CO_2 capture and storage modelling for enhanced gas recovery and environmental purposes

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Abstract

Numerical simulations of CO_2 injection for enhanced gas recovery (EGR) and storage are investigated using the 'Tempest' commercial reservoir simulator; with experimentally data produced (by Clean Gas Technology Australia) input data. In the oil and gas industry, the CO_2-EGR policy has become attractive because it maintains the use of fossil fuels while reducing the CO_2 concentration in the atmosphere. Accordingly, the effect of gas miscibility is studied for the developed reservoir model in terms of methane contamination by CO_2 to find the optimum miscibility parameters. Several scenarios are considered, including continuous primary CO_2 injection into the gas reservoir prior to primary depletion. CO_2 injection scenarios at deeper reservoir levels are considered as they enable sweep efficiency. The main goal of the analysis is to maximise methane production, while simultaneously storing the injected CO_2. In addition, various CO_2 costs involved in the CO_2-EGR and storage are investigated. This investigation is undertaken to determine whether the technique is feasible, that is, whether the CO_2 content in the production and preparation stages is economically viable.
Keywords: gas production, CO_2 storage, capture cost, compression cost, transportation cost, injection cost, carbon credit.

1 Introduction

Injection of CO_2 for enhanced oil recovery CO_2-EOR is a mature technology and its application has been widely investigated [1, 2]. However, the enhanced gas

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recovery CO_2-EGR concept is new and there appears to be growing interest throughout the world, [1]. CO_2-EGR is considered less attractive when compared to enhanced oil recovery, because of the risk of contamination to recoverable gas that is initially in place. Therefore, enhanced gas recovery may not cover capture and storage costs [3]. While some published simulation studies consider CO_2 injection into depleted natural gas reservoirs mainly to reduce greenhouse gas emission, none of these studies examine the impact of mixing (CO_2-CH_4) on the recovery process prior depleted reservoir. 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, no follow up results have been published on the final gain in reserve recovery [4]. In this paper, a reservoir simulation model is developed by using experimental data at high pressure and temperature, incorporated with detailed engineering-economic modules. In this development, three dissimilar models of the hypothetical reservoir are considered by using the compositional reservoir simulation software "Tempest". The models developed are: base-case, early stage at different rates of CO_2 injection, and late stage at a high injection rate. Simulations of CO_2 injection into a natural gas reservoir are conducted, and confirm the potential of CO_2 injection as a means to store carbon dioxide while enhancing methane recovery. The simulations indicate that the properties of natural gas and CO_2 are favourable for re-pressurization, and thus, CO_2 injection and enhanced methane recovery is technically feasible for this reservoir, while gas-gas mixing is limited via good reservoir management and production control. Engineering-economic models of these processes are developed based on fundamentals of the performance reservoir model to provide robust qualitative comparisons when reservoir model parameter changes. Each economic module is used to estimate alternative costs for cases involving capture, compression, transport and injection. Economic analyses indicate the incremental costs of producing natural gas and CO_2 storage.

2 Reservoir modelling and case studies

The reservoir model is constructed to enable investigation of the potential for CO_2 injection for enhanced gas recovery. The numbers of grid blocks are 17 and 22 in the X and Y directions, respectively. The reservoir thickness varies by layer, and each layer represents different geological characterization of core plugs. The geological properties of the reservoir, and composition of the components in the gas mixture, are reported elsewhere (2, 3). The simulation calls for three production wells and two injection wells allocated to the upper and bottom layers of the reservoir, respectively. The simulation of natural gas production without any injection is performed for a base-case under normal production conditions. That is, the bottom-hole wells pressure declines over 20 years. In addition, the maximum gas production is sat at 7500, 8500 and 9000 m^3/day for wells number 1, 2 and 3, respectively. This case is 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 rates and times of injection. Under second case, for the first scenario, two injector wells are used as disposal wells to inject CO_2 at a rate of 1125 and 1125 m^3/day for each injector. The maximum gas production rates for the producer wells are the same as for the base-case. Secondly, "scenario two" CO_2 injection is simulated at a lower rate 637.5 m^3/day for each injector, while gas production rates for each producer are same as for the high injection scenario. The purpose of this case is to estimate the time of CO_2 breakthrough. Case three attempts to find a CO_2 injection timing strategy. Here, CO_2 is injected at the high rate 2250 m^3/day based on the normal case, when the bottom hole pressure of the production wells decline to around 280 bar in March 27, 2017. That is, only a fraction of the methane is produced before injection. 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 20%, the shut-in production well is converted to become Injector 3 to accelerate methane production, with less CO_2 production for the life of the reservoir. The converted well has a changed depth completion from the second layer to the bottom layer of the reservoir. Finally, the effects of the different scenarios on CO_2 storage are estimated to account for the carbon credit.

2.1 CO_2 capture cost module

This assignment is commonly based on three types of power plants, viz., integrated coal Gasification Combined Cycle (IGCC), Pulverized Coal (PC), and Natural Gas Combined Cycle (NGCC) power plants [5]. Current techniques employed to calculate costs of CO_2 capture in these cases are illustrated based on CO_2 capture at reference plant (no capture), and CO_2 at the capture plant. In general, these cases attribute to energy consumption and cause increases in electricity generation. This energy is originally produced by fuel combustion. This combustion will reduce the capture efficiency and net power outputs when compared to each other. Power plants with captured CO_2 will consume more fuel [6]. A widely used measure of the costs of CO_2 capture and storage is the cost of CO_2 avoided or mitigation. This value is expressed as the difference in cost of electricity $(\text{COE ¢/kWh})_{\text{capture}}$ - $(\text{COE ¢/kWh})_{\text{reference}}$ in a given period divided by the difference in volume of CO_2 emitted $(CO_2\ kWH^{-1})_{\text{reference}}$ - $(CO_2\ kWH^{-1})_{\text{capture}}$ for the period. In addition, cost of the CO_2 capture is defined as the difference in cost of electricity divided by the volume of CO_2 capture $(CO_2\ kWH^{-1})_{\text{capture}}$. Furthermore, data and calculations for this cost component are reported elsewhere [7, 8].

2.2 CO_2 compression cost module

In this section the optimum flow rate is determined based on daily CO_2 requirements are provided either from the production stream or power plants. The CO_2 requirement prior to transportation is compressed to change the CO_2 from gas to liquid state to determine the technical and economic conditions suitable for transportation [9]. Therefore, energy requirements for compressing the available volume of CO_2 must be considered. To transport CO_2 via pipeline, the gas must be compressed to a pressure above 8MPa (1200psi) to ensure that a single phase flow is achieved while keeping the density high. Thus, when CO_2 is in a gaseous phase, a compressor is used to increase the pressure from 0.1 to 7.38 MPa, while a pump is used when CO_2 is in liquid phase to boost the pressure (from 7.38 to 15 MPa or the desired final pressure) [10]. The captured gas and the initial CO_2 production from the gas reservoir compressed is assumed to have a capacity factor of 0.08, while the electricity price is assumed as 0.065 $/Kwh for each compressor and pump. In addition, the capital cost is annualised by a capital recovery factor value of 0.15, and the operating and maintenance cost is applied via an operating and maintenance factor value of 0.04 to the capital cost of compression and pumping. Detailed information about this module in terms of power requirement for compression and pumping reported in the published literature [11].

$$C_{comp} = m_{train}\ N_{train}\left[\left(0.13\times10^{6}\right)\left(m_{train}\right)^{-0.71} + \left(1.40\times10^{6}\right)\left(m_{train}\right)^{-0.60}\ln\left(\frac{P_{cut-off}}{P_{initial}}\right)\right] \quad (1)$$

$$C_{pump} = \left[\left(1.11\times10^{6}\right)\times\left(\frac{W_p}{1000}\right)\right] + 0.07\times10^{6} \quad (2)$$

C_{comp} Capital cost of compressor $, C_{pump} Capital cost of pump $, M_{train} CO_2 mass flow rate through each compressor train kg/s, N_{train} Number of parallel compressor trains, P_{intial} Initial pressure of CO_2 directly from capture system MPa, $P_{cut-off}$ Pressure at which compression switches to pumping MPa, Wp Pumping power requirement kW

2.3 CO_2 transportation cost module

In addition, the compressed CO_2 is transported through pipelines with the same capacity factor as the injection source. McCollum [12] studied similarities and differences among recent CO_2 transportation models, and developed a new CO_2 pipeline capital cost (C_{cap}) model that is a function only of CO_2 mass flow rate (m) and pipeline length (L). In addition, the model avoids reliance on advance pipeline diameter calculations. The distance between the source and the sink site observed in this study is 200 km. The capital cost is annualised by using a capital recovery factor value of 0.15, and the operating and maintenance cost determined is by applying an operating and maintenance factor value of 2.5% to the capital cost [11]. The transported CO_2 is also scaled by a location factor (F_L) and terrain factor (F_T) 0.1 and 2.7, respectively. A full list of factors is provided in elsewhere [13].

$$C_{cap} = 9970\times(m^{0.35})\times(L^{0.13}) \quad (3)$$

$$C_{total} = F_L\times F_T\times L\times C_{cap} \quad (4)$$

2.4 CO_2 injection cost module

Cost documentations reported in this section are organised based on the Join Association Survey cost study recently updated and published by API Advanced

Resources International based using Louisiana field data [14]. In terms of production well cost calculations, some of the equations are updated based on the required number of wells as a function of the well depth for the reservoir model (Table 1). Accordingly, IPCC [7] developed equations for the operating and maintenance (O&M) costs associated with well drilling. Cost data are based on data originally produced by Energy Information Administration. The average cost values are adjusted to account for the number of wells and well depths. These activities are included in Table 2:

Table 1: Well capital cost components.

Inputs	Equations	Fixed Cost Constant	
		a_1	a_0
Well D&C Costs	$y = a_0 \times D^{a1}$	2.7405	1.3665
Well Equipping Costs	$y = a_0 + a_1 D$	81403	7.033
Well Conversion Costs	$y = a_0 + a_1 D$	16607	6.973

Table 2: Operating and maintenance costs of wells drilling [7].

Normal daily expenses	- Cost of supervision and overheads - Cost of labor - Consumables - Operative supplies - Pumping and field power
Normal Daily Expenses $/well	**= number of well × 6,700**
Consumables $/well	number of well × 17,900
Surface maintenance (repair and Services)	- Labor - Supplies and services - Equipment usage - Other
Surface Maintenance (Repair and Services) $/well	**= 13,600×(7,389/(280×Number_of_wells))$^{0.5}$**
Subsurface maintenance (repair and Services)	- Work over rig services - Remedial services - Equipment repair - Other
Subsurface Maintenance (Repair and Services) $/well	**= 5,000×Well_depth/1219**

2.5 Introduction of carbon credits

Early successes with both limited CO_2 storage numbers and experience with enhanced oil recovery add confidence that long term storage is possible in an appropriately selected geological storage reservoir [15]. Although, current cost estimates of CO_2 capture and storage technology CCS is high, the technology will probably not be used without financial motivations such as tax incentives [16]. Furthermore, the notion of carbon credit has also not been widely practiced, despite extensive coverage and political positioning. Therefore, there is no standard method to calculate carbon credits [3]. In this paper, the concept is expressed as a function of carbon credits and carbon tax. For equation (5), the first term on the right-hand side shows the storage of the injected CO_2 multiplied by the carbon credit. This term estimates the received price for per tonne of CO_2 storage. This term is estimated in terms of injection rate of CO_2, production rate of CO_2 and also production rate of the injected CO_2. This is an addition source of revenue for the process. The second term on the right-hand-side shows the amount of CO_2 released into the atmosphere. This term is evaluated in by energy penalty applied during the process of CO_2 storage as a function of the injected CO_2. Once carbon tax is considered, this represents a reduction in the additional source of revenue.

$$Cp = \sum_{n=1}^{N} \left[\frac{\left[Mass - \left[\frac{(PFCO_2 - CO_2 IIP)}{(PRCO_2)^{-1}} \right] \right]}{(CC)^{-1}} \right]_n - \left[\frac{(EP \times Mass)}{(Ct)^{-1}} \right]_n \tag{5}$$

where 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 CO2 tonne/year, EP: energy penalty %, Mass: mass flow rate of CO_2 injection, Ct: Carbon tax \$/tonne

When carbon credit markets are established, a reduction of one ton of CO_2 fossil emissions by either preventing leakage into the atmosphere or by extracting it from the atmosphere will represent an additional revenue source, while the amount of the CO_2 emission is an additional cost. The estimated difference between the quantities measures the net carbon credit. Therefore, the introduction of a carbon credit scheme can be considered as an additional source of revenue, or the re-injection cost recovery.

3 Economic evaluation scheme

The economic feasibility of the sample gas reservoir depends on the increment benefit of gas recovery relative to the incremental expense of CO_2-EGR. Cumulative discounted cash flow curves are calculated for the scenarios with and without net carbon credits. Additionally, the model is subjected to sensitivity analysis with a high degree of uncertainty. In the real world future market prices for hydrocarbon are uncertain and volatile [17]. To deal with this uncertainty, most recently published studies specify wellhead gas prices as constant, with value ranges from 3 to 5 $/Mcf. The values are used to calculate the net present value of projects [2, 3]. However, this approach cannot illustrate project evaluations when the future price varies. Therefore, in this study, the long term annual wellhead gas price is applied from the EIA annual energy outlook [18]. Because the gas reservoir simulation model is evaluated for the period 2012 through 2032, future gas prices are estimated from 3.4 to 5.81 $/Mcf. This range is close to those that have mentioned in the current literature. Three probability levels are considered for the seven parameters to illustrate the effect of changing economic conditions (Table 3).

Table 3: Fiscal and economic parameter for sensitivity analysis [2].

Uncertain Values	Scenarios		
	a	b	c
CO_2 separation $/t	3	5.2	6
CO_2 emission %	10	15	25
Carbon Price $/t	1	10	20
Carbon tax $/t	0	20	23
Royalty %	11	12.5	15
Income Tax %	20	25	30
Discount rate %	11	13	15

4 Results and discussion

The production data obtained from the simulation results are applied to the economic criteria allow evaluation of the projects' feasibility (Figure 1). Economic feasibility in the base-case is used to compare cases designed to optimize gas production under different alternative scenarios. The base case is described by wellhead prices for pipeline gas sales and the costs of drilling

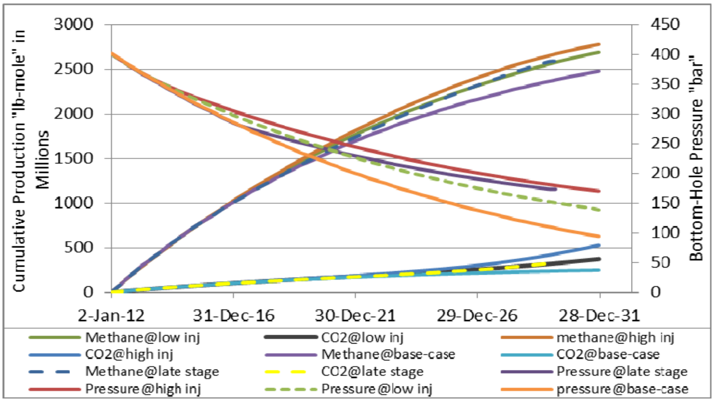

Figure 1: Cumulative gas production under different cases.

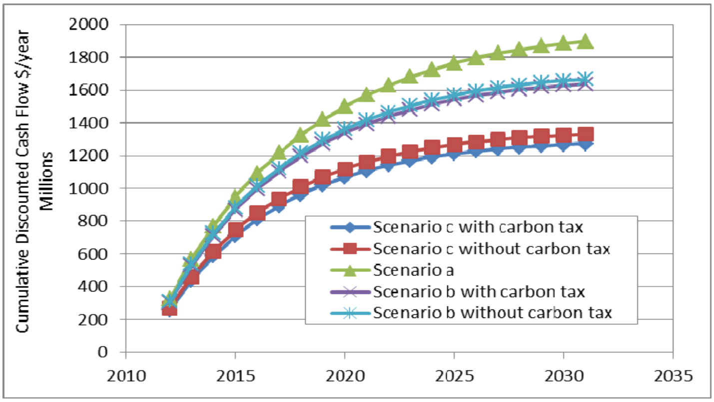

Figure 2: Cumulative discounted cash flow under the base-case.

production wells in Table 4. Other fiscal parameters, mentioned in Table 5, result in estimation of discounted cash flow for scenario a, b, and c. However, the costs of production wells are considered for all scenarios. However, the costs of injecting wells are not estimated as the injection technique is not applied in this scenario. In addition, the carbon tax for venting separated CO_2 into the atmosphere is estimated at $ (0.00E+00, 8.46E+07, and 1.95E+08) for scenarios a, b, and c, respectively. Therefore, Figure 2 shows the cumulative discounted cash flow and the impact of a carbon tax on the project. Under the CO_2 injection case, additional CO_2 from power plants and CO_2 production from the gas reservoir are injected into the gas reservoir. Gas production rates since initiation of the project are estimated under alternative strategies, with the costs of EGR and storage for each case estimated with techno-economic modules as a part of the cash flow analysis (see Tables 5 and 6).

Similarly, the net present value of the projects is calculated in terms of carbon credit for CO_2 storage, and compared with same net present value when carbon credit is not considered. This calculation determines whether the project is financially credible. Results show that for all cases, net present value is higher where net carbon credit is included. A comparative analysis of net present values magnitude for the “a, b and c” scenarios, with and without considering carbon tax, are depicted.

Table 4: Wells production costs.

Start-up Costs	Number of Well	Total Cost “Million US$”
Production well D&C cost	3	3.44
Production well equipment cost	3	0.52
Injection well conversion costs	1	0.10
Total costs	3.69	

Table 5: Total CO_2 capture and compression costs under different cases.

Case-1- Scenario of early injection at low rate of CO_2			
Capture $	Total Compression Cost $		
	CAPEX	OPEX	Electricity
6.41E+08	8.59E+07	2.29E+07	1.54E+08
Case-1- Scenario of early injection at high rate of CO_2			
Capture $	Total Compression Cost $		
	CAPEX	OPEX	Electricity
1.23E+09	1.07E+08	2.85E+07	2.63E+08
Case-2- Late stage of injection at high rate of CO_2			
Capture $	Total Compression Cost $		
	CAPEX	OPEX	Electricity
1.14E+09	7.26E+07	1.94E+07	1.85E+08

Table 6: Total CO_2 transportation and injection costs under different cases.

Case-1- Scenario of early injection at low rate of CO_2			
Total Transport Cost $		Total Injection Cost $	
OPEX	CAPEX	OPEX	CAPEX
3.56E+07	2.13E+08	1.70E+06	1.64E+06
Case-1- Scenario of early injection at high rate of CO2			
Total Transport Cost $		Total Injection Cost $	
OPEX	CAPEX	OPEX	CAPEX
4.27E+07	2.56E+08	2.18E+06	1.88E+06
Case-2- Late stage of injection at high rate of CO2			
Total Transportation Cost $		Total Injection Cost $	
OPEX	CAPEX	OPEX	CAPEX
2.88E+07	1.73E+08	1.52E+06	1.56E+06

The figures (3, 4 and 5) show that low values for the effective net present value are determined in part by the CO_2 production rate as a function carbon tax for per tonne of production. The gas recovery factor in Scenario 1 for the early injection case is greater than that in Scenario 2. According to the simulation results, technically, the high injection rate of CO_2 enhances incremental increases in gas production. However, it will lower the gas quality by excessive mixing and by early breakthrough creating more CO_2 production (Figure 1). Under late stage injection, CO_2 production rates under normal production conditions are similar to that for the base case. After the commencement of CO_2 injection, CO_2 production starts to increase and ultimately exceeds the low injection rate. Cost wise, there is a direct link between methane and CO_2 production.

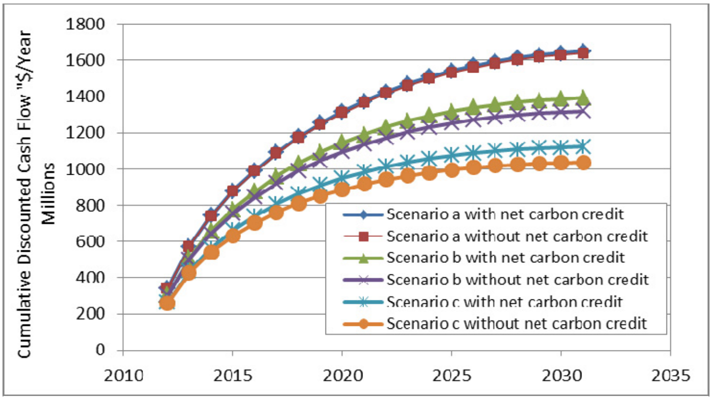

Figure 3: Cumulative discounted cash flow under high case injection.

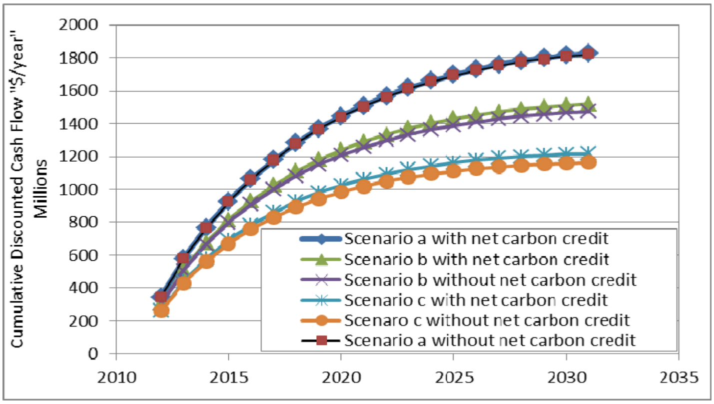

Figure 4: Cumulative discounted cash flow under low case injection.

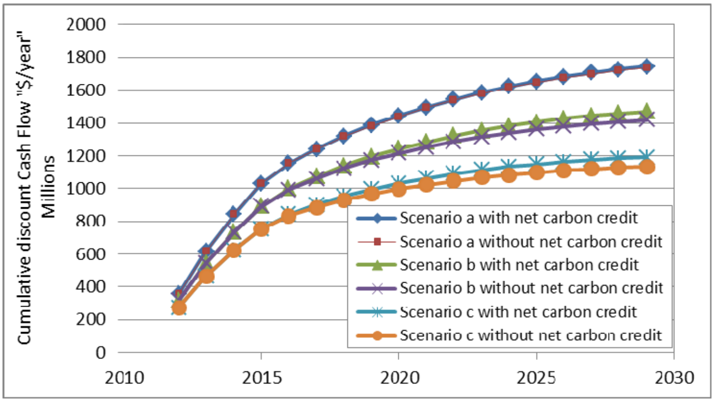

Figure 5: Cumulative discounted cash flow under late stage of injection.

In general, the cost of CO_2 capture declines through time after CO_2 breakthrough occurs. Conversely, CO_2 separation costs continuously increase due to CO_2 breakthrough. The simulation results show that the early stage at low injection rates is economically optimum. Finally, late stage injection at the high rates also appear to be 'near optimum' when compared to low CO_2 injection at an early stage of injection. The reason why these scenarios have almost optimal is because of time factors and the rate of CO_2 injection. For example, the smaller CO_2 costs for the second scenario at an early stage of low injection and higher injection at late stage of injection results in low cost of CO_2 under the last case.

5 Conclusion

A techno-economic model of CO_2 injection for enhanced gas recovery and storage is developed using reservoir simulation software based on experimental data produced by Clean Gas Technology Australia. Study results indicate that the model is technically and physically feasible for the proposed reservoir. Inevitably, gas contamination at production wells increases costs associated with the process. Importantly, these costs can be limited by good reservoir management and production control measures. The economic evaluations of the scenarios suggest that returns on investment are affected by the high costs of CO_2; however, carbon credit improves economic viability of the project.

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