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The geospatial and economic viability of CO_2 storage in hydrocarbon depleted fractured shale formations

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ABSTRACT

Hydrocarbon depleted fractured shale (HDFS) formations could be attractive for geologic carbon dioxide (CO_2) storage. Shale formations may be able to leverage existing infrastructure, have larger capacities, and be more secure than saline aquifers. We compared regional storage capacities and integrated CO_2 capture, transport, and storage systems that use HDFS with those that use saline aquifers in a region of the United States with extensive shale development that overlies prospective saline aquifers. We estimated HDFS storage capacities with a production-based method and costs by adapting methods developed for saline aquifers and found that HDFS formations in this region might be able to store with less cost an estimated ~14× more CO_2 on average than saline aquifers at the same location. The potential for smaller Areas of Review and less investment in infrastructure accounted for up to 84% of the difference in estimated storage costs. We implemented an engineering-economic geospatial optimization model to determine and compare the viability of storage capacity for these two storage resources. Across the state-specific and regional scenarios we investigated, our results for this region suggest that integrated CCS systems using HDFS could be more centralized, require less pipelines, prioritize different routes for trunklines, and be 6.4–6.8% ($5-10/t$CO_2$) cheaper than systems using saline aquifers. Overall, CO_2 storage in HDFS could be technically and economically attractive and may lower barriers to large scale CO_2 storage if they can be permitted.

1. Introduction

In the mid 2000s, the production of natural gas in the United States began to increase rapidly when it became profitable to produce hydrocarbons from shale formations. At this time, production from these new resources became cost-effective due to a confluence of technological advances (e.g., horizontal drilling), market incentives (e.g., high energy prices), and policy—including the 2005 Energy Policy Act which exempted hydraulic fracturing from regulation under the Safe Drinking Water Act (U.S. Congress, 2005; Vann et al., 2014). Unlike conventional oil and gas reservoirs, which occur in formations that are naturally permeable so that fluids like oil and natural gas can flow through them, shale formations have low intrinsic permeability. Hydraulic fracturing is a technique that artificially enhances permeability and pore-connectivity within organic shale, so that natural gas can flow from the formation to a production well. As a result, hydrocarbons that are contained within the nano-scale pore structure of the shale can be produced by artificially stimulating fractures to connect the pores.

This unconventional development of shale gas has a complicated impact on the greenhouse gas emissions that drive anthropogenic climate change. Shale wells and their supporting infrastructure can leak natural gas. The principal component of natural gas, methane (CH_4), has a high radiative forcing and that exacerbates climate change when it accumulates the atmosphere. Further, the carbon dioxide (CO_2) that is produced when fossil fuels like natural gas are burned combines with the much larger global CO_2 emissions to produce much greater radiative forcing than the aggregate global CH_4 emissions. In contrast, most natural gas from shale is used to produce electricity that would otherwise have been generated using coal-fired power plants. During combustion, coal power plants emit about twice as much CO_2 per unit energy as natural gas power plants, and thus the CO_2 emissions from the U.S. electricity sector have decreased because of the availability of

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inexpensive natural gas. But from another perspective, the enormous amount of fossil fuels in shale formations is now economical to produce. Approximately 1250 $GtCO_2$—roughly 39× global emissions in 2016—could be emitted if the estimated seven trillion cubic feet of natural gas that is contained in shale formations worldwide is developed (U.S. DOE EIA, 2013). If these resources are produced and burned in conjunction with other sources of emissions, targets for stabilizing the concentration of CO_2 in the atmosphere by limiting CO_2 emissions will not be attainable (Fuss et al., 2014; GEA, 2012; IPCC, 2014).

One option to address these CO_2 emissions could come from the hydraulically fractured shales. Large volumes of CO_2 could be emplaced in the fracture networks by using the pore connectivity that facilitates the withdrawal of large volumes of CH_4 from the formation. The CO_2 could be diverted from the atmosphere and into the hydrocarbon depleted fractured shale (HDFS) as a part of a CO_2 capture and storage (CCS) system. CCS is a technological process in which CO_2 is separated from the exhaust streams of large point-source emitters (e.g., coal or natural gas power plants) and compressed and transported to locations where it is injected into deep geologic formations to prevent its release into the atmosphere. The most commonly studied approach for CO_2 storage is to inject it into deep, porous, and permeable saline aquifers that are overlain by low permeability caprock (such as shale) that provides a physical barrier to constrain the vertical migration of the CO_2, which is buoyant in the connate brine (Bachu, 2015; IPCC, 2005). These saline aquifers are attractive for storing CO_2 because they are ubiquitous, have large estimated storage capacities, and the processes involved with storing CO_2 in them are well understood (NETL, 2015). But the deployment of CCS using deep saline aquifers may be impeded by the potential for the buoyant CO_2 to leak through natural or man-made breaches (e.g., faults, fractures, existing wells) in the caprock, as well as the real and perceived hazards associated with induced seismicity due to the increase in pore pressure from CO_2 injection (Ashworth et al., 2015; Pawar et al., 2015; White et al., 2014). Some strategies have been developed to actively manage this increase in pore pressure, including those which produce brine during or before CO_2 injection (Bergmo et al., 2011; Birkholzer et al., 2012; Buscheck et al., 2016a,b, 2012; Celia et al., 2015).

Shale formations that are fractured and depleted of oil and natural gas could be more attractive repositories than saline aquifers. From a physicochemical standpoint, these are a number of reasons that fractured shale formations could be an attractive repository for CO_2 storage. During natural gas production, CO_2 could be used as an alternative to water in the fracturing process, which could reduce capillary trapping and lead to higher yields (Middleton et al., 2015; Wilkins et al., 2016). After natural gas production, the pressure in the shale fracture networks would be somewhat lower than the surrounding formations so injecting CO_2 into that pore space is unlikely to substantially increase the pore pressure differences and the associated risks related to caprock failure or induced seismicity. In addition, several characteristics of shale formations suggest that they are less likely than saline aquifers to leak injected CO_2. In a saline aquifer, much of the injected CO_2 is mobile during the operational timeline (a few decades) and may encounter pathways through which it could leak into overlying sedimentary formations (Bachu, 2015; Bielicki et al., 2015, 2014b; Celia et al., 2015). But in shale formations, fracture networks could propagate horizontally along bedding planes and most of the CO_2 would exist within these fracture networks (Levine et al., 2016) with a nicely conformant fracture. The low intrinsic permeability and reactivity of the bulk shale rock is likely to limit vertical migration of buoyant CO_2 within the storage formation—in the same way that shales are currently envisioned as caprocks above more permeable storage formations, and other overlying aquitards provide secondary trapping (Bielicki et al., 2016, 2015). In addition, much of the CO_2 could sorb into the nano-scale pore structure of the shale, be immobilized within the rock, and further decrease the pore pressure of the fluid (Busch et al., 2008; Heller and Zoback, 2014; Kang et al., 2011). These characteristics may result in lower monetized leakage risk (Bielicki et al., 2016) for CO_2 storage in HDFS formations relative to CO_2 storage in saline aquifers, but fluid flow through shale formations is complex (e.g., the fate of much of the water that is used in hydraulic fracturing is poorly understood at present) and the high density of existing shale wells relative to the mobility of the emplaced CO_2, and other considerations (e.g., potential existence of corrosion, shale wells have experienced at least one high pressure event), warrants further investigation of the degree of leakage potential (Bielicki et al., 2015).

The potential for leakage is an important economic and regulatory concern for geologic CO_2 storage (Bielicki et al., 2015, 2014b). In fact, the U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class VI rules for geologic CO_2 storage specify that an Area of Review (AoR) must be identified where leakage from the storage reservoir could endanger an underground source of drinking water (USDW) (U.S. EPA, 2013). The existence of the AoR will result in costs because the UIC Class VI rules require that operators assess, and perhaps remediate, the potential leakage pathways within the AoR.

There are two primary ways that the AoR could be defined for saline aquifers: (1) the areal extent of the CO_2 plume in the reservoir, where buoyant CO_2 could encounter leakage pathways; or (2) by the areal extent where the increase in the pore pressure is sufficient to displace brine upward through leakage pathways into the groundwater aquifer. This definition of the AoR is based on the premise that CO_2 and resident brine are mobile, but a portion of the CO_2 that would be injected into a HDFS formation would be immobilized due to adsorption by the shale and there is little in situ brine to be displaced. Since the shale formations are not naturally porous and permeable, the injected CO_2 may not freely migrate laterally, and pressurize and displace brine, within the shale and encounter vertical leakage pathways into overlying formations. Given the differences in the physical characteristics of the two storage options, and different approaches to regulatory treatment between hydraulic fracturing and geologic CO_2 storage (Dammel et al., 2011) there may be ambiguity in how UIC Class VI regulations apply to the use of existing hydraulically fractured wells, and the identification of the AoR, for CO_2 injection and storage in HDFS.

A number of recent studies have estimated the CO_2 storage capacity of this HDFS storage option (Edwards et al., 2015; Godec et al., 2013; Tao et al., 2014; Tao and Clarens, 2013a, 2016). These studies use a variety of methods based on either historical production, volume, or reservoir modeling to estimate the storage capacity of various shale plays around the world. Even though the modeling approaches and the formations vary, these studies generally estimate that a depleted shale formation could store between 0.2 $MtCO_2$ and 9 $MtCO_2$ per well over 20 years, although the allowable injection rates could decrease quickly and the likely capacity is on the order of 1 $MtCO_2$ per well.

In light of the physical and chemical characteristics that make HDFS formations desirable targets for CO_2 storage, there is a need to better understand the economic, geospatial, and logistical aspects of this pathway at the systems-scale. CCS is an attractive option for reducing CO_2 emissions to the atmosphere because it can be scaled to handle the large amounts of emissions from existing point sources, but integrated CO_2 capture, transport, and storage (i.e., CCS) systems are costly. CO_2 storage in saline aquifers will likely be a greenfield operation, where sites need to be acquired and developed, wellpads and other infrastructure established, pore space obtained, and permits issued for injection. In contrast, CO_2 storage in shale may be able to reduce costs by leveraging the existing well pads and at least some portion of the costly wells, understanding of formation geology, monitoring plans, nearby pipeline infrastructure, and logistics (Levine et al., 2016). The potential for brownfield designation of existing shale development could reduce costs, ease permitting processes, and potentially sidestep concerns about pore ownership, liability, and social acceptance.

Even though few unconventional shale wells have been retired to date, tens of thousands of hydraulically fractured shale wells will be taken out of production in the coming decades because the