An Analysis of the Distribution and Economics of Oil Fields

for Enhanced Oil Recovery-Carbon Capture and Storage

by

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Thesis submitted in partial fulfillment of
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ABSTRACT

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Abstract

One option for mitigating climate change is to store industrial CO2 emissions in geologic reservoirs as part of a process known as carbon capture and storage (CCS). There is general consensus that large-scale deployment of CCS would best be initiated by combining geologic sequestration with enhanced oil recovery (EOR), which can use CO2 to improve production from declining oil fields. Revenues from the produced oil could help offset the current high costs of CCS.

The cumulative potential of CCS-EOR in the continental U.S. has been evaluated in terms of both CO2 storage capacity and additional oil production. This thesis examines the same potential, but on a reservoir-by-reservoir basis. Reservoir properties from the Nehring Oil and Gas Database are used as inputs to a CCS-EOR model developed by McCoy (YR) to estimate the storage capacity, oil production and CCS-EOR costs for over 10,000 oil reservoirs located throughout the continental United States.

We find that 86% of the reservoirs could store ≤1 y or CO_2 emissions from a single 500 MW coal-fired power plant (i.e., 3 Mtons CO_2). Less than 1% of the reservoirs, on the other hand, appear capable of storing ≥30 y of CO_2 emissions from a 500 MW plan. But these larger reservoirs are also estimated to contain 48% of the predicted additional oil that could be produced through CCS-EOR. The McCoy model also predicts that the reservoirs will on average produce 4.5 bbl of oil for each ton of

sequestered CO_2, a ratio known as the utilization factor. This utilization factor is 1.5 times higher that arrived at by the U.S. Department of Energy, and leads to a cumulative production of oil for all the reservoirs examined of ~183 billion barrels along with a cumulative storage capacity of 41 Mtons CO2. This is equivalent to 26.5 y of current oil consumption by the nation, and 8.5 y of current coal plant emissions.

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1. Introduction

Carbon Capture and Sequestration (CCS) is one of the potential approaches for mitigating CO_2 emissions contributing to global warming. In CCS, CO_2 emitted by sources such as power plants, is separated from other emissions before they are released into the atmosphere. The captured CO_2 is then stored underground in geological reservoirs (NETL 2009). Three of the most viable reservoirs are saline aquifers, unmineable coal bed seams, and oil & gas reservoirs. While deep saline formations have the largest storage potential, the capacity of oil and gas reservoirs is still significant (NETL 2009). In the U.S., these reservoirs could store up to 43 billion metric tons of CO_2, or 18.5 years of current annual emissions from the U.S. electric power sector.

A major incentive for CCS projects involving oil and gas reservoirs is that the CO_2 can be used for enhanced oil recovery (EOR), providing a revenue stream that would help offset the cost of CCS (UNIDO 2010). In EOR using CO_2, pressurized CO_2 is injected into the reservoir through a central injection well where it mixes with the remaining oil. The CO_2 dissolves into the oil, causing it to swell and reducing its viscosity, which improves the efficiency of oil displacement (NETL 2010a). At the same time, the mixture is driven by the pressure gradient away from the injection well and towards a surrounding ring of production wells where the oil along with a fraction of the injected CO_2 is recovered (NETL 2008).

As of 2010 only about 20% of the CO_2 used in EOR came from natural gas processing plants while most of the remainder was produced from natural underground CO_2 reservoirs. So to date, EOR using CO_2 has produced a net increase rather than reduction in emissions due to the CO_2 released from burning the oil produced. Furthermore, because oil and gas companies currently pay for the CO_2, they have little if any financial incentive to allow it to remain sequestered underground. Instead, CO_2 that returns to the surface with the produced oil can be reused onsite or elsewhere, mitigating EOR costs. Should CCS be implemented on a large scale, much more CO_2 will need to be available from industrial sources, and the objective of EOR projects using CO_2 will likely change from recovering as much CO_2 as possible to maximizing the amount stored underground.

As of April 2010, 115 of 194 EOR projects reported in the Oil and Gas Journal used CO_2 EOR as opposed to thermal, hydrocarbon or nitrogen injection (Koottungal 2010). The cost of the CO_2 for these projects can range from $40 to $117/ton (Mohan, Biglarbigi, and Carolus 2009). If this price could be reduced to $19-57/ton through increased supply, an additional 200 CO_2 EOR projects would become economic, yielding another 1 million barrels per day in oil production (Mohan, Biglarbigi, and Carolus 2009).

Despite the cumulative potential for storing CO_2 in oil and gas reservoirs, numerous drawbacks to using them also exist. For example, many are located far from power plants and would require significant pipeline infrastructure to reach them increasing the cost of CO_2 transportation (IPCC 2005). The oil and gas industry has spent >$1 billion on 2,200 miles of CO_2 pipeline to support CO_2 flooding in the Permian Basin (NETL 2010b).

Existing CCS studies of oil and gas reservoirs have tended to focus on the cumulative storage potential of multiple fields. In order to determine the fraction of potential storage available in any given reservoir, however, it must be assessed individually. Here we use the Nehring Significant Oil and Gas Fields of the United States Database to estimate the capacity and cost of conducting CCS with EOR in 10,000 separate onshore oil and gas reservoirs located in the lower 48 states of the U.S. We also estimate the amount of oil that might be recovered from each reservoir through the EOR (Nehring Associates 2010).

The Nehring database is extensive and provides average measurements per reservoir for the range physical characteristics:

- Reservoir Composition
- Location
- Lithology
- Depth
- Thickness
- Oil Viscosity
- Pressure
- Temperature
- Porosity
- Permeability
- Formation Volume Factor
- Oil Saturation
- API Gravity
- Gas Composition
- Area

We use the distribution of sizes and depths of the reservoirs to constrain which are physically viable for CCS-EOR. We then estimate the lifting costs for oil and storage costs for CO_2 for each reservoir independent of the price at which oil might be sold or the CO_2 bought. In turn, these costs allow us to construct marginal supply curves for the amount of CO_2 that can be stored in the reservoirs and the amount of additional oil that can be produced from them. Finally, we use these figures along with the amount of CO_2 that would be generated from burning the recovered oil to estimate the net reduction CO_2 in emissions that would result from CCS EOR that uses purely industrial CO_2.

2. Background

Enhanced oil recovery has existed in some form since the 1970's (DOE 2011a). Throughout the development of EOR engineers have used modeling in an attempt to understand and maximize the amount of oil recovered from reservoirs. As mentioned previously, a fundamental difference between EOR using CO_2 and CCS-EOR is the end goal for the CO_2. Currently, oil companies have no financial incentive to leave CO_2 in the ground following EOR since it results in an economic loss equal to the cost of the CO_2 not recovered (Marston 2008). CCS-EOR on the other hand would seek to maximize the amount of CO_2 left in the ground. Consequently there are three types of models involving CO_2 and/or EOR: CO_2 storage models, EOR production models, and combined storage-production models. A brief summary of each is given before focusing on the combined storage-production model used in this study.

2.1 Carbon Dioxide Storage Model

CO_2 storage capacity models ignore potential oil production and simply calculate the volume of pore space in which CO_2 could potentially be stored. This volume in conjunction with the density at which the CO_2 would be stored yields the mass of potential CO_2 storage.

Issues arise in estimating the accessible pore space, for not all of it is available (MIT 2010). Numerous factors contribute to limiting the available pore space including the presence of interstitial oil and/or water, and the permeability of the sediments, which affects the ability of the CO_2 to reach the pore space. The two primary ways that total storage capacity is estimated are volumetric and production based. Volumetric estimates calculate the available pore space and then subtract out the estimated volume of water and oil present and incorporate an efficiency factor relating to the movement of CO_2 through the reservoirs. Production estimates examine the amount of oil produced, the amount of liquids (i.e. water) injected into the reservoir, and the amount of oil and water produced to estimate the net pore space available for storage.

2.1.1 U.S. Department of Energy – NATCARB

The National Energy and Technology Laboratory (NETL) of the Department of Energy (DOE) released the *2010 Carbon Sequestration Atlas of the United States and Canada*, which explains the standard method used by the DOE to estimate potential CO_2 storage in oil and gas reservoirs. The approach is based upon the volumetric method (Eq. 2.1) in which it is assumed that all available pore space that previously held oil can store CO_2 (NETL 2010a).

$$G_{CO2} = A\, h_n\, \phi\, (1 - S_w)\, \phi_{CO2,r}\, E \tag{2.1}$$

The variables in this equation are the mass of CO_2 stored (G_{CO2}), the production area (A), the net thickness (h_n), the average effective porosity (ϕ), the hydrocarbon saturation (1-initial water saturation), the density of the CO_2 at reservoir conditions ($\rho_{CO2,r}$), and the CO_2 EOR oil recovery factor, more commonly known as the efficiency factor (E). The latter is the volume of CO_2 that can be stored per volume of original oil in place (OOIP). It ranges in value from 0-1 and varies greatly from field to field.

2.1.2 Stefan Bachu - CO_2 Storage Capacity Model

Bachu and others (2007) proposes two methods for estimating CO_2 storage capacity in oil and gas reservoirs, both of which are based on the volume of available pore space in the reservoirs. Unlike the DOE method (2010), however, these estimations also take into account the production and injection of water, which can affect the amount of storage available. Consequently, the Bachu equations more suitable for analysis of individual reservoirs.

$$G_{CO2} = \rho_{CO2,r}\left[\frac{R_f OOIP}{B_f} - V_{iw} + V_{pw}\right]C_e \tag{2.2}$$

$$G_{CO2} = \rho_{CO2,r}\left[R_f Ah ç(1 - S_w) - V_{iw} + V_{pw}\right]C_e \tag{2.3}$$

In these equations, the density of the CO_2 at reservoir conditions ($\varrho_{CO2,\,r}$) is used in conjunction with the oil recovery factor (R_f), the volume of water injected (V_{iw}), the volume of water produced (V_{pw}), the capacity efficiency (C_e) and either the original oil in place divided by the formation volume factor for reservoir conditions ($OOIP/B_f$) or the initial pore volume, which is calculated using area (A), thickness (h), porosity (ϕ) and initial water saturation (S_w).

The fundamental assumption made in both Equations 2.2 and 2.3 is that the volume previously occupied by hydrocarbons is available for CO_2 storage (Bachu 2005). This assumption is valid for reservoirs that are not in hydrodynamic contact with aquifers or flooded during secondary oil recovery. The problem with reservoirs that are in contact with aquifers is that water will invade the pore space available for CO_2 storage. However the injection of CO_2 can partially reverse the influx of water from the aquifer and if CO_2 injection is combined with EOR then the influx of water is even further diminished by the counteracting pressure exerted by the injected CO_2; it replaces the oil in the reservoirs while simultaneously preventing water from invading the pore space previously occupied by the oil (Bachu 2005). The CO_2 injection will also aid in forcing water from secondary recovery out of the reservoirs during the oil production (Bachu 2005).

2.2 Enhanced Oil Recovery Model

EOR models that have been developed often incorporate Water-Alternating Gas Injection (WAG). This means that when EOR is preformed on a field, a "slug" of CO_2 is injected to increase the mobility of the oil followed by the injection of a water "chaser" to push the oil out. This is done to decrease the amount of CO_2 needed for a project since currently the cost of the CO_2 is a significant fraction ($30-90/metric ton) of the expense for EOR using CO_2 (Hovorka and Tinker 2010). The EOR WAG models can be divided into two main types: (1) basic evaluations, and (2) actual production estimations.

Rivas and others (1994) developed the main model used to screen and rank reservoirs with respect to their suitability and potential for EOR. The model relies on the following reservoir parameters: API gravity, temperature, permeability, oil saturation, pressure, porosity dip angle and thickness. In the model, all of these parameters are weighted based on their correlation with the productivity of past EOR projects. The results are then normalized using a theoretical "ideal" reservoir giving a ranking from 1-100 (Rivas, Embid, and Bolivar 1994). Note that the model does not estimate the actual storage capacity.

CO_2-Prophet is a streamtube-based model that was developed in 1986 by Texaco with the DOE and incorporates the following reservoir parameters: pressure, temperature, porosity, oil saturation, water saturation, area and injection/production rates. The model uses these parameters to calculate the relative permeability and saturation changes over the time of an EOR project (Dobitz, Prieditis, and Texaco 1994).

Even more detailed analysis of EOR potential can be accomplished with sophisticated numerical models of multiphase fluid flow through a porous media. The reservoir characteristics are determined from core samples allowing for a 2D or 3D model to be run to examine the flow of the fluids through the specific reservoir over time.

$$\frac{\partial(\phi\mu_\alpha S_\alpha)}{\partial t} = -\nabla\cdot(\rho_\alpha u_\alpha) + q_\alpha \tag{2.4}$$

$$u_\alpha = -\frac{k_\alpha}{\mu_\alpha}(\nabla P_\alpha - \rho_\alpha \nabla z) \quad (2.5)$$

In these equations, S is the saturation of the fluid, ρ is the fluid density, q is the flow in and out of the reservoir through injection or production, ϕ is the rock matrix porosity, and u is the Darcy Flux also known as the Darcy velocity. The subscript α is a variable designating which fluid is being analyzed so the equations need to be replicated for each of the fluids present in the reservoir (i.e. water, oil, CO_2). The Darcy Flux contains the relative permeability of the fluid (k) the partial pressure gradient (P), fluid viscosity (μ) and elevation gradient (z) (Chen 2006). These base equations are solved using finite element methods in complex computer programs such as Eclipse (REF), which model the movements of the fluids in the reservoir over time, and so allow petroleum engineers to estimate the potential recoverable oil. These models are site-specific and data intensive, making it difficult to use them to rapidly model a large number of geologically heterogeneous fields.

2.3 Enhanced Oil Recovery – Carbon Capture and Storage Model

Few models have been developed for CCS-EOR that combine estimates of CO_2 storage, oil recovery, and project economics. The two main models that have been developed for this purpose are a modified version of the Prophet model used by the DOE, and a model created by Sean McCoy at Carnegie Mellon University. Both of these models address the injection of pure CO_2 to maximize storage potential.

2.3.1 DOE CCS-EOR Model

The DOE has developed a simplified version the Prophet model that includes a cash flow component for analyzing the project economics. The model has been used to evaluate the EOR-CCS potential of 1,800 onshore fields and 4,000 offshore fields that combined account for 75% of the residual oil estimated to be ultimately recoverable in the United States (2011). The DOE estimates that the total technically recoverable oil using next generation EOR-CCS technology is 136.6 billion barrels of oil and that 45.4 billion metric tons of CO_2 can be stored underground in place of the oil (ARI 2011). These results in a utilization ratio of 3 barrels of oil recovered for every metric tons of CO_2 stored.

2.3.2 Sean McCoy Model

In this study, we examine the EOR potential and CO_2 storage capacity of oil and gas fields using the semi-analytical CCS-EOR model developed by Sean McCoy (McCoy 2008). McCoy's model differs from the modified Prophet model in that it yields estimates of the amount of CO_2 that can be stored in a field, the amount of additional oil that might be recovered, and the costs associated with the project. The model accomplishes this using limited site-specific data, enabling a larger quantity of reservoirs to be rapidly analyzed.

The McCoy model is broken down into to two main interconnected parts; production and economics (Figure 1). Similarly, the model inputs can be divided into several groups. The characteristics of the reservoir needed are area, thickness, porosity, permeability, depth, Dykstra-Parsons coefficient, formation volume factor, temperature and pressure at reservoir conditions. The oil characteristics used are percentage of oil saturation, API gravity and viscosity. The economic parameters needed are the discount rate and physical location of the reservoir.

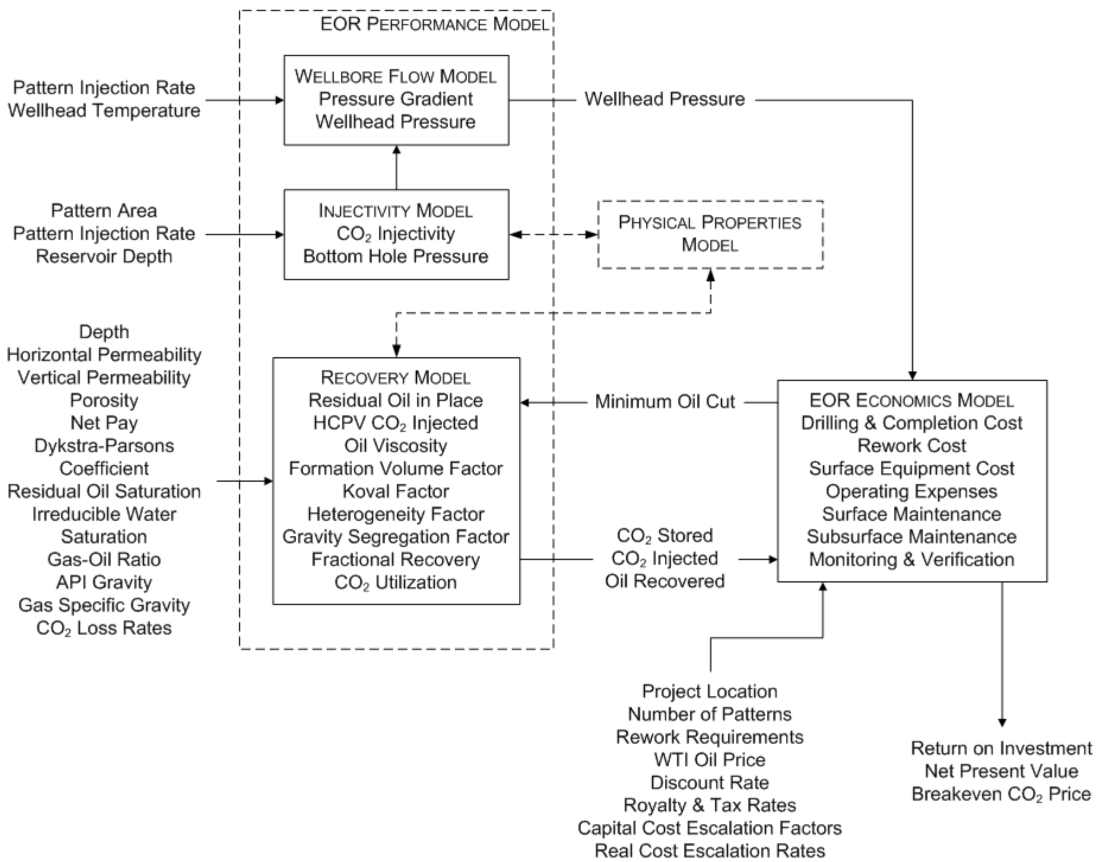

Figure 1: Schematics of McCoy Model

All of the reservoir characteristics factor into a multi step process to estimate the efficiency percentage. This process is further explained in Appendix A. The final outputs for the model give values for the total cost, amount of oil recovered and amount of CO_2 stored.

3. Methods

We use the McCoy model to analyze ~10,000 of the 25,000 oil & gas reservoirs catalogued in the Nehring Major Oil and Gas Reservoirs Dataset. The reservoirs we used met the following three criteria: (1) they were located onshore; (2) they contained some fraction of oil; (3) they either had a complete set of the reservoir parameters needed by the McCoy model, or a subset of these parameters from which the others could be estimated; and (4) the average pressure and temperature of the reservoir was such that the CO_2, which would be injected under supercritical conditions, would remain supercritical, allowing it to move through the rock matrix like a gas but mix with the oil like a liquid while maximizing the amount of CO_2 storage (Teledyne ISCO 2007). In the case of the latter criteria, this included reservoirs with an average temperature >31.1 °C and an average pressure >7.39 MPa.

Again, the key variables for the McCoy model are: depth, area, thickness, porosity, permeability, temperature, pressure, residual oil, oil viscosity, the API gravity of the oil, and the oil formation volume factor (FVF). The number of reservoirs in the Nehring database that have values for these variables is shown in Figure 2.

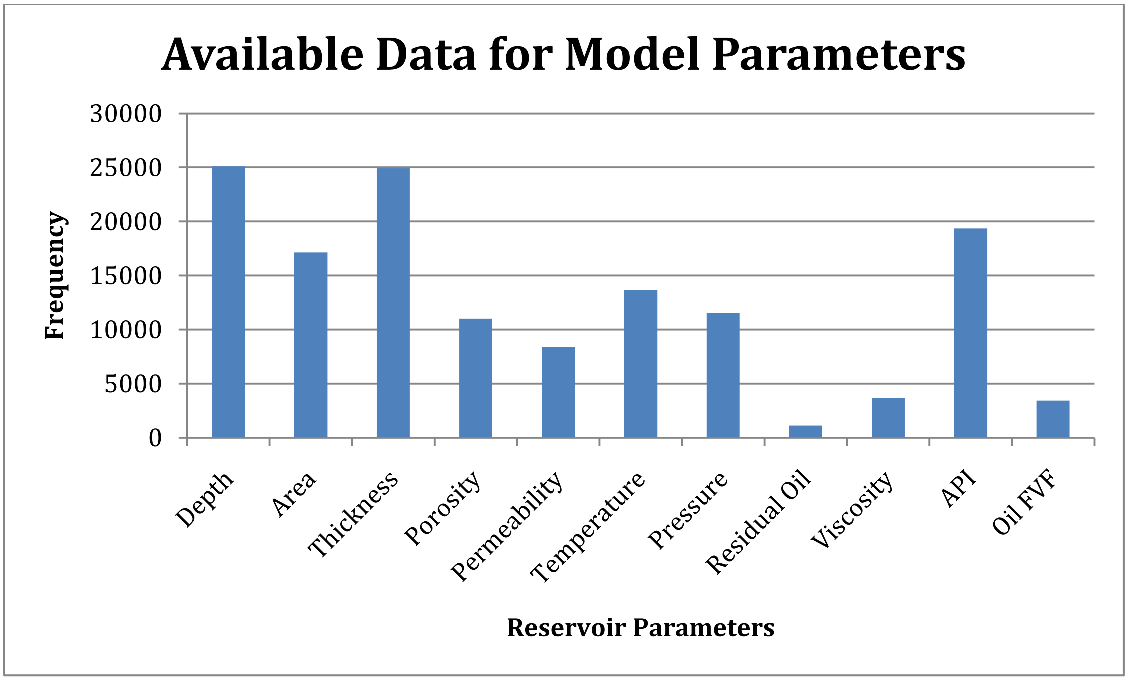

Figure 2: Availability of Model Input Data

All the reservoirs we analyze have values for area, thickness, depth and API gravity. If the database lacked values for the other variables for a reservoir, we estimated them. Unknown temperature and pressure values were estimated using the linear relationship with the depth of the reservoir in Eccles et al. (2009), i.e.

$$T_r = G_T d + T_{STP} \tag{3.1}$$

$$P_r = G_P d + P_{STP} \tag{3.2}$$

T_r is the reservoir temperature, G_T is the temperature gradient, d is depth, and T_{STP} is temperature at standard conditions (273 K). P_r is the pressure at reservoir conditions, G_p

is the pressure gradient, and P_{STP} is the pressure at standard conditions (101 kPa). In order to maximize storage potential, all reservoirs were assessed under pressures equal to 90% the fracturing pressure, which calculated based upon the depth of the reservoir (McCoy 2008).

$$P_f = \left(22.62 - 9.24e^{-4.36\times10^{-4}d}\right)d \tag{3.3}$$

Unknown porosity values were estimated using an exponential relationship with the depth of the reservoir based on Athy (1930).

$$\varphi = c_1 e^{c_2 d} \tag{3.4}$$

Note that porosity (ϕ) is a function of depth (d) and two constants, c_1 and c_2. The first represents the surface permeability while the second reflects the compaction coefficient. In this study we used constants based upon fitting the equation to the Nehring data and the lithology.

With porosity, it is then possible to calculate a first-order estimate of unknown permeability values using Timur (1968) where:

$$k = 0.136\frac{\phi^{4.4}}{S_{wi}^2} \tag{3.5}$$

In this equation the porosity (ϕ) and the initial water saturation (S) are used to estimate the permeability (k) (Balan 1995).

The unknown formation volume factors for the oil and the residual oil saturations were assigned fixed values of 1.5 and 30%, respectively. These figures are general values based upon the mean for both variables.

4. Results

As previously stated, we selected the McCoy model for this study because it yields estimates of CO_2 storage capacity, residual oil production, and EOR-CCS economics for individual reservoirs based on limited data via a semi-analytical calculation that can be rapidly applied to a large number of reservoirs. The McCoy model has seen limited use to date, however, and there is some question as to its accuracy. The key model output is the efficiency of barrels of oil produced/tons of CO_2 stored. Hovorka and Tinker (2010) find that the utilization produced by the McCoy model ranges from 3.7-6.7 barrels per metric ton. Note that the high end of this range is 45% greater than that produced by the DOE's modified Prophet model which had a utilization of 3 BBL/metric ton, suggesting that the McCoy model either estimates higher oil production or lower storage capacity. Consequently, we begin by conducting a sensitivity analysis of the model and also apply it to a small set of EOR/CCS projects for which there is published data against which we can benchmark the model results. With this understanding of the model, we then apply it to the Nehring database

4.1 Sensitivity Analysis

The sensitivity of the McCoy model outputs for utilization ratio, cost per metric ton and cost per barrel were evaluated using the average values for the model inputs from the ~10,000 reservoirs selected from the Nehring database. These average values formed the base case or "average reservoir" for the sensitivity analysis. Each input was then varied separately while the others were held constant. The input being varied was changed from 50% to 150% of its average value at 25% increments. The results of this sensitivity analysis are shown in Figure 3.

Changes in oil saturation, porosity, thickness and area, equally affect the model predictions for oil recovered and CO_2 stored, leaving the model prediction for the ratio of the two, i.e. the utilization factor, unchanged. Changes in oil viscosity, API gravity, V_{DP} and reservoir permeability affect the modeled utilization factor by only a fraction of a percent and so have a negligible impact. The inputs that the influence the utilization ratio the most are the formation volume factor, temperature (which is influenced by depth), and depth (depth reflects pressure). As the formation volume factor and depth increase, the utilization factor decreases due to the increase in the density of the $CO_2$and the decrease in the amount of oil recovered due to the greater presence of gas in the oil. Increasing the temperature of the reservoir on the other hand increases the utilization factor by decreasing the density of the CO_2 resulting in less CO_2 stored.

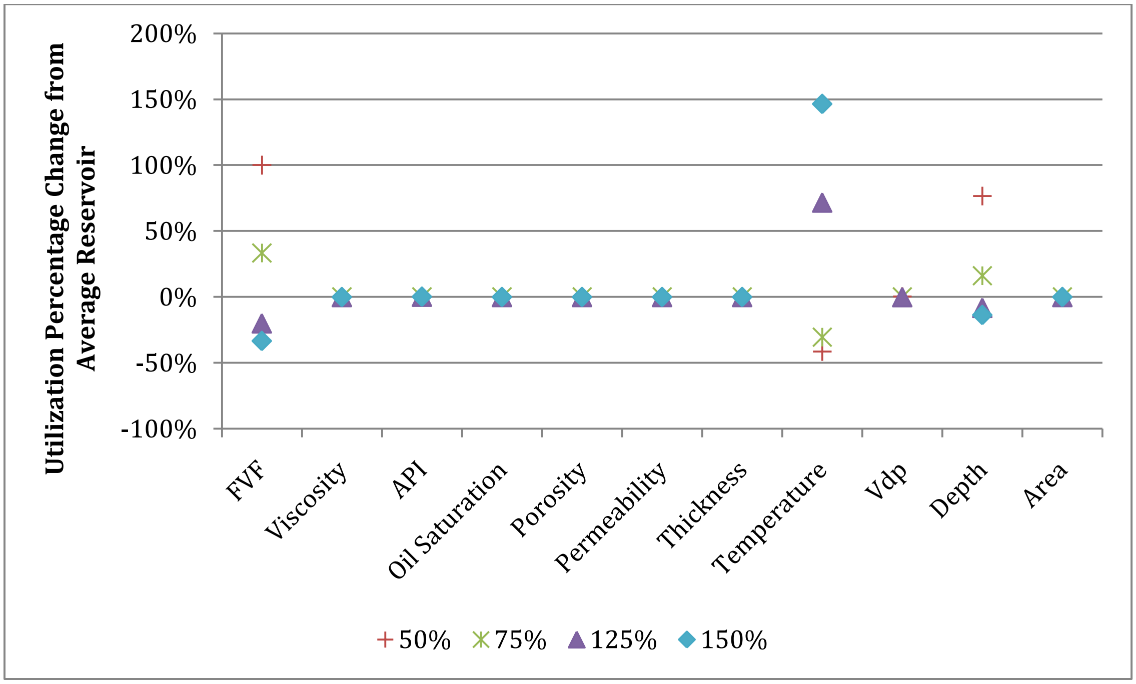

Figure 3: Sensitivity of Utilization

All of the inputs to the McCoy model have some effect on the average costs predicted by the model for CO_2 stored and oil recovered (Figure and Figure 5).

Increases in the formation volume factor lead to a slight decrease in the average cost of CO_2 stored, but a significant increase in the average cost per barrel recovered. This is because a higher FVF means more gas is dissolved in the oil in the reservoir, so when the oil is brought to the surface, the final amount produced is less. But since the volume of the reservoir vacated by the oil remains the same, more CO_2 can be stored there, decreasing the storage cost.

The model cost-estimates are also sensitive to the oil viscosity and reservoir temperature, with the costs increasing as the values of these variables increase. This is because the higher viscosity of the oil, the less of it that can be recovered, which in turn reduces the pore space vacated for storage. Similarly, increased reservoir temperature raises storage costs because it decreases the density at which the CO_2 will be stored and thus the amount that can be stored in the reservoir.

Changes in API gravity, oil saturation, and reservoir porosity, thickness, depth and area all have the opposite effect on modeled costs, decreasing these costs as the variables themselves increase. Increasing oil saturation and porosity increases the volume of available pore space, decreasing storage costs. The same effect is produced by increases in the thickness and area of a reservoir. Increasing the depth of a reservoir raises the reservoir pressure, increasing the density of both oil and CO_2 and thus increasing the amount of oil that might be recovered and the amount of CO_2 that could be stored in the reservoir.

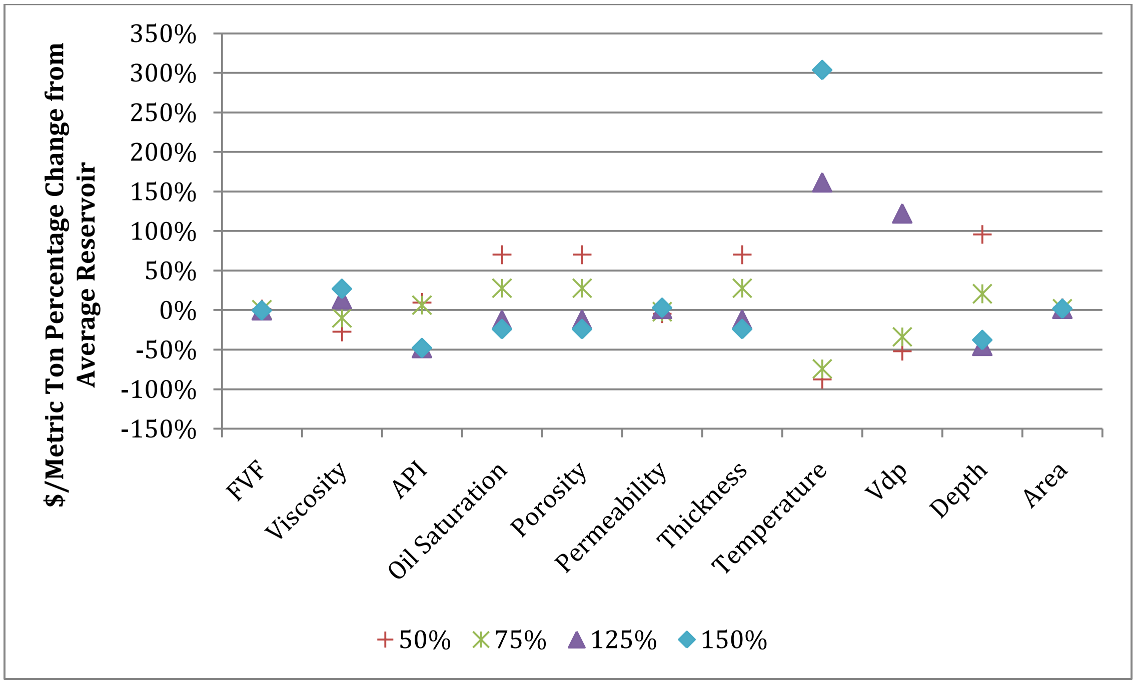

Figure 4: Sensitivity of $/Metric Ton

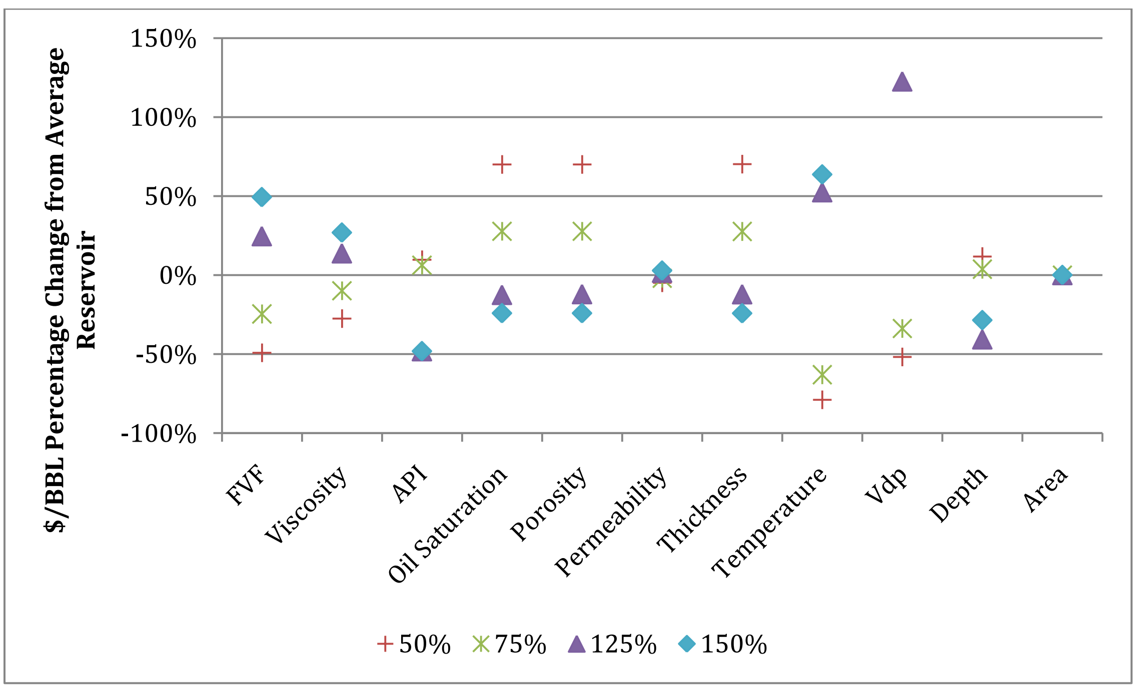

Figure 5: Sensitivity of $/BBL

4.2 Case Studies

The McCoy model is most sensitive to the input variables depth, oil saturation, porosity and heterogeneity. We next explore the accuracy of the model when these and other inputs variables are known or at least constrained. When McCoy published his model, he only tested it against the results of another model, which was the Kinder Morgan – Water Alternating Gas model (KM-WAG). Here we test the model against published results from the Weyburn Project, the only large-scale CCS-EOR project that has been operating for decades. We also compare the model against published results for three EOR projects for which we have estimated their CCS potential using the NATCARB methodology (Eq. 2.1). Published values for the McCoy model inputs for these four projects are listed in Table 1.

Table 1: Reservoir Physical Properties of Case Studies

	East Vacuum[1]	Slaughter Estate[2]	SAROC[3]	Weyburn[4]
Area (acres)	5,000	12.29	49.900	44478
Depth (m)	1,341	1519	2042	1500
Thickness (m)	22	23	42.4	7.8
Porosity (%)	11.7	12	9.41	17.2
Permeability (md)	11	6.4	19.4	20
Temperature (K)	311	314	328	333
Pressure (MPa)	11.1	15.1	16.5	14
Oil Saturation (%)	50.5	45.6	62.7	41.9
API (degrees)	38	30	41	29
Viscosity (cp)	1	1.38	0.4	0.5
FVF (RB/STB)	1.288	1.228	1.5	1.1
Pattern Area (acres)	80	12.29	40	80
Water Saturation (%)	15.9	8.1	21.9	31.7

[1] (Brownlee and Sugg 1987) and (Harpole and Hallenbeck 1996)
[2] (Ader and Stein 1984)
[3] (Langston, Hoadley, and Young 1988)
[4] (Malik and Islam 2000)

For all four projects, the oil remaining after project completion (S_{of}) is based upon the literature estimates. The recovery/storage efficiency (E) is assigned a range of 25 – 50% due to the wide discrepancy in the efficiency value between reservoirs (Bachu et al. 2005). The Dykstra-Parsons coefficient is also assigned a fixed value, in this case 0.7, which is the mean of the range (0.5-0.9) given for oil reservoirs by Willhite (1986).

Table 2 compares model results against the data for the projects. The table shows that the model estimates compare favorably to the data, each model output being within 25% of the recorded values for the projects. Variability between the model estimates and the data can be attributed at least in part to the Dykstra-Parsons coefficient of heterogeneity (V_{DP}) being estimated for the projects and to these projects not having the same five-spot injection pattern assumed by the model (i.e., one injection well surrounded by five equally spaced production wells). Furthermore, most of the projects used the WAG (water alternating gas) approach to EOR instead of the pure CO_2 injection approach assumed by the McCoy model. For completeness, all assumed parameters for the projects are shown in Table 3.

Table 2: Physical Results of Case Studies

	East Vacuum[1]	**Slaughter Estate**[2]	**SAROC**[3]	**Weyburn**[4]
Model Oil (MMBBL)	31	91	758	165
Lit Oil (MMBBL)	30	119	1027	155
Model CO_2 (Million Tonne)	5.4	0.017	149	22
DOE CO_2 (Million Tonne)	3.6 – 7.3	0.015 – 0.032	86.8 – 174	26

[1] (Brownlee and Sugg 1987) and (Harpole and Hallenbeck 1996)
[2] (Ader and Stein 1984)
[3] (Langston, Hoadley, and Young 1988)
[4] (Malik and Islam 2000)

Table 3: Assumed Characteristics for the McCoy Model

Variable	**Value**
V_{DP}	0.7
Surface Losses of CO_2	2%
Reservoir Losses of CO_2	5%
$f_{co2,max}$	0.9
Discount Rate	12%
Pattern Construction Occurs	Year 0
Pattern Area	40 acres

Note that since Weyburn was the only project with CCS-EOR cost estimates, it forms the sole basis of our economic evaluation of the model. The projected cumulative capital and operating costs for the project are $1 billion Canadian dollars (Malik and Islam 2000) while the estimate produced by the McCoy Model is $0.91 billion CAD, a difference of only 9%.

4.3 Results from Applying the McCoy Model to the Nehring Database

Having established both the sensitivity of the McCoy model to its inputs and shown that the model yields reasonable first-order estimates for CO_2 storage potential, enhanced oil production, and the costs associated with CCS-EOR projects, we now apply the model to the ~10,000 onshore oil and gas reservoirs in the Nehring database that we have screened as being suitable for CCS-EOR. We begin by looking at the geographic distribution of these reservoirs. Figure shows their locations across the continental U.S. with respect to that of coal-fired power plants (U.S. EPA 2011), the largest stationary source of U.S. CO_2 emissions (James Kratzer et al. 2007). In 2009, these coal plants met 25% of the total U.S. energy demand and 50% of the nation's electricity generation. A single 500-megawatt coal-fired power plant produces approximately 3 million tons of CO_2 year (James Kratzer et al. 2007, ix).

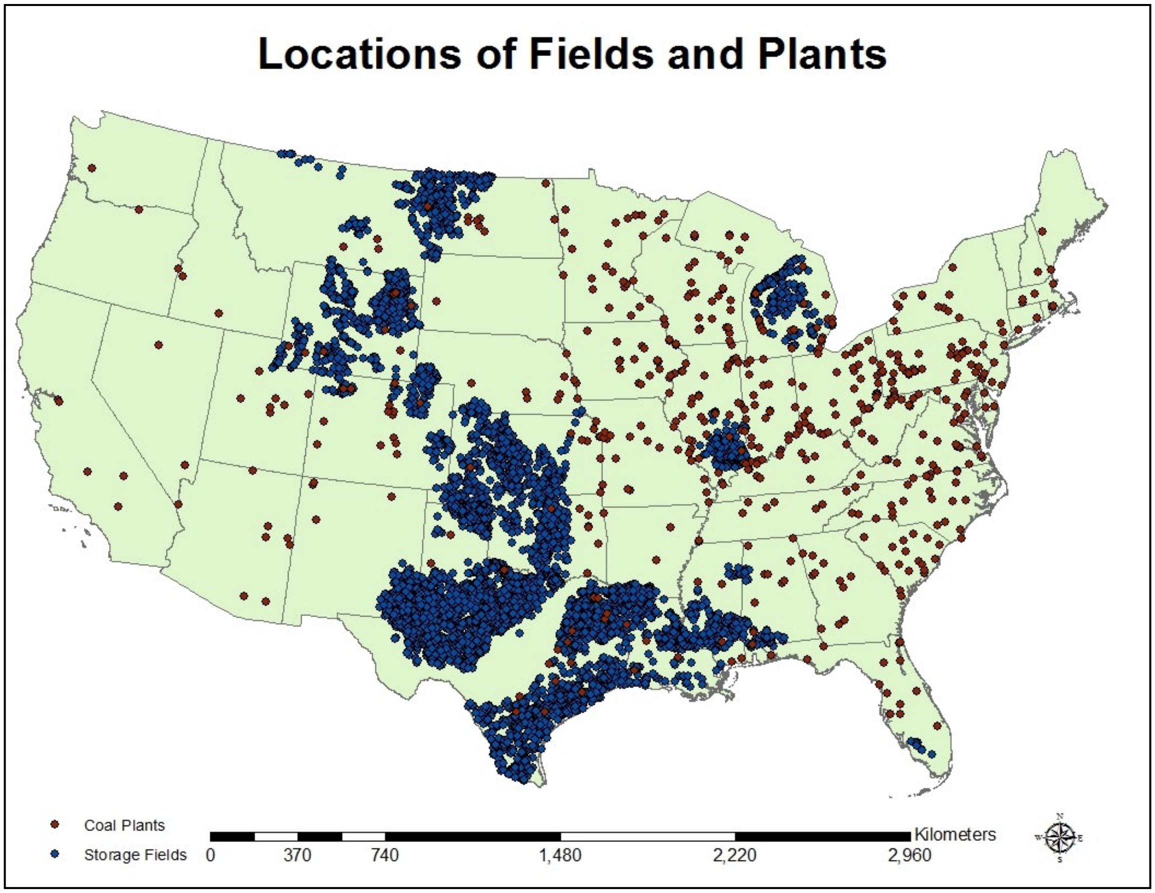

Figure 6: Location of Oil Fields and Coal Power Plants

Figure 6 shows that while coal plants occur across the U.S., the majority lies east of the Mississippi. And while Michigan, Illinois, and the U.S. Gulf Coast contain a number of oil reservoirs, the majority of these lies west of the Mississippi. At present, there is little more than 3,000 mi pipelines for transporting CO_2 with much of this limited to connecting natural CO_2 reservoirs in Utah, Colorado and New Mexico to the Permian Basin in west Texas. In order to link most coal plants to oil reservoirs, an extensive pipeline network would need to be built, the greater the distance the CO_2 has to be moved, the greater the total cost of CCS. Other types of fossil-fuel burning plants, such as cement and aluminum, could provide alternative sources of CO_2, but their cumulative emissions are 13 times less than coal plants, rendering the former as less effective targets for reducing the nation's CO_2 emissions (U.S. EPA 2011). The distribution of straight-line distances from the any of the 583 coal plants in the continental U.S. to the nearest oil field is shown in Figure 7. The mean for this distribution is 308 km with the standard being 251 km, but note that the distribution is not uniform. Only 27% of the plants are within 100km of a reservoir.

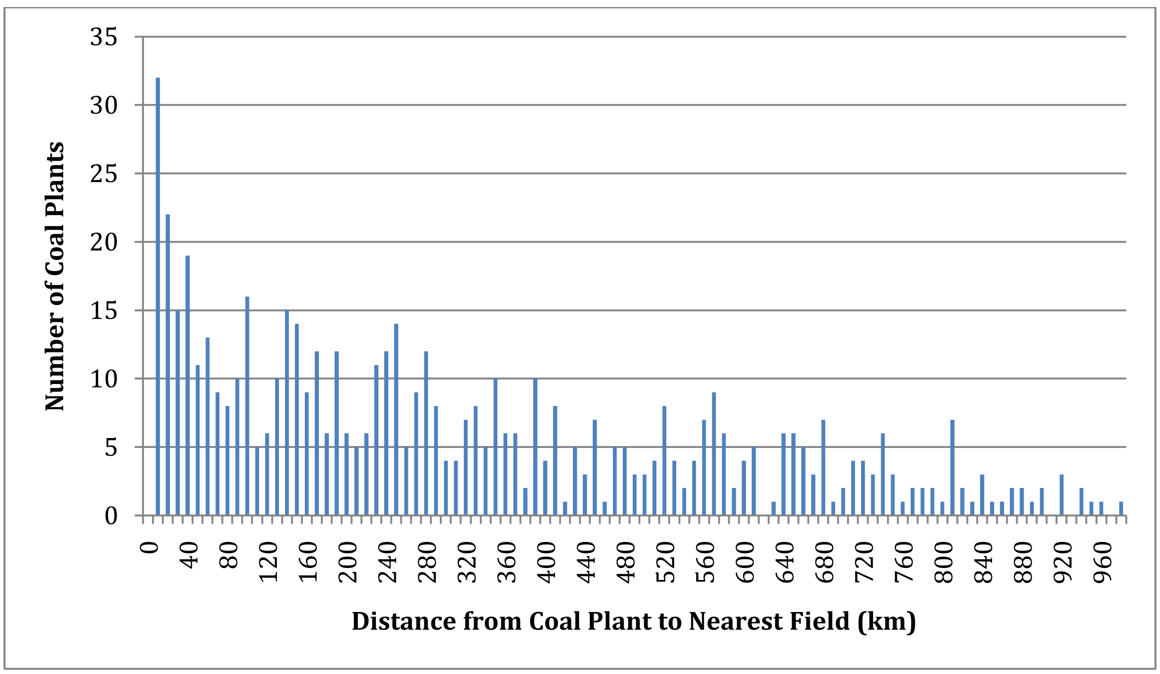

Figure 7: Distance from Coal Plant to Nearest Field

Distances become further refined when the capacities of the individual reservoirs are taken into account. Figure 8 plots the frequency of storage capacities estimated for the reservoirs. In total, we estimate this potential storage to be 41 billion metric tons of CO_2, which is equivalent to 8.5 years of such emissions from all of U.S. coal plants (U.S. EPA 2012). However when viewed on an individual basis, 86% of the reservoirs could only store <1y of CO_2 emissions from a 500 MW coal power plant. Some 12% of the reservoirs could store 1-10 y of such a plant's emissions, 1%) 10-30 y, and only 1% >30 y of emissions.

The primary characteristics that influence the storage capacity of oil reservoirs are area, thickness, porosity, CO_2 density and storage efficiency. Reservoir area is generally 2-3 orders of magnitude greater than reservoir thickness, though there is no significant correlation between the two parameters. Storage potential is maximized where the density of CO_2 would be high due to the pressure and temperature conditions of the reservoir, but these two factors tend to counteract one another. Pressure increases with depth, which increases density, but temperature also increases with depth, which decreases density (Eccles 2009). Furthermore, porosity decreases with depth, reducing the volume of pore space available for storage (Athy 1930). Geologic variability in these three factors (pressure, temperature and porosity) among the 10,000 reservoirs contributes to our broad range of storage capacity estimates.

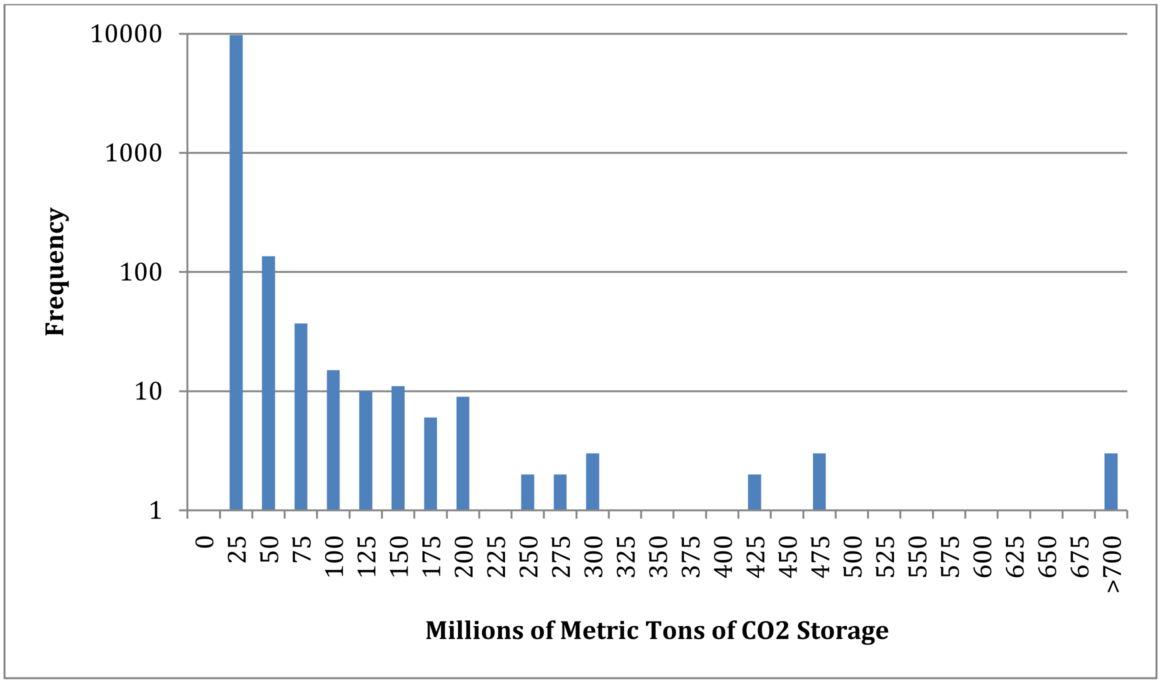

Figure 8 Distribution of Field Storage Capacity

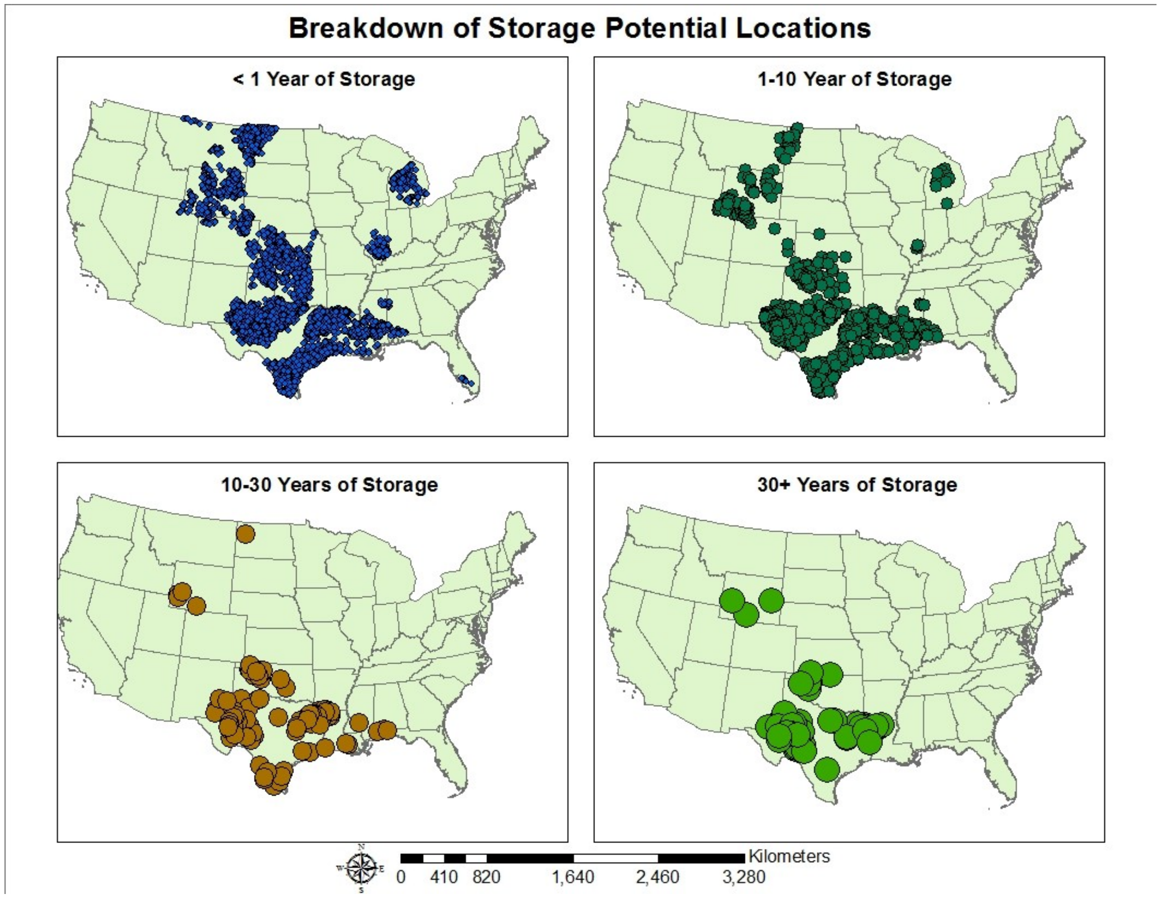

Figure 9: Locations of Storage Potential Broken Down by Years of Storage

As Figure 9 shows, the location of the fields with 30+ years of potential storage are confined primarily to Texas with several others being in Oklahoma. This is a relatively localized region of the country when compared to the distribution of deep-saline aquifers, which are spread across the entire continental U.S. and have a collective storage capacity that is 12-141 times that of oil reservoirs (NETL 2010a).

The largest 100 reservoirs, or 1% of the reservoirs examined, contain 54% of the estimated storage potential. These reservoirs also account for ~54% of the estimated recoverable oil. The frequency distribution of potential oil recovery from the individual reservoirs is plotted in Figure 0. This potential sums to an estimated total of 183 billion barrels of oil. Almost half the reservoirs analyzed (46%) contain less than one million barrels of oil in them while another 13% have between 1-2 million barrels.

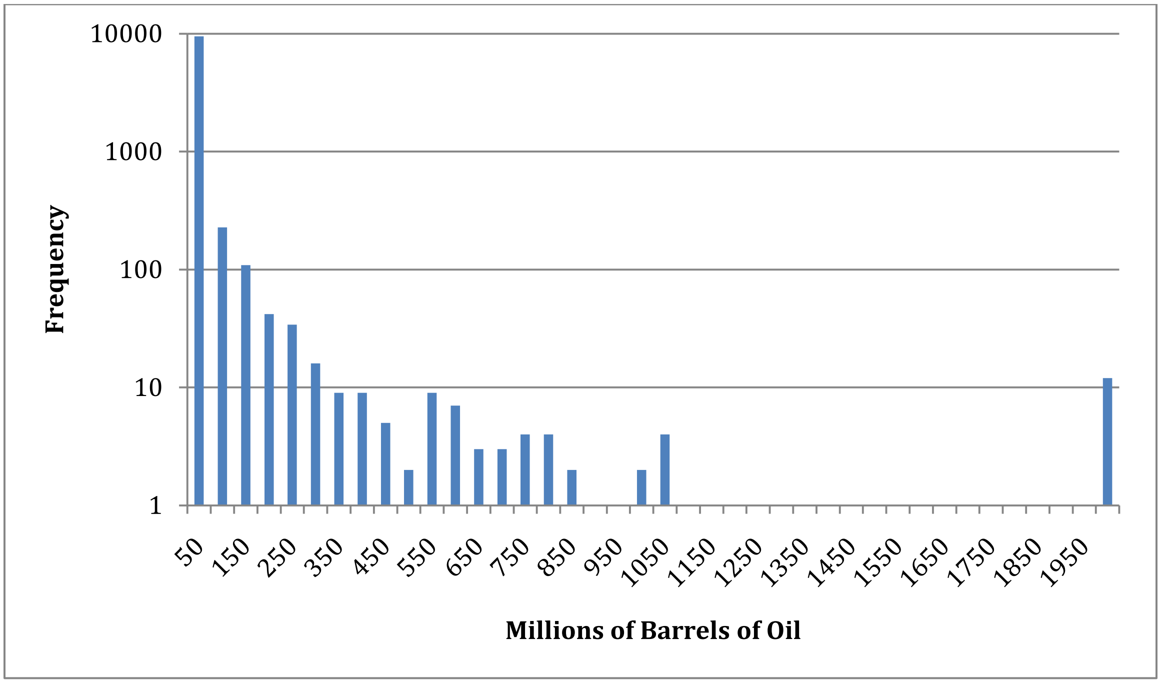

Figure 10: Distribution of Potential Oil Recovery

The connection between the reservoirs with the largest CO_2 storage potential also having the largest remaining oil reserves is not unexpected given that CO_2 storage potential and oil recovery estimations are based upon pore space calculations. A potential benefit is that fewer EOR-CCS projects are needed to recover a lot of oil while also storing a lot of CO_2.

A downside with CCS-EOR from an environmental perspective is that even as anthropogenic CO_2 emissions are being sequestered underground, oil is also being produced which when burned will add to anthropogenic emissions, potentially offsetting the mitigating effects of sequestration. The net reduction in emissions can be examined by dividing the amount of CO_2 that can be stored in each reservoir into the amount of CO_2 that will be released from burning the oil produced from the reservoir. The frequency distribution of these net emissions is shown in Figure 1. Based on this distribution, the mean net reduction is 55% (the median being 52%) with a standard deviation of 7%. Only 0.4% of the reservoirs would have a net reduction of 75% or greater, while only 0.1% would have a net reduction of <25%.

Note that these net reductions do not take into account the emissions created through the process of CCS-EOR or by the capture and transportation of CO_2. Consequently, actual net reductions will be somewhat less than those graphed in Figure 11.

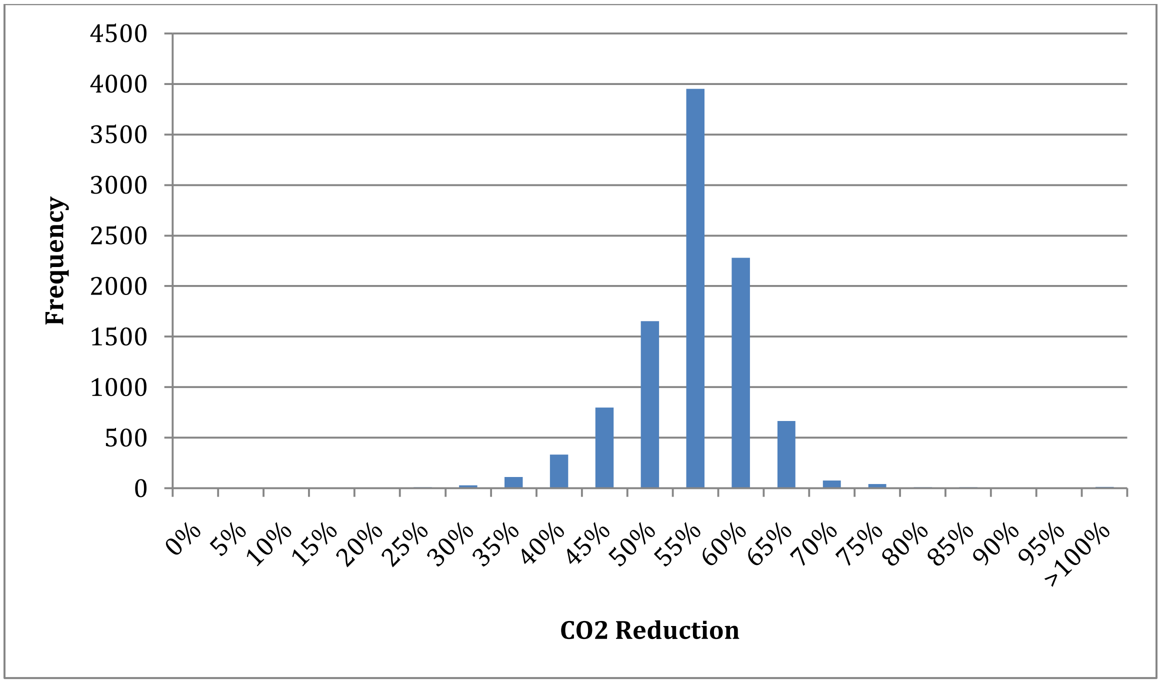

Figure 11: Distribution of Net Reduction in Emissions

The relationship between the amount of oil recovered and the amount of CO_2 stored is not the same for every field. Depending on the different characteristics of a reservoir, it utilization factor (barrels of oil produced/metric tons of CO_2 sequestered) can vary as shown in Figure 12. In this study, we find that the utilization can range from 3-7 with a mean value of 4.5 and a standard deviation of 0.7.

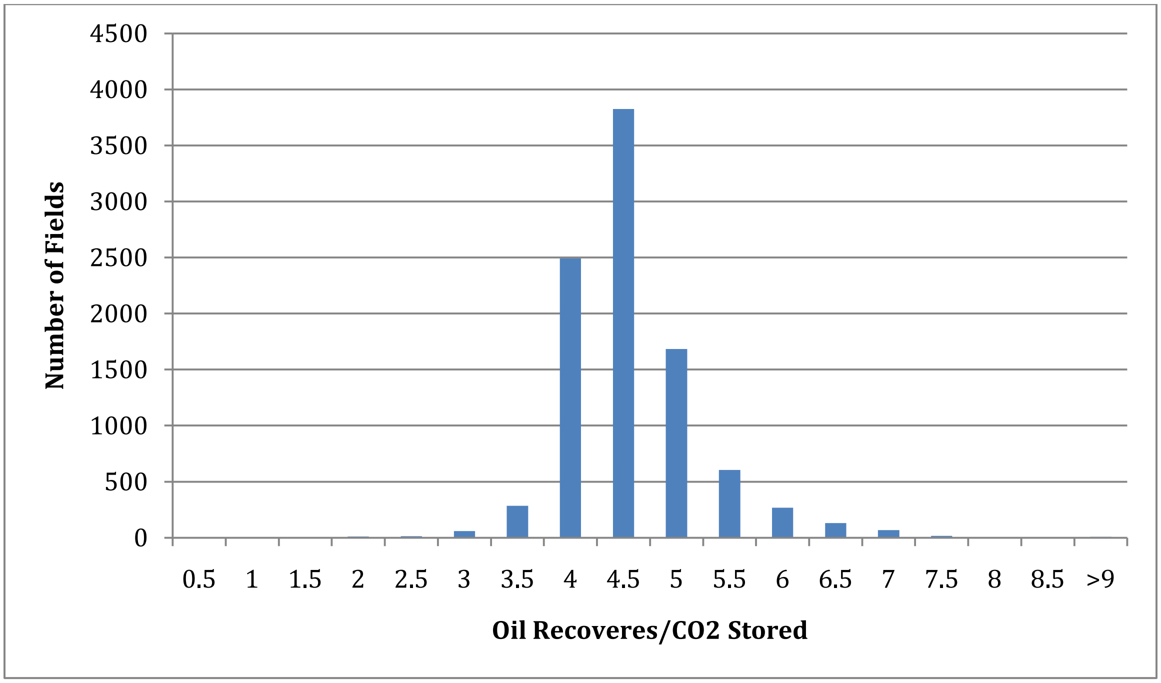

Figure 12: Distribution of Utilization Factor (BBL/Metric Ton)

Plotting storage costs against the amount of CO_2 that can be stored shows that the cost of storage declines as the volume of potential storage rises (Figure 13). A best-fit regression to this plot yields the following power-law function, which provides a rough estimate of the cost of storage given the potential capacity in an oil reservoir

$$C_{CO2} = 23176\, G_{CO2}{}^{-0.389} \tag{4.1}$$

Here C_{CO2} is the cost of storage, and G_{CO2} is the mass of storage. Clearly, reservoirs with greater storage potential are more likely to be economically viable sites for CCS-EOR on a per ton of CO_2 basis. The lower costs for larger reservoirs is due to the McCoy model predicting longer CCS-EOR project lifetimes for these sites, thereby reducing their total annualized costs.

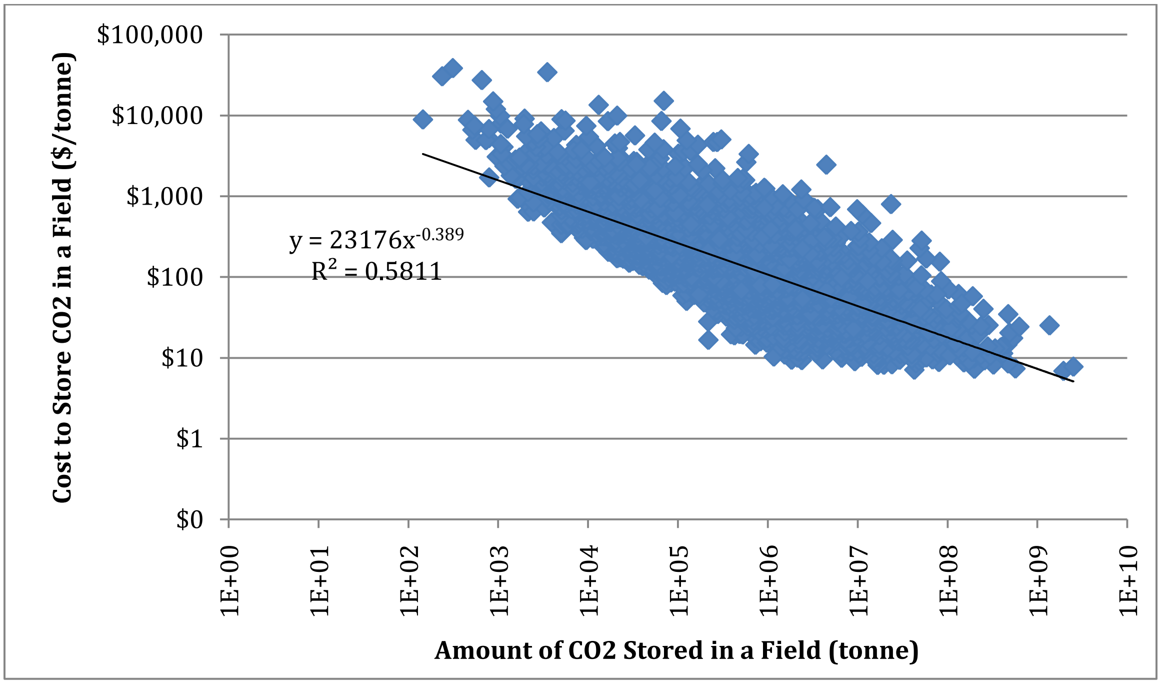

Figure 13: Comparison of Storage Amount to Cost of Storage

Constructing a similar plot for the cost of oil recovery versus the amount of oil recovered per reservoir yields a similar a power-law relationship (Figure 14) that gives a rough estimate of the cost to recover the oil

$$C_{oil} = 8954.9{G_{oil}}^{-0.387} \tag{4.2}$$

In this equation, C_{oil} is the cost of lifting the oil, and G_{oil} is the barrels of oil recovered.

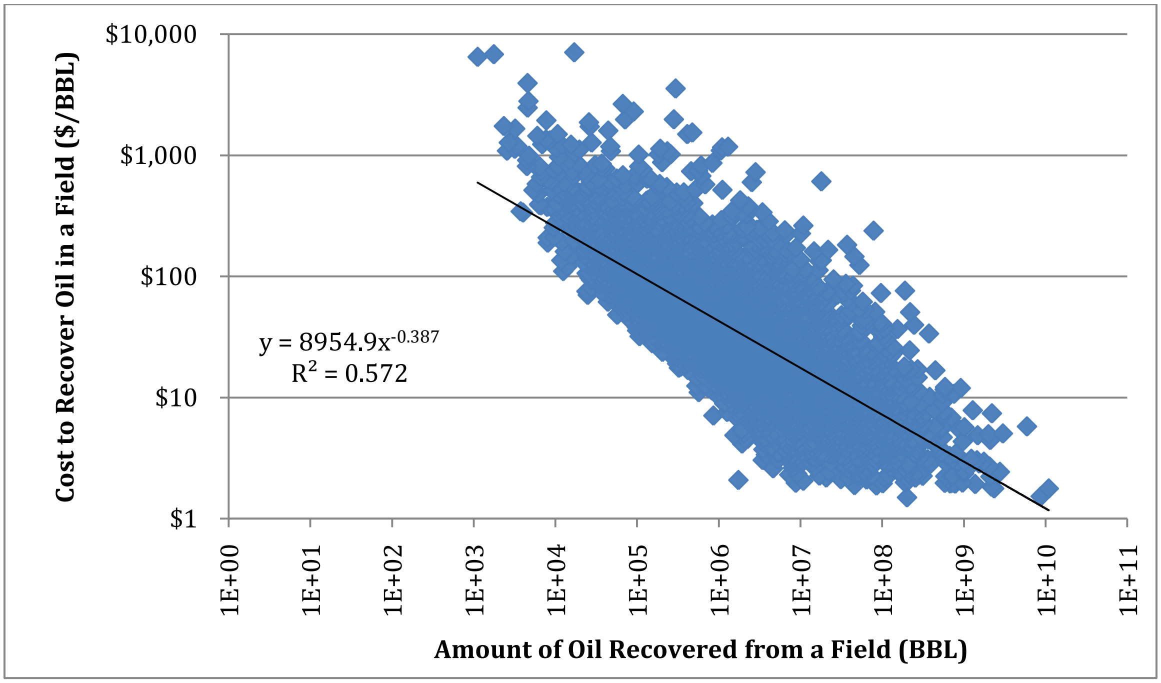

Figure 14: Comparison of Oil Recovery Amount to Cost of Recovery

Finally, the model results can be used to construct marginal supply curves for CO_2 storage capacity and recoverable oil among the 10,000 reservoirs. Figure 15 is the marginal supply curve for CO_2 storage. It shows that the median cost of storage is $25/metric ton, which will support the sequestration of up to 20 billion metric tons of CO_2 (Figure 15). Much of this storage potential occurs at the lower range of costs. The marginal supply curve takes a steep upward turn at the smaller fields more expensive reservoirs with less storage potential.

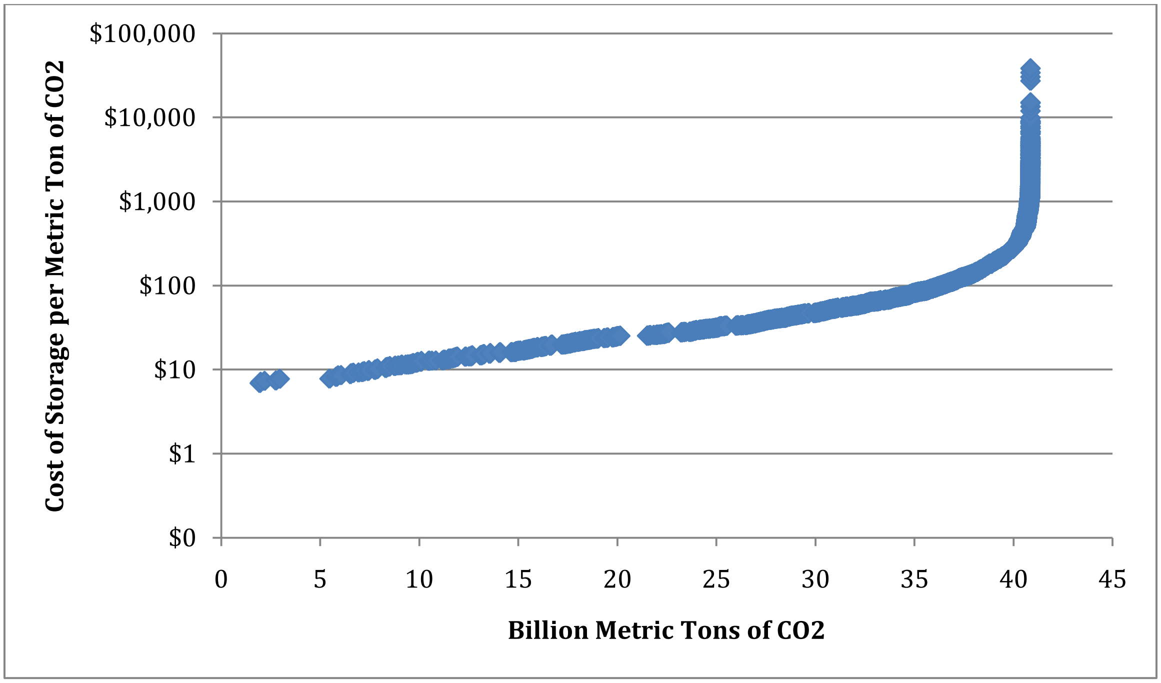

Figure 15: Cumulative Storage Cost Curve

The marginal supply curve for produced oil is shown in Figure 16. The production or lifting cost of the oil has a median value of $5.43/bbl at which up to 92 MMBBL may be recoverable (Figure 16). Note that this lifting cost does not include the cost of the CO_2, which at current rates of 2% the price of oil would raise the lifting cost to $Y/bbl. The fields less likely to be developed once again are the smaller fields with the higher cost per barrel recovered. However many of these fields could become viable since an estimated 182 billion barrels are available at a lifting cost of <$100/bbl and 178 billion barrels are available at a lifting cost of <$50/bbl. However, these figures do not take into account royalty payments and severance taxes that would be levied on the produced oil.

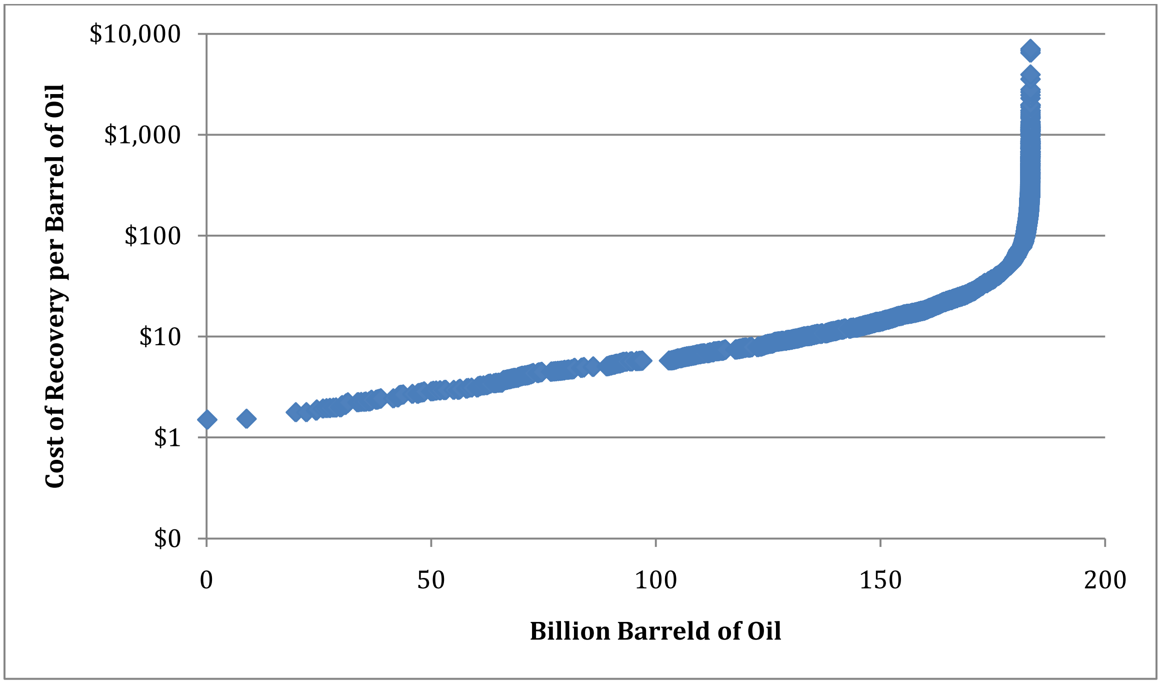

Figure 16: Cumulative Oil Recovery Curve

Since both of the marginal supply curves display an exponential increase towards the right, the cutoff point for economic viability is rather abrupt and will be determined based upon the price of oil and the cost of CO_2. A large amount of the potential storage and potential oil recovery occurs at the lower end of the cost curves, however, due to the large volume of potential storage and remaining oil reserves comes available in the relatively few large oil reservoirs.

5. Discussion

One area of difficulty with storage in oil fields as opposed to saline aquifers is the distribution of their size in relation to storage capacity. Approximately 93% of the fields examined have one year or less of storage of emissions from a 500 MW coal power plant. This limits the likely use of most oil fields for CCS-EOR as capital cost would need to be spent yearly to set up new infrastructure to bring CO_2 to the smaller fields. Limiting CCS-EOR to the largest oil fields makes the most economic sense, for these would have the longest lifetimes and be the most cost effective.

Nonetheless, small fields might still be viable under certain conditions. For example in certain locations, smaller fields could grouped together to receive CO_2 from a single nearby collection point, allowing infrastructure to be shared or easily moved (NETL 2010b). Smaller fields might also be viable if they are in close proximity to a CO_2 source. In fact, future anthropogenic CO_2 sources might be located in part based upon the availability of nearby sequestration options. However, this would be highly dependent on any future government regulations of emissions. Finally, smaller fields could become viable through an increase in the price of oil or a decline in the price of CO_2, with the latter becoming more attractive if oil producers were paid for taking the CO_2 rather than having to pay for it. In the latter case, oil producers would receive two revenue streams for the project instead of one. Again however, this scenario remains highly dependent on government regulations for CO_2 emissions, such as a carbon tax or the implementation of cap and trade system for carbon emissions.

The costs for CCS-EOR examined in this study are for the lifting of oil and storing CO_2. They take into account capital costs, O&M costs and CO_2 recycling costs, but do not include the cost of CO_2 or any offset to costs through via profits from selling the produced oil.

Our marginal supply curves for CO_2 storage suggest that with storage costs starting at less than $10/metric ton and the median cost being $25/metric ton, EOR-CCS is financially feasibility as long as the price of CO_2 remains low. Such projects could become even more economically advantageous if government incentives were offered for greenhouse gas reductions. In contrast to other forms of CCS, CCS-EOR projects could actually net a profit. According to our marginal supply curve for produced oil, a barrel of oil could potentially be produced for less than $10, with the median cost being $5.42/bbl. Like the marginal supply curve for storage, this does not take into account additional costs, such as those for the transport of the CO_2 or the produced oil, so the overall price per barrel will be higher.

The potential impact of EOR on domestic oil production while also allowing for a reduction in CO_2 emissions is not insignificant. Our analysis using the McCoy model suggests that the potential for increasing oil production is 183 billion barrels. This value is high when compared to the DOE's CCS-EOR estimation of 137 billion barrels of recoverable oil using "Next Generation" CO_2-EOR technology which was the only study found that analyzes both CCS and EOR potential together. The DOE (ARI 2011) also estimates that 45 billion metric tons of CO_2 could be stored in conjunction with this production, while our estimate is 41 billion tons. The discrepancy is a result of the higher utilization factor that comes from the McCoy model. If the DOE's utilization factor of 3

BBL of oil stored per metric ton of CO_2 is used with the storage capacity of 41 billion metric tons of CO_2 then the predicted results have their being 123 billion barrels of oil which is in line with the DOE's estimation for total recovery potential. With the increasing oil prices and unrest in the Middle East, having greater domestic oil supply is both financially and politically advantageous, increasing domestic supply as well as jobs (NEORI 2012).

While the estimate of storage potential is in line with the DOE's estimate for "Next Generation" CCS-EOR it is significantly smaller than the storage potential reported by NATCARB when they were analyzing storage potential for all oil and gas fields independent of EOR, which is 88 billion metric tons (NETL 2010a). One of the reasons for this discrepancy is that while the NATCARB study used the same Nehring database, their study was not looking for EOR which made more fields available for storage such as depleted fields with no EOR potential. The NATCARB model field locations are shown in Figure 8 and include both fields for EOR and depleted fields. This study did not include the California reservoirs or the reservoirs available in the Pennsylvania/Ohio region.

When the Nehring data is run using a price for oil of $85/bbl and a price for CO_2 of $40/metric tons assuming an economically viable reservoir is one having at least a 20% rate of return, the results from the McCoy model predict production of 167 billion barrels and sequestration of 38 billion metric tons of CO_2 storage. Using these same assumptions, the DOE estimates that CCS-EOR will yield 136 billion barrels of oil and 20 billion metric tons of economically feasible storage (Figure 17). However, when a similar price comparison is made for just the Wasson Denver Unit, we estimate a profit of $32/bbl compared to the DOE's estimated $38/bbl at an oil price of $75/bbl.

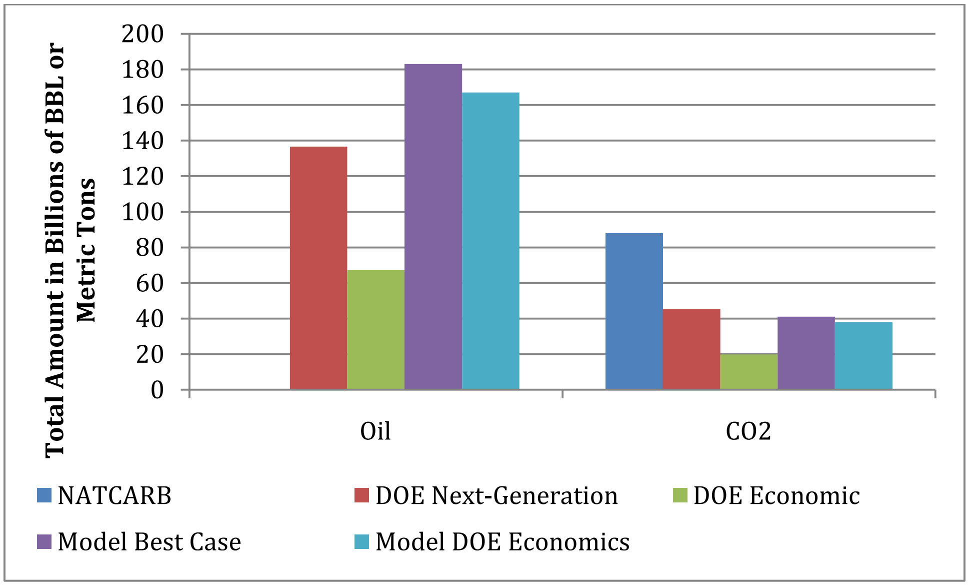

Figure 17: Comparison of Storage and Recovery

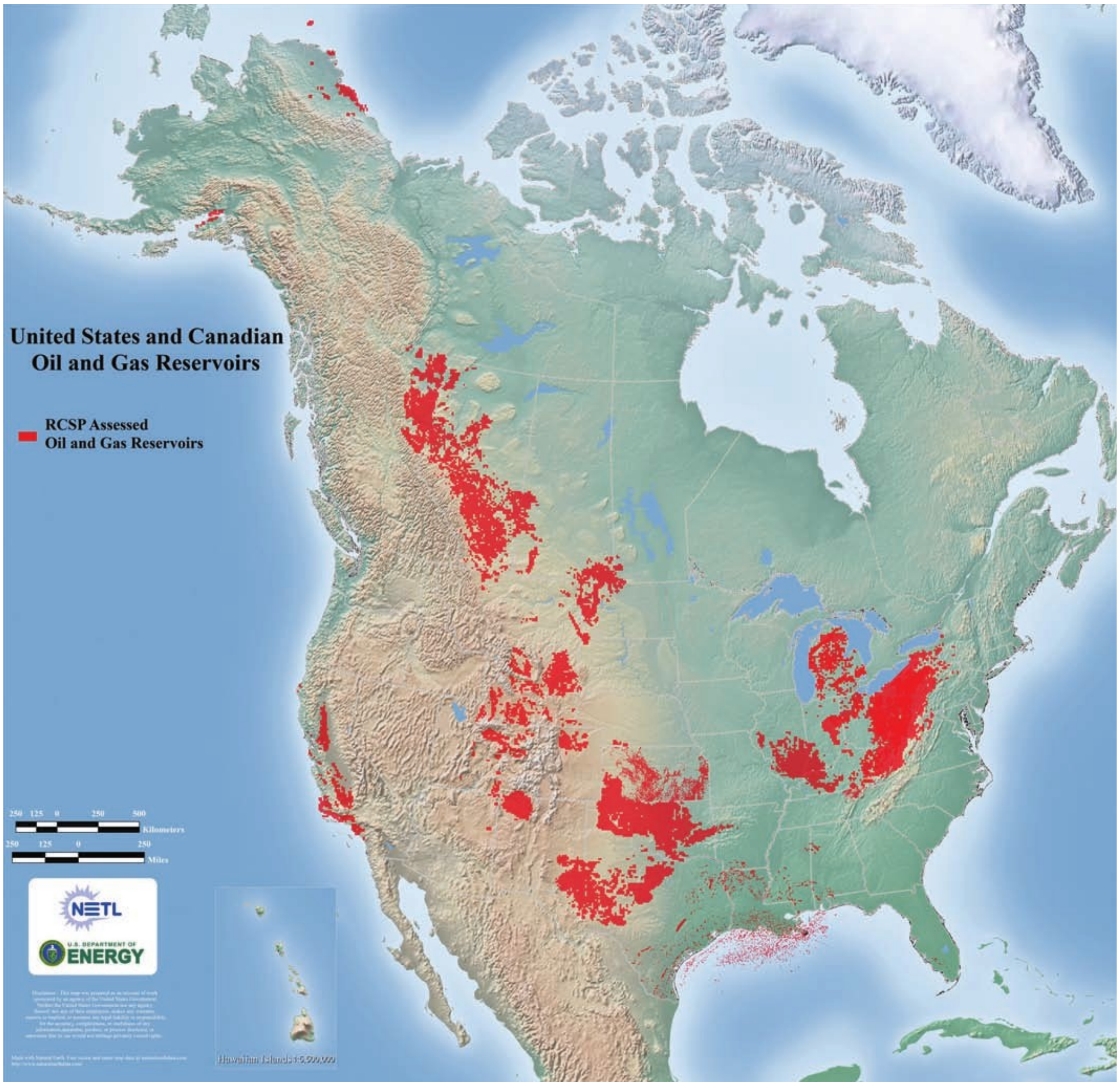

Figure 18: NATCARB Oil and Gas Field Locations

The environmental benefits of EOR in conjunction with CCS are only relevant if the oil produced does not cause greater CO_2 emissions than the amount stored. Currently most of the EOR projects use CO_2 from naturally occurring domes, as this is the cheapest source. Any sequestration of this natural CO_2 does not contribute to a net reduction in emissions, and in fact it is probably increasing emissions since in the process of collecting and injecting the natural CO_2 some to escapes into the atmosphere. A net reduction in emissions can only occur if the CO_2 comes from anthropogenic sources. We estimate that in most cases, CCS-EOR will lead to a net reduction in CO_2 of between 50-75% when compared to the amount of CO_2 emitted from burning the recovered oil. Considering the United States oil demand continues to rise, such an amount of emission reduction would be advantageous.

Appendix A

The model developed by Sean McCoy is a multi step process to determine the potential oil production, CO_2 storage and cost for a CCS-EOR project. A schematic of the model can be seen in Figure 1. The model can be broken down into two primary parts, a performance module and an economic module.

A1 Performance Module

The performance module takes inputs relating to the reservoir and oil characteristics such as area, depth, pressure, temperature, etc. The module then uses these parameters to estimate the amount of oil recovered and CO_2 stored.

A1.1 Injection Process

The rate at which CO_2 can be injected into the system is known as the injectivity (I) and is calculated based upon the injection rate (q), the well bottom pressure (p_{wb}) and the equilibrium pressure (p_e) as shown in Equation A1.1. Based upon the five-spot injection pattern shown in Figure 19 the injectivity can be calculated based upon the distance from the injection well to the line that intersects two of the production wells (l), the porosity (k), viscosity of the CO_2 (μ), reservoir thickness (h) and the well radius (r_w). The equilibrium pressure is calculated based upon Equation A1.2 where d is the depth and G is the pressure gradient. One thing to consider is that the well bottom pressure cannot be above the fracture pressure (p_f), which is calculated based upon the reservoir depth and several constants. It is assumed that $r_w << l$ so that the equation can be solved for the well bottom pressure.

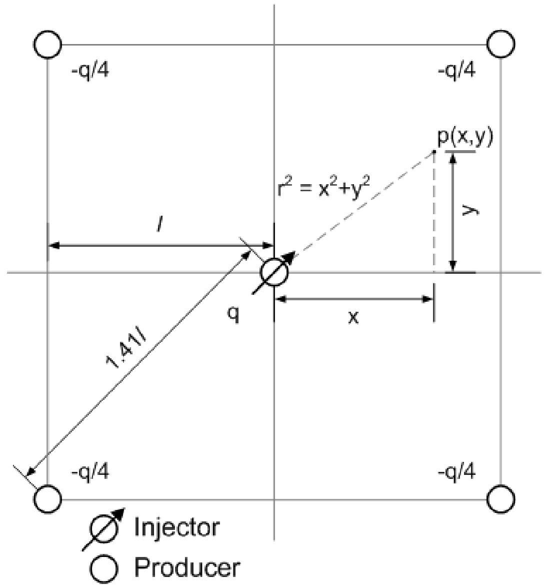

Figure 39: Five-Well Injection Pattern

$$I = \frac{q}{p_{wb} - p_e} = \frac{4\pi kh}{\mu \ln\left\{\frac{[(l+r_w)^2+l^2]^{1/2}[(l-r_w)^2+l^2]^{1/2}}{r_w^2}\right\}} \tag{A1.1}$$

$$\begin{aligned} p_e &= Gd \\ G_f &= \gamma - \beta e^{-\alpha d} \\ p_f &= G_f d \end{aligned} \tag{A1.2}$$

The pressure characteristics can then be calculated along the well using Equation A1.3 assuming the changes in pressure can be characterized by a linear approximation. These parameters are then used to estimate oil recovery.

$$p_{wb} = \frac{\Delta P}{\Delta L} L + p_{wh} \tag{A1.3}$$

A1.2 Estimating Oil Recovery Efficiency

The estimation of oil recovery is based upon overall recovery efficiency (E) that is calculated using Equation A1.4 where E_m is the mobilization efficiency, E_d is the linear displacement efficiency, E_a is the areal (horizontal) sweep efficiency and E_v is the vertical sweep efficiency which are calculated from the reservoirs physical characteristics. Using the overall recovery efficiency (E) and the volume of oil in place prior to the start of the EOR (V_{pd}) the volume of oil produced can be calculated.

$$E = E_m E_d E_a E_v \tag{A1.4}$$

The mobilization efficiency is the fraction of potential oil recovery from a differential volume of reservoir rock at the microscopic level. It is calculated with the assumption that the CO_2 becomes completely miscible within the reservoir when injected (S_{of} = 0) so E_m is equal to 100% as shown in Equation A1.5 were S_{oi} is the initial oil saturation and S_{or} is the residual oil saturation following the project.

$$E_m = \frac{S_{or} - S_{of}}{S_{or}} \tag{A1.5}$$

The displacement efficiency reflects the fraction of the oil swept from the reservoir in a linear displacement as a function of the volume of CO_2 injected (V_{pi}). It is represented as:

$$E_d = \frac{S_{oi} - S_o(V_{pi})}{S_{oi} - S_{or}} \tag{A1.6}$$

The saturation of oil for a given volume of injected CO_2 must be estimated based upon a fractional flow based model. As such the fractional flow of the displaced fluid (f_d), which in this case is oil, can be calculated as:

$$f_d = \frac{1}{1 + \left(\frac{\mu_d}{\mu_o}\frac{k_{ro}}{k_{rd}}\right)} \tag{A1.7}$$

Where μ is the viscosity of the displacing fluid (d) and oil (o) and k_r is the relative permeability of the rock with respect to each of the fluids. If it is assumed that the relative permeability of the rock with respect to each of the fluids is a function of a linear relationship with the displacement saturation fluid (S_d) then:

$$\frac{k_{ro}}{k_{rd}} = \frac{1 - S_d}{S_d} \tag{A1.8}$$

With the mobility ratio defined as:

$$M = \frac{\mu_o}{\mu_d} \tag{A1.9}$$

So that they can be substituted into Equation A1.7 resulting in:

$$f_d = \frac{1}{1 + \left(\frac{1-S_d}{S_d}\right)\left(\frac{1}{M}\right)} \tag{A1.10}$$

This equation only works for stable displacement with mobility ration (M) of less than or equal to one which is not the case with CO_2-flooding process. As such the mobility ration (M) is replaced with the effective mobility ratio (K) as explained by Koval. This has been modified to take into account the vertical sweep efficiency (E_v) which is the fraction of the reservoir swept by the displacing fluid which in this case is CO_2. The inclusion of vertical sweep efficiency is done be incorporating the gravity segregation factor so that:

$$K = EHG \tag{A1.11}$$

Where E is the effective mobility, H is the heterogeneity factor and G is the gravity segregation factor. These variables are further defined as:

$$E = \left(0.78 + 0.22M^{1/4}\right)^4 \tag{A1.12}$$

$$\log H = \left[\frac{V_{DP}}{(1 - V_{DP})^{0.2}}\right] \tag{A1.13}$$

$$G = 0.565log\left(\frac{t_h}{t_v}\right) + 0.870, where \quad \frac{t_h}{t_v} = 2.5271k_vA\frac{\Delta\rho}{q\mu_s} \tag{A1.14}$$

Where V_{DP} is the Dykstra-Parsons coefficient, k_v is the vertical reservoir permeability in md, q is the gross injection rate of CO_2 in RB/day, A is the pattern area in acres and $\Delta\rho$ is the density difference between CO_2 and oil in kg/m^3. The Buckley-Leverett equation relating distance of a plane of fluid of fluid to distance in a reservoir can then be used to produce:

$$f_d = \frac{K - \sqrt{K/V_{i,PV}}}{(K-1)} \tag{A1.15}$$

Where f_d is the "cut" of the displacing fluid which in this case is CO_2 and $V_{i,PV}$ is the dimensionless pore volume of fluid injected into the reservoir. In order to determine the pore volume of oil produced equivalent to E_dE_v the above equation must be integrated and added to the pore volume produced prior to breakthrough at the injection of 1/K pore volumes of CO_2. This results in:

$$E_dE_v = \frac{2\sqrt{KV_{i,PV}} - V_{i,PV} - 1}{(K-1)} \tag{A1.16}$$

The final efficiency incorporated is the areal sweep efficiency (E_a) and it is the fraction of the well pattern swept by the displacing fluid. Then $V_{i,PV}$ can be replaced by $V_{d,PV}$ which is the pore volume of fluid injected relative to the volume fraction swept by the injected fluid which is:

$$V_{d,PV} = \frac{V_{i,PV}}{E_a} = \left(\frac{E_dE_v}{E_a}\right)V_{a,PV} \tag{A1.17}$$

The areal sweep efficiency can then be calculated:

$$E_{a,bt} = \begin{cases} V_{a,PV}, & V_{a,PV} \leq 1 \\ 1.0, & V_{a,PV} > 1 \end{cases} \tag{A1.18}$$

$$M_{bt} = \frac{1 - E_{a,bt}}{E_{a,bt} - 0.4}$$

$$E_a = \frac{E_{a,bt} + M'}{1 + M''}$$

$$M' = 25\frac{{M_{bt}}^{5/6} + 0.3 + 2.3\left(V_{a,PV} - 1\right)}{V_{a,PV} + 1}$$

$$M'' = \frac{M - M_{bt}}{(M' - M_{bt})^{\left(0.85 - 0.55E_{a,bt} + 0.25V_{a,PV}\right)}}$$

Once all of the efficiency values are known the fraction of oil recovered can be calculated. As there is no analytical solution to the equations an iteration scheme (Figure 20) is used to determine the values.

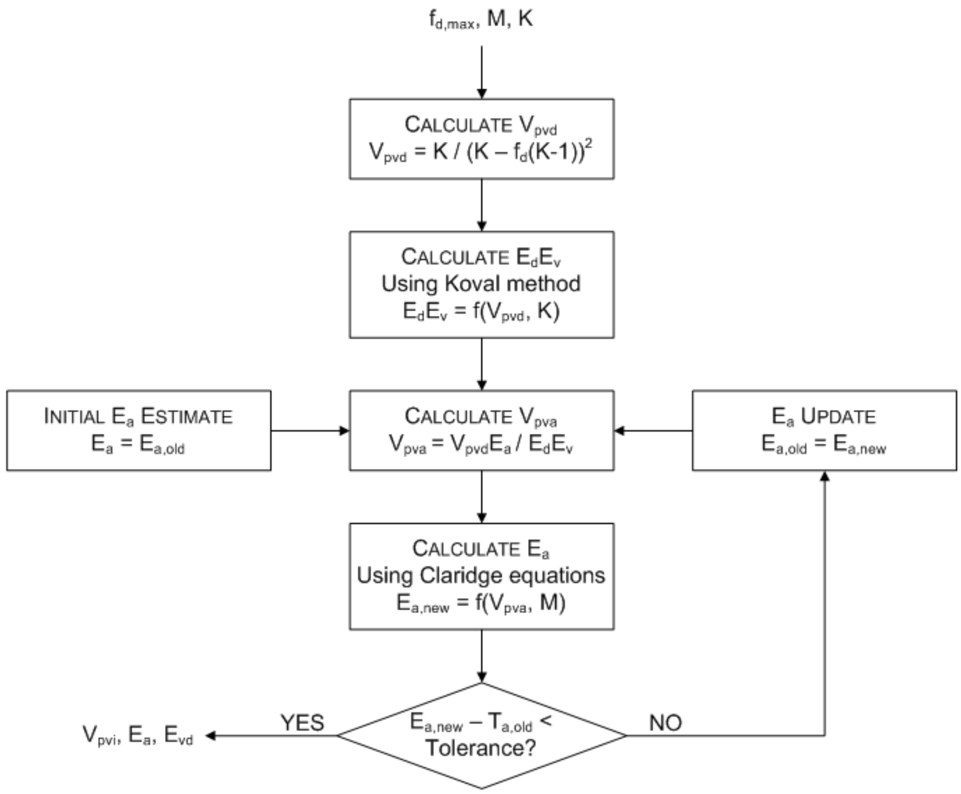

Figure 20: Iterative Efficiency Calculation Process

A1.3 Estimating Net CO_2 Stored and Oil Recovered

The volume of CO_2 injected is many times greater than the volume of CO_2 stored. This means that a great deal of what is injected returns to the surface and is recycled. The display of the system can be seen in Figure1. When the mass balance equations are written the results are:

$$q_{prod} = q_{gross}(1-\tau)$$

$$q_{rcy} = q_{gross} f_d (1-\tau)(1-\eta) \tag{A.19}$$

$$q_{net} = q_{gross}[1 - f_d(1-\tau)(1-\eta)]$$

Where τ is the rate of CO_2 escape from the pattern and η is the rate at which CO_2 is lost to the atmosphere from the separator. The volume of oil produced and CO_2 stored can be calculated using Equations A1.20, A1.21 and A1.22 where S_{or} is the oil saturation of the reservoir at the start of EOR.

$$V_{prod} = EA\, h\, \phi\, S_{or} + V_{co2} \tag{A1.20}$$

$$V_{CO2} = E_a A\, h\, \phi S_{or} V_{pvd,CO2} \tag{A1.21}$$

$$V_{pvd,CO2} = \frac{KV_{pvd} - 2\sqrt{K/V_{pvd,}} + 1}{K - 1} \tag{A1.22}$$

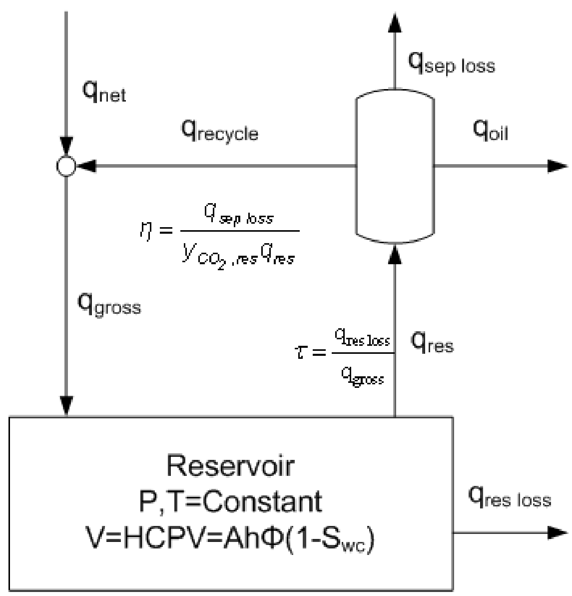

Figure 21: CO_2 Flow Path

A.2 Economic Properties

Knowing the amount of CO_2 stored and oil recovered along with the location and depth of the fields allows for the economics to be calculated based upon McCoy's model

(McCoy 2008). A key component to the economic model is the capital costs equations developed by the Department of Energy brought forward into 2004$US (Lewin and Associates, Inc. 1981). The cost for different regions of the United States are calculated based upon region (Figure) and depth.

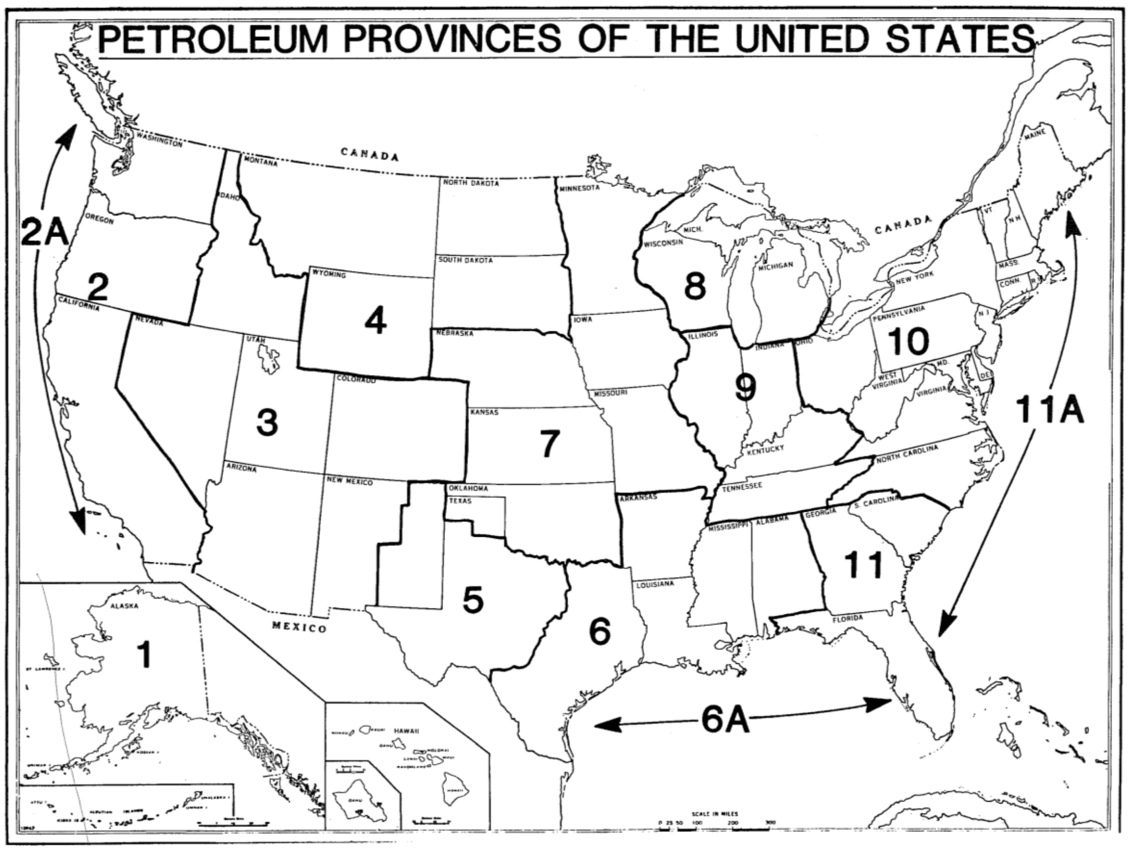

Figure 22: Economic Regions

The basic equation used to calculate the lease equipment capital cost, pattern equipment capital cost, drilling and completion capital costs and O&M costs is:

$$C = a_1\, e^{a_2 d} \tag{A1.23}$$

The coefficients a_1 and a_2 are set by a study conducted by Lewin and Associates using a regression analysis. The cost for the CO_2 processing equipment is calculated as:

$$\log(C_{CPE}) = a_0 + a_1\, \log\left(N_p q_{rcy,max}\right) \tag{A1.24}$$

Where C_{cpe} is the capital cost of the CO_2 processing equipment, N_p is the number of patterns and $q_{rcy,max}$ is the pattern recycle rate.

Once the costs are known the marginal costs were calculated for each field and a marginal cost curve was made for storage and recovery. The percentage reduction was then calculated based upon the EPA's value of 0.43 metric tons of CO_2 are emitted per barrel of oil (U.S. EPA). A key element that must be remembered is the price of oil and cost of CO_2 were both set to zero so that the results could be found independent of these factors.

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