A model of CO_2-flood enhanced oil recovery with applications to oil price influence on CO_2 storage costs

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Abstract

Geological sequestration of CO_2 through Enhanced Oil Recovery (EOR) presents an opportunity to achieve significant emissions reductions. However, there is considerable uncertainty over the amount of CO_2 that can be stored over the economic life of an EOR project. This paper presents the development of a model that provides first-order cost estimates, sensitive to key site-specific or project-specific parameters, for CO_2-EOR projects. The model is based on previous work in the literature on modeling of recovery in unstable miscible flooding processes, and shows good agreement with predictions by other types of models in the illustrative case shown here. Future development of the cost model will allow the most important parameters affecting the economics of CO_2-EOR projects to be identified, and help CO_2 producers and field operators to make more informed strategic decisions.

Keywords: CO_2, geologic storage, enhanced oil recovery, utilization

Introduction

In recent years, global concerns about greenhouse gas emissions have stimulated considerable interest in CO_2 capture and sequestration (CCS) as a potential "bridging technology" that can achieve significant CO_2 emission reductions while allowing fossil fuels to be used until alternative energy sources are more widely deployed. One method of sequestering carbon dioxide is through CO_2-flood enhanced oil recovery (CO_2-EOR), which could reduce the cost of CO_2 sequestration through oil production. The recent IPCC report [1] has identified CO_2-flood EOR (for oil recovery) as a mature technology; however, there are very few papers that examine sensitivity of EOR projects to various reservoir and economic parameters in the context of CO_2 storage. For example, many studies have identified utilization rates of CO_2 (i.e., volume of CO_2 required to produce a barrel of oil) for various operating projects but few studies have explicitly looked at changes in utilization rates over time and effects of reservoir parameters on utilization rates. Thus, there is considerable uncertainty over the net utilization of CO_2, the amount of CO_2 stored over the life of an EOR project, and, consequently, the relationship between oil price and maximum CO_2 price.

This paper details development of a performance model for CO_2-EOR that, in particular, allows estimation of the amount of CO_2 stored for various sizes of EOR projects. When coupled with an economic model of capital and operating cost of CO_2-EOR projects, the overall model can be used to estimate the relationship between oil price and maximum CO_2 price for a profitable project. The intent of the model is to provide first-order cost estimates that are sensitive to key site-specific or project-specific parameters, both technical and financial. It is being developed in conjunction with the IECM power plant model—a USDOE-sponsored project to provide a publicly available tool for estimating the performance, emissions and costs of alternative CCS systems.

Performance Model

As shown in Figure 1, the model can be separated into two parts: a performance model and cost model. The performance model predicts the amount of incremental oil recovered as a function of the gross amount of CO_2 injected and the net amount of CO_2 required as a function of the gross amount injected.

The performance model developed here is a fractional-flow based screening model, similar to other models previously developed and used in the literature [2-5]. It is based on the Koval method [6] for predicting recovery in a secondary CO_2-flood, modified by Claridge [5] for aerial sweep in an inverted five-spot pattern. Koval developed the original method to model 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.

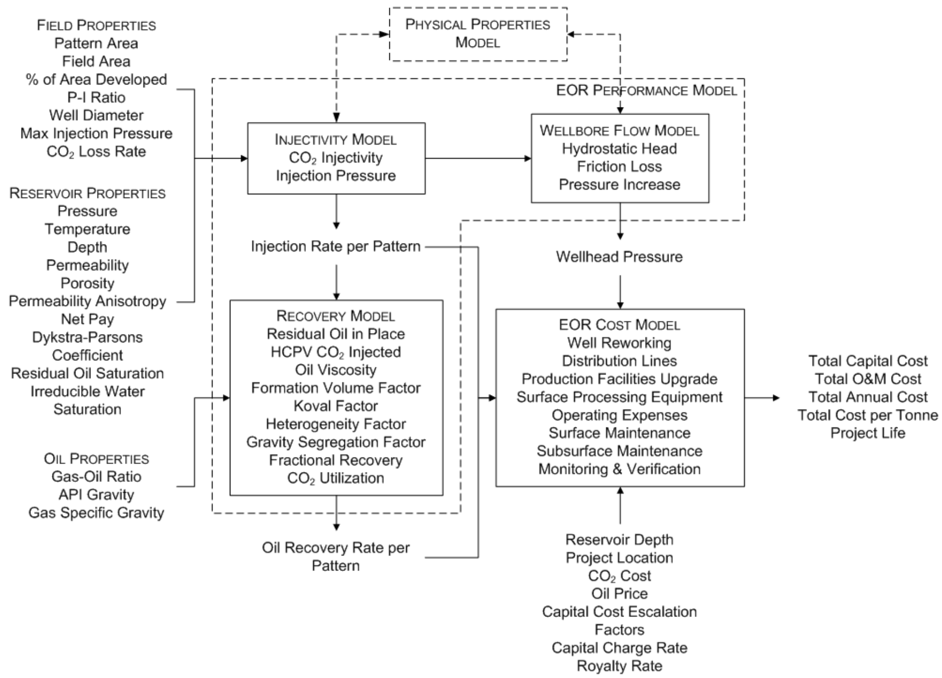

Figure 1. The CO_2-EOR model developed here, showing the division between the performance and the cost models.

Figure 2 shows the simplified recovery curves based on the work of Koval modified by Claridge. These curves relate the fraction of the displaceable oil in place after primary production recovered as a function of the mobility ratio between the oil and solvent phases for different hydrocarbon pore volumes (HCPV) of injected CO_2. The curves in Figure 2 are represented by Equations 1 and 2, from Claridge [5].

$$(F_i)_{bt} = \sqrt{\frac{0.9}{(M+1.1)}} \qquad (1)$$

$$N_p = \frac{\alpha + (F_i)_{BT}}{1+\alpha}, \text{ where } \alpha = \frac{1.6}{K^{0.61}}\left[\frac{F_i - (F_i)_{bt}}{1-(F_i)_{bt}}\right]^{\left(1.28/K^{0.26}\right)} \qquad (2)$$

In Equations 1 and 2, $(F_i)_{bt}$ represents the HCPV of CO_2 injected at the point at which CO_2 reaches the production wells (i.e., breakthrough), F_i is number of HCPV of CO_2 injected, M is the mobility ratio of the two fluids, K is the Koval factor, and N_p is the fraction of the displaceable residual oil in place (ROIP) recovered. The actual volume of oil recovered is arrives at by multiplying N_p and the volume of movable oil remaining after primary production.

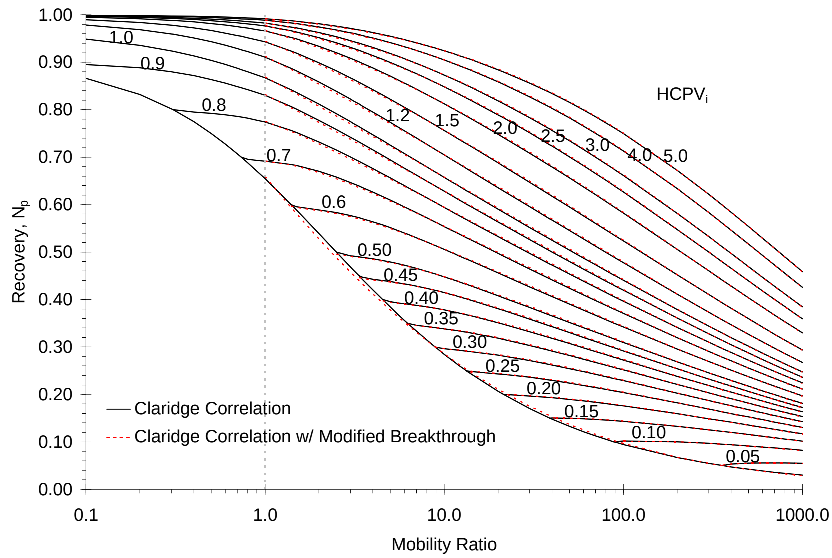

Figure 2. The fraction of residual oil in place recovered as a function of the mobility ratio between the oil and solvent phases for different hydrocarbon pore volumes injected based the correlation presented by Claridge.

Unfortunately, the correlation presented by Claridge in Equation 1 is not a function of the Koval mobility factor. Thus, the pore volume predicted by Equation 1 is not affected by the Koval factor, and may be too high in heterogeneous reservoirs or reservoirs where significant gravity segregation occurs. Thus, the model uses a correlation between the pore volumes injected at breakthrough predicted by Equation 1 and the Koval factor, which are both functions of the mobility ratio. The correlation used to replace Equation 1 in the model as Equation 3.

$$\log(F_i)_{bt} = 0.2232\log(K)^2 - 1.3847\log(K) - 0.1809 \qquad (3)$$

Equation 3 is only accurate for situations in which the mobility ratio, M, is greater than one. This is not a serious constraint as in every real CO_2-EOR project, the oil viscosity will be greater than the viscosity of the injected CO_2. The dashed lines in Figure 2 show that the correlation in Equation 3 agrees well with the results presented by Claridge.

The screening model uses a corrected mobility ratio in an attempt to account for permeability heterogeneity of the reservoir and gravity segregation of the injected CO_2. The corrected mobility ratio, K, is the product of the Koval mobility [6] factor, E, the gravity segregation factor [4], G, and permeability heterogeneity factor [6,7], H. These correction factors are presented in Equations 4 through 8.

$$K = EHG \qquad (4)$$

$$E = \left[0.78 + 0.22M^{1/4}\right]^4 \qquad (5)$$

$$M = \frac{\mu_o}{\mu_s} \qquad (6)$$

$$H = \left[\frac{V_{DP}}{(1 - V_{DP})^{0.2}}\right]^{10} \qquad (7)$$

$$G = 0.565\log\left(\frac{t_h}{t_v}\right) + 0.870\text{, where } \frac{t_h}{t_v} = 2.5271 k_v A \frac{\Delta\rho}{q_{gross}\mu_s} \qquad (8)$$

In Equations 4 through 8, μ is the viscosity of the oil (o) or CO_2 (s), V_{DP} represents the Dykstra-Parsons coefficient, k_v is the reservoir permeability in the vertical direction, A is the pattern area, q_{gross} is the gross injection rate (i.e., recycle plus CO_2 purchased) of CO_2, and $\Delta\rho$ is the density difference between CO_2 and oil.

To estimate the production rate from the reservoir, the injection rate of CO_2 must be known. In reality, the injection rate will vary over the life of the project and depends on many factors. However, the screening model assumes that the injection rate is limited only by the fracture pressure of the reservoir and the operator will always choose to inject CO_2 at a rate such that the bottom-hole pressure (BHIP) does not exceed the formation fracture pressure. The fracture pressure can be estimated using the correlation of Heller and Taber [8], given in Equation 9, which calculates the fracture gradient (g_f) in kPa/m for a reservoir of a given depth (d) in m. The BHIP is then some fraction of the fracture pressure input by the user.

$$g_f = 1 - 9.0482e^{-0.0003d} \qquad (9)$$

Based on the difference between the BHIP and the field pressure, the pattern area, and reservoir permeability, the injection rate of CO_2 for a given pattern can then be calculated using the analytical solution for injectivity into an inverted five-spot [9].

With the injection rate of CO_2 known, the production rate can then be estimated by taking the derivative of Equation 2 with respect to F_i. The production rate is then calculated by multiplying this derivative and the volume of displaceable oil remaining after primary production, then dividing by the hydrocarbon pore volumes of CO_2 injected. This result, along with the gross injection rate of CO_2, is in a volumetric balance to calculate the net rate of CO_2 stored by the project.

The volumetric balance on the reservoir assumes that the pressure and temperature, and thus oil and CO_2 formation volume factors (i.e, the ratio of oil or CO_2 density in the reservoir to that at standard conditions), are constant. Moreover, it is assumed that one volume of CO_2 injected into the reservoir effectively displaces one volume of oil in place. This assumption does not account for miscibility of injected CO_2 with oil in place and subsequent oil swelling that may occur, nor does it account for solubility of injected CO_2 in the formation water. To account for these processes, a loss factor, l, has been introduced in the volumetric balance. In addition, a second loss factor, η, has been introduced to account for imperfect separation of CO_2 from oil at the surface. The net storage rate of CO_2 by the project is then given by Equation 10, where q_{net} is the net injection rate and q_{oil} is the oil production rate.

$$q_{net} = (1-\eta)\left\{q_{oil} + q_{gross}\left[\frac{l(1+\eta)+\eta}{1-\eta}\right]\right\} \qquad (10)$$

Illustrative Results from the Performance Model

To illustrate the behavior of the performance model and to compare the results with predictions by other models, the model has been applied to a design study in the literature [10]. The field used in the design study was the Port Neches Field, located in Orange County, Texas. The field was previously waterflooded, and CO_2 injection into the Marginulina sandstone reservoir began in 1993 in a project sponsored by the US Department of Energy. Properties of the field, reservoir, and oil used in the performance model are listed in Table 1 [10].

Table 1. Properties of the Marginulina reservoir and reservoir fluids at the Port Neeches field used in the screening model.

Reservoir Properties	
P [MPa]	23
T [^oC]	74
Φ	0.30
h [m]	9.14
$k_{h,\mu}$ [md]	3000
k_v/k_h	0.85
V_{DP}	0.70
D [m]	1798
S_{orw}	0.30
S_{orm}	0.008
S_{wir}	0.20

Oil Properties	
R_s [scf/STB]	11.0
γ_{API}	34.6
μ_o [mPa s]	3.30
ρ [kg/m^3]	851.9
γ_g	0.6
B_{oi} [RB/STB]	1.05

Field Properties	
Pattern Area [acres]	40
r_w [in]	5
p_{max} [% of p_f]	74%
CO_2 Losses	5%

Figure 3(a) illustrates the fractional recovery as a function of the hydrocarbon pore volumes injected as predicted here for the Marginulina reservoir, while Figure 3(b) are the results of the design study for the three different types of simulators used to predict the recovery [10]. This figure indicates the relatively good agreement between the more complex simulators used in the design study and the model developed here.

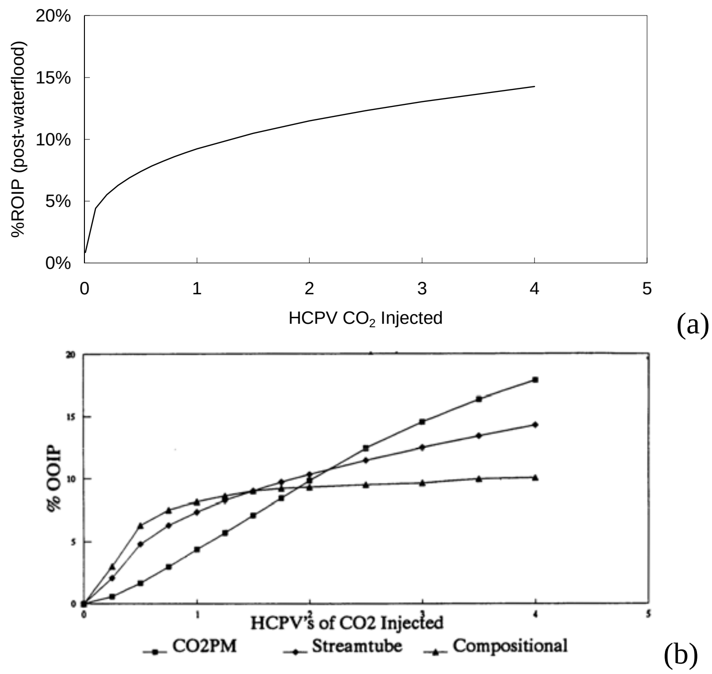

Figure 3. The fractional recovery as a function of hydrocarbon pore volume (HCPV) injected as predicted by the model developed here (a), and the from the original design study (b) [10].

As with the fractional recovery, there is also relatively good agreement between the more complex simulators used in the design study and the model developed here on the yield of oil produced (i.e., oil production per volume of CO_2 injected) as a function of pore volumes of CO_2 injected. Moreover, the oil net CO_2 utilization rate in this case is on the order of 10 mscf/bbl, depending on pore volumes of CO_2 injected, which is within the range for utilization rates presented elsewhere [11].

Cost Model

The cost model being developed takes output from the performance model to predict the profit (or cost) per tonne of CO_2 stored. The cost model is based on the assumption that the field being modeled has already undergone waterflooding and has suitable well spacing for CO_2 injection. Thus, the model assumes that infill drilling is not required. However, the field is assumed to require conversion of water injection wells to CO_2 injection, reworking of production wells, upgrades to production facilities, CO_2 distribution piping, and CO_2 surface processing equipment [12,13,14]. Further details of the cost model, and illustrative results from the cost model coupled to the performance model will be forthcoming in future publications.

Conclusions

The CO_2-EOR model developed here shows good agreement with other predictions for the performance of CO_2-EOR projects, and will be useful for estimating the potential impact of CO_2-flood EOR as a strategy for reducing CO_2 emissions. The screening level approach taken here allows performance of a field to be estimated based on limited amount of information about the reservoir and the fluids within, and is suitable for incorporation into models such as the IECM. Future development of the cost model will allow the most important parameters affecting the economics of CO_2-EOR projects for CO_2 storage to be identified, and help CO_2 producers and field operators to make more informed strategic decisions.

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