Jurnal Geosaintek Vol 11. No. 3. Desember 2025. p-ISSN : 2460-9072, e-ISSN : 2502-3659

HYDRAULIC FRACTURING DESIGN AND GROSS SPLIT ECONOMIC ANALYSIS USING FRACCADE FOR TIGHT OIL RESERVOIR: 10-YEAR PRODUCTION WELL FORECAST SIMULATION

Riki Darma[1*], Boni Swadesi[1], Herianto[1], Suranto[1]
[1]Magister Teknik Perminyakan, Fakultas Teknologi Mineral dan Energi, UPN "Veteran" Yogyakarta
e-mail: riki.dar73@gmail.com

Abstract. *This study evaluates the technical and economic feasibility of hydraulic fracturing in a tight oil reservoir using FracCADE simulation. A comparative analysis between fractured and unfractured wells was conducted, followed by a 10-year production forecast using decline curve analysis and an economic evaluation under Indonesia's gross split contract scheme. The results demonstrate that optimized hydraulic fracturing significantly enhances well productivity and project economics, although financial performance remains sensitive to oil price and total production. The optimized HF design achieved a 237 ft fracture half-length and 1,064.5 mD·ft conductivity, with 98% slurry efficiency, anticipating a significantly reduced skin factor. The 10-year forecast projects an initial 300 BOPD for fractured wells, showing a productive decline, while unfractured wells are deemed economically unviable. Economically, the project demonstrates strong feasibility under gross split, with a contractor NPV of 18,563,527.11 USD (at 10% discount rate), an IRR of 28%, a PI of 1.52, and a POT of just 1.64 years. These findings highlight how optimal HF not only significantly boosts production but also ensures robust financial returns, despite sensitivity to production volume and oil price fluctuations.*
Keywords: *fraccade; gross split; hydraulic fracturing; reservoir tight oil*

INTRODUCTION

The ever-increasing global demand for energy has continuously propelled the oil and gas industry to seek innovative and efficient methods for optimizing hydrocarbon recovery. This relentless pursuit extends beyond conventional approaches, encompassing advanced techniques such as Enhanced Oil Recovery (EOR) to maximize the economic viability of mature fields (W. Li et al., 2021; X.-X. Lv et al., 2021; X. Lv et al., 2021. However, the inherent uncertainties and high-risk nature of subsurface operations necessitate thorough and robust evaluations for production optimization, not only at the field level but also for individual wells (Suenaga et al., 2012; Xiaoxiao et al., 2021. This is particularly critical when dealing with challenging reservoirs.

One such challenging reservoir type that has gained significant attention in recent years is the "tight oil" reservoir. Characterized by extremely low permeability, typically less than 0.1 millidarcy (mD), these reservoirs naturally restrict the flow of hydrocarbons to the wellbore, making conventional production economically unfeasible. Tight oil is commonly found in compacted sandstones or shale formations and currently represents a vital source of unconventional energy within the oil and gas industry (Gasparrini et al., 2020; Xu et al., 2018; You et al., 2018. To unlock the substantial hydrocarbon potential trapped within these formations, hydraulic fracturing (HF) has emerged as an indispensable stimulation technique.

Indonesia possesses considerable tight oil resources, particularly within major sedimentary basins such as the Kutai, Central Sumatra, and South Sumatra basins. Several studies and government reports indicate that unconventional oil resources, including tight oil, could contribute significantly to future domestic energy supply if supported by appropriate stimulation technologies. However, low permeability and complex reservoir characteristics have limited their commercial development. This condition highlights the urgency of evaluating hydraulic fracturing as a viable strategy to unlock tight oil potential in Indonesia.

DOI : http://dx.doi.org/10.12962/j25023659.v11i3.8971

Received : 29-10-2025 Reviewed : 21-11-2025 Accepted : 12-12-2025 Available Online : 31-12-2025

Table 1. Tight Oil Potential in East Kalimantan

Basin / Area	Target Formation	Resource Type	Estimated Potential (MMBO)	Development Status	Notes
Kutai Basin	Balikpapan Formation	Tight Oil	300 – 1.000	Not yet commercial	Low permebility, requires HF
Kutai Basin	Kampung Baru Formation	Tight Oil	200 – 700	Preliminary study	Heterogeneous reservoir
Kutai Basin	Pulubalang Formation	Tight Oil	150 – 500	Limited exploration	Promising potential but technically challenging
Delta Mahakam	Batupasir deltaik	Tight Oil	100 – 300	Declining conventional production	Candidate for EOR/HF
Onshore Kutai Timur	Multiple sand packages	Tight Oil	250 – 800	Not yet developed	Economically sensitive
Indicative total for East Kalimantan	–	–	**~1.000 – 3.300**	–	Unconventional resources

Hydraulic fracturing fundamentally involves the injection of high-pressure fluid into the rock formation to create artificial fractures, thereby enhancing the reservoir's conductivity and allowing hydrocarbons to flow more readily to the wellbore (Bai et al., 2020; Wu et al., 2020; Zou et al., 2020. This process effectively modifies the rock's structure, leading to an increase in both porosity and permeability (Aminzadeh, 2019. While HF operations are undeniably capital-intensive, requiring substantial volumes of specialized fluids, proppant materials, and dedicated equipment, their criticality in unlocking the vast potential of tight oil resources cannot be overstated. Nevertheless, it's worth noting that the high uncertainty associated with the oil and gas industry means that HF implementation does not always guarantee a production increase (X. Liu et al., 2020; Lu & He, 2020; L. Wang et al., 2020, underscoring the need for meticulous planning and analysis. Hydraulic Fracturing is generally applied to reservoirs with low porosity and permeability characteristics, which restrict the flow of hydrocarbon fluids to the surface.

Given the complexities and significant investment involved, optimizing HF design is paramount. This research focuses on the application of hydraulic fracturing in tight oil reservoirs, leveraging advanced simulation software, FracCADE, to design optimal HF scenarios. FracCADE's capabilities allow for the detailed modeling of fluid injection strategies, appropriate proppant selection, and the customization of designs to match specific reservoir characteristics, ultimately aiming to maximize fracturing effectiveness. Following the technical design, a comprehensive economic analysis will be conducted, utilizing the gross split contract scheme, which is the prevailing fiscal regime in Indonesia's upstream oil and gas sector. This analysis will project production over a 10-year forecast period, providing a robust financial assessment of the HF project.

The primary objective of this study is to thoroughly evaluate the technical effectiveness, economic feasibility, and overall viability of implementing hydraulic fracturing in tight oil reservoirs using FracCADE. Specifically, this research aims to:

1. Design and simulate optimal hydraulic fracturing treatments for tight oil wells using FracCADE software.
2. Analyze and compare the production profiles and 10-year forecast differences between fractured and unfractured wells.
3. Assess the economic feasibility of hydraulic fracturing implementation under the gross split contract scheme, using key indicators such as Net Present Value (NPV), Internal Rate of Return (IRR), and Payout Time (POT).
4. Provide technical and economic recommendations for the strategic optimization of tight oil reservoir development in Indonesia.

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It is hypothesized that a meticulously designed hydraulic fracturing treatment using FracCADE will lead to a significant increase in oil production from tight oil reservoirs. Furthermore, this enhanced production is expected to positively impact the project's economics, resulting in improved NPV, IRR, and a shorter POT under the gross split contract scheme. This research is anticipated to contribute significantly to the optimization of tight oil reservoir development through hydraulic fracturing and serve as a strategic guide for investment decisions in Indonesia's gross split oil and gas contracts.

METHODOLOGY

This research adopts a quantitative, simulation-based approach primarily aimed at optimizing hydraulic fracturing processes in tight oil reservoirs using the FracCADE software. Furthermore, it seeks to conduct a long-term 10-year production forecast post-stimulation and analyze the project's economics under the gross split production sharing contract scheme. The entire research process is structured, commencing with secondary data collection, followed by reservoir and production data processing, hydraulic fracturing simulation design, future production rate prediction, and finally, the calculation of economic indicators.

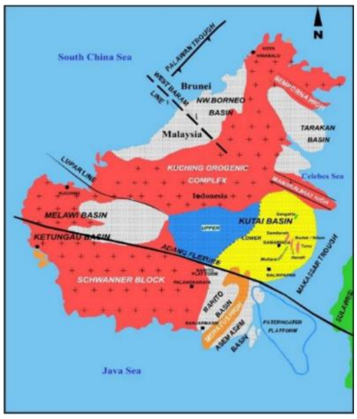

Figure 1. Tectonic Map of Kalimantan Island (modified from Nuay, 1985; Rose and Hartono, 1978

The geographic scope of this study primarily focuses on the Kutai Basin, located in northeastern Kalimantan Island, Indonesia. This basin is bounded by the Mangkalihat High to the north, the Meratus High to the south (separating it from the Barito Basin), and the Kuching High to the west, which is believed to be its main sediment source. The eastern boundary extends to the continental shelf in the Sulawesi Sea, likely terminating at the depths of the Makassar Strait. Specifically, this research centers on the Semberah Field, an integral part of the Kutai Basin, situated in East Kalimantan Province. Geologically, the Kutai Basin formed during the Middle Eocene rifting, followed by basin subsidence until the Late Oligocene. Sediments have continuously filled the basin from west to east since the early Tertiary, with the depocenter shifting eastward since the Late Miocene. The Semberah Field is structurally part of the Samarinda anticlinorium complex, specifically within the Semberah-Pelarang anticline complex.

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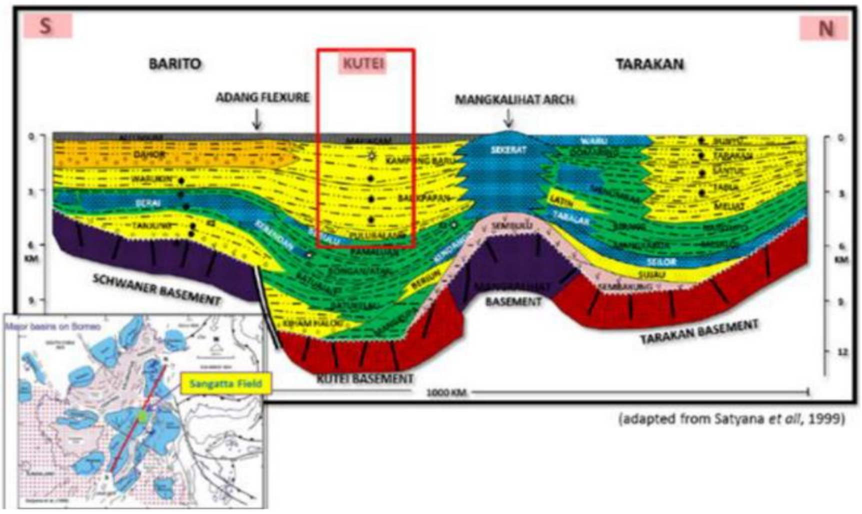

Figure 2. Stratigraphic Model of Kutai Basin (Satyana et all., 1999

The first step in this research involved the collection of secondary data, encompassing geological, petrophysical, reservoir, and historical production data. This data, obtained from well log interpretations, technical field reports, and relevant academic literature, includes formation thickness, lithology type, porosity, permeability, fluid saturation, as well as reservoir pressure and temperature. Following data acquisition and validation, reservoir characterization was performed to understand the initial conditions prior to hydraulic fracturing. This stage was crucial for determining the input parameters for the HF simulation, conducted using FracCADE software. The HF design phase involved modeling various scenarios by varying parameters such as frac fluid volume, proppant type and size, number of fracture stages, and pumping rate and pressure. The objective was to identify the optimal design for enhancing fracture conductivity and oil production rates. FracCADE provided outputs including fracture length, width, height, pressure distribution, proppant placement efficiency, and estimated permeability enhancement. These simulation results were then compared to identify the design yielding the most significant production increase.

The next stage involved simulating a 10-year production forecast for each HF design scenario. This was performed using decline curve analysis (DCA), specifically the Arps method, assuming exponential or hyperbolic production decline over time, a common practice for stimulated unconventional wells. Parameters such as initial production rate, decline rate, and decline shape factor were adjusted based on FracCADE's outputs for each scenario. The annual oil production and cumulative production over 10 years were projected from these simulations, forming the basis for the subsequent economic analysis. Project economic assessment was conducted using the gross split contract model, as regulated in Indonesia. This model calculates revenue division between the government and the contractor based on gross revenue, without a cost recovery mechanism. The calculation incorporated base split percentages (e.g., 57% for government, 43% for contractor) and additional splits based on field complexity, geographical location, and production status. Key economic indicators calculated were Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period (PBP). NPV was determined by discounting all cash flows over the project life at a 10% discount rate. Data for economic analysis included estimated oil prices, Capital Expenditure (CAPEX) for drilling and fracturing, and annual Operational Expenditure (OPEX). These values were sourced from literature and similar field feasibility studies, adjusted to simulation conditions. To understand the project's sensitivity to economic and technical changes, a sensitivity analysis was also performed. Key parameters like oil price, investment costs, operational costs, and initial production rate were varied within ±10% to ±20% ranges to assess their impact on NPV and IRR.

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RESULT AND DISCUSSION

The design of hydraulic fracturing treatments represents a crucial stage in optimizing hydrocarbon production from unconventional reservoirs, particularly tight oil formations characterized by extremely low matrix permeability. This process aims to create conductive, low-pressure pathways by injecting specialized fluids and proppant materials into the rock formation. Accurate modeling and simulation are the backbone of designing effective HF operations, predicting fracture geometry, and evaluating potential well productivity enhancements. In this study, FracCADE (Fracpro 2019 software was employed to analyze and design HF operations for Well X, a vertical well targeting a tight oil formation.

The target formation, identified as a Tight Oil Formation/Reservoir, exhibits a very low reference permeability of 0.00449 mD. This inherently indicates that the well's natural production rate would be minimal, often economically unfeasible, typically yielding less than 50 BOPD. Such low permeability is the primary justification for implementing massive stimulation techniques like hydraulic fracturing.

Well X targets a tight oil formation at approximately 7,525 ft. The formation is characterized by very low permeability, with an average reference formation permeability of 0.00449 mD, underscoring the necessity of HF stimulation for economic production. The perforated interval ranges from 7,500 to 7,550 ft TVD/MD, with an effective perforated layer thickness of 50 ft. Understanding this thickness is vital for identifying the ideal target zone for fracture initiation and propagation. Geomechanical parameters, including in-situ stress, Young's modulus, and Poisson's ratio, were inputted to predict fracture behavior. Specifically, the target zone (Layer #2 at 7,525-7,575 ft) exhibited a stress of 7,022 psi with a stress gradient of 0.930 psi/ft, a Young's modulus of 4.00e+06 psi, and a Poisson's ratio of 0.250. Bounding layers (Layer #1 and #3, shale) displayed higher stress (9,030 psi with a gradient of 1.200 psi/ft) and a larger Young's modulus (6.00e+06 psi), indicating their role as natural barriers for vertical fracture growth. The presence of a Composite Layering Effect (CLE) of 25.00 outside the payzone and 1.00 within the production zone suggests considering layer heterogeneity's impact on fracture propagation. The reservoir pore pressure was 3,500 psi with a reservoir temperature of 200°F, crucial data for fluid leakoff calculations and pressure response during operations.

Proper selection of fracturing fluid and proppant is critical for HF success. The main fluid used was Halliburton's HG25G2K (Hybor system), a 25 lb/Mgal gel with 2% KCl. This fluid showed an initial viscosity of 50.75 cp at 200°F reservoir temperature, with varying n' and k' values over time and temperature, indicating non-Newtonian characteristics and viscosity degradation. Brady-20/40, an uncoated sand material, was chosen as proppant. It has a density of 100 lbm/ft^3 and a specific gravity of 2.65, with an average diameter of 0.023 inches. The proppant's permeability to closure stress is crucial, ranging from 320 D at 0 psi to 14,329 D at 10,000 psi, and decreasing to 0.000 D at 20,000 psi. This permeability reduction due to compression and fragmentation under pressure is a significant factor in calculating effective fracture conductivity.

The simulation results revealed an impressive fracture half-length of 237 ft, with the propped half-length being identical at 237 ft. This indicates that the entire generated fracture length was successfully propped, signifying an excellent design achievement for ensuring long-term conductivity. The total fracture height reached 143 ft, while the total propped height was 60 ft. This difference suggests some vertical fracture growth beyond the propped zone, likely into the bounding shale layers with higher fracture toughness. The fracture top and bottom depths were 7,478 ft and 7,620 ft, respectively, while the propped fracture top was at 7,478 ft and bottom at 7,538 ft. This implies that the propped zone is concentrated around the perforated interval (7,500-7,550 ft), but the overall fracture exhibits greater vertical expansion. Fracture width varied along the fracture and over time.

Fracture conductivity, a key parameter describing the fracture's ability to flow fluid from the formation to the well, showed an Average Conductivity (after applying Total Damage Factor and Proppant Embedment) of 1,064.5 mD·ft. This value demonstrates that the created fracture provides an efficient flow path. The Dimensionless Conductivity of 1,001.04 also indicates the fracture's effectiveness in increasing productivity relative to formation permeability. Several proppant conductivity damage factors were considered, including a Proppant Damage Factor of 0.50, an Apparent Damage Factor (due to non-Darcy and multi-phase flow) of

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0.06, leading to a Total Damage Factor of 0.56. Despite this reduction, the final proppant permeability remained very high 16,487 mD from an Undamaged Prop Perm at Stress of 35,109 mD), confirming that Brady-20/40 proppant effectively maintained conductivity under formation pressure.

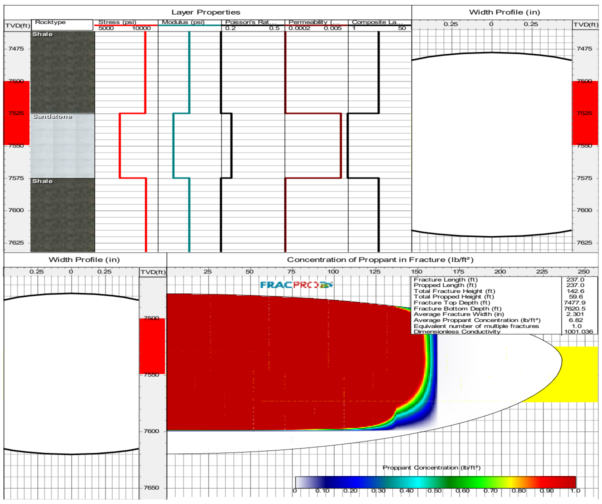

Figure 3. Simulation and analysis results generated using FracCADE software

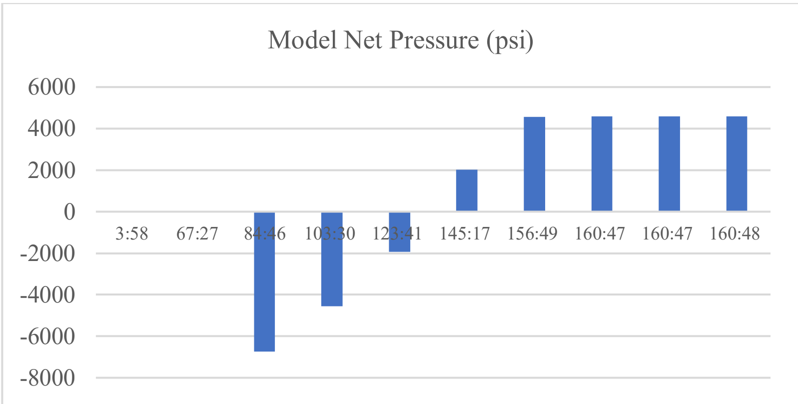

Figure 4. Net Pressure Vs Time using FracCADE software

The effective permeability increase post-frac for the well is expected to be substantial. While a direct new K value is unavailable, the fracture conductivity of 1,064.5 mD·ft, when converted to effective permeability within the stimulated zone, will significantly exceed the original formation's 0.00449 mD. This increase will directly impact the well's effective flow capacity (Kh), calculated as effective permeability multiplied by productive layer thickness. With a total propped height of 60 ft, the effective Kh increase will be highly significant, fundamentally improving the well's ability to flow oil. For Well X, the fracture half-length is 237 ft, confirmed by the same propped half-length, indicating full proppant support. The Effective Propped Length was recorded at 134 ft, representing the fracture length that effectively contributes to flow after considering proppant damage and other effects. This fracture half-length denotes how far the fracture extends horizontally from the well, essentially acting as the radius of drainage created by the HF stimulation, significantly increasing the well's contact area with the reservoir.

The high fracture conductivity 1,064.5 mD·ft) and adequate effective propped length 134 ft) strongly suggest that the hydraulic fracturing in Well X was highly effective in reducing flow resistance. Although the simulation noted a Total Damage Factor of 0.56 on the proppant and 0.008 inches of proppant embedment, which slightly reduced proppant permeability (from 35,109 mD to 16,487 mD), these effects did not negate the conductive benefits of the fracture. Therefore, the post-HF skin factor (S new) is expected to be very low or negative, indicating a substantial increase in productivity.

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This change in skin factor directly impacts the well's Inflow Performance Relationship (IPR). Considering the tight oil formation's very low permeability (0.00449 mD), the IPR curve before HF would be very "flat" or have a very small slope. This signifies that a small increase in flow rate would require a very large bottomhole pressure drop, indicating severely limited well productivity and a very low Productivity Index (PI). After successful HF with a fracture half-length of 237 ft and fracture conductivity of 1,064.5 mD·ft, the IPR curve will become much "steeper" or have a larger slope. This implies that for the same bottomhole pressure drop, the well will be capable of producing significantly higher flow rates. This PI increase reflects the elimination or significant reduction of flow barriers around the well (skin effect) and the creation of a vast contact area with the reservoir.

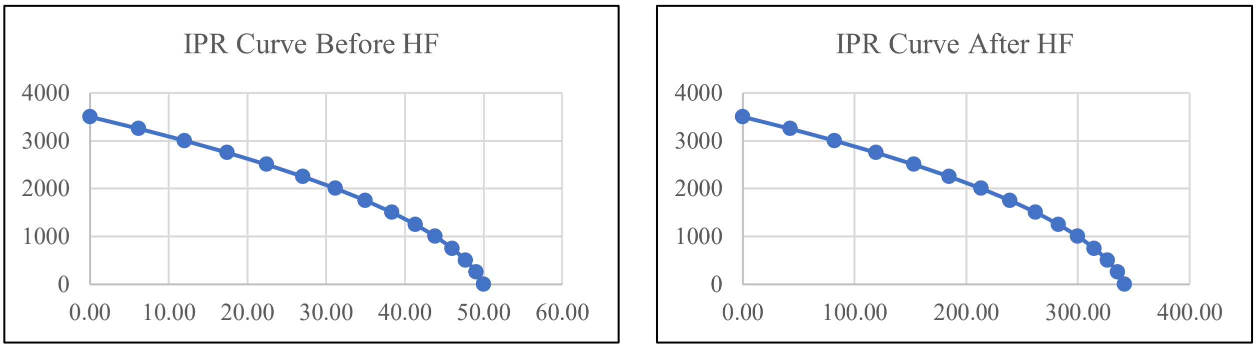

Figure 5. IPR Curve using FracCADE software

Following the successful hydraulic fracturing (HF) design, which optimized fracture geometry, conductivity, and minimized fluid loss through FracCADE modeling, the next step was to project the well's potential hydrocarbon production. Based on initial analysis and the effective stimulation of the tight oil reservoir, an initial daily production rate post-frac is estimated to be in the range of 200 – 300 BOPD. For this production forecast, an initial production rate (qi) in 2020 was assumed to be 300 BOPD. Production forecasting was performed using decline curve analysis (DCA) with a hyperbolic decline model, which is commonly applied for hydraulically fractured wells in unconventional reservoirs. The hyperbolic parameters, including initial production rate, decline rate, and decline exponent (b-factor), were determined based on the post-fracture performance predicted by FracCADE.The parameters used were a decline exponent (b-factor) of 0.9 and a nominal daily decline rate of 0.0389% 15%/year). Production rates for subsequent years (Prod (d)) were obtained by applying the DCA formula and then multiplied by 365 days to get annual production (Prod (y)). For instance, the average daily production rate in 2021 is projected to decrease to 260.87 BOPD, and this decline trend continues gradually until 2029, where the daily production rate is projected to reach 205.31 BOPD. This measured decline pattern reflects the natural reservoir depletion characteristics post-stimulation, yet still demonstrates significantly higher productivity performance compared to the pre-frac potential.

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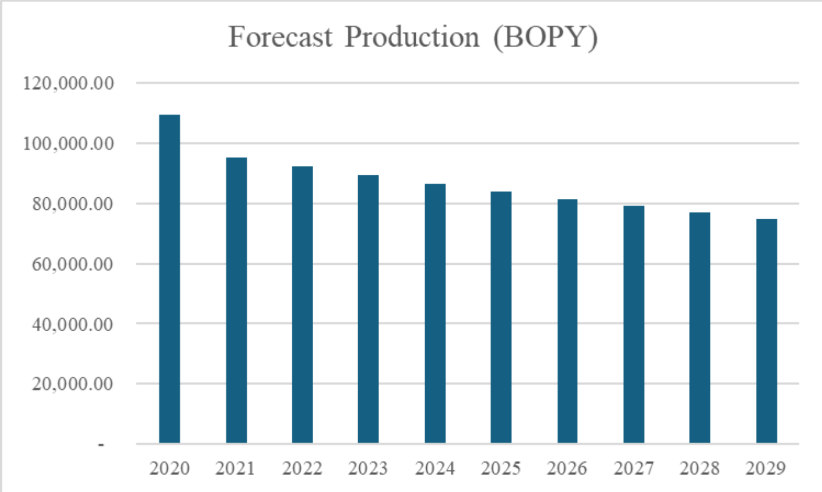

Figure 6. Forecast Production FracCADE software

The implementation of the Gross Split scheme necessitates a meticulous understanding of the revenue-sharing mechanism between the contractor and the government. In this case, the revenue split percentage is determined by a series of corrections that consider field characteristics and progressive split factors. Based on calculations, the total split for the contractor was determined to be 87.25% of the total gross revenue, while the government received 12.75%. This total contractor split comprises a base split of 43%, a variable split of 33%, and a progressive split of 11%. Significant corrections included POD 2 field status (3%), tight oil reservoir condition 16%), API gravity of 20 1%), total content of 55% (3%), and tertiary production stage 10% and 33%). The progressive split was applied based on an oil price of $80 USD/bbl, contributing 1.25%, and cumulative production less than 30 MMboe, contributing 10%. This reflects an effort to provide adequate incentives for investment in challenging fields like tight oil reservoirs.

The economic analysis commenced with projecting the Gross Revenue over 10 years, based on the oil production forecast and assumed oil price. With a total cumulative production of 868,833.39 BOPY over the projection period until 2029 and an assumed oil price of $80 USD/bbl, the expected cumulative Gross Revenue is 69,506,671.28 USD. In this analysis, OPEX was assumed to be 8 USD/bbl , indicating calculated operational efficiency in the project design. The cumulative Total Operating Cost over the projection period reached 6,950,667.13 USD.

Revenue sharing between the contractor and the government was calculated from the Gross Revenue. The Contractor Share, representing the contractor's portion of the gross revenue after the split, cumulatively reached 60,644,570.69 USD over the projection period. From this amount, the contractor then covers all operating costs and capital expenditures (Cash Out). The Government Share, as the portion received by the government, amounted to 8,862,100.59 USD. Cumulative Cash Out, encompassing investment and operational costs, totaled 42,630,667.13 USD. Considering contractor revenue and expenditures, Net Cash Flow (NCF) represents the remaining funds available to the contractor annually. The total cumulative NCF obtained by the contractor is 18,013,903.56 USD. Meanwhile, Cumulative Cash Flow (CCF) shows the accumulation of NCF over time, reaching 18,013,903.56 USD at the end of the projection period.

The economic indicators derived from the cash flow analysis provide a comprehensive overview of the project's investment viability:

- Net Present Value (NPV) Contractor: At a 10% discount rate, the contractor's NPV is estimated at 18,563,527.11 USD. This significant positive NPV indicates that the project holds economic added value above the calculated cost of capital, making it financially attractive to the contractor.
- Internal Rate of Return (IRR): The project's IRR is 28%.
- Profitability Index (PI): The PI obtained is 1.52. A PI value greater than 1.0 signifies that every dollar invested yields more than one dollar in present value returns, reaffirming project profitability.

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- Pay Out Time (POT): The POT was recorded at 1.64 years. This relatively short period indicates a rapid return of initial capital investment for the contractor, suggesting controlled financial risk

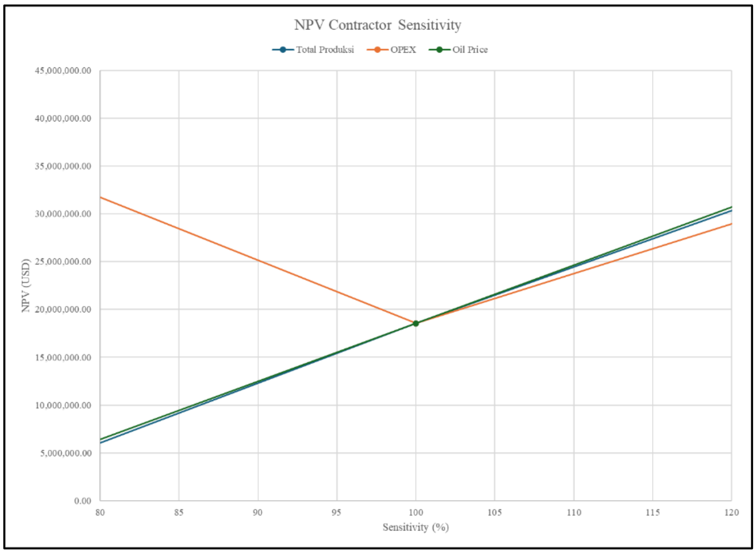

Figure 7. NPV Contractor Sensitivity

Ultimately, the project's financial viability proves that technical HF success can indeed generate economic value. The project's economic indicators are highly positive, with a Contractor NPV reaching 18,563,527.11 USD, an IRR of 28%, a PI of 1.52, and a POT of only 1.64 years. The favorable Gross Split allocation to the contractor (87.25% Contractor Split) also plays a significant role in attracting investment. Further sensitivity analysis confirms that while strong, the project is highly sensitive to changes in total production and oil price. A 30% decrease in either of these parameters can drastically erode financial viability, even leading to a negative NPV. This emphasizes the critical importance of accurate production forecasts and global market stability in mitigating project risks. Overall, the integration of optimal HF design with realistic production projections solidifies this project as a promising investment, though it requires careful risk management against external factors.

CONCLUSIONS

Based on the analysis conducted, this study yields several key conclusions:

1. Optimal HF design and simulation for tight oil wells were successfully achieved using FracCADE, yielding an optimal fracture half-length of 237 ft and 1,064.5 mD·ft conductivity with 98% slurry efficiency.
2. A significant 10-year production forecast difference was observed between fractured wells (initial 300 BOPD, showing productive decline) and unfractured wells (expected to be economically unviable).
3. Hydraulic fracturing under the Gross Split scheme demonstrated strong economic feasibility, evidenced by a positive NPV 18,563,527.11 USD), high IRR 28%), PI of 1.52, and a short POT 1.64 years).
4. Despite the strong technical and economic performance, sensitivity analysis indicates that the project's financial viability is highly dependent on oil price and total production volume. A significant decline in either parameter may substantially reduce NPV and IRR, highlighting oil price volatility and production uncertainty as the primary risks in tight oil hydraulic fracturing projects.

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