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The effect of high oil prices on EOR project economics

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Abstract

This paper examines two questions: (1) in a high oil price (and operating cost) environment what are typical breakeven prices for CO_2? and, (2) are these prices sufficient to incentivize development of large-scale CCS projects? To address these questions we have developed an engineering-economic model for geological storage of CO_2 through EOR. In this paper we briefly describe the performance and cost models for CO_2-flood EOR, and use them to estimate the breakeven price for CO_2 as a function of significant variables. In particular, the relationship between breakeven CO_2 price and oil price is developed for four illustrative cases, all of which are, or were, operating EOR projects in North America. The sensitivity of the breakeven CO_2 price to variability and uncertainty in reservoir characteristics and other model input parameters is also examined in detail for one of the cases.
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Keywords: carbon capture and storage; geologic sequestration; enhanced oil recoery; carbon dioxide; storage economics.

1. Introduction

There are numerous options for geologic sequestration of carbon dioxide (CO_2) [1] and, while there is considerable uncertainty over the total capacity available for sequestration [2], it is clear that saline aquifers offer the largest potential for long term storage. However, in many countries the regulatory framework for aquifer sequestration is non-existent or under development [3, 4]. Consequently, even in jurisdictions that have adopted emissions reduction goals the economics and commercial feasibility of aquifer sequestration are unclear. Conversely, sequestration through CO_2-flood Enhanced Oil Recovery (EOR) is very attractive because there is considerable commercial experience with CO_2-flooding; it can slow declining domestic oil production from mature basins; the regulations surrounding CO_2-flooding are clear in most jurisdictions; and, with forethought, the infrastructure built today for CO_2-flooding will compliment the development of saline aquifer sequestration in future.

The objective of this paper is to briefly describe and then apply a semi-analytical model to estimate the cost of geological storage of CO_2 via miscible CO_2-flood EOR[2] under the economic conditions of relatively high oil prices

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[2] Herein the term CO_2-flooding will refer to the miscible process; while the immiscible process is also commercially practiced, it operates via different mechanisms that do not offer the same potential for increasing oil recovery.

and capital costs for a number of scenarios. In addition, this engineering-economic model will be used to assess the sensitivity of storage cost to changes in geological settings and assumptions regarding the development of the EOR. It will also show the potential range of costs that could occur and the probability associated with these costs for a given scenario.

2. Model Description

The model of the EOR process developed here can be separated into two parts: a performance model, and a economics model. As shown in Figure 1, the performance model takes inputs that describe reservoir and oil properties, and the operating strategy. From these inputs the model estimates the oil recovery rate as a function of the amount of CO_2 injected, the required wellhead pressure to achieve the desired injection rate, and the total amount of oil recovered from the project at the end of its economic life.

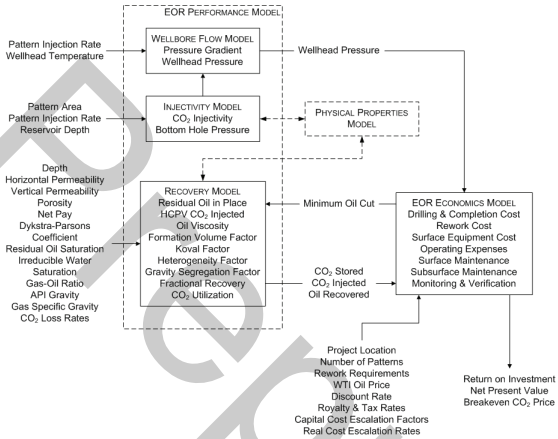

Figure 1. The CO_2-flood EOR engineering-economic model described here.

The overall recovery efficiency for a particular reservoir is estimated using a fractional-flow based screening model, similar to other models previously developed and used in the literature [5-8]. It is based on the Koval method [9] for predicting recovery in a secondary CO_2-flood, extended by Claridge for areal sweep in a five-spot pattern [8], and Paul and Lake [7] for vertical sweep. This method applies to secondary unstable miscible flooding processes, in which there is no mobile water, and the fractional flow of CO_2 and oil is only dependent on the viscosity ratio of oil to CO_2. Further details on this method and its implementation can be found elsewhere [10].

The economics model developed for EOR storage of CO_2 takes a number of inputs (shown in Figure 1), along with the performance model results, to estimate the profitability of the CO_2 flood, measured by net present value (NPV) and return on investment (ROI). The model estimates NPV and ROI by performing a discounted cash flow analysis using the oil production rates and CO_2 consumption rates from the performance model.

The capital cost of the project is estimated based on the requirements for field production equipment, field CO_2 processing equipment, new pattern injection and production equipment, drilling and completion (D&C) costs for new wells, and workovers for existing wells. These capital costs are amortized over the life of the field using the project discount rate. Regressions relating the components of capital cost to reservoir depth have been developed from a number of data sets, and take either exponential (Equation 1) or power (Equation 2) forms.

$$C = a_1 e^{a_2 d} \tag{1}$$

$$C = a_1 d^{a_2} \tag{2}$$

In both Equations 1 and 2, C is the component capital cost, d is the reservoir depth in meters, and a_1 and a_2 are regression coefficients.

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The regression for D&C cost was developed using data from the 2001 Joint Association Survey on Drilling Cost [11], while the costs for production well equipment, injection well equipment, and lease equipment were developed from Energy Information Administration survey data [12]. Regression coefficient estimates are given in Table 1, and yield capital costs in 2004 US dollars. The generalized models given in Equations 1 and 2 account for a large proportion of the variation in the data sets as reflected by an adjusted-r^2 value of greater than 0.90 for most cost component regressions.

Table 1. Capital cost categories included in the model, their regression form, and the associated regression coefficient estimates for each region in the model. All capital costs are in 2004 US dollars.

	Drilling & Completion		Production Well Equipment		Lease Equipment		Injection Well Equipment	
	Exponential		Power		Power		Exponential	
Region	a_1	a_2	a_1	a_2	a_1	a_2	a_1	a_2
W-TX	\$122,555	8.04×10^{-4}	\$61	9.75×10^{-1}	\$36,749	2.99×10^{-2}	\$31,226	2.81×10^{-4}
S-TX	\$136,434	8.04×10^{-4}	\$4,681	3.04×10^{-1}	\$4,207	3.83×10^{-1}	\$37,040	1.16×10^{-4}
S-LA	\$190,790	8.04×10^{-4}	\$3,539	3.47×10^{-1}	\$5,803	3.54×10^{-1}	\$39,876	1.13×10^{-4}
MCR	\$110,907	8.04×10^{-4}	\$888	5.74×10^{-1}	\$11,413	2.10×10^{-1}	\$39,876	1.13×10^{-4}
RMR	\$178,547	8.04×10^{-4}	\$36	1.02×10^{0}	\$23,801	1.35×10^{-1}	\$29,611	2.60×10^{-4}
CA	\$165,290	8.04×10^{-4}	\$9,214	2.58×10^{-1}	\$56,711	6.70×10^{-2}	\$38,931	2.10×10^{-4}
AK	\$531,697	8.04×10^{-4}	\$9,214	2.58×10^{-1}	\$56,711	6.70×10^{-2}	\$38,931	2.10×10^{-4}
APPL	\$88,263	8.04×10^{-4}	\$888	5.74×10^{-1}	\$11,413	2.10×10^{-1}	\$39,876	1.13×10^{-4}
OTHR	\$110,907	8.04×10^{-4}	\$888	5.74×10^{-1}	\$11,413	2.10×10^{-1}	\$39,876	1.13×10^{-4}

For wells that are already in place and only require a well workover (i.e., tubing and downhole equipment replacement) prior to CO_2-flooding, the cost is expressed as a sum of a fraction of the production or injection equipment cost (depending on whether the well is a producer or injector) and the drilling and completion cost (D&C). The expression for workover cost is [13]:

$$C_{WO} = 0.48C_{D\&C} + 0.50C_{EQ} \tag{3}$$

where $C_{D\&C}$ are the drilling and completion capital cost (discussed in the following section) and C_{EQ} is the cost of production or injection equipment.

The costs for CO_2 processing equipment—also lease equipment, but not included in the regressions above—vary widely depending on the type of processing required. The capital cost is generally lower for simple compression and dehydration equipment than for more complex facilities incorporating NGL separation. For simple compression and dehydration systems, a regression has been developed based on 12 point estimates presented in the literature [6, 14-17]. The regression equation takes the form:

$$\log(C_{CPE}) = 0.9374 + 5.851\log(N_p q_{rcy,\max}) \tag{4}$$

where C_{CPE} is the capital cost of CO_2 processing equipment, N_p is the number of patterns, and $q_{rcy,max}$ is the pattern recycle rate (at the maximum CO_2 cut) in mmscf (million standard cubic feet) per day. If construction is staggered (e.g., 10 patterns in year zero, 12 patterns in year 1), N_p would in this case be equal to the maximum number of patterns constructed in a given year (i.e., 12).

The first purchase price for the crude oil produced from the project is related to the West Texas Intermediate marker price and adjusted for API gravity using a regression detailed elsewhere [10].

Operating and maintenance (O&M) costs for CO_2-flooding includes operating expenses for labor, consumables, surface equipment maintenance, and subsurface equipment maintenance (including periodic well workovers). These costs for CO_2 flooding are assumed to be comparable to those for waterflooding, with the exception that both surface- and subsurface maintenance costs are doubled due to more frequent maintained requirements associated

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with handling corrosive, wet CO_2. The O&M cost correlations are based on the EIA Oil and Gas Lease Equipment and Operating Cost index [12]. Energy costs are based on the compression energy required for the recycle stream of CO_2 [10].

3. Case Study—Deterministic Results

The engineering-economic model has been applied to four illustrative case study reservoirs, selected from successful projects that currently are (or were) operating and have published reservoir descriptions. These four reservoirs cover a range of performance parameter values—*kh* from 1,500 to 5200 md·ft and pattern areas from 40 acres to 160 acres—and two lithologies—sandstone and limestone. Key model performance inputs and other pertinent data are shown in Table 2 (see elsewhere for a full description of the reservoirs and projects [10]).

Table 2. Key performance model parameters for the four case study reservoirs as well as residual oil in place (ROIP) prior to CO_2-flooding and the original oil in place (OOIP) at discovery [10].

Parameter	Northeast Purdy Unit	SACROC Unit, Kelly-Snyder Field	Ford Geraldine Unit	Joffre Viking Unit
Location	Oklahoma	Texas	Texas	Alberta
Reservoir	Purdy Springer A	Canyon Reef	Ramsey	Viking
Lithology	Sandstone	Limestone	Sandstone	Sandstone
Previous Recovery	Primary & Waterflood	Primary & Waterflood	Primary & Waterflood	Primary & Waterflood
Productive Area (acres)	9,177	49,900	5,280	16,611
Number of Patterns	229	1,248	132	208
Depth (m)	2,499	2,042	2,680	1,500
γ_{API} (^{o}API)	35	41	40	42
ROIP (MMSTB)	146	1,163	76	47
OOIP (MMSTB)	220	2,163	97	93

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Each of the case studies was evaluated at a constant injection rate of 600 mscf (thousand standard cubic feet) per CO_2 per day per pattern (32 tonnes CO_2 per day) with the exception of the Joffre-Viking, where injection was modeled at a constant 300 mscf CO_2 per day (16 tonnes per day) due to the extremely high permeability of the Viking pool. Injection rates on the order of hundreds of mscf per day per pattern are typical of current practice [18].

Economics model parameter values used in the case studies are listed in Table 3 and are the same for each case, making comparisons among the four cases simpler (see elsewhere for a full description of the economic paramters [10]). The WTI oil price is varied parametrically in the estimation of the breakeven cost for CO_2. The breakeven cost for CO_2 is the CO_2 purchase price at which the project net present value (NPV) equals zero.

The pattern construction schedule used for all of the cases assumes 50% of the patterns built in the year prior to the start of injection (year zero); 30% of the patterns built in the first year; and, 20% of the patterns built in the second year. In all of the cases, the necessary injectors and producers were assumed to be available from secondary production and require only workovers for conversion to CO_2-flooding. Using this pattern schedule, the performance parameters in Table 2, and economics parameter values in Table 3, results in the CO_2-flood performance summarized in Table 4.

The results in Table 4 show that, from the standpoint of large-scale CO_2 sequestration, projects similar to Northeast Purdy, Ford Geraldine or Joffre Viking would be of limited value as stand-alone projects, as they store small amounts of CO_2 relative to the amount of CO_2 produced from a large point source such as a power plant over its lifetime of operation (e.g. 500 MW coal fired plant over 30 years produces emissions of 90 Mt). Moreover, the rate at which these three projects store CO_2 is much lower than the rate that a large point source produces CO_2 (e.g. 500 MW coal fired plant produces emissions of 2-3 Mt per year), as illustrated in Figure 2. Conversely, a large field

similar to the SACROC Kelly-Snyder field in Texas (developed rapidly, as in the case study) could sequester large amounts of CO_2 at rates compatible with a large point source.

Table 3. Key economics model parameter values used in the four case studies.

Project Parameter	Deterministic Value
WTI Oil Price ($/STB)	60.00
CO_2 Purchase Price ($/mscf)	2.00
Real Discount Rate (%)	12
CO_2 Processing O&M Cost ($/mscf)	0.50
Lifting O&M Cost ($/STB)	0.60
Taxes & Royalties	
Royalty Rate (%)	12.5
Severance Tax Rate (%)	5.0
Ad Valorium Tax Rate (%)	2.0
CO_2 Tax ($/tonne)	0.00
Real Escalation Rates	
Oil Price (%/year)	1

Table 4. Results for the four illustrative cases described in Table 2.

Parameter	Northeast Purdy Unit	SACROC Unit, Kelly-Snyder Field	Ford Geraldine Unit	Joffre Viking Pool
CO_2 Cut at End-of-Life	0.90	0.87	0.89	0.92
Oil Produced (MMSTB)	36	357	15	20
CO_2 Stored (Mt)	5.8	72.4	2.7	2.7
Capital Cost (million 2004 US Dollars)	$243	$1,036	$180	$107
NPV (million 2004 US Dollars)	$212	$3,454	$6	$153
ROI	62%	138%	14%	90%

The breakeven CO_2 price was also calculated by the model, as shown in Figure 3. The breakeven CO_2 price can be interpreted as the highest price a CO_2-flood developer would be willing to pay for CO_2 delivered to the site, based on the assumed benchmark oil price (and numerous other factors).

As would be expected based on pattern performance, there is considerable variation between breakeven costs for each case. However, at recent oil prices (i.e., greater than $60/bbl) three of the case study projects would be able to breakeven paying at least $3 per mscf CO_2 ($57 per tonne CO_2). The breakeven costs shown in Figure 3 are somewhat more pessimistic than those estimated in the literature [19] for generic sandstone and carbonate west-Texas reservoirs, but this may be the result of a number of factors: the model here uses higher capital costs compared to earlier studies; operation of the field can increase recovery (and the amount of CO_2 stored [20]) for example, by "shutting-in" patterns, drilling additional wells, and inverting injection patterns; and, improved mobility control in traditional water alternating gas (WAG) CO_2-floods results in lower CO_2 utilization rates. Both the addition of a third mobile phase to the reservoir (as occurs in WAG CO_2-floods) and the effects of operational decisions can not modeled analytically.

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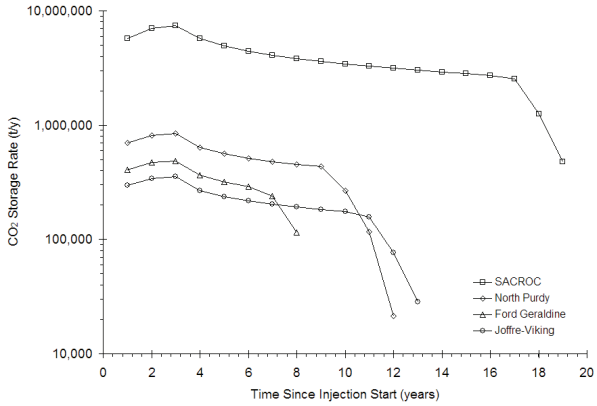

Figure 2 CO_2 storage rates for the four illustrative cases.

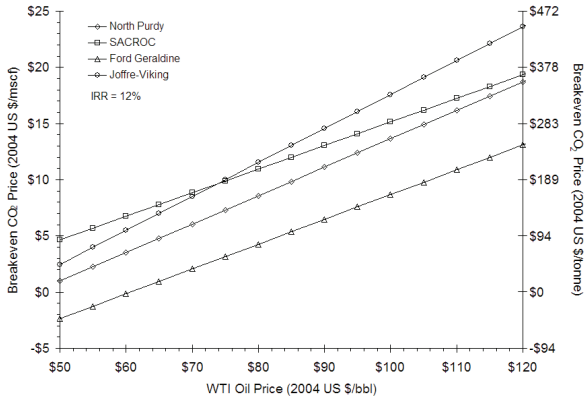

Figure 3. The breakeven CO_2 price for the four illustrative cases.

4. Case Study—Sensitivity Analysis

To assess the sensitivity of the model to changes in multiple performance and economic parameters, uniform distributions were assigned to a number of parameters and the model was used to estimate the breakeven price for CO_2 over a series of Monte Carlo trials for the SACROC Kelly-Snyder case. The uniform distribution was selected to represent uncertainty or variability because there is no prior information that would suggest choosing a more complex distribution (such as a triangular or lognormal distribution). Twelve performance model parameters and seven economic model parameters were assigned distributions; the distributions for the parameter values can be found elsewhere [10].

Performance parameters selected for the sensitivity analysis are those likely to vary over a large reservoir such as the Kelly-Snyder Canyon Reef. Parameters that directly affect the amount of oil in place at the beginning of the project were assumed to vary less from their deterministic values than those that vary considerably over the life of the project (e.g. reservoir pressure), or those that are largely speculative (i.e., loss fractions), because the amount of oil in place would likely be well known at the beginning of a tertiary CO_2-flood. All performance and economic model parameters not selected for the sensitivity analysis were treated as constants (with the values listed in Table 2 and Table 3) and the optimum NPV-maximizing CO_2 cut of 0.87 for the SACROC Kelly-Snyder deterministic case was used. For this analysis, 1,000 trials were conducted.

Figure 4 shows the CDF for the breakeven CO_2 price based on an oil price of \$60/bbl with the uncertain real price escalation rate between -1% and 2% per year. The median breakeven price of CO_2 from the sensitivity analysis is \$7.90 per mscf CO_2 (\$149 per tonne CO_2), with a 90% confidence interval of \$6.21 to \$10.33 per mscf CO_2 (\$117 to \$195 per tonne CO_2, respectively).

Results of the Monte Carlo trials can also be used to assess the sensitivity of breakeven cost to the model parameters assigned distributions. The measure used to assess the sensitivity is the Spearman rank-order correlation (r_s) [21]. The value of the rank order correlation coefficient between the breakeven CO_2 price and the model parameters assigned distributions is shown in Figure 5. The dashed vertical lines to the left and the right of the axis in Figure 5 indicate the 5% significance level (rs = ±0.07); thus rank-order correlation coefficients smaller than this value are not statistically significant at the 5% level. Figure 5 shows the strongest correlation is between the reservoir loss fraction (r_s = -0.56) and breakeven CO_2 price, followed by reservoir pressure (r_s = -0.53) and the oil price escalation rate (r_s = 0.35)—a proxy for oil price. Following these, significant rank-order correlation coefficients (by decreasing magnitude) are the: reservoir temperature, Dykstra-Parsons coefficient (representing permeability heterogeneity), gross injection rate, surface loss rate, escalation in drilling and completion cost, net pay, discount rate, escalation in lease equipment, CO_2 processing O&M cost, and permeability.

These results show that the breakeven CO_2 price is highly sensitive to a number of factors. In practice, however, the uncertainty around some of these parameters should be relatively small. Factors such as reservoir pressure, temperature, and initial oil saturation (i.e., residual to waterflooding) may vary from area to area within the field, but

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they will be well characterized by the time tertiary CO_2 flooding is being planned. Moreover, reservoir pressure and reservoir loss rates can be controlled to some extent. In contrast, the uncertainty associated surrounding future oil prices over the operating life of the field is far and away the most difficult parameter to estimate. In this analysis the real oil price at the start of the CO_2-flood has been assumed to be well known compared to the nominal oil price in some future year of operation; thus, the real oil price escalation rate has been assigned uncertainty.

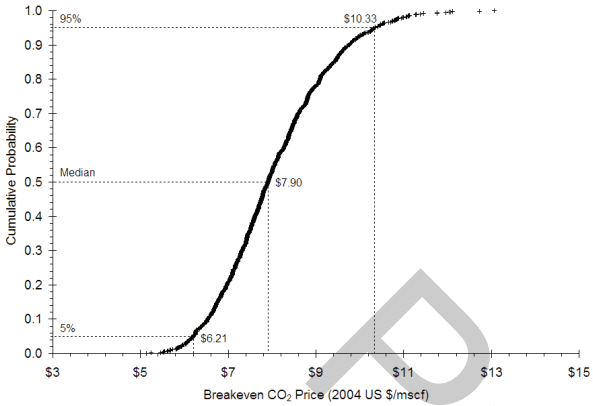

Figure 4 CDF for the breakeven CO_2 price for the SACROC Kelly-Snyder case

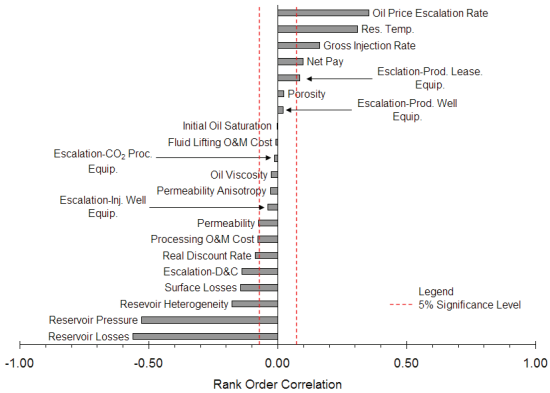

Figure 5. Rank-order correlation between the results of the Monte Carlo sensitivity analysis and the parameters assigned uniform distributions.

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5. Conclusion

These high breakeven CO_2 prices suggest that there is ample profit incentive to early entrants who are able to provide CO_2 for successful EOR projects because typical CO_2 capture costs are much lower than the breakeven prices estimated here. However, a CO_2 producer may not be able to realize these prices as many oil producers may choose to delay fixing CO_2 supply contracts for EOR projects until the US Federal Government introduces a CO_2 emissions cap. Even under low permit prices (or tax rates), the price for CO_2 will likely be driven to zero—or less—as relatively pure streams of CO_2 are captured.

The results from these case studies also highlight that, for many EOR projects, the rate of CO_2 storage and the total capacity for CO_2 storage are very small in relation to the rate and amount of CO_2 produced by a modern coal-fired power plant (i.e., 2 to 3 Mt CO_2 per year for 500 MW of coal fired capacity). This highlights that the viability of CO_2-flood EOR as a means to mitigate CO_2 emissions hinges on whether there are fields remaining that are amenable to CO_2-flooding that can accept these large amounts of CO_2 at practical rates. In a study of the Alberta and Williston Basins (Western Canada), Bachu and Shaw found that the majority of EOR-related CO_2 storage capacity is in a very small fraction of reservoirs and that when reservoirs with total capacities of less than 1 Mt CO_2 were excluded, only 2% of reservoirs were suitable for CO_2 storage [22]. The results would likely be similar for other sedimentary basins. Consequently, while commercially attractive, CO_2-flood EOR alone will not be the solution for mitigating emissions on a large-scale.

6. Acknowledgements

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