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Capital Budgeting and Risk Analysis for High $C0^2$ Gas Development Using DCF Model and Monte Carlo Simulation

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Abstract:
Gas supplies in West Java are projected to have a shortage starting in 2023. Thus, PT. ABC seeks to increase gas production by re-evaluating marginal fields. One field that has the potential is X Field. However, X Field has a high $C0^2$ content (70%) which makes this development project require a significant investment to separate the $C0^2$ content. Thus, the economics of the project becomes very crucial.
This paper conducts a budgeting analysis to evaluate the economics of the X Field development project. By using the discounted cash flow (DCF) method, the results of this study will assist the company in determining whether X Field is feasible to develop or not. The following approach uses Monte Carlo Simulation to consider all risks in each parameter.
The results of the economic calculations show that X Field is feasible to be developed. The scenario chosen is the No Facility scenario or selling gas directly at the wellhead. The resulting NPV is 2,580 M$ with an IRR of 12.9% and a POT of 5.8 years. The Monte Carlo simulation shows that the project is risky, with a negative NPV probability of 16%. Therefore, setting the lowest gas price at 2.5 $/MMBtu is recommended.

Keywords: *Gas field development, capital budgeting analysis, discounted cash flow, Monte Carlo simulation*

1. Introduction

Natural gas is the third most widely used primary energy in Indonesia after oil and coal. According to BP Statistical World Energy (2021), Indonesia's total primary energy consumption in 2022 is 8.11 Exajoules, and Natural gas contributes 18.5% (Figure 1). This data shows that natural gas has an essential role in the energy mix policy in Indonesia. Moreover, Natural Gas is the most environmentally friendly fossil energy compared to oil and coal, so the use of Natural gas is very relevant to the government's commitment to reducing carbon emissions as part of the implementation of the Paris Agreement, which was ratified in 2016.

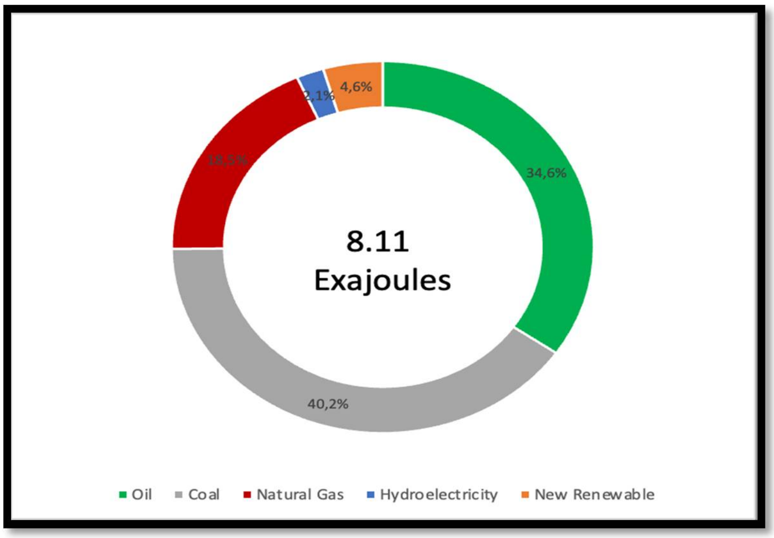

Figure 1: Indonesia Energy Mix 2020
Source: BP World Energy, 2021

In line with the increasing domestic energy consumption, natural gas consumption in Indonesia has continued to increase in the last decade. According to BP Statistical World Energy (2021), as shown in Figure 2, Indonesia's primary energy consumption grew by 26% in the 2011-2019 range, while Natural Gas consumption grew by around 2.6% or about 0.4% per year. The number of gas fields found in Indonesia, such as the Arun Field in Aceh and the Tangguh Field in Papua, and the aggressive government policy in encouraging the provision of reliable gas infrastructure (pipeline/LNG/CNG), play a critical role in stimulating the use of Natural Gas throughout Indonesia, especially for industrial needs, fertilizer and electricity needs.

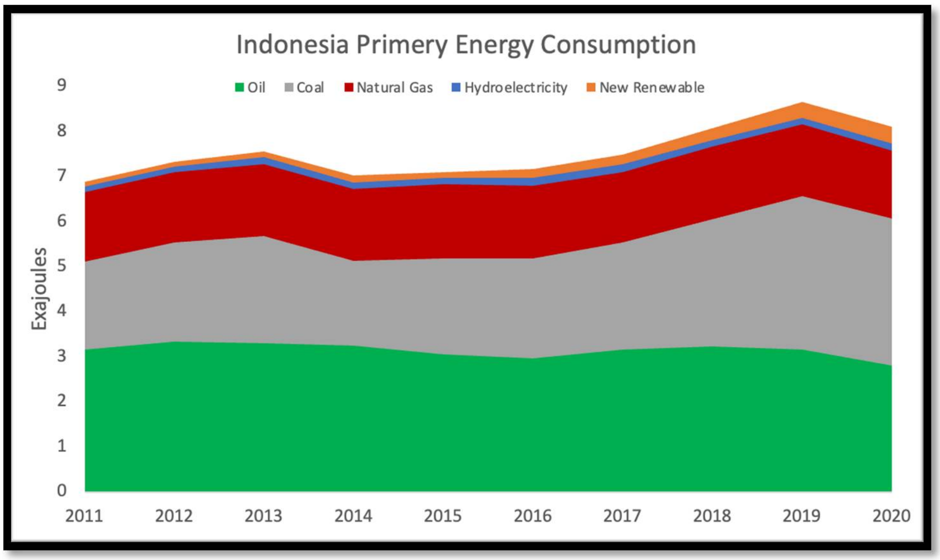

Figure 2: Indonesia's Primary Energy Consumption
Source: BP World Energy, 2021

Unfortunately, the COVID-19 pandemic that emerged in early 2020 contributed significantly to the weakening of the world economy. Indonesia is no exception. During the pandemic, the government imposed restrictions on community activities. As a result, there was a slowdown in the domestic economy. The slowdown in economic activity caused domestic economic growth to contract. Based on the Ministry of Finance (2020) data, Indonesia's economic growth has contracted by -2.07%. This also significantly impacted the energy consumption decline in Indonesia by -6.7% from the previous year. Likewise, Natural Gas consumption decreased by -5.2% (Figure 2).

However, with the increased optimism about Indonesia's economic recovery after the Covid-19 pandemic, energy consumption is estimated to return to normal and continue to grow. A study conducted by the Pertamina Energy Institute (2021) estimates that Indonesia's primary energy consumption will increase by an average of 3% per year from 2020 to 2060 (Figure 3). This growth is caused by population growth and sectoral economic growth, such as the industrial, transportation, and commercial sectors, which are the largest energy consumers, with almost 80% of Indonesia's total primary energy consumption (PEI, 2020).

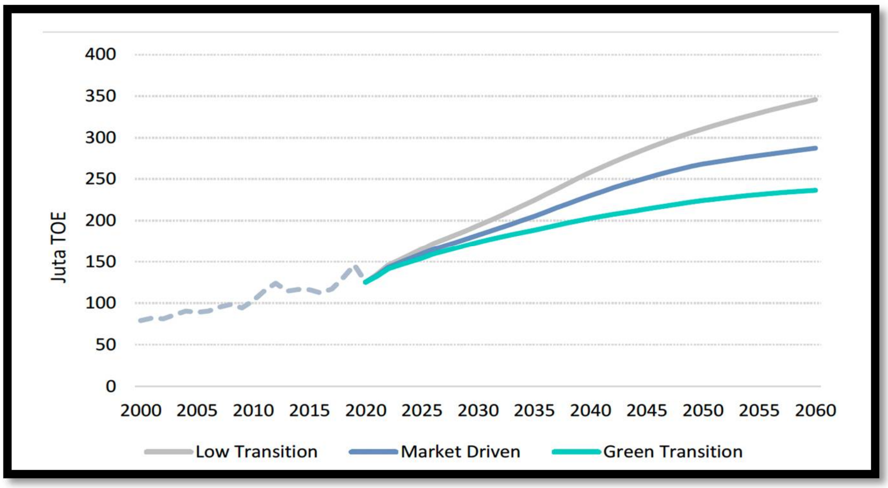

Figure 1: Indonesia Energy Outlook
Source: PEI, 2021

One of the reasons for this consumption growth was the growth in Natural Gas consumption of 6.3% per year (Figure 4). Even with a green transition scenario, a scenario with a Net Zero Emission (NZE) target in 2050, Natural Gas consumption still grows by 1.9% per year. This is in stark contrast to other fossil energy sources. Consumption of coal and oil in the green transition scenario will experience a decline in consumption in 2050. Coal and oil produce more emissions than natural gas. So, it is reasonable that their share must be slowly reduced and replaced with cleaner and lower-emission energy such as natural gas and new renewable energy (wind, solar, biomass, etc.) to meet the NZE in 2050.

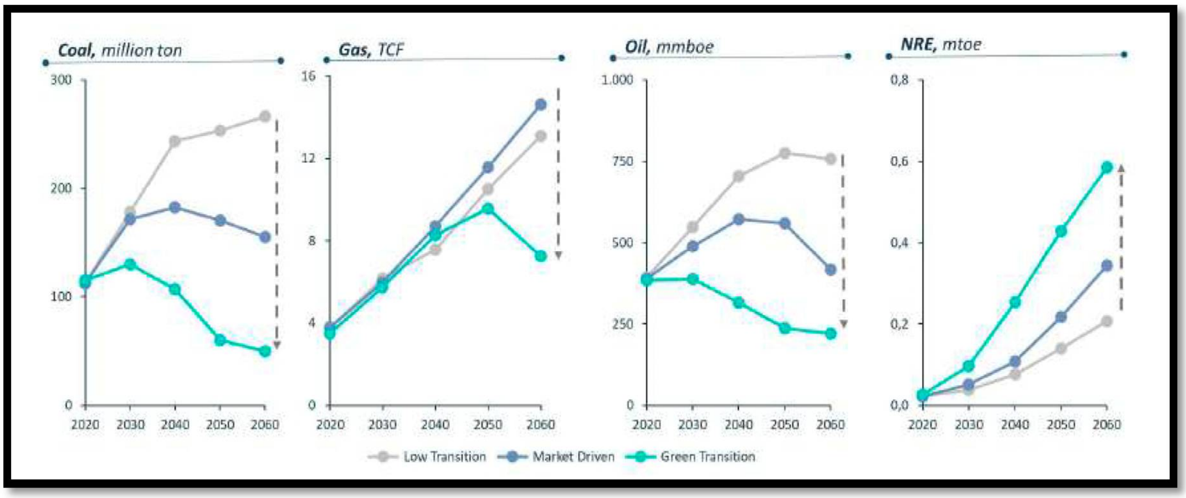

Figure 2: Indonesia Energy Outlook per Source
Source: PEI, 2021

This prediction is undoubtedly good news for companies that manage gas fields in Indonesia. However, on the other hand, the growth in consumption of Natural Gas was not followed by an increase in the number of gas reserves in Indonesia. Indonesia's natural gas reserves continue to decline every year. From Energy & Economic Statistics of Indonesia (2021) data, as shown in Figure 5, Natural Gas reserves in 2020 decreased by 72% from 2010, or 7.2% per year. This condition is undoubtedly quite worrying because it will come to a point where the available reserves are smaller than the required amount of consumption. This will result in a shortage in the country. Currently, a natural gas exporting country, Indonesia inevitably has to import gas to meet domestic energy consumption. Therefore, it is urgent to find and develop new gas fields to cover the gas shortage in the next few years.

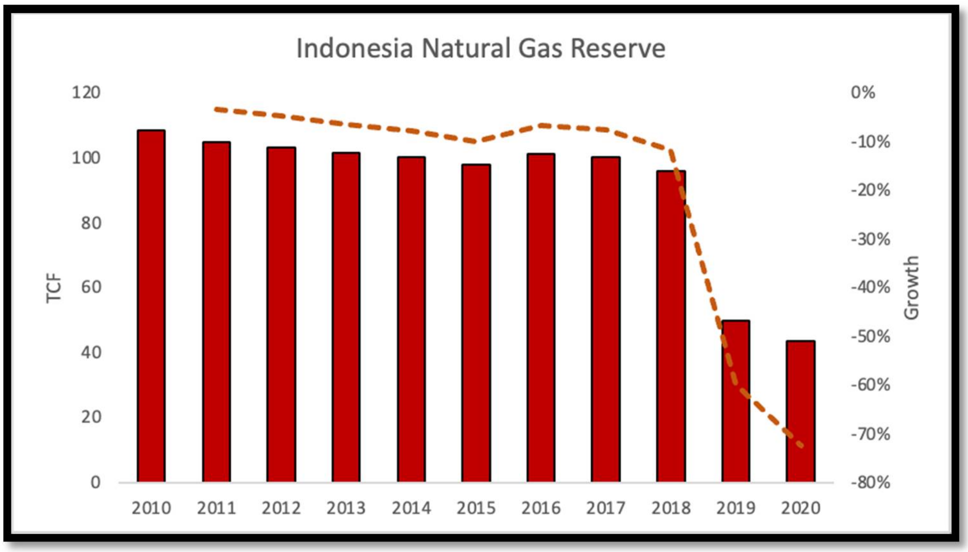

Figure 3: Indonesia Natural Gas Reserve
Source: Energy & Economic Statistic of Indonesia, 2021

In addition, based on gas balance data 2022 from PT. ABC (Figure 6), there is a potential shortage of gas needs in the West Java, Indonesia, area starting in 2023. The production shortage will be even more significant if new consumers start converting their energy consumption from oil and coal to cleaner sources as a source of energy to support the Government's program to reduce carbon emissions. Therefore, an additional gas supply is urgently needed to overcome this situation. To add gas supply and fulfill the commitment to distribute gas to consumers in the West Java area, PT. ABC aggressively seeks to produce and develop new gas fields. These efforts focus on assets that have been proven from exploration activities but have not been commercialized for various reasons, including small reserves, large amounts of impurities, and the lack of adequate infrastructure, with the potential for shortages in the future, PT. ABC re-evaluates these fields. The evaluation integrates subsurface and non-subsurface aspects such as surface facilities, commerciality, and economy. All of this is done to ensure that the field development project positively impacts the company's value.

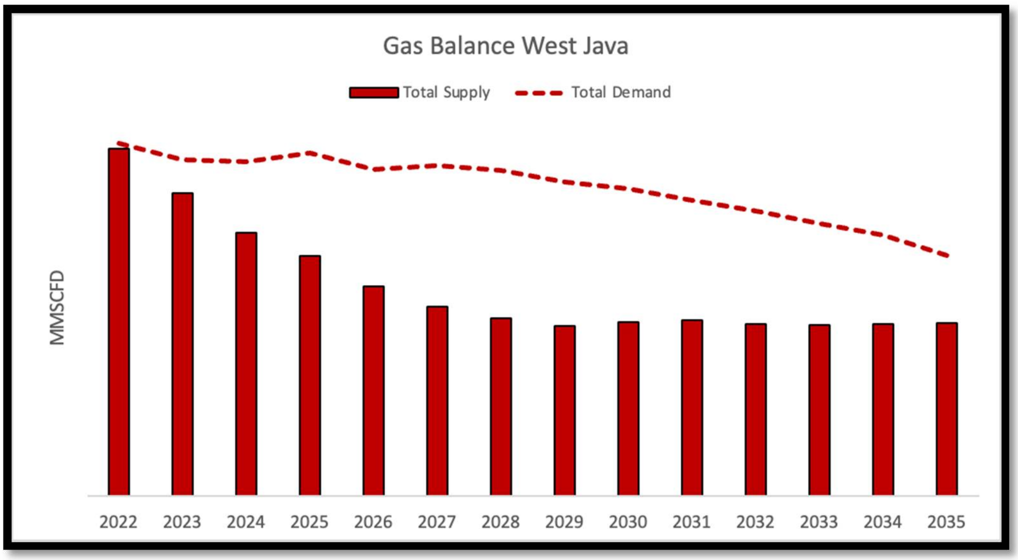

Figure 6: Gas Balance in West Java Area
Source: PT. ABC

One of the gas fields included in the evaluation is X Field. This gas field was discovered in 1982 through the discovery of the X-01 exploration well. From the DST (Drill Stem Test) data, it is known that there is a potential HC from reservoir Y with a production test of 5 million standard cubic feet per day (MMSCFD). However, due to the large number of impurities, namely 70% $C0^2$, this field has not been developed and suspended until now. The X Field has no production facilities, so it needs investment to provide suitable production facilities, especially to separate $C0^2$ from Natural Gas content. The results of the latest subsurface study show that the potential reserves of X Field are pretty large. However, a significant CAPEX is required to drill new wells and provide production facilities to produce optimal gas. Therefore, a comprehensive economic evaluation of this X Field development project is urgently needed to ensure that the field development project positively impacts the company's value.

2. Literature Review

Developing a gas field is a long-term investment that requires a significant investment. This investment is related to the cost of drilling new wells and constructing surface facilities. Because it requires substantial expenses, it is necessary to ensure that the investment has benefits in increasing the company's value in the future. The process of deciding on a long-term investment requires the concept of Capital Budgeting. According to Lawrence J. Gitman and Chad J. Zutter, in their book entitled 'Principles of Managerial Finance', Capital Budgeting is a process of evaluating and selecting long-term investments that can maximize shareholders' wealth (2015: 442).

A long-term project proposal will be accepted if the value exceeds the minimum acceptance criterion set by the company. According to Lawrence J. Gitman and Chad J. Zutter, three parameters are commonly used to evaluate the feasibility of a long-term investment: payback period, NPV, and internal rate of return (2015: 445-456). Each of these parameters has its criteria in the decision process which will usually support each other. However, sometimes, this may not happen. If that happens, the company must decide to prioritize specific parameters in making the final decision.

2.1. Payback Period

The payback period is the time required by the company to return all initial investments in the project (Gitman & Zutter, 2015, p. 445). In simple terms, the project will be accepted if the break-even point is not more than the maximum acceptable payback period the company has set and vice versa. How long the maximum proper payback period will depend on each company's subjectivity and policies.

The payback period approach is straightforward because the basis of the calculation only uses cash flow. Therefore, this approach does not fully describe how much wealth maximization the project can provide, which should be reflected in the discounting cash flow.

2.2. Net Present Value (NPV)

The NPV approach uses the concept of the time value of money. The time value of money refers to the observation that it is better to receive money sooner than later (Gitman & Zutter, 2015, p. 210). The money we have today can be invested to get a positive return to get more money in the future. One dollar today could be worth more than one dollar in the future, depending on how significant the compound interest is. Thus, money today is more valuable than money in the future. Therefore, to assess whether an investment is appropriate, all cash flows generated from the project must be converted at a present value and ensure that the value is greater than the initial investment.

According to Lawrence J. Gitman and Chad J. Zutter, the net present value is found by subtracting a project's initial investment (CF0) from the current value of its cash flows (CFt) discounted at a rate equal to the firm's cost of capital (r) (2015: 449):

NPV = present value of cash flows – Initial investment

$$NPV = \sum_{t=1}^{n} \frac{CFt}{(1+r)^t} - CF0 \qquad (1)$$

The final decision criteria used when using NPV as an indicator of an accepted-rejected project are as follows:
- If NPV>0, then the project is accepted
- If NPV<0, then the project is rejected

2.3. Internal Rate of Return (IRR)

IRR has the same concept as NPV, taking into account the time value of money in evaluating investment feasibility. IRR is the discount rate (r) when NPV = 0 or the present value of cash flow is equal to the initial investment (Gitman & Zutter, 2015, p. 453).

$$\$0 = \sum_{t=1}^{n} \frac{CFt}{(1+IRR)^t} - CF0 \qquad (2)$$

$$\sum_{t=1}^{n} \frac{CFt}{(1+IRR)^t} = CF0 \qquad (3)$$

The final decision criteria used when using IRR as an indicator of an accepted-rejected project are as follows:
- If IRR > cost of capital, the project is accepted
- If IRR < cost of capital, then the project is rejected

3. Methods

3.1. Research Methodology

The research method used in solving the business issues in this final project uses the quantitative approach. The data collected and analyzed are the primary data that came from internal companies that have gone through the internal maturation process. The data are:
- Production forecast,
- Estimated drilling cost,
- Facility construction cost estimate, and
- Operating cost estimate

Then, the data is processed using the discounted cash flow method with PSC cost recovery to get the project's economic value.

3.2. Research Design

Here is the flow of completing the problem of this paper:
- Performing project economic calculations using the discounted cash flow (DCF) method with the PSC Cost Recovery model. Project economic calculations are carried out in various alternative solutions based on the type of operation scheme and the development scenario. This alternative will be compared to select the best scenario that provides the most attractive economy.
- Conduct risk analysis to see economic deviations if there is a change in the assumptions used. Risk analysis in this project is carried out by performing sensitivity analysis and Monte Carlo simulation. Sensitivity analysis is carried out by making changes of +-20% of the assumptions used, namely the price, production, and expenditures variables, to see which variables are the most sensitive to the project's economy. Meanwhile, the Monte Carlo simulation is a statistical approach that applies a probabilistic distribution and a random number to get a risky outcome (Gitman & Zutter, 2015, p. 520). The simulation is carried out with iterations numerous times to obtain economic outcome indicators in the form of a probabilistic distribution.

3.3. Alternative Solution

The alternative solutions combine the operating scheme and the development scenario. The operational scheme consists of its own operation and Partnership. With Partnership scheme allows the company to transfer all risks to third parties. As the field owner, the company will get a production share by the agreement with the Partner, and all costs required will be the Partner's responsibility. Actually, from the company side, the own operation scheme is always the priority for developing the oil/gas field. The partnership option will be chosen if only the economics is marginal. Meanwhile, the development scenario consists of three scenarios: Build, Rent, and No Facility.
- Build. Build permanent production facilities. This scenario requires a significant investment at the project's beginning and annual operating costs for maintenance and operations.

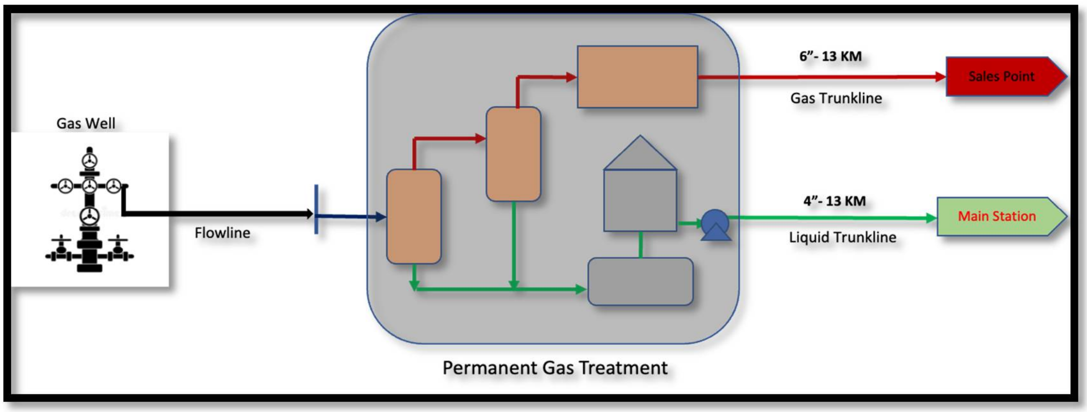

Figure 7: Flow Diagram for Build Scenario

- Rent: Rent gas treatment facilities from the beginning of the project to the PSC End. This scenario does not require investment costs to build gas treatment facilities, only the annual rental fee, which includes maintenance and operational costs. However, investment is still needed to make a flowline from the well to the temporary gas treatment and trunkline from these facilities to the sales point and central gathering station.

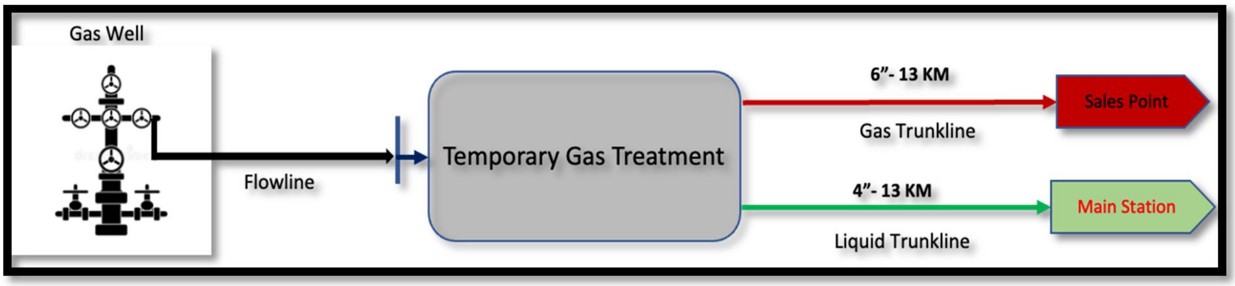

Figure 8: Flow Diagram for Rent Scenario

- No Facility: Sell gas at the wellhead, so the buyer directly bears the production facilities. The company has no expenditure on production facilities except for the flowline. Instead, the company sells gas much lower than the current price, and the buyer has a higher bargaining position during the negotiation process.

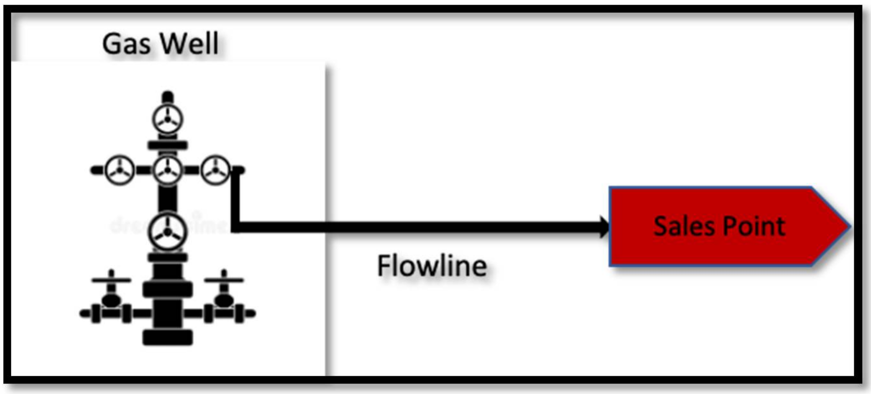

Figure 9: Flow Diagram for No Facility Scenario

3.4. Data Preparation

The subsurface study was conducted internally and has resulted in a work plan that will be applied in the X field. The work plan that is prepared is an effort that will be carried out to optimize the gas potential in the X field. Through work over 1 (one) well and infill drilling 3 (three) wells in 2025, it is projected that the development of X field will produce a gas volume of approximately 45 billion standard cubic feet of gas (gross) and 242 thousand barrels of condensate up to PSC End.

Activities	Scenario			Note
	Build	Rent	No	
Work Over	Y	Y	Y	1 well
Infill Drilling	Y	Y	Y	3 wells
Production Facility				
a. FEED	Y	Y	-	Front End Engineering Design
b. Flowline	Y	Y	Y	Flowline from well to gathering station
c. Trunkline gas	Y	Y	-	Gas line from gathering station to the sales network
d. Trunkline liquid	Y	Y	-	Liquid line from gathering station to main station
e. Gas treatment	Y	-	-	Facilities to separate gas from liquid and $C0^2$
f. Land acquisition	Y	Y	-	Land for gas treatment
TOTAL (M$)	62.988	33.154	25.343	

Table 1: Capital Expenditure (CAPEX) Estimation

All costs incurred in the X field development plan are divided into capital expenditure (CAPEX) and operational expenditure (OPEX). Cost estimates are made using reference prices from several existing contracts PT. ABC has with service companies or suppliers. In addition, it also uses actual costs on similar items issued in the previous year and escalated in the year of project execution. Capital Expenditure (CAPEX) consists of work over costs, infill drilling costs, and construction of production facilities. The drilling cost will apply in all scenarios, while the CAPEX for surface facilities will be different for any scenario. CAPEX for each scenario can be seen in table 1. The Operational Expenditure (OPEX) is a routine cost incurred to support operational activities. The expenses charged to this project are incremental OPEX. It means that the costs are only additional costs arising from this X field development activity, consisting of well-intervention, workforce, O&M, Abandonment & Site Restoration (ASR), variable cost, and Rent cost for the Rent scenario. OPEX for each scenario can be seen in table 2.

Items	Scenario		
	Build	Rent	No
Well Intervention	Y	Y	Y
Manpower	Y	Y	Y
O&M $C0^2$ Removal	Y	-	-
Maintenance	Y	-	-
Abandonment & restoration	Y	Y	Y
Variable Cost	Y	Y	Y
Rent facilities	Y	Y	-
TOTAL (M$)	25.886	67.604	8.170

Table 2: Operational Expenditure (OPEX) Estimation

3.5. Economic Parameters

The economic parameters used in the calculation can be seen in the table below. The parameter's value is officially used in the company. Actually, the gas prices depend on the results of negotiations with the buyer, so this variable is slightly controllable. Therefore, the gas price could be a variable for economic optimization.

Parameter	Unit	Value
Oil price	$/bbl	75
Gas price (net)	$/mmbtu	6
Gas price (gross)	$/mmbtu	2
Cost of capital	%	9.28

Table 3: Economics Parameters

4. Result and Discussion

4.1. Economic Calculation Result

The table below shows the result of economics calculation using the DCF model with a fiscal regime of PSC Cost Recovery.

Operation Scheme	NPV M$			IRR %		
	Build Facility	Rent Facility	No Facility	Build Facility	Rent Facility	No Facility
Own Operation	(4.191)	829	2.580	6,9%	10,2%	12,9%
Partnership	6.139	5.047	4.190	-	-	-

Table 4: Economics Calculation Results

From the table, it can be seen that the Partnership scenario provides the largest NPV for PT. ABC. However, this scenario is not the priority to be applied because the Own operation scenario with Cost Recovery still provides a positive NPV, namely the 'No Facility' scenario with an NPV of 2,580 M$ and an IRR of 12.9%. In addition, the Partnership scenario is very detrimental from the Partner's side with a negative NPV. The Partners get a positive NPV if they reduce the estimated expenditure by around 20%-40%. However, the Partnership scheme can still be the second option to be considered.

Generally, in the Partnership/Joint Operation (JO) process, potential partners will submit a proposal for a field development plan complete with an economic analysis. The economics calculations carried out by the Partner may be better than the calculations from PT. ABC. It can happen because Partners usually have different references in estimating costs. Hence, the estimated costs may be far below the estimated costs from PT. ABC. Therefore, it could be that a project with a marginal NPV becomes more attractive if it is calculated from the Partner's perspective so that the partnership scheme becomes the main option to develop economically marginal fields. However, as long as the economics with own operations is still very attractive/excellent, PT. ABC will prioritize its own operation instead of collaborating with third parties unless there are other compelling reasons beyond the economic analysis.

Here are the Pros and Cons of the selected alternative solutions:

Scenario	Pros	Cons
First Priority Own Operation, PSC CR, No Facility	• Positive NPV • PT. ABC has the flexibility to optimize the production • PT. ABC has the opportunity to get more than estimated (subsurface uncertainty) • Risk is shared between PT. ABC and the buyer	• The project's on-stream will be highly dependent on the buyer, so it has the potential to be delayed. • NPV is not very excellent • Gas price is low
Second Priority Partnership, PSC CR, No Facility	• Positive NPV and greater than Own operation scenario • PT. ABC does not incur any costs, so the Partner bears all risks • PT. ABC can be focused on developing the backbone field	• PT. ABC cannot optimize assets. It all depends on the Partner • PT. ABC lost the opportunity to earn more than estimated • There are potential conflicts regarding data accuracy

Table 5: Pros and Cons of the Scenario Alternative

4.2. Risk Analysis

In capital budgeting, the term risk means all the uncertainties that affect the project in generating cash flow, creating a degree of cash flow variability. The greater the degree of variability, the riskier the project will be, and vice versa (Gitman & Zutter, 2015, p. 518). The oil and gas business is a high-risk business because it deals with subsurface behavior with much uncertainty. Therefore, a comprehensive risk analysis must be included in the economic analysis of this project to ensure that all possible uncertainties have been accommodated in the NPV calculation.

The scenario that the Risk Analysis will carry out is the scenario that becomes the priority: the Own operation scenario with a fiscal term of Cost Recovery that provides the best NPV: the 'No Facility' scenario.

4.3. Sensitivity Analysis

Sensitivity analysis in this paper is done by changing the variable's value by -20% and +20% from the initial assumption. Variables carried out by sensitivity analysis are oil & gas price, production profile, and expenditure (CAPEX & OPEX). Spider diagrams and torpedo charts illustrate the sensitivity profile. The figures below show the sensitivity analysis results for the company's NPV. The spider chart below shows that changes in gas price and production of -20% from the initial assumption resulted in a negative NPV for the company. Likewise, a change in CAPEX of +20% makes the NPV negative. Meanwhile, changes in oil price and OPEX of +-20% did not significantly change the NPV of the project. Even the NPV of the project is still positive even though the parameter has changed dramatically.

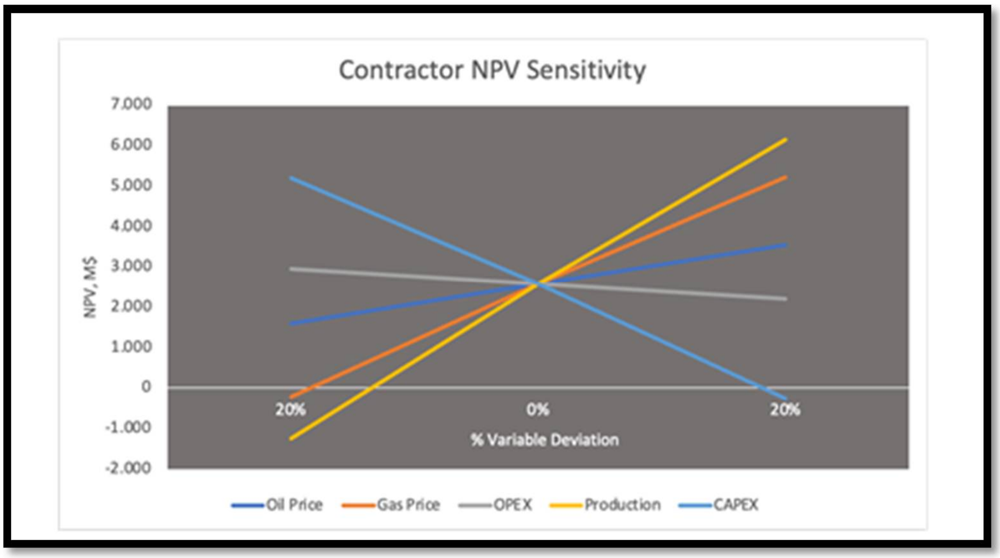

Figure 10: Company's NPV Spider Diagram

The Tornado chart shows that the most sensitive variables to the company's NPV are gas price, production, and CAPEX. Changes in gas prices by -20% and 20% resulted in changes in the company's NPV of -108% and 102%, respectively. Changes in production of -20% and 20% resulted in changes in NPV of -148% and 138%, respectively. Meanwhile, changes in CAPEX of -20% and 20% resulted in changes in the company's NPV of -102% and 110%, respectively. However, changes in oil price and OPEX are not very sensitive to NPV. Changes of -20% and 20% in oil price and OPEX only result in changes in NPV of +-38% and +-14%, respectively. The condensate production is a side product whose volume is much smaller than gas as the main product, so oil revenue changes are not too sensitive to project cash flow. Meanwhile, the OPEX required in the 'No facility' scenario is the lowest compared to other alternatives, so the impact of the changes is not too significant on the company's NPV.

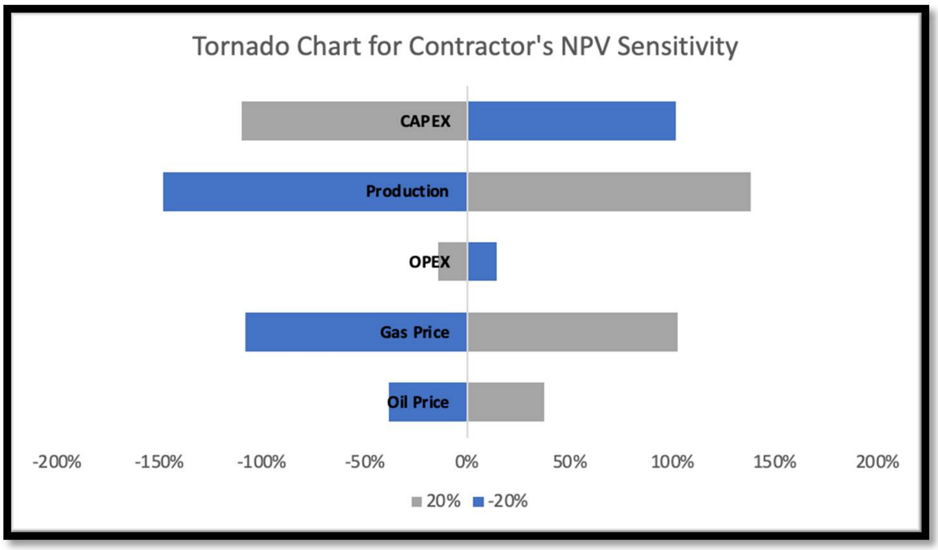

Figure 11: Company's NPV Tornado Chart

In addition, the on-stream project time also dramatically influences the NPV calculation. The project's economy is calculated only until the PSC End in 2035. So, with the on-stream project delay, the reserves that will be obtained will decrease, ultimately reducing revenue. The 'No Facility' scenario has the potential to experience project delays because the construction of surface facilities is the responsibility of the buyer. This factor is not fully controllable for the company. So it becomes very risky for delays.

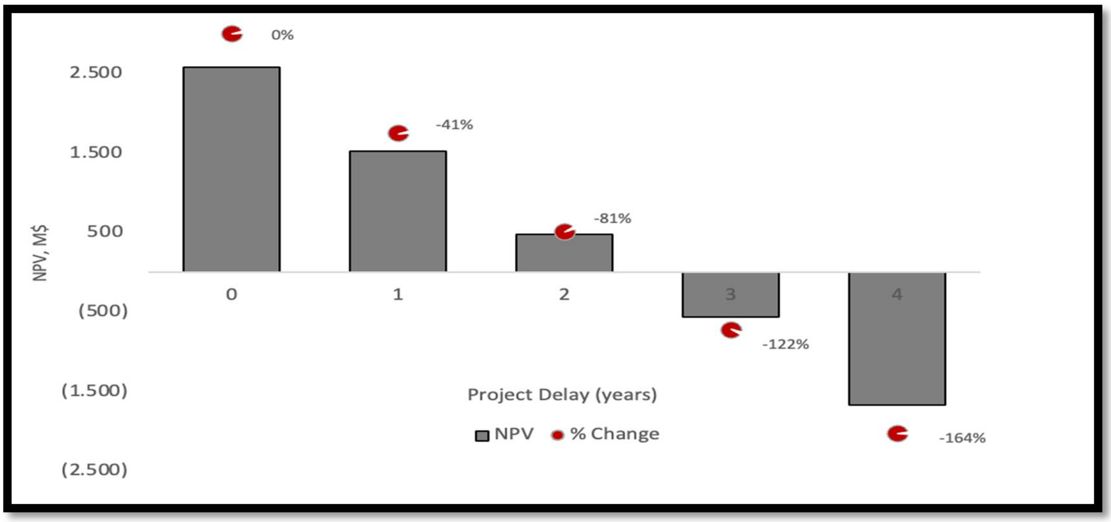

Figure 12: Company's NPV Change with Project Delay

Figure 12 above shows that for every one-year project delay from the initial plan in 2025, the company's NPV will decrease by 41% from the initial NPV. Moreover, if the delay is more than two years, the NPV becomes negative. So, it is essential to ensure that the project can be on-stream on time or that the maximum delay does not exceed 2 (two) years.

4.4. Monte Carlo Simulation

The Monte Carlo simulation includes:

- A probabilistic distribution and
- A random number of each uncertainty to produce a probabilistic distribution of NPV

Uncertainty in each parameter is reflected in the estimated low, best, and high case values, as shown in the table below.

Parameter Uncertainty	Unit	Low	Best	High	Standard Deviation
Gas Production/Year	MMSCF	3.929	4.136	4.715	407
Condensate Production/Year	MSTB	21	22	25	2
Avg. Gas Price	$/MMBTU	2,0	2,0	3,5	0,9
Avg. Oil Price	$/BBL	61	75	92	15
CAPEX	M$	30.412	25.343	22.809	3.871
OPEX/Year	M$	720	654	589	65

Table 6: Parameters Uncertainty

The low case is a pessimistic estimate that produces the smallest NPV, and the high case is the most optimistic estimate that has the largest NPV. At the same time, the best case is an average estimate that produces an average NPV. The gas and condensate productions are subsurface uncertainties generated using software that includes:

- Uncertainties on reservoir volume,
- Reservoir properties, and
- Drive mechanisms that allow fluid to flow from the reservoir to the surface

The low, best, and high estimates of the oil price are measured using data from PT. ABC. The gas price will depend on the negotiation during the formulation of the Gas Sale and Purchase Agreement (GSA). In this case, the minimum gas price that must be set is 2$/MMBTU because the NPV becomes very unattractive if it is less than that. The CAPEX estimation has gone through the FEED (Front End Engineering Design) mechanism, so the deviation will only be around +-10% from the initial estimate.

Parameters	Unit	NPV
Mean	M$	2.575
Standard deviasi	M$	2.657
Min	M$	(8.060)
Max	M$	11.006
P10	M$	(805)
P50	M$	2.573
P90	M$	5.933
Risk of Loss of Value		16%

Table 7: Monte Carlo Simulation Result

The Monte Carlo simulation was carried out using Microsoft Excel with 2000 iterations. The simulation results can be seen in the table and graph below. The average NPV obtained is 2,575 M$, the lowest NPV is -8,060 M$, and the highest NPV is 11,006 M$. Even though the average NPV is positive, it is still possible to get a negative NPV with a probability of 16%. Moreover, the NPV of P10 (Low case) is also negative, with a value of -805 M$. So, this project can be categorized as a medium-high risk due to the negative NPV of P10 (Low case), and the probability of getting the negative NPV is higher than 10%. Therefore, mitigation is needed by optimizing certain variables so that the results of the probabilistic simulation are better than before and the project risk can be reduced to low risk.

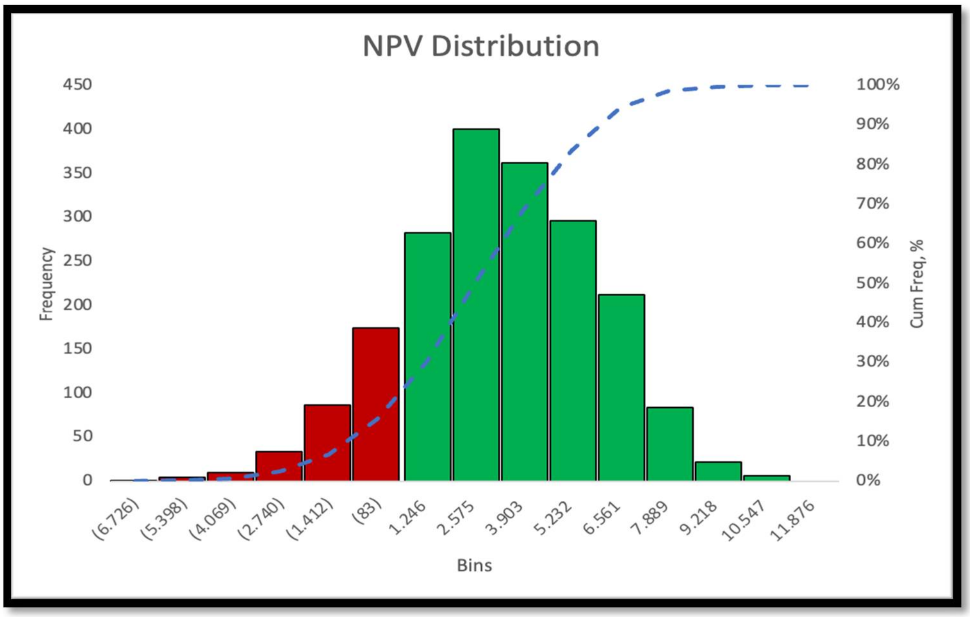

Figure 13: Company's NPV Distribution

The sensitivity analysis shows that production, CAPEX, and gas price are the most sensitive variables. Of the three variables, only gas price is relatively controllable (not fully controlled) because it can be negotiated in the Gas Sales Agreement (GSA) process. Meanwhile, variable production and CAPEX cannot be controlled because production is a subsurface product with high uncertainty, and CAPEX highly depends on market conditions influenced by supply and demand. Therefore, the gas price can be optimized to get a better economic outcome.

From the Monte Carlo simulation with 2000 iterations, a change in the minimum gas price of 0.5$/MMBtu, from 2$/MMBtu to 2.5$/MMBtu, results in an excellent NPV distribution. The average NPV obtained is 6,030 M$ with the lowest NPV of -618 M$ and the highest NPV of 11,962 M$. The possibility of a negative NPV is 0%, with P10 (Lowercase) obtained at 3,445 M$. The NPV of P10 (Lowercase) is 34% higher than the average NPV (Best case) when using a minimum gas price of 2$/MMBtu.

Parameters	Unit	NPV
Mean	M$	6.039
Standard deviasi	M$	2.015
Min	M$	(618)
Max	M$	11.962
P10	M$	3.448
P50	M$	6.120
P90	M$	8.540
Risk of Loss of Value		0%

Table 8: Monte Carlo Simulation Result after Optimization

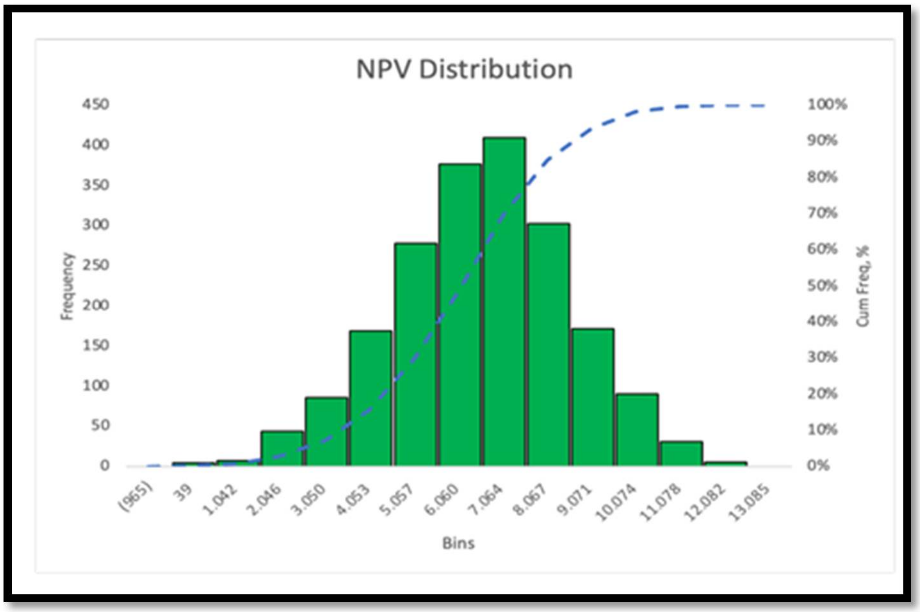

Figure 14: Company's NPV Distribution after Gas Price Optimization

4.5. Risk Mitigation

The following table shows the potential risk of the X Field development project and also the mitigation plan.

No	Risk	Impact	Risk Mitigation
1	Project delay	- Project delay 1-year causes NPV to decrease by 41% - Project more than 2 years cause NPV becomes negative	1. Conduct comprehensive market research on prospective buyers regarding track records and financial capabilities. 2. Include a punishment article in the sale and purchase agreement (GSA) for any achievement failure due to the delay of the project's onstream.
2	Gas price too low	NPV is less attractive, and the project becomes riskier	1. Set the lower limit of the gas price of 2.5$/MMBtu. 2. If an agreement cannot be reached on gas prices above 2.5$/MMBtu, it is recommended to apply the Partnership scenario.

Table 9: Risk Mitigation of the Project

5. Conclusion and Recommendation

The following is the conclusion of this paper:

- The X field is feasible to be developed. Economic analysis shows a positive NPV with an IRR more significant than the cost of capital. Hence, the development of X field has the potential to provide added value for the company and the Government as well.
- The selected development scenarios are as follows:

- The first priority is the 'No Facility' scenario with the Own Operation scheme and using the fiscal Regime Cost Recovery (following PT. ABC's PSC contract). This scenario provides an NPV of 2,580 M$ with an IRR of 12.9% and a POT of 5.8 years.
- The second priority is the Partnership scheme. This scenario provides a very attractive NPV for the company, which is 4,190 M$, but from the Partner's perspective, optimization in expenditure is needed to make the NPV become positive.
- From the sensitivity analysis, it can be concluded that the factors that are very sensitive to the project's economics are gas price, CAPEX, and production.
- Monte Carlo analysis is carried out with 2000 iterations and includes uncertainties on input variables. The average NPV obtained from simulation is 2,575 M$, the lowest NPV is -8,060 M$, and the highest NPV is 11,006 M$. Even though the average NPV is positive, it is still possible to get a negative NPV with a probability of 16%. With the possibility of a negative NPV of 16% and a negative NPV of -805 M$ in P10 (Low case), this project can be categorized as a medium-high risk.
- From the Monte Carlo simulation with 2000 iterations, a change in the minimum gas price of 0.5$/MMBtu, from 2$/MMBtu to 2.5$/MMBtu, results in an excellent NPV distribution. The average NPV obtained is 6,030 M$ with the lowest NPV of -618 M$ and the highest NPV of 11,962 M$. The possibility of a negative NPV is 0% with P10 (Low case) obtained at 3,445 M$. The NPV of P10 (Low case) is 34% higher than the average NPV (Best case) when using a minimum gas price of 2$/MMBtu.

The recommendation of this paper is:

- It is recommended to develop the X field with the 'No Facility' scenario using the Own operation scheme with a minimum gas price as a lower limit during commercialization is 2.5$/MMBtu.
- If an agreement cannot be reached on gas prices above 2.5$/MMBtu, it is recommended to apply the Partnership scenario. Because the gas price below 2.5$/MMBtu makes the project's economy too risky.

6. References

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