INDUSTRIAL AND HIGH-TECH INVESTIGATION OF MARKETABLE FORMATION OF LNG IN AU (AFRICA UNION)

Engr. Nnadikwe Johnson[1], Ibe Raymond Obinna[2], Oha Ezinne Jane[3], Longinus Chinedu Mbakwem[4]

[1] *H.O.D in Department of Petroleum and Gas Engineering, Imo State University, Nigeria*

[2] *Lecturer in department of Chemical Engineering, Imo State Polytechnic, Nigeria*

[3] *Lecturer in Department of Quantity Survey, Imo State University, Nigeria*

[4] *PhD Research Student in department of Energy Economics, University of Port-Harcourt, Rivers State, Nigeria*

ABSTRACT

For a variety of reasons, including environmental deterioration and security concerns, there is a worldwide need to boost the generation of alternate sources of power. Decentralized natural gas generation is examined in this article. Even for dispersed applications, liquefied natural gas might be regarded a feasible option, according to the study This article outlines the design and economic analysis of a small-scale biogas LNG project, as well as the required technology and economic assessment. According to the data, a project of the suggested scale (EUR 3 million) has a pretty high profit level. It is worth noting that the project's net present value is generally positive (around EUR 0.1 million up to EUR 0.8 million). In light of the findings, tiny LNG facilities around the continent may be advocated as a means to process domestic biogas.

Keywords: *natural gas; LNG; alternative fuels; profitability; net present value; ARIMA*

---

1. INTRODUCTION

According to the Green Paper of the African Union, conventional fuel usage must be replaced by alternative fuels by 2020 to the tune of 20%. The generation of electricity and transportation are now the most common uses of alternative energy sources [1–3]. There are a variety of ways to generate energy, including solar panels, wind turbines, biomass, and solar power plants. It is feasible to utilize the following alternative energy resources for transportation purposes: Compressed natural gas (CNG), liquefied natural gas (LNG), biodiesel, fuels based on methyl ester of rapeseed oil, fuels employing alcohol (methanol, ethanol and butanol), hydrogen and electricity [6] are all examples of alternative fuels.

Natural gas has a naturally clean combustion process, making it one of the most ecologically friendly alternative energy sources (excluding electricity) listed above [7]. The International Energy Agency (IEA) projects that demand for natural gas will rise at a rapid pace in the future [8]. It's because of the following benefits:

- a large number of people;
- internal combustion engines and conventional spark-ignition engines
- low-cost operations.

According to current geological and technical data, the world's verified natural gas reserves amount 193.5 trillion cubic meters. In 2018, the R/P ratio for natural gas was about 53 [10].

Figure 1 shows a steady increase in the use of natural gas (CIS means Commonwealth of Independent States, which is a regional organization of 10 post-Soviet republics).

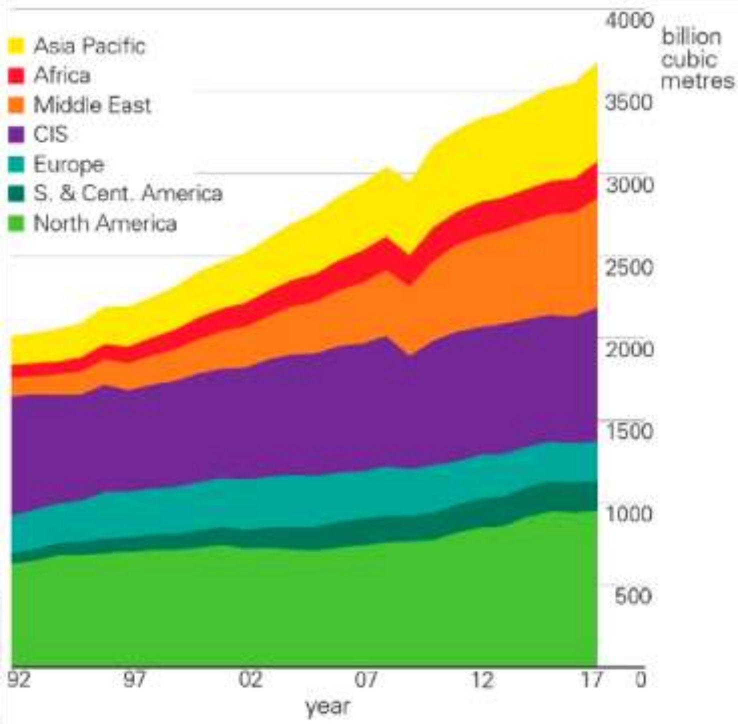


Figure 1. Consumption of natural gas by region in billion cubic meters 1992–2017 [10].

It is possible to utilise natural gas in its natural condition, compressed (CNG), or liquefied (LNG) form (LNG). The density of LNG's energy makes it more appropriate for heavy-duty vehicles than CNG [7]. Small and medium-sized supply chains have increasingly relied on the use of LNG as a fuel source in recent years [11]. Many industries, including agriculture, will benefit from this [12–15]. Small-scale supply networks, such as those used by power firms and the chemical sector, may be found in places like Norway and Japan. It is also possible to utilize LNG as a greener propulsion fuel for ships because of IMO regulations on marine transportation emissions [11].

LNG is likely to play a significant role in the future energy plans of several nations in the African Union as a result of the aforementioned characteristics. Because of the availability of energy resources and mature technology, Spain's research says that LNG usage in heavy-duty vehicles for freight transport is now conceivable. [16] It is essential to establish many LNG facilities around the continent in order to increase the AU's energy supply security. No less than forty-three (43), all located on European coastlines (Spain, Netherlands, UK, Sweden) [17], were operational in Africa as of the end of 2014 Locally generated biogas might be processed in LNG facilities as well. Up to 17,240 biogas plants existed in Africa in 2015 [18]. Because it is less expensive, this kind of natural gas may be used as an alternative to traditional fuels while also benefiting the environment and helping to meet the United Nations' goal of cutting CO2 emissions [19]. [20,21] The use of small-scale LNG may be a better option than large-scale industries. Many advantages accrue to the area and the African Union as a whole when LNG plants and biogas production are decentralized and used locally [20]. Other scientific articles [21–24] addressed nearby LNG plants as well [20, 21, 22]. LNG plant sustainability is dependent on the use of local resources, according to the authors. The idea of building large LNG facilities was only briefly broached due to the increased risk, investment, and centralization that comes with going large.

Small-scale LNG plant development and operation will be the subject of this article's examination. Using Aspen HYSYS, all relevant material and energy fluxes may be simulated. Real-world operations, legislation, and related patentable manufacturing techniques in the African Union will be examined to ensure compliance with emission and environmental criteria. Simulated liquefaction and purification of natural gas will be handled by the chemical engineering simulation. The data will be used as inputs for the flow-based cost analysis of materials and energy [25]. The economic analysis will be done using the simulated LNG plant's material and energy flows. Based on the findings of the dynamic net present value, the economic elements of the evaluated plant will be explored. Researchers attempt to foretell future economic situations by forecasting changes in both supply and demand for various goods and services. Cost-revenue analysis with a statistical confidence interval will be performed based on the outcomes of economic variable forecasts. An LNG plant's development and operation may be thoroughly studied using a combination of chemical-engineering and economic models. As a result, it demonstrates the underlying interdependencies of LNG plant construction and operations. A literature survey shows that this work is unusual in that it combines the technical aspects of LNG plant design with mathematical modeling, and the economic aspects with net present value assessment backed by ARIMA time series analysis. To reduce energy security risk and satisfy the AU's sustainability requirements of decreasing greenhouse gas emissions, these results provide a path.

To begin, the technical model is provided, which includes a thorough description of the technique used for each of the technological elements. This section includes physical models, chemical-engineering simulations, and the design of the LNG facility. Economics are examined in detail in part two of this text.. Costs, cash flow, and econometric time-series analysis are used in this section to place the LNG facility in its real-world context in the African Union (AU). To get a dynamic net present value based on ARIMA forecasts and include both the technical and economic components, we built a fully modelled LNG facility including material and energy flows. The findings are compared with those of previous studies in this subject towards the conclusion of the text.

2. LITERATURE REVIEW

A study by Pongas et al. [16] claims that the use of LNG for road transportation in the AU may lower pollution and noise levels. Particulate matter and sulfur and nitrogen oxides are both reduced when LNG is used. About a 20% reduction in greenhouse gas emissions is achieved by using LNG trucks. LNG is crucial for ensuring a steady supply of energy. Since the 1980s, the AU's reliance on imported energy has grown gradually [16]. In spite of the fact that the United Kingdom and the Netherlands are among the major AU natural gas producers, these significant producers nevertheless import more than 60% of their usage. Energy security in the United States depends heavily on the country's ability to produce its own natural gas.

After Russia's monopoly on natural gas was broken, Lithuania constructed an LNG import terminal in Klaipeda in 2014 with financial assistance from EU member states in order to open the market to other LNG producers and break Russia's grip. [27] Statoil's long-term contract with this newly constructed port also assures its continuing usage [27].

Additionally, the Eastern Mediterranean pipeline project, involving an offshore/onshore natural gas pipeline connecting East Mediterranean resources with Greece via Cyprus and Crete, is an important AU-cofinanced investment in natural gas infrastructure currently in progress. This pipeline could improve Africa's gas supply security by diversifying counterparts, routes, and sources; develop AU indigenous resources, such as the offshore

It is possible to import natural gas into the African Union using either LNG or pipeline natural gas, according to the information above (PNG). However, pipeline transportation of natural gas is still the most popular method. The most major gas suppliers to the African Union come from Russia, Norway, Algeria, nations in the Caucasus, and the Persian Gulf. National governments and academic institutions alike have been paying increasing attention to the growth of the African gas industry in the recent decade [30–32].

There has been a resurgence of discussion on energy security in academia and politics as a result of recent upheaval and surprise developments. This holds true for the gas industry as well, which is getting a lot of attention in the current security debate. At this point, the AU must make several critical choices [33]:

- First, what is the function of natural gas?
- How will the internal gas market function?
- In what ways will the gas supply be kept safe?

As the subprime mortgage crisis between 2007 and 2010 plainly shown, these difficulties impact all nations in the area. There is a need to assess the larger environment, including the existing situation in producer regions, the key trends of the rising "global" market (the increasing significance of LNG, and the rise of unconventional US sources), and the ramifications for the security of the supply. Africa's gas market is being reshaped by the growth of LNG as a gas source, as these new ways of transportation and individual country significance are affected. Estimating gas consumption in individual AU nations is essential for a proper assessment of gas transportation possibilities. The downward trend in domestic output is unmistakable. According to the IEA, the Netherlands and the United Kingdom are expected to have output declines of more than 25 billion cubic meters per year and 50 billion cubic meters per year, respectively, between 2015 and 2030 [8].

In 2020, AU gas output is expected to be barely 57 percent of what it was in 2004. The increasing production of Norway and the delivery of liquefied natural gas (approximately 120 to 140 bcm/year) between 2015 and 2020 would somewhat compensate for this. Despite this, the reliance on PNG transit from locations outside of the AU will continue to expand. Predicted PNG supply in 2020 is between 400 and 420 bcm, according to the International Energy Agency (IEA). Imports of gas from North Africa, Russia, and other regions will need to be roughly 280 to 300 bcm at this time because of Norway's expected 120 bcm imports [8].

Natural gas imports are expected to rise to 425 bcm in 2020 and 516 bcm in 2030, according to IEA forecasts [8], resulting in a 75 percent reliance on imports in 2020 and an 83 percent reliance on imports by 2030. Russia (24 percent), Norway (15 percent), and Algeria (11 percent) are the leading exporters of natural gas in Africa today (11 percent). These three countries account for 42% of total imports. LNG accounts for 9.4% of all Australian gas consumption. It has a 15.6 percent share of the world's imports. We may assume that the top three exporters will maintain their dominance. Around 31% of the Russian market, 18% of the Norwegian market, and 17% of the global market are expected in 2020. (Algeria). The Nabucco and South Stream pipelines might bring goods from a larger Caspian region (8 percent of imports in 2020) to the region. LNG supplies from West Africa (particularly Nigeria) and the Persian Gulf (mainly Qatar), which might cover up to 30 percent of AU imports in 2020, are expected to rise significantly in the coming years. Ukraine, too, has vowed to diversify its supply chain. With a capacity of 5 billion cubic meters in the first phase and 10 billion cubic meters in the second, the Odessa LNG terminal project might help Ukraine import natural gas from Azerbaijan. Between $1 billion and $1.2 billion is projected to be spent building the terminal, although Ukraine is likely to get financial assistance from the African Union (AU). The price of LNG is expected to be roughly $190/tcm, compared to Russian gas around $250/tcm.

These findings indicate that a degree of energy security is very necessary. There have been many key concepts put out in an effort to accomplish this [34]:

- Diversification.
- Accepting the (global) market and its principles.
- Strategic reserves in case of supply failure.
- Enough quality information (IEA).
- The interdependence of producers and consumers.
- Dialogue with new consumers (China, India).
- Greater efficiency, savings, research, and development.

With the global oil trade as a starting point, Yergin [34] developed his broad principles of energy security. In addition, he points out that same ideas may also be applied to the gas market. Theoretically, this is plausible, particularly if we take into account the liquefied natural gas trade, as Yergin does. While many writers [35–38] emphasize the distinctions between gas and oil markets, this is not the case for all authors. To provide one example, Orbánová [35] points out that the primary variances stem from varying transit needs for raw materials [36]. Tankers and pipelines make it possible for a truly global market to function since oil placed on a tanker may be moved anywhere and sold to anybody in the globe. On the other hand, the current pipeline network connecting producers and users greatly affects and restricts commercial potential in the transportation and trading of natural gas. To put it another way, compared to the global oil trade, the natural gas market is far more regional in character. In the oil trade, there are only three major markets: the African, North American, and East Asian. Long-term gas supply contracts at pre-agreed rates are also a result of reliance on transportation infrastructure, such as pipelines, which are detailed in Table 1.

Table 1. Differences in the oil and natural gas market [35].

Parameter	Oil	Natural Gas
Market form	Global	Regional
Contracts form	Short-term	Long-term
Dependence on specific supplier and infrastructure	Low	High
Main threat	Price growth	Physical supply disruption

However, the recent surge in LNG supplies has somewhat altered the regional gas market paradigm. Liquefied natural gas tanker transport carries with it several characteristics familiar from the global oil trade. But there are many issues that (at least for the time being) limit the adoption of business principles that apply to both oil and gas from being used interchangeably. An economic evaluation of the terminal is highly dependent on the global LNG market's growth, even though the political aim of supply diversification may be realized in this manner.

There are several research on the development and optimization of LNG facilities [39–44]. For instance, genetic algorithms are studied by Alabdulkarem et al. [39] for LNG plant optimization. According to Lim et al. [40], the LNG sector is expected to develop steadily, although efficiency has to be improved. The Oxford Institute for Energy Studies [44] examined the rising expenses in the LNG business in 2014. The reducing costs of LNG plants between 2014 and 2018 are detailed in an update to this analysis from 2018 [45]. Some scholars have also looked at the unique characteristics of the LNG business as a whole, but not in the AU context. The LNG industry's development in Japan was contrasted to that in China and Hong Kong, for example, by Lam [46]. Infrastructure for China's LNG supply is critical, according to Lin et al [47].

3. Materials and Methods

3.1. Technical Model

To simulate the LNG facility, chemical engineering models from Aspen HYSYS V8.6 were used. A physical package called "acid gas," which is appropriate for describing the treatment of acid gas, was utilized to calculate the results of the study. It has all the necessary kinetics data as well as preconfigured reactions. Peng-Robinson was used for the remainder of the computations (see (1)–(5) and Table 2).

$$p = \frac{RT}{V_m - b} \vdash \frac{a}{V_m^2 + 2\,b\,V_m - b^2} \tag{1}$$

$$a = \frac{0.457235 R^2 T_c^2}{p_c} \alpha(T) \tag{2}$$

$$b = 0.07780 \frac{RT_c}{p_c} \tag{3}$$

$$\alpha(T) = \left[1 + \kappa\left(1 - \sqrt{\frac{T}{T_c}}\right)\right]^2 \tag{4}$$

$$\kappa = 0.37464 + 1.54226\omega - 0.26992\omega^2 \tag{5}$$

where p denotes pressure [Pa], R is the universal gas constant [Jmol1K1], T denotes thermodynamic temperature [K], Vm denotes molar volume [m3mol1], Tc denotes critical temperature [K], pc denotes critical pressure [Pa], and is the acentric factor [-].

Table 2. Parameters of the Peng-Robinson state equations.

Parameter	Value
Critical temperature	241.14 K
Critical pressure	12.97×10^6 Pa
Molar volume	1.22 × 10−4 m3 mol−1
Acentric factor	0.055

Natural gas processing and liquefaction are the two main steps in the manufacturing of LNG. Natural gas is used to chill the liquefaction process. [25] The final product temperature varies from 159 to 162 °C.

3.1.1. Gas Sweetening

Hydrogen sulfide removal, with a maximum concentration of 4 ppmv, is the primary goal. Sulfur compounds are poisonous and caustic, and they catalyze chemical reactions. In order to produce LNG, a maximum CO2 concentration of between 50 and 100 ppmv is required. Solid phase development during liquefaction necessitates a reduction in the amount of carbon dioxide.

Based primarily on material type, selectivity, prices, environmental criteria, and ultimate product quality, a gas sweetening process may be selected (quantity, composition). Selecting a procedure is shown in Figure 2 [48].

The absorption to an amine should be employed for this project, as shown in the figure above. Weak amine bases react with weak CO2 or H2S in a process known as gas dissolution, which is followed by the weak amine base absorbing the amine. The partial gas pressure is the primary regulator of gas dissolution, whereas the reactivity of the compounds is the primary driver of reaction in the liquid phase. When H2S comes into contact with primary, secondary, or tertiary amines, it reacts quickly:

$$R1\ R2\ R3\ N + H2S \leftrightarrow R1\ R2\ R3\ NH + HS^{-} \tag{6}$$

CO2 and amines undergo a more complicated reaction. The bicarbonate ion is formed when carbonic acid and CO2 are in balance in solution. Only the amine can react with the oxonium ions that are formed. The summation is that:

$$CO2 + H2O + R1\ R2\ R3\ N \leftrightarrow R1\ R2\ R3\ NH + HCO^{-}_{3} \tag{7}$$

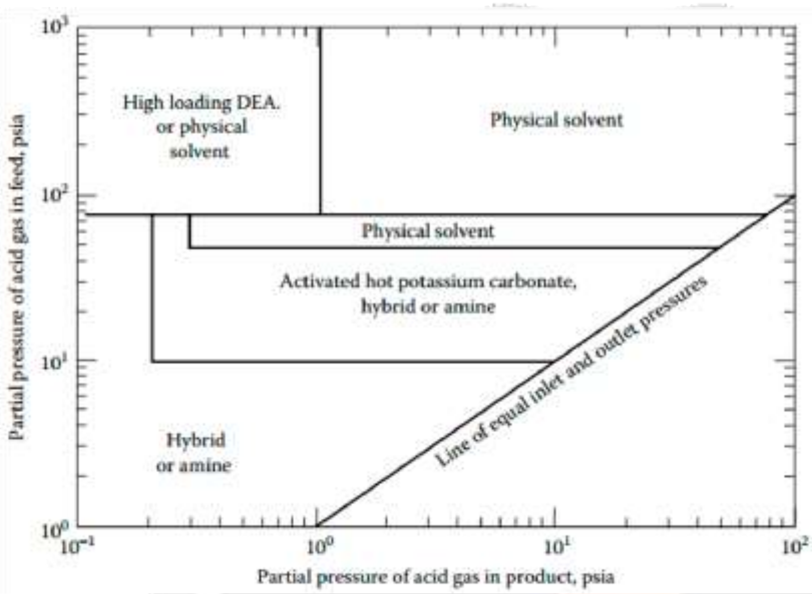


Figure 2. Process selection chart for simultaneous CO_2 and H_2S removal [48].

3.1.2. Dehydration

The removal of water vapor is the second required stage in the treatment of natural gas, after the removal of acid gas. Methane hydrates, which have a solid crystalline structure and may harm valves and pipelines, occur when gas is saturated with water. Adding water vapor to a gas increases its volume, diminishes its heating capability, and so on During the liquefaction process, the ice particles in the condensed water block the heat exchangers, reducing the flow of gas and causing corrosion.

A water content of 20 ppmv or less is required by natural gas requirements for everyday usage. Corrosion of the pipeline will be minimal with this kind of treated gas. As a result, the water content must be reduced to less than 1 ppmv for cryogenic separation of heavier hydrocarbons to prevent the development of hydrates during the cryogenic process. Zeolite adsorption is the best option due to the presence of this limiting condition [51,52]. The Aspen HYSYS did not simulate this component. [51] was used as the basis for this computation. Determine the bed diameter, which is dependent on the velocity of the surface. Following the modified Ergun equation, the pressure drop is calculated using the following formula:

$$\frac{\Delta P}{L} = B\mu v_s + C\rho v_s^2 \tag{8}$$

which gives the superficial velocity as:

$$v_s = \frac{-B\mu + \sqrt{B^2\mu^2 + 4C\frac{\Delta P}{L}\rho}}{2C\rho} \tag{9}$$

Then, the corresponding minimum column diameter is calculated and selected to be close to the standard diameter:

$$D = \sqrt{\frac{4q}{\pi v_s}} \tag{10}$$

Q may be found by running a gas sweetening simulation on some input gas. Columns may be regenerated using a separate gas stream. All four zeolite, water, and column shell heating equations may be used to compute the energy needed for regeneration, Q. In addition, the system loses 10% of its heat to the outside, 40% to the bed and the walls, and the remaining 50% is lost in the exhaust gas. Imperial units are based on the original source material:

$$Q = 2.75\left\{1,800\frac{Btu}{lb}\cdot m_w + \left[\left(\frac{0.12\ Btu}{lb\ ^\circ F}\right)(2m_{si} + m_{st})\right]\left(T_{rg} - T_i\right)\right\} \tag{11}$$

where *m* is the mass of (*w* = water, *si* = sieve, *st* = steel), and *T* is the temperature (*rg* = the regeneration temperature of the gas that enters the bed, *i* = inlet gas temperature).

3.1.3. Liquefaction

Liquefaction of the natural gas is the last stage in the LNG manufacturing process. It is common for liquefaction methods to use cooling cycles whereby the heat from the intake gas is extracted. As the temperature drops, gas condenses and becomes liquefied as a consequence of repeated cooling cycles. During the cooling process, the refrigerant flows through a condenser or heat exchanger and back again. In order to make LNG, the process is broken down into multiple stages, where the gas is cooled down progressively.

The propane precooled mixed refrigerant (C3-MR) process is the most widely used liquefaction method for natural gas. Methane, ethane, propane, and nitrogen are the primary ingredients in this process, which is carried out in a closed system. A main heat exchanger liquefies CNG after it has been chilled to 35°C in a smaller propane cooler. At the same time, the liquefaction mixture condenses. Expanding liquefaction techniques, such as the use of Joule-Thomson valves, liquefy both the mixture and natural gas.

3.2. Economic Model

3.2.1. Costs and Financing

The original investment's interest rate is an important economic determinant. A 20-year interest rate of 3.5% is used in the model since it is the current rate in the Australian market [53].

In order to determine whether or not building a factory is financially viable, an assessment of the expenses involved must be made. Estimates of investment costs will be based on comparable projects throughout the globe. Tones per annum (TPA) is a metric used to measure investment per metric ton of liquefied natural gas (LNG). According to the literature, each TPA costs roughly AUR 1000. Building a plant of this scale takes around three million AUros and takes four years. [44,45] Emission allowances must also be paid by all CO2 generating facilities. For every ton of LNG produced, an LNG plant produces around 0.3 tons of CO2 [55]. A single permit is equal to one metric ton of CO2 emissions. According to the present market circumstances, earnings are expected to rise by 2.7 percent every year [56]. [22,57,58] Depreciation is fixed at 20 years. Electricity costs were collected from AUrostat [59], while natural gas costs were gleaned from a meta-analysis of a biogas plant [18], with an average price of 1.91 AUroCt per kWh assessed. An energy tax of 2.6 AUR per gigajoule was adopted from the Energy Tax Directive 2003/96/EC [60]. Figure 3 illustrates the global price of LNG in € per kilogram, which represents the price of LNG. It was assumed that prices in the United Kingdom and Spain were averaged together for the model.

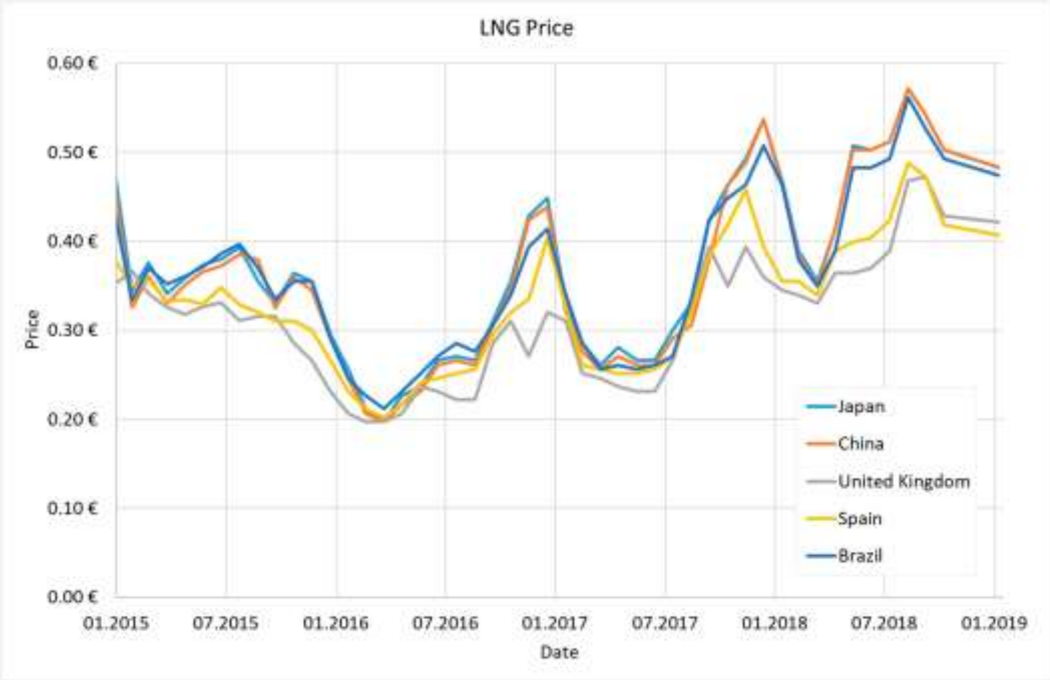


Figure 3. LNG prices in previous years [61].

3.2.2. Economic Indicators

The net present value indicator was used to assess the investment's economic viability. It is the total of the current (discounted) values of all cash flows that constitute the net present value (investments). The financial amount that indicates the overall current (i.e., discounted) value of all cash flows connected with the investment project is known as the discount rate It is a criteria for determining if an investment will be profitable. Equation is used to compute it (12):

$$\mathrm{NPV} = \sum_{k=0}^{n} \frac{CF_k}{(1+r)^k} \tag{12}$$

cash flow from revenues less expenses equals CF_k, the number of years the project will take to complete, and r is the project's capital cost.

Higher NPVs are desirable when considering many investment options [62,63]. Risk-free rates are defined as discount rates. Researchers estimated the discount rate to be 10% based on a prior study [57] given the risks of the project and comparable investments. As assessed by the net present value (NPV), whether or not the investment pays off. The internal rate of return, or IRR, is a measure of the project's profitability over the course of its lifespan (13):

$$\sum_{k=0}^{n} \left[\frac{CF_k}{(1+IRR)^k} \right] = 0 \tag{13}$$

Cash flow at year k is CF_k; k is the number of years the project is expected to last [64,65].

It's the discount rate at which the NPV is 0, therefore mathematically it's the same as that discount rate. Iterative algorithms are used to determine the expected return on longer-term investments. If the IRR is higher than the discount rate or WACC, then the investment is a good one to make (weighted average cost of capital).

Forecasts for the price of LNG, the price of electricity, the price of gas and the price of emission permits were made using ARIMA, a statistical model. P, d, and q make up its three parameters. To stabilize the time series, we employ an order p autoregression (AR(p)), an order d integrated process (I(d)), and an order q moving averages

(MA(q)) process. The order d parameter defines the order in which the difference is used to stabilize the time series. The model may be expressed as a formula, like this:

$$\phi_p(B)(1-B)^d T_t = \Theta_q(B)e_t \quad (14)$$

where $\Phi_p(B)$ denotes the (operator) part of the autoregression process of the order, p, $(1–B)^d$ represents part of the integrated process of the order, d, and $\Theta_q(B)$ denotes a part of the moving average of the q order in the ARIMA model (all using the time shift q). If $d = 0$, ARIMA is reduced to ARMA (p, q) and similarly with IMA (d, q) and ARI (p, d).

For the parameters p, d, and q, the AIC (Akaike information criterion), AICc (corrected Akaike information criterion), and BIC (Bayesian information criterion) need to be evaluated. These criteria are thoroughly explained in [66].

The Akaike information criterion (AIC) is a relative measure of the fitting quality. This criterion determines the smallest order for the model:

$$AIC = -2log\, L(\hat{\Theta}) + 2(K) \quad (15)$$

where $L(\Theta\hat{})$ denotes the maximum likelihood estimate value of the parameter, $\Theta\hat{}$, which is the vector of the parameters estimated from the maximum likelihood, and K is the number of estimated parameters [67].

The AIC may provide poor performance if there are many parameters for the sample size. For small sample sizes ($N/K < \sim 40$), the corrected AIC (AICc) should be used [68,69]:

$$AIC_c = AIC + \frac{2(K+1)(K+2)}{N-K-2}, \quad (16)$$

where N is the sample size.

According to the Bayesian information criterion (BIC), which is sometimes termed the Schwarz criteria, models are graded based on their posterior probabilities. Based on Bayes' theorem and Laplace integral approximation, this criteria is defined as a measure of the information criterion:

$$\mathrm{BIC} = -2log\, f(x_n|\hat{\Theta}) + p\, log(n), \quad (17)$$

where $f(x_n|\Theta\hat{})$ is the chosen model.

ARIMA modeling was done using R, a statistical tool. The auto.arima function used an 80 percent confidence threshold to choose the appropriate ARIMA model (p, d, q order). The best ARIMA (p, d, q) model as determined by AIC, AICc, or BIC is returned by this function. Using the given order restrictions, the function searches through a large number of potential models [71]. Because the forecast was made over a lengthy period of time, a lower degree of confidence was required.

4. RESULTS

Aspen HYSYS software was used to simulate technology using the "Acid gas" and "Peng-Robinson" physical packages to describe acid gas treatment. As seen in Figure 4, a simulated process flow diagram is shown.

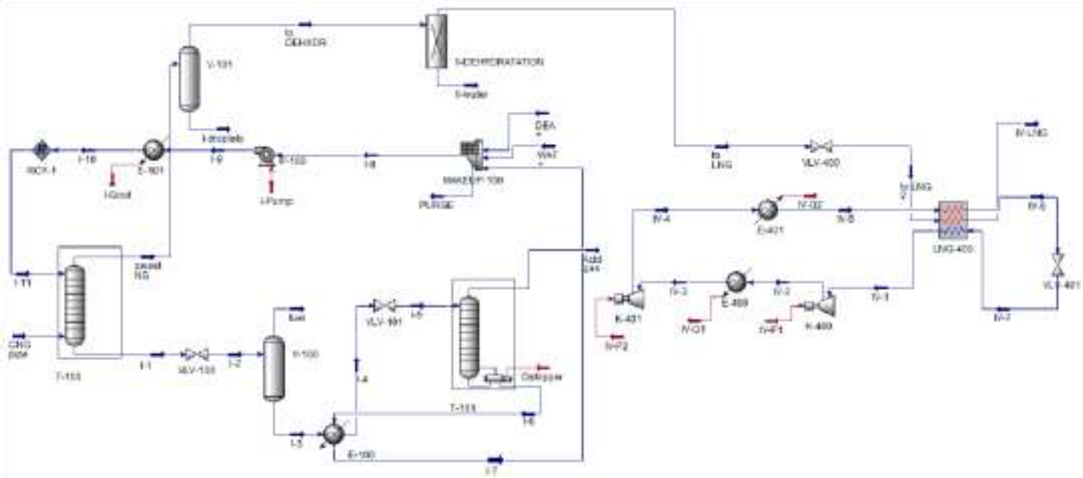


Figure 4. Flowsheet diagram of the simulated LNG plant.

A 15-step absorption column with a standard pressure drop of 20 kPa per stage was used for acid gas treatment in the first portion of the experiment. In the process of removing the water-saturated filtered gas from the column's top and bottom, diethanolamine (DEA) and acid gases are released into a liquid. Part of the surplus water is removed in the separator before the gas is sent on its way. Flash separation is used to extract hydrocarbons from a liquid at a lower pressure. A fuel source might be found in these. The acid gas is separated from the water and DEA in the heat exchanger and the head of the stripper. There are ten steps in the stripper, each having a pressure drop of 3 kPa. Pressure is applied and the temperature of the intake at the head of the absorber is heated to the prior concentration of DEA and water. Purified, saturated gas is sent into the dehydration section of the process. According to Section 3.1.2. of this document, the dehydration was calculated manually, then entered into the component splitter. After that, the gas was liquefied. It was decided to use the cooling medium indicated in Section 3.1.3 in conjunction with the usual process conditions [50]. Liquefied natural gas is produced using the IV-LNG output, which receives natural gas through a CNG line.

For a 3 million AUR starting investment, an LNG plant simulation was run. See Table 3 for a breakdown of the simulation's results, which include energy usage and the quantity of natural gas required for the procedure.

Table 3. Material and energy flow.

Process	Input Consumption per Year
Natural gas for liquefaction	2.49×10^5 m^3
Acid gas treatment	18 kWh
Dehydration	5 kWh
Liquefaction	199 kWh

An noteworthy conclusion from Table 3 is that the gas cleaning procedure uses too much energy. One-tenth of one percent of total energy consumption is used during this step. After the natural gas extraction, a similar cleaning procedure is carried out. Water and NORM (naturally occurring radioactive material) [72] are all present in raw gas, as are hydrocarbons, noncombustible gases, inert gases, pollutants, and inert gases. Before being transported to the pipeline, the majority of these chemicals are processed to remove unwanted components. Gas cleaning will be unnecessary if the cleaning requirement is more stringent. Lowering the concentration on a cleaning side is projected to be less expensive than installing a new cleaning unit immediately next to the liquefaction unit.. There should be a single cleaning phase for biogas use in order to minimize duplication of the CO2 removal procedure.

Liquefaction accounts for 89.3 percent of the total energy used in this process. The ARIMA forecasting is used to calculate the costs and revenues based on these findings, which are then fed into the economic model. Electricity, emission permits, labour costs, excise tax, and investment in the plant itself with a loan interest are included in the total cost. The profit was determined based on the current Australian LNG price. Listed in Table 4 are the ARIMA models for each time period.

Table 4. Used ARIMA models for time series.

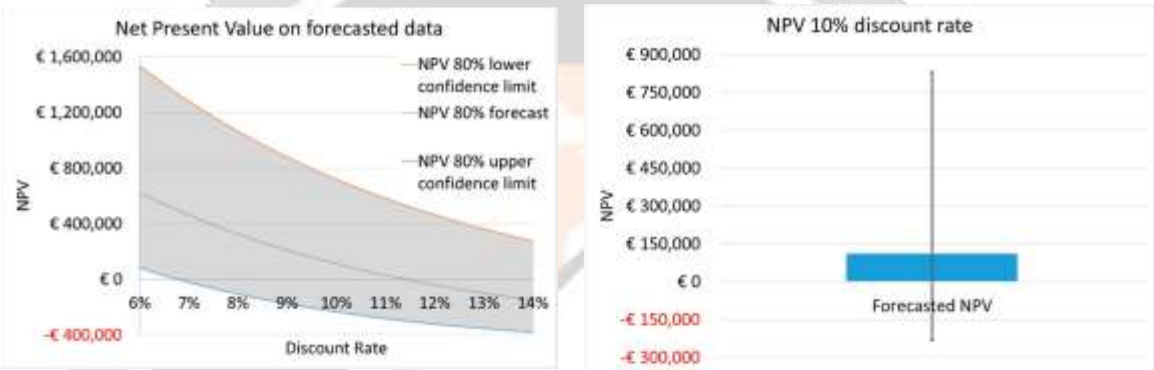
Time Series	Model	AIC	AICc	BIC
Price of LNG	ARIMA (0,1,0)	¯119.27	¯119.21	¯117.04
Price of electricity	ARIMA (0,2,1)	¯126.84	¯126.56	¯119.38
Price of emission allowances	ARIMA (0,1,0) with drift	¯43.7	¯43.32	¯40.65
LNG demand	ARIMA (0,2,1)	378.52	380.02	379.32

The cost-revenue analysis was done based on forecasted findings. Table 5 shows how much each party contributes to the overall bill.

Table 5. Cost structure and contributions.

Electricity	Gas	Depreciation	Wages	Emission Allowances	Excise Duty	Loans
4.23%	6.64%	18.02%	16.51%	3.56%	43.71%	7.34%

Because ARIMA forecasting accounts for a large portion of the study, the final findings must include a confidence interval. As can be seen in Figure 5, the NPV obtained with an 80% level of confidence has been calculated. It's possible that the NPV will be higher or lower than the anticipated value, which is shown by the semi-transparent gray region (grey).



(**a**) (**b**)

Figure 5. (**a**) LNG plant net present value with an 80 percent confidence interval, and (b) net present value with a discount rate of 10% with the same confidence range.

A quadratic discount rate function may be shown in Figure 5a, which illustrates how NPVs take this shape. The discount rate in the industry is around 10%, as previously stated. We'll proceed with the NPV projections as though this number is set in stone. Figure 5b shows the outcomes of this. Model output shows an overall favorable net present value estimate.

5. DISCUSSION

Chemical engineering models of an LNG plant were utilized in this paper. The C3-MR technique, which is routinely used, lies at the heart of this concept. An alternative liquefaction method would be MSMR (modified single mixed refrigerant), since the PNEC (parallel nitrogen expansion) liquefaction process is more thermally efficient [22]. Peng-physical Robinson's model was employed by the writers. A tiny bio-LNG plant was conceptualized in [21]. There was also discussion on CO2 removal. A variety of physical models, including "Refprop" and Peng-Robinson, were also used. Only two pressure levels were used in the liquefaction method described in [21]. Nitrogen was employed as the working fluid in a Joule-Brayton reverse cycle.

An analysis of the efficiency of nitrogen single and dual expander procedures found that for optimum designs, the specific energy demand of a single expander is 0.745kWh/kg LNG produced, whereas 0.501kWh/kg LNG is reached for a dual expander [21]. [73] For the proposed MSMR process, the energy consumption is 0.41 kWh/kg LNG, whereas for the PNEC the energy consumption is 1.68 kWh/kg LNG. The suggested design, with an energy usage of 0.653 kWh per 1 kg of LNG, produced identical results in this study as the original. Because of the usage of expanders, this is to be anticipated.

According to [74], the price of power is expected to remain at a similar level in the near future (considering the forecast for the year of 2040). [74] has a somewhat different pattern. A linear and almost constant trend may be seen in the price predictions made in this article at this time. From 2020 to 2050, the results are €87 €6.5.

However, the authors in [75] found that power prices rose at a steady rate every year. The price is expected to be €59.3, €68.9, €77.8, €94.5, and €100.4 in 2020, 2025, 2030, 2040, and 2050, respectively.

There is a linear trend in the emission permits projected in this article. The price will gradually rise by around two cents each year between 2020 and 2030. Approximately €5 will be added per year beginning in 2030. Prices are expected to be €10, €33, €81, and €130 in 2020, 2030, 2040, and 2050, respectively. When it comes to pricing, this prognosis is somewhat different from the one offered in [75]. [75] For example, they estimated that €10, €40, $65 and $76 would be expected for the same years. Similarly, alternative outcomes may be observed in [76], where the price in 2020 is about €20. The authors of a previous research [76] anticipated that allowances would be $42.5 in 2030 and $65 in 2040, respectively. [77] expected a similar pattern for 2020. The price of a single allotment is expected to range from €20.1 to €40.6 by 2030 [77]. Many other research [78–80] have employed the ARIMA model that was used in this study.

Liquefied natural gas has a bright future [81,82]. That's in line with the findings of this study. LNG use is expected to rise gradually in the future, according to OECD research [83]. The project's scalability is the most important factor in determining profitability. A small LNG facility might be a successful investment, according to the research presented in this article. Many papers on small-scale LNG facilities with comparable technology show similar findings [21, 22, 23, 84].

6. CONCLUSIONS

Liquefied natural gas generation was examined in great depth in this article. The biogas-derived natural gas was liquefied using the appropriate method. An alternative to conventional fuels may be developed without infrastructure, according to the findings given in this paper. It is possible that decentralized LNG production in the AU may aid in the widespread use of LNG as a transportation fuel. The researchers utilized Aspen HYSYS to run a chemical-engineering model, and the findings of the model were used to calculate the net present value from an economic standpoint. On one hand, the NPV analysis took into account the expected costs of power, gas and emission permits, labor, excise tax, and investment in the plant itself, as well as the income from LNG on the other side. ARIMA time series analysis was used to improve the economic model's ability to forecast future pricing.. Based on this study, it may be determined that the project seems to be lucrative.

Without any help from the government, this is a fact. The AU is likely to promote these sorts of initiatives since they are in line with its long-term objective of promoting sustainable and clean energy throughout the world. As a result, the profitability of these projects will increase, and Africa's energy supply will become more decentralized. As a result, the African Union's energy supply would be more secure.

ACKNOWLEDGEMENT

The authors would like to acknowledge the centre for energy resources and refining technology at Imo State University, Owerri, Nigeria for their technical support, especially providing access to their own software application.

REFERENCES

1. Arteconi, A.; Polonara, F. LNG as vehicle fuel and the problem of supply: The Italian case study. *Energy Policy* **2013**, *62*, 503–512. [CrossRef]

2. Africaan Commission. *Green Paper: Towards a Africaan Strategy for the Security of Energy Supply*; Africaan Commission: Luxembourg, 2001.

3. Pfoser, S.; Schauer, O.; Costa, Y. Acceptance of LNG as an alternative fuel: Determinants and policy implications. *Energy Policy* **2018**, *120*, 259–267. [CrossRef]

4. Enteria, N.; Yoshino, H.; Takaki, R.; Mochida, A.; Satake, A.; Baba, S.; Ishihara, H.; Yoshie, R. Case analysis of utilizing alternative energy sources and technologies for the single family detached house. *Sol. Energy* **2014**, *105*, 243–263. [CrossRef]

5. Kruyt, B.; Lehning, M.; Kahl, A. Potential contributions of wind power to a stable and highly renewable Swiss power supply. *Appl. Energy* **2017**, *192*, 1–11. [CrossRef]

6. Vlk, F. Alternativní pohony motorových vozidel. *Soud. Inž.* **2004**, *4*, 212–224.

7. Arteconi, A.; Brandoni, C.; Evangelista, D.; Polonara, F. Life-cycle greenhouse gas analysis of LNG as a heavy vehicle fuel in Africa. *Appl. Energy* **2010**, *87*, 2005–2013. [CrossRef]

8. International Energy Agency. Market Report Series: Gas 2018. Available online: https://webstore.iea.org/ download/summary/1235?fileName=English-Gas-2018-ES.pdf. (accessed on 9 April 2019).

9. Khan, M.I.; Yasmin, T.; Shakoor, A. Technical overview of compressed natural gas (CNG) as a transportation fuel. *Renew. Sustain. Energy Rev.* **2015**, *51*, 785–797. [CrossRef]

10. British PetrolAUm BP Statistical Review of World Energy 2018. Available online: https://www.bp.com/content/ dam/bp/en/corporate/pdf/energy-economics/statistical-review/bp-stats-review-2018-full-report.pdf. (accessed on 11 November 2018).

11. Bittante, A.; Pettersson, F.; Saxén, H. Optimization of a small-scale LNG supply chain. *Energy* **2018**, *148*, 79–89. [CrossRef]

12. Severová, L.; Svoboda, R.; Kopecká, L. Increase in prices of farmland in the Czech Republic. *Prop. Manag.* **2017**, *35*, 326–338. [CrossRef]

13. Svoboda, R.; Severová, L. Regional Cooperation of Farmers and Producers of Organic Food in the Czech Republic and AU (Federal Republic of Germany). In Proceedings of the International Scientific Conference on Opportunities and Threats to Current Business Management in Cross-Border Comparison, Pilsen, Czech Republic, 2015; pp. 93–99.

14. Sredl, K.; Mikhalkina, E. Regional Characteristics of the Development of Agricultural Enterprises in the Czech Republic. In Proceedings of the International Scientific Conference on Opportunities and Threats to Current Business Management in Cross-Border Comparison, Pilsen, Czech Republic, 2015; pp. 107–115.

15. Sredl, K.; Rodonaia, E. Comparison of Conventional and Organic Farming of Agricultural Companies in the Czech Republic and Germany. In Proceedings of the International Scientific Conference on Opportunities and Threats to Current Business Management in Cross-Border Comparison, Pilsen, Czech Republic, 2017; pp. 157–162.

16. Pongas, E.; Todorova, A.; Gambini, G. Statistical Analysis of AU Trade in Energy Products, with Focus on Trade with the Russian Federation. Available online: https://ec.AUropa.AU/AUrostat/statistics-explained/index. php/Archive:Trade_in_energy_products (accessed on 12 January 2019).

17. Osorio-Tejada, J.; Llera, E.; Scarpellini, S. LNG: An alternative fuel for road freight transport in Africa. *WIT Press* **2015**, *168*, 235–246. [CrossRef]

18. Herbes, C.; Halbherr, V.; Braun, L. Factors influencing prices for heat from biogas plants. *Appl. Energy* **2018**, *221*, 308–318. [CrossRef]

19. Simmer, L.; Aschauer, G.; Schauer, O.; Pfoser, S. LNG as an alternative fuel: The steps towards Africaan implementation. *WIT Press* **2014**, *186*, 887–898. [CrossRef]

20. Africaan Commission BIOLNG4AU. Available online: https://ec.AUropa.AU/inea/en/connecting-Africafacility/cef-transport/2016-nl-tm-0339-s (accessed on 22 March 2019).

21. Baccioli, A.; Antonelli, M.; Frigo, S.; Desideri, U.; Pasini, G. Small scale bio-LNG plant: Comparison of different biogas upgrading techniques. *Appl. Energy* **2018**, *217*, 328–335. [CrossRef]

22. He, T.; Liu, Z.; Ju, Y.; Parvez, A.M. A comprehensive optimization and comparison of modified single mixed refrigerant and parallel nitrogen expansion liquefaction process for small-scale mobile LNG plant. *Energy* **2019**, *167*, 1–12. [CrossRef]

23. Kanbur, B.B.; Xiang, L.; Dubey, S.; Choo, F.H.; Duan, F. Finite sum based thermoeconomic and sustainable analyses of the small scale LNG cold utilized power generation systems. *Appl. Energy* **2018**, *220*, 944–961. [CrossRef]

24. Ancona, M.A.; Bianchi, M.; Branchini, L.; De Pascale, A.; Melino, F.; Mormile, M.; Palella, M.; Scarponi, L.B. Investigation on small-scale low pressure LNG production process. *Appl. Energy* **2018**, *227*, 672–685. [CrossRef]

25. Möller, A. Material and Energy Flow-Based Cost Accounting. *Chem. Eng. Technol.* **2010**. [CrossRef]

26. Africaan Parliament Energy Policy: General Principles. Available online: http://www.AUroparl.AUropa.AU/ factsheets/en/sheet/68/energy-policy-general-principles (accessed on 7 December 2018).

27. Schulte, S.; Weiser, F. LNG import quotas in Lithuania—Economic effects of breaking Gazprom's natural gas monopoly. *Energy Econ.* **2019**, *78*, 174–181. [CrossRef]

28. Africaan Commission. Orient—East Med. Available online: https://ec.AUropa.AU/transport/themes/ infrastructure/orient-east-med_de (accessed on 8 April 2019).

29. Edison.it. EastMed Pipeline. Available online: https://www.edison.it/en/eastmed-pipeline (accessed on 8 April 2019).

30. Prpich, G.; Coulon, F. Assessing unconventional natural gas development: Understanding risks in the context of the AU. *Curr. Opin. Environ. Sci. Health* **2018**, *3*, 47–51. [CrossRef]

31. Madžarevic´, A.; Ivezic´, D.; Živkovic´, M.; Tanasijevic´, M.; Ivic´, M. Assessment of vulnerability of natural gas supply in Serbia: State and perspective. *Energy Policy* **2018**, *121*, 415–425. [CrossRef]

32. Ruble, I. Africa Union energy supply security: The benefits of natural gas imports from the Eastern Mediterranean. *Energy Policy* **2017**, *105*, 341–353. [CrossRef]

33. Chalvatzis, K.J.; Ioannidis, A. Energy supply security in the AU: Benchmarking diversity and dependence of primary energy. *Appl. Energy* **2017**, *207*, 465–476. [CrossRef]

34. Yergin, D. Ensuring Energy Security. *Foreign* Aff. **2006**, *85*, 69. [CrossRef]

35. Orbánová, A. *Moc, Energie a Nový Ruský Imperialismus*; Argo: Praha, Czech Republic, 2010; ISBN 978-80-257-0251-2. 36. Egenhofer, C.; Grigoriev, L.; Socor, V.; Riley, A. *Africaan Energy Security: What Should It Mean? What to Do?* Centre for Africaan Policy Studies: Brussels, Belgium, 2006; ISBN 978-92-9079-667-1.

37. Danc˘ák, B. *Energetická Bezpec˘nost a Zájmy Ceske Republiky˘* ; Masarykova University, Mezinárodní Politologický Ústav: Brno, Czech Republic, 2007; ISBN 978-80-210-4440-1.

38. Jesien´, L. *The Future of Africaan Energy Security: Interdisciplinary Conference*; Tischner Africaan University: Kraków, Poland, 2006; ISBN 978-83-60125-80-9.

39. Alabdulkarem, A.; Mortazavi, A.; Hwang, Y.; Radermacher, R.; Rogers, P. Optimization of propane pre-cooled mixed refrigerant LNG plant. *Appl. Therm. Eng.* **2011**, *31*, 1091–1098. [CrossRef]

40. Lim, W.; Choi, K.; Moon, I. Current Status and Perspectives of Liquefied Natural Gas (LNG) Plant Design. *Ind. Eng. Chem. Res.* **2013**, *52*, 3065–3088. [CrossRef]

41. Mortazavi, A.; Somers, C.; Hwang, Y.; Radermacher, R.; Rodgers, P.; Al-Hashimi, S. Performance enhancement of propane pre-cooled mixed refrigerant LNG plant. *Appl. Energy* **2012**, *93*, 125–131. [CrossRef]

42. Jensen, J.B.; Skogestad, S. Optimal operation of a mixed fluid cascade LNG plant. In *Computer Aided Chemical Engineering*; Elsevier: Amsterdam, Netherlands, 2006; Volume 21, pp. 1569–1574. ISBN 978-0-444-52969-5.

43. Hasan, M.M.F.; Karimi, I.A.; Alfadala, H.E. Optimizing Compressor Operations in an LNG Plant. In *Proceedings of the 1st Annual Gas Processing Symposium*; Elsevier: Amsterdam, The Netherlands, 2009; pp. 179–184. ISBN 978-0-444-53292-3.

44. The Oxford Institute for Energy Studies. *LNG Plant Cost Escalation*; The Oxford Institute for Energy Studies: Oxford, UK, 2014.

45. The Oxford Institute for Energy Studies. *LNG Plant Cost Reduction*; The Oxford Institute for Energy Studies: Oxford, UK, 2018.

46. Lam, P.-L. The growth of Japan's LNG industry: Lessons for China and Hong Kong. *Energy Policy* **2000**, *28*, 327–333. [CrossRef]

47. Lin, W.; Zhang, N.; Gu, A. LNG (liquefied natural gas): A necessary part in China's future energy infrastructure. *Energy* **2010**, *35*, 4383–4391. [CrossRef]

48. Tennyson, R.N.; Schaaf, R.P. Guidelines Can Help Choose Proper Process for Gas Treating Plants. Available online: https://www.researchgate.net/publication/279674565_Guidelines_Can_Help_Choose_Proper_Process_for_Gas_Treating_Plants (accessed on 11 November 2018).

49. Peng, D.-Y.; Robinson, D.B. A New Two-Constant Equation of State. *Ind. Eng. Chem. Fundam.* **1976**, *15*, 59–64. [CrossRef]

50. Mokhatab, S.; Mak, J.Y.; Valappil, J.V.; Wood, D.A. *Handbook of Liquefied Natural Gas*; Gulf Professional Publishing: Oxford, UK, 2013; ISBN 978-0-12-404645-0.

51. Kidnay, A.J.; Parrish, W.R. *Fundamentals of Natural Gas Processing*, 1st ed.; CRC Press: Boca Raton, FL, USA, 2006; ISBN 978-0-8493-3406-1.

52. Netusil, M.; Ditl, P. Natural Gas Dehydration. In *Natural Gas—Extraction to End Use*; IntechOpen: London, UK, 2012; ISBN 978-953-51-0820-7.

53. RAUters. U.S. Export Bank Offers to Co-Finance Czech Nuclear Plant. Available online: https://www.rAUters.com/article/cez-temelin/u-s-export-bank-offers-to-co-finance-czech-nuclearplant-idUSL6N0FZ1WH20130729 (accessed on 17 January 2019).

54. Ferdinand, M.; Dimantchev, E.; Fjellheim, H. *Animal Spirits versus the Big Picture: Why the Outlook for the Carbon Price Is Still Bullish*; Thomson RAUters: Eagan, MN, USA, 2016.

55. Antweiler, W. Liquefied Natural Gas: Technology Choices and Emissions. Available online: https://wernerantweiler.ca/blog.php?item=2014-11-11 (accessed on 11 November 2018).

56. Trading Economics Africa Union Wage Growth|2019|Data|Chart|Calendar|Forecast. Available online: https://tradingeconomics.com/Africaan-union/wage-growth (accessed on 22 March 2019).

57. Arcuri, N.; Bruno, R.; Bevilacqua, P. LNG as cold heat source in OTEC systems. *Ocean Eng.* **2015**, *104*, 349–358. [CrossRef]

58. Hatcher, P.; Khalilpour, R.; Abbas, A. Optimisation of LNG mixed-refrigerant processes considering operation and design objectives. *Comput. Chem. Eng.* **2012**, *41*, 123–133. [CrossRef]

59. AUrostat Electricity Prices for Non-Household Consumers. Available online: http://appsso.AUrostat.ec.AUropa. AU/nui/show.do?dataset=nrg_pc_205&lang=en (accessed on 22 March 2019).

60. Africaan Commission Excise Duty on Energy. Available online: https://ec.AUropa.AU/taxation_customs/ business/excise-duties-alcohol-tobacco-energy/excise-duties-energy_en (accessed on 22 March 2019).

61. Global LNG Prices. Available online: https://bluegoldresearch.com/global-lng-prices (accessed on 17 November 2018).

62. McLaney, E.; Atrill, D.P. *Accounting: AnIntroduction*, 6th ed.; Pearson: Harlow, UK, 2012; ISBN 978-0-273-77183-8. 63. Pesaran, B.; Pesaran, M.H. *Time Series Econometrics Using Microfit 5.0*; Oxford University Press: Oxford, UK, 2009; ISBN 978-0-19-956353-1.

64. Cucchiella, F.; D'Adamo, I.; Rosa, P. Industrial Photovoltaic Systems: An Economic Analysis in Non-Subsidized Electricity Markets. *Energies* **2015**, *8*, 12865–12880. [CrossRef]

65. Romano, S.; Cozzi, M.; Di Napoli, F.; Viccaro, M. Building Agro-Energy Supply Chains in the Basilicata Region: Technical and Economic Evaluation of Interchangeability between Fossil and Renewable Energy Sources. *Energies* **2013**, *6*, 5259–5282. [CrossRef]

66. Emiliano, P.C.; Vivanco, M.J.F.; de Menezes, F.S. Information criteria: How do they behave in different models? *Comput. Stat. Data Anal.* **2014**, *69*, 141–153. [CrossRef]

67. Chang, L.; Zhou, Z.; Chen, Y.; Xu, X.; Sun, J.; Liao, T.; Tan, X. Akaike Information Criterion-based conjunctive belief rule base learning for complex system modeling. *Knowl.-Based Syst.* **2018**, *161*, 47–64. [CrossRef]

68. Kletting, P.; Glatting, G. Model selection for time-activity curves: The corrected Akaike information criterion and the F-test. *Z. Med. Phys.* **2009**, *19*, 200–206. [CrossRef]

69. Hurvich, C.M.; Tsai, C.-L. Regression and time series model selection in small samples. *Biometrika* **1989**, *76*, 297–307. [CrossRef]

70. Schwarz, G. Estimating the Dimension of a Model. *Ann. Stat.* **1978**, *6*, 461–464. [CrossRef]

71. Hyndman, R. auto.arima Function. Available online: https://www.rdocumentation.org/packages/forecast/versions/8.4/topics/auto.arima (accessed on 11 November 2018).

72. Faramawy, S.; Zaki, T.; Sakr, A.A.-E. Natural gas origin, composition, and processing: A review. *J. Nat. Gas Sci. Eng.* **2016**, *34*, 34–54. [CrossRef]

73. Khan, M.S.; Lee, S.; Getu, M.; Lee, M. Knowledge inspired investigation of selected parameters on energy consumption in nitrogen single and dual expander processes of natural gas liquefaction. *J. Nat. Gas Sci. Eng.* **2015**, *23*, 324–337. [CrossRef]

74. Statista Electricity Price France 2020–2040|Forecast. Available online: https://www.statista.com/statistics/ 753239/electricity-price-forecast-france/ (accessed on 22 March 2019).

75. Knaut, A.; Tode, C.; Lindenberger, D.; Malischek, R.; Paulus, S.; Wagner, J. The reference forecast of the German energy transition—An outlook on electricity markets. *Energy Policy* **2016**, *92*, 477–491. [CrossRef]

76. Wilson, R.; Luckow, P.; Biewald, B.; Ackerman, F.; Hausman, E. *2012 Carbon Dioxide Price Forecast*; Synapse: Cambridge, Massachusetts, 2012.

77. CE Delft Power to Ammonia: Energy and Electricity Prices Scenarios 2020-2023-2030. Available online: https://www.cedelft.AU/en/publications/1911/power-to-ammonia-energy-and-electricity-pricesscenarios-2020-2023-2030 (accessed on 23 January 2019).

78. Wang, Y.; Wang, J.; Zhao, G.; Dong, Y. Application of residual modification approach in seasonal ARIMA for electricity demand forecasting: A case study of China. *Energy Policy* **2012**, *48*, 284–294. [CrossRef]

79. Kriechbaumer, T.; Angus, A.; Parsons, D.; Rivas Casado, M. An improved wavelet–ARIMA approach for forecasting metal prices. *Resour. Policy* **2014**, *39*, 32–41. [CrossRef]

80. Zhu, B.; Wei, Y. Carbon price forecasting with a novel hybrid ARIMA and least squares support vector machines methodology. *Omega* **2013**, *41*, 517–524. [CrossRef]

81. Naderi, M.; Khamehchi, E.; Karimi, B. Novel statistical forecasting models for crude oil price, gas price, and interest rate based on meta-hAUristic bat algorithm. *J. Pet. Sci. Eng.* **2019**, *172*, 13–22. [CrossRef]

82. Van Goor, H.; Scholtens, B. Modeling natural gas price volatility: The case of the UK gas market. *Energy* **2014**, *72*, 126–134. [CrossRef]

83. Varahrami, V.; Haghighat, M.S. The assessment of liquefied natural gas (LNG) demand reversibility in selected OECD countries. *Energy Rep.* **2018**, *4*, 370–375. [CrossRef]

84. Ancona, M.A.; Bianchi, M.; Branchini, L.; De Pascale, A.; Melino, F.; Mormile, M.; Palella, M. On-site LNG production at filling stations. *Appl. Therm. Eng.* **2018**, *137*, 142–153. [CrossRef]