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Utilization of Natural Gas in the Sinamar Field as a Fuel for Gas Powered Power Plant from the Both Scope of the Gas Business

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ABSTRACT

Natural gas has the potential to play an important role as a “bridge” fuel in the transition from fossil fuels towards a cleaner energy mix and a low-carbon future. The use of natural gas as a source of energy for electricity generation has advantages over oil fuel and coal. Apart from being cleaner, the use of natural gas for electricity is relatively more competitive than for oil fuel. One of the gas fields in Indonesia that has quite a large gas reserve but has not been utilized is the Sinamar field, which is located in West Sumatra Province. In the plan of development, natural gas from the Sinamar field will be used as fuel for a generator that will generate electricity. The total gas to be produced and to be lifting for 17 years is 10.49 BCF with an estimated sales gas flow rate of 1.72 MMSCFD. The results of the economic calculation from the Upstream business obtained economic indicators such as IRR of 25.7% and NPV of 3.56 MUS$ with a POT of 5.68 years. Meanwhile, from the Downstream business with a lower target electricity tariff with the regional BPP, Gas Engine power plant produces an IRR of 11.87% and NPV of 0.47 MUS$. Financially, the use of Gas Engine technology is more feasible than Gas Turbine Combine Cycle. Technically and economically, the Sinamar Gas field monetization project is feasible to be applied.

Key words: Plan of Development, Natural Gas Usage, Surface Facilities, Power Generation, Economics

INTRODUCTION

Based on sources from the IEA (2018), the World Energy Outlook level of natural gas consumption is getting bigger in 2000 to 2018 and so is the estimated consumption of natural gas from 2018-2040, in the Asia Pacific region itself the estimated consumption of natural gas in 2040 will be reached around 1,880 Billion cubic meters [1], as shown in Figure 1.

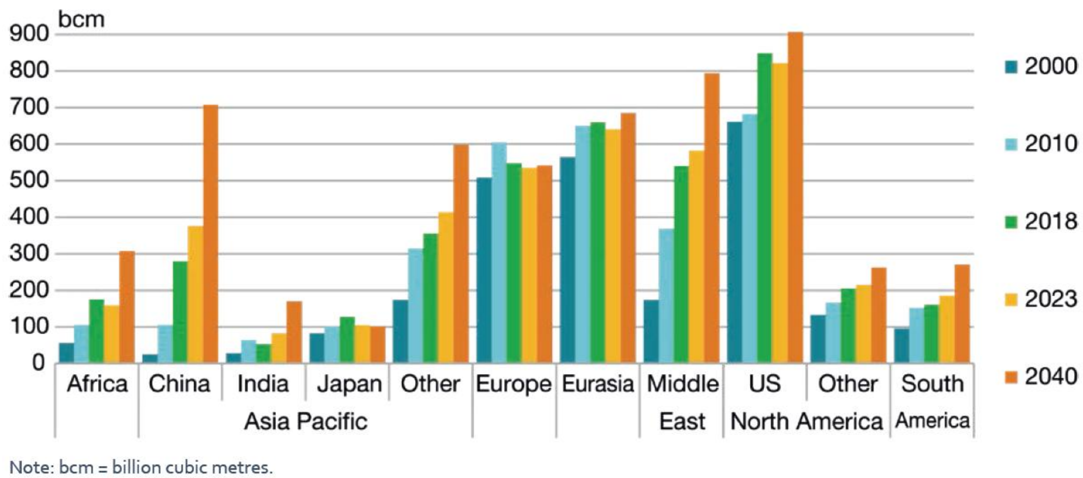

Fig. 1 Natural Gas Consumption Information

In Indonesia, local gas demand has gradually increased, followed by a reduction in oil subsidies from the government and the government has begun to allocate gas utilization priorities to meet domestic needs, this condition can be seen from the trend of increasing the domestic gas utilization ratio which continues to increase to 60%. in 2018 [2] Quoting from the Indonesian Natural Gas Balance issued by the Ministry of Energy and Mineral Resources of the total natural gas production in 2017, Indonesia's natural gas utilization was 58.59% absorbed by domestic and 41.41% for export [3].

In the business plan of providing electricity, for the province of West Sumatra the current installed generating capacity is 814.4 MW with a net capacity of 685.1 MW, while the projected electricity demand in West Sumatra province until 2028 is 1,151 MW [4]. To meet the demand for electricity, the construction of generating facilities is required by taking into account the potential of local primary energy sources.

The plan to utilize the gas from the sinamar field to be used as fuel for power plants must consider from two business sides, namely the upstream business side which is managed by the Cooperation Contract Contractor (KKKS) which has a "Production Sharing Contract" [5] collaboration with the government. The downstream business in this case the Independent Power Producer (IPP) company which will buy the gas and turn it into electrical energy which will later enter into a power purchase agreement with the end-user.

This research will examine the technological and economic design from both sides of the gas business, namely from the upstream business side and the downstream business side. From the upstream business side, they can sell gas according to gas specifications that are suitable for use with gas prices guided by the economic parameters of the development plan that has been approved by the government, then from the downstream business side, the cost of generating electricity is not more than the limit of the value of the electricity supply cost PT. PLN for the province of West Sumatra. Economic feasibility parameters of the project will look at the value of Net Present Value (NPV), Internal Rate of Return (IRR), and Pay Out Time (POT) generated from both sides of the business.

DESIGN, MATERIAL, PROCEDURE, TECHNIQUE OR METHODS

In this study, the focus will be on the utilization of gas from the sinamar #1 and #2 wells as gas production wells, with an estimated flow rate below 5 MMSCFD so as to produce a power generation unit with a maximum capacity of 10 MW. The maximum generating capacity of 10 MW will be used for the needs of the local electricity system in Sijunjung district.

The flow diagram for research from the upstream business side from data collection to upstream business economic analysis and for research from the downstream business side from data collection to economic analysis of the upstream business is shown in Figure 2

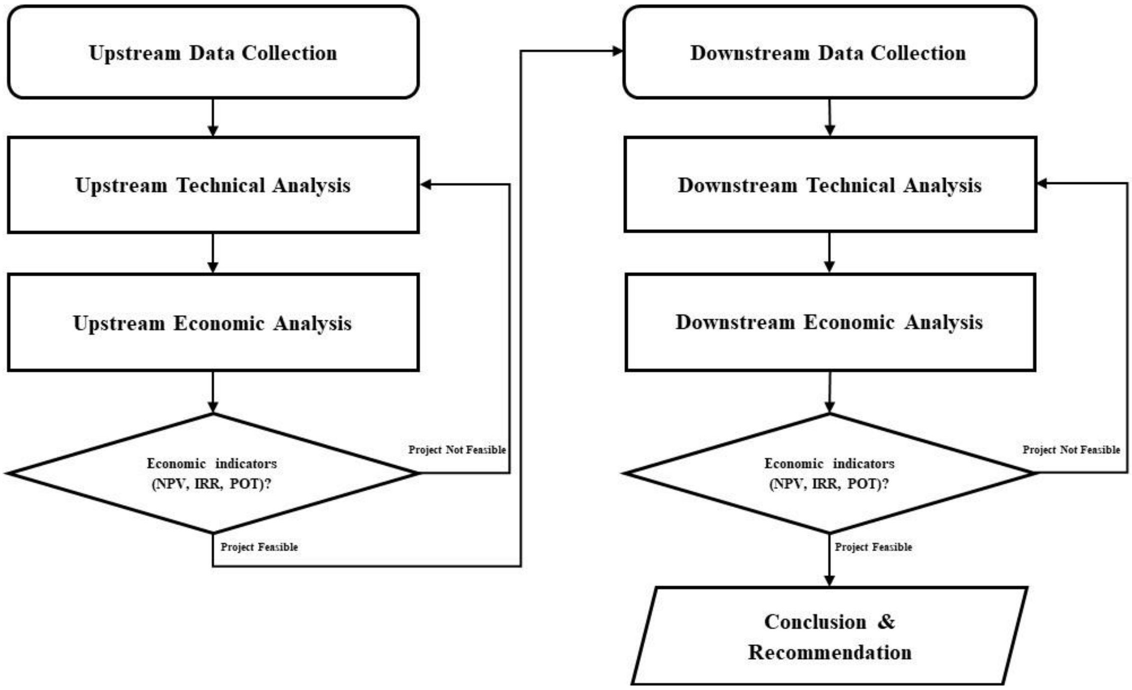

Fig. 2 Research flow chart

Sensitivity Analysis

The purpose of the sensitivity analysis is to find out how much influence certain parameters have on the project's economy. For the upstream side, the parameters referred to are gas selling price, gas production flow rate, Capex&Opex costs. Meanwhile, for the downstream side, the parameters that will be sensitive are the gas purchase price, and the Capex&Opex investment cost.

Upstream Business Data Collection

The data on the hydrocarbon content of the Sinamar field were taken from the results of the exploration drilling of the Sinamar 1 and Sinamar 2 wells [6]. Table-1 shows the data on the gas composition of the Sinamar field.

Table -1 Sinamar Field Gas Composition

Description	**Component**	**Sinamar 1 (% mole)**	**Sinamar 2 (% mole)**
Hydrogen Sulfide	H_2S	0.00	0.00
Carbon Dioxide	CO_2	40.49	44.1009
Nitrogen	N_2	3.57	4.0663
Methane	C_1	44.64	40.6631
Ethane	C_2	6.48	5.6201
Propane	C_3	2.96	2.725
Iso-Butane	$i\text{-}C_4$	0.62	0.6424
n-Butane	$n\text{-}C_4$	0.72	0.8458
Iso-Pentane	$i\text{-}C_5$	0.24	0.4054
n-Pentane	$n\text{-}C_5$	0.16	0.3195
Hexanes	C_6	0.08	0.378
Heptanes	C_7	0.04	0.1864
Octanes	C_8		0.0455
Nonanes	C_9		0.0087
Decanes	C_{10}		0.0022
Undecanes	C_{11}		0.0005
Dodecanes Plus	C_{12+}		0.0002
Total		**100.00**	**100.00**
Calc. Gas Gravity	(air =1,000)	1.0499	1.1022
Calc. Gross HV	**BTU**	**703.54**	**688**

The next data to be used is the estimated production flow rate, the method used is to use a reservoir simulation model to obtain an estimated gas production of 3 MMSCFD and condensate of ± 60 BCPD [5] which is shown in Figure 3.

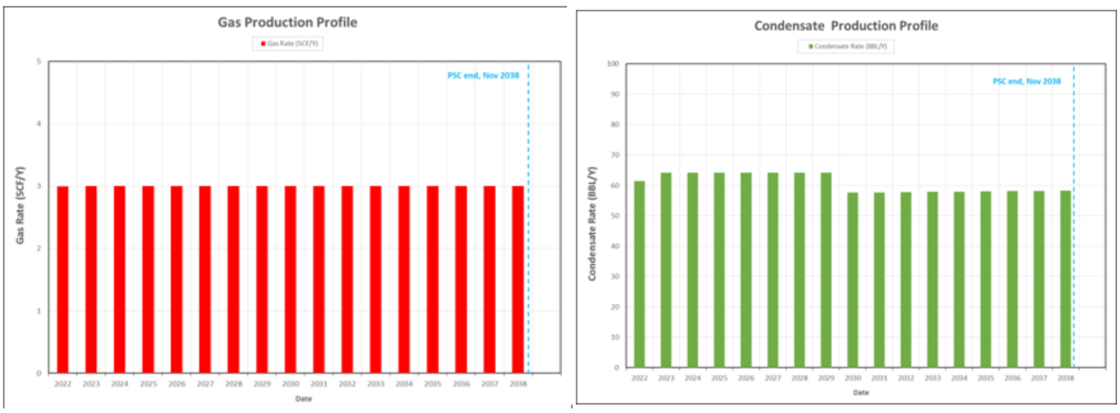

Fig. 3 Production Forecast

After the required data has been collected, the next step is to analyze and simulate from the technical aspect. From the upstream side of oil and gas, in order to flow natural gas from the reservoir in the Sinamar field, production wells, gas piping systems, and production facilities systems are needed. For processed gas specificationsthe specifications suitable for natural gas use will refer to the natural gas specifications for industry by pipeline contained in SNI 8414:2017 [7].

RESULTS AND DISCUSSION

Upstream Business Analysis

To be able to produce gas according to the production plan, 3 wells are needed which are located in different locations. This can be seen in Figure 4 which shows a map of the location of the well and gas production facilities in the Sinamar field. The flowline length of the Sinamar-2 well to the production facility is 1,400 meters long, the Sinamar-1 TW well to the production facility is 150 meters long and the WD-5 well to the production facility is 950 meters long. The length of this flowline will be the basis for calculating the flowline in economic calculations.

a. Well Work Program

To be able to produce a gas flow rate of 3 MMSCFD in accordance with the production plan, it is necessary to carry out well work, including:

- Re-Entry Sinamar-2 Well
  Sinamar 2 well is an exploration well that was drilled and tested well in 2015. Currently, the condition of the Sinamar 2 well is temporarily suspended, so re-entry work is required to reopen the well. The plan to do this work is in 2022.
- Sinamar-1 TW Development Well
  The Sinamar 1 TW development well is a new well that is planned to be drilled in 2023.
- WD-5 Development Well
  The Sinamar WD-5 development well is a new well that is planned to be drilled in 2030, with the aim of maintaining the Sinamar field production of 3 MMSCFD due to a decrease in the flow rate of gas production by the previous 2 wells.

Fig. 4 Map of Well locations and Gas Production Facilities (*Google Earth*, 2021)

b. Sinamar Field Well Piping System

The hydraulic flowline simulation was carried out using the Pipesim 2011 software to determine the most suitable diameter size for the flowline. Table-2 shows the simulation results for the selection of pipe diameters according to the design criteria. The 3 inch pipe meets all the criteria set out in the API 14E reference for the selection of flowline pipe diameters.

Table -2 Simulation Results and Pipe Diameter Selection

Design Criteria	Pipe Size	Simulation Results	Note
Gas Velocity Minimum 5 Psi/ft Maximum 60 Psi/ft	Pipe 2” Pipe 3” Pipe 4”	12.41 Psi/ft 5.48 Psi/ft 3.18 Psi/ft	**Ok** **Ok** **x** (< 5 psi/ft)
Erosional Velocity Ratio (EVR) EVR < 1	Pipe 2” Pipe 3” Pipe 4”	0.48 0.21 0.12	**Ok** **Ok** **Ok**
Allowable Diff. Pressure Drop 1,5 Psi/100ft	Pipe 2” Pipe 3” Pipe 4”	3.85 Psi/100ft 0.21 Psi/100ft 0.12 Psi/100ft	**x** (> 1.5 Psi/100 ft) **Ok** **Ok**

c. Sinamar Field Production Facility Concept

The hydrocarbons entering the separator will be divided into gas phase, condensate and produced water. The gas coming out of the separator will be passed to CO_2 removal to reduce the percentage level of CO_2 in the gas and then the gas go to system the Dehydration process to reduce the water content in the gas. The Dehydration system was used to remove moisture in the gas to reach thespecificationvalue of 7 lb/MMSCF. This system consists of pre-treatment by the MEG injection system and further processing by the Dew point conditioning system to achieve the specification of the water content in the gas. This process is carried out using a Glycol Dehydration Unit. The gas from the dehydration unit process will be fed the gas metering system and then be ready for sale.

The condensate that comes out of the separator will be delivered to a condensate stabilization process and then it will be accommodated in the condensate storage tank to be ready for sale via truck tank transportation to the nearest collection station. And the produced water will be subjected to a water treatment process to achieve quality standards and then the water injection process will be carried outThe conclusion of the simulation is as follows, the simulation model can be seen in Figure 5 below.

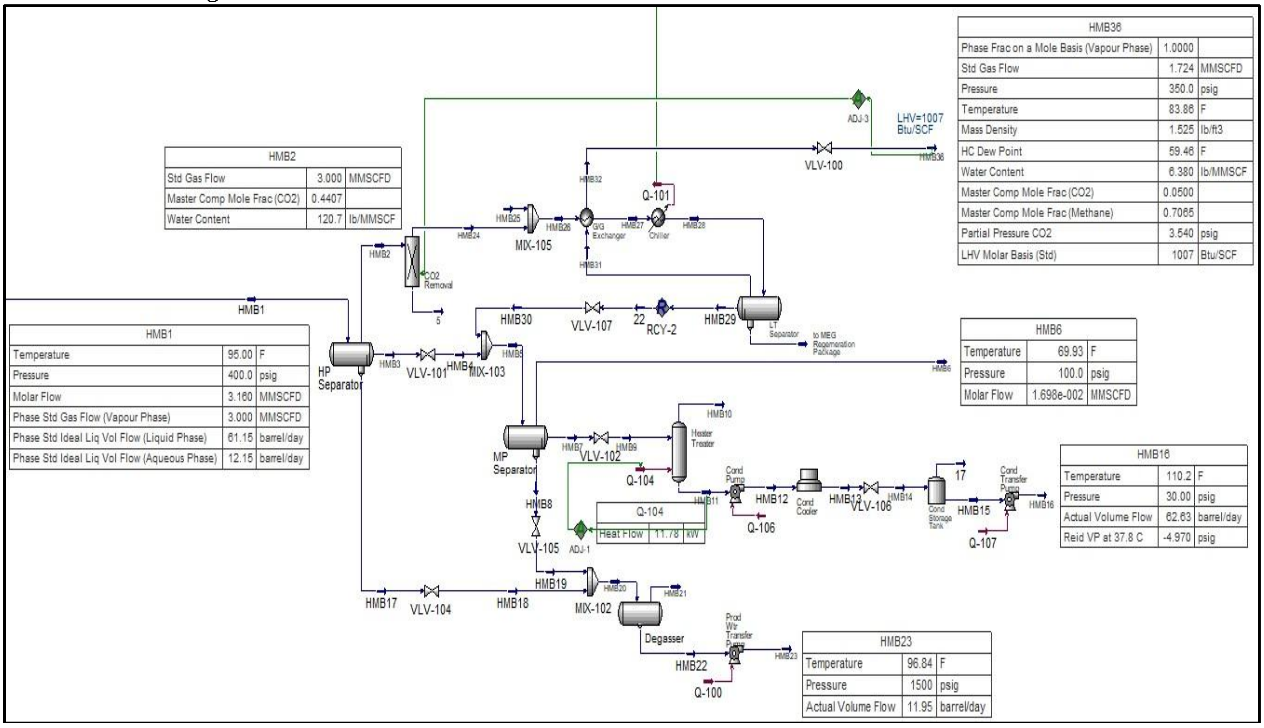

Fig. 5 HYSYS Simulation Model

d. Upstream Economic Analysis

The field development costs in question are costs for Drilling and Completion work, Production Facilities, Abandonment and Site Restoration (ASR) and Operating Expenditure.The estimated production flow rate of Lean Gas production is 1.72 MMSCFD with a cumulative total gas of 10.49 BSCF produced during 2022 to 2038 and a condensate production flow rate of ± 64 BCPD with a cumulative total production of condensate of 369.59 Mbbl. The gas price is assumed to be 5.00 US$/MMBTU and the condensate price is 65 US$/bbl. The results of the economic calculations are shown in Figure 6 and Table-3 below.

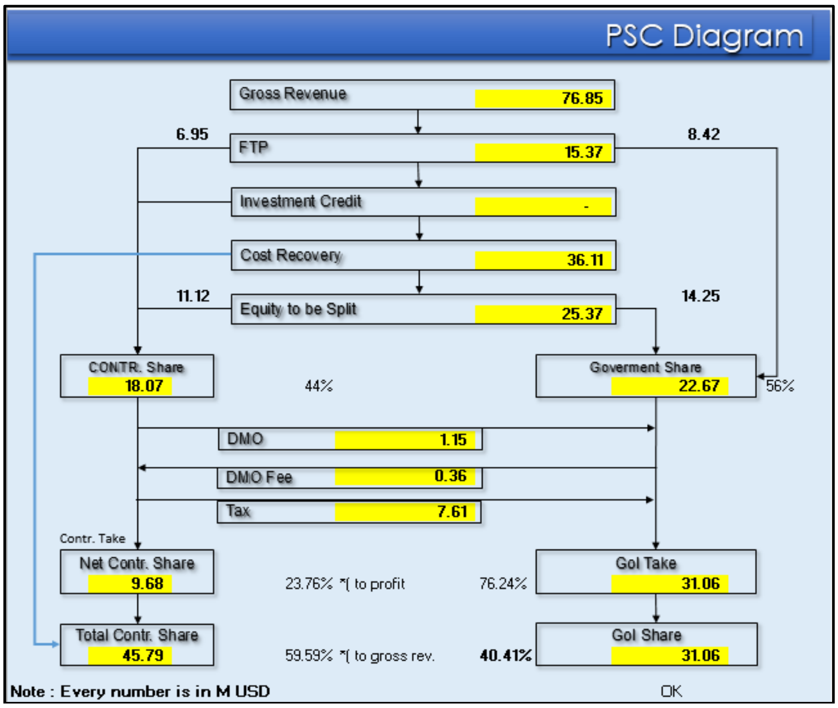

Fig. 6 PSC Diagram Result

Table -3 Economic Calculation Results

Parameter	**Unit**	**Value**
Gas Lifting	BCF	10.49
	TBTU	10.56
Condensate Lifting	MMSTB	0.37
Gas Price	US$/MMBTU	5
Condensate Price	US$/bbl	65
Investment Cost	MUS$	15.85
Operation Expenditure	MUS$	17.86
ASR	MUS$	1.28
Gross Revenue	MUS$	**76.85**
Cost Recovery	MUS$	**36.11**
	%	**46.99**
Equity to be split	MUS$	**25.37**
Contractor Equity	MUS$	**11.12**
Government Equity	MUS$	**14.25**
Contractor		
Net Contractor share	MUS$	**9.68**
	%	**12.60**
IRR	%	**25.7**
NPV@10%	MUS$	**3.56**
POT	years	**5.68**
Government Income (GOI)		
FTP Share	MUS$	8.42
Equity Share	MUS$	14.25
Net DMO	MUS$	0.78
Tax	MUS$	7.61
Total GOI Take	MUS$	**31.06**
	%	**40.41**

From the results of the PSC economic calculation, it can be explained that the economics of the Sinamar Field obtained a gross revenue of 76.85 million dollars with the income of each party as follows:

- The government amounted to 31.06 million dollars, the income was obtained from the government split, FTP split share, Domestic Market Obligation (DMO) and taxes.
- Contractors amounting to 9.68 million dollars, the income is obtained from the split contractor, FTP split share and DMO Fee.
- Cost recovery of 36.11 million dollars which will later be given to the contractor as a substitute for project costs

Downstream Business Analysis

a. Power Generation Selection

The next step is to determine the generating capacity based on the reference gas engine, gas turbine and gas turbine combine cycle that are on the market and are able to take advantage of the gas potential with specifications that have been calculated and analyzed previously.Table-4 below shows the results of the evaluation of the selection of power generation technology.

Table -4 Economic Calculation Results

No	Technical Parameter	Specification		
		Gas Engine	**Gas Turbine**	**Gas Turbine CC**
1	Tipe& Manufacture	CAT-G3520E Caterpillar [8]	KHI - GPB80 Kawasaki [9]	SGT-50 CCPP Siemens [10]
2	Configuration	4 unit	1 Unit	3 GT – 3 HRSG – 1 ST
3	Capacity per Unit	2,070 kW	7,054 kW	9,513 kW
4	Installed capacity	8,280 kW	7,054 kW	9,513 kW
5	Heat Rate Engine	8,941 BTU/kWh	10,640 BTU/kWh	7,569 BTU/kWh
6	Capacity (Gross)	8.08 MW	7.054 MW	9.513 MW
7	**Capacity (Net)**	**7.68 MW**	**6.873 MW**	**8.657 MW**
8	NPHR	9,412 BTU/kWh	10,919 BTU/kWh	8,318 BTU/kWh
9	**Net Eff.**	**36.2 %**	**31.25%**	**41 %**
10	Capacity Factor	80%	80%	80%
	Result :			
	Evaluation Rating	**2**	**3**	**1**

From the results of the comparison evaluation, it can be seen that a gas turbine combined with a steam turbine utilizing the exhaust heat of a gas turbine or the usual Gas and Steam Power Plant or Gas Turbine Combine Cycle is better from the technical side because it is able to produce greater power with optimal efficiency. For further selection, it is necessary from the economic side of the project, for this stage only the two types of technology with the first and second rank in the technical selection will be compared.

b. Downstream Economic Analysis

Engineering Procurement & Construction (EPC) Cost the EPC fee is the main cost to build a new Power Plant. This cost includes for project design and design, procurement, manufacture, delivery, erection, installation, testing and commissioning as well as services during the warranty period. Operation and Maintance (O&M) costs for a Power Plant vary depending on the type and characteristics of the Generator including the mode of operation, and consist of fixed and variable O&M costs, as follows:

- Operational & Maintenance Fixed Costs Fixed O&M costs are O&M costs that do not change with energy production, such as and include: Wages, administrative costs, maintenance costs.
- Variable Operational & Maintenance Costs Variable O&M costs are O&M costs that will vary with production. For the purposes of this study, the fixed and variable O&M Cost Estimates for the 8.08 MW Gas Engine plant are assumed to be 0.59 cUSD/kWh and 0.20 cUSD/kWh, respectively, and then the 9.5 MW Gas Turbine Combine Cycle plant is assumed to be 0.74 cUSD/kWh and 0.25 cUSD/kWh.

The results of the economic analysis can be seen in Table-5 below.

Table -5 Economic Calculation Results

Parameter	Unit	Gas Engine		GTCC	
		LCOE	**Base Case**	**LCOE**	**Base Case**
Gross Capacity	MW	8.08	8.08	9.51	9.51
Net Capacity	MW	7.27	7.27	8.65	8.65
NPHR	BTU/kWh	8,946	8,946	8,318	8,318
Capacity Factor (CF)	%	80	80	80	80

WACC	%	10	10	10	10
Gas Price	USD/MMBTU	5	5	5	5
Total Generation Cost	MUS$	9.58	9.58	13.35	13.35
Loan (70/30 DER)	MUS$	6.71	6.71	9.35	9.35
Interest	%	2.5	2.5	2.5	2.5
Construction Period	months	18	18	24	24
Repayment Period	sa	22	22	22	22
Equity	MUS$	2.87	2.87	4.01	4.01
Component ABCD Electricity Tariff	cUSD/kWh	**7.26**	**7.42**	**7.39**	**7.42**
	Rp/kWh	1.034	1.057	1.052	1,057
Breakdown :					
Component A	cUSD/kWh	1.991	2.147	2.23	2.261
Component B	cUSD/kWh	0.6	0.6	0.75	0.75
Component C	cUSD/kWh	4.473	4.473	4.159	4.159
Component D	cUSD/kWh	0.2	0.2	0.25	0.25
IRR on Equity	%	**10**	**11.87**	**10**	**10.32**
IRR on Project	%	7.82	9.04	7.85	8.06
NPV of Equity Payback	MUS$	0	0.47	0	0.11
Payback Period	Year	8.26	7	8.11	8
DSCR Min.		1.23	1.33	1.26	1.27

It can be seen from the financial summary table that the comparison between the 8.08 MW Gas Engine plant and the 9.51 MW Gas Turbine Combine Cycle (GTCC) generator shows that the IRR equity value achieved by the Gas Engine generator is better than the GTCC generator with the same target electricity tariff (7.42 cUSD/kWh) in the base case condition that is equal to 11.87%. In levelized Cost of Electricity (LCOE) conditions, the selling price of electricity achieved by the Gas Engine generator is also lower than the GTCC plant, which is 7.26 cUSD/kWh, making it more competitive.

By looking at the results of the calculation of the IRR on equity value achieved and the NPV of the equity value of 0.47 MUS$ and a minimum DSCR of 1.33 for the Gas Engine plant, it can be concluded that this plant is more financially feasible as gas downstream business and the electricity tariff is lower. proposed to be slightly lower than the 2019 West Sumatra BPP [11], which is 7.43 cUSD / kWh (Rp 1,058.00 / kWh).

Sensitivity Analysis

a. Upstream Business

Sensitivity analysis was carried out based on 4 (four) parameters, namely: price, production, capital expenditure and operating expenditure. Figure 7 shows the changes in the economic indicators of NPV and IRR to the sensitivity carried out.

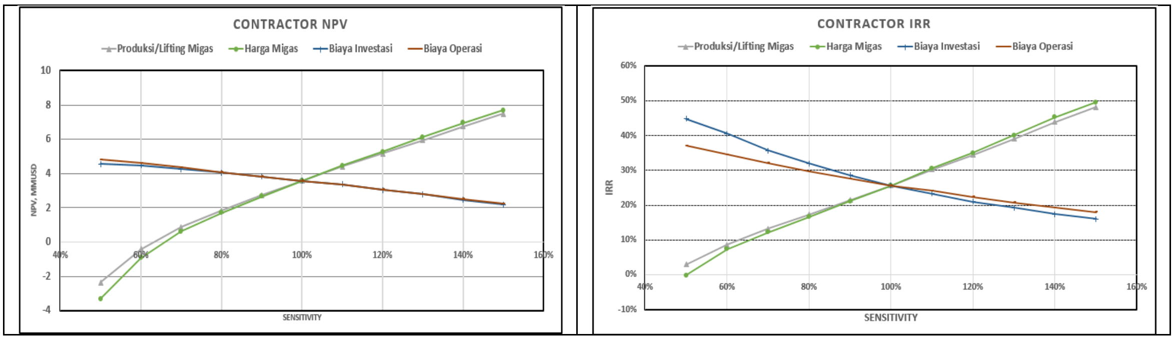

Fig. 7 Sensitivity NPV and IRR Contractor Upstream

From the results of the NPV sensitivity in Figure 8 it can be explained that to maintain a positive NPV, gas production and gas prices should not be below 60% of the parameters used in the economy.From the IRR sensitivity results in Figure 8, it can be explained that in order to maintain a minimum IRR value with the company's Minimum Attractive Rate of Return (MARR), gas production and gas prices should not be below 70% of the parameters used in the economy.

b. Downstream Business

This sensitivity is carried out to determine changes or impacts on the value of IRR on equity and NPV, if there are adjustments to EPC Costs (Capital Expenditure), Maintenance Costs (Operation Expenditure) and Gas Prices. The sensitivity carried out on the financial calculation of the Gas Engine generator at a target rate of 7.42 cUSD/kWh or below 2019 West Sumatra BPP can be seen in Figure 8 below.

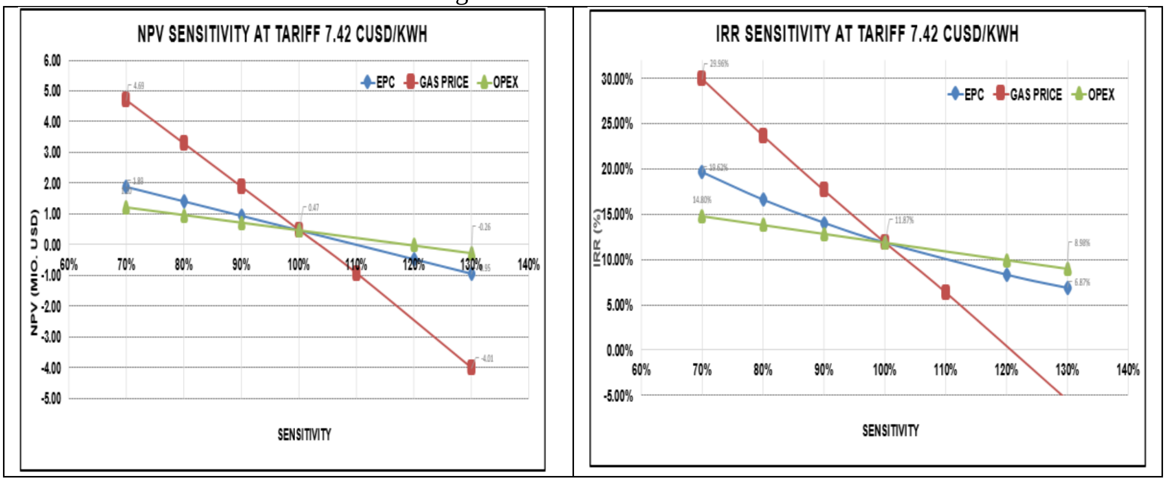

Fig. 8 Sensitivity NPV and IRR Contractor Downstream

It can be seen in the IRR sensitivity graph that the increase and decrease in each cost factor such as EPC costs, maintenance and gas prices greatly affect the amount of IRR on equity achieved. Figure 4.30 shows the sensitivity assumption which is calculated based on an increase and decrease of up to 30% of each cost factor, for example if the gas price is reduced by 10%, the IRR will increase to 17.64% and vice versa if the gas price increases by 10% the IRR will decrease to value of 6.34%.The increase and decrease in the value of IRR on the trend of gas prices has the greatest slope angle compared to the trend of capital expenditure (capex) and operation expenditure (opex), this indicates that gas prices have an important role in the financial feasibility of a gas-fired power plant.

It is the same with NPV sensitivity that the increase and decrease in value is influenced by EPC costs, Opex and gas prices, but the most significant is if there is a change in gas prices. With a 10% increase in gas prices, the NPV will be negative to minus 0.94 MUS$, but if there is a 10% decrease in Gas Prices or to 4.5 USD/MMBTU then the NPV value will increase to 1.88 MUS$ or increase the NPV value up to 4 times from the base case NPV value of only 0.47 MUS$ at a gas price of 5 USD/MMBTU.

CONCLUSION

The conclusions in this study viewed from the concept of upstream and downstream oil and gas are as follows :

- The total gas to be produced for a period of 17 years until the end of the contract work area is 18.6 BCF with a target flow rate of 3 MMSCFD. From the simulation results, it is found that the sales gas flow rate is 1.72 MMSCFD and the total gas lifting is 10.49 BCF.
- The results of the economic calculation of the Sinamar field using a gas selling price of 5 US$/MMBTU and a condensate price of 65 US$/bbl, obtained the following results:
  - Government revenue of 31.06 MUS$ (40.41% of revenue)
  - Cost Recovery of 36.11 MUS$ (46.99% of revenue)
  - Contractor revenue of 9.68 MUS$ (12.60% of revenue)
  - The IRR contractor is 25.7% and the NPV is 3.56 MUS$ with a POT of 5.68years.
- Sales of gas from the Sinamar field of 1.72 MMSCFD is used for primary energy in the downstream business, namely as fuel for Gas Power Plants with a choice of generating technology and the capacity that can be produced as follows:
  - Gas Engine with a net capacity of 7.68 MW
  - Gas Turbine with a net capacity of 6.87 MW
  - Gas Turbine Combine Cycle with a net capacity of 8.65 MW
- In an economic analysis with the same target electricity tariff at 7.42 cUSD/kWh Gas Engine is able to produce an Internal Rate Return (IRR) value of 11.87% while the GTCC is only 10.32% so that it can be concluded that the IRR Gas Engine value is 15 % better than GTCC IRR. In terms of other benefits, with the same contract duration for 17 years, the Gas Engine also produces a better NPV value of 0.47 MUS$ or four times greater than the GTCC NPV value which is only 0.11 MUS$. It can be concluded that Gas Engine is more financially feasible compared to other power generation technology options.
- From the results of the research conducted, the results of the IRR parameter are above the company's MARR value and a positive NPV value which can provide benefits for the upstream business and downstream oil and

gas business, so that the Sinamar gas field utilization project is feasible to be applied.

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