Pressure profiles for CO$_2$-EOR and CCS: Implications for regulatory frameworks

**Philip Marston** explores the fundamental operational differences between geologic storage in active CO$_2$-based EOR operations and the storage operations in non-EOR-based projects. He puts forward a case that the current regulatory paradigm fails to recognize these fundamental operational differences and this could have significant implications for the deployment of CCS technology.

Analysts and regulators around the world have devoted a great deal of effort in recent years to crafting a regulatory framework for geologic storage of carbon dioxide (CO$_2$). The work has been premised largely on the assumption that CO$_2$ will be captured from emissions sources and then injected and geologically stored solely for the purpose of reducing atmospheric emissions of a greenhouse gas, as is done in several of the high-profile demonstration projects (such as Sleipner and In Salah).

While well-suited for its intended purpose, this approach risks creating a serious regulatory obstacle to the successful deployment of carbon capture and storage technology in the United States or other jurisdictions where the captured CO$_2$ will be used – and incidentally stored – in enhanced oil recovery (EOR) operations. Although EOR is not intended as a CCS technology strategy, the geologic storage of CO$_2$ that occurs during routine EOR operations can provide tangible and measureable emission reduction benefits where the CO$_2$ has been captured from an emissions source. Hence a sound CCS policy should avoid creating regulatory barriers to integrating supplies of captured CO$_2$ into traditional EOR operation.

A problem may arise, however, where the regulatory paradigm fails to recognize the fundamental operational differences between geologic storage in active CO$_2$-based EOR operations and the storage operations in non-EOR-based projects (whether in saline formations or non-producing hydrocarbon reservoirs). This feature focuses on the regulatory implications of the differing pressure profile of CO$_2$-EOR operations, a point that is little discussed in the relevant literature. As explained later, the subsurface formation pressure profile of a CO$_2$-EOR operation is essentially constant as a result of the continual removal of formation fluids from production wells (oil, water, and CO$_2$) at the same time as incremental quantities of CO$_2$ are added via injection wells.

**Striking the balance: pressure profile of a CO$_2$-EOR operation**

The basics of routine CO$_2$-EOR operations and the incidental CO$_2$ storage that occurs are well documented in the literature. At bottom, it involves injecting CO$_2$, alone or in various combinations with water, into a pattern of injection wells in a formerly depleted oil reservoir. The CO$_2$ mixes with the remaining oil in the reservoir, causing the oil droplets in the pores of the rock to expand and to detach from the rock surface, thus becoming mobile. The mix of CO$_2$ and oil is brought to the surface via the...
producing well, together with the brine which normally fills the remaining formation pore space.

Figure 1 traces the CO₂-EOR pressure profile. While the schematic is illustrative only, it is based on an actual operating EOR field and the pressure data are derived from the data reported to the state oil and gas regulator. As shown in Fig. 1, the original formation pressure prior to commencing the oil production was about 4850 psig, considerably below the formation fracture pressure of roughly 7800 psig. The original reservoir pressure in an EOR formation is, of course, always below the fracture pressure because otherwise the oil would not have remained trapped and there would be no oil field to develop in the first place.

Over the 20 or 30 years or so of primary production (perhaps followed by secondary production using water flooding), the reservoir pressure declines. This pressure decline results from the extraction of the original reservoir fluids (oil and brine). Eventually, an economic limit is reached and production operations come to a close, leaving the formation at a lower pressure than had originally prevailed. As shown by Fig. 1, it is at this point that an CO₂-EOR operation may begin (although it is not uncommon for a field to be non-producing, or only marginally producing for years prior to commencement of a CO₂-EOR operation). Adequate supplies of CO₂ at attractive prices are still the exception, not the rule, in most oil fields in the USA. More plentiful supplies of CO₂ captured from industrial facilities could make a very substantial difference in the extent of CO₂-EOR operations.³

Initially, the operator injects CO₂ without removing reservoir fluids from the producing wells in order to return the reservoir to approximately its original pressure. This step takes months or even more than a year. The goal is normally to raise the reservoir pressure slightly above its original pressure. In the field illustrated in Fig. 1, pressure was raised about 250 psig above the original, pre-production pressure. Even after this 're-pressurization' of the reservoir, the operating pressure was about 5100 psig, well below the formation fracture pressure of 7800 psig over the life of the operation and indeed well below the limit set by state regulations governing injection operations (typically 90% of fracture pressure). Keeping the pressure below fracture pressure is critically important to efficient EOR operations since exceeding that pressure could lead to loss of the valuable CO₂ and a loss of efficiency in sweeping oil from the reservoir. Hence, CO₂-EOR operations are also quite different.
from hydraulic fracturing (or 'fracking') operations where fluid injections are deliberately increased above the fracture point precisely in order to allow hydrocarbons in the fractured formation to flow to the well.

Once the target operating pressure is reached and oil production begins, the reservoir is maintained in a pressure equilibrium in which the quantity of CO$_2$ injected is balanced by the quantity of oil, water, and CO$_2$ that is extracted from the producing wells. This balance is maintained over the entire productive life of the operation, which may last on the order of 20 to 40 years or so, as shown by Fig. 1. As one CO$_2$-EOR reservoir engineering expert explains:

*The EOR project is designed to maintain a constant operating pressure which is accomplished by balancing the fluids injected with a comparable quantity of fluids produced* (Sutherland, R. pers. comm.).

Over time, as the recoverable oil diminishes, the composition of the production stream changes. There will be a greater amount of recycled CO$_2$ (and water) as compared to the oil. The produced CO$_2$ continues to be dehydrated, compressed, and re-injected in the reservoir such that at the end of the operation most of the CO$_2$ injected in the field will be recycled CO$_2$, reducing the need of this operation for incremental CO$_2$ from an off-site supply source. To further conserve scarce supplies of CO$_2$, the operator may inject water with (or in alternation with) the CO$_2$ in order to maintain the pressure balance.

Reservoir engineers note that the operational efficiency of a CO$_2$ flood may actually be increased to the extent the operator can lower the pressure somewhat further still. This results from the fact that at a lower pressure, the CO$_2$ will be less compressed such that a given quantity of injected CO$_2$ will occupy a relatively larger volume of the pore space, allowing the operator to achieve a greater output of oil with a correspondingly smaller amount of CO$_2$. Hence, the key economic incentives for the EOR operator are generally to maintain the reservoir pressure at the lowest pressure consistent with meeting the other necessary operational parameters (i.e. the minimum miscibility pressure).

When the costs of maintaining the operation are no longer justified by the value of the oil recovered, the CO$_2$-EOR operation is brought to an end by terminating both injections and withdrawals. All the wells are plugged and abandoned in accordance with the applicable state regulation. With no further injection or withdrawal of fluids, the pressure balance struck during operations remains, although the mix of fluids is different because large amounts of CO$_2$ now occupy the space previously occupied by oil and brine. The net quantity of CO$_2$ injected (net of recycling, of course) is then trapped and permanently stored in the formation. Following site closure, the reservoir pressure remains stable or may decline somewhat as the injected fluids gradually disperse further in the formation.

This pressure profile contrasts sharply from that presented by a non-EOR storage location, where reservoir fluids are not withdrawn as CO$_2$ is injected. With no balancing of fluid injection and withdrawals, the subsurface pressure tends to rise continuously. In an 'open' formation, such as a saline aquifer that is not closed by nearby lateral traps, the pressure build-up may be dissipated somewhat as the CO$_2$ plume migrates through the formation. But the operator may have to adjust injections if the pressure rises too close to the fracture pressure and wait for the pressure to dissipate before additional injections proceed. Alternatively, of course the storage site operator could imitate a CO$_2$-EOR operation by drilling pressure relief wells ahead of the CO$_2$ plume to extract brine from the formation to lessen the pressure. Drilling such pressure-relief wells would increase the cost the operation significantly, however.

**Implications for regulation of geologic storage of CO$_2$**

The US Environmental Protection Agency (EPA) has recognized that EOR operations (regulated by state agencies under Class II of the federal Underground Injection Control Program) present a lower risk profile than non-EOR geologic storage sites. These non-EOR storage sites will be subject to a new 'Class VI' regime. The regulations contemplate a potential transition from Class II to Class VI when the primary purpose of the injection is for long-term storage and there is an increased risk to underground sources of drinking water (USDWs) as compared to traditional Class II operations using CO$_2$.

*Traditional EOR projects are not impacted by this rulemaking and will continue operating under Class II permitting requirements. EPA recognizes that*
there may be some CO₂ trapped in the subsurface at these operations; however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II.

But while the EPA recognizes that geologic storage occurs in EOR and that EOR operations present a lower risk profile (as documented earlier), the EPA’s rules do not provide an explicit mechanism for accounting for and verifying the precise quantities of CO₂ stored during EOR operations other than under the standards developed for the higher-risk, non-EOR storage which are found in Subpart RR of the agency’s greenhouse gas reporting rules. Moreover, a serious problem may arise if a developer of a potential carbon capture facility finds that captured CO₂ will not be treated by regulators as geologically stored unless it is stored in accordance with standards designed for the higher-risk, non-EOR storage, even though the captured CO₂ is to be sold for use and simultaneously stored in the lower-risk, EOR operation.

Ironically, however, this is the position urged by some commenters on the EPA’s proposed rule to establish emissions performance standards for new stationary sources: to deny qualification under the emissions performance standard for captured CO₂ unless it is stored under the Class VI rules—rules designed for the higher-risk storage that lacks the pressure balance of EOR-based storage.

Such an approach would likely create a major regulatory obstacle to the deployment of carbon capture and storage technology. EOR operators storing CO₂ via the lower pressure/lower risk process of EOR have no reason to operate under the higher pressure/higher risk regime for which the EPA’s Class VI rules have been designed. Because of the sharply increased costs of meeting those standards however, the effect would be to devalue CO₂ captured for emissions reduction purpose, making it less attractive for use and concurrent geologic storage during EOR operations and placing supplies of CO₂ captured for emissions reduction purposes at a serious competitive disadvantage as compared to other sources of CO₂.

Thus, failure to appreciate the differing pressure profile of CO₂-EOR operations could lead to regulatory policies that could only discourage and delay the actual deployment of CCS technology as a greenhouse gas emissions technology.

Endnote References
1. Marston P, Bridging the Gap: An analysis and comparison of legal and regulatory frameworks for CO₂-EOR and CO₂-CCS. Global Carbon Capture and Storage Institute, Canberra, Australia (in press).
2. Hill B, Hovorka S and Melzar S, Geologic carbon storage through enhanced oil recovery. Energy Procedia 00 (2013) 000–000. Available at: https://www4.eventsinteractive.com/iea/viewpdf.asp?id=270035&file=1DCFILE0E1\EP11%244\Eventwin\Pcmoffice27\docs\pdf\ghgt-11Final00517.pdf [May 23, 2013].

NOTE to describe author:
Mr Marston is an attorney whose practice is focused on energy regulation, with an office near Washington DC. He may also be reached at http://www.marstonlaw.com. The views expressed here are personal.