Supporting Information

Part 1: Cost Analysis of Carbon Capture and Storage from U.S. Natural Gas-fired Power Plants

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KEYWORDS

Carbon capture, avoided emissions, natural gas combined cycle (NGCC)

Cost Model: Baseline Assumptions

Table S1 outlines the baseline assumptions used in base case cost model, as well as the three configurations considered in this study. Variations in cost parameters are described below. All costs reported in constant USD 2017.

Table S1. Cost parameters used for the four cases under study. Variations occur due to changes in input CO_2 concentration and heat source quality.

Parameter	Value
IECM values	
CONFIGURE SESSION	
Plant type	NGCC
Configuration	Typical new plant
MEA Scrubber	amine system
Water and solids management	wet cooling tower
Plant Location	set to region of interest
PERFORMANCE	
Number of turbines	set to desired output (1 – 5)
Capacity factor	75%
REGULATIONS AND TAXES	
Total CO_2 removal constraint	90%
FINANCING AND COST YEAR	
Year costs reported?	2017
Constant or current dollars	constant
Discount rate (before taxes)	7.09%
Fixed charge factor	11.28%
Plant life	30 years
FUEL	
Natural gas cost	129.6 $/mscm
GAS TURBINE PERFORMANCE	
Gas turbine model	GE 7FB
RETROFIT ADJUSTMENT FACTORS	
All values	1.09
CO_2 CAPTURE, TRANSPORT, AND STORAGE	
System used	FG+
CO_2 product compressor used?	NO

Compression and Trucking

Due to the smaller volumes of CO_2 delivered in this analysis, refrigerated tanker trucking was selected as the mode of transport. This entails compression to approximately 1.7 MPa. The costing method is detailed meticulously in the work of McCollum and Ogden.[1] A 5-stage compressor train with dehydration and inter-stage cooling is employed to prepare the CO_2 stream for trucking transport (1.7 MPa and -30 °C). The inlet temperature at each stage is 343 K with compression ratio of 1.76 and isoentropic efficiency 0.75. Cooling to final transport temperature is achieved at 16.5 kWh/ tCO_2. The trucking model is based on the work of Berwick and Farooq[2], and outlined in detail by Psarras and collaborators.[3] It takes as inputs the overall volume of CO_2 to be delivered per route and total distance per route.

Learning through CO_2-EOR

Natural CO_2 fields provide the main source of CO_2 for current CO_2-EOR projects in the U.S. (~55 Mt CO_2 per year). Roughly 80% of the CO_2 used for CO_2-EOR activities in the U.S. comes from four major natural CO_2 fields, i.e., Jackson Dome, Sheep Mountain, McElmo Dome, and Bravo Dome. The remainder of the CO_2 used for CO_2-EOR projects (approximately 17 Mt CO_2 per year) is supplied from anthropogenic sources as previously discussed.[4] The costs of producing CO_2 from these natural sources is associated primarily with compression and pipeline transport. For tanker delivery, liquefied CO_2 is stored in cryogenic vessels and transported by tanker trucks with capacity ranging from 2 to 30 tonnes and CO_2 compressed to 1.7 MPa at -30 °C, which costs approximately \$6/tCO_2. On the order of 100s to 1000s of ktCO_2/yr transport, trucking costs are approximately \$0.14/tonne-mile. When considering loads greater than 750 ktCO_2/yr, pipeline transport becomes more economical at approximately \$0.07/tonne-mile. Based upon the current model, pipeline transport of CO_2 requires compression ranging from 9-15 MPa and temperatures between 10-35 °C, at an approximate cost of \$8/tCO_2.[3,5] The existence of these natural sources combined with the demand of CO_2 for EOR, provided the economic incentive to establish the majority of the CO_2 pipelines that exist in the U.S. today.

Enhanced oil recovery has been a commercial activity for nearing 50 years, with the first successful pilot-scale tests taking place in Texas in the early 1960s.[6] Based upon EOR activities and subsequent experience in the U.S., EOR using CO_2 has shown to increase the recovery of the original oil in place by up to 15%.[7] The way in which EOR is carried out in the U.S. today would not be considered negative or neutral since roughly 80% of the CO_2 used for EOR is sourced naturally from CO_2 that has been stored in the earth for millions of years, not unlike the oil and gas that are being recovered. Table S2[4,8] shows the volumes and sources of natural- versus anthropogenic-sourced CO_2 used for the various EOR projects in the U.S. today.

Table S2. Volume and source of CO_2 injected for EOR projects in the U.S. (adapted from [4,8])

Location	CO_2 source type	CO_2 supply (MMscfd)	
		Natural	Anthropogenic
Texas/Utah/New Mexico/Oklahoma	Geologically stored Natural gas processing	1730	335
Mississippi/Louisiana	Geologically stored	1100	-
Colorado/Wyoming	Natural gas processing	-	340
Michigan	Ammonia plant	-	15
Oklahoma	Fertilizer plant	-	30
Saskatchewan	Coal gasification	-	150
Total (MMscfd)		2830	870
Total (Mt/year)[a]		55	17

[a]MMscfd can be converted to Mt CO_2 per year by first multiplying by 365 (days per year) and then dividing by 18.9 Mscf per metric ton

In particular for MS-EOR, the net CO_2 utilization is 0.9 tCO_2/bbl of oil recovered with an incremental increase in oil recovery by 13%. Work of Hovorka (2013),[9] has shown that this level of storage may be possible by using CO_2 in a once-through system rather than recycling it, which is similar to the "stacked storage" approach used when injecting CO_2 into a saline aquifer. Although the costs that CO_2-EOR producers typically pay for CO_2 is proprietary, it has been well established that it is tied to oil prices and are generally found to be in the range of several dollars per thousand standard cubic feet (Mscf). At oil prices of \$70/bbl, it has been reported that contracts were priced at \$30/tCO_2.[10] Also, the CO_2-EOR producers who own the geologic formations that naturally store CO_2 (e.g., Denbury Resources, Kinder Morgan, and Occidental Petroleum), pay significantly less for the CO_2, i.e., several U.S. dollars per tonne at comparable oil prices.[11]

Geological Sequestration

Ideal reservoirs are typically located at depths greater than 1 km in the earth in order to maintain the CO_2 in its supercritical phase, and are comprised of porous rocks such as sandstone, limestone and dolomite, or mixtures thereof. The pore space of these reservoirs is filled by salty water, oil, or gas, which are denser than supercritical CO_2. The prevention of leakage thus requires the presence of a cap rock made of low permeability rocks, such as shale, anhydrite or low permeability carbonates. Ideal sequestration sites also require favorable geo-mechanical conditions to prevent reservoir or seal fracturing during injection, suitable conditions for monitoring, low likelihood of affecting groundwater, and compatibility with existing land and resource use.

Data regarding CO_2 storage were provided by the USGS Assessment of Geologic Carbon Storage Resources in the U.S. The capacity of each basin is the mean technically accessible CO_2 storage resource provided on the USGS website. Further details for the capacity calculation are provided in USGS reports.[12] Each basin is composed of one or several Storage Assessment Units (SAU), that can overlap geographically at different depths. The USGS defines SAUs as a "mappable volume of rock that consist of a porous reservoir." These porous reservoirs are sedimentary formations made of siliciclastic and carbonate rocks. The USGS identified 186 SAUs in 34 basins in the contiguous U.S. among which 176 SAUs in 31 basins have quantitative data. The dataset of quantitative SAUs includes the depth of the unit, its thickness h, its porosity $\emptyset$ and its permeability k. From these parameters provided by USGS and the parameters provided by Baik et al., 2018[12,13] (Table S3), the injectivity Q_{max} of each SAU was calculated using a radial Darcy's law for single-phase flow.[14]

$$Q_{max} = \frac{2\pi\, k\, h\, \Delta P_{max}}{\mu \log\left(\frac{r_e}{r_w}\right)} \quad \text{, with} \quad r_e = \sqrt{\frac{2\, k\, T}{\emptyset\, \mu\, C}}$$

$$\Delta P_{max} = \rho\, g\, d\, \alpha$$

Table S3. Parameters used for injection capacity estimation and pressure calculation[13]

Parameter	Description	Nominal value	Units
Q	Volumetric injection rate	Site-specific	$m^3 \cdot s^{-1}$
k	Permeability of the formation	Site-specific	m^2
h	Thickness of porous region in formation	Site-specific	m
ΔP_{max}	Pressure buildup at the injection well	Site-specific	Pa
μ	Dynamic viscosity of water	5.8×10^{-4}(at ~47°C)	Pa·s
T	Time frame for injection	30 yr ($= 9.5 \times 10^8$s)	s
∅	Porosity of formation	Site-specific	-
C	Compressibility of rocks	1×10^{-9}	Pa^{-1}
r_e	Radius of pressure influence	Site-specific	m
r_w	Tubing radius of the injection well	0.1	m
ρ	Density of water	1,000	$kg \cdot m^{-3}$
g	Acceleration of gravity	9.81	$m \cdot s^{-2}$
d	Depth to center of formation	Site-specific	m
α	Maximum allowable pressure differential	0.5	-

The calculation of the pressure gradient ΔP_{max}, assumes a 50% allowable pressure increase at the well bore (α = 0.5). The CO_2 injection wells are classified as class VI wells by the Environmental Protection Agency. The maximum injection pressure allowed for this type of well is 90% of the fracture pressure of the subsurface. The hydrostatic pressure gradient used in this study is about 10 MPa/km so the maximum pressure increase at the borehole is 5 MPa/km, corresponding to 90% of 5.5 MPa/km. The fracture gradient in this study is thus 15.5 MPa/km and corresponds to the lower end of the common fracture gradient range from 14 MPa/km to 23 MPa/km.[15]

The injectivity of each basin on the Figure S1 was calculated by averaging the injectivities of its SAU weighted by the volume of each SAU. The data for the CO_2 pipeline network were obtained from the Stanford University's Digital Repository.[16] Each basin contains several reservoirs called Storage Assessment Units (SAUs), that can geographically overlap each other at different depths. The USGS provides numerous parameters for each SAU including, depth, thickness, porosity, and permeability. Using the method described in Baik et al., 2018, the injectivities were calculated for each SAU. The results range from 23 ktCO_2/yr for the Eastern Mesozoic Rift Basin under New Jersey and Pennsylvania to 138,000 ktCO_2/yr for the Los Angeles Basin under California (Figure S1). Based on the work of Baik et al. (2018), injectivities below 250 ktCO_2/yr are not suitable for injection due to risks associated with demonstration-scale injection of CO_2 into low-injectivity reservoirs. The Eastern Mesozoic Rift, Paradox, Uinta and Piceance, Eastern Great, Black Warrior and Kansas basins are therefore discarded from the potential basins for injection. Uinta and Piceance basins have global injectivities lower than 250 ktCO_2/yr, but some of their SAUs are still over this limit and could be used for CO_2 storage (Figure 3 from manuscript). Overall of the basins considered in the contiguous U.S., 103 SAU are above the 250 ktCO_2 cut-off and may be suitable for CO_2 injection. If one were to drill only one well in each of the SAUs with CO_2 injection at maximum injectivity, the contiguous U.S. would have the ability of storing roughly 2 GtCO_2/yr or 40% of the annual emissions of the U.S. (2018 US CO_2 emissions ~ 5.3 Gt).

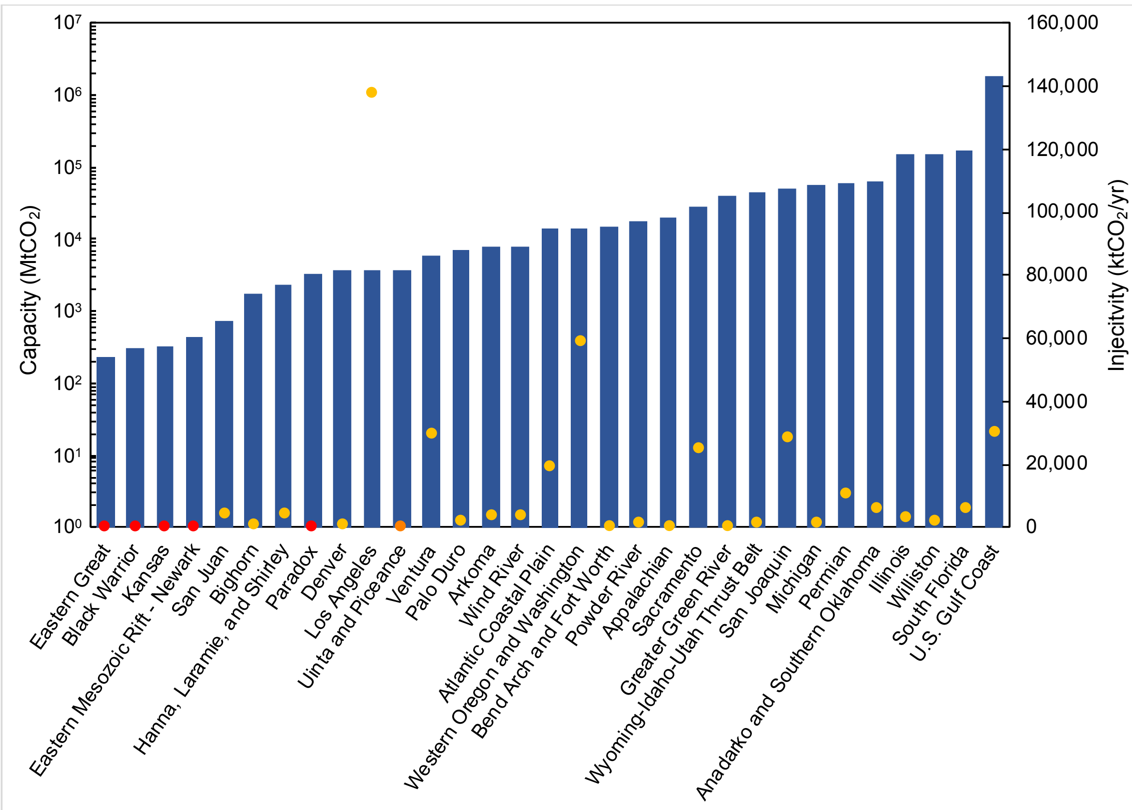

Figure S1. Capacity and injectivity of CO_2 in reservoirs assessed by the USGS for CO_2 sequestration in the contiguous U.S. Blue bars represent the capacity of each reservoir in MtCO_2. Dots represent the injectivity of CO_2 in ktCO_2/yr. The basins with injectivities over the cut-off of 250 ktCO_2 are represented by the yellow dots, while those with injectivities below the cut-off are represented by the red dots, and the orange dot represents the basin with global injectivity below the cut-off but with injectivity over the cut-off for at least one SAU.

Trucking Transportation is the Most Cost-Effective for Scales < 500 ktCO_2/yr

While large scale CO_2 transport is dominated by pipeline, transport economics begin to favor trucking at less than 500 ktCO_2/yr.[3] Since this describes the range of CO_2 output for the DAC plants considered in this study, trucking is selected as the mode of choice for transport between DAC plants and various end uses. A modal optimization (i.e., cluster identification and hub stationing) is not performed in this analysis but could be of use to identify ideal locations for infrastructure development.[17] The trucking model is based largely on the work of Berwick and Farooq (2003),[2] using updated fuel emission intensities, fuel costs, and labor costs. Liquefaction costs are assumed in the DAC plant capital and operating expenses, assuming conditions of 1.7 MPa and -30 °C.[5] Source-end use distances were obtained by performing an origin-destination distance matrix over a U.S. street network dataset. This set of distances together with the estimated CO_2 demand for each end use served as model inputs.

Trucking transport costs are controlled mainly by two factors: hauling capacity and distance traveled. At very low volumes (~ 5 ktCO_2/yr and below) costs are dominated by trucking lease or purchasing as hauling remains well below capacity. As delivery closes in on maximum capacity per truck (here constrained to 100,000 miles total travel per year), economies of scale are optimized, and costs are minimized. Figure S2 shows how increased load affects costs at fixed distance hauls of 20, 50 and 100 miles (one-way).

Maximum hauling payload per delivery is set at 20 tonnes CO_2. The number of roundtrips required is obtained by dividing the total volume to be delivered by the maximum payload. This factor, termed *payloads*, determines all variable operating expenses. For fuel consumption, a cost of \$0.3166 per mile is applied for the full truck (pre-delivery) and \$0.2468 per mile for post-delivery transit. Labor costs are calculated at \$20/hr and include time traveled, assuming an average speed of 38 miles per hour, and accounting for an additional hour in waiting time during CO_2 transfer from truck to on-site storage tanks (the cost of storage tanks and any associated on-site piping is not included in the model and assumed to be incurred by the host). Tire replacement and general vehicle maintenance is calculated at \$0.0477 and \$0.886 per mile traveled, respectively. The refrigerated tanker purchase price is \$175,000 and is serviceable for 5 years, with a hard-constrain of 100,000 miles traveled per year. Additional trucks must be added to the fleet for transport demands in excess of 100,000 miles total travel.

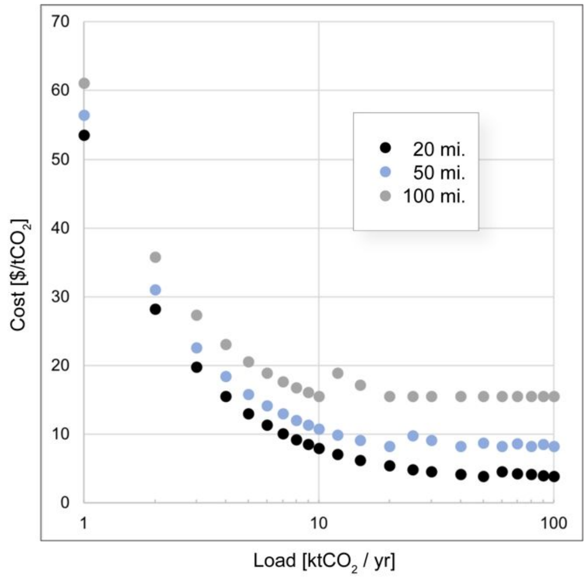

Figure S2. Cost of trucking transport as a function of load at fixed-distance hauls (20, 50, and 100 miles). At low volumes, costs are dominated by truck lease and purchasing. Costs converge to a minimum as hauling approaches capacity, where small cost bumps reflect the addition of trucks as justified by model constraints.

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