

GEOLOGIC CARBON STORAGE: UNDERSTANDING THE RULES OF THE UNDERGROUND

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ABSTRACT

The geologic sequestration (GS) of carbon dioxide (CO₂) is emerging as an option for carbon management. Few studies have explored the regulatory needs of GS or compared these needs with regulations governing underground injection. We review the technical and regulatory history of deep underground injection in the U.S. Our treatment focuses on the technical and regulatory aspects that are most likely to be important for GS.

INTRODUCTION

The use of CO₂ capture and sequestration (CCS) is emerging as a potentially important tool for managing carbon. The CO₂ could be captured from electric power plants, hydrogen production, or other industrial processes and sequestered in geologic formations or in the ocean. Because of its compatibility with the current fossil energy infrastructure, CCS may prove an important tool for achieving significant reductions in emissions at reasonable cost. We focus on GS, which we define as the process of injecting CO₂ into deep (greater than about 1 km) geologic formations for the explicit purpose of avoiding atmospheric emission of CO₂.

Many studies have explored the technological and scientific aspects of GS (cf. [1]), but few have assessed the regulatory environment for GS [2]. In the U.S., an extensive regulatory framework for underground injection already exists, and the research agenda for GS is now being set. Efforts to understand and adapt the regulatory environment for GS cannot wait until the technology is ready for large-scale application.

THE TECHNOLOGY AND ITS RISKS

In general, GS is accomplished by injecting CO₂ at depths greater than ~1 km into porous sedimentary formations using technologies derived from the oil and gas industry, where CO₂ is currently injected to enhance oil recovery (CO₂-EOR). Industrial experience with CO₂-EOR and with the disposal of CO₂-rich acid gas streams, as well as related experience with natural gas storage and the underground disposal of other wastes, allows some confidence in estimating the cost of GS, and suggests that the risks may be manageable.

Suitable formations are found in deep sedimentary basins. Pore waters are generally very saline, and at almost all plausible injection sites, CO₂ will be less dense than the displaced fluids, so the buoyant CO₂ will flow upwards until it is confined by a low-permeability caprock. The buoyant flow makes any breach in the confining layer a possible pathway for upward escape, and also drives horizontal movement, making the areal extent of the CO₂ plume much larger than it would be for a neutral buoyancy fluid [2]. The CO₂ will eventually (decades to

millennia) dissolve into pore fluids, eliminating buoyant forces that drive upward motion and greatly reducing the rate at which CO₂ is transported out of the formation (solubility trapping), while on longer timescales CO₂ may be immobilized through geochemical reactions (mineral trapping) [2; 3].

It is convenient to group GS risks into two categories: local environmental, health, and safety risks (EHS); and global risk arising from leaks (Figure 1). The global risk may be viewed as uncertainty in the effectiveness of sequestration. The local risks arise through three processes: release of CO₂ to the surface, chemical effects of CO₂, or the displacement of other fluids in the subsurface.

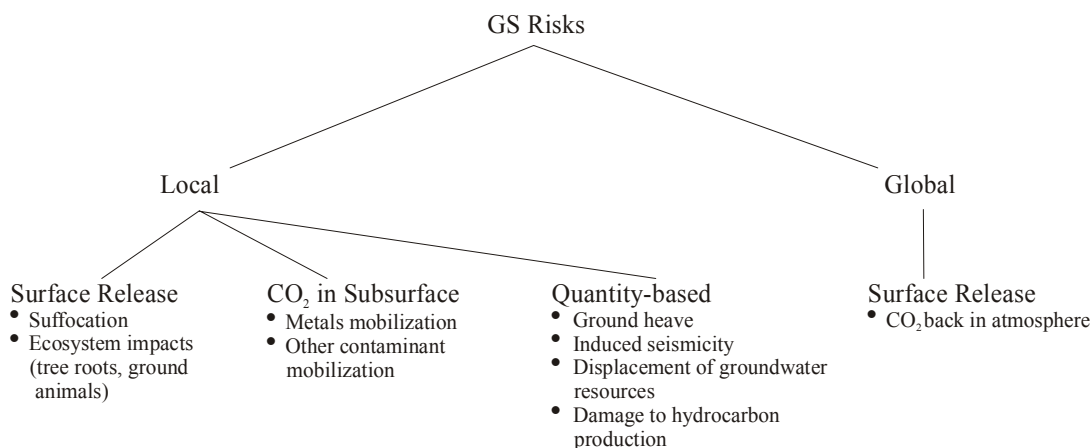


Figure 1. Taxonomy of possible risks of geologic sequestration

UNDERGROUND INJECTION IN THE U.S.

In the 1930s, petroleum technologies were adapted to inject oilfield-produced brine wastes underground to avoid surface water contamination [4]. Industrial waste injection began primarily with the strengthening of surface water pollution control regulations, part of the ongoing search for a more secure sink for industrial by-products [5]. Industrial injection wells were first mentioned in a 1939 article describing Dow Chemical’s problems with a well disposing of industrial brines (cited in [6]). By 1950 there were about four waste injection wells (cited in [6]). Growth was then rapid: there were 30 industrial wells in 1964, 110 in 1968, 246 in 1972, and 333 industrial and municipal wells in 1974 [7]¹.

Regulation of injection began with the states. In 1934, Kansas gave the State Corporation Commission control over oilfield brine injection [7]. The Texas Injection Well Act of 1961 was the first to specifically address other kinds of wastes, giving authority for oil field wastes to the Texas Railroad Commission (TRC), with injection of all other wastes requiring a permit from the Texas Board of Water Engineers [7].

Federal regulation of underground injection began in the 1970s due to disposal well failures. In 1968, a Hamermill Paper Company (Erie, PA) well was thought to have contributed to groundwater contamination 5 miles away [8]. In the 1960s, the U.S. Geological Survey and the U.S. Army Corps of Engineers determined that a series of earthquakes near Denver, CO, were triggered by injection well disposal at the Rocky Mountain Arsenal, with one tremor measuring 5.5 on the Richter scale [8]. In response to such incidents, the pre-Environmental Protection Agency (EPA) Federal Water Quality Administration adopted a policy that “opposed the disposal or storage of wastes by subsurface injection without strict controls and a clear demonstration that such [injected] wastes will not interfere with present or potential use of subsurface water supplies [...] or otherwise damage the environment” (as quoted in [9]). The policy proceeded to declare that underground injection should be used “only until better methods of disposal are developed” [9].

¹ These numbers are not strictly comparable as different definitions were used. However, they do illustrate a rapid rise in the number of injection wells and the increasing importance of waste injection.

The EPA initially tried to regulate underground injection via the Clean Water Act (CWA), but this proved impractical. At issue is whether the CWA provides groundwater protection [10]. The CWA adopts a broad use of the term “navigable waters,” defining them as “waters of the United States” [10]. In December 1973, EPA’s Office of the General Counsel issued an opinion that, while the CWA issued permits for the “discharge of a pollutant,” this was defined under the Commerce Clause to include only discharges into navigable waters [11].

Congress extended EPA’s authority to regulate underground injection in 1974 with the Safe Drinking Water Act (SDWA). SDWA gave the EPA Administrator responsibility for developing regulations for state underground injection programs that provide minimum standards and ensure that injection activities do not harm Underground Sources of Drinking Water (USDWs)[7]. These minimum federal standards could be either adopted by state programs or implemented directly by the EPA.

The first set of Underground Injection and Control (UIC) regulations under the SDWA were proposed in 1976, but were soon withdrawn after receiving substantial adverse commentary [12, p 145]. The difficulty in preparing the regulations was due in part to the paucity of data, the challenge of coordinating the various state and federal agencies. Revised regulations were presented in April 1979 and finally promulgated in 1980.

With the exception of natural gas storage, which was exempted in the 1980 SDWA reauthorization, the regulation of underground injection is controlled by the EPA’s UIC program, although many states are granted authority for implementation². Pipeline transport is regulated by the U.S. Department of Transportation, and most of the surface risks are handled by state health and safety regulations. The regulations divide underground injection activities into five major classes. Of interest for GS: Class I hazardous, industrial, or municipal wells are managed by state departments of environment or natural resources, while Class II hydrocarbon production wells are managed by state conservation commissions or divisions of oil and gas.

The explicit goal of the UIC program is to protect current and potential sources of public drinking water. The movement of injectate into a USDW is explicitly prohibited, where a USDW is defined as an aquifer that has a total dissolved solids content of less than 10,000 mg/L [4]. The rules mandate *zero* contamination: if any water quality monitoring for Class I, II, or III wells demonstrates “the movement of any contaminant into the underground source of drinking water,” corrective actions will be taken “as are necessary to prevent such movement,” [14]. However, with the exception of specific Class I hazardous wells, where monitoring can be required, no federal requirements exist for monitoring USDWs above the injection zone. Since the 1980 regulations were adopted, there have been only four cases of wastewater migration from underground injection wells and no reported case of USDW contamination from Class I hazardous or industrial wells [15].

UNDERGROUND INJECTION: CURRENT PRACTICE AND GS ANALOGS

This section examines three GS analogs: Florida municipal wastewater injection, hazardous waste injection, and CO₂-EOR. Florida municipal wells manage large quantities of a buoyant fluid. Hazardous waste injection permits require that injected wastes be modeled and demonstrate that they will not migrate from the injection zone for 10,000 years, the only type of UIC injection permit to specify a containment time. CO₂-EOR injection shows direct experience with CO₂ transport, injection, and management in the field.

The current UIC program has extensive experience managing large volumes of wastes. Class I municipal wells in Florida, for instance, inject quantities of wastewater similar to what it would take to make the State of Florida carbon-neutral. Florida municipal wastewater disposal injects approximately 0.5 Gt/year³ [16] in some of the largest injection wells in the country (0.75 m in diameter), handling almost 70,000 m³/day [8].

In contrast to the Florida municipal wells, quantities handled by the Class I hazardous program are small (roughly 34 Mt/year), but represent 50% of the liquid hazardous waste in the U.S. [8]. The siting, construction,

² Currently 34 states have been granted implementation authority. EPA shares responsibility for UIC program implementation in 6 states, while EPA regional offices implement the UIC program for all well classes in 10 states and on all Tribal Lands. Regional EPA offices also manage all Class I hazardous no-migration demonstrations[13].

³ This number was obtained by extrapolating October flows for an annual figure.

and operational requirements are the strictest of all well classes, and are relatively costly by comparison. While the Class I hazardous program may be run through the state, operators of hazardous waste wells must submit a “no-migration” demonstration to the regional EPA office, in addition to their state-granted permits [4; 17]. Unfortunately, the “no-migration” demonstration modeling results have not been compared in detail with actual injectate behavior. Class I hazardous wells exist in 10 states, the majority in Texas (64) and Louisiana (17).

Most regulatory experience has been with liquids, but the definition of injected fluids is broad, including gases⁴. Gases and CO₂ injection are directly managed under the UIC program. While CO₂ is currently being injected for disposal in the U.S., a significant amount of CO₂ (roughly 28 Mt/year in the Permian Basin alone [18]) is injected for EOR under the auspices of the UIC program where they are regulated as Class II injection wells.

Miscible CO₂-EOR is a well-established tertiary oil recovery technology, suitable for lighter petroleum reserves. In the Permian Basin, CO₂ is currently supplied by natural CO₂ reservoirs and transported by pipeline hundreds of kilometers to injection sites. In addition to the natural CO₂, gas processing plants, a fertilizer plant, and a coal gasification plant all capture anthropogenic CO₂ and inject it for EOR (~5 Mt/year internationally) [19]. The practical experience from handling CO₂ for injection is important; construction materials, operational procedures, behavior in reservoirs, etc. all have added substantial to knowledge to CO₂ handling and management.

MANAGING THE RISKS

A robust framework for managing these risks will be required if GS is to play a significant role in mitigating CO₂ emissions. While local risks of GS can perhaps be managed within the existing regulatory framework, global risk management will ultimately require international agreement. The U.S. will need to decide if CO₂ injected underground counts, or partially counts, as a non-emission to the atmosphere. This decision will need to be integrated into a larger body of international law governing carbon management and emissions accounting.

As a signatory to the UN Framework Convention on Climate Change (UN-FCCC), the U.S. is required to produce an annual inventory of its greenhouse gas emissions. Currently, the EPA’s Office of Atmospheric Programs prepares the inventory, and does not systematically account for geologic carbon sequestration. While GS is mentioned in the Kyoto Protocol and has been discussed in subsequent meetings of the parties to the UN-FCCC (COP6 and COP7), there are no guidelines as to how to account for the emissions.

There are several possible approaches to regulating GS. The permitting process for underground injection is mostly procedural, with some performance-based measures (e.g., the no-migration petitions). A performance-based standard might enable better management of the risks. Like regulations governing geologic storage of radioactive nuclear wastes [20], a probabilistic site evaluation would be performed and acceptable leak levels specified. Allowable CO₂ leaks would be limited, but a small amount of leakage could be tolerated over a defined time frame, as it is for radioactive waste. Such an approach could incorporate some allowance for imperfect sequestration—essential if GS is ever to play a significant role. However, this approach may pose additional difficulties. Monitoring surface leaks over the background CO₂ flux, has not been demonstrated for large-scale operations. Additionally, the potential political difficulties in converging on acceptable techniques and release levels should not be underestimated. The difficulty of converging upon an acceptable risk level within a group of stakeholders with widely differing political agendas is one of the crucial lessons from the nuclear waste storage debate. Such divergent political motivations are bound to stall any regulatory consensus process.

Procedural and performance-based approaches to regulation are not as divergent as they might seem. Both have a defined goal. For performance-based standards, this is explicitly defined and operationalized through monitoring and verification activities to ensure acceptable risk levels are not exceeded. In procedural regulations, the goal is implicit, guided by rules, and performance standards that will hopefully arrive at an acceptable risk level.

⁴ In the UIC regulations, a fluid is defined as “any material or substance, which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state” [14].

CONCLUSIONS

The U.S. has considerable experience injecting fluids underground for purposes of storage, recovery, and disposal. An extensive regulatory framework has evolved to ensure the impact of injection activities is minimized. Experience is greatest in regions with historic oil and gas production and traditional industrial production.

Many federal and state regulations and actors are charged with ensuring that materials are handled, transported, and injected safely. Pipeline transport is regulated by the U. S. Department of Transportation, for instance, while most of the EHS regulations are set by OSHA and adopted and enforced by the states. The EPA regulates underground injection activities on land, with primacy given to state agencies that can show an effective program. Permitting requirements vary by individual well class. Even within the same jurisdiction, the injection of identical fluids is treated differently, depending on their source. Brine from a hydrocarbon production operation and that from an industrial process, for example, fall under different well classes, are managed by different institutions, and are subject to different site characterization, construction, management, and reporting requirements.

The inconsistencies in treatment of underground injection mean that, even assuming there was a consensus on the appropriate regime for regulating GS, it would be difficult to include that regime in the regulatory structure. Any permit obtained under the regulations for CO₂ injection does not specify the length of time that injected CO₂ must stay underground or address how long injected CO₂ needs to remain underground. While not fully explored in this paper, storage time is a crucial question for GS. "How long is long enough?" is a question that will drive the research agenda, determine the appropriateness of individual technologies, and shape regulatory structures for the future. It is unclear if CO₂-specific regulations would be integrated within the underground injection regulations or if an entirely different regulatory approach would be required.

There is a clear need to begin to think of regulation for GS now. Linking any GS activity with the national GHG emissions inventory is key. Current inconsistencies in accounting for CO₂ injected underground are being addressed slowly. Additionally, the research agenda for GS is being set now, and it is important to ensure that regulatory needs (risk characterization, pathways to exposure, etc.) are adequately incorporated. Providing regulatory consistency for injected CO₂, regardless of source, is another logical consideration. Building a national and international coalition of stakeholders to ensure that regulation of GS is consistent and able to meet the stated objectives will take time, but is necessary if GS is to play a role in reducing atmospheric CO₂ emissions.

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