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

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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 time-frame 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 mechanism 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.
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 CO₂ and occasional presence of H₂S. These issues require technological advancements not only in gas separation issues, but also mitigation of CO₂ and H₂S 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).

Produced reservoir fluid can be classified as retrograde condensate with high CO₂ (> 22%) and H₂S 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 CO₂ 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 CO₂ seen below. It is also important to note that the effectiveness of CCUS in maintaining gas reservoir pressure is reliant on CO₂ sequestration capacity of the aforementioned reservoir. Therefore, a correlation

<table>
<thead>
<tr>
<th>Pore Volume (m³)</th>
<th>Peq2 (kg/m³)</th>
<th>GCO₂ Low (Mt)</th>
<th>GCO₂ Best (Mt)</th>
<th>GCO₂ High (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>671 x 10⁶</td>
<td>435</td>
<td>1.17</td>
<td>4.38</td>
<td>11.97</td>
</tr>
</tbody>
</table>
proposed by Goodman et al (2011) is proposed as a method to estimate the amount of CO\textsubscript{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\textsubscript{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\textsubscript{2} / day)**
  - CO\textsubscript{2} injection rate: 0.57 MMSCFD
  - Injection Duration: 2 years
- **Case-2 (143 ton CO\textsubscript{2} /day) Pilot Project**
  - CO\textsubscript{2} injection rate: 2.85 MMSCFD
  - Injection Duration: 2 years
- **Case-3 (750 ton CO\textsubscript{2} / day) Full Capacity of Gundih CPP**
  - CO\textsubscript{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\textsubscript{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:

- \( \frac{k_v}{k_h} : 0.5 \) (RCAL data in water / targeted zone is required to reduce uncertainty)
- No hysteresis effect: no residual CO\textsubscript{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**

<table>
<thead>
<tr>
<th>Component</th>
<th>Separator Liquid Mol%</th>
<th>Separator Gas Mol%</th>
<th>Well Stream Mol%</th>
<th>Weight %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen Sulphide</td>
<td>0.069</td>
<td>0.468</td>
<td>0.467</td>
<td>0.656</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>0.951</td>
<td>22.869</td>
<td>22.811</td>
<td>41.412</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.165</td>
<td>0.353</td>
<td>0.353</td>
<td>0.407</td>
</tr>
<tr>
<td>Methane</td>
<td>1.102</td>
<td>71.444</td>
<td>71.256</td>
<td>47.157</td>
</tr>
<tr>
<td>Ethane</td>
<td>0.309</td>
<td>2.706</td>
<td>2.700</td>
<td>3.349</td>
</tr>
<tr>
<td>Propane</td>
<td>0.400</td>
<td>1.001</td>
<td>0.999</td>
<td>1.818</td>
</tr>
<tr>
<td>i-Butane</td>
<td>0.195</td>
<td>0.195</td>
<td>0.195</td>
<td>0.468</td>
</tr>
<tr>
<td>n-Butane</td>
<td>0.414</td>
<td>0.267</td>
<td>0.267</td>
<td>0.641</td>
</tr>
<tr>
<td>i-Pentane</td>
<td>0.405</td>
<td>0.107</td>
<td>0.108</td>
<td>0.321</td>
</tr>
<tr>
<td>n-Pentane</td>
<td>0.490</td>
<td>0.090</td>
<td>0.091</td>
<td>0.271</td>
</tr>
<tr>
<td>Hexanes</td>
<td>1.938</td>
<td>0.110</td>
<td>0.115</td>
<td>0.398</td>
</tr>
<tr>
<td>Heptanes</td>
<td>7.692</td>
<td>0.228</td>
<td>0.248</td>
<td>0.869</td>
</tr>
<tr>
<td>Octanes</td>
<td>14.435</td>
<td>0.122</td>
<td>0.160</td>
<td>0.646</td>
</tr>
<tr>
<td>Nonanes</td>
<td>15.646</td>
<td>0.027</td>
<td>0.069</td>
<td>0.315</td>
</tr>
<tr>
<td>Decanes</td>
<td>10.419</td>
<td>0.009</td>
<td>0.036</td>
<td>0.196</td>
</tr>
<tr>
<td>Undecanes</td>
<td>7.065</td>
<td>0.004</td>
<td>0.023</td>
<td>0.138</td>
</tr>
<tr>
<td>Dodecanes plus</td>
<td>38.305</td>
<td>0.000</td>
<td>0.102</td>
<td>0.938</td>
</tr>
</tbody>
</table>

| Total              | 100.000               | 100.000            | 1.414           | 100.000  |

Figure 3
Reservoir fluid characterization for B field

DOI.org/10.29017/SCOG.46.1.1321

Figure 4
Results of gas rate history matching

- fluid injection composition: 100% CO₂ (in actual condition, H₂S 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
performed below the gas-water contact therefore reducing the possibility of CO₂ 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 CO₂ injection in order to monitor CO₂ 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 (CO₂ 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.

- Case 2 (Injection Case of 140 tonnes CO₂ per day)
  The second case, injection of 140 tonnes of CO₂ 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

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 CO₂ per day)
  The second case, injection of 140 tonnes of CO₂ 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
noting that controlled injection is important in terms of maintaining plume growth stability.

• Case 3 (Injection Case of 700 tonnes CO₂ per day)

The third case, shown figure 10, is the best in terms of CO₂ plume growth and areal extent of the injected CO₂. From lateral view, it can be seen that injected CO₂ 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 break-through does not occur to gas bearing zones.

The injection study is then extended into full reservoir simulation study to observe the effect of injected CO₂ 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 CO₂ 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 CO₂ tax of 3$/ ton CO₂.
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

Increase Gas Production up to 5.4%
(36 BSCF)
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 CO₂ 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 CO₂ 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 CO₂ to reservoir performance.

GLOSSARY OF TERMS

<table>
<thead>
<tr>
<th>Unit</th>
<th>Definition</th>
<th>Symbol</th>
</tr>
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<tbody>
<tr>
<td>SCF</td>
<td>Initial Gas In Place</td>
<td>IGIP</td>
</tr>
<tr>
<td>STB</td>
<td>Initial Condensate in Place</td>
<td>ICIP</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Storage</td>
<td></td>
</tr>
<tr>
<td>CCUS</td>
<td>Carbon Capture, Utilization and Storage</td>
<td></td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
<td></td>
</tr>
<tr>
<td>IGIP</td>
<td>Initial Gas In Place</td>
<td></td>
</tr>
<tr>
<td>ICIP</td>
<td>Initial Condensate in Place</td>
<td></td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
<td></td>
</tr>
<tr>
<td>H₂S</td>
<td>Hydrogen Sulfide</td>
<td></td>
</tr>
<tr>
<td>Ppm</td>
<td>Parts Per Million</td>
<td></td>
</tr>
<tr>
<td>MSTB</td>
<td>Thousand Stock Tank</td>
<td></td>
</tr>
<tr>
<td>kg/m³</td>
<td>Density</td>
<td></td>
</tr>
<tr>
<td>MMSCFD</td>
<td>Million Standard Cubic Feet Per Day</td>
<td></td>
</tr>
</tbody>
</table>

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