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Implications of Compensating Property-Owners for Geologic Sequestration of CO_2

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Abstract

Geologic sequestration (GS) of carbon dioxide (CO_2) is contingent upon securing the legal right to use deep subsurface pore space. Under the assumption that compensation is required to use pore space for GS, we examine the cost of acquiring rights to sequester 160-million metric tons of CO_2 (the 30-year emissions output for an 800 megawatt power plant at 90% capture efficiency) using a probabilistic model to simulate the temporal-spatial distribution of subsurface CO_2 plumes in several brine-filled sandstones in Pennsylvania and Ohio. For comparison, the Frio Sandstone in the Texas Gulf Coast and the Mt. Simon Sandstone in Illinois were also analyzed. The predicted CO_2 plume distributions have a median range of 3,700 km^2 to 9,600 km^2 for the Ohio and Pennsylvania sandstones compared to 320 km^2 and 300 km^2 for the thicker Frio and Mt. Simon Sandstones. We model the cost to use pore space in Pennsylvania and Ohio and, alternatively, the cost of piping CO_2 from Pennsylvania and Ohio to the Mt. Simon or Frio Sandstones. The results suggest that pore space acquisition costs could be significant, and that using thin local formations for sequestration may be more expensive than piping CO_2 to thicker formations at distant sites.

1. Introduction

Geological sequestration (GS) of carbon dioxide (CO_2) from power plants and direct air capture has the potential to significantly reduce CO_2 emissions to the atmosphere. However, because CO_2 sequestered in deep geologic pore space could migrate laterally over a very sizeable area [1, 2], sequestration capacity may be limited in some parts of the United States. Since CO_2 plumes could be large, there is a very real possibility that GS injection fields will overlap and interfere with competing uses of the subsurface. Before a sequestration reservoir can be developed, the project developer will have to acquire the legal right to access and use pore space to avoid liability for subsurface trespass. Trespass is a legal theory that redresses property owners for physical invasions of their property (surface and subsurface) by others and/or activities that substantially limit their ability to use and enjoy their property fully. [3, 4] Under current law, if a GS project developer negotiates an agreement with a landowner to use the pore space in exchange for monetary compensation then risks to the developer for liability in trespass would be effectively eliminated.

However, it remains unclear whether, or how widely, compensation for the use of pore space will be legally required. For example, U.S. courts have consistently ruled that, due to the overarching public benefit of disposing fluid waste underground, technical trespass claims against waste injection operators properly licensed under the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) program are generally compensable only when a material impairment with use of the subsurface or the surface can be demonstrated by the aggrieved property owner. [4-7] This same rationale has been applied to state-authorized enhanced oil and natural gas recovery operations and field unitzation – that is, claims for subsurface trespass must yield to the public interest of efficiently producing natural resources. [4-7] In these cases, finding that a trespass occurred depends both on the degree of financial importance as well as the feasibility of future utilization of the resource. [4]

To our knowledge, none of the hundreds of operations currently injecting fluid wastes under the EPA UIC program compensate landowners for the use of pore space. [8]

However, absent specific new legislation limiting trespass liability, it is not safe to assume that the same will be the case for sequestration of CO_2. For one, GS facility operators will likely have "deep pockets," so there is a high probability the issue will be litigated. Secondly, some legal commentators posit that the body of case law controlling property disputes arising from the underground storage of natural gas might be invoked by landowners when sequestered CO_2 migrates under their property, providing them with a legally cognizable expectation of compensation. [4, 6, 9] This notion has credence in large part because it is common practice for a natural gas storage company to compensate all property owners potentially affected by a storage project outright in exchange for control of the entire storage field. [4, 6, 10]

In the future, new law might assure access to pore space and expressly limit trespass liability for GS. [7] Absent such a legal or regulatory regime, one issue that could affect the viability of GS in the United States is the cost of compensating landowners for the use of pore space. No existing literature examines the degree to which compensating landowners for the use of pore space will affect the economics of GS. Moreover, only analogues, rather than CCS-specific precedents, exist which can provide a guide to calculating the cost of compensating pore space owners. The cost of acquiring pore space rights will be highly dependent on the requirements of the regulatory and common law and business practices to which a GS project is subject. Here we assess the economic impact if GS project developers must lease or purchase the rights to sequester CO_2 in the subsurface under arrangements similar to those now used for natural gas storage.

The primary predictor of cost will be the land surface footprint under which the injected CO_2 is likely to migrate over a fixed time interval. We designed a probabilistic model to: 1) simulate the temporal and spatial evolution of a subsurface CO_2 plume using geologic data available for deep saline-filled sandstones considered to be suitable GS targets in the Pennsylvania, Ohio, Illinois and the Texas Gulf Coast; and 2) calculate the cost to lease and purchase pore space rights as a function of CO_2 plume size. This analysis ignores the potential impacts of pressure perturbations that can extend far beyond the footprint of the injected CO_2. [11, 12] Because the geologic properties of the reservoirs examined in this analysis vary substantially (this is true among all potential sequestration reservoirs in the United States [13]), CO_2 plume sizes and the cost of acquiring pore space rights could span several orders of magnitude. Thus, the cost of acquiring pore space rights could be high enough for a GS project developer to consider transporting CO_2 to a location where pore space acquisition costs will be lower. We conclude by assessing the cost of transporting CO_2 via pipeline from the Ohio and Pennsylvania area, where the relatively thin local reservoirs and the potential for very large CO_2 plume extents may not be conducive to large-scale GS [14], to the thick reservoirs in Illinois and the Texas Gulf Coast.

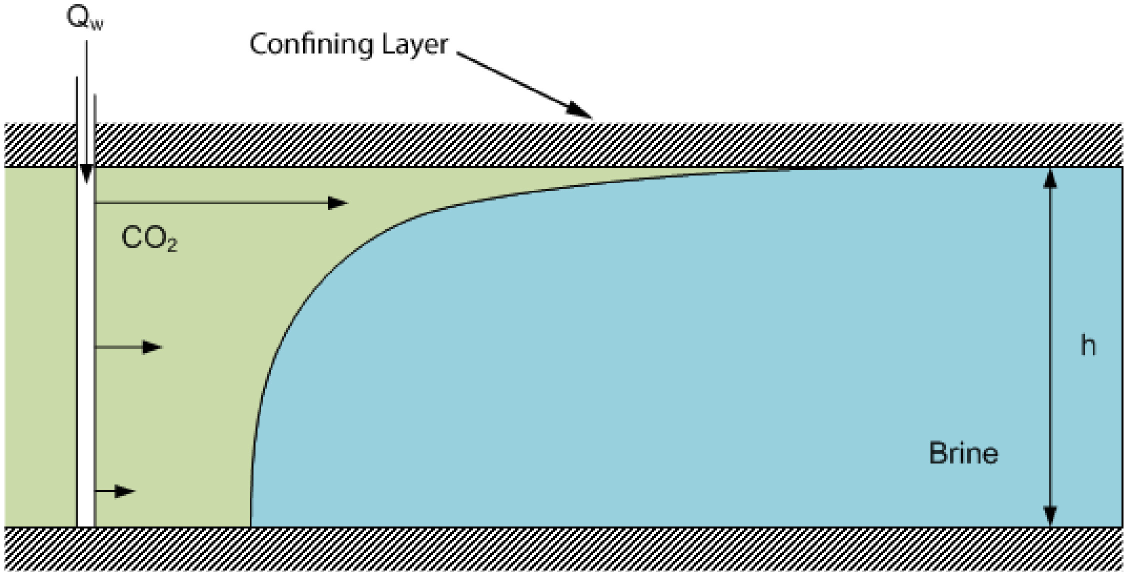
2. Analytical Model: Estimating CO_2 Plume Size and the Cost of Acquiring Pore Space Property Rights

2.1. CO_2 Plume Migration Model

Injection of CO_2 into saline formations and depleted or producing oil and gas reservoirs results in the flow of multiple fluid phases through the porous medium. [15] Multiphase flow models that account for differing fluid and rock properties enable fluid flow processes, such as those occurring in GS, to be simulated. We developed a probabilistic model using the analytical multiphase solution for estimating the areal distribution of a plume created by injecting CO_2 into a deep saline formation over a specified time horizon presented by Nordbotten et al. [15] Although simplified analytical methods are not sufficient to predict the movement of injected CO_2 in heterogeneous and anisotropic formations with high degrees of accuracy, typically not enough geological data are available during the early phases of any site selection process to allow for the use of more complex numerical models. The Nordbotten et al. solution provides the means for calculating a useful bounding estimate for the extent of migration of a CO_2 plume given the constraints of the geological data currently available for deep saline-filled formations.

Nordbotten et al. [15] showed that, under typical sequestration conditions, the velocity of the CO_2 front is higher near the top of the reservoir than at the bottom; thus, the general shape of the CO_2-brine interface has a progressively increasing (upward) vertical location with increasing radial distance from the injection well (see Figure 1).This result minimizes the work required to inject CO_2 into a homogeneous, isotropic geological formation. The general shape of the invading front is the basis for the development of their simple analytical solution, coupled with an assumption of a sharp interface between the fluids. [15]

Figure 1: Geometry of a system where CO_2 is displacing brine under the Nordbotten et al. solution.[15]



CO_2 is typically sequestered as a supercritical fluid to maximize sequestration efficiency.[16] For temperatures greater than T_c=31.1 °C and pressures greater than P_c =7.38 MPa, CO_2 is in a supercritical state. [16] At these pressure and temperature conditions, CO_2 behaves like a gas by filling all the available volume and has a "gas-like" viscosity, but a "liquid-like" density that increases, depending on pressure and temperature, from 150 to >800 kg/m^3. [16] The higher the density of CO_2, the more efficiently the pore space can be used to sequester CO_2 as a separate phase because buoyant forces, which drive CO_2 upwards and laterally (underneath the confining layer), decreases as the density of the CO_2 phase approaches that of the brine. To maximize the efficiency of geological sequestration, CO_2 injection is typically limited to depths greater than 800 meters, where supercritical conditions would be met assuming a hydrostatic pressure gradient 1 MPa per 100 m and geothermal gradient of 25 °C per km. [17]

Thus, migration models of the CO_2 must account for: gravity override caused by buoyancy of the CO_2 phase; the greater lateral mobility of CO_2 compared to brine, which results from the lower viscosity of CO_2; and, the injection work-minimizing distribution of CO_2 in the formation. [15] The importance of the buoyant forces in sequestration

relative to the viscosity and pressure forces is related by the dimensionless quantity, Γ,

given by:

$$\Gamma = \frac{2\pi g \lambda_w k \Delta\rho h^2}{Q_w} \qquad \text{(Eq. 1)}$$

where g [m/s^2] is acceleration due to gravity, λ_w [$1/Pa\ s$] is the phase mobility of brine, k [m^2] is permeability of the rock matrix, $\Delta\rho$ [kg/m^3] is the density difference between the brine and CO_2 phases, h [m] is the net thickness of the formation, and Q_w [m^3/s] is the volumetric injection rate of CO_2 at reservoir conditions.

When buoyancy is insignificant relative to viscous effects (i.e. the value of Γ is small) the full solution for calculating plume size reduces to the radial Buckley-Leverett equation (Equation S-8, Supporting Information), a transport equation used to model two-phase flow in porous media. [15] This equation has been the basis of a number of analytical models of deep well fluid injection. [18-20] Using this simplification, the equation for the maximum radial extent of the CO_2 plume, $r_{\max}$, which for a constant volumetric injection rate of Q_w given by [15]:

$$r_{\max}\left[km\right] = \sqrt{\frac{\lambda_c V}{\pi h \varphi \lambda_w \left(1 - S_{wc}\right)}} \times \frac{1\,km}{10^3\,m} \qquad \text{(Eq. 2)}$$

where λ_c $\left[1/Pa \cdot s\right]$ is the phase mobility of CO_2, V $\left[m^3\right]$ is the volume of injected CO_2, φ $\left[\%\right]$ is formation porosity, and S_{wc} $\left[\%\right]$ is the residual brine saturation in formation. In the cases where the value of Γ is large—in this case, greater than 0.5—the buoyant forces cannot be neglected and the more complex solution incorporating buoyant effects developed by Norbotten et al. [15] is used to estimate $r_{\max}$ (Equation S-12, Supporting Information). Physical properties of CO_2 at reservoir conditions were estimated using the cubic equation of state with Peng-Robinson parameters and the transport properties using the method of Chung et al., and modified for high pressure application by Reid et al. [21-23] Physical and transport properties of brine were estimated using the correlation of Batzle and Wang. [24]

The model assumes a homogeneous, isotropic reservoir, and calculates CO_2 plume footprints that result from a single vertical injection well, completed through the total thickness of the formation. Of course, due to the heterogeneous nature of rock properties, and structural and stratigraphic features, no CO_2 plume will migrate uniformly. Moreover, because of pressure constraints in the subsurface due to the need to avoid fracturing the geological containing unit, multiple injection points would likely be required to carry-out a GS project of this size (~15,000 tonnes per day injected). [25-27] Further details on the model and the underlying assumptions can be found in Nordbotten et al. and in the Supporting Information. [15]

2.2. Cost of Acquiring Pore Space Rights

We estimate the cost to lease pore space on an annual basis and long-term basis, along with the cost to purchase pore space rights up-front. In theory, pore space leases could contractually require the project developer to compensate the pore space owner in perpetuity because free-phase CO_2, which could ostensibly preclude alternative uses of the pore space, will be present in the reservoir for hundreds to thousands of years. Therefore, the cost of leasing pore space annually was examined over a 100-year time horizon. Because of discounting, present value cost assessments beyond 100 years are not meaningful. For the 100-year lease, it is assumed the injected CO_2 ceases to migrate beyond the 30-year plume size calculated by the model.

The annual lease rate ($/acre/year) for pore space is based on the going rates for natural gas storage on both privately owned lands and state-owned forestlands in Pennsylvania.

[28] At $45-65 per acre-per year, the Commonweatlh exacts a premium from natural gas storage firms for use of its pore space compared to what private landowners receive, typcially $2-10 per acre-per year. This analysis assumes natural gas storage lease rates are fairly uniform throughout the United States. Acquisition price per acre was extrapolated from the annual lease rates for the long-term lease scenario. The long-term lease bears a higher per acre price tag ($20 to $600 per acre) than the annual lease because all compensation for use of the pore space is redeemed up-front. These rates represent the present value (with a 15% discount rate and 4% inflation rate) of the aggregate payment streams generated over 100 years across the range of annual lease rates applied to the model. The per acre cost of purchasing pore space was calculated by taking the product of the maximum CO_2 plume size estimate and the present value of (also with a 15% discount rate and 4% inflation rate) of the aggregate payment streams generated over 30-years across the range of annual lease rates applied to the model. Due to discounting, the per acre purchase cost is nearly identical to the long-term lease rate.

Application of the annual lease scenario supposes regulations will require that the legal rights to all pore space lying under the areal footprint (referred to as the area of review) predicted using a CO_2 plume distribution model must be acquired by the GS project developer as a precondition to commencing any injection activities. On the other hand, the long-term lease scenario examined here would not require project developers to acquire all pore space rights identified to be within the area of review, but rather allows the developer to acquire, for a one-time payment made to each relevant landowners situated within the area of review, the option to lease their subsurface pore space. From thereon, up-front per acre lease payments would only be made on an “as needed” basis, meaning that as periodic subsurface monitoring reveals the actual migratory path of the CO_2 plume, only the affected landowners would receive a one-time lease payment. Monitoring costs are not considered in this calculation because prudent sequestration operators will conduct periodic seismic tests to monitor CO_2 plume migration regardless of whether a pore lease option is employed. For example, Benson et al. developed scenarios in which seismic surveys are performed in the each of the first two years, the fifth-year, and every fifth year thereafter for 80 years. [29]

3. Pipeline Transport Model

Transport of CO_2 to a sequestration site by pipeline is simulated using an engineering economic model developed by McCoy and Rubin. [30] CO_2 is piped in a supercritical state to maximize transport efficiency. Because there are many similarities between the transport of natural gas and CO_2, capital costs are based on a regression analysis of natural gas pipeline project costs available in Federal Energy Regulatory Commission (FERC) filings from interstate gas transmission companies. [30-32] Capital costs for pipeline include costs for materials, labor, rights-of-way (ROW), and miscellaneous charges (such as taxes, project management, administration and overheads, regulatory fillings fees, and contingencies allowances). [30, 31, 33] Pipeline costs generally vary based on the length and diameter of the pipeline as well as the quantity of CO_2 transported. Pipeline diameter is a function of CO_2 mass flow rate. [30, 31] Pipeline costs will therefore vary with pipeline length and the CO_2 flow rate. Specific pipeline costs also vary by geographic region and terrain. [30, 31] Regional cost differences are captured in the model, though the impact of terrain on cost is not considered. The project regions are the same as those used by the Energy Information Agency (EIA). [30, 34] Capital costs were annualized using a fixed charge factor of 15%, which corresponds to a project with a 30-year life and a 14.8% real discount rate.

4. Model Application

The total mass of CO_2 injected was fixed at 160-million tonnes (MT), approximately the amount of CO_2 captured from an 800 MW coal plant in Pennsylvania or Ohio, operating with a 60% capacity factor and at 90% capture for 30 years. [8, 35] Pennsylvania and Ohio were chosen for analysis because they are major coal-burning states that are also thought to contain geology suitable for large-scale sequestration of CO_2. In 2007, 70% of the electricity generated in Pennsylvania and Ohio was generated using coal as a fuel source. [36] Pennsylvania and Ohio alone combine to make up roughly 13% of America's coal-fired electricity generation, and nearly 10% of all electricity generation in the United States is generated by burning coal in these two states. [36]

The Midwest Regional Carbon Sequestration Partnership (MRCSP) estimated that Pennsylvania and Ohio have potential GS capacities of around 90 gigatonnes and 46 gigatones, respectively. [37] The saline formations with the largest capacity in the MRCSP region are the Mt. Simon, St. Peter, and Medina/Tuscarora Sandstones. [38] Others are the Oriskany Sandstone, Rose Run, and the Sylvania Sandstones. [38] Sufficient geologic core data from numerous oil and natural gas fields in the MRCSP region are available to support analysis of the Clinton (OH), Medina (PA), Oriskany (PA), and Rose Run Sandstones (OH). These data were obtained from the Ohio Department of Natural Resources Division of Geological Survey. [39] Observations for which the average formation depth is shallower than 800 meters were removed from the dataset. Only observations with a net thickness greater than or equal to 10 meters were included in the analysis because portions of these reservoirs where net sand is less than 10 meters may be too thin for sequestration to be feasible. [27] The point estimates for the average formation depth, net thickness, porosity and salinity for each oil and gas field in the Clinton, Medina, Oriskany and Rose Run Sandstones that met these cut-off criteria were then aggregated and converted into triangular distributions (Table S-1, Supporting Information). Stochastic simulations were run using the parameterized geological data as inputs into the CO_2 plume distribution model.

Simulations were also run using deterministic input values based on three oil and gas fields – the Volant, East Canton Consolidated-S, and Baltic fields – with large estimated CO_2 sequestration capacities respectively located in the Medina, Clinton, and Rose Run Sandstones (Table S-1, Supporting Information). Maximum CO_2 plume areas were predicted using deterministic input values for two case comparisons: the Frio Sandstone in the Texas Gulf Coast, and the Mt. Simon Sandstone at the Mattoon, IL site originally selected for the FutureGen™project. The Frio dataset is a compilation of core analysis data, geophysical logs, and data extrapolated from available literature by the Texas Bureau of Economic Geology (BEG). [13] The geologic inputs for the Frio Sandstone represent the mean value for each parameter (Table S-1, Supporting Information). The Mt. Simon data were assembled by the Illinois State Geological Survey for the site selection proposal submitted by the Survey to the FutureGen™Alliance (Table S-1, Supporting Information). [40, 41] The Mt. Simon data were taken from geophysical log data and limited core analysis data. Only point estimates for the Mt. Simon Sandstone were available for each geologic parameter.

The CO_2 pipeline model was applied to determine the cost of constructing and operating the necessary infrastructure to transport carbon dioxide captured from a hypothetical 800 MW coal-fired power plant operating for 30 years near the middle of the Pennsylvania/Ohio border to either the Mt. Simon Sandstone in Mattoon, IL (710 km), or a non-specific location in the Frio Sandstone along the North Texas Gulf Coast (1,860 km). A new, stand-alone pipeline would be required for the Mattoon site, whereas a new pipeline originating near the middle Pennsylvania/Ohio border carrying CO_2 to Texas could tie into existing CO_2 pipeline infrastructure in Jackson, MS (see Figure S-9, Supporting Information). Because capital and operating costs for CO_2 pipelines vary by region as noted above, annualized costs were weighted based on the proportion of the pipeline that traverses each region.

5. Results

5.1. CO_2 Plume Size

Probabilistic simulations for the Medina, Oriskany, Clinton, and Rose Run Sandstones predict median CO_2 plumes sizes ranging from 3,700 km^2 to 9,600 km^2 in areal extent. The distribution of predicted plume sizes plume sizes at the 5th, 50th, and 95th percentile statistical levels for each reservoir are presented in Table 1. The deterministic estimates for Volant, East Canton, and Baltic oil and gas fields are 1,100 km^2, 5,200 km^2, and 4,200 km^2, respectively. The deterministic simulations predict much smaller plumes for the Frio and Mt. Simon Sandstones: 320 km^2 and 300 km^2, respectively. Given that the Mt. Simon and Frio Sandstones are much thicker (net sand) than the sandstones in the MRCSP region we examined, we expected to observe smaller predicted CO_2 plume distributions for each of these cases.

Cumulative distribution curves comparing the results obtained for the Medina, Oriskany, Clinton, and Rose Run Sandstones from implementation of the probabilistic plume-distribution model are provided in the Supporting Information. The sensitivity of CO_2

plume size for each Pennsylvania and Ohio sandstone formation to uncertainty and variability in depth, net thickness, porosity, and salinity was examined probabilistically. With the exception of the Rose Run Sandstone simulation, formation thickness, porosity, and residual brine saturation had the greatest effects on predicted CO_2 plume size (see Supporting Information). Plume size is negatively correlated with thickness and porosity, but positively correlated with residual brine saturation. Plume distribution estimates for the Rose Run Sandstone were most heavily influenced by formation depth, and were smaller at greater depths.

Table 1: Areal extent of CO_2 plume size at 30-years for a total of ~160-million tonnes CO_2 injected

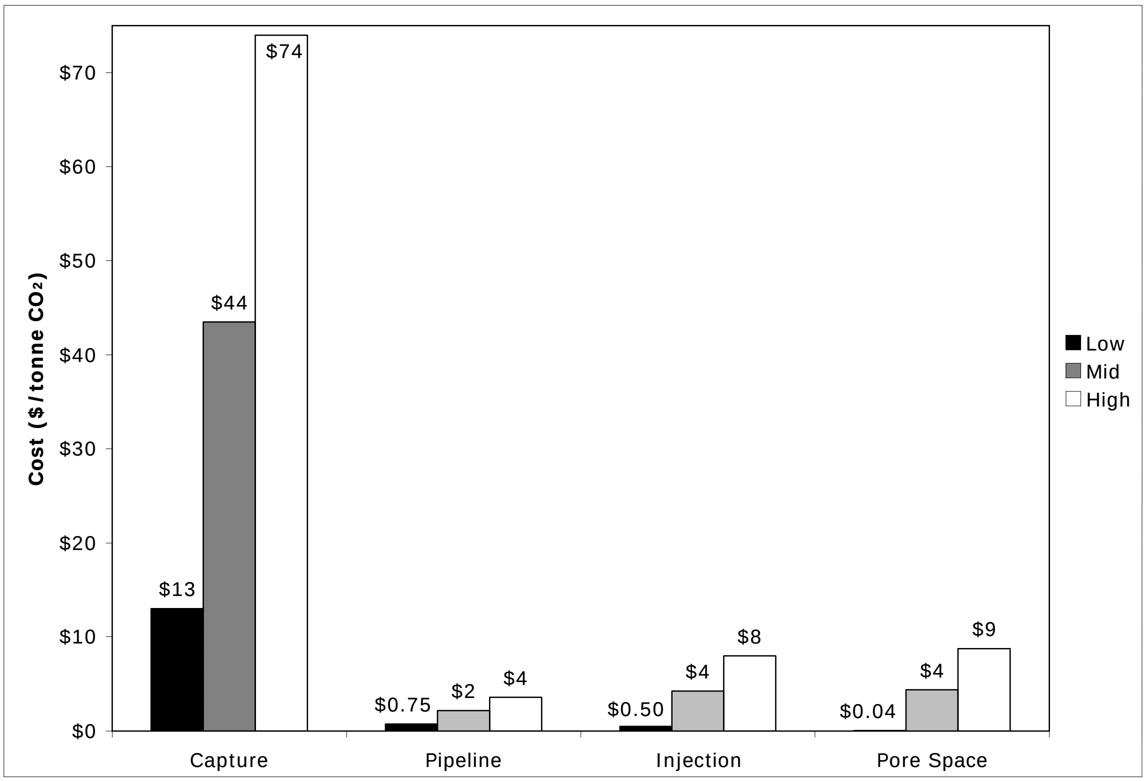
Formations and Oil & Gas Fields	**Plume Size Estimates (km^2)**
Frio Sandstone (TX)	320
Mt. Simon Sandstone (IL)	300
Medina Sandstone (PA)	
5th Percentile	1,400
Median	3,700
95th Percentile	11,000
Volant Field	1,100
Oriskany Sandstone (PA)	
5th Percentile	2,800
Median	6,400
95th Percentile	17,100
Clinton Sandstone (OH)	
5th Percentile	5,000
Median	8,600
95th Percentile	19,000
E. Canton Consolidated-S Field	5,200
Rose Run Sandstone (OH)	
5th Percentile	5,600
Median	9,600
95th Percentile	21,000
Baltic Field	4,200

5.2. Pore Space Acquisition Cost

Results suggest that if operators must pay for rights to use pore space for GS under the assumptions outlined above, the median cost in Pennsylvania and Ohio could range from \$18-million to \$220-million for privately owned land and \$380-million to \$1.4-billion for state-owned land if pore space is either leased annually or purchased outright; and between \$5.7-million and \$68-million for privately owned land and \$110-million to

$410-million for state-owned land if pore space is leased up-front (see Table S-3, Supporting Information). This is roughly the equivalent of $0.04 to $9 per tonne of CO_2 injected. This means the cost of acquiring the legal right to sequester CO_2 could be comparable to, or even exceed, the operational cost of GS, which the Intergovernmental Panel on Climate Change (IPCC) estimated to be between $0.5 to $8 per tonne CO_2. [33] Figure 2 presents a comparison of the costs for each individual activity in the sequestration chain.

Figure 2: Comparison of CCS Activity Costs: Capture [42], Pipeline [30], Injection [33] & Pore Space Acquisition



If compensation is required for access to and use of pore space for GS, the long-term lease approach is consistently the most favorable from an economic standpoint compared to both the annual lease and purchase options by a factor of 3. It should be noted that if pore space is leased annually under a mechanism applied to the long-term lease scenario – that is, annual lease payments are a function of incremental plume growth rather than maximum predicted areal extent of the plume – the costs under the two lease scenarios are nearly equal, despite the lower per acre annual lease rates.

Economics aside, pore space leases, regardless of their construction, might not actually be practical in the long-term. Because the risk of leakage and other adverse consequences, however small, are likely to persist beyond the lifetimes of the private firms operating sequestration facilities, there is general agreement that long-term responsibility for the stewardship of closed sequestration sites must be assumed by the national or state governments, or other institutions designed to last for many hundreds of years. [43, 44] Hence, these institutions might need to take on ownership of the subsurface for closed sequestration sites for the same reason. In order for such agreements to be viable, GS project developers would need to actually own the pore space because it is unlikely these institutions would agree to take on the economic burden of making lease payments to private landowners. Purchasing pore space rights up-front would be a relatively straightforward contractual matter. However, in order to avoid the situation where the GS project developer delays the decision to purchase pore space rights until the end of the original lease period and the landowner effectively holds the rights hostage by demanding an unreasonably high purchase price, the developer could render an option payment at the beginning of the original lease term for the right to purchase the rights at the conclusion of the lease term for a predetermined price.

5.3. Pipeline Construction and 30-year Operation Cost

The total annualized cost (capital and operational) of transporting approximately 5-million tonnes CO_2 annually from a large coal-fired power plant near the Pennsylvania-Ohio boarder (such as the Bruce Mansfield plant [35]) to the Mt. Simon Sandstone in Mattoon, IL is $41-million ($8 per tonne CO_2), and $75-million ($14 per tonne CO_2) if the CO_2 is piped to the Frio Sandstone in the North Texas Gulf Coast region. Thus, for an operational lifetime of 30 years, the total cost to transport CO_2 to the Mattoon site and acquire the necessary pore space rights would be $380-million ($2 per tonne CO_2), and $680-million ($5 per tonne CO_2) for the Frio site (see Table 2).

Table 2: Pipeline & pore space acquisition cost (millions 2008$) – PA/OH to Mattoon, IL and Texas Gulf Coast

	Pipeline Cost			Pore Space Acquisition Cost			
	Pipeline Length (km)	Annualized Cost ($/yr)	Cost of 30-yr Operation ($)	Plume Size (km^2)	Annual Lease[a] ($)	Long-Term Lease[b] ($)	Purchase Cost ($)
Frio (TX)	1,860	$75	$680	320	$1.4-46	$0.5-12	$1.6-47
Mt. Simon (IL)	710	$40	$380	300	$1.4-46	$0.5-13	$1.5-44

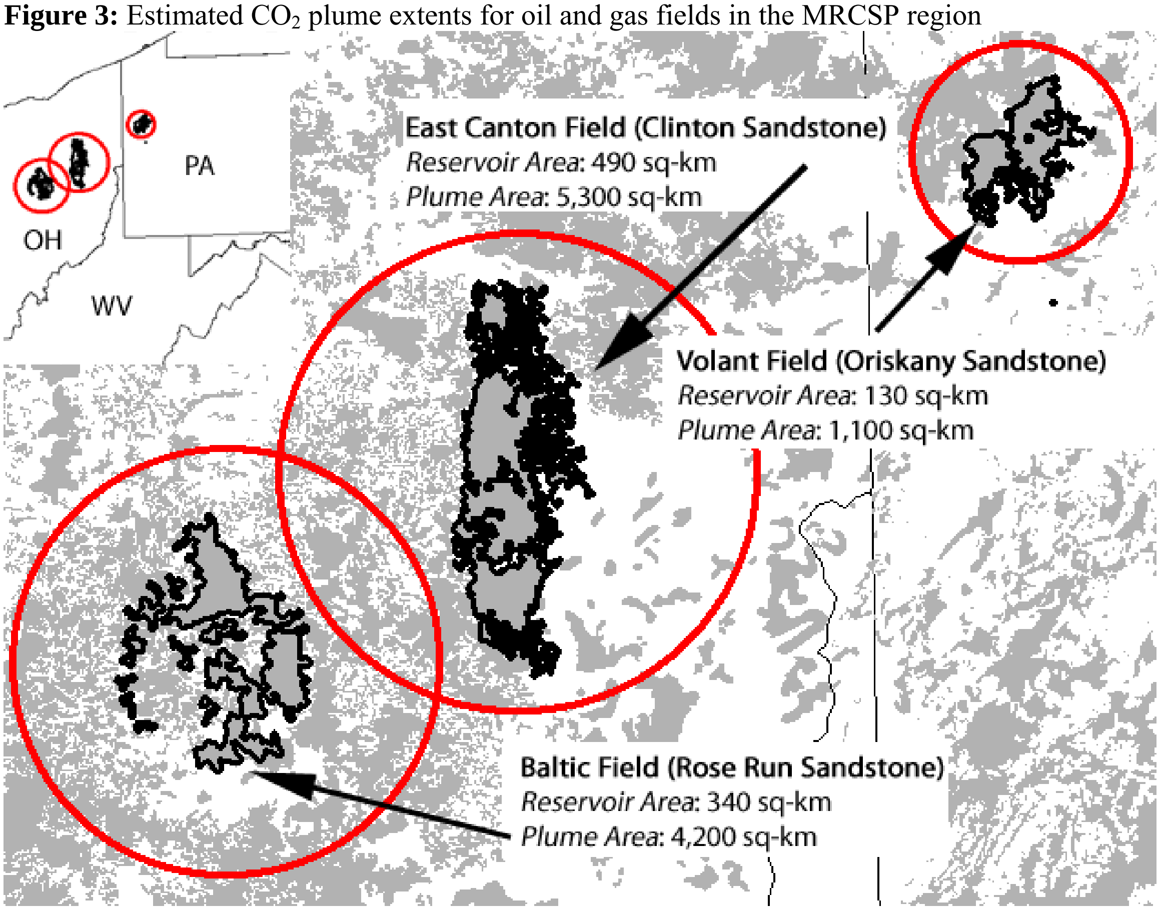
[a]Annual lease rate range $2-10 per acre per year for private land, and $45-65 per acre per year for state-owned land.
[b]Long-term lease rate and purchase cost range is $20-100 per acre for private land, and $400-600 per acre for state-owned land.

6. Discussion

The results indicate the potential for CO_2 plumes that will evolve to be very large in size, increasing the degree of legal complexity and, should it be necessary, the transaction costs associated with acquiring pore space rights. The results of this analysis are predicated upon the assumption that the examined rock formations exhibit homogenous and uniform geologic properties, so one should not consider the CO_2 plume simulation estimates to be instructive with respect to all sequestration targets and CO_2 injection scenarios. Nevertheless, the results strongly suggest that sequestration capacity for Pennsylvania and Ohio might be much smaller than theoretical estimates due to the practical difficulties of dealing with such large plume extents (both from the standpoint of pore space acquisition and site characterization and monitoring). Even though the CO_2 sequestration capacities estimated by the MRCSP for the Volant, East Canton, and Baltic oil and gas fields exceed 160-million tonnes (see Table S-2, Supporting Information) [37, 45], Figure 3 shows that the maximum extent of the CO_2 plumes could extend beyond the field boundaries by at least a factor of 8 in each case. While our model does not consider pressure perturbations, the relatively thin formations in these two states may also impose non-financial limits due to pressure fronts from interacting injections.

Results from analytical models, numerical simulations, and pilot projects agree that a relatively small fraction of the available pore space will be occupied by injected CO_2, resulting in the CO_2 migrating over large areas. [46] Should the use of a marginally suitable reservoir for GS result in a CO_2 plume that is within the same order of magnitude in size as the very large plumes predicted in our analysis, the cost of acquiring pore space rights could significantly limit economically available sequestration capacity, even if the physical capacity is available. Geologic sequestration of CO_2 should be carried out in the best reservoirs first, where the physical capacity is available and the geologic characteristics are optimal for limiting plume migration. This recommendation may, in some cases, be at odds with injection into an open formation where pressure build-up can be minimized, thus maximizing the capacity and injection rate. [26, 47] Thus, in some cases there is likely a trade-off between the cost of acquiring pore space and the capacity of sequestration targets.

Figure 3: Estimated CO_2 plume extents for oil and gas fields in the MRCSP region



The areas outlined in bold-black represent the oil and gas fields, and the areas outlined in bold-red represent the estimated CO_2 plume areas resulting from sequestration of 160-million tonnes CO_2 in each field.

While large plumes in the relatively thin formations of Pennsylvania and Ohio are likely, pipelines could be constructed and used at a reasonable cost to transport captured CO_2 to the most suitable reservoirs from regions of the United States where coal-fired electricity generation is abundant but sequestration opportunities are limited. If reservoir resources are limited, however, competition for the available pore space could drive up the cost of acquiring subsurface property rights for sequestration. If circumstances eventually require the use of reservoirs with a low mass-to-volume storage capacity, the cost of acquiring pore space rights could increase overall sequestration costs significantly, but even such costs are likely to be smaller than the costs of capture.

If compensation for the use of pore space *is* required, the cost of acquiring pore space for even large plumes may be reduced if serious efforts are focused on examining alternative models for standardizing the procedures for acquiring and transferring pore space rights that limit administrative and transaction costs. Even though the economic cost of acquiring the right to use pore space under the Frio and Mt. Simon Sandstone injection cases examined in this paper would not hinder development of the reservoirs for GS, the task of negotiating with all relevant landowners within even their relatively small 320 km^2 (Frio Sandstone) to 300 km^2 (Mt. Simon Sandstone) area could prove to be difficult. Furthermore, “hold-out” landowners could prevent the development of a GS reservoir.

In other writing we argue for Federal legislation that would resolve this issue by assuring that GS operators would have access to pore space and protection against trespass similar to that enjoyed in practice by other operators of programs that inject waste fluids underground. [7] Under such a construction, compensation for the use of pore space would be required only when the migration of CO_2 interferes with a demonstrated preexisting or imminent use of the subsurface. [7] We argue for this legislative solution both because we believe there is an overriding national interest to limit emissions of CO_2 to the atmosphere, and because if issues of access to pore space get resolved by state courts and legislation, the U.S. could end up with a patch-work of rules and legal precedents that could further impede the already slow adoption of carbon capture with GS.

Acknowledgements

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Implications of Compensating Property-Owners for Geologic Sequestration of CO_2

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Supporting Information

Model Input Parameters

The model requires eight input parameters: formation depth, net thickness, porosity, permeability, salinity, temperature and pressure. Formation thickness, porosity, permeability, and depth are likely to have large effects on injections rates, and these properties can vary by several orders of magnitude among and within reservoirs. The parameterized and deterministic inputs to the model are show in Table S-1.

Formation Depth, Net Thickness, Porosity and Salinity. Formation depth is the depth of the geological formation below the surface (meters). Formation thickness is the net thickness of the permeable zones of the geological formation (meters). Net thickness is used because formations typically have zones of high permeability inter-layered with low-permeability zones. Effective porosity is the percentage of the volume of connected pores in a unit volume of the formation. Porosity decreases with depth at an exponential rate. [1] Since the net thickness of high-permeability zones is used in this model, the effective porosity of high permeability zones is also used here. Salinity is the amount of dissolved NaCl in the interstitial pore water in the target formation, expressed as part per million by weight (ppm).

Formation Pressure. The relationship between pressure and depth is modeled as linear under hydrostatic conditions. At hydrostatic conditions, pressure typically increases at approximately 10 MPa/km. The relationship is expressed as:

$$P_d = G_p d + P_a \quad [MPa]$$

where P_d is pressure as a function of depth, G_p is the hydrostatic pressure gradient, 10 MPa/km, *d* is formation depth, and P_a is atmospheric pressure.

Formation Temperature. The relationship between temperature and depth is also modeled using a linear approximation. The geothermal gradient is assumed to be approximately 25 °C/km. The relationship between temperature and depth is expressed as:

$$T_d = G_T d + T_s \quad [K]$$

where T_d is temperature as a function of depth, G_T is the geothermal gradient, 25 °C/km, d is formation depth, and T_s is the surface temperature.

Table S-1: Model Input Parameters

	Depth (m)	Net Thickness (m)	Porosity (%)	Salinity (ppm)	Residual Brine Saturation (%)
Frio Sandstone (TX)					
Deterministic	1,900	300	30	100,000	30%
Mt. Simon Sandstone (IL)					
Deterministic	2,300	90[1]	13	125,000	30%
Medina Sandstone (PA)					
Triangular	810	10	3%	100,000	30%
	2,000	57	18%	250,000	90%
	1,500	20	8%	190,000	60%
Volant Field					
Deterministic	1,800	26	18%	230,000	30%
Oriskany Sandstone (PA)					
Triangular	2,000	10	2%	250,000	30%
	2,800	41	10%	350,000	90%
	2,700	13	5%	340,000	60%
Clinton Sandstone (OH)					
Triangular	830	11	7%	100,000	30%
	1,700	20	10%	210,000	90%
	1,100	11	8%	130,000	60%
E. Canton Consol.-S Field					
Deterministic	1,600	13	8%	200,000	30%
Rose Run Sandstone (OH)					
Triangular	830	10	8%	100,000	30%
	2,300	12	10%	280,000	90%
	1,600	11	8%	200,000	60%
Baltic Field					
Deterministic	1,900	12	10%	240,000	30%

[1]To provide a conservative estimate that accounts for uncertainty with respect to permeability and porosity in the Mt. Simon Sandstone at the Mattoon site, half the value of the gross thickness reported by the Illinois Geological Survey was used in our analysis. [2, 3]

Residual Brine Saturation

Brennan and Burruss note that as residual brine saturation (i.e., the interstitial pore water that is not displaced by injected CO_2) in the sequestration reservoir increases, storage capacity (in mass per unit volume) decreases, and the areal extent of the CO_2 plume becomes larger. [4] Brennan and Burruss' performed their storage capacity analysis applying residual water saturations at 5%, 50%, 75%, and 100%. [4] Numerical simulations predicting CO_2 plume migration the Frio injection project have assumed residual brine saturations between 70% and 95%. [5] Therefore, values for residual brine saturation were parameterized [Triangular (90,30,60)] and input into the model.

CO_2 Plume Distribution Model: Analytical Solution Derivation [6]

Model predictions depend largely on the values of key parameters, which describe the properties of the formation and native fluids. Multiphase models solve a series of governing equations to predict the composition and volumetric fraction (i.e., the fraction of the formation pore space taken up by fluid) of each phase state (e.g., liquid, gas, supercritical fluid), as well as fluid pressures, as a function of location and time for a particular set of conditions.

The results obtained by Nordbotten et al [2] agree broadly with Buckley-Leverett theory for small values of the dimensionless gravity factor, Γ. For convenience, their result is derived here using the similar assumptions—namely, effects of capillary pressure are negligible, fluids are incompressible, and the reservoir petrophysical properties are homogeneous—using arguments analogous to those used by Dake [7] for an unstable, horizontal displacement.

For a differential cylindrical volume of the system shown in Figure 1 of the paper, the volumetric balance on the CO_2 phase can be written:

$$\varphi \frac{\partial \overline{S}_c(r,t)}{\partial t} + \nabla \cdot q_c(r,t) = 0 \qquad \text{(Eq. S-1)}$$

where: $\overline{S}_c$ is the vertically averaged saturation of CO_2, φ is the reservoir porosity, q_c is the flux of CO_2, r represents radial distance from the injection well, and t is time. Assuming drainage (i.e., CO_2 is displacing brine in a brine-wet reservoir), the vertically averaged saturation of CO_2, $\overline{S}_c$, is defined as:

$$\overline{S}_c = \beta(1 - S_{wc}) \qquad \text{(Eq. S-2)}$$

Darcy's law for the brine and CO_2 phases can be written as:

$$q_c = -K\beta\lambda_c \nabla p_c \qquad \text{(Eq. S-3)}$$

$$q_w = -K(1-\beta)\lambda_w \nabla p_c \qquad \text{(Eq. S-4)}$$

In Equations S-3 and S-4, K is the intrinsic permeability of the reservoir, β is the fraction of the reservoir thickness invaded by the CO_2 plume, λ_n is the mobility (k_r/u) for the CO_2 phase (*c*) or the brine phase (*w*), and ∇p is the pressure gradient.

Since the fluids are incompressible $(\nabla \cdot q = 0)$, the flux into the system equals the flux out of the system and the total apparent flux, q_t, is:

$$q_t = \frac{Q_{well}}{A} = q_c + q_w$$

where Q_{well} is the injection rate of CO_2 into the system and A is the area across which the flux occurs. Assuming capillary pressure is negligible and, therefore $\nabla p_c = \nabla p_w = \nabla p$, substituting Equations S-3 and S-4, we arrive at:

$$\frac{Q_{well}}{A} = -K\left[\beta\lambda_c + (1-\beta)\lambda_w\right]\nabla p \qquad \text{(Eq. S-5)}$$

Solving Equation S-5 for pressure gradient results in:

$$\nabla p = -\frac{Q_{well}}{KA\left[\beta\lambda_c + (1-\beta)\lambda_w\right]}$$

which can then be substituted into Equation S-3 to arrive at the flux of the CO_2 phase as a function of the injection rate.

$$\nabla p = \frac{\beta\lambda_c}{\beta\lambda_c + (1-\beta)\lambda_w}\left(\frac{Q_{well}}{A}\right) = f_c \frac{Q_{well}}{A} \qquad \text{(Eq. S-6)}$$

In Equation S-8, the term referred to as f_c is the fractional flow of the carbon dioxide phase in the system. Substituting this equation into the volumetric balance, Equation S-1 yields:

$$\varphi \frac{\partial \bar{S}_c}{\partial t} + \nabla \cdot \left(f_c \frac{Q_{well}}{A} \right) = 0$$

Writing the divergence operator for a cylindrical coordinate system gives:

$$\varphi \frac{\partial \bar{S}_c}{\partial t} + \frac{1}{r}\frac{\partial}{dr}\left(r f_c \frac{Q_{well}}{2\pi r h} \right) = 0$$

Simplifying results in:

$$\varphi \frac{\partial \bar{S}_c}{\partial t} + \frac{Q_{well}}{2\pi r h}\frac{\partial f_c}{dr} = 0 \qquad \text{(Eq. S-7)}$$

Applying the chain rule to the fractional flow equation, the $\partial f_c / dr$ can be rewritten:

$$\frac{\partial f_c}{dr} = \frac{\partial f_c}{d\bar{S}_c} \times \frac{\partial \bar{S}_c}{\partial r} = f_c' \frac{\partial \bar{S}_c}{\partial r}$$

Upon substitution into Equation S-7, we arrive at a statement of the Buckley-Leverett equation for a radial system:

$$\frac{\partial \bar{S}_c}{\partial t} + \frac{Q_{well} f_c'}{2\pi r h \varphi}\frac{\partial \bar{S}_c}{\partial r} = 0 \qquad \text{(S-8)}$$

This equation was solved by Woods and Comer [8] for the boundary conditions $r = r_w$ at $t = 0$, resulting in:

$$r\left(\bar{S}_c\right) = \sqrt{\frac{f_c' Q_{well} t}{\pi h \varphi} + r_w^2} \qquad \text{(S-9)}$$

If vertically averaged saturation of the CO_2 phase was not assumed (i.e., Eq. S-4), determination of f_c' would require an assumption of the shape of the relative permeability curves for the CO_2-brine system and particular reservoir rock. However, operating under the assumption saturation is a linear average of phase saturations (i.e., Eq. S-2), f_c' can be expressed via the chain rule as:

$$f_c' = \frac{df_c}{d\beta} \times \frac{d\beta}{d\bar{S}_c} = \frac{\lambda_w \lambda_c}{\left[\lambda_w + \beta(\lambda_c - \lambda_w)\right]^2}\left(\frac{1}{1 - S_{wc}}\right)$$

Substituting this into the above equation, we arrive at an expression for the radial distance as a function of the fraction of the formation height invaded by the CO_2 plume:

$$r(\beta) = \sqrt{\frac{\lambda_w \lambda_c Q_{well} t}{\pi h \varphi (1 - S_{wc})[\lambda_w + \beta(\lambda_c - \lambda_w)]^2} + r_w^2} \quad \text{(Eq. S-10)}$$

Assuming the injection well radius is much smaller than the radius of the CO_2 plume, the maximum extent of the CO_2 plume occurs at $\beta = 0$:

$$r_{\max} = \sqrt{\frac{\lambda_c V}{\pi h \varphi \lambda_w (1 - S_{wc})}} \quad [m] \quad \text{(Eq. S-11)}$$

In the situation where the dimensionless gravity factor, Γ, is large, the solution presented in Equation S-11 under predicts the extent of migration of the CO_2-brine interface. However, after incorporating the effects of buoyancy into the derivation (and making the same assumptions as above) Nordbotten et al. arrived at:

$$r_{\max} = \sqrt{\frac{(\lambda - 1)V}{2\pi \Lambda h \varphi (1 - S_{wc})}} \quad [m] \quad \text{(Eq. S-12)}$$

where λ is the mobility ratio for the displacement (λ_c / λ_w), and Λ is the Lagrangian multiplier. The Lagrangian multiplier, Λ, comes from the numerical solution of:

$$\Lambda(\lambda - 1)^2 - \Gamma(\lambda - 1) + \Gamma \lambda \ln\left(\frac{\Gamma + \Lambda}{\Lambda \lambda}\right) = \frac{2\lambda[\Lambda(\lambda - 1) - \Gamma]^2}{\lambda - 1} \quad \text{(Eq. S-13)}$$

Estimated Oil & Gas Field CO_2 Sequestration Capacities in the MRCSP Region

Table S-2: Oil & gas field CO_2 Sequestration Capacities in the MRCSP Region [9, 10]

Producing Formation	Field Name	State	# Wells	km^2	GS Potential (million tonnes)
Medina	Volant	PA	353	130	310
Clinton	E. Canton Consolidated-S	OH	1,290	490	250
Rose Run	Baltic	OH	113	340	230

CO_2 Plume Size Results

Figure S-1

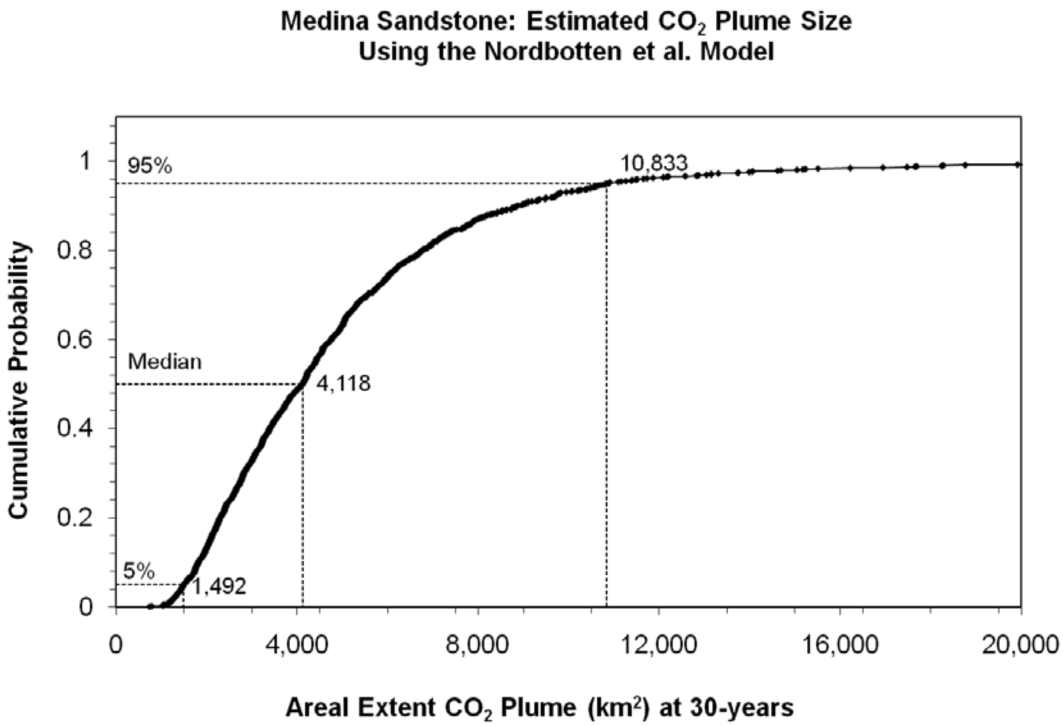


Figure S-2

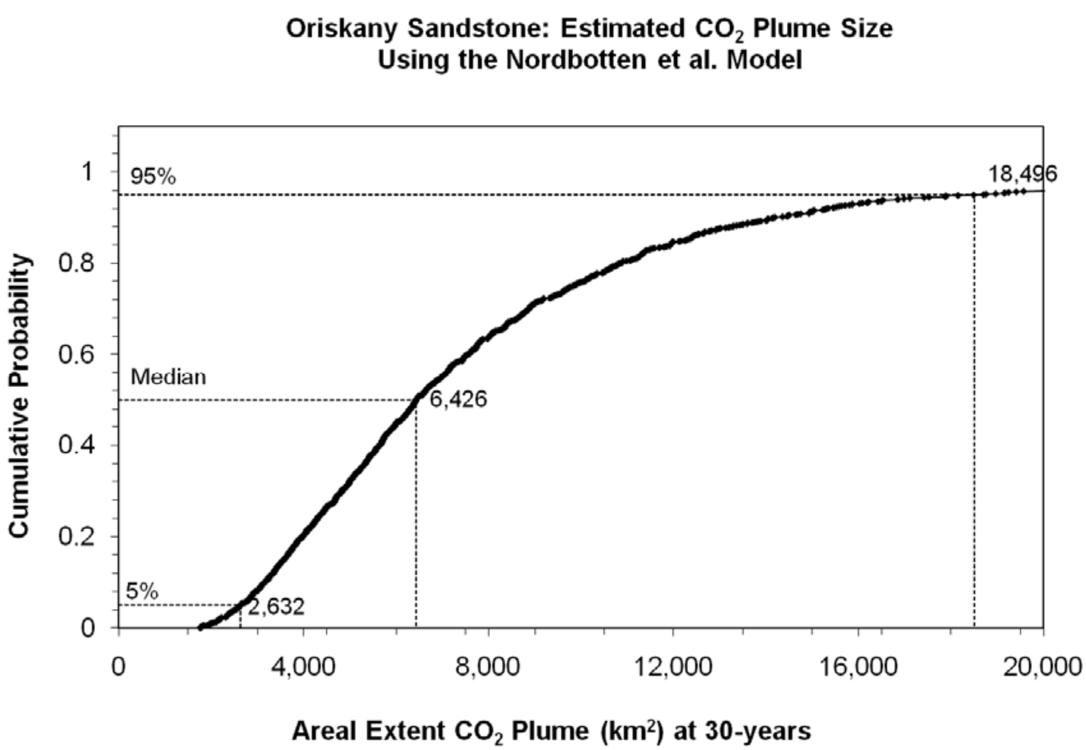


Figure S-3

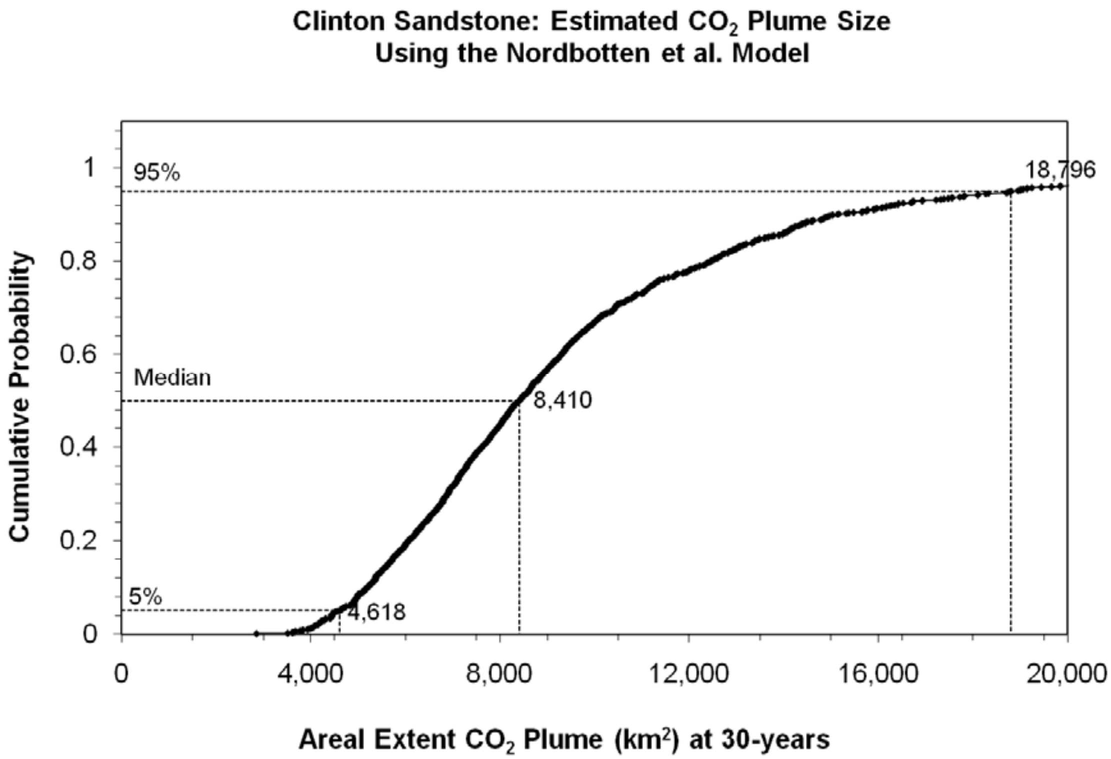
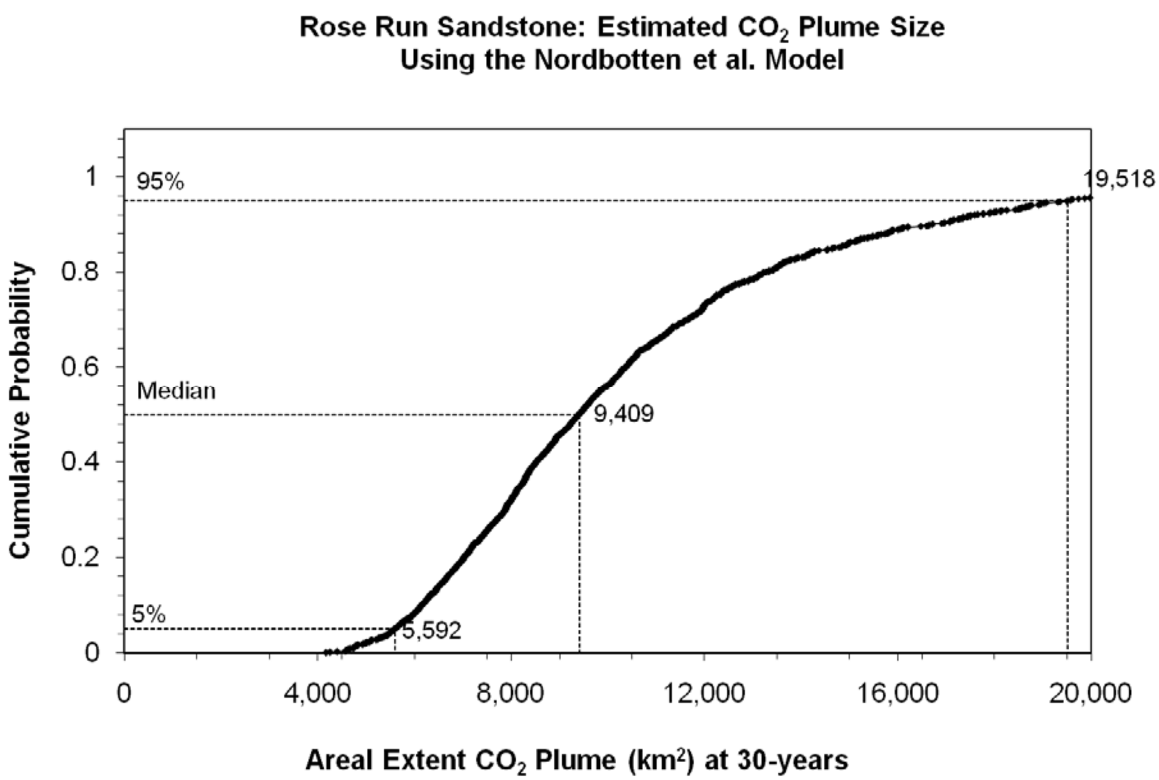


Figure S-4



CO_2 Plume Model Sensitivity

Figure S-5

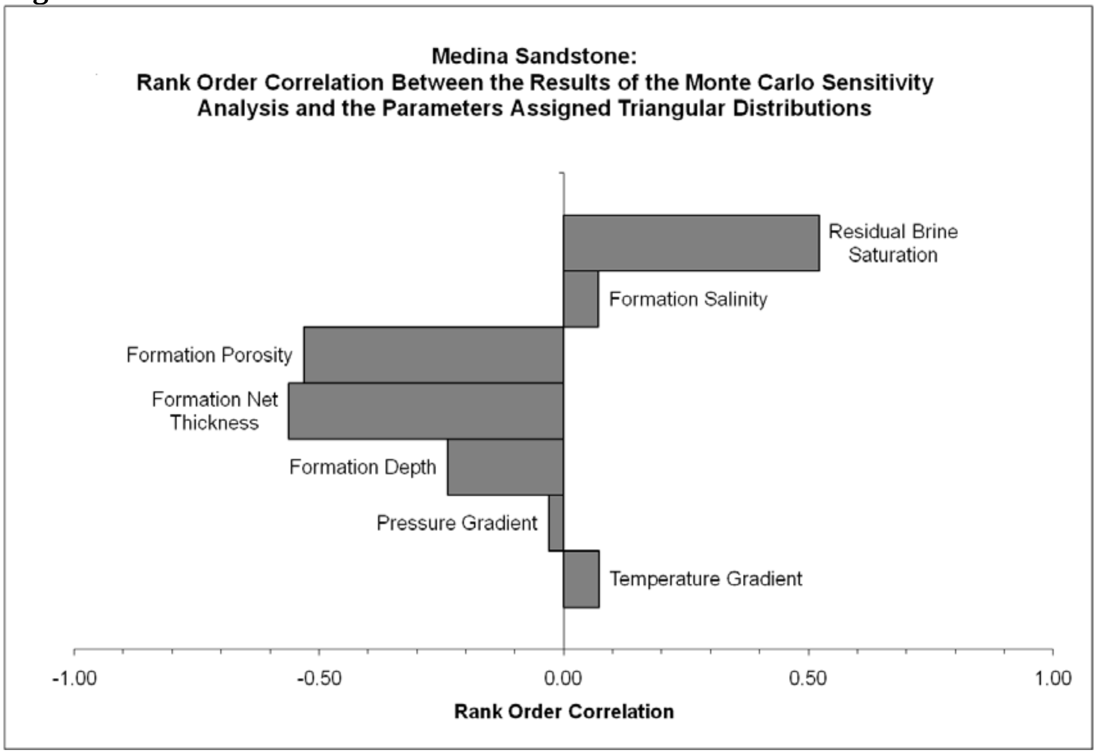


Figure S-6

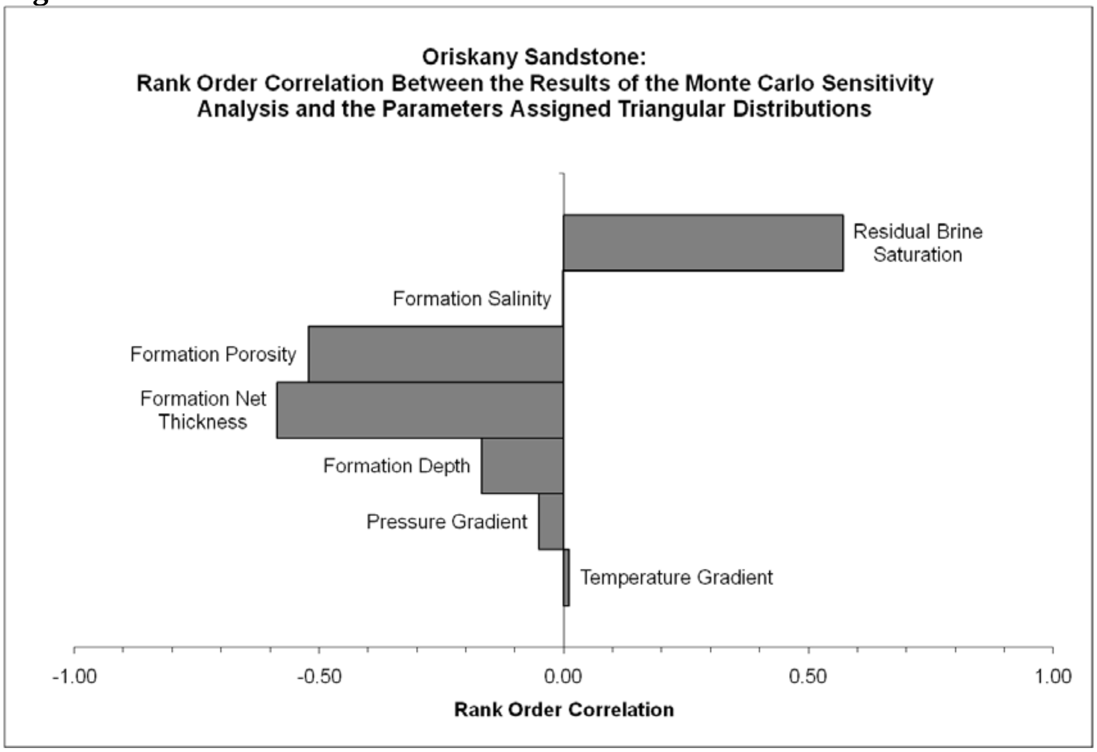


Figure S-7

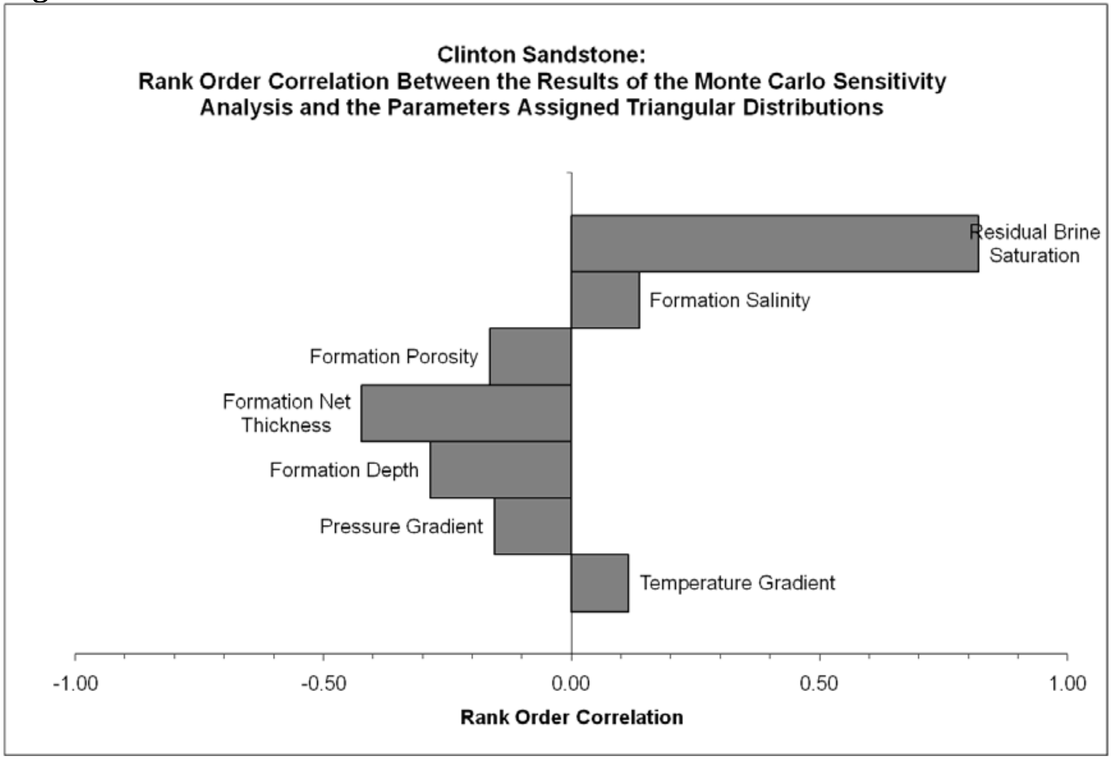
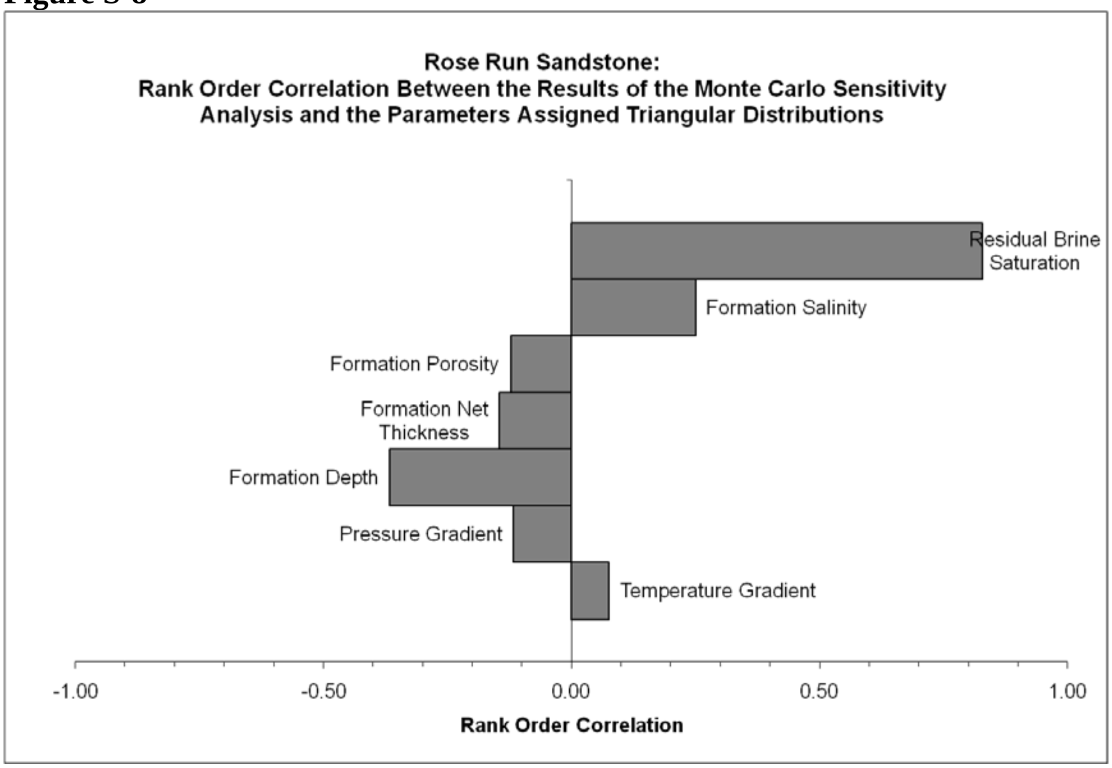


Figure S-8



Distribution of Pore Space Acquisition Costs

The value of the one-time payment for the long-term lease is assumed to be $500, the equivalent sum paid to landowners in Illinois for the option to lease pore space rights for the FutureGen™ Alliance project. [11] Even if as many as 120 (the number assumed for this paper) landowners fall within the areal extent of the CO_2 plume, the $60,000 expenditure to secure the option to lease is insignificant compared to the total lease cost. If the CO_2 plume underlies more densely populated areas, the option cost would no longer be insignificant.

Table S-3: Total Lease Cost vs. Purchase Cost (millions 2008$)[1]

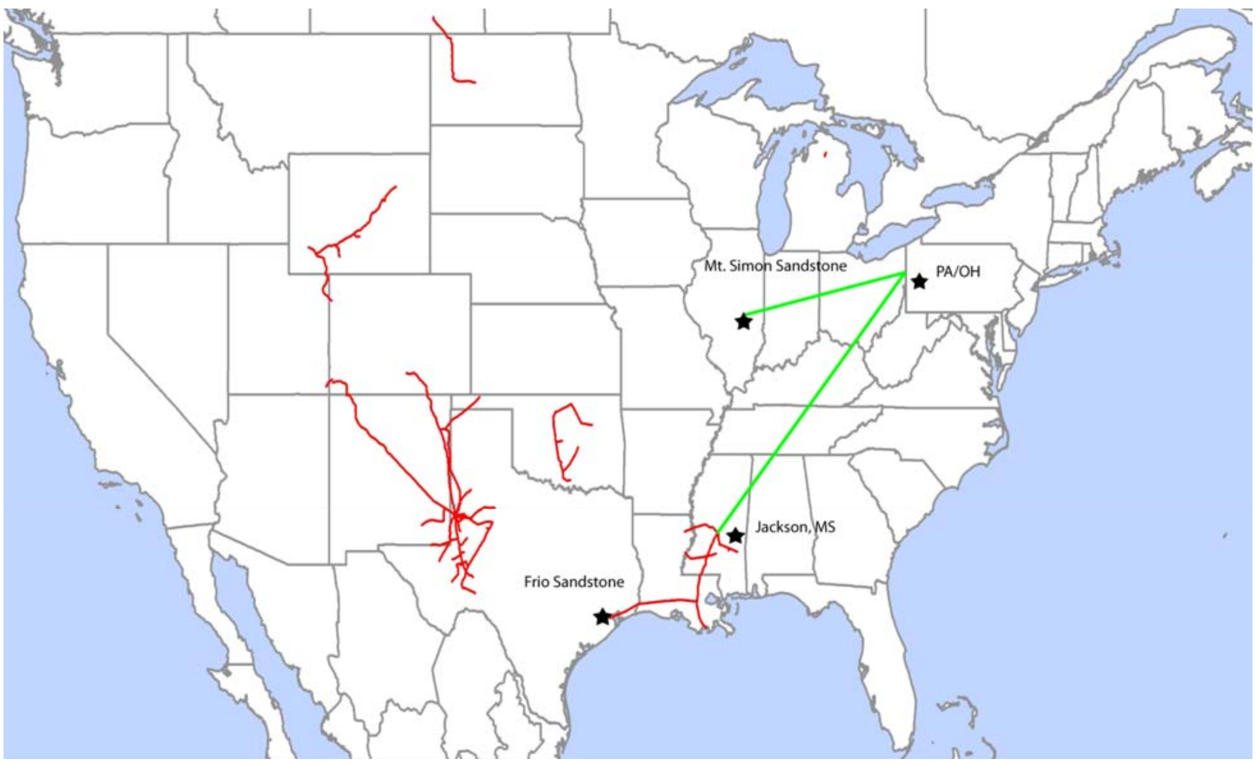
	Annual Lease[a]		**Long-Term Lease[b]**		**Purchase Cost[b]**	
	Private	*State*	*Private*	*State*	*Private*	*State*
Medina (PA)						
5th Percentile	$7.1-33	$150-210	$2.3-10	$41-61	$7.7-36	$140-210
Median	$18-86	$390-570	$5.7-27	$110-170	$19-93	$380-570
95th Percentile	$48-300	$1,200-1,700	$15-93	$330-490	$52-320	$1,100-1,700
Oriskany (PA)						
5th Percentile	$13-65	$260-400	$4.1-20	$74-120	$14-70	$260-400
Median	$28-150	$660-960	$9.0-47	$190-280	$30-160	$640-970
95th Percentile	$80-420	$1,800-2,800	$25-130	$500-810	$87-460	$1,700-2,800
Clinton (OH)						
5th Percentile	$23-110	$490-710	$7.2-35	$140-210	$25-120	$480-710
Median	$39-200	$870-1,300	$12-62	$240-370	$42-210	$840-1,300
95th Percentile	$84-420	$2,000-2,800	$27-130	$570-810	$92-450	$2,000-2,800
Rose Run (OH)						
5th Percentile	$25-130	$570-840	$8.1-40	$160-240	$28-140	$550-840
Median	$45-220	$960-1,400	$14-68	$270-410	$49-240	$930-1,400
95th Percentile	$100-470	$2,100-3,100	$32-150	$600-890	$110-510	$2,100-3,100

[1] Assumes 15% discount rate and 4% inflation rate.
[a] Annual lease rate range $2-10 per acre per year for private land, and $45-65 per acre per year for private land.
[b] Long-term lease rate and purchase cost range $20-100 per acre for private land, and $400-600 per acre for state-owned land.

Pipeline Model Design and Assumptions

Operating pressures throughout the pipeline remain above 10.3 MPa to ensure the CO_2 does not fall into a subcritical state. [12, 13] Injection pressure, booster compressors, and pipeline diameter all influence pipeline pressure. A fixed size is assumed for both injection and booster compressors. To ensure CO_2 remains supercritical throughout the pipeline, the required diameter for a pipeline segment is sized according to operating parameters such as pressure drop, CO_2 density and mass flow rate, and frictional losses. [12, 14] Pipeline diameter is calculated while holding the upstream and downstream pressures constant. [12] Depending on the pipeline length, additional pumping stations might be required to boost the pressure along the pipeline to compensate for pressure losses. [12, 14] It is assumed a booster station is required when the length of a pipeline segment exceeds 205 miles (402 km).

Figure S-9: Pipeline from PA/OH to the Mt. Simon and Frio Sandstones [15]



Red lines represent existing CO_2 pipeline infrastructure; the green lines represent the hypothetical pipeline scenarios we assess in this paper.

Pipeline Model Annualized Costs

Table S-4: Pipeline Annualized Costs

	Pipeline Length		Proportion of Total Pipeline Length	Annualized Cost	
	(km)	(miles)	(%)	($/yr)	($/tonne)
Volant, PA to Mattoon, IL					
(2 segments; 1 booster station)					
Northeast Region	20	12	3%	$47,000,000	$8.6
Capital Cost				$44,000,000	
Operational Cost				$2,500,000	
Energy Cost for Booster				$500,000	
Midwest Region	690	429	97%	$41,000,000	$7.5
Capital Cost				$38,000,000	
Operational Cost				$2,500,000	
Energy Cost for Booster				$500,000	
Total	710	441		$41,180,000	$7.6
Volant, PA to Jackson, MS					
(4 segments; 3 booster stations)					
Northeast Region	20	12	1%	$117,000,000	$21.5
Capital Cost				$109,000,000	
Operational Cost				$6,450,000	
Energy Cost for Booster				$1,000,000	
Midwest Region	310	193	16%	$103,000,000	$18.9
Capital Cost				$96,000,000	
Operational Cost				$6,450,000	
Energy Cost for Booster				$1,000,000	
Southeast Region	970	603	49%	$113,000,000	$20.8
Capital Cost				$105,000,000	
Operational Cost				$6,450,000	
Energy Cost for Booster				$1,000,000	
Jackson, MS to TX Gulf Coast					
(No new construction required)					
Southeast Region	160	99	8%	$7,400,000	$1.4
Operational Cost				$6,450,000	
Energy Cost for Booster				$1,00,000	
Southwest Region	540	336	27%	$7,400,000	$1.4
Operational Cost				$6,450,000	
Energy Cost for Booster				$1,000,000	
Total	1,860	808		$74,526,000	$13.7

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