Edelweiss Applied Science and Technology
ISSN: 2576-8484
Vol. 8, No. 6, 7327-7365
2024
Publisher: Learning Gate
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

Marginal oil and gas field development using stranded and flaring gas

Sutrasno Kartohardjono[1*], Hadid Fadilah[2]
[1,2]Department of Chemical Engineering, Faculty of Engineering, Universitas Indonesia, Depok, Indonesia;
sutrasno@che.ui.ac.id (S.K.) hadid.fadilah31@ui.ac.id (H.F.).

Abstract: Indonesia's abundant natural gas reserves present an opportunity to transition towards natural gas as a primary energy source due to its efficiency and industrial versatility. However, stranded gas and flare gas remain underutilized, especially in remote and challenging areas like Papua, Indonesia. This research investigates the utilization of such limited gas resources through technical and economic evaluations. This region is characterized by logistical challenges and a scarcity of natural gas users, making it a representative example for similar cases across Indonesia. The study assessed product and technology options for utilizing feed gas with an average volume of 2.5 MMSCFD over a 15-year production lifetime. The findings indicate that converting the gas into CNG and LPG is the most viable solution, yielding an average of 1,264 MMBTU/day of CNG and 4 MT/day of LPG. Economic analysis shows a net present value (NPV) of USD 1.83 million, an internal rate of return (IRR) of 13.01%, and a payback period (POT) of 6.31 years. The use of skid-mounted transportation modules and barges aligns well with the geographical complexities of Eastern Indonesia, offering a scalable and commercially viable approach to stranded gas utilization. This research highlights a sustainable pathway for monetizing marginal gas fields.

Keywords: *Compressed natural gas (CNG), Flare gas, Marginal oil and gas fields, Skid transportation module, Stranded gas.*

1. Introduction

Natural gas is one of the hydrocarbons that can be used as an efficient and easy-to-use fuel or energy source, with applications across a wide range of industries [1]. Fortunately, Indonesia has substantial potential for natural gas production, with reserves discovered in both large and small quantities through exploration activities in various oil and gas fields. With abundant reserves, natural gas has the potential to become a major, efficient, and economical energy source for various industries in Indonesia. Research and technological advances have strengthened the supply and security of gas projects in many countries, and it is hoped that similar approaches can be applied in Indonesia. With the right strategies, Indonesia could maximize its gas resources, optimize production, improve infrastructure, and reduce distribution costs, thereby enhancing the role of natural gas in the national energy mix.

Nevertheless, the utilization of small gas reserves and stranded gas—or gas reserves that are challenging to reach—still faces significant obstacles. Often, stranded gas cannot be exploited due to geographical constraints, particularly in remote areas far from processing facilities, transportation systems, and industrial markets. This issue is compounded by the economic infeasibility of developing infrastructure in remote regions for small-sized gas reserves. Additionally, gas reserves found in association with oil (associated gas) create a dilemma. To produce oil, the gas must be released, but due to limited facilities, much of it is flared, resulting in energy waste and potential environmental harm.

The utilization of stranded gas and flared gas is a primary concern for the oil and gas industry, both in Indonesia and globally. Numerous studies have been conducted to find solutions, but Indonesia, with its vast geographical expanse and significant distribution challenges, has yet to find a practically implementable technology to commercialize stranded gas. Nevertheless, harnessing the potential of stranded and flared gas could help Indonesia reach its targeted production of 1 million barrels of oil per

© 2024 by the authors; licensee Learning Gate
* Correspondence: sutrasno@che.ui.ac.id

day and 12 billion cubic feet of gas per day by 2030, as agreed upon between the Indonesian Government and Oil and Gas Operators [2].

In particular, Eastern Indonesia faces greater challenges in terms of infrastructure and energy distribution. The pace of infrastructure development in this region is slower than in Western Indonesia, which has limited the potential energy utilization. Research related to developing this region needs to be intensified, especially focusing on technologies for the utilization and distribution of natural gas. One of the areas under study is Salawati Island in Southwest Papua, represented by a KKKS with oil processing facilities. Although oil can already be commercialized, gas is still limited to internal needs, and any excess is flared. If efficient technologies and distribution systems can be identified to optimize stranded and flared gas, it would significantly contribute to the development of Eastern Indonesia and strengthen national energy security.

2. Materials and Methods

Natural gas is a natural hydrocarbon product that exists in a gaseous phase under atmospheric pressure and temperature, obtained from oil and gas extraction processes. The molecular composition of natural gas primarily consists of methane (CH_4) and other heavier hydrocarbon molecules such as ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), pentane (C_5H_{12}), and hexane (C_6H_{14}). Additionally, other molecules, commonly referred to as impurities, such as nitrogen, helium, hydrogen sulfide, carbon dioxide, hydrogen, and mercury, may also be present in natural gas. The molecular composition of natural gas possesses calorific value or energy content, enabling it to be utilized as an energy source [3].

The natural gas production process involves separating calorific components from non-calorific impurities, enabling the commercialization of natural gas products. Technological advances have so far provided various methods for distributing and converting natural gas into several products with physical transportation options, such as pipeline gas for transmission, liquefied natural gas (LNG), compressed natural gas (CNG), liquefied petroleum gas (LPG), and gas to hydrate (GTH). There are also products converted through chemical processes, including gas to liquids (GTL), gas to chemicals (GTC), and gas to wire (GTW) [4].

Natural gas products that meet quality specifications are then distributed through various methods. Common distribution methods in Indonesia include pipeline gas transmission, LNG, CNG, and LPG. Factors such as operational complexity, high investment costs, market dependency on specific industries, and additional infrastructure requirements are reasons why GTH, GTL, GTC, and GTW options are not prioritized in this study. Compared to other gas product options such as pipeline gas, CNG, LNG, and LPG, these are considered more practical, economical, and flexible for the development of marginal oil and gas fields and hard-to-reach areas [5].

2.1. Marginal Oil and Gas Field

A marginal oil and gas field refers to a field with limited reserves or low production rates, making development often seem uneconomical using conventional technology and infrastructure. These fields typically face limitations such as distance from distribution centers, minimal infrastructure, or remote locations. High exploration and production costs, combined with fluctuating oil and gas prices, add investment risk. Marginal fields are classified as potentially economically viable only through the application of innovative options, both technically and financially.

The concept of a marginal field is generally understood as economic rather than technical. An oil and gas field is considered marginal if it cannot be developed with a reasonable profit using proven, conventional technology. For marginal fields, an alternative approach to technology is to employ what is known as "marginal field technology," which has the following characteristics:

- Low capital costs. This usually involves a trade-off with higher operational costs and reduced reliability.
- Rapid development period. This reduces the time between initial expenditure and first production.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

- Short-term suitability. This supports mobility and the reuse of systems in other fields.
- Flexible for innovative financing schemes.

Although there is no specific rule for an acceptable rate of return, most companies consider the real rate of return for marginal fields to be between 7% and 15%. If projected returns fall below this range, development is typically delayed; conversely, if the rate of return is higher, the project is more likely to proceed [6]. By applying innovative additional technologies and efficient business strategies, marginal oil and gas fields can still be profitable. Another positive impact of utilizing marginal oil and gas resources is reducing dependency on energy imports, increasing domestic supply, and supporting the use of previously overlooked gas resources, such as stranded gas and flare gas. Therefore, selecting appropriate processing and distribution solutions is essential to ensure the economic viability and sustainability of marginal oil and gas field projects.

2.2. Stranded and Flare Gas Potential in Indonesia

According to the Ministry of Energy and Mineral Resources' 2023 performance report, natural gas distribution in 2023 reached 3,745 BBTUD for domestic needs and 1,749 BBTUD for exports. The largest domestic gas consumption was for industry, accounting for 1,515.8 BBTUD (40.5%). This represents both a potential and a challenge for increasing natural gas production, as Indonesia's energy needs far exceed this value, with 140 villages still lacking electricity, as reported by the Ministry [7].

Data from the Indonesia Oil & Gas (IOG) 4.0 Strategic Plan by SKK Migas, dated August 31, 2023, shows that Indonesia has proven oil and gas reserves of 4.17 BBO and 54.83 TCF, and additional potential across 68 unexplored basins. This significant potential must be planned carefully to maximize its utilization [8].

The concept of stranded gas refers to natural gas reserves discovered through oil and gas exploration but not exploited yet due to technical or economic reasons. Stranded gas often arises in remote locations with inadequate infrastructure or high processing costs relative to market gas prices [9]. This is a common issue in Indonesia, where the exploitation of stranded gas is constrained by the country's archipelagic geography. Stranded gas discoveries often pose challenges for field operators, known as Cooperation Contract Contractors, but also present substantial potential for further exploitation with technological innovation and appropriate project feasibility studies.

Flare gas is natural gas that must be burned or released into the atmosphere as a byproduct of oil or natural gas production [10]. Flaring occurs when facilities are unable to manage the gas or when flaring is necessary to prevent the accumulation of hazardous gases. Flare gas still holds potential to be processed into valuable products, and Indonesia has several opportunities for flare gas utilization. The government continues to seek alternative technologies to enhance flare gas utilization, encouraging oil and gas industry operators in both upstream and downstream sectors to increase flare gas utilization, reduce flare gas volumes, and lower greenhouse gas emissions. This has been proven to have a positive impact, as stated in the 2018 Annual Report on Development Achievements titled "Utilization of Natural Gas for Equitable Energy", issued by the Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources. The report mentions that the increased utilization of flare gas has been implemented by 64% of Business Entities / Permanent Establishments, representing a 6.67% increase compared to the previous year [11]. Flare gas regulations in Indonesia are outlined in the Ministry of Energy and Mineral Resources Regulation No.17 year 2021, "Management of Flaring Gas in Oil and Gas Activities"; setting limits at (a) 2% of daily feed gas flow for each natural gas field, (b) a 6-month average daily flow rate of 2 MMSCFD for each oil field [12].

2.3. Technical Study

2.3.1. Gas Utilization Methods

The final products of natural gas processing can be utilized in various forms with commercial value, including products in gaseous, liquid, and solid phases, which are then transported using various modes of transportation or chemically converted. However, in this study, the utilization options for stranded

© 2024 by the authors; licensee Learning Gate

gas and flaring gas will be limited to four product options: sales gas pipeline, Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG), and Liquefied Petroleum Gas (LPG).

2.3.2. Sales Gas Pipeline

The definition of pipeline-sale gas refers to natural gas that has been processed to meet the required specifications and is then delivered to the buyer's custody transfer point via a gas transmission pipeline. The transportation process through transmission pipelines involves compression stages, pressure regulation, and quality monitoring of the pipeline-sale gas. Selling natural gas as pipeline-sale gas is typically used for buyers located within a maximum range of approximately ±2,000 km, ensuring the largest production volume, based on practical engineering guidelines. Pipeline-sale gas delivered to the buyer's location remains in the gas phase at a pressure suitable for immediate use by the buyer.

2.3.3. Compressed Natural Gas (CNG)

The utilization of natural gas in its gaseous phase faces challenges in storage and delivery to locations that cannot be reached by gas transmission pipelines. One solution to this challenge is to store compressed natural gas at high pressures, typically around 200–250 bar, as Compressed Natural Gas (CNG). CNG is stored in high-pressure containers (skids) and transported using trucks (CNG trucking) or ships (CNG marine). Selling natural gas as CNG is typically applied for medium-range volumes and maximum distances similar to pipeline-sale gas, approximately ±2,000 km, based on practical engineering guidelines. CNG delivered to the buyer's location requires pressure reduction adjustment according to the buyer's needs before use.

2.3.4. Liquefied Natural Gas (LNG)

Another solution to the challenges of storing and transporting natural gas products is to convert the gas phase into a liquid phase. This phase change is achieved through extreme cooling at very low temperatures, typically below (-)160°C / (-)256°F, transforming the gas into a liquid. This process allows natural gas to be stored in temperature-controlled containers (skids) in a significantly smaller volume than in its gaseous phase. The LNG product is then transported to distant buyers using LNG tanker ships or specialized LNG tank trucks. Selling natural gas as LNG is utilized for delivery to buyers at the farthest distances and with the largest volumes, based on practical engineering guidelines. LNG delivered to the buyer's location needs to be re-converted to its gaseous phase, with its temperature and pressure adjusted according to the buyer's requirements for use.

2.3.5. Liquefied Petroleum Gas (LPG)

Liquefied Petroleum Gas (LPG) is a by-product of natural gas processing, consisting of a mixture of propane (C_3H_8), butane (C_4H_{10}), or both, with minor amounts of ethane (C_2H_6) and other gases. This natural gas product also addresses the challenges of storage and transportation, enabling its optimal utilization. LPG is in liquid form at higher temperatures and pressures compared to LNG, and it is stored and transported in pressurized containers (skids) or cylinders commonly used for household or vehicular purposes. LPG delivered to the buyer's location must be reconverted to its gaseous phase, with its temperature and pressure adjusted as needed for the buyer's use.

Natural gas from the well is processed at a gas plant facility comprising purification and processing systems. It is then combined with associated gas, which has typically been flared, and processed into CNG and LPG. The CNG processing system includes compression and storage systems, while the LPG processing system involves liquefaction, compression, and storage systems [13]. Each product is then transferred to storage containers and transported via trucks or ships to the buyer.

2.3.6. Gas Processing Facilities

Small-scale gas processing facilities are typically designed as equipment packages to simplify installation, operation, and maintenance processes, while minimizing investment, operational, and

© 2024 by the authors; licensee Learning Gate

maintenance costs. Key components of these facilities include a compressor system, Acid Gas Removal Unit (AGRU), Dew Point Control Unit (DPCU), and Adsorption Dehydration.

2.3.7. Compressor System

The compressor system is used to increase gas pressure to meet transportation specifications or further processing requirements. Small-scale compressors typically use screw or reciprocating types with varying capacities. These compressors are widely used for transporting gas through pipeline networks or as feed gas preparation for LNG and CNG facilities. The international code and standard governing this equipment is API 618, "Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services." This standard outlines the minimum requirements for reciprocating compressors and their drivers used in the petroleum, chemical, and gas industries to handle air or process gases, whether with lubricated or non-lubricated cylinders. Compressors covered by this standard operate at medium to low speeds and are used in critical services. The standard also addresses associated lubrication systems, controls, instrumentation, intercoolers, aftercoolers, pulsation dampeners, and other supporting equipment [14].

2.3.8. Acid Gas Removal Unit (AGRU)

AGRU is a gas processing system designed to remove acid gases such as hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from natural gas or process gas streams. These compounds must be removed because they are corrosive and can damage equipment and pipelines, as well as reduce the calorific value of the gas. Small-scale AGRU technology often utilizes membrane-based systems or amine solutions such as MEA, DEA, or MDEA.

- Membrane-based AGRU is a gas separation technology that uses a semi-permeable membrane layer to separate acid gases from natural gas streams. This technology offers a simpler and more energy-efficient solution compared to conventional methods like amine scrubbing. Membrane-based AGRUs are often used for small to medium-scale applications. The technology leverages the difference in gas permeability through the membrane, with acid gases exhibiting higher permeability than methane (CH_4), allowing them to pass through the membrane more quickly. Membrane technology is now widely used for CO_2 capture to produce clean fuels from gas mixtures. CO_2 capture using membranes is an innovative solution that continues to evolve and can be applied to all types of natural gas processing, with its main advantage being the ability to combine membranes with modular small-scale fuel cells. Overall, membrane-based technology is ideal for applications requiring simplicity and low operating costs, although its efficiency may be less optimal for gases with high H_2S content [15].
- Amine-based AGRU is a system designed to remove acid gases from a gas stream using amine compounds, which function as acid gas absorbents. With the ability of amines to react with acid gases, this system can produce cleaner gas that meets the desired specifications for further applications. The gas purification process using amines generally consists of an absorber unit, a regenerator unit, and supporting equipment. In the absorber, the amine solution flowing downward absorbs H_2S and CO_2 from the acid gas flowing upward, producing a purified gas stream—gas free from hydrogen sulfide and carbon dioxide—as well as an amine solution rich in dissolved acid gases. This "rich" amine solution is then sent to the regenerator (stripper with reboiler) to produce regenerated or "lean" amine, which will be recycled and reused in the absorber. The residual gas from the regenerator contains high concentrations of H_2S and CO_2 [16].

2.3.9. Dew Point Control Unit (DPCU)

DPCU is a unit designed to remove water vapor and regulate the dew point of natural gas. Water vapor in natural gas can cause operational issues such as hydrates and corrosion in pipelines and equipment. Natural gas can be dehydrated to meet pipeline specifications through several processes, including the use of liquid desiccants (glycol) and solid desiccants (alumina, silica gel, and molecular

© 2024 by the authors; licensee Learning Gate

sieves). In the liquid state, water molecules are tightly bound due to hydrogen bonding. The hydroxyl and ether groups in glycol form associations similar to water molecules. The hydrogen bonds in this liquid phase explain why glycol has a high affinity for water and why the equilibrium vapor pressure of water above a glycol solution is much lower. Solid desiccants are characterized by an internal porous structure with a very large internal surface area (e.g., 200–800 m^2/g) and very small curvature radii (0.001–0.2 μm). The equilibrium vapor pressure of water above this concave surface is much lower compared to a flat surface, which gives solid desiccants a very high affinity for water. These desiccants have a capacity ranging from 5% to 15% by weight and can dry natural gas to a moisture content of less than 0.1 ppm or a dew point of −150°F.

2.3.10. Adsorption Dehydration

Adsorption dehydration is used to remove moisture from gas, typically using high-porosity adsorbent materials such as molecular sieve or silica gel. This technology is important to prevent the formation of ice hydrates in pipelines during compression and transportation. On a small scale, this system is available as a skid-mounted unit. The process of adsorption dehydration, where the adsorbent bed absorbs water molecules as gas flows through the material, works as follows: Adsorption Phase: Moist gas flows through the adsorbent material (e.g., molecular sieve or silica gel), and water molecules adhere to the surface of the adsorbent. Regeneration Phase: Once the adsorption capacity is full, the adsorbent bed is regenerated by passing hot gas or applying a vacuum to release the absorbed water. Cooling: After regeneration, the bed is cooled before being reused for the next cycle.

2.3.11. Gas Transportation Methods

2.3.11.1. Pipeline Gas Transmission

A transmission pipeline is the primary method for transporting natural gas from production sites to processing facilities or to buyer locations. The transmission pipeline serves to continuously deliver gas at high pressure through a network of pipelines that can span thousands of kilometers. These pipelines utilize a series of compressor stations along the route to move the gas over long distances. Additionally, gas coolers are used downstream of compressor stations to maintain the temperature of the compressed gas within certain limits. This is crucial to reduce pressure drop in the pipeline and protect both the internal and external layers of the pipeline from damage caused by high temperatures. Transmission pipeline systems can be constructed above ground or buried underground.

2.3.11.2. CNG Transportation

CNG products can be stored in high-pressure cylinders or tubes because they have a smaller volume compared to natural gas in its normal gaseous state. A commonly used and proven reliable transportation method for CNG is through CNG modules. These modules include CNG skid transportation modules, ISO tank containers, and CNG cascades, which are suitable for land-based distribution. For transportation across waterways, specialized vessels such as CRG carriers or CNG marine vessels are used. However, CNG transportation technology via sea is still limited and not widely available in the market today. In CNG transportation, there are common terms used namely mother station and daughter station. For small-scale CNG deliveries that need to pass through waterways, the use of CNG skid transportation module trucks combined with barges to cross the waterways is becoming increasingly common. This transportation method is considered suitable for the development of projects with small-scale CNG delivery specifications.

2.3.11.3. LNG Transportation

LNG transportation is typically carried out through shipments using specialized LNG tankers designed to transport gas in its liquid form at extremely low temperatures. This transportation method is the primary solution for connecting LNG production facilities in offshore or remote locations with distant consumption markets. These ships are equipped with highly insulated tanks to maintain cryogenic temperatures and prevent excessive evaporation during transit. For small-scale LNG transportation or distribution to buyer locations, LNG trucks can be used. LNG transportation costs

© 2024 by the authors; licensee Learning Gate

account for approximately 10 to 30 percent of the overall LNG logistics chain costs. The development of LNG carriers has progressed rapidly. Initially, the first ships were modified cargo vessels with aluminum tanks insulated with balsa wood. Today, modern LNG vessels are double-hulled ships specifically designed to safely and efficiently transport cryogenic liquids. Around half of the LNG fleet worldwide uses a membrane design, while the rest uses a spherical design. Membrane-designed ships are more popular due to innovations that allow for increased cargo capacity within a certain hull size, while also reducing construction costs and time. Additionally, some ships use a prismatic tank design. These prismatic tanks, similar to spherical tanks, are independent of the ship's hull. In the event of an LNG leak, the liquid will either evaporate or flow into a containment vessel beneath the tank [17].

2.3.11.4. LPG Transportation

LPG transportation uses methods similar to those for LNG. Several transportation methods are adjusted based on volume, distance, and the geographical conditions of the destination. One of the main methods is shipping via LPG tankers, especially for export and cross-border shipments. These ships are equipped with low-pressure cryogenic tanks that can maintain LPG in its liquid form at specific temperatures and pressures. Additionally, for domestic distribution or medium-distance transportation, LPG is typically transported using tank trucks and special railcars. In projects involving archipelagic areas, LPG can also be transported using barges to cross waterways.

2.4. Economic Study

The economic feasibility study of utilizing stranded gas and flare gas in this research involves a cost analysis of product and technology selection to create value-added products. This evaluation includes calculating the initial investment costs for infrastructure development as well as operational and maintenance expenses. Additionally, the study considers market prices and potential revenue from each gas product, taking into account factors such as energy price fluctuations, market demand, and government policies affecting the energy economy. The analysis is conducted using NPV, IRR, and payback period calculations, aiming to assess the most financially advantageous technology option and provide strategic recommendations for the development of infrastructure and technology for stranded gas and flare gas utilization [18].

The determination of capital expenditures (CAPEX) and operational and maintenance costs (OPEX) is conducted using methods outlined in this study. Specifications and sizing details of key equipment for each product and technology option were obtained from process simulation results. The next step is to establish the required CAPEX and OPEX costs for the economic analysis, referencing the costs of similar projects and relevant sources. These estimated costs are then adjusted to the project's year using linearization.

The economic analysis is performed using the NPV cash flow method to identify the option with the best outcome, considering IRR and payback period (POT) indicators to determine project feasibility. The selected product and technology options are analyzed in accordance with the upstream oil and gas sector regulations in Indonesia. Therefore, the NPV cash flow calculation uses the gross split contract scheme applicable to the Cooperation Contract Contractor (KKKS) where this research is conducted. The feasibility criteria for each option are a positive NPV and an IRR greater than the established MARR value of 13%.

2.5. Sensitivity Analysis

Sensitivity analysis on the economic input parameters is conducted for variations in investment costs, operational and maintenance costs, and gas sales prices for each option in different market potentials. This sensitivity analysis in the study is intended to test the resilience and reliability of the technical and economic assessments related to the utilization of stranded gas and flare gas [19]. By running various scenarios and simulations that account for fluctuations in these parameters, this analysis aims to provide deeper insights into risks and uncertainties, as well as support more informed decision-making for investment in the stranded gas and flare gas utilization sector [20].

© 2024 by the authors; licensee Learning Gate

3. Result and Discussion

A comprehensive analysis of the technical and economic aspects of gas product and technology utilization options was conducted. This analysis includes a thorough evaluation of the technical effectiveness in generating products and an assessment of related costs, including both initial capital expenditure (CAPEX) and ongoing operational and maintenance costs (OPEX) over the project's operational period. The goal of this analysis is to identify the most economically beneficial option aligned with project objectives.

The chemical process simulation in this study was performed using Unisim R390.1 simulation software. The simulation results not only estimate the quantity of final products but also provide insights into the sizing and specifications of key equipment required. This information is crucial, as it forms the basis for calculating capital expenditure for equipment procurement and determining operational and maintenance costs over the project's life cycle. Thus, this simulation plays a vital role in offering a more detailed understanding of the technical and economic implications of each analyzed option.

The economic analysis adheres to the regulations within the upstream oil and gas sector in Indonesia, with the NPV cash flow calculation using the gross split contract scheme applicable to the Cooperation Contract Contractor (KKKS) where this research is conducted. Additionally, the economic analysis of each option follows the current policies and regulations within Indonesia's upstream oil and gas sector. Cash flow calculations employ the NPV method, a widely used approach to evaluate the economic feasibility of a project. In this study, the gross split scheme is utilized in NPV calculations to provide a realistic perspective on potential profits. This approach aims to identify options that excel not only technically but also deliver optimal and sustainable economic benefits to the project overall.

3.1. Design Basis

This research examines three types of feed gas that will be processed into gas products: gas well, associated gas, and stranded gas. **Table 1** provides an overview of the fluid characteristics and gas component composition for these three gas sources.

Table 1.
Feed gas fluid characteristics and components.

Description	Unit	Gas well	Gas asso	Gas stranded
Initial pressure	Psig	1.000	100	1.400
Final pressure	Psig	250	48	250
Temperature	°F	104	95	100
Volume (Peak)	MMscfd	1.52	0.40	4.20
Methane	C_1	90.89	82.55	90.29
Ethane	C_2	2.87	4.82	3.29
Propane	C_3	1.21	3.91	1.46
Iso-Butane	i-C_4	0.47	1.41	0.54
n-Butane	n-C_4	0.57	1.77	0.34
Iso-Pentane	i-C_5	0.34	0.59	0.22
n-Pentane	n-C_5	0.29	0.88	0.19
Hexanes	C_6	0.31	0.51	0.23
Heptanes plus	C_{7+}	0.00	0.00	0.26
Carbon dioxide	CO_2	2.99	3.31	2.85
Nitrogen	N_2	0.06	0.25	0.33
H_2S content	ppmv	600	5.000	400
H_2O content	ppmv	12	28	10

Figure 1 provides an overview of the estimated gas production from the three gas sources throughout the project period.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

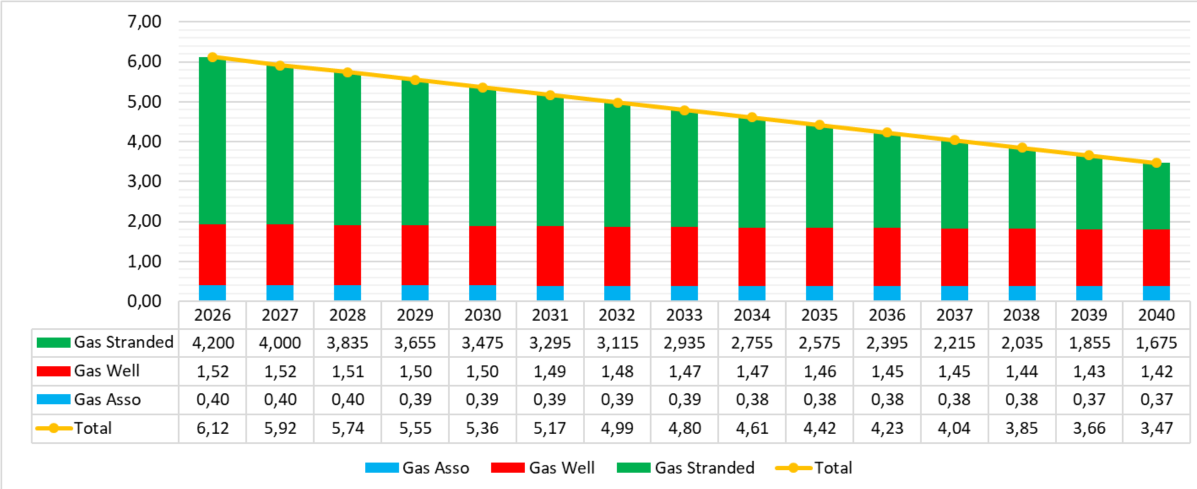

Figure 1.
Feed gas production forecast.

3.2. Production Facilities

In small-scale gas production facility design, a modular approach for equipment is highly prioritized. Modular systems allow processing units to be divided into several smaller modules that can be arranged and operated independently. This approach provides greater flexibility in facility management, particularly for operations and maintenance. With smaller modules, routine maintenance can be carried out without halting the entire process. Additionally, operational and initial investment costs can be reduced, as modules are easier to install, operate, and replace in case of damage. This modular design also facilitates capacity expansion if gas production demands increase in the future, making it an economical and efficient solution for small-scale facilities [21].

The compressor system is used to increase gas pressure to meet the specifications for transportation or further processing. Small-scale compressors use the reciprocating type. The international code and standard applied is API 618 "Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services". This standard outlines the minimum requirements for reciprocating compressors and their drivers used in the petroleum industry, whether lubricated or non-lubricated. The compressors covered operate at medium to low speeds and include lubrication systems, controls, instrumentation, intercoolers, aftercoolers, pulsation suppression devices, and other auxiliary equipment [22].

The Acid Gas Removal Unit (AGRU) system used is membrane-based. Membrane technology is widely used today for CO_2 capture to produce clean fuel from gas mixtures. CO_2 capture using membranes is an innovative and evolving solution that can be applied to all types of natural gas processing, with its main advantage being the ability to integrate membranes with small-scale modular fuel cells. Overall, membrane-based technology is ideal for applications with simple requirements and low operating costs, although its efficiency may be less optimal for gas with high H_2S content [23].

The Dew Point Control Unit (DPCU) system used is solid desiccants based, that are demisters and desiccants. A demister functions as a filter to separate liquid droplets and water mist from natural gas, typically used to handle liquid condensates before the gas enters the desiccant stage. A desiccant is an absorbent material that attracts and binds water molecules from the gas stream. The main characteristic of the DPCU system with demisters and desiccants lies in its simple system design, making it suitable for small to medium gas flow rates [24].

3.4. Feed Gas Simulation

The simulation performed using Unisim R390.1 to obtain the mixed feed gas fluid is illustrated in Figure 2, showing the feed gas mixture simulation, and its results are presented in **Table 2**, showing the feed gas mixture simulation results.

© 2024 by the authors; licensee Learning Gate

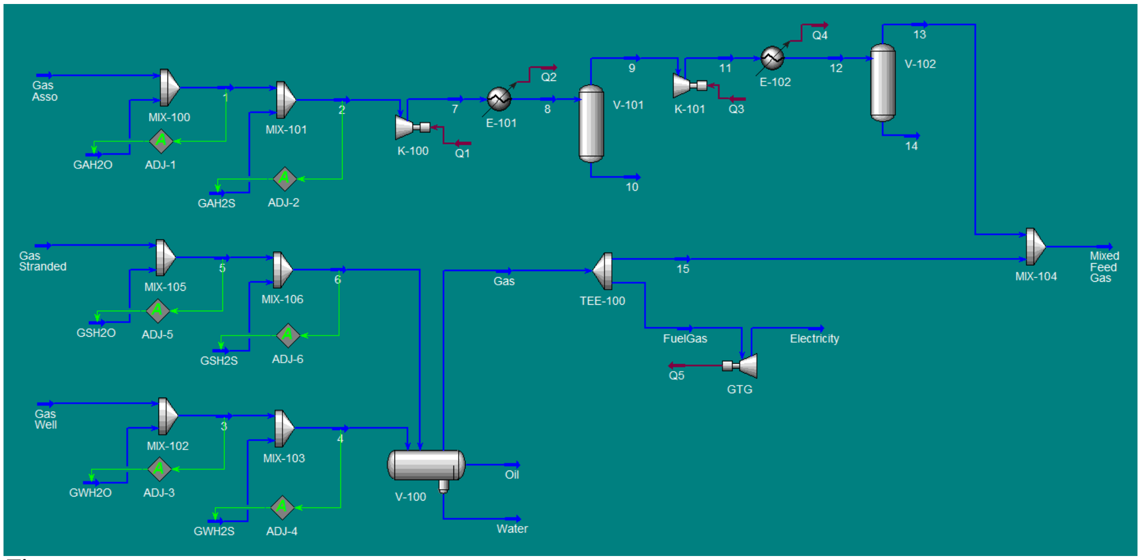

Figure 2.
Feed gas simulation.

Table 2.
Feed gas simulation result.

Deskripsi	Unit	Node							
		Gas well	**Gas asso**	**Gas strd**	**Gas**	**13**	**15**	**Fuel gas**	**Mixed FG**
Pressure	Psig	1.000	100	1.400	250	250	250	250	250
Temperature	°F	104	95	100	101	95	101	101	100
Flow rate	MMscfd	1.52	0.40	4.20	5.71	0.40	3.43	1.99	4.12
Methane. C_1	% Mol	90.89	82.55	90.29	90.64	81.51	90.64	90.64	89.69
Ethane. C_2	% Mol	2.87	4.82	3.29	3.18	4.76	3.18	3.18	3.35
Propane. C_3	% Mol	1.21	3.91	1.46	1.39	3.86	1.39	1.39	1.65
Iso-Butane. i-C_4	% Mol	0.47	1.41	0.54	0.52	1.39	0.52	0.52	0.61
n-Butane. n-C_4	% Mol	0.57	1.77	0.34	0.39	1.75	0.39	0.39	0.54
Iso-Pentane. i-C_5	% Mol	0.34	0.59	0.22	0.25	0.58	0.25	0.25	0.28
n-Pentane. n-C_5	% Mol	0.29	0.88	0.19	0.21	0.87	0.21	0.21	0.28
Hexanes. C_6	% Mol	0.31	0.51	0.23	0.23	0.50	0.23	0.23	0.26
Heptanes plus. C_{7+}	% Mol	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
Carbon dioxide. CO_2	% Mol	2.99	3.31	2.85	2.89	3.27	2.89	2.89	2.93
Nitrogen. N_2	% Mol	0.06	0.25	0.33	0.26	0.25	0.26	0.26	0.26
H_2S content	ppm	600	5.000	400	996	5.000	650	348	5.650
H_2O content	ppm	12	28	10	23	28	15	8	41

Based on the simulation above, it is determined that the maximum feed gas volume that can be used as a source for gas products, after subtracting the volume required for the fuel gas used for own consumption, is 4.12 MMscfd, at a pressure of 250 psig and a temperature of 100°F.

3.5. Gas Processing Facilities Simulation

The simulation conducted on the gas processing facility to process the feed gas mixture into gas products is illustrated in Figure 3, showing the gas processing facility simulation, and the results are presented in Table 3, showing the gas processing facility simulation results.

© 2024 by the authors; licensee Learning Gate

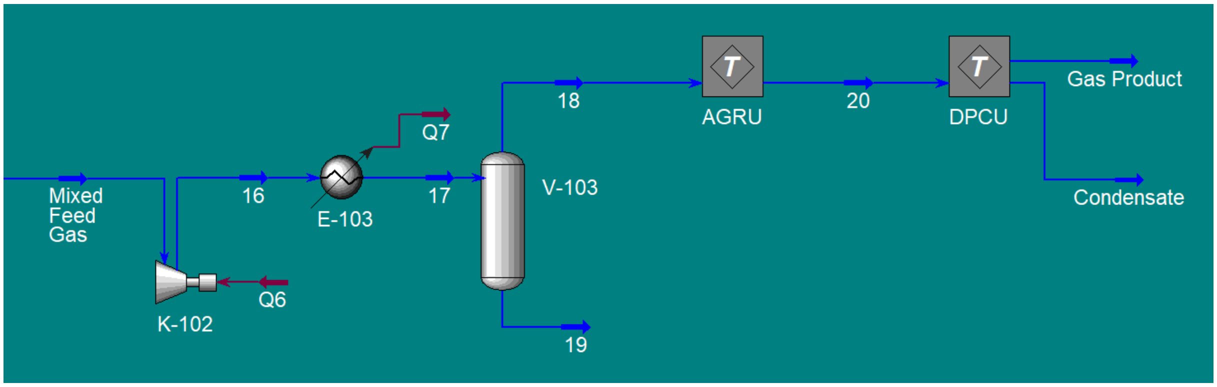

Figure 3.
Gas processing facilities simulation.

Table 3.
Gas processing facilities simulation result.

Deskripsi	Unit	Node				
		Mixed FG	18	20	Gas product	Conden-sate
Pressure	Psig	250	550	550	550	atm
Temperature	°F	100	100	100	100	77
Flow rate gas	MMscfd	4.12	4.12	3.99	3.96	-
Flow rate condensate	Barrel/day	-	-	-	-	18.59
Methane. C_1	% Mol	89.69	89.69	92.53	93.33	0.00
Ethane. C_2	% Mol	3.35	3.35	3.46	3.48	0.00
Propane. C_3	% Mol	1.65	1.65	1.70	1.72	0.00
Iso-Butane. i-C_4	% Mol	0.61	0.61	0.63	0.64	0.00
n-Butane. n-C_4	% Mol	0.54	0.54	0.56	0.56	0.00
Iso-Pentane. i-C_5	% Mol	0.28	0.28	0.29	0.00	34.17
n-Pentane. n-C_5	% Mol	0.28	0.28	0.29	0.00	33.91
Hexanes. C_6	% Mol	0.26	0.26	0.27	0.00	31.68
Heptanes plus. C_{7+}	% Mol	0.00	0.00	0.00	0.00	0.24
Carbon Dioxide. CO_2	% Mol	2.93	2.93	0.00	0.00	0.00
Nitrogen. N_2	% Mol	0.26	0.26	0.26	0.27	0.00
H_2S content	ppm	5.650	5.650	0.00	0.00	0.00
H_2O content	ppm	41	41	0.00	0.00	0.00

Based on the simulation above, it is known that the peak volume of gas resulting from the processing that can be utilized as a gas product is 3.96 MMSCFD, at a pressure of 550 psig and a temperature of 100°F. Additionally, a by-product in the form of condensate with a volume of 18.59 barrel/day is obtained, at atmospheric pressure and a temperature of 77°F.

This condensate product has economic value and can be further commercialized as a high-value product. To optimize its utilization, the condensate product will be routed and processed at the existing and operational oil facilities in the field. This integration maximizes operational efficiency and reduces the need for new investments, as it utilizes the existing infrastructure for processing the additional product.

3.6. Sales Gas Pipeline Production Facilities

The gas product produced from the gas processing facility at this stage has met the characteristics and composition in accordance with the specifications for transmission pipeline gas, and therefore does not require additional processing. This gas is ready for immediate use by gas-consuming industries

© 2024 by the authors; licensee Learning Gate

without further treatment. The next step is to conduct a transmission pipeline design analysis with optimal technical specifications to ensure the gas is delivered efficiently and safely to the buyer's location. This pipeline design must consider aspects such as pressure, materials, and a strategic route to ensure reliable gas distribution that meets the operational needs of the customer.

The gas product from the processing facility that meets the transmission pipeline gas specifications is then delivered to the gas buyer's facility using the gas transmission pipeline. The distance from the gas processing facility to the potential gas buyer location spans both onshore and offshore routes, as illustrated on the map showing the distance from the production facility to the potential gas buyer's location. This distance has been measured according to the potential Right of Way (ROW) for the transmission pipeline to be used. **Figure 4** below provides an overview of the gas delivery scheme via the transmission pipeline.

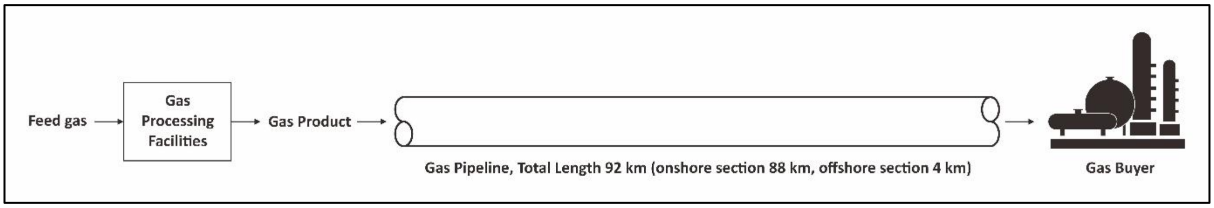

Figure 4.
Schematic of sales gas pipeline.

3.7. CNG Production Facilities

The gas products produced from the gas processing facility at this stage require an additional process for storage and transportation in the form of CNG, which requires a compression system to raise the pressure to 200 – 250 bar (2,900 – 3,626 psi). This compression process is important to compress the gas so it can be stored in a smaller volume and more easily distributed. The next step is to conduct a design analysis for a suitable CNG compression and storage system, as well as design a distribution method. This design must consider compression process efficiency, transportation capacity, and safety standards, so that the CNG supply can be delivered safely and reliably to the buyer's location. The resulting CNG is then stored in storage tanks, transferred to CNG trucks, and transported to the buyer's location. This study will also analyze additional processes that allow LPG to be produced as a by-product of CNG production, with the aim of maximizing the efficiency and economic value of the entire process.

The CNG product, which meets the specifications and is stored in a special storage tank, is then distributed to CNG trucks for transportation to the buyer's location. This journey crosses both land and water routes, as illustrated on the map showing the distance from the production facility to potential gas buyers. To cross the water route, the CNG trucks will be supported by barges that serve as crossing vehicles. **Figure 5** below illustrates the transportation scheme for CNG products.

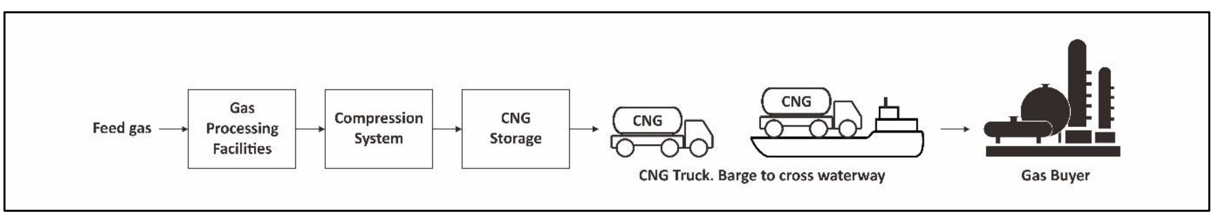

Figure 5.
Schematic of CNG transportation.

3.8. LNG Production Facilities

The gas product produced from the gas processing facility at this stage requires an additional process for storage and transportation in the form of LNG, which involves the liquefaction of gas at very low temperatures, around -162°C. At this stage, an efficient liquefaction system is needed to

DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

remove contaminants and lower the gas temperature, producing LNG with high quality. After liquefaction, LNG is stored in low-pressure tanks specially designed to maintain cryogenic conditions and prevent leaks. This study will also analyze the additional process that allows LPG to be produced as a by-product of LNG production, with the hope of maximizing the efficiency and economic value of the entire process.

The LNG product, which meets the specifications and is stored in special storage tanks, is then pumped into LNG trucks for transportation to the buyer's location. This journey spans both land and water routes, as illustrated on the map showing the distance from the production facility to the potential gas buyer location. To cross the water route, the LNG truck will be supported by barges serving as the crossing means. Figure 6 below provides an overview of the LNG product transportation scheme.

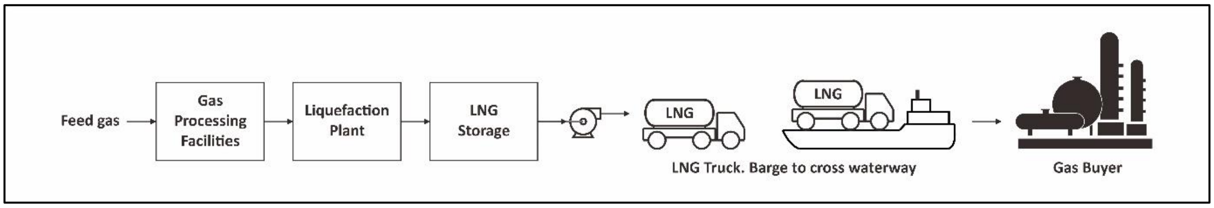

Figure 6.
Schematic of LNG transportation.

3.9. LPG Production Facilities

The additional process to obtain LPG is the fractionation process. This process is used to separate propane and butane components, as well as purify each fraction. This is done using a Depropanizer to separate propane from the butane fraction and other components, and a Debutanizer to purify the butane fraction from heavier components. After the fractionation process, the resulting liquid LPG is stored in storage tanks, then pumped into LPG trucks for transportation to the buyer's location.

The LPG product, which meets the specifications and is stored in a special storage tank, is then pumped into LPG trucks for transportation to the buyer's location. This journey crosses both land and water routes, as illustrated on the map showing the distance from the production facility to potential gas buyers. To cross the water route, the LPG trucks will be supported by barges that serve as crossing vehicles. Figure 7 below illustrates the transportation scheme for LPG products.

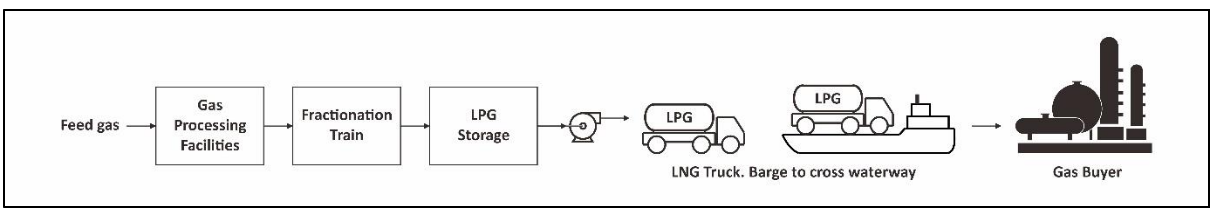

Figure 7.
Schematic of LPG transportation.

3.10. Potential Gas Buyer Locations

Based on practical engineering guidelines, the economic feasibility of a project utilizing natural gas production can be determined by comparing the volume of natural gas production with the distance to its end-users [25]. In this research, there are three potential locations identified as gas buyers at distances of 20 km, 76 km, and 92 km. These distances are calculated based on the available access roads. Along these routes, there is a waterway that must be crossed, approximately 4 km in length. The selection of buyer locations in this study will be determined by considering several key factors, such as the distance from the gas processing facility and the gas demand at each location, which play a crucial role in ensuring sustainable and stable demand. Additionally, the availability of infrastructure and supporting facilities at the gas receiving terminal is critical to ensure efficient gas delivery. Further analysis will also consider geographic accessibility and transportation ease. The main factor affecting

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

the economic analysis of gas buyers is the distance. Therefore, the economic analysis will begin by evaluating the potential buyers at the nearest distance. If the economic targets are met, the analysis will continue progressively with potential buyers at further distances.

3.11. Technical Analysis of Sales Gas Pipeline

3.11.1. Selected Gas Pipeline Specifications

Based on the calculations of pressure drop, fluid velocity, pipe diameter, and pipe wall thickness, the appropriate pipe specifications are presented in **Table 4**.

Table 4.
Selected gas pipeline specifications.

Design code	**ASME B31.8**
Material	Carbon steel, API 5L Grade B
Size	NPS 6
Wall thickness	Sch.40
Length	± 92 km

3.11.2. Simulation

The simulation was conducted for the gas product transported through the gas transmission pipeline to the buyer's location, as illustrated in Figure 8. The characteristics and composition of the simulation results are listed in Table 5.

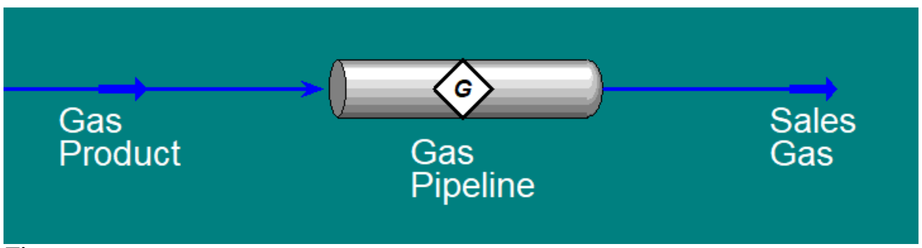

Figure 8.
Sales gas pipeline simulation.

Table 5.
Characteristics and composition of the simulation results.

Description	**Unit**	**Sales gas**
Tekanan	Psig	250
Suhu	°F	100
Flow rate gas	MMscfd	3.68
Methane, C_1	% Mol	93.33
Ethane, C_2	% Mol	3.48
Propane, C_3	% Mol	1.72
Iso-Butane, i-C_4	% Mol	0.64
n-Butane, n-C_4	% Mol	0.56
Iso-Pentane, i-C_5	% Mol	0.00
n-Pentane, n-C_5	% Mol	0.00
Hexanes, C_6	% Mol	0.00
Heptanes plus, C_{7+}	% Mol	0.00
Carbon dioxide, CO_2	% Mol	0.00
Nitrogen, N_2	% Mol	0.27
H_2S content	ppm	0.00
Water content	ppm	0.00

© 2024 by the authors; licensee Learning Gate

3.11.3. Technical Evaluation

Next, the characteristics and composition of the sales gas obtained from the simulation results are compared with the specified sales gas specifications, as shown in Table 6 below.

Table 6.
Comparison of sales gas pipeline specifications.

Spesification	Unit	Value	Result	Remarks
Gross heating value (GHV)	BTU/scf	950 – 1.250	1.086,58	Comply
Min. Methane, C_1 Content	Vol%	80	93.33	Comply
Max. Water, H_2O content	Lbs/MMscf	15	0	Comply
Max. H_2S content	Ppmv	8	0	Comply
Max. CO_2 content	Vol%	5	0	Comply
Max. N2 content	Vol%	5	0.27	Comply
Max. total inert	Vol%	10	0	Comply
Specific gravity	-	0,6 – 0,8	0.65	Comply
Suhu	°F	(-)18 – 120	100	Comply
Min. tekanan	Psig	250	250	Comply

Based on the simulation above, it is clear that the gas processed at the gas processing facility and transported through the transmission pipeline designed in this study has successfully met the required sales gas pipeline specifications.

3.11.4. Production Forecast

Based on the estimated feed gas production profile, which is then processed at the gas processing facility to produce sales gas pipeline products, and after subtracting the volume of gas required for self-consumption fuel use, **Figure 9** provides an estimate of the daily net (nett) sales gas pipeline production volume over the project's lifespan. Condensate, as a byproduct produced from the sales gas pipeline product, is shown in **Figure 10** which provides an estimate of the daily net (nett) condensate production volume over the project's lifespan.

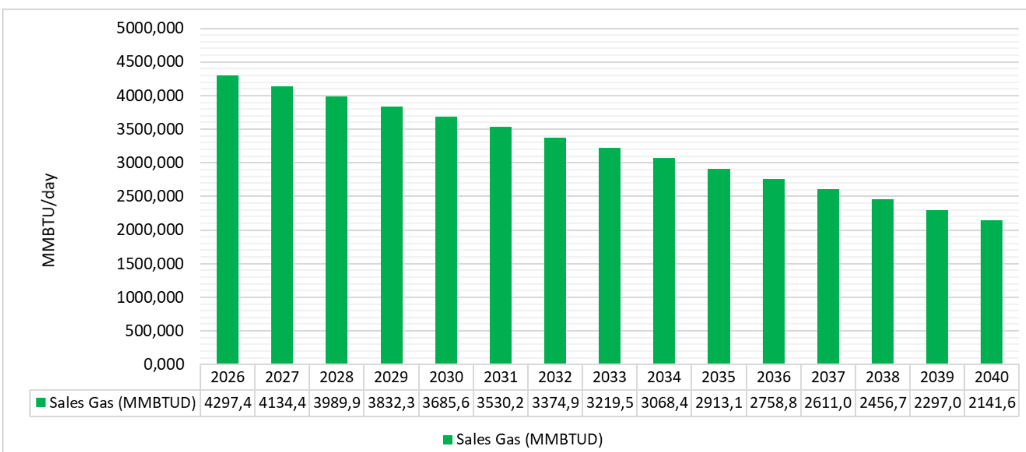

Figure 9.
Sales gas pipeline production forecast.

Edelweiss Applied Science and Technology
ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

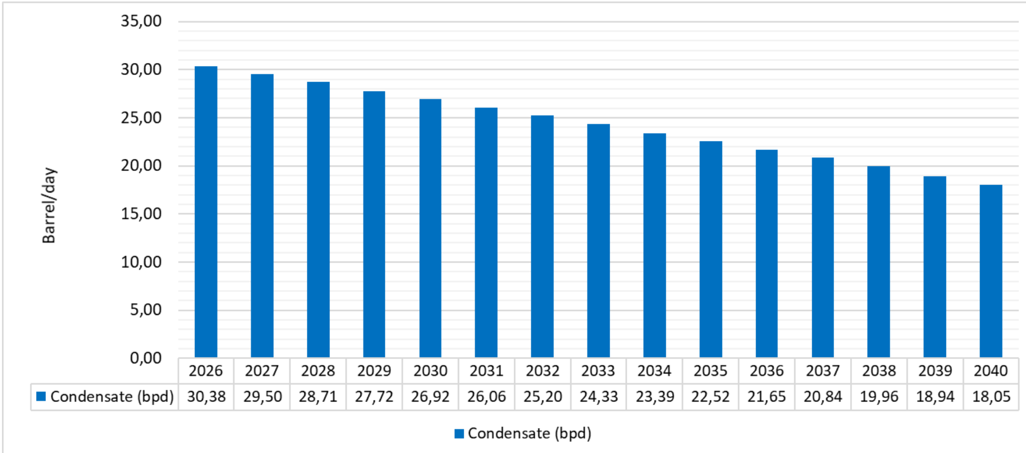

Figure 10.
Condensate production forecast.

3.12. Technical Analysis of CNG

3.12.1. Compressor System Calculation

To compress gas to be stored in a smaller volume and distributed more easily, a compressor system is required. The gas pressure from the gas processing facility, initially at 550 psi, is increased to meet the CNG specification pressure of 200–250 bar (2,900–3,626 psi). **Table 7** provides details on the specifications of the compressor system used in this study.

Table 7.
CNG compressor system specifications.

Type	Reciprocating
No of stage	2
Compression ratio	1 : 2.34
Suction pressure	550 Psig
Discharge pressure	3.000 Psig
Operating temperature	100 °F
CNG temperature	Ambient (77 °F)
Power	281.13 kW
Fuel gas consumption	1.59 MMscfd

3.12.2. Simulation

The simulation conducted to produce CNG is illustrated in **Figure 11** and the characteristics and composition resulting from the simulation are presented in **Table 8**.

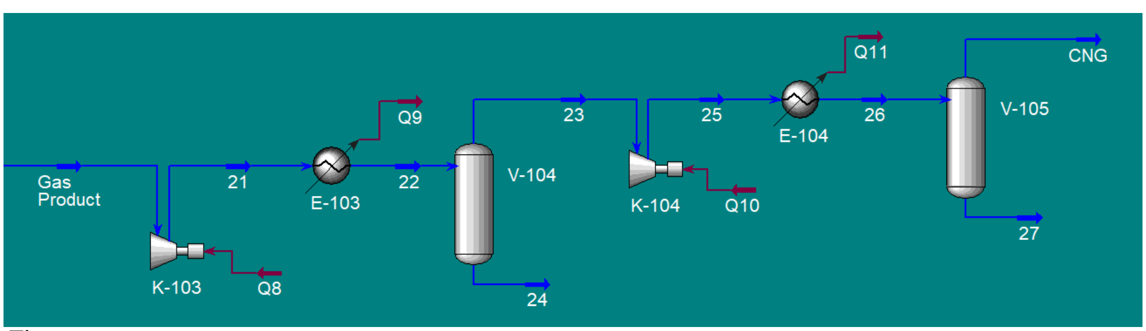

Figure 11.
CNG simulation.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

Table 8.
Characteristic and composition of CNG simulation result.

Description	Unit	CNG
Tekanan	Bar	207
Suhu	°F	77
Flow rate gas	MMscfd	3.67
Methane. C_1	% Mol	93.33
Ethane. C_2	% Mol	3.48
Propane. C_3	% Mol	1.72
Iso-Butane. i-C_4	% Mol	0.64
n-Butane. n-C_4	% Mol	0.56
Iso-Pentane. i-C_5	% Mol	0.00
n-Pentane. n-C_5	% Mol	0.00
Hexanes. C_6	% Mol	0.00
Heptanes plus. C_{7+}	% Mol	0.00
Carbon dioxide. CO_2	% Mol	0.00
Nitrogen. N_2	% Mol	0.27
H_2S content	ppm	0.00
Water content	ppm	0.00

3.12.3. Technical Evaluation

The characteristics and composition of CNG obtained from the simulation are compared with the specified CNG requirements, as shown in **Table 9**.

Table 9. Comparison of CNG specifications.

Specification	Unit	Value	Result	Remarks
Pressure	Bar	200 – 250	207	Comply
Temperature	°F	Ambient (77 °F)	77	Comply
Min. Methane. C_1	Vol%	77.00	93.33	Comply
Max. Ethane. C_2	Vol%	8.00	3.48	Comply
Max. Propane. C_3	Vol%	4.00	1.72	Comply
Max. Butane. C_4	Vol%	1.00	1.20	Not comply
Max. Pentane. C_5	Vol%	1.00	0.00	Comply
Max. Hexanes. C_6	Vol%	0.50	0.00	Comply
Max. N_2	Vol%	3.00	0.27	Comply
Max. H_2S	Vol%	10.00	0.00	Comply
Max. Hg	Vol%	100	0.00	Comply
Max. O_2	Vol%	0.10	0.00	Comply
Max. H_2O	Vol%	3.00	0.00	Comply
Max. CO_2	Vol%	5.00	0.00	Comply

Based on the simulation, it was found that the gas processed at the gas processing facility designed in this study does not meet the specified CNG target specifications. This is due to the maximum volume percentage of butane content exceeding the allowable limit. Therefore, further processes and analysis are required to separate this component.

3.12.4. CNG and LPG Simulation

A simulation was conducted to produce CNG that meets the target specifications and to obtain an additional product in the form of LPG, as shown in **Figure 12**. The characteristics and composition of the CNG product resulting from the simulation are listed in **Table 10**.

© 2024 by the authors; licensee Learning Gate

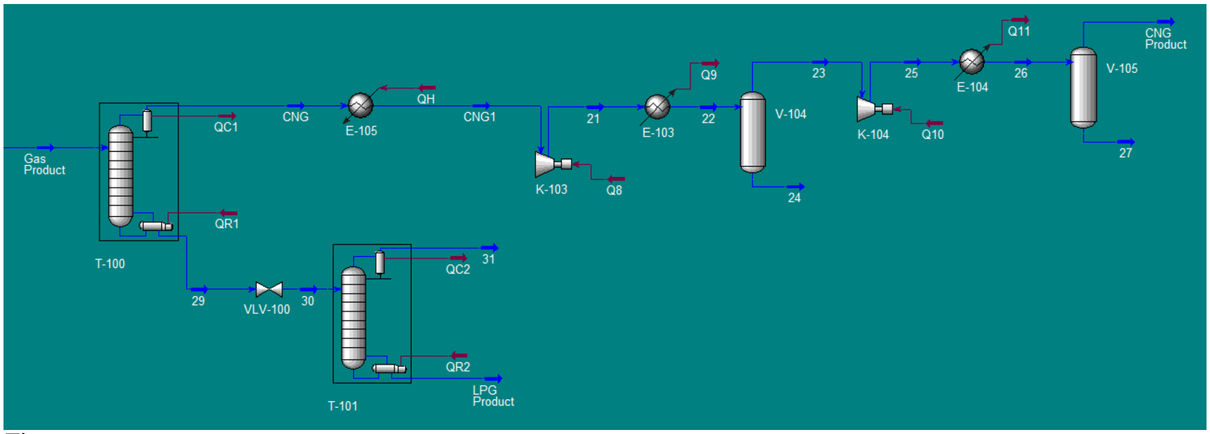

Figure 12.
CNG and LPG simulation.

Table 10.
Characteristic and composition simulation result of CNG and LPG.

Description	Unit	CNG	LPG
Pressure	Bar	207	18.29
Temperature	°F	77	165
Flow rate gas	MMscfd	1.97	-
LPG liquid flow	Bbl/day	-	69.81
Methane. C_1	% Mol	99.50	0.00
Ethane. C_2	% Mol	0.01	0.01
Propane. C_3	% Mol	0.00	55.68
Iso-Butane. i-C_4	% Mol	0.00	23.52
n-Butane. n-C_4	% Mol	0.00	20.79
Iso-Pentane. i-C_5	% Mol	0.00	0.00
n-Pentane. n-C_5	% Mol	0.00	0.00
Hexanes. C_6	% Mol	0.00	0.00
Heptanes plus. C_{7+}	% Mol	0.00	0.00
Carbon dioxide. CO_2	% Mol	0.00	0.00
Nitrogen. N_2	% Mol	0.49	0.00
H_2S content	ppm	0.00	0.00
Water content	ppm	0.00	0.00

3.12.5. Technical Evaluation CNG and LPG

Characteristics and composition of CNG and LPG obtained from the simulation results are compared with the specified CNG and LPG specifications, as shown in **Table 11** and **Table 12**.

Table 11.
Comparison of CNG specification.

Specification	Unit	Value	Result	Remarks
Pressure	Bar	200 – 250	207	Comply
Temperature	°F	Ambient (77 °F)	77	Comply
Min. Methane. C_1	Vol%	77.00	99.50	Comply
Max. Ethane. C_2	Vol%	8.00	0.01	Comply
Max. Propane. C_3	Vol%	4.00	0.00	Comply
Max. Butane. C_4	Vol%	1.00	0.00	Comply
Max. Pentane. C_5	Vol%	1.00	0.00	Comply
Max. Hexanes. C_6	Vol%	0.50	0.00	Comply

© 2024 by the authors; licensee Learning Gate

Max. N_2	Vol%	3.00	0.49	Comply
Max. H_2S	Vol%	10.00	0.00	Comply
Max. Hg	Vol%	100	0.00	Comply
Max. O_2	Vol%	0.10	0.00	Comply
Max. H_2O	Vol%	3.00	0.00	Comply
Max. CO_2	Vol%	5.00	0.00	Comply

Table 12.
Comparison of LPG specification.

Specification	Unit	Value	Result	Remarks
Relative density at 60/60 °F	-	reported	0.45	Comply
Max. vapor pressure at 100 °F	Psig	145	114	Comply
Max. total sulfur content	Grains/100 cu.ft	15	0	Comply
Water Content	-	No free water	0	Comply
Max. Ethane, C_2	Vol%	0.8	0.01	Comply
Min. Propane, C_3 and Butane, C_4	Vol%	97.0	99.99	Comply
Max. Pentane, C_5 and heavier	Vol%	2.0	0.00	Comply
Min. ethyl or buthyl mercaptan	Lb/10000 AG	1.0	1.0	Comply

Based on the simulation above, it is known that the gas produced from the gas processing facility, processed with an additional system to obtain CNG and LPG products as designed in this study, has successfully met the required CNG and LPG specifications.

Based on the results of the simulation, it can also be concluded that CNG production cannot be achieved without the production of LPG as a by-product. This is due to the interrelation of the hydrocarbon component separation process in natural gas, where heavier fractions (such as propane and butane) need to be separated and processed into LPG in order for CNG to be produced with the appropriate quality and specifications. Therefore, to obtain CNG, LPG must also be produced simultaneously.

3.12.6. Production Forecast

Figure 13 provides an estimate of the gas volume that can be processed into CNG products. Figure 14 and Figure 15 provides an estimate of LPG and condensate product respectively.

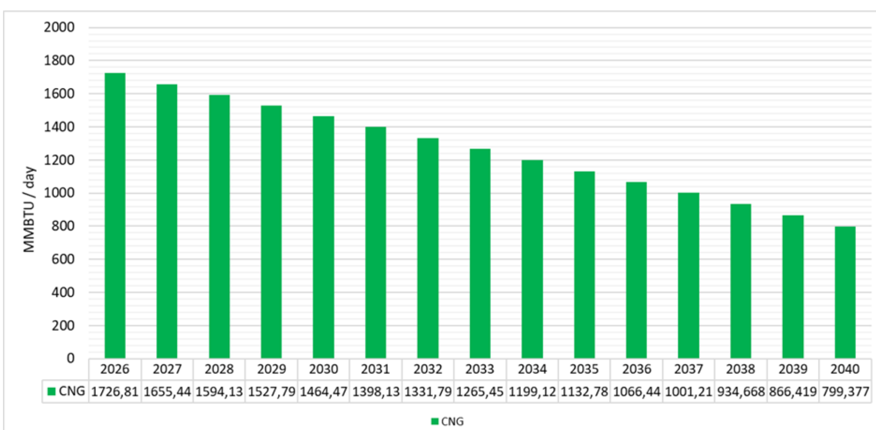

Figure 13.
CNG production forecast.

© 2024 by the authors; licensee Learning Gate

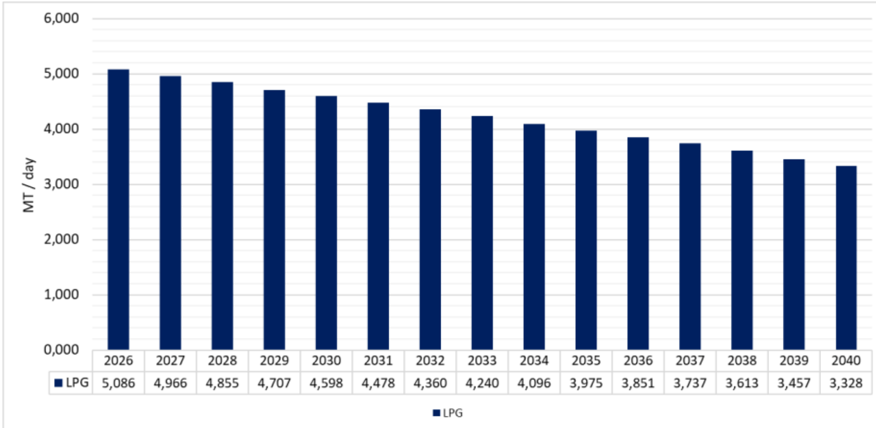

Figure 14.
LPG production forecast.

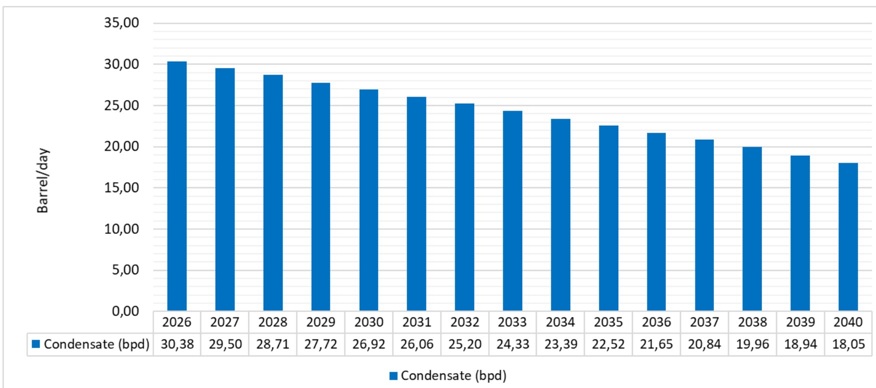

Figure 15.
Condensate production forecast.

3.12.7. Storage System

CNG products will be stored directly from the production facility to the CNG Skid. This direct filling system is designed to provide efficiency in CNG distribution at marginal fields. The CNG product can be immediately transferred to the CNG skid without the need for additional storage tanks, thus reducing waiting time and maximizing operational efficiency. Direct filling is suitable for small-scale production facilities with limited gas production rates, while still being able to serve CNG distribution demands more quickly and flexibly. Additionally, the need for large storage infrastructure investment can be avoided. Direct filling from the production facility to the CNG skid is feasible because the gas pressure from the compression facility is already suitable. The CNG skid can then be installed on a truck for transportation to the buyer's location.

LPG products will also be stored directly from the production facility to the LPG storage tank (skid), which is connected to the LPG transport truck. Once the storage tank is fully filled, the transport truck will directly take it to the destination without significant waiting time. This storage method allows for fast and flexible LPG distribution, suitable for small-scale production facilities with limited gas production rates. Direct filling is made possible because the filling system is designed to meet the required pressure and safety standards. Therefore, investment in large storage infrastructure can be avoided, while maintaining an efficient transportation system and ensuring timely and safe LPG supply to the buyer.

© 2024 by the authors; licensee Learning Gate

3.12.8. Transportation System

The CNG and LPG products, once placed in their respective storage units, are then transported to the buyer's location using trucks, crossing a combination of land and water areas. To cross the water areas, the truck is assisted by a barge. The transportation system for these products is carried out using the mother station and daughter station method [26].

3.13. Technical Analysis of LNG

3.13.1. Simulation

The simulation conducted to produce LNG is illustrated in **Figure 16**. The characteristics and composition of the simulation results are presented in **Table 13**.

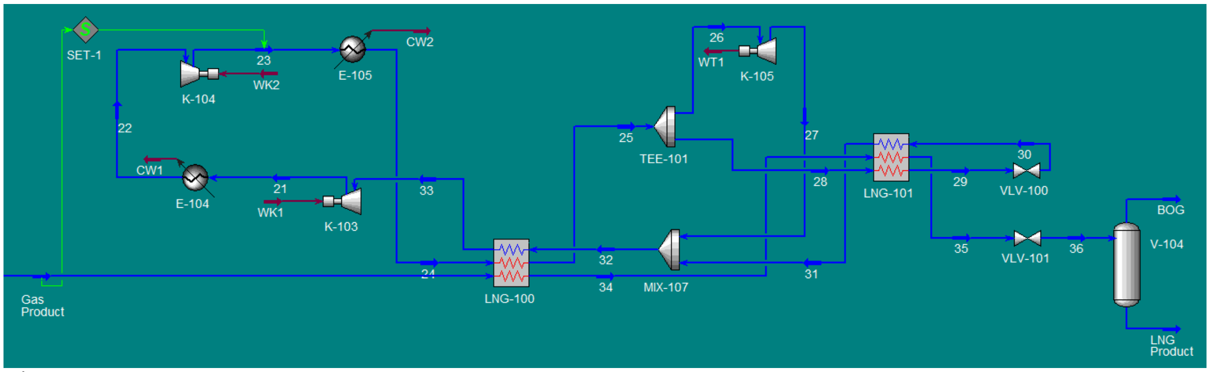

Figure 16.
LNG simulation.

Table 13.
Characteristics and composition of LNG simulation results.

Description	Unit	LNG
Pressure	Bar	2.00
Temperature	°F	-241.40
Liquid flow rate	Bbl/day	1502
Methane, C_1	% Mol	92.87
Ethane, C_2	% Mol	3.85
Propane, C_3	% Mol	1.88
Iso-Butane, i-C_4	% Mol	0.70
n-Butane, n-C_4	% Mol	0.61
Iso-Pentane, i-C_5	% Mol	0.00
n-Pentane, n-C_5	% Mol	0.00
Hexanes, C_6	% Mol	0.00
Heptanes plus, C_{7+}	% Mol	0.00
Carbon dioxide, CO_2	% Mol	0.00
Nitrogen, N_2	% Mol	0.09
H_2S content	ppm	0.00
Water content	ppm	0.00

3.13.2. Technical Evaluation

The characteristics and composition of LNG obtained from the simulation results are compared with the specified LNG standards, as presented in Table 14.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

Table 14.
Comparison of LNG specifications.

Specification	Unit	Value	Result	Remarks
Gross heating value (GHV)	BTU/scf	1.020 – 1.170	1096,05	Comply
Min. Methane, C_1	Mol%	85	92.87	Comply
Max. Butane, C_4 and heavier	Mol%	2	1.31	Comply
Max. Pentane, C_5 and heavier	Mol%	0.1	0.00	Comply
Max. N_2	Mol%	1	0.09	Comply
Max. H_2S	grains/100 scf	0.25	0.00	Comply

Based on the simulation, it is evident that the gas processed at the gas processing facility into LNG, as designed in this study, has successfully met the required LNG specifications.

3.13.3. Production Forecast

Figure 17 illustrates the estimated volume of gas that can be processed into LNG product.

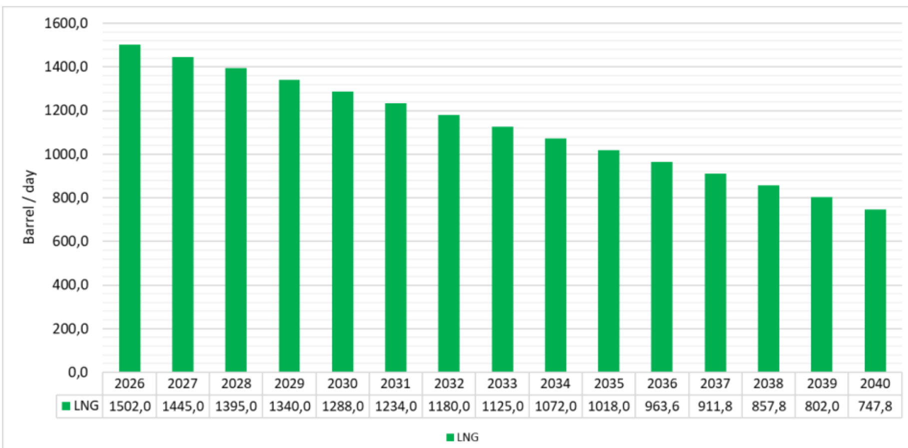

Figure 17.
LNG production forecast.

3.13.4. Storage System

The LNG product will be stored directly from the production facility into LNG storage tanks (skids) connected to LNG transport trucks. Once the storage tanks are fully loaded, the transport trucks will immediately deliver the LNG to the destination without significant waiting time. This storage method enables fast and flexible LNG distribution, making it suitable for small-scale production facilities with limited gas production rates.

This direct filling process is made possible by a filling system designed to meet the required pressure and safety standards. This approach avoids the need for large-scale storage infrastructure investments while maintaining an efficient transportation system, ensuring timely and safe LNG supply for buyers.

3.13.5. Transportation System

The LNG product stored in its tank is then transported to the buyer's location using trucks, traversing a combination of land and water areas. To cross water areas, the trucks are assisted by barges.

3.14. Economic Study

After completing a thorough technical analysis, the next important step is to conduct an economic feasibility study to determine the best strategy for selecting the product options and technologies to be

© 2024 by the authors; licensee Learning Gate

used in gas utilization. The goal of this analysis is to ensure that the chosen option not only provides technical benefits but also maximizes the overall economic value of the project. In the context of developing marginal oil and gas fields, economic efficiency becomes one of the key success factors, given the challenges faced in fields with limited production potential.

This economic feasibility study is conducted by considering various cost components that affect the overall project lifecycle. First, there are drilling costs, which are often one of the main components of total initial expenditure. Then, there are capital expenditures (CAPEX), which include the procurement of equipment, infrastructure, and technology to produce and process the gas. Operational expenditures (OPEX) are also an important part of maintaining operational efficiency throughout the project, including maintenance, operation, and management of production facilities.

In addition, this study also takes into account abandonment and site restoration (ASR) costs, which include the project's responsibility to close wells and restore the environment after production ends. All of these cost components are carefully planned, along with the project timeline, to ensure that each stage is completed on schedule and to avoid delays that may impact profitability.

With this in-depth and comprehensive analysis, the economic feasibility study is expected to determine the most viable gas utilization product among the options considered. The final decision will be based on the economic aspects of each option to ensure that the selected product provides the best economic value and supports the sustainable success of developing this marginal oil and gas field.

3.14.1. Sunk Cost

In this economic feasibility study for gas utilization, no sunk costs are directly allocated to the project under review. All sunk costs arising from previous field development stages are comprehensively evaluated within the context of the overall KKKS Working Area, rather than this individual project. This approach ensures that the economic analysis focuses on future costs and benefits, as well as relevant operational and investment expenses. As a result, project decisions can be made more objectively and efficiently, without being influenced by past investments not directly connected to this project. This also enables a more optimal allocation of resources, ensuring that each gas utilization product and technology option is selected based on its potential to deliver the best economic value across the entire Working Area.

3.14.2. Drilling Cost

In this study, the drilling costs considered originate from the drilling activities of the stranded gas source well. The total drilling cost is USD 4,073,000, comprising tangible costs of USD 790,000 and intangible costs of USD 3,283,000. This total includes all drilling activities, from rig mobilization, supporting equipment, drilling materials, and labor to logistics costs. The cost reference is based on similar-specification drilling in neighboring fields within the KKKS Working Area. The drilling costs are uniformly applied across all types of gas utilization product options and technologies in this study.

3.14.3. Capital Expenditure (CAPEX)

The determination of capital expenditure (CAPEX) in this study refers to various credible and relevant sources. One of the primary references is the Chemical Engineering Index, which is used to update cost estimates based on current market conditions. Additionally, cost estimates are sourced from price quotations provided by goods and service suppliers, historical procurement records, market prices available online, and other reliable literature sources. This approach aims to ensure that every cost component is calculated accurately and reflects industry realities.

In this study, CAPEX is categorized into two types: costs uniform across all product and technology options and costs varying for each gas utilization option. The uniform CAPEX across all product options amounts to USD 4,953,000. Variations in CAPEX occur in gas processing facilities tailored to each product and technology option, such as pipeline gas transmission, CNG, LNG, and LPG. Each technology and product has specific infrastructure requirements, which will be detailed in subsequent sections.

© 2024 by the authors; licensee Learning Gate

3.14.4. Operational Expenditure (OPEX)

The determination of operational and maintenance costs (OPEX) in this study uses various references to ensure accuracy and relevance to current industry conditions. OPEX includes all routine costs incurred during facility operations, such as maintenance, energy consumption, labor, and fuel. The primary references are historical data and project experience in KKKS, industry reports and benchmarking of similar projects, academic study journals, international energy databases, cost components related to CAPEX calculated as a percentage of the asset investment value, and other reliable literature sources. This approach enables a comprehensive and realistic economic analysis of the project, reflecting the actual operational costs that will be encountered.

In this study, OPEX is divided into variable OPEX and fixed OPEX. Variable OPEX fluctuates with production volume, so higher production volumes result in higher costs. Fixed OPEX includes routine operational and maintenance costs for feed gas systems, Health, Safety, and Environment (HSE), and Corporate Social Responsibility (CSR). The fixed OPEX cost determined in this study is 2.5% of the CAPEX [27], with an annual cost escalation rate of 2% [28]. The variable OPEX cost is set at 3 USD/BOE [29].

Differences in fixed and variable OPEX arise in the gas processing facilities for each product and technology option, including pipeline gas transmission, CNG, LNG, and LPG. Each technology and product has specific infrastructure needs, which will be detailed further in the subsequent sections.

In the economic analysis conducted in this study, OPEX is incurred annually. OPEX is treated as a recurring expense charged during the operational period, considering its continuous nature throughout the production phase. The allocation of OPEX also accounts for inflation projections and the time value of money by considering the present value factor. This ensures that all future costs are accurately estimated.

3.14.5. Abandonment and Site Restoration (ASR) Cost

ASR costs refer to expenses allocated for facility decommissioning and project site restoration activities at the end of the operational period. The calculation of ASR costs in this study follows the SKK Migas Guidelines on ASR. According to these guidelines, ASR activities are divided into several categories as follows: Engineering Design, Permits and Regulatory Compliance, Well Closure, Dismantling (a) Platforms, (b) Gathering/Processing Stations, (c) Tanks and Accessories, (d) Terminals, (e) Transmission Pipelines, (f) Power and Control Cables, (g) Supporting Facilities, (h) Other Facilities, Transportation, Storage, and Site Restoration.

The ASR cost calculations will differ for each product option and gas utilization technology studied in this research. Specific ASR costs for each option will be discussed in subsequent sections.

ASR funding is collected incrementally each year throughout the project period. This approach ensures that the funds required for ASR activities at the end of the project are fully accumulated and ready for use, without imposing a significant financial burden on the cash flow in the project's final phase. The ASR costs calculated in this study cover only activities directly associated with the gas utilization project discussed. This method distributes the ASR costs evenly over the project's lifespan, ensuring they do not adversely affect profitability or cash flow stability.

3.15. Economic Study of Sales Gas Pipeline

The total CAPEX for the entire project is the sum of the CAPEX for the gas processing facility and the CAPEX for the sales gas pipeline, amounts to USD 13,189,000.

The calculation of variable OPEX costs each year will fluctuate depending on production volume, as shown in Figure 18.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

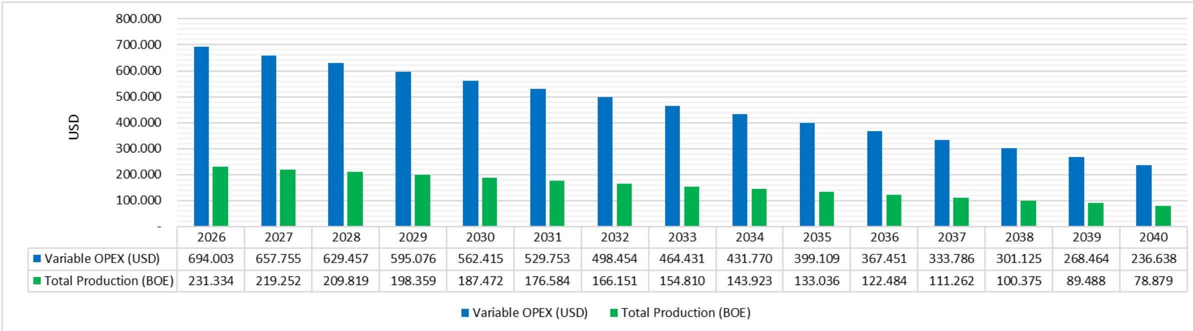

Figure 18.
Yearly variable OPEX sales gas pipeline.

Thus, the total OPEX cost calculation for sales gas pipeline products over the project's lifespan is USD 11,248,000, with a breakdown of fixed OPEX amounting to USD 4,278,000 and variable OPEX amounting to USD 6,970,000.

Based on the costs outlined above, the following **Table 15** provides the annual work budget for sales gas pipeline products:

Table 15.
Annual work budget sales gas pipeline.

Tahun	Drilling		Surface Facilities		OPEX		
	Tangible	Intangible	Tangible	Intangible	Fix	Variable	ASR
2024	790.000	3.283.000	6.594.500	-	-	-	-
2025	-	-	6.594.500	-	-	-	-
2026	-	-	-	-	247.372	694.003	37.467
2027	-	-	-	-	252.319	657.755	37.467
2028	-	-	-	-	257.366	629.457	37.467
2029	-	-	-	-	262.513	595.076	37.467
2030	-	-	-	-	267.763	562.415	37.467
2031	-	-	-	-	273.118	529.753	37.467
2032	-	-	-	-	278.581	498.454	37.467
2033	-	-	-	-	284.152	464.431	37.467
2034	-	-	-	-	289.835	431.770	37.467
2035	-	-	-	-	295.632	399.109	37.467
2036	-	-	-	-	301.545	367.451	37.467
2037	-	-	-	-	307.576	333.786	37.467
2038	-	-	-	-	313.727	301.125	37.467
2039	-	-	-	-	320.002	268.464	37.467
2040	-	-	-	-	326.402	236.638	37.467
Total	790.000	3.283.000	13.189.000	-	4.278.000	6.970.000	562.000

3.15.1. Project Economics

After calculating the costs and annual work budget outlined above, the next step is to perform an economic analysis of the project utilizing feed gas into sales gas pipeline products.

The project's economic analysis shows that it generates positive cash flow. Overall, the cumulative cash flow continues to increase and reaches the break-even point before the end of the project period. This indicates that the project has good profit potential and is feasible to run until completion. Figure 19 shows the annual and cumulative net cash flow for the sales gas pipeline project on the KKKS side.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

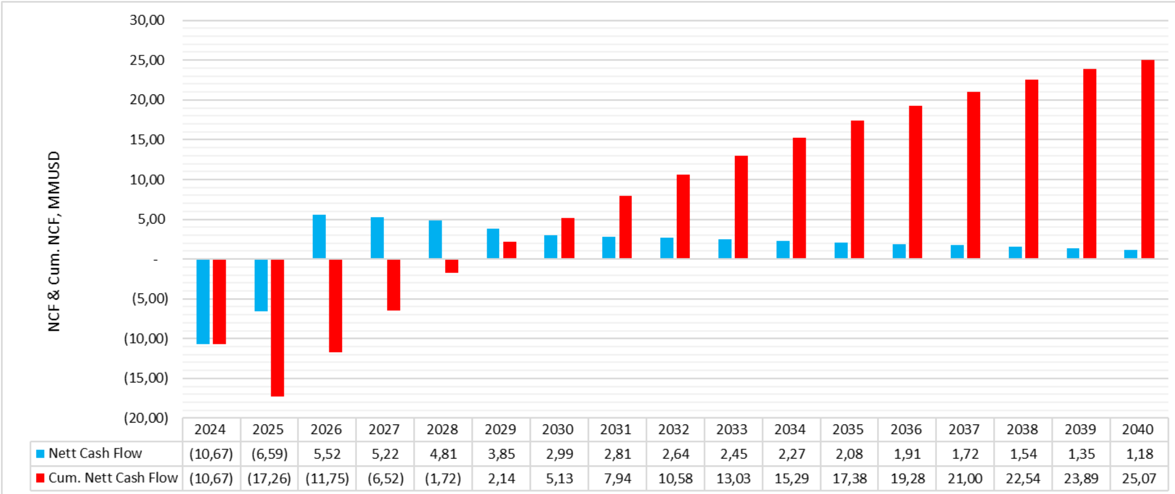

Figure 19.
Net cash flow for KKKS of the sales gas pipeline products.

Next, the tabulation of the economic analysis of the CNG and LPG product options is analyzed against economic parameters, as presented in Table 8.

Table 16.
Economic analysis of the sales gas pipeline product project.

Parameter	Unit	Nilai
Lifting condensate	MMSTB	0.13
Lifting gas	TBTU	14.66
WAP - Condensate	US$/BBL	69.19
WAP - Gas	US$/MMBTU	6.00
Gross rev.	MM$	97.14
Sunk cost	MM$	-
Investasi (Drilling. Facilities)	MM$	17.26
Opex (Incl. tax)	MM$	11.25
ASR	MM$	0.56
Cost recoverable (Deductible cost)	MM$	29.07
(% Gross rev)		29.93%
Unrec. cost (Final carry forward cost)	MM$	-
(% Cost Recovery)		0.00%
Contractor (Profitability):		
Contr. CF (Net contractor cashflow)	MM$	25.07
Net Contr. Share (Net operating profit)	MM$	25.07
%Contr.		25.81%
NPV10	MM$	6.01
IRR		17.46%
POT	Years	5.45
PV ratio		0.36
GOI (Profitability) :		
Gross share	MM$	30.93
Tax	MM$	12.07
GOI take	MM$	43.00
% GOI Share		44.26%

© 2024 by the authors; licensee Learning Gate

GOI PV	MM$	20.11
GoI Take (Incl. Ind. Tax)	MM$	43.00
%Gross Rev	MM$	44%
Gov NPV (Incl. Ind. Tax)	MM$	20.11

Based on the economic analysis presented in the tables and figures above, it is evident that this project for potential buyers at a distance of ± 20 km can achieve the expected economic targets. This project has the potential to be implemented profitably and provide a viable economic value.

3.15.2. Economic Evaluation

After confirming that the project can meet economic targets for a potential buyer at a distance of approximately 20 km, further analysis is conducted to test the project's sensitivity for potential buyers located at distances of approximately ±76 km and ±92 km. **Table 17** provides a comparison of the economic analysis results for each potential buyer.

Table 17.
Comparison of economic analysis results for potential sales gas pipeline buyers.

Parameter	**Unit**	**Distance to potential buyer**		
		±20 km	**±76 km**	**±92 km**
NPV	MM$	6.01	-6.57	-10.54
IRR		17.46%	5.01%	2.87%
POT	Years	5.45	9.29	10.85
Result		Comply	Not comply	Not comply

Figure 20 provides a sensitivity analysis of economic parameters relative to the distance to potential buyers.

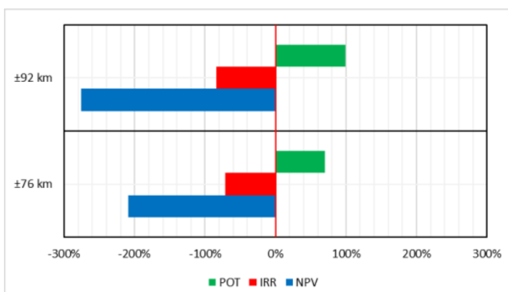

Figure 20.
Sensitivity analysis of buyer distance.

Next, for the project that meets economic targets, a sensitivity analysis is conducted on changes in price, production volume, OPEX, and CAPEX costs, with variations of a 25% decrease and increase. The results of this sensitivity analysis are presented in Table 18 and Figure 21.

© 2024 by the authors; licensee Learning Gate

Table 18.
Sensitivity analysis results.

Price sensitivity					**Production sensitivity**				
Parameter	**Unit**	**75%**	**100%**	**125%**	**Parameter**	**Unit**	**75%**	**100%**	**125%**
Harga	$/MMBTU	4.50	6.00	7.50	Produksi	TBTU	10.99	14.66	18.32
NPV	MM$	1.59	6.01	10.23	NPV	MM$	0.71	6.01	11.16
IRR		12.07%	17.46%	22.14%	IRR		10.93%	17.46%	23.12%
POT	Years	6.53	5.45	4.87	POT	Years	6.81	5.45	4.78
OPEX Sensitivity					CAPEX Sensitivity				
Parameter	Unit	75%	100%	125%	Parameter	Unit	75%	100%	125%
Cost	MM$	8.44	11.25	14.06	Cost	MM$	9.89	13.19	16.49
NPV	MM$	6.91	6.01	5.11	NPV	MM$	8.42	6.01	3.54
IRR		18.47%	17.46%	16.42%	IRR		22.25%	17.46%	13.82%
POT	Years	5.31	5.45	5.59	POT	Years	4.84	5.45	6.04

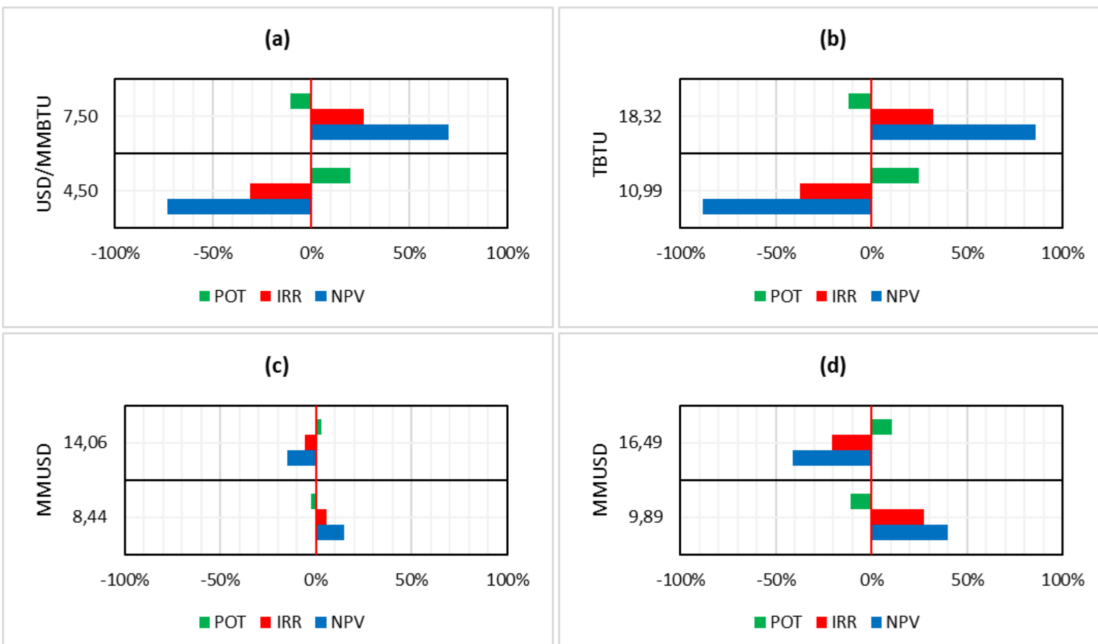

Figure 21.
Graph of sensitivity analysis results: (a) Price Sensitivity, (b) Production Sensitivity, (c) OPEX Sensitivity, (d) CAPEX Sensitivity.

3.16. Economic Study of CNG & LPG

The total CAPEX cost of the entire project, including the CAPEX for the gas processing facility and CNG and LPG, amounts to USD 9,073,239.

The calculation of variable OPEX costs each year will fluctuate depending on production volume, as shown in **Figure 22**.

© 2024 by the authors; licensee Learning Gate

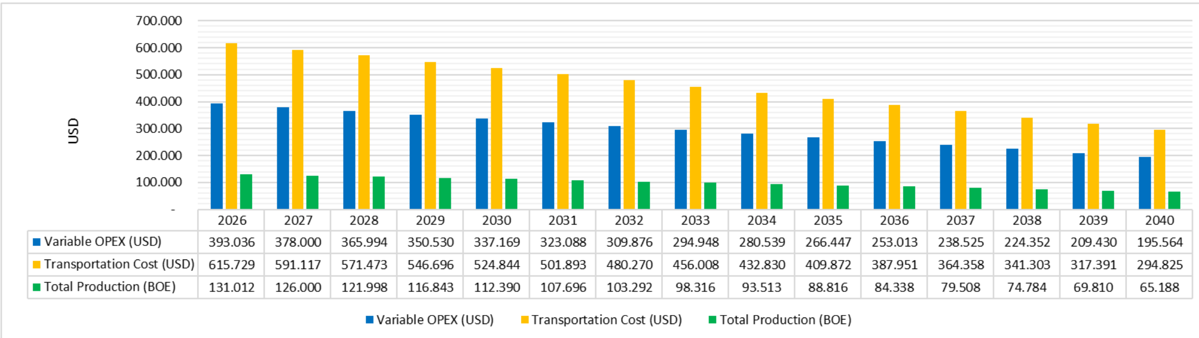

Figure 22.
Yearly variable OPEX.

Thus, the total OPEX cost calculation for CNG and LPG products over the project's lifespan is USD 15,179,755, with a breakdown of fixed OPEX amounting to USD 3,922,683 and variable OPEX amounting to USD 11,257,073.

Based on the costs outlined above, the following **Table 19** provides the annual work budget for CNG and LPG products:

Table 19.
Annual work budget.

Year	Drilling		Surface facilities		OPEX		
	Tangible	Intangible	Tangible	Intangible	Fix	Variable	ASR
2024	789.979	3.283.343	4.536.620	-	-	-	-
2025	-	-	4.536.620	-	-	-	-
2026	-	-	-	-	226.831	1.008.765	28.383
2027	-	-	-	-	231.368	969.117	28.383
2028	-	-	-	-	235.995	937.467	28.383
2029	-	-	-	-	240.715	897.226	28.383
2030	-	-	-	-	245.529	862.013	28.383
2031	-	-	-	-	250.440	824.981	28.383
2032	-	-	-	-	255.449	790.146	28.383
2033	-	-	-	-	260.558	750.956	28.383
2034	-	-	-	-	265.769	713.369	28.383
2035	-	-	-	-	271.084	676.319	28.383
2036	-	-	-	-	276.506	640.965	28.383
2037	-	-	-	-	282.036	602.883	28.383
2038	-	-	-	-	287.677	565.655	28.383
2039	-	-	-	-	293.430	526.822	28.383
2040	-	-	-	-	299.299	490.389	28.383
Total	789.979	3.283.343	9.073.239	-	3.922.683	11.257.073	425.748

3.16.1. Project Economics of CNG and LPG

After calculating the costs and annual work budget outlined above, the next step is to perform an economic analysis of the project utilizing feed gas into CNG and LPG products.

The project's economic analysis shows that it generates positive cash flow. Overall, the cumulative cash flow continues to increase and reaches the break-even point before the end of the project period. This indicates that the project has good profit potential and is feasible to run until completion. **Figure 23** shows the annual and cumulative net cash flow for the CNG and LPG gas project on the KKKS side.

© 2024 by the authors; licensee Learning Gate

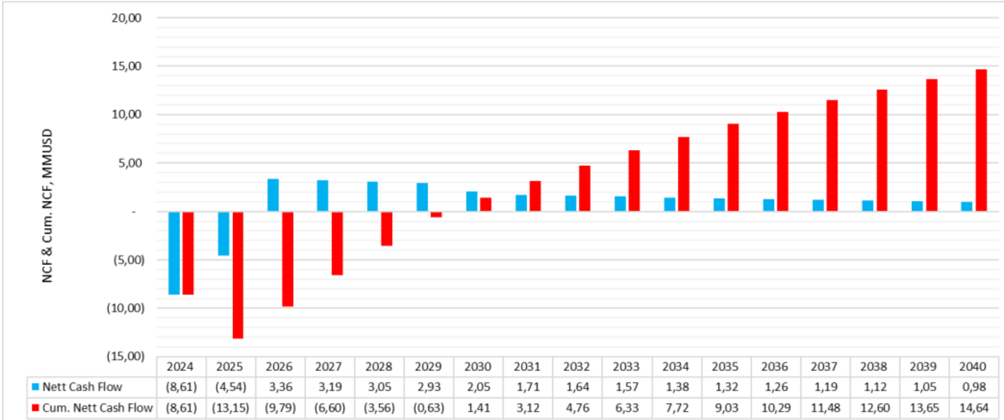

Figure 23.
Net cash flow for KKKS of the CNG and LPG products.

Next, the tabulation of the economic analysis of the CNG and LPG product options is analyzed against economic parameters, as presented in **Table 20**.

Table 20.
Economic analysis of the CNG and LPG product project.

Parameter	Unit	Value
Lifting condensate	MMSTB	0,13
Lifting CNG	TBTU	6,93
Lifting LPG	MTON	23.138,05
WAP - Condensate	US$/BBL	69,19
WAP - CNG	US$/MMBTU	6,00
WAP - LPG	US$/MTON	622,78
Gross Rev.	MM$	67,24
Sunk Cost	MM$	-
Investment (Drilling, Facilities)	MM$	13,15
OPEX (Incl. tax)	MM$	15,18
ASR	MM$	0,43
Cost recoverable (Deductible cost)	MM$	28,75
(% Gross rev)		42,76%
Unrec. Cost (Final carry forward cost)	MM$	-
(% Cost recovery)		0,00%
Contractor (Profitability):		
Contr. CF (Net contractor cashflow)	MM$	14,64
Net contr. share (Net operating profit)	MM$	14,64
%Contr.		21,77%
NPV10	MM$	1,83
IRR		13,01%
POT	Years	6,31
PV ratio		0,14
GOI (Profitability) :		
Gross share	MM$	16,80
Tax	MM$	7,05
GOI take	MM$	23,85
% GOI share		35,47%
GOI PV	MM$	9,84

© 2024 by the authors; licensee Learning Gate

GoI take (Incl. Ind. Tax)	MM$	23,85
%Gross rev	MM$	35%
Gov NPV (Incl. Ind. Tax)	MM$	9,84

Based on the economic analysis presented in the table and figure above, it is determined that for a potential buyer located approximately 20 km away, this project can achieve the expected economic targets. The project has the potential to be run profitably and provide substantial economic value.

3.17. Economic Evaluation of CNG and LPG

After confirming that the project can meet economic targets for a potential buyer at a distance of approximately 20 km, further analysis is conducted to test the project's sensitivity for potential buyers located at distances of approximately ±76 km and ±92 km. **Table 21** provides a comparison of the economic analysis results for each potential buyer.

Table 21.
Comparison of economic analysis results for potential CNG and LPG buyers.

Parameter	**Unit**	**Distance to potential buyer**		
		±20 km	**±76 km**	**±92 km**
NPV	MM$	1.83	0.86	0.58
IRR		13.01%	11.43%	10.97%
POT	Years	6,31	6.72	6.83
Result		Comply	Not comply	Not comply

Figure 24 provides a sensitivity analysis of economic parameters relative to the distance to potential buyers.

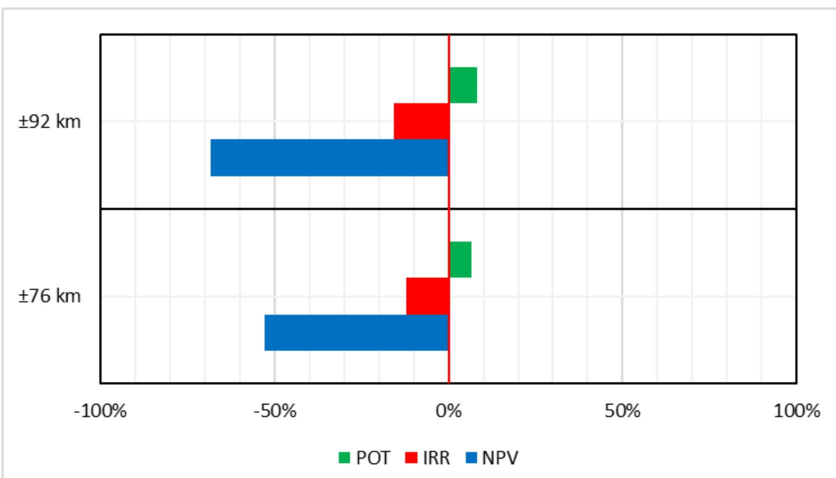

Figure 24.
Sensitivity analysis of buyer distance.

Next, for the project that meets economic targets, a sensitivity analysis is conducted on changes in price, production volume, OPEX, and CAPEX costs, with variations of a 25% decrease and increase. The results of this sensitivity analysis are presented in Table 22 and Figure 25.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

Table 22.
Sensitivity analysis results.

Price sensitivity					**Production sensitivity**				
Parameter	**Unit**	**75%**	**100%**	**125%**	**Parameter**	**Unit**	**75%**	**100%**	**125%**
Price	$/MMBTU	4.50	6.00	7.50	Production	TBTU	5.20	6.93	8.66
NPV	MM$	-1.03	1.83	4.62	NPV	MM$	-1.03	1.83	4.62
IRR		8.24%	13.01%	17.33%	IRR		8.24%	13.01%	17.33%
POT	Years	7.83	6.31	5.47	POT	Years	7.83	6.31	5.47
OPEX sensitivity					CAPEX sensitivity				
Parameter	Unit	75%	100%	125%	Parameter	Unit	75%	100%	125%
Cost	MM$	11.39	15.18	18.98	Cost	MM$	6.80	9.07	11.34
NPV	MM$	3.06	1.83	0.59	NPV	MM$	3.55	1.83	0.08
IRR		14.92%	13.01%	10.99%	IRR		16.76%	13.01%	10.11%
POT	Years	5.88	6.31	6.81	POT	Years	5.54	6.31	7.1

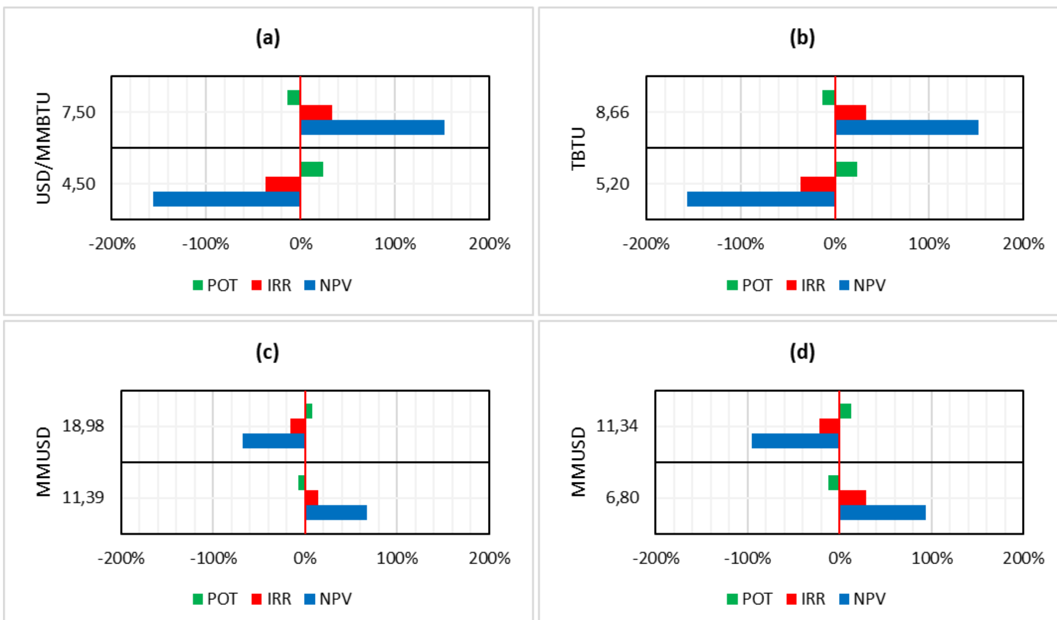

Figure 25.
Graph of sensitivity analysis results: (a) Price Sensitivity, (b) Production Sensitivity, (c) OPEX Sensitivity, (d) CAPEX Sensitivity.

Based on the comparison results, the CNG & LPG options were selected for the utilization project of stranded gas and flare gas in the marginal oil and gas field at the study case location of this research. This option was chosen because it meets the expected technical and economic requirements. Additionally, this option demonstrates flexibility in product delivery over short distances while still maintaining adequate economic viability over longer distances.

The selection of marginal field development technology using packaged equipment and the product transportation method via skid transportation modules combined with barges to cross water areas is considered highly suitable for the development of the oil and gas field in this study, which is a marginal field in a remote area in eastern Indonesia.

3.18. Economic Study of LNG

The total CAPEX cost of the entire project, including the CAPEX for the gas processing facility and LNG, amounts to USD 14,992,000.

© 2024 by the authors; licensee Learning Gate

The calculation of variable OPEX costs each year will fluctuate depending on production volume, as shown in Figure 26.

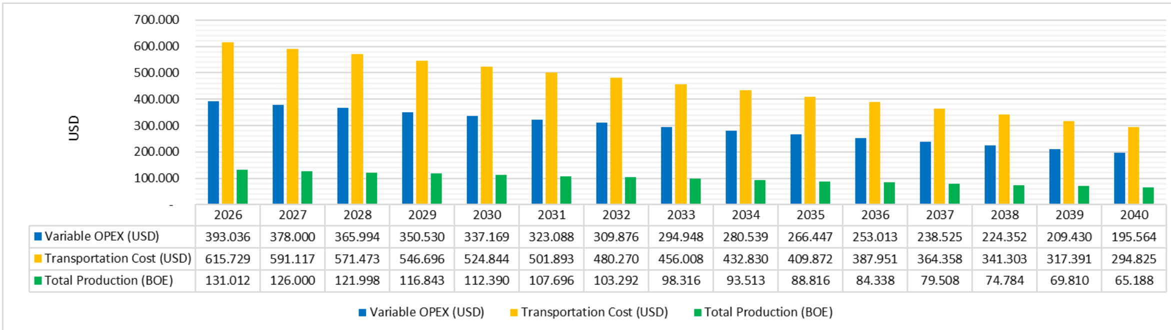

Figure 26.
Yearly variable OPEX.

Thus, the total OPEX cost calculation for LNG products over the project's lifespan is USD 18,884,000 with a breakdown of fixed OPEX amounting to USD 4,745,000 and variable OPEX amounting to USD 14,139,000.

Based on the costs outlined above, the following **Table 23** provides the annual work budget for LNG:

Table 23.
Annual work budget.

Year	Drilling		Surface facilities		OPEX		
	Tangible	Intangible	Tangible	Intangible	Fix	Variable	ASR
2024	790.000	3.283.000	7.496.000	-	-	-	-
2025	-	-	7.496.000	-	-	-	-
2026	-	-	-	-	274.411	1.257.074	28.400
2027	-	-	-	-	279.899	1.209.369	28.400
2028	-	-	-	-	285.497	1.170.721	28.400
2029	-	-	-	-	291.207	1.121.491	28.400
2030	-	-	-	-	297.031	1.077.970	28.400
2031	-	-	-	-	302.972	1.032.776	28.400
2032	-	-	-	-	309.031	990.287	28.400
2033	-	-	-	-	315.212	941.550	28.400
2034	-	-	-	-	321.516	897.193	28.400
2035	-	-	-	-	327.946	851.998	28.400
2036	-	-	-	-	334.505	808.678	28.400
2037	-	-	-	-	341.195	763.116	28.400
2038	-	-	-	-	348.019	717.921	28.400
2039	-	-	-	-	354.980	671.221	28.400
2040	-	-	-	-	362.079	627.573	28.400
Total	790.000	3.283.000	14.992.000	-	4.745.000	14.139.000	*3.18*

3.18.1. Project Economics of LNG

After calculating the costs and annual work budget outlined above, the next step is to perform an economic analysis of the project utilizing feed gas into LNG products.

The project's economic analysis shows that it generates positive cash flow. Overall, the cumulative cash flow continues to increase and reaches the break-even point before the end of the project period.

ISSN: 2576-8484
Vol. 8, No. 6: 7327-7365, 2024
DOI: 10.55214/25768484.v8i6.3586
© 2024 by the authors; licensee Learning Gate

This indicates that the project has good profit potential and is feasible to run until completion. **Figure 27** shows the annual and cumulative net cash flow for the LNG gas project on the KKKS side.

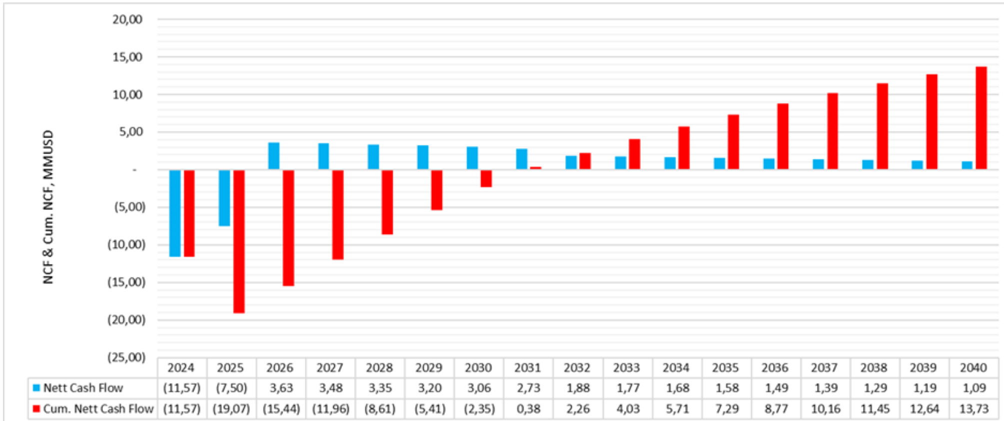

Figure 27.
Net cash flow for KKKS of the LNG products.

Next, the tabulation of the economic analysis of the LNG product options is analyzed against economic parameters, as presented in Table 24.

Table 24.
Economic analysis of the LNG product project.

Parameter	Unit	Nilai
Lifting condensate	MMSTB	0.13
Lifting LNG	TBTU	6.77
WAP - Condensate	US$/BBL	69.19
WAP - LNG	US$/MMBTU	13.80
Gross rev.	MM$	102.53
Sunk cost	MM$	-
Investasi (Drilling. Facilities)	MM$	19.07
Opex (Incl. Tax)	MM$	18.88
ASR	MM$	0.43
Cost recoverable (Deductible Cost)	MM$	38.38
(% Gross rev)		37.43%
Unrec. cost (Final Carry Forward Cost)	MM$	-
(% Cost recovery)		0.00%
Contractor (Profitability):		
Contr. CF (Net contractor cashflow)	MM$	13.73
Net contr. share (Net Operating Profit)	MM$	13.73
%Contr.		13.39%
NPV10	MM$	(1.33)
IRR		8.45%
POT	Years	7.86
PV Ratio		(0.07)
GOI (Profitability) :		
Gross Share	MM$	43.81
Tax	MM$	6.61
GOI take	MM$	50.42
% GOI share		49.18%

© 2024 by the authors; licensee Learning Gate

GOI PV	MM$	22.94
GoI take (Incl. Ind. Tax)	MM$	50.42
%Gross rev	MM$	49%
Gov NPV (Incl. Ind. Tax)	MM$	22.94

Based on the economic analysis presented in the tables and figures above, it is evident that this project for the nearest potential buyers, at a distance of ± 20 km, has not yet been able to achieve the expected economic targets. With the available LNG volume and the set selling price, this project cannot be implemented profitably or provide a viable economic value.

3.18.2. Economic Evaluation of LNG

After the results of the economic analysis for potential buyers at a distance of ± 20 km have been determined, a further sensitivity analysis of the project will be conducted for potential buyers at distances of ± 76 km and ± 92 km. **Table 25** provides a comparison of the economic analysis results for each potential buyer.

Table 25.
Comparison of economic analysis results for potential LNG buyers.

Parameter	Unit	Distance to potential buyer		
		±20 km	±76 km	±92 km
NPV	MM$	-1.33	-3.64	-3.96
IRR		8.45%	5.66%	5.25%
POT	Years	7.86	9.18	9.46
Result		Not comply	Not comply	Not comply

Figure 28 provides a sensitivity analysis of economic parameters relative to the distance to potential buyers.

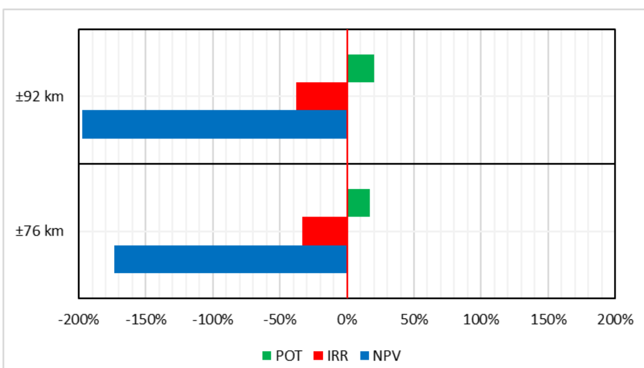

Figure 28.
Sensitivity analysis of buyer distance.

Next, for the project that meets economic targets, a sensitivity analysis is conducted on changes in price, production volume, OPEX, and CAPEX costs, with variations of a 25% decrease and increase. The results of this sensitivity analysis are presented in Table 26 and Figure 29.

© 2024 by the authors; licensee Learning Gate

Table 26.
Sensitivity analysis results.

Price sensitivity					**Production sensitivity**				
Parameter	**Unit**	**75%**	**100%**	**125%**	**Parameter**	**Unit**	**75%**	**100%**	**125%**
Price	$/MMBTU	10.35	13.80	17.24	Production	TBTU	5.08	6.77	8.46
NPV	MM$	-3.86	-1.33	-0.24	NPV	MM$	-6.08	-1.33	3.20
IRR		5.39%	8.45%	9.72%	IRR		2.61%	8.45%	13.57%
POT	Years	9.38	7.86	7.43	POT	Years	11.48	7.86	6.32
OPEX Sensitivity					CAPEX Sensitivity				
Parameter	Unit	75%	100%	125%	Parameter	Unit	75%	100%	125%
Cost	MM$	14.16	18.88	23.61	Cost	MM$	11.24	14.99	18.74
NPV	MM$	0.25	-1.33	-2.93	NPV	MM$	1.60	-1.33	-4.33
IRR		10.29%	8.45%	6.52%	IRR		12.25%	8.45%	5.67%
POT	Years	7.23	7.86	8.73	POT	Years	6.64	7.86	9.21

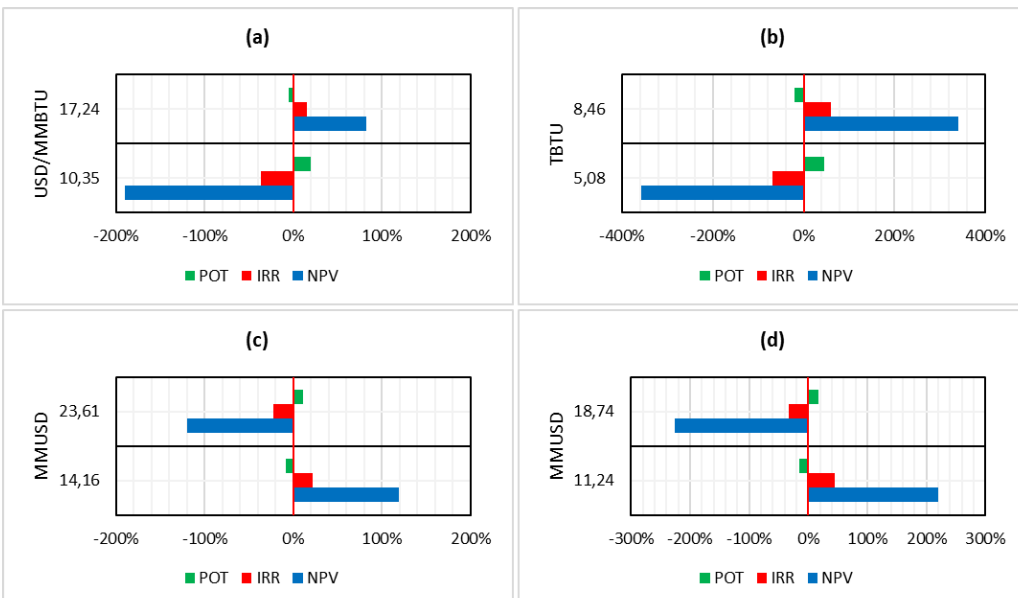

Figure 29.
Graph of sensitivity analysis results: (a) Price Sensitivity, (b) Production Sensitivity, (c) OPEX Sensitivity, (d) CAPEX Sensitivity.

3.19. Product Option Selection

A comprehensive technical and economic study for three product options has been conducted to assess each option based on the critical aspects supporting the project's success. Subsequently, the most viable option was selected, which not only meets all technical requirements but also achieves the expected economic targets. **Table 27** provides a summary comparison of the three options, and **Figure 30** presents the sensitivity analysis results for distances of ±76 km and ±92 km.

© 2024 by the authors; licensee Learning Gate

Table 27.
Comparison results of the three product options.

No	Product	Unit	Potential buyer distance		
			±20 km	**±76 km**	**±92 km**
1	Sales gas pipeline		Comply	Not comply	Not comply
	NPV	MM$	6.01	-6.57	-10.54
	IRR		17.46%	5.01%	2.87%
	POT	Years	5.45	9.29	10.85
2	CNG & LPG		Comply	Not comply	Not comply
	NPV	MM$	1.83	0.86	0.58
	IRR		13.01%	11.43%	10.97%
	POT	Years	6.31	6.72	6.83
3	LNG		Not comply	Not comply	Not comply
	NPV	MM$	-1.33	-3.64	-3.96
	IRR		8.45%	5.66%	5.25%
	POT	Years	7.86	9.18	9.46

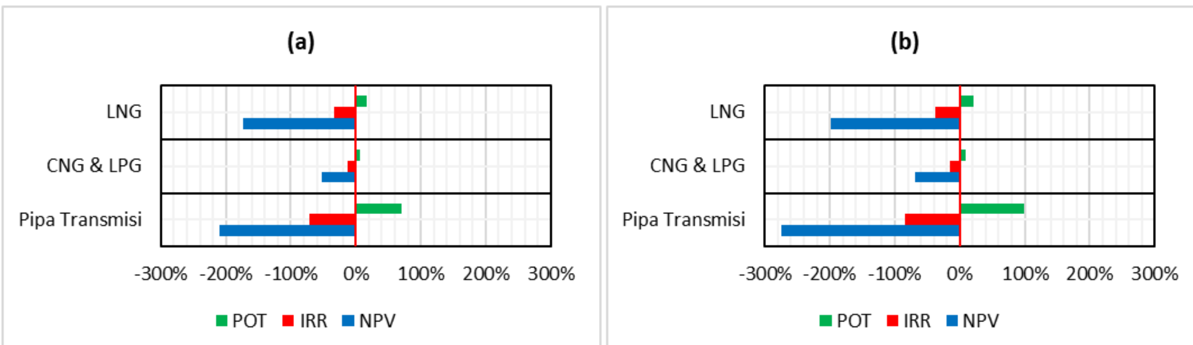

Figure 30.
The results of the sensitivity analysis comparison for the three product options: (a) sensitivity at a distance of ±76 km, (b) sensitivity at a distance of ±92 km.

3.19.1. Sales Gas Pipeline

The project is considered feasible for the closest potential buyers. However, for the next two potential buyer distances, the project cannot meet the expected economic targets. Evaluation of these two potential buyers shows a negative NPV, a significant decrease in IRR, and a very long payback period for the investment.

3.19.2. CNG & LPG

The project is feasible for the closest potential buyers. However, for the next two potential buyer distances, the project cannot meet the expected economic targets. Evaluation of these two potential buyers shows a positive NPV, an IRR still meeting the minimum IRR threshold without margin, and a payback period that is not significantly different.

3.19.3. LPG

The project cannot meet the economic targets for all potential buyers. Therefore, the project is deemed unfeasible.

3.19.4. Selected Option

Based on the comparison results, the CNG & LPG options were selected for the utilization project of stranded gas and flare gas in the marginal oil and gas field at the study case location of this research. This option was chosen because it meets the expected technical and economic requirements.

© 2024 by the authors; licensee Learning Gate

Additionally, this option demonstrates flexibility in product delivery over short distances while still maintaining adequate economic viability over longer distances.

The selection of marginal field development technology using packaged equipment and the product transportation method via skid transportation modules combined with barges to cross water areas is considered highly suitable for the development of the oil and gas field in this study, which is a marginal field in a remote area in eastern Indonesia.

4. Conclusion

At the end of this research process, the option to utilize feed gas into CNG and LPG products were selected as the best options as they meet the required technical and economic criteria. These selected products offer added value in terms of operational flexibility compared to other product options. The optimal production method to maximize additional hydrocarbon production is to process the feed gas into CNG, with LPG and condensate as byproducts. Producing CNG and LPG requires additional processing facilities in the form of modular equipment packages for small-scale gas processing, while condensate processing can utilize existing facilities. The feed gas with an average production volume of 2.5 MMSCFD is assessed to provide good economic value, producing an average of 1,264 MMBTU of CNG per day and 4 MT of LPG per day. This demonstrates that marginal oil and gas fields are also viable and attractive for development.

The commercialization method using a transportation system that combines skid transportation modules and barges is an appropriate solution for the geographical conditions of eastern Indonesia. This method shows economic result as NPV of USD 1.83 million, an IRR of 13.01%, and a POT of 6.31 years. The selected products have shown, even under worst-case conditions — such as a decline in product prices and production volumes, as well as increased OPEX and CAPEX — that the project remains sufficiently attractive to proceed. This indicates that the project has good economic resilience against various risk factors from changing conditions.

Acknowledgements:

The successful completion of this study was made possible through the invaluable support and contributions of numerous individuals and organizations. My deepest appreciation goes to my colleagues and advisors at Universitas Indonesia for their unwavering support, thoughtful feedback, and collaborative spirit, which enriched every stage of this research journey. Also, a sincere thank you to data providers for granting access to critical data, which served as the foundation for the analysis and findings of this research. Your collective contributions have been vital to the success of this work, and I am truly honored to have had your support.

Copyright:

© 2024 by the authors. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

References

[1] R. Swennen, China's Gas Development Strategies, Beijing, China, 2017.

[2] ESDM, "Website Kementerian Energi Dan Sumber Daya Mineral," ESDM, 16 July 2021. [Online]. Available: https://www.esdm.go.id/id/berita-unit/direktorat-jenderal-minyak-dan-gas-bumi/pemerintah-dan-kkks-perkuat-komitmen-capai-produksi-minyak-1-juta-barel. [Diakses 30 January 2024].

[3] James G. Speight, PHD, DSC, Natural Gas A Basic Handbook, Gulf Professional Publishing, 2018.

[4] Saeid Mokahatab, John Y. Mak, Jaleel V. Valappil, David A. Wood, Handbook of Liquefied Natural Gas, 2014.

[5] Muharam, Widodo Wahyu Purwanto. Slamet. Sutrasno Kartohardjono. Asep Handaya Saputra. Yuswan, Teknologi Gas Bumi: Pengolahan, Transportasi, dan Utilisasi, Depok: PT. Pena Persada Kerta Utama, 2023.

[6] D.A. Fee, J. O'Dea, Technology for Developing Marginal Offshore Oilfields, London: Elsevier Applied Science Publishers Ltd, 1986.

[7] ESDM, "Capaian Kinerja Sektor ESDM Tahun 2023," Kementerian Energi Dan Sumber Daya Mineral Republik Indonesia, Jakarta, 2023.

[8] SKK Migas, "Website SKK Migas. Rencana Strategis Indonesia Oil and Gas (IOG) 4.0, Indonesia Oil and Gas Fact Sheet," SKK Migas, 31 Agustus 2023. [Online]. Available: https://www.skkmigas.go.id/page/Renstra%20IOG/renstra-iog-4.0FvnzU. [Diakses 26 February 2024].

[9] Michael J. Economides, David A. Wood, "The State of Natural Gas," Elsevier, Journal of Natural Gas Science and Engineering, July 2009.
[10] Ali Barati, Vahid Pirozfar, "Flare Gas Review in Oil and Gas Industry," ISSN: 0974-2328. J Biochem Tech, 2019.
[11] Kementerian Energi Dan Sumber Daya Mineral (ESDM). Direktorat Jenderal Minyak Dan Gas Bumi, "Pemanfaatan Gas Bumi Untuk Energi Berkeadilan," 2018.
[12] Peraturan Menteri ESDM No.17, "Peraturan Menteri Energi Dan Sumber Daya Mineral Republik Indonesia Nomor 17 Tahun 2021 Tentang Pelaksanaan Pengelolaan Gas Suar Pada Kegiatan Usaha Minyak Dan Gas Bumi," ESDM, Indonesia, 2021.
[13] Dr. Duncan Seddon, Gas Usage & Value The Technology And Economics of Natural Gas Use In The Process Industries, PennWell Corporation, 2006.
[14] Ariel Corporation, "API 618 Compressors Product Catalogue," www.arielcorp.com, 2020.
[15] J.K. Adewole, A.S. Sultan, Polymeric Membranes for Natural Gas, Center for Integrative Petroleum Research, King Fahd University of Petroleum and Minerals, Dhahran, Saudi Arabia: Springer Nature Switzerland AG, 2019.
[16] Arthur Kohl, Richard Nielson, Gas Purification, Gulf Publishing, 1997.
[17] Department of Energy, USA, "Liquified Natural Gas: Understanding the Basic Facts," 2005.
[18] Rajab Khalilpour, I.A. Karimi, "Evaluation of Utilization Alternatives for Stranded Natural Gas," Elsevier, Energy, April 2012.
[19] Emanuele Borgonovo, Elmar Plischke, "Sensitivity Analysis: A Review of Recent Advances," Elsevier, European Journal of Operational Research, 2015.
[20] Sergei Schreider, Jonathan Plummer, Daniel McInnes, Boris Miller, "Sensitivity Analysis of Gas Supply Optimization Models," Annals of Operations Research, 2014.
[21] T. Bieringer, S. Buchholz, N. Kockmann, "Future Production Concepts in the Chemical Industry: Modular – Small-Scale – Continuous," Chemical Engineering & Technology, 2013.
[22] American Petroleum Institute, API Standard 618. Fifth Edition. Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services, Washington D.C.: American Petroleum Institute, 2008.
[23] Sandra Kentish, Angelo Basile, Suzana Pereira Nunes, Advanced Membrane Science and Technology for Sustainable Energy and Environmental Applications, Woodhead Publishing Series in Energy, 2011.
[24] F.S. Manning, R.E. Thompson, Oilfield Processing of Petroleum Volume One: Natural Gas, Oklahoma: Pennwell Books, 1991.
[25] Tractebel Engineering, World Bank Group, Global Gas Flaring Reduction, CNG for commercialization of small volumes of associated gas, 2015.
[26] Reethau Clean Energy, "reethau.com," Reethau Clean Energy, 2024. [Online]. Available: https://reethau.com/en/. [Diakses 30 October 2024].
[27] Max S. Peters, Klaus D. Timmerhaus, Ronald E. West, Plant Design and Economics for Chemical Engineers, Fifth Edition, McGraw-Hill Chemical Engineering Series, 2003.
[28] Badan Pusat Statistik, "Berita Resmi Statistik," Badan Pusat Statistik Indonesia, 2024.
[29] B Daramola, C Iheobi, "Stranded Gas Field Development Economics–Justifying Incentives to Boost Investment," SPE Gas & Oil Technology, 2024.

© 2024 by the authors; licensee Learning Gate