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Energy Procedia 4 (2011) 2361–2368
Energy Procedia
www.elsevier.com/locate/procedia

GHGT-10

A quantitative comparison of the cost of employing EOR-coupled CCS supplemented with secondary DSF storage for two large CO_2 point sources

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Abstract

This paper explores the impact of the temporally dynamic demand for CO_2 for CCS-coupled EOR by evaluating the variable demand for new (i.e., non-recycled) anthropogenic CO_2 within EOR projects and the extent to which EOR-coupled CCS is compatible with the need for baseload CO_2 storage options for large anthropogenic point sources. A profile of CO_2 demand over an assumed EOR project lifetime is applied across two different storage scenarios to illustrate the differences in cost associated with different EOR-coupled CCS configurations. The first scenario pairs a single EOR field with a DSF used to store any CO_2 that is not used to increase oil recovery in the EOR field; the second scenario is designed to minimize storage in the DSF and maximize lower-cost EOR-based storage by bringing multiple EOR projects online over time as the previous project's CO_2 demand declines, making the source's CO_2 available for a subsequent project. Each scenario is evaluated for two facilities, emitting 3 and 6 $MtCO_2$/y. Annual and lifetime average CO_2 transport and storage costs are presented, and the impact of added capture and compression costs on overall project economics is examined.

The research reported here suggests that the cost of implementing a CCS-coupled EOR project will be more than is typically assumed; in many cases a positive price on CO_2 emitted to the atmosphere will be required to motivate deployment of these CO_2-based EOR projects, except in the most idealized cases. The reasons for this conclusion are twofold. First, the costs of capitalizing, operating and monitoring a secondary DSF to provide backup storage for CO_2 not demanded by the EOR operation can cut sharply into EOR revenues. Second, except in cases where a single firm figures both the CO_2 source emissions and the associated EOR recovery on the same balance sheet, the oil production company is not likely to share a significant portion of revenues from the EOR field with the CO_2 source. Thus, while EOR-coupled CCS may offer attractive early opportunities, these opportunities are likely only available to a small fraction of the CO_2 source fleet in the U.S.

Keywords: CCS; EOR; deep saline formation; economics

doi:10.1016/j.egypro.2011.02.128

1. Introduction

To date, many studies of the cost of employing carbon dioxide capture and storage (CCS) at regional or national scales assume that (1) large anthropogenic CO_2 point sources will be paired with a single reservoir class for the duration of their operational lifetimes; (2) all of the potential storage capacity for a given formation is available immediately; and (3) the injection rate into the deep geologic formation will remain constant over time. These simplifying assumption are likely valid for deep saline formations (DSFs) with large capacities and good injectivities. However, as discussed by Dahowski and Bachu [1], storing CO_2 in a field undergoing CO_2 flooding for enhanced oil recovery (EOR) is subject to a set of constraints to which storage in DSFs is not. In particular, the variable demand for new (i.e., non-recycled) CO_2 may strongly influence the ability of an EOR field to serve as a baseload storage option for commercial scale CCS projects undertaken as a means of addressing climate change mitigation targets.

Demand for newly sourced CO_2 for a tertiary oil recovery project – i.e., CO_2 derived from the anthropogenic source rather than recycled from the EOR field itself – is likely to be highest in the early months and years of an EOR flood; demand will diminish markedly as CO_2 breaks through at the production well, requiring CO_2 separation and recycling back into the injection pattern, and demand for new CO_2 will eventually drop to zero once the EOR project's declining CO_2 demand can be satisfied entirely by recycled CO_2. Both [2] and [3] explicitly reference this changing temporal demand for new (i.e., non-recycled) CO_2. While each EOR project will be unique and exhibit a different CO_2 response based on reservoir-specific characteristics, project design, and operation, Figure 1 illustrates the general pattern of high initial demand for new CO_2 quickly decreasing as recycled CO_2 is used for an increasingly large portion of the total injection volume. This behavior is consistent with most current CO_2-EOR practices and is critical to understanding the impact on commercial-scale CO_2 storage in EOR fields.

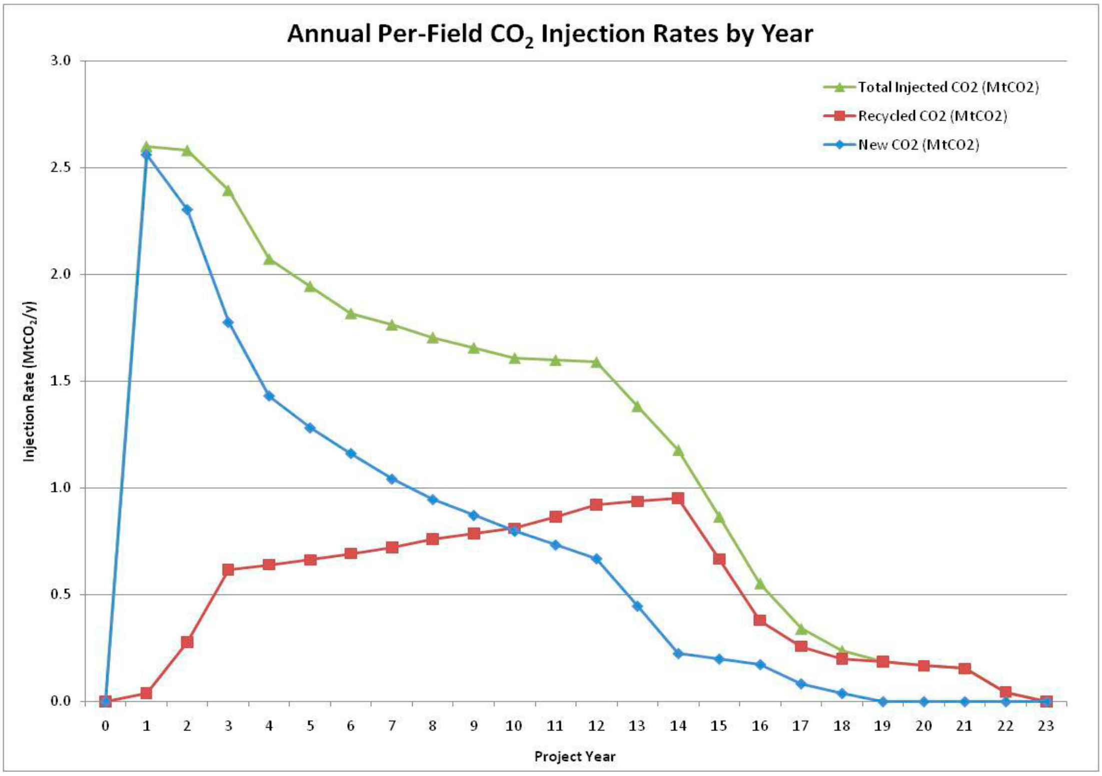

Figure 1. Annual CO_2 demand for a single EOR project as applied for this study (after Jarrell, et al. [4]).

While EOR-based CO_2 storage is attractive because of its potential for incremental oil recovery and associated revenues, industrial sources seeking to store their CO_2 are expected to optimize their own output – electric power, refined fuels or cement, for example – based on demand for that product, rather than an EOR project's fluctuating demand for CO_2 at any moment in time. Thus, it is reasonable to expect that the CO_2 flow rate from an anthropogenic source is unlikely to match the CO_2 demanded by the EOR field for any meaningful fraction of the duration of the source's design lifetime. Based upon this assumption, it is also reasonable to assume that, because the industrial source's CO_2 storage is motivated by an economic disincentive associated with emitting that CO_2 to the atmosphere, the variable rate at which CO_2 is demanded for the EOR project will necessitate a secondary, backup storage formation to avoid venting CO_2 not demanded by the EOR operator, and thus avoid the economic penalty[1].

Though the backup DSF may well be co-located with the EOR field being used for value-added CO_2 storage, the costs associated with the infrastructure requirements and management of a second storage reservoir are non-trivial. These costs have typically been omitted in per-ton storage costs for EOR-based CO_2 storage [5-7], resulting in an underestimation of the costs of operating an EOR-coupled CCS project, as well as an overestimation of the potential these types of projects may hold as early CCS deployment opportunities.

By modeling the cost impacts associated with the need for a backup DSF for the storage of excess CO_2, this work develops levelized per-ton and time-dependent storage costs for several scenarios to present a more realistic range of costs for EOR-coupled CO_2 storage that will in turn inform a more effective evaluation of the potential for early opportunities for EOR-based CCS deployment.

2. Methodology

The characteristics of the set of potential EOR-coupled CCS projects is likely to be extremely diverse. In this context, it is impractical to attempt to model individual scenarios that closely approximate a large fraction of the projects likely to be deployed. However, in this study, the authors have attempted to present scenarios such that the factors of interest here – in particular, the fraction of CO_2 being stored in a value-added EOR field versus the fraction being stored in a deep saline reservoir – are evaluated as endmembers of the potential spectrum of projects likely to deploy, while other highly site-dependent factors have been selected to generalize a field that is representative of those likely to be encountered for commercial EOR projects with a CO_2 storage component.

To accomplish this, "representative" reservoir characteristics were selected as typical for both a candidate EOR reservoir and its supplemental DSF, and these two representative storage formations formed the basis of the study. Representative reservoir parameters are based in part on assumptions presented by the authors in previous studies [5, 6] and are shown in Table 1.

Table 1. Assumed characteristics for reservoirs evaluated in this study.

Parameter	EOR Project(s)	Deep Saline Formation
Depth	1000 m	1500 m
Thickness	20 m	100 m
Effective Porosity	10%	10%
Per-Well Injection Rate	21,000 tCO_2/y	200,000 tCO_2/y
Oil Recovery Rate	1.74 bbl/tCO_2	n/a
Distance to Storage Site	100 km	100 km

EOR Project Demand for CO_2

For the scenarios analyzed in this study, it was necessary to understand the volume of CO_2 demanded by the EOR project(s) in any given time period to accurately represent the fractional volume of CO_2 going to the EOR field or the DSF, and associated economic impacts to the project. Because the demand for CO_2 over the course of a project's lifetime is heavily dependent upon parameters derived from data products that are both proprietary and

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[1] While this work is agnostic regarding the mechanism(s) by which CO_2 is valued in macro- and microeconomic decisions, for the purposes of this analysis, the effect of a CO_2 tax or a cap and trade system is the same. Either framework would establish a monetary penalty for emitting a given ton of CO_2 and thus alter the underlying production economics with respect to a world that has no climate policy.

business sensitive, there is a paucity of demand profile data presented in both the peer reviewed and gray literature. One of the few examples, and the one selected for this study, is the curve presented by Jarrell, et al. [3], which we have generalized – both by extrapolating per-pattern rates to per-project rates and smoothing Jarrell's periodic demand to reflect annual demand – as shown in Figure 1. Though the Jarrell monograph does not explicitly cite the source of these data, the authors of that document suggest that the curve is representative of demand for CO_2 within the EOR fields of the Permian Basin, in West Texas, USA. Our modeling suggests that a large portion of EOR-coupled CCS deployment in the U.S. is likely to take place in West Texas [5], suggesting that the curve shown in Figure 1 is a suitable starting point for evaluating the economics of EOR-coupled CCS deployment.

Scenario-Specific Assumptions

In order to understand the range of likely average storage costs for EOR projects where excess CO_2 supply must be stored in a DSF in order to avoid paying emissions penalties, the authors have chosen two scenarios that represent either end of the likely cost spectrum for a given project. In the first scenario, a single EOR field is paired with a DSF, and the economic impacts of this storage configuration are examined for both the 3 $MtCO_2$/y high-purity source and the 6 $MtCO_2$/y low-purity source. In the second scenario, intended to represent a more idealized storage case, multiple co-located EOR project areas are assumed to exist and are utilized for storage with project start-dates staggered to optimize for low-cost EOR-based storage and to better align demand for CO_2 with supply over the course of the CO_2 source's design life. The two endmember scenarios are defined below.

Scenario A: Single EOR project with a backup DSF – Under this scenario, both sources are paired with a single EOR project and all CO_2 not demanded by the EOR field in any given year is stored in a co-located DSF. While the DSF and EOR reservoirs may be stacked, this analysis assumes that separate injection wells and wellfield infrastructure are required for each reservoir regardless of proximity. However, economies of scale associated with stacked reservoirs have been accounted for in both the characterization and transport costs under this scenario. Characterization costs for the more expensive of the two reservoirs are assumed to cover both the EOR field and DSF[2]. For the reservoirs described in Table 1, calculated characterization costs [6] were highest for the EOR fields, primarily because the thinner reservoirs employed for EOR result in larger plume areas, increasing the per-volume footprint and thus any area-dependent costs, including characterization; characterization costs for DSFs are omitted to account for cost savings associated with characterizing both reservoirs at the same time. Similarly, because the two reservoir injection fields are assumed to be co-located, transport from the CO_2 source to the storage site is assumed to be via a single pipeline despite the use of two different storage reservoirs. All costs are calculated using peak flow rates over the lifetime of the project to ensure that facilities are built to meet the project's needs in all time periods. All other costs and revenues accrue to the project as described by Dahowski, et al. [6].

Scenario B: Multi-staged EOR projects with a complementary DSF – This scenario assumes a highly idealized case under which every available tonne of CO_2 possible is squeezed into an EOR field, per the constraints imposed by the EOR demand curve given in Figure 1, and DSF-based storage is minimized. The CO_2 source is initially paired with a single EOR project and DSF, as in Scenario A. However, once the annual volume of excess CO_2 available from the source (i.e., the volume of CO_2 not demanded by the first EOR project) is sufficient to meet the annual demand from a second EOR project (with demand per Figure 1), a second project is assumed to come online in response to increased CO_2 availability. This process continues until the CO_2 produced by the plant is insufficient to satisfy the CO_2 requirements for every year of an additional EOR project. As in Scenario A, all CO_2 not demanded by EOR fields in a given year is stored in the co-located DSF. This scenario uses the same transport and characterization costing employed in Scenario A. And as in the previous case, the DSF as well as individual EOR projects are expected to incur full costs for injection and production infrastructure, and project costs are calculated

[2] Characterization costs discussed in this paper do not include additional costs associated with primary or secondary oil production. However, some data developed during these phases of production are likely to be applicable when evaluating the field for tertiary recovery as well as long-term CO_2 storage. Still, between new data needed to optimize production and ascertain long-term storage security in the EOR reservoir as well as additional data acquisition and analysis in the deep saline formation, significant new costs associated with field characterization are likely to be incurred by the project operator. For this reason, the authors believe that characterization costs in these fields cannot be entirely neglected.

using maximum instantaneous flow rates. This assumption allows infrastructure to be sized to meet maximum demand, though it also implies that capital is being employed at less than full capacity in most time periods.

Scenarios A and B were each evaluated for two CO_2 source types. Source 1 is a large, low-purity source (e.g., a power plant) emitting 6 $MtCO_2$/y. Source 2 is a smaller, high-purity source (e.g., a natural gas processing facility) emitting 3 $MtCO_2$/y. These source configurations were selected because they are fairly representative of the types of facilities likely to employ CCS in the United States and in areas near oil fields with EOR potential. The modeled projects have differing flowrates and CO_2 stream purities in order to highlight the economic impacts of economies of scale associated with transport and injection infrastructure and the impact of capture and compression requirements on average per-ton costs for each project and scenario.

3. Results and Discussion

Table 2 presents a summary of the modeled assumptions and costs resulting from the analysis discussed above. Case names (A1, A2, B1 and B2) reflect the scenario designations modeled (A: single EOR project with DSF or B: optimized EOR projects with DSF) and source (1: large or 2: small). All costs are presented in 2005 dollars. For each scenario, injection project costs for both the EOR and DSF reservoirs were estimated per the reservoir characteristics described in Table 1 as well as the scenario- and source-specific parameters listed in Table 2. Levelized storage costs for EOR fields include offsetting revenue derived from incremental oil production, valued using a market oil price of \$58.83/bbl. The per-tonne EOR costs are negative across all cases, but particularly so for the B cases, where EOR-based storage is maximized by the use of multiple, staggered EOR projects with each additional project deployed as soon as enough CO_2 is available from the source to supply a new field per the demand curve shown in Figure 1. These decreased EOR-based storage costs are the result of higher oil recoveries and increased economies of scale resulting from production capital costs being amortized over more tonnes of CO_2 being stored into EOR field, and this is primarily driven by economies of scale in CO_2 recycling costs. In the absence of offsetting revenues, and because they must be sized in all cases to accept the maximum flow rate from the CO_2 source, levelized DSF costs are the same across scenarios for the two source types – \$3.70/tCO_2 for the smaller source and \$2.45/tCO_2 for the larger source, reflecting economies of scale associated with injection infrastructure.

Table 2. Selected case-specific assumptions, estimated storage volumes and per-tonne costs

Parameter	A1	A2	B1	B2
Flow rate ($MtCO_2$/y)	6	3	6	3
CO_2 source design lifetime (years)	50	50	50	50
EOR projects used for storage	1	1	11	3
DSFs used for storage	1	1	1	1
Lifetime CO_2 stored in EOR field(s) ($MtCO_2$)	17	17	115	50
Lifetime CO_2 stored in DSF ($MtCO_2$)	283	133	185	100
Levelized EOR transport & storage cost (\$/tCO_2)	\$ (34.06)	\$ (32.90)	\$ (53.16)	\$ (48.31)
Levelized DSF transport & storage cost (\$/tCO_2)	\$ 2.45	\$ 3.70	\$ 2.45	\$ 3.70
Lifetime average transport & storage cost (\$/tCO_2)	\$ 0.41	\$ (0.39)	\$ (31.71)	\$ (13.72)
Capture / compression costs (\$/tCO_2)	\$ 30.00	\$ 8.00	\$ 30.00	\$ 8.00
Lifetime average capture, transport & storage cost (\$/tCO_2)	\$ 30.41	\$ 7.61	\$ (1.71)	\$ (5.72)

Average Transport and Storage Costs

Average per-tonne costs – including lifetime averages presented above as well as annual averages presented in Figure 2 – were estimated as a function of the fractional volume of CO_2 stored in each formation type and the per-ton cost for that formation type:

$$\text{AVERAGE COST} = [\%CO2_{DSF} \text{ X } \text{COST}_{DSF}] + [\%CO2_{EOR} \text{ X } \text{COST}_{EOR}]$$

where $\%CO2_{DSF}$ and $\%CO2_{EOR}$ are the fraction of CO_2 stored in the DSF and EOR reservoir(s) respectively, and COST_{DSF} and COST_{EOR} are the scenario- and reservoir- specific levelized per-ton costs. Thus, the annual average transport and storage costs shown in Table 2 – ranging from -\$31.71/tCO_2 (Case B1) to \$0.41/tCO_2 (Case A1) – reflect overall per-tonne costs in a given year based on the proportion of storage being utilized at each cost level.

By this measure, case A1 has the highest per-tonne costs because the annual CO_2 supplied by the source is more than twice the CO_2 demanded by the single EOR project even in the project's highest demand year. The DSF accounts for well over 90% of the CO_2 stored under this case, diluting the impact of the much lower per-tonne EOR costs on the average transport and storage costs.

However, the same source also has the lowest average transport and storage costs – -\$31.71/tCO_2 – under the optimized scenario (B1), where the source was allowed to access as many EOR projects as it could supply over time. Under this scenario, the larger of the two sources was able to access a total of eleven EOR floods over the course of its 50-year lifetime, resulting in a higher fraction of its CO_2 being stored at EOR per-tonne costs than in any of the other cases evaluated here. In particular, because the larger source can supply CO_2 at a rate roughly double that demanded by the EOR formation, multiple projects were able to come online over a shorter period of time relative to B1. This is why the optimized case for the larger source is able to access eleven EOR projects, while the smaller source (B2) is only able to supply three projects, despite the larger source offering double the capacity of the smaller source.

By contrast, the smaller source is able to store a larger fraction of its CO_2 in the single-EOR formation case (A2) than the larger source, since both projects are storing identical volumes of CO_2 into the EOR project in this case. Variation in levelized transport and storage costs between A1 and A2 derive exclusively from the transport cost differences, which are slightly lower for the larger source due to economies of scale associated with per-ton pipeline costs. Average annual and cumulative per-ton costs for transport and storage under the four modeled cases are presented in Figure 2.

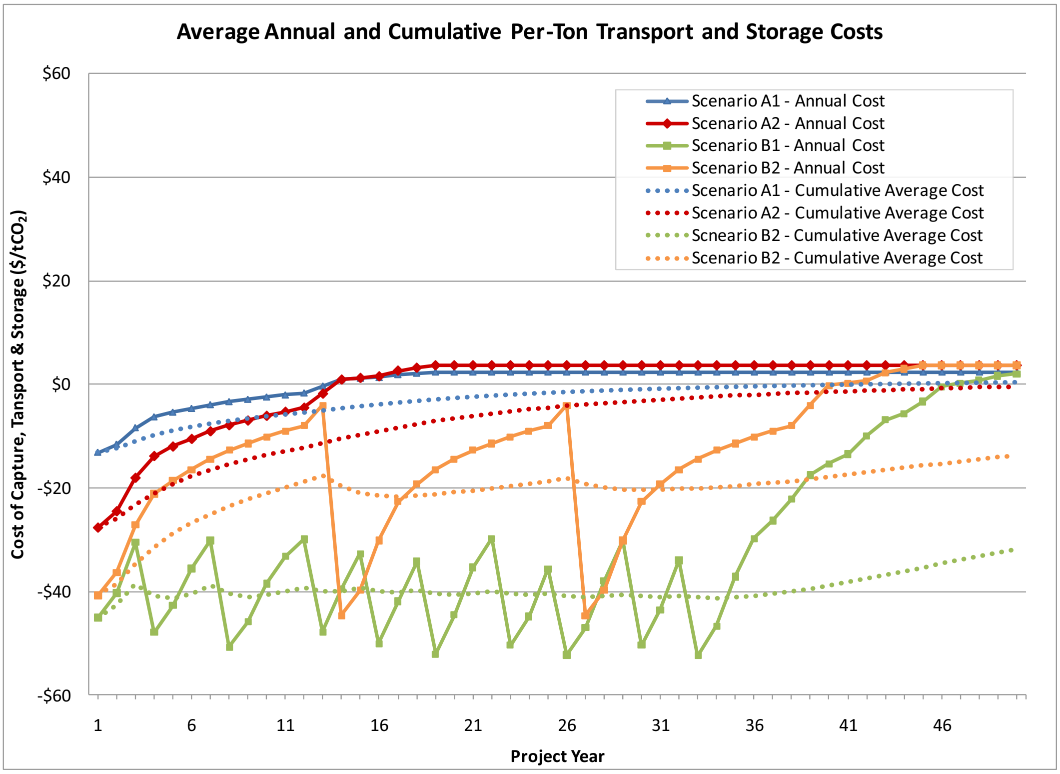

Figure 2. Annual and cumulative per-tonne transport and storage costs.

The Impact of Capture and Compression on Average Costs

Average transport and storage costs illuminate the cost impacts of project size and the fraction of CO_2 being stored in either the lower-cost EOR field(s) rather than the DSF. Capture costs add another layer of complexity because higher-purity CO_2 streams are less expensive to capture, and in some cases must simply be compressed to be readied for pipeline transport and storage. As discussed earlier, the two source types examined here were loosely categorized as low and high purity for Sources 1 and 2 respectively. To quantify the impact of capture and compression costs on overall average CO_2 storage costs for each of the four cases examined, costs were assumed to be \$30/tCO_2 (capture and compression) for the low-purity source and \$8/tCO_2 (compression only) for the high-purity source.

Figure 3 shows the same average costs (annual and cumulative) shown in Figure 2, but with capture and compression costs included in the per-tonne costs. This shifts each curve up, but for the A1 and B1 cases (lower-purity source) the curves shift up by \$30/tCO_2 while the A2 and B2 cases (higher-purity source) shift up only \$8/tCO_2. This has the effect of pushing costs for the A1 cases well beyond those for the other case, while A2, B1 and B2 converge. Of particular interest are the B1 and B2 scenarios; with the added capture and compression costs, the economies of scale experienced by the larger, high-purity source are all but negated by the difference in capture and compression costs. In fact, adding in these costs brings the average lifetime per-ton costs for these two cases to within just a few dollars of each other.

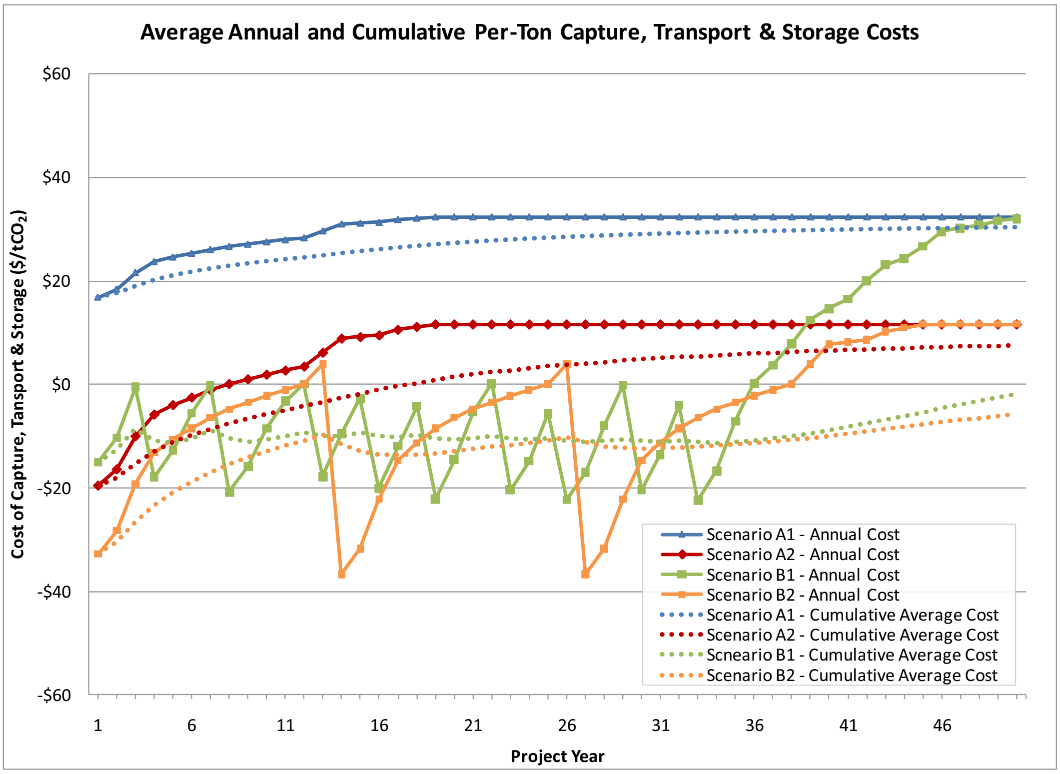

Figure 3. Average annual and cumulative per-tonne costs for CO_2 capture, compression, transport and storage.

4. Conclusions

While attempts to quantify the costs associated with various modes of geologic CO_2 storage at the national scale have proven both useful and necessary [8] for increasing our understanding of how CCS may deploy regionally, constraining these costs to reflect more realistic demand for CO_2 from EOR fields yields a more rigorous and realistic method for evaluating average per-ton geologic storage costs over the course of a CO_2 source's lifetime. Though societal costs – as defined by the system boundaries presented here – are still lower for projects utilizing an EOR formation for a portion of their CO_2 storage relative to projects storing exclusively in DSFs, costs are unlikely to reflect a \$20-80/tCO_2 profit for every tonne of CO_2 injected into the ground for a project utilizing EOR-coupled storage. Indeed, even in the most idealized case presented here – assuming more perfect foresight and the ability to bring EOR projects online at a rate in step with the excess CO_2 supply – the cost signal associated with EOR revenues is likely to be dampened significantly by the additional expense of capitalizing and operating a second

DSF storage operation to ensure that the climate change mitigation (and, under a presumed climate policy, cost mitigation) goals of the CCS projects are met consistently over the lifetime of the industrial facility.

It is also important to note that, while this study presents societal costs – net storage costs that apply revenues associated with incremental oil production from the EOR portion of the project to offset capital and operating costs associated with the geologic storage portion of the project – it is unlikely under most scenarios that the revenues from additional produced oil will be shared with the CO_2 source operator. Thus, it is not reasonable to expect that a CO_2 source such as a power plant or cement facility will receive a significant share of the project's net savings – or a meaningful reduction in their cost of capture or cost per unit of output – for supplying CO_2 to the project. As more and more large, industrial sources capture and seek disposal options for their CO_2, the constrained resource – and thus the valued commodity – will become geologic storage space, rather than the CO_2 itself. In this case, with far more CO_2 on offer than demand for that CO_2 from EOR fields, EOR operators are highly unlikely to pay a significantly positive price for CO_2 from anthropogenic sources. There may be a premium for high-purity CO_2 or CO_2 delivered to the EOR field, but the likelihood that revenues from the sale of oil produced using anthropogenic CO_2 will actually be passed along to or shared with the producer of that CO_2 is extremely low.

The exception to this may be instances where each component of the project (CO_2 source, pipeline, and storage operations) is owned by a single company. For example, an oil and gas production company that uses CO_2 produced by its natural gas sweetening plant to inject into its EOR fields will likely incur the costs associated with the CO_2 storage operation as well as the revenues from the incremental oil produced via CO_2-EOR. In this case, where costs and revenues may literally appear on the same balance sheet, "societal" costs calculated using the method presented in this study may represent actual per-ton project costs for the CCS project, suggesting an opportunity for CO_2 storage at a negative cost, resulting in net per-tonne profit to the company. In most other cases, however, storage costs in any formation type are likely to be positive for CO_2 producers who do not operate their own EOR projects.

To the extent that there are economic benefits associated with EOR-coupled CCS projects, these projects still represent an appealing option by facilitating both the long-term storage of CO_2 in the subsurface and the production of oil that may otherwise be unrecoverable. However, even in the most optimistic of cases, many EOR-coupled CCS projects are unlikely to result in per-ton profits on the order of those discussed in the literature, even assuming a highly inclusive system boundary such as that used in this study. It is even less likely that the majority of individual CO_2 sources will be able to turn EOR-coupled CCS into a profit-making venture.

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