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Economic Modelling of CO_2 Injection for Enhanced Gas Recovery and Storage: A Reservoir Simulation Study of Operational Parameters

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Abstract

This paper focuses on the recovery factor of natural gas production and storage by injecting CO_2 into a natural gas reservoir. This task will be performed by using reservoir simulation software (Roxar-Tempest) with experimental data initially produced by Clean Gas Technology Australia for a known field in North West Shelf Australia. The Optimum case is determined among different cases scenarios as a function of different injection rates, various stages of injection, destination of injection and production wells placement, and various layers in terms of rock qualities "Core Plugs". In addition, the economic feasibility of CO_2 injection for enhanced gas recovery CO_2-EGR and storage is valuated in terms development costs, costs associated with the process of CO_2 capture and storage as well as carbon credit with considering carbon tax for CO_2 storage. The simulation results show that the process of CO_2 injection and enhanced natural gas recovery can be technically feasible for this particular reservoir. Occurrence of mixing CO_2 with the initial gas in place is inevitable issue, while it can be limited by good reservoir management and production control measurements. Economically, the process of CO_2-EGR and storage is affected by many parameters such as CO_2 and natural gas prices and carbon tax, while carbon credit still makes the process more attractive.

Keywords: CO_2 reinjection rate, injection stage, gas recovery, CO_2 storage, net carbon credit

1. Introduction

The use of CO_2 injection in enhanced oil recovery is a mature well practice technology. Enhancing gas recovery through the injection of CO_2 however is yet to be tested in the field (Hussen et al., 2012). Although there are some published simulation studies that have been carried out to comprehend by which process CO_2 sequestration in a depleted gas reservoir could lead to enhance gas recovery, none of these studies have ever attempted to manifest the effect of mixing (CO_2-CH_4) on the recovery process prior to depleted reservoir. These studies were mainly aimed to reduce greenhouse gas emission in the atmosphere and sequestrating in a depleted gas reservoir or in an aquifer. In the year 2005, a project by Gas de France Production Netherland was in progress to assess the feasibility CO_2 injection prior to depletion of the gas reservoir (K12-B) for EGR and storage. However, since then no follow up results have been published on the final gain in reserve recovery (Meer, 2005).

Generally, high natural gas recovery factors along with concerns with degrading of the natural gas resource through mixing of the natural gas and CO_2 have led to very little interest been shown in CO_2-EGR (Clemens, 2002). In terms of sequestration, natural gas reservoirs can be a perfect place for carbon dioxide storage by direct carbon dioxide injection. This is because of the ability of such reservoirs to permeate gas during production and their proven integrity to seal the gas against future escape (Oldenburg et al., 2001). However, displacement of natural gas by injection CO_2 at supper critical state has not been studied extensively and not well understood (Mamora, 2002). Despite of the fact that CO_2 and natural gas are mixable, their physical properties such as viscosity, density and solubility are potentially favourable for reservoir re-pressurisation without extensive mixing (Oldenburg & Benson, 2002; Al-Hashami et al., 2005; Al-Hashami et al., 2005; Oldenburg et al., 2001). Technically, this phenomenon gas-gas mixing could be supervised via good reservoir management and production control measures, because these physical properties of CO_2 undergo changes as the pressure increases (Oldenburg & Benson, 2002).

Current research studies suggested that CO_2 emissions from fossil fuel have strong impacts on the environment, and its amount in the atmosphere is far beyond to be ignored (Ozkilic & Gumrah, 2009). There are many options for the separation and capture of CO_2 and some of them commercially available; none of them has been applied at the scale required as part of a CO_2 emissions mitigation strategy (David, 2000). However, carbon capture and sequestration is the most discussed method of sequestration and reduce CO_2 emission (Gupta, 2009).

The injected CO_2 in geological formations undergo geochemical interactions, such as structural, stratigraphic and hydrodynamic trapping. The injected CO_2 is trapped either in the form of physical trapping as a separate phase or as a chemical trapping where it reacts with other minerals present in the geological formation (International Energy Agency, 2010). As time passes, CO_2 becomes immobilized in the geological formation as a function of given long time scales. This is known as geological sequestration. Oldenburg (2003) simulated CO_2 as a storage gas. The results suggested that CO_2 injection as a supercritical fluid allows more CO_2 storage as the pressure increases due to its high compressibility factor. Thus, an expansion of the compressed is expected due to changes in pressure and temperature. As a result, there will be a point when gas production no longer is economically feasible.

Economically, (Gaspar, 2005) claimed the major obstacle for applying CO_2-EGR is the high costs involved in the process of CO_2 capture and storage. However, increasing knowledge and experience with contributions of new technologies will probably decrease these costs. Currently, CO_2-EGR and storage is promising when carbon credit is considered. However, this scheme is unlikely to be implemented into practice without any financial motivation or tax incentive (International Energy Agency, 2010).

In this study, the assessment of potential injection of carbon dioxide into a natural gas reservoir prior depletion is investigated based on experimental data produced at the Clean Gas Technology Australia and the results are very promising not just in terms of gas recovery, but also as a method for reducing anthropogenic gas emission simultaneously with increasing ultimate recovery of natural gas. In addition, this process is studied economically and illustrates the effects of carbon credit scheme on the project as a function carbon tax for CO_2 emission and credit for CO_2 storage during the process of CO_2-EGR and storage.

2. Reservoir Simulation

The base reservoir model used in this study is based on a known field in the North West Shelf. It is composed of sandstone which has homogeneous layer-cake geology and contains natural gas at a depth of 3650 meter. Reservoir core samples were studied experimentally to estimate the general petro-physical characteristics of the reservoir. The physical properties for each one of the tested cores were used as the base assignment to represent the geological model. The reservoir properties were then allocated throughout the reservoir simulation based on the interpretations of each pore plug. The gas reservoir model was created and controlled by variousness of cells distributions in terms of width, length and thickness.

The dimensions of the geological model, in the X-direction 17 grid-blocks used and 22 grid-blocks used in the Y direction. The divisions in the Z directions vary by layers, with 4, 5, 6 and 4 grid-blocks formed to represent layers L1, L2, L3 and L4, respectively. Thickness of each layer is various. Thus, the arrangement of the layers from top to bottom of the reservoir model start as very low, high, medium and low quality rock, respectively.

Table 1. General reservoir characteristic by layer

Layer	Z thickness (m)	Z direction (cells)	Kx (md)	Ky (md)	Kz (md)	Porosity (%)	Sgcr	Swcr	Core plugs
Very low	50	4	6	6	4	0.04	0.05	0.120	S_A_4
High	70	3	390	390	370	0.17	0.03	0.175	S_A_1
Medium	120	6	115	115	100	0.14	0.04	0.145	S_A_2
Low	60	5	8.5	8.5	6	0.09	0.05	0.100	S_A_3

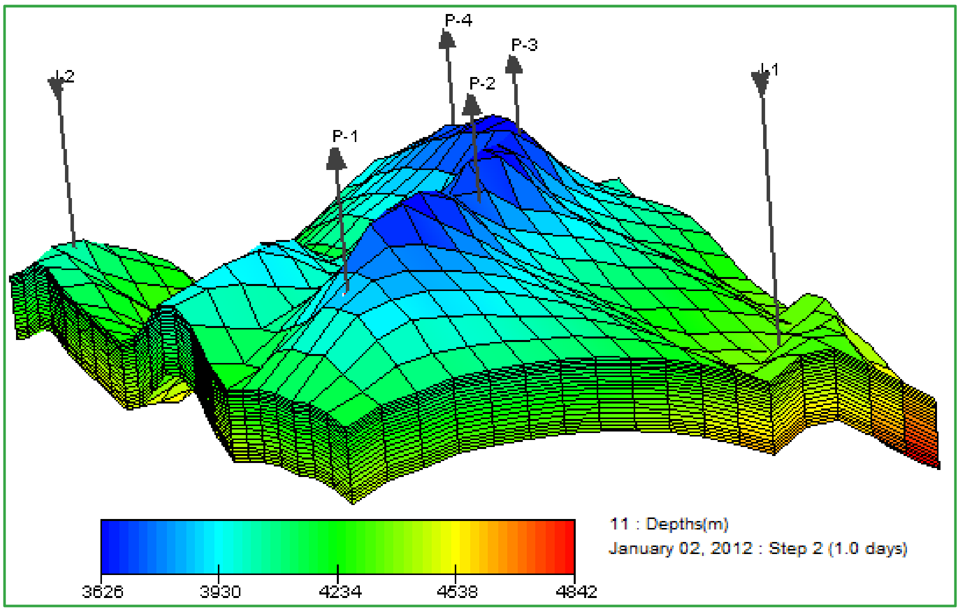

Figure 1. Reservoir simulation model

In terms of gas/water contact, reference depth of the reservoir, pressure and temperature at the reference depth and depth specifying the Water-Gas contact was calibrated to achieve the equilibrium initialisation. This provides indications of a transition zone between gas and water. As a result the simulator will take these values into account and stabilise the initial aquifer zone, which is allocated in depths of the bottom cells in the gas reservoir model. Beneath of this aquifer zones is the target for drilling and completion the injector wells where the injection strategies are proposed.

In general, the modelled aquifer in the subsurface of this gas reservoir meets the physical conditions of aquifers. First of all, the top layer of the aquifer is at a depth of "4400 m". Source (Gaspar et al., 2005) claims that aquifer beyond the depth of 800 m makes CO_2 to act as a supercritical fluid and it would have density as high as that for water. CO_2 density in aquifers with depth of greater than 3650 is higher compare to that of sweat water. In addition to the aquifer, the location and depth completion of the injection wells might have sufficient permeability and porosity to resist keeping the injected CO_2 in the aquifer.

CO_2 injection at the gas-water contact of the reservoir model has potential to act as a substitute support for pressure maintenance, thereby allowing simultaneously production of gas. In addition, it has been anticipated that the process will improve displacement efficiency and resulting in increased ultimate recovery factor (Knox et al., 2002). In order to understand the impact of the reservoir geology on potential development schemes, the simulation process uses the 'Solvent' option of the reservoir simulator, an extended black-oil model in which components coexist. The simulation standard compositions (SCMP) are reservoir gas (RESV) and solvent gas (SOLV). The reservoir gas depicts the mole fraction of the components in the mixture of the gas reservoir, which originally represents gas initial in place. The solvent gas specifies the solvent concentration in the injected gas (CO_2). The initial pressure of the reservoir model is set at 406 bar, and temperature of 160 C. 'PVT-Sim' used to generate the necessary PVT data for simulation. Furthermore, the relative permeability curves are generated using Darcy's Law to achieve displacement between the gases.

Table 2. Reservoir model parameters

Property	Value
Reservoir type	Sandstone
Reservoir depth	3650 m
Area (X-Y direction)	1700 m x, 2300 m y
Thickness (z direction)	300 m
Grids in X direction	17
Grids in Y direction	22
Grids in Z direction	4, 5, 6 and 4 for L1, L2, L3 and L4
Relative permeability	JBN method and Darcy's law
Initial reservoir temperature	160 C
Initial reservoir pressure	406 bar
Well injector pressure (maximum)	450 bar
Well producer pressure (minimum)	50 bar
CO_2 injection rate	2400 and 1260 $\times 1000$ m^3/day
Maximum gas production rate	14000 $\times 1000$ m^3/day

The development of the geological model is designed to illustrate optimisation of the gas recovery initial in place. In order to determine the optimal development plan and to test its robustness over the uncertainty range of reserves, a number of dynamic reserve simulation models are constructed. Over all, for all scenarios the initial component names in the gas mixture are listed as C_1, C_2, C_3 and CO_2. A mole fraction or initial composition of each one of the mentioned components is 0.9, 0.005, 0.005 and 0.09 respectively (Table 3). Production of these gases can be economically advantageous and replacing the produced gas would allocate extra space for further CO_2 deposition.

Table 3. Compositional table

Component	Composition
CO_2	0.09
C_1	0.9
C_2	0.005
C_3	0.005

In addition, a simplified gas layered model in which the components coexist consists of 1.7×2.3×0.3 km grid cells (see Table 2). In addition, the detailed geological modelling is used to test the selected development plans against wide range of geological outcomes. This model incorporates significant areas of local grid refinement to properly model the fluid flow in the neighbourhood of the production wells. The base case development plan calls for three vertical production wells, allocated and perforated in the upper layers of the reservoir. These production wells are expected to produce natural gas at same rates. In general, the production wells are controlled as a function of a maximum gas production rate per day and a minimum producing bottom-hole pressure for each well. The summation of the production rates for each one of the wells is equivalent to the total gas production per day "14000$\times$ 1000 m^3/d" of the reservoir simulation.

The simulation suggests that there is sufficient vertical permeability in the reservoir to allow the gas in the lower portions to move towards the wells. Two gas injectors well are proposed to dispose of the produced CO_2 by re-injecting it into the gas reservoir down-dip of the production wells. The perforated locations of the wells will be at a distance such that CO_2 breakthrough at the production wells is after the plateau production (Willetts et al., 1999). By contrast to the producer wells, the injection well is perforated in the bottom layer beneath the zone of G/W contact in order to take gravity effects into account. This potentially could have enough capacity to handle breakthrough volumes as wells as CO_2 re-injection.

3. Base-Case Simulation Model

The objective is to investigate the influence on the flow through the main reservoir characteristic units, like porosity, permeability, and water and gas saturation. In addition to this case, the maximum gas production is sat at 3500×1000 m^3/day for each well. In order to test the model, the reservoir layers estimated to be filled with a homogeneous gas mixture (Table 3). Simulation of natural gas production without any injection is performed for a base-case under normal production conditions in such a way that the bottom-hole wells pressure decline at a time period of 20 years. In this way potentially the full range of the reservoir geological is carried through the dynamic reservoir modelling. As a consequence, the proposed development cases can be optimised over the range of the reservoir uncertainty and also illustrate the sweep efficiency of CO_2 injection. Under this case, cumulative methane and CO_2 production "lb-mole" and bottom-hole pressure "bar" are estimated for the selected period of time (Figures 2, 3 and 4).

This case is intended to be the basis for comparison, to illustrate the acceleration of methane production, and lower CO_2 production under a case of CO_2 injection as a function of given different injection rates, various stages of injection, destination of injection and production wells placement, and various layers in terms of rock qualities "Core Plugs". The bottom-hole pressure BHP is measured in this case and under a late stage of CO_2 injection, the measured BHP decline is used to determine the time start of CO_2 injection.

4. Development Case Study

4.1 High Injection Rate

Under the base-case, the initial gas production from this gas reservoir model is started in January 2012 through Well 1, 2, 3 and 4. The pressure declined gradually from its initial pressure around 380 bar as a response to the gas production. Accordingly, two injector wells are used as disposal wells to re-inject the initial CO_2 production directly into the formation instead of it being emitted into the atmosphere. Thus, CO_2 is injected in a liquid-like state into the gas reservoir at a rate of 1200 m^3/day for each well. The maximum gas production rates for each one of the producer wells is sat as it was under the base-case. This case shows the effects of CO_2 injection onCO_2 storage and the enhancement of natural gas production compared to the natural gas production that under the base case. In addition, different case scenarios are investigated as a function of strategy and operational parameters of CO_2 injection. Under injection process, the simulation results show, CO_2 injection allows enhancing the initial natural gas production and potentially maintaining initial reservoir pressure decline during gas production (Figures 2, 3 and 4).

In this scenario the layers of the reservoir model arranged from the top to the bottom as very low, high medium and low quality of rock respectively. In the following section, various layer arrangements are tested to determine the optimum layer arrangement for CO_2 injection as a function of enhance gas recovery and storage. This investigation is performed based on effects reservoir re-pressurisation in terms of injectivity of CO_2 and distribution of the injected CO_2 as a function of permeability. Therefore, the simulation study is examined for another two more scenarios, for second scenario as very low, low, medium and high rock quality and for the third scenario as high medium low and very low quality of rock.

Under scenario 2, injectivity of CO_2 is higher than the other two scenarios (Figure 9). Thus, the injected CO_2 is first expected to distribute from the bottom of the reservoir faster and results in reservoir re-pressurisation faster, before it starts to rise to the top of the reservoir. But because the other two layers from the top of the reservoir represent very low and low permeability, the injected CO_2 is expected to overrun the native gases presented in the bottom of the reservoir to production wells faster than it is under the first scenario. This would have side effects on sweep efficiency. On the contrary, the third scenario represents the lowest injectivity of CO_2. In this case CO_2 is injected into very low permeable layer and the layer followed by another low permeable layer. Therefore, the injected CO_2 is expected to find its own path and potentially will prefer to break through the production wells rather than to be distributed in the bottom of the reservoir.

In general the simulation results indicate that scenario 1 has the highest recovery factor of methane production and scenario 3 represents the highest CO_2 recovery factor. In addition, scenario 2 comes as the second recovery factor for both CO_2 and methane(Figures 3 and 4).While, scenario 3 produces the lowest methane recovery factor and scenario 1 yield the lowest CO_2 recovery factor. As a result scenario 1 is the optimum for enhance gas recovery and storage under CO_2 injection process. Despite of reservoir layers, Feather and Archer (2010) claimed that during CO_2 injection for a gas reservoir, the re-pressurization will happen faster, while the actual flow of the fluid will take longer. Therefore, it is advantageous to place the injection well as far as possible from the production wells. Destination between injection and production wells will lead to increase initial gas production and delay the breakthrough of CO_2 for as long as possible (See Figure 5).

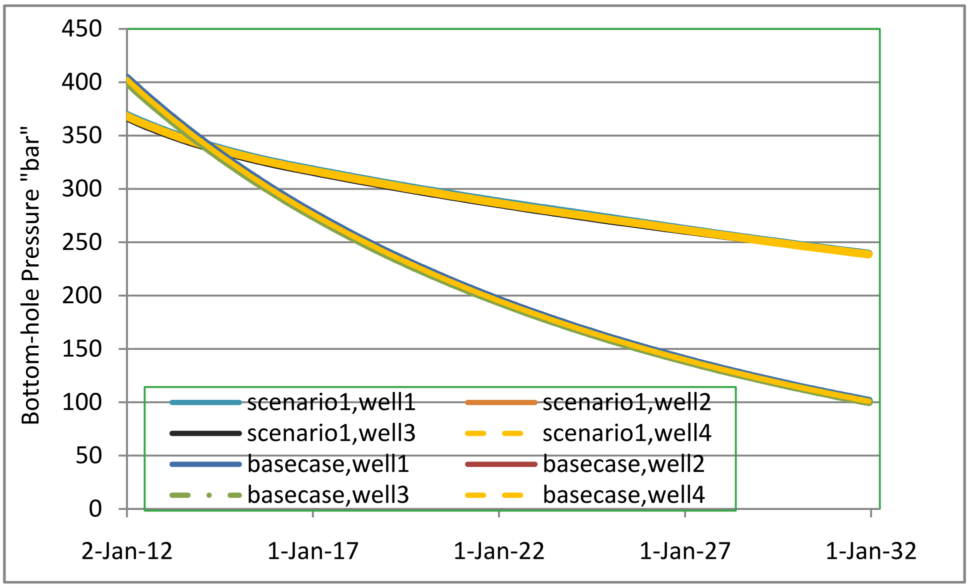

Figure 2. Bottom-hole pressure of base case versus first scenario

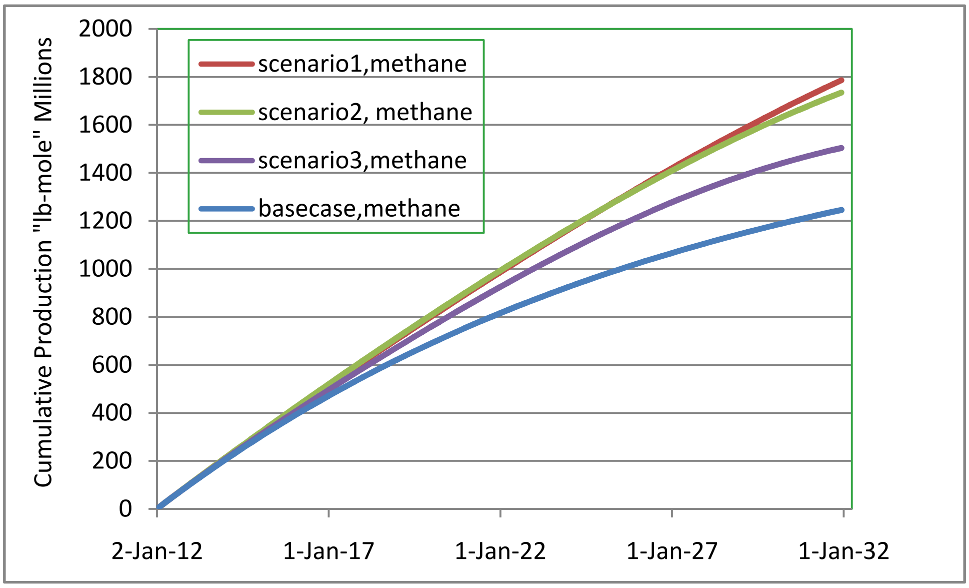

Figure 3. Comparisons of cumulative methane production under different conditions

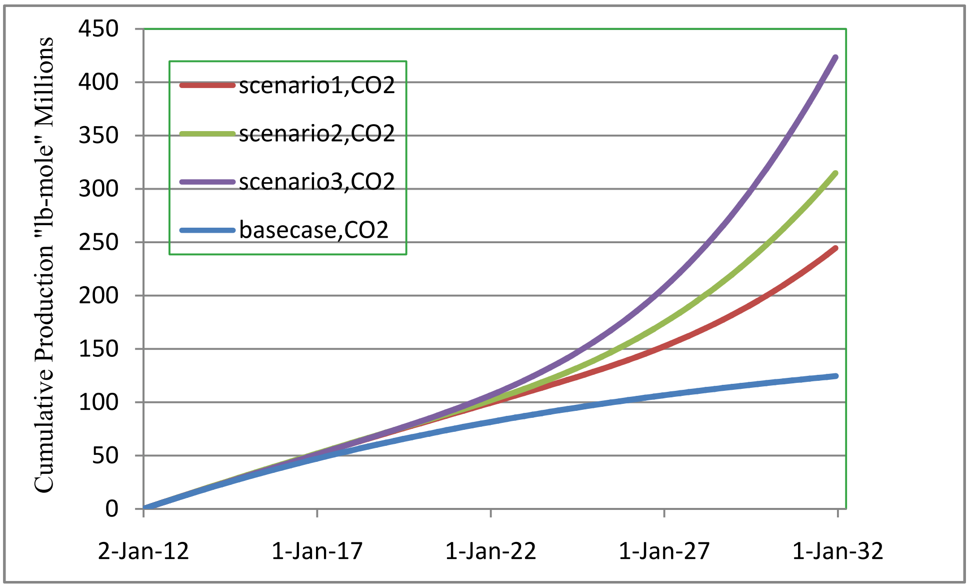

Figure 4. Comparisons of cumulative CO_2 production under different conditions

For the optimum scenario the simulation is run without considering solubility factor. The results of the simulation suggest that with CO_2 dissolution in the formation water, Figure 5 shows the CO_2 breakthrough points to be in 26 December 2016 (well 1), 31 March 2015 (well 2), 27 September 2015 (well 3) and 29 December 2014 (well 4). In comparisons to these dates without case of solubility, the simulation indicates breakthrough on 26 September 2016, 28 September 2014, 28 June 2015 and 29 June 2014 for production wells 1, 2, 3 and 4 respectively. This comparison demonstrates the maximum methane production and the fraction of CO_2 remaining in the reservoir. The comparisons between the scenarios indicated that the solubility of CO_2 is greater than methane at all relevant pressure and temperature. This implies a reduction in the volume of CO_2 available in the gas reservoir to mix with methane, which potentially delays CO_2 breakthrough. The effect of CO_2 solubility obtained in this study accords with Al-Hashami et al. (2005). Thus, in the following cases continuously only the scenario of solubility is taken into account.

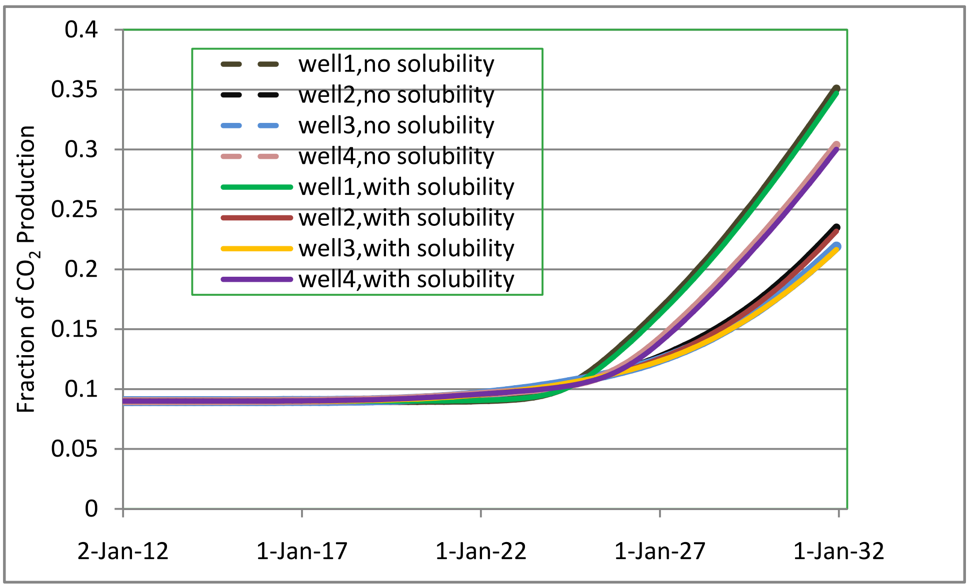

Figure 5. A comparison of CO_2 breakthrough with and without solubility consideration versus Time

4.2 Low Injection Rate

In this case the optimum scenario with considering solubility is investigated under low injection rate. The maximum CO_2 injection rate is sat at 1260× 1000 m^3/day.This injection rate partially is 9% of the total maximum gas production. To achieve higher injection rate, additional amount of CO_2 is required to reach to the required rate of injection. Economically, this will have jeopardising influences on the project. Because the higher is the injection rate the more costs would be involved in the process of CO_2 capture and storage. In this study, the priority focus is on reinjecting the produced CO_2 from the production stream directly to the sink rather than vented it into the atmosphere. This is for the purposes of environmentally friendly, production enhancement and beneficial of carbon credit. Therefore, CO_2 injection rate will be sat as close as the production rate of CO_2, during the injection strategies, any extra or less CO_2 requirement compared to CO_2 production will be considered in terms of cost of CO_2 capture and storage. In this prospective, costs of CO_2 might not have big jeopardizing effects compare to that under the higher injection rate.

Figures 6 and 7, illustrate comparisons between high and low injection rates as a function of enhanced gas recovery and CO_2 breakthrough. The comparison between the two different injection rates indicates the gas recovery factor under the high injection rate is greater than that in the lower case and the base-case.Accordingly, the bottom-hole pressure decline less gentle than it is under the high rate of injection (Figures 2). On the other hand, Figure 7 demonstrates different times of CO_2 breakthrough under different injection rates and indicate that the high injection rate of CO_2 the earlier breakthrough is occurred. As a result, the simulation suggested that even though CO_2 injection excessive gas mixing, at the same time it has potential to increase incremental gas recovery.

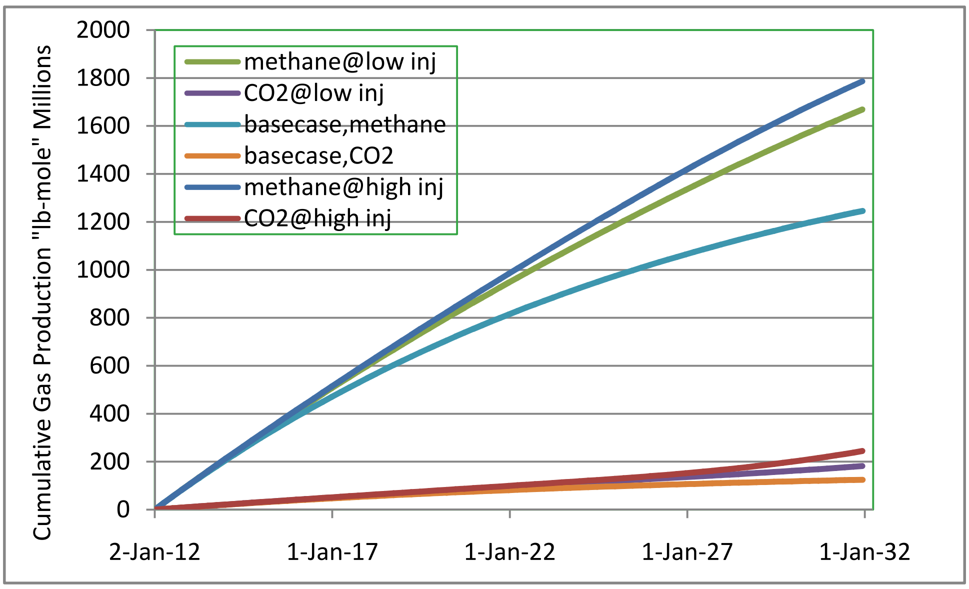

Figure 6. Cumulative methane and CO_2 production “lb-mole”

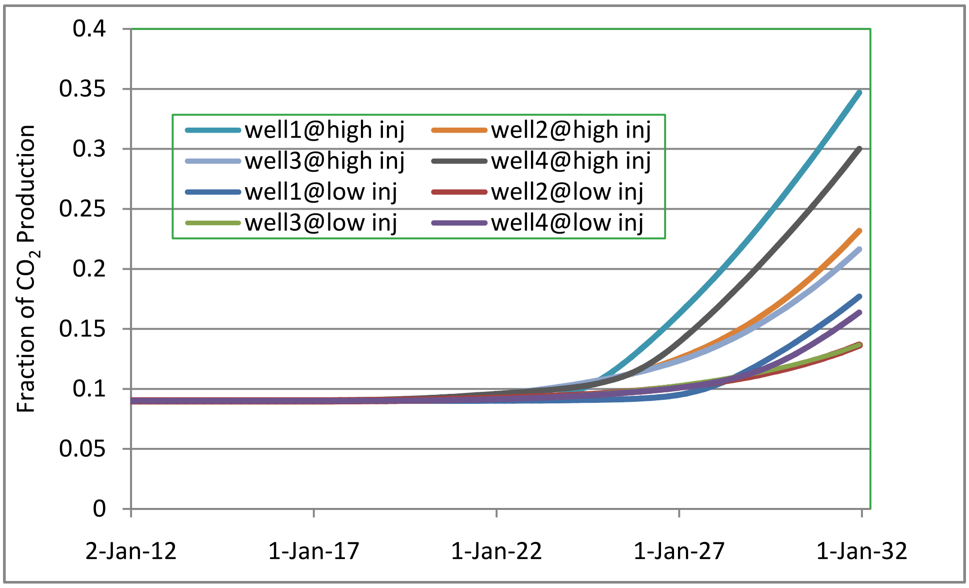

Figure 7. CO_2 breakthrough at different injection rates

4.3 Late Stage of Injection

This case scenario attempts to find CO_2 injection timing for comparison with the recovery factors in the above cases. In this case, reservoir heterogeneity accelerated the CO_2 breakthrough in the production well, and off course reservoir re-pressurization was considered as additional support for mitigation against CO_2 breakthrough. Accordingly, CO_2 is re-injected at the high rate 2400 × 1000 m^3/day based on the normal case, when the bottom hole pressure of the production wells decline to about 271 bar in March 27, 2017 (See Figure 2). That is, only a fraction of the methane is produced before injection. However, after almost five years of gas production, CO_2 is re-injected back into the reservoir at the high rate to re-pressurize and increase incremental gas recovery, resulting in continuation of gas production for the wells. The first production well that shows CO_2 breakthrough is automatically shut-in at that time. When the concentration of CO_2 in the produced gas reaches 15% in September 9, 2029, the shut-in production well (Well 1) is converted to become Injector 3, this is to accelerate methane production, with less CO_2 production for the life of the reservoir (Figure 8). The converted well will have a changed depth completion from the second layer to the bottom layer of the reservoir. In term of the reservoir model under this scenario, the maximum gas production rate is sat at 14000×1000 m^3/day. In the beginning of gas production there are four gas producers well. The maximum gas production rate of each producer well set at 3500×1000 m^3/day for each producer. At the announcement stage of injection, the maximum injection rate of CO_2 for the injector wells is 1200 m^3/d as it was under the scenario of high injection. After the conversion of the producer well 1, the gas production rate of the producers well is re-sat at 4666.667×1000 m^3/day for the wells number 1, 2 and 3, respectively, and the injection rate is re-set at rate of 800×1000 m^3/day for each one of the new and the old injector wells.

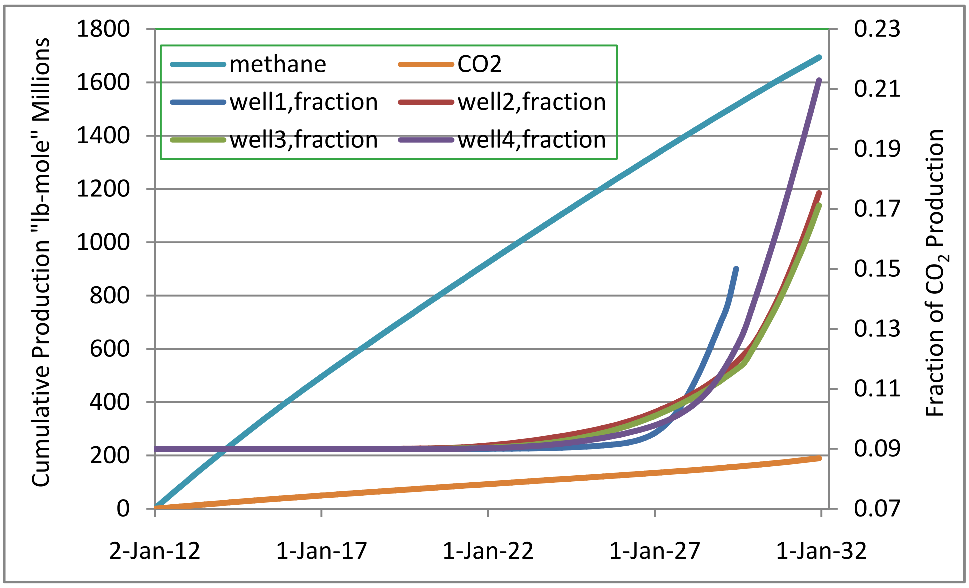

Figure 8. Cumulative production andCO_2 breakthrough under late stage of injection

5. Storage of the Injected CO_2

Storage volumes of CO_2 are documented by using well established mass balance method developed through the results of the reservoir simulation. This method qualifies the volume of CO_2 initially in place and tracks the changes in the producible volumes as reservoir management techniques, when CO_2 injection is applied during the life of the field. Estimation of CO_2 storage is based on the idea of CO_2 breakthrough for the production wells. It is estimated that 9% of CO_2 is present in the reservoir and 90% for methane.

In addition, Figures 5, 7 and 8 depicts the produced CO_2 fraction in the reservoir for each producer wellswhen there is different injection of CO_2 at different stage. As a result, when there is injection, the produced fraction of CO_2 is increased due to the produced fraction of injected CO_2. After when this concept of CO_2 breakthrough is illustrated, during CO_2 re-injection process the fraction of the produced CO_2 that exceeds the CO_2 fraction initially has been presented in the reservoir will represent the produced fraction of the injected CO_2. Figure 9 shows different injection rate at different stages of injection for all the cases and also illustrates gradual increases in CO_2 injection rates, until each case reaches the required rate of CO_2 injection. Under the stage of late injection, the injected CO_2 reach to the required rate of CO_2 injection faster than the other cases. This is due to the gas production under normal production conditionsbefore the commencement of CO_2 injection. Therefore, when CO_2 injection starts, the injected CO_2 displaces the natural gas already has been produced from the gas reservoir and after a couple months will reach to the desirable rate of injection. CO_2 storage is evaluated after when the concept of CO_2 breakthrough illustrated for the case scenarios in terms of the produced fraction of injected CO_2 “PFICO_2” and CO_2 component originally present in the gas reservoir. After the estimation of the PFICO_2 for each one of the cases, production rate of the injected CO_2 is calculated by multiplying the PFICO_2 by production rate of CO_2 during CO_2 injection. In addition, a difference between the production of the injected CO_2 and the injection rate evaluates CO_2 storage of the injected CO_2 for each one of the cases (Figure 10).

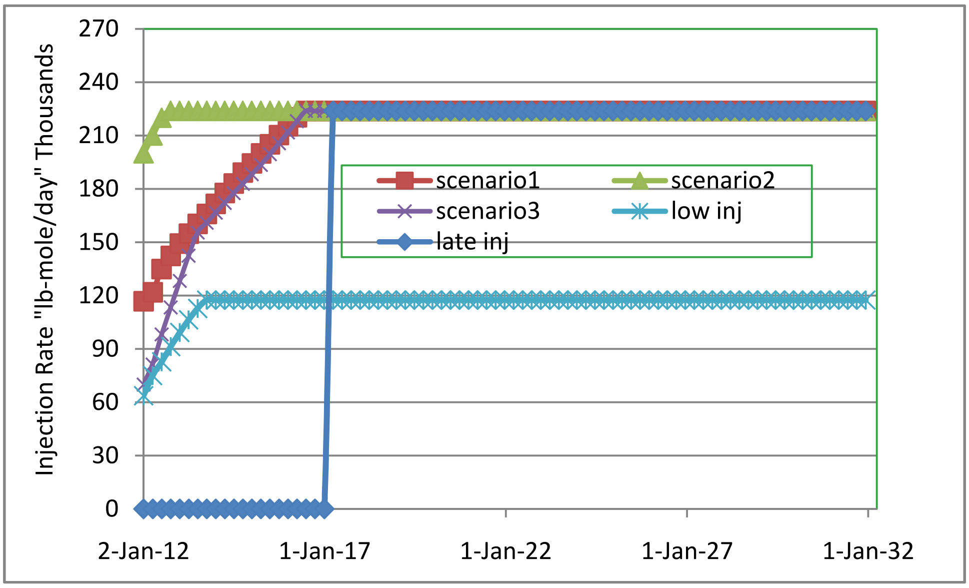

Figure 9. CO_2 injection rate under different cases

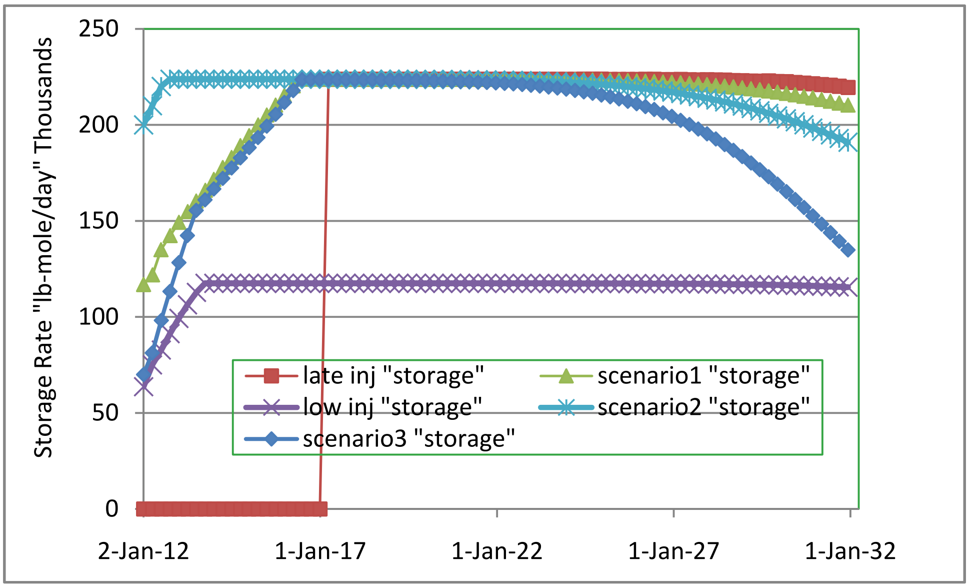

Figure 10. CO_2 storage rate under different cases

6. Simulation Results and Discussion

The base-case scenario was simulated and enabling gas to be produced continuously under normal production conditions. Vertical production and injection wells allocated with different depths with consideration of aquifer zone beneath the gas reservoir. For all the case scenarios, CO_2 injection into the lower portion of the reservoir technically for reservoir re-pressurisation and efficiently sweeps natural gas from bottom layers in the direction toward the production wells, while minimising contamination and gas mixing in the upper parts of the reservoir. Therefore, different layers were tested for injection purposes as a function of enhanced gas recovery and storage. The arrangement of layers from the top to the bottom of the reservoir “very low, high medium and low” quality presented the highest methane production, CO_2 storage and lowest CO_2 production. This arrangement layers were selected as an optimum scenario to investigate and determine the optimistic case scenario in terms of best injection rate, stage of injection announcement. Conversely, the layers high medium, low and very low quality of rock considered to be the most pessimistic scenario due to its low methane production, low volume of CO_2 storage and highest CO_2 production rate. Because CO_2 injected into lowest permeable layer, thus the injected

CO_2 will arise upward rather than distribute in the bottom of the reservoir. Consequently, it will find its own path and breakthrough the production wells.

In terms of well placement, CO_2 breakthrough occurs faster at the production wells allocated closer to the injection wells. In addition, the simulation results indicated higher CO_2 injection rate will cause CO_2 breakthrough time occurred faster. It is worth mentioning that the initial gas reservoir pressure is high and even though, the production wells are allocated at the same layer, but their depth completions is different from each other. Therefore, we anticipated some compositional gradient due to gravity and temperature effects generated by the depth variation and high density contrast of CO_2 compared to methane. However, the observation of the compositional variation was very minimal.Thus the produced fraction of CO_2 in each well is seen as a straight line from the beginning of production (See Figures 5, 7 and 8).The breakthrough time defined as the time when the injected CO_2 arrived to the production wells. The volume of CO_2 breakthrough was determined as the volume that exceeded the initial volume of CO_2 that supposed to be produced from the reservoir. Lower grids in the bottom layers of the reservoir showed the faster increase in CO_2 concentration due to gravity, temperature and pressure effects generated by high density of CO_2 and depth variations. Technically the simulation results indicated that, the higher injection rate of CO_2 can potentially enhance more incremental increases in gas production; however, it will lower the natural gas quality by excessive mixing and early breakthrough creating more CO_2 production.

Geologically, injection of CO_2 into the aquifer with the depth of 3650 m had strong effects on methane production and CO_2 storage. At this depth, CO_2 acts as a supercritical fluid and would have a density close as to water. As expected, the solubility of the injected CO_2 is reduced when the initial brine of the reservoir is being saturated. As a result, feasibility of CO_2 injection is a function of aquifer depth, low permeability, brine saturation and the distance between the injection and production wells.

Figure 11 shows the efficient tendency of CO_2 flows downward and stabilises the displacement of the native gas due to it physical properties as a function the gravitational effects.

Clearly it can be observed that after some period of injection, the reservoir "lower portion" is partially filled with the injected CO_2. The heterogeneity of reservoir preferentially flow CO_2 from the bottom layer toward the production wells as a function of permeability existence for each layers, especially in the second and third layers from bottom of the reservoir (high permeable). Eventually, it will cause breakthrough based on the physical properties of the layers and detrimentally effects enhanced gas recovery with time.

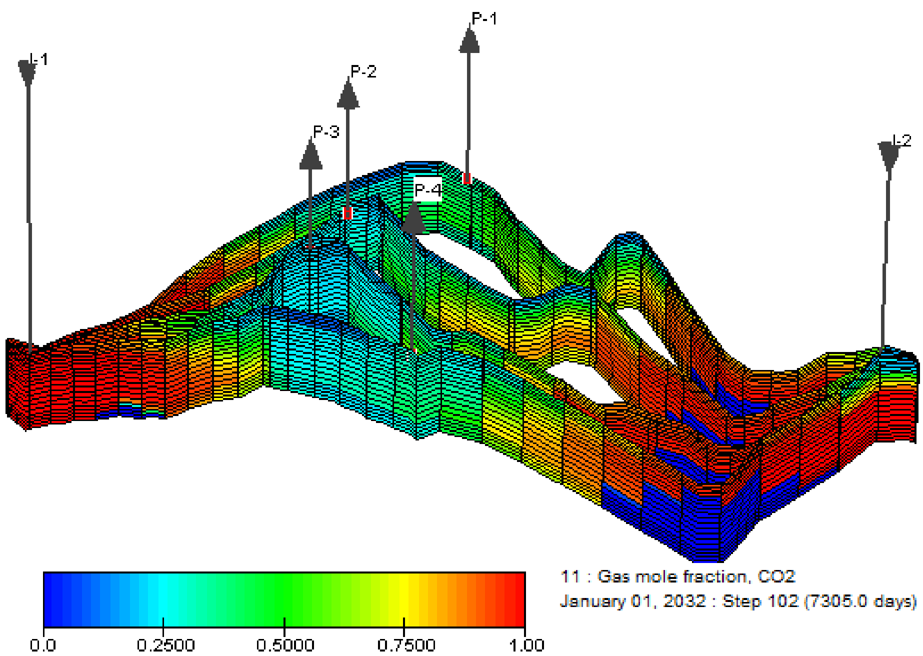

Figure 11. Reservoir heterogeneity and CO_2 sweep efficiency

Next we presented some results for the case scenario, when CO_2 injection commenced after 6 years of gas production under normal production conditions. The simulation indicated that the high rate and early stage of CO_2 injection had the highest methane production at the same time it had highest CO_2 production and total CO_2 storage (Figures 10 and 12). Time appeared to have a significant impact on the planned strategies. The high rate and late stage of CO_2 injection is appeared to be near the optimum strategy. Under this case, more methane is produced compare to that under the base case and low injection strategy. In addition, less time of CO_2 injection "late injection" could have less costs of CO_2 compared to the case of early stage under high injection. But this case could only be considered when the project is proposed for enhanced gas recovery because it will have the highest CO_2 emissions due to late injection and releasing the CO_2 production into the atmosphere before the commencement of injection process. Economically, this will affect the project when carbon tax is taken into account. As a result of comparisons between the case scenarios, high rate and early stage of CO_2 injection is the optimum and this case can be vital especially when the project is planned for both together, EGR and sequestration (Figure 12).

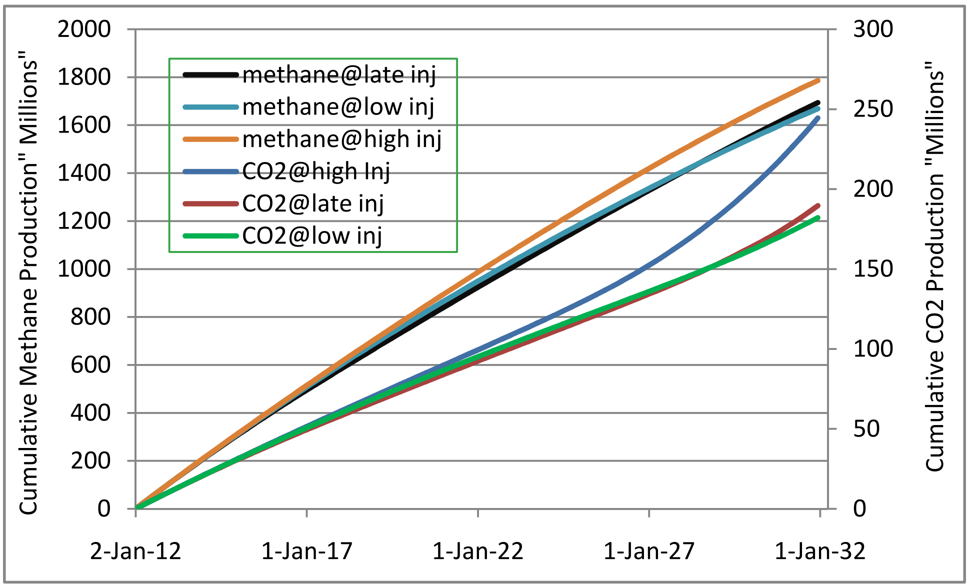

Figure 12. Cumulative production "lb-mole" under three different injection strategies

The objectives of this research study were to investigate the feasibility of CO_2 re-injection for enhanced gas recovery and storage. In terms of CO_2 production, low injection strategy is considered to be the candidate for CO_2 re-injection, because with consideration of the native CO_2 production, less additional CO_2 will be requiredto reach to the desired rate of CO_2 injection. Economically, it will reduce the high costs involved in the process of CO_2 capture and storage compare to the other two cases under higher rate CO_2 injection.Therefore, in the following section we will investigate the economic feasibility of CO_2 re-injection for enhanced gas recovery and storage under low and early stage of injection.

7. Economic Valuation of CO_2-EGR and Storage

In order to make the process of CO_2-EGR and storage economically more attractive the costs involved in the process need to be lowered or carbon credit be taken into account. Currently, cost estimations of CO_2 capture and storage (CCS) technology is very high. This technology is unlikely to be put into practice effectively without any financial motivation or Tax incentives. Economically it becomes more feasible if it is combined with the process of CO_2 capture and storage, this is due re-injection of the native CO_2 production into the reservoir and may result in less CO_2 requirement from other source or producers (Algharaib & Abu Al-Soof, 2008). Overall, the concept of CO_2 storage from the same source potentially provides a reasonable structure for carbon credit to be fully developed during the process of CO_2-EGR and storage. In particular, CO_2 capture and separation systems and storage (compression, transportation and injection) systems are considered as an emission reduction approach (McCollum, 2006). A credit for this reduction is reduced by producing additional CO_2 per ton injected; possibly released into the atmosphere during the CO_2 storage process.

Discounted cash flow (DCF) analysis is used as economic criteria to evaluate the attractiveness an investment opportunity under CO_2-EGR. The economic feasibility for the sample gas reservoir depends on the incremental benefits of gas recovery relatively to the incremental expenses of CO_2-EGR. Cumulative discounted cash flow curves are demonstrated for the case scenarios with and without net carbon credit consideration to achieve a comprehensive understanding of the project financially. Even though, the model is subject to sensitivity analysis, still associated with high degree of uncertainty, for example, reservoir evaluation (volume), capital and operation costs, current and future prices of gas and interest rate, etc.

First of all, in terms of cost, some capital expenditures associated with drilling, completion and equipment have been extracted based from recent published data (Akinnikawe et al., 2010). The costs originally were produced by Join Association Survey (JAS) and recently been updated and published by Advanced Resource International (ARI). In general these cost had initially been calculated with consideration of a fixed cost constant for site preparation and other fixed cost items and a variable costthat are changed with increases exponentially with depth.

Table 4. Production Well capital cost components

Start-up Costs	Equations	Fixed Cost Constant		Costs "$/ft"	Number of wells
		a_0	a_1		Injector and producer
Well D&C Costs	$y = a_0 \times D^{a1}$	2.7405	1.3665	4,322,375	4
Well Equipping Costs	$y = a_0 + a_1 D$	81403	7.033	675,701	4
Well Conversion Costs	$y = a_0 + a_1 D$	16607	6.973	123,168	1

In this section only capital costs of production well are estimated. In addition, costs associated with injection wells are usually considered as inputs parameters in the injection costs calculation for CO_2 capture and storage preparation process.

Because literature studies show large variation in the costs of CCS to adjust common economic basis such as cost of CO_2 separation, compression, transportation and injection. Therefore, for this study, practically, three levels of probability for twelve parameters were considered to illustrate the effect of changing any economic parameters involved in the low injection cases based on some assumptions elements and the source of the values are initially extracted from current literature studies in order to perform a comprehensive sensitivity analysis for diverse net present calculations (Table 5).

Table 5. Fiscal and economic parameter for sensitivity analysis

Uncertain Values	Scenarios			References
	a	b	c	
Wellhead Price $/Mcf	3	4	5	(Oldenburg et al., 2004); (Gharbi, 2001); (Hussen et al., 2012)
CO_2 capture $/Mcf	1.04	1.86	2.38	(David, 2000)
CO_2 separation $/Mcf	0.17	0.3	0.35	(Gaspar et al., 2005); (Gozalpouret al., 2005); (Al-Hashami et al., 2005)
Compression $/Mcf	0.22	0.41	0.65	(Gaspar et al., 2005)
Transportation $/Mcf	0.47	0.87	1.16	(International Energy Agency, 2010)
Injection $/Mcf	0.09	0.17	0.26	(Gaspar et al., 2005)
CO_2 emission %	10	15	25	(David, 2000)
Carbon Price $/Mcf	0.06	0.59	1.16	(Springer, 2003)
Carbon tax $/Mcf	0	1.16	1.34	(Benson, 2006)
Royalty %	11	12.5	15	(Gharbi, 2001); (Paidin et al., 2010)
Income Tax %	20	25	30	(Paidin et al., 2010)
Discount rate %	11	13	15	(Ghomian et al., 2008)

However, the idea of carbon credit has been around, but world widely has not been put into practice yet despite extensive coverage and political positioning. Therefore, there is no standard method presented in the published studies for calculating carbon credit (David & Herzog, 2000). So here, the concept is expressed as a function of carbon credit and carbon tax. Therefore, based on the reservoir simulation results, an equation has been developed to evaluate net carbon credits. According to the equation below, the first part of the equation shows the storage of the injected CO_2 and multiplied by the carbon credit. This will estimate the received price for per tonne of CO_2 storage. Accordingly, this part will be estimated in terms of injection rate of CO_2, production rate of CO_2 and also production rate of the injected CO_2. As a result, this will be considered as the addition source of revenue for the process. The second part of the equation shows the released amount of CO_2 into the atmosphere. This section will be evaluated in terms of energy penalty during the process of CO_2 storage as a function of the injected CO_2. Once carbon tax is considered, this will represent a reduction in the additional source of revenue.

$$Cp = \sum_{n=1}^{N} \left[\frac{\left[Mass - \left[\frac{(PFCO_2 - CO_2 IIP)}{(PRCO_2)^{-1}} \right] \right]}{(CC)^{-1}} \right]_n - \left[\frac{(EP \times Mass)}{(Ct)^{-1}} \right]_n \tag{1}$$

Cp: Net carbon credit \$/tonne

N: the number of the project years

n: is n^{th} year

CC: carbon credit \$/tonne

$PFCO_2$: produced faction of CO_2 “fraction”

CO_2 IIP: initial CO_2 in place “fraction”

$PRCO_2$: production of CO_2 tonne/year

EP: energy penalty %

Mass: mass flow rate of CO_2 injection

Ct: Carbon tax \$/tonne

So here we used discounted cash flowas an economic method to determine the best scenario for the optimum case. There is a direct link between methane and CO_2 production. In general, cost of CO_2 capture is declining with time after the occurrence of CO_2 breakthrough. On the other hand cost of CO_2 separation continuously in increasing with time due to CO_2 breakthrough. The economic evaluation for the optimum case suggests that return on investment for the scenarios “a, b and c” are viable over the estimated years.

Gas price and net carbon credit, costs of CO_2, methane production and CO_2 storage play important roles in the project viability. Under the case where net carbon credit is not considered, it is obvious that the higheris the price of methane the better return on the investment is expected t. The sensitivity analysis suggested that, even though, there is higher price for methane in scenarios “c” compare to the second scenario “b”, but their economic evaluation still not more attractive than the scenario “b” (Figure 13). The reason is that scenario “c” represents the highest costs of CO_2, in addition to the fiscal assumptions such as royalty and income taxes. In general, the production of methane declines with time, conversely the production rate of CO_2 increases after the occurrence of CO_2 breakthrough. Consequently, the revenue for this scenario “c” cannot catch up to offset the high costs associated with CO_2 as it is under scenario “b”. In comparison, the second scenario “b” has the highest cumulative DCF.

In terms of carbon credits, all the three scenarios “a, b, and c” have bigger values of cumulative discounted cash flow compared to that were under the scenarios where carbon credit was not taken into account (Figures 13 and 14). If the concept of carbon credit is applied, the storage site will represent addition source of revenue and the amount of CO_2 emission represents additional cost of CO_2. We proposed that the difference between them represent net carbon price. This concept could partially offset the costs associated with the process of CCS. If CO_2 markets involve effective payment for CO_2 sequestration compare to carbon tax for CO_2 emission, optimistically, the economic feasibility for the three scenarios would last longer and would make the scenario “c” economically more attractive.

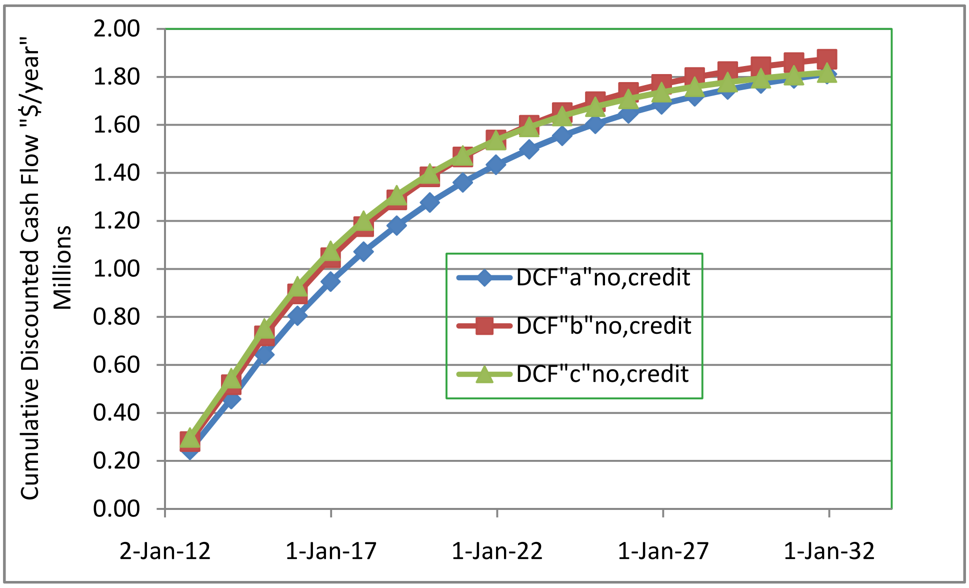

Figure 13. Cumulative discounted cash flow under case of low injection without carbon credit consideration

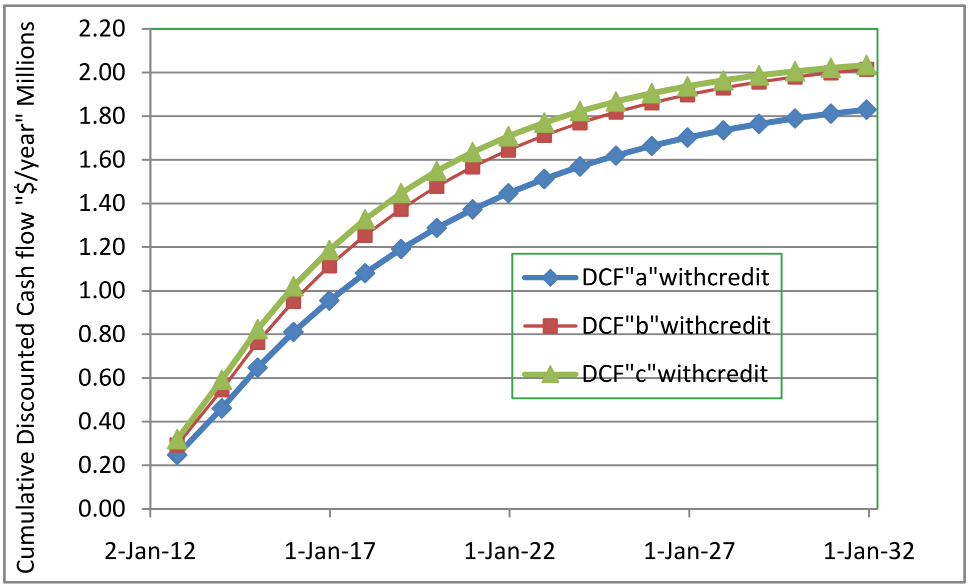

Figure 14. Cumulative discounted cash flow under case of low injection with carbon credit consideration

8. Conclusion

The simulation studies of the hypothetical reservoir model suggested that CO_2 injection for enhanced gas recovery and storage process can be technically and economically feasible based on the experimental data produced by Clean Gas Technology Australia. The main obstacles for applying CO_2-EGR and storage are production contamination by CO_2 injection and high costs involved in the process. However,good reservoir management, production control measures and contributions of new technologies could reduce the effects of these problems on the project.

CO_2 injections into the lower portions that represent high permeability of the reservoir and perforate the production wells in the upper part of the reservoir with low permeability are technically feasible due to reservoir re-pressurisation. So here reservoir re-pressurisation could be considered as a support against CO_2 breakthrough, because it could happen before the occurrence of CO_2 breakthrough. The optimal strategy is to take advantage of high viscosity, density and solubility of CO_2, in addition to allocate the injection wells as far as possible from the production well during the process of CO_2 injection. These operational parameters are potentially promising to drive out natural gas from the bottom layers of the reservoir, while minimizing mixing contamination in the upper part of the reservoir. The simulation results suggested that the high rate and early stage of injection has the higher gas recovery, but economically will contaminate the production due to early CO_2 breakthrough. While, late stage of CO_2 injection is as an attractive especially when the project is planned for sequestration, but it will have the highest rate of carbon tax due to release the CO_2 production into atmosphere before the commencement of CO_2 injection. Economically, this will affect the project when carbon credit is applied.In this paper, early stage and low rate of CO_2 injection is considered to be more attractive due to its low CO_2 costs compared to the other cases. This case could be vital when the project is proposed for enhanced gas recovery and storage.If the carbon credit markets come into existence in any significant way as a reduction of one ton of CO_2 fossil emissions by either preventing it from the atmosphere (natural gas reservoir) or by extracting it out of the atmosphere (power plan) and effective payment for CO_2 storage compared to carbon tax for CO_2 emission, the introduction of a carbon credit scheme will optimistically make the process of CO_2-EGR more attractive.

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