Final Scientific Report for

Recovery Act: 'Carbonsheds' as a Framework for Optimizing United States Carbon Capture and Storage (CCS) Pipeline Transport on a Regional to National Scale

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ABSTRACT

Carbonsheds are regions in which the estimated cost of transporting CO_2 from any (plant) location in the region to the storage site it encompasses is cheaper than piping the CO_2 to a storage site outside the region. We use carbonsheds to analyze the cost of transport and storage of CO_2 in deploying CCS on land and offshore of the continental U.S. We find that onshore the average cost of transport and storage within carbonsheds is roughly $10/t when sources cooperate to reduce transport costs, with the costs increasing as storage options are depleted over time. Offshore transport and storage costs by comparison are found to be roughly twice as expensive but t may still be attractive because of easier access to property rights for sub-seafloor storage as well as a simpler regulatory system, and possibly lower MMV requirements, at least in the deep-ocean where pressures and temperatures would keep the CO_2 negatively buoyant. Agent-based modeling of CCS deployment within carbonsheds under various policy scenarios suggests that the most cost-effective strategy at this point in time is to focus detailed geology characterization of storage potential on only the largest onshore reservoirs where the potential for mitigating emissions is greatest and the cost of storage appears that it will be among the cheapest.

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EXECUTIVE SUMMARY

Our overarching goal for this project was to use our concept of "carbonsheds" as a framework for optimizing CO_2 transport on an integrated technical, economic, societal and environmental basis. We define carbonsheds as regions in which the estimated cost of transporting CO_2 from any (plant) location in the region to the storage site it encompasses is cheaper than piping the CO_2 to a storage site outside the region. We developed the concept while evaluating the storage potential and costs associated with sequestering CO_2 in deep sandstone saline aquifers. Through this project, we broadened and improved our approach for defining carbonsheds and for understanding how these regions might evolve with time under different carbon mitigation scenarios.

Our specific objectives were to:

1. Include in our carbonshed analysis the other major types of potential CO_2 storage sites identified and catalogued by NATCARB, i.e. oil and gas reservoirs, and unmineable coal seams;
2. Examine the potential offshore extension of US carbonsheds were sub-seafloor CO_2 storage permitted;
3. Explore the impacts of different economic/policy scenarios (e.g., the Waxman-Markey Climate Bill) on the future demand for CO_2 transport with in different carbonsheds using agent-based socio-economic modeling.

We achieved all of our objectives during the project and have documented our research and findings in six manuscripts (four of which are published, one of which is in review, and one that is in preparation), one PhD dissertation, and one Masters of Science Thesis. The latter two publications were produced as a partial requirement for the degrees received by the PhD student (Dr. Jordan Eccles) and Masters student (Ms. Kristyn Hall) who were supported and trained by this project.

During the project, we:

- Developed general model that uses geologic data of candidate reservoirs to make rapid geospatial estimates of storage capacity and cost.
- Saw our storage capacity/cost model adopted by EIA for NEMS.
- Used the model ourselves to estimate storage capacities/costs of onshore saline aquifers, offshore sediments, and oil fields.
- Defined onshore and offshore carbonsheds in the continental U.S. for which we then estimated combined CO_2 transport and storage costs.

The principal findings of our work ordered by objective are as follows:

Objective 1 – We estimate that the average value of transport and storage when sources cooperate to reduce transport costs is roughly \$10/t, with costs decreasing as more storage reservoir options are included, and increasing as storage resources are depleted. Large, centralized reservoirs could form the backbone of a major carbon storage system in the United

States. Large-scale storage networks could be rapidly advanced by skipping fragmented early networks and moving to centralized systems at a relatively minor cost.

Objective 2 – Ocean storage is likely to be two or more times as expensive as onshore storage. The higher total offshore costs are due to a combination of increases in transport and storage costs, with transport costs dominating total costs with increasing distance from shore. The cost advantage of onshore storage over offshore storage may be mitigated by such offshore advantages as easier access to property rights, simplified regulation, and possibly lower MMV requirements.

Objective 3 – It may be significantly more cost effective at this point to focusing on detailed characterization of only the largest onshore geologic storage reservoirs. Policymakers may also consider underwriting the risk for long-term storage in these few reservoirs, or locally develop policies particularly favorable to property rights acquisition.

APPROACH

The methods and data we used to address our objectives are summarized below. The description of these methods and data come from our three most recent papers (Publications 4-6 in Appendix I), which are the ones that most directly and completely target our objectives. Note, however, that these manuscripts build on research that we completed earlier in the project (Publications 1-3 & 7-8, Appendix I). The latter addressed necessary intermediate steps towards our final objectives while also producing novel results that warranted publication in international peer-reviewed journals.

Objective 1: Onshore Carbonshed Analysis

Overview

Our method for mapping out carbonsheds is similar to that used for mapping out watersheds. Like watersheds, carbonsheds are discrete regions within larger land (or ocean) areas, such as the continental United States. Carbonsheds are defined not by topography, however, but by a cost surface in which every point on the surface has a combined cost of CO_2 transport and storage (See Fig 1).

In this analysis, our cost surface is a geo-referenced raster grid with cell areas of 1 km x 1 km. Each cell in the grid is assigned a cost of CO_2 transport and storage depending on its geographic location with respect to the CO_2 storage sites being considered. Grid cells that directly overlie a storage site are assumed to not need transport and so are only assigned a storage cost. Grid cells that occur around but outside of the storage site are assigned the storage cost plus an additional cost for transport of CO_2 to the site. This second cost rises with increasing distance from the storage site until locations are reached where it becomes just as cost effective to ship CO_2 to an adjacent storage site and sequester it there. These locations of equivalent transport plus storage cost thus form the boundaries between carbonsheds and serve to delineate them (Fig. 1).

Storage Reservoir Injectivity, Capacity and Cost

The storage sites evaluated in this analysis are deep saline aquifers (DSAs) and oil and gas reservoirs (OGRs). We estimate the storage injection rates, capacities and costs for the reservoirs using the model of Eccles et al. [*1*]. The inputs to this model are depth to top of the reservoir, total reservoir thickness, net sand thickness, and reservoir temperature, pressure, salinity, porosity and permeability. The model estimates storage capacity using a relatively simple bulk volume calculation similar to that found in other capacity assessments like the DOE's Carbon Atlas [*2*]. Injection rate is solved for using a radial integration of the Theis solution for an injection well [*3*]. Storage cost is estimated on a per-well basis in dollars per tonne using the cost formulation we develop in Eccles et al. [*1*] where a complete explanation of the model can be found.

Storage Reservoir Data

While there appear to be a number thick, laterally extensive reservoirs where CO_2 could be geologically sequestered beneath the U.S., most still lack sufficient physical property data for estimating CO_2 storage capacity and cost. Here we rely on the dataset compiled by the Bureau of Economic Geology for 19 major sandstone and carbonate DSAs in the continental U.S. [*4*]. The dataset contains sufficient information for characterizing the different DSAs in their partial to complete entirety over an area that totals ~750,000 km2. As in Eccles et al [*1*], we convert the BEG data for each needed reservoir property (e.g. porosity, permeability, etc.) into raster grids having the same 1 km x 1 km grid cell size as our cost surface. This allows us to then compute storage cost and capacity at every grid cell in the cost surface that overlies a DSA region in the BEG database.

OGRs are significantly smaller than DSAs and given the national scale we are working at we assume the former are uniform and homogeneous and can be adequately characterized by their average reservoir properties. We obtain these average properties from the Nehring Major Oil and Gas Reservoirs 2010 Dataset, which contains such information for thousands of onshore U.S. oil and gas fields. We limit our analysis of OGRs, however, to roughly 40 fields that we calculate are large enough to store 20 years of commercial-scale injection. The areal footprints of these OGRs are represented as single cells at the reported geospatial coordinates, which is then assigned a single storage cost and an overall capacity as calculated from the average reservoir properties for the OGR.

Delineation of Storage Sites within Reservoirs

Because we model OGRs as having single storage costs (and overall capacities), we assume each OGR is a storage site unto itself and that CO_2 only needs to be transported to the grid cell where the OGR is located. Distribution pipelines would then carry the CO2 to injection wells positioned about the OGR, the costs for all of which are included in the total cost for storage.

This characterization is too simplistic for DSAs, however, which are much larger and have storage costs (and capacities) that vary spatially. As a result, DSA regions are likely to contain multiple storage sites, which we refer to as reservoir blocks. These are sub-regions within a DSA where CO_2 would be "dropped off" at the boundary of the block for distribution and injection within it.

DSAs are subdivided into reservoir blocks using the algorithm introduced by Eccles and Pratson [*5*]. As illustrated in Figure 2, this algorithm delineates blocks by grouping economically similar grid cells until their aggregate storage volume reaches a minimum threshold capacity of 200 MT, or 1.1 GW worth of average coal-fired power plant emissions over a 20-year period. The algorithm begins with the lowest cost cell and searches upward in cost, adding cells to the block until its cumulative capacity reaches or exceeds the threshold. As differences in costs between cells can be minor, even a cost increment of $0.10/ton CO_2 can lead the algorithm to produce very large blocks that exceed the 200 MT threshold by a significant amount. The end result, though, is a series of discrete storage sites extending over many individual grid cells that are similar in terms of capacity, but differ in average storage cost.

Transport Costs

For grid cells in the cost surface located outside a DSA or OGR storage site, the cost of transporting the CO_2 to the site must be added to the cost of storing the CO_2 at the site. We represent the total cost for transport and storage C as

$$C = C_s + f(r, Q) \qquad [1]$$

Here C_s is the cost of storage, and $f(r,Q)$ is the cost of transport derived by Chandel et al. [*6*]

$$f(r, Q) = r * \exp\left(-4.48 + \frac{1.13}{Q} - 0.17 * \ln(Q)\right) \qquad [2]$$

in which Q is an annual flux of CO_2 to be transported and r is the transport distance.

Note that the transport equation includes the effects of topography and land use on costs, both of which can be significant. Routing pipelines through urban areas or across waterways can increase transport costs, while using existing pipeline infrastructure and rights of ways can decrease these costs. Previous optimization studies have accounted for these impacts with a cost surface that weights transport costs according to local land use and/or infrastructure (e.g. [*7*]). Inclusion of local weights for transport costs, however, significantly increases computation time and thus greatly limits the number of storage options that can be included in the optimization. We instead make the highly simplifying assumption that, at the regional scale we are evaluating, the cost to transport a fixed flux of CO_2 (Q) can be approximated to first order as a function of distance (r) only (eq. 2). We calculate this transport distance as the Euclidean distance between the grid cell in the cost surface and the nearest storage option. Using this approach, we are able to reduce computation time by a factor of 150, allowing us to include thousands rather than dozens of reservoir options in our optimization.

Mechanics of Carbonshed Delineation

We delineate carbonsheds computationally through a multi-step process. Starting with the first possible storage site, which can be an OGR or a reservoir block within a DSA, we solve for what it would cost to transport and store CO_2 at this site from every grid cell in the cost surface. We reference these costs with an index of i = 1 to indicate that they are associated with the first storage site. The process is then repeated for all the other storage sites such that by the end each grid cell in the cost surface has $i = 1 \ldots n$ transport and cost estimates, one set for each storage site. Of these, each grid cell is only assigned the i set of costs that yields the lowest total cost at the cell location, i.e.

$$\dot{C} = \min\,(C_i) \qquad [3]$$

Note that i also identifies what storage site and thus carbonshed for the storage site the grid cell belongs to. Also note that local maxima in total cost occur at carbonshed boundaries (Fig. 1), which is how these are automatically delineated.

Scenarios

Cooperative vs. Distributed CCS Systems

We assume that a cooperative system will be characterized by an extensive pipeline network that collects CO_2 from many small sources or a few large ones and delivers it to reservoirs for storage. For a distributed system, we envision that the multiple CO_2 sources will often have their own independent pipelines to a reservoir. This would lead to pipeline networks that are considerably more segmented and an overall CCS system that involves a larger number of reservoirs with low to moderate as well as high storage capacities.

A set of scenarios that range between these two end-member systems are used to explore the impact that different reservoir options could have on carbonshed arrangement and the total cost of CO_2 transport and storage. In the end-member scenario that approximates a cooperative CCS system, pipelines transport 10 MT CO_2/year, which is 1.1 GW of average coal-fired emissions. This constraint requires that the pipelines be shared by several large CO_2 sources or many small ones so as to capture savings in transport costs through higher transport rates as modeled by Chandel et al. [*6*]. The other end-member scenario approximates a distributed CCS system in which pipeline transport is restricted to 1 MT CO_2/y (110 MW). The constraint here reflects little if any sharing of pipelines by CO_2 sources resulting in higher transport costs.

Reservoir Depletion with Time

Carbonshed arrangement and the total cost of CO_2 transport and storage will also be affected by the exhaustion of different reservoirs with time. As storage resources are depleted, new CCS projects will presumably face fewer storage options causing the size and shape of carbonsheds to evolve.

We explore the impact of reservoir depletion on carbonshed evolution by modeling the order in which OGRs and DSAs would be filled to capacity were they injected with the CO_2 emissions captured from existing coal-fired power plants located within the carbonsheds for these reservoirs. We draw information on the locations, heat rates, and emissions of the coal plants from the eGRID 2007 database [*8*]. Heat rate significantly affects the economics of carbon capture, so we use it as a proxy for a rising carbon price to order the plants for retrofit [*9-11*]. We recognize that this order is highly speculative and note that our ordering is simplistic and meant to be illustrative, not predictive.

Starting with the first plant, we subtract 20 y (the projected lifetime of a typical CCS project [*12*]) of the plant's annual emissions from the storage capacity of the reservoir whose carbonshed the plant is located in. We then repeat this step for subsequent plants, checking after each plant to see if any of the reservoirs have been depleted. If so, the depleted reservoir is removed from the cost surface as a storage option and the carbonsheds are recomputed. The process is then repeated. We preform this analysis for both the distributed and cooperative scenarios.

Objective 2: Extension of Carbonshed Analysis to the Offshore

Overview

We use data from a previous publication [*1*] on offshore storage capacity to assess its cost. These data include geo-referenced grids of seafloor depth, and sub-seafloor sediment thickness and temperature, as well as digitized Deep-Sea Drilling Project and Ocean Drilling Project core data. Eccles and Pratson [*13*] describe in detail how these data are used to estimate the net-to-gross thickness of offshore sands in which CO_2 might be stored, which we extend to all offshore storage in addition to self-sealing storage (see Fig. 3 for conceptual model of offshore storage options considered). They also explain how the data are used to map out the locations and thicknesses of the self-sealing marine strata. For these details, the interested reader is referred to Eccles and Pratson [*13*].

In this paper, we limit our analysis to that portion of our offshore dataset from within the U.S. EEZ. Furthermore, we increase the resolution of our grids from 5' (roughly 15 km) to 1km and convert the grids to equal-area projections in order to keep bulk volume calculations accurate. Finally, permeability measurements from sand deposits in ocean sediments are limited, so we assume a uniform permeability for the grid cells of a low 22 mD. This value is both the average permeability in the onshore Mt. Simon DSA, and the log-average permeability of all the sandstone DSAs in the BEG data. Permeability data from offshore sediments at this depth (e.g. Wetzel [*14*]) generally does not shed light on likely sand permeabilities because it focuses on other sediment types.

To estimate the cost of offshore storage, we modify the economic model in Eccles et al. [*1,12*] into a version that is appropriate for the ocean environment. In this model, net sand thickness b is critical for calculating both storage capacity and cost [*1,12*]. Unfortunately, net-sand thickness is not known for ocean sediments [*13*], so we use the net-to-gross ratios we arrive at in Eccles and Pratson [*13*] to estimate net sand thickness from total sediment thickness as done in the USDOE's Carbon Sequestration Atlas [2,*13*]. We have estimated the net-to-gross ratio for self-sealing regions to be roughly 2.0%, while that for offshore sediments in water depths <~3,000 m to be a similar 1.8%.12 We believe the latter is an underestimate for some regions beneath the continental shelf, but note that at even such low ratios, the estimated values for b average several hundred meters [*13*].

The major cost components for offshore storage are same in nature to those for onshore storage but can differ in scale. In our economic model for onshore storage (Eccles et al. [*7,12*]), the cost components are represented by the index variable k. e.g. k =1 for injection well costs, k =2 for site evaluation costs, and so on. A detailed explanation of each component and the basis for its cost in onshore storage is explained in Eccles et al. [*1*].

For offshore storage, we scale each component k by an associated scaling factor B_k to account for any difference in cost between the two environments, i.e.

$$C_{k=1}^{offshore} = B_{k=1} * C_{k=1}^{onshore} \qquad [4]$$

The total cost for offshore storage is thus

$$C = \sum_k C_k^{offshore} \qquad [5]$$

For most components, B_k ~ 1; e.g. depending on land use/land cover, ocean seismic surveys may actually be cheaper than their onshore counterparts [*15*]. Two components, however, are assigned a B_k > 1. These are injection well construction, and pipeline infrastructure. For injection wells, we calculate B_k using the following empirical formula derived from regressing offshore rig day-rate data24 against the water depths d in which the rigs can operate

$$B_k = -3.18 * 10^{-8} * d^3 - 5.38 * 10^{-5} * d^2 - 0.0413 * d + 1.9752 \qquad [6]$$

Where d > 1000 m, we set B_k = 20, a multiplier appropriate for the only class of rigs regularly deployed in these depths [*16*].

The other cost component for which we set B_k >1 is offshore pipeline infrastructure. In this case, we use the same multiplier as the IPCC (2005) i.e. B_k =2.

Reservoir Blocks

A storage site is likely to include several separate injection zones because the site may contain more than one reservoir, and the quality of the of each reservoir (including its seal) will probably vary spatially (See Fig. 2a). Consequently, infrastructure for a storage site will likely be configured to include a central receiving point for incoming CO_2 that connects to a system of distribution pipelines which then carry the CO_2 to individual injection wells positioned about the storage site [*17*]. In this study, we define a reservoir block as a region where CO2 would be delivered to a site hub for distribution and injection within the region (See S3 in Figure 2e). The 1 km2 area of the cells in our grids of the DSAs and offshore storage reservoirs have too little capacity and thus are too small to be treated as reservoir blocks, because the latter need to be large enough to store many years of commercial-scale injection. We map out our hypothetical reservoir blocks by grouping economically similar grid cells until their aggregate storage volume reaches a minimum threshold for what we arbitrarily define as a viable “storage site”, with the capacity to hold a project lifetime’s worth of emissions. We set the capacity threshold for onshore reservoir blocks at 200 MT, or 1.1 GW worth of average coal-fired power plant emissions over 20 years [*8*] For offshore reservoirs, we raise the threshold to a five-fold higher minimum capacity of 1 GT (5.5 GW). This is to compensate for the original resolution of the data, and the lack information in our grids on the true distribution, extent and thickness of offshore sands.

Figure 2b-d is a schematic of our algorithm for aggregating grid cells based on storage capacity and cost. The algorithm begins with the lowest cost cell and searches upward in cost, adding cells to the block until its cumulative capacity reaches the minimum threshold. As differences in costs between cells can be very small, even small step sizes like \$0.10/ton CO_2 can lead the algorithm to produce very large blocks that exceed the minimum capacity threshold by a significant amount. The end result, though, is a series of discrete storage sites that are similar in terms of capacity, but can differ in average storage cost and in distance from a CO_2 source.

Transport and Storage Optimization

The final step in our analysis is to match CO_2 sources with sinks so that a marginal abatement cost curve showing the combined cost of transport and storage can be used to evaluate the economics of onshore vs. offshore storage. We first compute the Euclidean distance from each CO_2 source to all possible sinks. In this analysis, we limit the CO_2 sources to coal-fired power plants in the EGRID database [*8*]. We also subdivide the storage options into three sets: onshore DSAs, offshore non-self-sealing regions, and offshore self-sealing regions.

Minimum distances between sources (pn, Fig. 5e) and sinks (sn, Fig. 5e) are converted to a cost per tonne using a simplification in Chandel et al [*6*] that relates the cost per tonne of CO_2 per kilometer transported to the total amount transported. We select a transport mass of 10 MT/yr, which is the emission rate of 1.1 GW of average coal-fired power [*8*]. This corresponds to a scenario in which large plants could use their own transport networks while smaller plants would cooperate to join a larger-scale transport network to capture economies of scale (the gray “p cluster” in Fig 2e); note that we only assume clustering of small plants into feeder networks and do not explicitly model this in our analysis.

Again, offshore transport is increased to twice the cost of onshore transport (triple lines in Fig 2e [*18*]) but we do not optimize offshore transport routes for cost, so there may be some transport savings in an actual deployment of offshore CCS (t5b in Fig 2e). Similarly, no cost surface (a planning tool for which areas are assigned weights according to their relative or absolute cost of transport) is used to route pipelines onshore around high-cost areas such as urban areas, wetlands, or rugged terrain, which could increase the cost of transport (t1b). The benefit of cost surface calculations is well-established in transport modeling [*7*], but for source-sink networks of far less complexity than the one we deal with here, i.e. dozens of sources and sinks in the case of the former vs. the 628 sources and roughly 3000 sinks we assess here. The scale of our analysis produces a computationally intractable problem if cost distance is used instead of Euclidean distance.

After sources have been optimally matched to sinks, a marginal abatement curve is assembled by ordering the sources according to their integrated cost of transport and storage, and then plotting the combined costs against annual emissions from the sources (less capture costs, see Fig 2e inset).

Objective 3: Agent-Based Modeling of Economic/Policy Scenarios for CCS

We utilize an optimization model akin to evolutionary or genetic algorithms that identifies optimal decisions for coal-fired power producers by generating many thousands of candidate producers and eliminating all but those that are able to produce electricity at the lowest cost. This identifies which power producer decision models would be able to compete most effectively in both restructured and regulated markets, applicable to existing plants and new generation capacity.

The process for creating the competing plants is relatively straightforward. A list of coordinates within the continental United States is generated and assigned to an arbitrary number of plants; we use roughly 3.5 million plants, which is one plant per 2 sq km. This coordinate list is meant to represent the spatial decision model, i.e. where a new plant might be placed or defining regions of optimal decision models for existing plants, i.e. if our plants coincide with existing plants and "survive," that decision model might be viable for the existing plant.

The power generation facilities are given other characteristics, such as generation capacity, and various properties are calculated, such as emissions, generation, and so on, with factors summarized in Table 1. Although in principle any of these factors can vary to provide insight into plant characteristic optimization, we only vary the capacity of the plant, since it has bearing on the cost of transport and storage.

The plants are also given decision models relating specifically to transport and storage. We investigate several decision options and how they interact with policy scenarios. The first decision option is, of course, the decision to capture CO_2. Once captured, we have four decision options regarding the fate of the CO_2, since the goal of our investigation was to evaluate alternate CO_2 disposal paradigms.

The first decision option is a global optimization of transport and storage cost with all geological storage options open. While ocean storage options are technically viable, they are expensive relative to onshore reservoirs, so in this first case the options are restricted to large oil and gas fields and a selection of sandstone aquifers. Our data for these aquifers cover 750,000 sq km, although the aquifers themselves cover 2.1 mln sq km; in total roughly 65,000 cubic km of bulk volume has been evaluated; this is perhaps 20% of the volume evaluated for capacity in NATCARB's database.

For this first decision option, a power plant considers all possibilities, including their cost of storage and transport, and selects the cheapest of these. This is essentially a hands-off approach to decision-making that assumes a generally well-informed plant operator. This decision option is labeled "sandstoneog."

For the second decision option, which we label "centralized," the plant operator can only choose between two major storage locations: the Mt Simon (here localized to the Michigan Basin) and the Texas Gulf Coast, including the Frio formation. This corresponds to either a policy restriction/incentive or one of two market restrictions: asymmetric information, where these large, cheap reservoirs are well-characterized compared to other options (reducing risk) or social/environmental issues (e.g., local opposition to storage) that prevent development of many smaller sites.'

The third and fourth decision options are both ocean storage. They represent an operator's intent to consider only options for geological storage below the seafloor (option 3) or the more limiting case of storage in offshore self-sealing zones, which occur below roughly 3000m depth (option 4, see Eccles and Pratson 2012a).

The plants interact with carbonsheds representing these decision options to calculate the cost of transport and storage. They also evaluate the cost of capture and the energy penalty associated with it, if they "decide" to capture. Power plants must also consider the cost associated with connecting to fuel and transmission infrastructure, so they similarly calculate the cost of building transmission lines to existing transmission infrastructure and rail spurs to navigable waterways or existing rail lines for fuel.

Finally, the power plants interact with policy scenarios. We investigate several policy scenarios to determine the impact on transport and storage decision optimization. The first is evaluating CO_2 prices at different levels to determine when (in our model) capture and storage becomes viable. Plant emissions (if any) are used to calculate the cost of CO_2. The second is embedded in decision option 2, which might include implicit or explicit restriction to centralized storage. The last is subsidization of ocean storage. For this last policy scenario, captured emissions are given a credit in addition to the comparative advantage of lower emissions under a carbon price.

Each plant combines all of the cost information available to it and calculates the levelized cost of electricity for the included components. For our analysis, the top 10% of plants are selected as the "winners," the characteristics of which we interpret to be viable decision options for new plants or, where appropriate, existing plants.

RESULTS

The principal results for by objective are:

Objective 1: Onshore Carbonshed Analysis

<u>Cooperative vs. Distributed CCS Scenarios</u>

The results of our carbonshed analysis suggest that whether a CCS system is cooperative, distributed or somewhere in between, combined transport and storage costs have the potential to vary considerably. In all the scenarios we model, these costs range from \$0.70-\$53/tonne CO_2, with the breadth resulting from variability in the cost of storage between and within reservoirs, substantial differences in transport costs depending on pipeline capacity, and the range of distances over which CO_2 must be transported.

The end result of our baseline cooperative CCS scenario is shown in Figure 4a. It includes carbonsheds for 9 of the 19 initial DSAs along with several carbonsheds that would utilize OGRs. The lesser number of carbonsheds than initial DSAs is because the omitted DSAs ended up being too expensive to store CO_2 in and so were bypassed for more economical storage sites.

The largest and cheapest DSAs such as the Mt. Simon and Frio have so much low-cost storage that they end up being subdivided into numerous reservoir blocks. Many of these blocks have only minor differences in storage costs, which is not generally the case for the reservoir blocks in other DSAs. It is interesting to note that the large, low cost carbonsheds for Mt. Simon and Frio DSAs also coincidentally contain the majority of existing coal-fired power plants (7, 13, and 16).

The final configuration for the baseline distributed CCS system scenario is shown in Figure 4b. It ends up being more fragmented than the cooperative system, finishing with 4 additional carbonsheds. The result is due to the scenario's more independent, restrictive and ultimately costly 1 MT CO_2/y pipeline restriction, which fragments the CCS system by making it cheaper in many regions to rely on local but more expensive storage options over less costly options located farther away.

The carbonshed maps in Figure 4 reveal significant geographic differences in the optimal deployment of CCS under a centralized vs. distributive CCS system. Potential cost differences between the two types of systems on the other hand are best seen in the marginal cost curves shown in Figure 5. These curves were constructed using the costs for transport and storage at the locations of the coal-fired power plants in the eGrid 2007 database [*8*] ordered as a function of cumulative annual emissions from the plants. Despite some bias to the plant locations (such as being near rivers or railroads), their distribution is a reasonably good sampling of the total number of cells in the cost surface, having similar average cost and standard deviation.

The contrast between the marginal cost curves for the distributed and cooperative CCS scenarios suggests that if CO_2 sources do not share pipelines, overall costs could double as the sources settle for closer but more expensive storage options (Fig. 5). Even under the more costly and restrictive distributive scenario, however, almost 1 Gt CO2/y could be sequestered for 20 years at <$10/t. This amount rises to >2 Gt CO_2/y for <$10/t when the larger pipelines and thus cheaper transport systems are used in the centralized CCS scenario.

The marginal cost curves also provide insight to the effect of adding more storage options to a CCS system. Our baseline scenarios used sandstone DSAs with the OGRs, but did not include carbonate reservoirs. We also explored several alternatives consisting of OGRs only, sandstone DSAs only, and all DSAs and OGRs. These alternatives reveal that without a large, geographically diverse set of reservoirs, such as in the OGR only scenario, the costs for transport and storage are very high, even in the cooperative scenario. Conversely, once there is large, geographically diverse set of reservoirs, the addition of even more reservoirs has a relatively minor effect in lowering transport and storage costs even more, the example here being the inclusion of carbonate DSAs with the sandstone DSAs and OGRs. This latter result is partly because more the power plants occur near sandstone DSAs than carbonate DSAs, but it is also because once there are enough large-scale, low cost storage sites, additional storage options provide less marginal cost savings.

Depletion Scenarios

Since the baseline cooperative scenario ends up being more cost effective than the distributive scenario, we next focus on how an initially cooperative CCS system might evolve over time as storage sites are depleted. The carbonshed maps for the beginning and end of this depletion scenario are shown in Figures 6a & b, respectively, while the marginal cost curves corresponding to these maps are plotted in Figure 6c.

Recall that the depletion scenario does not correspond to a specific timeframe or price on CO_2 emissions. Rather it assumes that all existing coal plants will retrofit for carbon capture in the order of decreasing plant efficiency and thus presumably increasing cost of compliance. Under this highly idealized scenario, the emissions from these coal plants deplete four of the initial 10 reservoirs by the time all of the plants have joined the CCS system. Five of the remaining six carbonsheds assimilate their depleted neighbors thus expand in size. The one carbonshed that does not grow substantially is that surrounding the Woodbine (#20) DSA; it changes shape, but grows by only 11% in area. Except for the Western U.S. where there are relatively few power plants, the final arrangement of carbonsheds is more centralized such that any new coal plant would likely pipe its emissions to either the Mt. Simon or Frio Formations.

The marginal cost curves show that by the end of the depletion scenario, transport and storage costs have increased by a maximum of $5/ton, a very modest amount when compared to the total cost of CCS [*40*]. Also shown is a “by plant” curve, which curve consists of the transport and storage costs at each coal plant over the course of the carbonshed depletion process. As might be expected, reservoir depletion increases the cost of both transport and storage, but for much of the supply curve this combined cost remains <$1/t CO_2. The major effects of depletion are not on price, but on the evolution of carbonsheds. This leads us to conclude that the difference between a cooperative scenario and a highly centralized storage system is relatively small in terms of overall cost but might could result in significant difference in how and where infrastructure is deployed.

Objective 2: Extension of Carbonshed Analysis to the Offshore

Geological Storage Cost and Capacity

Our results for onshore storage capacity and cost are essentially the same as those reported in Eccles et al. [*1*], despite the minor revisions to our geo-economic model to account for variations in the spacing of injection wells. The gridded cost and capacity estimates are plotted in Figure 7.

Our offshore storage cost and capacity estimates, however, are an entirely new contribution to literature. Within the US EEZ, there is an enormous quantity of storage available (see Fig 7). In offshore storage regions close to the coast, there is 1,424 gigatonnes available, 1,111 gigatonnes of which may cost <$10/tonne. This low-cost storage generally lies along the Eastern Seaboard and in the Gulf of Mexico (See Fig 7), relatively old-age passive continental margins where sediments eroded from the continental U.S. have been deposited for over 200 million years to form extensive accumulations of marine strata [*19*]. The West Coast, on the other hand, has much poorer storage options. This is due to it being an active margin setting where sediments are being uplifted and accreted onto the continent or being subducted beneath it north of the Mendocino Triple Junction [*20*]. The seismic activity along this margin further reduces its attraction for use in CO_2 storage [*20*].

The marine strata along the Eastern and Gulf of Mexico U.S. are thinnest near to shore and thicken seaward across the continental slope before thinning again beneath the continental rise and abyssal plain. Continental shelf strata at the appropriate depth range for storing CO_2 in a supercritical state are in general a relatively expensive storage option at >$10/tonne. An exception appears to be the shelf offshore New Jersey and Delaware where we estimate storage could run <$5/ton within 70 km of the coastline. There also appear to be regions along the continental shelf in Gulf Coast where storage could run ~$10/tonne.

In the strata further offshore beneath the continental slope and uppermost rise, storage costs drop to <$10/tonne. This includes the storage potential in the deep-water self-sealing regions, which we estimate to total 414 gigatonnes, 226 of which could be available for <$10/tonne (See Fig 8). Extensive self-sealing storage resources are available off the Eastern Seaboard and GOM, though the broad continental shelves in these regions (e.g. Texas, Maine) raise the cost of accessing these strata (See Fig 7). The closest and thus likely cheapest available self-sealing storage is off the coast of North Carolina. Self-sealing storage is even closer to the West Coast, but along this margin these strata are so thin that they make a poor storage option.

In general, the cost for offshore storage in self-sealing strata ranges from $4.28/t up to over $1000/t. Non-self-sealing offshore storage starts at $3.76/t and likewise goes over $1000/t. The average grid value for self-sealing storage is $142 (std. dev. $241), while that for non-self-sealing storage is $57.9 (std. dev. $158).

Relatedly, the range for storage capacity in self-sealing strata is 53-3.34e6 t/km2 with the average being 6.36e5 (std. dev. 6.16e5). Non-self-sealing strata has storage capacities ranging from 17-3.51e6t/km2, and a mean of 1.04e6 (std dev 9.72e5). Note that the distribution of values in our storage capacity and cost grids is highly skewed, so the mean values do not adequately reflect the fact that most grid cells have lower cost values and higher capacity estimates.

Transport and Storage

Figure 8 is our integrated transport and storage cost curve in which the cumulative annual emissions of the coal-fired power plants are plotted against the minimum cost per tonne of CO_2 each plant faces to transport and store its emissions. This supply curve is broken down into its transport and storage components, and shows the quantity of CO_2 emissions that could be sequestered for a given carbon price minus the cost of capture.

The results of the transport optimization process indicate that offshore storage is more expensive than onshore storage, which is not surprising given that the latter is both farther from the CO_2 sources and is assumed to incur double the costs of onshore transport seaward of the coastline. Without exception, when offered all options for storage, power plants in the

U.S. should find it most economical to transport to onshore reservoirs, at least until these reservoirs are depleted or circumstances arise that raise the cost of onshore sequestration. Roughly 370 Mt/yr of CO_2 can be stored in onshore reservoirs before the combined cost of transport and storage reaches the minimum cost for offshore storage of roughly $5/t (See Fig 9). Onshore, 1 Gt/y can be stored for below $5.66/t, with nearly all current U.S. CO_2 sources (which produce 2.1 Gt/y of emissions) having access to storage for <$10/t.

In the case of offshore storage, the minimum cost starts at >$5/t (off the coast of New Jersey), with up to 500 Mt/y of storage available for <$10/t or $5/t more than what it would cost onshore. Half of this difference is due to the higher cost offshore storage, and half is due to the higher cost of offshore transport. Additional offshore storage is located farther from the coast, rapidly raising the cost of transport even where storage costs decline so that the combined cost of transport and storage jumps to $13.5/t for 1 Gt/y of storage and $31.2/t for 2 Gt/y storage.

Finally, self-sealing storage of and by itself has a minimum cost of just over $10/t. Up to 500 Mt/y of such storage capacity is available for <$14.5/t, which is about $5/t more than other offshore storage, and about $10/t more than storage onshore. Almost all of this greater cost for self-sealing strata relative to the other options is due to the greater transport costs need to reach the strata. Similar to non-self-sealing offshore storage, the cost for self-sealing storage rises quickly to $18.1/t for 1 Gt/y of capacity and $35.4/t for 2 Gt/y of capacity.

Objective 3: Agent-Based Modeling of Economic/Policy Scenarios for CCS

The spatial arrangement of winning plants and their decision options under two end-member carbon price scenarios addressed with our agent-based model is shown in Figure 10. Figure 10b shows how plants should arrange themselves without a carbon price, which is to say, the optimal decision is to not capture CO_2 at all. In this case, the model should accurately reproduce the locations of existing plants, since they by necessity must already be near a rail line or waterway and transmission lines. Note that the model produces a representation of areas a plant could be located, not necessarily areas where plants must be located.

Figure 10a shows how things change when a carbon price is applied. We examined a range of carbon prices, the effects of which are shown in Figure 11. As might be expected, when the carbon price is high enough to offset the cost of capture and storage, there is a transition stage where some winning plants can capture/store CO_2 cheaper than the cost of emission, but not all. By $70/t, the winning plants are all plants that decided to capture CO_2, with a variety of secondary decision options. Figure 10a shows $80/t, which is essentially the same outcome.

The spatial diversity of storage options and their cost is apparent from the decision models that win in these policy scenarios. The baseline decision option, which includes all storage options but which ends up utilizing only onshore options, is the option with the broadest viability. All along the east coast, where Cretaceous sediments close to shore are likely available, above and near the Mt. Simon in the Midwest, and near a combination of oil and gas fields in Texas and California, this decision option is likely to produce electricity at low costs and is thus a viable decision option. 67% of the winners are plants with this decision model.

Not surprisingly, the centralized decision model is essentially a subset of this broader decision model, as can be seen in Figure 10a. The overlap between regions populated by centralized decision model plants and sandstone/og decision model plants is complete. Roughly 31% of winners are centralized decision models. A centralized national storage system with just these two reservoir regions would thus capture a market that is smaller than a distributed storage system, but it would still represent a substantial portion of existing or future emissions without any major subsidy.

Most interesting, even though it is generally much more expensive than onshore storage, over 2% of winners had the ocean storage decision model. None had the self-sealing decision model, which is not surprising, but again, the spatial diversity of storage options is such that even ocean storage is a viable option for some regions – the Mid-Atlantic and Gulf Coasts, according to our model.

The majority of coal-fired plants (512 of 607 in our database) are within 5km of the winning sandstone/og decision model plants, a total of 1.75 Gt of 2005 emissions, which indicates that these plants might consider a global optimization decision option or that if left unstructured, a carbon market might see them retrofit to capture. Over half (323) are within 5 km of centralized plant winners, indicating that the centralized strategy could be viable for 1.18 Gt/yr of coal-fired power plant emissions. Almost no emissions are within 5 km of ocean storage (27 plants emitting 70 Mt/yr); in this scenario, it is a niche strategy with relatively low potential. This does not take into account the different heatrates of existing plants, however, so may not be a universal guide for optimal decision-making.

Subsidizing ocean storage by only $5/t dramatically alters the landscape. Figure 12 shows the distribution of winning plants with the ocean subsidy policy option, now including a substantial number of ocean decision models in both regular ocean storage and the deeper self-sealing ocean storage. Almost the entire Eastern Seaboard and Gulf Coast inland several hundred km have ocean decision model winners, in addition to the sandstone/OG pattern seen earlier. Self-sealing storage model winners are found along the Mid-Altantic coast, notably relatively far inland in North Carolina, and along the Gulf Coast.

In this policy scenario, 54% of winning plants are the sandstone/OG decision model. 26% are centralized, but 20% are ocean storage and almost 2% are self-sealing storage. For the relatively small size of the subsidy, that is a massive change in competitiveness. In this scenario. 1.5 Gt of existing coal-fired emissions are within 5 km of the sandstone/OG, 1.03 Gt of centralized, and 735 Mt and 75 Mt are within 5km of ocean and self-sealing decision models, respectively.

Finally, our model included variations in the capacity of the power plants and thus the scale of the transport system they would utilize. We expected that the distribution of winning plants' capacity would have a higher average than the entire population of plants, since they would have lower costs of transport. However, we find that the distribution of plant sizes of the winners matches that of the entire population. The spatial distribution, however, is slightly different – smaller plants are common closer to sinks and larger plants "win" further away, since they are able to support the additional cost of transport.

DISCUSSION

The major implications of these results for each objective are:

Objective 1: Onshore Carbonshed Analysis

Our carbonshed analysis for the continental U.S. suggests that it would be more cost effective to deploy CCS in a centralized rather than distributed fashion. This finding of course is a function of our parameterizations for storage and transport costs. In the case of storage costs, we account for a wide variety of expenses, from site characterization and the operation and maintenance of the injection wells to measurement, monitoring, and verification, and long-term restoration of the storage site [*1,21*]. We also include costs for minimizing pressure interference between injection wells as in Eccles et al [*17*]. We do not, however include costs for more advanced pressure management techniques or for obtaining storage property rights, both which would add to the expense of sequestration [*22-24*].

A more significant influence on our cost model, however, may be its omission of local variations in transport costs due to topography and/or land use. These costs are undoubtedly higher than what we model based on Euclidean distance, and spatial variations in transport costs could affect the size, shape and location of the carbonsheds we map.

An analysis of the MIT 5 km x 5 km grid of weights for pipeline costs due infrastructure and land use in the U.S. [*25*], however, suggests that local variations in transport costs may largely offset one another, at least where coal-fired power plants are concentrated. Weights in this grid range from 1-71, but for most of the eastern and central U.S., the weights are uniformly distributed and have a low average value of ~6. Averages are higher from the Rocky Mountains westward due to the region's rugged topography, but the Western US contains only 64 coal plants, 10% of the U.S. total. There are also regions east of the Rockies with relatively high average cost-surface weights, such as parts of the Appalachian Mountains, but these are less common than in the Western U.S. and do not form the same type of continuous geographic cost "barrier" as the Rocky Mountains. So while CCS transport costs in the Western U.S. are probably higher than we estimate, we believe our carbonshed boundaries to be fairly accurate east of the Rockies. We also believe that our simplifying assumption regarding the calculation of transport costs does not significantly affect our marginal cost curves, for these compare favorably with the curves of previous analyses [*7,26-28*], and encompass average cost estimates arrived at by others [*22,29-33*].

Assuming then that our modeling results are reasonable, they suggest that there are at least three distinct ways carbonsheds would develop. First, regardless of transport cooperation, the inclusion of even a small number of high-capacity, low-cost storage reservoirs in a CCS system reduces overall costs dramatically. Second, poor transport cooperation and thus the greater use of lower capacity pipelines (e.g., 1 MT CO_2/y) will promote the use of smaller and/or costlier storage reservoirs, leading to more carbonsheds, increased CCS system fragmentation, and higher average transport and storage costs. The third and most economic form of development occurs when CO2 sources do cooperate such that pipeline transport costs are low. In this case, large, cheap reservoirs become the most economic storage options, leading to the formation of stable carbonsheds with relatively low combined transport and storage costs and potential for even cheaper centralization..

The last form of development appears to require two critical elements. One is that a few large, cheap reservoirs are needed to dramatically reduce average storage costs. Once these large reservoirs are part of a CCS system, the effect of additional reservoirs on the marginal cost for storage and transport is diminished. This is demonstrated in Figure 5 where including OGRs along with sandstone DSAs results in a marginal cost curve that is little changed from the DSA-only cost curve, while adding carbonate DSAs reduces costs by only about \$1/t CO_2. Relatedly, in the depletion scenarios that include reservoirs with a range of storage capacities (i.e. OGRs and DSAs), smaller more costly reservoirs (many of the OGRs) are rapidly depleted, becoming too expensive to be utilized over the larger, cheaper reservoirs (DSAs). As a result, the carbonsheds for the latter subsume those of the former and grow to become dominant in a carbonshed arrangement that stabilizes with time.

The second requirement for a stable, low cost transport and storage system is pipeline cooperation, which dramatically reduces the complexity and cost of the overall system. Under this condition, not only are transport costs lower, but the storage system is less fragmented because it tends towards involving only large, low-cost storage sites with potential for economies of scale. The level of cooperation does not have to be particularly high – just 10 MT of emissions per year, or 1.1 GW of average power – to dramatically impact overall cost and geographic distribution of carbonsheds.

Our cooperation scenario brings into focus just how narrow the gap between planned and evolved centralization might be as CCS is deployed at scale. A centralized CCS system (i.e., the final state of the depleted cooperative scenario) has an overall cost for transport and storage that is only slightly higher than the initial cooperative state. However, an overarching strategy for developing a centralized CCS system could help its deployment bypass early-stage complexities and fragmentation – possibly even reducing cost further if the strategy helps simplify such factors as regulations, property rights acquisition, and the establishment of rights of way for trunk pipeline development.

In fact, it is noteworthy that regardless of whether the CCS system begins in a cooperative or distributive fashion, the massive Mt. Simon, Frio and Potamic reservoirs end up being major storage sites in our carbonshed framework. This suggests that these large reservoirs could form the backbone of a national-scale transport and storage system, providing policymakers with a framework for considering how any deployment of CCS might best be promoted. For example, instead of stranding early capital investments in CCS infrastructure at marginal reservoirs due to suboptimal deployment, CCS operators could be encouraged to begin by developing centralized storage systems at large reservoirs. In turn, centralization could focus the tasks of gathering geologic information on the main storage reservoirs, regulating them, and encouraging cooperation in transport services [*9,34,35*]. In the case of the latter, we find that cooperation in transport would reduce the cost of transport and storage by half compared to individual, small-scale transport networks.

Objective 2: Extension of Carbonshed Analysis to the Offshore

Our results show that there is substantial capacity for sequestering industrial CO2 emissions beneath the seafloor within the US EEZ, but that doing so would be nearly twice as expensive (including transport costs) as storing CO2 onshore in DSAs. Interestingly, we arrive at essentially the same cost ratios for onshore versus offshore storage estimated by earlier studies summarized in the IPCC special report and by more recent private assessments [*18,32*], all of which relied upon less information than we used. We also find that while standard offshore storage is twice as expensive as onshore storage, onshore storage costs about a third of that for self-sealing offshore storage, which becomes even more expensive for cumulative capacities >500 Mt/y.

We stress that even with the extensive information that forms the basis for our analysis, our storage capacity and cost estimates involve considerable uncertainty, not only with respect to the geology of DSAs and even more so offshore reservoirs, but also in the implementation of our reservoir block and transport models (see Fig 2e). We do find that our cost estimates for onshore and offshore storage encompass previously reported estimates (e.g. those in Hendriks et al or the BCG report [*32,36*]), and that our combined cost for onshore transport and storage is similar to that of Middleton and Bielicki [*7*], for example, but this appears to be the limit to which we can verify our estimates.

Our offshore cost/capacity maps depend heavily on our translation of the sediment thickness dataset into net sand thickness via the net-to-gross ratio we calculated from DSDP/ODP cores as described in Eccles and Pratson [*13*]. There is significant variation among cores in the net-to-gross ratio, however, which undoubtedly corresponds to geospatial variations in sand distribution resulting from the different routes (e.g., submarine canyons, channels and fans) and mechanisms (e.g., seafloor failures to turbidity currents) by which sands are carried into the deep sea [*13*].

In fact, our maps of storage capacity show a correspondence to the regional geology of the U.S. EEZ inherent in the sediment thickness data. Areas we estimate to have good storage potential are located in thick sedimentary basins on the outer continental shelf and slope such as the Carolina and Baltimore Canyon Troughs. In fact, we probably underestimate the sand potential in these Troughs, where Lower Cretaceous strata include “massive to thin” sandstones (~1000m), and underlying Jurassic sediments consist of even more (several ~100m formations) sands [*37*]. The same holds true for the Texas Gulf Coast, where massive Tertiary sand deposits extend many kilometers seaward across the continental shelf, and have formed the reservoirs for the significant amount oil and natural gas that has been produced in the region [*38,39*]. Consequently, our simplifying assumptions for this analysis likely make our gross storage capacity estimates for the U.S. EEZ minimum estimates.

While we do offer estimates of storage cost, the focus of our analysis is the difference in cost between onshore and offshore storage, which we estimate to be roughly $5/t and $10/t for non-self-sealing and self-sealing offshore storage, respectively. If these differences are accurate, they represent an interesting window of opportunity for offshore storage. On the scale of the total cost of the CCS system, in which capture costs may range from $50/t to over $100/t, $5-$10/t is not particularly expensive [*40*]. In fact the cost difference may be offset by a variety of factors that could increase the expense and/or complexity of onshore storage projects, making offshore projects more attractive.

First, the offshore regulatory environment may be greatly simplified. Much uncertainty regarding regulation of CO_2 injection wells was put to rest with the EPA Class IV rules [*41*], but state and local regulations could still pose a significant hurdle to the approval and operation of CCS projects. Perhaps more importantly, buoyant CO_2 gas bubbles and dissolved CO_2 gas in groundwater at CCS projects could now run afoul of new EPA regulations concerning the contamination of U.S. Drinking Water (USDW), preventing onshore storage at many sites previously thought viable for CCS [*41*]. Seaward of State jurisdiction in ocean waters (generally 3 mi), the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) is the only agency that would regulate offshore CCS projects, potentially simplifying the project approval and oversight process.

In addition to this, monitoring, measurement, and verification may be less complex in offshore storage projects, particularly for self-sealing storage where the combination of the NBZ and HBZ mechanisms for trapping CO_2 offers a safety redundancy against leakage [*42*]. Although the costs for MMV are relatively small compared to the cost of offshore injection in our analysis – recall that injection costs are adjusted upward, but MMV costs are not - any reduction in the former would still decrease the gap in total costs between onshore and offshore storage.

Finally, offshore property rights are managed by BOEMRE whereas onshore property rights for CO_2 storage will involve a large number of private as well as public owners, making leasing of these rights costly in terms of both time and money. Research by Gresham et al indicate that the costs for such rights may range between $1-$5/t, which by itself could make offshore CO_2 storage an economically competitive option [*23*]. There is also the problem of overcoming issues with public acceptance. Finally, both onshore and offshore storage would have to deal with transport rights of way, but we anticipate that the cost of offshore rights of ways will be less, a factor not included in our transport cost analysis [*28*,*43*]

These factors, alluded to previously in our discussion of Schrag's persuasive piece [*42*] could end up making offshore storage economically competitive with onshore storage and thus reduce barriers to adoption of the former.

However, there are also significant reasons against storing CO_2 offshore. One is cost. Based on this analysis, we estimate that the total cost of a 10 Mt/yr offshore storage project could run nearly half a billion dollars more than its onshore equivalent, and be nearly a billion dollars more expensive if the project is involves deep-water self-sealing storage. This is a significant amount of capital that may prevent private investors or storage system operators from utilizing offshore storage resources regardless of regulatory risk or other barriers to adoption.

Another important reason for not storing CO_2 offshore is the possibility of environmental damage if undersea storage goes awry. The recent Deep Horizon disaster demonstrates the complexity of maritime contamination accidents and their long-term effects, and CO_2 storage projects may be no different from oil and gas extraction or, for that matter, proposed geo-engineer projects also designed to mitigate carbon emissions [*44*]. Sub-seabed storage must be carefully evaluated with further research into both its physical and economic impacts and deployed only as a cost-effective measure to mitigate climate change that does not adversely affect the environment it is meant to protect.

Objective 3: Agent-Based Modeling of Economic/Policy Scenarios for CCS

Our results indicate that a variety of decision models for new and existing plants could produce electricity at competitive costs. The novel structure of our model means these results must be carefully interpreted, but the implications for coal-fired electricity in a carbon-constrained future are nonetheless clear.

Although the value of more powerful or detailed linear optimization models is obvious, it can be challenging to interpret the results of such models when exploring alternate decision models quickly and efficiently. Our previous work indicated that large, cheap reservoirs might provide the backbone of a large-scale national storage system, but it was difficult to say with any certainty that a centralized system would be comparable in cost or abatement potential to a distributed system. Similarly, ocean storage would be more expensive than onshore storage.

Our understanding of the nature of storage has not changed, but our results improve our ability to project what emitters – in this case, coal-fired power plants – might do under various policy constraints. The "fuzzy" nature of evolutionary algorithms produces many plausible decision models that could produce electricity at costs competitive with other decision models. Considering the large uncertainty surrounding any number of elements of the capture and storage system, from the price of carbon to the cost of property rights to the social and environmental implications of underground waste disposal, it is not out of the question to say that any of our winning decision models might be not only close to optimal but in fact the globally superior options.

As noted in the results, the spatial diversity in geological storage reservoirs produces a wide range of decision model portfolios around the country. Certainly in the Northeast, the Midwest, and Texas, new plants or existing plants could plausibly do any of several strategies and still produce electricity at competitive costs if a carbon price supports capture and storage. Depending on how close the source is to a sink option, the emitter may not have to cooperate with other emitters to achieve low cost transport through economies of scale. They may not have to develop global optimization models to select the best storage option and simply pick the largest centralized reservoir. If un-priced difficulties with onshore storage (property rights, environmental opposition) add to the cost of storage onshore – or the policy environment subsidizes offshore storage – they could dispose of CO_2 below the seafloor.

From the policymaker's perspective, the options for encouraging adoption of CCS are fairly diverse and may be less challenging than previously expected. For example, much attention has gone to characterizing all storage options, under the assumption that any geological formation might prove important for CO_2 storage. However, we believe that our results indicate that policymakers could fund characterization in great detail of only a few storage reservoirs and get substantial impact on existing and future emissions. Policymakers may also underwrite risk, especially of long-term storage, in these reservoirs only, or locally develop policies particularly favorable to property rights acquisition.

If onshore storage proves intractable or policymakers simply wish to encourage offshore storage, the cost of doing so is very small compared to the overall size of the carbon price under which CCS is competitive. There are certainly advantages to offshore storage that are difficult to price, and it may not even cost as much as our model indicates.

Obviously our results depend on some degree on the parameters of our model, which leads us to caution against using these numbers with too much confidence. The carbon price that supports the capture decision model, for example, is fundamentally a function of our assumptions, which doesn't even account for variations in heat rate in plants. The relatively low cost of transport and storage in our underlying calculations, moreover, means that the differential between offshore and onshore storage may be particularly untrustworthy. Sensitivity tests with higher transport and storage costs, however, give results that are essentially unchanged except for the particulars of the transition to capture and the subsidy for ocean storage.

We can also imagine different decision criteria for "winning," such as the difference between the price of electricity delivered to consumers and the levelized cost of generating that electricity, which is a rough measure of profit for electricity producers. When we run the model with this decision criterion, however, the output is fairly predictable – all decision models, even costly ones, are viable in California and the Northeast, where electricity prices are much, much higher than the rest of the country. This is certainly valuable information; we can conclude that there is much more flexibility in these markets for decision models, but it doesn't tell us much about the viability of different storage decision models in other markets.

Finally, it is important to note that the model as framed does not compare the decision to capture and store CO_2 to other electricity production options with different CO2 emission characteristics. When compared to natural gas or renewables, the power plant agents in this particular instantiation might do quite poorly. Extensions of this research are intended to explore this option and incorporate more detailed policy environments and a broader array of generation technologies to enable more comprehensive modeling.

CONCLUSIONS

Our principal conclusions for each objective are as follows:

Objective 1: Onshore Carbonshed Analysis

We find that the average value of transport and storage when sources cooperate to reduce transport costs is roughly $10/t, with costs decreasing as more storage reservoir options are included, and increasing as storage resources are depleted. Our depletion analysis indicates that large, centralized reservoirs could form the backbone of a major carbon storage system in the United States. Policymakers and industry planners could rapidly advance large-scale storage networks by skipping fragmented early networks and moving to centralized systems at a relatively minor cost of $0-2/t if 1.5 Gt/yr are captured from existing power plants.

Objective 2: Extension of Carbonshed Analysis to the Offshore

We compared the integrated transport and injection cost estimates for self-sealing and non-self-sealing offshore storage against the same integrated cost estimates for onshore storage in 15 deep-saline sandstone aquifers located throughout the continental U.S. The comparison was presented in the form of marginal abatement cost curves, which show that ocean storage is likely to be two or more times as expensive as onshore storage. 500 million tonnes of annual CO_2 emissions from coal-fired power plants in the U.S. is available for <$5/tonne in onshore DSAs, < $10/tonne in non-self-sealing offshore strata, and < $15/tonne in self-sealing offshore strata, with the cost differential between onshore and offshore storage increasing further up the supply curve. The higher total offshore costs are due to a combination of increases in transport and storage costs, with transport costs dominating total costs with increasing distance from shore. This suggests that CO2 capture system operators would have to pay substantially more for offshore geologic storage over onshore options. The cost difference may be mitigated by certain advantages of offshore storage, which could include easier access to property rights, simplified regulation, and possibly lower MMV requirements.

Objective 3: Agent-Based Modeling of Economic/Policy Scenarios for CCS

While we are still finalizing the findings from our agent-based modeling, one of the most important conclusions we can make at this point is that it may be significantly more cost effective for policymakers to move from supporting the characterization of many geologic options for CO_2 storage to funding detailed characterization of only the largest of these options; i.e. reservoirs that could store substantial amounts of existing and future emissions. Policymakers may also consider underwriting the risk for long-term storage in these few reservoirs, or locally develop policies particularly favorable to property rights acquisition.

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FIGURES

Figure 1: Schematic Representation of Carbonshed Concept. A simple representation of how carbonsheds are constructed and what information they show. In Panel A, transport between two sinks modeled in one dimension is shown, with cost equal in the sinks and transport cost increasing with distance. The carbonshed boundary is in the middle. In Panel B, we can see the effect of higher cost in sink 2 on the cost of transport and storage as well as the carbonshed boundary. Panel C shows this extended to a two-dimensional cost surface, which is how we display our integrated cost of transport and storage.

Figure 2: Aggregation of storage site cells into reservoir blocks. Panel (a) shows reservoir aggregation in a reality and panel (b) shows how that process is simulated using raster cells to form (in this case) 20 MT blocks. Adapted from Eccles et al.[26]

Figure 3: Schematic of onshore storage and two types of sub-seafloor ocean storage. Standard offshore storage involves a cap rock and generally occurs above 3000 m water depth. Self-sealing storage does not require a cap rock because density-driven gravitational mechanisms will keep the CO2 below the seafloor. This type of storage occurs below 3000 m water depth (adapted from Eccles and Pratson12).

Figure 4: Cooperative and Distributed Carbonsheds. The carbonsheds for the cooperative (a) and distributed (b) scenarios are shown. Several carbonsheds include OGR reservoirs (Index 1), but the majority of the landscape in both scenarios is dominated by DSA's. 9 and 13 sandstone DSAs (out of 15) are included in the carbonsheds in the cooperative and distributed scenarios, respectively. The costs vary dramatically between the two scenarios.

Figure 5: Cost Curves for Carbonshed Scenarios. This figure shows cooperative (10 MT) and distributed (1 MT) supply curves showing the cumulative annual emissions from power plants ordered by cost of transport and storage. Our main scenarios (green) are functionally identical to the scenarios without OGRs (blue). Without any major large, cheap reservoirs (OGR only - red), costs are extremely high, but once enough DSA's are available (blue, green), even adding large, cheap carbonate reservoirs (orange) does not move the cost curve very much.

Figure 6: Depletion of Carbonshed Example. The depletion of the Sandstone/O/G carbonshed (corresponding to Figure 2A) is shown, with summaries of the cost curves and the proportion of costs from storage and transport. Note that storage becomes highly centralized in the end of the depletion scenario, with relatively little impact on cost – mostly from increased transport costs.

Figure 7: Offshore cost (top) and capacity (bottom) for CO2 storage. Significant storage resources occur offshore along the Eastern Seaboard and in the Gulf of Mexico. Panels also include the onshore cost (top) and capacity (bottom) of 15 DSAs. Inset shows how offshore cost raster is divided into reservoir blocks.

Figure 8: Offshore marginal abatement cost curve for non-self-sealing and self-sealing offshore

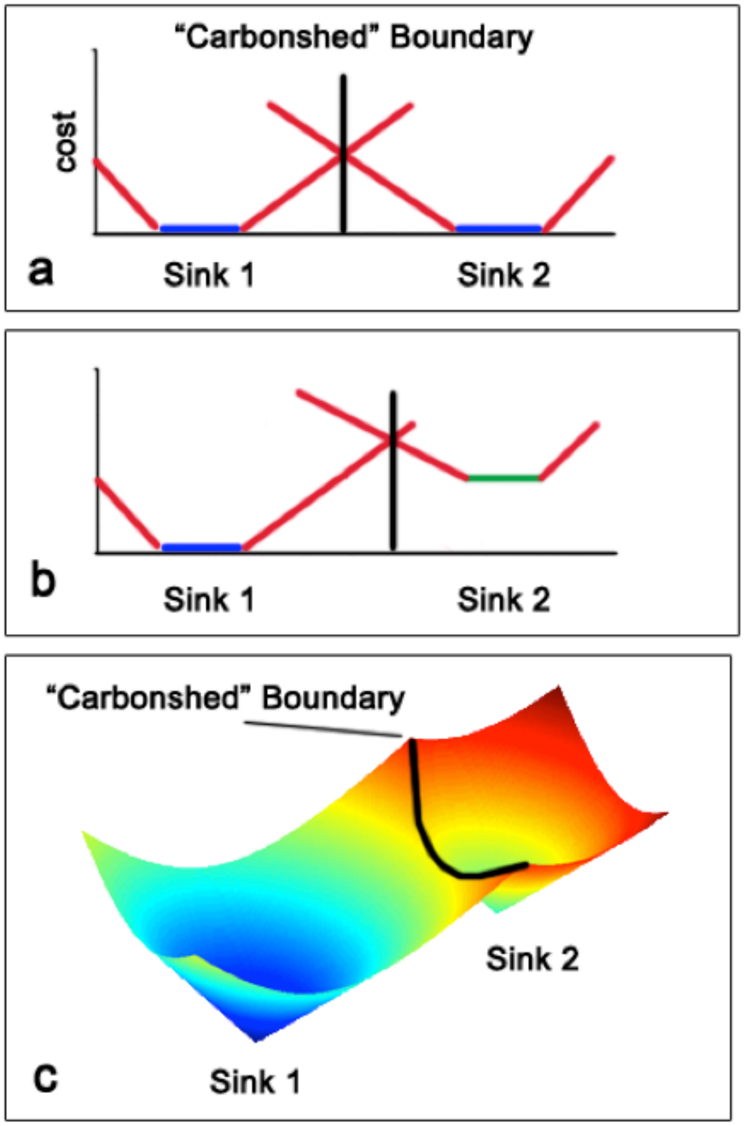
strata in the US EEZ.

Figure 9: Marginal abatement cost curve for onshore and offshore Storage based on the integrated cost of transport and storage for the three storage options: onshore, non-self-sealing offshore, and self-sealing offshore. The contribution of the transport and storage components of the integrated cost are also shown.

Figure 10. Spatial arrangement of winning plants and their decision options under two end-member carbon price scenarios. (b) How plants should arrange themselves without a carbon price. (a) How arrangement changes when a carbon price is applied

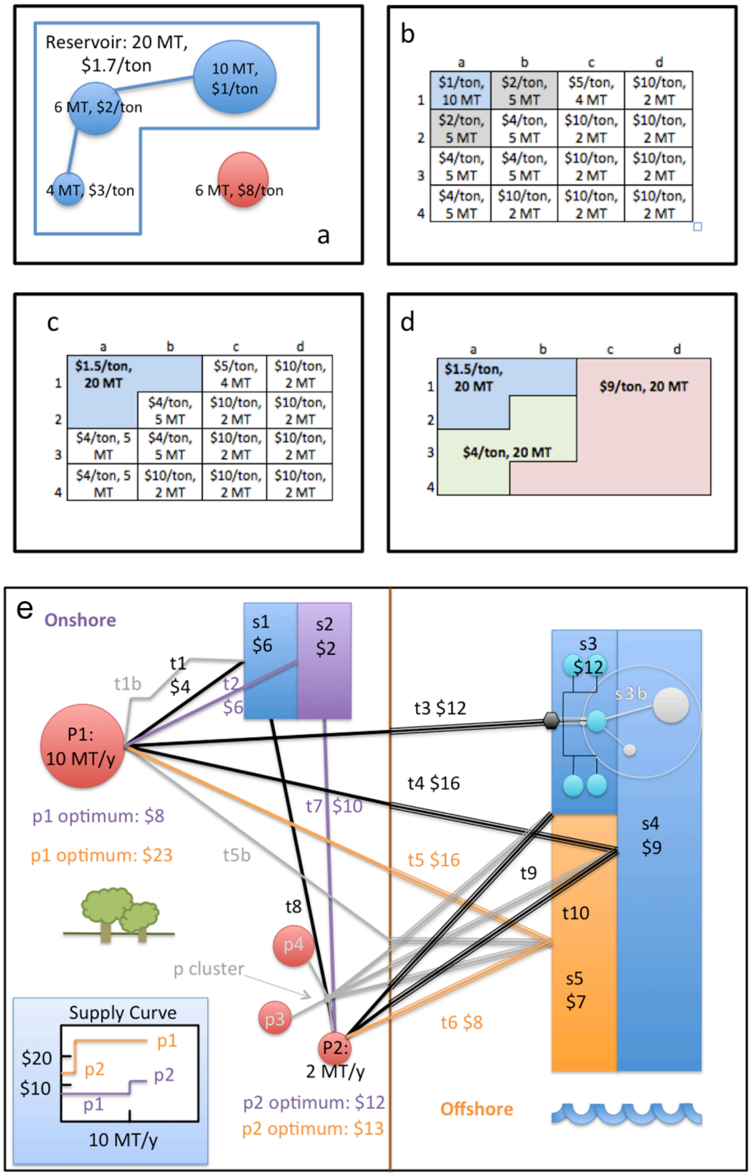
Figure 11. Plant participation as a function of carbon price.

Figure 12. Distribution of winning plants with the ocean subsidy policy option.



"Carbonshed" Boundary
cost
a
Sink 1
Sink 2
b
Sink 1
Sink 2
"Carbonshed" Boundary
Sink 2
c
Sink 1

Figure 1.



Reservoir: 20 MT, $1.7/ton
10 MT, $1/ton
6 MT, $2/ton
4 MT, $3/ton
6 MT, $8/ton
a
b
c
d
e
Onshore
s1 $6
s2 $2
t1 $4
t1b
t2 $6
P1: 10 MT/y
t3 $12
s3 $12
s3b
t4 $16
t7 $10
p1 optimum: $8
p1 optimum: $23
t5b
t5 $16
t9
s4 $9
t10
t8
p4
p cluster
p3
P2: 2 MT/y
s5 $7
t6 $8
Supply Curve
$20
$10
p1
p2
10 MT/y
p2 optimum: $12
p2 optimum: $13
Offshore

Figure 2.

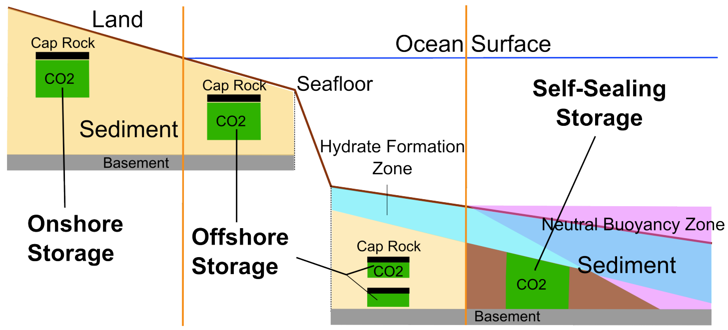

Land
Ocean Surface
Cap Rock
CO2
Sediment
Basement
Cap Rock
CO2
Seafloor
Self-Sealing Storage
Hydrate Formation Zone
Onshore Storage
Offshore Storage
Neutral Buoyancy Zone
Cap Rock
CO2
Sediment
CO2
Basement

Figure 3.

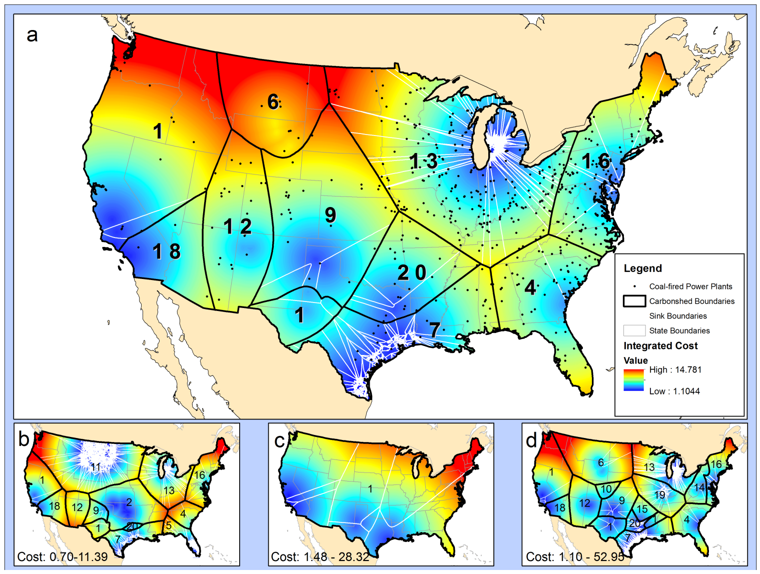
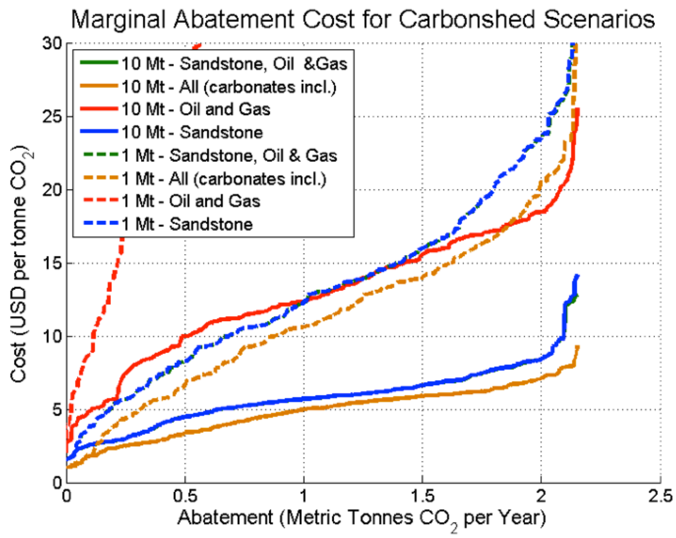

a
Legend
Coal-fired Power Plants
Carbonshed Boundaries
Sink Boundaries
State Boundaries
Integrated Cost
Value
High : 14.781
Low : 1.1044
b
Cost: 0.70-11.39
c
Cost: 1.48 - 28.32
d
Cost: 1.10 - 52.95

Figure 4.



Marginal Abatement Cost for Carbonshed Scenarios
10 Mt - Sandstone, Oil &Gas
10 Mt - All (carbonates incl.)
10 Mt - Oil and Gas
10 Mt - Sandstone
1 Mt - Sandstone, Oil & Gas
1 Mt - All (carbonates incl.)
1 Mt - Oil and Gas
1 Mt - Sandstone
Cost (USD per tonne CO_2)
Abatement (Metric Tonnes CO_2 per Year)
0
5
10
15
20
25
30
0
0.5
1
1.5
2
2.5

Figure 5.

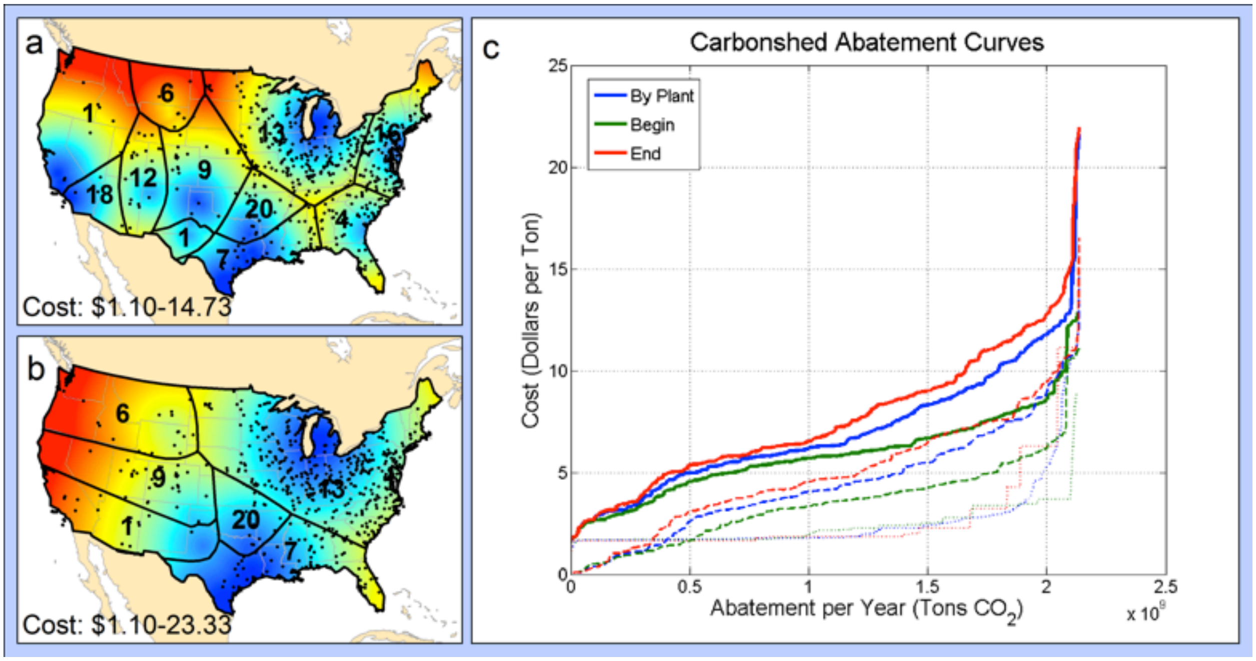

a
Cost: $1.10-14.73
b
Cost: $1.10-23.33
c
Carbonshed Abatement Curves
By Plant
Begin
End
Cost (Dollars per Ton)
Abatement per Year (Tons CO_2)
x 10^9

Figure 6.

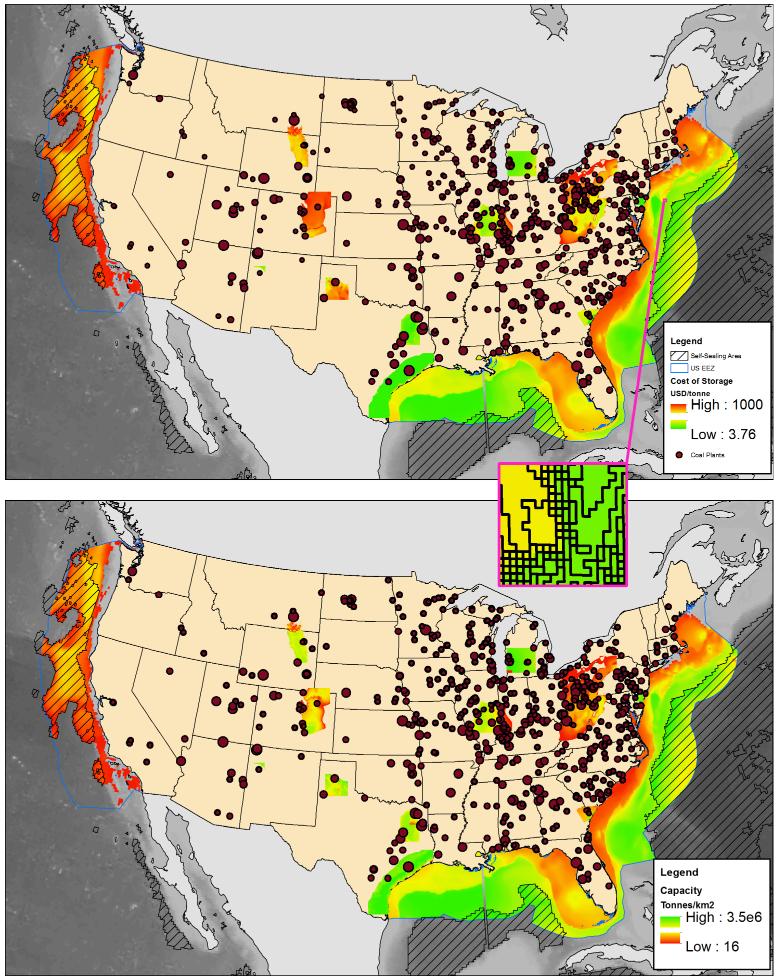
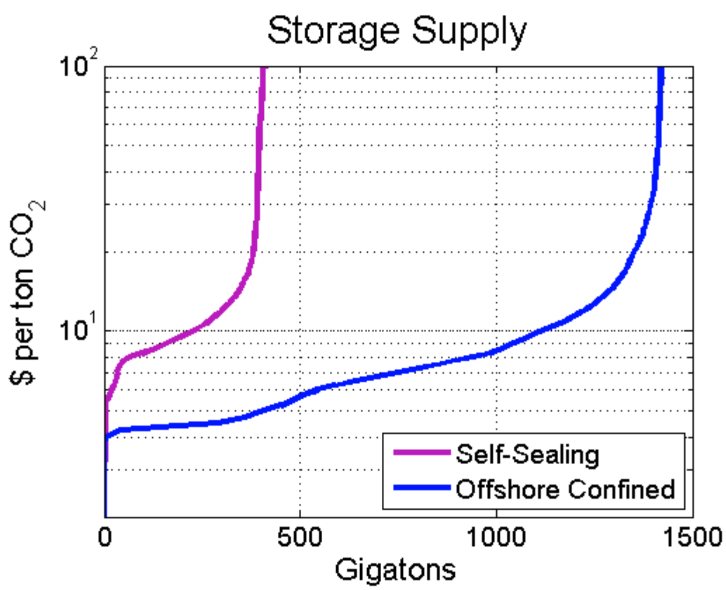

Legend
Self-Sealing Area
US EEZ
Cost of Storage
USD/tonne
High : 1000
Low : 3.76
Coal Plants
Legend
Capacity
Tonnes/km2
High : 3.5e6
Low : 16

Figure 7.



Storage Supply
10^2
10^1
$ per ton CO_2
Self-Sealing
Offshore Confined
0
500
1000
1500
Gigatons

Figure 8.

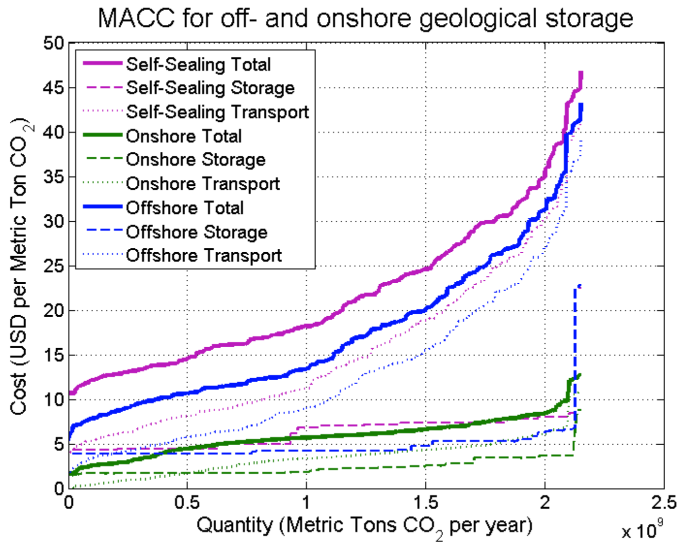

MACC for off- and onshore geological storage
Self-Sealing Total
Self-Sealing Storage
Self-Sealing Transport
Onshore Total
Onshore Storage
Onshore Transport
Offshore Total
Offshore Storage
Offshore Transport
Cost (USD per Metric Ton CO2)
Quantity (Metric Tons CO2 per year)
x 10^9
0
5
10
15
20
25
30
35
40
45
50
0.5
1
1.5
2
2.5

Figure 9.

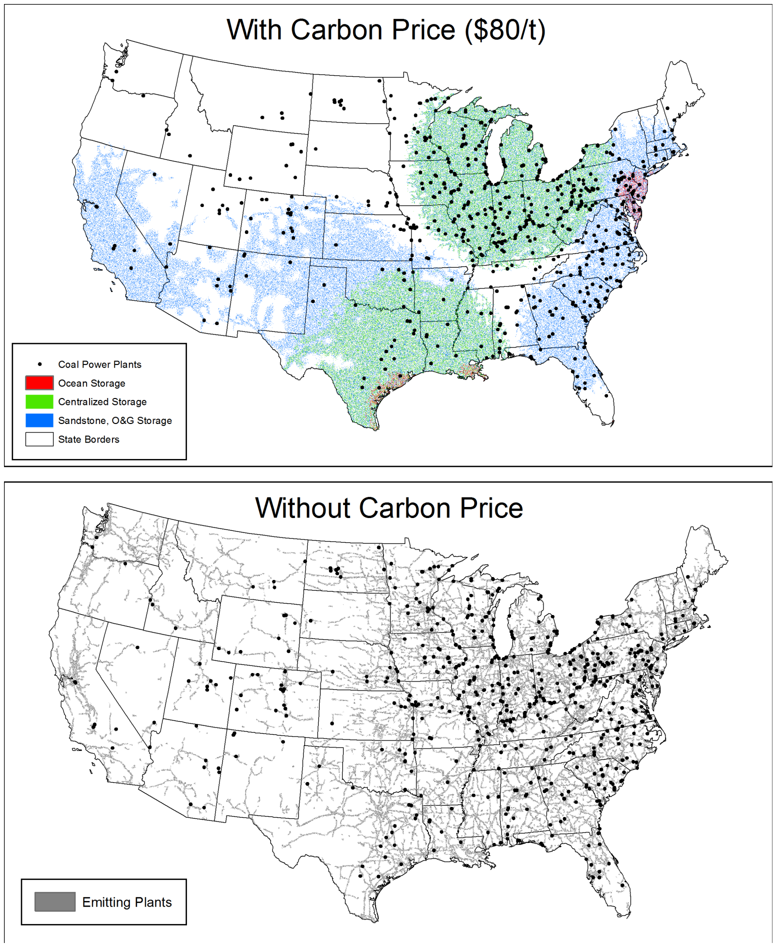

With Carbon Price ($80/t)
Coal Power Plants
Ocean Storage
Centralized Storage
Sandstone, O&G Storage
State Borders
Without Carbon Price
Emitting Plants

Figure 10.

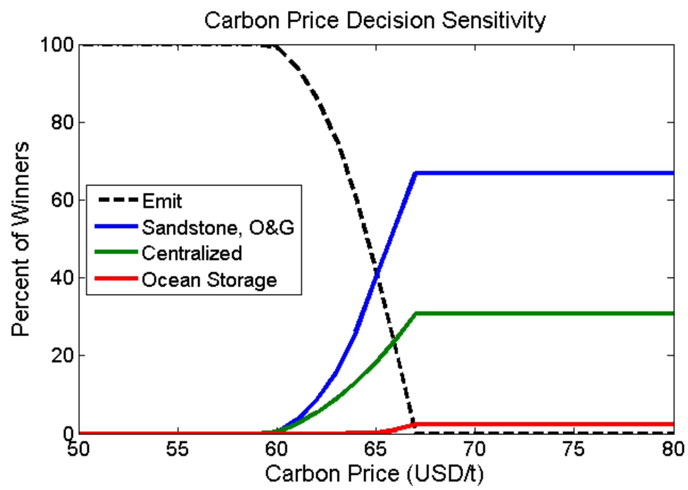

Carbon Price Decision Sensitivity
100
80
60
40
20
0
50
55
60
65
70
75
80
Percent of Winners
Carbon Price (USD/t)
Emit
Sandstone, O&G
Centralized
Ocean Storage

Figure 11.

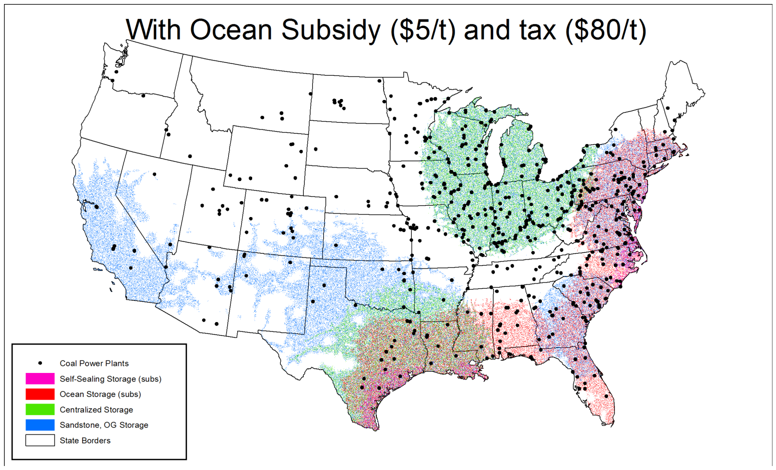

With Ocean Subsidy ($5/t) and tax ($80/t)
Coal Power Plants
Self-Sealing Storage (subs)
Ocean Storage (subs)
Centralized Storage
Sandstone, OG Storage
State Borders

Figure 12.

APPENDIX I – PAPERS & THESIS PRODUCED DURING THIS PROJECT

Papers

1. Eccles, J., L. Pratson, R.G. Newell, and R.B. Jackson, 2012, The impact of geologic variability on capacity and cost estimates for storing CO2 in deep-saline aquifers: *Energy Economics*, v. 35:5, p. 1569-1579.

2. Eccles, J., M.K. Chandel, and L.F. Pratson, 2012, Effects of well spacing on geologic storage site costs and surface footpring: *Environmental Science & Technology*, v. 46:8, p. 4649-4656.

3. Eccles, J.K, and L. Pratson, 2012, Global CO2 storage potential of self-sealing marine sedimentary strata: *Geophysical Research Letters*, v. 39:19.

4. Eccles, J.K, and L. Pratson, *in press*, Economic evaluation of offshore storage potential in the US Exclusive Economic Zone: *Greenhouse Gases: Science and Technology*.

5. Eccles, J.K, and L. Pratson, *in review*, A “Carbonshed” assessment of distributed vs. centralized CCS deployment in the continental U.S.: *Applied Energy*.

6. Eccles, J.K, and L. Pratson, *in prep*, An agent-based model for evaluating CCS deployment: to be submitted to *Applied Energy*.

Theses

7. Eccles, J., 2011, “Impacts of Geological Variability on Carbon Storage Potential”: PhD Dissertation, Duke University, Durham, NC, 143 pp.

8. Hall, K., 2012, “An Analysis of the Distribution and Economics of Oil Fields for Enhanced Oil Recovery-Carbon Capture and Storage”: MS Thesis, Duke University, Durham, NC, 58 pp.

APPENDIX II – PROJECT COSTS

Baseline Reporting Quarter	Year 1 Start: 12/1/2009 End: 11/30/2010				Year 2 Start: 12/1/2010 End: 11/30/2011				Year 3 Start: 12/1/2011 End: 11/30/2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Baseline Cost Plan	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633
Federal Share	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633
Non Federal Share	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
Total Planned (Federal and Non-Federal)	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633
Cumulitive Baseline Cost	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633	$298,633

	Year 1 Start: End:				Year 2 Start:12/1/2011 End:11/30/2011				Year 3 Start: 12/1/2011 End: 11/30/2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Actual Incurred Costs	$13,806	$31,320	$71,219	$100,525	$128,397	$157,471	$195,826	$234,130	$247,811	$262,967	$275,493	$291,709
Federal Share	$13,806	$31,320	$71,219	$100,525	$128,397	$157,471	$195,826	$234,130	$247,811	$262,967	$275,493	$291,709
Non Federal Share	$0	$0	$0	$0	$0	$0						
Total Planned (Federal and Non-Federal)	$13,806	$31,320	$71,219	$100,525	$128,397	$157,471	$195,826	$234,130	$247,811	$262,967	$275,493	$291,709
Cumulitive Baseline Cost	$13,806	$31,320	$71,219	$100,525	$128,397	$157,471	$195,826	$234,130	$247,811	$262,967	$275,493	$291,709

	Year 1 Start: End:				Year 2 Start:12/1/2011 End:11/30/2011				Year 3 Start: 12/1/2011 End: 11/30/2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Variances	$284,827	$267,313	$227,414	$198,108	$170,236	$141,162	$102,807	$64,503	$50,822	$35,666	$23,140	$127
Federal Share	$284,827	$267,313	$227,414	$198,108	$170,236	$141,162	$102,807	$64,503	$50,822	$35,666	$23,140	$127
Non Federal Share	$0	$0	$0		$0	$0	$0					
Total Planned (Federal and Non-Federal)	$284,827	$267,313	$227,414	$198,108	$170,236	$141,162	$102,807	$64,503	$50,822	$35,666	$23,140	$127
Cumulitive Baseline Cost	$284,827	$267,313	$227,414	$198,108	$170,236	$141,162	$102,807	$64,503	$50,822	$35,666	$23,140	$127

Cost elements	ITD Plan	ITD Actual	Balance	
60000 Salary	140,273.00	148,925.88	8,652.88-	
* Salaries and Wages	140,273.00	148,925.88	8,652.88-	106.17%
610000 FRINGE BENEFITS	9,969.00	17,881.09	7,912.09-	
* Fringe Benefits	9,969.00	17,881.09	7,912.09-	179.37%
647000 PUBLICATION EXPEN	4,500.00		4,500.00	
* Supplies and Materials	4,500.00		4,500.00	0.00%
698600 TRAV&LIVING EXP-D	7,500.00	2,673.58	4,826.42	
* Travel	7,500.00	5,069.86	2,430.14	67.60%
634700 FED AWARD-TUIT RE	45,535.00	30,378.00	15,157.00	
* Trainee Expenses	45,535.00	30,378.00	15,157.00	66.71%
** TOTAL DIRECT COSTS	207,777.00	202,254.83	5,522.17	97.34%
694600 INDIRECT COSTS -	90,856.00	96,251.08	5,395.08-	
** INDIRECT COSTS	90,856.00	96,251.08	5,395.08-	105.94%
*** TOTAL PROJECT COSTS	298,633.00	298,505.91	127.09	99.96%
**** Cost element group	298,633.00	298,505.91	127.09	99.96%

APPENDIX III – SCHEDULE/MILESTONE STATUS

We completed all of our tasks during the project except for the final task under Objective 3. As was noted in our last Progress Report (3rd Quarter, Year 3), we anticipated completing the agent-based modeling, but did not anticipate having a manuscript on the study submitted before this project closed. While that ended up being the case, we have completed a draft of the manuscript and plan to submit it for publication later this spring (2013).

Objective	Task/ Subtask #	Project Milestone Description	Project Duration - Start: 1/1/2010 End: 12/31/2012											
			Project Year (PY) 1				PY2				PY3			
			Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12
1. Expand Carbonshed Analysis to include all major types of potential CO2 storage sites	1.1	Access NATCARB database and adjust mapping algorithms to be able to draw inputs from database.												
	1.2	Develop economic geosequestration models for other major types of potential CO2 storage sites.												
	1.3	Build composite carbonshed scenarios involving multiple storage types.												
	1.4	Construct supply curves for types of storage sites, potential depletion timescales, and evolution of carbonshed landscape.												
	1.5	Submit manuscript on composite carbonshed scenarios to peer-reviewed journal.												
2. Develop regional-scale assessments of US offshore CO2 storage potential, transport options to access this potential, and its impact on national carbonsheds and the cost of transport.	2.1	Map out subseafloor regions (areal extents and depths) where CO2 should remain supercritical if stored beneath the seafloor.												
	2.2	Build an economic model for offshore transport and storage of CO2 that accounts for existing regional infrastructure												
	2.3	Integrate offshore storage into the carbonshed framework, indicating how US land-based carbonsheds could link to and be affected by potential offshore storage regions.												
	2.4	Submit manuscript on inclusion of US offshore carbonshed potential to peer-reviewed journal.												
3. Explore the impacts of different economic/policy scenarios on the future demand for CO2 transport with in different carbonsheds using agent-based socio-economic modeling.	3.1	Assemble US cost maps of variables that will affect the deployment of CCS, including power plants, demand centers, and transmission.												
	3.2	Use existing econometric models and/or develop new ones for how policy/economic conditions will affect the behaviors of these variables.												
	3.3	Conduct agent-based modeling of how various potential CCS participant with different decision priorities and spatial locations will respond in terms of participating in a CCS system under economic and policy scenarios that affect the cost of CCS.												
	3.4	Submit manuscript on impact of economic/policy on US carbonshed evolution.												Pending