Mesoscale Carbon Sequestration Site Screening and CCS Infrastructure Analysis

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Received May 1, 2010. Revised manuscript received July 16, 2010. Accepted July 22, 2010.

We explore carbon capture and sequestration (CCS) at the mesoscale, a level of study between regional carbon accounting and highly detailed reservoir models for individual sites. We develop an approach to CO2 sequestration site screening for industries or energy development policies that involves identification of appropriate sequestration basin, analysis of geologic formations, definition of surface sites, design of infrastructure, and analysis of CO2 transport and storage costs. Our case study involves carbon management for potential oil shale development in the Piceance-Uinta Basin, CO and UT. This study uses new capabilities of the CO2-PENS model for site screening, including reservoir capacity, injectivity, and cost calculations for simple reservoirs at multiple sites. We couple this with a model of optimized source-sink-network infrastructure (SimCCS) to design pipeline networks and minimize CCS cost for a given industry or region. The CLEARp dynamical assessment model calculates the CO2 source term for various oil production levels. Nine sites in a 13,300 km2 area have the capacity to store 6.5 GtCO2 corresponding to shale-oil production of 1.3 Mbibl/day for 50 years (about 1/4 of U.S. crude oil production). Our results highlight the complex, nonlinear relationship between the spatial deployment of CCS infrastructure and the oil-shale production rate.

1. Introduction

Carbon Capture and Storage (CCS) through injection of CO2 into deep geologic formations is one of the most promising technologies for mitigation of human-induced climate change (1, 2). Active examples of CCS are limited in both the scale of the injections being performed and the complexity of the facilities involved (3). For example, at two of the largest industrial CCS sites (In Salah and Sleipner), CO2 is removed from a gas production stream, separated, and reinjected into geologic formations quite near the gas source region at rates of approximately 1 million metric tons per year (MtCO2/yr) (4, 5). As noted by the U.S. Secretary of Energy, Steven Chu, tackling the climate problem while still utilizing coal and other nontraditional sources of energy (oil shale, tar sands) will require much larger CCS projects to be undertaken (6). Because the scale of anthropogenic CO2 emissions is so large (18 billion tCO2/yr), sequestration of this volume could require on the order of 30 km3 per year (correction from ref 6 using subsurface storage density of supercritical CO2 = 600 kg/m3).

The increase in the scale of injection scenarios that will be required to sequester ever increasing volumes of CO2 necessitates a new methodology of systems analysis that moves beyond the primary current paradigm of single injection reservoirs coupled to limited sources (7). Currently, analysis of large scale injection systems has been limited to basin-scale reservoir modeling of long-term total injections on the order of 1–10 km3, without infrastructure optimization (8, 9). Analysis of CCS infrastructure (e.g., pipeline networks) has taken into consideration multiple CO2 source and sink locations (10), but associated injection calculations have been simplified. On the other end of the scale, recent studies of greenhouse gas (GHG) emissions management have approached the potential solution of CCS by evaluating the regional match between CO2 sources and available gross pore space in geologic formations (e.g. ref 11). While studies on the broad scale are a necessary first step to bound the problem for policy making and industry planning, the practical challenge of building an integrated and realistic CCS infrastructure system requires more detailed analysis. However, well-characterized sites (e.g., depleted oil reservoirs) and detailed reservoir models may not be available in the vicinity of the CO2 sources of interest. Prior to defining target pore space and developing reservoir models, a mesoscale evaluation of CO2 transport and storage can highlight important information to inform later site-scale studies, such as important reservoir properties and costs.

The process of capturing, transporting, and storing CO2 ultimately requires deciding where and what capacity infrastructure to construct. These infrastructure decisions include where and how much CO2 to capture, where and why new pipelines to build, and where and how much CO2 should be stored. However, almost all regional CCS studies make simplifying assumptions regarding the location and capacity of CCS infrastructure (10); for example, that all sinks in a region have the same injection and storage cost, that sources must capture all produced CO2 regardless of other nontraditional sources of energy (oil shale, tar sands), and that pipelines directly connect CO2 sources to geologic reservoirs. In reality, infrastructure costs and capacities vary considerably across a region and consequently understanding how CO2 should be captured, transported, and stored is a complex decision. For example, aggregating CO2 flows into large trunk-pipelines generates economies of scale that cannot be achieved using direct source-sink pipelines. Also, for instance, using a single cost-value for CO2 storage obfuscates the complex relationship between captured CO2 and spatially varying CO2 storage. Consequently, it is critical to use a spatially explicit approach for modeling how CO2 is captured, transported, and stored and to understand and quantify the impact of space on CCS costs and feasibility.

In this paper we explore the mesoscale CCS analysis that lies between regional carbon accounting and highly detailed reservoir models for individual sites. We describe an approach to CO2 sequestration site screening for industries or energy development policies that involves identification of ap-
proportionate sequestration basin, analysis of sequestration target formations, surface site definition, infrastructure design, and analysis of costs for CO2 transport and storage. This approach uses new CO2-PENS (Predicting Engineered Natural Systems) model capabilities for site screening, including capacity, injectivity, and cost calculations for simple reservoirs at multiple sites (7, 12). The site screening capability is integrated with a model of optimized source-sink-network infrastructure (SimCCS—Scalable infrastructure model for Carbon Capture and Storage) to design pipeline networks and minimize costs of CCS for a given industry or region.

2. Overview of Oil Shale Case Study

Our case study for exploring the mesoscale CCS analysis addresses substantial new power production required and the associated carbon management to support transportation fuel security through potential oil shale development in the western U.S. Reserves of oil shale in the Rocky Mountain region have been estimated at 1.8 trillion bbl (13); in comparison, the proven oil reserves in Saudi Arabia are estimated at only 0.26 trillion barrels (14). These resources are under increased scrutiny as global consumption and prices of oil increase, and projections of future energy demand in the U.S. may require the use of heavy or unconventional hydrocarbon resources (11, 15). Furthermore, the Task Force on Strategic Unconventional Fuels (including members from DOE, DOD, and several Western states) defined a target for Green River Formation oil shale production of 2.5 million barrels of oil per day (bbl/day) by the year 2035 (16), about half of current domestic crude oil production (17). Recent law briefly prohibited federal agencies from procuring fuels derived from unconventional sources unless the lifecycle greenhouse gas (GHG) emissions of that fuel are less than or equal to those associated with conventional fuels (18). As regulations over everything from land use, to water rights, to air quality are debated among all stakeholders, industrial interests have made progress in developing and deploying novel technologies for in situ resource production at the field demonstration scale. These new methods seek to convert the oil shale (actually a kerogen-rich marl stone) to a refinable crude via subsurface heating. One of the leading potential production processes that has emerged in the literature, Shell’s in situ conversion process (ICP), requires gigawatts of electrical power for the in situ retort process, primarily for the down-hole heaters (19). Carbon dioxide (CO2) emitted during electricity generation and retort gas cleanup must be managed in order to mitigate this excess carbon intensity of the resulting fuel. Given the magnitude of the resources involved in large-scale oil-shale production, carbon management is best analyzed at the basin scale, addressing the interdependency of energy, water, and carbon. Whereas the oil-shale to fuel production process provides a good demonstration for basin-wide carbon management, the issues are directly relevant to other regional power production concerns, including modifications or replacements of existing power production facilities.

The feasibility of oil shale development is based in part on the costs associated with mitigation of GHG emissions, which scale with the fuel production rate. The U.S. Geological Survey estimates an oil shale resource in place in the Green River formation of about 1.5 trillion barrels in the Piceance Basin, Colorado, alone (20). Farrell and Brandt (15) suggest that CCS could reduce total emissions from the production of oil shale-derived transportation fuels by 50%, primarily by mitigating the electricity-generation emissions. CCS costs lie primarily in capturing, transporting, and injecting CO2 into subsurface geologic reservoirs. In addition, the injection of CO2 may require treatment of a nearly equivalent volume of produced saline water and disposal of nontreatable water (9).

In this study we assume that the copious electricity required for industry scale shale oil production in the Piceance Basin would be generated by new power plants utilizing efficient natural gas combined cycle (NGCC) or integrated gasification combined cycle (IGCC) power plants and their associated capture efficiencies and costs (21). Captured CO2 emissions from oil shale development are assumed to be transported via pipelines to geologic sequestration sites in saline aquifers in the region.

3. Approach for Screening Sequestration Sites and Infrastructure

Geologic sequestration of CO2 requires the availability of sufficient storage capacity while at the same time ensuring that natural barriers prevent the potential migration of the injected fluid. In geologic terms, this translates to deeply buried porous, permeable rock which will accept and hold large amounts of CO2 and which is bounded by low-permeability confining layers to prevent CO2 escape into the accessible environment. As such, the primary criteria for selecting geologic sequestration targets include 1) capacity and injectivity parameters such as porosity, permeability, thickness, and spatial extent of formation; 2) physical trapping mechanisms such as low-permeability caprock and structural confinement (e.g., fold or dome); 3) depth range conducive to pressure and temperature conditions supporting supercritical CO2 and feasible for drilling and injection; 4) proximity to CO2 source; 5) accessibility of land surface and pore space; and 6) safety and risk considerations and public acceptance (22, 23).

Bachu (22) identifies 15 criteria for screening and ranking sedimentary basins at the continental scale in terms of suitability for carbon sequestration, ranging from tectonic setting through geothermal conditions to infrastructure. Once a particular CO2 source has been identified, the site screening process to meet the conditions above can be simplified to 1. identification of a sequestration basin in reasonable proximity to the emissions sources. 2. selection of potential sequestration target formations (saline formations, depleted oil and gas reservoirs, coal beds, etc.). 3. land-access screening. 4. analysis of reservoir capacity and injectivity at one or more sites. 5. infrastructure analysis. 6. assessment of safety and risk, including feasibility of monitoring, verification, and accounting (MVA) of CO2 leakage.

Cost is an important variable in each of these steps.

4. Description of Models

We evaluate the feasibility of managing CO2 emissions from oil shale development activities in Colorado’s Piceance Basin using models of geologic sequestration (CO2-PENS), infrastructure design (SimCCS), and CO2 production rate from oil shale development activities (CLEARd). Risk assessment with CO2-PENS as described by Stauffer and others (7) is not part of this study. Additional information on these models is included in the Supporting Information.

CO2-PENS is a hybrid system model for performance and risk assessment of geologic sequestration of CO2 (7, 12). The model is designed to perform probabilistic simulations of CO2 capture, transport, injection, and migration in geologic reservoirs and to calculate associated costs. The latest version of CO2-PENS used in this study includes explicit spatial data such as topography on the reservoir/cap-rock interface, evolution of saturation and pressure during injection, and dip on overlying aquifers that may be impacted by leakage upward through wellbores and faults. The inclusion of spatial
awareness in risk analysis is becoming increasingly necessary for problems such as CO2 sequestration and long-term storage of nuclear waste at DOE controlled facilities.

*SimCCS* is an economic-engineering optimization model developed by Middleton and Bielicki (10). *SimCCS* spatially deploys CCS infrastructure (CO2 sources, pipelines, and sinks) using a combination of infrastructure costs (economics) and infrastructure capacities (engineering). *SimCCS* is a spatially explicit model: CO2 sources and sinks are connected via a capacitated network of pipelines and individual pipeline routes that are designed to avoid geographically costly areas. Given a target amount of CO2 to capture in a region, *SimCCS* optimally selects (i) which sources should capture CO2 and (ii) how much; (iii) which geologic reservoirs should store CO2 and (iv) how much; (v) where dedicated CO2 pipelines should be constructed and (vi) at what capacity; and (vii) how to optimally allocate CO2 among the optimal set of sources and sinks.

*CLEARuff* (CLimate-Energy Assessment for Resiliency applied to Unconventional Fossil Fuels) is a dynamical assessment model that uses an integrated framework to simulate the oil shale production process; demands for electricity, water, and labor; GHG emissions; and economics (24). *CLEARuff* calculates the total CO2 emissions as the sum of the contributions from electricity generation and cleanup of the NG coproduced during the in situ retort process (ICP).

In this study we focus on two of the scenarios for electricity generation in the *CLEARuff* model: (1) 100% natural gas combined cycle (NGCC) power plants, both for on-site and off-site power production, and (2) NGCC for onsite power production combined with offsite coal combustion in an integrated gasification combined cycle (IGCC) power plant (e.g. ref 11). Both of these scenarios incorporate advanced thermo-electric generation technologies that are capable of integral CO2 capture and both consider power production within the basin of study. The largest proportion of CO2 emissions originates in the production of electricity for the ICP heating process; for example, in our first scenario approximately 86% of the emissions result from electricity generation by NGCC and about 14% of the emissions result from stripping CO2 from retort gases. Costs for the capture process are included in *CLEARuff* in terms of capital costs and electricity and water demand. Captured CO2 emissions from oil shale development are assumed to be transported via pipelines to geologic sequestration sites in saline aquifers in the region.

5. Example

5.1. Site-Screening Considerations. We developed a set of potential geologic sequestration sites to place CO2 emissions from the hypothetical Piceance Basin oil shale industry, based on the screening approach described in Section 3. Considering information from previous CO2 sequestration modeling studies and assessments of oil, gas, and oil shale resources, we chose the eastern Uinta Basin (Figure 1) for our sequestration area, and we chose the Entrada and Castlegate Sandstones as target formations (details of these choices are presented in the Supporting Information).

In addition to geological considerations (suitable stratigraphy and structure), the selection of potential CO2 seque-
we ran two sets of CO2-PENS from the presumed CO2 source in the center of the Piceance top of the reservoir (average 1500 to 3500 m), and distance formation (Castlegate or Entrada sandstone), depth to the Basin.

The Castlegate sites (top) are similar (ca. 500 to 750 km²), as reflected in the consistent range of injection capacity (4 to 25 MtCO₂/yr) for each site. The reservoir volume required to sequester a given amount of CO₂ decreases with increasing reservoir depth. The areas of the Entrada sites decrease in sites 6, 7, and 8 (812, 504, and 289 km², respectively), and their point clouds define a smooth arc of increasing injection capacity with increasing volume as depth increases.

b) Plot of total on-site cost vs permeability for the areas of the Entrada sites decrease in sites 6, 7, and 8 (812, 504, and 289 km², respectively), and their point clouds define a smooth arc of increasing injection capacity with increasing volume as depth increases.

Figure 2. a) Plot of reservoir capacity vs reservoir volume for the Entrada and Castlegate sites at various reservoir depths. Point clouds represent 100 CO2-PENS realizations for each site, sampling distributions for multiple input parameters. The areas of most of the Castlegate sites (top) are similar (ca. 500 to 750 km²), as reflected in the consistent range of injection capacity (4 to 25 MtCO₂/yr) for each site. The reservoir volume required to sequester a given amount of CO₂ decreases with increasing reservoir depth. The areas of the Entrada sites decrease in sites 6, 7, and 8 (812, 504, and 289 km², respectively), and their point clouds define a smooth arc of increasing injection capacity with increasing volume as depth increases. b) Plot of total on-site cost vs permeability for the Entrada and Castlegate sites at various reservoir depths. Sites at greater depth require fewer wells to inject a given mass of CO₂ and therefore incur lower total storage costs.

CO₂-PENS Results. The combined mean capacity of the nine sequestration sites is 6.5 GtCO₂ or about 131 MtCO₂/yr over 50 years (Supporting Information, Table S-3). Reservoir capacity and annual injection capacity are most strongly controlled by variations in porosity and reservoir thickness (Figure 2a). In order to compare injectivity values among sites of different areas, the reservoir volume is calculated for each realization by multiplying the site area by the reservoir thickness sampled for each model realization. The point
clouds representing 100 CO\textsubscript{2}-PENS realizations for each site in volume-capacity space are shown in Figure 2. With increasing depth, the reservoir volume required to sequester a given mass of CO\textsubscript{2} decreases, as a result of the variations in water and CO\textsubscript{2} phase mobilities that favor flow of supercritical CO\textsubscript{2} with increasing pressure and temperature (7).

Total on-site cost is most sensitive to permeability, and the steepness of the slope of that relationship varies inversely with depth at a given site (Figure 2b). The primary contributor to on-site costs is drilling new injector wells (ca. 94%), with on-site distribution piping and on-site maintenance over the first 50 years contributing far less (3% each). This primary effect of drilling cost can be seen in the vertical stacking of on-site costs by depth among the examples sites (Figure 2b). For a given formation, a deeper reservoir is actually cheaper to utilize than a shallower reservoir, as noted by Stauffer and others (7).

5.3. Infrastructure Considerations.

Approach. Previous studies involving SimCCS (10, 26, 27) used a weighted-cost surface developed by MIT (28). The MIT surface was generated by assigning an individual weight to geographical features (such as national/state parks and urban areas) and summing these weights for each 1 km by 1 km grid cell. The cost to construct a pipeline across a grid cell was derived by multiplying the cell-weight by the engineering construction cost for a 1 km pipeline (capacity dependent) using natural gas pipelines as an analogue. The MIT approach has several distinct shortcomings: engineering costs should not vary with all underlying geography (e.g., federal/state parks), right-of-way (ROW) and engineering costs are not separated, and the cost surface produces excessively large construction costs.

In this study, we generate a new approach to developing a weighted-cost surface. First, the cost surface is based on much more refined (spatially and contextually) geographical inputs: land use (e.g., cropland, forest, lakes), land ownership (e.g., federal, Indian, private), population density, and topography. Topography and population inputs themselves are more sophisticated. For example, a change of slope can increase construction costs while aspect may lower (pipeline running parallel to slope) or increase (down/upslope) costs. And the impact of urban areas is no longer a Boolean decision; instead costs are broadly proportional to population density. Second, construction and ROW costs are derived separately. For example, topography impacts construction costs but not ROW, whereas land use may reduce (e.g., pastureland, scrubland) or increase (e.g., wetlands, forests) construction costs. As a result, SimCCS combines and balances—ROW costs are almost invariable to pipeline capacity, whereas construction costs are highly dependent—two separate cost surfaces. Finally, in this study, we use a cost surface based on 800 m grid cells (see Figure 1). The cost surface ranges from brown (grid cells representing areas with, on average, high combined ROW and construction costs) to yellow (lower costs).

SimCCS Results. The amount of CO\textsubscript{2} generated and captured by the oil-shale industry is proportional to the fuel production rate. The CLEAR\textsubscript{off} model calculates that a single oil-shale company producing 0.1 million bbl/day (36.5 million bbl/year) would capture between 6 MtCO\textsubscript{2}/yr (Scenario 1: 100% NG in an NGCC power plant) and 10 MtCO\textsubscript{2}/yr (Scenario 2: combination of NGCC and IGCC power plants) once the maximum fuel production level is reached. A group of companies producing 0.5 million bbl/day within the Piceance Basin would capture between 32 and 47 MtCO\textsubscript{2}/yr. Extensive oil-shale development producing 1.3 million bbl/day, approximately one-quarter of current domestic crude oil production (7), would require CCS infrastructure for between 83 and 127 MtCO\textsubscript{2}/yr; the latter is approaching the total capacity of the nine sinks identified in this study (131 MtCO\textsubscript{2}/yr over 50 years) but certainly not the total capacity of the Uinta Basin. Additional information on the CLEAR\textsubscript{off} calculation of the CO\textsubscript{2} source term is included in the Supporting Information.

There is a complex and nonlinear relationship between the spatial deployment of CCS infrastructure (transport and inject/store CO\textsubscript{2}) and the oil-shale production rate. Figure 3 illustrates the spatial infrastructure required to transport and store 35 and 40 MtCO\textsubscript{2}/yr. SimCCS optimally constructs a 30” pipeline (35.13 MtCO\textsubscript{2}/yr capacity) between the oil-shale industry and sink #6, and a 16” pipeline (6.86 MtCO\textsubscript{2}/yr capacity) spur from this trunkline to sink #4; 31 MtCO\textsubscript{2}/yr is delivered to sink #6 (31 MtCO\textsubscript{2}/yr capacity) and 4 MtCO\textsubscript{2}/yr is delivered to sink #7. However, the trade-offs between transportation, storage, and on-site distribution/piping and on-site maintenance over 50 years are much more refined for the chosen scenarios. The unweighted volume limits illustrate the candidate pipeline routes. Green lines illustrate where the pipeline network was constructed for each scenario; line width is proportional to the pipeline capacity deployed. The cost surface ranges from low costs (yellow) through to high costs (brown).
**6. Discussion**

The evaluation of carbon management options for potential new industries requires a shift from theoretical considerations of aggregate regional CO₂ emissions and pore-space capacity to consideration of specific sequestration sites and local transport infrastructure. At that scale, one must consider the details of injection formations, land surface and pore space access, pipeline routing, environmental regulations, risk and safety, and costs. The mesoscale evaluation of CO₂ transport and storage focuses on infrastructure configurations at the level of the basin that contains the emissions sources. The combination of CO₂-PENS and SimCCS provides a quantitative assessment of important parameters in sequestration site selection and pipeline network design. The statistical approach considers uncertainty in the characterization of storage reservoirs and produces variable infrastructure costs and network connectivity.

Storage capacity for as much as 33 GtCO₂ may exist within the pores of permeable formations within 50 miles of the Uinta-Piceance Basins, and nearly half of this capacity may be available within the actual basins (11). Storage targets include saline formations (90% of capacity), unmineable coal seams, and depleted oil and gas reservoirs. In the present study, we analyze the capacity and costs for injection of CO₂ into saline formations at nine hypothetical sites in the Uinta basin. Our example sites have a combined mean capacity of about 6.5 GtCO₂ or 131 MtCO₂/yr over 50 years of injection. This calculated total capacity is about one-fifth of the in-basin capacity as assessed by Dooley and others (11).

The aggregate capacity of the study sites (131 MtCO₂/yr) can store the total captured CO₂ from power production using 100% NGCC and retort natural gas cleanup for shale oil production rates up to about 2 million bbl/day and using a combination of NGCC and IGCC up to 1.3 million bbl/day. The full shale oil production rate for the Green River Formation in Utah, Colorado, and Wyoming has been estimated at 2.5 to 3 million bbl/day (11, 29). This production rate would require up to twice as much CO₂ sequestration capacity as was modeled in this study, depending on the technology used to generate the necessary electricity. Taking into consideration that technical, regulatory, and societal limitations will reduce the amount of CO₂ that can realistically be stored in the basins (e.g., ref 11), we conclude that, by simply scaling the capacities modeled in this study to geologic formations at basin scale, the Uinta and Piceance Basins would provide the capacity necessary to store the CO₂ emissions from the full output of the oil shale industry in the region. However, mesoscale studies of potential sequestration sites in adjoining areas (e.g., the Green River Basin) would be necessary for evaluating the potential for managing CO₂ emissions from development of the entire Green River Formation oil shale.

There is a complex, nonlinear relationship between the spatial deployment of CCS infrastructure and the oil-shale production rate. The interplay among pipeline size (capacity), sink capacity and cost, and sink location relative to the source produce nonintuitive variations in the network topology and cost as the oil production (and CO₂ source rate) increase. The placement of pipeline trunklines and spurs to sinks balances optimal pipeline length and pipe size with the capacity, cost, and proximity of available sinks. Although a sink may be closer to the oil-shale industry than the others, the cost savings of a shorter pipeline may be outweighed by the sink’s high cost. Conversely, the economies of scale achieved by transporting CO₂ by a longer pipeline may make it possible to use more distant, cheaper sinks.

As the CCS infrastructure increases in size, economies of scale are realized. Pipeline diameter is strongly anticorrelated with cost, especially among small pipe sizes, leading to a steep initial decline in transport costs as the CCS capacity ramps up. Storage capacity and costs may be relatively constant during the initial phases of CCS development if the
capacity of the first storage site is sufficiently large. The combination of the cost curves for CO₂ transport and storage may result in a window of minimum costs for a particular range in size of the CCS program: in this study, transport and storage of 30 to 80 MtCO₂/yr resulted in the most cost-effective program size.

Apart from EOR projects, existing CCS projects typically link a single CO₂ source to a single reservoir using a single pipeline. As a result, cost estimates and reports in the literature for capturing, transporting, and storing CO₂ tend to a summation of these individual costs. These summations fail to take into account savings through economies of scale or extended expenses such as a large CCS system being forced to use more expensive storage reservoirs (as opposed to the a single, optimized reservoir). Regardless, the CCS infrastructure costs for the Piceance basin oil-shale industry calculated by SimCCS fall approximately in the middle of the range of previously published estimates. For example, the IPCC (29) report estimates U.S. onshore injection and storage in a saline aquifer between $0.4/tCO₂ and $4.5/tCO₂, with a representative value of $0.5/tCO₂.

Uncertainties in reservoir properties (e.g., permeability, thickness, porosity) as well as reservoir heterogeneity will strongly affect the injectivity, capacity, and costs associated with any potential sequestration reservoir. We used constant representative values for reservoir properties in this analysis, and the resulting infrastructure analysis illustrates the basic variability in utilizing various combinations of storage sites. A next step is to investigate the effect of uncertainty in reservoir characteristics on the infrastructure costs and design. An outcome will be the choice of optimal transport and storage configuration in the face of uncertainty.

In contrast to depleted oil and gas reservoirs, the use of saline formations for CO₂ sequestration provides the opportunity to use new formations and undeveloped reservoirs. However, the patchwork of land ownership and variable land use means that access to pore space may not be easy. We screen for land access as a proxy for pore space access, highlighting opportunities and limitations for defining individual injection sites. Although the legal aspects of pore-space ownership, as distinct from mineral rights and surface rights, are being defined at the level of state governments (and could result in a highly variable legal landscape), early movers such as Montana are linking the pore space estate to the surface estate.

While not considered in this report, it will be important to consider risk due to CO₂ leakage from the reservoir via multiple pathways (e.g., wells and faults) as part of site selection. Monitoring, verification, and accounting (MVA) feasibility and costs will also factor into site screening and decisions about development of particular locations for carbon sequestration. Rules are currently in development at the state and federal levels for regulating MVA, and this study will be followed by site-scale studies involving detailed reservoir characterization, assessment of injectivity and storage capacity, identification of potential leakage pathways, and risk assessment. For so-called green-field areas and undeveloped geologic formations, the mesoscale evaluation provides a cost-effective means to develop important information on capacity, cost, and infrastructure design for these later site-scale studies.

Acknowledgments
The study of carbon management for oil shale production in the Piceance Basin was performed as part of a larger feasibility study of oil shale development within environmental constraints funded by the DOE Office of Naval Petroleum and Oil Shale Reserves. We are grateful to James Killen, our project manager in DOE-FE, for his valuable insight and support. Development of the injectivity and capacity model of the CO₂-PENS model was funded by DOE Office of Fossil Energy through the NETL Carbon Program. We thank Rick Kelley for GIS analysis. Three anonymous reviewers contributed to the clarity of presentation.

Supporting Information Available
Supporting Information associated with this paper contains additional technical details on geologic site screening, sequestration reservoir properties, functionality and use of the CO₂-PENS, SimCCS, and CLEAR₉ models, and the oil shale case study. This material is available free of charge via the Internet at http://pubs.acs.org.

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ES101470M