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Energy Recovery Potential from Fugitive Methane Emission in the Nigerian Upstream Oil and Gas Sector: An Assessment

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Abstract: Fugitive methane emissions from Nigeria's upstream oil and gas sector were quantified to assess their energy recovery potential and the techno-economic and environmental viability of identified methane recovery systems. The study focused on Nigeria's oil- and gas-producing states, and applied complementary IPCC Tier 1 and Tier 3 methodologies. Tier 1 used activity data and emission factors, while Tier 3 integrated atmospheric methane retrievals from TROPOMI Sentinel-5P satellite with geospatial infrastructure mapping and meteorological data. Potential energy recoverable was estimated from quantified methane emissions using methane's lower heating value. The techno-economic and environmental viability of the recovery technologies (Vapour Recovery Unit (VRU) and Pressure Swing Adsorption (PSA)) were analysed using financial performance indicators and a comparative fuel substitution analysis. Average methane emissions were estimated at 769.64 Gg CH₄/year (21.55 Mt CO₂e/yr) for Tier 1 and 1,284.90 Gg CH₄/year (35.98 Mt CO₂e/yr) for Tier 3. The potentially recoverable energy was calculated at 38,482 TJ for Tier 1, and 64,245 TJ for Tier 3. The techno-economic analysis indicates that both recovery technologies are viable under the base CNG price assumption, although PSA systems outperformed VRUs across several financial indicators and demonstrated stronger price resilience. Replacing firewood and Liquefied Petroleum Gas (LPG) with recovered methane (Compressed Natural Gas (CNG)) reduced combustion-related CO₂ emissions by approximately 55% and 21%, respectively. The study provides evidence that methane recovery in Nigeria's oil and gas industry can be economically viable and environmentally beneficial under the stated modelling assumptions. The findings indicate the potential of satellite-enabled methane management systems to support climate mitigation and investment decision-making.

Keywords: Energy Recovery; Fugitive Methane Emissions; IPCC Tier Methodology; TROPOMI; Geospatial Analysis; Techno-Economic Analysis; Oil and Gas Sector

1. Introduction

Fugitive emissions refer to gases that are released unintentionally and at times uncontrollably into the atmosphere and are a byproduct of domestic, industrial, and natural activities [1]. These emissions primarily consist

of greenhouse gases (GHGs), including carbon dioxide (CO₂), nitrous oxide (N₂O), and methane (CH₄) [2]. Among these gases, CH₄ is the second most predominant after CO₂ [3]. Others include chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), and hydrofluorocarbons (HFCs) [2]. GHGs are atmospheric gases that reside in the atmosphere, trap heat by absorbing outgoing solar radiation, and prevent its release into space [4]. This process is called the greenhouse effect. Ideally, this process is important for maintaining Earth's temperature, but it becomes detrimental when amplified in the atmosphere due to increased human and industrial activities, resulting in global warming [4]. Global warming has significant consequences for the environment.

Methane is a particularly important greenhouse gas because it is a primary component of natural gas [5]. Methane makes up about 85% of natural gas, and natural gas is considered a low-carbon transition fuel and a cleaner energy source compared to crude oil [5]. Hence, if fugitive methane emissions are not properly managed from natural gas systems, they might undermine the importance of natural gas as a cleaner energy source [6]. CH₄ has a global warming potential (GWP), of about 28 times that of CO₂ over a 100-year period and 86 times higher over 20 years [7]. Additionally, CH₄ has a short atmospheric lifetime of about 12 years, after which it breaks down into other GHGs, including CO₂ and H₂O. In contrast, CO₂ can remain in the atmosphere for about a century or longer before being removed by natural processes [8]. This implies that immediate reductions in CH₄ emissions will produce short-term progress towards climate change mitigation [9].

In the energy sector, oil, gas, and coal are the major sources of anthropogenic CH₄ emissions [10]. A substantial amount of CH₄ emissions occur during the extraction and production phases, through leakages, venting, and flaring [10]. Mitigation and recovery of methane emissions in the Nigerian oil and gas sector are important for several reasons. First, the Nigerian oil and gas subsector is a major revenue generator, a key employer, and a significant source of foreign exchange [11,12]. Second, in 2023, Nigeria was listed as one of Africa's leading oil producers [13], with proven reserves of approximately 37.5 billion barrels of crude oil and 209 trillion standard cubic feet of natural gas [14]. Furthermore, Nigeria's oil and gas reserve-to-production ratios are 57.01 and 77.5 years, respectively, indicating decades of remaining producible resources. Third, Nigeria's Nationally Determined Contributions (NDCs) document produced in 2018 and submitted under the Paris Agreement, identified the energy sector as the largest source of Nigeria's GHG emissions (209 Mt CO₂e), with oil and gas contributing over 36% [15]. Also, Nigeria has a large population of about 234 million people, is one of the largest African economies with a GDP of ₦58,855,142.27 million in Q1 2024 [16], and has a high level of fossil fuel consumption and dependence on fossil fuels. This high dependence on fossil fuel translates into increased methane emissions. Furthermore, Nigeria is a signatory to several key international agreements aimed at reducing GHG emissions, such as the Paris Agreement and the Global Methane Pledge [17]. A 45% reduction in anthropogenic sources of CH₄ would reduce the global temperature by 0.3 °C [18]. Hence, initiatives aimed at recovering these emissions will help Nigeria meet its international emission control commitments.

Fortunately, fugitive CH₄ emissions are not inevitable. They could be effectively captured using proven recovery technologies such as Vapour Recovery Units (VRUs) and Pressure Swing Adsorption systems (PSAs) [19,20]. The VRUs are able to capture about 95% of emissions in low-pressure sources, thereby minimizing emissions from storage tanks and vents, and pipeline pigging [10]. Overall, these technologies can reduce emissions by up to 70% [2]. Beyond environmental benefits including improvements in air and water quality, management of global warming, and minimization of both mine and well explosions, recovered methane has high economic potential through energy and/or revenue generation.

Despite growing concerns over fugitive methane emissions from the Nigerian oil and gas sector, limited studies have integrated satellite-based methane quantification studies. Existing studies have focused on methane inventories or mitigation policies without determining the energy recovery potential and/or economic viability and environmental feasibility of the methane recovery technologies within the Nigerian context. This study therefore quantifies fugitive CH₄ emissions from primary sources in the Nigerian oil and gas sector, assesses the potential energy recoverable from the quantified emissions, and evaluates the techno-economic and environmental viability of the identified methane recovery technologies.

Aim and Objectives of the Study

The aim of this study is to quantify fugitive CH₄ emissions in the Nigerian oil and gas sector, determine their energy recovery potential, as well as the techno-economic and environmental viability of methane recovery tech-

nologies. The specific objectives are to:

- i. Quantify fugitive CH₄ emissions from primary sources in the Nigerian Upstream oil and gas sector, and assess the corresponding energy recovery potential;
- ii. Evaluate the techno-economic and environmental viability of the identified methane recovery technologies.

2. Literature Review

2.1. Methane Recovery Technologies

Due to increasing concerns regarding energy shortages and environmental degradation, more research has focused on methane recovery technologies with the aim of cutting methane emissions and promoting energy utilisation efficiency [21]. Rather than flaring or venting this valuable hydrocarbon, advanced gas capture technologies like Vapour Recovery Units (VRUs) and Pressure Swing Adsorption (PSA) systems provide a dual benefit: environmental protection and energy recovery. These technologies are viable pathways for methane capture, purification, and subsequent processing into compressed natural gas (CNG) suitable for domestic cooking, especially in energy-deficient regions.

VRUs are devices widely used in oil and gas facilities for recovering fugitive emissions from storage tanks, rail car, truck, or marine loading terminals, as well as other low-emission sources [10]. Gases that were initially flared or vented are recovered and conveyed through compressors and separation systems [22]. They are then reused in the form of naphtha, condensates, benzene, xylenes, toluene, methanol and ethanol, Methyl tert-butyl ether, etc. or reintegrated into gas supply streams, thereby significantly minimising atmospheric methane release [23,24]. VRUs are highly effective for methane recovery and, under suitable conditions, can recover about 95% of methane emissions [25]. However, VRUs may not be suitable in remote areas lacking reliable electricity supply, because many of them run on electrically driven compressors and control systems [25].

The PSA system is another important CH₄ capture system especially in oil and gas facilities for gas purification and upgrading. The system operates through alternating cycles of pressurization and depressurization, using adsorbents, (such as zeolites or activated carbon) that selectively trap unwanted gases. Recent innovations have enhanced CH₄ recovery efficiencies in PSA systems to over 95%, with minimal energy costs [26]. The purified methane output is suitable for compression into CNG, making it a practical option for bottling and domestic use. In some hybrid systems, PSA systems are integrated with membrane separation or vacuum swing adsorption for even greater purification. This enhances methane quality to levels suitable for cooking fuel applications and vehicle-grade CNG standard.

2.2. Detection and Measurement of Fugitive Methane Emissions: TROPOMI 5p Sentinel

Detection and measurement technologies can be broadly classified as bottom-up or top-down. In the bottom-up approach, emissions are identified and measured from the ground and directly from the source such as wellhead, pump, and valves. The top-down approach on the other hand, entails the detection and measurement of methane using aerial means (satellite or aircraft-based systems) such as aircraft, satellites, observation towers [27]. The top-down approach essentially measures the atmospheric concentration of methane over a geographic area and is then disaggregated to determine the emission rate per component or facility [28].

The use of satellite-based sensors for the detection and measurement aligns with the IPCC Tier 3 approach [29]. These sensors detect methane by measuring the distinctive pattern of methane-specific light absorption. One of these satellites is the TROPOMI instrument onboard the Copernicus Sentinel-5 Precursor satellite, developed by the European Space Agency (ESA) [30,31]. TROPOMI follows the legacy of ultraviolet-visible backscatter measurements made by satellites and is built on the decades of satellite measurements of trace gas column densities that are used in air quality and atmospheric health analysis [31].

The Sentinel 5P satellite was developed to cover three important areas of the environment such as air quality assessment, stratospheric ozone layer monitoring, and monitoring and prediction of climate change [32,33]. The monitoring of CH₄ emissions occurs as part of the climate change observation [32]. TROPOMI is a hyperspectral spectrometer, and it records data in eight spectral bands within the ultraviolet (UV), visible (VIS), near-infrared (NIR), and shortwave infrared (SWIR) spectrum [32]. A significant aspect of TROPOMI is its quick revisit period of less than one day. This enables a quasi-real-time mapping and observation of different air quality parameters.

TROPOMI is also a push-broom spectrometer with a swath width of approximately 2,600 km and a spatial resolution of about 5.5 km × 7 km for CO and CH₄ (across × along track), retrieved from the Short-Wave Infrared (SWIR) [34]. The instrument sees a complete swath every second and completes a full orbit around Earth in approximately 100 min.

Measurements based on satellites, specifically on Sentinel-5P TROPOMI sensor, have become necessary to monitor methane and other trace gases in the atmosphere. A satellite inversion study [35] revealed a significant underrepresentation of global methane emissions (by up to 30%) compared to values reported in the UNFCCC assessments. Corradino et al. [32] also validated that satellite remote sensing helps overcome logistical difficulties encountered in the on-site sampling of volcanic gases, while offering significant benefits through hyperspectral monitoring.

Despite these benefits, satellite-based measurements are subject to several limitations as highlighted by several studies. Ialongo et al. [36] discovered that TROPOMI's coarse vertical resolution slightly underestimated the high NO₂ values and overestimated low ones, highlighting the need for high-quality instruments, such as Pandora for calibration and validation. Similarly, Lindqvist et al. [37] found systematic biases in TROPOMI CH₄ retrievals at polar latitudes, which depend on retrieval algorithms, solar angles, and surface reflectance. These studies collectively reinforce that while satellite platforms offer invaluable large-scale, near-real-time insights, ground-based measurements remain critical for improving vertical accuracy, reducing uncertainties, and validating top-down estimates, especially in complex environments like urban hotspots, high-latitude terrains, and flaring-dense oil regions.

2.3. IPCC Three-Tier Approach

The IPCC guidelines provide internationally acceptable methodological frameworks and standards for the compilation, categorization, and reporting of greenhouse gas emissions data under the UNFCCC [38]. The IPCC guidelines are extensively implemented by countries that are signatories to the UNFCCC. Over time, the UNFCCC has adopted several versions of the IPCC guidelines to aid in reporting, and they include the 1996, 2006, and 2019 versions [39].

The IPCC guideline is categorized into three Tiers: Tier 1, Tier 2, and Tier 3. A tier represents the different levels of methodological complexity. Within the framework of the IPCC guidelines, Tier 1 is regarded as the most basic and default method for estimating methane emissions [40]. This method basically represents a generalised estimate, based on standardized emission factors obtained in international databases such as the IPCC itself. Tier 1 is adopted by countries with limited oil and gas industry, site measurement facilities, and technological capacity for carrying out field measurement.

The Tier 2 presents a moderate degree of complexity, and a balance between resources, time, budget, and precision of results. In comparison to Tier 1, it involves country-specific emission factors and activity information/data that incorporate local industrial activity and environmental conditions [38]. This increases its accuracy and makes the national greenhouse gas inventories and mitigation plans more informed.

The Tier 3 is at the top of the sophistication level and is characterized by strict data requirements. This methodology is the most accurate given the inclusion of direct and continuous monitoring of emissions. The assessment usually involves facility-based evaluations or remote sensing measurements using satellite data. Tiers 2 and 3 are typically regarded as advanced approaches compared to Tier 1, due to their greater accuracy, relevance to the country-specific conditions [41].

Some studies have noted challenges with the IPCC methodologies. A major problem is the process of development of the guidelines themselves [42]. The existing guidelines require great improvement so as to reflect the complications surrounding reporting of GHGs. Also, the guidelines have undergone some revisions since their inception, these revisions have not been extensive enough to capture the prevailing realities and developments in the area of greenhouse gas [42]. Additionally, countries implement methodological Tiers, according to their technical capacity and resources [38]. The UNFCCC/Kyoto Protocol obliges the Annex I countries (United States, Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, and Cyprus) [43] to submit annual greenhouse gas inventories [44]. Nations without the resources or capacity to carry out Tier 3 may produce less accurate emission estimates [38], hence preventing efforts to design effective greenhouse gas mitigation measures. In order to address these issues, it is important that the Tier 1 methodology is firmly based on the latest scientific knowledge and technological progress. The inclusion of machine learning tools would make the process of gathering qualitative and quantitative

data more effective and provide opportunities to reorganise and refine the current guidelines [45].

2.4. Compressed Natural Gas (CNG)

Compressed Natural Gas (CNG) is primarily CH_4 gas that has been compressed to a much lower volume compared to its volume at atmospheric pressure, for easy storage and transportation [46]. It is kept in high-pressure cylinders, and is a cleaner fuel compared to kerosene, firewood or even LPG. CNG is also used as cooking fuel, and is used with special CNG cooking stoves [47]. CNG generates fewer emissions and this makes it a safe and environmentally friendly option especially when used indoors. The establishment of small-scale CNG bottling and distribution systems will help reduce the overdependence on imported LPG and contribute to national clean energy objectives [47]. CNG is also less carbon-intensive, cheaper than LPG and firewood. It produces less smoke, hence, minimizes problems associated with air pollution, especially in rural areas where household air pollution is a major concern.

Some of the constraints to the adoption of CNG include high cost of compression and bottling infrastructure, safety issues, lack of awareness, and insufficient rural coverage in distribution networks. Most people are unwilling to use CNG because they feel it is unsafe (possibility of explosion), there are few CNG refilling points, and the government does not have sufficient supportive policies in place. In order to successfully promote the use of compressed natural gas (CNG), some major steps are needed. These steps include public awareness campaigns to educate the citizens on the safety and benefits of CNG, governmental support and regulatory systems to ensure affordability and accessibility, and the establishment of liaisons with the companies in the private sector to increase the infrastructure required to distribute CNG on a large scale.

2.5. Liquefied Petroleum Gas (LPG)

Liquefied Petroleum Gas (LPG) is widely marketed as a clean cooking fuel, particularly in the low- and middle-income countries where biomass consumption is widely observed. LPG has been found to significantly decrease household air pollution (HAP) during biomass stoves substitution [48]. Nonetheless, randomized controlled trials show that the use of LPG has resulted in limited improvements in health conditions like respiratory diseases or heart-related diseases as a result of incomplete combustion and rebound behaviors [49,50].

The popularity of LPG is due to its scalability, control, as well as cleaner burning characteristics compared to solid fuels. Nevertheless, the socio-economic factors, including affordability, reliability of supply chains, and logistical support of cylinder refilling are still challenges in rural locations [51]. Comparative emission research has shown that, although LPG produces significantly lower levels of particulate matter, carbon monoxide (CO), and other harmful pollutants compared to biomass, it still emits GHGs [52]. LPG could also be used as a bridge in clean energy, particularly in areas where electrification or biogas cannot yet be used. However, a global approach must weigh LPG's fossil fuel origin and broader sustainability implications.

2.6. Firewood

Firewood continues to be the most widely used household cooking fuel in most rural communities particularly in sub-Saharan Africa and Southeast Asia, but has dire environmental and health effects. A meta-analysis conducted by Zigabe et al. [53] indicated that prenatal and postnatal household exposure to air pollution caused by biomass fuels such as firewood was associated with a high risk of respiratory infections, pulmonary tuberculosis and poor lung functioning in children. Outside of its health hazards, firewood harvesting is a cause of deforestation, degradation of the ecosystem, and emission of greenhouse gases. These effects are further worsened by the use of ineffective cookstoves or traditional three-stone stoves which do not fully combust wood [54]. Additionally, adoption of improved cooking technologies remains low due to cultural preferences, perceived flavour benefits, and socio-economic constraints [55]. Among household cooking fuels, firewood has the highest pollutant emissions, such as particulate matter, carbon monoxide (CO), and methane (CH_4), due to incomplete combustion [53,54]. Hence, it contributes to short-term climate pollutants and indoor air pollution [54]. In this regard, methane recovery and CNG utilization for clean cooking will provide an opportunity for cleaner household energy supply.

3. Methodology

3.1. Study Area

This study is based on oil and gas-producing regions in Nigeria particularly within the Niger Delta and other emerging hydrocarbon zones.

The South-South region of Nigeria is the centre of oil and gas business and the states include Rivers, Bayelsa, Delta, Akwa Ibom, Cross River, and Edo [56]. These states lie at the heart of the Niger Delta, and hosts the majority of the oil deposits in Nigeria, and an elaborate system of inland and offshore oil pipelines, oil fields and oil terminals [57].

The South-West region, which was historically not a part of the core oil belt is slowly becoming a major participant in recent years. The states involved are Ondo and Lagos [56], and the oil fields are located in the coastal creeks of Ondo, and offshore oil installations in Lagos, such as the Aje oil field [58]. Another factor that makes the region strategically important is the oil-related logistics hub, maritime services, and recently commissioned Dangote Refinery [58].

The South-Eastern region comprises States like Abia, Imo, and Anambra [56] which are characterized by developing oil and gas activities. Imo and Abia have marginal fields and small-scale refinery plants, and more recently, Anambra was identified as a potential oil and gas region [59]. These changes are transforming the economic trends of the region, which was long associated with agriculture and trading.

3.2. Research Design

The study used a multi-method quantitative analytical approach to achieve its objectives.

Objective 1:

To achieve objective 1, a multi-method quantitative analytical approach was adopted. The IPCC Tier 1 and 3 methodologies were used to quantify methane emissions, and the methane to energy conversion methodology was used to determine the potential energy recoverable from the quantified methane emissions.

The IPCC 2019 Refinement to the 2006 Guidelines was adopted for this study due to its improved accuracy and updated methodologies [60]. A key distinction is that the 2019 guidelines embed venting and flaring within the activity data and advise against calculating them separately, unlike the 2006 version [60,61]. Data used were obtained from the Carbon Majors dataset compiled by the Climate Accountability Institute, the Nigerian Upstream Petroleum Regulatory Commission (NUPRC), Nigerian National Petroleum Company Limited (NNPCL), and reconciled using data from the National Bureau of Statistics. The emission factors used were obtained from the IPCC 2019 guidelines [60]. Satellite data were obtained from the Tropospheric Monitoring Instrument (TROPOMI) aboard the Sentinel-5 Precursor satellite, and used for the IPCC Tier 3 methodology. It required using direct atmospheric measurements to determine emission estimates rather than using activity data and default emission factors. To determine the potential energy recoverable, the quantified methane was multiplied by the lower heating value (LHV) of methane.

Tier 1 and Tier 3 methodologies were both applied in order to cross-verify the methane emission estimates obtained, since each approach offers a different perspective with its own strengths and limitations. Tier 1 provides a bottom-up, inventory-based baseline derived from activity data and emission factors, while Tier 3 provides an independent, top-down check based on satellite-observed atmospheric methane concentrations. Combining both approaches offers a more robust and holistic picture of actual emissions than either could provide alone. Importantly, the difference between the two estimates is itself considered a substantive finding because it provides insight into the disparities between the inventory-based (Tier 1) and atmospheric-observation-based (Tier 3) approaches to methane emission estimation.

Objective 2:

To achieve objective 2, a multi-method quantitative analytical approach was adopted. First, a techno-economic analysis was conducted using some economic principles of engineering, including Net Present Value (NPV), Levelised Cost of Energy (LCOE), Return on Investment (ROI), and Payback Period to test the viability of the methane recovery technologies under Tier 1 and 3. The process was repeated for the two technologies identified: VRUs and the PSA system. Second, a comparative fuel substitution analysis was carried out on CNG, LPG, and firewood in order to determine the environmental benefit of CNG. The comparative fuel substitution analysis involved multiplying

the emission factor of each fuel (kg CO₂ per kg of fuel) to the mass of fuel required to generate approximately 100 GJ of energy. The amount of emission generated by each of the fuels was documented and then compared for their environmental viability.

Overall Methodological Framework

Figure 1 shows a schematic breakdown of the study methodology, illustrating the sequential stages from data acquisition through to spatial analysis and result validation.

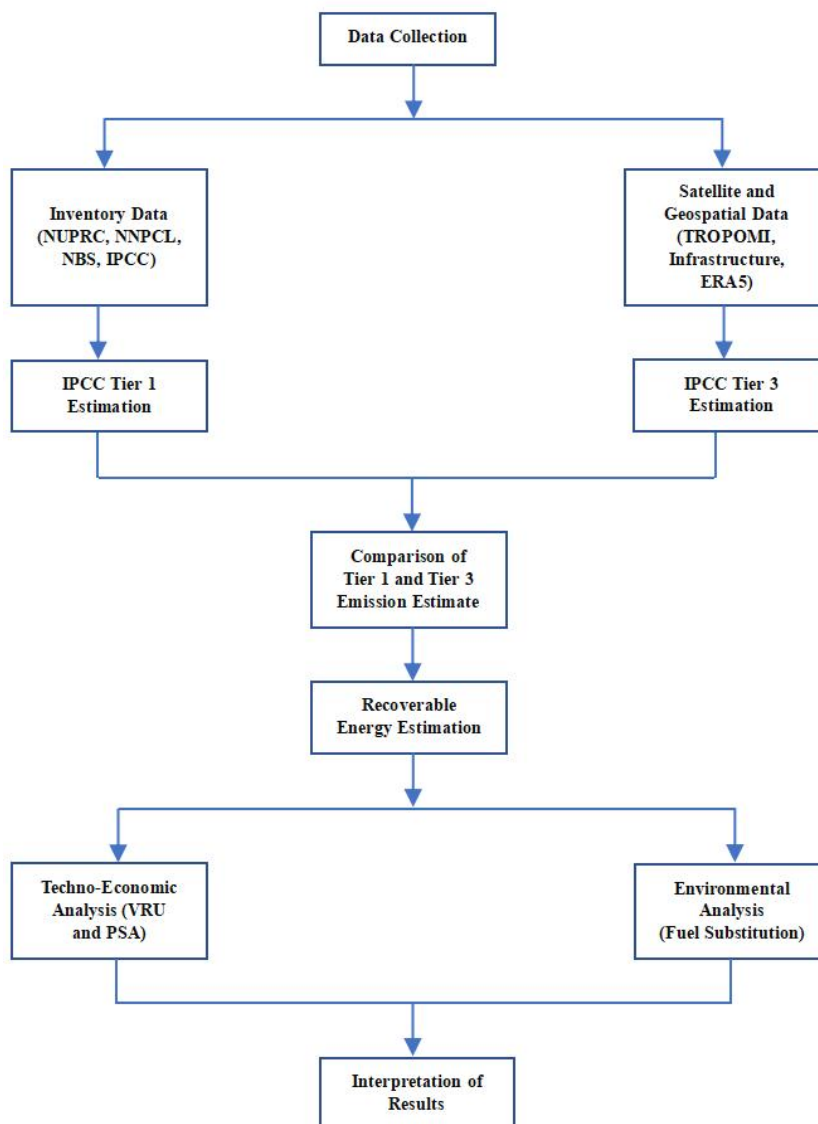


Figure 1. Overall Methodological Framework of the Study.

3.3. Method of Data Analysis

3.3.1. Objective 1

IPCC Tier 1 and 3 methods were used to quantify fugitive methane emissions.

A. IPCC Tier 1 Methodology

The IPCC Tier 1 utilised activity data (oil and gas production data) and the emission factors indicated in the IPCC 2019 recommendations to estimate emissions. The emission factors of CH₄ were multiplied by the activity

data to quantify its emissions as shown in Equations (1) and (2) [60].

Estimating fugitive emissions from an industry segment:

$$E_{oil/gas, industry segment} = A_{industry segment} \times EF_{oil/gas, industry segment} \quad (1)$$

Total Fugitive Emissions from Industry Segments:

$$E_{oil/gas} = \sum (E_{oil/gas, industry segment}) \quad (2)$$

Where:

$E_{oil/gas, industry segment}$ = Total/Annual emissions of CH₄ (tonnes) from an oil or gas industry segments.

$EF_{oil/gas, industry segment}$ = Emission factor for CH₄, (tonnes/unit of activity) from an oil or gas industry segments.

$A_{industry segment}$ = activity value (units of activity) for an oil or gas industry segments.

The subscript oil/gas denotes that the equation is applied separately to oil industry segments and natural gas industry segments respectively, following the IPCC Guidelines [60,61].

Table 1 summarizes the entire dataset needed to provide a comprehensive estimate of the emissions in the oil and gas sector.

Table 1. Activity data needed.

IPCC Code 2019	Sector Category	Activity Data Needed
1.B.2.a	Oil	Exploration, production and upgrading, transport, refining, distribution of oil products, other, and abandoned wells.
1.B.2.b	Gas	Exploration, production and gathering, processing, transmission and storage, distribution, gas post-meter, other, gas fired engines and engine exhaust, and abandoned gas wells.

The data used cover a 24-year period from 2001 to 2024.

B. IPCC Tier 3 Methodology

The IPCC Tier 3 approach estimated methane emission using Sentinel-5P TROPOMI, geospatially referenced oil and gas infrastructure data, and ERA5 meteorological information. Unlike the inventory-based approach used in this study which relied on activity data and emission factors, Tier 3 methodologies use atmospheric observations to quantify methane emission enhancements associated with infrastructure locations. The emission rates were calculated using a physically based mass-balance relationship known as the Integrated Methane Enhancement (IME) framework [62]. This approach is applicable in oil systems where a large fraction of associated and solution gas is vented or flared [60]. Python-based scripts and geospatial analysis were used for the extraction, interpolation, and visualisation of methane emissions.

The locations of active oil and gas wells in Nigeria are proprietary data, hence, an alternative data sourcing strategy was adopted. Publicly available reports and journal articles [63,64] provided relevant information on the distribution of upstream oil fields, flow stations and pipelines across the chosen areas. Georeferencing and on-screen digitization were carried out on recognizable control points comprising oil fields, flow stations and pipelines [65] as shown in **Figures 2** and **3** using ArcMap 10.8. This resulted in a dataset comprising about 227 upstream oil and gas infrastructure sites as shown in **Figures 4** and **5**.

Data cleaning, processing, and reconciliation, were carried out to remove incomplete entries and duplicate locations within 5 km, ensuring spatial precision and reliability. After this process, 161 coordinates remained comprising both points infrastructures (oil fields, flow stations, and processing stations) and lines infrastructures (pipeline corridors). The cleaning was completed prior to the estimation of CH₄ enhancements. Oil and gas facilities and pipelines were represented as spatial reference points and lines, respectively. Due to the medium resolution of TROPOMI (approximately 7 km by 5.5 km), methane identified within the vicinity of mapped infrastructures are interpreted as infrastructure associated emissions, rather than directly measured emissions from specific oil and gas facilities. The integration of satellite remote sensing and geospatial technologies enables more accurate monitoring and quantification of GHG emissions, supporting the implementation of IPCC Tier 3 methodologies [60,66,67].

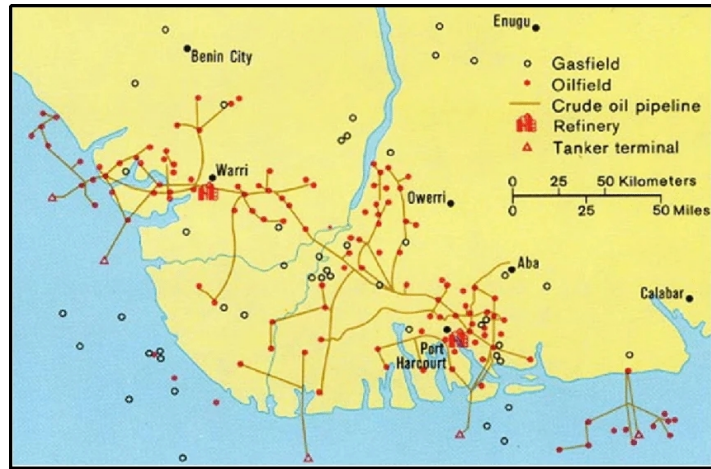


Figure 2. Map of Nigeria Showing Oil and Gas Fields, Crude Oil Pipeline, Refinery and Tanker Terminal [63].



Figure 3. Map of Nigeria Showing SPDC Oil and Gas Fields and Terminals [64].

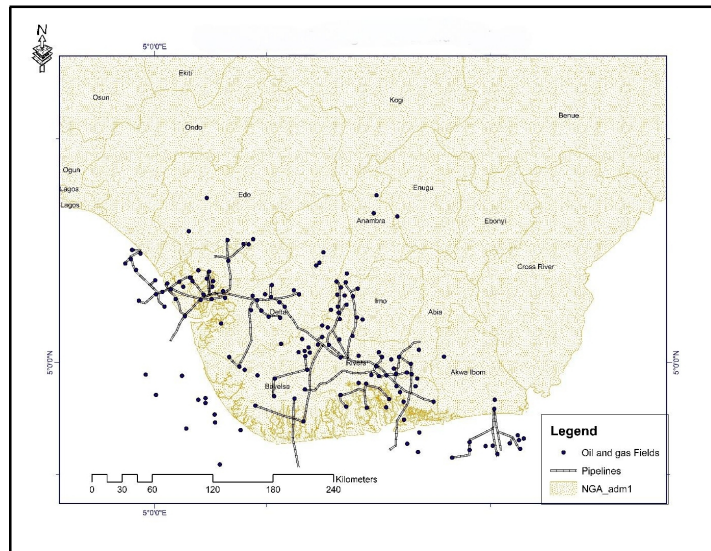


Figure 4. Map of Georeferenced oil fields and Pipelines in Nigeria.

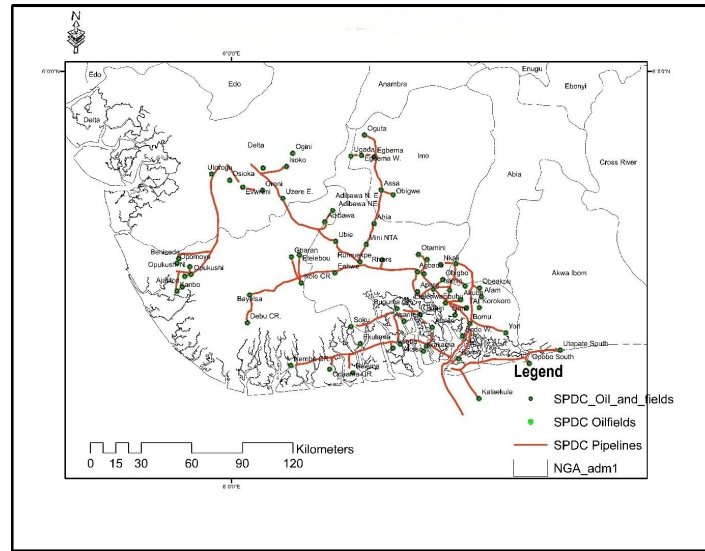


Figure 5. Map of Nigeria Showing Georeferenced oil fields and Pipelines in Nigeria.

Following the identification and cleaning of the infrastructure location, a series of methane processing and emission quantification procedures were carried out to estimate infrastructure-associated methane emissions. These procedures are outlined below:

I. TROPOMI 5P Sentinel Methane Processing:

Annual methane composite data were obtained from Sentinel-5P TROPOMI data, from 2019 to 2024. The variable of analysis is the column-averaged dry-air mixing ratio of methane (XCH_4), and represented by the product variable $CH_4_column_volume_mixing_ratio_dry_air$, and expressed in parts per billion (ppb). This makes XCH_4 a strong proxy for atmospheric methane concentration, and well suited for regional emission estimates [30].

II. Infrastructure-Associated Pixel Selection:

To restrict the analysis to methane signals plausibly associated with oil and gas facilities, a spatial association procedure was applied. For each TROPOMI pixel within the study area ($4.0^\circ N-8.0^\circ N$, $2.5^\circ E-10.0^\circ E$), the distance to the nearest of the 161 digitized infrastructure locations was calculated using the nearest neighbour spatial search [65]. Pixels located within 5 km of any of the infrastructure locations were retained as infrastructure-associated, and all other pixels were excluded from this analysis. The 5 km distance was adopted in order to maintain consistency with the threshold adopted during the infrastructure data cleaning, and to account for the spatial resolution of TROPOMI observations. This step is important because without it, methane enhancement and emission would be derived from the entire regional methane data field, which includes sources unrelated to oil and gas infrastructures.

III. Background Determination:

The background methane concentration was assumed as the mean of the lowest 10th percentile of XCH_4 values among the infrastructure-associated pixels. This background was calculated from the infrastructure-associated pixel population rather than the full regional TROPOMI raster because the study is concerned with infrastructure-associated methane concentration. The percentile-based approach is established in an atmospheric-based methane research [68]. The background concentration was calculated for each of the years (2019 to 2024), hence reflecting the year-to-year variation in atmospheric methane levels. The estimated annual background XCH_4 values were 1,852.57 ppb in 2019, 1,859.20 ppb in 2020, 1,881.76 ppb in 2021, 1,888.01 ppb in 2022, 1,910.48 ppb in 2023, and 1,917.66 ppb in 2024. This study acknowledges that in regions that are heavily industrialised, the 10th percentile of local observations may contain residual anthropogenic emissions which means that the calculated enhancements may represent minimum rather than maximum values [68].

IV. Methane Enhancement and Footprint Delineation:

The methane enhancements for each infrastructure-associated pixel were computed using Equation (3) [69]:

$$(\Delta XCH_4) = XCH_{4_{obs}} - XCH_{4_{bg}} \quad (3)$$

Where:

ΔXCH_4 = Methane enhancement (ppb).

$XCH_{4_{obs}}$ = the observed methane mixing ratio at a given pixel.

$XCH_{4_{bg}}$ = the background concentration for each year.

The methane enhancement footprint was defined as the set of infrastructure-associated pixels satisfying Equation (4):

$$\Delta XCH_4 > T \quad (4)$$

Where T = the selected enhancement threshold (ppb).

The total number of pixels contained within the enhancement footprint was calculated using Equation (5):

$$N = \sum_{i=1}^n (I_i) \quad (5)$$

Where:

$$I_i = \begin{cases} 1, & \Delta XCH_{4,i} > T \\ 0, & \Delta XCH_{4,i} \leq T \end{cases}$$

N = the total number of pixels retained in the footprint for a given year and threshold.

I_i = indicator function.

n = total number of pixels in the study domain.

Enhancement thresholds of 0, 10, 20, 30, and 40 ppb were evaluated through sensitivity analysis in order to assess the influence of the footprint delineation on methane emission estimates [69]. Thresholds below 20 ppb retained a greater number of enhancement pixels and consequently produced larger methane footprints. However, thresholds above 20 ppb restricted the footprints to pixels exhibiting stronger methane enhancements. A threshold of 20 ppb reduced the footprint size while retaining most of the methane enhancement signal, thereby maintaining a spatially representative enhancement footprint. 20 ppb was therefore selected as the primary threshold.

V. Footprint Area:

The total methane enhancement footprint area was estimated using Equation (6) [70]:

$$A = N \times A_p \quad (6)$$

Where:

A = total footprint area (km²).

N = Number of pixels retained within the footprint.

A_p = Area of a single TROPOMI Pixel (km²).

The area of an individual TROPOMI pixel (A_p) was calculated using Equation (7):

$$A_p = L_p \times W_p \quad (7)$$

L_p = Pixel length (km).

W_p = Pixel width (km).

TROPOMI observes XCH_4 with a pixel size of approximately 7 km × 5.5 km [70].

VI. Characteristic Transport Length:

According to the Standard Cross-Sectional Flux (CSF) and the Integrated Mass Enhancement (IME) methods, the characteristic transport length is defined as the observed length of a single, discrete, instantaneous plume detected in a satellite image [70]. However, the annual TROPOMI composites used in this study do not exhibit a single, well-defined plume axis. Instead, it reflects the cumulative effect of multiple distributed infrastructure sources over an entire year. Hence, a full plume length cannot be objectively defined. The characteristic

transport length was therefore approximated as the square root of the methane enhancement footprint area using Equation (8):

$$L = \sqrt{A} \quad (8)$$

Where:

L = Characteristic transport length (km).

A = methane enhancement footprint area (km²).

Although the characteristic transport length is first estimated in kilometres from the footprint area, it was converted to metres before applying Equation (16) so that U/L has units of s⁻¹ and Q is expressed in kg s⁻¹.

VII. ERA5 Meteorological Processing:

Meteorological parameters were derived from the ECMWF ERA5 reanalysis dataset via the Copernicus Climate Data Store. The monthly averaged reanalysis data on single levels were downloaded from January 2019 to December 2024, covering the 10m u-component of wind (U_{10}), the 10m v-component of wind (V_{10}), the surface pressure (sp), over the domain 4.0° N–8.0° N, 2.5° E–10.0° E, encompassing the major oil and gas producing states included in this study. For each grid cell and time step, wind speed was calculated using Equation (9) [70]:

$$U = \sqrt{U_{10}^2 + V_{10}^2} \quad (9)$$

Where:

U = wind speed (m/s);

U_{10} = the east-west wind component at 10 m above ground level (m/s);

V_{10} = the north-south wind component at 10 m above ground level (m/s).

Spatial averaging was performed across all ERA5 grid cells within the study domain, and the monthly averages were aggregated to annual means. The resulting annual means are shown in **Table 2**.

Table 2. Results Obtained from ERA5.

Year	Mean Wind Speed (m s ⁻¹)	Mean Surface Pressure (hPa)	Mean Temperature (°C)
2019	2.09	996.02	26.7
2020	2.24	996.07	26.90
2021	2.05	995.66	27.02
2022	2.07	995.7	26.72
2023	2.05	995.95	27.17
2024	2.17	996.1	27.52
Average	2.11	995.92	27.02

To assess the sensitivity of the emission estimate to wind speed, a supplementary sensitivity analysis was conducted using three wind speed scenarios as shown in **Table 3** [70]. The scenarios are a central estimate based on the ERA5 derived wind speed ($U_{10} = 2.11$ m/s), and two high wind estimates obtained by extrapolating the ERA5 wind speed to U_{50} and U_{100} above ground level using the power-law wind profile [71] as shown in Equation (10). These scenarios better represent methane transport conditions throughout the atmospheric boundary layer.

Table 3. Wind Speed Scenarios.

Scenario	Windspeed (m/s)	Purpose
U_{10}	2.11	Lower bound
U_{50}	2.48	Primary estimate
U_{100}	2.66	Upper bound

$$U_z = U_{10} \left(\frac{z}{10} \right)^\alpha \quad (10)$$

Where

$$\alpha = 0.10.$$

$$U_{10} = 2.11 \text{ m/s.}$$

For U_{50} :

$$U_{50} = 2.11 \left(\frac{50}{10} \right)^{0.10}$$

$$U_{50} = 2.48 \text{ m/s}$$

For U_{100} :

$$U_{100} = 2.11 \left(\frac{100}{10} \right)^{0.10}$$

$$U_{100} = 2.66 \text{ m/s}$$

U_{50} was adopted as the primary wind speed used for emission estimation because it better reflects methane transport through the full depth of the atmospheric boundary layer which is consistent with TROPOMI-based methane studies that use effective wind speed above the surface layer [70]. U_{10} and U_{100} were adopted as the lower and upper sensitivity limit respectively.

VIII. Derivation of the Column-Mass Conversion Factor:

In order to convert methane mixing-ratio enhancements (ppb) into a column mass enhancement (kg/m^2), a Conversion Factor (CF) was derived using the ERA5-derived mean surface pressure for the study domain [69]. Firstly, the mass of dry air was calculated using Equation (11).

$$M_{air} = \frac{P_s}{g} \quad (11)$$

Where:

M_{air} = dry-air column mass (kg/m^2).

P_s = mean surface pressure (Pa).

g = gravitational acceleration (9.81 m/s^2).

$$M_{air} = \frac{99,592}{9.81}$$

$$M_{air} = 10,152 \text{ kg/m}^2$$

The resulting dry air column mass was converted to moles of dry air using the molar mass of air as shown in Equation (12).

$$N_{air} = \frac{M_{air}}{MW_{air}} \quad (12)$$

N_{air} = dry-air mole abundance (mol m^{-2}).

$M_{air} = 10,152 \text{ kg/m}^2$.

$MW_{air} = 0.02896 \text{ kg/mol}$.

$$N_{air} = \frac{10,152}{0.02896}$$

$$N_{air} = 350,552.48 \text{ mol/m}^2$$

1 ppb was converted to methane moles using Equation (13)

$$1 \text{ ppb} = 10^{-9}$$

$$N_{CH_4} = N_{air} \times 10^{-9} \quad (13)$$

N_{CH_4} = methane mole abundance per unit area ($\text{mol m}^{-2} \text{ ppb}^{-1}$).

$$N_{CH_4} = 350,552.48 \text{ mol/m}^2 \times 10^{-9}$$

$$N_{CH_4} = 3.51 \times 10^{-4} \text{ mol/m}^2 \text{ per ppb}$$

The methane moles are then converted to methane mass using Equation (14).

$$CF = N_{CH_4} \times MW_{CH_4} \quad (14)$$

$$MW_{CH_4} = 0.01604 \text{ kg/mol.}$$

$$CF = 3.51 \times 10^{-4} \times 0.01604$$

$$CF = 0.0000056229 \text{ kg/m}^2/\text{ppb}$$

$$CF = 5.62 \times 10^{-6} \text{ kg/m}^2/\text{ppb}$$

This means that $1 \text{ ppb} = 5.62 \times 10^{-6} \text{ kg/m}^2$.

IX. Integrated Methane Enhancement (IME):

The total excess methane mass contained within the footprint was estimated using Equation (15) [62]:

$$IME = \sum_{i=1}^N (\Delta XCH_{4,i} \times CF \times A_i) \quad (15)$$

Where:

IME = Integrated Methane Enhancement.

$\Delta XCH_{4,i}$ = methane enhancement in pixel i (ppb).

CF = methane column-mass conversion factor ($\text{kg/m}^2/\text{ppb}$).

A_i = area of pixel i (m^2).

X. Methane Emission Rate:

Methane emissions were subsequently estimated using the Integrated Methane Enhancement framework established by Frankenberg et al. [62] and applied in subsequent TROPOMI based studies. The emission rate is calculated using Equation (16):

$$Q = \frac{U}{L} \times IME \quad (16)$$

Where:

Q = methane emission rate (kg/s).

U = Effective wind speed (m/s).

L = characteristic transport length converted to meters (m).

IME = Integrated methane enhancement.

Since emission rate is directly proportional to wind speed, additional calculations were performed using alternative wind speed scenarios to assess the sensitivity of the emission rate to atmospheric transport assumptions.

XI. Annual Methane Emissions:

Annual methane emissions were calculated using Equation (17):

$$E_{CH_4} = Q \times t \quad (17)$$

Where:

E_{CH_4} = Annual methane emissions (kg/yr).

Q = methane emissions rate (kg/s).

t = number of seconds per year = 31,536,000 s.

XII. Carbon Dioxide Equivalent:

Methane emissions is converted to its carbon dioxide equivalent using the IPCC AR5 global warming potential as shown in Equation (18) [60]:

$$CO_{2e} = E_{CH_4} \times GWP_{100} \quad (18)$$

Where:

CO_{2e} = Carbon dioxide equivalent emissions ($\text{kg CO}_2\text{e/yr}$).

E_{CH_4} = annual methane emissions ($\text{kg CH}_4/\text{yr}$).

$GWP_{100} = 28$.

C. Potential Energy Recoverable:

To estimate the energy recoverable from the quantified methane emissions obtained using Tier 1 and Tier 3 methodology, Equation (19) was applied.

$$Energy\ Recoverable = CH_4 Mass \times LHV\ of\ CH_4 \quad (19)$$

Where:

$CH_4 Mass$ = amount of methane emission quantified.

$LHV\ of\ CH_4$ = The Lower Heating Value (LHV) of methane, and refers to the amount of usable energy released per unit mass in Megajoules = 50 MJ/kg.

An LHV of 50 MJ/kg was used for this study because it aligns with standard energy conversion values identified in Literature and in the IPCC Guidelines [60].

3.3.2. Objective 2: Techno-Economic Analysis and Environmental Viability

Techno-economic analysis was used to evaluate the technical and economic performance of methane recovery technologies by integrating engineering data, operational data, and cost benefit analysis. The environmental viability analysis was conducted to evaluate the environmental benefits associated with the recovery of CH_4 emission reduction for clean cooking.

A. Techno-economic Analysis

Objective 2 was achieved by applying fundamental principles of engineering economics. The analysis began with a comprehensive cost-benefit of the methane recovery technologies. Although VRUs and PSAs function as distinct recovery technologies as explained in Section 2.1, both technologies were evaluated using the same financial metrics such as Net present Value (NPV), Internal Rate of Return (IRR), Return on Investment (ROI) and Payback period. The results were further computed using the Excel workbook. The Equations used for the engineering economics calculations are shown in Equations (20)–(24).

- i. **Net Present Value (NPV):** NPV determines the present value of future cash flows from methane recovery projects, considering investment costs, operational expenses, and revenue from energy sales. This is shown in Equation (20).

$$NPV = \sum_{t=1}^n \frac{NCF_t}{(1+i)^t} - I_0 \quad (20)$$

Where:

NCF_t = net cash flow in year t (annual revenue minus annual operating cost).

i = interest rate.

n = project life cycle.

t = duration of time.

I_0 = Initial investment cost (Total Fixed Capital and Cash in Hand).

If the NPV is positive, the methane-to-energy project is financially viable. A negative NPV suggests the project may not be profitable unless costs are reduced or revenue increases (e.g., via subsidies, carbon trading).

- ii. **Return on Investment (ROI):** ROI measures the profitability of the methane recovery project by comparing net profit to total investment. This is shown in Equation (21).

$$ROI = \frac{Annual\ Net\ Cash\ flow}{Total\ Investment} \times 100 \quad (21)$$

A higher ROI indicates a more profitable venture or investment. ROI is useful for comparing methane capture investments against other renewable energy projects (solar or wind).

- iii. **Payback Period (PP):** The payback period refers to the amount of time required for a recovered energy project to recover its initial investment costs through the savings or revenues it generates. This is shown in Equation (22).

$$PP = \frac{Total\ Investment}{Annual\ net\ cash\ inflow} \quad (22)$$

A shorter payback period is better as it reduces financial risk.

- iv. **Levelised Cost of Energy (LCOE):** The levelised cost of energy (LCOE) represents the average total cost of constructing and operating an energy-generating asset per unit of power produced over its assumed operational lifetime. This metric is crucial for evaluating the economic feasibility of energy projects, as it provides a comprehensive measure to determine whether proceeding with a particular investment is financially justified. This is shown in Equation (23).

$$LCOE = \frac{Total\ Investment + (Annual\ Operating\ Cost \times n)}{Annual\ Methane\ Produced \times n} \quad (23)$$

Internal Rate of Return (IRR): The internal rate of return represents the discount rate at which the net present value of a project becomes equal to zero. It shows the expected rate of return generated by the methane recovery project over its lifetime. In this study, IRR was used to assess whether the methane recovery technologies could generate returns higher than the minimum acceptable rate of return (MARR). A project is considered financially attractive when the IRR is greater than the MARR. This is shown in Equation (24).

$$0 = \sum_{t=1}^n \frac{NCF_t}{(1 + IRR)^t} - I_0 \quad (24)$$

Where:

NCF_t = net cash flow in year t, calculated as annual revenue minus annual operating cost.

n = project lifecycle.

t = time.

I_0 = initial investment cost, comprising total fixed capital and cash in hand.

Scenario-based analytical framework was adopted using Tier 1 and Tier 3 methane emission estimates. With this approach, inventory-based methane estimation (Tier 1) and satellite-based methane estimations (Tier 3) were carried out. This method ensures that methodological range and uncertainties associated with methane quantification are adequately covered, and also allows for comparative analysis. Sensitivity analysis was also carried out for the price of CNG, to determine the effect of changing market condition on the robustness of this project. This involved analyzing the impact of changing CNG prices on annual cash revenue, net cash flow, NPV, payback period, LCOE, IRR, and ROI. The base CNG price which is \$0.06/kg was adjusted by -40% to +40%. All costs are reported in United States Dollars (\$).

B. Environmental Viability

Using a comparative fuel substitution analysis, the environmental viability of different fuel options was evaluated. The goal was to determine whether methane recovery projects provide net environmental benefits over existing energy options. For this assessment, energy-based emission factors from the IPCC guidelines and the LHV of selected fuels were used. The LHV values of each fuel were converted from megajoules per kilogram (MJ/kg) to gigajoules per kilogram (GJ/kg) to maintain consistency in units across calculations as shown in **Table 4**.

Table 4. Combustion Emissions per kg of Fuel Used.

Fuel Type	LHV (GJ/kg)	Emission Factor (kg CO ₂ /GJ)	Emissions per kg Fuel (kg CO ₂)
LPG	0.0461	63.1	2.91
CNG (CH ₄)	0.05	50	2.5
Firewood	0.0155	112	1.74

The emission factor of LPG is 63.1 kg CO₂ per GJ, with an LHV of 46.1 MJ/kg (0.0461 GJ/kg) [56]. For recovered methane (CNG), the emission factor is 50 kg CO₂ per GJ, and its LHV is 50 MJ/kg (0.0500 GJ/kg) [56]. Firewood has an emission factor of 112 kg CO₂ per GJ with an LHV of 15.5 MJ/kg (0.0155 GJ/kg) [60]. The higher emission factor for firewood indicates its high carbon intensity, potential environmental burden, and non-renewable nature.

To estimate the emissions per kilogram of each fuel, the respective LHV values were multiplied by their corresponding emission factors. Furthermore, the total emissions required to meet a standard cooking energy demand

of 100 GJ were calculated by multiplying the emission factor of each fuel by this energy requirement. This methodology provided a comparative evaluation of the greenhouse gas emissions associated with each fuel, and generated insights into their environmental impacts.

4. Results and Discussion

This section presents the results of methane emissions quantification, estimated recoverable energy, techno-economic analysis of methane recovery technologies, and the environmental viability assessment.

4.1. Quantifying Methane Emissions from the Nigerian Oil and Gas Sector

4.1.1. IPCC Tier 1 Approach

Tables 5 and 6 present the estimated fugitive CH₄ emissions associated with oil and natural gas production in Nigeria between the years 2001 and 2024. Under the Tier 1 inventory approach, methane emissions closely followed annual production volumes because the estimates were derived from production activity data and default emission factors. Consequently, temporal variations in production were directly reflected in the estimated methane emissions.

Table 5. Oil Production in Nigeria from 2001 to 2024.

Year	Oil Production Bbls	Oil Production (10 ³ m ³)	Emission t CH ₄	Emission Gg CH ₄
2001	865,173,584.00	137,562.60	471,839.72	471.84
2002	740,687,180.00	117,769.26	403,948.57	403.95
2003	844,150,929.00	134,220.00	460,374.59	460.37
2004	910,156,489.00	144,714.88	496,372.04	496.37
2005	918,966,506.00	146,115.67	501,176.76	501.18
2006	869,196,506.00	138,202.24	474,033.70	474.03
2007	803,000,708.00	127,677.11	437,932.50	437.93
2008	768,745,932.00	122,230.60	419,250.97	419.25
2009	780,347,940.00	124,075.32	425,578.36	425.58
2010	896,043,406.00	142,470.90	488,675.19	488.68
2011	921,270,000.00	146,481.93	502,433.02	502.43
2012	910,770,000.00	144,812.43	496,706.63	496.71
2013	925,500,000.00	147,154.50	504,739.94	504.74
2014	851,630,000.00	135,409.17	464,453.45	464.45
2015	808,680,000.00	128,580.12	441,029.81	441.03
2016	867,030,000.00	137,857.77	472,852.15	472.85
2017	801,430,000.00	127,427.37	437,075.88	437.08
2018	773,825,133.00	123,038.20	422,021.01	422.02
2019	754,620,000.00	119,984.58	411,547.11	411.55
2020	670,854,624.37	106,665.89	365,863.99	365.86
2021	591,199,314.39	94,000.69	322,422.37	322.42
2022	502,990,303.72	79,975.46	274,315.82	274.32
2023	446,432,843.17	70,982.82	243,471.08	243.47
2024	515,840,690.02	82,018.67	281,324.04	281.32
Total	18,738,542,089	2,979,428.18	10,219,438.7	10,219.43

Table 6. Gas Production in Nigeria from 2001 to 2024.

Year	Gas Production MMSCF	Gas Production (10 ⁶ m ³)	EMISSION CH ₄ (Gg)
2001	1,943,595.9730	55,036.5156	269.6789
2002	1,751,134.4600	49,586.6118	242.9744
2003	1,903,328.4210	53,896.2654	264.0917
2004	2,110,178.0400	59,753.5950	292.7926
2005	2,135,338.7400	60,466.0668	296.2837
2006	2,289,891.5900	64,842.5167	317.7283
2007	2,606,865.3200	73,818.2142	361.7092
2008	2,580,396.6100	73,068.7037	358.0366
2009	2,228,116.2400	63,093.2334	309.1568
2010	2,819,681.8500	79,844.5080	391.2381
2011	2,966,653.1900	84,006.2734	411.6307
2012	2,996,036.0700	84,838.3040	415.7077
2013	2,811,981.3800	79,626.4549	390.1696
2014	3,048,546.4900	86,325.2337	422.9936
2015	3,003,179.0000	85,040.5693	416.6988
2016	2,711,803.0400	76,789.7199	376.2696
2017	2,937,937.7500	83,193.1426	407.6464
2018	2,909,143.5600	82,377.7818	403.6511

Table 6. Cont.

Year	Gas Production MMSCF	Gas Production (10 ⁶ m ³)	EMISSION CH ₄ (Gg)
2019	1,689,031.4700	47,828.0508	234.3574
2020	1,763,863.3200	49,947.0531	244.7406
2021	2,744,312.7942	77,710.2937	380.7804
2022	2,521,242.0000	71,393.6315	349.8288
2023	2,491,481.0000	70,550.8938	345.6994
2024	2,508,275.6400	71,026.4651	348.0297
Total	59,472,013.9482	1,684,060.0982	8,251.8945

Between 2001 and 2024, cumulative estimated methane emissions from oil production were 10,219.43 Gg CH₄, with an annual average of 425.81 Gg CH₄/year.

Methane emissions remained relatively high during periods of sustained crude oil production but declined noticeably from 2021 onwards, reflecting the reduction in national oil output. Since the Tier 1 methodology assumes fixed emission factors, the observed decline primarily reflects reduced production activity rather than improvements in operational methane management.

Table 6 also showed a strong relationship between gas production volumes and estimated methane emissions. Cumulative estimated methane emissions from gas production were 8,251.90 Gg CH₄, with an annual average of 343.83 Gg CH₄/year. Methane emissions increased progressively during the early 2000s, reaching their highest levels around 2011–2015 before declining in 2019–2020 in response to reduced gas production. The subsequent recovery after 2020 reflects renewed production growth rather than changes in emission intensity.

Figures 6 and 7 further illustrate the temporal evolution of methane emissions from the oil and gas subsectors. Although both subsectors generally followed production trends, the oil subsector consistently contributed a larger share of estimated methane emissions than the gas subsector throughout the study period. Average annual methane emissions were estimated at 425.81 Gg CH₄ for oil production compared with 343.83 Gg CH₄ for gas production. This difference reflects the greater contribution of associated gas operations within Nigeria's oil production system, where methane losses may occur through venting, fugitive releases and incomplete gas utilisation. In contrast, methane emissions associated with gas production primarily originate from non-associated gas operations [72]. The dominance of the oil subsector suggests that methane mitigation strategies targeting oil production infrastructure could yield greater emission reductions and energy recovery opportunities than interventions focusing exclusively on gas production facilities.

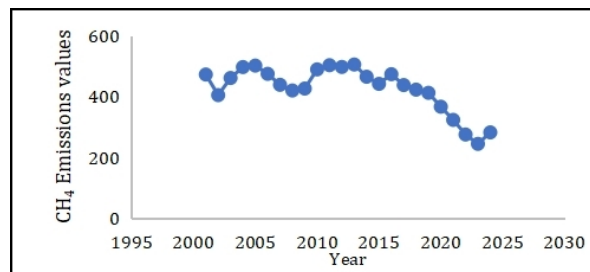


Figure 6. Trends in CH₄ Emissions within the Oil Subsector from 2001 to 2024.

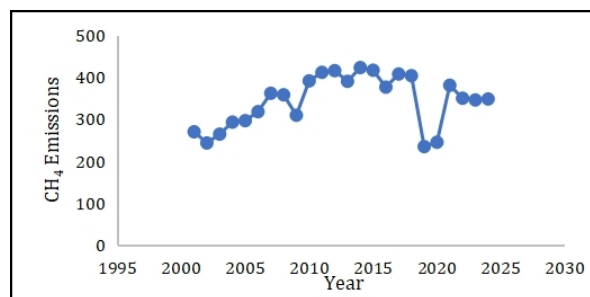


Figure 7. Chart Showing Trends in CH₄ Emissions within the Gas Subsector from 2001 to 2024.

The estimated methane emissions were subsequently converted to recoverable energy potential (**Table 7** and **Figure 8**). Consistent with the emission trends, recoverable energy closely mirrored changes in production activity, increasing from 37,076 TJ in 2001 to approximately 39,873 TJ in 2005 and reaching peak values of 45,703 TJ and 45,621 TJ in 2011 and 2012, respectively. The direct relationship between methane emissions and recoverable energy demonstrates that fugitive methane represents not only an environmental liability but also a potentially valuable indigenous energy resource. Recovering even a proportion of these emissions could contribute meaningfully to Nigeria's domestic energy supply while simultaneously reducing greenhouse gas emissions. A sustained decline in recoverable energy potential was observed after 2015, decreasing from 42,886 TJ in 2015 to 30,530 TJ in 2020, representing a reduction of approximately 29%. Recoverable energy remained below 35,200 TJ year⁻¹ throughout 2021–2024, reaching a minimum of 29,458 TJ in 2023.

Table 7. Annual Fugitive Methane Emissions from Oil and Gas Operations and Recoverable Energy Potential.

Year	Emissions from Oil Gg CH ₄	Emissions from Gas Gg CH ₄	Total Emissions Gg CH ₄	Energy Recoverable TJ
2001	471.84	269.6789	741.5189	37,075.94
2002	403.95	242.9744	646.9244	32,346.22
2003	460.37	264.0917	724.4617	36,223.09
2004	496.37	292.7926	789.1626	39,458.13
2005	501.18	296.2837	797.4637	39,873.19
2006	474.03	317.7283	791.7583	39,587.92
2007	437.93	361.7092	799.6392	39,981.96
2008	419.25	358.0366	777.2866	38,864.33
2009	425.58	309.1568	734.7368	36,736.84
2010	488.68	391.2381	879.9181	43,995.91
2011	502.43	411.6307	914.0607	45,703.04
2012	496.71	415.7077	912.4177	45,620.89
2013	504.74	390.1696	894.9096	44,745.48
2014	464.45	422.9936	887.4436	44,372.18
2015	441.03	416.6988	857.7288	42,886.44
2016	472.85	376.2696	849.1196	42,455.98
2017	437.08	407.6464	844.7264	42,236.32
2018	422.02	403.6511	825.6711	41,283.56
2019	411.55	234.3574	645.9074	32,295.37
2020	365.86	244.7406	610.6006	30,530.03
2021	322.42	380.7804	703.2004	35,160.02
2022	274.32	349.8288	624.1488	31,207.44
2023	243.47	345.6994	589.1694	29,458.47
2024	281.32	348.0297	629.3497	31,467.49
Total	10,219.43	8,251.8941	18,471.3241	923,566.205

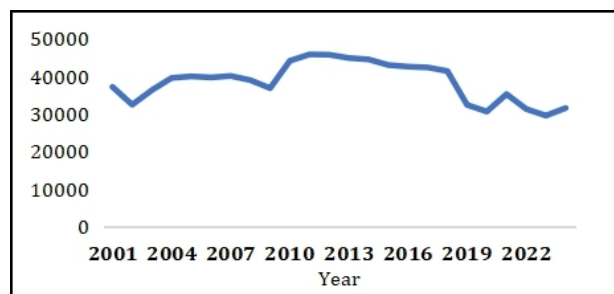


Figure 8. Annual Trend of Energy Recoverable from Fugitive Methane Emissions.

Overall, the Tier 1 assessment provides an important baseline estimate of fugitive methane emissions from Nigeria's upstream oil and gas sector. However, because it relies on generalized emission factors and reported production data, the methodology is inherently constrained in its ability to capture facility-level variability, abnormal emission events, or temporal fluctuations in operational performance. These limitations provide the rationale for applying the complementary Tier 3 satellite-based methodology, which offers an independent observational perspective on methane emissions and enables a more comprehensive assessment of Nigeria's methane recovery potential.

4.1.2. IPCC Tier 3 Approach

Figures 9–14 present the annual spatial distribution of column-averaged atmospheric methane (XCH_4) across Nigeria's upstream oil and gas producing regions between 2019 and 2024 derived from TROPOMI Sentinel-5P observations. Unlike the IPCC Tier 1 methodology, which estimates methane emissions using production activity data and default emission factors, the Tier 3 approach utilises satellite-derived XCH_4 observations integrated with infrastructure mapping, meteorological data and the Integrated Mass Enhancement (IME) framework to estimate infrastructure-associated methane emissions.

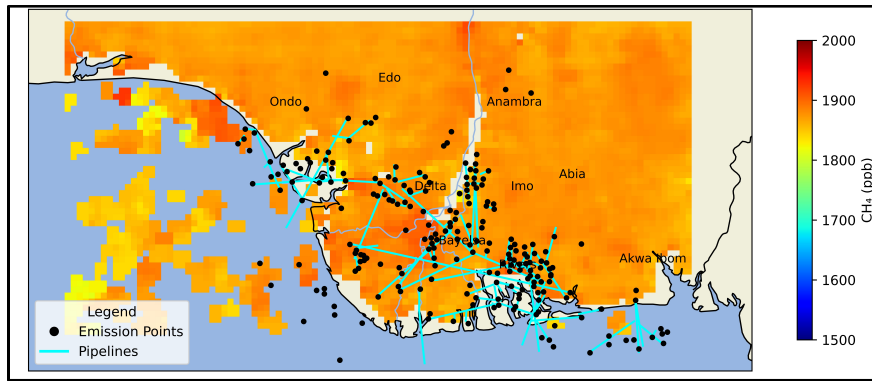


Figure 9. Satellite Image Showing Methane (CH_4) Concentration across Nigeria's Upstream Oil and Gas Emission Zones (2019).

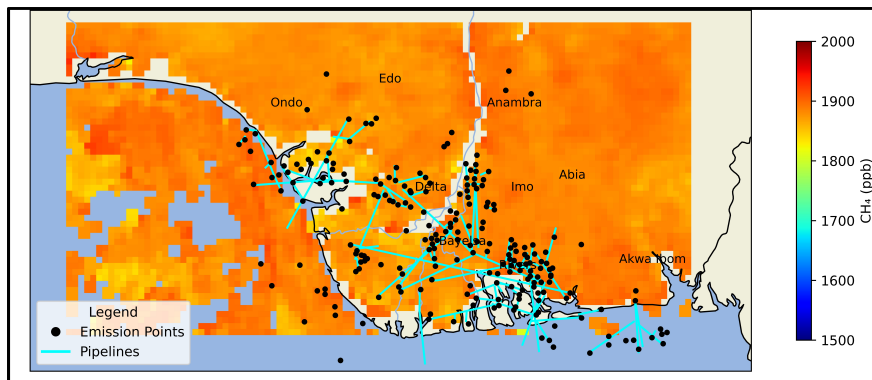


Figure 10. Satellite Image Showing Methane (CH_4) Concentration across Nigeria's Upstream Oil and Gas Emission Zones (2020).

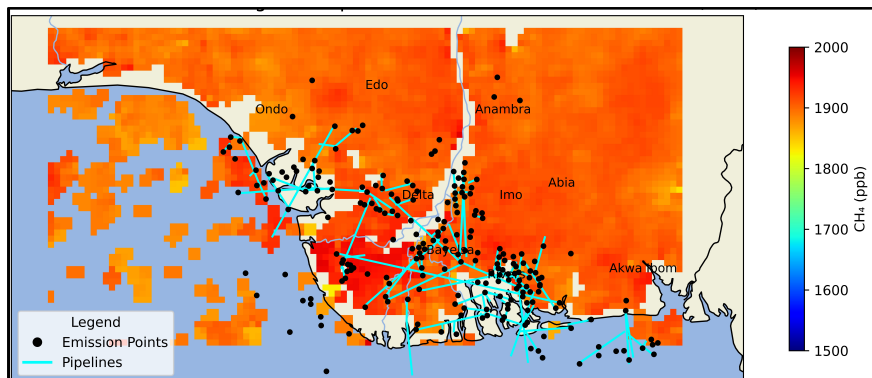


Figure 11. Satellite Image Showing Methane (CH_4) Concentration across Nigeria's Upstream Oil and Gas Emission Zones (2021).

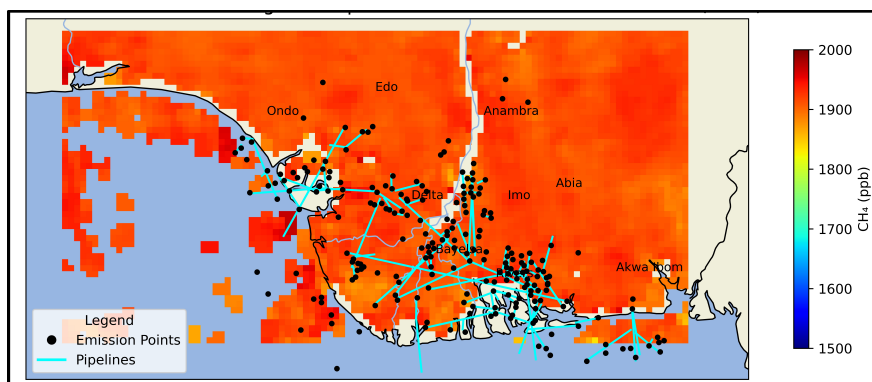


Figure 12. Satellite Image Showing Methane (CH_4) Concentration across Nigeria's Upstream Oil and Gas Emission Zones (2022).

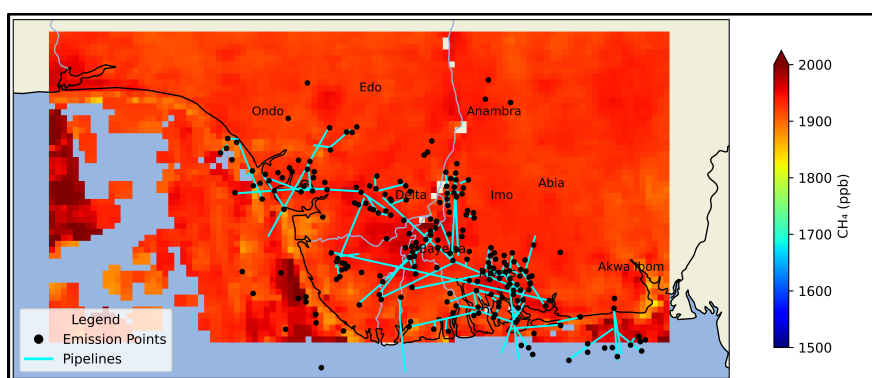


Figure 13. Satellite Image Showing Methane (CH_4) Concentration across Nigeria's Upstream Oil and Gas Emission Zones (2023).

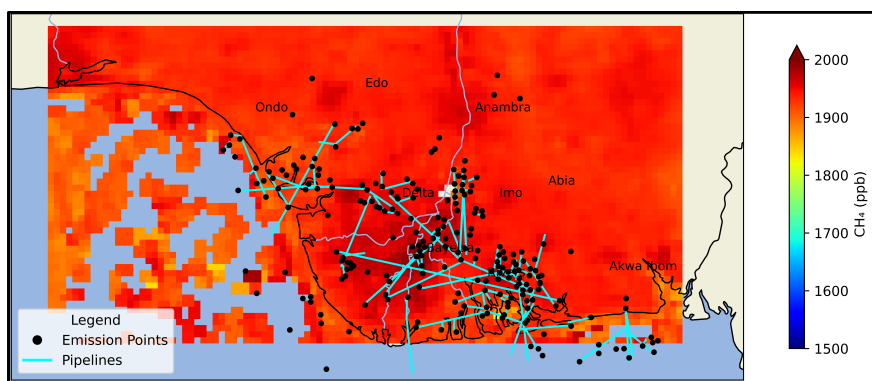


Figure 14. Satellite Image Showing Methane (CH_4) Concentration across Nigeria's Upstream Oil and Gas Emission Zones (2024).

Figure 9 illustrates the spatial distribution of XCH_4 across the study area in 2019. The calculated background XCH_4 concentration derived from the infrastructure-associated pixel population was 1,852.57 ppb, while relatively elevated XCH_4 values were observed over major upstream oil and gas producing areas, particularly Delta, Bayelsa and Rivers States. These enhanced XCH_4 concentrations spatially coincide with regions containing dense oil production facilities, gas processing infrastructure and pipeline networks. Although XCH_4 observations alone cannot uniquely identify individual emission sources, the close spatial correspondence between elevated XCH_4 and

upstream infrastructure suggests that oil and gas activities contribute substantially to the observed atmospheric methane enhancement.

Figure 10 depicts a broader spatial distribution of XCH_4 concentration intensity, especially in the offshore regions and the South-Southern states such as Akwa Ibom and Cross River. Compared with 2019, elevated XCH_4 concentrations appear more spatially extensive in 2020. This spatial pattern is consistent with the cumulative influence of multiple upstream production, processing and transportation activities across the Niger Delta petroleum province.

Figure 11 demonstrates a further expansion of elevated XCH_4 during 2021, extending inland towards Imo and Abia States. The progression from relatively localised XCH_4 enhancement in 2019 to a broader regional atmospheric signal by 2021 suggests increasing spatial continuity of methane enhancement across the producing region. Such observations demonstrate one of the principal strengths of satellite remote sensing, namely its ability to capture regional atmospheric methane behaviour that cannot readily be resolved using inventory-based estimation methods alone.

The spatial evolution continued during 2022 (**Figure 12**), with elevated XCH_4 extending westwards into Edo and Ondo States. Relatively pronounced enhancement patterns were also observed along major pipeline corridors. While the spatial coincidence between enhanced XCH_4 and transportation infrastructure may indicate methane releases associated with gas transmission systems, satellite observations alone cannot distinguish whether these enhancements originate from operational venting, fugitive equipment leaks, maintenance activities, ageing infrastructure or third-party interference.

The highest regional XCH_4 enhancement occurred during 2023 (**Figure 13**), when elevated atmospheric methane became widespread across almost all producing states, particularly Rivers and Bayelsa States. Compared with previous years, the XCH_4 field appeared considerably more homogeneous, indicating persistent atmospheric methane enhancement over a large proportion of the upstream production region rather than isolated localised anomalies. Although the present analysis does not permit direct attribution of these observations to specific operational practices, the persistence of elevated XCH_4 suggests sustained methane release across multiple infrastructure systems and highlights the importance of continuous atmospheric monitoring within Nigeria's upstream oil and gas sector.

Figure 14 indicates that elevated XCH_4 remained widespread during 2024, although subtle spatial redistribution occurred across parts of Delta and Akwa Ibom States. While XCH_4 decreased in certain areas, new enhancement zones emerged elsewhere within the producing region. These spatial shifts may reflect changes in production activity, infrastructure utilisation, maintenance schedules or operational configurations. Nevertheless, the continued presence of elevated XCH_4 throughout the study area demonstrates that atmospheric methane enhancement remains persistent across Nigeria's upstream petroleum basin.

Overall, the annual XCH_4 maps reveal a progressive increase in the spatial extent of atmospheric methane enhancement between 2019 and 2024. Whereas enhanced XCH_4 was relatively localised during the early years of the analysis, later observations show broader regional enhancement extending across much of the Niger Delta petroleum province. The consistency of these spatial patterns with independent international atmospheric monitoring systems [33] provides additional confidence in the satellite observations. More importantly, the results demonstrate the value of satellite-derived XCH_4 measurements for identifying methane hotspots, monitoring regional atmospheric methane behaviour and supporting independent verification of inventory-based methane estimates.

The observed XCH_4 enhancements were subsequently converted into infrastructure-associated methane emission estimates using the Integrated Mass Enhancement (IME) framework under three representative wind-speed scenarios (**Table 8**). As described in the methodology, the U_{50} scenario (2.48 m/s), representing the median wind speed derived from the ERA5-Land dataset, was adopted as the primary emission estimate because it provides the most representative atmospheric transport condition for the study area. The U_{10} and U_{100} scenarios were evaluated as sensitivity bounds to quantify the influence of wind-speed uncertainty on the emission estimates. Based on the selected U_{50} scenario, cumulative methane emissions between 2019 and 2024 were estimated at 7,709.37 Gg CH_4 , corresponding to an annual average of 1,284.90 Gg CH_4 /year. Emissions show a general increasing trend across the study period, with 2020 recording the lowest estimate (1,056.727 Gg) and 2024 recording the highest (1,578.341 Gg). The U_{10} and U_{100} scenarios provide the lower (1,094.752 Gg/yr) and upper (1,378.154 Gg/yr) sensitivity bounds respectively. The relatively narrow range of emission estimates across the three wind scenarios

suggests that the IME framework is reasonably robust to uncertainty in atmospheric transport conditions. Given that wind speed is one of the principal sources of uncertainty in satellite-based emission quantification, the modest variation observed between the sensitivity scenarios provides additional confidence that the estimated methane emissions are not unduly influenced by the selected meteorological parameters.

Table 8. Annual Infrastructure-Associated Methane Emissions (Gg CH₄/yr) at T = 20 ppb.

Year	U ₁₀ (2.11 m/s)	U ₅₀ (2.48 m/s)	U ₁₀₀ (2.66 m/s)
2019	1,017.55	1,194.29	1,280.97
2020	900.349	1,056.73	1,133.43
2021	1,124.88	1,320.26	1,416.08
2022	1,071.15	1,257.20	1,348.45
2023	1,109.80	1,302.56	1,397.10
2024	1,344.77	1,578.34	1,692.90
Total	6,568.51	7,709.37	8,268.92
Average	1,094.75	1,284.90	1,378.15

Table 9 presents the carbon dioxide equivalent (CO₂e) of the estimated methane emissions, converted using the IPCC AR5 100-year global warming potential (GWP₁₀₀ = 28). Under the primary U₅₀ scenario, average annual emissions were estimated at 35.98 Mt CO₂e/yr, corresponding to a cumulative total of 215.86 Mt CO₂e over the six-year study period. The lower bound (U₁₀) gives an average of 30.653 Mt CO₂e/yr, while the upper bound (U₁₀₀) gives 38.588 Mt CO₂e/yr.

Table 9. Annual Infrastructure-Associated CO₂e Emissions (Mt CO₂e/yr) at T = 20 ppb.

Year	U ₁₀ (2.11 m/s)	U ₅₀ (2.48 m/s)	U ₁₀₀ (2.66 m/s)
2019	28.49	33.44	35.87
2020	25.21	29.59	31.74
2021	31.50	36.97	39.65
2022	29.99	35.20	37.77
2023	31.08	36.47	39.12
2024	37.65	44.19	47.40
Total	183.92	215.86	231.53
Average	30.65	35.98	38.59

The threshold sensitivity analysis (**Tables 10 and 11**) assesses the influence of the selected XCH₄ enhancement threshold on the estimated methane emissions. Methane emission estimates remained relatively stable across enhancement thresholds of 0, 10 and 20 ppb, varying by less than approximately 5%, indicating that the adopted 20 ppb threshold does not introduce substantial bias relative to lower thresholds. In contrast, the progressively lower emission estimates obtained at 30 ppb and 40 ppb demonstrate that increasingly stringent thresholds exclude weaker, but spatially coherent, XCH₄ enhancements that may still be associated with infrastructure-related methane emissions. These findings support the selection of the 20 ppb threshold as a reasonable compromise between minimising background atmospheric variability and retaining meaningful methane enhancement signals.

Table 10. Threshold Sensitivity Analysis—CH₄ Emissions (Gg/yr), U₅₀ Scenario Only.

Year	0 ppb	10 ppb	20 ppb	30 ppb	40 ppb
2019	1,203.88	1,218.17	1,194.29	980.33	736.90
2020	1,038.57	1,079.50	1,056.73	771.8	510.80
2021	1,271.70	1,306.36	1,320.26	1,231.50	1,075.07
2022	1,250.96	1,270.35	1,257.2	1,071.61	730.15
2023	1,294.11	1,318.52	1,302.56	1,096.52	899.11
2024	1,535.41	1,567.39	1,578.34	1,478.70	1,299.22
Total	7,594.62	7,760.29	7,709.37	6,630.47	5,251.94
Average	1,265.77	1,293.38	1,284.89	1,105.08	875.32

Table 11. Threshold Sensitivity Analysis—CO₂e Emissions (Mt/yr), U₅₀ Scenario Only.

Year	0 ppb	10 ppb	20 ppb	30 ppb	40 ppb
2019	33.71	34.11	33.44	27.45	20.63
2020	29.08	30.23	29.59	21.61	14.30

Table 11. Cont.

Year	0 ppb	10 ppb	20 ppb	30 ppb	40 ppb
2021	35.61	36.56	36.96	34.48	30.10
2022	35.03	35.57	35.20	30.01	20.44
2023	36.24	36.92	36.47	30.71	25.18
2024	42.99	43.89	44.19	41.40	36.38
Total	212.65	217.29	215.86	185.65	147.03
Average	35.44	36.22	35.98	30.94	24.51

Annual methane emission estimates derived from the IME framework are summarised in **Table 12**. Although moderate interannual variability is evident, methane emissions remained consistently high throughout the observation period, culminating in the highest annual estimate of 1,578.34 Gg CH₄ in 2024. Notably, the Tier 3 estimates are substantially higher than those obtained using the Tier 1 inventory methodology. This difference highlights the complementary value of satellite observations in capturing regional atmospheric methane enhancement that may not be fully represented by production-based inventory methods, thereby providing an independent line of evidence for methane emission assessment.

Table 12. Total and Average Emissions from Tropomi 5P-Sentinel.

Year	(Gg CH ₄ /yr)	(Mt CO ₂ e/yr)
2019	1,194.29	33.44
2020	1,056.73	29.59
2021	1,320.26	36.97
2022	1,257.20	35.20
2023	1,302.56	36.47
2024	1,578.34	44.19
Total	7,709.37	215.86
Average	1,284.90	35.98

Overall, the Tier 3 methodology demonstrates how satellite-derived XCH₄ observations can be integrated with infrastructure mapping and atmospheric transport modelling to provide spatially explicit methane emission estimates for Nigeria's upstream oil and gas sector. Beyond improving methane quantification, the approach strengthens emission verification, enables the identification of priority mitigation areas, and provides an evidence base for investment planning, methane management, and climate policy development.

4.1.3. Potential Energy Recoverable

In line with Objective 1, the average annual methane emissions estimated using the Tier 1 and Tier 3 approaches corresponded to approximately 21.55 Mt CO₂e/yr and 35.98 Mt CO₂e/yr, respectively. Applying the lower heating value of methane to these emission estimates yielded recoverable energy potentials of 38,482 TJ/year for Tier 1 and 64,245 TJ/year for Tier 3. The higher Tier 3 energy estimate reflects the larger methane emission value derived from the satellite-based assessment and reinforces the importance of using complementary inventory-based and observation-based approaches when evaluating methane recovery opportunities.

To contextualise the recoverable energy potential within the household cooking energy sector, Emagbetere et al. [73] reported that the average Nigerian family in Ikeja uses approximately 18.96 GJ (0.01896 TJ) of energy to cook annually. At the National level, the Nigeria Residential Energy Demand-Side Survey (2024) reports that 0.24 billion kilograms of LPG were purchased in the country for cooking [74]. ECOWAS [74] also reports that the monthly expense of households on LPG is 10,239.70 Naira on average. Using the average energy content of 13.6 kWh per kg, this corresponds to a total household cooking energy of about 3.26 billion kWh [74]. Since 1 kWh is equivalent to 0.0036 GJ, the national LPG demand is approximately 11,750 TJ.

Based on this estimate, the potential energy recoverable from methane emissions quantified under Tier 3 (64,245 TJ) is approximately 5.5 times greater than the estimated annual LPG-based cooking energy demand. Similarly, the Tier 1 estimate of 38,482 TJ is approximately 3.3 times the national LPG cooking energy demand. These findings indicate that if methane emissions are effectively captured and converted, they can contribute significantly to Nigeria's clean cooking energy transition, reduce dependence on conventional household fuels and strengthen the energy security value of methane mitigation.

4.2. Techno-Economic Analysis and Environmental Viability

This section evaluates the technical feasibility, economic performance, and environmental implications of the methane recovery technologies.

4.2.1. Techno-Economic Analysis

Techno-economic analysis was carried out on the methane recovery technologies using key engineering economic indicators such as Net Present Value (NPV), Internal Rate of Return (IRR), Payback Period, and Return on Investment (ROI). These indicators were estimated using estimated methane recovery volumes, technology-specific capital and operating costs, methane market price, and project lifetime assumptions. To account for uncertainty in this study, the analysis adopted a scenario-based framework comprising Tier 1 and Tier 3 methane emission estimates as shown in **Tables 13** and **14** respectively.

Table 13. Techno-Economic Cost-Benefit Assessment of VRU and PSA (Tier 1).

Indicators	VRU	PSA
Methane recovered/input methane (kg)	769,638,504	769,638,504
Machine Efficiency (90%; 85%) (kg)	692,674,654	654,192,728
Machine Downtime (5%; 5%) (kg)	34,633,733	32,709,636
Net usable methane (kg)	658,040,921	621,483,092
Selling Price of CNG (\$/kg)	0.06	0.06
Lifetime (years)	15	15
Costs	(\$)	(\$)
Capital Costs		
Equipment Purchase	27,482,333.09	28,995,122.07
Engineering, Procurement and Design	12,909,132.61	11,850,180.32
Installation and Construction	11,724,114.57	10,873,170.77
Instrumentation and Control Systems	6,454,566.31	8,131,240.76
Contingency	7,563,944.88	7,059,681.90
Land	900,000.00	900,000.00
Total Fixed Capital	67,034,091.47	67,809,395.82
Cash in Hand	15,594,306.63	10,230,854.02
Total Investment	82,628,398.10	78,040,249.85
Annual Operating Costs		
Operations and Maintenance Staff	3,791,904.80	1,961,397.62
Maintenance and Spare Parts	2,527,936.54	1,307,598.41
Power/Energy Costs	1,895,952.40	980,698.81
Administration and Insurance	1,263,968.26	653,799.21
Technical Support and Vendor Contracts	1,011,174.62	523,039.36
Environmental Monitoring and Compliance	631,984.13	509,355.20
Security and Site Services	884,777.79	700,933.56
Contingency (Operational Buffer)	631,984.13	326,899.60
Transportation and Logistics	2,954,623.96	3,267,132.26
Total Operating Costs	15,594,306.63	10,230,854.03
Revenue		
Annual Revenue	39,482,455.26	37,288,985.52
Annual Net Cash Flow	23,888,148.62	27,058,131.48
Total Lifetime Cost	316,542,997.55	231,503,060.30

Table 14. Techno-Economic Cost-Benefit Assessment of VRU and PSA (Tier 3).

Indicators	VRUs	PSA
Methane recovered (kg)	1,284,900,000	1,284,900,000
Machine Efficiency (90%; 85%) (kg)	1,156,410,000	1,092,165,000
Machine Downtime (5%; 5%) (kg)	57,820,500	54,608,250
Net Usable Methane	1,098,589,500	1,037,556,750
Selling Price of CNG (\$/kg)	0.06	0.06
Lifetime (years)	15	15
Costs	(\$ Dollars)	(\$ Dollars)
Capital Costs		
Equipment Purchase (\$)	37,875,000	39,956,000
Engineering, Procurement and Design	17,790,000	16,326,000
Installation and Construction (\$)	16,156,000	14,982,000
Instrumentation and Control Systems (\$)	8,894,000	11,205,000
Contingency (\$)	10,423,000	9,728,000
Land (\$)	782,000	782,000
Total Fixed Capital (\$)	91,920,000	92,979,000
Cash in Hand (\$)	23,474,000	15,939,000
Total Investment (\$)	115,394,000	108,918,000
Annual Operating Costs:		
Operations and Maintenance Staff (\$)	5,416,000	2,801,000

Table 14. Cont.

Indicators	VRUs	PSA
Maintenance and Spare Parts (\$)	3,610,000	1,868,000
Power/Energy Costs (\$)	2,708,000	1,401,000
Administration and Insurance (\$)	1,805,000	934,000
Technical Support and Vendor Contracts (\$)	1,444,000	747,000
Environmental Monitoring and Compliance (\$)	902,000	727,000
Security and Site Services (\$)	1,264,000	1,001,000
Contingency (Operational Buffer) (\$)	902,000	467,000
Transportation and Logistics (\$)	5,420,000	5,993,000
Total Operating Costs (\$)	23,474,000	15,939,000
MARR = 27.5%		
Total Lifetime Cost	467,504,000	348,003,000

Tier 1:

The techno-economic analysis of VRUs and PSA recovery systems under Tier 1 is presented in **Table 13**.

The assumed capture efficiency of VRU was 90%, yielding approximately 692.67 million kilograms of methane from the estimated 769.64 million kilograms of methane. After applying a 5% downtime allowance, equivalent to 34.63 million kg, the net usable methane is approximately 658.04 million kg annually. The capital expenditure (CAPEX) and total investment cost were estimated at \$67.03 and \$82.63 million respectively. Annual Operational expenditure was estimated at approximately \$15.59 million. Based on a market value of \$0.06 per kg, the annual revenue was projected at about \$39.48 million. After deducting operating costs, the annual net cash flow was approximately \$23.89 million. A discount rate (MARR) of 27.5% was used for this analysis.

In contrast, the PSA system assumed a lower methane capture efficiency of about 85%, resulting in about 654.19 million kilograms of methane from the estimated 769.64 million kilograms. A downtime factor of 5% was also accounted for, resulting in about 621.48 million kilograms of net usable methane annually. Estimated Capital expenditure were estimated at \$67.81 million, while the total investment cost was about \$78.04 million. The annual operational expenditure is estimated at approximately \$10.23 million. At the selling price of \$0.06 per kilogram, the estimated annual revenue was estimated at \$37.29 million and an annual net cash flow of \$27.06 million.

Under Tier 1 Scenario, both technologies were financially viable. PSA systems however demonstrated stronger economic performance because of its lower operating cost, annual net cash flow, shorter payback period, higher ROI, higher IRR, and higher NPV. PSA had lower annual operating costs of approximately \$10.23 million compared to \$15.59 million for VRU, giving it a higher annual net cash flow of approximately \$27.06 million compared to \$23.89 million for VRU (**Table 15**). The PSA system also recorded a shorter payback period of 2.88 years compared to 3.46 years for VRU, a higher ROI of 34.67% compared to 28.91%, and a higher IRR of 34.25% compared to 28.22%. In terms of discounted financial performance, VRU recorded a positive NPV of approximately \$1.97 million, while PSA recorded a substantially higher NPV of approximately \$17.78 million. This indicates that PSA is more financially resilient under the capacity-adjusted Tier 1 methane recovery scenario.

Table 15. Comparative Financial Performance Indicators for VRU and PSA Projects.

S/N	Financial Indicator	VRU	PSA
1	Levelised Cost of Energy (\$/kg CH ₄ recovered)	0.032	0.025
2	Payback Period (years)	3.46	2.88
3	Return on Investment (%)	28.91	34.67
4	Internal Rate of Return (%)	28.22	34.25
5	Net Present Value (\$)	1,966,702.02	17,780,710.50

Tier 3:

The techno-economic analysis of VRUs and PSA recovery systems under Tier 3 is presented in **Table 14**. For VRUs, the model assumes a methane capture efficiency of 90%, yielding approximately 1.16 billion kilograms of methane from the estimated 1.29 billion kilograms of recoverable methane. After applying a 5% downtime allowance, equivalent to 57.82 million kg to allow for machine repairs and maintenance, the net usable methane became approximately 1.10 billion kg annually. The capital expenditure (CAPEX) requirement is about \$91.92 million, while annual operational expenditure (OPEX) is estimated at \$23.47 million. Based on a methane market value of \$0.06 per kilogram (equivalent to approximately ₦96/kg at an exchange rate of ₦1,600/\$, or about ₦100/kg

when rounded), the annual revenue is projected at approximately \$65.92 million. After accounting for OPEX, the estimated annual net cash flow is around \$42.44 million. With a discount rate of 27.5%, the payback period is approximately 2.72 years compared to the 15 years project lifespan, an ROI of 36.8%, and an NPV of \$34.90 million (Table 16).

Table 16. Comparative Financial Performance Indicators for VRU and PSA Projects.

S/N	Financial Indicators	VRUs	PSA
1	Levelised cost of Energy (\$/kg CH ₄ recovered)	0.03	0.02
2	Payback period (years)	2.72	2.35
3	Return on Investment (ROI) (%)	36.78	42.52
4	Internal Rate of Return (IRR %)	36.43	42.31
5	Net Present Value (\$)	34,903,623	55,095,201

In contrast, PSA, assumes a slightly lower methane capture efficiency of 85%, resulting in approximately 1.09 billion kilograms of methane. After applying a 5% downtime allowance, equivalent to 54.61 million kg, the resulting net usable methane became approximately 1.04 billion kilograms. The CAPEX was estimated at \$92.98 million, but annual OPEX is about \$15.94 million. This configuration yields an annual revenue of roughly \$62.25 million at the selling price of \$0.06 per kilogram. After operational costs, the annual net cash flow is estimated at around \$46.31 million. The PSA system records a payback period of 2.35 years, an ROI of about 42.5%, and an NPV of \$55.10 million.

Price Sensitivity Analysis:

A one-way price sensitivity analysis for the unit price of CNG was performed to assess the financial strength of proposed VRU and PSA methane recovery system under various market conditions in Tier 1 and Tier 3 techno-economic evaluations. The base CNG price of \$0.06/kg was manipulated across nine scenarios ranging from -40% to +40% in steps of 10%, resulting in the price varying from \$0.036/kg to \$0.084/kg (Table 17).

Table 17. Price Sensitivity Analysis.

Change	New Price (\$)
-40%	0.036/kg
-30%	0.042/kg
-20%	0.048/kg
-10%	0.054/kg
Base	0.060/kg
10%	0.066/kg
20%	0.072/kg
30%	0.078/kg
40%	0.084/kg

The net cash flow, net present value (NPV), internal rate of return (IRR), and payback period (PBP) were calculated for each scenario at a minimum acceptable rate of return (MARR) of 27.5% for a project lifetime of 15 years. As shown in Tables 18–21, the findings indicate a clear and consistent positive correlation between CNG price and all the financial performance indicators for both technologies and estimation levels, which corroborates that one of the most influential factors affecting the viability of CNG projects is the price volatility of CNG.

Table 18. Price Sensitivity Analysis for VRU (Tier 1).

Price Change	CNG Price (\$/kg)	Annual Net Cash Flow (\$M)	NPV (\$M)	IRR (%)	Payback Period (Years)
-40%	0.036	8.1	-53.96	5.25	10.21
-30%	0.042	12.04	-39.98	11.86	6.86
-20%	0.048	15.99	-26	17.67	5.17
-10%	0.054	19.94	-12.02	23.06	4.14
Base	0.06	23.89	1.97	28.22	3.46
10%	0.066	27.84	15.95	33.23	2.97
20%	0.072	31.78	29.93	38.17	2.6
30%	0.078	35.73	43.91	43.04	2.31
40%	0.084	39.68	57.89	47.89	2.08

Table 19. Price Sensitivity Analysis for PSA (Tier 1).

Price Change	CNG Price (\$/kg)	Annual Net Cash Flow (\$M)	NPV (\$M)	IRR (%)	Payback Period (Years)
-40%	0.036	12.14	-35.04	13.11	6.43
-30%	0.042	15.87	-21.83	18.8	4.92
-20%	0.048	19.60	-8.63	24.13	3.98
-10%	0.054	23.33	4.58	29.26	3.35
Base	0.06	27.06	17.78	34.25	2.88
10%	0.066	30.79	30.99	39.17	2.53
20%	0.072	34.52	44.19	44.04	2.26
30%	0.078	38.24	57.4	48.88	2.04
40%	0.084	41.97	70.6	53.7	1.86

Table 20. Price Sensitivity Analysis for VRU (Tier 3).

Price Change	CNG Price (\$/kg)	Annual Net Cash Flow (\$M)	NPV (\$M)	IRR (%)	Payback Period (Years)
-40%	0.036	16.08	-58.47	11.03	7.18
-30%	0.042	22.67	-35.12	18.00	5.09
-20%	0.048	29.26	-11.78	24.40	3.94
-10%	0.054	35.85	11.56	30.49	3.22
Base	0.060	42.44	34.90	36.43	2.72
10%	0.066	49.03	58.25	42.28	2.35
20%	0.072	55.62	81.59	48.07	2.07
30%	0.078	62.22	104.93	53.83	1.85
40%	0.084	68.81	128.27	59.57	1.68

Table 21. Price Sensitivity Analysis for PSA (Tier 3).

Price Change	CNG Price (\$/kg)	Annual Net Cash Flow (\$M)	NPV (\$M)	IRR (%)	Payback Period (Years)
-40%	0.036	21.41	-33.09	18.02	5.09
-30%	0.042	27.64	-11.04	24.42	3.94
-20%	0.048	33.86	11.00	30.52	3.22
-10%	0.054	40.09	33.05	36.46	2.72
Base	0.06	46.31	55.10	42.31	2.35
10%	0.066	52.54	77.14	48.10	2.07
20%	0.072	58.77	99.19	53.87	1.85
30%	0.078	64.99	121.23	59.62	1.68
40%	0.084	71.22	143.28	65.35	1.53

In Tier 1 conditions, the VRU system had the lowest financial margin to failure, showing a positive NPV of about \$1.97 million at base price, an IRR of 28.22%, and a payback period of 3.46 years. However, NPV was negative at every price point under \$0.06/kg, suggesting that there was essentially no downside price tolerance for the VRU system (**Table 18**).

Compared with the VRU system, the PSA configuration demonstrated greater resilience to fluctuations in CNG prices under Tier 1 conditions (**Table 19**), achieving a higher base-case NPV of approximately \$17.78 million, an IRR of 34.25%, and a shorter payback period of 2.88 years. Furthermore, the PSA system remained economically viable at a CNG price of \$0.054/kg, maintaining a positive NPV of approximately \$4.58 million, indicating a wider profitability margin and greater tolerance to adverse market conditions than the VRU system.

In contrast, under Tier 3 base case assumptions, both technologies demonstrated much better financial metrics, which may have been driven by the recovery of much higher volumes of methane. At the base price, the VRU system achieved a net cash flow of \$42.44 M, NPV of \$34.90, an IRR of 36.43, and a payback period of 2.72 years (**Table 20**).

The PSA system recorded an annual net cash flow of approximately \$46.31 million, an NPV of \$55.10 million, IRR of 42.31%, and payback period of 2.35 years (**Table 21**). Furthermore, PSA systems maintained a positive NPV down to \$0.048/kg, while the VRU system remained profitable down to about \$0.054/kg.

4.2.2. Environmental Viability

This section assesses the environmental viability of LPG, CNG, and firewood using the comparative fuel substitution analysis (**Table 22**). Based on the direct combustion emissions for 100 GJ cooking energy demand, recovered methane used as CNG produces lower CO₂ emission than LPG and firewood. The comparison indicates an estimated

emission reduction of approximately 21% relative to LPG and 55% relative to firewood. This implies that CNG emits lower direct CO₂ than LPG and firewood. Firewood on the other hand, produces the greatest amount of CO₂ more than twice the amount produced by CNG. Thus, recovered methane has high environmental benefits, particularly when used to replace firewood, which has low energy efficiency and high net emissions as well as poor environmental benefit due to unsustainable harvesting resulting in deforestation. In conclusion, this evaluation shows that recovering methane to make CNG is an environmentally feasible alternative, which provides significant reductions in direct combustion CO₂ emissions gases when compared to the current cooking fuel used in Nigeria, as well as avoiding fugitive methane release and fulfilling energy security objectives.

Table 22. Direct Combustion CO₂ Emissions from CNG, LPG and Firewood, for 100 GJ Energy Demand.

Fuel Type	Energy Demand (GJ)	Emission Factor (kg CO ₂ /GJ)	Total Emissions (kg CO ₂)
LPG	100	63.1	6,310
CNG (methane)	100	50.0	5,000
Firewood	100	112.0	11,200

This is consistent with the lower direct CO₂ emission factor of CNG relative to LPG and firewood [75]. Li et al. [76] reported that the cost of electricity per year is higher than natural gas, and hence cooking with natural gas is better compared to cooking with electricity. This is because natural gas significantly reduces pollution at a low cost, making it an easily adoptable alternative to firewood and coal. Mohammad et al. [77] also emphasised the role of natural gas as an important alternative energy source in sustainable energy transition, particularly because of its cleaner-burning characteristics and potential to support the shift from more carbon-intensive fuels. This benefit is attributed to its cleaner-burning characteristics, lower carbon intensity relative to solid fuels, and potential role as a transition fuel.

4.3. Discussion

4.3.1. Interpretation of Methane Emission Estimates

The Tier 1 average annual emission of 769.64 Gg CH₄/yr and the Tier 3 primary estimate of 1,284.90 Gg CH₄/yr provide two independent perspectives on methane emissions from Nigeria's upstream oil and gas sector. The approximate 67% difference between Tier 3 and Tier 1 is not unexpected and is not necessarily an indication of error in either Tier 1 or Tier 3. Instead, it demonstrates a trend common to the methane monitoring literature where inventory-based methods systematically underestimate emissions from oil and gas infrastructure. This underestimation is largely due to the use of default emission factors which may not fully represent the diversity of site-specific conditions. Factors such as irregular venting events, ageing pipeline infrastructure, and inadequate maintenance regimes found in many upstream sites across Nigeria may be underestimated, leading to lower emission estimates than those derived from direct satellite measurement [60,61]. The Tier 3 method measures atmospheric methane levels directly, rather than from activity data, making it more sensitive to high magnitude, irregular emission events such as wind speed [78].

The Tier 3 estimate of 1.285 Tg CH₄/yr is comparable to the national-scale satellite inversion estimate reported by Shen et al. [35], who estimated methane emissions from Nigeria's oil and gas sector at 1.5 ± 1.2 Tg CH₄/yr. The estimate from this study is reasonably lower than the national midpoint because this study only includes upstream infrastructure rather than the entire oil and gas sector. Despite methodological differences, this consistency between the Tier 3 estimates and the estimates reported by Shen et al. [35] increases confidence in the robustness of the results.

4.3.2. Interannual Variability and the 2020 Anomaly

An interesting outcome from the Tier 3 results is that the estimated emissions reached their lowest level in 2020 (1,056.73 Gg under U50) of the six-year study period. This trend aligns with the documented decline in oil and gas activities in the industry in 2020 as a result of the COVID-19 pandemic and the corresponding oil price crisis that resulted in significant production cuts including in the Nigerian oil and gas industry [79]. This production reduction correlates with the reduction in emissions in 2020 within the two tiers, thereby, providing validation and explanation for the results and supporting the reliability of the methodologies used. The overall increase in Tier

3 emissions from 2021 to 2024, despite fluctuating Tier 1 estimates, is consistent with an also observed trend in the raw TROPOMI composite maps (**Figures 9–14**) that shows the methane concentrations across the study area becoming more saturated from 2021 to 2024.

Importantly, this increase in Tier 3 estimates reflects a rise in background concentration from 1,852.57 ppb in 2019 to 1,917.66 ppb in 2024, consistent with the globally documented rise in atmospheric CH₄ concentration over the past few decades. The increase in the annual background XCH₄ values from 1,852.57 ppb in 2019 to 1,917.66 ppb in 2024 is consistent with the global rise in atmospheric CH₄ concentrations. These year-specific background values, however, were employed for background correction prior to the estimation of methane enhancement. Thus, the observed rise in Tier 3 emission estimates should be understood in the context of background-subtracted enhancement footprint, wind-speed assumptions, and IME-based emission calculation, and not as a result of a change in background methane concentration alone.

4.3.3. Techno-Economic Performance in Context

The superior performance of the PSA system in both tiers and across all financial metrics are consistent with previous techno-economic analyses of gas purification technologies in low- and middle-income country settings [80,81]. The benefits of the PSA system are due to the much lower operating costs of PSA (\$15.94M a year under Tier 3) in comparison with VRUs' electrically driven compression systems. This operational cost benefit becomes more evident in Nigeria, a setting where grid electricity is unreliable and costly, and operational disruptions, including those caused by power failures could have a significant impact on VRU performance in practice [82]. The higher price resilience of PSA systems (NPV remained positive even when CNG prices fall to \$0.048/kg under Tier 3 conditions, compared with Tier 3 at \$0.054/kg for VRU) is particularly relevant because of the volatility in the Nigerian price of CNG and natural gas resulting from regulatory uncertainty, exchange rate uncertainty and constraints in the downstream natural gas supply chain.

The improved financial performance observed in the Tier 3 scenario compared to Tier 1 for both VRU and the PSA system are directly translated to the larger volume of methane recovered under Tier 3 scenario. Greater volumes of CNG recovery directly translates to greater revenue base, lower break-even CNG prices, and better ROI across all measures assuming all factors remain constant. The economic benefits of investment in methane recovery projects exceed those estimated under Tier 1, because Tier 1 estimates and financial models may systematically underestimate the returns of investment in methane recovery in Nigeria.

4.3.4. Environmental Viability in the Nigerian Cooking Energy Context

The 55% and 21% reduction in CO₂ levels from replacing firewood and LPG with recovered methane CNG respectively are significant environmental benefits that extend beyond direct climate benefits of not releasing CH₄ emissions. The CO₂ comparison does not effectively capture co-benefits such as deforestation, gender inequitable exposure to cooking smoke, and indoor air pollution associated with firewood use in Nigeria, yet these remain co-benefits of the transition to clean cooking. Given the magnitude of the recoverable energy (64,245 TJ per annum under Tier 3, which represents about 5.5 times the annual LPG cooking energy demand in Nigeria), even moderate recovery rates from the identified infrastructure zones can make a significant contribution to Nigeria's clean cooking access goals, without the need for additional energy infrastructure beyond the recovery and distribution systems themselves.

4.3.5. Methodological Limitations and Future Research

The study introduces several adaptations to establish Cross-Sectional Flux (CSF) and Integrated Methane Enhancement (IME). Due to the use of annual TROPOMI methane composite comprising fields instead of plume images from individual overpasses, the individual plume shapes and directions cannot be determined. Hence, the characteristic transport length L was defined as the square root of the enhancement footprint area. While this substitution is reasonable, it might introduce geometric bias into the emission estimates. Secondly, the percentile-based background method is well documented in the literature, but might introduce some anthropogenic methane in the background estimate for highly industrialised areas such as the Niger Delta, leading to underestimation of the contributions from infrastructure enhancement.

For future research directions, it is recommended to conduct ground-based flux measurements at the selected

infrastructural sites, utilise high resolution satellite data, and to perform a complete Life Cycle Assessment (LCA) of recovered methane as CNG, to fully account for upstream, midstream and downstream emissions.

5. Conclusions

5.1. Main Conclusion

This study quantified fugitive methane emissions from the upstream oil and gas sector in Nigeria, estimated the energy recovery potential of the emissions from the sector, and evaluated the techno-economic and environmental feasibility of methane recovery technologies based on a two-tier IPCC methodological framework. The Tier 1 approach (inventory-based) and Tier 3 approach (satellite-observation-based) were complementary in giving different perspectives on the magnitude of emissions. Tier 1 produced 769.64 Gg CH₄/yr (21.55 Mt CO₂e) on average over the period 2001–2024, while Tier 3 produced a primary estimate of 1,284.90 Gg CH₄/yr (35.98 Mt CO₂e/yr) for the U₅₀ wind scenario in the 2019–2024 period. The convergence of these two independent methodologies within a factor of 1.7 lends confidence to the overall finding that fugitive methane emissions from Nigeria's upstream sector represent a substantial and persistent atmospheric source.

Under the stated cost, recovery-efficiency and base CNG price assumptions, both recovery technologies showed economic viability. PSA systems, however, exhibited stronger financial performance and appear more favourable for pilot testing and scale-up consideration. The lower operating costs of PSA systems, its price resilience, and superior NPVs make PSA systems appear more favourable for pilot testing, scale-up consideration and future methane recovery investment. The fuel substitution analysis also demonstrated significant direct combustion CO₂ reduction benefits of recovered methane CNG compared to firewood (55%) and LPG (21%), highlighting the climate and energy benefits of methane recovery.

Taken together, the findings provide evidence for the potential technical, economic, and environmental feasibility of recovering methane in the upstream oil and gas industry in Nigeria. The identified energy recovery potential (38,482 TJ for Tier 1 and 64,245 TJ for Tier 3) is a significant domestic energy resource that is being released into the atmosphere but could make a meaningful contribution to Nigeria's transition to clean cooking and international climate targets under the Paris Agreement and the Global Methane Pledge. These findings make a compelling case for the need to emphasize methane recovery as a near-term, high-impact initiative in Nigeria's energy transition and emissions reduction efforts.

5.2. Recommendation

Based on the findings of this study, the following recommendations are proposed.

Establishment of a centralised methane source inventory system: with a mandatory, source-disaggregated national methane inventory in place, all operators will be obligated to report emissions based on sources and clusters. An inventory of this nature will improve accuracy of future methane quantification, support regulatory, and targeted mitigation.

Scaling up satellite-based methane monitoring system: The marked difference between Tier 1 and Tier 3 estimates of emissions supports the idea that activity data-based methods greatly underestimate actual fugitive emissions in Nigeria. The use of TROPOMI and next-generation satellite sensors in the national GHG monitoring system in Nigeria is highly recommended for accurate emissions reporting, implementation of international climate obligations under UNFCCC and the detection of super-emitters in real time.

Pilot implementation of methane recovery projects in high emission clusters: Industry stakeholders and government are urged to prioritize the implementation of pilot methane recovery projects such as VRUs, micro-CNG, and PSA, in the highest-emission clusters identified by the Tier 3 spatial analysis. These pilots must be supported with strict techno-economic and environmental assessment to establish their scalability, optimize the Return on Investment, and create the empirical evidence base for sector-wide policy to support methane recovery and utilization in Nigeria.

Author Contributions

K.E.O. was the primary researcher for the study, which formed part of her MSc thesis. She contributed to the conceptualisation of the research, literature review, data collection, data analysis, interpretation of findings, and

preparation of the initial manuscript draft. E.A.U. contributed to the computational aspects of the study. He supported the coding process, reviewed and verified the scripts used for data processing and analysis, and contributed to the technical validation of the computational workflow. A.R.O. contributed as a co-researcher by supporting the technical review of the study, particularly in relation to the analytical procedures. She also contributed to the review and refinement of the manuscript. O.B.O. contributed to the policy analysis component of the study. He reviewed the policy-related aspects of the work and supported the development of policy-relevant interpretations and recommendations. O.I.O. supervised the research and provided academic guidance throughout the study. He contributed to the refinement of the research design, methodological quality, interpretation of findings, and critical review of the manuscript. M.A.S. contributed to the conceptualisation and original framing of the study, drawing on his technical engagement with methane-emissions-related project work in Nigeria. He also provided academic and technical supervision, guided the development of the research direction, supported the refinement of the methodology, and contributed to the interpretation of findings and critical review of the manuscript. All authors reviewed and approved the final version of the manuscript.

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Data Availability Statement

Production data were obtained from the Carbon Majors dataset compiled by the Climate Accountability Institute, the Nigerian National Petroleum Company Limited, and the Nigerian Upstream Petroleum Regulatory Commission, and reconciled using data from the National Bureau of Statistics. TROPOMI Sentinel-5P and ERA5 reanalysis data are publicly available via the Copernicus Open Access Hub and Copernicus Climate Data Store, respectively. Techno-economic cost parameters were derived using a capacity-based scaling methodology anchored to published pressure swing adsorption cost literature. All emission, energy recovery, and techno-economic estimates generated during this study are available within the article's tables and supplementary material, with detailed source documentation available from the corresponding author upon reasonable request.

Conflicts of Interest

The authors declare that there are no financial, institutional, or personal conflicts of interest associated with this study. Although the conceptual framing of the study benefited from prior technical engagement with methane-emissions-related project work in Nigeria, this did not influence the independence of the data analysis, interpretation of results, or conclusions presented in the manuscript.

AI Use Statement

During the preparation of this work the authors used Quill Bot to improve grammar, language clarity, and sentence structure. No AI tools were used for data analysis, interpretation, or generation of scientific content. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

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