INTERNATIONAL JOURNAL OF MULTIDISCIPLINARY RESEARCH AND ANALYSIS

ISSN(print): 2643-9840, ISSN(online): 2643-9875

Volume 08 Issue 12 December 2025

DOI: 10.47191/ijmra/v8-i12-60, Impact Factor: 8.266

Page No. 7083-7097

Financial Viability of Beta Gas Field Development: Comparative Analysis of Two Commercial Options

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ABSTRACT: Beta Gas Field development in the Celebes Block faces a critical commercialization decision between two strategies under Indonesia's Gross Split PSC framework. This research compares two scenarios: Beta to Alfa Field integration connecting to existing infrastructure for immediate PLN sales starting 2026, versus Beta Field Only development waiting for mini-LNG infrastructure completion in 2028. The study aims to determine optimal commercialization strategy by evaluating financial performance, identifying critical risk variables, and providing strategic recommendations. This study uses detailed financial modeling with deterministic analysis, sensitivity analysis, and Monte Carlo simulation across 1,000 scenarios under the Gross Split PSC framework with 12.68% discount rate. The findings show that connecting Beta to Alfa Field is clearly superior, generating USD 77.75 million NPV compared to USD 64.69 million for Beta Only (20% better), with higher returns of 49.70% IRR versus 43.18%, and faster capital recovery of 3.38 years versus 3.93 years. These better results come from producing more gas (119.78 BSCF versus 102.01 BSCF) over a longer 13-year field life and earning higher revenue (USD 628.71 million versus USD 520.27 million) by starting production earlier. The risk analysis reveals that production volume has the biggest impact on project success, where 20% changes can swing NPV by USD 21 million, followed by gas price affecting NPV by USD 17-19 million. The simulation tested 1,000 different scenarios and found both options remain profitable, with Beta to Alfa demonstrating more consistent and predictable results. The The study concludes that Beta to Alfa Field integration is the optimal strategy with superior financial returns and lower risk. The research recommends immediate project execution targeting early 2026 production, monitoring mini-LNG progress, updating economic evaluations regularly, negotiating PLN contract extension beyond 2029, and implementing production optimization and cost control programs.

KEYWORDS: Financial Viability, Gross Split PSC, NPV, Sensitivity Analysis, Monte Carlo Simulation.

I. INTRODUCTION

Natural gas is a vital energy commodity for Indonesia, both as a domestic energy source and as a high-value export commodity. As a relatively clean fossil fuel, natural gas plays a strategic role in supporting national economic growth, energy security, and industrial development. For the government, natural gas represents a significant source of state revenue through taxes, royalties, and production sharing (Adamopoulos & Syrou, 2022; Dodanwala et al., 2023). For communities, natural gas provides benefits such as more stable electricity supply, cleaner household fuel, and employment opportunities in the energy sector (Kabeyi & Olanrewaju, 2022; Mohammad et al., 2021; Pizarro-Loaiza et al., 2021). Therefore, optimal management and utilization of natural gas directly impact community welfare, industrial competitiveness, and sustainable economic development. Natural gas utilization data for 2024 released by the Ministry of Energy and Mineral Resources (ESDM) shows that the government has prioritized meeting domestic needs with an allocation of 67% of total production, while the remaining 33% is allocated for export. Total natural gas utilization in 2024 reached 5,786 BBTUD, with 3,881 BBTUD for the domestic market and 1,905 BBTUD for export. Domestic gas utilization is dominated by the industrial sector at 1,473 BBTUD (40%), followed by electricity 707 BBTUD (19%), domestic LNG 695 BBTUD (19%), and fertilizer 690 BBTUD (19%). Smaller portions are allocated for domestic LPG 77 BBTUD (2%), city gas 15.48 BBTUD (1%), and gas fuel 3.95 BBTUD. This allocation reflects the vital role of natural gas in supporting national industrialization and electrification.

Analysis of natural gas utilization trends during the 2019-2024 period shows promising positive development. Total natural gas utilization in 2019 reached 6,140 BBTUD, consisting of 3,985 BBTUD for domestic use and 2,155 BBTUD for export. Over the past five years, despite some fluctuations, there are strong indications of increasing gas demand, especially approaching 2024.

Domestic utilization shows a relatively stable trend with an increasing tendency. This data reflects the success of government efforts in promoting domestic gas utilization as a transitional energy towards clean energy, while maintaining a balance with export needs to optimize state revenue. In contrast to the increasing demand for natural gas, national gas production realization data for the 2015-2024 period shows a consistent downward trend. natural gas production decreased from 8,678 MMSCFD in 2015 to 6,452 MMSCFD in 2024, representing a decline of 20.2%. This production decline is primarily caused by high dependency on existing fields, approximately 70% of which have entered the mature category. Additionally, delayed commercialization of gas from new fields due to infrastructure completion delays has significantly contributed to the failure to achieve national production targets (Ayodele, 2024; Hermawan et al., 2024; Kemfert et al., 2022). The gap between gas production and demand creates serious challenges for national energy security and sustainable gas supply for strategic industries, necessitating a comprehensive strategy to optimize production and commercialization of gas from both existing and new fields.

The gas production profile of the Celebes Block reveals an increasingly pronounced divergence between planned targets and actual output, indicating a structural misalignment between development assumptions and operational realities. During the 2022–2024 period, actual production levels of approximately 40–45 MMSCFD remained broadly aligned with targets of 41–48 MMSCFD, reflecting stable performance supported by the mature Alpha Field. In contrast, 2025 represents a critical inflection point, as production targets escalated sharply to 87 MMSCFD based on the anticipated contribution from the Beta Field, while realized production stagnated at 47 MMSCFD, resulting in a gap of roughly 41 MMSCFD. This shortfall is primarily attributable to the continued reliance on the declining Alpha Field, as the Beta Field remains undeveloped due to prolonged delays in Mini LNG infrastructure construction by the gas buyer. These delays stem from funding constraints, complex permitting requirements, land acquisition challenges, and technical construction obstacles, collectively inhibiting the timely monetization of Beta Field resources (Husain, 2024). Consequently, the approximately 50% underachievement relative to targets has generated substantial economic losses through unrealized reserves and deferred contributions to national gas supply objectives. This condition underscores the urgency of formulating alternative gas commercialization strategies that reduce dependency on Mini LNG infrastructure and enable the optimization of Beta Field's economic value through diversified commercialization pathways, thereby closing the production gap and unlocking the field's full development potential.

PT ABC is a Production Sharing Contract (PSC) contractor operating the Celebes Block in Eastern Indonesia with contract tenure extending until 2042, positioning itself as a key contributor to Indonesia's upstream oil and gas sector and national energy security. The company manages two principal gas fields, namely the mature Alfa Field, which has been producing since 1997 with cumulative production exceeding 300 BSCF and supplying gas to PLN's combined cycle gas turbine power plant, and the Beta Field, which is planned for development with a production scenario of approximately 40 MMSCFD over seven years and total expected recovery of 102 BSCF. PT ABC operates integrated upstream infrastructure, including a central gas processing plant with a capacity of 60 MMSCFD, dedicated transmission pipelines, power generation supply facilities, and an extensive city gas network serving more than 15,000 households, while managing proven gas reserves of approximately 800 BCF and gas resources of around 2 TCF. Guided by a vision to become one of Indonesia's leading upstream oil and gas companies, PT ABC is committed to delivering sustainable value through responsible exploration, exploitation, and production activities conducted under stringent health, safety, and environmental standards. The company is supported by a comprehensive organizational structure covering exploration, drilling, facilities engineering, field operations, safety and environment, finance, supply chain, human resources, and legal functions to ensure operational efficiency and governance (Akano et al., 2024; Egbumokei et al., 2024; Money et al., 2025). In parallel with its core operations, PT ABC implements sustainability and community development programs focused on education, healthcare, local economic empowerment, and infrastructure development. Strategically, the company prioritizes continued exploration, production optimization, expansion of gas utilization, and integration of advanced technologies to enhance efficiency, thereby reinforcing its long-term contribution to power generation, industrial energy supply, household gas access, and the reduction of national energy import dependency.

The principal business issue confronting PT ABC is the prolonged delay in commercializing gas from the Beta Field in the Celebes Block, primarily driven by setbacks in the development of Mini LNG infrastructure. This delay has generated a substantial disparity between production targets and actual output, resulting in material economic losses, heightened risks to national energy security, and deferred contributions to Indonesia's 2030 national gas production objectives. The challenge is further compounded by a fundamental shift in the fiscal regime from Cost Recovery to Gross Split during the contract extension period (Pereira et al., 2022). While the original Plan of Development for the Beta Field was approved under the Cost Recovery scheme, allowing investment costs to be recovered prior to profit sharing the transition to the Gross Split regime has significantly altered the project's financial structure, as revenues are now divided based on predetermined percentages without cost recovery, thereby reshaping investment incentives and overall project viability. In response to this situation, PT ABC is undertaking a comprehensive financial viability assessment to compare two strategic gas commercialization options under the current Gross Split framework. The first option involves maintaining the original strategy of waiting for the completion of Mini LNG infrastructure before selling raw gas from the Beta Field, which necessitates careful evaluation of financial feasibility amid uncertainty, delays, and opportunity costs. The second option proposes connecting the Beta Field to the existing Alfa Field via pipeline infrastructure, enabling gas processing at Alfa Field's facilities and accelerating sales to the national power utility, thereby potentially expediting revenue realization despite higher upfront capital expenditure. Through detailed cash flow modeling, investment appraisal metrics, and risk sensitivity analysis, this comparative evaluation is intended to identify the most economically attractive option, support informed decision-making by PT ABC, and facilitate constructive engagement with regulators and other stakeholders to optimize project returns while safeguarding national energy interests.

II. RESEARCH QUESTIONS

To address the commercialization challenges at Beta Gas Field, this study will focus on two essential questions examining the financial performance of the available options:

1. How do the two commercial options for Beta Gas Field compare in terms of financial analysis based on Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period (PBP) parameters?
2. Which variables have the most significant impact on the financial performance of each commercial option?
3. Which option is most optimum for Beta Gas Field based on the results of financial analysis?

III. RESEARCH METHODOLOGY

This study adopts a structured and quantitative research design aimed at evaluating the financial viability of alternative gas commercialization strategies under Indonesia's Production Sharing Contract (PSC) Gross Split regime. The research begins with the systematic identification and definition of two strategic commercialization options, followed by the compilation of key technical and commercial inputs, including production forecasts, gas pricing assumptions, and fiscal parameters. These inputs form the basis for gross revenue estimation, which is subsequently allocated between the contractor and the government in accordance with the Gross Split mechanism, incorporating base, variable, and progressive split components. The analytical framework integrates capital expenditure, operational expenditure, and abandonment and site restoration costs to derive taxable income, government take, and contractor take, thereby enabling a comprehensive assessment of project cash flows and economic distribution across the project life cycle.

Data collection employs a mixed-source approach to ensure analytical robustness and contextual validity. Primary data are obtained through semi-structured interviews with key stakeholders across subsurface, development planning, commercial, operations, and supply chain functions, providing expert insights into reservoir performance, infrastructure requirements, cost structures, market conditions, and operational constraints. These interviews serve to validate assumptions, refine economic parameters, and capture organizational and implementation risks. Secondary data are derived from extensive reviews of internal corporate documents, including PSC terms, Plan of Development approvals, work programs and budgets, authorization for expenditures, historical production forecasts, and existing commercial agreements, complemented by external sources such as regulatory guidelines, government reports, industry studies, and academic literature on oil and gas economics and risk management.

The data analysis methodology is grounded in discounted cash flow (DCF) modeling to assess investment feasibility and comparative economic performance. Gross revenue is calculated based on production volumes and gas prices, with appropriate conversion from volumetric to energy units using gross heating value parameters. Cost structures are categorized into capital expenditure, operating expenditure, and abandonment and site restoration provisions, all of which are treated as deductible expenses for tax purposes. Contractor taxable income is determined after deducting these costs from contractor revenue, with income tax applied in accordance with prevailing PSC regulations. Capital budgeting indicators, including Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period, are computed and evaluated against the Weighted Average Cost of Capital as the hurdle rate to determine economic viability and investment attractiveness.

To address uncertainty and financial risk inherent in upstream gas projects, the methodology incorporates sensitivity analysis and Monte Carlo simulation. Sensitivity analysis is conducted in line with SKK Migas guidelines to identify key variables, such as gas price, production volume, capital expenditure, and operating costs that exert the greatest influence on project NPV within a defined variance range. Monte Carlo simulation further enhances risk assessment by simultaneously randomizing critical variables using triangular probability distributions and executing a large number of iterations to generate probabilistic NPV outcomes. Project feasibility is ultimately evaluated based on the probability distribution of NPV results, providing a rigorous basis for comparing commercialization options and supporting evidence-based decision-making under the Gross Split fiscal regime.

IV. RESULTS AND DISCUSSIONS

A. Business Situation Analysis

The business situation analysis of the Beta gas field development integrates a comprehensive assessment of external macro-environmental conditions through the PESTEL framework. From a political perspective, Indonesia's strong governmental commitment to enhancing national energy security, reflected in ambitious production targets and supportive fiscal regimes such as the option between Gross Split and Cost Recovery Production Sharing Contracts, creates a favorable investment climate for upstream gas projects. Economically, project viability is shaped by volatile global gas prices, exchange rate fluctuations between the Rupiah and the US Dollar, inflationary pressures on operational costs, and simultaneously rising domestic and regional gas demand driven by economic growth, power generation needs, and industrial expansion. Socially, the project offers positive employment and regional development impacts, although potential land acquisition issues and community-related conflicts necessitate proactive stakeholder engagement to safeguard the social license to operate (Amponsah & Agyemang, 2024; Hasibuan et al., 2023). Technological advancements, including enhanced drilling, completion, and digital monitoring systems, provide significant opportunities to optimize recovery, improve operational efficiency, and reduce lifecycle costs (Ochulor et al., 2024; Ozowe et al., 2024). Environmentally, Indonesia's net-zero emission commitment by 2060 imposes stricter compliance requirements, positioning gas development as a relatively lower-carbon transitional energy source, provided that robust environmental management practices, including AMDAL compliance, emission controls, and site rehabilitation, are rigorously implemented. From a legal standpoint, regulatory reforms, particularly the refinement of the Gross Split PSC framework, offer contractual flexibility, administrative simplicity, and more predictable cash flows, thereby strengthening the overall investment attractiveness of the Beta Field.

Complementing the external assessment, the SWOT analysis captures the internal strategic position of the Beta gas field development by evaluating its inherent strengths and weaknesses in relation to external opportunities and threats. Key strengths include alignment with national energy policy, favorable regulatory structures under the Gross Split PSC, and access to modern extraction and digital technologies that enhance efficiency and economic performance. These strengths position the project to capitalize on opportunities arising from increasing domestic gas demand, cleaner energy transition policies, and potential integration with downstream or export markets. Nevertheless, internal weaknesses such as exposure to price volatility, foreign exchange risk, and cost sensitivity under inflationary conditions may constrain financial resilience if not properly managed. External threats, including regulatory tightening related to environmental standards, social resistance, and market uncertainty driven by geopolitical dynamics, further underscore the need for robust risk management, adaptive financial planning, and continuous stakeholder engagement. Collectively, the SWOT analysis demonstrates that while the Beta Field development possesses strong strategic fundamentals, its long-term success depends on the effective mitigation of economic, social, and regulatory risks within a dynamic operating environment as sown in table 1.

Table 1. SWOT Analysis

Strength	**Weakness**
• Proven gas reserves with established field data and geological understanding • Strategic location with access to gas markets and infrastructure • Adaptability to fiscal regimes (Gross Split PSC) • Strong technical expertise in gas field development and operations • Completed Environmental Impact Assessment (AMDAL) compliance • Relatively cleaner energy source (lower emissions than oil)	• Significant capital investment required for new field development • Limited production history and reservoir performance uncertainty • High exposure to gas price volatility and cost inflation • Dependency on infrastructure development for monetization • LNG facility commissioning uncertainty with potential schedule delays
Opportunity	**Threat**
• Government commitment to increase domestic gas production • Growing gas demand from PLN and industrial users • Potential for integrated development (Beta to Alfa Field scenario)	• Volatile global gas prices creating revenue uncertainty • LNG infrastructure commissioning delays • Regulatory and fiscal policy changes • Competition from renewable energy and coal • Permitting delays and potential social conflicts

- Expanding LNG export markets with favorable global demand
- Technological innovations for operational efficiency and cost savings
- Indonesia's energy transition supporting gas as cleaner alternative
- Job creation and regional economic development
- Climate change and decarbonization pressure

B. Financial Data Assumption

The financial analysis is developed based on a comprehensive and structured set of assumptions derived from Production Sharing Contract provisions, historical performance data, and relevant industry benchmarks, which collectively establish a robust foundation for assessing the economic feasibility of each development scenario. These assumptions encompass key variables such as production forecasts, pricing mechanisms, fiscal and taxation terms, cost recovery arrangements, and capital expenditure requirements, all of which are governed by the Production Sharing Contract regulating gas commercialization activities in the Celebes Block. The PSC defines the fiscal and operational relationship between the contractor and the Government of Indonesia and directly influences project cash flows, government take, tax liabilities, and overall investment returns; therefore, its provisions constitute the primary basis for the financial modeling and economic evaluation applied in this study, as shown in Table 2.

Table 2. PSC Contact Summary

Contract Term	Value
Partnership Interest	PT ABC: 100%
Contract Period	20 Years (2022 – 2042)
Gross Split	100%
Base Split - Gas	Government: 52%; Contractor: 48%
Tax Rate	40%
Gross Heating Value (GHV)	1,020 BTU/SCF

The gas production forecast for the Beta Field reflects a single-field development strategy aligned with the availability of LNG infrastructure, with production commencing in 2028 upon the start-up of LNG facilities. The field is projected to achieve a stable plateau production of 40 MMSCFD over a six-year period from 2028 to 2033, followed by a slight decline to 39.38 MMSCFD in 2034, resulting in a total cumulative production of 102.014 BSCF over seven years of operation. Production is terminated in 2034 due to natural reservoir pressure depletion, as the absence of pressure maintenance or enhanced recovery mechanisms prevents the field from sustaining economically viable production rates beyond this period, as shown in Figure 1.

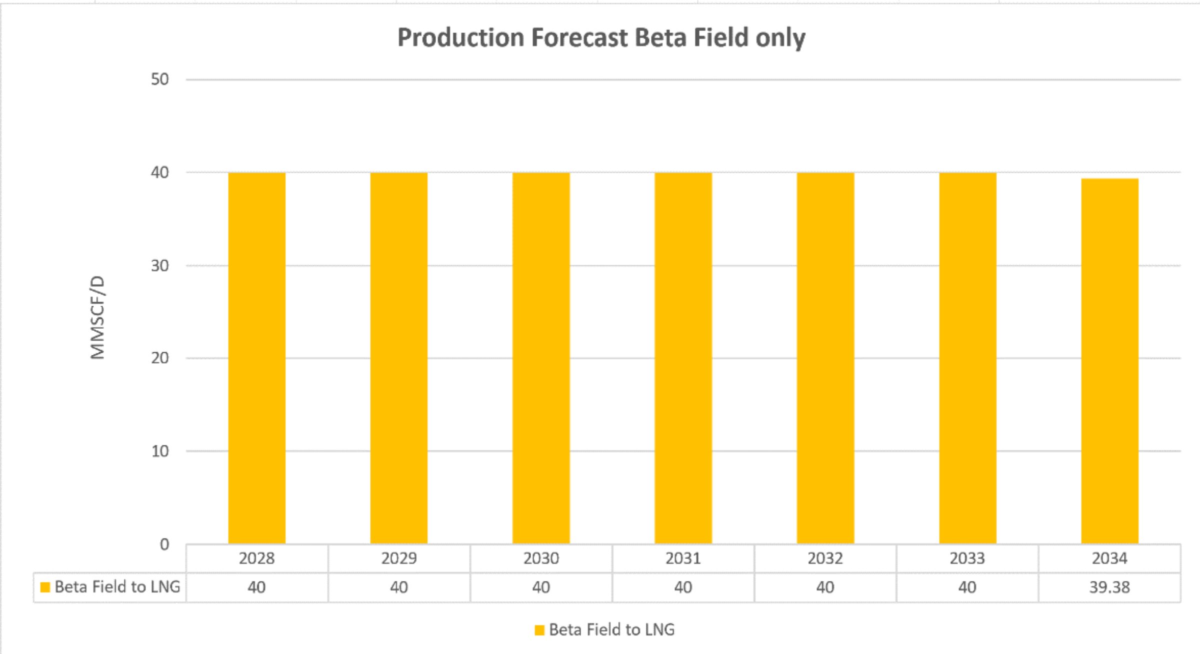

Figure 1. Production Forecast Beta Field Only

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The Beta to Alfa scenario takes an integrated approach by developing both fields to maximize total recovery and commercial flexibility. Production begins in 2026 and extends through 2037, achieving 119.782 BSCF cumulative production over 13 years a 17.4% increase compared to the Beta Only option. The strategy capitalizes on a key opportunity: PLN requires 60 MMSCFD for their 315 MW power generation facility, but the Alfa field can only deliver 48 MMSCFD due to reservoir limitations. The Beta field supplements the remaining 12 MMSCFD during 2026-2029, fulfilling PLN's complete requirement while operating at a moderate rate that preserves reservoir pressure. When the PLN contract expires in 2030 without renewal option, both fields redirect to the LNG market. This continued dual-field production provides critical reservoir pressure maintenance, enabling the Beta field to sustain economic flow rates through 2037, three years longer than the Beta Only scenario. From 2030 onwards, the Alfa field consistently delivers 15 MMSCFD, while the Beta field maintains 25 MMSCFD to mini-LNG, creating a stable and diversified production profile that generates substantial additional value through extended field life and incremental reserve recovery as shown in figure 2.

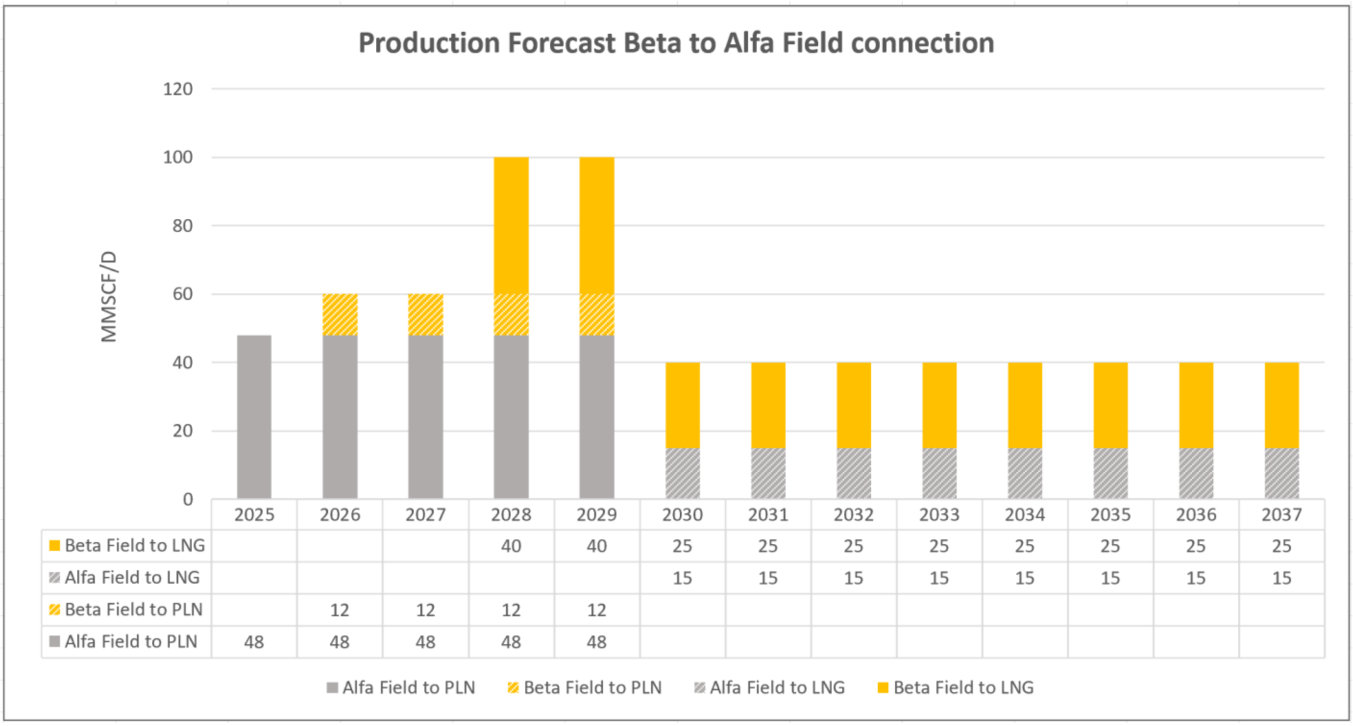

Figure 2. Production Forecast Beta to Alpha Field Connection

Gas pricing assumptions are critical drivers of project economics and vary based on the market destination. Although both development options target the domestic market in Indonesia, the pricing structure differs significantly between the mini-LNG market and the power generation sector (PLN). For the Beta Only development scenario, gas will be exclusively sold to the mini-LNG facility at a fixed price of USD 5.00 per MMBTU. This pricing is derived from the LNG value chain breakdown provided by the company, calculated by back-calculating from the LNG price and deducting all downstream costs including:

- LNG processing cost (approximately USD 3.00/MMBTU)
- Shipping cost (approximately USD 1.50/MMBTU)
- FSRU cost (approximately USD 2.50/MMBTU)
- Gas pipeline distribution cost (approximately USD 1.50/MMBTU)
- End user (approximately USD 13.50/MMBTU)

The Beta to Alfa Field Scenario adopts a phased dual-market commercialization strategy in which gas production is allocated to two distinct market segments to optimize revenue stability and flexibility. In the initial phase, gas is sold directly to PT PLN for power generation under a long-term Gas Sales Agreement at a fixed price of USD 6.00 per MMBTU without escalation, ensuring contractual certainty and stable cash flows, while in the subsequent phase, surplus gas after meeting PLN obligations is marketed to a mini-LNG facility at USD 5.00 per MMBTU under the same pricing mechanism as the Beta Only option. Revenue sharing between the contractor and the government is governed by the Gross Split Production Sharing Contract regime in accordance with Ministry of Energy and Mineral Resources Regulation No. 8/2017 as amended by Regulation No. 52/2017, under which cost recovery is eliminated and the split is determined ex ante based on base, variable, and progressive components. Specifically, under the Beta Field Scenario, the contractor retains a stable 65.00% share and the government 35.00% throughout the 2028–2034 production period, reflecting consistent progressive split parameters derived from uniform gas pricing to the mini-LNG market, with the contractor further benefiting from an additional 3% variable split adjustment attributable to H2S content (1%) and local content (TKDN) compliance (2%) as shown in table 3.

Table 3. Split for Beta Field Scenario

Type of Split	*Characteristics*	*Parameter*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*
Base Split Gas	Government	%	52%	52%	52%	52%	52%	52%	52%
	Contractor	%	48%	48%	48%	48%	48%	48%	48%
Variable Split	H2S (ppm) - 450 ppm	100≤x<1000	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
	Local content (%) - 47,5%	30≤x<50	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Progresive Split	Harga Gas Bumi (US$/MMBTU) 5 US$/MMBTU	(7-Gas Price)x2,5%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
	Kumulatif Produksi (MMBOE) - 55 MMBOE	30 ≤ x < 60	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Split	**Government**		**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**
	Contractor		**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**

The Beta to Alfa scenario demonstrates a dynamic split pattern due to varying gas prices and cumulative production levels. The contractor share starts at 62.50% in early production years (2026-2027), adjusts to 64.42% during the transition period (2028-2029), and stabilizes at 65.00% from 2030 onwards. Similar to the Beta Only scenario, the contractor receives an additional 3% from variable split adjustments (1% from H2S content and 2% from TKDN). This evolution reflects the progressive split adjustments based on gas price variations between PLN (USD 6.00/MMBTU) and mini-LNG markets (USD 5.00/MMBTU), as well as increasing cumulative production. The detailed annual split calculation is presented in Table 4 below.

Table 4. Split for Beta to Alpha Field Scenario

Type of Split	*Characteristics*	*Parameter*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*
Base Split Gas	Government	%	52%	52%	52%	52%	52%	52%	52%	52%	52%	52%	52%	52%
	Contractor	%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%
Variable Split	H2S (ppm) - 450 ppm	100≤x<1000	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
	Local content (%) - 47,5%	30≤x<50	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Progresive Split	Harga Gas Bumi (US$/MMBTU) 5-6 US$/MMBTU	(7-Gas Price)x2,5%	2.5%	2.5%	4.4%	4.4%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
	Kumulatif Produksi (MMBOE) - 55 MMBOE	30 ≤ x < 60	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Split	**Government**		**37.5%**	**37.5%**	**35.6%**	**35.6%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**	**35.0%**
	Contractor		**62.5%**	**62.5%**	**64.4%**	**64.4%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**	**65.0%**

Gross revenue represents a fundamental component in financial feasibility analysis, calculated by multiplying production volume with gas price. For Beta Field, the revenue calculation depends on the selected development option, as each approach has different pricing mechanisms and commercial arrangements that affect how the gas price is determined. Under the gross split contract framework, the contractor gross revenue is obtained from the contractor's allocated split share, which is determined based on the contractual terms defined at the beginning of the project. The detailed breakdown of contractor gross revenue for each development option is presented in the table 5 below.

Table 5. Contractor Gross Revenue for Beta Field Only and Beta to Alpha Field

Description	*Unit*	2028	2029	2030	2031	2032	2033	2034
Production for LNG	MMBTU	14,892	14,892	14,892	14,933	14,892	14,892	14,661
Gas Price LNG	USD/MMBTU	5	5	5	5	5	5	5
Gross Revenue from LNG	MUSD	74,460	74,460	74,460	74,664	74,460	74,460	73,306
Contractor Split	(%)	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
Contractor Gross Revenue	**MUSD**	**48,399**	**48,399**	**48,399**	**48,532**	**48,399**	**48,399**	**47,649**

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Description	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Production for PLN	MMBTU	4,468	4,480	4,468	4,468								
Gas Price PLN	USD/MMBTU	6	6	6	6								
Gross Revenue from PLN	MUSD	26,806	26,879	26,806	26,806								
Production for LNG	MMBTU			14,892	14,892	9,308	9,333	9,308	9,308	9,308	9,333	9,308	9,308
Gas Price LNG	USD/MMBTU	-	-	5	5	5	5	5	5	5	5	5	5
Gross Revenue from LNG	MUSD			74,460	74,460	46,538	46,665	46,538	46,538	46,538	46,665	46,538	46,538
Total Gross Revenue	MUSD	26,806	26,879	101,266	101,266	46,538	46,665	46,538	46,538	46,538	46,665	46,538	46,538
Contractor Split	(%)	62.5%	62.5%	64.4%	64.4%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
Contractor Gross Revenue	**MUSD**	**16,754**	**16,799**	**65,238**	**65,238**	**30,249**	**30,332**	**30,249**	**30,249**	**30,249**	**30,332**	**30,249**	**30,249**

Capital, drilling, and operating expenditures represent the primary cost components in the financial model. These expenditures are estimated based on engineering studies and historical cost data from similar projects. The capital expenditure consists of flowline installation, export line, and metering station infrastructure. The Beta Only scenario requires total CAPEX of USD 23.287 million, while the Beta to Alfa scenario requires USD 31.261 million. The USD 7.974 million difference is attributed to the additional 8" flowline along 12 km required to connect Beta field to the existing Alfa field facilities. The detailed CAPEX breakdown is presented in the table 6 below.

Table 6. Capital Expenditures

Item	Years of Investment	Beta Field Scenario Capex (MUSD)			Beta to Alfa Field Scenario Capex (MUSD)		
		Cost	Vat 12%	Total	Cost	Vat 12%	Total
Flowline 6" Beta-2T to Beta header	2025	224	31	255	224	31	255
Flowline 6" Beta-3 to Beta header	2025	299	41	340	299	41	340
Flowline 6" Beta-1T to Beta header	2025	598	82	680	598	82	680
Flowline 6" Beta North-1T to Beta North header	2025	359	49	408	359	49	408
Flowline 8" Beta North header to Beta Header	2025	1,672	228	1,900	1,672	228	1,900
Exportline 16" Beta header to metering Station	2025	10,262	1,399	11,661	10,262	1,399	11,661
Metering Station	2025	6,636	905	7,541	6,636	905	7,541
Flowline 6" Beta North-2 to Beta North header	2030	442	60	502	442	60	502
Flowline 8" 12 km Beta to Alfa Field	2025				7,017	957	7,974
TOTAL				**23,287**			**31,261**

This project has four existing wells that have received cost recovery. One additional development well is required in the Beta North area with estimated drilling costs as presented in Table 7 below. The total drilling cost for Beta North-2 well is USD 8.316 million. This drilling cost applies to both Beta Only and Beta to Alfa scenarios as the well is essential for field development plan in 2029.

Table 7. Drilling Expenditures

Item	Drilling Expenditure (MUSD)			
	Type	Cost	Vat 12%	Total
Drilling Beta North-2	Tangible	2,195	299	2,495
	Intangible	5,122	699	5,821
TOTAL				**8,316**

Operating costs comprise fixed and variable components with an annual escalation of 5% as stipulated in the approved Plan of Development, with average OPEX estimated at approximately USD 0.6 per MSCF, covering variable costs linked to production volumes such as chemicals, utilities, and consumables, as well as fixed costs including personnel, facility maintenance, and insurance. In addition, Abandonment and Site Restoration costs for end-of-field decommissioning are budgeted at USD 5.4 million. Over the project life, total operating expenditure amounts to USD 109.83 million for the Beta to Alfa scenario and USD 91.91 million for the Beta Only scenario, with the higher cost attributable to the longer production period of the Beta to Alfa case (2026–2037) compared to the Beta Only case (2028–2034).

Table 8. Operating Expenditures + ASR Beta Field Only

Beta Field Scenario		2028	2029	2030	2031	2032	2033	2034
- Opex (w/ Vat)	MUSD	10,648	11,180	11,739	12,360	12,943	13,590	14,048
- ASR	MUSD	771	771	771	771	771	771	771
Total	**MUSD**	**11,419**	**11,952**	**12,511**	**13,131**	**13,714**	**14,361**	**14,819**

Table 9. Operating Expenditures + ASR Beta to Alpha Field

Income tax is calculated at 40% of the contractor's taxable income, which is determined by deducting all eligible expenses including capital depreciation, operational costs, and ASR from the contractor's gross revenue. The tables below present the annual income tax calculations for both Beta Field and Beta to Alfa Field scenarios, showing how tax obligations fluctuate based on production profiles, revenue streams, and the depreciation schedule of capital investments over the project's operational life.

Table 9. Income Tax for Beta Field only

Description			*Unit*	2028	2029	2030	2031	2032	2033	2034
Contractor Gross Revenue			MUSD	48,399	48,399	48,399	48,532	48,399	48,399	47,649
Expenditure										
	Capex (Depreciation)		MUSD	(5,696)	(4,272)	(3,204)	(2,403)	(7,209)		
	Drillex	Tangible (Depreciation)	MUSD		(749)	(562)	(421)	(316)	(948)	
		Intangible	MUSD		(5,821)					
	Opex + ASR		MUSD	(11,419)	(11,952)	(12,511)	(13,131)	(13,714)	(14,361)	(14,819)
Total Expenditure/Cost Recoverable			MUSD	(17,115)	(22,794)	(16,277)	(15,956)	(21,239)	(15,309)	(14,819)
Contractor Taxable Income			MUSD	31,284	25,605	32,122	32,576	27,160	33,090	32,829
Income Tax		**40%**	**MUSD**	**12,513**	**10,242**	**12,849**	**13,030**	**10,864**	**13,236**	**13,132**

Table 10. Income Tax for Beta to Afa Field

Description			*Unit*	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Contractor Gross Revenue			MUSD	16,754	16,799	65,238	65,238	30,249	30,332	30,249	30,249	30,249	30,332	30,249	30,249
Expenditure															
	Capex (Depreciation)		MUSD	(2,889)	(2,167)	(6,426)	(4,819)	(6,357)	(2,025)	(6,076)					
	Drillex	Tangible (Depreciation)	MUSD				(749)	(562)	(421)	(316)	(948)				
		Intangible	MUSD				(5,821)								
	Opex + ASR		MUSD	(3,347)	(3,501)	(14,292)	(14,984)	(7,787)	(8,175)	(8,539)	(8,944)	(9,368)	(9,840)	(10,282)	(10,774)
Total Expenditure/Cost Recoverable			MUSD	(6,237)	(5,667)	(20,718)	(26,374)	(14,706)	(10,622)	(14,931)	(9,892)	(9,368)	(9,840)	(10,282)	(10,774)
Contractor Taxable Income			MUSD	10,517	11,132	44,521	38,865	15,544	19,711	15,319	20,358	20,881	20,492	19,967	19,475
Income Tax		**40%**	**MUSD**	**4,207**	**4,453**	**17,808**	**15,546**	**6,217**	**7,884**	**6,127**	**8,143**	**8,352**	**8,197**	**7,987**	**7,790**

C. Data Analysis

The data analysis employs capital budgeting techniques to assess the economic feasibility of each development scenario, beginning with the determination of the Weighted Average Cost of Capital (WACC) as the project's hurdle rate, reflecting the blended cost of debt and equity weighted by their proportions in the capital structure. This WACC serves as the benchmark for evaluating investment performance and is applied in the calculation of key financial indicators, notably Net Present Value (NPV) and Internal Rate of Return (IRR), to determine the financial viability and value creation potential of the Beta Field project

Table 11. WACC Calculation

Parameters	Value
Market Value of Equity (E)	**1,328.56 MUSD**
Book Value Of Debt (D)	**283.75 MUSD**
Capital = Equity (E) + Debt (D)	**1,612.32 MUSD**
Weight of Equity (E / (D + E))	82.40%
Weight of Debt (D / (D + E))	17.60%
Cost of Equity (Ke)	**13.67%**
Risk Free Rate (Rf)	6.14%
Beta (β)	1.02
Market Risk Premium (Rm-Rf)	7.38%
Cost of Debt After Tax (Kd)	**8.08%**
Cost of Debt Before Tax	13.47%
Tax Rate	40%
WEIGHTED AVERAGE COST OF CAPITAL	**12.68%**

Financial Viability of Beta Gas Field Development: Comparative Analysis of Two Commercial Options

The Beta Field project applies a Weighted Average Cost of Capital (WACC) of 12.68%, based on a capital structure comprising 82.40% equity with a cost of 13.67% and 17.60% debt with an after-tax cost of 8.08%, which serves as the minimum required return and the discount rate for financial evaluation. Capital budgeting is employed to assess the project's financial feasibility through systematic analysis of projected cash inflows and outflows over the project life, generating key indicators such as Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period. The analysis utilizes discounted cash flow techniques to convert future cashflows into present values, with detailed annual projections illustrating the transition from contractor gross revenue to net cashflow after capital and operating expenditures, thereby enabling a comparative assessment of the Beta Field and Beta to Alfa Field development scenarios (Assaf et al., 2022; Jamal & Sudrajat, 2022; Msawil et al., 2021; Subroto & Faturohman, 2024).

Table 12. Cashflow Projection for Beta Field only

Description	*Unit*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contractor Gross Revenue	MUSD				48,399	48,399	48,399	48,532	48,399	48,399	47,649
Expenditure											
Capex	MUSD	(22,785)				(502)					
Drillex	MUSD					(8,316)					
Opex + ASR	MUSD				(11,419)	(11,952)	(12,511)	(13,131)	(13,714)	(14,361)	(14,819)
Income Tax	MUSD				(12,513)	(10,242)	(12,849)	(13,030)	(10,864)	(13,236)	(13,132)
Cashflow	MUSD	(22,785)	-	-	24,466	17,388	23,039	22,370	23,821	20,802	19,698
Cummulative Cashflow	MUSD	(22,785)	(22,785)	(22,785)	1,682	19,069	42,109	64,478	88,300	109,102	128,799
Discounted Cashflow @10%	MUSD	(22,785)	-	-	18,382	11,876	14,306	12,627	12,224	9,704	8,354
NPV	**MUSD**										**64,688**
IRR	**%**										**43.18%**
POT	**Years**										**3.93**

Table 13. Cashflow Projection for Beta to Alfa Field

Description	*Unit*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Contractor Gross Revenue	MUSD		16,754	16,799	65,238	65,238	30,249	30,332	30,249	30,249	30,249	30,332	30,249	30,249
Expenditure														
Capex	MUSD	(30,759)				(502)								
Drillex	MUSD					(8,316)								
Opex + ASR	MUSD		(3,347)	(3,501)	(14,292)	(14,984)	(7,787)	(8,175)	(8,539)	(8,944)	(9,368)	(9,840)	(10,282)	(10,774)
Income Tax	MUSD		(4,207)	(4,453)	(17,808)	(15,546)	(6,217)	(7,884)	(6,127)	(8,143)	(8,352)	(8,197)	(7,987)	(7,790)
Cashflow	MUSD	(30,759)	9,199	8,846	33,138	25,890	16,245	14,273	15,583	13,163	12,529	12,295	11,980	11,685
Cummulative Cashflow	MUSD	(30,759)	(21,559)	(12,713)	20,425	46,315	62,560	76,833	92,416	105,579	118,108	130,403	142,383	154,069
Discounted Cashflow @10%	MUSD	(30,759)	8,363	7,311	24,897	17,684	10,087	8,057	7,996	6,141	5,313	4,740	4,199	3,723
NPV	**MUSD**													**77,753**
IRR	**%**													**49.74%**
POT	**Years**													**3.38**

Table summarizes the key economic indicators comparing both development scenarios. Beta to Alfa Field demonstrates superior performance with an NPV of $77,753 million and IRR of 49.7% compared to Beta Field's NPV of $64,688 million and IRR of 43.18%. The integrated development scenario shows higher production (119.78 BSCF vs 102.01 BSCF), greater gross revenue ($628,711 million vs $520,270 million), and improved contractor cashflow ($154,069 million vs $128,799 million), with payback periods of 3.38 years and 3.93 years respectively. Additionally, the Beta to Alfa Field scenario generates significantly higher government revenue, with GOI Take of $325,293 million compared to $267,961 million from Beta Field alone, demonstrating the mutual benefits of the integrated development approach for both contractor and government.

Table 14. Comparative Economic Summary: Beta Field vs Beta to Alfa Field

Parameter	Unit	Beta Field Only	Beta to Alfa Field
Gas Production	BSCF	102.01	119.78
	BBTU	104.05	122.18
WAP - Gas Price	US$/MMBTU	5.00	5.21
Gross Revenue	MUSD	520,270	628,771
Drilex	MUSD	8,316	8,316
Capex	MUSD	23,287	31,261
Opex	MUSD	91,907	109,833
Deductible Cost	MUSD	123,510	149,410
(% Gross Rev)	%	23.7%	23.8%
Contractor Cashflow	MUSD	**128,799**	**154,069**
Contractor Take	MUSD	128,799	154,069
% Contr. Share	%	24.8%	24.5%
NPV10 (fullcycle)	**MUSD**	**64,688**	**77,753**
IRR (fullcycle)	**%**	**43.18%**	**49.7%**
POT	**Years**	**3.93**	**3.38**
GOI (Profitability) :			
Gross Share	MUSD	182,094	222,580
Tax	MUSD	85,866	102,712
GOI Take	MUSD	267,961	325,293
% GOI Share	%	51.50%	51.73%

The financial risk analysis assesses the sensitivity of the Beta Field project's economic performance, particularly Net Present Value (NPV), to uncertainty in key input variables by applying sensitivity analysis and Monte Carlo simulation. Sensitivity analysis is conducted by varying production levels, gas prices, capital expenditures, and operating expenditures by ±20% from the base case to identify the most critical value drivers, recognizing that these variations are analytical assumptions rather than precise real-world forecasts. The results indicate a strong positive correlation between NPV and both production realization and gas prices, while capital and operating expenditures exhibit a negative relationship with NPV. Under the Beta Field Scenario, gas price and production emerge as the most influential factors with the greatest impact on NPV, as reflected by the steepest slopes and widest ranges in the spider and tornado charts, whereas Opex and Capex show moderate sensitivity and drilling expenditures demonstrate relatively low impact.

Table 15. Sensitivity Analysis of NPV for Beta Field Only

Variable	-20%	-10%	0%	10%	20%
Gas Price	44.94	55.04	64.69	73.89	82.64
Production	47.21	55.95	64.69	73.43	82.17
Opex	75.08	69.88	64.69	59.49	54.30
Capex	68.15	66.42	64.69	62.96	61.22
Drilex	65.39	65.04	64.69	64.34	63.98

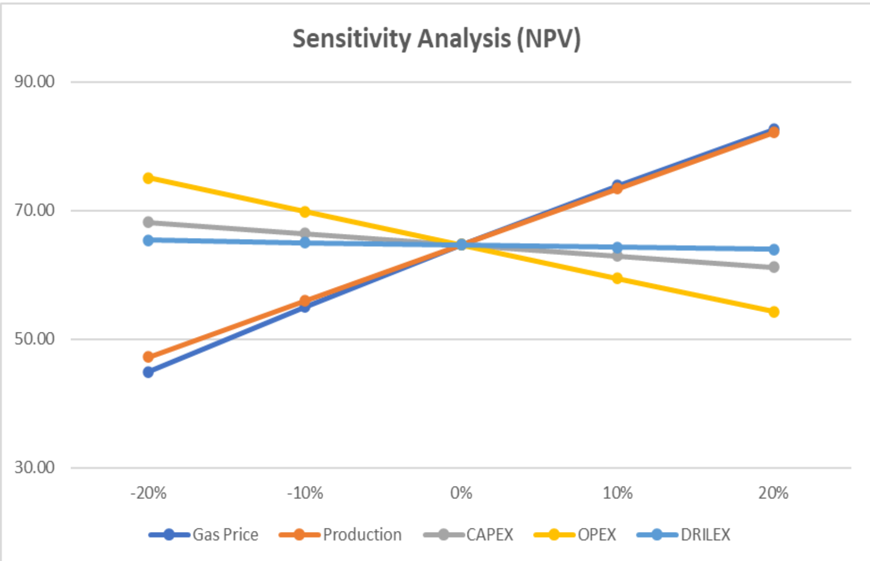

Figure 3. Spider Chart of Sensitivity Analysis for Beta Field Only

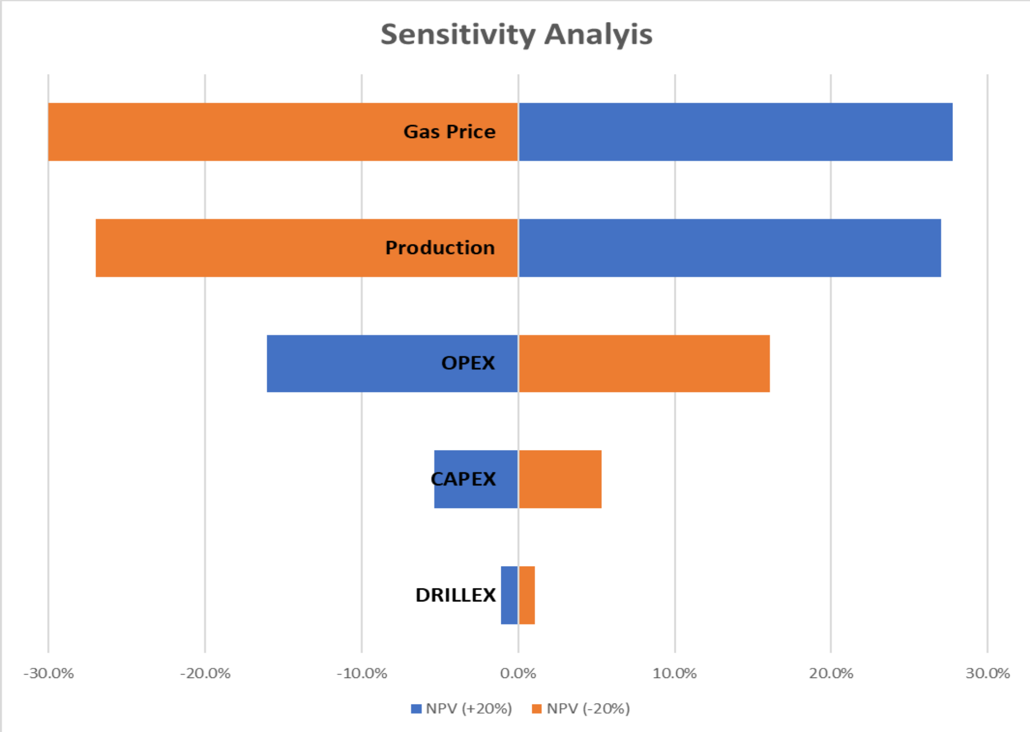

Figure 4. Tornado Chart of Sensitivity Analysis for Beta Field Only

The sensitivity analysis reveals a similar pattern to the Beta Field scenario, where Production and Gas Price remain the most influential variables affecting Beta to Alfa Field's NPV, demonstrating the steepest slopes and widest impact ranges in both the spider and tornado charts. Likewise, operational expenditures Opex and Capex demonstrate medium impacts, with Drillex consistently showing low sensitivity across both scenarios.

Table 16. Sensitivity Analysis of NPV for Beta to Alfa Field

Variable	-20%	-10%	0%	10%	20%
Gas Price	59.73	68.93	77.75	86.20	94.27
Production	56.59	67.17	77.75	88.33	98.91
Opex	89.70	83.72	77.75	71.78	65.81
Capex	82.29	80.02	77.75	75.48	73.21
Drilex	78.46	78.10	77.75	77.40	77.05

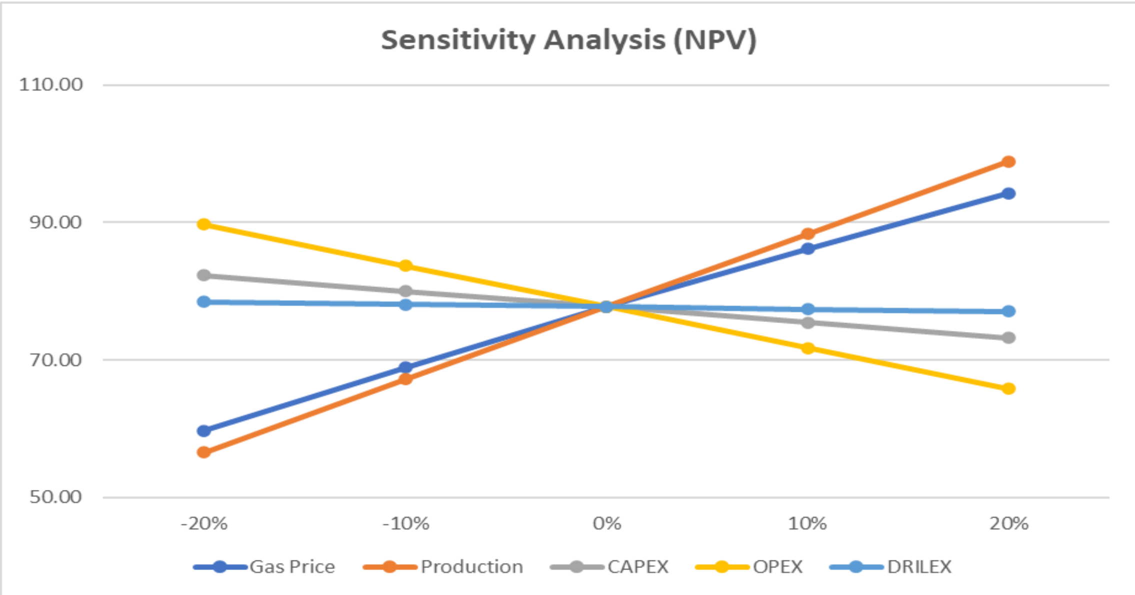

Figure 5. Spider Chart of Sensitivity Analysis for Beta to Alfa Field

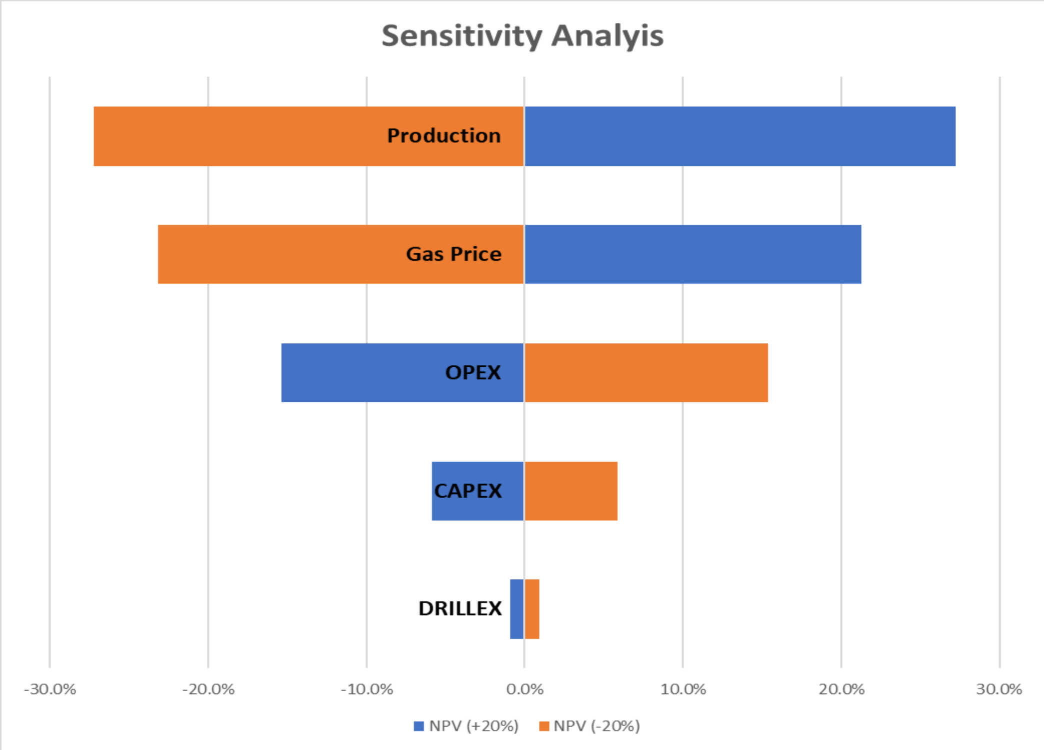

Figure 6. Tornado Chart of Sensitivity Analysis for Beta to Alfa Field

D. Monte Carlo Simulation

Combining sensitivity analysis findings with Monte Carlo simulation creates a comprehensive framework for evaluating the project's risk exposure. This approach incorporates probability distributions for critical input variables identified through sensitivity analysis, enabling a thorough examination of potential variations in Net Present Value (NPV). This method allows for the quantification of risks associated with the project, accounting for the interplay of multiple uncertainties simultaneously. The simulation ran thousands of iterations, with each iteration representing a possible scenario where key variables such as production rates, gas prices, capital expenditures, and operational expenditures fluctuate within their defined probabilistic ranges. These ranges were constructed using company projections and data randomized through statistical formulas to accurately reflect the possible outcomes based on technical evaluations. The Monte Carlo simulation, consisting of 1,000 iterations, produced a distribution of NPV outcomes that illustrates the project's risk profile. The simulation results are presented below.

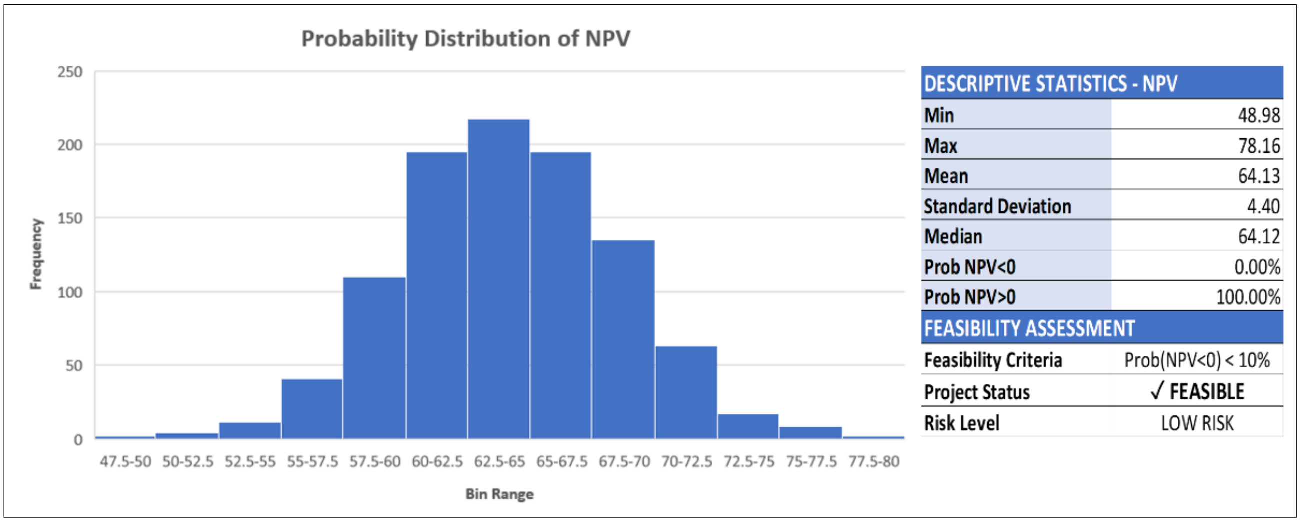

Figure 7. Probability of Distribution Histogram of NPV for Beta Field Only

The Monte Carlo simulation demonstrates strong financial viability for Beta Field, with a mean NPV of $64.13 million. Importantly, the calculated NPV of $64.69 million from the base case closely aligns with the simulation mean, validating the accuracy and reliability of the base case assumptions. The simulation shows zero probability of negative NPV, confirming the project as "Feasible" with "Low Risk" classification. The relatively tight standard deviation of $4.40 million indicates stable and predictable outcomes, reinforcing confidence in the project's profitability with minimal downside risk.

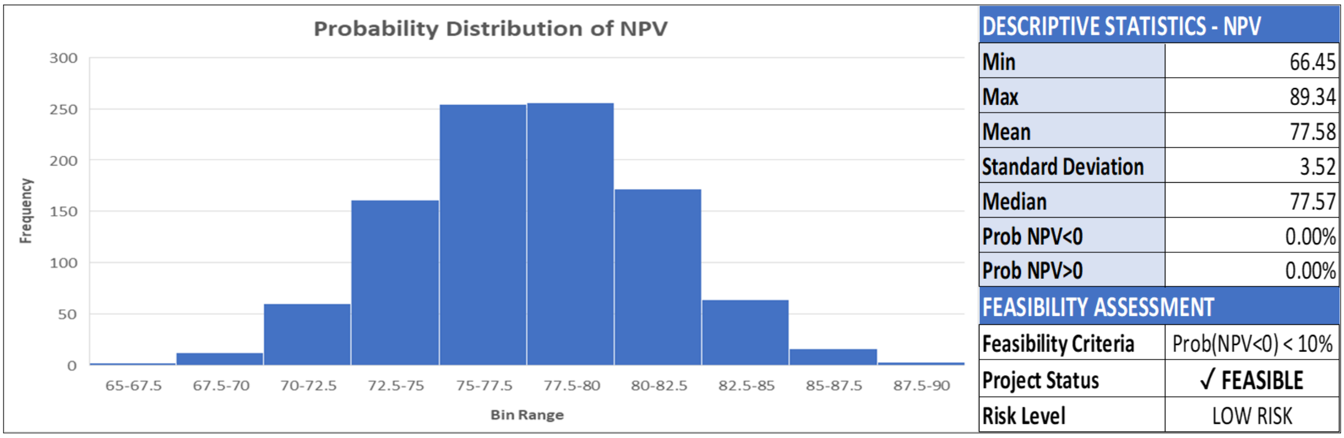

Figure 8. Probability of Distribution Histogram of NPV for Beta to Alfa Field

Similarly, the Monte Carlo simulation for Beta to Alfa Field scenario demonstrates even stronger financial viability, with a mean NPV of $77.58 million. The calculated NPV of $77.75 million from the base case closely aligns with the simulation mean, again validating the accuracy and reliability of the base case assumptions. Consistent with the Beta Field results, this scenario also shows zero probability of negative NPV, confirming "Feasible" status with "Low Risk" classification. The standard deviation of $3.60 million slightly tighter than Beta Field, indicates highly stable and predictable outcomes, further reinforcing confidence in the project's profitability with minimal downside risk.

V. CONCLUSIONS

The financial evaluation confirms that the Beta to Alfa Field integrated commercialization strategy is decisively superior to the Beta Only option under the Gross Split PSC framework. The integrated scenario delivers a significantly higher NPV (USD 77.75 million versus USD 64.69 million), stronger IRR (49.70% versus 43.18%), and a faster payback period driven by earlier PLN gas sales starting in 2026, extended field life, higher cumulative production, and premium pricing. Sensitivity and Monte Carlo analyses further demonstrate that production volume and gas price are the dominant value drivers, while overall project risk remains low and predictable, with the Beta to Alfa option exhibiting greater stability due to market diversification and longer production horizons. Importantly, this strategy generates a clear win–win outcome by increasing contractor value while simultaneously enhancing government revenue and supporting national energy security objectives.

Based on these results, it is recommended that PT ABC proceed with the Beta to Alfa Field integrated development by promptly submitting the Plan of Development to SKK Migas, securing internal approvals, and targeting first production in early 2026 to avoid material value erosion from delays. Continuous coordination with mini-LNG developers, periodic updates of economic assumptions, and proactive negotiation of potential PLN contract extensions are essential to preserve market stability and pricing advantages. In parallel, management should prioritize cost efficiency through disciplined CAPEX and OPEX control, as well as robust production performance management, to maximize project resilience, long-term profitability, and alignment with Indonesia’s gas and power development goals.

ACKNOWLEDGMENT

The author gratefully acknowledges the contributions of Allah SWT for spiritual guidance; his family including dr. Dina Marselina, Sp.A, Muhammad Abqory Arkananta, Muhammad Arrasya Rafandra, Ungku, Oma Pariaman, Mami Santi, Papi Aib, Pak Elok, and Pak Uncu for their unwavering support; his thesis supervisor Oktofa Yudha Sudrajad, S.T., M.S.M., Ph.D. for academic mentorship; fellow students of Sindikat Beruang Madu Balikpapan namely Bobby Yusuf, Cindy Savitri, Rian Ikhsan, Hafizhan Ihsandani, and Satrio Wicaksono for collegial support.

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