Biogenic gas – "from drilling hazard to promising future hydrocarbon resource": study of Mamberamo Frontier Basin, North Papua, Indonesia

Efrina Chandra Agusti Putri[1*], *Hermes* Panggabean[2], *Hamriani* Ryka[1], and *Nor* Shahida Henri[3]

[1]Geological Engineering Study Programme, Sekolah Tinggi Teknologi Migas Balikpapan, 76127, Indonesia
[2]Pusat Survey Geologi, Bandung, 40122, Indonesia
[3]Department of Geoscience, Faculty of Earth Science, Universiti Malaysia Kelantan Jeli Campus, 17600 Jeli, Kelantan, Malaysia

Abstract. Biogenic gas was previously considered as a drilling hazard before it has become captivating with competitive price and due to high demand. This study was done to diagnose rock formations which are prospective match up to revolutionary hydrocarbon system variables and to cast up volume estimation. The North Papua Basin, which classified as a foreland (hybrid) basin, is reckoned to have significant gas potentials from well data compliments Pleistocene Mamberamo sandstone with robust biogenic gas parameters, high methane composition (99-100%) and low CO2, H2S or N2 contents. Rapid sedimentation and low geothermal gradient play great role to establish effective biogenic gas system, followed by young-aged reservoir parameter. Field data comprise of soil gas sample supports geochemical investigation. Petrophysical and seismic interpretation results, as follow, are applied to assist volumetric calculation and uncertainty analysis using Monte Carlo simulation. Source rock evaluation from two wells reveals that Mamberamo Member D layer as the target is highly potential to become good source rock and storage of biogenic gas system in the area. The Monte Carlo simulation draws adequate correlation linking P50 (the most likely case) to the highest cumulative frequency in CDF curves, and testifies reasonable volumetric and resource calculation to be considered.

1 Introduction

As demand of fossil energy is still excessive, biogenic gas becomes more popular and is taken into consideration as an alternative. A shifting from oil to gas may be another reason to extending expedition and production of frontier basins to meet the potential composing favourable hydrocarbon resource. Biogenic gas is typically more environment-friendly due

* Corresponding author: efrinacap@gmail.com

to less carbon dioxide production than other fossil fuel type. The methane-rich gas is favourable since they widely spread in shallower depths of sedimentary basins, stored in both unconventional and conventional reservoirs [1,2,3]. Mamberamo Frontier Basin deems to have major gas field potential as supported by exploration during 1950s. From 12 wells drilled, almost half were pronounced as dry wells, meanwhile gas was found 2 other wells, and oil and gas well discovery from last well. Gas which is stored in Pleistocene Mamberamo Sandstones (Figure 1) in Niengo-1 well matched up to biogenic gas characteristic with 99-100% methane with low CO_2, H2S, and/or N2 content. Identification on how the rock formations are prospective match up to unconventional gas system parameters using geochemical and petrophysical approaches, along with seismic interpretation to create surface boundaries and allow to construct hydrocarbon volume calculation using *Monte Carlo Simulation*.

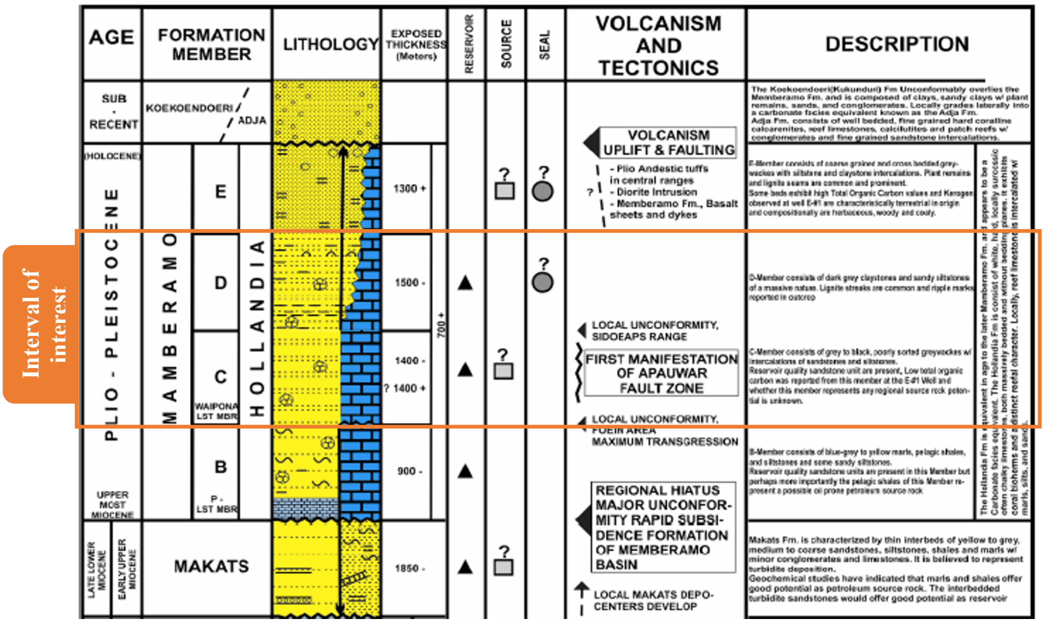

Figure 1. Mamberamo Frontier Basin stratigraphic column and petroleum system potential [4]

2 Research methods

2.1 Geochemical examination

Geochemical examination is sorted into two main processes, start with source rock appraisal from well Apauwar-1 and Muwar-1, supported by surface analysis of soil gas samples. Soil gas inspection obtained from microseepage is carried out to support subsurface geochemical analysis as a direct proof to active hydrocarbon prevalence in reservoir rocks, as well as to identify composition of light hydrocarbon to identify light hydrocarbon type in the research area [5]. In 1987, Whitaker and Sellens elaborated gas parameters, wetness (Wh), hydrocarbon balance (Bh) and character (Ch) to portray the gas generated from the formation, following light hydrocarbon ratio equation 1,

$$Wh = \frac{100(C2+C3+C4+C5)}{(C1+C2+C3+C4+C5)}; Bh = \frac{C1+C2}{C3+C4+C5}; Ch = \frac{C4+C5}{C3} \quad (1)$$

C1: methane; C2: ethane; C3: propane; C4: butane; C5: pentane

Gas dryness [6] equivalents to methane ratio divided by all light hydrocarbons (ΣCn) and will recapitulate as dry gas when the value is more than 0.95. The dryness ranking for each factor is presented in Table 1, coupled with previous parameters, gas signature graph which patronize gas type in samples as shown in Figure 2.

Table 1. Whitaker and Sellens classification of gas parameters and dryness [7]

Dryness	C1/ΣCn	Wetness and HC Balance	
Dry gas	>0.95	Dry gas	Wh < 0.5; Bh > 100
Possible condensate or light oil	0.85 – 0.95	Condensate or light oil	0.5 < Wh < 17.5; Wh < Bh < 100
Possible productive oil	0.6 – 0.85	Oil	17.5 < WH < 40; Wh < Bh
Residual oil	<0.6	Residual oil or water	Wh > 40

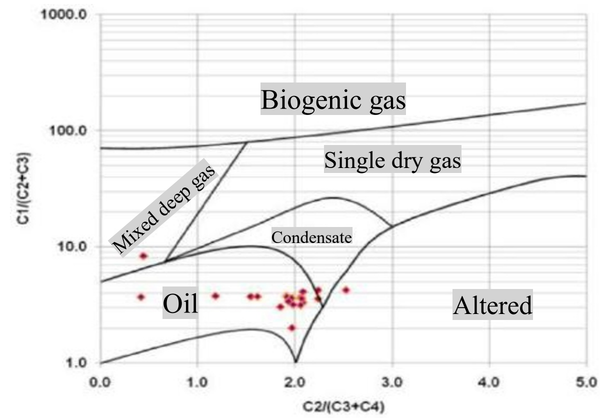

Figure 2. Gas signature cross plot [8].

2.2 Petrophysical analysis

The six wireline logs data act towards petrophysical investigation that subsequently will be employed in reservoir potential estimation. Shale volume was calculated based on quantitative approach using GR histogram, where sand base line is assigned at 5% percentile and the shale base line concurrently set at 95% percentile. Porosity estimation is derived from neutron-density logs using cross-plot between neutron porosity (NPHI) and bulk density (RHOB). Due to inadequate data, we made fresh water to become reservoir fluid as an assumption, with neutron porosity (NPHI) and bulk density (RHOB) equal to 1 v/v and 1000 kg/m^3 respectively. As per matrix parameter, quartz-matrix sandstone is taken on as the reservoir formation lithology so NPHI and RHOB will follow -0.05 v/v and 2.65 g/cm^3 consecutively.

Water saturation is determined using Humble equation owing to relatively low porosity value of reservoir interval with cementation factor m = 2 and n = 0.8. Salinity prediction conducted afterwards, before water saturation (S_w) by applying Indonesian equation, which suitable for sand heterogeneity in some reservoir intervals. Permeability calculation yields from Coates-Dummanoir Equation (1974) [9], by taking irreducible water saturation (Swirr) equals to 0.4.

Cut-off analysis is also carried on during the analysis to decide volume of shale (V_{sh}) value and effective porosity (PHIE) to next be using for calculating net to gross (N/G) value for each prospective closure from seismic line interpretation. Cross-plotting PHIE and V_{sh} in

X- and Y-axis respectively were done to get single cutoff value for Vsh and PHIE, and afterwards compute N/G (net to gross) value for each prospect.

2.3 Seismic line interpretation

By applying 15 offshore and 13 onshore acquisition seismic lines, we run seismic line interpretation. Top and base surface of interest interval is defined from 2-D seismic as well as contact surface in the middle of water and gas, which are formulated with several hypothesis taking into account top zone boundary, lowermost resistivity anomaly, or somewhere in between to define halved probability.

2.4 Uncertainty analysis to define resource appraisal with Monte Carlo Simulation

Preliminary resource estimation becomes crucial to some extent to define upcoming exploration step or whether any oil or gas field still worth under some uncertainties. Monte Carlo Simulation is applied to assess the resource potential in the study area and sort it using uncertainty analysis outlining worst case (P10), most-likely (P50), and best case (P90). This method is statistic-approached analytical tool which yields probability opposed to some resource appraisal parameter values [10]. The mechanism involves random distribution sampling according to probability parameter within the model to propagate hundred to thousand scenarios [11]. The uncertainties are pivotal to be settled down, either data sorting and interpretation stages (Samimi and Karimi, 2014), which brought up parameters like fluid contacts and petrophysical properties. The results are presented in histogram with all calculated probability levels, followed by presentation of cumulative distribution function (CDF) as the outcome to uncertainty variables and it should comply with triangular mode to attain nearly fair interpretation.

3 Result and discussion

3.1 Geochemical interpretation

From a new viewpoint in this research, Mamberamo Formation is indicated as the main source for unconventional biogenic gas system in North Papua Basin. This postulation is set up after brief evaluation on well data and geochemical analysis, and backed up by regional stratigraphic study conducted by McAdoo and Haebig [4], describing Mamberamo Formation (Plio-Pleistocene) comprises of sand-shale interbedded sequence that has good potential both as source rock and reservoir. Source rock analysis from well M-1 indicates 0.7-2% total organic carbon (TOC) in Mamberamo D interval which point out good organic richness (Table 1).

From soil gas analysis, quantitatively, the methane component magnitude looks to be notably prominent than other light hydrocarbon types and coincides with high CO_2 reading (Table 2).

Table 2. Gas magnitude summary from soil gas analysis in the research area

Gas type	# Sites	Minimum	Maximum	Mean	ST Dev	ST Dev/Mean
Methane	310	0.078	751330.000	4978.912	147872.521	1.972
Ethane	310	0.000	2.930	0.146	0.375	2.575
Propane	310	0.000	2.964	0.227	0.391	1.722

Iso-butane	310	0.000	0.841	0.037	0.072	1.923
N-butane	310	0.000	0.270	0.025	0.039	1.529
Ethylene	310	0.000	0.214	0.017	0.025	1.458
Propylene	310	0.000	0.431	0.005	0.026	4.883
CO_2	310	0.015	48.756	6.971	6.336	0.909

Gas quality analysis using modified Haword method is conducted furtherly to examine and define gas characteristics and is resumed in Table 3. Bernard parameter supports bacterial sourced gas generation, with value around 4.11×10^5 in average. This correlate to gas signature crossplot that backup biogenic gas result (Figure 3).

Table 3. Average value of gas quality ratio parameter

Parameters	# Sites	Minimum
Balance (Bh)	(C1+C2)/(C3+C4+C5)	480324.8127
Wetness (Wh)	(C2+C3+C4+C5)/(C1+C2+C3+C4+C5)*100	1.249702835
Gas Dryness	C1/ΣCn	99.02553583
Bernard Parameter	C1/(C2+C3)	410484.9934

3.2 Reservoir (petrophysical) analysis result

Based on V-shale calculation (Table 4), shale mostly goes hand in hand with some thin sand layers in between within Mamberamo D Member (Figure 4), that also actually supports regional stratigraphic study stated Mamberamo D Member compises mostly of deep marine shales. Thin sand sheets might still be prospective to be capable unconventional reservoir inter-shales (Table 5).

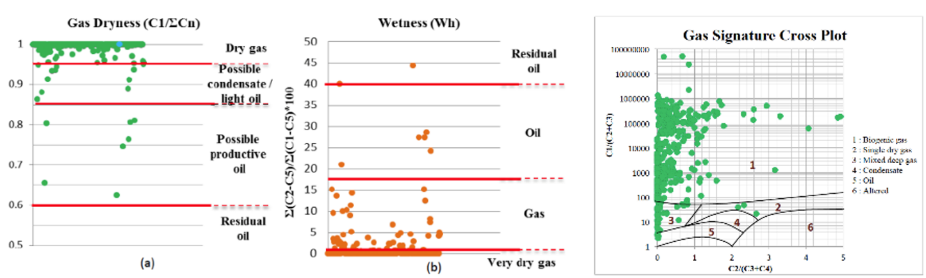

Figure 3. (a) Gas dryness plot (b) wetness (Wh) plot of soil gas sample; on the right: gas signature cross plot

Thin sand sheets can be still potential to become suitable unconventional reservoir in the middle of shale layer (Table 5). Effective porosity and V-shale base value that are determined based on cut-off analysis gives 0.09 and 0.5 respectively, in which needed for prospect net to gross calculation. To tackle unreliable parameter values, well data improvement can be done by conducting other tests, e.g. PVT (pressure volume temperature) test to record reliable gas formation volume factor (Bg), DST (drill stem test) to determine better water/hydrocarbon bearing zone, and core data to help validate each parameter, plus mud logging data to assure V-shale value.

Table 4. Mamberamo D Member gamma ray value in Apauwar-1 and Muwar-1 wells (5% - clean sand baseline and 95% - pure shale baseline) [12]

Wells	Mamberamo D Member GR values (API unit)		
	5%	50%	95%
Apauwar-1	53.125	70.629	88.427

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Muwar-1	54.848	64.385	91.605

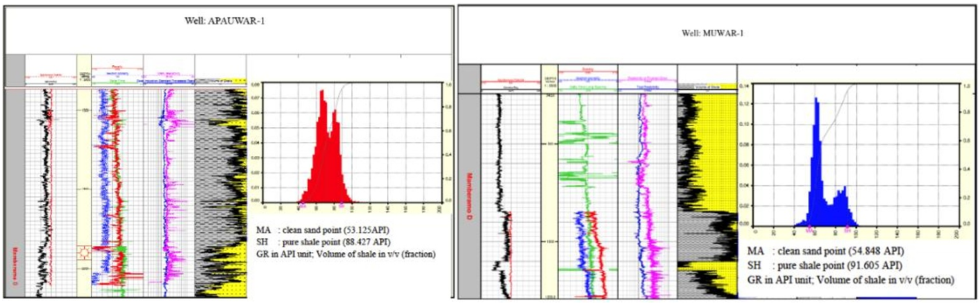

Figure 4. V-shale log and histogram showing clean sand and pure shale boundary in Apauwar-1 and Muwar-1 wells [13]

Table 5. Petrophysical parameters summary for Mamberamo Formation

Formation	Effective porosity (%)		Permeability (mD)		Water saturation (%)	
	range	average	range	average	range	average
Mamberamo E	13.8 – 29	22.2	5.1 – 96.7	33.5	0.94 – 0.97	0.95
Mamberamo D	**7.6 – 15.1**	**11.3**	**0.2 – 7.2**	**2.2**	**0.93 – 0.97**	**0.96**
Mamberamo B/C	8.4 – 24.9	12.1	0.3 – 53.5	2.8	0.87 – 0.97	0.95

3.3 Play concept and resource appraisal

Mamberamo D Member top and base surfaces were assigned from seismic line interpretation with well tops from nearby wells as the guidance. Surface smoothing and extrapolation were done to enhance and cover all area which is not well-represented by seismic. Scattered and low-quality seismic lines bring difficulties to some extent to be bounded by faults in fault modelling.

Prospective region is defined by looking for structural feature (dome or anticlinal look-like) from top surface of Mamberamo D Member. Closure A is located under Apauwar-1 well, whereas Closure B and C are underneath Muwar-1 well (Figure 5). Monte Carlo simulation follows by running through every prospect to assign distribution of probability and modelling uncertainty parameters because reservoirs are heterogenous and uncertain. The probabilistic technique deals with full range of values for each variable in reserve approximation, such as gas water contact (GWC), effective porosity and water saturation (fraction), gas formation factor (rcf/scf) and net to gross (NTG) value.

Gas water contact (GWC) value is established derived from deepest closed closure contour lines for P90 minimum value and for uppermost interval, high resistivity depth is used for maximum value (P10). Porosity and water saturation numbers are obtained from closure nearby well data. Gas formation factor comes to an assumption that gas follows conventional system nature with value 0.01[14] (Table 6).

The result (Table 7) is value of resource calculation escorted by uncertainty projection, ranging from P10, P50 until P90 using initial gas in place (IGIP) in Equation 4,

$$IGIP = \frac{Vb \times 43560 \times \phi \times (1-Sw)}{Bgi} \quad (4)$$

Vb : bulk volume, acre feet   Bgi : gas formation factor (scf)

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ϕ : porosity   Sw : water saturation
43560: conversion factor for gas in place

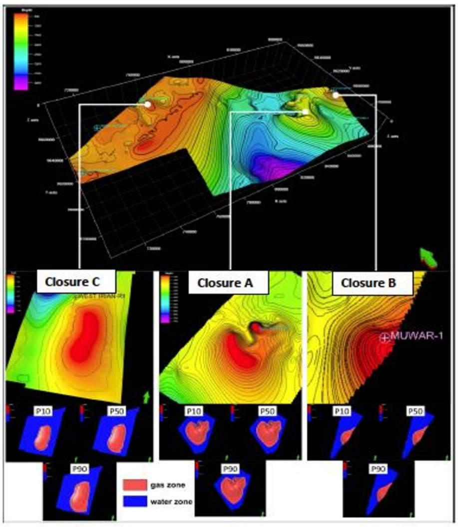

Figure 5. Prospect closures are determined from Mamberamo D Member top surface

Table 6. Uncertainty analysis parameter range and distribution calculated with Monte Carlo Simulation

Parameter of Uncertainty	Annotations	Base value	Distribution	Arguments Min	Arguments Mode	Arguments Max
Closure A						
Gas water contact (m)	\$GWC	-1981	Triangular	-2078	-1981	-1883
Effective porosity (fraction)	\$Porosity	0.11	Triangular	0.03	0.11	0.31
Water saturation (fraction)	\$Sw	0.7	Triangular	0.4	0.7	0.9
Gas formation factor (rcf/scf)	Bg	0.01	Normal			
Net to gross	NTG	0.073	Normal			
Closure B						
Gas water contact (m)	\$GWC	-1209	Triangular	-1280	-1209	-1138
Effective porosity (fraction)	\$Porosity	0.08	Triangular	0.02	0.08	0.26
Water saturation (fraction)	\$Sw	0.7	Triangular	0.4	0.7	0.95
Gas formation factor (rcf/scf)	Bg	0.01	Normal			
Net to gross	NTG	0.092	Normal			
Closure C						
Gas water contact (m)	\$GWC	-537	Triangular	-560	-537	-514
Effective porosity (fraction)	\$Porosity	0.11	Triangular	0.03	0.11	0.31
Water saturation (fraction)	\$Sw	0.7	Triangular	0.4	0.7	0.9
Gas formation factor (rcf/scf)	Bg	0.01	Normal			
Net to gross	NTG	0.025	Normal			

The quality of seismic data in this study may be unreliable, however the resource capacity approximation is quite acceptable to be take into account.

Table 7. Resource calculation results for all closures in P90, P50 and P10 probability

Probability	Closure A in m^3	Closure A in TCF	Closure B in m^3	Closure B in TCF	Closure C in m^3	Closure C in TCF
P90	3.82E+11	13.49	1.87E+10	0.66	4.07E+08	0.0144
P50	2.05E+11	7.24	9.23E+09	0.33	2.16E+08	0.0076
P10	9.71E+10	3.43	4.15E+09	0.15	1.03E+08	0.0036

It also is supported by Monte Carlo simulation that engaged great connection between most likely case (P50) to the highest cumulative frequency in CDF curves (Figure 6).

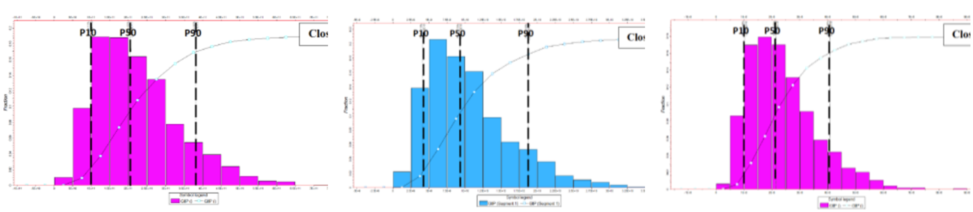

Figure 6. Cumulative Distribution Function (CDF) histograms for each closure in research area

4 Conclusions

Mamberamo D member has recognized to rise good unconventional source rock in the study area and suitable to be possible biogenic gas storage and manufacturer. From petrophysics side, the favourable interval has 11.3% and 2.2mD porosity and permeability values respectively. The best resource estimation for biogenic gas is valued 13.49 trillion cubic feet (TCF) and from uncertainty analysis pairing with volumetric calculation using Monte Carlo simulation arises 7.2 TCF in average. This study illustrates more comprehensive analyses of the biogenic gas system will be needed to give better knowledge to more fitting fieldwork and data gathering, that may guide to enhancing field development and beneficial production value.

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