

Long-Term Risks and Short-Term Regulations

*Modeling the Transition from
Enhanced Oil Recovery to
Geologic Carbon Sequestration*

Alexander J. Bandza and Shalini P. Vajjhala

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Abstract

Recent policy debates suggest that geologic carbon sequestration (GS) likely will play an important role in a carbon-constrained future. As GS evolves from the analogous technologies and practices of enhanced oil recovery (EOR) operations to a long-term, dedicated emissions mitigation option, regulations must evolve simultaneously to manage the risks associated with underground migration and surface trespass of carbon dioxide (CO₂). In this paper, we develop a basic engineering-economic model of four illustrative strategies available to a sophisticated site operator to better understand key deployment pathways in the transition from EOR to GS operations. All of these strategies focus on whether or not a sophisticated site operator would store CO₂ in a geologic formation. We evaluate these strategies based on illustrative scenarios of (a) oil and CO₂ prices; (b) leakage estimates; and (c) transportation, injection, and monitoring costs, as obtained from our understanding of the literature. Major results reveal that CO₂ storage in depleted hydrocarbon reservoirs after oil recovery is associated with the greatest net revenues (i.e., the “most-preferred” strategy) under a range of scenarios. This finding ultimately suggests that GS regulatory design should anticipate the use of the potentially leakiest, or “worst,” sites first.

Key Words: carbon sequestration, enhanced oil recovery, leakage, regulatory design, risk management

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1. Introduction

Climate change has brought to bear a wide variety of new technologies, along with their potential risks and opportunities. Policies to reduce greenhouse-gas (GHG) emissions encompass a range of mitigation options, from small-scale technologies (*e.g.*, energy-efficient light bulbs and appliances) to large-scale deployment of low-carbon energy sources (*e.g.*, wind and solar power). The portfolio of potential climate-change mitigation options also includes less familiar, emerging technologies. One of the most prominent of these emerging technologies is carbon capture and sequestration (CCS).

CCS is a broad term that encompasses a range of processes and technologies, although the term generally refers to (a) the capture of carbon dioxide (CO₂) from anthropogenic sources; (b) the transport of CO₂ to the ultimate storage location; and (c) the sequestration of CO₂ in perpetuity. Geologic sequestration (GS) is one form of CCS, in which CO₂ is injected into geologic formations for the purpose of long-term storage.¹ As of this writing, 135 CCS projects are active around the world (DOE 2010c). Three of the largest of these projects are Sleipner (Norway), In-Salah (Algeria), and Weyburn (Canada), with annual injection rates of approximately one million metric tons (MMT) of CO₂ (IEA 2006). Despite their size, these operations represent a small fraction of annual global energy-related CO₂ emissions, which totaled approximately 29,700 MMT in 2007 (DOE 2010b).

Scientists have opined that 3,500 new GS projects worldwide—each comparable in size to the largest existing projects—must be operational within the next few decades for CCS to

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¹ The terms “carbon sequestration” and “CCS” also are used generally to refer to the terrestrial storage of CO₂ in forests and soils. We focus solely on on-shore geologic carbon sequestration in this paper and use the term “GS” herein to avoid any confusion with other possible forms of CO₂ sequestration.

materially reduce anthropogenic CO₂ emissions (Pacala and Socolow 2004; IPCC 2005). The sheer number of new GS projects needed has raised questions about the adequacy of existing regulatory frameworks to effectively manage operational and *in-situ* risks, as well as to build public acceptance of the technology (Wilson et al. 2008). Ongoing operations have provided some preliminary characterizations of potential short- and long-term risks, which may include the underground migration and surface trespass of CO₂, with the resulting potential for environmental and biological impacts (Damen et al. 2006; Heinrich et al. 2003; Wilson et al. 2003).² Notwithstanding the limited number of GS projects brought on line to date, and the long-term technical and geophysical uncertainties, CCS is considered one of the few CO₂ mitigation options with the potential for large-scale, near-term deployment.

An effective and robust regulatory framework to manage these uncertainties likely will require a comprehensive view of all GS projects. Recent studies have examined the probability of leakage associated with specific *types* of geologic formations, sites, and project contexts (Benson 2005; Hovorka et al. 2006).³ However, possible *deployment pathways* of GS projects (*i.e.*, a collection of investments in GS operations not limited to one geologic formation or context) remain poorly understood. This gap in understanding poses a challenge for regulatory design—balancing regulations that are stringent enough to build public confidence in GS, yet flexible enough to avoid stymieing deployment (Wilson et al. 2008).

The varied underground formations appropriate for GS potentially can exacerbate this regulatory challenge. These formations include (a) depleted hydrocarbon reservoirs; (b) deep saline aquifers; and (c) unmineable coal seams. It is expected that initial GS operations will employ depleted hydrocarbon reservoirs. Depleted hydrocarbon reservoirs are familiar to the industry through decades of enhanced oil recovery (EOR) operations, an oil-industry practice in which CO₂ (or other media) is injected underground into declining production sites to extract additional oil (SPE 2010). Further, revenues from the oil produced in EOR operations can offset the large expense of undertaking a GS operation.

² By way of example, these risks may be related to (a) short-term impacts, including the suffocation of humans and other animals, biological impacts on plants, and seismic effects or local ground heave; or (b) longer-term impacts from gradual releases, including the contamination of groundwater or drinking-water sources through mineral mobilization or displacement of brine or hydrocarbons (Wilson et al. 2003).

³ We note in this regard that the site-specific variation in the geologic characteristics of potential GS formations may be significant. Notwithstanding this variation, some project types inherently could be riskier than others.

However, there are reasons to believe that GS likely will be deployed widely in formations other than depleted hydrocarbon reservoirs. Globally, significantly more storage volume is available in deep saline aquifers than in depleted hydrocarbon reservoirs (IPCC 2005). In addition, deep saline aquifers tend to be less geologically disturbed than depleted hydrocarbon reservoirs, which contain tens, if not hundreds, of remaining production and injection wells that might later serve as leakage pathways for injected CO₂.

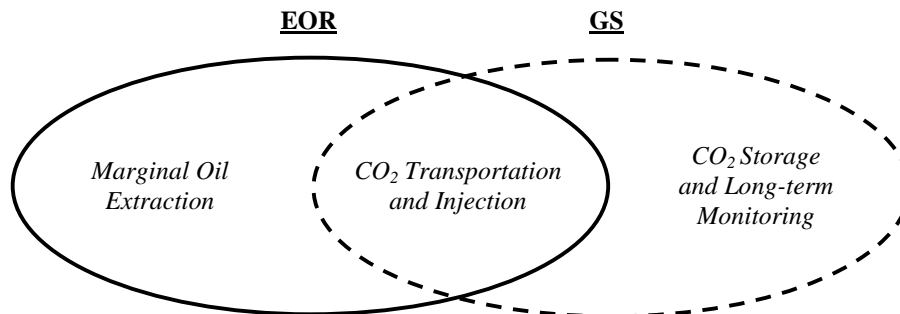
In light of these challenges, we characterize the big-picture differences in the geologic formations and operational goals of EOR and GS to address two main research questions: (1) Which types of GS projects are likely to emerge initially and in greatest numbers under different scenarios (*e.g.*, global oil and CO₂ prices)?; and (2) What are the implications of these different deployment pathways for GS regulatory design? To address these questions, we model four illustrative site strategies that may emerge within the total portfolio of North American GS projects. These strategies qualify our hypothesis that the deployment of GS operations may shift first from existing EOR operations to increasing numbers of hybrid EOR-GS projects,⁴ and later to dedicated GS operations.

We develop this strategy-based approach for several scenarios of the major cost and revenue drivers of GS, in order to examine this compositional shift in GS deployment pathways. In the following sections, we (a) provide a brief background on EOR and GS technologies, practices, and regulations (Section 2); (b) introduce our four key strategies and model framework (Section 3); (c) outline our key variables and assumptions (Section 4); (d) present our major results (Section 5); and (e) discuss policy implications (Section 6).

2. Linking Enhanced Oil Recovery and Geologic Sequestration

EOR can serve as an analogue for GS, because EOR and GS share several processes, and GS likely will use several EOR technologies. The main components of EOR include (a) transportation of CO₂ to a mature oil field; (b) injection of pressurized CO₂ into the field; and (c) extraction of oil. GS projects share the initial transportation and injection components of EOR and further involve (a) permanently securing the CO₂ underground; and (b) long-term monitoring of the site for CO₂ leakage. The overlap in EOR and GS components is shown in Figure 1 below.

⁴ We define “hybrid EOR-GS” projects to be any project with both EOR and GS objectives.

Figure 1: Shared Components of EOR and GS Operations

While the technical foundation for some components of EOR and GS may be substantially similar, EOR and GS operations diverge in their objectives. The primary objective of EOR operations is to maximize the amount of oil extracted per unit of CO₂ injected, without regard for CO₂ storage. Conversely, the goal of GS operations is to maximize the amount of CO₂ stored per unit of CO₂ injected, without regard for oil production. In the following subsections, we briefly describe the key features of EOR and GS operations and the associated regulatory challenges.

2.1 Enhanced Oil Recovery

EOR is a mature process that has been used worldwide for more than 30 years and employs a variety of methods and injection media (Anderson and Newell 2004). CO₂ is one of the primary media used for EOR, and therefore EOR operations offer direct industry experience with the transport and underground injection of CO₂.⁵

Most CO₂-based EOR operations employ *miscible* CO₂ injection.⁶ In this process, much of the CO₂ returns to the surface with the extracted oil. To minimize the total amount of CO₂ used, the returned CO₂ generally is separated and re-injected. It is possible to benchmark the efficiency of the EOR operation by calculating the *oil response ratio* (ORR)—the ratio of the

⁵ The term “EOR” can refer to injection media other than CO₂. By way of example, other injection media include steam and nitrogen (Kooottungal 2008). As used herein, “EOR” shall refer only to CO₂-based EOR.

⁶ “Miscible” CO₂ injection is a process in which CO₂ is injected above a certain pressure to create a single homogeneous phase of CO₂ and oil. Mixing CO₂ and oil in a single phase above the minimum miscibility pressure reduces the oil’s viscosity and causes it to swell, facilitating extraction. Because this process depends on the pressure and weight of the crude oil being extracted, miscible CO₂ injection is not possible in all cases (Kooottungal 2008).

amount of oil recovered over the amount of CO₂ injected. On completion of an EOR operation, site operators have little financial incentive for *in-situ* CO₂ storage, and they typically recycle or sell the remaining CO₂.⁷

2.2 Geologic Carbon Sequestration

Whereas most EOR operations employ CO₂ obtained from naturally occurring sources, GS for the purposes of climate-change mitigation must employ CO₂ captured *only* from anthropogenic sources.⁸ CO₂ can be captured from large, stationary CO₂ sources using gas absorbers or scrubbers, which have been employed in a variety of industrial applications for more than 60 years.⁹

In a typical GS project, the captured CO₂ is transported to the storage site by pipeline, ship, or road, and then is injected deep underground into a secure geologic formation.¹⁰ At most GS sites, CO₂ injection is expected to occur over several decades. CO₂ transportation and injection are mature practices that rely on developed technologies—in the U.S. alone, there are over 2,500 km of pipeline transporting approximately 50 MMT CO₂ annually to supply underground injection, all with a notable lack of injuries or fatalities (de Figueiredo 2007; IPCC 2005).

Geologic formations appropriate for GS include (a) depleted hydrocarbon reservoirs; (b) deep saline aquifers; and (c) unmineable coal seams. EOR operations occur in depleted hydrocarbon reservoirs, and the extent of industry experience with EOR suggests an initial use of these formations for CO₂ storage. Conversely, deep saline aquifers may prove more attractive in

⁷ In some situations, site operators also will reclaim previously injected CO₂ that did not return to the surface with the extracted oil. This process is known as “blowdown.”

⁸ CO₂ captured from naturally occurring sources would not satisfy an “avoided” amount of CO₂ for the purposes of any CO₂ reduction policy.

⁹ By way of example, industrial processes amenable to CO₂ capture include (a) fuel combustion for power generation; (b) refinement of fossil fuels; and (c) production of carbon-intensive industrial materials like iron, steel, hydrogen, ammonia, and cement (IPCC 2005).

¹⁰ The transportation and injection of captured CO₂ from anthropogenic sources pose additional risks associated with the purity of the CO₂ stream. In contrast to natural CO₂ deposits, captured CO₂ may have hydrogen sulfide or other contaminants entrained that could corrode pipelines and injection-well heads, resulting in a higher probability of contamination or leakage (Damen et al. 2006; Heinrich et al. 2003). These contaminants may have integrity-management implications for existing oil and gas wells that were not designed for “contaminated” CO₂.

the long run, given their greater availability and capacity, as well as less disturbed geologic characteristics.

After CO₂ injection is complete and a site is closed, monitoring and verification of the stored CO₂ must occur over several decades, possibly centuries, to ensure environmental integrity. Monitoring techniques from ongoing EOR operations can be adapted for GS projects, such as seismic imaging and surveying (IPCC 2005).

2.3 Risk Management and Regulatory Design

The extensive use of EOR over several decades indicates the apparent industry understanding of EOR-specific risks and regulations. However, the divergent aims of EOR and GS suggest a careful evaluation of (a) GS-specific risks; and (b) any reliance on EOR-specific regulatory frameworks to manage GS-specific risks.

It remains ambiguous how policies to price CO₂ and/or provide incentives for GS deployment might influence the number and timing of EOR and GS projects in the long run. Given the time span over which a reservoir might be operational, it is plausible that EOR and GS operations could exist in the same reservoir. For example, depending on long-term average prices of CO₂ and oil, one might expect to initially see a number of EOR and GS operations in the same reservoir (*i.e.*, hybrid EOR-GS projects) if the price of CO₂ is not high enough to incent dedicated CO₂ storage (*i.e.*, GS without EOR). The technical feasibility and potential attractiveness of CO₂ storage as an afterthought to an EOR operation suggest a pathway-based approach that views EOR and GS operations along a “technical continuum,” as opposed to two entirely different project types.

Conversely, the differences in the operational goals and underground formations available for EOR and GS warrant caution in viewing EOR and GS along a “regulatory continuum.” Notwithstanding differences in the goals of each operation, GS simply requires a larger amount of CO₂ than EOR (Heinrich et al. 2003). Even in an identical reservoir, modeling suggests that the amount of CO₂ injected for the purpose of GS is larger than the amount for

EOR (Kovscek and Cakici 2005).¹¹ With respect to this difference in the scale of CO₂ injection, regulations applicable to EOR operations may be unsuitable and/or irrelevant for GS operations.

The underground formations available to EOR and GS operations also pose a unique set of risks. Depleted hydrocarbon reservoirs—a formation appropriate for both EOR and GS—contain tens, if not hundreds, of injection and production wells that have punctured the cap rock of the reservoir. A site with extensive cap-rock puncturing tends to pose a higher risk of leakage to the surface than a site with an undisturbed cap rock (Bossie-Codreanu and Le Gallo 2004). The tens, if not hundreds, of injection and production wells inherent to an oil recovery operation introduce potential leakage pathways into the cap rock. Although depleted hydrocarbon reservoirs initially might be attractive due to broader industry experience with them, the lower propensity for surface leakage of deep saline aquifers might make aquifers more attractive in the long term. Therefore, GS-specific regulations need to recognize this potential shift in usage from depleted hydrocarbon reservoirs to deep saline aquifers.

Governments around the world are implementing efforts to encourage GS¹² in light of apparently inadequate or inappropriate existing regulatory structures (Wilson et al. 2008; Stephens and van der Zwaan 2005). Efforts are underway in the U.S. to address this gap—in 2008, the U.S. Environmental Protection Agency (EPA) proposed rules to clarify injection regulations for GS operations under the Underground Injection Control (UIC) program.¹³

¹¹ We note in this regard that reservoir modeling of CO₂ injection for EOR suggests that the total volume of CO₂ injected for the purposes of EOR, even in cases of “overinjection” (*i.e.*, beyond the point of profitable oil recovery), would occupy a maximum of 60% of a reservoir’s volume (Kovscek and Cakici 2005). In this regard, the amount of CO₂ injected for EOR operations is limited by the maximum oil production rate, whereas the amount for GS operations is limited only by the CO₂ capacity of the reservoir. We understand that the former is generally more limiting with respect to the amount of CO₂ injected.

¹² By way of example, the European Union has advanced proposals to include GS projects under Phase II of the Emissions Trading Scheme (ETS). The European Commission also has issued statements on the importance of options for coal in a carbon-constrained world (European Commission 2006). Public-private partnerships and regional carbon-sequestration partnerships in the United States are attempting to advance GS demonstration and deployment (Anderson and Newell 2004; DOE 2008).

¹³ Underground injection of CO₂ is regulated federally through the EPA UIC Program, as authorized under the Safe Drinking Water Act (Safe Drinking Water Act of 1974). The UIC Program regulates wells according to five injection-well classes based on design and operating techniques; EOR operations fall under Class II (EPA 2008). In July 2008, EPA proposed to modify the UIC program to create a new class of wells—Class VI—for GS projects and establish minimum technical requirements for sequestration operations (EPA 2008). As well, EPA apparently expects the use of reservoirs for both EOR and GS purposes. It is our understanding that under this proposed modification hybrid EOR-GS operations will be regulated according to the instant operational objective of the site—*i.e.*, hybrid EOR-GS operations initially would be permitted in Class II until EOR is complete, with reapplication required to continue as a GS operation under Class VI.

Developing regulatory standards for GS operations will require balancing efforts to encourage GS with the need for careful risk management under the wide range of possible GS project types and underground formations. Depending on the incentives and uncertainties surrounding new GS projects, the composition of the GS project portfolio could vary significantly over time. This deployment-focused view is especially critical when evaluating how the earliest GS projects could evolve from current EOR operations.

3. A Framework for Deployment-Pathway Analysis

To date, most studies of GS risks have been site specific, examining the technical feasibility of GS using reservoir modeling, experiments, or observations of industry practice (Benson 2005; Kovscek and Cakici 2005). Studies of GS deployment at larger scales have focused on incentives for and barriers to GS operations relative to other types of emissions reduction options (Dooley et al. 2004; Newell and Anderson 2004; Bielicki 2008). However, little attention has been given to the shift from EOR operations to hybrid EOR-GS and ultimately to dedicated GS operations. Herein, we introduce a deployment-pathway approach to evaluate this transition.

We hypothesize that transitions from EOR to GS operations occur due to shifts in the lifetime costs and benefits of recovering oil and/or storing CO₂. These shifts are the result of a sophisticated site operator optimizing whether to (a) maximize oil recovery; (b) maximize CO₂ storage; or (c) both. To illustrate the key points along this transition, we develop the following four strategies outlined in Table 1 below.

Table 1: Illustrative Strategies in the Model

| Strategy | Process(es) Optimized | Oil extraction | CO ₂ storage | Description |
|---------------------|-----------------------|----------------|-------------------------|---|
| Indifferent | EOR | ✓ | | Oil extraction is the sole objective without consideration of CO ₂ storage. |
| Afterthought | EOR <i>then</i> GS | ✓ | ✓ | Oil extraction is the initial objective, and CO ₂ storage is the final objective. |
| Planned | EOR <i>and</i> GS | ✓ | ✓ | Co-optimization of oil extraction and CO ₂ storage is the objective for the entirety of the operation. |
| Dedicated | GS | | ✓ | CO ₂ storage is the sole objective without consideration of oil extraction. |

The Indifferent strategy is comparable to current EOR operations. Oil recovery is the only source of revenues, and no payments are provided for any CO₂ that remains underground at the end of the operation (*i.e.*, the site operator is indifferent to CO₂ storage). The Afterthought strategy represents our characterization of the “first step” toward GS—a sophisticated site

operator seeks additional revenues as an afterthought to the EOR operation by securing the remaining CO₂ (and may even inject additional CO₂) to obtain credit and/or offset revenues at the prevailing price of CO₂. The Planned strategy is our estimation of the incremental step after the Afterthought strategy—a sophisticated site operator plans from the beginning for the operation to co-optimize oil recovery and CO₂ storage. Finally, the Dedicated strategy represents an operation consistent with our understanding of widespread GS deployment—dedicated CO₂ storage in underground formations unrelated to oil recovery.

We believe these strategies broadly cover the types of projects that might comprise the total portfolio of EOR and GS operations in the coming decades. Given a set of reservoir characteristics and costs for each strategy, we employ a simplified cost-benefit analysis to determine which strategy has the highest revenues for particular scenarios of oil and CO₂ prices. The strategy with the highest net revenues under that scenario of oil and CO₂ prices would be the one we expect to “dominate” the investment decisions of sophisticated site operators at that moment.¹⁴ We believe this illustrative exercise can yield an initial understanding of what prices of oil and CO₂ might incent a sophisticated site operator to shift from EOR to GS operations.

4. Model Formulation and Key Variables

In the subsections that follow, we outline the model and its key variables and assumptions used for our lifetime cost-benefit analysis. We focus on three key drivers of EOR and GS operations: (a) the oil response ratio (ORR); (b) the lifetime leakage rate (LLR); and (c) the total cost of the operation, which includes transportation, storage, and monitoring costs. For each of these variables, we have obtained mean values and/or upper and lower bounds from our understanding of the literature. Using this approach, we define a specific range of values for each variable in each strategy.

¹⁴ We focus solely on the dominant strategy under different scenarios of oil and CO₂ prices. We particularly note that non-dominant strategies also might be “profitable,” in that they yield positive net revenues; however, by definition, they are not the *most* profitable. This approach is intended to highlight the points at which specific operational strategies might become attractive to sophisticated site operators. Investors in these operations, faced with a multitude of technical, legal, and regulatory uncertainties surrounding GS, likely will require higher returns to mitigate the long-term financial risks associated with deploying a new technology. We believe this dominant-strategy approach is consistent with the emphasis on high returns that a sophisticated site operator would require to shift operational strategies.

4.1 Model Formulation

To determine the dominant strategy for a given scenario, we employ the following equation across all strategies to calculate net revenues:

$$\Pi = Q_{CO_2 \text{ injected}} * [(7.33)(ORR)(P_{oil}) + (1 - LLR)(P_{CO_2}) - Cost]$$

where:

- (a) Π is the net revenue of the operation;
- (b) $Q_{CO_2 \text{ injected}}$ is the total amount of CO₂ injected (metric tons);
- (c) 7.33 is the conversion factor from barrels to metric tons of oil;¹⁵
- (d) ORR is the ratio of oil recovered (metric tons) per CO₂ injected (metric tons);
- (e) P_{oil} is the price of oil (USD/barrel);
- (f) LLR is the ratio of CO₂ lost per CO₂ injected (metric tons);
- (g) P_{CO_2} is the price of CO₂ (USD/metric ton); and
- (h) $Cost$ is the sum of transport, storage, and monitoring costs (USD/metric ton).

We outline below our estimates of each variable in this equation. Because of the uncertainty surrounding specific strategies and variables, means and/or ranges of variables are sometimes poorly characterized or unavailable. For these variables, we estimate the upper and lower bounds from multiple sources. If this still is not possible, we use a margin of error of $\pm 10\%$ around the mean value for each strategy as a preliminary sensitivity analysis. We close this section with the major assumptions that we used in the model.

4.2 Key Variables

4.2.1 Oil Response Ratio

The ORR represents the “efficiency” of the EOR operation, and indicates the ratio of the amount of oil recovered over the amount of CO₂ injected. The ORR in the context of EOR operations apparently is well understood from decades of industry experience. However, the ORRs for our stylized strategies are less known, and our estimates are meant to serve as illustrative. Table 2 below indicates the ranges of ORRs used in each strategy.

¹⁵ Conversion factor obtained from DOE (2009a).

Table 2: ORRs by Strategy

| Strategy | Values ^a | | | Notes |
|---------------------|---------------------|-------------------|-------------------|--|
| | Low | Mean | High | |
| Indifferent | 0.24 ^b | 0.60 ^c | 1.04 ^b | Current EOR in depleted hydrocarbon reservoirs. |
| Afterthought | 0.10 ^d | 0.18 ^e | 0.60 ^f | Additional CO ₂ is injected to fill the reservoir for long-term storage, resulting in a greater volume of total CO ₂ injected and generally lower ORRs than in the Indifferent strategy. |
| Planned | 0.05 ^h | 0.30 ⁱ | 0.52 ⁱ | Co-optimization of EOR and GS suggests lower ORRs than in the Indifferent strategy. Oil recovery may be limited to improve CO ₂ storage, which also drives down ORRs. |
| Dedicated | - | - | - | Anticipated GS in deep saline aquifers. No oil recovery is possible. |

Notes:

a. Indicates the ratio of oil barrels recovered per metric ton of CO₂ injected.

b. Converted from the Martin and Taber (1992) range of 2.5-11.0 Mcf of CO₂ injected per barrel of oil produced.

c. Typical ORR from EOR operations (Kallbekken and Torvanger 2004).

d. Our estimate. May be the result of worse-than-expected oil recovery or greater-than-anticipated CO₂ injection capacity.

e. Our estimate. Emberley et al. (2004) and White et al. (2007) calculate the total oil recovery potential in the Weyburn EOR reservoir in Canada, a formation undergoing feasibility analysis for CO₂ storage. Both studies estimate oil recovery of approximately 18 MMT. Emberley et al. (2004) notes that Weyburn has 100 MMT of CO₂ storage potential. Assuming that no extra oil is recovered when additional CO₂ is injected for the purposes of GS, Weyburn would have an ORR of 0.18 (18 MMT of oil/100 MMT of CO₂ injected).

f. Our estimate. Reservoir modeling suggests that the amount of CO₂ injected for EOR operations may approach 60 percent of a reservoir's volume (Kovscek and Cakici 2005). It would seem unlikely that the ORR in an EOR-GS hybrid operation would ever exceed the ORR related to EOR alone. Therefore, we limit this range to the mean of the Indifferent strategy at 0.60.

h. Our estimate. The greater emphasis on CO₂ storage relative to both the Afterthought and Indifferent strategies would yield an ORR at half the corresponding value in the Afterthought strategy.

i. Our estimate. Kovscek and Cakici (2005) indicate that well-control methods during EOR can double CO₂ storage for the same amount of oil recovered over traditional EOR methods. Therefore, we estimate this value at half of the corresponding value in the Indifferent strategy.

4.2.2 Lifetime Leakage Rates

We define leakage as the total amount of injected CO₂ lost from a reservoir over the lifetime of the operation.¹⁶ The LLR is the percentage of injected CO₂ that is lost over the lifetime of the project. Therefore, the quantity $(1 - leakage)$ indicates the long-term storage potential of the reservoir.¹⁷

Ha-Duong and Keith (2003) consider an annual leakage rate of 0.1 percent to be essentially “perfect” storage, and suggest that an annual leakage rate of 0.5 percent is too great

¹⁶ We focus solely on leakage to the surface; *i.e.*, we do not take into account any seepage or migration of CO₂ underground. Leakage pathways (*e.g.*, cap-rock fractures and inadequately plugged wells) remain poorly understood, and there is little to suggest that the strategies evaluated in our analysis are associated with substantially different *types* of leakage (Damen et al. 2006; Wilson et al. 2003). As a result, we do not differentiate between sudden, large leaks and gradual, diffuse leaks. Instead, we assume that leakage pathways are substantially similar across all strategies, and the only material difference is the total amount of CO₂ lost over the lifetime of the operation. We assume that site operators only stand to earn revenues for injected CO₂ that remains in the reservoir. We further do not account for additional costs (*e.g.*, insurance premiums and/or risk-spreading instruments) that might be incurred to mitigate the financial liabilities related to the risk of catastrophic leakage.

¹⁷ As noted, the quantity $(1 - leakage)$ also represents the amount of CO₂ that may earn revenues at the prevailing price of CO₂.

for the purposes of climate-change mitigation. Pacala (2003) opines that a 100-year time frame is useful for evaluating the emissions reduction potential of GS operations.¹⁸ After 100 years, an annual leakage rate of 0.1 percent would result in the retention of approximately 90 percent of the original CO₂ injected, corresponding to an LLR of 10 percent. There is nothing to suggest, however, that an LLR of 10 percent is the absolute lowest amount of leakage possible in any reservoir. An annual leakage rate of 0.5 percent is equivalent to 60 percent retained, or an LLR of 40 percent. Therefore, we use 40 percent as the upper bound of LLR across all strategies.¹⁹

Identifying a mean LLR and setting ranges for each strategy within this larger range is more complicated. The difference between the leakage potential of depleted hydrocarbon reservoirs (*i.e.*, the Afterthought and Planned strategies) and deep saline aquifers (*i.e.*, the Dedicated strategy) is not well understood. In light of this uncertainty, we outline the LLRs for each strategy in Table 3 below.

Table 3: LLRs by Strategy

| Strategy | Values ^a | | | Notes |
|---------------------|---------------------|--------------------|-------------------|---|
| | Low | Mean | High | |
| Indifferent | - | - | - | Current EOR operations do not earn revenues related to CO ₂ storage. |
| Afterthought | 0.20 ^b | 0.30 ^b | 0.40 ^b | At the end of a typical EOR operation, the reservoir geology likely is compromised from tens, if not hundreds, of production wells. We expect the LLR to be highest in this strategy. |
| Planned | 0.10 ^c | 0.20 ^c | 0.30 ^c | We expect well control and other methods for the co-optimization of oil recovery and CO ₂ storage to yield better LLRs than the Afterthought strategy. |
| Dedicated | 0.01 ^d | 0.055 ^d | 0.10 ^d | GS operations in deep saline aquifers, with lightly disturbed reservoir geology, should yield the lowest LLRs of any strategy. |

Notes:

a. Indicates the ratio of CO₂ stored relative to CO₂ injected.

b. Our estimate. Based on the higher end of the range identified by Ha-Duong and Keith (2003).

c. Our estimate. Based on the lower end of the range identified by Ha-Duong and Keith (2003).

d. Our estimate. Based on the Hepple and Benson (2005) GS goal of 90 to 99 percent retention of injected CO₂. Only undisturbed deep saline aquifers are used, as Bossie-Codreanu and Le Gallo (2004) note that cap-rock integrity is a key factor related to the leakage potential of the site.

¹⁸ We note in this regard that several trapping mechanisms (*e.g.*, structural, capillary, solubility, and mineral) mitigate leakage at different periods and to different degrees over the lifetime of the project (Benson and Cole 2008). Therefore, within this 100-year time frame, periods of non-zero leakage appear possible. As we focus on project lifetimes in this analysis, we are more interested in the total amount of CO₂ leaked over the lifetime of the project, as opposed to variations in leakage rates over certain periods of a project.

¹⁹ Hepple and Benson (2005) suggest that the goal of sequestration should be the retention of 90 to 99 percent of the original CO₂ injected. Because site operators in this model receive compensation for only the amount of original CO₂ not leaked over the lifetime of the project, the extrapolated Ha-Duong and Keith (2003) range of 60 to 90 percent of the injected CO₂ retained provides a conservative estimate for revenues from CO₂ sequestration.

4.2.3. Total Project Costs

We consider three categories of costs for each strategy: (a) transportation; (b) storage (injection); and (c) monitoring. We discuss each of these costs individually below. All costs are in USD per metric ton of CO₂ unless otherwise noted.

Transportation Costs

CO₂ transportation by pipeline for EOR operations is a mature practice in the U.S., with over 2,500 km of pipeline transporting 40 MtCO₂ annually to supply underground injection (de Figueiredo 2007; IPCC 2005). Pipelines also are expected to be the least-cost transportation option for long-term GS operations (Bielicki 2008).

Total transportation costs for any operation are partially a function of pipeline distance from the CO₂ source to an injection site (Bielicki 2008; McCoy and Rubin 2008). Geospatial modeling by Dahowski and Dooley (2004) indicates that most depleted hydrocarbon reservoirs lie more than 50 miles from existing large-scale CO₂ sources, whereas most aquifer storage lies fewer than 50 miles from the same sources. Therefore, strategies that employ storage with some type of EOR (*i.e.*, the Indifferent, Afterthought, and Planned strategies) face longer transport distances in this model than the strategy without EOR (*i.e.*, the Dedicated strategy). Our estimates and assumptions for transportation costs are outlined in Table 4 below.

Table 4: Transportation Costs by Strategy

| Strategy | Values ^a | | | Notes |
|---------------------|---------------------|---------------------|---------------------|--|
| | Low | Mean | High | |
| Indifferent | \$3.79 ^b | \$5.41 ^c | \$7.03 ^d | Estimate of a 200-km pipeline. |
| Afterthought | \$3.79 ^b | \$5.41 ^c | \$7.03 ^d | Estimate of a 200-km pipeline. |
| Planned | \$3.79 ^b | \$5.41 ^c | \$7.03 ^d | Estimate of a 200-km pipeline. |
| Dedicated | \$0.75 ^e | \$1.16 ^f | \$3.56 ^g | Estimate of a 100-km pipeline. May be conservative based on the average distance from CO ₂ source to aquifer of less than 50 km, as reported by Dahowski and Dooley (2004). |

Notes:

a. Indicates cost (USD) per metric ton of CO₂ injected.

b. Our estimate. McCoy and Rubin (2008) note 30 percent variation in costs; calculated as 30 percent less than the corresponding mean value.

c. Estimated levelized cost of a 200-km pipeline with a 75 percent capacity factor (McCoy and Rubin 2008).

d. Our estimate. McCoy and Rubin (2008) note 30 percent variation in costs; calculated as 30 percent greater than the corresponding mean value.

e. Minimum value predicted by the McCoy and Rubin (2008) model for a 100-km pipeline with a 100 percent capacity factor.

f. Estimated levelized cost of a 100-km pipeline with a 100 percent capacity factor (McCoy and Rubin 2008).

g. Maximum value predicted by the McCoy and Rubin (2008) model for a 100-km pipeline with a 100 percent capacity factor.

Storage Costs

Storage costs encompass all costs incurred by site operators in the injection, operation, maintenance, and closure of a site secured for long-term GS. These costs are largely a function of the amount of CO₂ initially injected. The IPCC (2005) has identified storage costs based on

reservoir type, which we deem applicable to all strategies of the model. The estimates for storage costs are listed in Table 5 below.

Table 5: Storage Costs by Strategy

| Strategy | Values ^{a,b} | | | Notes |
|---------------------|-----------------------|--------|--------|---|
| | Low | Mean | High | |
| Indifferent | - | - | - | Current EOR operations do not seek long-term CO ₂ storage. |
| Afterthought | \$0.50 | \$1.30 | \$4.00 | Storage costs for a depleted hydrocarbon reservoir in the U.S. |
| Planned | \$0.50 | \$1.30 | \$4.00 | Storage costs for a depleted hydrocarbon reservoir in the U.S. |
| Dedicated | \$0.40 | \$0.50 | \$4.50 | Storage costs for a deep saline aquifer in the U.S. |

Notes:
a. Indicates cost (USD) per metric ton of CO₂ injected.
b. IPCC (2005).

Monitoring Costs

The final component of total project cost is the cost related to long-term monitoring of the site to ensure environmental integrity. It appears that many monitoring technologies and practices used for ongoing EOR operations can be adapted for the long-term monitoring of stored CO₂. Table 6 outlines our estimates for monitoring costs.

Table 6: Monitoring Costs by Strategy

| Strategy | Values ^a | | | Notes |
|---------------------|---------------------|---------------------|---------------------|--|
| | Low | Mean | High | |
| Indifferent | - | - | - | Long-term CO ₂ monitoring not appropriate for current EOR operations. |
| Afterthought | \$0.27 ^b | \$0.30 ^c | \$0.33 ^d | Storage costs for a depleted hydrocarbon reservoir in the U.S. |
| Planned | \$0.15 ^b | \$0.17 ^e | \$0.19 ^d | Storage costs for a depleted hydrocarbon reservoir in the U.S. |
| Dedicated | \$0.16 ^f | \$0.18 ^g | \$0.19 ^h | Storage costs for a deep saline aquifer in the U.S. |

Notes:
a. Indicates cost (USD) per metric ton of CO₂ injected.
b. Our estimate. Minus 10 percent of the corresponding mean value.
c. “Enhanced monitoring package” for an “EOR reservoir” from Benson et al. (2004).
d. Our estimate. Plus 10 percent of the corresponding mean value.
e. “Basic monitoring package” for an “EOR reservoir” from Benson et al. (2004).
f. Lower end of the “basic monitoring package” for a “saline formation” from Benson et al. (2004).
g. Straight-line average of the corresponding low and high values.
h. Upper end of the “basic monitoring package” for a “saline formation” from Benson et al. (2004).

4.3 Major Assumptions

In this analysis, we fix the quantity of CO₂ injected across all scenarios to enable the comparison between EOR and GS operations.²⁰ We assume that the amount of CO₂ injected is

²⁰ This approach is analogous to examining the per-ton return to injecting CO₂, regardless of operational purpose.

optimized for the operational purposes of that strategy. To achieve this optimization, we allow the size of the reservoir across strategies to vary.²¹ By fixing the total amount of CO₂ injected across strategies, we can compare the lifetime net revenues of each *strategy*, instead of comparing the lifetime net revenues of different strategies *for a particular storage site*.

This “reservoir-less” approach permits a broad examination of GS versus EOR operations, rather than focusing on the idiosyncrasies of reservoirs. In this regard, we acknowledge that lifetime net revenues *for particular storage sites* likely will be dependent on the geologic characteristics of the formation and the quantity of CO₂ that can be injected, and there is a role for further research on the economies of scale for individual formations. We assume that economies of scale are identical across strategies.²²

To compare total revenues across strategies, we focus on a lifetime net-revenue analysis in recognition of the different lifetimes of EOR and GS operations. The lifetime of an EOR operation could be as short as 10 years, whereas a GS project may continue for hundreds of years before monitoring is complete. In this regard, we do not discount future cash flows.

We assume that capture costs are equal across all strategies, and we set these costs to zero. Depending on the policy instrument(s) used to price CO₂ emissions, capture costs could vary significantly and be absorbed or passed through at different points by various emitters.²³ We have no reason to believe that sophisticated site operators would experience different capture costs across strategies, because all strategies use CO₂ from anthropogenic sources.²⁴

²¹ By way of illustration, to optimize the operational purposes of the Afterthought and Indifferent strategies with the same amount of CO₂ injected, the Afterthought strategy (*i.e.*, oil recovery, then CO₂ storage) likely would exist in a much smaller reservoir than the Indifferent strategy (*i.e.*, oil recovery alone). If we invert this approach—*i.e.*, by fixing reservoir size and varying the amount of CO₂ injected across strategies—a sophisticated site operator likely would inject more CO₂ under the Afterthought strategy than under the Indifferent strategy, to both (a) yield the same amount of oil as the Indifferent strategy; and (b) store CO₂ in the formation.

²² Bielicki (2008) states:

Each segment of the CCS chain – capture at source, transportation in pipeline, and storage in reservoir – can benefit from increasing returns to scale, but the coupling of the technological cost structures over space determines the returns to scale for the overall system.

He finds further that capture costs typically are the largest cost component of integrated CCS systems (Bielicki 2008). Because our analysis compares strategies after the point of capture, we find that our analysis is more sensitive to the revenues than to the costs of each strategy. We found that results generally were not sensitive to even large shifts in the range of transportation, injection, and monitoring costs across strategies.

²³ Patiño-Echeverri et al. (2007) contains a detailed discussion of power-plant capture technology options.

²⁴ Although several EOR operations currently use naturally occurring pockets of CO₂ instead of anthropogenic sources, this is not necessarily a requirement for all EOR operations (Anderson and Newell 2004).

For strategies that recover oil, we assume that the injected CO₂ is not recycled.²⁵ EOR operations in the past have recycled CO₂ returned to the surface with oil recovery in order to save on CO₂ costs (White et al. 2004).²⁶ In this regard, we assume that any return of injected CO₂ to the surface occurs only as a result of leakage across the lifetime of the project.²⁷

5. Model Results: Transitions from EOR to GS

Each strategy yields separate lifetime net revenues based on the different ORRs, LLRs, and total costs outlined in Section 4. As would be expected, all four strategies yield different lifetime net revenues under various scenarios of oil and CO₂ prices. Several figures in this section present particular combinations of ORRs, LLRs, and total costs. These combinations include (a) “Best-Case EOR”; (b) “Best-Case GS”; and (c) “Best-Case Hybrid EOR-GS.”²⁸ Each named combination highlights particular combinations of ORRs, LLRs, and total costs that are most favorable to EOR operations, GS operations, or hybrid EOR-GS operations, respectively, under most scenarios of oil and CO₂ prices.

We illustrate the results of this model in two ways. First, we present results for these particular combinations under scenarios of oil prices up to 100 USD/barrel and CO₂ prices up to

²⁵ Because we assume that CO₂ is not recycled in the EOR process, we assume further that the energy costs (and related CO₂ emissions) associated with injection and re-injection processes are not included in the analysis.

²⁶ Experience from the Weyburn reservoir has shown CO₂ recycling to return approximately 20% of the CO₂ originally injected for further use (White et al. 2004). Because CO₂ recycling currently is used at several EOR sites, we infer that recycling and re-injecting a unit of CO₂ is cheaper than acquiring a “new” unit of CO₂ from the source pipeline. Because this analysis ignores CO₂ recycling, we believe our cost estimates are conservative, as all CO₂ injected originates from the source pipeline. We also note that our ORR estimates are undisturbed, because the ORR is a function of CO₂ injected, regardless of whether that CO₂ came from the source pipeline or through recycling.

²⁷ This return of CO₂ to the surface would be the result of the leakage pathways described earlier. This assumption may appear inconsistent with current miscible EOR operations, in which CO₂ returns to the surface with the recovered oil (*i.e.*, we would underestimate the amount of CO₂ injected as part of a hybrid EOR-GS operation, because additional CO₂ would need to be injected to supplement the CO₂ returned to the surface as part of the EOR operation). However, we note that CO₂ recycling is ignored in this model (*i.e.*, we would overestimate the amount of CO₂ injected as part of a hybrid EOR-GS operation, because we do not account for the reuse of CO₂ for the EOR operation and ultimately stored as part of the GS operation). Taken together, these two assumptions may partially offset the bias that each introduces individually. However, we note in this regard that the particular impact of these assumptions may be subject to the variation in the site-specific characteristics of any formation.

²⁸ We do not identify any “worst-case” combinations. Instead we assume that the ORR, LLR, and total costs that are optimal for one combination are sub-optimal for other combinations.

250 USD/metric ton.²⁹ Second, we present results for these particular combinations under an expected long-term oil price and projected CO₂ prices under a climate-change policy over time. This second presentation method permits a temporal understanding of the shift from EOR to GS operations. We describe these results in the subsections below.

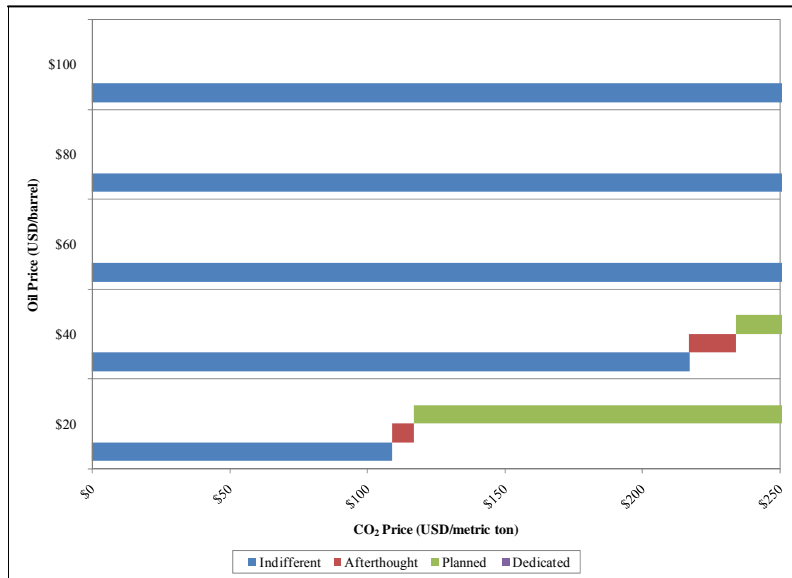
5.1 Model Results for Ranges of Oil and CO₂ Prices

This first set of results presents three combinations of ORRs, LLRs, and total costs, which we have termed (a) Best-Case EOR; (b) Best-Case GS; and (c) Best-Case Hybrid EOR-GS. In each figure, we present oil prices of 20, 40, 60, 80, and 100 USD/barrel, and CO₂ prices from zero to 250 USD/metric ton.

The Best-Case EOR combination is characterized by a high ORR, a high LLR, and low costs. This combination is illustrative of formations with generous oil recovery (where possible) and significant leakage across the board. The results for the Best-Case EOR combination are presented in Figure 2 below. It is apparent that any GS operation generates the greatest net revenues at low prices of oil (*i.e.*, less than 40 USD/barrel) and high prices of CO₂ (*i.e.*, greater than 100 USD/metric ton).

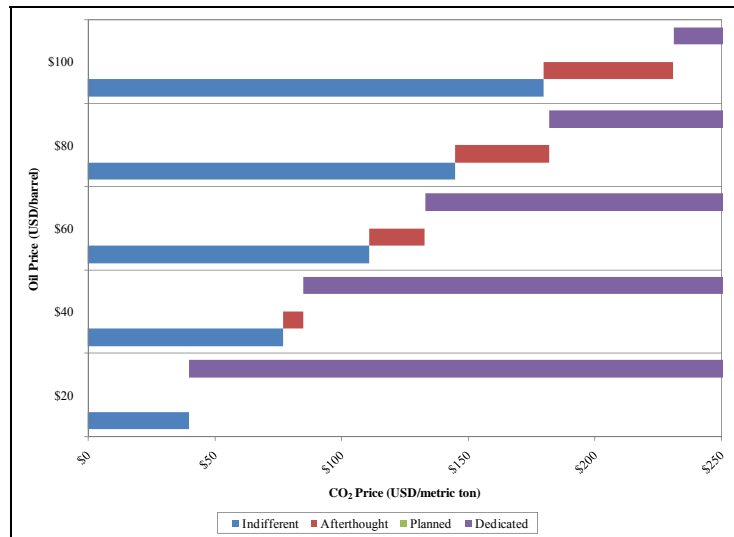
²⁹ Although in recent history oil prices have exceeded the 100 USD/barrel considered here, our analysis reveals that the Indifferent strategy is dominant for oil prices greater than 100 USD/barrel. Therefore, we limit our presentation and discussion of results to oil prices between 20 and 100 USD/barrel.

Figure 2: Best-Case EOR (high oil output, high leakage, low cost)

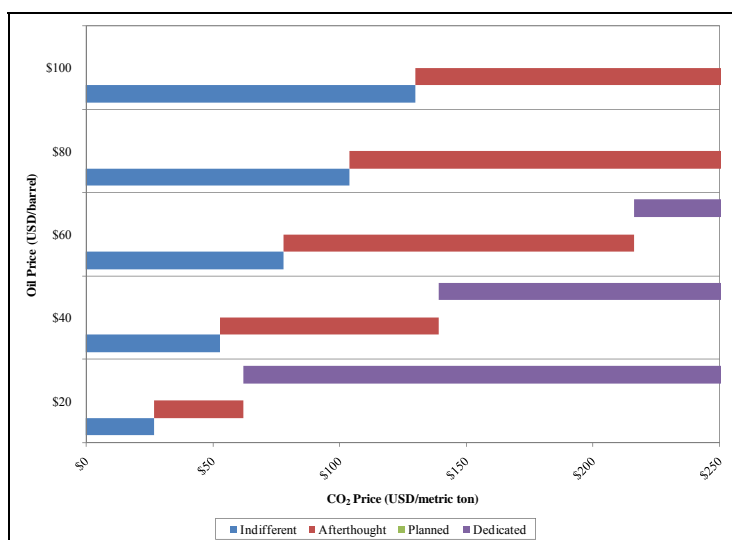


The Best-Case GS combination is characterized by low ORR, high LLR, and high costs. This combination is illustrative of formations with little oil recovery (where possible) and insignificant leakage across the board. The results for the Best-Case GS combination are presented in Figure 3 below. It is clear that GS operations in this combination generate the greatest net revenues at relatively lower CO₂ prices compared to the Best-Case EOR combination for a given price of oil. The Best-Case GS combination also demonstrates that it is possible to “skip” strategies—e.g., at an oil price of 20 USD/barrel, the most preferred strategy “jumps” from Indifferent to Dedicated near 50 USD/metric ton of CO₂.

Figure 3: Best-Case GS (low oil output, high leakage, high cost)



The Best-Case Hybrid EOR-GS combination is characterized by low ORR, low LLR, and low costs. This combination is illustrative of formations with little oil recovery (where possible) and insignificant leakage across the board. This combination also has low costs, as opposed to the high costs that characterize the Best-Case GS combination. The results for the Best-Case Hybrid EOR-GS combination are presented in Figure 4 below. It is interesting that hybrid EOR-GS operations in this combination generate the greatest net revenues at relatively lower CO₂ prices than the Best-Case GS combination.

Figure 4: Best-Case Hybrid EOR-GS (low oil output, low leakage, low cost)

Given the volatility and recent spikes in oil prices, low oil prices appear unlikely to be the norm in the long run. DOE projections show oil prices ranging from approximately 70 to 130 USD/barrel for the years 2010 to 2035 (DOE 2010a).³⁰ For this range of oil prices, the Afterthought strategy becomes most profitable at approximately 100 USD/metric ton of CO₂ in the Best-Case Hybrid EOR-GS combination. The Dedicated strategy becomes most profitable at approximately 150 USD/metric ton of CO₂ in the Best-Case GS combination. This first collection of results suggests that merely “putting a price on CO₂” likely will not provide a sufficient financial incentive to promote the widespread deployment of GS operations.³¹

5.2 Model Results for Expected CO₂ Prices under a Climate Policy

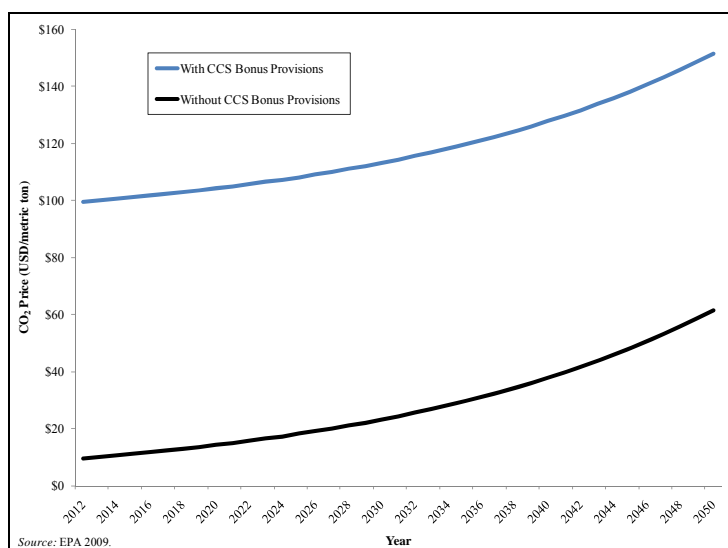
To focus our understanding of the transition from EOR to GS operations over time, we limited the analysis to oil and CO₂ prices estimated in governmental projections. Oil-price projections are based on DOE estimates, and the results for a long-term oil price of 70

³⁰ Projections are from the “Reference Case” and provided in 2008 USD.

³¹ This finding is consistent with the capture-related findings contained in Patiño-Echeverri et al. (2007)—higher prices of CO₂ are required to incent the installation of CO₂ capture technologies on coal-fired power plants.

USD/barrel are presented here.³² CO₂-price projections are based on EPA estimations of the American Clean Energy and Security Act of 2009 (ACESA).³³ In this second set of results, we provide results for two projections of CO₂ prices: (a) estimated CO₂ prices under ACESA,³⁴ and (b) estimated CO₂ prices with our inference on the CCS-specific bonus provisions outlined in ACESA.³⁵ These two CO₂ price projections are presented in Figure 5 below.

Figure 5: CO₂ Price Projection under ACESA with our Inference on CCS Bonus Provisions



³² DOE projections show oil prices ranging from approximately 70 to 130 USD/barrel for the years 2010 to 2035 (DOE 2010a). Based on the first set of results for ranges of oil and CO₂ prices, GS expectedly becomes less financially attractive as the long-term price of oil rises. Therefore, we present the projected oil price most favorable to GS, in recognition that anything greater makes the transition from EOR to GS less financially attractive for a given price on CO₂.

³³ Also informally known as the “Waxman-Markey” climate bill.

³⁴ The price path from EPA’s IGEM model of EPA Scenario 2 of the bill (EPA 2009).

³⁵ Section 786 of the bill outlines provisions for bonus allowances related to CCS operations (S. 1 2009). For the first six gigawatts (GW) of CCS projects deployed under the bill, operators can receive a bonus of up to 90 USD/metric ton of CO₂. If operators capture less than 85 percent of the emitted CO₂, the bonus is adjusted downward. The bonus also can be adjusted downward if the captured CO₂ will be used for the purposes of EOR as opposed to GS. To incorporate the CCS bonus provisions into our analysis, we add 90 USD/metric ton to the CO₂ prices estimated by EPA for all years, with the understanding and caveat that this is a generous interpretation of the CCS bonus provisions regarding CO₂ prices.

For these two CO₂ price projections, we present results for the years 2012 to 2050 for each of the Best-Case combinations, which include (a) Best-Case EOR; (b) Best-Case GS; and (c) Best-Case Hybrid EOR-GS. Results for all three Best-Case combinations under the two CO₂ price projections are presented in Figure 6 below.

Figure 6: Results for Best-Case Combinations for CO₂ Price Projections under ACESA

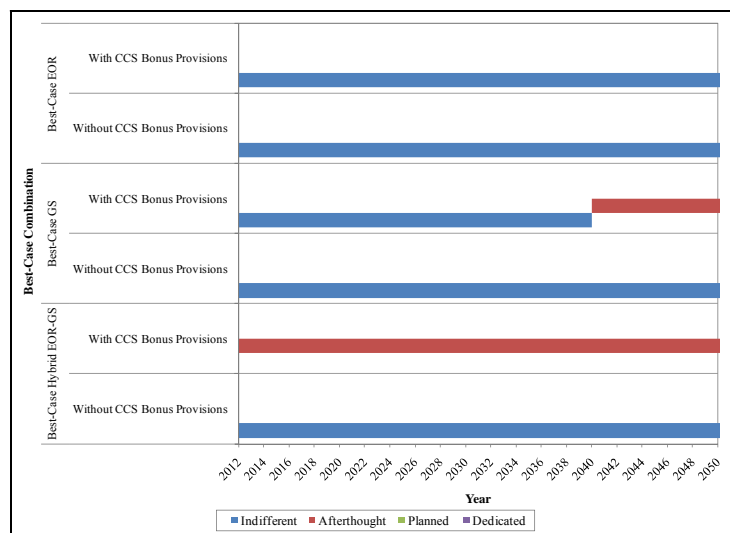


Figure 6 illustrates the challenge associated with designing appropriate incentives for GS deployment. Given a price on CO₂ without CCS bonus provisions, the Indifferent strategy is dominant across all three Best-Case combinations. Given a price on CO₂ and CCS bonus provisions, the Indifferent strategy remains dominant for one of three Best-Case combinations (*i.e.*, Best-Case EOR). The Afterthought strategy dominates in only the Best-Case GS and Best-Case Hybrid EOR-GS combinations with CCS bonus provisions. Further, the Afterthought strategy dominates only the Best-Case GS combination for the later period of the CO₂ price projection. The Planned and Dedicated strategies are not dominant for any period of the CO₂ price projections under any Best-Case combination.

The timing of these transitions under our optimistic interpretation of the ACESA CCS bonus provisions suggests that GS-related strategies might require substantial incentives to support near-term deployment. As Figure 6 illustrates, lower prices of CO₂ are unlikely to spur widespread investment in GS. Instead, CO₂ prices must reach levels much higher than the prevailing prices in current carbon markets like the ETS (PointCarbon, Inc. 2008). This finding suggests that CCS bonus provisions are a critical component of any climate and/or energy policy

that seeks widespread GS deployment. This finding also is consistent with the relationship of the largest GS projects currently in operation (*e.g.*, the Sleipner, Weyburn, and In Salah operations) to oil or gas extraction.

6. Conclusions and Policy Implications

This analysis illustrates the challenge of designing policies for GS given the diversity of project types and risks associated with the option. Although EOR operations can serve as a technical foundation for GS in many respects, foregoing oil recovery to store CO₂ in deep saline aquifer formations can be costly. Our dominant-strategy approach indicates that oil prices have a far greater impact on total net revenues than both project costs and the storage integrity of the site (*i.e.*, the LLR). In the absence of very high prices of CO₂ (*i.e.*, greater than 200 USD/metric ton), our analysis indicates that GS operations likely may co-exist with EOR operations for some time, even under more favorable conditions to dedicated GS operations.

These results suggest that a price on CO₂ is needed for any deployment of GS, although early prevailing prices of CO₂ likely will incent only hybrid EOR-GS operations, if that. Generous bonus provisions for CCS are needed to encourage dedicated GS operations. Even with the CCS bonus provisions as proposed in ACESA, the near-term GS deployment likely would consist primarily of hybrid EOR-GS operations. Higher oil prices further diminish the financial motivation to forego oil recovery completely for a dedicated GS operation, making stand-alone GS operations unlikely to dominate the investment decisions of sophisticated site operators in the near term.

These results have serious implications for risk management and regulatory design. Near-term deployment of mostly hybrid EOR-GS operations may require more stringent regulations due to the potentially greater risk of leakage associated with storage in depleted hydrocarbon reservoirs. Similarly, a regulatory framework designed to address all GS projects must address the different probabilities and/or potential types of leakage associated with different storage formations. This suggests a need for tiered standards or targeted regulation based on the storage formation and/or the operational goals of the project, both to reduce investment uncertainty and to address varying long-term liabilities associated with different project types. (With regard to the current EPA UIC proposal, reapplication as a Class VI well should be required for any well that initially was permitted as a Class II well in order to begin GS operations.) At minimum, these findings warrant caution in merely extending the regulatory framework of EOR operations to GS operations without careful scrutiny.

Widespread deployment of GS currently is difficult, for several reasons beyond reaching various “trigger” prices of oil and CO₂. For example, other barriers include (a) the uncertainty surrounding the long-term behavior of injected CO₂ underground; (b) related geophysical, health, and environmental risks to underground CO₂ migration; and (c) ambiguity over long-term stewardship of the site. Regardless, an understanding of the transition from EOR to GS operations is essential for designing effective regulations that ensure both investment in and long-term public acceptance of GS as a major climate-change mitigation option. Our analysis addresses this potential co-evolution of EOR and GS projects, demonstrating how profit maximization under different strategies and various price scenarios may shape the deployment of an emerging technology in an uncertain regulatory environment.

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