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Scenario Analysis of a Gas Field Development Project in South Sumatra, Indonesia - Reserves Volume and Gas Price Scenarios

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Abstract - **As the largest oil and gas producing country in ASEAN, Indonesia has been facing challenges in maintaining its production level. Existing mature fields, lack of new discoveries, changes in the government policies and investors' limited appetite in exploring new resources due to economic reasons have contributed to the decline of national production. The recent gas discovery in Palembang PSC in South Sumatra region has brought new optimism in the country's energy industry. The main objective of this study is to explore how PSC contractor evaluate and perform decision making under several uncertainties within the project and what types of government incentives are required for scenarios that are deemed uneconomic to be executed. The research focuses on project economics for the contractor under the recently implemented domestic gas price cap policy to industrial and electricity sectors using scenario analysis on gas resource volumes, development, capital and operational expenses, and gas market allocations. The study concluded that government incentives are critically important to ensure that the project development is economically feasible to be progressed in order to provide positive returns to both PSC contractor and Indonesian government.**

Keywords – **Decision Making Under Uncertainty, Economic Evaluation, Gas Commercialization, Gas Field Development, Scenario Analysis**

I. INTRODUCTION

In a challenging period of Indonesia's upstream oil and gas industry, Hispania Energy, one of the most active energy companies conducting exploration activities in Indonesia, recently announced a gas discovery in one of its operated exploration blocks in South Sumatra, Palembang PSC. When the gas discovery was announced in early 2019, it was stated that the exploration well drilled had found preliminary estimation of at least 2 TCF of recoverable resources and was regarded as the largest hydrocarbon discovery in Indonesia for the past two decades, which will represent new resources for the Indonesian market that will help to stimulate national economic development. After a promising test result from the initial exploration well, where the company conducted production test from the fractured basement reservoir, Hispania Energy and its Joint Venture partners in the PSC, along with the government of Indonesia have mutually decided that the development of the discovered gas field will be executed in two phases to monetize part of the gas resource volume earlier. In parallel with the initial phase of development, the company will drill a further appraisal well with the objective of confirming and validating a larger discovery within the gas field.

With uncertainties surrounding the size of the gas resource volume, which will be subject to the result of the appraisal well, applicable domestic gas price due to the Minister of MEMR Regulations concerning domestic gas price cap for certain industrial and electricity sectors, possibility to export part of the resource volume to obtain higher price, the current case of Palembang PSC project development in South Sumatra will provide an ideal example of how an upstream project development that is still conditional on the gas discovery volume and gas price will progress under different scenarios and what types of incentives would be required if the project is uneconomic under a certain scenario.

This study has run different simulations to Palembang PSC project development scenarios using low, base and high case scenarios of multiple project elements in order to test the project economics and how the results will fit into the PSC contractor's economic and investment threshold, and subsequently affecting the decision-making process of the investors in executing the project. The main results of this study provided evidence that under certain circumstances, the Palembang PSC project development will not be economically feasible to be progressed and would require a number of alternative government incentives in order to make the project economic.

II. LITERATURE REVIEW

Petroleum Fiscal Term. Petroleum fiscal term for oil and gas exploration and development activities was established many decades ago and is regarded as a primary non-resource factor that International Oil Companies ("IOC") consider before they decide to enter or make investment in a country. The level of attractiveness of a country's fiscal terms has a fundamental impact on the IOC's project viability and economic value and it is also a key parameter to evaluate the oil and gas investment climate in a particular country (Luo, Yan, 2010, Mian, 2010).

Growing global fossil fuel demand has increased the search for more fossil fuel resources, and has resulted in expansions of IOCs exploration and operation towards global deep-water offshore basins and other remote underexplored areas (Weimer and Pettingill, 2007). Consistent with that trend, Indonesia's upstream exploration activities in recent years have shifted to the underexplored basins in the Eastern part of Indonesia, where the risks, costs and level of technology associated with exploration projects in those areas are much higher compare to the proven prolific basins in other parts of Indonesia.

Principally, host governments of countries with petroleum reserves must be thoughtful in determining the strategic level of signature bonus, royalty rate, production bonus, First Tranche Petroleum ("FTP"), revenue split between government and contractor, cost recovery limit, Domestic Market Obligation ("DMO"), corporate tax rate and Investment Credit ("IC"), as those are considered as key elements in a country's fiscal regime and have significant influences for investment decisions in the oil and gas industry (Dharmadji, Parlindungan 2002).

The fact that petroleum resources are a vital asset to the majority of the developing countries in their capacity as oil and gas producers, these countries have been encouraged to allocate more emphasis on the importance of profit related fiscal instruments to maximize their government take and investments (Kemp, 1992). In line with that concept, Johnston (1997) originated the introduction of two new fiscal elements in petroleum fiscal terms, namely revenue protection and access to gross revenues.

For host governments, revenue protection concept is the minimum share of gross revenues they will receive in any given accounting period from each project, while for investors, access to gross revenues is the maximum share of gross revenues investors will receive from its working interest, which may be restricted by the government's equity split, cost recovery limits and other fiscal term components, like tax (Johnston, 1997).

Under Indonesia's Production Sharing Contract ("PSC") cost recovery arrangement, as is the case for the Palembang PSC, the government is guaranteed early revenue protection through the shareable FTP scheme and tax, while the contractor is guaranteed its early revenue from the FTP arrangement.

Decision Making under Uncertainty in the Upstream Oil and Gas Industry. In many business cases, the level of consequences of the alternative courses of action in the decision-making process cannot be projected with certainty. More often, decision makers are unable and/or unwilling to project or to forecast the probabilities of the outcomes of their decisions, where, as a result they would make pessimistic assumptions on the outcomes of their decisions (Goodwin & Wright, 2004). The level of uncertainties within the oil and gas projects vary depending on the phase of the project. In the exploration phase, the level of uncertainty is very high as oil and gas companies have a low probability in finding hydrocarbon resources under the ground due to the associated sub-surface risks. The probability of success level in an exploration well will be subject and conditional on the evaluation results of the following four critical geological aspects, namely the presence of reservoir rock, geological structure, hydrocarbon charge and existence of sealed trap (Rose, 1987).

Risks and uncertainties are integral parts of the investment nature in petroleum exploration ventures. One of the major objectives of the decision-making processes within the exploration phase is to consistently deal with risk and uncertainty factors, and to reduce the level of those factors, whenever possible, in a realistic manner. It is also important to consider that making judgements under uncertainty environment are also vulnerable to biases, where in oil and gas exploration projects generally influence the geologic estimates of the size of prospect target, probability of the petroleum discovery, and the finding costs. Target size estimates of an oil or gas field prospect tend to range widely, based on the statistical confidence level of the estimate, which in the oil and gas industry is generally known as P10 – P50 – P90 and PMean, where P50 is a good middle estimate, PMean usually lie in about P40 – P30 level, and P90 and P10 are low and high estimates respectively (Cooper Energy, 2021). In addition, oil and gas companies tend to be overoptimistic in estimating the size of its target prospect (Rose, 1987).

Not only that oil and gas companies tend to be overoptimistic on the size of its target prospect, but they also tend to be overoptimistic on the probability estimates of the oil or gas discovery, mainly because companies often do not differentiate between the success of the initial exploration well and the subsequent appraisal well, and assume that the success of the initial exploration well will automatically translate into a guaranteed success in the succeeding appraisal well campaign. Another issue concerning the technical aspect also includes the inability of the exploration team in identifying which of the geological risk factors (reservoir, geological structure, hydrocarbon charge and trap) actually constitutes the primary exploration risk for an explored prospect, which may hinder the chance of the company in finding a petroleum discovery (Rose, 1987).

The estimates in cost of finding petroleum discovery seem to display the least deviation from the predictive accuracy, as the estimates of exploration costs will have adequate references from other past projects with similar field sub-surface characteristics. In the case of Palembang PSC, where it is located in a prolific and mature oil and gas basin of South Sumatra, the project will have sufficient other existing projects in the surrounding area for cost references purpose and to validate whether the company's costs estimate is justified.

Factors of Uncertainties in Upstream Project. Oil and gas reserves volume, rate of production level, investment and operational costs, prices and interest rates are all key elements that will affect the profitability of a petroleum project, and the predictions are made under uncertainty. Based on that fact, every economic evaluation of an upstream oil and gas project will require multiple

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deterministic projections, in the form of scenarios. The challenge in setting deterministic projections of the technical and non-technical uncertainties in the upstream project is how to determine realistic values of each input so that they can be utilized properly in the project's economic evaluation model and provide measurable and anticipated outputs to allow the company with sufficient range of expected results in strategizing its path forward (Rose, 1992).

Biases in Determining Parameters under Uncertainty. The same issue can be framed in different ways if the decision-making process involve psychological principles that govern the perception of decision problems and the assessment of probabilities and expected outcomes, which at the end will produce predictable shifts of preference. Tversky & Kahneman (1981) have identified the following psychological biases that tend to produce inconsistencies when the estimates are made under uncertainty:

a. Overconfidence : The estimators are much less accurate than the expected level.
b. Representativeness : Producing analogs based on small sample size may not be truly accurate.
c. Availability : Latest or outstanding examples are more likely to be cited, regardless of their real frequency in reality.
d. Anchoring : In providing estimates, a low starting point leads to a lower final estimate, and a high starting point leads to a higher final estimate.
e. Unrecognized limits : Exploration team who is projecting future hydrocarbon discoveries in the same block may neglect non-geological factors.
f. Motivation : Geologist or sub-surface teams overstate the scale of reserves in order to obtain personal or for a specific deal purposes.
g. Conservatism : The sense that overestimating a project is worse than underestimating it.

Research Framework

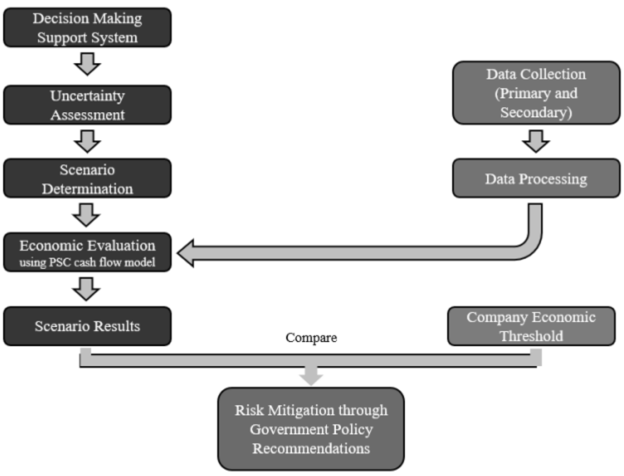

Fig. 1 Research Framework

III. METHODOLOGY

This research simulates the terms in the Indonesian PSC with the support of financial simulation modelling and a set of model fields. The model fields have been designed to reflect the onshore conditions in terms of production profiles and costs. A number of field size simulations have been used in this research to provide various probabilities of future O&G field discoveries in South Sumatra area in Indonesia. The various range of field sizes result in a wide variety of investment factor in form of capital expenditure such as drilling capital-, non-capital- and facility costs, as well as operating expenditure depending on the difficulty level across the simulated fields such as infrastructure availability and quality of the reservoir. The wide ranges of investment- and operating costs in this research have been employed to reflect the various types of onshore conditions and development requirements. The model also assumed a flat domestic gas price of US$4.00/MMBtu at upstream wellhead to reflect the current business environment in the gas industry in Indonesia and a flat export gas price to Singapore of US$6.50/MMBtu.

Techniques for financial measures are applied in this research to produce the results of net present value (NPV), Internal Rate of Return (IRR), payback period, contractor and government shares and scenario analysis. NPV, IRR, return on investment, payback period, sensitivity analysis and scenario analysis are among traditional techniques for managing strategic projects (Asrilhant, Meadows & Dyson 2004). In each project evaluation scenarios, the main objective of the Palembang PSC contractor is to achieve a minimum Internal Rate of Return ("IRR") of 15 percent for the contractor. If one or more scenario results in an IRR of less than 15 percent, then the PSC contractor will engage in a discussion and negotiation with the government on what types of incentives would be required in order for the project to achieve the minimum IRR that the contractor is targeting.

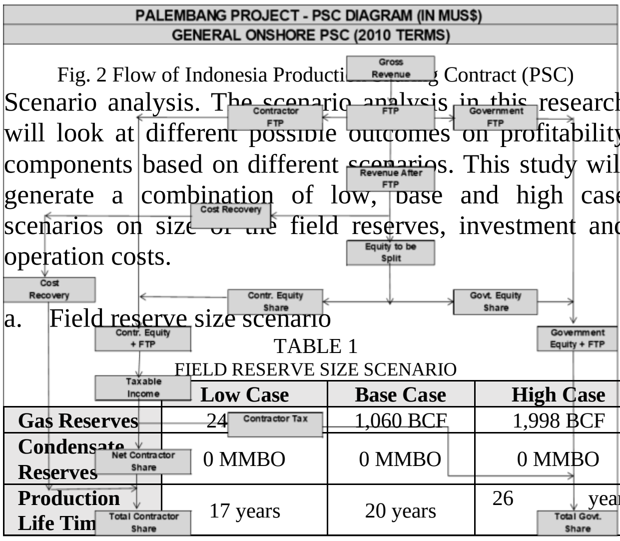

Fig. 2 Flow of Indonesia Producti[illegible] Contract (PSC)

Scenario analysis. The scenario analysis in this research will look at different possible outcomes on profitability components based on different scenarios. This study will generate a combination of low, base and high case scenarios on size of the field reserves, investment and operation costs.

a. Field reserve size scenario

TABLE 1
FIELD RESERVE SIZE SCENARIO

	Low Case	Base Case	High Case
Gas Reserves	24[illegible]	1,060 BCF	1,998 BCF
Condensate Reserves	0 MMBO	0 MMBO	0 MMBO
Production Life Tim[illegible]	17 years	20 years	26 year

South Sumatra basin is well known to be a prolific oil and gas-producing basin in Indonesia and has a proven

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petroleum system that has been producing large volume of hydrocarbons over the past few decades. One of the under-explored formations in this basin, which is known as the Fractured Basement Reservoir may provide oil and gas exploration companies like Hispania Energy with sufficient level of potential in discovering material size of hydrocarbon discoveries in the future. In the low case scenario, it will assume that the appraisal well will result in a failure or a dry hole, while in the base- and high cases it will assume that the appraisal well will result in a success and provide the initial gas discovery with different results in incremental volumes. The type of gas that will be produced from the reservoir will be categorized as dry gas, therefore no associated condensate will be co-produced from the reservoir. The period of production will vary between one case to another depending on the size of the gas reserves to provide a full cycle valuation to both the PSC contractor and the Government of Indonesia.

b. Capital and operation expenses scenario

TABLE 2
CAPITAL AND OPERATION EXPENSES SCENARIO

	Low Case	Base Case	High Case
Operation Expenses (Opex)	US$360.36 million	US$1,070.65 million	US$1,404.04 million
Capital Expenses (Capex)	US$319.18 million	US$942.56 million	US$1,413.00 million
Decommissioning Costs (ASR)	US$55.00 million	US$110.00 million	US$154.99 million

The capital-, operation- and decommissioning expenses were generated with the help of an oil and gas project development software using similar gas project environment and concept as in the South Sumatra area. The capital costs consist of Front-End Engineering Design ("FEED") costs, drilling, production facilities, pipelines, other infrastructure costs and contingency costs, while the operating costs consist of fixed and variable operating costs. The total decommissioning costs have been distributed equally during the years of production as part of the PSC Contractor's Abandonment and Site Restoration ("ASR") commitment.

c. Gas price scenario

TABLE 3
GAS PRICE SCENARIO

	Domestic Gas Price (US$/MMBtu)	Export Gas Price (US$/MMBtu)
Flat gas price basis	4.00	6.50

The domestic gas price will be set at US$4.00/MMBtu flat at upstream wellhead, with the assumption that the gas will be sold and delivered to the regulated industrial sector in West Java through the PGN's SSWJ gas pipeline, serving the same market as PT Pertamina EP – PEP (Asset II Region) and Corridor PSC, with adjusted upstream gas price of US$4.00/MMBtu and transportation fee of US$2.00/MMBtu, based on the ESDM Minister Decree Number 89K/10/MEM/2020. For export gas pipeline price to Singapore, a single flat gas price of US$6.50/MMBtu has been determined for this study.

IV. RESULTS AND DISCUSSIONS

TABLE 4
SUMMARY RESULT OF THE PROJECT CASE SCENARIO

No.	Parameter	Unit	Low	Base	High
1.	Gas Production	BCF	247	1,060	1,998
	Oil Production	MSTB	0	0	0
2.	Gas Production Life Time	Year	17	20	26
	Oil Production Life Time	Year	0	0	0
3	Gas Allocation	%	100	100	100
	Domestic Market	%	100	50	25
	Export Market	%	0	50	75
4	Gas Price Domestic	US$/MMBtu	4.00	4.00	4.00
	Gas Price Export	US$/MMBtu	6.50	6.50	6.50
5	Gross Revenue	(000's) US$	1,038,736	5,845,747	12,327,321
6	FTP	(000's) US$	207,747	1,169,590	2,483,716
	Contractor FTP	(000's) US$	138,498	779,433	1,643,643
	Government FTP	(000's) US$	69,249	390,157	840,073
7	Sunk Costs	(000's) US$	70,000	70,000	70,000
8	Investment	(000's) US$	262,107	942,979	1,469,915
	Capital	(000's) US$	235,857	700,674	1,146,505
	Intangible	(000's) US$	26,250	242,305	323,410
9	Operational Cost (Opex)	(000's) US$	520,429	1,536,345	2,149,034
10	Cost Recovery	(000's) US$	797,802	2,291,782	3,628,384
	(% on Gross Revenue)	%	76.8%	39.2%	29.4%
	Unrecovered Cost	(000's) US$	54,733	81,848	0
	(% on Gross Revenue)	%	5.269%	1.400%	0.000%
11	Equity to be Split (ETS)	(000's) US$	33,186	2,384,816	6,233,473
	Contractor Equity Share	(000's) US$	22,124	1,589,877	4,155,649
	Government Equity Share	(000's) US$	11,062	794,939	2,077,824
12	**Contractor**				
	Net Contractor Share	(000's) US$	96,373	1,421,586	3,479,575
	(% on Gross Revenue)	%	9.3%	24.3%	28.2%
	Contractor Cash Flow (include sunk cost)	(000's) US$	111,640	1,234,044	3,489,009
	Payback Period	Years	9.43	7.01	7.33
	IRR	%	8.42%	20.95%	21.12%
	NPV @10% Discount Factor	(000's) US$	-13,175	367,288	742,803
13	**Government**				
	FTP + Equity oil and gas	(000's) US$	80,311	1,185,096	2,917,897
	Tax	(000's) US$	64,249	947,724	2,319,717
	GOI Take	(000's) US$	144,560	2,132,820	5,237,614
	(% on Gross Revenue)	%	13.9%	36.5%	42.5%
	Government Present Value @10%	(000's) US$	21,825	402,288	777,803

On the contractor section, the low case scenario provides the lowest level of IRR and NPV at 8.42 percent and –US$13,175,000 respectively, thus does not pass the minimum 15 percent required IRR threshold for the contractor. The base and high case scenarios on the other side provide contractor with an IRR level of 20.95 percent and 21.12 percent respectively, with NPV of US$367,288,000 for the base case and US$742,803,000 for the high case. On the government side, the total government take for the three project scenarios are US$144,560,000, US$2,132,820,000 and US$5,237,614,000 for the low, base and high project cases respectively.

Sensitivity analysis. The main objective of the sensitivity analysis in this study is to test a number of assumed parameters in the project's economic evaluation and how the changes on those parameters will affect the overall result of the contractor's NPV level. The sensitivity analysis focuses on three different categories of assumptions, namely gas price, capital expenditures and operational expenditures, which are believed to be uncertain and likely to be highly influential to the project result (Sterman, 2000).

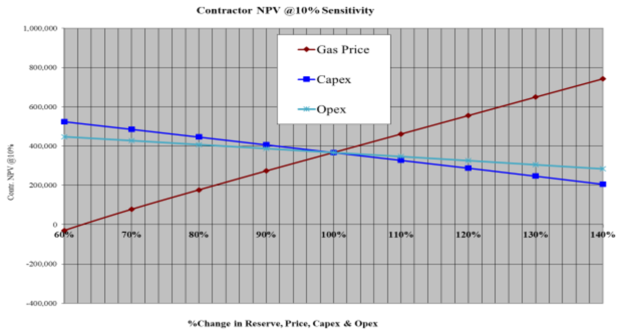

Fig. 3 Spider diagram of sensitivity analysis on base case scenario

V. CONCLUSION AND RECOMMENDATIONS

With the low case scenario resulting in a contractor IRR of below 15 percent, which is lower than the requirement of the PSC contractor to execute the project, this study has proposed two alternative government incentives which can directly improve the economics of the project, namely through modification of the PSC split and increase of the domestic gas price. For the base and high case project scenarios, the healthy economic returns from both scenarios of Palembang PSC project development also provide a strong justification to the government to maintain pipeline gas export to Singapore as the export gas price will support the project in obtaining more optimum revenues to the PSC contractor and the government, and without the gas export allocation, both the base and high case scenarios will not be economically feasible to be progressed.

The final results of this research are expected to provide influence on the decision-making process within the internal management of Hispania Energy on what types of strategies and engagement plans should the company prepare under different project outputs, as well as to provide the Government of Indonesia with a general overview on what incentive options would be workable and supportive towards creating an economically feasible project for the Palembang PSC development. Additionally, this research will also serve as an economic reference database for new investors who are looking to develop an upstream gas project in Indonesia under the current regulated domestic gas price regime.

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