercialization Project was launched to enable private investors to bid for flare sites and develop infrastructure to capture and utilize the gas for domestic consumption

be brought to market at a price of 5 USD/MMBtu. Under these assumptions, most mitigation measures assessed fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e).

Figure 12. Nigeria Marginal Abatement Cost Curve for selected mitigation options



**Biannual costs reflect costs of increasing from annual to biannual. Quarterly costs reflect costs of increasing from biannual to quarterly*
Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Technology-specific factors also shape costs: vapor recovery units are cheaper onshore than offshore due to space and feasibility constraints, while flaring-related measures always have positive costs because the gas is still flared and does not generate any additional source of revenue. Reducing unlit flaring can be achieved using relatively low-cost technologies, while improving flaring efficiency requires significant capital and operational resources.

Beyond gas monetization, abatement costs are influenced by a range of implementation factors, including import costs (such as taxes and permitting requirements), the need to mobilize foreign service providers for LDAR activities or technology installation, site accessibility constraints, and higher travel and logistics costs for offshore assets compared to onshore operations.

Overall, deploying the full portfolio of considered abatement measures could result in 533 kt of methane emissions reductions per year at a total cost of around USD 95 million/year. *If all recovered upstream gas were assumed to be saleable at 5 USD/MMBtu, total abatement costs could decline to around USD 65 million/year.*

Summary of analyzed mitigation technologies

Improve flaring practices *Improvement of flaring practices through increased flare efficiency and elimination of unlit flaring*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	133 kt CH_4 abatable	486 USD/tCH_4

The current regulation requires all flared gas to be combusted using an auto-igniter or continuous pilot and mandates that operations maintain a minimum 98% destruction removal efficiency (DRE) for hydrocarbons. If a flare is found unlit while venting gas, operators shall restore ignition within 48 hours.[132]

Average destruction removal efficiency is currently estimated at 96%, and most operators prioritize reducing flare volume over optimizing flare performance. To avoid flaring penalties, companies are investing in gas utilization or monetization solutions, including reinjection where immediate use isn't feasible.

Install Vapor Recovery Units *Installation of vapor recovery units (VRUs) on storage tanks*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Low adoption	121 kt CH_4 abatable	157 USD/tCH_4

The current regulation requires storage tanks with potential to emit more than 2 tons per year of volatile organic compounds to have vapor recovery units or to send vapors to a combustion system. International and local operators are gradually installing this technology.[133]

Adoption remains limited by the high cost of vapor recovery unit installation and the need for recovered gas to have on-site or market value for the investment to pay off (typically within a couple of years). Integration challenges further slow deployment, especially offshore where space, weight, and safety constraints can make retrofits more complex and expensive.

Leak Detection and Repair (LDAR) *Implementation of Leak detection and repair (LDAR) programs at quarterly inspection frequency*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Easy	Medium adoption	198 kt CH_4 abatable	48 USD/tCH_4

For upstream operations, the current regulation requires quarterly LDAR inspections, with companies operating over 10 facilities allowed to use phased inspections covering 50% of sites over two years, and sets out timelines according to which detected leaks should be repaired.[134]

LDAR deployment is led by international operators, while some local operators have begun implementing detection programs, often carried out in partnership with international service providers. Nonetheless, adoption of LDAR remains comparatively lower among indigenous operators.

Despite challenges around funding and equipment costs, the policy framework is increasingly encouraging operators to strengthen LDAR practices.

[132] NUPRC. *Guidelines on fugitive methane and GHG emissions in the upstream oil and gas operations.* (see footnote 130)
[133] NUPRC. *Guidelines on fugitive methane and GHG emissions in the upstream oil and gas operations.* (see footnote 130)
[134] NUPRC. *Guidelines on fugitive methane and GHG emissions in the upstream oil and gas operations.* (see footnote 130)

Replace natural gas-driven equipment *Replacement of natural gas-driven pumps and controllers with electric or air-driven alternatives*			
Ease of deployment	Current practices	Abatement potential	Marginal abatement cost
Intermediate	Medium adoption	82 kt CH_4 abatable	43 USD/tCH_4
The current regulation bans natural-gas-driven controllers and pumps, requiring operators to retrofit with zero-bleed electric or devices, or route emissions to a vapor-recovery system by 2027.[135] In practice, companies have begun reducing reliance on continuous bleed pneumatic equipment using improved pneumatic designs, electric drives, or instrument air systems, particularly on newer assets.			

Policies recommendations

Nigeria has developed a relatively comprehensive regulatory framework covering the methane mitigation technologies assessed and is now **transitioning from policy development to implementation**. The marginal abatement cost curve (MACC) indicates that, if effectively implemented, methane mitigation measures could deliver net economic benefits while addressing remaining adoption barriers. Near-term priorities could therefore focus on **strengthening implementation and enforcement of existing regulations**, alongside the development of effective measurement, reporting and verification (MRV) systems and improved institutional coordination across the gas value chain. Several mitigation options (notably LDAR, VRU installation, and replacement of natural gas-driven equipment) show low or negative marginal abatement costs, thanks mainly to the possible return from saved gas outweighing the cost of the measures. For these low-cost measures, regulatory action, including strict enforcement of existing bans, equipment standards and emissions limits can further support their implementation, as well as capacity-building programs for operators.

Over the medium term, **targeted policy instruments** such as concessional loans, tax incentives, or fiscal transfers could help address financial barriers, particularly where ownership structures affect who captures the value of recovered gas. **Continued investment in gas processing and transport infrastructure** would further improve commercialization prospects.

In the longer term, creating an enabling environment for sustained financing and investment would support the scaling methane mitigation. Within this context, **international climate or carbon finance** could be used where appropriate to support higher-cost measures.

[135] NUPRC. *Guidelines on fugitive methane and GHG emissions in the upstream oil and gas operations.* (see footnote 130)

5 Technology fact sheets

5.1 Improve flaring practices

Description of the abatement option

Improving flare practices refers to measures that reduce methane emissions from flaring by ensuring that gas sent to a flare is consistently and effectively burned. Field measurements show the prevalence of unlit flares and that average methane destruction at flares can be lower than commonly assumed[136,137], while well-designed, well-operated, and well-maintained flares can achieve destruction efficiencies exceeding 99%. This abatement option focuses exclusively on improving the performance and reliability of existing flaring systems. It does not include new gas capture, utilization, reinjection, or any other measures aimed at reducing flared volumes. Instead, it targets two distinct but complementary actions:

1. **Removing unlit flaring** by ensuring that flares remain continuously lit. This includes the installation of reliable pilot and auto-ignition systems, supported by continuous or frequent monitoring (e.g. flame or temperature detectors, cameras) and appropriate operational response procedures.
2. **Increasing flare destruction efficiency** for lit flares, through retrofit or replacement of flare systems and associated equipment, including assist systems (air/steam), improved gas routing and pressure management to ensure stable combustion conditions, enhanced automation and control to detect and correct abnormal operation, and stronger operational and maintenance (O&M) practices to sustain high combustion performance over time.

Costs range

Table 7 presents per-equipment costs associated with the two mitigation options considered for improving flaring practices. Cost estimates are indicative and may vary significantly depending on site conditions, local market conditions, labor and logistics costs, regulatory requirements, import fees, supply chain availability, and project-specific factors (e.g., scale, location, and existing infrastructure).

Table 7. Indicative cost ranges for flaring performance improvement measures

Mitigation option	**Capital costs** (USD/equipment)	**Operating costs** (annual)
Removing unlit flaring	USD 0 – USD 500,000	<5% of CAPEX
Increasing flare destruction efficiency	USD 500,000 – USD 1,000,000	<5% of CAPEX

Source: Carbon Limits analysis based on interviews with technology and service providers

Current policies and practices

Table 8 presents an overview of the current status of regulatory frameworks and the level of adoption of flaring performance improvement measures across selected countries. For further details on the elements presented, please refer to the individual country fact sheets.

[136] Genevieve Plant et al. *Inefficient and unlit natural gas flares both emit large quantities of methane.* (see footnote 16)
[137] Environmental Defense Fund (EDF) (2020). *Helicopter Surveys Indicate Malfunctioning Flares in the Permian Basin are Releasing at Least 300,000 Metric Tons of Unburned Methane a Year.* Available at: https://www.edf.org/media/helicopter-surveys-indicate-malfunctioning-flares-permian-basin-are-releasing-least-300000

Table 8. Status of regulatory frameworks and adoption of flaring performance improvement measures

Country	Regulatory framework in place	Level of adoption
Algeria	No	Low
Angola	No	Low
Argentina	No	Low
Brazil	No	Medium
Egypt	No	Low
Ghana	Yes (national)	Low
Libya	No	Low
Mexico	Yes (national)	Low
Nigeria	Yes (national)	Low

Source: Carbon Limits analysis, supplemented by interviews with regulators and oil and gas companies

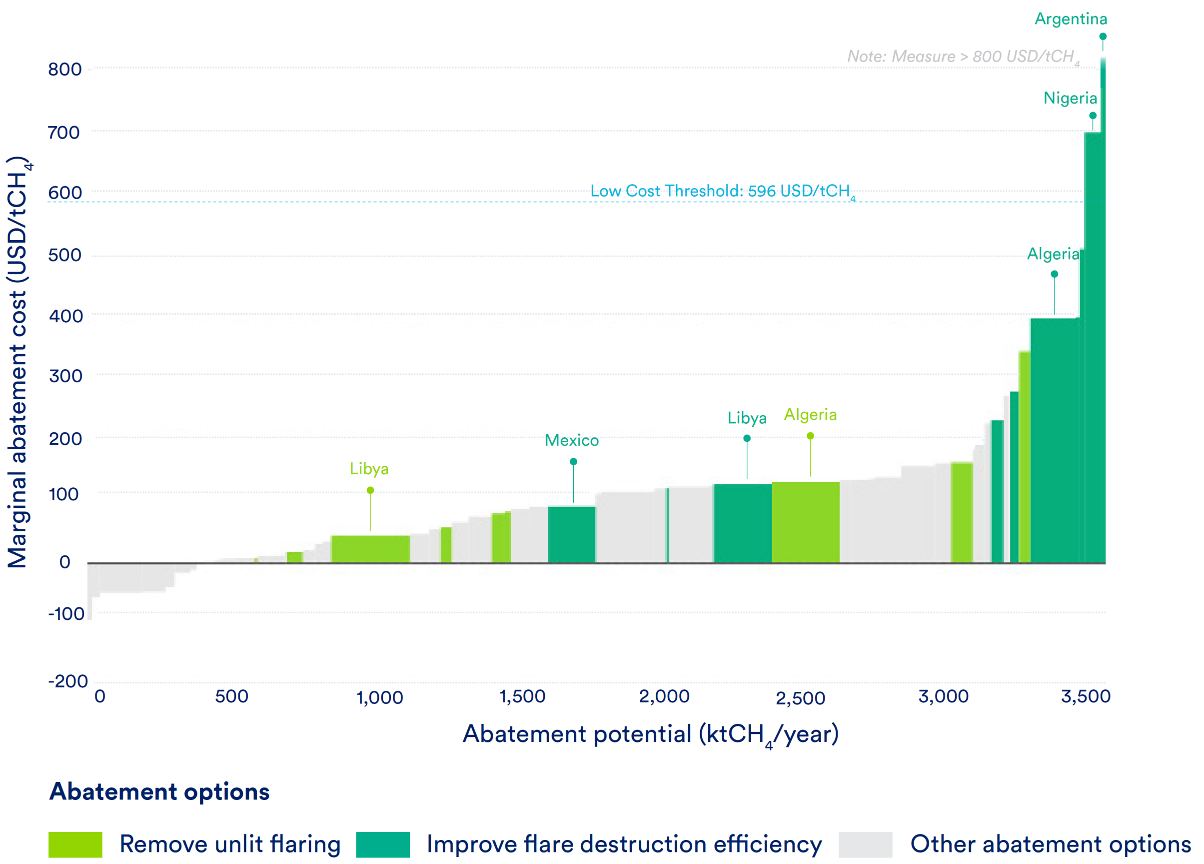
Marginal Abatement Cost Curve

Figure 13 presents a standardized Marginal Abatement Cost Curve (MACC) illustrating the cost-effectiveness of considered methane mitigation options across selected countries. Abatement options are disaggregated by country and technology, with marginal costs aggregated at the country–technology level using weighted averages based on abatement potential across segments (upstream and midstream) and locations (onshore and offshore). Measures related to improving flaring practices are highlighted in green, while all other mitigation options are shown in grey.

Flaring-related mitigation measures consistently have positive abatement costs, as the gas continues to be flared and does not generate additional revenue, unlike capture-based options such as vapor recovery units. The priority action is to eliminate unlit flaring, which represents a relatively low-cost and readily achievable opportunity across all assessed countries. Once unlit flaring is addressed, efforts can shift to improving flare destruction efficiency, which is typically relatively higher cost. Nevertheless, in this analysis, most flaring-related measures fall below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e), even in the absence of revenue generation. Countries such as Libya and Algeria account for a large share of the global emissions-reduction potential at relatively low cost, driven by high flaring volumes per site that improve cost efficiency. In contrast, Argentina and Nigeria face higher costs and lower abatement potential due to lower flaring volumes per site, which reduces the cost-efficiency of equipment deployment.

Overall, abatement costs are not proportional to emission reductions, as improvements in flare performance involve fixed per-flare costs that apply regardless of the volume of gas flared. Cost variations are also influenced by local cost structures, import costs, and prevailing industry practices.

Figure 13. Marginal Abatement Cost Curve for considered methane mitigation options, with a focus on improving flaring practices



Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Challenges and barriers to wider deployment

Despite the potential of improving flaring performance as a methane mitigation measure, several challenges limit its broader implementation:

- **Regulatory focus on venting and flaring volumes**. Regulations often prioritize reducing venting and routine flaring through limits or penalties on flared volumes (e.g., Ghana, Mexico and Nigeria). As a result, operator investment tends to focus on measures that reduce gas sent to flares (such as utilization, reinjection, or monetization). Upgrades to flare performance itself remain limited, reflecting both the absence of specific regulatory requirements and the lack of direct revenue incentives. While this focus is warranted, particularly in countries with high levels of flaring, it is essential that upgrades to flare systems are not overlooked, particularly in cases where gas utilization infrastructure will take several years to build and to ensure that remaining [non-routine] flaring does not lead to unnecessary emissions.
- **High operation and maintenance requirements**. Maintaining effective flare performance requires regular inspection, maintenance, and ongoing adjustment to changing flow conditions. Operating expenses include repeated mobilization of trained personnel, sometimes to remote sites, resulting in ongoing operating costs.
- **Limited cost-efficiency of flare efficiency upgrades at low volumes**. Improving flaring destruction efficiency typically involves equipment upgrades with largely fixed capital costs per flare, as well as ongoing operating and maintenance costs, regardless of the volumes flared. Where flaring is low or intermittent, this results in poor cost-efficiency and high abatement costs per ton.

5.2 Install Vapor Recovery Units (VRUs)

Description of the abatement option

VRUs are designed to capture hydrocarbon vapors from storage tanks and other equipment like Vapor Recovery Towers (VRT) that would overwise be vented to the atmosphere. The recovered vapors are then:

1. **Separated** in an inlet scrubber/separator which removes any liquids (e.g., oil, water), protecting downstream equipment and improving the system performance.
2. **Compressed** to increase pressure and temperature for transport or use. Compressor selection depends on vapor composition, discharge pressure, flow variability and site conditions.
3. **Recovered or routed** to sales lines, used on site as fuel or sent to flare when sales or use is not feasible.

VRUs are typically assumed to reduce emissions by around 95%[138], reflecting an estimated 5% annual downtime; when operating, emissions are expected to be negligible. However, their performance depends on several key factors, including the design, the volume and composition of the vapor (including any fluctuations), and maintenance practices, which may also be influenced by external environmental conditions.

This study assesses the installation of VRUs on storage tanks (including crude oil, condensate, and produced water tanks). The analysis considers two scenarios for the captured gas: sale through existing infrastructure or disposal through flaring or reinjection if utilization infrastructure is not available.

Costs range

Table 9 presents per-equipment costs associated with associated with the implementation of VRUs on storage tanks. Cost estimates are indicative and may vary significantly depending on site conditions, local market conditions, labor and logistics costs, regulatory requirements, import fees, supply chain availability, and project-specific factors (e.g., scale, location, and existing infrastructure). This table does not include benefits (e.g., savings from avoided gas losses, gas sales, or avoided penalties).

Table 9. Indicative cost ranges for the implementation of vapor recovery units on storage tanks

Mitigation option	**Capital costs** (USD/equipment)	**Operating costs** (annual)
Vapor recovery unit	> USD 1,000,000	<5% of CAPEX

Source: Carbon Limits analysis based on interviews with technology and service providers

Current policies and practices

Table 10 presents an overview of the current status of regulatory frameworks and the level of adoption of VRUs on storage tanks across selected countries. For further details on the elements presented, please refer to the individual country fact sheets.

Table 10. Status of regulatory frameworks and deployment of vapor recovery units on storage tanks

Country	Regulatory framework in place	Level of adoption
Algeria	No	Low
Angola	No	Low

[138] United States Environmental Protection Agency. (2026). *Vapor Recovery Units*. Available at: https://www.epa.gov/natural-gas-star-program/vapor-recovery-units

Country	Regulatory framework in place	Level of adoption
Argentina	No	Medium
Brazil	No	Low
Egypt	No	Low
Ghana	Yes (national)	Low
Libya	No	Low
Mexico	Yes (national)	Low
Nigeria	Yes (national)	Low

Source: Carbon Limits analysis, supplemented by interviews with regulators and oil and gas companies

Marginal Abatement Cost Curve

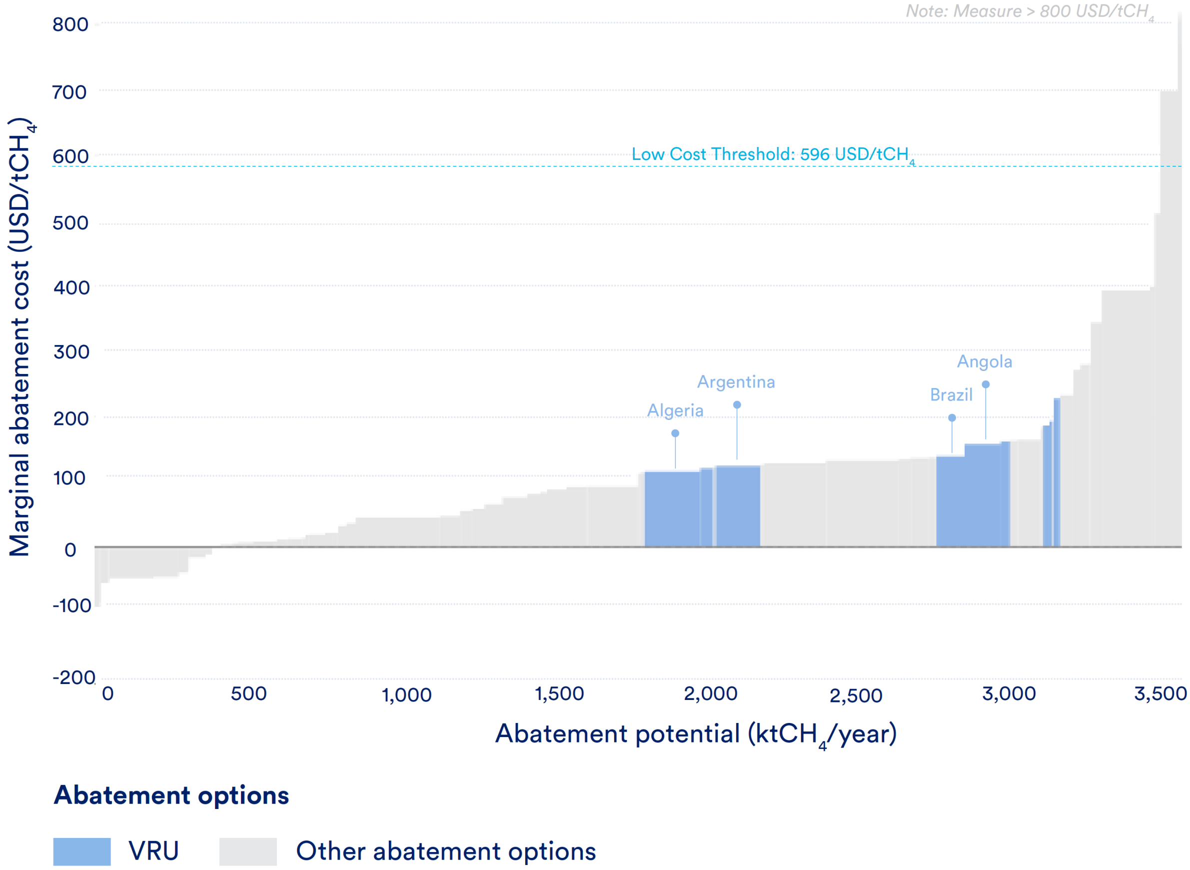
Figure 14 presents a standardized Marginal Abatement Cost Curve (MACC) illustrating the cost-effectiveness of considered methane mitigation options across selected countries. Abatement options are disaggregated by country and technology, with marginal costs aggregated at the country–technology level using weighted averages based on abatement potential across segments (upstream and midstream) and locations (onshore and offshore). Measures related to installing VRUs on storage tanks are highlighted in blue, while all other mitigation options are shown in grey.

The installation of VRUs generally results in positive abatement costs, despite revenues from captured gas. This reflects the fact that the high upfront CAPEX requires sufficiently large volumes of captured gas to achieve full cost recovery. Nevertheless, in this analysis, VRUs remain well below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e) for all countries.

A key driver of cost-effectiveness is the volume of methane emitted per site, which determines the emission reduction potential at the site level. Abatement costs are not proportional to emission reduction, as VRUs involve largely fixed equipment costs regardless of captured volumes. As a result, higher abatement costs on average are observed in countries with lower emissions per site (e.g., Brazil, Angola), where limited recovery volumes constrain the ability to amortize fixed investment costs compared to countries with relatively high emissions per site and favorable access to infrastructure (e.g., Algeria, Argentina). However, in some cases, certain sites are designed as centralized facilities collecting production from multiple nearby wells, resulting in higher volumes that may improve the cost-effectiveness of VRU deployment.

Additional variation arises from country-specific factors such as local cost structures, import requirements, and industry practices.

Figure 14. Marginal Abatement Cost Curve for considered methane mitigation options, with a focus on vapor recovery units for storage tanks



Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Challenges and barriers to wider deployment

Adoption of VRU on storage tanks remains very limited, reflecting several persistent challenges and barriers, even in countries with existing regulatory frameworks:

- **Complex installation and retrofit.** VRU deployment increases operational complexity, particularly offshore or at aging infrastructure, where retrofitting is often constrained by space, weight and safety requirements.
- **High upfront costs.** Installation requires significant capital investment, especially for older and offshore facilities. Combined with uncertain returns, this leads to selective, project-by-project deployment rather than systematic rollout. Projects are typically only viable where recovered gas can be effectively utilized or commercialized.
- **Limited infrastructure and market conditions.** Gaps in gathering, processing, and export infrastructure can undermine the business case, particularly in contexts where gas monetization options are limited (e.g., Mexico, Egypt). Offshore facilities face additional constraints related to the feasibility of gas export solutions, such as pipeline connections or floating LNG units.

5.3 Leak Detection and Repair (LDAR)

Description of the abatement option

LDAR programs are designed to identify and repair fugitive methane emissions from equipment components such as connections, open-ended lines, and valves. It can be implemented using a range of technologies, including Optical Gas Imaging (OGI) cameras, laser-based sensors (e.g., Tunable Diode Laser Absorption Spectroscopy), and ultrasonic leak detectors. These technologies can be deployed on various carriers including fixed monitoring stations, handheld devices, vehicle-mounted systems, drones, aircraft, and satellite-based instruments. As each of these technologies and deployment method presents advantages and limitations, selecting the most appropriate combination depends on site characteristics and equipment configuration.

The effectiveness of LDAR increases with inspection frequency, with assumed emission reductions of 40% (annual), 60% (biannual), and 80% (quarterly) compared to not having regular LDAR in place.[139]

This study focuses on ground-based OGI surveys conducted at different frequencies (annually, semi-annually, and quarterly). OGI detects methane based on its absorption of infrared radiation at specific wavelengths. This absorption creates an apparent temperature contrast between the gas plume and the background, allowing leaks to be visualized in real time. OGI is the most widely used leak detection technology globally. The analysis considers a hybrid implementation model, with half of surveys conducted in-house (requiring equipment procurement and internal team training) and half carried out by external service providers (local or international).

Costs range

Table 11 presents LDAR costs under two models: in-house implementation and outsourcing of detection. In-house campaigns include capital expenditure (CAPEX), such as equipment and training, and operating expenditure (OPEX), such as labor and maintenance for detection and repair. When detection is outsourced, CAPEX is avoided, and OPEX includes contractor fees for detection only, with repairs assumed to be performed internally. A 50/50 split is assumed in this study.

Cost estimates presented in Table 11 are indicative and may vary significantly depending on site conditions, local market conditions, labor and logistics costs, regulatory requirements, import fees, supply chain availability, and project-specific factors (e.g., scale, location, and existing infrastructure). This table does not include benefits (e.g., savings from avoided gas losses, gas sales, or avoided penalties).

Table 11. Indicative cost ranges for Leak Detection and Repair (LDAR) by detection model

Cost type	Detection model	Costs (USD/team)
Capital costs	In-house	USD 100,000 – USD 5,000,000
Operating costs – Detection	In-house	USD 0 – USD 100,000
Operating costs – Detection	Outsourced	USD 100,000 – USD 1,000,000
Operating costs – Repair	-	USD 100,000 – > USD 1,000,000

Source: Carbon Limits analysis based on interviews with technology and service providers

[139] United States Environmental Protection Agency. (2015). *Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities*. Available at: https://gaftp.epa.gov/air/nei/2017/doc/supporting_data/nonpoint/EPA_2015b_NSPS%20OOOOa%20TSD%20August%202015.pdf

Costs are presented per team (one equipment set per team). It is assumed that a single team can conduct 14 to 20 campaigns per year, with each campaign lasting around 1 to 2 weeks, depending on site complexity and location.

Per-team costs are similar across inspection frequencies, but total costs increase at higher frequencies as more teams are required. Repair costs also increase with inspection frequency: more frequent surveys detect more new leaks, leading to a higher number of repairs and, consequently, higher total repair costs. In this analysis, all repairs are assumed to be carried out by internal teams. However, savings from avoided gas losses represent economic benefits that are captured in the net costs used to develop the MACC but are not reflected in this table.

Current policies and practices

Table 12 presents an overview of the current status of regulatory frameworks and the level of adoption of LDAR across selected countries. For further details on the elements presented, please refer to the individual country fact sheets.

Table 12. Status of regulatory frameworks and implementation of Leak Detection and Repair (LDAR)

Country	Regulatory framework in place	Level of adoption
Algeria	No	Low
Angola	No	Medium
Argentina	Partial (subnational)	Medium
Brazil	No	Medium
Egypt	No	Low
Ghana	Yes (national)	Medium
Libya	No	Low
Mexico	Yes (national)	Medium
Nigeria	Yes (national)	Medium

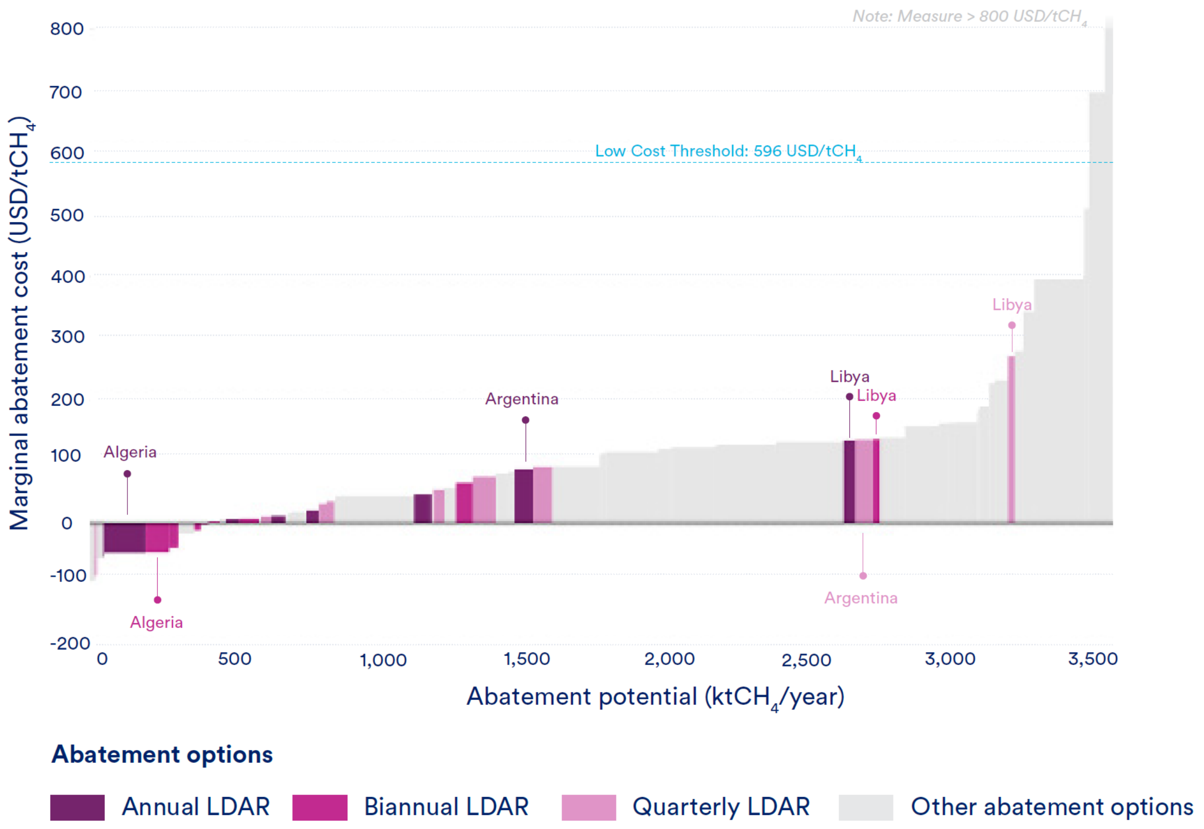
Source: Carbon Limits analysis, supplemented by interviews with regulators and oil and gas companies

Marginal Abatement Cost Curve

Figure 15 presents a standardized Marginal Abatement Cost Curve (MACC) illustrating the cost-effectiveness of considered methane mitigation options across selected countries. Abatement options are disaggregated by country and technology, with marginal costs aggregated at the country–technology level using weighted averages based on abatement potential across segments (upstream and midstream) and locations (onshore and offshore). Measures related to LDAR are highlighted in pink, while all other mitigation options are shown in grey.

To avoid double-counting emission reductions, the net costs and the volume of emissions reduced were calculated incrementally. The biannual LDAR option reflects the additional cost and emission reduction beyond those achieved through annual inspections. Similarly, the quarterly option reflects the incremental cost and emission reduction relative to biannual inspections. Each segment of the MACC therefore represents the marginal benefit of increasing inspection frequency, rather than cumulative totals.

Figure 15. Marginal Abatement Cost Curve for considered methane mitigation options, with a focus on Leak Detection and Repair (LDAR)



Based on emissions data from International Energy Agency (2025) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

LDAR measures, regardless of inspection frequency, can deliver a wide range of abatement potentials and may result in both positive and negative marginal abatement costs. This reflects the balance between implementation costs and revenues from recovered gas, with all options remaining well below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e). Two main patterns emerge:

- **High potential, low or negative cost contexts**, driven by a high share of salable gas and limited import-related costs for equipment and services. In countries such as Algeria, this results in significant abatement potential at negative cost, although deployment is not always supported by strong regulatory incentives.
- **Lower potential, higher cost contexts**, where high import costs, administrative barriers, and reliance on expensive external service providers reduce cost efficiency. Limited access to local expertise and equipment (e.g., OGI cameras, drones) further increases costs in countries such as Argentina and Libya.

It is also worth noting that marginal abatement costs are estimated based on baseline emissions from the IEA (Fugitive Leaks category). Satellite-detected emissions are not included, although some may correspond to large fugitive sources, potentially leading to an underestimation of abatement potential.

Overall, abatement costs are not directly proportional to emission reductions. They are strongly influenced by the share and value of salable gas, local market conditions, import constraints, and prevailing industry practices.

Challenges and barriers to wider deployment

Despite the potential of LDAR as a methane mitigation measure, several challenges limit its broader implementation:

- **Limited access to local trained personnel.** In some countries (e.g. Libya, Argentina), there is a lack of local service providers and technical capacity for in-house implementation. Domestic operators may have lower awareness or experience with LDAR, resulting in fewer campaigns. Partnerships with international oil companies have enabled pilot initiatives, the ability to scale these efforts remains uncertain.
- **Operational and logistical constraints.** LDAR implementation requires site access, coordination, and repeated inspections. Remote locations, security constraints, and complex operating environments can delay or limit deployment (e.g., Argentina), often resulting in lower inspection frequencies, particularly offshore.
- **High costs and reliance on imports.** LDAR programs involve upfront investment in detection technologies (e.g., OGI cameras, drones) and ongoing operational costs. In some contexts, dependence on imported equipment, sometimes associated with high costs and administrative burdens (e.g., Libya), and foreign service providers further increase costs and create additional logistical barriers.

Clear regulatory signals can significantly reduce these barriers to deployment, increase local capacity, streamline logistical challenges, and support upfront investments.

5.4 Replace natural gas-driven equipment

Description of the abatement option

Natural gas-driven pneumatic devices are widely used in oil and gas operations to control and automate process equipment. These devices rely on pressurized natural gas to regulate flows, inject chemicals or actuate valves. In doing so, they intentionally release methane to the atmosphere or "bleed" emissions as part of normal operation. To reduce or eliminate methane releases, these devices can be replaced with instrument air systems (which use compressed air), electrically powered devices, or low- or no-bleed pneumatic devices.

This study assesses the replacement of natural gas-driven pneumatic controllers and pumps with **(i) electric equipment** or **(ii) instrument air equipment (grid- or solar-powered)**. This replacement fully eliminates methane emission.[140]

Costs range

Table 13 presents per-equipment costs associated with the two mitigation options considered for improving flaring practices. Cost estimates are indicative and may vary significantly depending on site conditions, local market conditions, labor and logistics costs, regulatory requirements, import fees, supply chain availability, and project-specific factors (e.g., scale, location, and existing infrastructure). This table does not include benefits (e.g., savings from avoided gas losses, gas sales, or avoided penalties).

Table 13. Indicative cost ranges for replacing natural gas-driven equipment

Mitigation option	Capital costs (USD/equipment)	Operating costs (annual)
Electric equipment	USD 0 – USD 25,000	<5% of CAPEX
Instrument air equipment	USD 0 – USD 20,000	<5% of CAPEX

Source: Carbon Limits analysis based on interviews with technology and service providers

Current policies and practices

Table 14 presents an overview of the current status of regulatory frameworks and the level of adoption of electric or air-driven pumps and controllers across selected countries. For further details on the elements presented, please refer to the individual country fact sheets.

Table 14. Status of regulatory frameworks and deployment of alternatives to natural gas-driven equipment

Country	Regulatory framework in place	Level of adoption
Algeria	No	High
Angola	No	Medium
Argentina	No	High
Brazil	No	High
Egypt	Yes (national)	High
Ghana	Yes (national)	Medium
Libya	No	High

[140] United States Environmental Protection Agency. (2026). *Instrument Air Controllers*. Available at: https://www.epa.gov/natural-gas-star-program/instrument-air-controllers

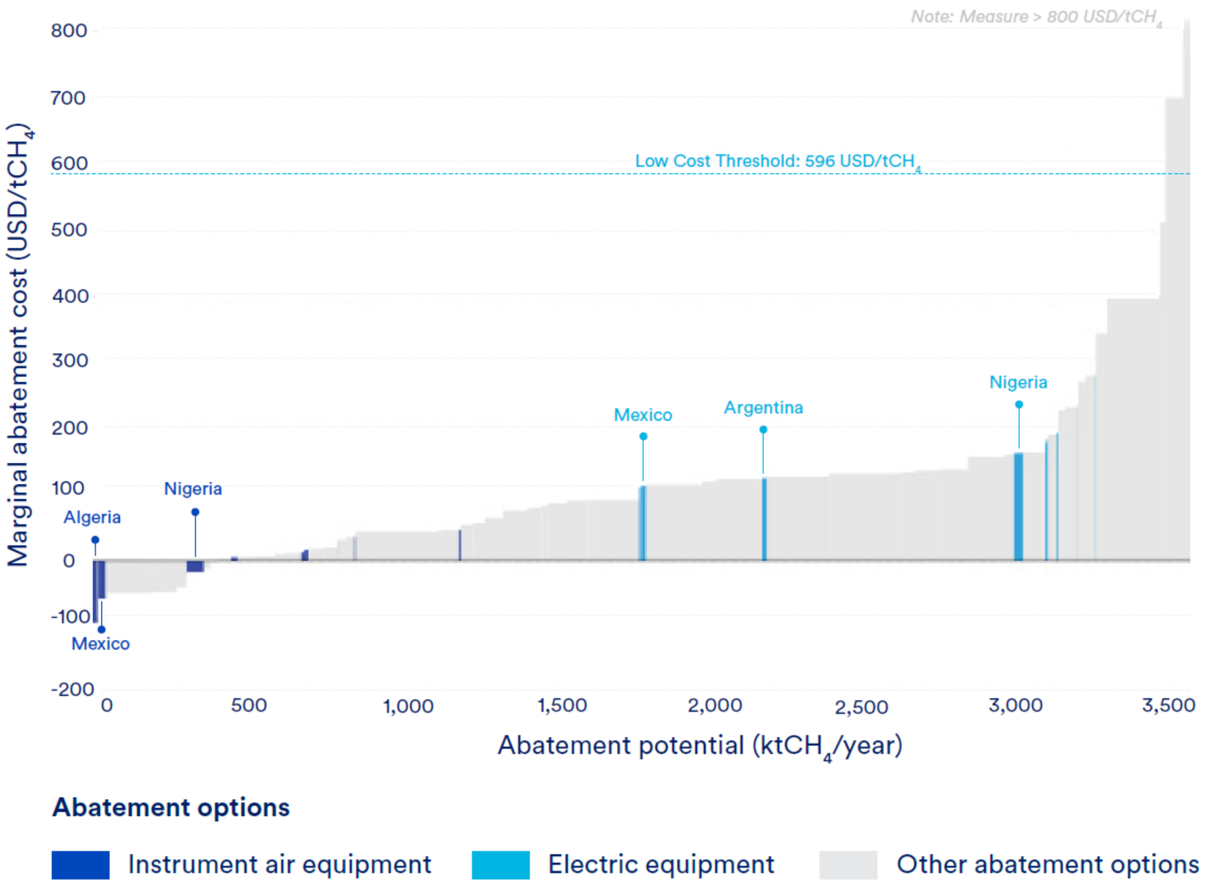
Country	Regulatory framework in place	Level of adoption
Mexico	Yes (national)	Medium
Nigeria	Yes (national)	Medium

Source: Carbon Limits analysis, supplemented by interviews with regulators and oil and gas companies

Marginal Abatement Cost Curve

Figure 16 presents a standardized Marginal Abatement Cost Curve (MACC) illustrating the cost-effectiveness of considered methane mitigation options across selected countries. Abatement options are disaggregated by country and technology, with marginal costs aggregated at the country–technology level using weighted averages based on abatement potential across segments (upstream and midstream) and locations (onshore and offshore). Measures related to replacing natural gas-driven equipment are highlighted in blue, while all other mitigation options are shown in grey.

Figure 16. Marginal Abatement Cost Curve for considered methane mitigation options, with a focus on replacing natural gas-driven equipment



Based on emissions data from International Energy Agency (2023) Methane Tracker Database - IEA; as modified by Carbon Limits/CATF

Methane emissions from pneumatic controllers are relatively low compared to other sources assessed (i.e., flaring, storage tanks and leaks), which reflects the two main contexts observed:

- Countries without targeted regulation, where operators retain flexibility and many assets already rely on electric or instrument air alternatives (e.g., Algeria, Argentina).

- Countries with restrictive regulation, where natural gas-driven equipment is banned (e.g., Nigeria) or strongly discouraged in favor of alternatives (e.g., Egypt, Mexico), has led to a widespread shift towards zero-bleed systems, particularly in new developments or major facility upgrades.

As a result, the remaining abatement potential is limited, given the already medium-to-high adoption levels observed across several of the assessed countries (e.g., Angola). However, the results of this study are still illustrative as they demonstrate the cost-effectiveness of this abatement option that can be pursued in other countries beyond the 9 considered in this study.

For the residual share of gas-driven pneumatic controllers, the marginal abatement cost of replacing gas-driven controllers with instrument air systems is well below the low-cost threshold of 596 USD/tCH_4 (20 USD/tCO_2e) and can even be negative due to avoided gas losses. Replacements with electric systems also remain low cost overall but tend to have slightly higher marginal abatement costs than instrument air options, reflecting somewhat higher CAPEX and OPEX requirements.

Challenges and barriers to wider deployment

For the residual share of gas-driven pneumatic controllers, key challenges to further deployment include:

- **Technical and operational constraints.** Retrofitting can be complex, particularly at aging facilities, due to space, safety, and integration constraints. Deployment may also be hindered by limited equipment availability and lack of technical familiarity. In addition, electric or instrument air systems depend on reliable power or compressed air infrastructure, which may be lacking in remote or offshore locations.
- **High retrofit costs and weak economic incentives.** Replacing existing systems requires upfront capital investment, with often limited financial returns, especially where gas has low or no commercial value or where methane pricing signals are weak, thereby slowing down replacement decisions.

6 Conclusion

This report demonstrates that significant methane emissions reductions are achievable across all assessed countries and emissions sources using existing technologies, and in many cases at relatively low cost. At the same time, the analysis also highlights that abatement costs are highly context-specific. Infrastructure availability, gas utilization opportunities, regulatory frameworks, and access to finance all affect the conditions under which mitigation measures can be viably deployed.

The results also point to several areas where policy action could accelerate the deployment of methane mitigation measures. Clear and predictable regulations establish consistent performance expectations across operators, reduce investment uncertainty, and support the business case for mitigation. Their effects extend to market development: long-term regulatory visibility can support the emergence and growth of local supply chains and service capacity and help reduce the risk perceptions that constrain access to capital. Regulatory development is also reinforced by complementary efforts, including transparency initiatives, voluntary industry commitments, and international cooperation.

In parallel, structural barriers represent a further constraint in several countries. Gaps in gas gathering and utilization infrastructure, as well as administrative, regulatory, and market access barriers affecting the import of key equipment, can significantly increase implementation costs and complexity. Addressing these barriers may require targeted policy measures, including steps to facilitate technology access and investments in gas infrastructure that would enable the monetization of recovered gas and improve the cost-effectiveness of a broader range of mitigation options. Where financing conditions remain a constraint, instruments such as concessional funding and fiscal incentives can improve the viability of these investments; such financial support is particularly important for national oil companies and other entities facing structural barriers to access capital markets.[141]

Taken together, the findings highlight that methane abatement is not only a question of technology availability, but of creating the right enabling conditions for deployment. By combining regulatory clarity, targeted financial support, and investments in infrastructure development, policymakers can improve cost-effectiveness and lower implementation barriers, creating more favorable conditions for emissions reductions over time.

[141] Methane Finance Working Group. *Guidance for Including Methane Abatement in Oil and Gas Debt Structuring*. (see footnote 32)

Appendices

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Appendix 1. Interview template – Technology and service providers

1. Technology specifications

- What methane abatement technologies or services do you offer?
- What are the typical costs, lifetimes, and performance metrics of your solutions?
- By how much can these technologies reduce emissions?
- How much gas can be recovered thanks to these technologies?

2. Deployment & applicability

- In which countries / companies have your technologies been deployed, among the following countries: Algeria, Angola, Argentina, Brazil, Egypt, Ghana, Libya, Mexico, Nigeria?
- Are there specific conditions (e.g., onshore/offshore, oil/gas) where your solutions are more or less applicable? Are there any prerequisites for installing your technologies?
- Are there import restrictions, duties, or local content requirements affecting your operations among the listed countries?
- Are there incentives or policies that have helped accelerate deployment of your technology in any of these countries?

3. Additional comments on methane mitigation

- Would you like to add anything about methane emissions, mitigation options and the challenges of implementation?

Appendix 2. Interview template – Oil and gas companies

1. Emissions overview

- What is the total volume of methane emissions from your operations in the country?
- Can you provide a breakdown of emissions by source? What are your main sources of emissions?
- What methodologies or tools do you use to quantify methane emissions?
- Regarding flaring, how much gas is flared each year? What is the average efficiency destruction of your flares? What is the percentage of unlit flaring?
- What is the average methane content in the gas?
- What percentage of oil and gas production does the company account for in the country? Do you have reason to think that the emissions sources at your company are typical for the country as a whole, or are other companies' operations in the country different from yours?

2. Abatement practices (by abatement technology)

- What methane abatement technologies are currently deployed in the country?
- By how much have these technologies helped to reduce emissions?
- What share of your facilities is equipped with these technologies?
- Do you plan to deploy these technologies on other facilities? In theory, would it be possible to deploy these technologies on all facilities or isn't it technically feasible?
- Are there specific barriers to wider deployment (e.g., cost, infrastructure, regulation, import restrictions or difficulties)?
- Are there any policies in the country that encourage or require the deployment of mitigation technologies?

3. Costs & benefits (by abatement technology)

For each:

- technologies to improve flare efficiency/reduce unlit flares
- technologies to perform leak detection and repair
- technologies to mitigate emissions from storage tanks

    - technologies to replace natural gas-driven equipment

- What are the capital and operational costs associated with abatement technologies in your operations? *(capital costs: equipment, installation, training / operational costs: maintenance and repairs, labor, energy price)*
- Are these technologies imported? If so, are there import tariffs or restrictions?
- What are the typical lifetimes of these technologies?
- How much gas is recovered thanks to these technologies? Is the recovered gas from abatement technologies flared, sold or used? At what price is gas sold (upstream)?
- Do you hire service providers or do the work in-house? Are there existing service providers or engineering firms in the country who can be hired to install or carry out these mitigation actions?

For all:

- If you recover additional gas, could you sell it (which presupposes local demand and suitable infrastructure to transport the gas) or would it require too much investment or be unprofitable?
- Are you able to generate or plan to generate carbon credits from methane reduction? If so, at what price do you (plan to) sell carbon credits, and how many carbon credits do you (plan to) generate?

4. Policies

- Are you affected by any national or subnational policies that currently regulate methane emissions or methane abatement technologies and practices in the oil and gas sector?
- Are there any bans or prescriptions on specific equipment or practices (e.g., flaring, LDAR)?
- Are limits on emissions or practices (amount of gas flared or vented) imposed through licensing or regulation? If so, what are the thresholds?
- Are there economic instruments in place (e.g., taxes, carbon markets, subsidies) targeting methane emissions?
- Are there government programs or funding mechanisms supporting methane abatement technologies? If so, what are the eligibility criteria and scope of these support mechanisms?

5. Additional comments on methane mitigation

- Would you like to add anything about methane emissions, mitigation options and the challenges of implementation?

Appendix 3. Interview template – Government stakeholders

1. Policies

- What national or subnational policies currently regulate methane emissions or methane abatement technologies and practices in the oil and gas sector?
- Are there any bans or prescriptions on specific equipment or practices (e.g., flaring, LDAR)?
- Are limits on emissions or practices (amount of gas flared or vented) imposed through licensing or regulation? If so, what are the thresholds?
- Are there economic instruments in place (e.g., taxes, carbon markets, subsidies) targeting methane emissions?
- Are there government programs or funding mechanisms supporting methane abatement technologies? If so, what are the eligibility criteria and scope of these support mechanisms?

2. Market & Infrastructure

- What is the country's total oil and gas production volume?
- What is the volume of oil and gas exported? What percentage is exported to the European Union?
- What is the volume of oil and gas imported?
- What is the structure of the domestic gas market (e.g., pricing, access, ownership, local demand)?

- Are there any infrastructure limitations (e.g., lack of pipelines, LNG terminals) that affect utilization of methane that has been mitigated (e.g., capturing gas with VRUs, for example, and then selling it)?
- At what price is gas sold (upstream)?
- What is the average methane content in the gas?

3. Emissions

- What is the total volume of methane emissions in the country?
- Can you provide a breakdown of emissions by source? What are the main sources of emissions?
- What methodologies or tools do you use to quantify methane emissions?
- Regarding flaring, how much gas is flared each year? What is the average efficiency destruction of the flares? What is the percentage of unlit flaring?

4. Abatement Practices (by abatement technology)

- What methane abatement technologies are currently deployed in the country/region?
- By how much have these technologies helped to reduce emissions?
- What share of the facilities is equipped with these technologies?
- Are there any plans to deploy these technologies on other facilities? In theory, would it be possible to deploy these technologies on all facilities (100% coverage) or isn't it technically feasible?
- Are there specific barriers to wider deployment (e.g., cost, infrastructure, regulation, import restrictions or difficulties)?

5. Additional comments on methane mitigation

- Would you like to add anything about methane emissions, mitigation options and the challenges of implementation?

Appendix 4. Estimated share of natural gas-driven pneumatic equipment by country

Country	Share of natural gas-driven pneumatic equipment in the country
Algeria	10%
Angola	30%
Argentina	20%
Brazil	10%
Egypt	10%
Ghana	60%
Libya	10%
Mexico	50%
Nigeria	40%

Source: Carbon Limits estimates, based on interviews and experience with local companies and regulators

Appendix 5. Current deployment of mitigation options in each country

Country	Location	Improve flaring	Remove unlit flaring	Replace with Electric or Air Equipment (Controller + Pump)	Install Vapor Recovery Units
Algeria	Onshore	10%	40%	90%	16%
Algeria	Offshore	na	na	na	na
Angola	Onshore	20%	55%	70%	16%
Angola	Offshore	30%	90%	70%	5%
Argentina	Onshore	20%	55%	80%	20%
Argentina	Offshore	30%	90%	80%	5%
Brazil	Onshore	40%	55%	90%	20%
Brazil	Offshore	50%	90%	90%	10%
Egypt	Onshore	20%	55%	90%	15%
Egypt	Offshore	30%	90%	90%	5%
Ghana	Onshore	20%	55%	40%	17%
Ghana	Offshore	30%	90%	40%	5%
Libya	Onshore	10%	40%	90%	17%
Libya	Offshore	20%	90%	90%	5%
Mexico	Onshore	20%	55%	50%	16%
Mexico	Offshore	30%	90%	50%	5%
Nigeria	Onshore	20%	55%	60%	16%
Nigeria	Offshore	30%	90%	60%	5%

Source: Carbon Limits estimates, based on interviews and experience with local companies and regulators.

Appendix 6. Glossary

Term	Definition
Leak Detection And Repair (LDAR)	A program to systematically detect and repair fugitive methane emissions from equipment components. In this study, LDAR refers only to Optical Gas Imaging (OGI)–based surveys and considers different frequencies (i.e., annual, biannual and quarterly). It excludes aerial surveys (e.g., drones, aircraft), continuous monitoring systems, satellite detection and any other non-OGI technologies.
Vapor Recovery Unit (VRU)	A system installed to capture hydrocarbon vapors from storage tanks, compress them, and return them to the gas handling system. VRUs reduce methane and Volatile Organic Compounds (VOC) emissions and can generate product revenue if recovered gas is usable.
Electric Equipment (Pumps, Controllers)	A mitigation measure involving the installation of fully electric alternatives (e.g., electric actuators, pumps, or compressors) to replace natural gas–driven pneumatic devices, thereby eliminating methane venting associated with pneumatic actuation.
Instrument Air Equipment (Pumps, Controllers)	A mitigation measure involving the use of instrument air systems, which replace natural gas with compressed air to operate pneumatic devices, thereby eliminating methane venting associated with pneumatic actuation. Two configurations are considered: - Electric-powered instrument air compressors installed on site, using grid electricity. - Solar-powered instrument air packages, designed for remote sites without grid access.
Improve flaring destruction efficiency	Increasing flare destruction efficiency for lit flares, through retrofit or replacement of flare systems and associated equipment, including assist systems (air/steam), improved gas routing and pressure management to ensure stable combustion conditions, enhanced automation and control to detect and correct abnormal operation, and stronger operational and maintenance (O&M) practices to sustain high combustion performance over time.
Remove unlit flaring	Ensuring that flares remain continuously lit. This includes the installation of reliable pilot and auto-ignition systems, supported by continuous or frequent monitoring (e.g. flame or temperature detectors, cameras) and appropriate operational response procedures.

Appendix 7. Average baseline flare Destruction and Removal Efficiency (DRE) by country

Country	Source *Priority to local data*	Average Destruction and Removal Efficiency (DRE) (excluding unlit flares)
Algeria	Plant et al.	95.2%
Angola	Plant et al.	95.2%
Argentina	Plant et al.	95.2%
Brazil	Plant et al.	95.2%
Egypt	Plant et al.	95.2%
Ghana	Plant et al.	95.2%
Libya	Plant et al.	95.2%
Mexico	Petróleos Mexicanos (PEMEX)	84%
Nigeria	Estimates based on interviews	95.5%

Sources: Carbon Limits estimates based on interviews (Nigeria), PEMEX[142] (Mexico), and Plant[143] for other countries

Appendix 8. Share of marketable gas per country

Country	Share of gas marketable		
	Upstream Onshore	Upstream Offshore	Midstream Onshore
Algeria	70%	NA	100%
Angola	40%	40%	100%
Argentina	85%	85%	100%
Brazil	72%	26%	100%
Egypt	50%	50%	100%
Ghana	41%	41%	100%
Libya	40%	40%	100%
Mexico	80%	55%	100%
Nigeria	80%	50%	100%

Sources: Carbon Limits estimates based on data from the National Agency for Oil, Gas and Biofuels (ANPG)[144] (Angola), the Argentinian Institute of Oil and Gas (IAPG)[145] [146] (Argentina), Brazilian National Agency for Petroleum, Natural Gas and Biofuels (ANP)[147] (Brazil), the Petroleum Commission of Ghana[148] (Ghana), and Nigerian Upstream Petroleum Regulatory Commission (NUPRC)[149] (Nigeria), supplemented by Carbon Limits expertise for other countries

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142 PEMEX. (2024). *Sustainability Report 2024.* Available at: https://www.pemex.com/etica_y_transparencia/transparencia/informes/Documents/sustainability_report_2024_eng.pdf

143 Genevieve Plant et al. (2022). *Inefficient and unlit natural gas flares both emit large quantities of methane.* Available at: https://www.science.org/doi/10.1126/science.abq0385

144 National Agency for Oil, Gas and Biofuels (ANPG). (2025). *Annual report 2024*. Available at: https://anpg.co.ao/wp-content/uploads/2025/06/Relatorio_de_Gestao_2024.pdf

145 Argentinian Institute of Oil and Gas (IAPG). (2025). *Monthly Oil and Natural Gas Production.* Available at: https://www.iapg.org.ar/suplemento/Diciembre2025/ProduccionPorMes.html

146 Argentinian Institute of Oil and Gas (IAPG). (2025). Natural Gas Balance. Available at: https://www.iapg.org.ar/suplemento/Octubre2025/BalanceGas.html

147 Brazilian National Agency for Petroleum, Natural Gas and Biofuels (ANP). (2026). *Oil and gas production. Available at: https://app.powerbi.com/view?r=eyJrIjoiNzVmNzI1MzQtNTY1NC00ZGVhLTk5N2ItNzBkMDNhY2IxZTIxIiwidCI6IjQ0OTlmNGZmLTI0YTYtNGI0Mi1iN2VmLTEyNGFmY2FkYzkxMyJ9*

148 The Petroleum Commission, Ghana. (2025). *2024 Fields Production Data* [Database]. Available at: https://petrocom.gov.gh/production-volume/

149 Nigerian Upstream Petroleum Regulatory Commission (NUPRC). (2025). *2025 Monthly gas data*. Available at: https://www.nuprc.gov.ng/wp-content/uploads/2026/01/2025-Monthly-Gas-Data-for-Publication_December-2025.pdf

Appendix 9. Project lifetime per mitigation option.

Mitigation option	Project lifetime (years)
Improve flaring destruction efficiency	10
Remove unlit flaring	5
Leak Detection and Repair (LDAR) – Annual	6
LDAR – Biannual	6
LDAR – Quarterly	6
Install Vapor Recovery Units	15
Replace with electric equipment	8
Replace with instrument air equipment	8

Note: Actual project lifetimes may be longer, but the values shown here are used for the economic evaluation. For LDAR options, project lifetime matters only when equipment is purchased and campaigns are carried out in-house rather than by external service providers.

Sources: Carbon Limits estimates based on interviews with technology and service providers

Appendix 10. Country-specific labor costs

Country	Labor cost (USD per hour)
Algeria	8.7
Angola	3.2
Argentina	17.7
Brazil	10.7
Egypt	3.0
Ghana	6.0
Libya	3.7
Mexico	15.6
Nigeria	14.7

Sources: Carbon Limits estimates based on Petroleum Engineer salaries from Glassdoor[150] (Angola, Egypt, Ghana, Libya, Nigeria), Salary Expert[151] (Argentina, Brazil, Mexico), and City Salary[152] (Algeria)

Appendix 11. Gas price per country

Country	Source *Default to main exporting region if no local data*	Upstream price (USD/MMBtu)	Midstream price (USD/MMBtu)
Algeria	EU gas price	5.1	10.2
Angola	EU gas price	5.1	10.2

[150] Glassdoor. (2025). *Petroleum Engineer Salaries*. Available at: https://www.glassdoor.com/Salaries/petroleum-engineer-salary-SRCH_IN1_KO0,18.htm
[151] Salary Expert. (2025). *Petroleum Engineer Salary.* Available at: https://www.salaryexpert.com/salary/job/petroleum-engineer
[152] City Salary. (2025). *Average Salaries in Algeria in Dollars in Public and Private Sectors 2025*. Available at: https://city-salary.com/%D9%85%D8%AA%D9%88%D8%B3%D8%B7-%D8%A7%D9%84%D8%B1%D9%88%D8%A7%D8%AA%D8%A8-%D9%81%D9%8A-%D8%A7%D9%84%D8%AC%D8%B2%D8%A7%D8%A6%D8%B1-%D8%A8%D8%A7%D9%84%D8%AF%D9%88%D9%84%D8%A7%D8%B1/

Country	Source *Default to main exporting region if no local data*	Upstream price (USD/MMBtu)	Midstream price (USD/MMBtu)
Argentina	Local gas price	3.1	2.6
Brazil	Local gas price	2.2	10.2
Egypt	Local gas price	2.8	3.3
Ghana	EU gas price	5.1	10.2
Libya	EU gas price	5.1	10.2
Mexico	Local gas price	3.0	3.0
Nigeria	EU gas price	5.1	10.2

Source: Carbon Limits estimates based on Secretary of Energy[153] (Argentina), Brazilian Association of Piped Gas Distributing Companies (ABEGÁS)[154] (Brazil), Business Insider Africa[155] and EntrepriseAM[156] (Egypt), and PEMEX[157] (Mexico), supplemented by prices for other countries derived from import price data reported by the Energy Institute[158] (see Table 6)

Appendix 12. Discount rate per country

Country	Discount rate
Algeria	8%
Angola	19%
Argentina	37%
Brazil	23%
Egypt	21%
Ghana	19%
Libya	21%
Mexico	9%
Nigeria	18%

Sources: Carbon Limits estimates based on World Bank[159] (Algeria, Angola), International Monetary Fund (IMF)[160] (Argentina), Central Bank of Egypt (CBE)[161] (Egypt), and CEIC Data[162] [163] [164](Brazil, Mexico, Nigeria), supplemented by Carbon Limits assumptions for Ghana and Libya

[153] Secretary of Energy, Argentina. (2026). *Natural Gas Price - Res 1/2018.* Available at: https://estadisticasenergia.mecon.gob.ar/superset/dashboard/175/?standalone=true

[154] Brazilian Association of Piped Gas Distributing Companies (ABEGÁS). (2025). *Governo quer oferecer preço menor em 1º leilão de gás natural do pré-sal, mas esbarra na Petrobras.* Available at: https://www.abegas.org.br/arquivos/94914

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[156] EnterpriseAM. (2025). *Egypt's Gov't Hikes Gas Transmission Tariff by 33%.* Available at: https://enterpriseam.com/logistics/2025/09/30/egypts-govt-hikes-gas-transmission-tariff-by-33/

[157] PEMEX. (2025). *Natural Gas Price*. Available at: https://www.pemex.com/nuestro-negocio/pep/sistema-informacion/vpm/gas-natural/Paginas/precio.aspx

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[161] Central Bank of Egypt (CBE). (2026). *Monetary Policy Rates*. Available at: https://www.cbe.org.eg/en/monetary-policy/monetary-policy-publications

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[163] CEIC Data. (2026). *Mexico Bank Lending Rate*. Available at: https://www.ceicdata.com/en/indicator/mexico/bank-lending-rate

[164] CEIC Data. (2026). *Nigeria Bank Lending Rate*. Available at: https://www.ceicdata.com/en/indicator/nigeria/bank-lending-rate

Appendix 13. Country-specific annual net abatement costs

Country	Annual net abatement cost (million USD/year)
Algeria	115.9
Angola	17.8
Argentina	82.0
Brazil	20.0
Egypt	17.4
Ghana	1.04
Libya	66.3
Mexico	24.4
Nigeria	84.4

Sources: Carbon Limits calculation

Appendix 14. Marginal abatement potential and costs for selected methane mitigation options in Algeria's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	14	-5.9	-424	-6.32
LDAR – Annual	Midstream	Onshore	25	-10.5	-424	-6.32
LDAR – Quarterly	Midstream	Onshore	14	-4.7	-334	-4.97
Replace with instrument air equipment	Upstream	Onshore	21	-1.9	-92	-1.38
LDAR – Annual	Upstream	Onshore	122	3.4	28	0.42
LDAR – Biannual	Upstream	Onshore	69	2.0	29	0.44
Replace with electric equipment	Upstream	Onshore	5	0.6	111	1.66
Install Vapor Recovery Units	Upstream	Onshore	183	21.1	115	1.71
Remove unlit flaring	Upstream	Onshore	238	31.3	132	1.96
LDAR – Quarterly	Upstream	Onshore	69	10.9	159	2.36
Improve flaring destruction efficiency	Upstream	Onshore	175	69.5	397	5.92

*Mbtu: thousand British thermal units

Appendix 15. Marginal abatement potential and costs for selected methane mitigation options in Angola's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	0.7	-0.3	-362	-5.39
LDAR – Quarterly	Midstream	Onshore	0.8	-0.3	-343	-5.10
LDAR – Annual	Midstream	Onshore	0.5	-0.2	-342	-5.09
LDAR – Biannual	Upstream	Offshore	20.4	-0.1	-3	-0.04
Remove unlit flaring	Upstream	Offshore	52.0	0.6	12	0.17
Replace with instrument air equipment	Upstream	Offshore	10.4	0.1	12	0.18
Replace with instrument air equipment	Upstream	Onshore	0.8	0.0	17	0.25
LDAR – Annual	Upstream	Offshore	14.7	0.4	29	0.43
LDAR – Quarterly	Upstream	Offshore	23.7	0.9	40	0.59
LDAR – Biannual	Upstream	Onshore	1.2	0.1	50	0.74
LDAR – Annual	Upstream	Onshore	0.9	0.1	97	1.45
LDAR – Quarterly	Upstream	Onshore	1.4	0.2	118	1.75
Replace with electric equipment	Upstream	Offshore	5.2	0.9	183	2.73
Replace with electric equipment	Upstream	Onshore	0.4	0.1	195	2.91
Improve flaring	Upstream	Offshore	43.4	9.3	215	3.20
Install Vapor Recovery Units	Upstream	Onshore	2.8	0.6	217	3.23
Install Vapor Recovery Units	Upstream	Offshore	17.3	3.9	228	3.40
Remove unlit flaring	Upstream	Onshore	0.8	0.4	449	6.69
Improve flaring	Upstream	Onshore	0.6	0.9	1483	22.08

*Mbtu: thousand British thermal units

Appendix 16. Marginal abatement potential and costs for selected methane mitigation options in Argentina's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Upstream	Offshore	3	-0.04	-17	-0.25
LDAR – Annual	Upstream	Offshore	3	-0.01	-3	-0.04
Replace with instrument air equipment	Upstream	Onshore	21	0.1	3	0.05
LDAR – Quarterly	Upstream	Offshore	3	0.02	8	0.12
LDAR – Biannual	Upstream	Onshore	45	2.9	66	0.98
Replace with instrument air equipment	Upstream	Offshore	0.5	0.04	79	1.17
LDAR – Biannual	Midstream	Onshore	12	0.9	81	1.21
LDAR – Annual	Upstream	Onshore	50	4.4	87	1.30
LDAR – Annual	Midstream	Onshore	13	1.4	106	1.58
Install Vapor Recovery Units	Upstream	Onshore	144	17.5	121	1.81
Replace with electric equipment	Upstream	Onshore	14	1.7	122	1.82
LDAR – Quarterly	Upstream	Onshore	48	6.5	137	2.04
LDAR – Quarterly	Midstream	Onshore	12	2.0	158	2.35
Replace with electric equipment	Upstream	Offshore	0.3	0.1	244	3.64
Install Vapor Recovery Units	Upstream	Offshore	1	0.3	275	4.10
Remove unlit flaring	Upstream	Onshore	39	13.2	342	5.09
Remove unlit flaring	Upstream	Offshore	0.1	0.1	672	10.01
Improve flaring destruction efficiency	Upstream	Onshore	28	30.2	1068	15.91
Improve flaring destruction efficiency	Upstream	Offshore	0.1	0.7	9848	146.70

*Mbtu: thousand British thermal units

Appendix 17. Marginal abatement potential and costs for selected methane mitigation options in Brazil's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	7	-2.0	-288	-4.29
LDAR – Annual	Midstream	Onshore	8	-2.3	-275	-4.10
LDAR – Quarterly	Midstream	Onshore	7	-1.6	-231	-3.45
Replace with instrument air equipment	Upstream	Onshore	1	0.03	33	0.50
Remove unlit flaring	Upstream	Offshore	19	0.7	38	0.56
Replace with instrument air equipment	Upstream	Offshore	4	0.2	50	0.74
LDAR – Biannual	Upstream	Offshore	30	1.7	58	0.86
LDAR – Annual	Upstream	Offshore	36	2.3	64	0.96
LDAR – Quarterly	Upstream	Offshore	30	3.1	103	1.54
LDAR – Biannual	Upstream	Onshore	3	0.4	111	1.66
Install Vapor Recovery Units	Upstream	Onshore	11	1.4	130	1.93
LDAR – Annual	Upstream	Onshore	4	0.6	134	2.00
Replace with electric equipment	Upstream	Offshore	3	0.5	174	2.59
Replace with electric equipment	Upstream	Onshore	1	0.1	201	2.99
LDAR – Quarterly	Upstream	Onshore	3	0.7	206	3.07
Install Vapor Recovery Units	Upstream	Offshore	20	4.5	225	3.35
Improve flaring destruction efficiency	Upstream	Offshore	16	7.4	455	6.78
Remove unlit flaring	Upstream	Onshore	1	1.0	718	10.69
Improve flaring destruction efficiency	Upstream	Onshore	1	1.4	1383	20.60

*Mbtu: thousand British thermal units

Appendix 18. Marginal abatement potential and costs for selected methane mitigation options in Egypt's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	10	-0.6	-62	-0.93
LDAR – Annual	Midstream	Onshore	17	-1.0	-56	-0.83
LDAR – Quarterly	Midstream	Onshore	10	-0.3	-31	-0.47
LDAR – Biannual	Upstream	Offshore	11	-0.1	-9	-0.14
LDAR – Annual	Upstream	Offshore	19	-0.1	-4	-0.06
LDAR – Quarterly	Upstream	Offshore	11	0.1	13	0.19
Remove unlit flaring	Upstream	Offshore	11	0.2	18	0.26
Replace with instrument air equipment	Upstream	Onshore	3	0.1	26	0.38
Replace with instrument air equipment	Upstream	Offshore	1	0.1	57	0.85
Remove unlit flaring	Upstream	Onshore	29	2.1	74	1.10
LDAR – Biannual	Upstream	Onshore	7	0.7	97	1.45
LDAR – Annual	Upstream	Onshore	12	1.3	112	1.67
Install Vapor Recovery Units	Upstream	Onshore	25	3.5	140	2.08
LDAR – Quarterly	Upstream	Onshore	7	1.1	167	2.49
Replace with electric equipment	Upstream	Onshore	1	0.2	241	3.59
Improve flaring destruction efficiency	Upstream	Onshore	21	5.4	255	3.80
Install Vapor Recovery Units	Upstream	Offshore	5	1.3	274	4.07
Improve flaring destruction efficiency	Upstream	Offshore	9	3.1	331	4.93
Replace with electric equipment	Upstream	Offshore	0.3	0.1	364	5.42

*Mbtu: thousand British thermal units

Appendix 19. Marginal abatement potential and costs for selected methane mitigation options in Ghana's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	1	-0.2	-347	-5.16
LDAR – Annual	Midstream	Onshore	1	-0.2	-301	-4.49
LDAR – Quarterly	Midstream	Onshore	1	-0.2	-290	-4.31
LDAR – Biannual	Upstream	Offshore	2	0.0	-10	-0.15
Replace with electric equipment	Upstream	Onshore	0	0	0	0
Replace with instrument air equipment	Upstream	Onshore	0	0	0	0
Improve flaring destruction efficiency	Upstream	Onshore	0	0	0	0
Remove unlit flaring	Upstream	Onshore	1	0	0	0
LDAR – Annual	Upstream	Onshore	0	0	0	0
LDAR – Biannual	Upstream	Onshore	0	0	0	0
LDAR – Quarterly	Upstream	Onshore	0	0	0	0
Install Vapor Recovery Units	Upstream	Onshore	0	0	0	0
Remove unlit flaring	Upstream	Offshore	8	0.1	9	0.13
LDAR – Annual	Upstream	Offshore	2	0.0	16	0.24
LDAR – Quarterly	Upstream	Offshore	2	0.1	37	0.55
Improve flaring destruction efficiency	Upstream	Offshore	6	0.8	131	1.95
Replace with electric equipment	Upstream	Offshore	1	0.2	236	3.52
Install Vapor Recovery Units	Upstream	Offshore	2	0.3	228	3.39

*Mbtu: thousand British thermal units

Appendix 20. Marginal abatement potential and costs for selected methane mitigation options in Libya's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Upstream	Offshore	1	-0.01	-6	-0.09
LDAR – Annual	Upstream	Offshore	2	-0.001	-1	-0.01
Replace with electric equipment	Upstream	Offshore	0	0	0	0
Replace with instrument air equipment	Upstream	Onshore	10	0.1	10	0.16
Remove unlit flaring	Upstream	Offshore	7	0.1	11	0.17
LDAR – Annual	Midstream	Onshore	3	0.1	19	0.28
LDAR – Biannual	Midstream	Onshore	2	0.0	21	0.31
LDAR – Quarterly	Upstream	Offshore	1	0.0	37	0.55
Remove unlit flaring	Upstream	Onshore	271	12.3	45	0.68
Improve flaring destruction efficiency	Upstream	Offshore	6	0.6	101	1.50
Improve flaring destruction efficiency	Upstream	Onshore	199	25.4	128	1.90
Install Vapor Recovery Units	Upstream	Onshore	90	12.4	138	2.06
LDAR – Annual	Upstream	Onshore	35	5.4	152	2.27
LDAR – Biannual	Upstream	Onshore	20	3.1	155	2.31
Install Vapor Recovery Units	Upstream	Offshore	1	0.1	186	2.77
Replace with electric equipment	Upstream	Onshore	3	0.5	193	2.87
LDAR – Quarterly	Midstream	Onshore	2	0.4	256	3.82
LDAR – Quarterly	Upstream	Onshore	20	5.7	287	4.27
Replace with instrument air equipment	Upstream	Offshore	0.1	0.1	366	5.46

*Mbtu: thousand British thermal units

Appendix 21. Marginal abatement potential and costs for selected methane mitigation options in Mexico's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	(USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	11	-1.4	-133	-1.99
LDAR – Quarterly	Midstream	Onshore	13	-1.3	-103	-1.53
LDAR – Annual	Midstream	Onshore	9	-0.8	-92	-1.37
Replace with instrument air equipment	Upstream	Onshore	14	-1.1	-77	-1.14
Replace with instrument air equipment	Upstream	Offshore	10	-0.3	-27	-0.41
LDAR – Biannual	Upstream	Offshore	12	-0.3	-24	-0.36
Remove unlit flaring	Upstream	Offshore	32	0.4	11	0.17
LDAR – Quarterly	Upstream	Offshore	15	0.2	16	0.23
LDAR – Annual	Upstream	Offshore	11	0.2	17	0.25
Improve flaring destruction efficiency	Upstream	Offshore	124	6.3	51	0.75
LDAR – Biannual	Upstream	Onshore	8	0.5	56	0.84
Replace with electric equipment	Upstream	Onshore	10	0.8	89	1.32
Install Vapor Recovery Units	Upstream	Onshore	34	3.2	95	1.42
Replace with electric equipment	Upstream	Offshore	7	1.0	146	2.18
LDAR – Quarterly	Upstream	Onshore	10	1.5	148	2.20
LDAR – Annual	Upstream	Onshore	7	1.2	170	2.53
Install Vapor Recovery Units	Upstream	Offshore	11	2.2	194	2.89
Improve flaring destruction efficiency	Upstream	Onshore	42	9.0	212	3.16
Remove unlit flaring	Upstream	Onshore	12	3.2	259	3.86

*Mbtu: thousand British thermal units

Appendix 22. Marginal abatement potential and costs for selected methane mitigation options in Nigeria's oil and gas sector

Mitigation option	Segment	Location	Abatement potential ($ktCH_4$/year)	Annualized cost (million USD/year)	Marginal Abatement cost (USD/tCH_4)	Marginal Abatement cost (USD/Mbtu*)
Leak Detection and Repair (LDAR) – Biannual	Midstream	Onshore	8	-2.4	-308	-4.59
LDAR – Annual	Midstream	Onshore	7	-1.9	-277	-4.13
LDAR – Quarterly	Midstream	Onshore	8	-1.9	-247	-3.68
Replace with instrument air equipment	Upstream	Onshore	37	-1.6	-44	-0.66
Remove unlit flaring	Upstream	Offshore	42	0.9	22	0.33
LDAR – Biannual	Upstream	Offshore	30	0.9	31	0.46
Replace with instrument air equipment	Upstream	Offshore	18	0.7	42	0.62
LDAR – Annual	Upstream	Offshore	27	1.4	53	0.79
LDAR – Biannual	Upstream	Onshore	31	2.0	64	0.96
LDAR – Quarterly	Upstream	Offshore	30	2.5	85	1.26
LDAR – Annual	Upstream	Onshore	28	3.3	121	1.81
Replace with electric equipment	Upstream	Onshore	18	2.3	126	1.88
Install Vapor Recovery Units	Upstream	Onshore	99	13.1	133	1.98
LDAR – Quarterly	Upstream	Onshore	31	5.6	183	2.72
Replace with electric equipment	Upstream	Offshore	9	2.1	238	3.54
Install Vapor Recovery Units	Upstream	Offshore	22	5.8	267	3.97
Remove unlit flaring	Upstream	Onshore	34	11.4	335	4.99
Improve flaring destruction efficiency	Upstream	Offshore	33	13.1	392	5.83
Improve flaring destruction efficiency	Upstream	Onshore	24	27.1	1119	16.66

*Mbtu: thousand British thermal units

Appendix 23. Absolute LDAR Costs for each frequency

Marginal Abatement cost (USD/ktCH4)									
Country	Onshore Upstream			Offshore Upstream			Midstream		
	Annual	Biannual	Quarterly	Annual	Biannual	Quarterly	Annual	Biannual	Quarterly
Algeria	28	29	63	-	-	-	-424	-424	-400
Angola	97	69	89	29	11	22	-342	-354	-349
Argentina	87	77	97	-3	-9	-4	106	94	115
Brazil	134	124	149	64	61	74	-275	-281	-266
Egypt	112	107	123	-4	-6	-1	-56	-58	-51
Ghana	0	0	0	16	2	14	-301	-325	-313
Libya	152	153	189	-545	-3	8	19	20	82
Mexico	170	109	124	17	-5	3	-92	-114	-110
Nigeria	121	91	123	53	41	56	-277	-293	-278

Marginal Abatement cost (USD/Mbtu*)									
Country	Onshore Upstream			Offshore Upstream			Midstream		
	Annual	Biannual	Quarterly	Annual	Biannual	Quarterly	Annual	Biannual	Quarterly
Algeria	0.42	0.43	0.94	-	-	-	-6.32	-6.32	-5.96
Angola	1.45	1.04	1.32	0.43	0.16	0.33	-5.09	-5.27	-5.20
Argentina	1.30	1.15	1.45	-0.04	-0.14	-0.05	1.58	1.40	1.72
Brazil	2.00	1.85	2.24	0.96	0.91	1.11	-4.10	-4.19	-3.96
Egypt	1.67	1.59	1.83	-0.06	-0.09	-0.01	-0.84	-0.87	-0.76
Ghana	0	0	0	0.24	0.04	0.21	-4.49	-4.84	-4.66
Libya	2.27	2.29	2.81	-0.01	-0.04	0.12	0.28	0.29	1.23
Mexico	2.53	1.62	1.85	0.25	-0.08	0.04	-1.38	-1.70	-1.64
Nigeria	1.81	1.36	1.83	0.79	0.62	0.84	-4.13	-4.37	-4.13

*Mbtu: thousand British thermal units

CARBON LIMITS

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