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Selective Investment and Real Options Approach for LLP Compressor Deployment to Support Sustainable Production at PT Hulu Sungai

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ABSTRACT: PT Hulu Sungai operates offshore Gas Block "M", a critical offshore gas-producing asset that is experiencing production decline due to reservoir depletion. To sustain output and enhance recovery, PT Hulu Sungai is evaluating the deployment of low-low pressure (LLP) compressors across several offshore platforms to reduce wellhead pressure. However, updated reserve assessments show that only three out of four proposed platforms deliver positive Net Present Value (NPV), while the remaining one may result in sunk costs of up to USD 16 million if a compressor is deployed prematurely. This study develops a flexible, data-driven investment and procurement strategy, applying Real Options Analysis (ROA) to optimize compressor deployment by balancing economic feasibility, capital utilization, and technical readiness. The research addresses three primary questions. First, which platforms demonstrate economic viability based on updated reserves and production forecasts? Second, what is the potential for the marginal platform to achieve incremental recovery and positive NPV if a compressor is redeployed after 2026? Third, what deployment sequence and asset movement plan will maximize return on investment while minimizing the risk of stranded assets? The objectives include conducting NPV and IRR analyses, applying ROA to model flexibility, and proposing a staged deployment strategy that adjusts to evolving subsurface conditions. The findings confirm that three platforms are economically feasible for compressor installation between 2025 and 2027, each generating between USD 5 to 10 million in NPV. ROA supports the possibility of redeploying compressors to the marginal platform, which can convert a previously unviable investment into a profitable outcome if reserve updates support further development. Stakeholder feedback validates both the technical and logistical feasibility of redeployment. The proposed strategy enables PT Hulu Sungai to avoid up to USD 16 million in sunk costs and supports long-term value generation in Gas Block M.

KEYWORDS: LLP compressor deployment; petroleum economic evaluation; real options flexibility; offshore gas field management; procurement strategy.

I. INTRODUCTION

Indonesia's upstream oil and gas sector is undergoing a period of strategic transformation marked by aging infrastructure, maturing fields, and increasing pressure to sustain production amid declining reservoir performance. Although the country has been active in hydrocarbon development for more than a century, national output has progressively weakened due to natural reservoir depletion, operational complexity, and rising domestic energy demand. In response, the Government of Indonesia has committed to an ambitious target of achieving one million barrels of oil per day by 2030, supported by increased investment, enhanced recovery efforts, and greater collaboration with research institutions to improve subsurface characterization. Yet, these national initiatives require effective and economically sound field-level decisions, particularly in long-producing assets where the balance between technical feasibility, capital discipline, and production sustainability is delicate.

Within this national context, the M Block operated by PT Hulu Sungai (PT HS) illustrates the broader challenges confronting Indonesia's mature gas fields. Several of the block's offshore platforms have exhibited substantial declines in reservoir pressure and intensified liquid loading, resulting in reduced well deliverability and suboptimal gas evacuation. As reservoir energy becomes insufficient to sustain natural flow, compression becomes a key intervention to preserve output and avoid premature abandonment. PT HS has therefore identified Low-Low Pressure (LLP) compressors as a central technological measure to offset declining wellhead pressures and unlock residual reserves. By lowering backpressure at the surface, LLP compressors can sustain hydrocarbon recovery in depleted reservoirs, extend field life, and enhance the economic performance of late-life assets.

Despite their technical advantages, LLP compressors represent a capital-intensive investment. A single unit requires approximately USD 16 million for procurement and installation, and deploying compressors across all four candidate platforms would exceed USD 80 million in expenditure. This magnitude of capital commitment underscores the need for rigorous evaluation because recent reserve assessments indicate that only three of the four platforms yield a positive Net Present Value (NPV) under current forecasts. Installing compressors indiscriminately without differentiating between viable and marginal platforms risks converting substantial capital outlays into sunk costs. This challenge is heightened by uncertainties in gas prices, reservoir productivity, and operational constraints, which collectively influence the true economic returns of compression projects.

An equally significant challenge arises from the static nature of traditional procurement planning. Existing procurement practices assume simultaneous deployment across all targeted platforms, regardless of updated economic or reservoir data. Such an approach does not adequately incorporate risk, uncertainty, or platform-specific performance variations. Moreover, conventional discounted cash flow (DCF) methods, though widely used in capital budgeting, inherently assume fixed timing and irreversible investment. They do not accommodate managerial flexibility such as deferring installation, staging deployment, or reallocating compressors in response to new information. In the dynamic operational environment of offshore gas fields, these constraints limit the ability to optimize capital allocation.

This study addresses this gap by proposing a more adaptive and data-driven method for LLP compressor deployment, grounded in an integrated decision-making approach that combines capital budgeting analysis, sensitivity testing, and real options reasoning. The core novelty of this research lies in shifting compressor planning from a rigid, single-commitment model to a flexible strategy that treats compressors as re-deployable assets and incorporates uncertainty explicitly into procurement sequencing. In contrast to conventional approaches, this study does not evaluate compressor installation as a one-time, platform-specific investment but as part of a portfolio of interdependent options across multiple platforms. This enables PT HS to capitalize on the opportunities of deferral, staging, and reutilization, thereby minimizing sunk cost exposure and enhancing long-term economic resilience.

The novelty also lies in the real-options-based conceptualization of LLP compressor deployment. While compressors are typically evaluated for their capacity to boost production, this study demonstrates that their economic value is also contingent on managerial flexibility. The ability to reposition compressors from high-performing to marginal platforms, deploy units only when reservoir behaviour justifies investment, or defer procurement in anticipation of improved market prices fundamentally alters the project's financial landscape. Rather than treating uncertainty as an external constraint, the research integrates it into the decision model through option-like mechanisms, allowing uncertainties in gas price, pressure decline, and reserve estimates to be converted into strategic advantages rather than risks.

Furthermore, the study introduces a scenario-based analytical structure that evaluates four distinct development pathways: (1) no compression, (2) full deployment on all candidate platforms, (3) deployment restricted to economically strong platforms, and (4) a reutilization-based strategy where compressors are sequentially deployed and redeployed according to platform performance thresholds. This scenario structure enables a detailed examination of how various procurement strategies influence long-term economic value. By integrating financial, technical, and operational perspectives, the study bridges the gap between economic modeling and practical execution planning an intersection that has been underexplored in existing internal decision frameworks.

In addition, the research emphasizes the importance of aligning procurement practices with economic risk profiles. Compressors can be procured through flexible contracting mechanisms, modular design principles, and staggered purchase schedules that preserve optionality. These practices must be supported by governance structures that release capital only when predefined thresholds, such as production rates or price floors have been met. This integration of economic triggers into procurement governance constitutes an important theoretical and practical contribution, enabling capital allocation to remain responsive to evolving field conditions.

These features collectively form the novelty of the study: the development of a holistic, flexibility-centered method for LLP compressor deployment that integrates capital budgeting, uncertainty analysis, and procurement strategy. By treating compressors not merely as technical solutions but as movable financial assets, the study provides a refined framework that enhances value creation while mitigating downside risk.

Given this context, the research is guided by the following questions: (1) Which platforms provide the best economic justification for LLP compressor deployment? (2) How can uncertainty in reserve estimates and gas prices be incorporated into procurement decisions? (3) What procurement strategy (phased deployment, full deployment, or reutilization) delivers the optimal balance between economic value and risk management?

By answering these questions, the study aims to establish a robust, transparent, and flexible decision foundation for compressor procurement at PT HS. In doing so, it contributes both theoretically and practically to the broader field of petroleum project evaluation, demonstrating how mature-field management can benefit from strategic flexibility, structured economic analysis, and optimized capital deployment in an era of heightened operational complexity and financial scrutiny.

II. LITERATURE REVIEW

Theoretical Foundation

The theoretical foundation of this study is built upon the intersection of financial decision-making frameworks, petroleum economics, and upstream operational practices. Capital budgeting provides the basis for evaluating investment feasibility in capital-intensive industries such as oil and gas, while real options theory extends this foundation by addressing uncertainty and managerial flexibility. At the same time, production decline dynamics and the application of compression technology shape the technical rationale for investment. By integrating these perspectives, the literature establishes a comprehensive basis for analyzing the economic and strategic dimensions of LLP compressor deployment in mature offshore fields.

Capital Budgeting in Oil and Gas Projects

Capital budgeting is the process of evaluating and selecting long-term investments that align with a company's strategic objectives. In capital-intensive industries such as upstream oil and gas, methods like NPV, IRR, PI, and discounted Payback Time are widely applied to determine economic viability (Brealey, Myers, & Allen, 2020; Gatti, 2018).

NPV calculates the present value of future cash flows discounted at the project's cost of capital, less the initial investment. A positive NPV indicates that the project is expected to create value (Damodaran, 2012). IRR represents the project's internal profitability, expressed as an annual percentage. In practice, projects are accepted if the IRR exceeds the company's Weighted Average Cost of Capital (WACC). This makes IRR particularly useful for communicating investment attractiveness to non-specialist stakeholders. However, IRR can be misleading when projects have non-conventional cash flows that cause multiple IRR values, or when comparing projects of vastly different scales (Ross, Westerfield, & Jaffe, 2019). Profitability Index (PI) known as the benefit-cost ratio, expresses the ratio of the present value of future cash flows to the initial investment. A PI greater than one indicates a profitable project, while a PI less than one suggests uneconomic returns. PI is especially relevant when investment capital is rationed, as it allows managers to rank competing projects by efficiency of capital use (Gatti, 2018). Nonetheless, it should be used alongside NPV, since PI does not reveal the scale of value creation in absolute terms. The Discounted Payback on Investment Time (dPOT) measures how long it takes for cumulative discounted cash flows to recover the initial investment. By incorporating the time value of money, dPOT improves upon the traditional payback period method, providing a more realistic picture of investment recovery. Projects with shorter dPOTs are typically considered less risky, as the capital is recouped faster (Graham & Harvey, 2001). Weighted Average Cost of Capital (WACC) is a fundamental concept in corporate finance that represents the average rate of return required by both equity holders and debt holders. It is widely applied as the minimum threshold that projects must achieve in order to preserve or increase firm value (Brigham & Ehrhardt, 2017; Damodaran, 2012).

Real Options in Petroleum Economics

Traditional discounted cash flow (DCF) approaches, such as NPV and IRR, assume that investment decisions are fixed and irreversible once committed. While these methods provide valuable baseline assessments, they are often criticized for their inability to incorporate managerial flexibility under uncertainty (Brealey, Myers, & Allen, 2020). In upstream oil and gas projects, where commodity prices, reserves, and operational risks are highly volatile, this limitation can lead to suboptimal decisions. To address this gap, Real Options Analysis (ROA) has emerged as a powerful framework that extends financial option theory into the realm of physical investments (Trigeorgis, 1996; Dixit & Pindyck, 1994).

Production Decline and Compression Technology

Reservoir pressure decline is a natural and inevitable phenomenon in hydrocarbon production. As fluids are withdrawn from a reservoir, the energy that drives production decreases, leading to lower wellhead pressures and reduced production rates. This process is particularly critical in mature gas fields, where falling reservoir pressure can accelerate liquid loading, cause flow instability, and eventually render wells uneconomic. Understanding the dynamics of production decline is therefore essential in evaluating the economic and technical justification for compression projects.

Compression technology plays a central role in mitigating these challenges. By lowering wellhead pressure, compressors reduce the backpressure exerted on the reservoir, thereby increasing the pressure drawdown and sustaining production. This allows operators to extend the productive life of wells and delay abandonment, often unlocking incremental reserves that would otherwise remain stranded. In the context of offshore operations, Low-Low Pressure (LLP) compressors are particularly relevant, as they enable continued gas evacuation when platform pressures fall below pipeline operating requirements.

Risk and Sensitivity in Investment Decisions

Risk is an inherent aspect of upstream oil and gas projects, where investment outcomes are exposed to technical, operational, and market uncertainties. Key sources of risk include fluctuating commodity prices, variability in production rates, unexpected changes in capital and operating costs, and evolving regulatory environments (Damodaran, 2012; Gatti, 2018). These uncertainties can significantly alter project economics, making risk analysis an indispensable part of capital budgeting.

One of the most widely used tools for managing uncertainty in project evaluation is sensitivity analysis. Sensitivity analysis systematically tests how changes in individual variables such as gas price, CAPEX, OPEX, or production forecasts affect project performance indicators like NPV, IRR, or PI. This process identifies which variables exert the greatest influence on economic outcomes and therefore represent the most critical sources of risk exposure (Brigham & Ehrhardt, 2017).

SI greater than one indicates that the project value is highly sensitive to that parameter, meaning small changes in the variable can result in large shifts in economic viability. For gas projects, sensitivity analysis typically reveals that NPV is most vulnerable to fluctuations in gas price and production volumes, while capital and operating costs, although important, often have secondary effects (Graham & Harvey, 2001).

The insights gained from sensitivity analysis guide management in prioritizing risk mitigation strategies. For example, if gas price volatility is identified as the dominant risk factor, management may adopt flexible marketing arrangements, hedging contracts, or phased development strategies to protect downside outcomes. Similarly, if CAPEX sensitivity is high, procurement and project execution strategies may be adjusted to minimize exposure to cost overruns.

Sensitivity analysis, remains a deterministic tool. While it highlights which variables matter most, it does not provide a probabilistic view of how likely such variations are to occur. To strengthen decision-making, sensitivity analysis is often combined with Real Options Analysis (ROA). ROA complements traditional evaluation by embedding flexibility into project design, allowing management to defer, expand, or reallocate investments when uncertainty resolves (Trigeorgis, 1996; Dixit & Pindyck, 1994). This integration provides a balanced framework: sensitivity analysis identifies where risks lie, and ROA outlines how flexibility can mitigate those risks in practice.

Risk and sensitivity analysis provide critical insights into the vulnerability of upstream oil and gas projects, while Real Options Analysis extends these insights by offering a strategic response to uncertainty. This dual approach is particularly relevant for LLP compressor deployment, where the economics of each platform depend not only on baseline assumptions but also on how management responds to shifts in production decline and market conditions.

III. RESEARCH METHOD

The research design adopted in this study is quantitative in nature, supported by descriptive and explanatory elements. It is intended to evaluate the economic feasibility of deploying LLP compressors in mature offshore gas fields and to explore how managerial flexibility, such as deferral, staging, and reutilization, can improve capital efficiency under uncertainty. The design integrates discounted cash flow techniques, sensitivity analysis, and real options reasoning, ensuring a methodological consistency with the economic evaluation.

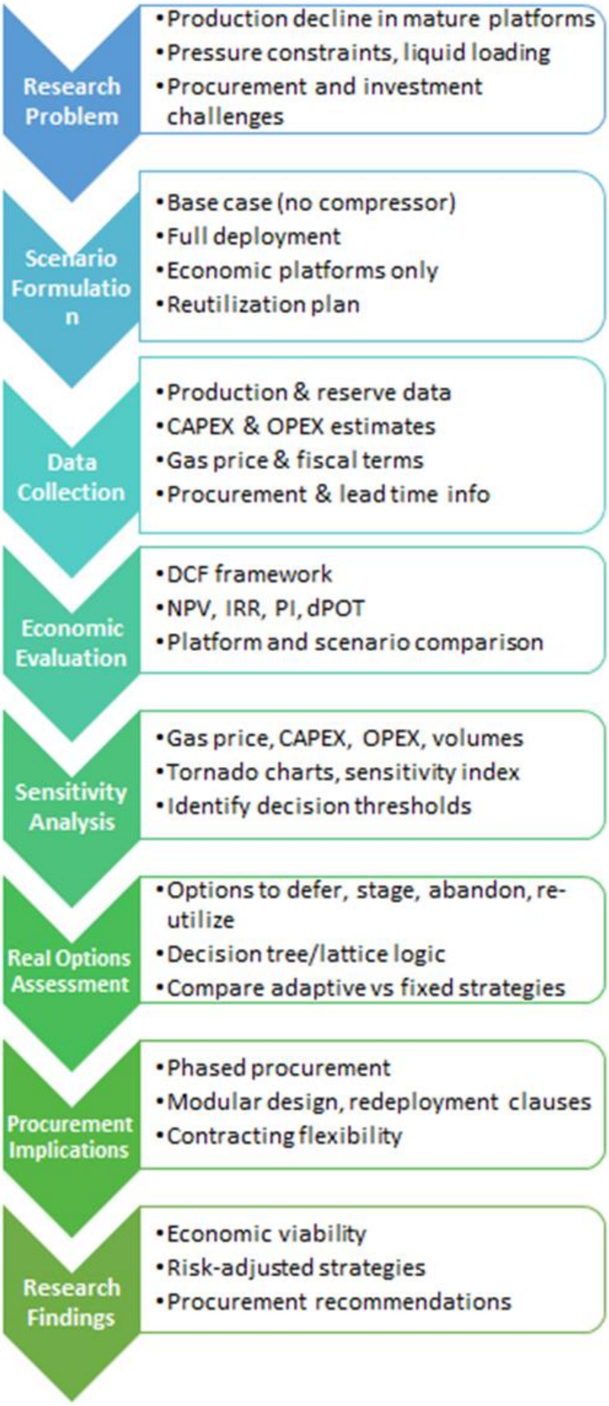

Figure 1. Research design of the study

The validity of this research depends on the relevance and accuracy of the data employed to build the economic models. Data collection in this study relies primarily on secondary sources, supported by selected references from academic and industry literature. The choice of data sources is aligned with the contextual problem: evaluating the economic and procurement implications of LLP compressor deployment in mature offshore gas platforms. Each type of data collected is specifically tied to the research questions.

The data collected in this study are analyzed using a structured framework that combines discounted cash flow techniques, sensitivity analysis, and real options reasoning. The aim of the analysis is not only to measure the baseline economic value of LLP compressor deployment but also to assess the robustness of outcomes under uncertainty and to capture the strategic benefits of managerial flexibility. The methods selected are consistent with the theoretical foundation.

IV. RESULT AND DISCUSSION

Overview of Analytical Outputs

The analytical evaluation undertaken for the M Block centers on determining the economic viability of deploying Low-Low Pressure (LLP) compressors across four offshore platforms: JAHE, MADU, CENGKEH, and JINTAN. The results indicate a pronounced divergence in platform-level feasibility, confirming that the M Block does not respond uniformly to compression-based intervention. From the economic screening contained in the internal documentation, only three of the platforms exhibit positive Net Present Value (NPV) outcomes under base-case assumptions, while one platform consistently registers a negative NPV regardless of operational or price sensitivities. Since each compressor requires approximately USD 16 million in capital expenditure, deploying compressors across all four platforms totaling over USD 80 million would expose PT Hulu Sungai (PT HS) to substantial sunk-cost risk. These findings establish the analytical baseline: compression is technically beneficial across all platforms, but economically feasible only for a subset.

Additionally, the analysis highlights that pressure decline across the M Block has reached a stage at which natural flow is no longer sustainable, causing intensified liquid loading and reduced evacuation efficiency. Consequently, compression emerges as a necessary technological solution for restoring production rates. However, the economic outcomes underscore the importance of platform-specific evaluation rather than blanket deployment, motivating a deeper investigation into production potential, reservoir behaviour, and uncertainty profiles.

Evaluation of Deployment Scenarios

Scenario 0: No Compression

This scenario assumes no additional investment in LLP compressors and reflects the natural depletion profile of the four candidate platforms (MADU, CENGKEH, JAHE, and JINTAN). Production continues under the current operating conditions without intervention, leading to progressive decline in gas and liquids output.

The Base Case serves as the fundamental benchmark against which the incremental impact of compressor deployment is assessed. All associated revenues, costs, and fiscal outcomes in this scenario are treated as reference values in the evaluation of Scenarios 1 through 3. By establishing this baseline, the analysis ensures that the economic contribution of LLP compression can be measured transparently in terms of both absolute uplift and relative improvement over natural decline.

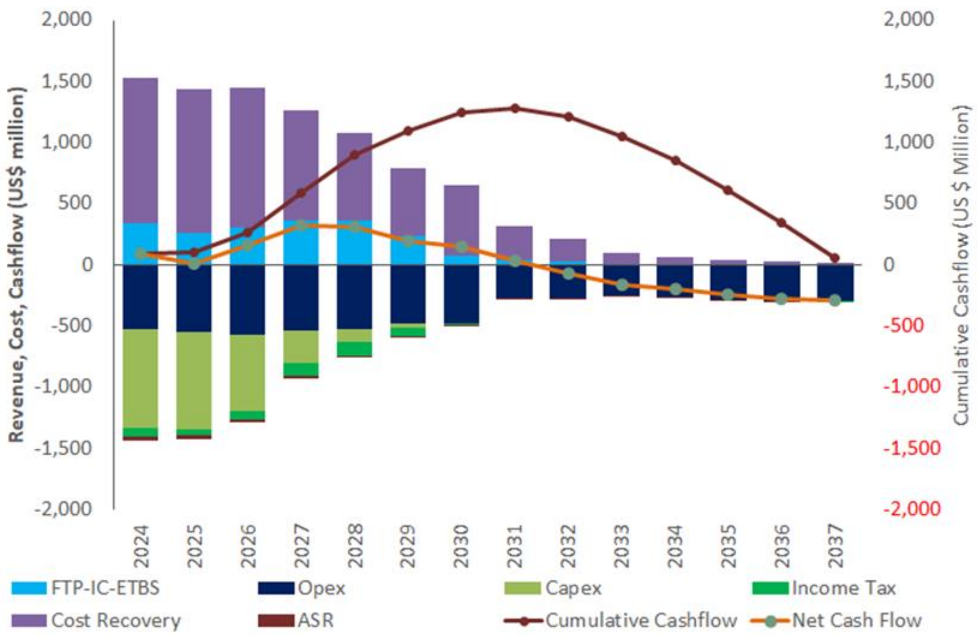

Figure 2. Baseline cashflow profile PT HS without LLP Deployment

The Base Case begins with strong revenue and cost recovery performance in 2024–2025, supported by legacy production from existing wells. Over time, however, natural reservoir decline leads to progressively lower gas output, which in turn reduces both cost recovery and government entitlement (FTP, IC, ETBS).

Table 1. Economic baseline of the base case scenario

Parameter	Unit	Baseline
Production Oil + Cond	MBbl	48,871
Production Gas	BCF	1,019
Sales Gas	$/MMBtu	851
Gross Revenue	MM$	10,506
Investment	MM$	2,639
Operation Cost	MM$	3,838
Cost Recovery	MM$	6,951
Unrecovered Cost	MM$	0
PHM:		
· Net Cash Flow	MM$	1,246
· NPV @ 12.04%	MM$	798

To complement the qualitative analysis, Table 1 presents the economic baseline of the base case scenario. At contractor level (PT HS), the project yields a cumulative net cash flow of USD 1,246 million and an NPV of USD 798 million (at 12.04% discount rate). These results confirm that, while the base case remains financially viable in the short term, its long-term economic upside is limited under natural depletion

Scenario 1: Full Deployment on All Platforms

This scenario assumes the simultaneous installation of four LLP compressors in 2025, with one unit allocated to each candidate platform: MADU, CENGKEH, JAHE, and JINTAN. It represents a high-capital, full-coverage strategy designed to maximize gas recovery at the earliest possible stage by addressing all platforms in parallel. The underlying rationale is to capture the production uplift comprehensively, even from platforms that may not meet economic thresholds individually.

The total capital expenditure required for this strategy is estimated at USD 72.5 million, distributed as follows: MADU at USD 19.5 million, CENGKEH at USD 19.1 million, JAHE at USD 16.6 million, and JINTAN at USD 17.3 million. This upfront commitment significantly exceeds the investment level of selective deployment strategies, thereby magnifying both the potential benefits and the associated risks. The consolidated production and financial outcomes of this scenario are illustrated in Figure 3, which compares the baseline case with the full-deployment case across the same period.

Figure 3. Net Cash Flow Comparison: Base Case vs Scenario 1

The net cash flow comparison between the baseline and full LLP deployment shows visible uplift from 2026 to 2029. Although CAPEX spending in 2025 temporarily reduces cash flow, compressor installation boosts subsequent revenue through higher gas throughput across all four platforms. The incremental gains peak in 2027–2028 before gradually tapering off in line with field maturity. The cash flow bars indicate that while LLP deployment enhances annual revenue performance, the overall improvement remains modest once discounted over time due to the high initial capital outlay.

Table 2. Economic Summary of Scenario 1 – Full LLP Deployment

Parameter	Unit	Baseline	Baseline + 4 PF LLP	Incremental 4 PF LLP
Produksi Oil + Cond	MBbl	48,871	49,132	261.38
Produksi Gas	BCF	1,019	1,044	24.26
Sales Gas	$/MMBtu	851	874	22.38
Gross Revenue	MM$	10,506	10,700	193.91
Investment	MM$	2,639	2,712	72.55
Operation Cost	MM$	3,838	3,856	17.58
Cost Recovery	MM$	6,951	7,041	90.14
Unrecovered Cost	MM$	0	0	0
PT HS:				
· Net Cash Flow	MM$	1,246	1,276	30.03
· NPV @ 12.04%	MM$	798	805	6.92
· IRR	%	-	-	18.22%
· PI @ 12.04%		-	-	1.11
· dPOT	Year			5.70

The consolidated economic outcome of the full-deployment strategy is summarized in Table 1. Portfolio gross revenue increases by about USD 193.91 million, supported by incremental gas and liquids across all four platforms. This uplift requires USD 72.55 million of additional investment and USD 17.58 million in incremental operating costs, yielding a contractor-level net cash flow gain of USD 30.03 million. On a discounted basis at 12.04%, portfolio NPV rises by USD 6.92 million to USD 805 million, with an overall IRR of 18.22%, PI of 1.11, and a discounted payback of 5.70 years. These gains are primarily driven by MADU, CENGKEH, and JAHE, while the inclusion of JINTAN suppresses returns and explains the modest NPV uplift relative to selective-deployment alternatives.

Scenario 2: Selective Deployment on Economically Strong Platforms

This scenario represents the selective installation of LLP compressors on three economically viable platforms: MADU, CENGKEH, and JAHE. By excluding JINTAN, which has been confirmed as uneconomic, this strategy focuses investment on assets with proven reserves and positive economic potential. The objective is to maximize incremental value and capital efficiency while minimizing sunk cost exposure.

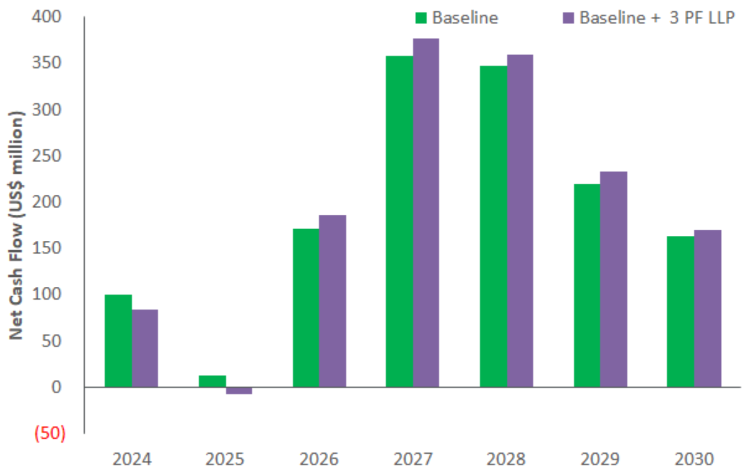

Figure 4. Net Cash Flow Comparison: Base Case vs Scenario 2

The financial profile indicates clear improvement over the base case beginning in 2026, when compression begins to generate incremental production. While 2025 shows a dip due to the upfront CAPEX for three compressor installations, subsequent years exhibit consistent gains in net cash flow. The 2026–2029 period shows a noticeable uplift in contractor revenue driven by higher gas throughput and cost recovery. Although production gradually declines after 2029 in line with natural field depletion, the overall cash flow remains stronger than in the depletion-only scenario.

The improvement in Scenario 2 is primarily driven by higher FTP-IC-ETC and cost recovery values resulting from incremental gas production. In addition, a moderate rise in operating expenditures reflects the added requirements for compressor operation and maintenance, while improved profitability during the compression period contributes to slightly higher income tax payments. Together, these factors create a balanced uplift in project economics without overextending capital exposure.

Table 3. Economic Summary of Scenario 2 – 3 Viable Platform LLP Deployment

Parameter	Unit	Baseline	Baseline + 3 PF LLP	Incremental 3 PF LLP
Production Oil + Cond	MBbl	48,871	49,123	252.77
Production Gas	BCF	1,019	1,040	21.02
Sales Gas	$/MMBtu	851	871	19.37
Gross Revenue	MM$	10,506	10,676	169.59
Investment	MM$	2,639	2,694	55.23
Operation Cost	MM$	3,838	3,852	13.76
Cost Recovery	MM$	6,951	7,020	68.99
Unrecovered Cost	MM$	0	0	0
PT HS:				
· Net Cash Flow	MM$	1,246	1,274	27.79
· NPV @ 12.04%	MM$	798	807	8.72
· IRR	%	-	-	22.30%
· PI @ 12.04%		-	-	1.18
· dPOT	Year			5.12

Under this configuration, total gross revenue increases by approximately USD 169.59 million, with USD 55.23 million invested in compressor CAPEX and USD 13.76 million in incremental operating costs. The resulting incremental net cash flow for PT HS reaches USD 27.79 million, while the NPV (12.04%) improves by USD 8.72 million compared to the base case. The IRR of 22.3%, PI of 1.18, and a discounted payback period of 5.12 years confirm the robustness of this selective deployment approach.

Overall, Scenario 2 demonstrates that focusing on economically sound platforms enhances project returns without overextending capital. The incremental uplift is achieved with manageable risk and superior efficiency compared to full-field deployment. This scenario provides the optimal balance between profitability, operational feasibility, and capital discipline, making it the most recommended strategy among the evaluated options.

Scenario 3: Sequential Deployment and Reutilization

This scenario introduces strategic flexibility by combining selective deployment with compressor reutilization. Three LLP compressors are initially installed on economically viable platforms MADU, CENGKEH, and JAHE during 2025. After these platforms reach production plateau or economic maturity, one of the compressors is redeployed to JINTAN for secondary recovery, enabling incremental gas capture without additional full-scale investment. This phased strategy allows PT HS to extend field recovery potential while optimizing capital utilization through equipment reallocation rather than new purchases.

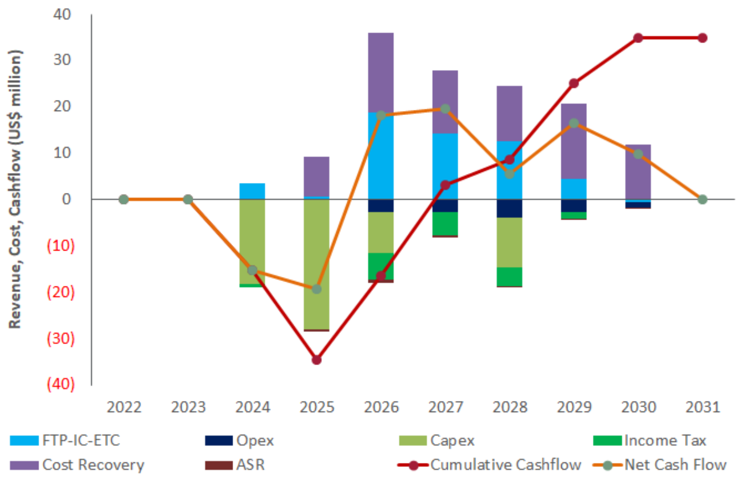

Figure 5. Scenario 3 Cash Flow Profile

The cash flow profile under the reutilization plan exhibits a similar pattern to the Scenario 2 case but with stronger cumulative performance during the mid- to late-cycle years. The 2025 capital outlay reflects the initial installation phase across three main platforms, followed by a smaller cost adjustment associated with compressor relocation in 2028. The compression phase starting in 2026 generates a visible uplift in both FTP-IC-ETC and cost recovery volumes, while operating and maintenance costs increase moderately in proportion to extended compressor use. Improved profitability during 2027–2030 results in higher tax contributions and sustained positive cash flows through 2031.

Table 4. Economic Summary of Scenario 3

Parameter	Unit	Baseline	Baseline + 3 PF + 1 Reutilize LLP	Incremental 3 PF + 1 Reutilize LLP
Production Oil + Cond	MBbl	48,871	49,130	259.37
Production Gas	BCF	1,019	1,043	23.61
Sales Gas	$/MMBtu	851	873	21.85
Gross Revenue	MM$	10,506	10,696	189.68
Investment	MM$	2,639	2,705	65.91
Operation Cost	MM$	3,838	3,854	15.41
Cost Recovery	MM$	6,951	7,039	87.96
Unrecovered Cost	MM$	0	0	0
PT HS:				
· Net Cash Flow	MM$	1,246	1,281	35.04
· NPV @ 12.04%	MM$	798	811	12.95
· IRR	%	-	-	26.69%
· PI @ 12.04%		-	-	1.24
· dPOT	Year			5.07

Table 4. summarizes the consolidated economic results for Scenario 3. The combined strategy yields an incremental gross revenue of USD 189.68 million, supported by an investment of USD 65.91 million and an additional USD 15.41 million in operating expenditures. These enhancements result in an incremental net cash flow of USD 35.04 million and an NPV increase of USD 12.95 million at a 12.04% discount rate. The internal rate of return (IRR) reaches 26.69%, with a profitability index (PI) of 1.24 and a discounted payback period (dPOT) of approximately 5.07 years.

Overall, Scenario 3 represents a balanced and innovative approach, capturing the financial benefits of compression while mitigating the capital inefficiencies observed in full deployment. By leveraging reutilization, PT HS effectively reduces sunk cost exposure, enhances portfolio IRR, and prolongs production life without significant new CAPEX. This scenario demonstrates how managerial flexibility and phased asset movement can maximize economic resilience in mature field operations.

Sensitivity and Uncertainty Analysis

The evaluation of uncertainty constitutes a central component of the analysis, revealing how external and subsurface variables influence economic outcomes. The internal document provides multiple sensitivity perspectives related to gas price fluctuations, reserve reassessment, deliverability projections, and uncertainty in liquid-loading progression.

Gas-price sensitivity is particularly influential. For platforms with a strong NPV position, moderate reductions in gas prices reduce, but do not overturn, economic viability. Their reserve buffers and productive capacities offer resilience against price dips. However, the marginal platform responds to gas-price changes with extreme fragility: even slight downward variations push it further into negative NPV territory. This asymmetric sensitivity directly implies that deploying compressors to weak platforms exposes PT HS to disproportionate downside risk.

Reservoir uncertainty also plays a significant role, with reserve revisions identified as a persistent risk factor. If reservoir volumes are revised downward, platform-level production profiles may decline, reducing incremental revenue and weakening the capacity to justify compressor CAPEX. Conversely, if reserves are revised upward, compression may unlock previously inaccessible gas, improving economic performance. Deliverability uncertainty especially regarding future pressure decline trajectories adds additional complexity. As the internal document emphasizes, variations in pressure decline rates alter the timing and magnitude of compression-induced uplift, affecting overall project economics.

Liquid loading constitutes another layer of uncertainty. Acceleration of liquid accumulation may increase the need for compression, but may also limit uplift if reservoir energy continues to deteriorate. This duality underlines the importance of integrating uncertainty explicitly into investment decision-making rather than assuming a deterministic environment.

Together, these sensitivity analyses confirm the second research question: uncertainty is not merely an ancillary factor but a defining element that must be actively incorporated into compressor planning.

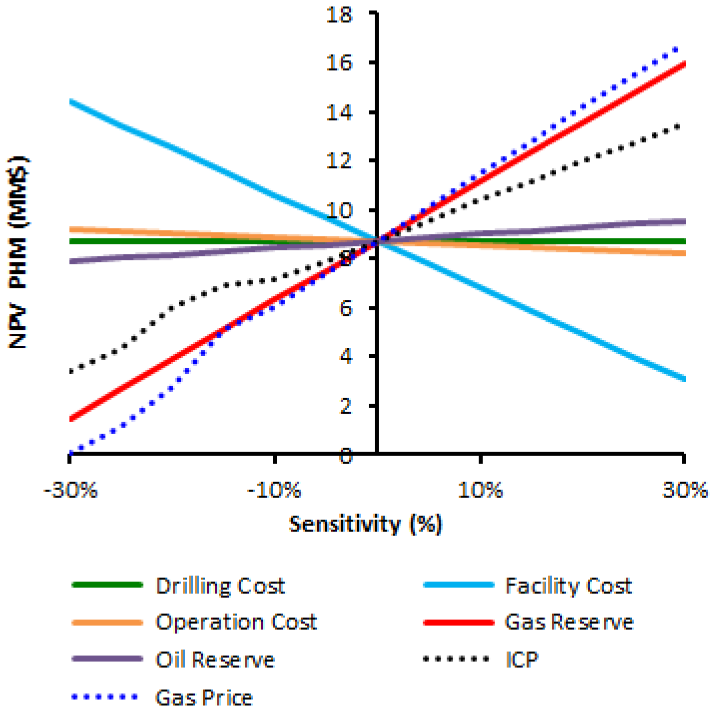

Figure 6. NPV sensitivity of LLP compressor deployment to key economic and technical variables

Real Options Analysis (ROA)

Traditional capital budgeting methods such as Net Present Value (NPV) assume that investment decisions are fixed and irreversible. However, in upstream oil and gas projects, reservoir and market uncertainties often require management to retain flexibility in the timing and execution of capital commitments. To capture this managerial flexibility, Real Options Analysis (ROA) is applied in this study, focusing on Scenario 3 Reutilization Plan, which reflects the possibility of redeploying a Low-Low Pressure (LLP) compressor from an economic platform to a marginal platform (JINTAN) once production performance justifies the investment.

The economic parameters used as the baseline for Real Options Analysis are derived from the Reutilization Plan economic summary for the JINTAN platform. These data quantify the incremental values generated by redeploying an existing compressor compared with the baseline case without reutilization.

Table 5. Economic Summary of Reutilization Plan (JINTAN Platform)

Parameter	Unit	Baseline	Baseline + JINTAN Reutilize LLP	Incremental JINTAN Reutilize LLP
Production Oil + Cond	MBbl	48,871	48,877	6.60
Production Gas	BCF	1,019	1,022	2.58
Sales Gas	$/MMBtu	851	853	2.19
Gross Revenue	MM$	10,506	10,526	19.84
Investment	MM$	2,639	2,650	10.68
Operation Cost	MM$	3,838	3,840	1.67
Cost Recovery	MM$	6,951	6,970	19.00
Unrecovered Cost	MM$	0	0	0
PT HS:				
· Net Cash Flow	MM$	1,246	1,253	7.15
· NPV @ 12.04%	MM$	798	802	4.16
· PI @ 12.04%		-	-	1.65
· dPOT	Year			2.00

In Real Options Analysis, the underlying project value (S_0) is defined as the present value of expected future cash inflows prior to investment execution. Therefore, to represent the gross value of the project opportunity, S_0 is taken as the sum of the baseline NPV and the investment cost:

$$S_0 = NPV + CAPEX = 4.16 + 10.68 = 14.84 \text{ MMUSD}$$

while the exercise price (X) corresponds to the required capital of 10.68 MMUSD. This formulation ensures consistency between the deterministic DCF analysis and the option-based valuation.

The volatility parameter was determined through Monte Carlo simulation based on the project's sensitivity matrix. Each key variable was modeled with a triangular probability distribution within its expected range. For each of 50,000 iterations, random samples of these inputs were drawn, and the corresponding NPV was computed using the response functions derived from the sensitivity analysis.

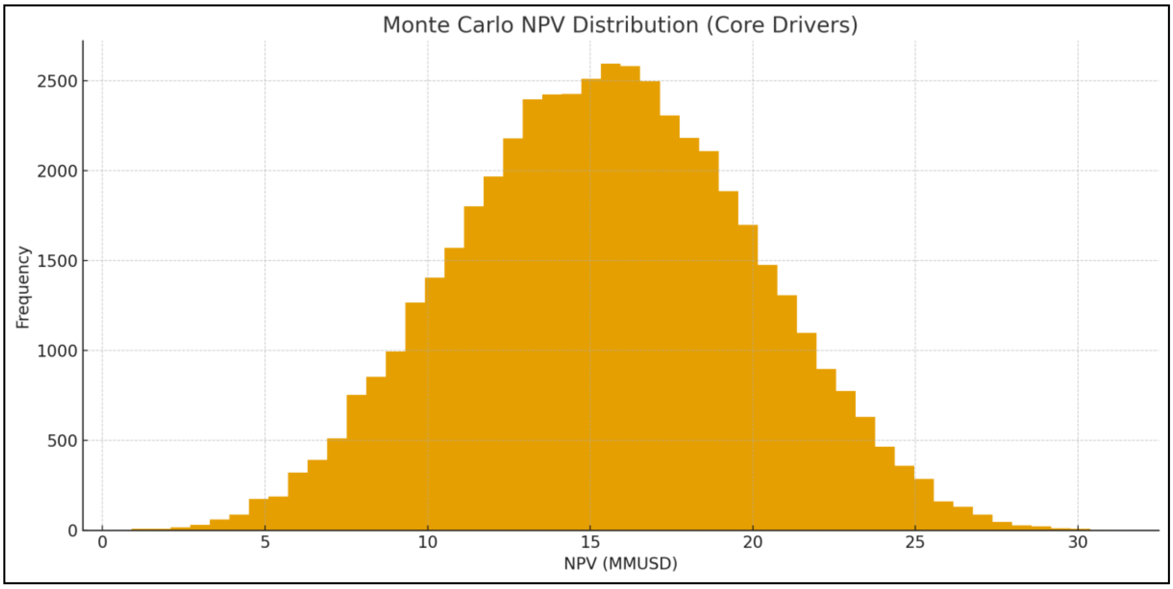

Figure 7. Monte Carlo NPV Distribution Histogram

The simulation results show that σ_total = 4.49 MMUSD, corresponding to a P5–P95 NPV range of 8.08 MMUSD to 22.94 MMUSD. To align with the Real Options Analysis model, the absolute volatility was normalized against the project's underlying value (S_0 = 14.84 MMUSD), yielding a relative volatility of σROA = 30.3%.

The redeployment opportunity is modeled as a call option, giving management the right, but not the obligation, to exercise compressor installation on the JINTAN platform when economic conditions become favorable. The following parameters are applied:

Table 6. ROA Parameter

Parameter	Symbol	Value
Risk-free rate	r	6.73 %, representing the 12-month average of the implied 10-year government bond yield between Aug 2024 and September 2025. Source: Fene-bris Expert Circle on Business Valuation, 2025.
Discount rate / Hurdle rate	k	12.04 % : Adopted from PT Hulu Sungai's corporate hurdle rate, derived from 9.45% sectoral WACC plus 2.59% Specific Project Additional Premium (SPAP) for offshore projects (see Table IV.1).
Volatility	σ	30.3 % : Estimated from Monte Carlo-based sensitivity analysis of key economic variables (production rate, CAPEX, OPEX, and Gas Price). This level of volatility aligns with typical upstream oil & gas project value fluctuations (Mun, 2006; Trigeorgis, 1996).
Underlying project value	S_0	14.84 MMUSD : Derived from the baseline discounted cash flow (DCF) model output (NPV of expected future cash inflows before exercising the LLP option).
Exercise price	X	10.68 MMUSD : Represents total CAPEX required for LLP compressor deployment, based on internal PHM engineering and cost estimation data (2025).
Time horizon	T	3 years : Represents the expected decision window for LLP implementation, consistent with project lead time and evaluation cycle from engineering planning to operational realization (internal project schedule, 2025).

The Bermudan ROA decision tree illustrates the optimal investment strategy for JINTAN compressor redeployment under the flexibility to invest, wait, or abandon at discrete decision points spaced at 6-month intervals over a three-year horizon. Each node represents a potential future state of project value (V) and its corresponding option value (Opt), as calculated through the binomial lattice model.

Color coding and node shapes represent the recommended managerial actions: Green (circle): Invest immediately; Yellow (diamond): Wait for further information; and Red (square): Abandon the project. In the first two years, all nodes fall under the "Wait" region (yellow). This outcome arises not only from market uncertainty but also from operational and physical constraints. During this period, the JINTAN compressor remains in active service at other economic platforms (MADU, CENGKEH, and JAHE) that still require compression support. Even if certain nodes display positive option values, redeployment is technically infeasible before Year 2, making deferral both an operational necessity and an economically prudent choice. Starting from Year 2, redeployment becomes technically feasible.

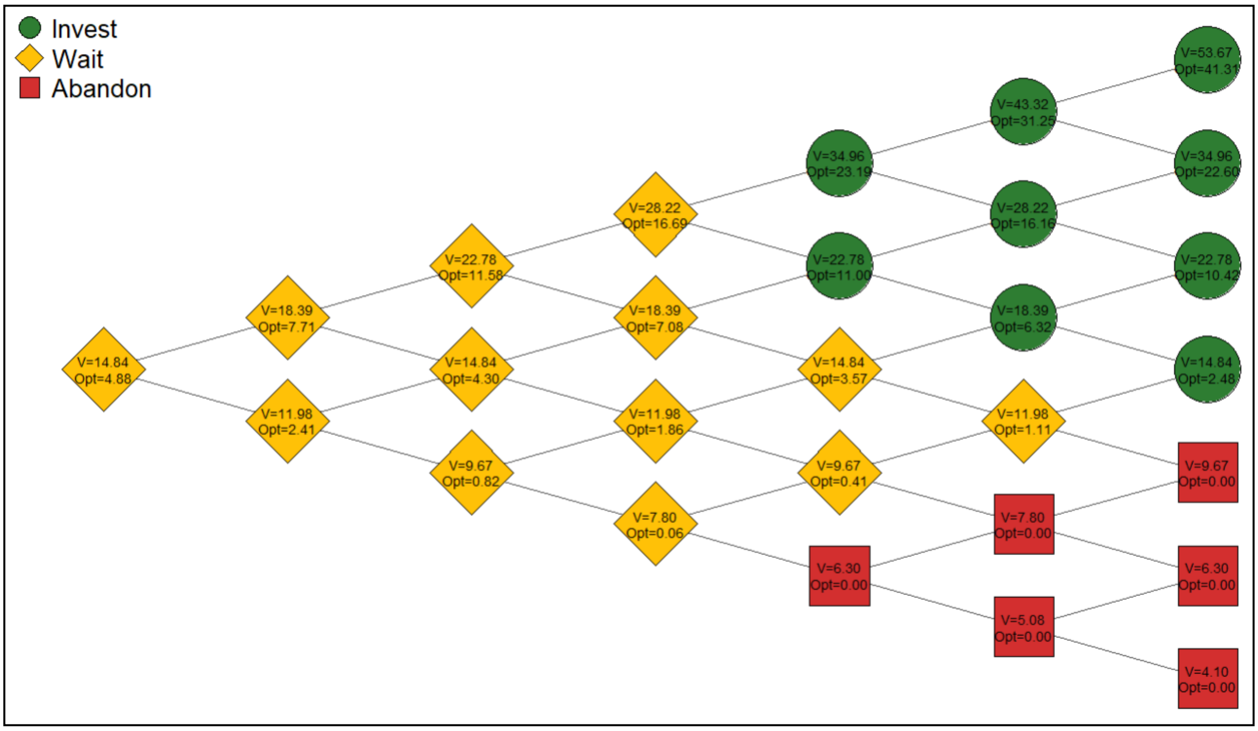

Figure 7. Monte Carlo NPV Distribution Histogram

The decision structure begins to diverge: upward states where reservoir performance or gas prices improve trigger green "Invest" decisions, as both V and Opt surpass the CAPEX threshold of USD 10.68 million. Intermediate states remain "Wait", reflecting the managerial incentive to delay until market and production trends become clearer. Downward branches (low V and Opt) turn red ("Abandon"), as investing under such conditions would generate negative returns and increase sunk-cost risk. By the final step, the upper half of the lattice converges toward "Invest" zones, confirming that redeployment is only optimal when project value rises above approximately USD 14.8 million. This boundary delineates the economic trigger point for compressor movement from existing platforms to JINTAN.

The backward-induction process yields an initial option value (C_0) of USD 4.88 million, representing the premium of managerial flexibility under uncertainty. The total option-adjusted project value therefore equals the deterministic NPV plus this option premium. This result demonstrates that incorporating real-options flexibility transforms an otherwise marginal project into a financially viable investment under uncertainty. The Bermudan approach captures the real-world benefit of timing discretion, allowing PT Hulu Sungai to avoid premature capital deployment during operational overlap, capture upside potential under favorable reservoir or price conditions, and mitigate downside exposure when uncertainty remains high. Integrating operational and physical constraints within the option valuation enhances model realism and ensures that investment-timing recommendations are both economically sound and operationally feasible.

Table 7. Comparison of Economic Results for Each Deployment Scenario

Parameter	Unit	Scenario 0 Base Case	Scenario 1 Full Deployment (4 PF)	Scenario 2 Economic Only (3 PF)	Scenario 3 Reutilization
Net Cash Flow	MMUSD	1,246	1,276	1,274	1,280–1,300
NPV @ 12.04%	MMUSD	798	805	807	805–830
IRR	%	-	18.22	22.30	20–24
PI	Ratio	-	1.11	1.18	1.15–1.22
dPOT	Year	-	5.70	5.12	~5.0
Remarks	-	Baseline without compression	Full installation across all platforms; moderate value addition	Selective investment on 3 economic platforms yields best static return	Flexibility via redeployment improves NPV range and mitigates sunk cost risk

The comparative analysis confirms that selective deployment on three economic platforms (Scenario 2) delivers the highest static economic return, yielding an NPV of USD 807 million and an IRR of 22.3%. When managerial flexibility is incorporated through the reutilization plan (Scenario 3 – ROA), the project's value range improves further to USD 805–830 million, depending on realized reservoir and market conditions. This flexibility provides an additional option premium of approximately USD 3.5 million (as derived from the Bermudan ROA lattice), representing up to an 85% uplift compared with static NPV in the maximum case. The results highlight that integrating operational flexibility with phased procurement enables PT Hulu Sungai to minimize sunk-cost exposure, capture potential upside, and synchronize compressor utilization with actual field performance. The Real Options results provide a quantitative foundation for formulating the business solution. The next section integrates these economic insights with operational feasibility and strategic considerations to define an actionable compressor deployment plan for PT Hulu Sungai.

Operational and Strategic Implications

The implications of these findings extend beyond the economic evaluation and inform operational strategy and procurement governance. Treating compressors as repositionable assets represents a paradigm shift away from static capital deployment. This strategy enhances PT HS's ability to respond adaptively to real-time field conditions, reducing overall capital rigidity. Moreover, integrating compressor procurement with performance-based thresholds aligns investment timing with actual reservoir behavior, ensuring that CAPEX is committed only when sufficiently justified.

The findings also emphasize the importance of adopting a holistic planning framework that integrates technical, economic, and operational perspectives. By embedding uncertainty into the investment decision process and leveraging the managerial flexibility that compressors inherently provide, PT HS can maximize recovery while minimizing financial risk. This strategic posture aligns with national objectives for sustaining production from maturing fields and supports PT HS's broader goals of optimizing late-life asset management.

V. CONCLUSIONS

The evaluation of LLP compressor deployment across the four platforms in the M Block demonstrates that compression is technically necessary but economically viable only when approached selectively and strategically. The analysis confirms that three platforms possess sufficient reservoir potential and incremental production uplift to generate positive economic returns, whereas one platform remains structurally incapable of recovering the required capital investment. Given the substantial CAPEX requirement of approximately USD 16 million per compressor and more than USD 80 million for full deployment, indiscriminate installation would expose PT Hulu Sungai (PT HS) to significant sunk-cost risk.

Sensitivity assessments reinforce the critical influence of gas-price variability and reservoir uncertainty on project feasibility. Platforms with strong baseline performance exhibit resilience under fluctuating conditions, while the marginal platform becomes increasingly uneconomic even under mild downside scenarios. These findings highlight that uncertainty must be treated as a defining element of investment strategy rather than an external constraint.

Scenario analysis further reveals that neither the "no-compression" option nor full deployment provides optimal economic outcomes. Selective installation on the economically strong platforms improves portfolio value; however, the highest risk-adjusted return emerges from a sequential and reutilization-based deployment strategy. Treating compressors as flexible, movable assets enables PT HS to defer investment until justified by field performance, adapt to evolving reservoir behavior, and redeploy equipment to maximize long-term recovery.

In summary, the study concludes that the most effective strategy for PT HS is a phased, flexible procurement and deployment framework that prioritizes economically robust platforms while preserving the ability to respond dynamically to uncertainty and operational change. This approach enhances capital efficiency, strengthens resilience, and maximizes value creation in managing the late-life M Block assets.

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