ENHANCED OIL RECOVERY (EOR) AS A STEPPING STONE TO CARBON CAPTURE AND SEQUESTRATION (CCS)

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Abstract

Environmental concerns about carbon emissions coupled with the oil industry's need to secure additional CO_2 for EOR has sparked interest in the potential CO_2-EOR may have in jumpstarting CCS. To study the practicality of wide scale implementation of CCS partnered with CO_2-EOR to full scale CCS, we build a unique two-stage dynamic optimization model that includes a carbon tax for emissions, which becomes a subsidy for sequestration. Our model tracks the response of total carbon movements and oil production, for a single field, during the CO_2-EOR process and continued sequestration after oil production has ceased. By tracking usage and sequestration of CO_2, from both natural reservoirs of CO_2 and anthropogenic sources, we appropriately account for all reductions in emissions. Our aim is to identify relevant factors that lead to the transition from CO_2-EOR to CCS and enables us to evaluate the producer's responsiveness to oil price and imposed policy; while informing policy makers on how to design policy in the presence of a market for CO_2 and inherent physical production constraints that influence the producer's reaction to market mechanisms.

Our model results suggest that small increases in the level of carbon tax can have large and discontinuous impacts on net sequestration. Total volumes of captured CO_2 sequestered across both stages is equivalent to 30% to 40% of the emissions from the use of the oil produced as part of the project. Moreover, because of the credits oil producers receive from sequestering CO_2, relatively high carbon taxes incentivize additional sequestration without significantly impacting the supply of oil and maintaining a steady stream of profits, a win-win situation for energy security and the climate.

I Introduction

The International Energy Agency (IEA) asserts that emissions from continued use of fossil fuels at current rates of consumption could increase average global temperature by more than 3.5°C by 2100. While CCS' technical viability and capability of abating immense amounts of this CO_2 per year make it a strong contender in mitigating these emissions. Yet, commercial deployment of CCS has been stunted from the lack of any significant carbon price coupled with the prohibitive cost of implementation, technological uncertainties in performance for large scale stationary sources and the absence of guaranteed storage sites. At the same time, the oil industry's infrastructure, expertise, and decades of experience in separating, transporting, injecting and sequestering CO_2 in underground oil reservoirs makes it a logical partner in improving commerciality of CCS (IEA, 2014).

Shifting to a world where atmospheric disposal of CO_2 is no longer free, policy makers, who will be influencing CO_2 prices, and oil companies, which will be reacting to them, all need more knowledge of the potential role that CO_2-EOR transitioning to full scale CCS might play. As such, there exists an opportunity for a CO_2 market to develop where carbon capture facilities supply the CO_2 to EOR projects. Then CO_2, typically considered a negative externality, which needs to be regulated, would have a market that values it as an input in production.

Published work highlighting the viability of CCS when coupled with EOR have generally placed more focus on either an engineering or an economic policy approach. Furthermore, modelling efforts on EOR have stopped at the end of the productive life of the field. Most engineering studies found focus on the technical aspects of the design of the CO_2-EOR project to produce the maximum amount of oil while simultaneously storing the most CO_2 with the economics as an afterthought. While most economic studies found have focused on a singular aspect of the issue such as impacts of exogenously varying injection rates.

We found only one study (Leach et al. (2011)) that simultaneously modeled engineering and economic tax policy while evaluating the coupling of CO_2-EOR and CCS in a dynamic optimization framework. Nonetheless, as highlighted by van't Veld et al. (2014), although the qualitative results of the seminal Leach et al. paper were sound, the technical assumptions related to the CO_2-EOR process needed enhancing. We build on this limited previous work by combining robust engineering features with economic policy to investigate the practicality of wide scale implementation of CCS in conjunction with CO_2-EOR.

To explore the potential transition from CO_2-EOR to full CO_2 sequestration, we build on Leach et al.'s (2011) single stage dynamic optimization model that maximizes a producer's profits subject to a tax policy and associated resource constraints. Given that the reservoir's storage capacity for CO_2 (measured in units of reservoir pore space) is dependent on historical production activities, our two-stage dynamic optimization allows us to evaluate the producer's tradeoff between oil and pore space. The producer must balance the amount of oil they produce and how they produce it against how much CO_2 they would subsequently be able to sequester beyond oil production activities. In our model, the government introduces market forces with a carbon tax for emissions and use of CO_2 from natural accumulations as well as a carbon subsidy for sequestration. Our model identifies and quantifies relevant factors that lead to the transition from CO_2-EOR to CCS and enables us to evaluate the producer's responsiveness to oil price and imposed policy.

In our model, the operator co-manages their two non-renewable resources, also state variables: oil (R) and pore space (S). Their historical oil production methods will influence pore space availability across both stages, which dictates how much CO_2 they can sequester. We also track the usage and sequestration of CO_2, from both natural reservoirs of CO_2 and anthropogenic sources, to appropriately account for all reductions in emissions. Our intent is to be able to inform policy makers on how to design policy in the presence of a market for CO_2 and inherent physical production constraints that influence the producer's reaction to market mechanisms (e.g. price and tax levels). The evaluation is conducted from the perspective of a profit maximizing EOR producer to study how the interaction influences the management of their two non-renewable resources that are interdependent. We start on an individual field level to develop an appropriate base with the potential to scale up the evaluation to a regional or even an international level.

The remainder of the paper is organized as follows: Section II provides a brief background on the technical aspects of both stages: CO_2-EOR and continued sequestration after oil production has ceased (which we designate as CCS). Section III describes and justifies the model used. Section IV details the numerical simulation results and their significance in quantifying CO_2-EOR's contribution to CCS. Conclusions and future work are presented in section V.

II Background

The three phases of oil recovery are: primary, secondary and tertiary. In the primary phase, no fluids are injected into the reservoir to assist in oil production. Oil produced makes pore space available for future use. In the secondary and tertiary phases, injected fluids provide necessary pressure support and help sweep oil left in the pore space. In our case, CO_2-EOR, injected CO_2 aids in reducing the viscosity of oil, increasing its mobility while providing needed pressure support. Injected CO_2 can dissolve into the oil or reservoir fluid, fill part of the pore space left by the oil produced, or cause a geochemical reaction with the reservoir rock. Since CO_2 in the reservoir is at a much higher pressure than at the surface, its volume can be reduced to about half of its surface volume (Donaldson, 1985).

During the CO_2-EOR process, an injection process called water alternating gas (WAG) is gaining significant popularity for improving oil recovery. The alternating injection of water and CO_2 to enhance oil recovery has the advantage of coupling the improved microscopic displacement efficiency of gas flooding with the improved macroscopic sweep efficiency of water injection. The result is an improvement in recovery compared to separate gas or water injection schemes. Water flooding sweeps most of the reservoir leaving a smaller amount of oil behind compared to CO_2, which can finger around some of the oil and leave that oil behind. On the other hand, CO_2 dissolves into the oil reducing its viscosity and allowing for easier mobility of the oil in the reservoir and subsequently to the surface (Verma, 2015). Increasing CO_2 injection levels will initially increase the incremental oil production, relative to the case of no CO_2 injection, until it reaches a critical injection rate beyond which the resulting magnitude of the incremental production declines. These subsequent diminishing marginal benefits of injection result from the CO_2 bypassing the oil in place (Donaldson, 1989).

Oil wells usually reach the height of their production shortly after they are brought on-stream and soon thereafter begins a production decline mainly resulting from depleting pressure drive. The rapidity of decline depends on several factors including reservoir characteristics and choice of recovery technique (Fetkovich, 1996). In addition to incremental oil recovery benefits, CO_2-EOR helps mitigate the speed of the production decline. In our model, we emulate a WAG recovery technique. Thus, our decline function depends on the total rate of injection at time t, $q_i(t)$, the summation of both water ($w(t)$) and CO_2 ($c(t)$) injected at time t. We represent this decline by a function $\delta(q_i(t))$, with oil production ($q_p^o(t)$) equal to the product of the decline rate function and remaining reserves at a given point in time ($\delta(q_i(t)) * R(t)$). Oil production declines over time because we produce a fraction of a declining pool of reserves with time. We construct these equations for use in our dynamic optimization model from reservoir simulation output. It should also be noted that all injected and produced volumes have been converted to reservoir barrel equivalent (rb).

III Methodology

Leach et al. (2011) use a field level optimal control model to evaluate how a CO_2-EOR producer can maximize the net present value (π) of an EOR project through the choice of the optimal rate of CO_2 injection ($c(t)$), constrained by a fixed oil stock ($R(t)$). They include a tax policy where the producer pays a tax (τ) for produced oil according to the amount of CO_2 emitted when the oil they produce is consumed and credits them for each unit of CO_2 they sequester. Their model determines the economic productive field life along with the optimal CO_2 injection, oil production and sequestration profiles. In doing so, Leach et al. endogenize oil production decline, which is a function of both CO_2 and H_2O injection rates as well as the optimal time to terminate the project.

We build on the Leach et al. model extending it in several ways in addition to tracking usage of CO_2 from multiple sources; natural accumulations (reservoirs) of CO_2 and anthropogenic sources. We also start on a single field level, but we add a second stage to the dynamic optimization modelling sequestration activities after oil production stops. This enables us to evaluate the transition to only CCS and the producer's responsiveness to the price of oil and a modified carbon policy through the transition. We use a reservoir simulation model to help us verify and achieve realistic representations of injection, production and sequestration profiles across both stages of our dynamic optimization model.

The reservoir simulation model allows us to predict the interaction and flow of fluids through the reservoir; mimicking observed behavior from actual field performance. Our simulation model was subjected to pressure, production and injection rate constraints to produce a more realistic output mirroring actual field performance with a WAG injection process in our productive stage and subsequently assess storage capacity for CO_2 post production activities. We also predict more accurately how CO_2 injection influences oil production and sequestration during the EOR process as well as continued sequestration once production has ceased.

We start with a basic static model assuming a flat homogenous 3D reservoir. We subsequently translate the static model to a dynamic simulation model using Schlumberger's simulator Eclipse. The inability to nest our reservoir simulation model in our dynamic optimization model because of the structural and time scale differences in both models necessitates an intermediate step. This intermediate step involves construction of the equations used in our two-stage dynamic optimization model from the simulator's resulting production streams. These equations include those relating total injection to both our production and sequestration profiles in stage one. While for stage two, the results allow us to estimate reservoir capacity for sequestration and assess limitations on CO_2 injection rates given the prescribed constraints, in our reservoir simulation model, such as fracture pressure. So even though the general structure of our first stage mirrors that of Leach et al., the coefficients or multipliers used to relate the production and sequestration profiles to CO_2 injection are modified, specifically via the decline rate function $\delta(q_i(t))$. Our second stage is a completely new construct which we added to the dynamic optimization model.

Our first stage involving oil production is based on material balances which dictate that total injection must equate to total production. This is coupled with the requirement of maintaining a minimum level of miscibility pressure within the reservoir to allow the CO_2 to dissolve in the oil guaranteeing the success of the CO_2-EOR operation. Maintaining this minimum pressure level requires an injection rate that maintains the pressure of the original oil in place assumed to be 1 million reservoir barrels. As the volume of CO_2 injection fluctuates, for technical or economic reasons, so will the volume of water to meet the total injection needed to achieve the minimum miscibility pressure. Miscibility occurs when both the displacing and displaced fluid mix in all proportions without interference leading to higher and more efficient recovery of oil.

In our setting, the ratio of output to reserves – represented by the decline rate function – is also related to the CO_2 fraction in the total injection stream. The decline function, $\delta(q_i(t))$, that dictates the share of remaining oil we can recover per unit of time is consistent with reservoir engineering studies and the results of our reservoir simulation model. The decline rate function used in our model is concave with an interior maximum such that: $\delta'(0) > 0 > \delta'(1)$. It takes on the following quadratic form in the model similar to Leach et. al.: $\delta(q_i(t)) = \delta_w + \delta_1 c(t) - \delta_2 c(t)^2$. δ_w is a parameter representing the impact of a water flood on oil recovery and $c(t)$ represents the rate of CO_2 injection at any given time 't'. If we're injecting only water the decline rate equates to $\delta(0)$ and if we're injecting purely CO_2 the decline rate equates to $\delta(1)$. The parameter values for δ_w, δ_1 and δ_2 are specific to the field being evaluated as the impacts of different recovery mechanisms will differ by reservoir. Our coefficients were derived from the results of our reservoir simulation model.

This limitation on overall injection, incorporated in our model, implies that even though CO_2-EOR provides incremental production benefits it is limited by inherent physical constraints associated with the reservoir being produced. We see increases in oil production associated with higher injection rates up to a critical value. The critical value of CO_2 injection, given an illustrative parameterization of 1 million rb, is 0.485 million rb/year. It should be noted that the optimal CO_2 injection rates considering associated revenues and costs will be lower than this critical value. This indicates that the producer is dynamically optimizing and continuously balancing revenues against cost over the life of the project.

Figure 1: Incremental Oil Production and CO_2 Sequestration as a Function of CO_2 Injection Rate

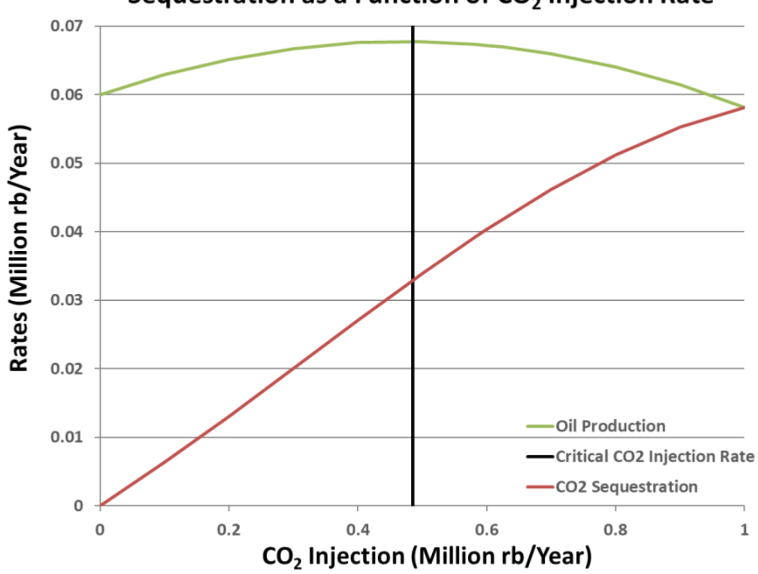


Figure 1 shows a static snapshot of the resulting oil production and CO_2 sequestration rates associated with different CO_2 injection rates given a $R(t)$ value of one. Our 1st derivative, oil production with respect to CO_2 injection, $\frac{\partial(Oil\ Production)}{\partial(CO_2\ Injection)}$ is positive. But, our second derivative $\frac{\partial^2(Oil\ Production)}{\partial(CO_2\ Injection)^2}$ will be positive up to the 'critical value' which is equivalent to an inflection point after which our second derivative will be negative.

Similarly, in terms of CO_2 sequestration with respect to CO_2 injection, our 1st derivative $\frac{\partial(CO_2\ Sequestration)}{\partial(CO_2\ Injection)}$ is positive. In this case the second derivative, $\frac{\partial^2(CO_2\ Sequestration)}{\partial(CO_2\ Injection)^2}$, will always be positive. In our discussion of our results in the next section, we discuss the potential impacts of these constraints on the producer's reactions to oil price (p_o) and tax levels (τ).

All costs related to the purchase, handling and transport of captured and natural CO_2 are represented by w_{CAP} and w_{NR} respectively. We also treat non-CO_2 related operational costs as fixed (F). We carried through this cost characterization to identify the impacts of the model changes we made on CO_2 injection, sequestration and oil production. It should be noted that an upper limit on the sequestration capacity is not implemented during our first stage because the CO_2 sequestered as part of the EOR process will not occupy all the available pore space in the reservoir. Lastly, the parameter β, presented in the model, describes the effect that the tax will have on the oil price received by the producer. It absorbs the conversion reflecting the amount of CO_2 emitted in the combustion of a barrel of oil. Prices and costs associated with the project are assumed to be exogenous and constant over the life of the project.

Unlike the Leach et al model, the oil producer in our first stage maximizes profits by optimizing the choice of using CO_2 from natural (q_{NR}) or captured sources (q_{CAP}) to achieve their optimal CO_2 injection rate (*c(t)*) which impacts both oil production (q_p^o) and CO_2 sequestration (q_s^c). In our model, the carbon tax penalizes the producer for every unit of CO_2 emitted when their oil is consumed as well as every unit of CO_2 they extract from natural sources during operations. The producer is also credited for every unit of CO_2 they sequester in the EOR process. This stage allows us to simulate oil production, CO_2 usage and sequestration by source to the end of the economically productive life of the field subject to a known oil stock constraint ($R(t)$), natural CO_2 stock constraint ($X(t)$) and reservoir capacity constraint ($S(t)$) that tracks pore volume availability. These variables also represent our state variables. Tracking the consumption of CO_2 from both natural and captured sources under increasing levels of carbon tax shows a transition from usage of natural CO_2, currently the most common and cheapest source of CO_2, to captured CO_2. This leads to the setup of our first stage, CO_2-EOR, outlined below.

$$\max \pi = \int_0^{t_1} e^{-rt}\left([p_o - \beta\tau]q_p^o(t) - w_{CAP}q_{CAP}^c - (w_{NR} + \tau)q_{NR}^c - w_r q_r^c + \tau q_s^c - F_1\right)dt$$

$$s.t.: \dot{R(t)} = -q_p^o(t) = -\delta(q_i(t))R(t)$$

$$\dot{X(t)} = -q_{NR}^c(t) = -\left(q_s^c(t) - q_{CAP}^c(t)\right) = -\left(\frac{c(t)}{q_i(t)}\delta(q_i(t))R(t) - q_{CAP}^c(t)\right) = q_{CAP}^c(t) - \frac{c(t)}{q_i(t)}\delta(q_i(t))R(t)$$

$$\dot{S(t)} = q_s^c(t) = \frac{c(t)}{q_i(t)}\delta(q_i(t))R(t)$$

$$R(0) = R_o \ \&\ R(t_1) \geq 0$$

$$X(0) = X_o \ \&\ X(t_1) \geq 0$$

$$S(0) = 0 \ \&\ S(t_1) \geq 0$$

$$0 \leq q_i(t) \leq 1 \text{ million reservoir barrels/unit time}$$

The second stage involves extending the model beyond oil production activities. The operator maximizes profits from selling pore space for sequestration of captured CO_2 via their optimal CO_2 injection rate subject to a reservoir capacity constraint ($S(t)$). Our reservoir capacity constraint in this stage is a function of cumulative oil production resulting from our first stage. This stage allows us to simulate CO_2 sequestration beyond oil production activities during which all production wells are suspended and CO_2 is injected into the reservoir with no physical outlet.

During our second stage, we need to ensure that our injection rate does not exceed the rate that could lead to reservoir fracture. Given the characteristics of our reservoir and related pressure and fluid flow constraints, the overall injection rate necessary to avoid fracturing of the reservoir equates to 1 million reservoir barrels/year. This physical constraint also forces us, unlike our first stage, to introduce a cap on sequestration in our second stage, which ties to the cumulative production resulting from the first stage. This leads to the setup of our second stage, sequestration after CO_2-EOR, outlined below.

$$\max \pi = \int_{t_1}^{T} e^{-rt} \left(p_p q_s^c\left(c(t)\right) - w_{INJ} c(t) - F_2\right) dt$$

$$s.t.\!: \dot{S}(t) = q_s^c\left(c(t)\right) = c(t)$$

$$S(t_1) = Given\ or\ Resulting\ from\ Stage\ 1\ \&\ S(T) \leq 1.2 * q_p^o(t) = \ 1.2 * \textstyle\sum_0^{t_1} \delta(q_i(t))R(t)$$

$0 \leq c(t) \leq 1$ million rb per unit of time.

Presented below is the table defining variables and parameters used in our 2-stage dynamic optimization.

Variables	
$q_p^o(t)$ = Oil produced at time 't' $q_r^c(t)$ = CO_2 recycled at time 't' $q_s^c(t)$ = CO_2 sequestered at time 't' $q_{NR}^c(t)$ = Amount of CO_2 purchased from natural reservoirs at time 't'. $q_i(t)$ = Total Injection at time 't'.	**Choice Variables:** $c(t)$ = CO_2 injection rate at time 't'. $q_{CAP}^c(t)$ = Amount of CO_2 purchased from captured sources at time 't'. **State Variables:** $R(t)$ = Stock of oil at time 't' $X(t)$ = Stock of natural CO_2 at time 't' $S(t)$ = Amount of CO_2 sequestered as of time 't'
Parameters	
p_o = Price of oil p_p = Price of pore space which equals the carbon tax. β = induced tax liability for a one dollar increase in the carbon tax.	w_{NR} = Price of CO_2 extracted from natural reservoirs w_{CAP} = Price of CO_2 purchased from captured sources w_r= Cost of a recycled unit of CO_2 F_1 = Total fixed costs include all other costs outside of what is associated with CO_2 purchases and recycling. w_{inj}= Cost associated with the handling and injection of CO_2 F_2 = Total fixed costs include all other costs outside of what is associated with handling and injection of CO_2.

In the first stage, the model solves for the producer's optimal usage of CO_2 from each source for the optimal CO_2 injection rate. Upon determining the producer's optimal usage of CO_2 from each source, the model can also determine the amount of CO_2 sequestered from each source along with the optimal time path of oil production. The second stage, allows us to observe how quickly the operator sells and occupies the existing pore space post production activities given the constraints on both injection rate and sequestration capacity. The importance of this model in addition to what each stage gives us on a singular basis is what it tells us in terms of optimal switching times from one stage to the other and total volumes of CO_2 sequestered by source.

The producer switches from one stage to the next when the total benefits that can be obtained from sequestering CO_2 is more than the total benefits that can be obtained during CO_2-EOR. This decision is affected by the interaction between geological, technical and market conditions. The major findings relate to the optimal time of switch from one stage to the other, total volumes of captured CO_2 sequestered and how both are influenced by the tax and oil price levels set in the first stage. The intent is to be able to inform policy makers how to design policy in the presence of a market for CO_2 and shed light on how inherent physical production constraints impact the producer's response to market mechanisms.

IV Results and Discussion

While the policy implementation in the Leach et al. model encourages the producer to sequester CO_2, there is no distinction between CO_2 used from natural reservoirs and captured sources. Sequestration of CO_2 from natural sources provides no net benefit to the environment. By using CO_2 produced from underground reservoirs, we are adding CO_2 to the existing stock that needs to be sequestered. Given the distribution of CO_2 supply in the US, most active CO_2-EOR projects make sole use of the lower cost CO_2 from natural sources or some combination of natural and captured CO_2 depending on location (NETL, 2014).

The model presented in this paper measures how the producer responds to a tax policy that encourages use and sequestration of captured CO_2. The policy ensures the transition from usage of natural CO_2 to captured CO_2 in the EOR process providing the needed benefit to the environment without significantly impacting the supply of oil. It additionally ensures the transition to continued sequestration beyond oil production activities allowing for the evaluation of changes to oil price and tax levels on the operator's decisions relating to the co-management of their non-renewable assets oil and pore volume. Knowing that their historical oil production methods will influence pore volume availability, of value to us is the evolution of pore space availability across both stages which dictate how much CO_2 they can sequester. We also wanted to track the usage and sequestration of CO_2 from various sources to appropriately account for reductions in emissions.

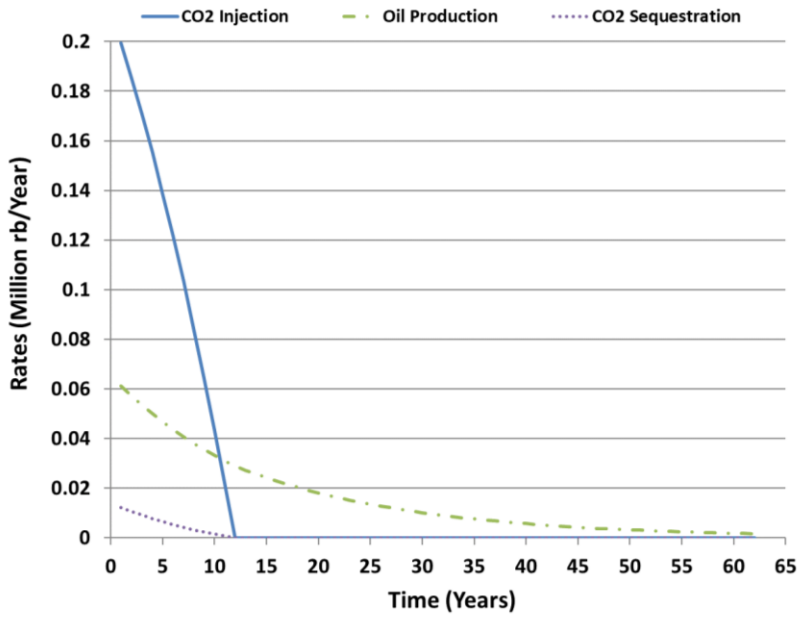
A series of numerical simulations, using the GAMS software, are conducted to solve for the optimal time paths of CO_2 usage from each source, oil production and how much CO_2 is sequestered from each source at various combinations of oil price and tax levels. Our simulation results also allow us to evaluate the timing of the switch from one stage to the next. We consider both oil price and tax level to be exogenous and remain constant over the life of the project. The simulations are run for several scenarios that include oil price levels of \$50, \$100, \$150 and \$200 per reservoir barrel of oil (rb) and for carbon tax levels varying from \$0 to \$120 per tonne of CO_2 (tCO_2). To ensure consistent units in running the numerical simulations quantities of oil and CO_2 are represented in reservoir barrels. Our results are obtained by running the simulations with the base case parameters tabulated below. Given the current distribution of CO_2 supply, we assumed that the cost used by Leach et al. was a reasonable estimate of costs related to the handling of natural CO_2 (w_{NR}). We also introduce two new parameters: cost of captured CO_2 (w_{CAP}) and a natural CO_2 stock ($X(t)$). We assume that the cost of captured CO_2 is about 1.5 times the cost of natural CO_2 for lack of defined estimates of that cost. It is also important to note that the oil and natural CO_2 stock are separate accumulations in different reservoirs.

Base Case Parameter Values		
R_o	1	Initial stock of oil in reservoir (million reservoir barrels)
X_o	1	Initial stock of natural CO_2 in reservoir (million reservoir barrels)
W_{cap}	6	Per reservoir barrel cost of CO_2 obtained from captured sources (\$)
W_{nr}	4	Per reservoir barrel cost of CO_2 obtained from natural reservoirs (\$)
w_r	1	Per reservoir barrel cost of recycled CO_2 (\$)
F	0.1	Fixed cost (million dollars) Is this per year?
β	2.2	Incidence of the carbon tax on the oil producer
r	0.05	Discount rate
δ_w	0.06	Intercept of $\delta(c)$ function
δ_1	0.0329	First coefficient of $\delta(c)$ function
δ_2	0.0348	Second coefficient of $\delta(c)$ function
P_{oil}	150	Price of oil in \$/bbl
τ	0	Tax in \$/CO_2

Although the limitation on overall injection capacity and the resource inventory hold a similar value, the first is a flow and the second is a stock value that should be viewed independently. The limitation on overall injection per time period is a function of reservoir properties and constraints including pressure. While the resource stock values, for both oil and natural CO_2, represent what is available to the producer for extraction. It is important to note that the initial oil stock does not represent the capacity of the reservoir to hold or store fluid it merely represents an initial inventory value not hindering our ability to inject at the rate necessary or store fluids. The fluids injected at every time period are balanced by an equivalent volume that is produced; the injection rate can also be viewed as a volume throughput.

We start with the characterization of the resulting time paths of CO_2 injection, sequestration and oil production in stage one. The trends we observe for these profiles will remain the same but the magnitudes observed for each will be impacted by price, costs and policy. CO_2 injection rates will decline with time until it reaches zero at which point the producer will continue extracting oil via a pure water flood scheme until their economic limit is reached. The reduction in the CO_2 injection rates with time can also be viewed as a reduction in the marginal product of CO_2 because of reduced associated oil production. Oil production declines over time because we produce lower fractions of a declining reserves pool at subsequent points in time. This necessary decline in oil production leads to less pore volume available to be occupied by CO_2, resulting in less CO_2 sequestration during the CO_2-EOR process. The decline in oil production and CO_2 sequestration also necessitates decline in the CO_2 injection rate. Figure 2 shows CO_2 injection, sequestration and oil production rates during the first stage of the project at an oil price level of \$150/bbl and no carbon tax. What is important to point out, which we will elaborate on later, is that with no tax incentives there is no use of anthropogenic CO_2 and therefore no associated sequestration.

Figure 2: P = \$150/bbl, τ = \$0/tCO2

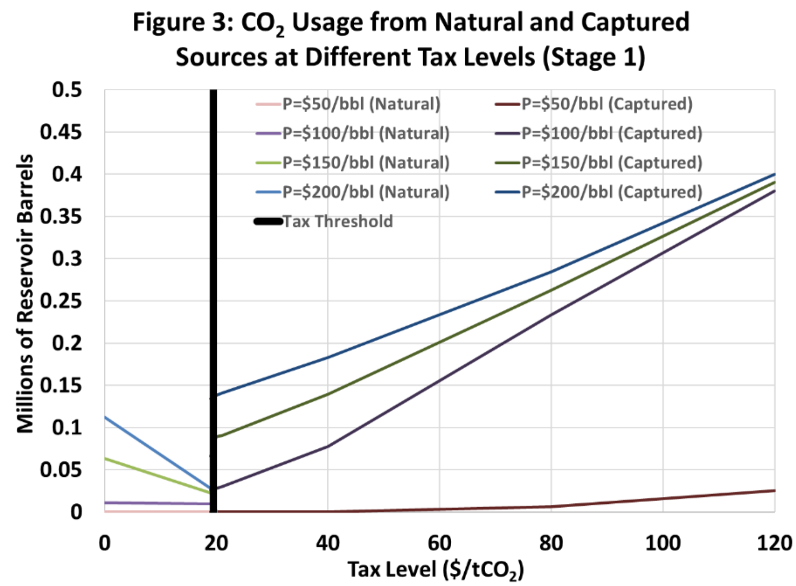


Higher tax levels induce higher CO_2 injection rates early on as compared to lower tax rates. But, will also induce a more rapid decline in CO_2 injection and thus an accelerated switch to pure water flood. As a result, we will see higher production early on at higher tax levels, resulting in a faster depletion of our reserves. So even though we may be injecting at a higher rate inducing higher recovery, after a period of time, we will be producing from a relatively smaller pool of reserves. This induces the producer to optimize their CO_2 injection rates and switch to water flood sooner, thus leading to lower production levels later in the life field for higher tax rates relative to lower tax rates or the no tax case. This results in a reduction in cumulative production at higher tax rates even though we were initially injecting more CO_2. Nonetheless, we will still see a positive impact on net CO_2 sequestration at higher tax rates above the threshold.

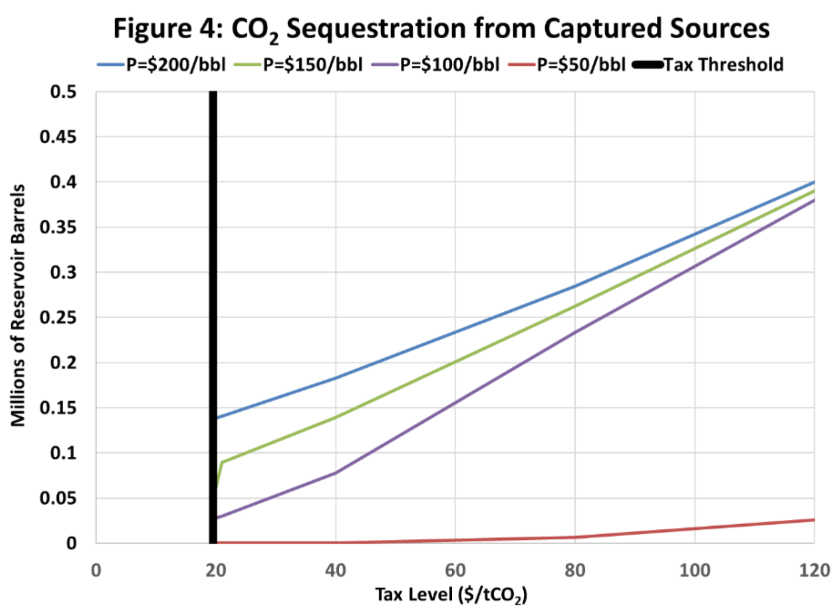
This acceleration in oil production, because of the trend of CO_2 injection at higher tax levels above the threshold described above, raises the concern about whether this will negate the objective of the policy implementation by increasing associated CO_2 emissions levels relative to the pre-policy implementation. Our results show that even though we do see acceleration in oil production at higher tax levels above the threshold, net CO_2 emissions resulting from the policy implementation will be lower relative to pre-policy implementation levels. These results in conjunction with the minimal impact on oil production are a win-win situation for both the producer and the environment.

Impact on Timing of Switch, CO_2 Usage and Sequestration across Both Stages

Adjusting the Leach et al policy to penalize the producer for every unit of natural CO_2 used is effective in encouraging the producer to transition from sole use of natural CO_2 to sole use of captured CO_2 in stage 1. Under the assumption that CO_2 from both sources are perfect substitutes, the tax threshold above which the producer switches from sole use of natural CO_2 to sole use of captured CO_2 is equal to the difference in price between captured and natural CO_2. Figure 3 shows the change in CO2 usage from each source at different price levels and varying tax values. Natural CO_2 usage declines with increases in tax levels up to the tax threshold because the credit they receive for sequestering CO_2 gets negated by the tax they have to pay for every unit of natural CO_2 they use. Above the threshold captured CO_2 usage increases with higher tax levels. The revenues accrued to the producer from CO_2 sequestration provide the needed incentive to increase CO_2 usage which will positively impact sequestration.



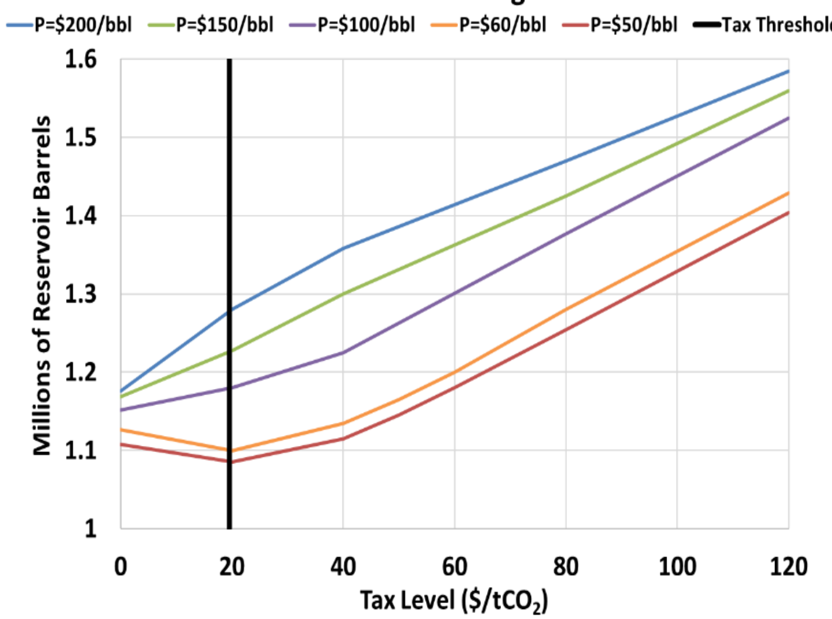
We consequently see a significant jump in net sequestration above the tax threshold. Figure 4 shows sequestration of captured CO_2 at different price levels and varying tax values. The jump in sequestration of captured CO_2 at tax levels above the threshold is attributed to the transition to sole use of captured CO_2 at those tax levels. Model results suggest that the amount of captured CO_2 sequestered in the EOR process, stage 1, is on the order of hundreds of thousands of barrels which equates to tens of thousands of tonnes. Mirroring the Leach et al. results, we observe that at higher oil prices resulting in higher revenues make it optimal to increase CO_2 injection levels over the life of the project leading to increases in cumulative sequestration. With higher tax rates, initial CO_2 injection rates are increased but we also observe a more rapid decline in the injection rates over time which results in an accelerated switch to water flood. Nonetheless, the impact on cumulative sequestration is positive because the amount of CO_2 sequestered early on when injection rates were higher more than compensates for the lower sequestration later in the productive field life due to reduced injection and earlier switch to water flood.



Leach et al. show that cumulative CO_2 sequestration does increase with increased oil price and tax levels, the main takeaway of their paper is that CO_2 injection and sequestration are more responsive to oil price than their carbon tax. The obvious implication is that policies raising the cost of CO_2 emissions may not induce the expected increase in magnitudes of CO_2 sequestration in the EOR process. Our model gives us the ability to track both sources of CO_2 usage and sequestration in the EOR process which has not been done before. As a result, comparisons of the amount of captured CO_2 sequestered resulting from our model with the status quo cannot be shown. Nonetheless, our model shows that small increases in the level of carbon tax can have a substantial impact on the amount of captured CO_2 sequestration. We will see a benefit, from a total carbon accounting point of view from making use of captured CO_2 in the EOR process. This quantification is necessary to give us a clear direction with regards to policy implementation.

The amount of CO_2 we can sequester in our second stage is a function of cumulative oil production resulting from the first stage. We assume in the second stage that the producer sells available pore space to facilities in need of storage space for their captured CO_2. As expected, total volumes of sequestered CO_2 across both stages eventually increases with higher tax rates as seen in figure 5. But at lower oil prices, we see the trend in volumes of captured CO_2 sequestered over both stages decrease until the tax threshold and then increase post the tax threshold. This can be explained by the fact that the burden of the tax at lower oil prices induces limited or no use of CO_2 in the production process leading to less cumulative oil production. Thus, leading to less sequestration across both stages because of the limited use of CO_2 and less cumulative oil production in stage one; releasing less space for sequestration in stage two.

Figure 5: Total Amount of Captured CO_2 Sequestered Across Both Stages



Oil price and tax levels will also influence the timing of the switch from our first stage to the second. We find that at fixed price levels, but increasing tax rates the time of switch from one stage to the next is accelerated. Increased tax accelerates oil production in the first stage which results in a quicker decline in oil production thus inducing the accelerated switch to the second stage where the operator can accrue greater profits from just sequestration. On the other hand, at fixed tax levels, but increasing prices the time of the switch from stage one to two is delayed. Higher oil prices encourage longer production periods coupled with the volumes of oil produced and CO_2 sequestered outweigh potential benefits from our second stage for longer periods of time.

Results from applying the model to a single field show that sequestration of captured CO_2 is on the order of a hundred thousand tonnes across both stages. These results are from a single field, but when aggregated across all fields on a national or global level it can be significant relative to annual CO_2 emissions. Quantifying impacts of implemented policy are necessary in establishing that CO_2-EOR will have a positive role in promoting carbon capture and sequestration with minimal impact on oil production and associated economic activity.

V Conclusions and Future Work

We see a minimal impact on cumulative oil production because of our tax implementation as compared to the pre-tax levels. But we do observe an acceleration in oil production as a result of the trend of CO_2 injection at higher tax levels above the threshold described above. This raises the concern about whether this will negate the objective of the policy implementation by increasing associated CO_2 emissions levels relative to the pre-policy implementation. Our results show that even though we do see acceleration in oil production at higher tax levels above the threshold, net CO_2 emissions because of the policy implementation will be lower relative to pre-policy implementation levels. These results in conjunction with the minimal impact on oil production are a win-win situation for both the producer and the environment.

The results of the modelling work done on one field indicate that given the appropriate economic environment, CO_2-EOR can contribute to the promotion of CCS. The model developed appropriately values CO_2 emissions and reservoir pore space. The results of the model in conjunction with estimates of CO_2 demand for EOR purposes provide an appropriate foundation for future work. We aim to continue bridging the gap between engineering and economic policy aspects whilst providing an easy to use tool that allows for evaluation the practicality of wide scale implementation of CCS when partnered with CO_2-EOR.

We hope to expand this modelling work focusing on the nuances of how the producers co-manage both oil production activities and pore volume capacity resulting from the impacts of varying both market and reservoir parameters (i.e. reservoir maturity, size, and quality). We assume a regional modelling effort or analysis will inform us on how to allocate both natural and captured CO_2 volumes across a portfolio of hydrocarbon producing assets allowing us to evaluate the dynamics between both the oil and CO_2 markets now tied together by pore volume management. This future study includes the evaluation of the mechanics of supply and demand of CO_2 on a regional and global scale providing the basis for creating an international CO_2 market.

The possible investigations addressed above highlight the flexibility of the model constructed. The potential studies suggested go beyond quantifying CO_2-EOR's contribution to CCS. Those studies allow us to investigate whether there is sufficient storage capacity on a global scale to allow for the capture and sequestration of enough CO_2 to sustain current and future levels of human and industrial activity. The research highlights the importance of using existing knowledge and infrastructure in the pursuit of our environmental objectives. Significant technical and engineering study, in addition to data collection, will be required to investigate these possibilities and formulate the functional forms of the equations in the model.

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