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-i12-25, Impact Factor: 8.266

Page No. 6788-6799

Economic Feasibility Analysis of Horizontal Well Planning in the Onshore Mahakam Delta, Field A - East Kalimantan

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ABSTRACT: Field A is located in the Onshore Mahakam Delta, Kutei Basin, East Kalimantan where actively producing oil and gas under Sanga Sanga Working Area that operated by PT. X. This field contributes more than half of the company productions by intensive development activities. Regardless the annual production target was achieved, the increment trend was still lower than expected. PT. X recognizes that this condition caused by the reservoir depletion due to drainage from the similar and / or existing area repeatedly by offset well placement concept and limited technology application to have optimal recovery efficiency. By understanding the challenges, PT. X is looking forward into the less drained reservoir and adapting technology advancement which not optimally recovered by conventional drilling and completion method. As a key initiative, PT. X plans to initiate horizontal well drilling through gas reservoir J.01. This reservoir is still not optimally recovered through eight conventional wells by the cumulative gas production of 1.83 Bcf, representing 24% recovery factor. Low-quality of reservoir properties is the main influence factor to the production performances. This research bridges the feasibility with technical and economic evaluations through the implementation of horizontal well in the Field A. It involves subsurface maturation, well planning, and capital budgeting. Subsurface maturation helps to estimate gas volume of the reservoir and understand the production performances. Well planning is guided by the understanding gained from the subsurface maturation, directly influences both capital and operational cost, which limited to determine the length of horizontal section for optimal incremental reserves using sensitivity analysis. The common practice in the PT. X for capital budgeting analysis is limited to Discounted Cash Flow (DCF) method by deterministic approach assisted by sensitivity analysis. This assumes a certain condition, without consider the range of uncertainty as a risk. Uncertainty analysis addresses the limitations of deterministic approach through multiple probability scenarios that influence the results of capital budgeting decisions. It applies a probabilistic approach using monte-carlo simulation to have better understanding through the range of possible results and quantify the probability to meet the objectives. The implementation of horizontal well significantly improving recovery efficiency by 3.59 Bcf gas incremental reserves or equal to 48% recovery factor with 1300 feet horizontal length along reservoir J.01. The integration between deterministic and probabilistic approaches for economic feasibility deal with the limitation of DCF method, providing a more detailed representation of the uncertainties. Based on the deterministic approach, through the base case implementation of horizontal well represents the NPV of 7.66 million USD. According to the probabilistic approach, the P50 value for each incremental reserve cases indicate an uncertainty range between low (1.93 Bcf), base (3.59 Bcf), and high (4.45 Bcf) cases, with the corresponding expected NPV's of 1.57 million USD (low case), 6.74 million USD (base case), and 9.47 million USD).

KEYWORDS: Horizontal, Recovery, Discounted Cash Flow, Sensitivity, and Uncertainty.

I. INTRODUCTION

Over the past few years, PT. X has faced challenges in enhancing oil and gas production in the mature oil and gas field as an operator, regardless by increasing development campaign was performed aggressively. More than half of the development activities and production contributions was driven by Field A, which served as the backbone. However, the production has remained relatively stable with only maintaining natural decline, although has an increment from gas production in the late 2024. After performed comprehensive evaluation, this condition was caused by the reservoir depletion due to drainage from the similar or exisiting area repeatedly as a target (offset well placement) and limited technology application to produce from the low-quality reservoir which not optimally recovered by conventional method. Understanding the challenges, PT. X is shifting their development strategy to produce from the undrained reservoir and / or utilize the advance technology to increase the production, while balancing with the usual approach to maintain natural production decline and production acceleration.

Nearby field development area where previously overlooked, currently considered for the development area with promising undrained reservoir potential. Another initiative is by the implementation of drilling horizontal well as an advanced technology improving the recovery efficiency compared to the typical vertical or deviated wells.

According to the comprehensive evaluation as an effort to improve the production, PT. X plans to initiate horizontal drilling in the Field A by targeting gas reservoir candidate J.01 in 2027. This reservoir is categorized as a low-quality reservoir, which is difficult to produce optimally using conventional drilling and completion method. However, reservoir J.01 has a good potential gas volume and less drained. Refer to Hazman (2008), the productivity of horizontal well expected a promising gain with up to three times recovery efficiency, compared to the conventional method which has produced by 8 wells with only 24% current recovery factor, despite the implementation of fracturing from one well in the late 2024. The promising gain will be the recommendation to be applied for future development program of oil reservoir target.

Oil and gas industry is known as high-risk business due to influence by the uncertainty. This is a dynamic upcoming condition from various variables in a certain period, including technical and business uncertainty that should be considered carefully when making a decision. Understanding the uncertainty is often referred as identifying the potential risks to be managed. It helps company to minimize risks and being flexible through the probabilities, identical with PT. X efforts to remain flexible to prevent the risk of production decline.

The common practice in the PT. X for capital budgeting analysis is limited to discounted cash flow (DCF) method by deterministic approach. This approach assumes a certain condition based on a single calculation, without consider the upcoming uncertainty as a risk. Sensitivity analysis was conducted to correlate the potential impact of various influencing parameters. It is worth to address the limitation in order to have better understanding through the range of uncertainty, in term of investment flexibility. This will be very helpful for the stakeholder including PT. X holding and regulator to determine the final investment decision (FID).

II. DATA COLLECTION

Data was collected through secondary references from PT. X internal document. Data characteristics can be divided based on the meaning into technical subsurface and economic data. In addition, relevant literatures were reviewed for benchmarking the variables, assumptions, forecasts, and case studies. Technical subsurface data is essential for subsurface evaluation / maturation and well planning. The data used includes; Seismic data, well logs, reservoir properties, pressure, post mortem wells, and production data. Economic data such as oil & gas prices, gross split scheme, capital expenditure (CAPEX), operational expenditure (OPEX), and other financial assumptions were also gathered to estimate capital budgeting for the development program investment.

III. METHODOLOGY

This research driven by the focus on the practical implications to the existing challenges in the PT. X. Since the research deals with technical subsurface and economic evaluation, a mixed methods design is chosen for the better understanding of the improvement effectiveness through several analyses which illustrates in the figure 1.

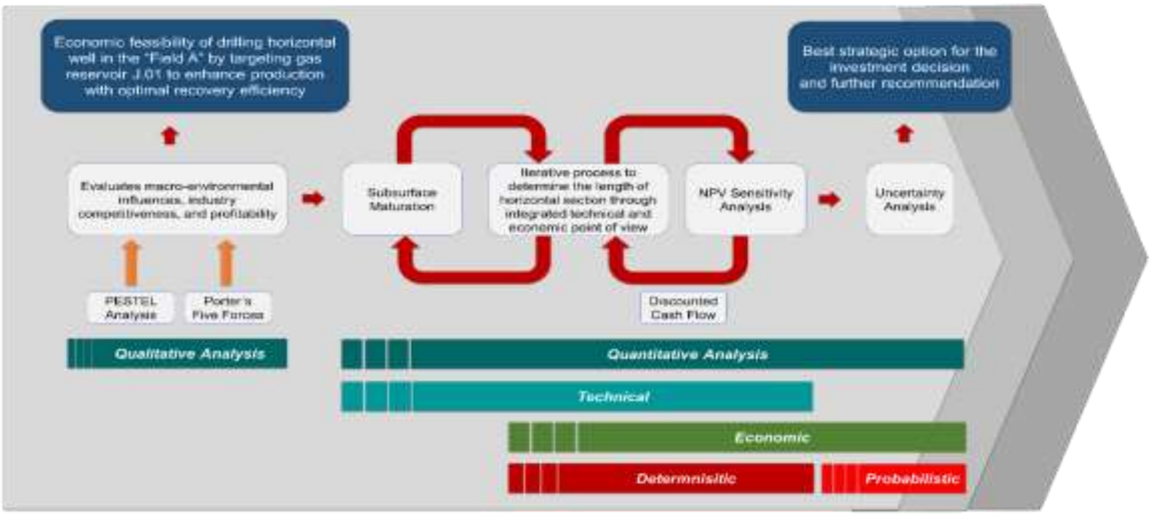

Figure 1. Methodology conceptual framework

1. External environment and competitive analysis

   The framework is related to current global condition of oil and gas industry. For the feasibility, PESTEL (Politic, Economic, Social, Technology, Environment, and Legal) analysis includes a systematic evaluation of macro-environmental circumstances in recognition of the influence of external factors to the optimization development plan for the expected strategic outcomes. A competitive analysis of oil and gas industry, particularly in Indonesia was conducted using Porter's Five Forces to have the awareness of potential profitability related to the project attractiveness.

2. Subsurface maturation

   The scope of subsurface maturation in this research is limited to the development phase of reservoir candidate J.01 in the Field A. Subsurface maturation is a set of integrated analyses which includes detailed subsets such as; geological static modelling and dynamic reservoir engineering simulation. This analysis utilized various quantitative data in estimating gas volume of the reservoir and production history / performance evaluation. This estimation is the foundation for well planning analysis in the context of defining the length of horizontal section

3. Well Planning

   In this part, the analysis leveraging the understanding gained from the subsurface maturation, directly influences both capital and operational cost, which limited to determine the length of horizontal section for optimal incremental reserves (additional recovery efficiency) using sensitivity analysis with reservoir properties and geometries as the parameters.

4. Capital budgeting using Discounted Cash Flow Analysis (DCF)

   This is a common tool used in capital budgeting to evaluate the economic feasibility of oil and gas projects. It calculates the net present value (NPV), internal rate of return (IRR), profitability index (PI), and estimates the payback period. DCF is appreciated for its simplicity, transparency, and compatibility with corporate finance frameworks. However, in the oil and gas field development, which characterized by the uncertainty condition, DCF has significant limitations which assumes certain project condition. The gap lies in its deterministic condition, which assumes constant critical parameters such as incremental reserves, production rates, prices, operational issues, CAPEX, and operational OPEX. In practice, these parameters are subject to significant uncertainty and can shift the realization due to factors such as subsurface complexity, price fluctuations, regulatory changes, and operational risks. Consequently, relying on a deterministic DCF analysis may oversimplify project uncertainties and lead to less accurate economic evaluations. To address these limitations, DCF can be complemented by additional analysis, such as sensitivity and uncertainty analysis through probabilistic approach. These methods provide a more comprehensive view of potential results and enable decision-makers to better assess both project risks and opportunities.

5. Sensitivity Analysis

   This is used to determine how sensitive the expected output of a model from different input parameters. In order to determine the optimal length of horizontal section, each gradual increments in trajectory were evaluated by a deterministic approach comparing the incremental reserves, total costs, and potential profit by NPV. This relationship is illustrated through an impact movement chart. For further analysis, five key parameters were tested, focusing on their influence on the output, especially from an economic perspective. These parameters include incremental reserves, oil prices, gas prices, CAPEX, and OPEX. According to the risk management framework of PT. X's holding company, these five parameters are identified as the main quantitative risks that significantly affect the project. The analysis was tested by applying 20% variation to each parameter individually while keeping the others constant. The results are typically illustrated by a tornado chart, which highlights the relative impact of each parameter on the overall feasibility.

6. Uncertainty Analysis

   The analysis addresses the limitations of deterministic approach through multiple scenarios that influence the results that capital budgeting decisions using discounted cash flow involving with the uncertainties. In the other words, scenario analysis is used as a testing parameter to assess different possible results. Unlike the deterministic evaluation, a probabilistic approach using monte-carlo simulation captures the range of possible results and quantify the probability to meet the objectives. A monte-carlo simulation is a statistic-based behavioral approach that randomly generates values for uncertain parameters over and over to simulate a model (Gitman and Zutter, 2012). Through repeated iterations, the simulation generates a wide range of possible results by a probability distribution. In this research, five key scenarios are evaluated to capture potential variations that could influence the project's performance refer to the incremental reserves. These scenarios include program execution achievement, oil prices, gas prices, CAPEX, and OPEX. Each scenario is designed with three defined conditions (low, base, and high) to represent a realistic range of possible outcomes. These variations are then simulated to analyze how changes in each parameter may affect the overall performance. The results are presented in the form of cumulative probability curves to illustrate the likelihood of achieving specific economic indicators.

IV. RESULTS AND DISCUSSIONS

A. External Environment and Competitive Analysis

PT. X operates in a relatively favorable competitive environment, especially within the domestic oil and gas industry. Threat of new entrants is limited by high capital requirements, regulatory barriers, and influence of owned-state national energy company. These conditions corresponding to industry rivalry. Also, supported by low bargaining power of buyers due to long-term agreement. The considerations are based on the perspective of the bargaining power of suppliers, which is by the limited number of experienced providers, as well as the threat of substitutions by the growing environmental concerns towards cleaner energy utilizations.

B. Subsurface Maturation

The geological static model for reservoir candidate J.01 in the Field A was developed to characterize the subsurface geological conditions in the Sangasanga axis of the Kutei Basin, Mahakam Onshore / Delta Mahakam. Facies associations were identified from core and log data, revealing multistacked channel systems as a product of fluvio-deltaic depositional environment with South East to South paleoflow direction. The result was distributed to represent petrophysical properties, hydrocarbon accumulation, and volume estimation. The hydrocarbon volume was calculated by multiple sensitivity scenarios. These deterministic scenarios representing a separate model based on the variations related to the key influence parameters such as fluid contact, porosity, and water saturation. These sensitivity scenarios served as the basis for the probabilistic approach by monte-carlo which considering the uncertainty condition. The results show that the base case from Initial Gas in Place (IGIP) is 7.498 Bcf (round up to 7.50 Bcf), with an uncertainty range from 6.817 Bcf (P10), 7.504 Bcf (P50), and 8.261 Bcf (P90). IGIP base case volume equals to P49 through the uncertainty distribution. The relatively narrow distribution suggests moderate geological risk and comprehensive data control. Sensitivity analysis highlights that fluid contact has the largest absolute impact on volume, followed by porosity and water saturation.

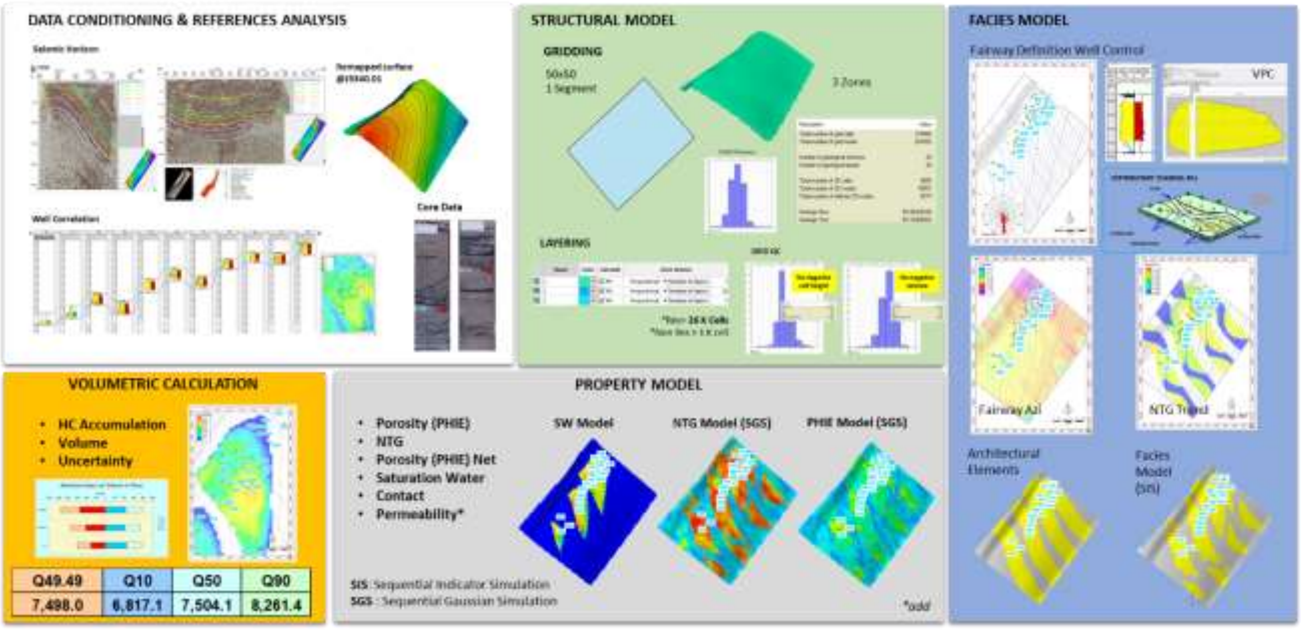

Figure 2. Reservoir J.01 geological static model summary

The dynamic reservoir evaluation was performed refer to production history and material-balance (MBAL) simulations. History-matching cumulative gas production and pressure data provided 7.53 Bcf gas volume (IGIP), which is remarkably close to the static model estimate of 7.498 Bcf, with a difference of only 0.4%. Cumulative gas production to date is approximately 1.83 Bcf, representing 24% of IGIP, leaving about 5.70 Bcf of remaining gas in place (RGIP). The MBAL analysis indicates that gas expansion is the dominant drive mechanism with weak aquifer support.

C. Well Planning

This involves an iterative process to determine the optimal horizontal section length in relation to the estimated incremental reserves. Performance expectations are supported by analogy with horizontal well in the nearby field with the similar reservoir characteristic which drilled by previous operator of PT. X. This analogue well, drilled with lateral length of 800 feet along reservoir J.02, achieved initial stabilized gas rate of 6.44 MMscfd (81% realization) and delivered incremental reserves of 1.6 Bcf, based on

0.2% daily decline rate. The gas reservoir volume is about 38.04 Bcf and has produced until mid-2025 with a cumulative production of 19.62 Bcf, equivalent to 52% recovery factor.

The incremental reserves estimation for the planned horizontal well in the Field A is divided into three cases:

- 1P / Low: The expected unrisked initial rate is multiply by the maximum recovery factor of the analogue well (52%).
- 2P / Base: The expected unrisked initial rate is adjusted to 81% based on the analogue well actual performance, then a decline rate of 0.2% per day is applied.
- 3P / High: The expected unrisked initial rate is directly subjected to a 0.2% decline rate without risk adjustment.

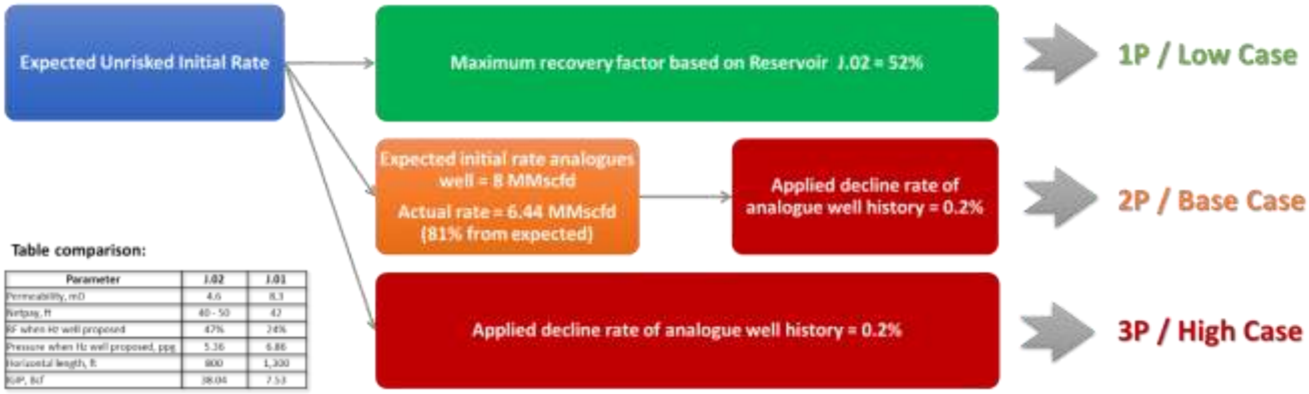

Figure 3. Incremental reserves estimation cases

The base case estimation is used to determine the optimal length of the horizontal well through a sensitivity analysis related to the incremental reserves. The horizontal section length was varied from 800 feet to 1500 feet, with increments of 100 feet. The difference of incremental reserves in this sensitivity analysis are influenced by the anisotropy of reservoir properties with each addition intervals. The sensitivity results indicate the optimal incremental reserves gain is achieved at a horizontal length of 1300 feet. Shorter than 1300 feet generate lower incremental reserves, while longer than 1300 feet suggest less improvement with flatten tendency from 1400 feet to 1500 feet. Therefore, the incremental reserves for the planned horizontal well in Field A, with an optimal length of 1,300 feet, are estimated at 1.93 Bcf (1P / Low), 3.59 Bcf (2P / Base), and 4.45 Bcf (3P / High). 2P / base case estimation equivalent to additional 50% incremental recovery factor (74% final recovery factor) is considered the most likely scenario for planning purposes, balancing with comprehensive technical analysis with further economic feasibility.

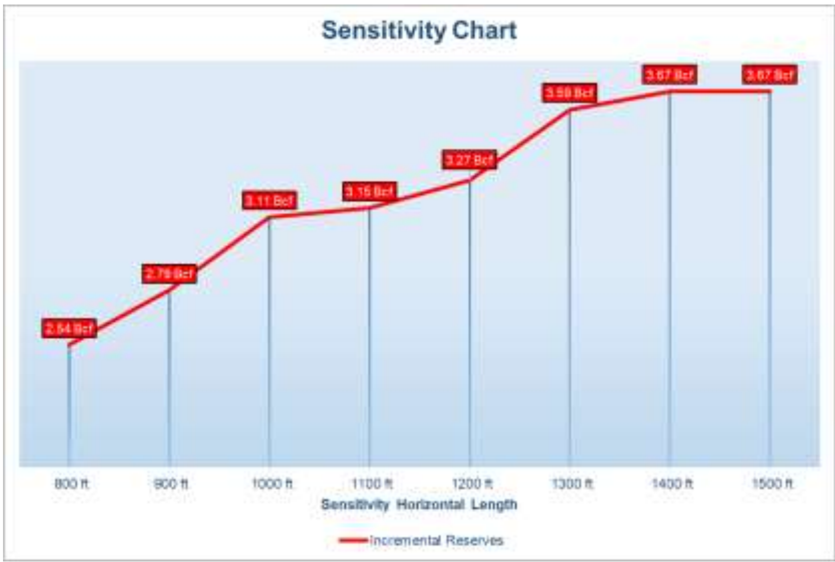

Figure 4. Incremental reserves estimation cases

D. Capital Budgeting Analysis

The capital budgeting analysis was performed to evaluate the economic feasibility of horizontal well various length scenarios. The analysis applied Discounted Cash Flow (DCF) method as a deterministic approach to calculate four key parameters: Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), and Payback Period. Among these parameters, NPV was selected as the primary representative metric for comparison against incremental reserves and total CAPEX, in order to determine the optimal horizontal length. This analysis was strengthened through a broader economic perspective, ensuring that the recommended design not only delivers optimal incremental reserves, but also makes financial sense and supports the project's long-term strategic goals.

Production was allocated to provide a detailed representation at the operated level, including contribution from oil, condensate, and gas (both at well head and inlet). Gas measured at the inlet (85% from well head) represents the portion commercialized through sales, while the remaining from well head is utilized as on-site consumption. This calculation assumes no oil production because the target is gas with condensate.

Table 1. Production allocation percentages

*US$ Million			2025	2026	2027	2028	2029	2030	2031	2032	2033
Days			365	365	365	365	365	365	365	365	365
Operated Level (Include Mahakam PSC)											
MBOE		0.60	0.00	0.00	0.34	0.16	0.08	0.04	0.02	0.01	
Oil, BOPD		0.00									
Cond, BOPD	27		0.00	0.00	139.79	67.26	32.35	15.58	7.50	3.27	
Production after %		100%									
Gas, MMCFD Wellhead	15%	3,592			5.18	2.49	1.20	0.58	0.28	0.12	
Gas, MMCFD Inlet		3,054	0.00	0.00	4.40	2.12	1.02	0.49	0.24	0.10	0.00
Gas, MMCFD Inlet		3,054	0.00	0.00	4.40	2.12	1.02	0.49	0.24	0.10	0.00
Oil, BOPD		0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Yield BRC, BBL/MMCF	5.00	15,268	0.00	0.00	22.00	10.59	5.09	2.45	1.18	0.51	0.00
Yield Associated Gas	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel & Flare											
Cond, BOPD		96,996	0.00	0.00	139.79	67.26	32.35	15.58	7.50	3.27	0.00
BRC, BOPD		15,268	0.00	0.00	22.00	10.59	5.09	2.45	1.18	0.51	0.00
Associated Gas, MMCFD Inlet	0.64	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas, MMCF Inlet		3,054	0.00	0.00	1606.27	772.83	371.74	179.02	86.21	37.52	0.00
Liquid, BBL (incl BRC)		112,264	0.00	0.00	59,053.91	28,412.80	13,667.04	6,581.46	3,169.34	1,379.45	0.00
Gas, MMCF Inlet		3,054	0.00	0.00	1606.27	772.83	371.74	179.02	86.21	37.52	0.00

OPEX refers to the production cost per barrel / equivalent, and abandonment site restoration. Meanwhile CAPEX includes tangible and intangible costs for new wells. The costs were adjusted to 12% Value Added Taxes (VAT) rate and 2% inflation rate, based on PT. X internal documents. Since PT. X operates under the gross split scheme, the contractor required to cover the VAT.

Table 2. Total cost (OPEX and CAPEX)

*US$ Million			2025	2026	2027	2028	2029	2030	2031	2032	2033
Days			365	365	365	365	365	365	365	365	365
OPEX											
Unit Opex, $/BBL			6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Common Opex + Inflation		4.39	0.00	0.00	2.27	1.12	0.55	0.27	0.13	0.06	0.00
Common Opex + Inflation + VAT		4.76	0.00	0.00	2.46	1.21	0.59	0.29	0.14	0.06	0.00
Abandonement Site Restoration (ASR)		0.10			0.10						
CAPEX											
Intangible Capex		5.16			5.16						
Tangible Capex (New Wells)		1.34			1.34						
Tangible Capex (Facilities)		0.00									
Capex without Inflation		100%									
Intangible Capex		5.16	0.00	0.00	5.16	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (New Wells)		1.34	0.00	0.00	1.34	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VAT		12.00%									
Capex without Inflation + VAT											
Intangible Capex		5.78	0.00	0.00	5.78	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (New Wells)		1.50	0.00	0.00	1.50	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VAT		1.15	0.00	0.00	0.97	0.09	0.05	0.02	0.01	0.00	0.00
Total Capex		7.28	0.00	0.00	7.28	0.00	0.00	0.00	0.00	0.00	0.00
Capex with Inflation + VAT											
Intangible Capex		6.02	0.00	0.00	6.02	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (New Wells)		1.56	0.00	0.00	1.56	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inflation Rate		2.00%	0.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17
Total Opex		4.86	0.00	0.00	2.56	1.21	0.59	0.29	0.14	0.06	0.00
Total Capex		7.58	0.00	0.00	7.58	0.00	0.00	0.00	0.00	0.00	0.00

The contractor split defines the percentages of production revenue allocated to the contractor under the PSC gross split scheme. It is derived from base, variable, and progressive split. In addition, PT. X receives a discretion from government as an incentive, with additional 20% split.

Table 3. Contractor split calculation

*US$ Million			2025	2026	2027	2028	2029	2030	2031	2032	2033
Days			365	365	365	365	365	365	365	365	365
Local Gov Interest		10%									
Contractor Split Calculation											
Base Split											
Gas		48%	48%	48%	48%	48%	48%	48%	48%	48%	48%
Oil		43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
Variable Correction Factor		6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
Progressive Correction Factor											
Cum Prod			9.0%	9.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
Gas Price		1.15%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.44%
Oil Price		0.14%	4.1%	4.8%	3.2%	2.7%	2.4%	1.6%	0.9%	0.1%	-0.1%
Gov't Discretion		20.00%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Final Contractor Share											
Gas			83%	83%	82%	82%	82%	82%	82%	82%	82%
Liquid			82%	83%	80%	80%	79%	79%	78%	77%	77%
Prices											
Oil, $/BBL		65.00	68.81	65.66	72.12	74.09	75.44	78.57	81.60	84.46	85.59
BRC, $/BBL		61.10	59.00	56.47	62.02	63.72	64.88	67.57	70.18	72.64	73.61
Gas, $/MMBTU			6.98	7.58	7.67	7.76	7.82	7.79	7.56	7.31	6.82
			0.10	0.12	0.11	0.10	0.10	0.10	0.09	0.09	0.08
Total BOE			0.00	0.00	335,996.41	161,659.05	77,760.73	37,446.21	18,032.48	7,848.60	0.00

The economic calculation for the base case – 1300 feet horizontal length scenario shows promising result based on key indicators such as Net Present Value (NPV), Internal Rate of Return (IRR), Profitability index (PI), and payback period. The cash flow analysis represents a positive value since the beginning year (2027 – payback period), with an NPV of USD 7.66 million. The Internal Rate of Return (IRR) percentage is more than 100%, compared to the hurdle rate of 12.90%. The Profitability Index (PI) value is 2.77, which indicates more than double returns investment.

Table 4. NPV, IRR, PI, and Payback period calculation

*US$ Million			2025	2026	2027	2028	2029	2030	2031	2032	2033
Days			365	365	365	365	365	365	365	365	365
Revenue Distribution											
Gas - Domestic			0%	0%	82%	82%	82%	82%	82%	82%	0%
Gross Revenue		21.18	0.00	0.00	11.08	5.40	2.62	1.25	0.59	0.25	0.00
Net Revenue		21.18	0.00	0.00	11.08	5.40	2.62	1.25	0.59	0.25	0.00
Contractor Share		17.37	0.00	0.00	9.09	4.42	2.15	1.03	0.48	0.20	0.00
Opex		3.61	0.00	0.00	1.90	0.90	0.44	0.22	0.11	0.05	0.00
Intangible Capex		4.46	0.00	0.00	4.46	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (New Wells)		1.16	0.00	0.00	1.16	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation		1.16	0.00	0.00	0.29	0.22	0.16	0.12	0.37	0.00	0.00
Deductible Cost			0.00	0.00	6.65	1.11	0.60	0.34	0.47	0.05	0.00
Liquid			0%	0%	18%	18%	18%	18%	18%	18%	0%
Condensate		7.16	0.00	0.00	3.68	1.82	0.89	0.45	0.22	0.10	0.00
BRC		0.97	0.00	0.00	0.50	0.25	0.12	0.06	0.03	0.01	0.00
Gross Revenue		7.32	0.00	0.00	3.78	1.86	0.91	0.46	0.23	0.10	0.00
Net Revenue		7.32	0.00	0.00	3.78	1.86	0.91	0.46	0.23	0.10	0.00
Contractor Share		5.84	0.00	0.00	3.02	1.48	0.72	0.36	0.18	0.08	0.00
Opex		0.77	0.00	0.00	0.41	0.18	0.09	0.05	0.02	0.01	0.00
Intangible Capex		0.96	0.00	0.00	0.95	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (New Wells)		0.25	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex (Facilities)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation		0.25	0.00	0.00	0.06	0.05	0.03	0.03	0.08	0.00	0.00
Deductible Cost			0.00	0.00	1.43	0.24	0.13	0.07	0.10	0.01	0.00

*US$ Million			2025	2026	2027	2028	2029	2030	2031	2032	2033
Days			365	365	365	365	365	365	365	365	365
Consolidated											
Net Revenue		28.50	0.00	0.00	14.94	7.25	3.53	1.71	0.81	0.35	0.00
Contractor Share		23.21	0.00	0.00	12.10	5.91	2.87	1.39	0.66	0.28	0.00
Opex		4.38	0.00	0.00	2.71	1.09	0.53	0.28	0.13	0.06	0.00
Intangible Capex		5.42	0.00	0.00	5.42	0.00	0.00	0.00	0.00	0.00	0.00
Tangible Capex		1.40	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation		1.40	0.00	0.00	0.35	0.26	0.20	0.15	0.44	0.00	0.00
Deductible Cost		11.19	0.00	0.00	8.07	1.35	0.73	0.41	0.57	0.06	0.00
Taxable Income		12.01	0.00	0.00	4.03	4.56	2.14	0.98	0.09	0.22	0.00
Tax	25%	3.00	0.00	0.00	1.01	1.14	0.53	0.24	0.02	0.05	0.00
Government Take		8.30	0.00	0.00	3.75	2.49	1.19	0.57	0.19	0.12	0.00
Contractor Take		20.20	0.00	0.00	11.18	4.77	2.33	1.14	0.64	0.22	0.00
Cash Cost		11.19	0.00	0.00	9.12	1.09	0.53	0.28	0.13	0.06	0.00
Net Cash Flow		9.01	0.00	0.00	1.97	3.68	1.80	0.86	0.51	0.17	0.00
NPV		7.66									
IRR											
PI		2.27									

Table 4. Economic calculation summary of all horizontal length scenarios

		HZ Length							
Cases / Scenarios	**Unit**	800ft	900ft	1000ft	1100ft	1200ft	1300ft	1400ft	1500ft
Incremental Reserves	**Bcf**	2.54	2.78	3.11	3.15	3.27	3.59	3.67	3.67
Gross Revenue	**$m**	20.15	22.08	24.65	24.97	25.93	28.50	29.14	29.14
Contractor Take after Tax	**$m**	14.73	16.00	17.68	17.90	18.53	20.20	20.63	20.64
OPEX	**$m**	3.47	3.79	4.22	4.27	4.43	4.86	4.97	4.97
CAPEX	**$m**	7.08	7.12	7.16	7.20	7.24	7.28	7.32	7.36
Cash Flow	**$m**	4.98	5.92	7.17	7.31	7.76	9.01	9.30	9.27
NPV	**$m**	4.03	4.88	6.01	6.12	6.53	7.66	7.92	7.89
Payback	**Year**	2028	2027	2027	2027	2027	2027	2027	2027
IRR	**%**	>100%	-	-	-	-	-	-	-
PI		1.69	1.83	2.01	2.03	2.09	2.27	2.30	2.29

The economic calculation for all length scenarios was compared with the incremental reserves, which had been compared through sensitivity analysis and adjusted for the additional CAPEX. The results show a clear pattern, emphasizing the higher incremental reserves generally lead to higher NPV, confirming the previous incremental reserves estimation. Among all determinisitic scenarios, the 1,300 feet scenario represents the most optimal option, providing the best combination of incremental reserves gain and NPV. Shorter lengths generate lower incremental reserves and NPV. Meanwhile, the longer lengths give additional improvement, but not significant. In fact, the 1500 feet length scenario shows a tendency for NPV to decline due to the increasing CAPEX, while incremental reserves remain relatively flat.

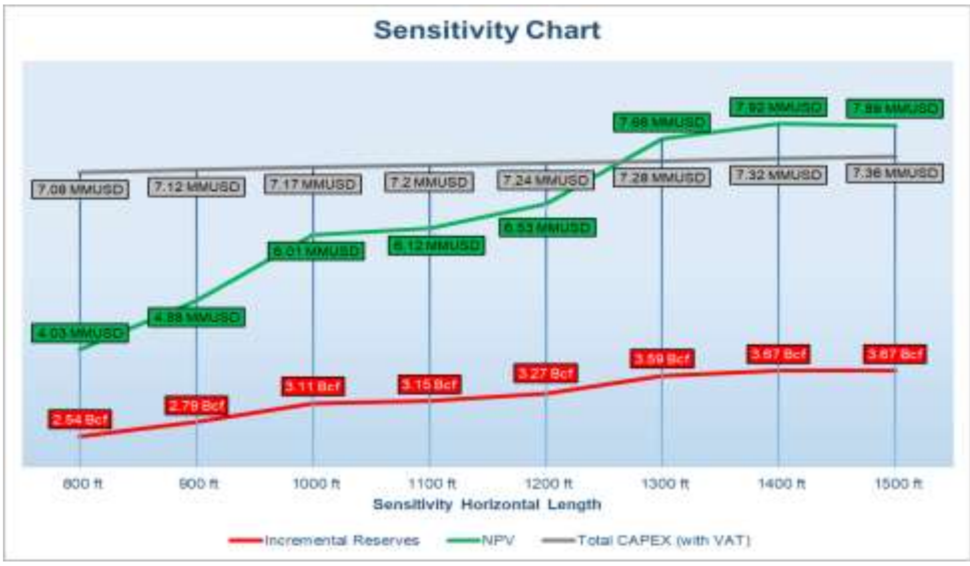

Figure 5. Incremental reserves, NPV, and total CAPEX sensitivity of the various horizontal length scenarios

E. Sensitivity Analysis

Five key parameters were tested against the NPV: incremental reserves, oil price, gas price, CAPEX, and OPEX. These parameters represent quantitative factors (uncertainties) that significantly influence the economic performance of the project at PT. X, serving as key determinants in the evaluation of the development plan under varying conditions (Internal Document of PT. X, 2025). Each parameter was adjusted by ±20% to evaluate the variations would affect the volatility of the NPV. The base case of 1300 feet horizontal length scenario, with an NPV of USD 7.66 million served as the reference point for comparison throughout the analysis.

Table 5. Sensitivity analysis results

Base Case / 2P							
Case / Scenario	Incremental Reserves, Bcf	CAPEX ($m)	OPEX ($m)	NPV ($m)	IRR	PI	Payback Period
1300ft	3.59	7.28	4.86	7.66	~	2.27	2027 / Year 1

Sensitivity				
Parameters	NPV ($m)	IRR	PI	Payback Period
1300ft +20% Oil Prices	8.23	~	2.36	2027 / Year 1
1300ft -20% Oil Prices	7.01	~	2.16	2027 / Year 1
1300ft +20% Gas Prices	10.03	~	2.66	2027 / Year 1
1300ft -20% Gas Prices	5.53	~	1.92	2027 / Year 1
1300ft +20% Reserves	10.24	~	2.70	2027 / Year 1
1300ft -20% Reserves	5.07	~	1.84	2027 / Year 1
1300ft +20% CAPEX	6.62	~	1.91	2027 / Year 1
1300ft -20% CAPEX	8.70	~	2.80	2027 / Year 1
1300ft -20% OPEX	7.08	~	2.17	2027 / Year 1
1300ft -20% CAPEX	8.24	~	2.37	2027 / Year 1

The sensitivity analysis results show how each parameter affects the NPV. Incremental reserves presenting the most influential parameter, highlighting the importance of the estimation accuracy according to the subsurface maturation and well planning. It was followed by gas prices, which is expected since the horizontal well is targeting a gas reservoir. On the other hand, OPEX had the least impact, suggesting that changes in operating costs have only a minor effect on the overall project.

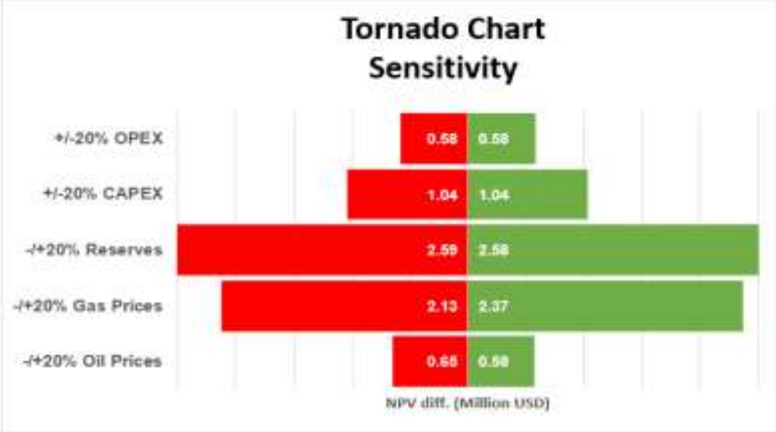

Figure 6. Tornado chart of the NPV's sensitivity analysis results

F. Uncertainty Analysis

Risk emerges as a consequence of uncertainty. In this context, risk can be described as the probability of a discrete event occurring, while uncertainty refers to the range of possible outcomes if the event occurs. The foundation is based on the deterministic evaluation, which consider each incremental reserve cases (1.93 Bcf (1P / Low), 3.59 Bcf (2P / Base), and 4.45 Bcf (3P / High)) through the integration of multiple scenarios associate with both technical and economic parameters. Furthermore, this analysis is using probabilistic approach by monte-carlo simulation to estimate full distribution of probabilistic values, which also represent the confidence levels of the results.

Here five parameter scenarios are presented to capture potential variations that may affect the project performance.

1. Program Execution Achievement: Operational success to achieve expected predetermined horizontal length (Low 800 feet - Base 1300 feet - High 1500 feet).
2. Oil Prices: Reference ICP – Internal document of PT. X holding company memo on July 2025 (Low – Middle – High).

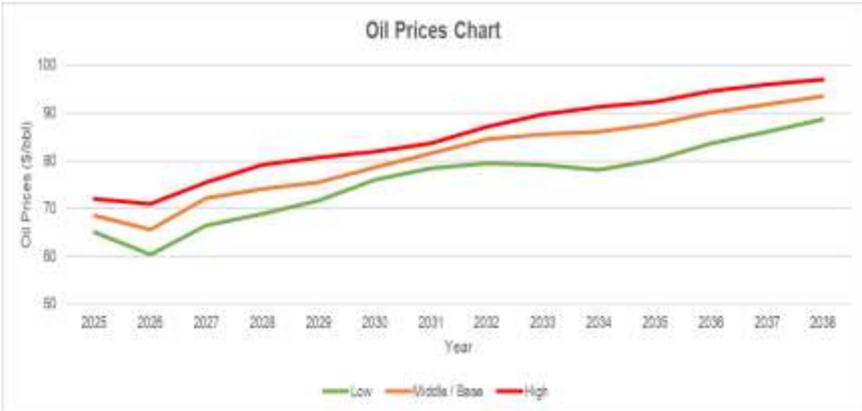

Figure 7. Oil prices chart

(Source: Internal document of PT. X holding company, 2025**)**

3. Gas Prices: Weighted average gas price through reference oil prices from ICP memo (Low - Base – High).

Figure 8. Gas prices chart

(Source: Internal document of PT. X holding company, 2025**)**

4. CAPEX (Capital Expenditure): The range of values refers to the drilling costs of post mortem wells 2024 & 2025. Figure 9 illustrates the comparison between the planned and actual CAPEX based on post mortem well in the Field A during 2024 and 2025. If the actual CAPEX aligns with the plan, the comparison would presents following the orange line. The yellow line, represents the trendline where actual CAPEX is higher than the plan (with a difference ratio approximately of 21%), while the gray line represents the trendline where actual CAPEX is lower than the plan (with a difference ratio of approximately 34%).

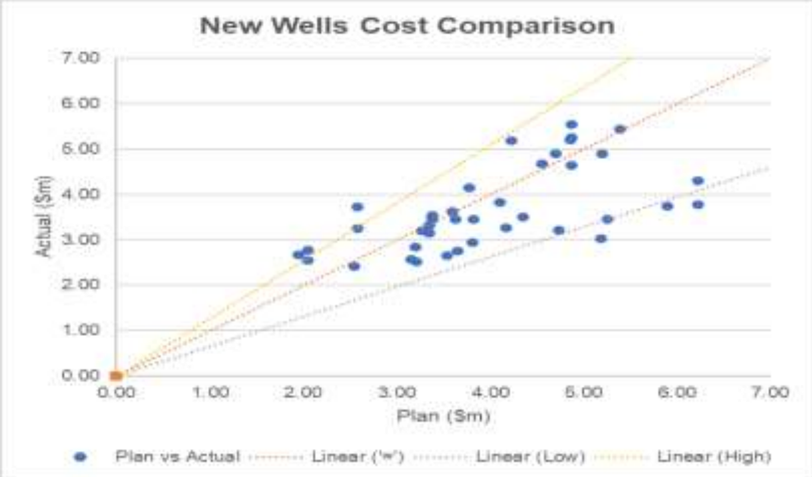

Figure 9. Post mortem of new wells cost comparison
(Source: Internal document of PT. X, 2025**)**

5. OPEX (Operational Expenditure): The range of values refers to the production costs of workover wells 2024 & 2025 in the Field A without optimization / efficiency. Figure 10 illustrates the realization costs where the planned estimation cost is 6.5 USD per barrel represent by orange line. The red line, represents higher realization cost compared to the plan (with a difference ratio approximately of 24%), while the gray line represents lower realization cost compared to the plan (with a difference ratio of approximately 35%).

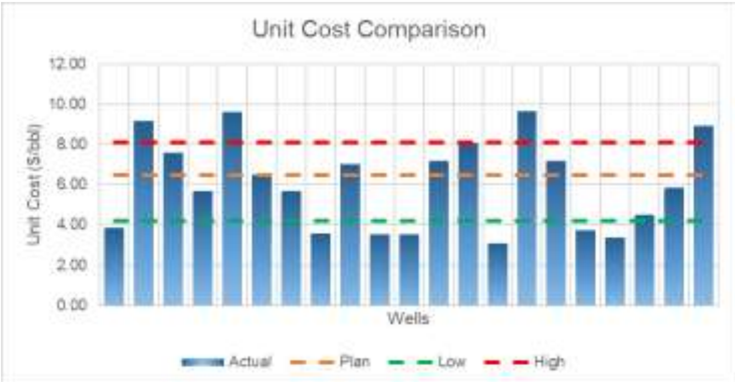

Figure 10. Production unit cost comparison
(Source: Internal document of PT. X, 2025**)**

Based on the probabilistic approach using monte-carlo simulation for each incremental reserves cases, the results show that the deterministic base case value tends to be relatively optimistic. This can be observed from its value within the probability distribution, ranging between Q72/P28 to Q82/P18. This tendency is influenced by the determination of the horizontal section length, where the deterministic approach targets the optimum point of incremental reserves, which is further reinforced by the corresponding NPV. This condition is closely related to the program execution achievement (operational excellence), which emerges as the most sensitive parameter to achieve the expected results. Align with this relationship, longer horizontal sections contribute to higher incremental reserves and NPV until the optimal point, while shorter horizontal sections correspond to lower incremental reserves and NPV. Program execution achievement appears asymmetrical between the downside and upside. This is happened due to the base case used for the horizontal length expected at the optimal point for incremental reserves and NPV of 1,300 feet, with a downside of 800 feet – similar to the length of analog well if the operational program cannot be achieved, while the upside value of 1,500 feet does not provide a significant increment beyond the optimal point.

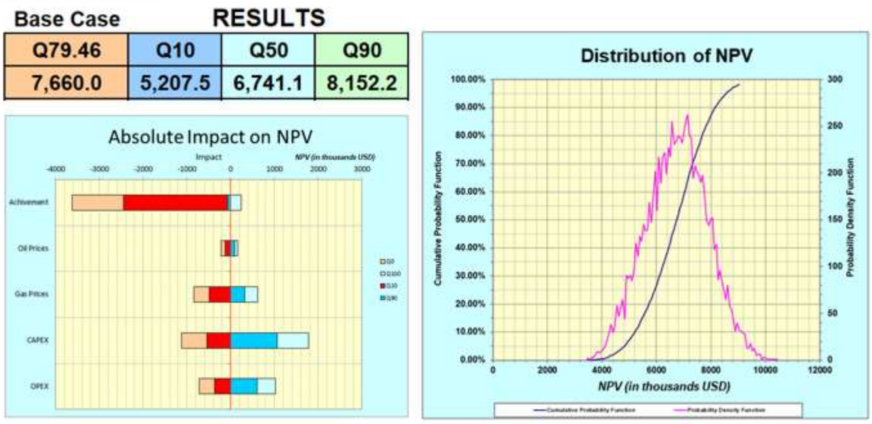

Figure 11. NPV Probability distribution
(reference to base case / 2P incremental reserves)

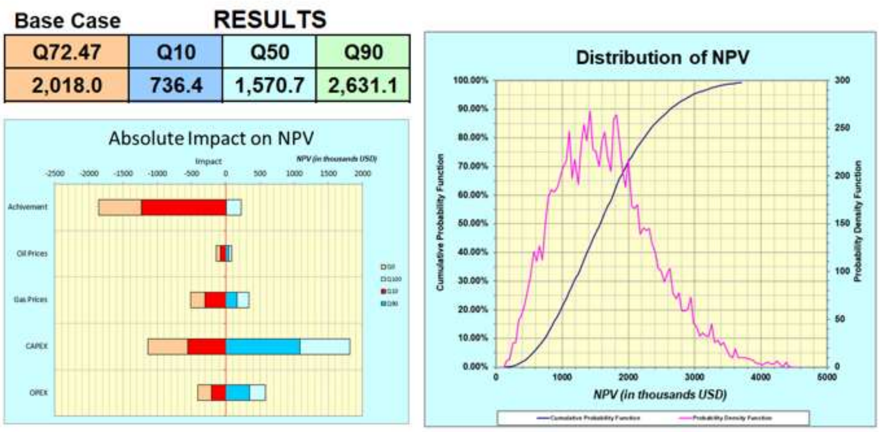

Figure 12. NPV Probability distribution
(reference to base case / 2P incremental reserves)

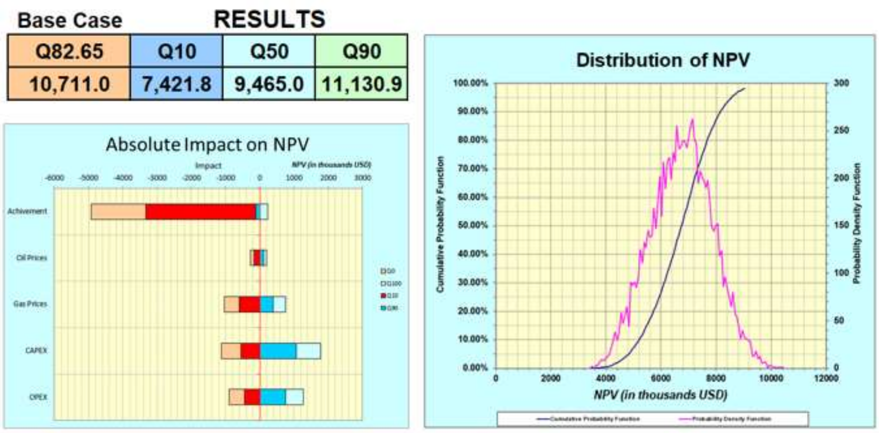

Figure 13. NPV Probability distribution (reference to base case / 2P incremental reserves)

V. CONCLUSIONS

In the conclusion, the implementation of horizontal well method in the Field A by targeting reservoir J.01 represents an effective improvement to enhance recovery efficiency / production in the low-quality reservoir. The results provide 3.59 Bcf gas incremental reserves or equal to 48% recovery factor with optimum horizontal length approximately 1,300 feet (Refer to sensitivity of relationship between length increment to incremental reserves). It is significant improvement compared to the 8 existing conventional wells which only recovered 24% of gas from total volume. The integration between deterministic and probabilistic approaches for economic feasibility address the limitation of single discounted cash flow method, providing a more detailed representation of the uncertainties. Based on the deterministic approach, through the base case implementation of horizontal well represents the NPV of 7.66 million USD. It complies with sensitivity analysis to illustrate potential variations caused by uncertainties in several influencing parameters, including reserves, oil prices, gas prices, CAPEX, and OPEX (following the hierarchy of sensitivity). According to the probabilistic approach, the P50 value for each incremental reserve cases indicate an uncertainty range between low (1.93 Bcf), base (3.59 Bcf), and high (4.45 Bcf) cases, with the corresponding expected NPV's of 1.57 million USD (low case), 6.74 million USD (base case), and 9.47 million USD). Through uncertainty analysis by monte-carlo simulation, this probabilistic approach effectively captured the range of uncertainties through key influence parameters such as program execution achievement, CAPEX, gas prices, OPEX, and oil prices (following the hierarchy of sensitivity). Horizontal well implementation is recommended to adapt for oil reservoir target to enhance overall oil production. It is also worth to try in the nearby field of PT. X working area for further development plan.

ACKNOWLEDGMENT

The author would like to express sincerely thanks to School of Business Management (SBM) Institute of Technology Bandung (ITB) and PT. X for the essential foundations, valuable guidances, constructive discussions, and consistent supports for this research completion.

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