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Techno-Economic Solution for Extending CCUS Application in Natural Gas Fields: a Case Study of B Gas Field in Indonesia

Prasandi Abdul Aziz[1], Mohammad Rachmat[1], Steven Chandra[1], Wijoyo Niti Daton[1] and Brian Tony[2]

[1]Dapartment of Petroleum Engineering, Faculty of Mining and Petroleum Engineering Institut Teknologi Bandung
Jl. Ganesha 10 Street, Lb. Siliwangi, Kecamatan Coblong, Bandung, West Java 40132, Indonesia

[2]Dapartment of Petroleum Engineering, Faculty of Technology Mineral Universitas Pembangunan Nasional "Veteran" Yogyakarta
Padjajaran Street, Sleman, Yogyakarta 55283, Indonesia
Corresponding author: amega.yasutra@itb.ac.id

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ABSTRACT - The application of carbon trading has been applied since 2005 in Northern America, has been adapted in Indonesia with pilot scale implementation namely as carbon capture and storage (CCS). One of the biggest issue is the lack of financial incentive in conducting the CCS. Therefore, carbon capture, utilization and storage (CCUS) serves as an alternative to increase the economic value of the injected CO_2. This study presents a new approach of CCUS studied in B Field in Indonesia, a natural gas producer with high CO_2 and H2S content. By injecting CO_2 as a mean of pressure maintenance, 5.8% of incremental gas production is achieved whilst being able to sequester 2.7 million tonnes of CO_2 for 10 years operation. This study should become a pioneer in continuing researches related to enhanced CCS methods by increasing the value of CO_2 as well as reducing dependency in expensive chemical EOR injection in the future.

Keywords: carbon capture and storage (CCS), carbon capture, utilization and storage (CCUS), CO_2, EOR

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INTRODUCTION

Background

The concept of Carbon Capture and Storage has been an endless talk since its inception in 2005 (IPCC, 2005). It has been projected that CCS will become one of the most effective solution in reducing the externalities generated from carbon dioxide pollution namely in large scale industries such as power plant, factories, and oil & gas industry. CCS has been successfully performed in several countries such as France, United States, Norway, and Canada (Global CCS Institute, 2017). Yet the problem arises when this policy cannot be wholly implemented in growing countries, such as Indonesia. One of the biggest obstacles that has to be faced is the lack of financial incentive in performing CCS, which is sometimes viewed as a non-rewarding work. Therefore, it is imperative to present an innovation in order to increase the economic attractiveness of CCS.

Indonesia, as one of the emerging economics in the world, is highly reliant on fossil fuel to power its economics. One of the most reliant sectors is oil and gas exploitation where approximately 47 million tonnes of CO_2 are produced in 2019 from this sector alone. The concern arises as Indonesia's economic growth goes bigger every year, its dependency on fossil fuel would render higher emission and reducing quality of life. However, without any incentive from the government to utilize CCS, major oil and gas companies does not have any intention in performing it without any certainties of both financial and legal underlying laws. In order to adapt the concept of CCS, it is then modified into Carbon Capture, Storage, and Utilization (CCUS) where the injected CO_2 is not only trapped but also provide some economic value, mostly to oil and gas business as an extension to enhanced oil recovery, a method to produce oil from reservoir that previously cannot be produced under conventional method or waterflood Green & Willhite., (1998). However, CO_2-EOR cannot be implemented in a shorter timeframe as it requires lengthy study, around 7-10 years and Indonesia's reservoir condition does not support field-wide, full scale EOR Muslim., (2013), Chandra et al., (2021). This publication presents a new concept on how to mitigate CO_2 production by reinjection to aquifer of gas reservoir, a concept which has not been previously applied due to the difficulty in finding the perfect sink. This study utilizes data from B Field in Indonesia, a highly productive natural gas field with excessive CO_2 production, intended to prove the concept of enhanced gas recovery (EGR) potential. Amijaya (2009), Usman (2021) and Bachu (2015) highlighted that exceptional CO_2 trapping mechanism would be performed on solubility and mineral trapping. It is most often that stratigraphic trapping would only be consistent for tens of years before CO_2 plume starts leaking, therefore the relatively massive aquifer present in B field would be an ideal solution for long term CO_2 sequestration, and also the presence of natural gas would be an added incentive for injecting CO_2 as a measure of pressure maintenance.

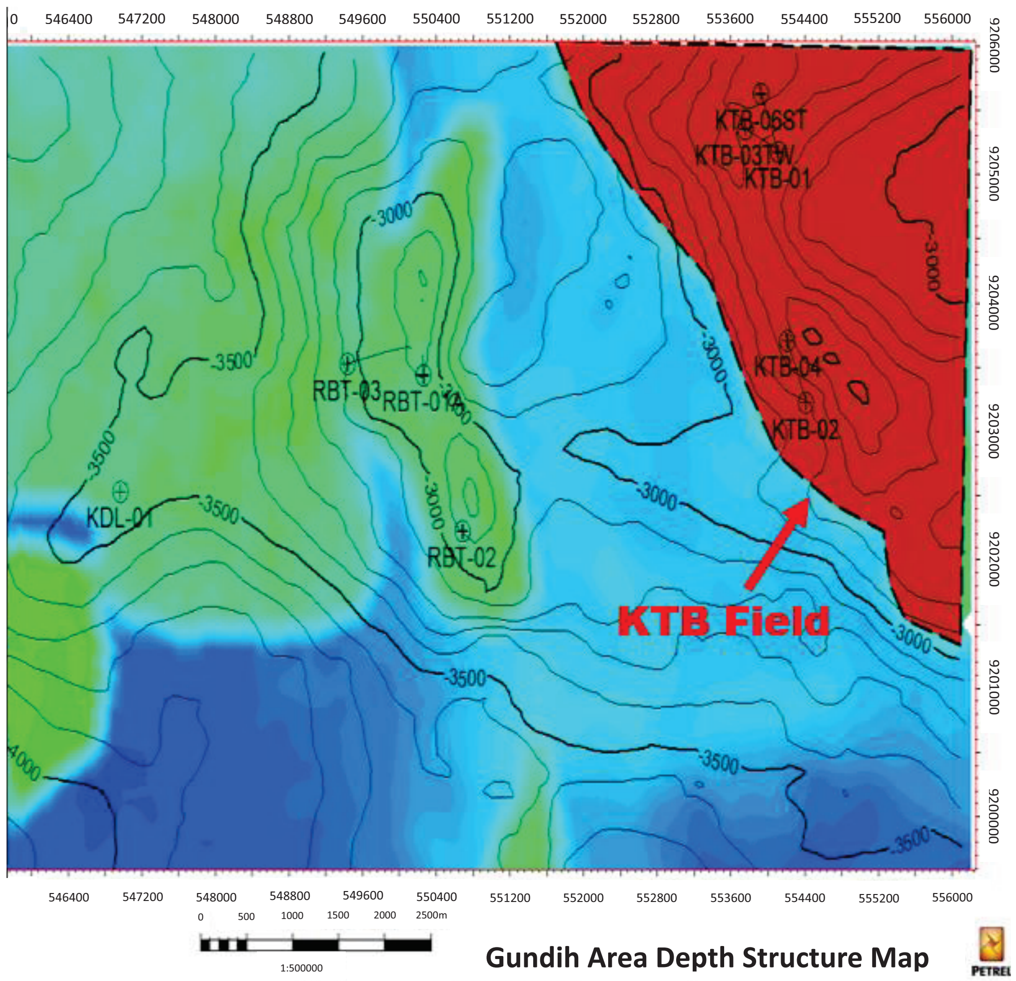


Figure 1
B Field location

Historical study in the nearby Gundih area has also proven that CCUS study can be performed without additional uncertainties Asikin., (2015) & Tsuji., (2014).

Field Characterization

B Field is a part of East Java Basin, seen on Figure 1, comprising of several major fields such as Bukit Tua, Banyu Urip, and Sukowati Oil and Gas Fields with estimated reserves of 15 billion barrels of oil and 19 trillion cubic feet of natural gas located in the Oligo-Miocene reef based basin system Satyana., (2002). Even though oil and gas has been actively explored since the times of Dutch East Indies, economically developing massive gas reserves in East Java Basin has been a challenge due to its nature, namely high presence of CO_2 and occasional presence of H_2S. These issues require technological advancements not only in gas separation issues, but also mitigation of CO_2 and H_2S waste. B Field has been operated since 2011, operated by Pertamina EP Asset-4. There are currently 5 active producing wells in the development area, shown below, bordering another prominent Randublatung Field. Based on geological characterization, B Field produces from carbonate reservoir with the main productive zone of Kujung Formation (Affandi et al, 2011).

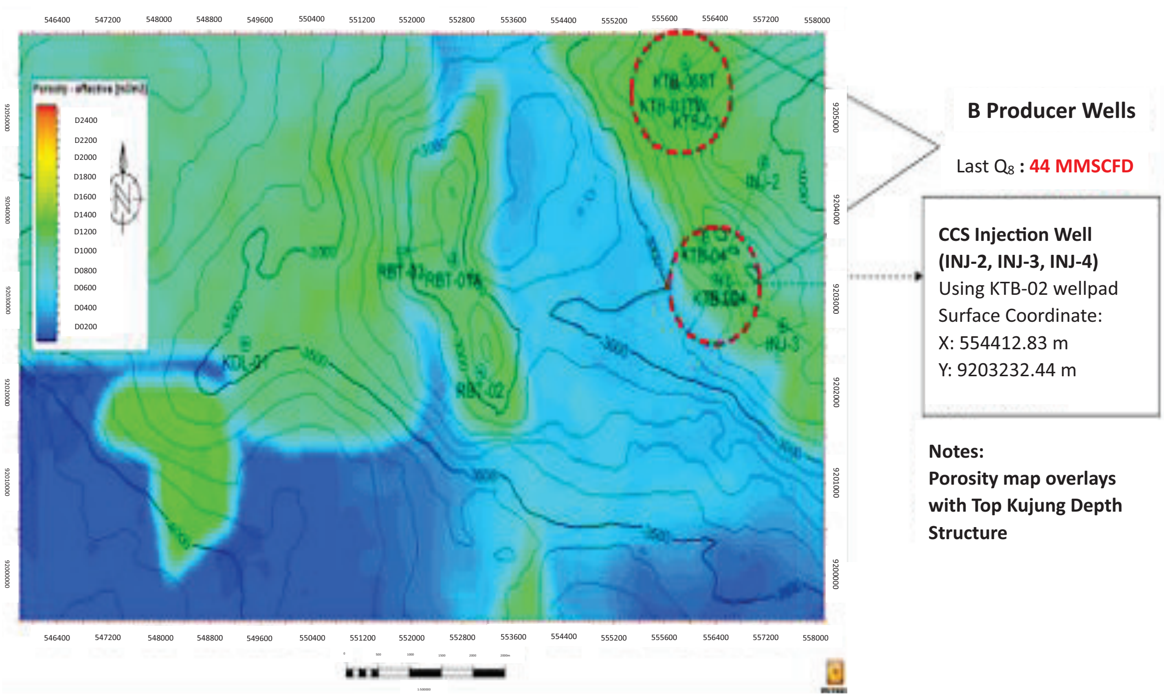


Figure 2
Location of The injected well

Produced reservoir fluid can be classified as retrograde condensate with high CO_2 (> 22%) and H_2S content (> 4000 ppm). Despite its challenge, the reservoir has been produced for almost 10 years, extracting around 79 BSCF of gas and 600 MSTB of oil.

In order to extend the lifetime of the reservoir, an idea is presented to inject CO_2 into the aquifer as a method of pressure maintenance to the gas reservoir above. It is a general practice that exploitation of gas reservoir hinges only on natural pressure difference between gas reservoir and the wellhead pressure, therefore maintaining high pressure is crucial in order to extend the life of gas reservoir. 2 wells are proposed to be an injection point of produced CO_2, seen below. It is also important to note that the effectivity of CCUS in maintaining gas reservoir pressure is reliant on CO_2 sequestration capacity of the aforementioned reservoir. Therefore, a correlation

Table 1
Estimation of CO_2 storability in B field

Pore Volume (m^3)	ρ_{co2} (kg/m^3)	GCO_2 Low (Mt)	GCO_2 Best (Mt)	GCO_2 High (Mt)
671 x 10^6	435	1.17	4.38	11.97

proposed by Goodman et al (2011) is proposed as a method to estimate the amount of CO_2 stored with three confidence levels shown below.

METHODOLOGY

In order to build a comprehensive case study that acknowledges uncertainties in CCUS for gas reservoir, several scenarios of injected CO_2 are then presented as shown on the list below.

- History Matching: 2014-2018
- Injection Start-up: Jan-2019
- Prediction until 2119 (100 years after injection)
- Case-1 (28 ton CO_2 / day)
  CO_2 injection rate: 0.57 MMSCFD
  Injection Duration: 2 years
- Case-2 (143 ton CO_2 /day) Pilot Project
  CO2 injection rate: 2.85 MMSCFD
  Injection Duration: 2 years
- Case-3 (750 ton CO_2 / day) Full Capacity of Gundih CPP
  CO_2 injection rate: 15 MMSCFD

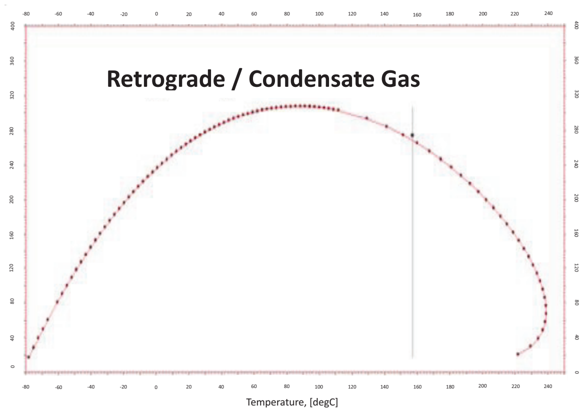
Injection Duration: 10 years

The following figures show reservoir fluid phase diagram, shown on Figure 3, concludes that the reservoir is a retrograde condensate reservoir, with initial gas in place (IGIP) of 297 BSCF and initial condensate in place (ICIP) of 4.6 MMSTB.

Prior to performing reservoir simulation, the model is first subjected into history matching, an effort to calibrate the reservoir model against test data from actively producing wells. There are several options to history match a natural gas reservoir, namely against gas rate, condensate rate, and/or bottom hole pressure. However, due to timing constraint of the study, only gas rate is matched, shown below, since the research emphasizes on the ability of injected CO_2 to maintain reservoir pressure and prolongs constant gas production rate ("plateau time").

Several assumptions are made in order to enhance the viability of the model, namely:

- k_v/k_h : 0.5 (RCAL data in water / targeted zone is required to reduce uncertainty)
- No hysteresis effect: no residual CO_2 trapping (SCAL data is required)
- Maximum Injection Pressure equals to Fracture Pressure, i.e. 8,000 psi (± 551 bar)
- The B field still producing (using last historical gas rate, i.e. q_g = ± 44 MMSCFD) until the end of field life



HYDROCARBON ANALYSIS OF SEPARATOR PRODUCTS AND CALCULATED WELL STREAM

Component	Separator Liquid Mol%	Separator Gas		Well Stream	
		MOL %	GPM	Mol %	Weight %
Hydrogen Sulphide	0.069	0.468		0.467	0.656
Carbon Dioxide	0.951	22.869		22.811	41.412
Nitrogen	0.165	0.353		0.353	0.407
Methane	1.102	71.444		71.256	47.157
Ethane	0.309	2.706	0.724	2.700	3.349
Propane	0.400	1.001	0.276	0.999	1.818
i-Butane	0.195	0.195	0.064	0.195	0.468
n-Butane	0.414	0.267	0.084	0.267	0.641
i-Pentane	0.405	0.107	0.039	0.108	0.321
n-Pentane	0.490	0.090	0.033	0.091	0.271
Hexanes	1.938	0.110	0.045	0.115	0.398
Heptanes	7.692	0.228	0.080	0.248	0.869
Octanes	14.435	0.122	0.049	0.160	0.646
Nonanes	15.646	0.027	0.013	0.069	0.315
Decanes	10.419	0.009	0.005	0.036	0.196
Undecanes	7.065	0.004	0.002	0.023	0.138
Dodecanes plus	38.305	0.000	0.000	0.102	0.938
Total	100.000	100.000	1.414	100.000	100.000

Figure 3
Reservoir fluid characterization for B field

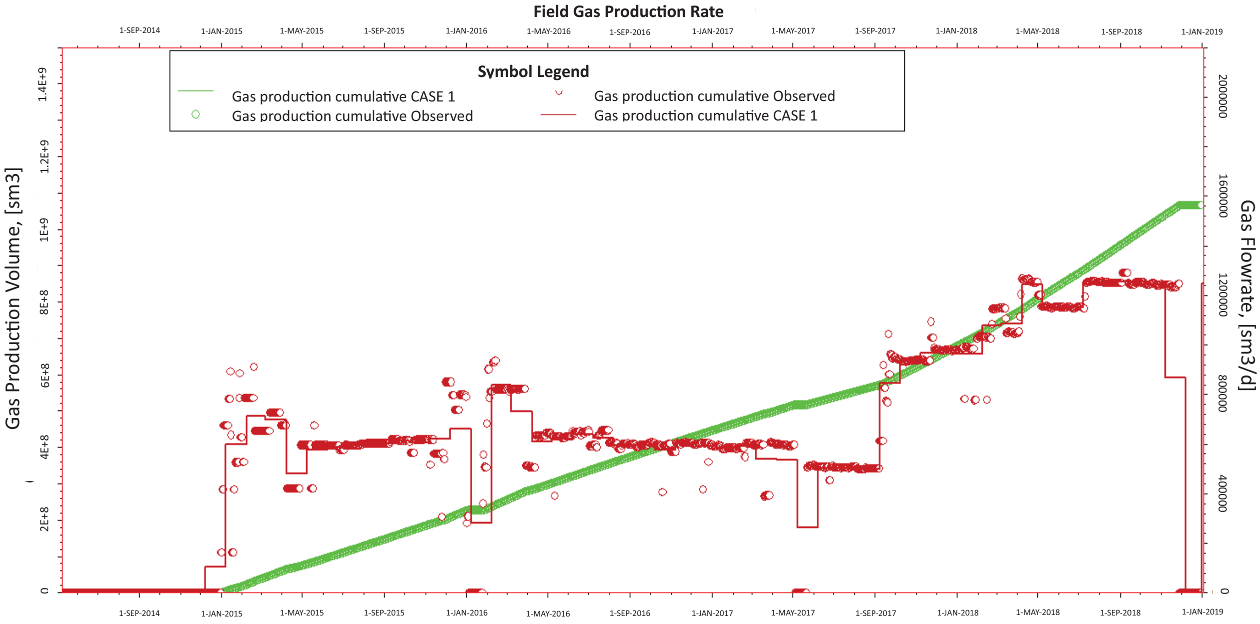


Figure 4
Results of gas rate history matching

- fluid injection composition: 100% CO_2 (in actual condition, H_2S can also be injected into reservoir but requires further study on well integrity)

The injection wells are located in the existing wellpad B-2, shown below, utilizing deviated well and perforated for 20 ft from 3896-3916 m MD. It is also important to note that the injection process is

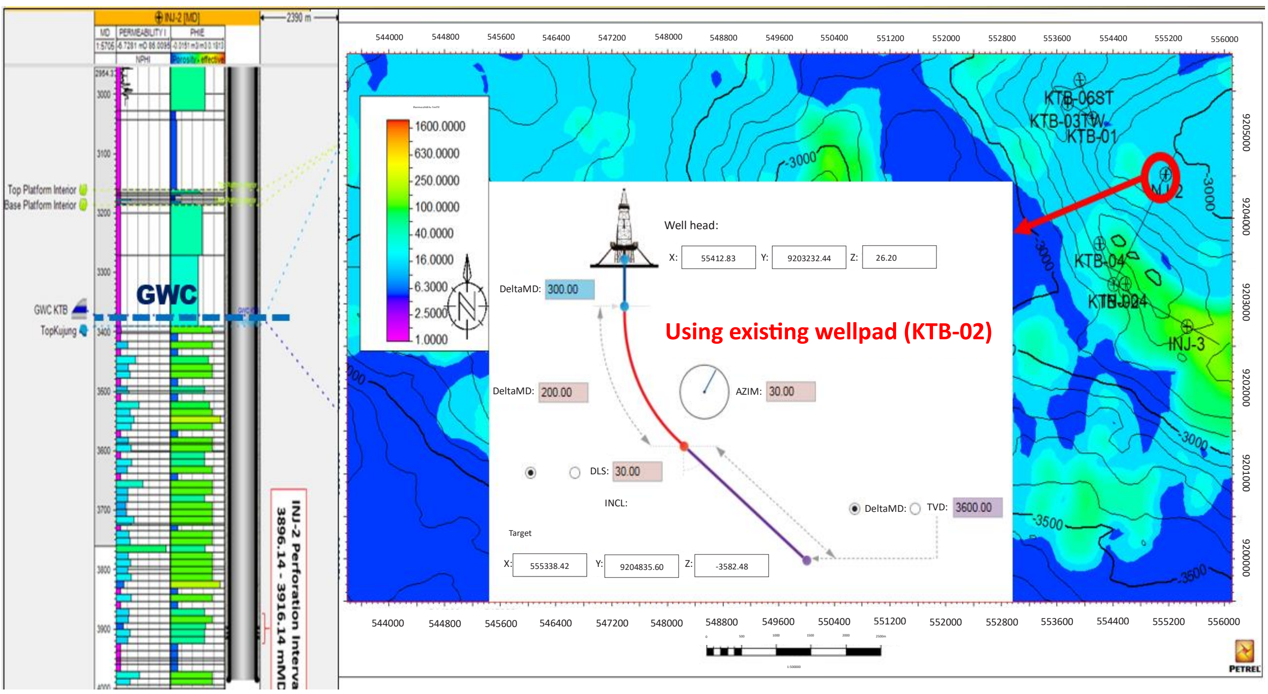


Figure 5
Injection well placement

performed below the gas-water contact therefore reducing the possibility of CO_2 leakage into the surface and limiting its role as pressure maintenance only.

RESULTS AND DISCUSSION

The following three cases are simulated for 100 years continuous CO_2 injection in order to monitor CO_2 plume growth as a function of time, as well as its effect on the overall performance to maintain adequate aquifer support for enhanced gas production.

- Case 1 (CO_2 Injection Rate 28 tonnes/day)

  The following figure 6 shows CO2 plume growth for case 1, where minimum plume growth of only 0.2 km in circumference is encountered during the 100 year injection.

As it is evident on the attached figures, minimum displacement is encountered on the first case.

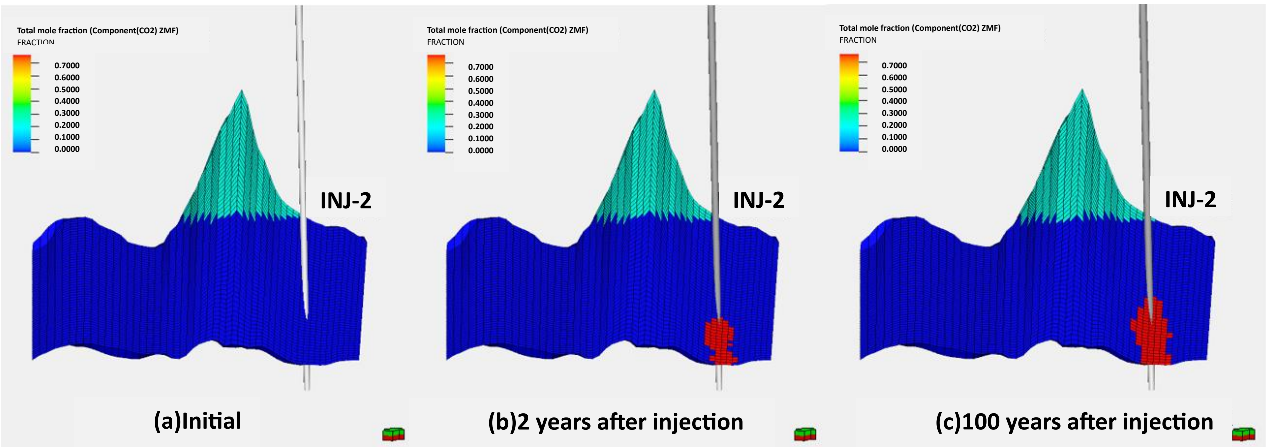


Figure 6
Cross section view of plume growth in case 1

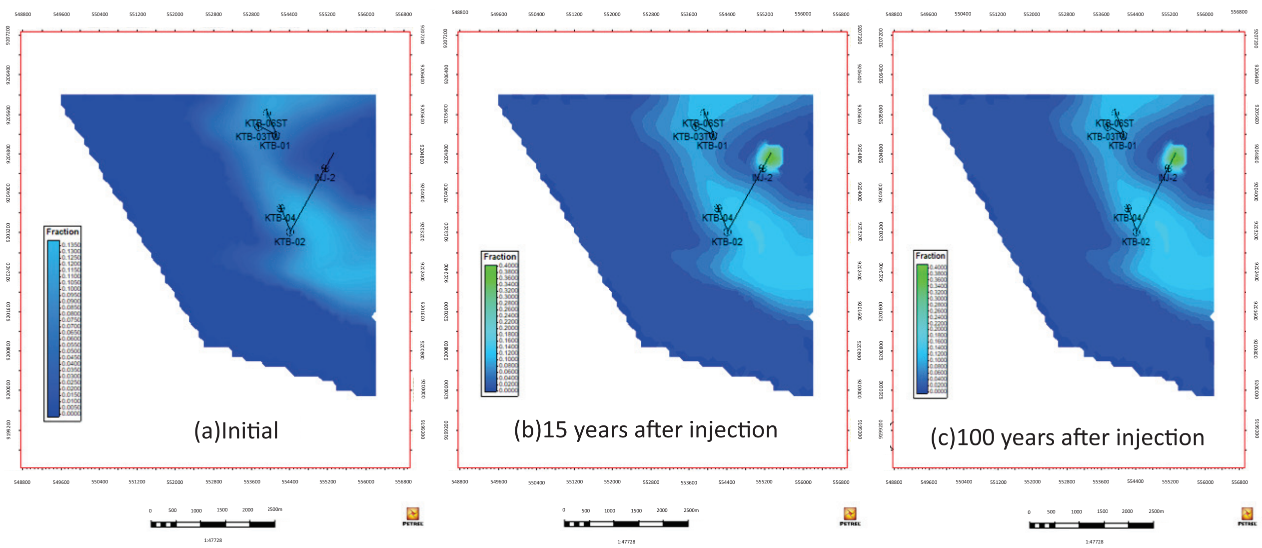


Figure 7
Lateral view of plume growth for case 1

However small it is, this injection sequence is highly important to be conducted prior to larger field scale injection process in order to assess reservoir storability and any potential of leakage.

- Case 2 (Injection Case of 140 tonnes CO_2 per day)

  The second case, injection of 140 tonnes of CO_2 per day shown in figure 7, performs better compared to the first case in terms of plume growth, analogous to better pressure support. It is worth

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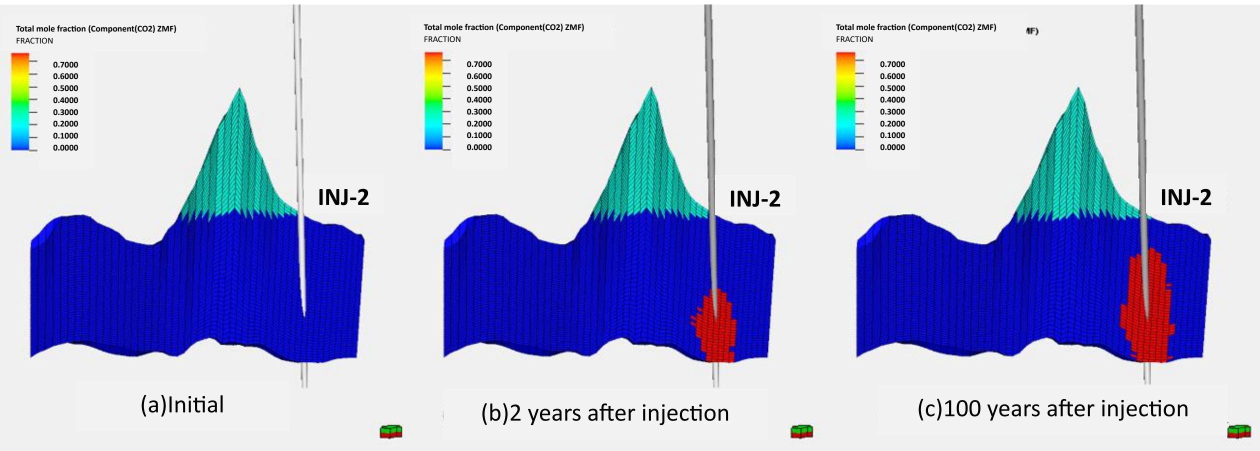

Figure 8
Cross section view of plume growth in case 2

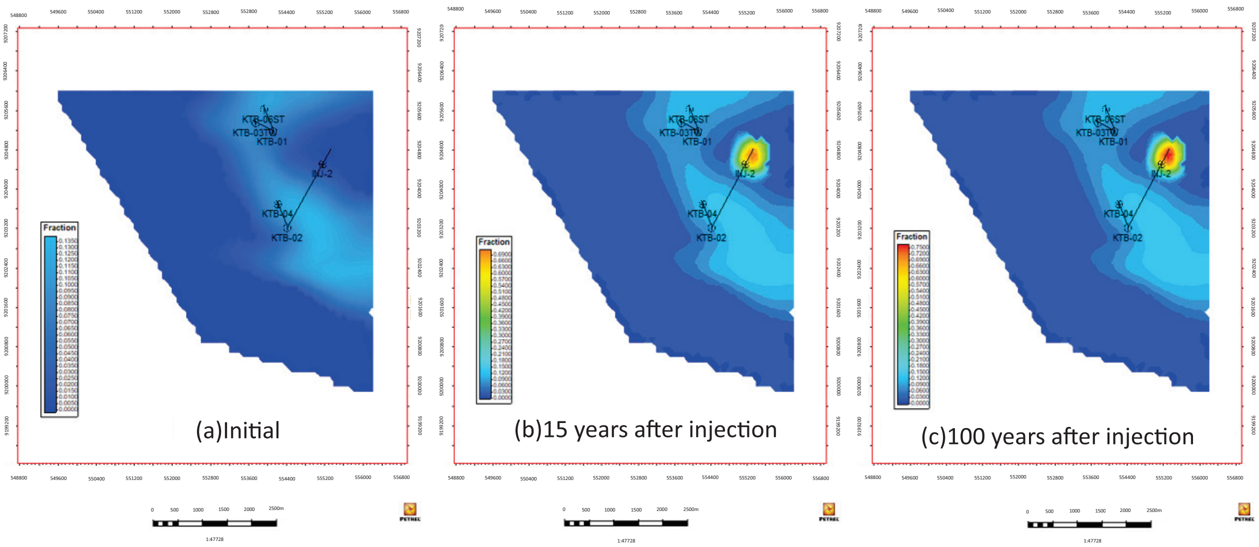

Figure 9
Lateral view of plume growth for case 2

noting that controlled injection is important in terms of maintaining plume growth stability.

- Case 3 (Injection Case of 700 tonnes CO_2 per day)

The third case, shown figure 10, is the best in terms of CO_2 plume growth and areal extent of the injected CO_2. From lateral view, it can be seen that injected CO_2 has an ability to extend aquifer support into two existing wellpads therefore increasing CCUS efficiency. Even though the result is promising, more study should be performed in order to ensure excessive breakthrough does not occur to gas bearing zones.

The injection study is then extended into full reservoir simulation study to observe the effect of injected CO_2 into reservoir performance. The selected case, case 3, is run and significant improvement in gas and condensate recovery, 36 BSCF and 382.7 MSTB, shown below, is observed whilst managing to sequestrate 2.7 Million tonnes of CO_2 in only 10 years of injection sequence. Approximate economic analysis is also calculated to measure the impact of the particular CCUS method, rendering 127 million USD assuming CO_2 tax of 3$/ ton CO_2.

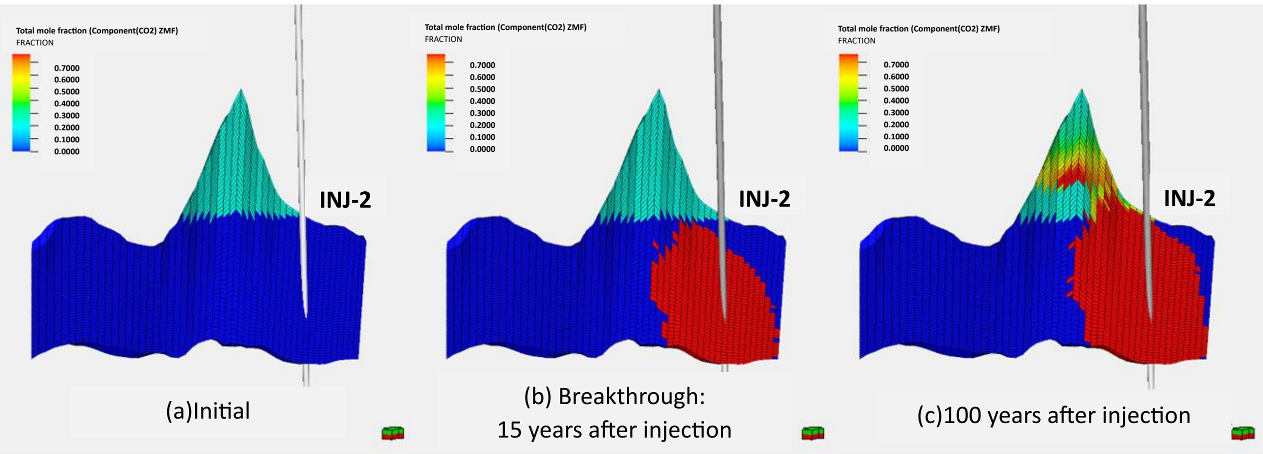

Figure 10
Cross section view of plume growth in case 3

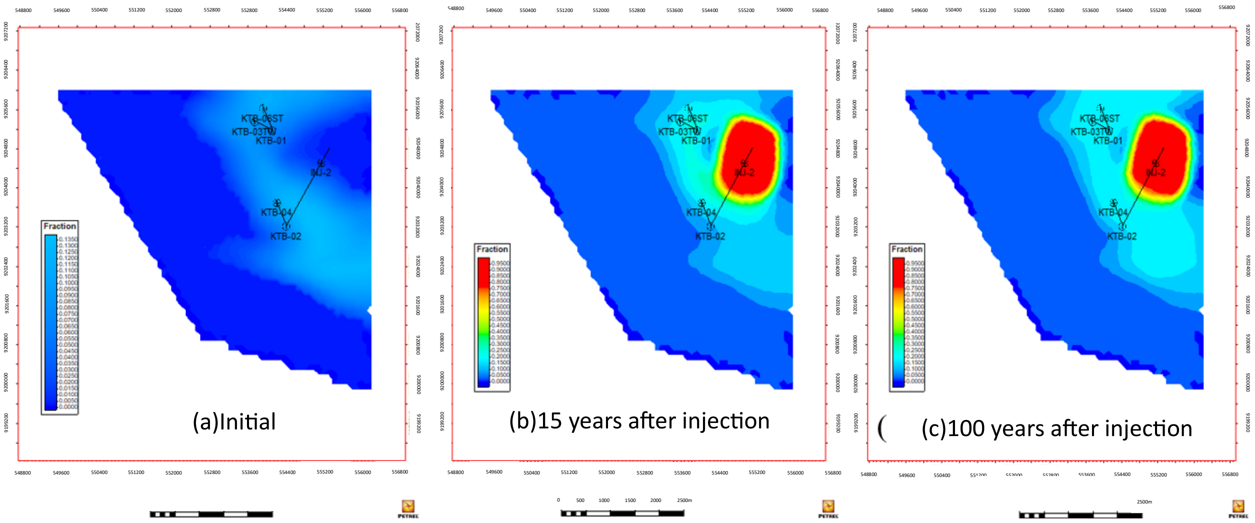

Figure 11
Lateral view of plume growth for case 3

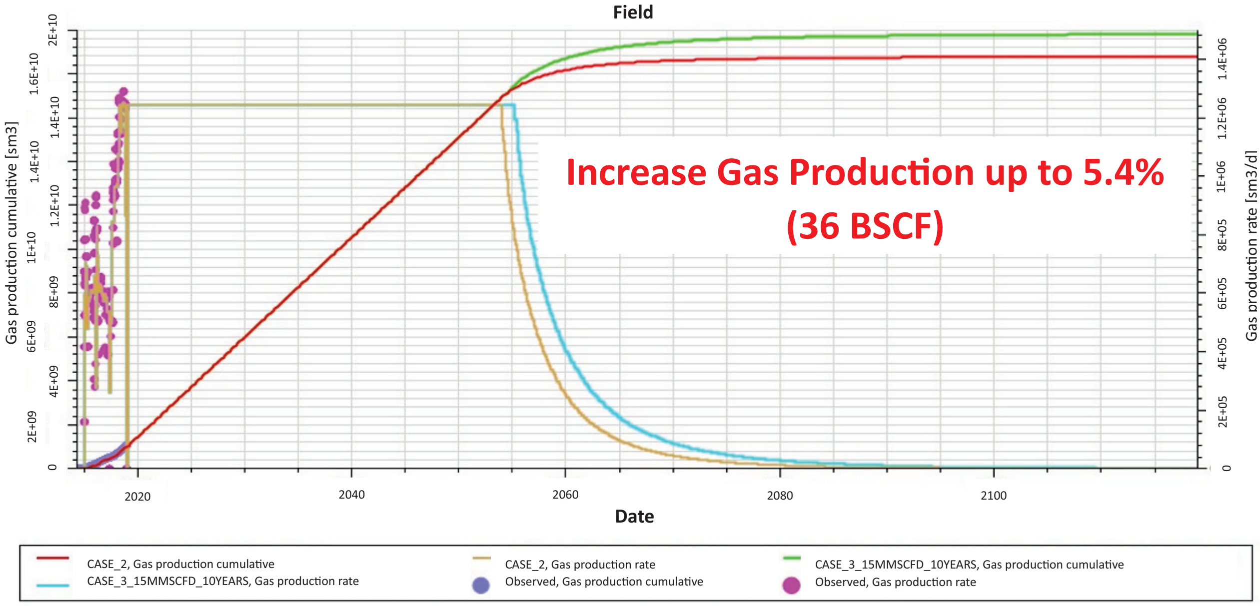

Figure 12
Incremental gas produced from case 3

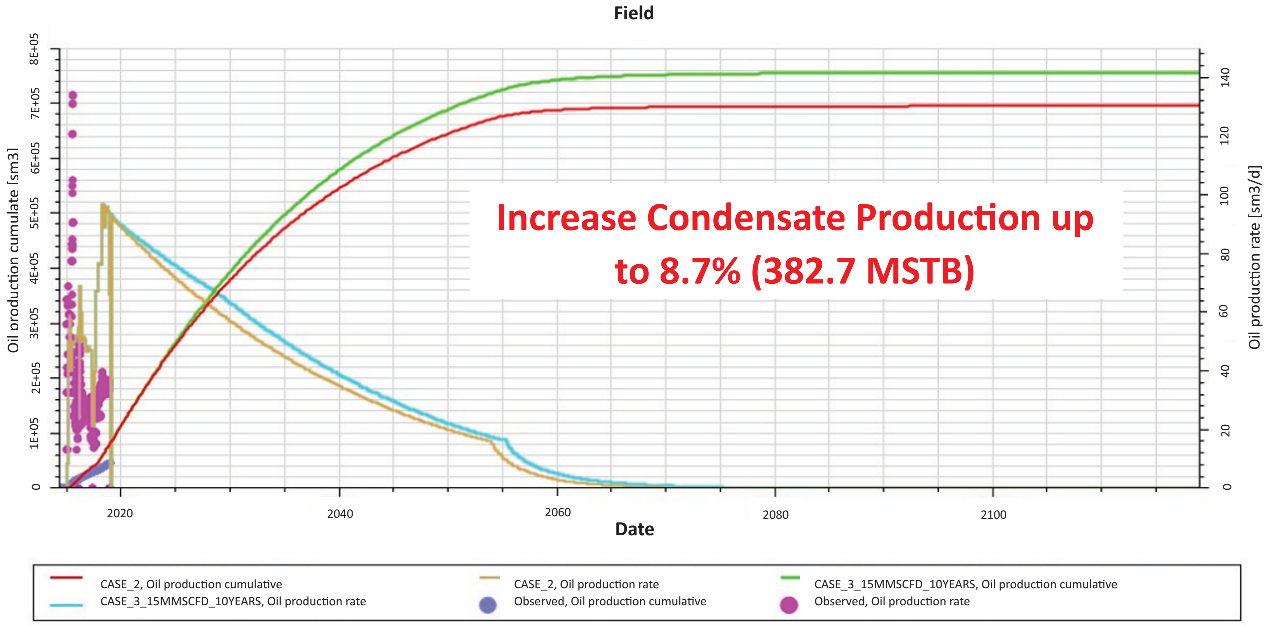

Figure 13
Incremental condensate produced from case 3

The results of the study has indicated that Enhanced Gas Recovery (EGR) Mechanism can be applied also in B Field, which corroborates the result from Muslim et al (2013) publication.

CONCLUSIONS

A new method of CCUS is presented in this publication where CO_2 is injected into natural gas reservoir as a method to maintain reservoir pressure. Simulation study performed on B Field in East Java, Indonesia has shown that sequestering 27 million tonnes of CO_2 generates incremental 36 BSCF of gas and 383 MSTB of condensate. Further study should enquire the effects of varying injection schedule as well as the effects of impurities in injected CO_2 to reservoir performance.

GLOSSARY OF TERMS

Unit	Definition	Symbol
	Carbon Capture and Storage	CCS
	Carbon Capture, Utilization and Storage	CCUS
	Enhanced Oil Recovery	EOR
SCF	Initial Gas In Place	IGIP
STB	Initial Condensate in Place	ICIP
	Carbon Dioxide	CO_2
	Hydrogen Sulfide	H_2S
Ppm	Parts Per Million	
MSTB	Thousand Stock Tank Barrels	
kg/m^3	Density	ρ
MMSCFD	Million Standard Cubic Feet Per Day	

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