gases

Review

A Review on Qualitative Assessment of Natural Gas Utilisation Options for Eliminating Routine Nigerian Gas Flaring

Robin Abu, Kumar Patchigolla * and Nigel Simms

School of Water, Energy and Environment, Cranfield University, Cranfield MK43 0AL, UK
* Correspondence: k.patchigolla@cranfield.ac.uk

Abstract: Natural gas flaring, with its harmful environmental, health, and economic effects, is common in the Nigerian oil and gas industry because of a lower tax regime for flared gases. Based on the adverse effects of flared gas, the Nigerian government has renewed and improved its efforts to reduce or eliminate gas flaring through the application of natural gas utilisation techniques. However, because the conventional approach to flare gas utilisation is heavily reliant on achieving scale, fuel, and end-product prices, not all technologies are technically and economically viable for typically capturing large and small quantities of associated gas from various flare sites or gas fields (located offshore or onshore). For these reasons, this paper reviews and compares various flare gas utilisation options to guide their proper selection for appropriate implementation in the eradication of routine gas flaring in Nigeria and to promote the Zero Routine Flaring initiative, which aims to reduce flaring levels dramatically by 2030. A qualitative assessment is used in this study to contrast the various flare gas utilisation options against key decision drivers. In this analysis, three natural gas utilisation processes—liquefied natural gas (LNG), gas to wire (GTW), and gas to methanol (GTM)—are recommended as options for Nigeria because of their economic significance, technological viability (both onshore and offshore), and environmental benefits. All these gas utilisation options have the potential to significantly reduce and prevent routine gas flaring in Nigeria and can be used separately or in combination to create synergies that could lower project costs and product market risk. This article clearly identifies the environmental benefits and the technical and economic viability of infrastructure investments to recover and repurpose flare gasses along with recommendation steps to select and optimise economies of scale for an associated natural gas utilisation option.

Keywords: utilisation; gas flaring; Nigeria; routine; options; sustainable development

Citation: Abu, R.; Patchigolla, K.; Simms, N. A Review on Qualitative Assessment of Natural Gas Utilisation Options for Eliminating Routine Nigerian Gas Flaring. *Gases* **2023**, 3, 1–24. https://doi.org/10.3390/gases3010001

Academic Editor: María Pilar Lisbona

Received: 26 November 2022
Revised: 3 January 2023
Accepted: 16 January 2023
Published: 28 January 2023

1. Introduction

Processes such as gas flaring and venting increase CO_2 emissions, but because flaring is less hazardous than venting, it is often the preferred method used in oil and gas operations to discard unwanted gases [1,2]. Gas flaring is the regulated combustion of unwanted associated natural gas (ANG) or trapped gas produced during the extraction, processing, and refining of oil and gas, petrochemical processes, landfill gas extraction, and coal-bed methane production [3]. It is an environmentally hazardous technique of removing excessive associated natural gas through combustion and processing operations during routine oil and gas production [4,5]. The disadvantages of gas flaring have long been identified and include global warming caused by greenhouse gas emissions, economic waste, energy loss, ecosystem disruption, negative health effects, and so on [6–8]. Several factors, which may be economic, technological, or regulatory in nature, such as a lack of gas infrastructure and technologies, poor policies guiding gas-flaring reduction, technological costs and processes, and a lack of gas markets to commercialise the product, impede the rapid eradication of gas flaring [9]. Natural gas is frequently an unwelcome by-product of the oil extraction process. Developers must either find a useful outlet for this associated gas, such as delivering it to consumers (which would necessitate infrastructure development), using it onsite for operational energy, or injecting it for pressure support or permanent disposal [10,11]. When operators fail to secure any of these alternatives, they may instead choose to burn the gas on a permanent or semi-permanent basis during production or use non-emergency flaring and venting (which causes even more environmental damage than flaring) [11]. In 2021, thousands of gas flares at oil production sites around the world burned approximately 144 billion cubic meters (bcm) of gas, the productive use of which would be worth more than USD 20 billion at current prices [12]. Assuming a 'standard' associated gas composition, a flare combustion efficiency of 98%, and a global warming potential for methane of 25, each cubic meter of associated gas flared results in approximately 2.8 kg of CO_2 equivalent emissions, totalling over 400 million tons of CO_2 equivalent emissions per year [13,14]. The annual CO_2 equivalent emissions are increased by approximately 100 million tons on this basis. Methane emissions caused by inefficient flare combustion contribute significantly to global warming. This is especially true in the short to medium term, as methane is more than 80 times more powerful than carbon dioxide as a warming gas over a 20-year timeframe, according to the Intergovernmental Panel on Climate Change [13].

Flaring is more easily avoidable than many other sources of GHG emissions [15,16]. The gas could potentially replace more polluting fuels like coal and diesel, which produce more emissions per unit of energy [15]. Moreover, due to lower GHG emissions, biomass pyrolysis may also be a viable choice as a renewable and clean fuel [17]. However, the focus of this study will be on the utilisation of ANG, which is gas associated with oil in the reservoir. Black carbon, also known as soot, is another pollutant released by gas flares in addition to GHG emissions. Black carbon is formed by the incomplete burning of fossil fuels, and despite only staying in the atmosphere for a few days or weeks, it may have the second-largest warming effect after carbon dioxide [13]. Routine gas flaring also denotes a missed opportunity to provide hundreds of millions of people with a useful energy source—as such, over 700 million people still lack access to energy, and an estimated 620 million people will still lack access in 2030, with 85% of them in sub-Saharan Africa [18]. Nigeria (the key country of interest for this paper) is regarded as one of the world's leading contributors of greenhouse gases because of its widespread gas flaring. The production or industrial activities on oil platforms, refineries, and chemical and coal plants in the Niger Delta region (a key location in Nigeria because of its vast hydrocarbon reserves) are the most common sources of gas flaring in Nigeria, accounting for more than 6.5 bcm of total annual flare gas in 2021. Following various efforts by all participants (government, oil and gas companies, and private and public partnerships), various technological methods such as the liquefied natural gas (LNG) process, gas re-injection, and so on have been applied and found to be successful to some extent [19]. Gas market availability for economic purposes, as well as a better regulatory process to support the government's 2030 zero-emission initiative, have also contributed to a reduction in gas flaring, but not sufficiently [20,21]. Nigeria announced in 2016 that it would include a gas utilisation scheme prohibiting non-emergency flaring in new field development plans by 2020. Even though Nigeria successfully reduced flared gas volumes by 70% between 2000 and 2019, significant flaring continues at many sites across the country [10]. Since the discovery of the negative impact of gas flaring activities in the oil and gas industry, flare gas utilisation has emerged as the best option to mitigate the negative impact of soaring gas flaring processes in both developed and developing oil- and gas-producing countries around the world. Natural gas utilisation methods include the use of a combination of technologies to collect, recycle, and use the waste gases produced (both on a large and a small scale) during oil and gas production activities for purposes other than flaring [4]. The use of flare gas has provided opportunities for developed and developing nations endowed with abundant hydrocarbon fuels to achieve high sustainability development for future use. Due to the difficulties involved in collecting, recycling, and utilising flare gases associated with oil and gas activities, such as an inaccessible geographic location, a lack of a gas market, expensive gas technologies, a lack of gas infrastructure for storing and transporting the gases, and so on, flare gas utilisation techniques are still not fully employed in the oil and gas industry [9,16]. Flare gas utilisation systems still have the capability of completely eradicating gas flaring processes. The aim of this paper is to perform a qualitative assessment of gas flaring utilisation options against various key decision drivers and their comparison as a guide in the proper selection of these options suitable for natural gas utilisation in Nigeria. This will ensure technical and economic feasibility and positive environmental impact through the reduction in routine gas flaring while also minimising CO_2 emissions. A rapid reduction in gas flaring levels in Nigeria and in oil and gas methane emissions is required for all pathways out of the current crisis, and it is critical to the design and achievement of the nation's Sustainable Development Goals. Eliminating routine flaring would already be a significant step towards this goal of rapidly reducing flaring levels by 2030.

2. Overview of Gas Flaring

2.1. Global Gas Flaring

Flaring is a problem in locations with little natural gas infrastructure [22]. In the early days of petroleum discovery, natural gas was not a practical fuel since it was difficult to move or handle. Gas was either burned off in the well or released into the atmosphere to prevent fires caused by equipment failure or human error. The amount of hydrocarbons or fossil fuel generated, stored, refined, and consumed is directly proportional to gas flaring emissions [23].

According to the GAO [23], approximately 3% (three percent) of the natural gas produced is flared, which tends to be a small proportion on the surface but reflects a large amount of unused natural capital. According to data from the World Bank's Global Gas Flaring Reduction collaboration and the US National Oceanic and Atmospheric Administration (NOAA), oil production fell by 6% in 2021 (from 82 million barrels per day (bpd) in 2019 to 77 million bpd in 2021), while global gas flaring fell by 4% (from 150 bcm in 2019 to 144 bcm in 2021)—roughly equivalent to Central and South America's natural gas demand. This resulted in approximately 361 million tonnes (Mt) CO_2 and nearly 39 Mt methane (240 Mt CO_2-eq) [10,14]. The United States accounted for 70% of the global decline, with gas flaring falling by 32% between 2019 and 2020, owing to an 8% drop in oil production coupled with innovative infrastructure to use gas that would otherwise be flared [18]. Since the first of two satellites was launched in 2012, Russia, Iraq, Iran, the United States, Venezuela, Algeria, and Nigeria have remained the top seven gas-flaring countries for nine years in a row, accounting for approximately 75 percent of all gas flared and 50 percent of global oil production. The 144 bcm of natural gas flared in 2021 could have produced approximately 1800 Terawatt hours (TWh) of energy, accounting for nearly two-thirds of the European Union's net domestic electricity generation, or more than Africa's current annual electricity demand [14,18]. From 1996 to 2021, the amount of gas flared (in million cubic meters) and the amount of oil generated are seen in Figure 1. While oil production has increased by roughly 20% since 1996, the amount of associated gas flared has decreased by 13%. This indicates that the oil industry is making progress as a long-standing correlation between oil production and gas flaring is gradually decoupled [14]. Most of the global flaring is caused by a small number of large flaring sites. In 2020, 12% of flare sites contributed 75% of total flaring volume globally [18]. Figure 2 depicts the most recent ranking of 10 countries that flare gas between 2012 and 2021. Figure 2 shows Russia's dominance as the world's leading gas flaring region, with 25.4 bcm of natural gas flared in 2021, followed by Iraq (17.8 bcm), Iran (17.3 bcm), the United States of America (USA) (8.7 bcm), Venezuela (8.2 bcm), and Algeria (8.1 bcm) [14]. Nigeria is positioned seventh in the ranking of the top 30 flaring countries with a volume of 6.6 bcm, accounting for more than 40% of Africa's total annual flare volume.

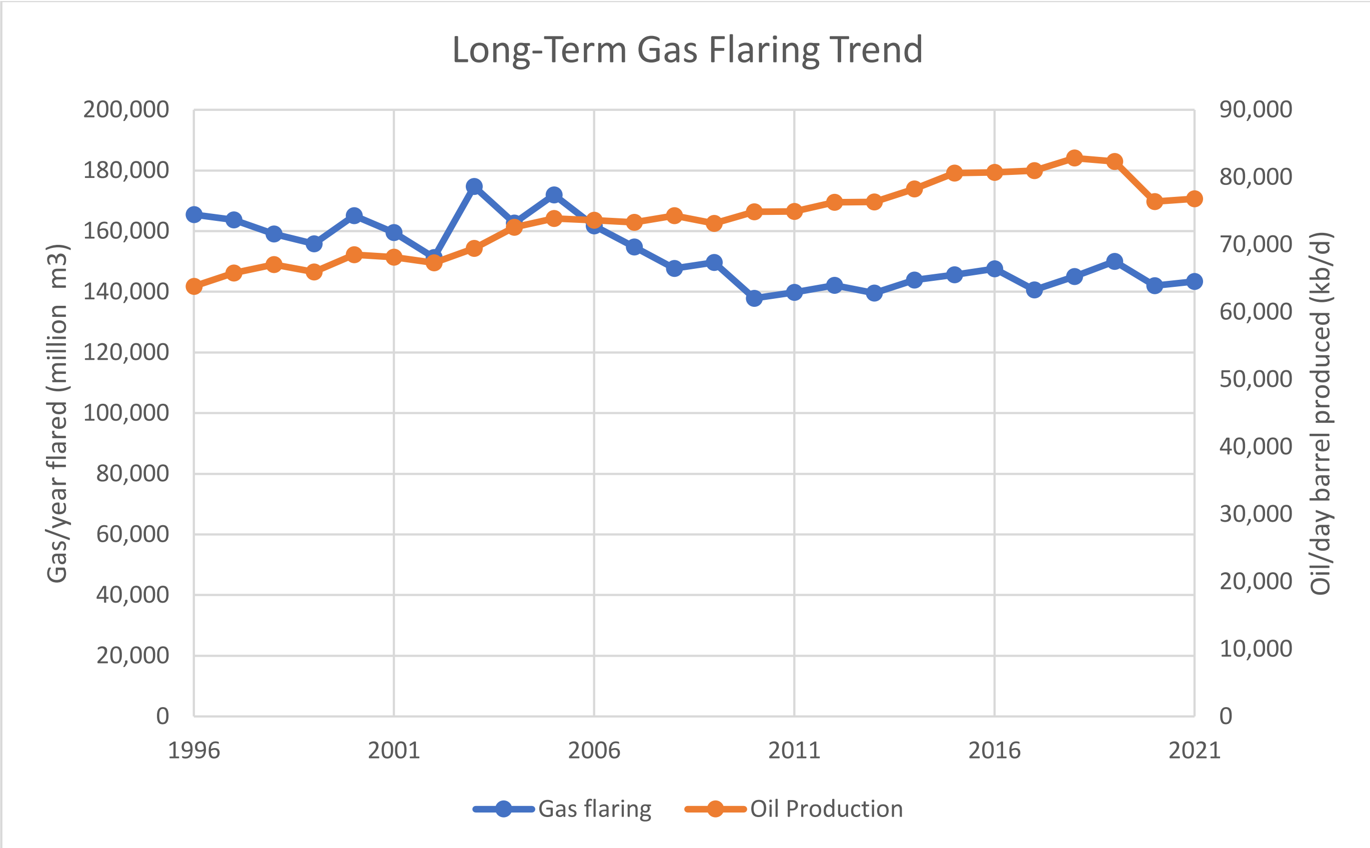

Figure 1. Global gas flaring and oil production: 1996 to 2021 (flaring only at upstream oil, gas, and LNG liquefaction plants) [14].

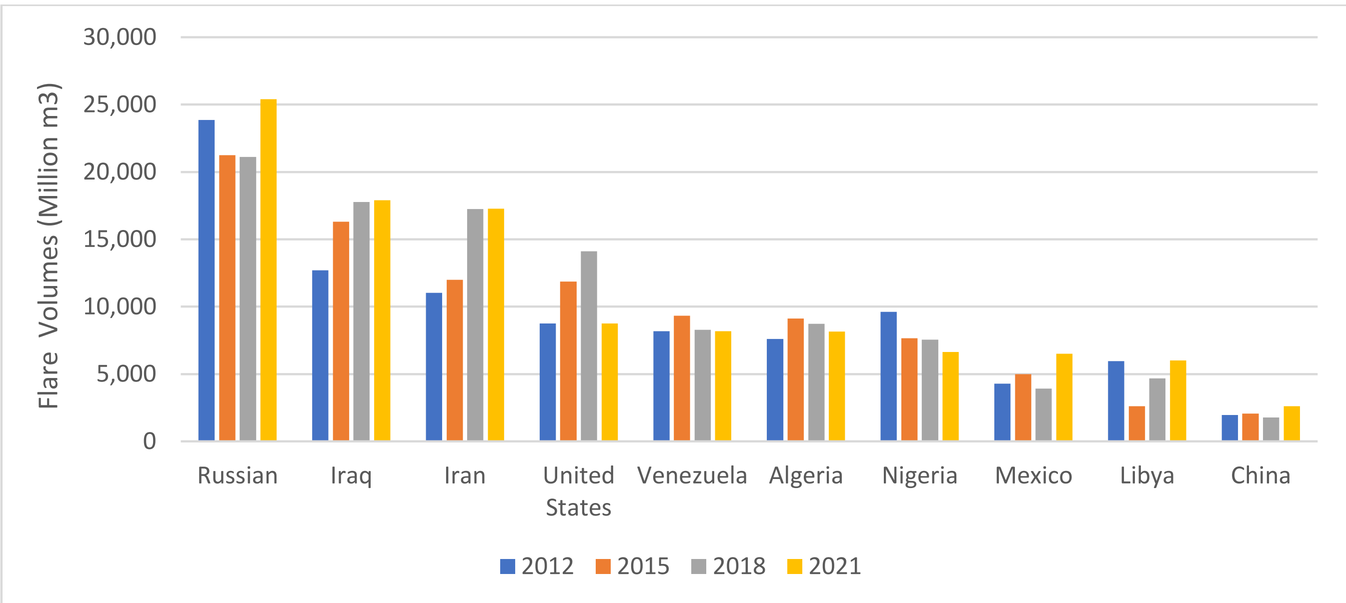

Figure 2. Flare volumes for the top 10 flaring countries for 2012, 2015, 2018, and 2021 [14].

2.2. *Gas Flaring in Nigeria and Efforts to Reduce Gas Flaring in Nigeria*

Flaring in Nigeria is linked to the first-ever hydrocarbon export from Nigeria [24]. According to the Department of Petroleum Resources, Nigeria has 159 oil fields and 1481 wells in operation [25,26]. With an estimated 37 billion barrels of proven crude oil reserves, Nigeria has the second largest crude oil reserves in Africa, behind Libya [27,28]. Despite remaining in the top seven flaring countries, Nigeria has reduced its gas flaring by 70% over the last 15 years. From 2012 to 2021, Nigeria reduced flaring by 31% and increased flare intensity by 10% [14]. In addition, oil production has remained essentially steady at around 2 million barrels per day [18].

This figure is, however, qualified by a report from NOSDRA, a government satellite tracker, which stated that 1.8 billion standard cubic feet (bscf) of gas per day was flared over the past 9 years, which resulted in 95.5 million tonnes of CO_2 emissions and a USD 3.6 billion penalty, but this was only paid in part [29]. This flared gas was estimated to be worth USD 6.3 billion, with a potential to generate 179.9 thousand GWh of electricity, a significant loss of revenue and power generation [29]. Oil firms burned natural gas worth USD 1.24 billion in 2020, enough to meet the power needs of 804 million Nigerians [29].

Numerous attempts have been made since 1969 by the Nigeria government to stamp out gas flaring. These include the amended Petroleum Act Decree of 1973 and the Associated Gas Reinjection Act of 1979, amongst others, all with varying levels of success [30–33]. Others include the National Environmental Standards and Regulation Act of 2007, which generally enables the National Environmental Standards and Regulations Enforcement Agency (NESREA) to protect and safeguard public health and welfare, as well as prevent the release of hazardous substances into Nigeria's air, land, and waterways, and the Environmental Impact Assessment Act (EIAA) of 1992, which requires an EIA study to precede every oil and gas project as a precautionary step for evaluating the project's environmental impact, as well as the Environmental Guidelines and Standards for the Petroleum Industry 2002 (EGASPIN). Despite the existence of these regulations, oil and gas firms in Nigeria have chosen to flare more gas rather than find workable solutions because of the low fines in place to restrict ANG flaring. Flare gas (prevention of waste and pollution) laws of 2018 [34] increased the penalties from NGN 183 (USD 0.50) per 1000 scf of gas flared to NGN 730 (USD 2.00) for 1000 scf of gas flared for those producing less than approximately 10,000 barrels of oil per day. According to preliminary estimates, even though the government generated additional revenue of USD 120 million in 2019, many consider this increase insignificant because gas flaring in Nigeria continues unabated [35].

The Nigerian government joining the Global Gas Flaring Reduction (GGFR) in 2002 was a significant step in efforts to reduce gas flaring. The GGFR's primary aim is to assist countries and oil and gas firms in increasing associated natural gas utilisation because of its significant role in global gas flaring volumes, thus reducing global gas flaring. As part of this aim, the GGFR in collaboration with the World Bank and other partner governments launched the Zero Routine Flaring 2030 project, which aims to eliminate routine gas flaring by 2030.

These and other measures have led to the Nigerian government and oil and gas companies developing several natural gas utilisation schemes such as Nigerian Liquefied Natural Gas (NLNG), the West African Gas Pipeline joint venture project, and the Chevron-managed gas to liquid project [32,36,37]. These offer a reduction in CO_2 emissions through increased ANG utilisation.

3. Natural Gas Utilisation Methods

In the oil and gas industry, as well as in the long-term environmental impact of flaring gas production, there are several methodologies for utilising waste gases. To ensure the successful selection, handling, and use of the quantity of gas collected, diverse utilisation strategies necessitate a variety of technological and often complicated arrangements of suitable structures. These gas utilisation methods are:

I. Liquefied natural gas (LNG)
II. Gas to liquid (GTL)
III. Natural gas to methanol (GTM)
IV. Natural gas to hydrogen (GTH)
V. Gas to wire (GTW)

VI. Compressed natural gas (CNG)
VII. Gas to fertiliser (GTF)
VIII. Gas re-injection process (GRP)
IX. Gas to hydrates (NGH)
X. Natural gas to pipelines (GTP)
XI. Liquefied petroleum gas (LPG)

3.1. Liquefied Natural Gas (LNG)

LNG allows long-distance transportation by liquefying and condensing natural gas into a liquid, reducing its volume by 600 times, and making the resource easier to store and ship [38–41]. The LNG industry is comprised of numerous chains, including the development of gas resources, LNG liquefaction plants, LNG transportation, LNG receiving terminals, and the connection of customers via power plants or municipal gas companies [42]. If justifiable (large gas volumes, robust LNG SPAs (sale and purchase agreements) between gas producers and buyers, etc.), it guarantees both economic benefits and flare reduction [42].

LNG is one of the cleanest fossil fuels, according to Elengy [43]. In the context of the European Commission's and world's ongoing energy transition, it offers a way to reduce greenhouse gas emissions and fight global warming. Its usage in transportation, especially trucks, cuts diesel noise by half. Its lower cost compared to standard transport fuels like diesel also makes it an intriguing gas option. As a marine fuel, it reduces carbon dioxide emissions by 25%, nitrogen oxide emissions by 90%, and sulphur and fine particle emissions by 90–100%. It has less environmental impact and the best thermodynamic yields and energy efficiency of any fuel and can be distributed to industrial areas or places without natural gas grids.

LNG production and transit cost less than other fossil fuels, according to Prima LNG [44]. Increasing LNG production by numerous providers, cheap technologies for using unconventional gas reserves, and controlled usage of natural gas as a feedstock have given natural gas and LNG a considerable edge over crude oil-linked products. A carbon tax makes LNG more appealing in the European Union. Its energy savings (3–5% more efficient than oil-fired products) demonstrate its sustainability as a gas option. LNG is a feasible energy choice because of its ease of distribution and large reserve base.

Developers have improved the economics of LNG expansion by boosting liquefaction efficiency and developing larger LNG trains, up to 7.8 million tonnes per annum (Mtpa) (located in Qatar). Due to industry demands for flexibility, smaller 1–2 Mtpa liquefaction trains are appearing [45]. A 1 Mtpa LNG facility requires 170 million standard cubic feet per day (mmscfd) of input gas. Gas flares with a capacity of 1 to 10 mmscfd must be combined to feed a single LNG train [46]. The advent of mini- and micro-scale LNG technologies has allowed the monetisation of flare gas. Mini- and micro-LNG suppliers can deliver up to 8 tonnes per day (tpd) (0.003 Mtpa, 0.4 mmscfd). However typical commercial mini-LNG plant capabilities vary from 5 mmscfd net gas (100 tpd) to 50 mmscfd net gas (1000 tpd) [46]. Modular designs allow scaling. A 1 mmscfd facility's engineering–procurement–construction (EPC) costs are USD 1.2 million with an annual Opex approximately 4.5 percent of Capex [47]. According to LNG project statistics for 2014–2018 [48], the cost of LNG plants (outside Australia) ranges from USD 600 to USD 1100 per tonne per annum (tpa) in capacity; however, other factors can affect cost (complexity, existing infrastructure, etc.).

Global LNG trade expanded 13% year on year to 354.7 million tonnes in 2019 because of increasing production capacity [49]. S&P Worldwide Platts Analytics estimates global LNG demand climbed 2% in 2020 to 362 million tonnes and 3% in 2021 [50]. The global LNG market was worth USD 30.34 billion in 2020 and is expected to be worth USD 66.13 billion by 2027 [51]. Global LNG demand will approach 700 million tonnes per year by 2040, up 90% from 2021 [52].

3.2. Gas to Liquid (GTL)

Oil companies, governments, and environmentalists worldwide are examining the need for alternative transportation or liquid fuels. GTL procedure provides such an opportunity. GTL was developed because consumers prefer liquids over gases since they are easier to handle and require less infrastructure [53]. GTL commercialises stranded and flared gases. It produces liquid fuels from natural gas by catalytic processing to provide naphtha, kerosene, gasoline, or waxes and many others [54]. The technique also produces cleaner fuels with superior environmental performance compared to conventional fuels derived from crude oil. GTL is being promoted as a clean, environmentally friendly fuel in numerous countries.

Over the years, the GTL method has evolved, which has helped to improve the operating efficiency of plants. Gas-to-liquid conversion has sweeping applications other than as a means of gas transmission. Several technology companies have produced modular GTL process variations. Oil companies may adopt small-scale, modular, and portable GTL technology to reduce their carbon footprints [53]. Shell and Chevron have developed large-scale GTL projects in Qatar (Oryx and Pearl) and Nigeria (Escravos GTL). GTL plants can capture flared-off gas at oil-producing facilities. This strategy gives oil producers a revenue boost. Companies can reduce emissions and fight climate change by avoiding gas flaring. GTL is a costly and complex way to use gas [53].

According to Visiongain, the global gas-to-liquids (GTL) market was valued at USD 2915 million in 2019 and is expected to reach USD 4881 million by 2030, growing at a compound annual growth rate (CAGR) of 4.7% between 2020 and 2030 [55]. GTL expansions have mainly focused on large developments to maximise economies of scale. Mini- and micro-GTL applications monetise stranded gas. GTL manufacturing benefits include clean, easily stored liquid fuels like diesel. Although units as low as 0.2 mmscfd (20 barrel per day (bpd)) are available, typically profitable applications range from 15 mmscfd (1500 bpd) to 150 mmscfd (15,000 bpd) [46]. GTL applications are flexible, scalable, and containerised. Some units produce synthetic crude that may be processed into diesel and naphtha, while others produce fuel, wax, and water from natural gas. Standard per-mmscf product yields are 100 bbl diesel, 1 bbl wax, and 2 bbl clean water. A 10 mmscfd plant is estimated to cost USD 45 million, with an annual Opex at 1.2 percent of Capex, plus 7 MW of power [46].

3.3. Natural Gas to Methanol (GTM)

Methanol is a clear colourless liquid at ambient conditions [56]. It is a clear, odourless liquid at room temperature [57] and its production can be regarded as a subset of GTM technology. Methanol, when used as a fuel, typically has minimal CO, NO_X, and hydrocarbon emissions compared to gasoline [58]. Methanol can be blended with gasoline or used as a diesel alternative in equipped cars. The production of methanol from natural gas begins with the formation of hydrogen by natural gas reforming (synthetic gas production) because methanol is predominantly made by hydrogenating carbon monoxide [59]. Methanol manufacturing has two phases. The first stage converts natural gas feedstock into synthesis gas via steam reforming [60]. The second stage converts synthesis gas into methanol. Different technologies offer options for each of these procedures. Onshore and offshore GTM approaches are similar, but design variables (space, safety, weight, and height) differ [61].

Dalena [56] noted that making methanol from CO_2 and H_2 reduces CO_2 emissions. Methanol production consumes the second-most hydrogen after ammonia. It is a preferred energy carrier for hydrogen synthesis by partial oxidation, auto-thermal reforming, etc. It is used in direct methanol fuel cells for power. It is easily stored and employed as a solvent in complex chemical compositions. In transportation, methanol can be blended with ordinary petrol without extensive vehicle modifications, e.g., M85 fuel, which is 85% methanol and 15% unleaded gasoline. The AFDC [62] also note its cheapness to produce relative to other alternative fuels, increased safety that is due to its lower flammability, and improved energy from its ability to be manufactured from carbon-based feedstocks such as natural gas.

The global methanol market generated around USD 28,114.27 million in 2021 and is expected to reach USD 41,974.76 million by the end of 2028. It is expected to grow at a compound annual growth rate (CAGR) of 5.2 percent from 2021 to 2028 [63]. The quantity of feed gas needed per ton of methanol is roughly 0.0313 mmscf. In addition to feed gas, the application needs electricity and oxygen, both of which may be produced on site. A 0.3 mmscfd unit generates 3500 tpa of methanol, whereas a 5 mmscfd unit generates 58,200 tpa [46]. Nigeria produces limited GTM. Most government funded GTM efforts in Nigeria are new. Continued development of GTM is needed to provide clean fuel and industrial chemicals, reduce gas flaring, and strengthen Nigeria's economy.

3.4. Natural Gas to Hydrogen (GTH)

Natural gas accounts for three-quarters of the commercial hydrogen production, which is currently about 70 Mtpa, and its use consumes 6% of worldwide natural gas [64]. A large proportion of hydrogen (approximately 95%) is manufactured from fossil fuels via steam reforming of natural gas, partial oxidation of methane, and coal gasification [64–66]. Other techniques for manufacturing hydrogen include biomass gasification, methane pyrolysis with no CO_2 emissions, and water electrolysis. In 2020, over 87 million tonnes of hydrogen were produced [67] globally for oil refining, ammonia (through the Haber process) and methanol (by carbon monoxide reduction), and transportation fuel. In 2017, the hydrogen production market was valued at USD 115.25 billion [64,66]. Natural gas, oil, coal, and electrolysis are the four main commercial sources of hydrogen, accounting for 48%, 30%, 18%, and 4% of global hydrogen production, respectively [68].

Hydrogen is often generated on site through steam methane reforming, split from by-product gases from petrochemical processes, or purchased as commercial hydrogen (typically produced in dedicated plants for hydrogen production using steam methane reforming) [66]. Storage and distribution constraints limit Nigeria's GTH production. Nigeria's government funded GTH initiatives are new. GTH development must continue to supply clean fuel, boost Nigeria's economy, and prevent gas flaring.

In 2020, the demand for hydrogen was 90 Mt with more than 70 Mt used as pure hydrogen and less than 20 Mt mixed with carbon-containing gases in methanol production and steel production [66]. Total industrial hydrogen demand is expected to grow 44% by 2030, with low-carbon hydrogen becoming highly significant (to 21 Mt in 2030) [66].

3.5. Gas to Wire (GTW)

Using natural gas for power helps to reduce gas flaring [69]. Compared to other gas utilisation technology, which necessitates costly gas processing technologies, using natural gas from oil and gas wells as an alternative fuel in power plants can have economic, environmental, and productivity benefits [42,70]. Using gas to power urban homes is also a sustainable option [71]. The gas-fuelled power plants can be located either near the oil and gas fields or near the population hubs where the most electricity is needed. For the first choice, a power transmission line ("wire") will be required if the power is to be delivered to consumers outside of oil and gas well locations [42]. If, on the other hand, the power generator is to be constructed near consumer centres, a gas pipeline or road transportation depends on the economics that will be required to transport gas from oil and gas wells to the site where electricity will be generated [42].

Anosike et al. [72] stated that GTW is a better use of associated gas than re-injection for enhanced oil recovery (EOR). In countries with a power production deficit like Nigeria, which generates less than 54% of its total power generation needs because of infrastructural limitations and gas supply deficits, GTW is a superior option with obvious economic incentives for investors. Lammey [73] cites GTW as a flexible and quick-responding power source that can stabilise energy systems. It also commented on GTW's ability to save costs by merging logistics. Access to unconventional deposits like shale gas has boosted global gas reserves, which are anticipated to last 130 years and more, giving a viable and sustainable method of power generation. Natural gas-fired thermal power plants may cut CO_2 by 81%, NOx by 8%, and SO_2 and fine particle emissions by 100%. This could reduce CO_2 emissions in Europe by 60% and globally by 20% [43].

Multiple technology companies provide container-based scalable, modular, and truck-mounted generator sets with small-scale capabilities ranging from 30 kW to 2 MW and larger-scale applications ranging from 250 kW to 30 MW using reciprocating engines (up to 5 MW per container). Larger 20–500 MW modular modules are also an option [46]. A total of 0.36 mmscfd of gas is needed per MW. Typically, smaller units (30 kW–1 MW) cost 1000–1700 USD/kW for up to 1 MW and 150–300 USD/kW for multi-MW. In addition to natural gas, diesel, propane, and kerosene can be multi-fuelled. Some systems control fluctuating gas composition (heat content), gas contaminants (CO_2, N_2, and H_2S), and variable flow rates in upstream ANG production from oil wells [46].

Nigeria's electricity generation sub-sector contains 23 grid-connected generating plants with a total installed capacity of 10,396 MW (available capacity of 6056 MW) and thermal-based generation with an installed capacity of 8457.6MW (available capacity of 4996 MW) in the Niger Delta [74]. This power is used on site, locally, and industrially. Nigeria produced 36,400 GWh of electricity in 2021, up from 35,700 GWh in 2020 [75]. Nigeria's average idle electricity generation rose to 3008.18 MW in 2021 from 1030.80 MW in 2013, a 291% increase in eight years caused by inadequate infrastructure [76].

3.6. Compressed Natural Gas (CNG)

CNG is generated by compressing natural gas to less than 1% of its initial volume at normal atmospheric pressure [77,78]. CNG is processed and supplied in big steel cylinders at 220 bar (3200 psi) [78]. CNG consists mostly of methane (CH_4), ethane, propane, and butane. According to the Alternative Fuel Data Centre [79–81], CNG consists of other gases such as carbon dioxide, hydrogen sulphide, nitrogen, helium, and water vapour. Compressed natural gas is the best alternative to gas pipelines and LNG plants [77]. CNG is a simple, accurate technology that requires minimal gas treatment or processing facilities and gas infrastructure, reducing offshore oil and gas processing capital costs.

CNG is typically confined to transportation fuels for natural gas vehicles (NGV) and is used in many large cities to reduce air pollution (such as in India and Pakistan). It encourages environmental friendliness with its low emission of hazardous gases and analogous engine performance [82]. CNG has a difficult time competing with either pipeline or power generation because of its storage and transportation requirements. However, where gas demand is limited and dispersed, CNG technology seems promising. As the demand for natural-gas-powered vehicles in urban areas grows, CNG technology can be a viable solution [42].

For the most part, compressed natural gas (CNG) is utilised as a transportation fuel for natural gas vehicles (NGV) and is widely implemented in many major cities to lessen air pollution (such as in China, Iran, India, and Pakistan) [42]. Due to the high costs associated with storing and transporting CNG, it cannot compete favourably with pipelines or power plants. However, CNG technology shows promise in areas with low and dispersed gas consumption. CNG technology may prove to be an effective response to the growing need for natural-gas-powered automobiles in populated areas [42].

The global compressed natural gas market size was valued at USD 9.9 billion in 2020 and is projected to reach USD 22.3 billion by 2030, growing at a CAGR of 8.2% from 2021 to 2030 [83]. Tractebel Engineering for the World Bank Group and GGFR found that CNG transportation expenses account for 79–86% of overall expenditures for large distances (750–1000 miles) and 57–65% for shorter distances (up to 250 miles). Onshore CNG development costs for 3–10 mmscfd were estimated at 2.5 USD/metric million British thermal unit (MMBtu) + USD 0.0088 per mile [46]. For a 10 mmscfd offshore development, this cost was 3.2 USD/MMBtu + USD 0.005 per nautical mile, and 4 USD/MMBtu + USD 0.006 per nautical mile for a smaller 3 mmscfd offshore development [84]. With a boost in cargo capacity, transportation costs for CNG transport by ship are expected to decline, and CNG is estimated to be commercial and able to compete with pipelines and LNG at deliverable volumes of 0.3–7 bcm per annum (30–675 mmscfd) across 800 km [46]. CNG is competitive at 4.7 bcm per year (450 mmscfd) over 700–2200 km, 1 bcm annually (100 mmsfd) over 250–1500 km, and 0.3 bcm yearly (30 mmscfd) over 100–1000 km [85].

In Nigeria, only a small percentage of cars run on compressed natural gas. In most cases, the CNG used is produced by a modest CNG processing facility. However, future development of CNG is warranted because Nigeria has several prospective gas reserves and widely dispersed locations with moderate demand for gas.

3.7. Natural Gas to Fertiliser (GTF)

The global fertiliser market will reach USD 323,375.0 million by 2028, up from USD 221,428.6 million in 2020 at a 5.0% CAGR [86]. Ammonia and urea fertilisers are primarily derived from natural gas and used extensively in Nigerian agriculture [87,88]. Ammonia is made by reacting nitrogen and hydrogen (from natural gas reforming) under high temperature and pressure [88]. Urea is made by heating and pressurising liquid ammonia and liquid carbon dioxide. Commercial grades have 45 to 46 percent nitrogen, which reduces handling, storage, and transportation costs. Urea is the most popular dry nitrogen fertiliser in the nations like Nigeria and the United States of America, accounting for 16% of all nitrogen consumption [89,90]. Urea is the most widely used and fastest-growing dry nitrogen fertiliser. It is the main fertiliser traded internationally. It fulfils 62 percent of the world's need for this essential nutrient [91]. Urea is predicted to account for more than 50% of all nitrogen fertilisers soon [90].

Nigeria is among the world's leading producers of nitrogen-rich fertilisers. Its exports to countries such as Ghana, Senegal, Uganda, and Kenya are valued at USD 1 billion. In 2018, Nigeria produced 1.8 million metric tonnes of nitrogenous fertilisers, demonstrating strong growth. Since 2014, the business sector has grown 9% annually [92]. Commercialised GTF plants in Nigeria include the 1.5 Mtpa Dangote fertiliser plant in Lagos state and the 1.4 Mtpa Indorama fertiliser and chemical plant.

3.8. Natural Gas Re-Injection Process (GRP)

Gas re-injection is one of the oldest ways to boost oil recovery [93]. The subsurface reservoir's natural energy is used to produce crude oil [94]. Once oil production by primary recovery techniques becomes unprofitable (because of reduced reservoir energy), pumping natural gas (secondary recovery method) into the reservoir to raise the pressure can enhance oil production [95]. The principal sources of natural reservoir energy are reservoir fluid expansion, the release of solution gas when reservoir pressure lowers, adjacent communication aquifers, and gravity [95]. Gas is re-injected into a zone of free gas (a gas cap) to optimise gravity drainage recovery. The re-injected gas is usually natural gas from the reservoir, delaying its sale until the gas flooding procedure is complete. Nitrogen can be pumped to maintain reservoir pressure, allowing natural gas to be sold as it is generated [95]. Natural gas can be re-injected into a reservoir for enhanced oil recovery (EOR), pressure maintenance, storage (for future use when markets are more developed), and normal flaring reduction. Re-injecting associated gas is not usually economical because of high costs and limited incremental oil reserves. Gas re-injection systems are useful when gas processing and export equipment is expensive [96].

Where creating an industrial infrastructure to process and transport the gas is impractical, treatment and re-injection may be a straightforward and inexpensive alternative. Flaring is far less expensive than gas treatment and re-injection, but it can be harmful to the environment. This is especially true if regulations do not require enterprises to undertake gas treatment and re-injection. Many oil and gas fields in Nigeria have not implemented suitable treatment and re-injection technologies to decrease flaring activities because of a lack of robust regulation.

3.9. Gas to Pipelines (GTP)

The gas pipeline system is the most versatile way to transfer associated and non-associated natural gas from offshore to onshore for processing to integrate with existing dispersion networks or terminals [97]. It is an easier approach to transport gas over shorter distances, particularly on land. Gas pipelines supply 75% of global associated and non-associated natural gas exports [78]. Large-diameter pipelines (subject to capacity) can transport gas for further processing or to be processed into pipeline sales gas [98]. A growth in industrial and residential transportation capacity allows for more gas transport. These pipelines use compressor stations at 80–160 km intervals to deliver gas over large distances. Natural gas processing involves removing oil, water, and gases such as H_2S, SO_2, helium, carbon dioxide, and natural gas liquids [99]. The gas must be purified before its pipe transportation to inhibit formation of liquid condensate or hydrate. However, the expense of the pipeline alternative may outweigh the economic worth of the gas being carried if the crude/gas fields are located a considerable distance from potential buyers. Gas pipeline economics are mostly controlled by pipeline length [78]. Pipelines can also be expensive if there is a low volume of gas being transported and the pipeline only has one endpoint. Transporting natural gas through pipes is the most logical, practical, and cost-efficient method; however, pipelines have geographical and economic limitations [100]. Nonetheless, development of a comprehensive pipeline network in and around dispersed oil and gas sources is a key factor in increasing natural gas consumption and reducing flaring [69].

Nigeria has built onshore and offshore pipelines to transport and distribute natural gas, but the system is fragmented and inefficient. Even while the fields in and around the Niger Delta region are relatively close to potential customers, they are still far from pipeline services, making them part of the many marginal offshore resources that lack such infrastructure.

The global pipeline transport market is to expand from USD 124.71 billion in 2021 to USD 136.2 billion in 2022 at 9.2% CAGR. The market will reach USD 183.29 billion in 2026 at a 7.7% CAGR [101].

3.10. Natural Gas to Hydrate (NGH)

Natural gas hydrate (NGH) forms at low temperatures and high pressures [102]. Natural gas hydrate contains one water molecule and eight natural gas molecules, usually methane, ethane, propane, normal butane, iso-butane, nitrous oxide, carbon dioxide, and hydrogen sulphide [103,104]. Natural gas hydrates are thought to be the largest of all other hydrocarbon resources [105]. NGHs are found in permafrost and deep-water marine environments. Boswell and Collett [106] analysed global gas hydrate production. Gudmundsson et al. conducted experiments in 1990, 1992, and 1994 [107–109] to create the framework for using hydrate for large-scale natural gas storage and transportation. One-fourth as much gas can be kept in hydrates as in LNG [102]. NGH has void sites trapped inside the hydrate structure, despite being mostly water. Gudmundsson et al. [109] showed that a ship transporting hydrates does not need a refrigerating unit, merely an enclosed bulk. NGH is a more feasible transport and storage solution because of its stability at atmospheric pressure and temperatures below 160 °C [104]. Wilson et al. [104] reported that a pilot NGH factory is currently functioning as a pilot project but noted that many technological obstacles must be resolved before the technique can be commercialised.

The government of Nigeria must investigate NGH as a possible alternative for utilising ANG in offshore deep-water oil and gas fields. This method can substitute LNG for ANG transportation and storage. Even though no NGH projects have been implemented in Nigeria, such a development may be imminent.

3.11. Liquefied Petroleum Gas (LPG)

The global LPG market had a value of USD 134,887 million in 2021 and is projected to expand at a CAGR of 5.02% between 2022 and 2032 [110]. There is a substantial gas market for cooking, heating, refrigeration, and air conditioning in temperate nations because of their climate [111]. LPG derived from natural gas can be used for this purpose. LPG is an oil- or natural-gas-derived hydrocarbon gas. LPG is derived from 55% refined natural gas and 45% crude oil [112]. LPG consists of propane, butane, or a combination of the two. Instead of fuels, ethane, ethylene, propylene, butylene, isobutene, and isobutylene are used as chemical feedstock [112,113].

Approximately 60 percent of Nigeria's population continues to cook with wood and coal, contributing to deforestation and climate change [114]. LPG is more environmentally friendly and efficient than kerosene [115]. However, a vast majority of the Nigerian populace uses kerosene and coal. The upfront expense of LPG appliances (gas cylinders), a lack of LPG delivery, a lack of information, and social and cultural concerns impede the use of LPG as a cooking fuel. As a result, the Nigeria LNG company boosted the allocation of LPG to the domestic market from 350,000 mt/year to 450,000 mt/year in 2019/2020 and from 450,000 mt/year to 100 percent of output in 2022 [116].

3.12. Summary of Gas Utilisation in Nigeria

In this section, a table (Table 1) has been used to present a brief summary of the various options for using ANG, along with their limitations, and the projects that are already underway in Nigeria.

Table 1. Summary of ANG utilisation, limitations, and existing projects in Nigeria.

Name of Technology	Usage in Nigeria	Limitations in Nigeria	Existing Projects in Nigeria
LNG	Nigeria LNG currently delivers around 40% of Nigeria's annual domestic cooking gas or LPG consumption needs and LNG sale or export	Limited advances are made to secure small to medium scale LNG projects for increased output and variability of ANG supplies	On Bonny Island in Nigeria, Nigeria LNG runs a six-train LNG facility capable of producing 22 Mtpa of LNG and 5 Mtpa of NGLs (LPG and condensate) from 3.5 billion standard cubic feet per day (bscfd) of natural gas intake [117].
GTL	Production of liquid fuels and chemicals	Small to medium scale GTL projects are yet to commence in stranded gas areas with minimum supply and Inconsistent supply of ANG	The Escravos gas-to-liquid (EGTL) plant (100 km south-east of Lagos) is the first project in Nigeria to use GTL technology. EGTL is a two-train plant designed to convert 330 MMscfd of natural gas into 34,000 barrels per day (bpd) of acceptable products. 1000 bpd of LPG [117].
LPG/NGL	Cooking gas	Limited supply to rural areas of Nigeria because of transportation costs, lack of gas processing facilities and availability of fuel	A two-train NGL plant with 550 mmscfd capacity (that converts ANG into NGLs which includes LPGs) located at its Oso field (offshore) in the south-eastern region of Nigeria. It started production for export in 1998 and produces about 50,000 bpd of NGL [117].
GTW	Electricity and heat generation	Fluctuating or limited supply of ANG, Scarcity of new power investments, poor maintenance of power plant	The Okpai power plant in Okpai community (Delta state, Nigeria) uses combined cycle technology. It has a 480 MW installed capacity and uses 120 mmscfd of gas [117].

Table 1. *Cont.*

Name of Technology	Usage in Nigeria	Limitations in Nigeria	Existing Projects in Nigeria
Gas re-injection	Enhanced oil recovery and storage	Limited to onsite use, economic unattractiveness to investors and limitation to certain type of reservoirs	A USD 1.3 billion gas reinjection project offshore Nigeria is being operated by a joint venture between NNPC (60%) and Mobil Producing Nigeria (40%) in the Ebok and Amenam-kpono fields. The project is expected to generate 530 million barrels of extra oil at a peak output of 120,000 bpd [117].
GTH	Transport fuel, applied in fuel cell for electricity generation, fertiliser production and petroleum refining	Difficulty in storing and transporting hydrogen and limited market size	Non-existing now.
NGH	Transportation of ANG and storage	Immature technology, no commercial application yet	Non-existing now.
CNG	Transport fuel, cooking fuel and power generation	Transportation limitation, limited availability	Powergas Africa limited operates four CNG plants in Nigeria, with a combined capacity of around 720,000 standard cubic metre per day [117].
GTF	To boost crop output and nutrient content in agriculture	Limited availability of product, high cost of product	1.5 Mtpa Dangote fertiliser plant in Lagos state.

4. Results

Qualitative Assessment of Gas Flaring Utilisation Options against Various Key Decision Drivers

Various important decision drivers that influence the application of an associated gas utilisation project may be identified [118]. They are as follows.

1. Capital Costs (CAPEX)—This is the most crucial driver that determines the project's practicability and viability. It is related to the netback value of the product depending on type of project.
2. Maturity of technology—In terms of cost and reliability, the maturity of the deployed technology is equally crucial.
3. Transportation to market—Products with a high energy density, such as liquids, are given precedence or have an advantage over gaseous products.
4. Carbon and energy efficiency—Should be assessed on a well-to-wheel (WTW) basis (including all efficiencies associated to fuel production, processing, distribution, and consumption) where products may substitute greater carbon-intensive fuels.
5. Revenue/Product uplift—CNG and LNG compete largely with fuels (such as oil and coal) for power production and residential heating, but GTL yields premium pricing by competing directly in the transportation sector.
6. Gas composition including sensitivity to contaminants—This is also a major decision driver since the greater the levels of pollutants such as CO_2 and H_2S in gas composition, the higher the cost of treating gas and disposing of waste.
7. Production profile—Associated gas volumes typically vary over the field life. It is therefore important to note the production profile of an oil field.
8. Community interdependency—May allow for interdependence/synergies with residents, which may minimise oil production risk from non-technical risk and develop a local market, reducing transportation costs.
9. Operational Safety Considerations—These are steps made to guarantee that the ANG utilisation system operation is safe and not hazardous. The more complicated the ANG utilisation system, the higher the unjustifiable risk of hazard incidence and the lower the operational safety reported.

10. Product Market size—This is another essential factor in determining the different ANG utilisation choices. It analyses the market's volume and value, the various consumer categories and purchasing patterns, the competitiveness, and the economic environment in terms of entry obstacles and regulation.
11. Plant Scale or Size (World scale)—This relates to the technical size range, which specifies the maximum natural gas throughput rate that each technology can realistically handle, or the production capacity range, which specifies the feasible plant's overall output.

5. Discussion

A key element that significantly affects the economic viability of the utilisation option is the ANG composition. The nature of the reservoir, the type of lift employed, the degree of reservoir depletion, and other factors all affect the quantity and composition of ANG [119]. Different ANG streams may require varying degrees of treatment and financial expenditure because of the variance in gas composition and contaminants (particularly CO_2 and H_2S). Even when using the same technological solutions, the variance in composition also means that different ANG streams will provide varied product yields and, consequently, varying economic values. Some gas utilisation options, including GRP and GTP, are less susceptible to impurities than other options and, as a result, are referred to as favourable or positive in Table 2. ANG production and recovery rates experience both short-term operational fluctuations and longer-term variations brought on by, among other things, changes in gas–oil ratios, the depletion of hydrocarbon reservoirs, differences in recovery techniques, the drilling of new wells, and the shutting of existing wells [119]. ANG quantities also tend to change over time, making it challenging to guarantee the best possible use of the infrastructure. If a consumer requires a constant volume, as in the case of employing ANG for electricity generation, the volatility in volume over time could potentially negatively affect the negotiated price for products derived from ANG [119]. This factor may have a considerable impact on all utilisation options because it is difficult to guarantee stable supply volume of a specific ANG from a specific field. The term "neutral" or "fair" is used to describe all ANG utilisation possibilities as a result of limited and changing supply over time of ANG (see Table 2).

Table 2. High-level qualitative assessment of available gas flaring utilisation options against the decision drivers.

	ANG Utilisation Options										
Decision Drivers	**LNG ***	**GTL ***	**GTM ***	**GTH**	**GTW ***	**CNG**	**GTF**	**NGH**	**GRP**	**GTP**	**LPG**
Gas composition	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Green	Green	Green	Orange
Production profile	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange
Revenue/Product uplift	Green	Green	Orange	Orange	Orange	Orange	Orange	Orange	Red	Orange	Orange
Capex	Orange	Red	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange
Technology maturity	Green	Green	Green	Green	Green	Orange	Green	Red	Green	Green	Green
Transport to market	Orange	Green	Green	Red	Green	Red	Orange	Orange	Grey	Orange	Orange
Energy and carbon efficiency	Green	Orange	Green	Green	Orange	Green	Orange	Orange	Red	Green	Green
Operational safety considerations	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Orange	Green	Green	Orange
Community interdependency	Green	Orange	Green	Green	Green	Green	Green	Orange	Red	Orange	Green
Product market size	Green	Green	Orange	Orange	Green	Orange	Orange	Orange	Red	Orange	Green
Plant size (world scale) **	Green	Green	Orange	Orange	Orange	Red	Orange	Orange	Orange	Green	Orange

* Revenue, technology maturity, Capex, and transport to market may vary with plant scale. ** For plant size, the green colour indicates large, the orange colour indicates medium, and the red colour indicates small. For general indicator, the green colour indicates positive/good, the orange colour indicated neutral/fair, the red colour indicates negative/bad, and the grey colour indicates not applicable. Source: author's modification based on [118].

The price, volume, and value of a product may influence the revenue generated from an ANG utilisation option. GTL and LNG display better revenue/product lift (positive) than CNG or any other ANG utilisation option in Table 2. GTF, GTM, and other ANG utilisation options have lower revenues than GTL or LNG, with GRP being the lowest. Table 2 illustrates this statement. Capital costs relate to the overall (fixed and operating) costs associated with converting the ANG into marketable products. These expenses result from the procurement of equipment, the handling and processing of ANG, and product transportation, among other things. Overall plant costs are typically significantly influenced by the complexity of the facilities, the transportability of the equipment, and the accessibility of the location for the ANG utilisation option. When compared to alternative options, GTL plant capital expenditures are often high (labelled as bad or negative in Table 2), although this also depends on the size of the plant. The plant costs for LNG, GTM, GTW, and other options range from medium to high and are categorised in Table 2 as neutral or fair. Capital costs have a significant impact on a project's economic feasibility. For example, if GTL and LNG solutions with high capital costs are to be economically viable, a large plant scale with a consistent high volume of ANG must be used to generate a product revenue that covers the high capital costs.

The growth of diverse technical possibilities for utilising ANG determines technology maturity. These innovations ensure lower process costs, excellent technological feasibility, and process reliability. Most ANG utilisation options (for example, LNG and GTL) have seen significant technological advancement over the years and are classified as positive or good in Table 2, whereas CNG, which has limitations in plant scale, transportation, and storage, has seen less technical advancement than the aforementioned options and is classified as neutral or fair. The NGH is the only ANG option labelled negative or bad since it is technically immature because of unresolved issues, implying a concern for near-term use [120]. Transportation to market includes the entire (fixed or operating) transportation expenses, as well as the feasibility of getting the products to the consumer. The distance to market and manner of transportation has significant impacts on transportation costs. Liquid products are easier to transport than gaseous products. GTL, GTM, and GTW may be advantageous (positive) for short to medium distances, whereas LNG may be less advantageous for short distances but advantageous or fair (neutral) for medium to long distances. Due to their fluctuating cost with distance, GTF, GTP, LPG, and NGH are also labelled as neutral or fair in Table 2. CNG and GTH are classified as negative or bad because of the former's limited range (preferable for short distances) and the latter's difficulty in storing and transporting hydrogen. Since GRP is exclusively intended for onsite use, transportation to market is not applicable.

High carbon and energy efficiency signify low carbon-intensive fuel products and less energy loss. LNG, GTH, GTM, CNG, GTP, and LPG are categorised as positive or good either because of their low carbon-intensive products or low energy loss, while GTL, GTW, NGH, and GTF are categorised as neutral or fair because of their moderate carbon-intensive products and moderate or high energy loss (see Table 2). GRP has the lowest carbon and energy efficiency compared to other options and is categorised as negative or bad. The more complex an ANG utilisation option is, the less secure are the operational safety and procedures because of increased risk. All ANG utilisation options are categorised as neutral or fair in Table 2 (because of their complexities, which vary with plant size) except GRP and GTP, which are categorised as positive or good because of their less complex mode of operation.

Community interdependence is a good choice motivator. GTW and six (6) other ANG utilisation alternatives have a favourable or good position for community synergy, which is needed for market expansion and cost savings. This boosts local oil and gas content. In Nigeria, most ANG generated in onshore oil fields are converted to electricity (through GTW) and used to supplement onsite and nearby power deficits. GTP and two other ANG utilisation options are categorised as neutral or fair while GRP is categorised as negative or bad since it has the lowest synergy with the community. A product's value, price, and volume, amongst other factors, influence the product's market size. The LNG, GTL, GTW, and LPG options have positive or good product market sizes, are more established, and are less volatile because of their products' high value, good price, larger revenue, and large available volume, while other ANG utilisation options except GRP have moderate (neutral or fair) product market sizes owing to their products' moderate price or low available volume or more volatile nature. GRP has the least product market size as no product or revenue is generated (see Table 2).

LNG offers flexibility, diversification, and supply assurance over pipelines [121]. For vast distances and offshore fields, LNG is preferable to pipelines. In addition, pipelines between countries can be hampered by terrorist strikes and political upheaval [121]. GTM has an advantage over GTH since it produces methanol, a cleaner liquid than hydrogen (or other fuels and gasoline) that is easy to store and transport. Unlike other liquid fuels, methanol may be converted into several key by-products. CNG is used commercially as an alternative to other ANG alternatives for small volumes and short distances, limiting its use for longer distances. NGH's lower fuel density and limited gas volume create problems compared to LNG. Due to the intricacy of the NGH process, slow hydrate formation rates, and high prices, no projects are commercialised [122], although scientific progress continues.

Methanol can utilise existing heat engines (such IC engines/turbines) and infrastructure with few adjustments [123]. Methanol has lower pollutants and a higher-octane rating than gasoline [123]. GTM is better than GTH since hydrogen storage is difficult.

GTL facilities are more complex, inefficient, and expensive than LNG ones. However, depending on plant size, GTL and LNG may have comparable capital costs [124]. GTF, GTM, and other ANG utilisation alternatives have lower revenues than GTL or LNG, with GRP being the lowest, and their Capex, while fair, is comparable depending on plant scale. Table 2 illustrates this.

A cost–benefit analysis of CNG versus local LNG liquefaction shows that CNG is more cost-effective for smaller plants with fewer backup hours; 500 MWh per week is CNG and LNG's break-even point (i.e., 5 hours per week for a 100 MW plant, 10 hours per week for a 50 MW plant, etc.) [46,125].

GTM, GTL, and GTH have similar modes of operation, but Table 2 shows a little variance. The GTM product (methanol) is easier to bring to market than the GTH product (hydrogen), providing the GTM process an advantage. Compared to GTL, GTM produces fewer carbon emissions and has less energy loss. Depending on plant size, GTM's and GTL's energy efficiencies may be similar.

Natural gas pipelines are the best route to transport stranded ANG, but output is usually limited to current infrastructure. The cost of new pipes is high and only justifiable for large capacity [126]. Another interesting approach is CNG, although it has limited capacity. CNG is cheaper to manufacture and store than LNG because it does not require cooling or cryogenic tanks. CNG, on the other hand, requires a much larger capacity to hold the energy equivalent of gasoline and extremely high pressures (205 to 275 bar) [127].

LNG is used to transport natural gas across long distances by ship, train, or pipeline, where it is converted to CNG and delivered to the end customer [127]. CNG is stored at high pressure, whereas LNG is uncompressed liquid. LNG has more energy per unit volume than CNG, making it better for long-distance road vehicles [120]. LNG requires handling and equipment, but CNG does not. Because CNG is light, leaks evaporate quickly. It has an unlimited hold period; thus, fuel is never wasted. Moreover, CNG is safer than LNG.

The GRP is not marketable because it is only used on site. Its limited ability to generate revenue makes it unattractive to investors. The novelty of the NGH process that is due to uncertainties and hurdles renders it less appropriate for use. As with CNG, NGH's key problem may be continuous gas generation [128]. NGH requires less room than LNG. NGH, which is safer than CNG, needs good shipboard storage.

Tables 2 and 3 show techniques that favour adequate ANG utilisation (>170 MMscfd) and can be scaled down to accommodate stranded ANG fields. Any of the above ANG utilisation strategies will help reduce flaring in Nigeria, pending additional decision drivers.

Offshore LNG has been implemented with up to 3 Mtpa production, whereas GTH technologies are still in the early stages of development. Due to the obvious immaturity of the technology and the large scale-up factors necessary to attain a commercial process offshore, a GTH transportation alternative is not technically possible. No clear indication exists of when GTH will be commercially available at commercial gas rates. Offshore GTM and GTL technologies are also commercially accessible. Floating GTW/offshore GTW via subsea cable is mature but limited in market distance. Table 3 shows ANG plant-scale summaries.

Overall, LNG is safer than diesel (made by the GTL FT process) and high-sulphur fuel oil because of its low sulphur content, lack of particle emissions during combustion, and lower real CO_2 emissions. Gas-to-wire (GTW) converts gas into power that can be brought to shore rapidly and cheaply, without pipelines. Due to its high octane and low emissions, methanol (a GTM product) is a popular gasoline additive. Methanol reduces hydrocarbons and hazardous carbon monoxide emissions [129]. Methanol is a liquid fuel with a high energy density and verified safety record. LNG, GTW, and GTM are in significant demand because of their economic, technological, social, and environmental benefits. This article recognises and proposes them to the Nigerian government as a crucial technology for ANG utilisation.

Table 3. Summary of plant scale for the various ANG utilisation options. Sources: authors' construction based on [46–48,130–134].

ANG Utilisation Technique	Technical Size Range in mmscfd	Production Size Range (Plant Size)	Typical Cost (USD m/mmscfd)
LNG	170–1360 (per LNG train)	1–8 Mtpa	3.5–6.5
GTL	270–1400	27,000–140,000 bpd (1–5.5 Mtpa)	6.5–10
GTM	75–317	1–4 Mtpa	5.5 @ 5 mmscfd [46]
GTW *	0.36–180	1–500 MW	2.8–4.7 @ 0.36 mmscfd [46]
GTH	20–200	22–224 kNm^3/h	2.2–3.2 @ 0.37 mmscfd [46]
GTP*	30–3300	-	Depends on size (in inch) per distance (mile)
CNG	0.25–15	-	1.5–2.5
GTF	75–308 (per train)	1–3 Mtpa	2.2–4.6
GRP *	5–275	-	0.2 @ 5 mmscfd
NGH	>15	>2 Mtpa	120/ton @ 2 Mpta (peak shaving process) [134]
Mini GTL	0.2–150	200–15,000 bpd (0.01–0.6 Mtpa)	4.5
Mini LNG	0.4–50	0.002–0.3 Mtpa	1.2 (+annual Opex at 4.5% of Capex) [46]
Mini GTM	0.3–30	0.004–0.4 Mtpa	15.1 @ 0.3 mmscfd [46]

* Plant scale may vary for GTW (e.g., combined cycle), GTP (due to pipe size) and GRP (due to oil reserve size).

6. Conclusions

Both venting and flaring of natural gas into the atmosphere represent a significant source of greenhouse gases. While the disadvantages of natural gas flaring far outweigh its advantages, utilisation strategies are needed worldwide, especially for countries like Nigeria. However, a shortage of practical strategies for natural gas utilisation, as well as a lack of reliable information and an efficient means to obtain this information to drive investment decisions in gas utilisation projects, has severely hindered associated natural gas (ANG) utilisation in Nigeria. The implementation of gas utilisation projects and the subsequent reduction in gas flaring in Nigeria are still lagging far behind those in other more-developed countries. Here, we have conducted a critical review of the various regulations and technical options for reducing gas flaring in Nigeria. When reviewing the regulations for reducing gas flaring in Nigeria, the overview of natural gas flaring in Nigeria (particularly in the Niger Delta region) shows that this is a major problem for Nigeria. In response, Nigeria has joined the Global Gas Flaring Reduction partnership and working to eradicate routine gas flaring by 2030 while increasing gas utilisation through initiatives such as the Nigerian liquefied natural gas joint venture project, the West African Gas Pipeline project, and the Chevron gas to liquid project.

This led to the review of several ANG utilisation strategies or technical options for reducing gas flaring in Nigeria, as well as a qualitative assessment and comparison of the various ANG utilisation options. This informed the choice of three natural gas utilisation processes, liquefied natural gas (LNG), gas to wire (GTW), and gas to methanol (GTM), which appear to have the greatest potential economic significance.

The oil and gas industry in Nigeria now has a variety of options to consider for capturing and using natural gas from various flare sites or gas fields. Not all these technologies, though, are technically and financially feasible for capturing associated gas on a large and small scale. Since achieving scale, reliance on fuel, and end-product prices are essential elements of the typical flare gas utilisation strategy, several gas utilisation options may not be economically viable for small gas fields. For large gas fields, using just one option might not be the best course of action. However, combining various gas utilisation options could result in synergies that lower both the project's overall cost and the risk associated with the product market. The steps below may help select and improve the technical feasibility and economies of scale for ANG utilisation options in the future:

- Identifying distinct development phases and the necessary ANG utilisation solution (single or combined option),
- Obtaining high-quality input data from appropriate potential investment parties to conduct adequate analysis,
- Techno-economic modelling of various ANG utilisation options (single or combined option), including an examination of potential net positive values,
- Evaluating the net economic impact of the proposed ANG utilisation options (single or combined),
- Evaluating the sensitivity and risks of ANG utilisation option (single or combined option),
- Consider combining supplies from multiple fields (clustering) to enhance the profitability of ANG utilisation through economies of scale, better capacity utilisation, and increased gas value (via increased sustainability of supply).

The implementation of small-scale technologies such as mini-GTL and mini-LNG in small and medium-sized fields has begun to evolve (gaining strength over the years), and the Nigerian government should promote it by involving and convincing multiple investors to invest. The clustering of gas supply to a central ANG utilisation centre must also be promoted since it appears to be the only realistic alternative for sustainable and profitable investments most of the time.

Flare gas new pathways to cleaner fuels: There are still several utilising pathways for ANG, and one of it is converting to blue hydrogen which could be key to producing sustainable energy for everyone which could lead to establishing wider infrastructures and supply chain business opportunities. According to world bank, some 144 billion m^3 of gas is flared each year, once all of it is diverted for blue hydrogen production, 10 million tonnes of hydrogen can be produced.

Author Contributions: Conceptualisation and methodology, R.A., K.P. and N.S.; writing—original draft and editing, R.A.; writing—review, K.P. and N.S.; supervision, K.P. and N.S. All authors have read and agreed to the published version of the manuscript.

Funding: The authors would like to thank Cranfield University for supporting Robin Abu's PhD programme.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The authors confirm that the data supporting the findings of this study are available within the article.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. Shore, D. Making the flare safe. *J. Loss Prev. Process Ind.* **1996**, *9*, 363–381. [CrossRef]
2. Akeredolu, F.A.; Sonibare, J.A. A review of the usefulness of gas flares in air pollution control. *Manag. Environ. Qual. Int. J.* **2004**, *15*, 574–583. [CrossRef]
3. Generon. What Is Gas Flaring?—Why Is It Done and Viable Alternatives. 2019. Available online: https://www.generon.com/what-is-gas-flaring-why-is-it-done-alternatives/ (accessed on 20 August 2022).
4. Emam, E.A. Gas Flaring in Industry: An Overview. *Pet. Coal.* **2015**, *57*, 532–555.
5. Kearns, J.; Armstrong, K.; Shirvill, L.; Garland, E.; Simon, C.; Monopolis, J. Flaring and venting in the oil and gas exploration and production industry, international association of oil. *Gas Prod. Rep.* **2000**, *2*, 288.
6. PriceWaterhouseCoopers (PwC). Assessing the Impact of Gas Flaring on the Nigerian Economy. 2019. Available online: https://www.pwc.com/ng/en/assets/pdf/gas-flaring-impact1.pdf (accessed on 7 July 2022).
7. Ramanathan, V.; Yan, F. Air pollution, greenhouse gases and climate change: Global and regional perspectives. *Atmos. Environ.* **2009**, *43*, 37–50. [CrossRef]
8. Oyewunmi, O.A.; Oyewunmi, A.E. Managing gas flaring and allied issues in the oil and gas industry: Reflections on Nigeria. *Mediterr. J. Soc. Sci.* **2016**, *7*, 643. [CrossRef]
9. The World Bank. Gas Flaring Explained. 2022. Available online: https://www.worldbank.org/en/programs/gasflaringreduction/technical-solutions (accessed on 24 August 2022).
10. IEA. *Flaring Emissions*; IEA: Paris, France, 2021. Available online: https://www.iea.org/reports/flaring-emissions (accessed on 30 July 2022).
11. Jacobs, T. Innovators Seek to Transform Flaring into Money and Power. *J. Pet. Technol.* **2020**, *72*, 24–29. Available online: https://jpt.spe.org/innovators-seek-transform-flaring-money-and-power (accessed on 20 August 2022).
12. Thurber, M. Gas Flaring: Why Does It Happen and What Can Stop It. *Energy Growth.* **2019**. Available online: https://www.energyforgrowth.org/wp-content/uploads/2019/02/Gas-Flaring.pdf (accessed on 20 August 2022).
13. World Bank. Gas Flaring Explained. Global Gas Flaring Reduction Partnership (GGFR). 2021. Available online: https://www.worldbank.org/en/programs/gasflaringreduction/gas-flaring-explained (accessed on 22 July 2022).
14. World Bank. Global Gas Flaring Tracker Report. Global Gas Flaring Reduction Partnership (GGFR). 2022. Available online: https://thedocs.worldbank.org/en/doc/1692f2ba2bd6408db82db9eb3894a789-0400072022/original/2022-Global-Gas-Flaring-Tracker-Report.pdf (accessed on 26 August 2022).
15. EIA. How Much Carbon Dioxide Is Produced When Different Fuels Are Burned? Energy Information Administration. 2021. Available online: https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 (accessed on 10 August 2022).
16. IEA. *Global Energy and CO_2 Status Report 2019*; International Energy Agency: Paris, France, 2019; Available online: https://www.iea.org/reports/global-energy-co2-status-report-2019 (accessed on 10 February 2022).
17. Akhtar, A.; Krepl, V.; Ivanova, T. A combined overview of combustion, pyrolysis, and gasification of biomass. *Energy Fuels* **2018**, *32*, 7294–7318. [CrossRef]
18. World Bank. Financing Solutions to Reduce Natural Gas Flaring and Methane Emissions. 2021. Available online: https://www.worldbank.org/en/topic/extractiveindustries/publication/financing-solutions-to-reduce-natural-gas-flaring-and-methane-emissions (accessed on 20 August 2022).
19. IEA. *Putting Gas Flaring in the Spotlight*; IEA: Paris, France, 2020; Available online: https://www.iea.org/commentaries/putting-gas-flaring-in-the-spotlight (accessed on 20 August 2022).
20. World Bank, Gas Flaring Data 2013–2018 for 85 Countries. 2019. Available online: http://pubdocs.worldbank.org/en/645771560185594790/pdf/New-ranking-Top-30-flaring-countries-2014-2018.pdf (accessed on 10 July 2022).
21. Department of Petroleum Resources (DPR). *Annual Oil and Gas Report*; Ministry of Petroleum in Nigeria: Abuja, Nigeria, 2018.
22. Orimoogunje, O.O.; Ayanlade, A.; Akinkuolie, T.A.; Odiong, A.U. Perception on effect of gas flaring on the environment. *Res. J. Environ. Earth Sci.* **2010**, *2*, 188–193.

23. GAO, Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions. Retrieved 1 November 2017, from U.S. Government Accountability Office. 2004. Available online: http://www.gao.gov/assets/250/243433.pdf (accessed on 20 July 2022).
24. Osuoka, A.; Roderick, P. *Gas Flaring in Nigeria: A Human Rights, Environmental and Economic Monstrosity*; Friends of the Earth International: Amsterdam, The Netherlands, 2005.
25. Niger Delta Environmental Survey (NDES). *Environmental and Socio-Economic Characteristics*; Environmental Resources Managers Ltd.: Lagos, Nigeria, 1997.
26. Imevbore, V.; Imevbore, A.; Gundlach, E. *Niger Delta Environmental Survey Final Report Phase I. Volume. I, Environmental and Socio-Economic Characteristics*; Environmental Resources Managers Ltd.: Lagos, Nigeria, 1997; p. 301.
27. Oil and Gas Journal (OGJ) Editors. 2019 Worldwide Reserves Survey (Table). *Oil Gas J.* **2020**. Available online: https://www.ogj.com/ogj-survey-downloads/worldwide-production/document/14287591/worldwide-reserves-and-production (accessed on 15 August 2022).
28. U.S. Energy Information Administration (EIA). Nigeria: The Overview. *Indep. Stat. Anal.* **2020**. Available online: https://www.eia.gov/international/analysis/country/NGA (accessed on 10 August 2022).
29. National Oil Spill Response and Detection Agency (NOSDRA). Nigeria Gas Flare Tracker: Satellite Gas Flaring Tracking from NOSDRA. 2021. Available online: https://nosdra.gasflaretracker.ng/ (accessed on 28 July 2022).
30. Bassey, N. Gas flaring: Assaulting communities, jeopardizing the world. In Proceedings of the a Paper Presented at the National Environmental Consultation Hosted by the Environmental Rights Action in Conjunction with the Federal Ministry of Environment at Reiz Hotel, Abuja, Nigeria, 10 December 2008; pp. 10–11.
31. Environmental Right Action. Shell's Devastation in Nigeria. The Case Against Shell. 2009. Available online: http://wiwavshell.org/shell%E2%80%99s-environmental-devastation-in-nigeria (accessed on 20 July 2022).
32. Hassan, A.; Kouhy, R. *Gas flaring in Nigeria: Analysis of Changes in Its Consequent Carbon Emission and Reporting*; Accounting Forum; Taylor & Francis: Oxfordshire, UK, 2013; Volume 37, pp. 124–134. [CrossRef]
33. Jaillet, A.; Laurent, J. *Outlook for Flare Reduction in Nigeria*; Technical Reports No. 34; Agence Française de Développement (AFD): Paris, France, 2013.
34. Nigeria Gas Flare Commercialization Programme (NGFCP). *The Flare Gas (Prevention of Waste and Pollution) Regulations*; Nigerian Upstream Petroleum Regulatory Commission: Abuja, Nigeria, 2018.
35. Hedley, T. Nigeria Takes Aim against Gas Flaring in 2020. Africa Oil and Power. 4 September 2020. Available online: https://www.africaoilandpower.com/2020/09/04/nigeria-takes-aim-against-gasflaring-in-2020 (accessed on 17 May 2022).
36. Malumfashi, G.I. *Phase-Out of Gas Flaring in Nigeria by 2008: The Prospects of a Multi-Win Project*; Centre for Energy Petroleum and Mineral Law and Policy (CEPMLP), University of Dundee: Scotland, UK, 2007.
37. Stanley, I.O. Gas-to-Liquid technology: Prospect for natural gas utilisation in Nigeria. *J. Nat. Gas Sci. Eng.* **2009**, *1*, 190–194. [CrossRef]
38. Panagiotidis, D. A Global Perspective of Liquefied Natural Gas Vessels Capacity. Mater's Thesis, Erasmus University Rotherdam, Rotherdam, The Netherlands, 2013. Available online: https://thesis.eur.nl/pub/41240/Panagiotidis-D.-A-global-perspective-of-Liquefied-Natural-Gas-vessels-capacity.pdf (accessed on 20 July 2022).
39. Strozek, A. *Fuel Distribution Networks*; Diplom. De: Hamburg, Germany, 8 October 2009; ISBN 978-3-8366-3654-4.
40. Shi, G.H.; Jing, Y.Y.; Wang, S.L.; Zhang, X.T. Development status of liquefied natural gas industry in China. *Energy Policy* **2010**, *38*, 7457–7465. [CrossRef]
41. Bahadori, A. *Natural Gas Processing: Technology and Engineering Design*; Gulf Professional Publishing: Houston, TX, USA, 2014; ISBN 978-0080999715.
42. Indonesia Climate Change Sectoral Roadmap (ICCSR). Energy Sector Part 3 (Gas Flaring Reduction). 2010. Available online: https://perpustakaan.bappenas.go.id/e-library/file_upload/koleksi/migrasi-data-publikasi/file/Policy_Paper/energy-sector-part-3-gas-flaring-reduction__20110217185935__0.pdf (accessed on 23 August 2022).
43. Elengy LNG: An Energy of the Future. 2020. Available online: https://www.elengy.com/en/lng/lng-an-energy-of-the-future.html (accessed on 24 May 2022).
44. Prima LNG. Benefits of LNG 2020. Available online: https://www.primalng.com/about-lng/benefits-of-lng (accessed on 20 May 2022).
45. Romsom, E.; McPhail, K. The Energy Transition in Asia: The Role of Liquefied Natural Gas and Implications for East African Producers. In *WIDER Working Paper 2020/80*; UNU-WIDER: Helsinki, Finland, 2020; ISBN 978-92-9256-837-5. [CrossRef]
46. Romsom, E.; McPhail, K. Capturing economic and social value from hydrocarbon gas flaring and venting: Solutions and actions. In *WIDER Working Paper 2021/6*; UNU-WIDER: Helsinki, Finland, 2021; ISBN 978-92-9256-940-2. [CrossRef]
47. GGFR. *GGFR Technology Overview: Utilization of Small-Scale Associated Gas*; World Bank: Washington, DC, USA, 2018; Available online: http://pubdocs.worldbank.org/en/801871519953431815/GGFR-TechnologyMASTER-February-2018.pdf (accessed on 12 June 2021).
48. Songhurst, B. LNG Plant Cost Reduction 2014–2018. In *OIES Paper NG137*; Oxford Institute for Energy Studies: Oxford, UK, 2018. [CrossRef]
49. International Gas Union (IGU). *World Liquefied Natural Gas (LNG) Annual Report*; International Gas Union (IGU): London, UK, 2020.

50. Yep, E. Commodities 2021: Global LNG to Continue Growth Trajectory in 2021 but at Slower Pace. S&P Global Commodity Insights, 2020. Available online: https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/123020-commodities-2021-global-lng-to-continue-growth-trajectory-in-2021-but-at-slower-pace (accessed on 15 August 2022).
51. Mordor Intelligence. LNG Market—Growth, Trends, COVID-19 Impact, and Forecasts (2022–2027). 2021. Available online: https://www.mordorintelligence.com/industry-reports/global-lng-market-industry (accessed on 15 August 2022).
52. Shell, R.D. *Shell LNG Outlook 2021*; Royal Dutch Shell: London, UK, 2021; pp. 1–31. Available online: https://www.shell.com/promos/energy-and-innovation/download-the-shell-lng-outlook-2021/_jcr_cotent.stream/1614823770264/2b5b3fdaa9feba85dadc9b3408c200f26eadf85f/lng-outlook-2021-final-pack-updated.pdf (accessed on 15 August 2022).
53. GlobalData Energy. GTL Process: An Excellent Alternative to Reduce Gas Flaring. Offshore Technology, 2020. Available online: https://www.offshore-technology.com/comment/gas-to-liquid-gtl-process/ (accessed on 30 August 2022).
54. Keshav, T.R.; Basu, S. Gas-to-liquid technologies: India's perspective. *Fuel Process. Technol.* **2007**, *88*, 493–500. [CrossRef]
55. Visiongain. Gas to Liquids (GTL) Market Forecast 2020–2030. Market Research. February, 2020. Available online: https://www.marketresearch.com/Visiongain-v1531/Gas-Liquids-GTL-Forecast-13241729/ (accessed on 20 August 2022).
56. Dalena, F.; Senatore, A.; Marino, A.; Gordano, A.; Basile, M.; Basile, A. Methanol production and applications: An overview. *Methanol* **2018**, 3–28. [CrossRef]
57. National Institute for Occupational Safety and Health (NIOSH). The Emergency Response Safety and Health Database: Methanol. 2008. Available online: https://www.cdc.gov/niosh/ershdb/EmergencyResponseCard_29750029.html (accessed on 17 March 2022).
58. Bromberg, L.; Cheng, W.K. *Methanol as an Alternative Transportation Fuel in the US: Options for Sustainable and/or Energy-Secure Transportation*; Sloan Automotive Laboratory, Massachusetts Institute of Technology: Cambridge, MA, USA, 2020. Available online: https://afdc.energy.gov/files/pdfs/mit_methanol_white_paper.pdf (accessed on 10 August 2022).
59. Ott, J.; Gronemann, V.; Pontzen, F.; Fiedler, E.; Grossmann, G.; Kersebohm, D.B.; Weiss, G.; Witte, C. Methanol. In *Ullmann's Encyclopedia of Industrial Chemistry*; Wiley-VCH Verlag GmbH & Co. KGaA: Weinheim, Germany, 2012; pp. 1–27. ISBN 978-3527306732. [CrossRef]
60. Mäyrä, O.; Kauko, L. *"Modeling in Methanol Synthesis." Methanol.*; Elsevier: Amsterdam, The Netherlands, 2018; pp. 475–492.
61. Kim, W.S.; Yang, D.R.; Moon, D.J.; Ahn, B.S. The process design and simulation for the methanol production on the FPSO (floating production, storage and off-loading) system. *Chem. Eng. Res. Des.* **2014**, *92*, 931–940. [CrossRef]
62. Alternative Fuels Data Center (AFDC). Methanol. 2020. Available online: https://afdc.energy.gov/fuels/emerging_methanol.html (accessed on 29 May 2022).
63. Research and Markets. Methanol Market Forecast to 2028—COVID-19 Impact and Global Analysis by Derivative End-User Industry (Report ID number-5557886). In *Research and Markets Reports*; Research and Markets: Dublin, Ireland, 2022; 174p, Available online: https://www.researchandmarkets.com/reports/5557886/methanol-market-forecast-to-2028-covid-19?utm_source=GNOM&utm_medium=PressRelease&utm_code=lv2z6s&utm_campaign=1676009+-+The+Worldwide+Methanol+Industry+is+Expected+to+Reach+%2441.9+Billion+by+2028&utm_exec=jamu273prd (accessed on 17 August 2022).
64. IEA. *The Future of Hydrogen*; IEA: Paris, France, 2019. Available online: https://www.iea.org/reports/the-future-of-hydrogen (accessed on 30 August 2022).
65. Liu, K.; Song, C.; Subramani, V. *Hydrogen and Syngas Production and Purification Technologies*; John Wiley & Sons: Hoboken, NJ, USA, 2010; ISBN 978-0-471-71975-5. [CrossRef]
66. IEA. *Hydrogen*; IEA: Paris, France, 2021; Available online: https://www.iea.org/reports/hydrogen (accessed on 30 August 2022).
67. Collins, L. A net-zero world 'Would Require 306 Million Tonnes of Green Hydrogen per Year by 2050': IEA. In *Recharge-Latest Renewable Energy News*; International Energy Agency: Paris, France, 2021; Available online: https://www.rechargenews.com/energy-transition/a-net-zero-world-would-require-306-million-tonnes-of-green-hydrogen-per-year-by-2050-iea/2-1-1011920 (accessed on 20 July 2022).
68. Santhanam, K.S.; Press, R.J.; Miri, M.J.; Alla, V.B.; Gerald, A.T. *Introduction to Hydrogen Technology*; John Wiley & Sons: Hoboken, NJ, USA, 2017.
69. Sonibare, J.A.; Akeredolu, F.A. Natural gas domestic market development for total elimination of routine flares in Nigeria's upstream petroleum operations. *Energy Policy* **2006**, *34*, 743–753. [CrossRef]
70. Indriani, G. *Gas Flaring Reduction in the Indonesian Oil and Gas Sector: Technical and Economic Potential of Clean Development Mechanism (CDM) Projects*; HWWA-Report 253, Hamburg Institute of International Economics (HWWA): Hamburg, Germany, 2005.
71. GGFR. Flared gas utilisation strategy opportunities for small scale uses of gas. In *Global Gas Flaring Reduction Report No. 4*; World Bank Group: Geneva, Switzerland, 2004.
72. Anosike, N.; El-Suleiman, A.; Pilidis, P. Associated gas utilization using gas turbine engine, performance implication—Nigerian case study. *Energy Power Eng.* **2016**, *8*, 137–145. [CrossRef]
73. Lammey, M. Gas to Wire Could Hold the Key to Further Cost Cuts, OGA Says. Energy Voice. 2018. Available online: https://www.energyvoice.com/otherenergy/181878/gas-to-wire-concept-could-hold-key-to-further-cost-cuts-oga-says/ (accessed on 20 May 2022).
74. Nigerian Electricity Regulation Commission (NERC). Generation: Power Generation in Nigeria NERC. 2020. Available online: https://nerc.gov.ng/index.php/home/nesi/403-generation (accessed on 20 August 2022).

75. Statista. Electricity Generation in Nigeria in 2020 and 2021. Statista Energy and Environment. 2022. Available online: https://www.statista.com/statistics/1294835/annual-electrical-energy-generation-in-nigeria/ (accessed on 20 August 2022).
76. Ediri, E. Power Generation: Nigeria's Average Unutilized Power Rises 291% to 3008.1MW in 8 Years. Vanguard Nigeria. 2021. Available online: https://www.vanguardngr.com/2021/11/power-generation-nigerias-average-unutilized-power-rises-291-to-3008-1mw-in-8-years/ (accessed on 20 August 2022).
77. Soltanieh, M.; Zohrabian, A.; Gholipour, M.J.; Kalnay, E. A review of global gas flaring and venting and impact on the environment: Case study of Iran. *Int. J. Greenh. Gas Control* **2016**, *49*, 488–509. [CrossRef]
78. Odumugbo, C.A. Natural gas utilisation in Nigeria: Challenges and opportunities. *J. Nat. Gas Sci. Eng.* **2010**, *2*, 310–316. [CrossRef]
79. Alternative Fuels Data Centre (AFDC) U.S. Department of Energy, United States of America. 2004. Available online: http://www.eere.energy.gov/afdc/altfuel/whatis_gas.html (accessed on 17 February 2022).
80. Wong, W.L. *Compressed Natural Gas as an Alternative Fuel in Diesel Engines*; University of South Queensland: Queensland, Australia, 2005; pp. 1–118. Available online: https://eprints.usq.edu.au/532/1/WONGWeiLoon-2005.pdf (accessed on 10 September 2022).
81. Venkateswarlu, K.; Murthy, B.S.R. *Alternative Fuels and Advanced Vehicle Technologies*; PHI Learning Pvt. Ltd.: Delhi, India, 2020; ISBN 978-81-94685-16-6.
82. United States Environmental Protection Agency. Clean Alternative Fuels: Compressed Natural Gas. 2002. Available online: http://www.epa.gov/otaq/consumer/fuels/altfuels/420f00033.pdf (accessed on 2 June 2022).
83. Saurabh, D.; Yerukula, E.P. Compressed Natural Gas Market Research. In *Allied Market Research*; Allied Market: Portland, OR, USA, 2022; Available online: https://www.alliedmarketresearch.com/compressed-natural-gas-market#:~{}:text=Compressed%20Natural%20Gas%20Market%20Research,8.2%25%20from%202021%20to%202030 (accessed on 12 July 2022).
84. Tractebel Engineering SA. *CNG for Commercialization of Small Volumes of Associated Gas*; GGFR and World Bank Group: Washington, DC, USA, 2015; Available online: https://openknowledge.worldbank.org/handle/10986/25918 (accessed on 12 June 2022).
85. Stenning, D.; Fitzpatrick, J. ABS Approves New CNG Carrier: The CNG Optimum 200. Gastech Insights, 2020. Available online: https://gastechinsights.com/node/5287 (accessed on 6 July 2022).
86. Research Dive. Global Fertilizer Market Analysis. 2021. Available online: https://www.researchdive.com/press-release/fertilizer-market.html (accessed on 20 July 2022).
87. Nelson, K.; Scharf, P.; Burdick, B.; Stevens, G. *Rescue N Applications for Corn: Yield Response, Leaf Burn, and Yield Loss*; University of Missouri: Columbia, MO, USA, 2004; p. 59.
88. The International Plant Nutrition Institute (IPNI). Nutrient Source Specifics. IPNI Canada. 2019. Available online: http://www.ipni.net/specifics-en (accessed on 19 July 2022).
89. Havlin, J.L.; Tisdale, S.L.; Nelson, W.L.; Beaton, J.D. *Soil Fertility and Fertilizers: An Introduction to Nutrient Management*, 6th ed.; Prentice Hall: Upper Saddle River, NJ, USA, 1999.
90. Medeiros, J.A. Management Alternatives for Urea Use in Corn and Wheat Production. Ph.D. Thesis, University of Missouri, Columbia, MO, USA, 2006.
91. IHS Markit. Urea Fertilizer Market and Price Analysis. S&P Global. 2022. Available online: https://ihsmarkit.com/products/fertilizers-urea.html#:~{}:text=Urea%20is%20the%20most%20widely%20used%20nitrogen%20fertilizer,tonnes%20of%20urea%20are%20produced%20and%20consumed%20annually (accessed on 14 July 2022).
92. Wigmoretrading. How to Export Nitrogenous Fertilizers From Nigeria: The Complete Guide. 2021. Available online: https://wigmoretrading.com/how-to-export-nitrogenous-fertilizers-from-nigeria-the-complete-guide/ (accessed on 23 August 2022).
93. Lyons, W.C.; Plisga, G.J. *Standard Handbook of Petroleum and Natural Gas Engineering*; Elsevier: Amsterdam, The Netherlands, 2011.
94. Alvarado, V.; Manrique, E. Enhanced oil recovery: An update review. *Energies* **2010**, *3*, 1529–1575. [CrossRef]
95. Speight, J.G. *Introduction to Enhanced Recovery Methods for Heavy Oil and Tar Sands*; Gulf Professional Publishing: Houston, TX, USA, 2016; ISBN ISBN: 9780128499061.
96. Schmidt, V.A. Social contracts under siege: National responses to globalized and Europeanized production in Europe. In *Global Capitalism Unbound*; Palgrave Macmillan: New York, NY, USA, 2007; pp. 113–129.
97. Ojijiagwo, E.; Oduoza, C.F.; Emekwuru, N. Economics of gas to wire technology applied in gas flare management. *Eng. Sci. Technol. Int. J.* **2016**, *19*, 2109–2118. [CrossRef]
98. Hughes, R. Processing of natural gas offshore. In *A Paper Presented in a Symposium on Production and Processing of Natural Gas*; King Saud University: Riyadh, Saudi Arabia, 1992.
99. EIA. Natural gas processing: The crucial link between natural gas production and its transportation to market. In *Energy Information Administration, Office of Oil and Gas*; Energy Information Administration: Washington, DC, USA, 2006.
100. Adegoke, A.A. Utilising the Heat Content of Gas-to-Liquids by-Product Streams for Commercial Power Generation. Master's Thesis, Texas A & M University, College Station, TX, USA, 2006.
101. Research and Markets. Pipeline Transport Global Market Report 2022. In *Cision PR Newswire*; Research and Markets: Dublin, Ireland, 2022; 20p, Available online: https://www.prnewswire.com/news-releases/pipeline-transport-global-market-report-2022-301523838.html#:~{}:text=The%20global%20pipeline%20transport%20market%20is%20expected%20to%20grow%20from,(CAGR)%20of%207.7%25 (accessed on 29 June 2022).

102. Ajagbe, O. *Natural Gas Utilization: A Case Study of GTW and GTL Technologies*; University of Oklahoma: Norman, OK, USA, 2019; Available online: https://shareok.org/bitstream/handle/11244/321400/2019_Olwatobi_Ajagbe_Publication.pdf?sequence=1 (accessed on 15 September 2022).
103. Sloan, E.D. Natural gas hydrates. *J. Pet. Technol.* **1991**, *43*, 1414–1417. [CrossRef]
104. Wilson, A. Comparison of Various Offshore Industrial Gas Technologies. *J. Pet. Technol.* **2018**, *70*, 73–75. [CrossRef]
105. Hancock, S.; Boswell, R.; Collett, T. Development of deepwater natural gas hydrates. In Proceedings of the Offshore Technology Conference, Houston, TX, USA, 6–9 May 2019.
106. Boswell, R.; Collett, T.S. Current perspectives on gas hydrate resources. *Energy Environ. Sci.* **2011**, *4*, 1206–1215. [CrossRef]
107. Gudmundsson, J.S. Method and Equipment for Production of Gas Hydrates. Norwegian Patent No. 172080, 1990.
108. Gudmundsson, J.S.; Parlaktuna, M. Storage of natural gas hydrate at refrigerated conditions. In Proceedings of the AICHE Spring National Meeting, New Orleans, LA, USA, 1992; p. 27.
109. Gudmundsson, J.S.; Parlaktuna, M.; Khokhar, A.A. Storage of natural gas as frozen hydrate. *SPE Prod. Facil.* **1994**, *9*, 69–73. [CrossRef]
110. Visiongain Ltd. Global Liquefied Petroleum Gas Market. In *GlobeNewswire*; Visiongain: London, UK, 2022; Available online: https://www.globenewswire.com/en/news-release/2022/04/05/2416842/0/en/Global-Liquefied-Petroleum-Gas-market-is-projected-to-grow-at-a-CAGR-of-5-02-By-2032-Visiongain-Research-Inc.html (accessed on 19 July 2022).
111. Akpan, S.E. Production and Utilization of Natural Gas Resources in Nigeria-A Review. In *Nigeria Annual International Conference and Exhibition*; OnePetro: Abuja, Nigeria, 2009.
112. Emmanuel, E.O.; Yusuf, F.A.; Caleb, N.S. Towards Effective Domestic Natural Gas Utilisation in Nigeria. *Int. J. Eng. Mod. Technol.* **2018**, *4*, 2504–8856.
113. Texas Comptroller of Public Accounts (TCPA). Liquefied Petroleum Gas (LPG). In *The Energy Report Q. 2008*; TCPA: Crockett, TX, USA, 2008.
114. Oyekale, A.S.; Dare, A.M.; Olugbire, O.O. Assessment of rural households cooking energy choice during kerosene subsidy in Nigeria: A case study of Oluyole Local Government Area of Oyo State. *Afr. J. Agric. Res.* **2012**, *7*, 5405–5411.
115. Bamiro, O.M.; Ogunjobi, J.O. Determinants of household energy consumption in Nigeria: Evidence from Ogun State. *Res. J. Soc. Sci. Manag.* **2015**, *4*, 35–41.
116. Akpan, U. NLPGA Commends NLNG as It Sets out to Supply 100% LPG Output to Domestic Market. Vanguard Energy. 2022. Available online: https://www.vanguardngr.com/2022/02/nlpga-commends-nlng-as-it-sets-out-to-supply-100-lpg-output-to-domestic-market/ (accessed on 23 August 2022).
117. National Petroleum Investment Management Services (NAPIMS). Gas Operations: Gas Utilisation Projects. NNPC Group. 2021. Available online: https://napims.nnpcgroup.com/ourservices/Pages/Gas-Operations.aspx (accessed on 18 July 2022).
118. Svensson, B. Best practices for Evaluating and Reducing Emissions from Oil and Gas Production: An Evaluation of Flare Gas Reduction Opportunities. Methane Expo 2013-Global Methane Initiative. GGFR. 2013. Available online: https://www.globalmethane.org/expo-docs/canada13/og_12_Svennson.pdf (accessed on 28 June 2022).
119. Haugland, T.; Saunier, S.; Pederstad, A.; Holm, T.; Darani, H.; Kertesheva, A. Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan. 2013. Available online: https://www.ebrd.com/downloads/sector/sei/ap-gas-flaringstudy-final-report.pdf (accessed on 20 August 2022).
120. Nwaoha, C.; Wood, D.A. A review of the utilization and monetization of Nigeria's natural gas resources: Current realities. *J. Nat. Gas Sci. Eng.* **2014**, *18*, 412–432. [CrossRef]
121. Mokhatab, S.; Mak, J.Y.; Valappil, J.V.; Wood, D.A. *Handbook of Liquefied Natural Gas*; Elsevier: Amsterdam, The Netherlands, 2014.
122. Rodgers, R.E.; Zbong, Y.; Arunkumar, R.; Etheridge, J.A.; Pearson, L.E.; Cown, J.M.; Hogancamp, K. Gas hydrate storage process for natural gas. *GasTIPS Winter* **2005**, *12*, 34–39.
123. Shekhar, C. Methanol: The New Hydrogen. *Technol. Rev.* **2006**, *109*, 55–72.
124. Dong, L.; Wei, S.A.; Tan, S.; Zhang, H. GTL or LNG: Which is the best way to monetize "stranded" natural gas? *Pet. Sci.* **2008**, *5*, 388–394. [CrossRef]
125. Berg, H. Natural Gas Takes the Role as Backup Fuel. Wärtsilä: Helsinki, Finland. 2018. Available online: https://www.wartsila.com/twentyfour7/in-detail/natural-gas-takes-the-role-as-backup-fuel (accessed on 17 July 2022).
126. Kezirian, M.T.; Phoenix, S.L. Natural gas hydrate as a storage mechanism for safe, sustainable and economical production from offshore petroleum reserves. *Energies* **2017**, *10*, 828. [CrossRef]
127. Speight, J.G. *Natural Gas: A Basic Handbook*; Gulf Professional Publishing: Houston, TX, USA, 2018.
128. Saavedra, C.G. Application of Gas Industrial Technologies Offshore. In Proceedings of the Offshore Technology Conference, Houston, TX, USA, 4 May 2017.
129. Bechtold, R.L.; Goodman, M.B.; Timbario, T.A. *Use of Methanol as a Transportation Fuel*; Methanol Institute: Charleston, WV, USA, 2007.
130. Walker, I.; Madden, B.; Tahir, F. *Hydrogen Supply Chain Evidence Base*; Element Energy Ltd.: Cambridge, UK, 2018.
131. Joshi, S.; Hussain, H.; Tiwari, P.; Rahman, D.; Aldajani, T. *Improve Gas Turbine/Engine Performance and Reduce Maintenance Using Membranes for Fuel Gas Conditioning*; Membrane Technology and Research: Newark, CA, USA, 2015; Available online: https://www.mtrinc.com/wpcontent/uploads/2018/09/NG08-MTR-Power-Gen-NG-2015.pdf (accessed on 29 June 2022).

132. Basye, L.; Swaminathan, S. *Hydrogen Production Costs—A Survey (No. DOE/GO/10170-T18)*; Sentech, Inc.: Bethesda, MD, USA, 1997.
133. Ahmadi, M.A.; Zeinali Hasanvand, M.; Shokrolahzadeh, S. Technical and economic feasibility study of flue gas injection in an Iranian oil field. *Petroleum* **2015**, *1*, 217–222. [CrossRef]
134. Mannel, D.; Puckett, D. *Transportation and Storage of Natural Gas Hydrates*; University of Oklahoma: Norman, OK, USA, 2008; Available online: https://ou.edu/class/che-design/a-design/projects-2008/Gas%20Hydrate%20Transportation.pdf. (accessed on 22 August 2022).