Techno-economic Feasibility Analysis of Replacement of Existing Power and Steam Generators at Arun LNG

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Abstract: Demands for electricity and steam at the Arun LNG Refinery Gas Processing Facility are 158,400,000 kWh/year and 180 tons/hour of steam produced by 3 (three) units of Gas Turbine Generators (GTGs) and 3 (three) units of Heat Recovery Steam Generators (HRSGs) at the generating unit at Arun Gas Processing Plant. The problem with electricity and steam generations at present is the high gaseous fuel requirement, namely 13.14 MMSCFD to process 30 MMSCFD of gas sold. The scarce availability of spare parts and several time operation interruptions (blackout) are also problems in the existing plant. The purpose of this research is to build a new generation unit at the separated from the existing GTGs and HRSGs with more efficient electricity generation and steam generation units and high level of availability. Replacement is carried out based on analysis of various generation alternatives, namely new GTG units & HRSG and boiler unit, new Gas Engine Generator (GEG) units & HRSG and a boiler unit, and connection to PLN (State Electricity Company) electricity network + a boiler unit. The results show that the installation of new GTG units & HRSG and a new boiler would require the gas fuel of 12.88 MMSCFD, which is 0.26 MMSCFD less than that of existing generations, and offer the least electricity generation tariff of \$ 0.221/kWh and steam generation tariff of \$ 0.0019/ton using cash flow economic method. The installation can support the operation and gas production activities at the ArunGas Processing Plant until the end of contract for the next 19 years.

1 INTRODUCTION

In carrying out its activities, the Arun Gas Processing Plantconsumes 158,400,000 kWh of electricity/year and 180 tons of steam / hour. The Arun power plant managed by PertaArun Gas (PAG) has 8 GTG units, with a capacity of 22 MW each installed in 1972. Six of the GTGs have been equipped with HRSG to produce steam. Currently operating, to meet plant requirements or utility demand, three GTG units are operated for gas processing and regasification needs. In operating the three GTG + HRSGs, 9.64 MMSCFD is needed for GTG and 3.5 MMSCFD for HRSG as supplementary firing. In fulfilling the electricity and steam generation, 13.14 MMSCFD of gas consumed as fuel to meet the demand for electricity and steam at Arun Gas Processing Plant is very large compared to gas sales of 30 MMSCFD. The low availability of power and steam is also a problem in itself, indicated by several times of black out.

In the present research, the need for gas processing operations at the Arun Gas Processing Plant is expected for the next 19 years (block contract ends), the replacement of the current GTG and HRSG with replacement units to meet electricity and steam needs efficiently and with a high level (Ganapathy, 1996) of availability so that Gas and Condensate production in Block B Field and NSO Field can take place.

2 THEORETICAL FRAMEWORK

2.1 GTG Conditions Benchmarking

Figure 1 shows a diagram of the utility fuel gas requirements used for gas processing at the Arun Gas Processing Plant.In comparison, the JOB Tomori Sulawesi field requires 6 MW of electricity to produce 340 MMSCFD, while processing gas at Arun Gas Processing Plantrequires 2.5 MW of electricity to process 20 MMSCFD of gas. However, an absolute comparison cannot be used because the gas processing facility at the plant is very large in size,

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which was designed for 450 MMSFD of gas/train but only processes 30 MMSCFD of sold gas at present. Therefore, in order to reduce the amount of electricity and steam generated, it is necessary to replace the oversized equipment into equipment that suits the current gas production needs.

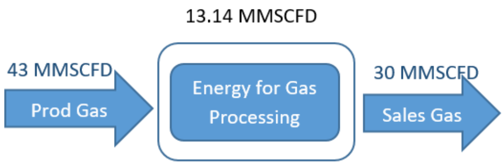

Figure 1. Energy requirement for gas processing

The ratio of energy requirement to gas sold is

$$\frac{13.14\ MMSCFD}{30\ MMSCFD} \times 100\% = 43.8\ \%$$

2.2 Heat Rate Comparison

With a fuel gas gross heat value (GHV) specification of 1074,774 BTU/SCF to produce power demand of 20,600 kWh requiring gas fuel of 9.46 MMSCFD, then the heat rate of the Gas Turbine Generator is 18.503 BTU/kWh. This is much larger than the GTG GE Frame-3 specification GHV which is 3,113 kcal/kWh or 12,345.12 BTU/kWh. In other words, the existing GTG is not efficient.This paper will discuss tariffs of power and steam generations in which for the need of very large steam, Combine Heat and Power (CHP) option is feasible to apply. This paper includes an alternative use of electricity from PLN which will be combined with a boiler to find out whether this alternative is cheaper than the conventional CHP.

2.3 Separation from Existing GTG

Arun Power Plant generates 30.6 MW with a Fuel Consumption of 14.5 MMSCFD. The power generated is intended for gas processing and regasification with load distribution shown in Figure 2.Therefore, replacing the existing GTG for gas processing also means separating the generation system to be built from the Arun Power Plant units and also separating the load distribution network such as substation and distribution cables. However, because steam is required and can be created in a HRSG, a new unit must be equipped with steam generation unit either as a new HRSG unit or a boiler to produce 180 tons/hour of steam.

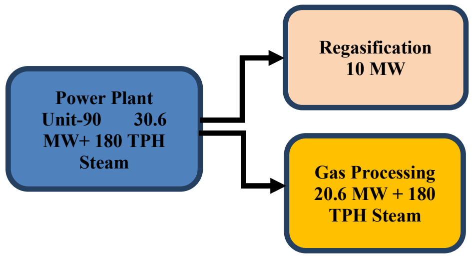

Figure 2. Load Distribution at Arun LNG Plant

The alternative generation utilities chosen were a new GTG and HRSG unit + Boiler, a new Gas Engine Generator (GEG) and HRSG + Boiler, and PLN electricity + Boiler. Figure 3 shows calculation aspects for technoeconomic calculation. From the economics point of view and availability analysis, the best option is chosen among those alternatives.

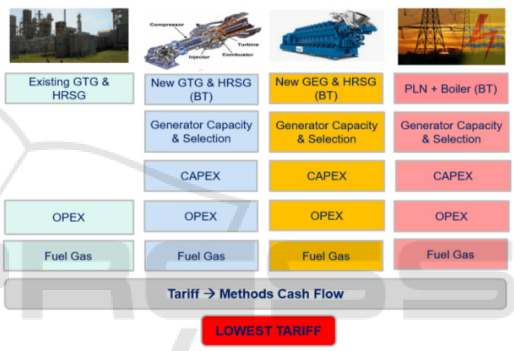

Figure 3. Generator Replacement Methods.

3 RESEARCH METHODS

Figure 3 represents flow for selecting alternative generator with the smallest tariff to be chosen to replace the existing power plant. Steps of calculations are as follows.

3.1 Find New Generator Capacity

From the data on the total load of Arun LNG Plant equipment can be found:

1. Continuous Load (kWh)= 20,600 kWh
2. Total Peak Load (kWh)

$$\textit{Peak Load (kW)} = x.\textit{Continuous(kW)}+y.\textit{Intermittent(kW)}+z.\textit{Standby (kW)} \quad (1)$$

3. Biggest motor starting

$$I_{FL} = \frac{kW_R \times 1000}{\sqrt{3} \times V \times \eta \times cos\varphi} \quad (2)$$

$$I_S = 600\% \times I_{FL} \tag{3}$$

where:

I_S =*Motor starting current (A)*
I_{FL}=*Motorrated current on full load(A)*
η =*Motorrated efficiency on full load(%)*
cos φ=Motorrated power factor on fullload(%)
V=Ratedvoltage(V)
kW_R=*RatedkW (kW)*

3.2 Select Generators

Table 1 shows a comparison of the efficiency, capacity, availability and performance of each Combine Heat & Power (CHP) technology currently. With the availability of new generators set at 99%, from the data in Table 1, the availability of a GTG unit is 72% - 99%. By taking the average availability value of 85.5%, it takes more than one GTG unit to produce 99% availability. The similar case for GEG. With 86 - 98 % availability, it needs more than one GEG unit to achieve 99%.

3.3 Calculate CAPEX and OPEX

CAPEX can be calculated using Table 1 or by market survey. OPEX can also use Table 1 or use general Operation and Maintenance (O&M) cost for power generation such as time to Major Inspection.
PLN tariff can be calculated using this formula

$$\big((a+b)\times c\ \times e\big) + \big((a+b)\ \times f\big) \tag{4}$$

Where
a is the price of non-subsidized electricity
b is the premium customer prices
c is the peak load
d is the peak load price
e is the duration of the peak load
f is the total hours outside peak load

Table 1. Comparison of CHP Technology Parameters, Cost, and Performance

Technology	Reciprocating Engine	Gas Turbine
Electric Efficiency (HHV)	27 - 41 %	5 - 40 %
Total Efficiency CHP (HHV)	77 -80 %	near 80%
Effective Power Efficiency	75 - 80 %	75 - 77 %
Specific Capacity	0.005 - 10	0.5 - upto hundred MW
Installation CHP Price ($/kWe)	1,500 - 2,900	670 - 1,100
Non-fuel O&M price ($/kWhe)	0.009 - 0.025	0.006 to 0.01
Availibility	96 - 98 %	72 - 99 %
Time to overhaul	30,000 - 60,000	>50,000
Fuel Pressure (psig)	1 - 75	n/a
Fuel Gas	Natural Gas, biogas, LPG, sour gas, waste industrial gas, manufactured gas	all
Output Thermal	Room Heater, Hot water, chiller, LP steam	process steam, enviroment heater, hot water, water cooler

Source: Catalog of CHP Technologies, EPA, 2017

3.4 Calculate Fuel

From Specification of Generator with current Gross Heat Value, fuel gas consumption for Power Generation of Arun LNG Plant can be found. Exhaust gas from power generation can be used to produce steam at HRSG with HYSYS simulation (Paoli, 2009). Boiler needs to satisfy steam requirement at 180 tons/h with 10.5 kg/cm^2 pressure (Oland, 2004).

3.5 Calculate Tariff

Tariff calculation needs basis data to obtain weighted average cost of capital (wacc). From wacc value, investment rate of return (irr) on free cash flow can be determined

4 RESULTS AND DISCUSSION

4.1 Generator Capacity

From Peak Load and Motor Starting calculation, generator capacity can be summarized in Table 2 and for Arun LNG Plant load is 20,939.81kW.

Table 2. Dedicated Load Generator Capacity

No.	Description	kW
1	Peak Load	20,939.81
2	Load during motor starting	17,926.23

4.2 Fuel Consumption

4.2.1 Two Units of New GTG + HRSG

With 2 units of GTG running simultaneously, each unit of GTG carries 50% of the load. In this scheme, the ArunGas Processing Plant burden, both dedicated and sharing, will be taken by the new GTG units with capacity of 20,600 kW each.In the market, a generator capacity that is close to 20,600 kW is a GTG brand LM2500 DLE with a capacity of 21.8 MW chosen (GE Power, 2019). Fuel Gas Consumption can be calculated by HYSYS Simulation.From the simulation obtained, one unit of LM2500 DLE with ambient air flow input of 123 tons/h can produce a generation load (net power) of 10,300 kW with fuel gas consumption of 2.51 MMSCFD. The exhaust gas of this generation is hot with a temperature of 539ºC which will be used to produce steam in a HRSG. The steam capacity generated in the HRSG is 24.34 tons/h per unit. Net efficiency GTG from simulation is 40.29 % which is higher from the specification because it neglects other losses like mechanical losses.Due to the demand for steam at the Arun Gas Processing Plant as much as 180 tons/h, an additional boiler unit is required to meet the demand for steam.

With 2 units of GEG running simultaneously, each unit of GTG will carry 50% of the load. In this scheme, Arun LNG Plant burden, both dedicated and sharing, will be taken by the new GEG units with a capacity of 10,300 kW each.In the market, a generator capacity close to 10,300 kW is a GTG brand Jenbacher J920 flextra with a capacity of 10.4 MW chosen. Fuel Gas Consumption can be calculated with HYSYS Simulation by using 2 unit J920 Flextra with ambient air flow input of 10.39 tons/h, the units can produce a generation load (net power) of 5,000 kW with fuel gas consumption of 1.19 MMSCFD. The exhaust gas is hot (609ºC) which will be used to produce steam in a HRSG. The steam capacity that can be generated in HRSG is 3.001 tons/h per unit. Due to the demand for steam at Arun Plant gas processing facility of 180 tons/h, an additional boiler unit is required.

4.2.2 PLN + Boiler

Using PLN power, grid installation capacity for peak load is 20,939.81 kWh. With premium costumer, the power comes from 150 kV transmission line from two sub-stations in order to maintain high availability, all steam will be produced by boilers. The schematic diagram of boiler system in this alternative is shown in Figure 4. Fuel Required is 11.29 MMSCFD. From calculations and simulations, fuel gas consumption in each alternative to produce 20,600 kW power and 180 tons/h of steam is as shown in Table 3.For economic evaluation based on fuel gas consumption, GEG alternative using GEG + HRSG+ Boiler uses 15.3 MMSCFD, which is higher than existing generation of 13.14 MMSCFD in addition to CAPEX for new unit. So, GEG alternative will be taken out from alternative option.

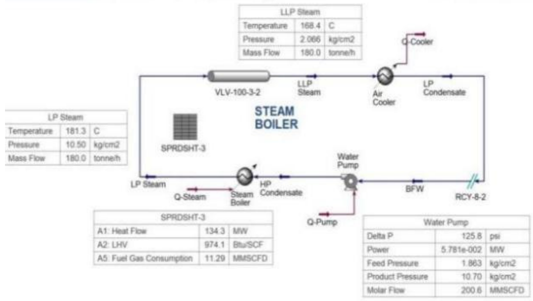

Figure 4. HYSYS Simulation of Boiler

Table 3. Fuel Gas Comparison for Alternative Replacement

No	Unit	Fuel Gas Consumption (MMSCFD)			
		New GTG	New GEG	PLN	Existing GTG
1	Power Generation	5.03	4.76	-	9.64
2	HRSG	-	-	-	3.5
3	Boiler	7.85	10.54	11.29	-
	Total	**12.88**	**15.3**	**11.29**	**13.14**

4.3 CAPEX and OPEX Calculation

Table 4. CAPEX and OPEX Comparison for Alternative Replacement

GTG + HRSG + Boiler			PLN + Boiler			Existing GTG + HRSG		
CAPEX			CAPEX			CAPEX		
Purchase and installation CHP	$	43,600,000	Transformers and Substation	$	2,470,000	Retrofit GTG	$	5,000,000
Boiler	$	4,690,000	Cable and installation	$	1,450,000			
			Control Room	$	30,000			
			PLN Connection Cost	$	1,155,000			
			Boiler	$	644,000			
Total CAPEX	**$**	**48,290,000**		**$**	**5,749,000**	$ 6.440.000	**$**	**5,000,000**
OPEX/year						**$ 11.545.000**		
Hot Path Gas Inspection (HGPI)	$	1,300,000	PLN Tarrif Rate ($0.121/kWh)	$	21,595,886	Cost O&M for Power to PAG	$	1,294,613
Major Inspection (MI)	$	2,500,000				Cost O&M for Steam to PAG	$	231,927
Man Power	$	25,000						
Spare Parts	$	100,000						
Fuel Gas	$	29,900,237	Fuel Gas	$	26,209,137	Fuel Gas	$	30,503,814
Total OPEX	**$**	**33,825,237**		**$**	**47,805,023**		**$**	**32,030,354**

Table 4 shows details of Capex and Opex as alternatives. Hot gas path inspection of new GTG will be carried out every 25,000 hours or 2.89 years and major inspections will be carried out every 50,000 hours or 5.7 years. For daily operation of the GTG + HRSG and Boilers, only manpower is needed to perform visual inspections at a budget of $ 25,000/year and spare parts is allocated $ 100,000/year.

4.4 Tariff Calculation

Table 5 shows an example of IRR calculation from New GTG + HRSG + Boiler with Debt share of 70% and Equity share of 30% having WACC 8.78%. IRR is 11%.

Table 5. IRR Calculation GTG

No.	Description		Numbers	Referensi	
a	Total Nilai Basis Aset, US$ Dollar	RAB	49.370.123	CAPEX Calculation	
b	Asset Depreciation, (Year)	ELA	19	Assumption	
c	inflation Rate	Inf	1,31%	5 Year Average US Inflation	
d	Risk Free Rate,(%)	Rf	2,13%	5 Year Average (1 January 2012 - 1 January 2017) Risk Free Return on Investment (US Treasury Bond) 10 Years	
e	Base Premium for Mature Equity Market,(%)	BPMEM	5,70%	Average 5 Years Base Premium for mature equity market 2013-2017	
f	Internal Country Risk Premium (Indonesia)	ICRP	3,24%	Indonesia 5 year average country risk premium 2013-2017	
g	Beta	β	1,079	5 Year Average (1 January 2012-1 January 2017) Size of fluctuation in investment portfolios or individual investment instruments compared to the market (stock market)	
h	Cost of Equity,(%)	Coe	11,78%	Coe = Rf + β * (BPMEM + ICRP)	
i	Debt Funding, US$ Dollar	DB	34.559.086	70%	Asumsi 70% Debt
j	Equity Funding, US$ Dollar	EQ	14.811.037	30%	Asumsi 30% Equity
k	Interest Of Debt,(%)	Indebt	10,00%	Assumption	
l	Income Tax,(%)	IT	25,00%	UU 36 of 2008 Article 17 Paragraph 2	
m	Cost of Debt,(%)	Cod	7,50%	Cod = Interest of Debt x (1 - Income Tax)	
n	WACC,(%)	WACC	8,78%	WACC = (DB/(DB+EQ))* Cod + (EQ/(DB+EQ))* Coe	
	IRR on Free Cash Flow should be equal to IRR		11,00287800%		

With free cash flow method, tariffs for Power and Steam can be obtained using data of CAPEX and OPEX (Lazard, 2017). With 19 years of operation and the expected running of 360 days to produce power and steam, then the tariffs for each alternative is as shown in Table 6.

Table 6. Tariff Comparison for Alternative Replacement

Comparison	GTG & HRSG + Boiler	GEG & HRSG + Boiler	PLN + Boiler	Existing GTG + HRSG
Power Tariff (USD/kWh)	0.221	0.282	0.310	0.205
Steam Tariff (USD/ ton)	0.0019	0.0025	0.0027	0.0018

5 CONCLUSION

Alternative GTG units & HRSG + a boiler offer electricity tariff of $ 0.221/kWh and a steam cost of $ 0.0019/ton. The largest contributor to the tariff is the purchase of units and their installation costing $ 48,290,000, with a fuel gas consumption of 12.88 MMSFD.

Alternative GEG units & HRSG + a boiler offer an electricity tariff of $ 0.282/kWh and a steam cost of $ 0.0025/ton. The largest contributor to the tariff is the use of fuel to produce steam in the boiler which reaches 15.3 MMSCFD, greater than the current fuel consumption. Moreover, operating cost of GEG is high due to frequent maintenance schedules.

Alternative connection to PLN + a boiler offer an electricity tariff of $ 0.31/kWh and a steam cost of $ 0.0027/ton. The largest contributor to the tariff is the PLN's tariff costing $ 21,595,886/year. Steam fuel cost for boiler is $ 26,209,137/year. Alternative GTG & HRSG + a boiler offer the least tariffs of both electricity and steam generated compared to other alternative units. Replacement of the existing GTG unit and HRSG could be more economical when applying steam descent activities at a gas processing facility. This is because most of the generation alternatives require a higher consumption of gas fuel to produce steam compared to that for electricity generation.

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