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Implications of Compensating Property Owners for Geologic Sequestration of CO_2

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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 might be required to use pore space for GS, we examine the cost of acquiring the rights to sequester 160-million metric tons of CO_2 (the 30-year emissions output for an 800 megawatt power plant operating with a 60% capacity factor and 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 median values of CO_2 plume footprints range from 4500 km^2 to 11,000 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, respectively. We use these footprints to bound 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 for sequestration. 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, CO_2 sequestered in deep geologic pore space could migrate laterally over a very sizable area (*1, 2*). Moreover, large CO_2 footprints increase the probability 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—including subsurface invasions—of their property by others or activities that substantially limit their ability to use and enjoy their property fully (*3–5*). Under current law, if a GS project developer negotiates an agreement with landowners 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—the same regulatory program that will very likely license and oversee the injection of CO_2 for geologic sequestration (*6*)—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, 7–9*). 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, 7–9*). 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 for long-term disposal (*10*). 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 be perceived to have "deep pockets," so there is a high probability the issue will be litigated. Second, 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, 8, 11*). 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, 8, 12*).

In the future, new law might ensure access to pore space and expressly limit trespass liability for GS (*9*). In fact, there exists a clear trend in U.S. case law to modify subsurface trespass law to require a showing of actual harm to the property-owner (*13*). Absent prevailing common law or a federally coordinated regulatory regime to this effect, however, 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 potential cost of compensating pore space owners. Should it be necessary, the cost of acquiring pore space rights will depend on the requirements of the regulations, 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

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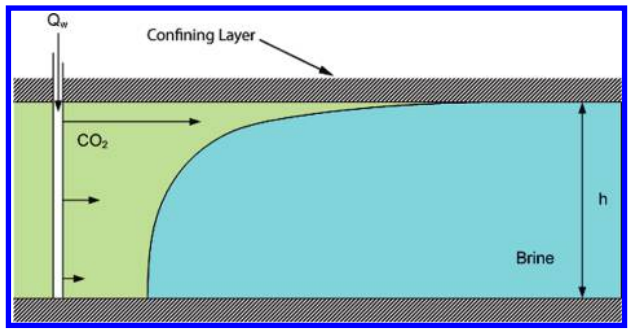

FIGURE 1. Geometry of a system where CO_2 is displacing brine under the Nordbotten et al. solution (*18*).

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 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 effects of pressure perturbations that can extend far beyond the footprint of the injected CO_2 (*14, 15*). Because, as expected (*16*), geologic properties of the reservoirs examined in this analysis vary substantially, CO_2 plume footprints 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 are lower. We conclude by assessing the cost of transporting CO_2 via pipeline from the Ohio and Pennsylvania area, where the potential for very large CO_2 plume footprints may not be conducive to large-scale GS (*17*), to the lower-cost reservoirs in Illinois and on 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 (*18*). 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 spatial distribution of injected CO_2 in deep saline formation presented by Nordbotten et al. (*18*). 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. (*18*) 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 (Figure 1). This result minimizes the work required to inject CO_2 into a homogeneous, isotropic geological formation. Nordbotten et al. use the general shape of the invading front, coupled with an assumption of a sharp interface between the fluids, to develop their simple analytical solution (*18*).

CO_2 is typically sequestered as a supercritical fluid to maximize sequestration efficiency (*19*). 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 (*19*). Above this pressure and temperature, CO_2 has a low, "gaslike" viscosity, but a "liquidlike" density between 150 to >800 kg/m^3 (*19*). The higher the density of CO_2, the more efficiently the pore space can be used to sequester it as a separate phase because buoyant force, which drives CO_2 upward and laterally under 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 m, where supercritical conditions are met assuming a hydrostatic pressure gradient 1 MPa per 100 m and geothermal gradient of 25 °C per km (*20*).

Thus, models of CO_2 distribution in the subsurface must account for the following: gravity override caused by buoyancy of the CO_2 phase; the greater lateral mobility of CO_2 compared to brine (that results from the lower viscosity of CO_2); and the injection work-minimizing distribution of CO_2 in the formation (*18*). The importance of buoyant force in sequestration relative to the viscosity and pressure forces is related by the dimensionless quantity, Γ, given by

$$\Gamma = \frac{2\pi g \lambda_w k \Delta\rho h^2}{Q_w} \tag{1}$$

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 S8, Supporting Information), a transport equation used to model two-phase flow in porous media (*18*). This equation has been the basis of a number of analytical models of deep well fluid injection (*21–23*). 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 (*18*)

$$r_{max}\,[\text{km}] = \sqrt{\frac{\lambda_c V}{\pi h \varphi \lambda_w (1 - S_{ir})}} \times \frac{1\ \text{km}}{10^3\ \text{m}} \tag{2}$$

where λ_c [1/Pa·s] is the phase mobility of CO_2, V [m^3] is the volume of injected CO_2, φ [%] is formation porosity, and S_{ir} [%] is the irreducible brine saturation in formation. When the value of Γ is large—in this case, greater than 0.5—buoyant force cannot be neglected, and the more complex solution incorporating buoyant effects developed by Nordbotten et al. (*18*) is used to estimate r_{max} (equation S12, Supporting Information). Physical properties of CO_2 at reservoir conditions were estimated using the Peng–Robinson equation of state (*24*) and the transport properties using the method of Chung et al. (*25*) and modified for high pressure application by Reid et al. (*26*). Physical and transport properties of brine were estimated using the correlation of Batzle and Wang (*27*).

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. Modeling injection into a single formation layer yields an upper bound on the size of the CO_2 plume, since injection into multiple stacked formations would yield a smaller footprint. Of course, due to the heterogeneous and anisotropic nature of rock properties and structural and

stratigraphic features, CO_2 plumes are unlikely to migrate uniformly. This behavior could reduce or enlarge the CO_2 plume footprint. In addition, the host rock, brine, and CO_2 are compressible, which would tend to reduce the plume footprint. Finally, 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) (*28–30*). Further details on the model and the underlying assumptions can be found in ref *18* and in the Supporting Information.

2.2. Cost of Acquiring Pore Space Rights. We estimate the cost to lease pore space on an annual and long-term basis. We also estimate 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 injection of CO_2 might preclude alternative uses of the pore space for hundreds to thousands of years. Therefore, the cost of leasing pore space annually was examined over a 100-year time horizon, beyond which the present value of additional costs becomes insignificant due to discounting. 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 (*31*). At $45−65 per acre-per year, Pennsylvania exacts a premium from natural gas storage companies for use of its pore space compared to what private landowners receive, typically $2−10/acre/year. We assume natural gas storage lease rates to be uniform throughout the United States. All cost estimates are calculated with a 15% discount rate and 4% inflation rate. For the long-term lease, the per acre cost was extrapolated from the annual lease rates. The long-term lease bears a higher per acre price tag ($20 to $600/acre) than the annual lease because all compensation for use of the pore space is redeemed up-front. These rates represent the present value 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 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 footprint predicted using a CO_2 plume distribution model must be acquired by the GS project developer as a precondition to commencing any injection activities. The long-term lease scenario examined here would not require project developers to acquire all pore space rights up front but would allow developers to acquire them as they become determined through subsurface monitoring. While not analyzed here, a similar approach could also be applied to the outright purchase of pore space. Monitoring costs are not considered in this calculation because prudent sequestration operators will conduct periodic monitoring to track the evolution of the CO_2 plume regardless of whether the use of pore space requires compensation. 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 for the purposes of monitoring (*32*).

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 (*33*). CO_2 is piped in a supercritical state to maximize transport efficiency. Capital costs used in the model 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 (*33–35*). Capital costs for pipeline include costs for materials, labor, rights-of-way, and miscellaneous charges (such as taxes, project management, administration and overheads, regulatory fees, and contingencies allowances) (*33, 34, 36*). The required pipeline diameter depends on the CO_2 mass flow rate and the acceptable pressure drop over the pipeline length (*33, 34*). Pipeline costs therefore vary with pipeline length and the CO_2 flow rate. Specific pipeline costs also vary by geographic region and terrain (*33, 34*). Regional cost differences are captured in the model, though the effect of terrain along a specific pipeline route is not captured by the model. The project regions are the same as those used by the Energy Information Agency (EIA) (*33, 37*). 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), the amount of CO_2 captured from an 800 MW coal plant operating with a 60% capacity factor and at 90% capture for 30 years (*10, 38*). 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 (*39*). 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 (*39*).

The Midwest Regional Carbon Sequestration Partnership (MRCSP) estimated that Pennsylvania and Ohio have potential GS capacities of around 90 gigatonnes and 46 gigatonnes, respectively (*40*). The saline formations estimated to have the largest theoretical capacity in the MRCSP region are the Mt. Simon, St. Peter, and Medina/Tuscarora Sandstones (*41*). Others are the Oriskany Sandstone, Rose Run, and the Sylvania Sandstones (*41*). 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 (*42*). Observations for which the average formation depth is shallower than 800 m were removed from the data set. Only observations with a net thickness of at least 10 m were included in the analysis because portions of these reservoirs where net sand is less than 10 m may be too thin for sequestration to be feasible (*30*). 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 cutoff criteria were then aggregated and converted into triangular distributions (Table S1, Supporting Information). Stochastic simulations were run using the parametrized geological data as inputs into the CO_2 plume distribution model.

Simulations were also run using deterministic input values based on geologic data from three oil and gas fields (the Volant, East Canton Consolidated-S, and Baltic fields) located in the Medina, Clinton, and Rose Run Sandstones and believed to have large CO_2 sequestration capacities (Table S1, Supporting Information). Maximum CO_2 plume footprints 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

TABLE 1. Extent of CO_2 Plume Size at 30-Years for a Total of 160-Million Tonnes CO_2 Injected

formations and oil and gas fields	plume size estimates (km^2)
Frio Sandstone (TX)	320
Mt. Simon Sandstone (IL)	300
Medina Sandstone (PA)	
5th percentile	1600
median	4500
95th percentile	14,000
Volant Field	1100
Oriskany Sandstone (PA)	
5th percentile	2800
median	6500
95th percentile	19,000
Clinton Sandstone (OH)	
5th percentile	5800
median	11,000
95th percentile	25,000
E. Canton Consolidated-S Field	5200
Rose Run Sandstone (OH)	
5th percentile	6500
median	11,000
95th percentile	27,000
Baltic Field	4200

selected for the FutureGen project. The Frio data set is a compilation of core analysis data, geophysical logs, and data extrapolated from available literature (*16*). The geologic inputs for the Frio Sandstone represent the mean value for each parameter (Table S1, Supporting Information). The Mt. Simon data come from the site selection proposal submitted by the Illinois State Geological Survey to the FutureGen Alliance (Table S1, Supporting Information) and are based on geophysical log data and limited core analysis data (*43, 44*). 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 CO_2 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 nonspecific location in the Frio Sandstone along the North Texas Gulf Coast (1860 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 (Figure S9, 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 footprints ranging from 4500 km^2 to 11,000 km^2 in areal extent. The distribution of predicted plume footprints at the fifth, 50th, and 95th percentile statistical levels for each reservoir are presented in Table 1. The deterministic estimates for the Volant, East Canton, and Baltic oil and gas fields are 1100 km^2, 5200 km^2, and 4200 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 have a greater net thickness than 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

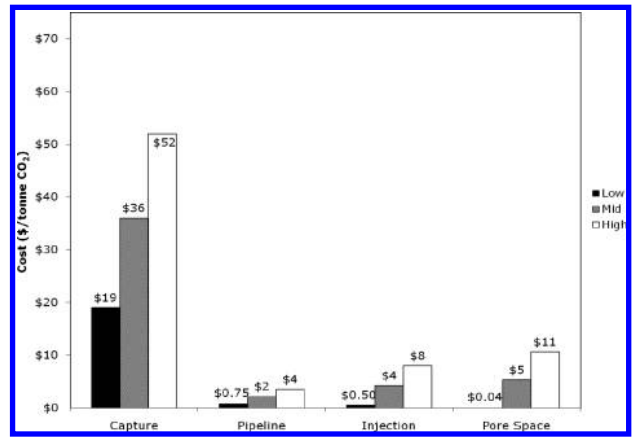

FIGURE 2. Comparison of CCS activity costs on the basis of dollar per tonne of CO_2 captured, transported, and injected: Capture (*45*), Pipeline (*33*), Injection (*36*) & Pore Space Acquisition. For capture costs, low = Integrated Gasification Combined Cycle (IGCC), mid = Pulverized Coal (PC), and high = Natural Gas Combined Cycle (NCGG) (all with installed capture systems).

Sandstones from implementation of the 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, salinity, irreducible brine saturation, and temperature gradient was examined probabilistically (Figures S5−S8, Supporting Information). Formation thickness, porosity, and irreducible brine saturation had the greatest effects on predicted CO_2 plume size for the Medina and Oriskany Sandstones. Plume size is negatively correlated with thickness and porosity but positively correlated with irreducible brine saturation. CO_2 plume footprint estimates for the Clinton and Rose Run Sandstones were most heavily influenced by formation depth, irreducible brine saturation, and temperature gradient, with plume footprints being smaller at greater depths.

5.2. Pore Space Acquisition Cost. Results suggest that if developers and 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 $21-million to $290-million for privately owned land and $500-million to $1.7-billion for state-owned land if pore space is either leased annually or purchased outright and between $6.8-million and $84-million for privately owned land and $140-million to $500-million for state-owned land if pore space is leased up-front (Table S3, Supporting Information). This is roughly the equivalent of $0.04 to $11 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 (*36*). Figure 2 presents a comparison of the costs for each individual activity in the sequestration chain.

If compensation is required to use 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 the maximum predicted plume footprint - the costs under the two lease scenarios are nearly equal, despite the lower per acre annual lease rates.

The need for long-term stewardship of sequestration sites may make pore space leases impractical. Some very small risk of leakage and other adverse consequences will persist beyond the lifetimes of the private firms operating seques-

TABLE 2. Pipeline Operation and Pore Space Acquisition Cost (Millions 2009$) - 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)	100-yr annual lease[a] ($)	100-yr long-term lease[b] ($)	purchase cost ($)
Frio (TX)	1860	$75	$680	320	$1.4–46	$0.5–12	$1.6–47
Mt. Simon (IL)	710	$41	$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.

tration facilities. Thus, there is wide agreement that the government, or other specially designed institutions, will have to assume long-term responsibility for closed sites (*46, 47*). It is unlikely these institutions would also take on the economic burden of making lease payments to private landowners, especially in perpetuity. The up-front acquisition of a fee title (i.e., the full possessory right) or servitude (i.e., easement) to the pore space by the GS developer would avoid this problem and be a relatively straightforward contractual matter.

5.3. Pipeline Construction and 30-Year Operation Cost. The annualized cost (capital and operational) of transporting approximately 5-million tones/year of CO_2 from a large coal-fired power plant near the Pennsylvania-Ohio border (such as the Bruce Mansfield plant (*38*)) 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 present value 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). This suggests that using thin local formations for sequestration may be more expensive than piping CO_2 to thicker formations at distant sites (Figures S10–S11, Supporting Information).

6. Discussion

The results indicate the potential for CO_2 plumes to be very large in size, increasing the degree of legal complexity and the cost associated with acquiring pore space rights, should that be necessary. The results of this analysis are predicated upon the assumption that the examined rock formations exhibit homogeneous and uniform geologic properties, so one should not consider the CO_2 plume simulation estimates to be generalizable to all sequestration targets and CO_2 injection scenarios. Nevertheless, the results suggest strongly that the practical sequestration capacity for Pennsylvania and Ohio might be much smaller than theoretical estimates due to the difficulties of dealing with such large plume extents (both from the standpoint of pore space acquisition and site characterization and monitoring). The MRCSP estimates that the theoretical sequestration capacity of the Volant, East Canton, and Baltic oil and gas fields each exceed 160-million tonnes (Table S2, Supporting Information) (*40, 48*). Figure 3 shows that, were the assumptions of our model fully applicable to these reservoirs, the CO_2 plume footprints would 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 nonfinancial 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 (*49*). Should the use of a marginally suitable reservoir for GS result in a

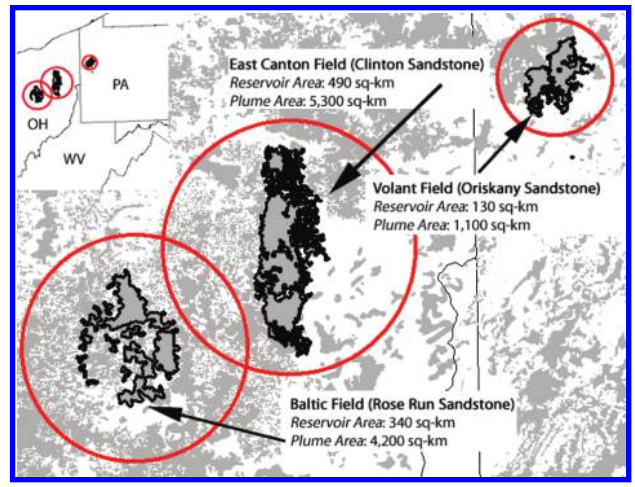

FIGURE 3. Estimated CO_2 plume footprints for oil and gas fields in the MRCSP region. The areas outlined in bold-black represent the oil and gas fields (*42*), and the areas outlined in bold-red represent the estimated CO_2 plume footprints resulting from sequestration of 160-million tonnes CO_2 in each field over 30 years.

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 (*29, 50*). Thus, in some cases there is likely a trade-off between the cost of acquiring pore space and the capacity of sequestration targets.

While very large plume footprints 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. Previous work has demonstrated that it is less expensive to build a coal plant with CCS near load than near a suitable reservoir (*34*). 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.

We have previously argued for Federal legislation that would resolve this issue by assuring that GS operators would have access to pore space and protection against subsurface trespass similar to that enjoyed in practice by other operators of programs that inject waste fluids underground (*9*). In this case, GS operators would have to acquire and pay compensation for surface and subsurface rights *only* at the location of the injection well, but not for the entire subsurface sequestration reservoir—like saltwater disposal in oil and gas operations. Under such a construction, compensation to property-owners neighboring the injection well for the use of pore space would be required *only* when the migration of CO_2 actually and substantially interferes with a demonstrated preexisting or imminent use of the subsurface (*9*). 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 patchwork of rules and legal precedents that could further impede the already slow adoption of carbon capture with GS.

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Supporting Information Available

Explanation and parametric distribution of model inputs, explanation of irreducible brine saturation, derivation of CO_2 plume distribution model, areal size and estimated CO_2 sequestration capacities in oil and gas fields analyzed in the MRCSP region, CO_2 pipeline model design and assumptions, and Tables S1−S3, and Figures S1−S11. This material is available free of charge via the Internet at http://pubs.acs.org.

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