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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.


*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.

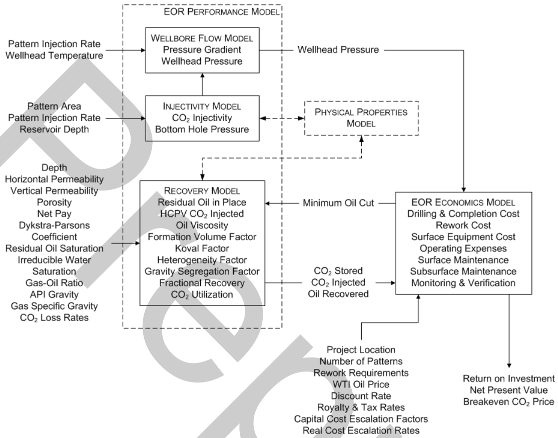


Figure 1. The $CO_2$-flood EOR engineering-economic model described here.



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.

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 | $8.04\times10^{-4}$ | $61 | $9.75\times10^{-1}$ | $36,749 | $2.99\times10^{-2}$ | $31,226 | $2.81\times10^{-4}$ |
| S-TX | $136,434 | $8.04\times10^{-4}$ | $4,681 | $3.04\times10^{-1}$ | $4,207 | $3.83\times10^{-1}$ | $37,040 | $1.16\times10^{-4}$ |
| S-LA | $190,790 | $8.04\times10^{-4}$ | $3,539 | $3.47\times10^{-1}$ | $5,803 | $3.54\times10^{-1}$ | $39,876 | $1.13\times10^{-4}$ |
| MCR | $110,907 | $8.04\times10^{-4}$ | $888 | $5.74\times10^{-1}$ | $11,413 | $2.10\times10^{-1}$ | $39,876 | $1.13\times10^{-4}$ |
| RMR | $178,547 | $8.04\times10^{-4}$ | $36 | $1.02\times10^{0}$ | $23,801 | $1.35\times10^{-1}$ | $29,611 | $2.60\times10^{-4}$ |
| CA | $165,290 | $8.04\times10^{-4}$ | $9,214 | $2.58\times10^{-1}$ | $56,711 | $6.70\times10^{-2}$ | $38,931 | $2.10\times10^{-4}$ |
| AK | $531,697 | $8.04\times10^{-4}$ | $9,214 | $2.58\times10^{-1}$ | $56,711 | $6.70\times10^{-2}$ | $38,931 | $2.10\times10^{-4}$ |
| APPL | $88,263 | $8.04\times10^{-4}$ | $888 | $5.74\times10^{-1}$ | $11,413 | $2.10\times10^{-1}$ | $39,876 | $1.13\times10^{-4}$ |
| OTHR | $110,907 | $8.04\times10^{-4}$ | $888 | $5.74\times10^{-1}$ | $11,413 | $2.10\times10^{-1}$ | $39,876 | $1.13\times10^{-4}$ |



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 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 |
| $\gamma_{API}$ ($^oAPI$) | 35 | 41 | 40 | 42 |
| ROIP (MMSTB) | 146 | 1,163 | 76 | 47 |
| OOIP (MMSTB) | 220 | 2,163 | 97 | 93 |



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.

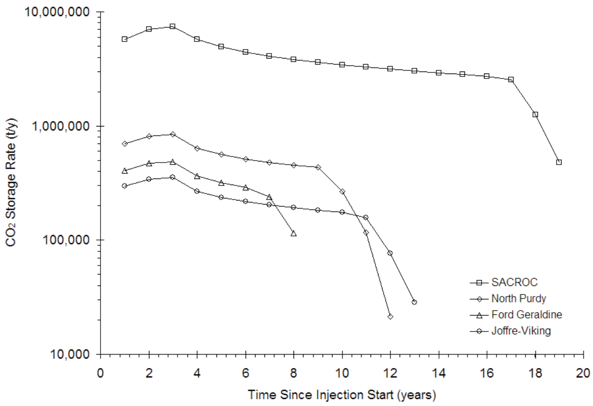


Figure 2 $CO_2$ storage rates for the four illustrative cases.

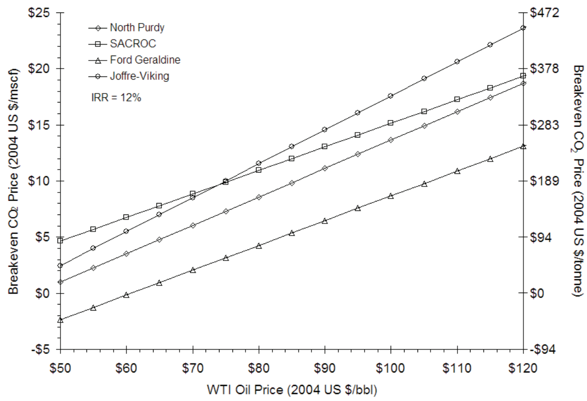


Figure 3. The breakeven $CO_2$ price for the four illustrative cases.



## 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 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.

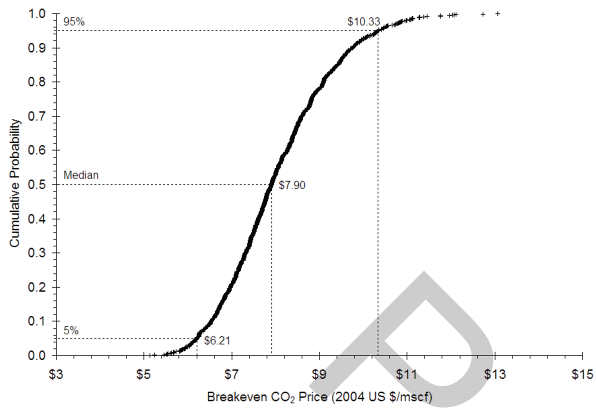


Figure 4 CDF for the breakeven $CO_2$ price for the SACROC Kelly-Snyder case

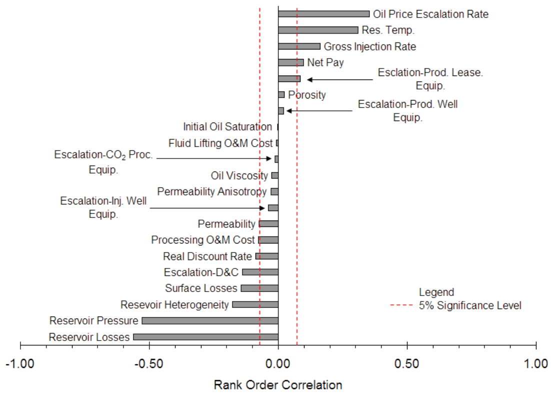


Figure 5. Rank-order correlation between the results of the Monte Carlo sensitivity analysis and the parameters assigned uniform distributions.



## 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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