INTERNATIONAL JOURNAL OF MULTIDISCIPLINARY RESEARCH AND ANALYSIS

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

Volume 08 Issue 11 November 2025

DOI: 10.47191/ijmra/v8-i11-69, Impact Factor: 8.266

Page No. 6508-6518

Enhancing Economic Viability of Mature Field Through Financial-Operational Balance

Cindy Dhevayani Savitri[1], Oktofa Yudha Sudrajat[2]

[1,2]School of Business Administration, Bandung Institute of Technology, Indonesia

ABSTRACT: The oil and gas industry face increasing challenges in maintaining profitability under volatile market conditions and rising operational costs, especially in mature fields with marginal reserves This issue is particularly important in Indonesia, where most of hydrocarbon production comes from reservoirs that have been exploited for decades and are classified as marginal well. This study is conducted at PT Pertamina Hulu Indonesia (PHI) Region 3 Zone in East Kalimantan, examines the balance between capital investment and operational expense to enhance the economic viability of development wells. Using a mixed qualitativequantitative approach, the study integrates cost structure evaluation, financial modelling through Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), and Pay Out Time (POT), as well as risk assessment through sensitivity and scenario analyses. The findings show that Capex, oil reserves, and oil price are the most influential variables affecting well economics. While cost optimization strategies such as rig day reduction and technology adaptation can improve efficiency, maintaining adequate reserves is the dominant factor sustaining project value. The study concludes with practical strategies emphasizing balanced development between high performing and marginal wells, technology utilization for Capex efficiency, and integrated financial strategic planning for portfolio resilience.

KEYWORDS: Capital Investment, Operational Expenditure, Financial Analysis, Sensitivity Analysis, Mature Oil Field, Strategy Optimization.

I. INTRODUCTION

The global oil and gas industry is undergoing significant changes, marked by volatile oil prices, declining reserves, and rising operational costs. These dynamics are crucial for mature fields, where marginal nature of remaining reserves require strict cost efficiency to maintain economic viability. In Indonesia, where most production originates from mature reservoirs, companies face increasingly tight profit margins due to fluctuating oil prices and rising drilling service costs.

PT Pertamina Hulu Indonesia (PHI) Region 3 Zone 9, operating in East Kalimantan, exemplifies this challenge. Several development wells in Field “S” have shown cost overruns beyond authorized budgets, which is resulting in declining project value and in some cases, negative NPVs. These inefficiencies raise strategic questions on how to sustain profitability in a mature asset while meeting production and corporate targets.

The primary business issue addressed in this study is the imbalance between capital investment and operational expenditures that undermines project economics. To address this, the study identifies cost drivers, evaluates financial feasibility, and formulates strategies that integrate both operational and financial considerations. This approach aligns with corporate’s strategic toward efficiency driven growth, emphasizing data driven decision making and disciplined cost control. Accordingly, this study aims to identify and analyse key cost elements contributing to budget overruns, apply financial frameworks for evaluating economic viability under different operational scenarios, and formulate cost effective also provide strategic recommendations to enhance the sustainability of the marginal wells.

II. LITERATURE REVIEW

A. Capital Budgeting and Financial Evaluation

Capital budgeting is a fundamental technique to evaluate long term investment projects, especially in capital intensive industry such as upstream oil and gas sector. According Gitman and Zutter (2012), financial managers employ tools such as Net Present Value (NPV), Internal Rate of Return (IRR), Pay Out Time (POT), and Profitability Index (PI) to assess investment viability.

The NPV method measures the present value of expected future cash flows discounted at a risk adjusted rate, which is ensuring that only projects with positive contributions to firm value are pursued. IRR identifies the discount rate that equates the NPV to zero, providing a benchmark for comparing investment alternatives. The PI offers a ratio-based assessment of project efficiency, while POT measures the duration required to recover initial investment.

Damodaran (2014) emphasizes the use of the Weighted Average Cost of Capital (WACC) as hurdle rate that integrates the cost of debt and equity to establish a project's minimum acceptable return. These financial principles are fundamental in upstream oil and gas investment, where projects are exposed to geological, technical, and market uncertainties that require systematic evaluation of returns against risks.

A.1. Cost of Debt (CoD)

Cost of Debt refers to the effective interest rate a company incurs on its borrowings from financial institutions or bondholders. It represents the required return by lenders for providing capital and is typically calculated as the ratio of annual interest expense to the total outstanding debt. In corporate finance, the cost of debt is considered after-tax, given that interest payments are tax-deductible. Therefore, the after-tax cost of debt is calculated as:

$$\text{CoD} = \text{Eff. Interest Rate} \times (1\text{-Tax}) \qquad \text{(Eq.1)}$$

A.2. Cost of Equity (CoE)

Cost of Equity represents the expected return required by shareholders for investing in a company, considering the risks associated with the investment. It reflects the opportunity cost of capital and is commonly estimated using the Capital Asset Pricing Model (CAPM), which is expressed as:

$$\text{CoE} = R_f + \beta \times (R_m - R_f) \qquad \text{(Eq.2)}$$

where:

R_f = Risk-free rate

β = Beta coefficient (company's sensitivity to market movement) $R_m - R_f$ = Market risk premium

A.3. Weighted Average Cost of Capital (WACC)

The Weighted Average Cost of Capital (WACC) is the average rate of return a company is expected to pay to finance its assets, determined by the average cost of debt and equity in its capital structure. Damodaran (2014) defined the hurdle rate as the minimum acceptable rate of return for allocating resources to a new investment. In practice, WACC is often used as a 'hurdle rate' for ensuring that the returns from an investment proposal is above its cost of capital. The formula is calculated as:

$$\text{WACC} = \text{CoE} \times (\text{Equity} / (\text{Equity} + \text{Debt})) + \text{CoD} \times (\text{Debt} / (\text{Equity} + \text{Debt})) \qquad \text{(Eq.3)}$$

A.4. Net Present Value (NPV)

Net present value (NPV) is a fundamental capital budgeting tehniques, which is employed to evaluate the long-term profitability investment project. The method calculates the present value of expected future cash flows, discounted at the cost of capital of the project. According to Gitman & Zutter (2012), NPV provides a direct measure of the added value of an investment will expected to the firm. The project should be accepted if its NPV > 0, therefore it is expected to generate revenue.

$$\text{NPV} = \Sigma\, (CF_t / (1 + r)^t) - CF_0 \qquad \text{(Eq.4)}$$

where:

CF_t = Net cash inflow/outflow in year t

r = Discount rate (reflecting risk and opportunity cost)

t = Time period (years)

CF_0 = Initial investment cost

A.5. Internal Rate of Return (IRR)

IRR represents the discount rate at with NPV of a project becomes zero (Gitman & Zutter, 2012). It provides the rate of return a firm can expect to earn from an investment. The project is considered acceptable if its IRR exceeds the firm's capital cost. The IRR method is particularly useful for comparing the relative profitability of multiple investment opportunities.

$$\$0 = \Sigma\, (CF_t / (1 + \text{IRR})^t) - CF_0 \qquad \text{(Eq.5)}$$

IRR is used to decide whether the project will be accepted or rejected. The decision criteria are as follows:

- If the IRR is greater than the cost of capital, accept the project.
- If the IRR is less than the cost of capital, reject the project.

A.6. Profitability Index (PI)

PI also known as the benefit-cost ratio, is a capital budgeting tool that measure the relative profitability of an investment by dividing the present value (PV) of future cash inflows by the initial investment cost. Referring to Gitman & Zutter (2012), a PI is greater than 1.0 indicates a project is financially viable, as it generates more value than it costs. This method is particularly helpful in ranking projects when capital is limited. It enables firms to identify investment that offer the highest return per unit investment.

Profitability Index (PI) = (PV of Future Cash Flows) / (Initial Investment) (Eq.6)

where:

PV of Future Clash Inflows = The present value of all future cash inflows, discounted at an appropriate rate (e.g., WACC or hurdle rate)

Initial Investment = The total upfront capital required for the project

A.7. Pay Out Time (POT)

Pay Out Time (POT), also known as the payback period, is a capital budgeting metric that refers to the amount of time required for an investment to recover its initial capital outlay through net cash inflows. In the context of oil and gas projects, POT indicates how quickly a development well can generate sufficient cash flow to repay its capital and operating expenditures.

B. Production Sharing Contract (PSC) Gross Split Framework

In the context of upstream oil and gas operations in Indonesia, the Production Sharing Contract serves as the prevailing contractual framework between the government and contractors. In 2017, the Indonesian government introduced a significant regulatory reform through Ministerial Regulation No. 08/2017, marking a shift from the traditional cost recovery PSC to a gross split PSC scheme. Pertamina, as one of the primary state-owned enterprises in this sector, has adopted the Gross Split model across various operating regions, including PHI Zone 9.

The gross split PSC offers several strategic advantages for both the government and contractors. From a regulatory standpoint, it eliminates the need for government approval of each expenditure item, thereby simplifying administrative processes. For contractors, the scheme fosters greater autonomy in operational decision-making, as costs are no longer subject to post-audit and approval. Additionally, the model encourages cost discipline and innovation since the contractor’s profitability is directly tied to their ability to optimize operations and reduce expenses. From the government’s perspective, the gross split system ensures a more predictable revenue stream without the complexity of reimbursing operational costs, hence aligning with fiscal sustainability goals.

C. Empirical Studies on Cost Efficiency and Risk Management

Several studies have investigated cost efficiency in the oil and gas sector, such as Wiryono & Yuswen (2008) provided an integrated economic evaluation framework that incorporates regional risk factors and dynamic investment prioritization. This methodology addresses the gap of limited integration of risk factors in investment analysis, offering insights into improving financial and risk assessment frameworks. Omosebi et al., (2014) proposed an integrated model-based approach to improve drilling project management by addressing limitations in traditional project management approaches. Their focus on dynamic well planning, real-time data integration, and enhanced risk management practices provides valuable insights for optimizing cost and time management. highlighted the importance of cross functional integration in risk management for infill drilling projects, specifically in mature fields with marginal resources. Their approach includes applying qualitative and quantitative risk treatment strategies, such as cost benefit analysis and risk monitoring. Lastly, Atolagbe & Mohammed (2022) explored how technological disruptions, such as automation, digitization, and predictive analytics, can drive cost control and project efficiency in the oil and gas industry. This research aligns with the investigation into the key cost elements contributing to overbudget expenses in your study. These previous studies provided a robust foundation for exploring the key cost elements, risk management frameworks, and technological strategies necessary to improve operational cost efficiency and ensure the economic viability of well development in PHI Zone 9.

D. Conceptual Framework

The conceptual framework (Figure 1) integrates cost, production, and macroeconomic variables into a structured analytical process. Inputs include internal cost components (drilling, completion, rig operations), production assumptions (reserves, decline rate), and external factors (oil price, PSC scheme). The process comprises descriptive cost analysis, financial evaluation, sensitivity and scenario analysis, and risk reflection. The expected outcome is a decision-support mechanism enabling management to balance Capex and Opex while ensuring long-term field sustainability.

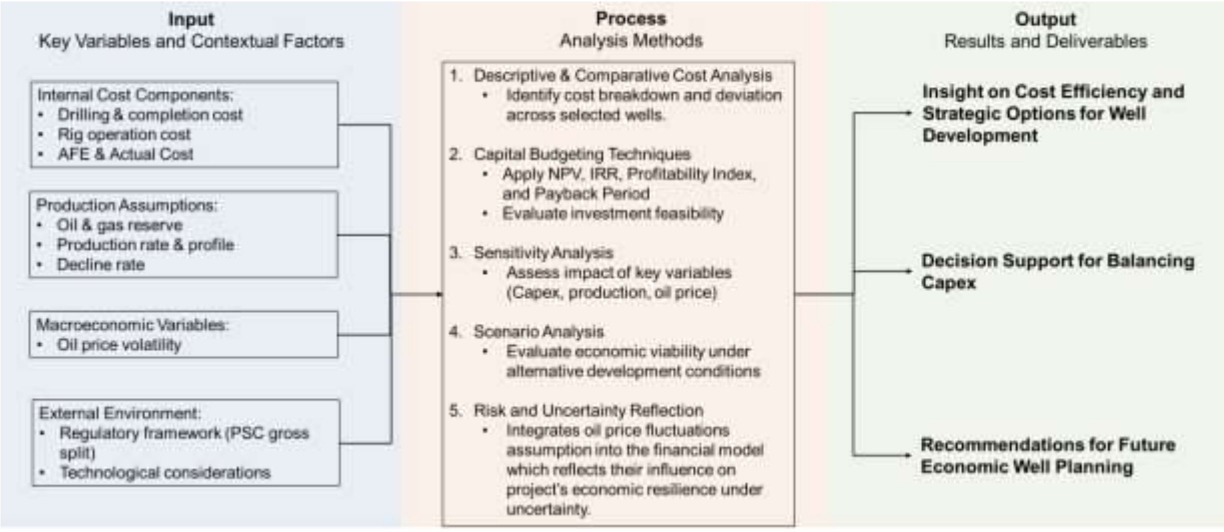

Figure 1. The conceptual framework

III. METHODOLOGY

A. Research Design

This research employs a descriptive and exploratory design integrating quantitative financial modelling and qualitative operational interpretation. The mixed-method approach allows the evaluation of both economic indicators and contextual operational insights to develop practical, evidence-based recommendations.

B. Data Collection

Data were obtained from PHI's internal reports and databases. Technical data included reserves, production profiles, Capex and Opex records, and drilling activity reports. Non-technical data encompassed oil price projections from the U.S. Energy Information Administration (EIA, 2024) and risk-free interest rate data for calculating the WACC. Two representative wells were selected: S-71 (high-performing) and S-73 (marginal), both drilled in 2024.

C. Analytical Methods

The analytical process consisted of five main stages: 1. Descriptive and comparative analysis

Identification of key cost drivers and deviations between Authorization for Expenditure (AFE) and actual expenditures.

2. Financial evaluation

   Application of capital budgeting techniques (NPV, IRR, PI, POT) using WACC as the discount rate.

3. Sensitivity analysis

   Assessment if economic resilience against variations in Capex, reserves, and oil price.

4. Scenario analysis

   Evaluation of financial outcomes under alternative operational strategies:

- Scenario 1: Capex optimization through adoption of Logging While Drilling (LWD) and rig day reduction.
- Scenario 2: Combined Capex and reserve reduction due to shallower drilling depth.

5. Strategic interpretation

   Translation of financial outcomes into managerial implications and recommendations for PHI's future drilling strategy.

   The combination of these analytical stages ensures comprehensive evaluation of both financial viability and strategic implications.

IV. RESULTS AND DISCUSSIONS

A. External and Industry Environment

The PESTEL framework is utilized in this study to analyse the macro-environmental factors that influence investment and operational decisions in the oil and gas industry, particularly in mature fields managed by PHI Zone 9. The PESTEL model categorizes into six factors: political, economic, sociocultural, technological, environmental and legal. These factors are critical for understanding the non-market conditions that shape strategic and financial decision in well development projects. Meanwhile, The Porter's five forces is utilized to give better understanding related to the competitive landscape and structural dynamics which influence investment decision in well developments. In PHI Zone 9 where the operational efficiency is critical, these forces help to identify external pressures that directly or indirectly affect the project economics.

Enhancing Economic Viability of Mature Field Through Financial-Operational Balance

PESTEL and Porter's Five Forces analyses indicate that PHI Zone 9 operates under moderate to highly competitive pressure, influenced by regulatory reforms, oil price volatility, and service cost escalation. Political and economic stability underpins continued exploration, yet market uncertainty requires conservative project assumptions. Technological trends particularly digitalization and real time monitoring, offer opportunities for cost efficiency. Environmental and social expectations further compel operators to adopt sustainable and transparent practices.

B. Financial Evaluation Results

In this study, the financial evaluation is primarily focused on a marginal well, which reflects the economic challenges faced in mature oil and gas fields. The analysis emphasizes cost efficiency, revenue generation, and overall project viability. Additionally, a high performing well in the same field is also used as a benchmark to provide an upper bound perspective on potential economic outcomes, though the main analysis focuses on the marginal case.

Prior conducting the financial evaluation, it is essential to establish the fundamental economic data that guide the analysis. Table 1 presents the key economic input parameters for the marginal well, including production profiles, contractor split calculations, and price assumptions. These data serve as the primary variables to estimate project revenues and profitability. The production profile outlines the forecasted output of oil, gas, and condensate over the project life, meanwhile the contractor split calculation reflects the revenue allocation based on the applicable PSC scheme. Price assumptions, derived from corporate planning scenarios, provide the basis for revenue projection and sensitivity testing in subsequent economic analyses. These parameters serve as the foundation inputs to calculate economic indicators such as NPV, IRR, PI, and determine the POT.

Table 1. Economic Input Parameters for Financial Evaluation of Well S-73

Well Name		S-73									
Year		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Days		366	365	365	365	366	365	365	365	366	365
Local Gov Interest		10%									
Production											
	Unit	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Gas	MMCFD	0.50	0.00	0.00	0.00	0.00	0.00	0.19	0.04	0.00	0.00
LPG	MMCFD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil, BOPD	BOPD	24.36	55.59	33.01	19.60	11.63	6.90	0.51	0.00	0.00	0.00
Cond, BOPD	BOPD	15.21	0.00	0.00	0.00	0.00	0.00	5.69	1.30	0.00	0.00
BRC, BOPD	BOPD	3.31	0.13	0.08	0.05	0.03	0.02	1.22	0.28	0.00	0.00
Associated Gas, MMCFD	MMCFD	0.01	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Gas, MMCF	MMSCF	186.17	7.47	4.43	2.63	1.57	0.93	68.35	15.54	0.00	0.00
Liquid, BBL (incl BRC)	BBL	15691.09	20339.18	12077.68	7171.89	4267.65	2525.30	2706.89	574.15	0.00	0.00
Contractor Split Calculation											
Base Split											
Gas		48.0%	48.0%	48.0%	48.0%	48.0%	48.0%	48.0%	48.0%	48.0%	48.0%
Oil		43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	43.0%
Variable Correction Factor		6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Progressive Correction Factor											
Cum Prod		9.0%	9%	9%	8%	8%	8%	8%	8%	8%	8%
Gas Price		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
Oil Price		0.8%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%
Gov't Discretion (Max 5%)		20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Final Contractor Share											
Gas		83%	83%	83%	82%	82%	82%	82%	82%	82%	82%
Liquid		79%	79%	79%	78%	78%	78%	78%	78%	78%	78%
Prices											
	Unit	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Oil	$/BBL	82	80	80	80	80	80	80	80	80	80
BRC	$/BBL	71	69	69	69	69	69	69	69	69	69
Gas	$/MMBTU	7.33	6.98	7.58	7.67	7.76	7.82	7.79	7.56	7.31	6.82

Following the establishment of economic input parameters, the next step in the financial evaluation involves estimating the revenue distribution from produced hydrocarbons. Table 2 summarizes the revenue allocation for gas, liquid (oil, condensate, and Badak Return Condensate (BRC)), the consolidated total over the project life, and projected net cash flow of well S-73. The distribution is calculated based on the forecasted production volumes, applicable sales prices, and contractor entitlement which is derived from PSC scheme. Additionally, the net cash flow projection provides the essential financial basis for further economic evaluation. The values are derived by subtracting total annual expenditures from total revenues by considering capital and operational costs, as well as fiscal obligation under the applied PSC scheme.

Table 2. Revenue Distribution for Gas, Liquid, and Consolidated Outputs of Well S-73

Revenue Distribution											
Gas											
	Unit	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Domestic	$M	0.48	0.25	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LNG	$M	0.45	0.21	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LPG	$M	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Revenue	$M	1.23	0.05	0.03	0.02	0.01	0.01	0.48	0.11	0.00	0.00
Cost of Sales, Marketing Fee	$M	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Revenue	$M	1.23	0.05	0.03	0.02	0.01	0.01	0.48	0.11	0.00	0.00
Contractor Share	$M	1.02	0.04	0.03	0.01	0.01	0.01	0.39	0.09	0.00	0.00
VAT LNG	$M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex & VAT LNG	$M	0.30	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Intangible Capex	$M	2.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (New Wells)	$M	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)	$M	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation	$M	0.12	0.09	0.07	0.05	0.15	0.00	0.00	0.00	0.00	0.00
Deductible Cost	$M	2.47	0.26	0.07	0.05	0.15	0.00	0.00	0.00	0.00	0.00
Weighted Average Price	$/MMBTU	7.33	6.98	7.58	7.67	7.76	7.82	7.79	7.56	7.31	6.82
Gas, MMCFD Sales											
SS Production (Gas Reserve)	MMCFD	0.51	0.02	0.01	0.01	0.00	0.00	0.19	0.04	0.00	0.00
Liquid											
Badak Crude	$M	1.19	1.62	0.96	0.57	0.34	0.20	0.18	0.04	0.00	0.00
BRC	$M	0.09	0.00	0.00	0.00	0.00	0.00	0.03	0.01	0.00	0.00
Gross Revenue	$M	1.27	1.63	0.97	0.57	0.34	0.20	0.21	0.04	0.00	0.00
Contractor Share	$M	1.00	1.29	0.77	0.45	0.27	0.16	0.17	0.04	0.00	0.00
Opex	$M	0.14	0.17	0.10	0.06	0.04	0.02	0.02	0.01	0.00	0.00
Intangible Capex	$M	0.81	0.05	0.05	0.00	0.00	0.09	0.02	0.00	0.00	0.00
Tangible Capex (New Wells)	$M	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)	$M	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation	$M	0.05	0.04	0.03	0.02	0.07	0.00	0.00	0.00	0.00	0.00
Deductible Cost	$M	1.00	0.26	0.18	0.09	0.11	0.12	0.04	0.01	0.00	0.00
Consolidated											
Net Revenue	$M	2.50	1.67	1.00	0.59	0.35	0.21	0.69	0.15	0.00	0.00
Contractor Share	$M	2.02	1.33	0.79	0.46	0.28	0.16	0.56	0.12	0.00	0.00
Opex	$M	0.44	0.31	0.11	0.07	0.04	0.02	0.02	0.01	0.00	0.00
Intangible Capex	$M	2.86	0.07	0.05	0.00	0.00	0.09	0.02	0.00	0.00	0.00
Tangible Capex	$M	0.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation	$M	0.17	0.13	0.10	0.07	0.22	0.00	0.00	0.00	0.00	0.00
Deductible Cost	$M	3.47	0.52	0.25	0.14	0.26	0.12	0.04	0.01	0.00	0.00
Deductible Cost + Unrec Cost	$M	3.47	0.52	0.25	0.14	0.26	0.12	0.04	0.01	0.00	0.00
Taxable Income	$M	-1.45	0.81	0.54	0.33	0.02	0.05	0.52	0.12	0.00	0.00
Tax	$M	0	0	0	0	0	0	0	0	0	0
Government Take	$M	0.48	0.35	0.21	0.13	0.08	0.05	0.13	0.03	0.00	0.00
Contractor Take	$M	2.02	1.33	0.79	0.46	0.28	0.16	0.56	0.12	0.00	0.00
Cash Cost	$M	3.99	0.39	0.16	0.07	0.04	0.12	0.04	0.01	0.00	0.00
Inventory Carry Over	$M	0	0	0	0	0	0	0	0	0	0
Cash Cost minus Inventory C/O	$M	3.99	0.39	0.16	0.07	0.04	0.12	0.04	0.01	0.00	0.00

	Unit	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capex	$M	3.55	0.07	0.05	0.00	0.00	0.09	0.02	0.00	0.00	0.00
Capex Cumulative	$M	3.78									
Opex	$M	0.44	0.31	0.11	0.07	0.04	0.02	0.02	0.01	0.00	0.00
Opex Cumulative	$M	1.02									
Net Cash Flow	**$M**	-1.97	0.94	0.64	0.40	0.24	0.05	0.52	0.12	0.00	0.00

Based on the tables above, the net cash flow of well S-73 begins with a negative cash flow in the initial year, reflecting the capital investment required before production revenues are realized. From the second year onward, positive cash flows are observed as production revenues exceed operating costs, although the overall magnitude remains relatively modest. This pattern highlights the economic vulnerability of marginal wells, where early capital intensity and limited production potential constrain in long term value creation.

Figure 2 presents the annual distribution of Capex, Opex, and the corresponding net cash flows over its projected economic life for well S-73. Referring to the graphs, it is known that S-73 utilizes a significant capital expenditure in 2024, corresponding to the initial investment required for drilling and completion activities. Therefore, S-73 has a negative cash flow of $-1.97 million in 2024, as the initial Capex exceeds early production revenues. From 2025 onward, positive net cash flows are observed as production revenues surpass annual operating costs. However, the overall magnitude remains modest and exhibits a gradual decline over time in line with the natural production profile.

Figure 2. Annual Cost and Net Cash Flow Profile for Well S-73

Based on the projected net cash flows, the economic performance of well S-73 were evaluated using standard capital budgeting techniques, including NPV (Eq. 4), IRR (Eq. 5), POT, and PI (Eq. 6), which is presented in Table 3. The marginal well yields a modest NPV of $0.20 million, a PI of 1.06, a POT in 2025, and an IRR of 15% that narrowly exceeds the company's hurdle rate. These results indicate that although the project delivers a positive return, its economic resilience remains limited and highly sensitive to cost and production variations.

For reference, Table 3 presents the summaries and differences of economic evaluation for marginal and high performing well. Well S-71 is a high performing well in the same field that demonstrate substantially stronger outcomes, with a high NPV of $5.52 million, a PI of 2.17, and rapid capital recovery within the first production year. Meanwhile, the IRR could not be calculated due to consistently positive cash flow since the first drilling year. This benchmark underscores the gaps in performance and highlights the importance for appropriate strategies to improve the economics of marginal wells.

Table 3. Summaries of Economic Evaluation for Well S-71 and S-73

Economic Indicator	S-71	S-73
NPV	5.52	0.20
IRR	-	15%
POT	2024	2025
PI	2.17	1.06

C. Sensitivity Analysis

The sensitivity analysis highlights the fragile economic profile of the marginal well. As presented in Table 4 and the corresponding tornado chart (Figure 3), the NPV of S-73 is highly sensitive to Capex, oil reserve, and oil price. Changes in Capex causes the greatest influence, shifting NPV from a negative $-0.63 million to a positive $0.85 million, highlighting the critical importance of cost control for marginal wells. Oil reserves and oil price also significantly affect the project value with NPV ranges of $-0.4 million to $0.79 million and $-0.41 million to $0.67 million, respectively. In contrast, gas reserves and Opex cause relatively limited influence, with narrower ranges of variations. These results confirm that even moderate cost increases or production underperformance could easily shift the project from positive to negative value, which is emphasizing the need for cautious planning and disciplined execution.

Table 4. NPV Sensitivity Analysis for Key Economic Variables in Well S-73

	Swing -20%		Base		Swing +20%	
	Value	NPV	Value	NPV	Value	NPV
Capex ($M)	3.03	-0.63	3.78	0.20	4.54	0.85
Opex ($M)	0.82	-0.07	1.02	0.20	1.22	0.29
Oil Price ($/BBL)	65	-0.41	80	0.20	100	0.67

Oil Reserves (BOPD)	121.28	-0.40	151.60	0.20	181.92	0.79
Gas Reserves (MMCFD)	0.63	-0.07	0.79	0.20	0.94	0.45

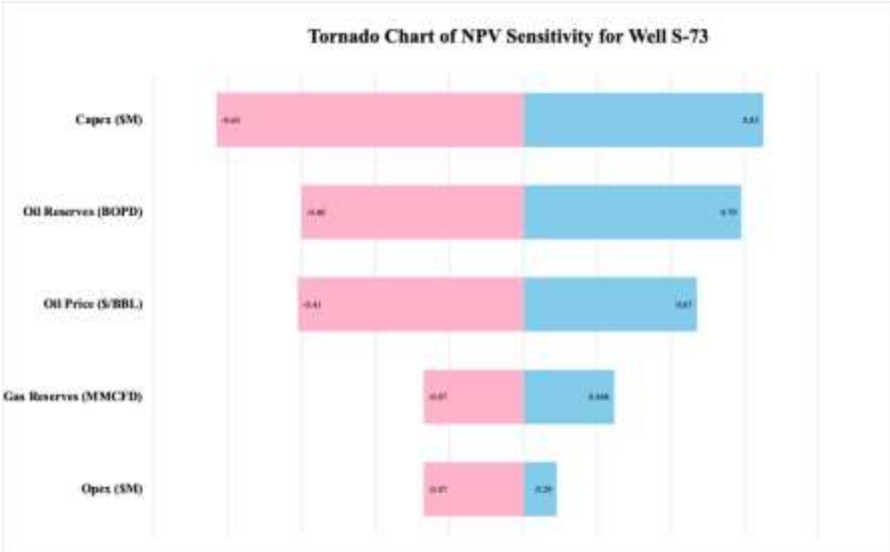

Figure 3. Tornado Chart of NPV Sensitivity for Well S-73

For reference, a sensitivity assessment was also performed on a high performing well in the same field. The results confirmed its strong economic resilience, with project value remaining robust under a wide range of operating conditions. Unlike the marginal well, which is highly sensitive to changes in Capex and production performance, the high performing well was influenced primarily by oil reserves and oil price. This contrast illustrates the fundamental differences between high performing and marginal wells and shows that targeted cost efficiency measures are more critical for sustaining the economics of marginal wells.

D. Scenario Analysis

Referring to the results of sensitivity analysis, scenario analysis is conducted to evaluate the combined impact of multiple variable changes on the economic performance of marginal well under certain operational and market conditions. This approach allows for the evaluation of multiple variable changes simultaneously, which provides a more comprehensive view of potential project outcomes. Two scenarios are considered in this study:

- Scenario 1 (Capex Optimization – Technology Adaptation)

Replacing wireline logging with LWD and reducing rig days achieved measurable Capex savings, but overall NPV gains were minimal due to limited leverage of logging cost within total expenditure.

- Scenario 2 (Capex and Reserve Reduction)

A shallower total depth reduced Capex but led to a proportionally greater reserve loss, further decreasing project value.

Scenario 1 – Capex Reduction (Technology Adaptation)

Scenario 1 explores the economic impact of replacing conventional wireline logging to LWD technology as a strategy to reduce Capex. Table 5 summarizes the current condition for S-73, while Table 6 presents the revised projection under scenario 1, where the effect of scenario 1 is more pronounced. Based on the analysis, it is observed that despite the expected Capex reduction through the elimination of wireline logging and slight rig days optimization, the resulting NPV change is minimal (NPV current condition of $0.2 million and NPV under scenario 1 of $0.27 million). This result reflects the marginal economic of the well S-73, where the cost of conventional wireline logging is already low, the difference in rig days is not significant, and the price of running LWD tools is still comparable to wireline Quad Combo service. Therefore, the strategy does generate an improvement, even though not significant. This suggests that deeper cost efficiency interventions or improved production scenario are required to enhance financial feasibility.

Table 5. Financial Performance Summary of Well S-73 Under Current Operational Condition

	Unit	Value	Remark
Initial Capex	$	3,548,073.7	
Actual Rig Days	Days	21	
Actual Drilling Days	Days	6.2	
Actual Wireline Job Days	Days	3	
Cumulative Moving & Rig Up Cost	$	479,853.6	
Cumulative Rig, Drilling, Operation, Manpower & Completion Cost	$	1,999,069.6	
Cumulative Other Additional Cost	$	1,069,150.5	
Wireline Cost (Quad Combo)	$	33,300.0	1 Day Operation
Wireline Cost (PTFA)	$	46,620.0	2 Days Operation
Average Daily Cost	$	95,193.8	
Average Daily Other Additional Cost	$	50,911.9	
LWD Cost	$/Hour	185.0	

Table 6. Economic Indicators of Well S-73 Under Scenario 1: Capex Optimization Through Wireline To LWD Scenario 1

Expected Rig Days	Days	20
Expected Drilling Days	Days	6.2
Expected Daily Rig, Drilling, Manpower & Completion Cost	$	1,903,875.8
Expected Other Additional Cost	$	1,018,238.6
Expected LWD Cost	$	27,528.0
Expected Capex	$	3,476,115.9
NPV ($M)	0.27	
IRR	17%	
POT (year)	2025	
PI	1.08	

Scenario 2 – Capex Reduction with Reserve Decrease

Scenario 2 explores the combined impact of reserve reduction and Capex saving which is resulting from shallower drilling depth. This scenario simulates a more conservative production outlook, where reductions in hydrocarbon reserve cause shorter well depth and fewer rig days. The analysis aims to evaluate how lower reserves and moderate cost efficiencies interact to influence overall project economics.

Table 7 presents the economic projection of well S-73 under scenario 2, which incorporates both Capex and reserve reduction. In this scenario, S-73 experiences reserve reductions of 30% of oil and 20% of gas, with a depth reduction of around 1,060 ft, also reduce around three fewer drilling days. Despite these cost saving measures are applied, the results demonstrate that the reduction in reserves has a much greater negative effect on project economics than the limited benefits gained from Capex efficiency. The well records a negative NPV of $-0.56 million and a negative IRR of -0.8%, signifying that discounted future revenues are insufficient to recover the initial investment. Given its marginal profile, the results confirm that well S-73 remains economically constrained. The sharp decline in NPV and PI highlights its fragile economics and the project's high sensitivity to production volumes. Overall, the analysis shoes that reserve reduction have a stronger negative impact that the savings from Capex efficiency, which confirms the marginal nature of S-73 and indicates its limited feasibility under current conditions.

Table 7. Economic Indicators of Well S-73 Under Scenario 2: Capex and Reserve Reduction

Scenario 2

Expected Rig Days	Days	18
Expected Drilling Days	Days	3.5
Expected Daily Rig, Drilling, Manpower & Completion Cost	$	1,713,488.2
Expected Other Additional Cost	$	916,414.7
Expected Capex	$	3,166,366.5
Oil Reserve Decrease	%	30
Gas Reserve Decrease	%	20
NPV ($M) IRR		-0.56
POT (year)		-0.8%
PI		2025
		0.82

These outcomes highlight that financial resilience in mature fields depends more on reserve preservation and production assurance than marginal Capex reduction. Sustainable improvement requires aligning cost efficiency with long term production objectives.

E. Business Solutions

The results of the financial evaluations and scenario analysis highlight the structural differences between marginal and high performing wells. While high performing well demonstrates robust economics with strong NPVs and rapid POT, marginal wells exhibit fragile performance, highly sensitive to Capex, reserve volumes, and oil price assumptions. Based on these findings, several business solutions are proposed to guide decision making in future well development planning. The business solutions are:

1. Portfolio balancing: Prioritize high performing wells to secure early revenue and stabilize cash flow, while applying strict cost discipline to marginal wells.
2. Technology integration: Deploy cost efficiency technologies, such as LWD, digital drilling dashboards, and predictive analytics, where return justification is strong.
3. Risk-based planning: Implement scenario-based financial planning, contingency budgeting, and apply conservative oil price assumptions to enhance project robustness.

Collectively, these strategies align with PHI's vision of operational excellence and capital efficiency, providing a roadmap for sustaining profitability under uncertain market conditions.

V. CONCLUSIONS

This study shows that sustaining the economic viability of mature oil and gas fields requires a balanced approach that integrates financial evaluation, operational efficiency, and strategic planning. The main conclusions are as follows:

1. The main factors reducing well economics are Capex, oil reserves, and oil price fluctuations. Capex escalation has the strongest effect on marginal wells, while reduction in reserves and oil price volatility directly diminish revenues.
2. Capital budgeting technique (NPV, IRR, PI, POT) supported by WACC, sensitivity, and scenario analysis provide a structured framework for evaluating feasibility. These tools help decision makers prioritize wells, allocate capital effectively, and anticipate risks from oil price, reserves, and costs.
3. Technology drive Capex reduction is key to improving returns, especially for marginal wells. While reserve preservation remains the most critical factor, cost efficiency can make borderline project viable. A phased 2026 plan is recommended: drill high performing wells early to secure revenue, then selectively develop marginal wells under strict financial and operational controls.

ACKNOWLEDGMENT

The author expresses sincere gratitude to the School of Business and Management, Institut Teknologi Bandung, and to PT Pertamina Hulu Indonesia Region 3 Zone 9 for their continuous support, collaboration, and provision of valuable data for this research.

REFERENCES

1) Gitman, L. J., & Zutter, C. J. (2012). Principles of Managerial Finance 13th Edition. Prentince Hall.
2) Damodaran, A. (2014). Equity Risk Premiums (ERP): Determinants, Estimation and Implications. SSRN, The 2014 Edition. https://dx.doi.org/10.2139/ssrn.2409198
3) Wiryono, S. K., & Yuswen, D. (2008). Economic Evaluation for Oil and Gas Exploration Drilling Project. Jurnal Manajemen Teknologi, 7 (2), 197. https://media.neliti.com/media/publications/114209-ID-none.pdf
4) Omosebi, O., Osisanya, S. O., & Ahmed, R. (2014). An Integrated Model-Based Approach to Drilling Project Management. SPE-172391-MS. https://doi.org/10.2118/172391-MS
5) Atolagbe, E., & Mohammed, S. (2022). Driving Project Efficiency and Cost Control in Nigeria's Oil and Gas Industry. Society of Petroleum Engineers - SPE Nigeria Annual International Conference and Exhibition, NAIC 2022. Scopus. https://doi.org/10.2118/212038-MS.
6) U.S. Energy Information Administration (EIA). (2024). Forecasts show U.S. crude oil production and price lower in 2024 and 2025. Today in Energy. https://www.eia.gov/todayinenergy/detail.php?id=64305