CARBON CAPTURE AND STORAGE

CO2 Capture and Storage Requires Challenging Engineering in Unfamiliar Spaces

Stunningly ambitious plans to create global carbon capture and storage that rivals the scale of today's oil and gas production will require a host of technical skills to determine if it is even possible.

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Shell's Quest carbon capture and storage project in Alberta is an example of the commercial demonstration sites from which lessons are being learned to build what could become a huge business. *Source: Shell.*

Storing staggering amounts of carbon dioxide (CO_2) in the ground could be the oil industry's ultimate moonshot.

The oil industry is the logical choice for the job because it has both the means and motivation to do it.

It has long experience injecting CO_2 into formations to increase production as well as many of the related skills, from subsurface evaluation to megaproject management.

And the industry needs to find a safe, socially acceptable, financially possible way to pull carbon out of the world's exhaust pipes and store it, if it wishes to keep selling fuels that generate the CO_2 that contributes to climate change.

Still, it is kind of a crazy thing to try to do. No one would want to launch a business with a plan to inject CO_2 deep into unfamiliar formations where they will be responsible for making sure it will remain there forever; and to make matters worse, it is not clear how the company creating the site will get paid, beyond the limited government programs available now to subsidize carbon capture or build storage test sites.

Major players in the oil industry are moving in that direction because they are feeling the intense pressure to remove as much CO_2 from the atmosphere as is emitted from the fuels they sell.

"Carbon management is something you are going to have to do—markets and the public will mandate it," said Michael Godec, vice president for Advanced Resources International (ARI), a data and consulting firm which has done lots of work on carbon capture, utilization, and storage (CCUS).

For engineers, it is worth learning about because it presents interesting problems that could create jobs in an industry potentially on the large scale of the oil business.

Like the technical people with varied skills hired to put a man on the moon, petroleum engineers have developed skills applicable to CCUS over the course of their own work. In this case, their work with producing reservoirs will provide a basis to figure out how things work when the flows of carbon are affect the world's atmosphere will require venturing into new spaces—particularly deep, saline aquifers. It is known that these spaces appear big enough to accommodate billions of tons of carbon; beyond that, the information is skimpy.

This challenge is one that would best be approached slowly and carefully. But getting anywhere near the International Energy Agency's goal of storing six gigatons (Gt) of CO2 per year by 2050 will require rapid movement. (Note: 1 Gt is equivalent to 1 billion tons.)

The volume of space needed to store that volume of CO_2 is roughly equal to 150% of the space evacuated each year by oil production, said Mark Zoback, professor of geophysics at Stanford University, during a speech at the recent CO_2 Conference in Midland, Texas.

Even a planned megaproject such as ExxonMobil's carbon disposal site in the Gulf of Mexico, which is expected to cost $100 billion, looks like a down payment on the total cost.

Zoback addressed a conference founded years ago by the select group of CO_2 enhanced oil recovery (EOR) experts concentrated in the Permian Basin. The growth of this effective technology has been limited by the volume of CO_2 from natural sources. The experts could see that business grow if US tax incentives spur on projects that capture a much larger, cheaper source of CO_2 from industrial emissions.

CO_2 EOR leaves a significant amount of gas in the ground, but even if it were used on a far larger scale, the available volume of gas would fall short of the levels needed to reach the CO_2 capture goals in climate control plans.

An ExxonMobil paper reported that the US Geological Survey (USGS) estimated that 30% of the space within US oil fields which was once filled by oil and gas could be used to hold the CO_2 injected by EOR.

While that figure represents a huge amount of past production, the "volume represents just a few percent" of the total storage capacity estimated by USGS, according to the ExxonMobil paper based on a presentation at the 2018 Greenhouse Gas Control Technologies Conference in Melbourne.

The First Cut

ExxonMobil's initial evaluation of US onshore storage capacity was 500 Gt, compared to the 3,000-Gt estimate by the USGS.

Although that is a big cut, Gary Teletzke, the lead author on the paper, said the subsurface storage capacity is sufficient to sustain a large-scale CO_2-storage industry.

Teletzke, a former senior technical advisor at ExxonMobil, noted the US currently generates about 5 Gt of CO_2/year, of which 2 Gt/year is emitted from large-point sources which could offer opportunities for commercial-scale carbon capture.

Most of the storage capacity is in porous underground aquifers full of extremely salty water, known as deep saline aquifers. And it does not include possible offshore locations, which is where ExxonMobil is working with large carbon emitters on a massive storage site in the Gulf of Mexico.

While the USGS estimate is based on a list of potential onshore sites, ExxonMobil reduced the total based on criteria including the subsurface geology, engineering, logistics, and proximity to sites beneath population centers, including the Houston metropolitan area. Site-by-site evaluations would be the next level in a review process, said Teletzke.

Because ExxonMobil wants to focus on large-scale operations, as it does in the oil business, it is looking for high-capacity sites, which would eliminate sites with thin layers or ones restricted by lateral barriers such as faults.

Its biggest adjustments to the USGS storage estimates were based on its "dynamic injectivity/storage efficiency" modeling.

The thinking behind that criterion offers an early definition of how engineers will determine how fast and how much they can inject into a commercial storage site.

ExxonMobil's evaluations add assumptions about the operating criteria for future projects that were not part of the USGS evaluation. The study assumed wells would be injecting 1 million tons/year and projects were expected to last 30 years.

ExxonMobil said its process used “simulation models to account for subsurface pressure limitations and the impact of permeability differences and lateral accessibility on CO_2 injectability.”

Another significant difference: ExxonMobil eliminated storage sites in “central Oklahoma due to reported induced seismicity.”

Water-Injection Lessons

Since the report was released, a rapid increase in low-level earthquakes in the Permian, like the ones in Oklahoma, led the Texas Railroad Commission to limit deep injection in several problem areas. It warned that similar orders may be required elsewhere, according to a *JPT* story that cited Rystad Energy’s projections of rising water injection in the years ahead.

The USGS and ExxonMobil maps include the Permian in a swath of potential storage sites covering states along the Gulf Coast. The ExxonMobil paper did not mention the risk of seismic events outside of Oklahoma but did say that more detailed site reviews would be required before a storage site could be developed.

Those reviews could be a significant job creator for engineers and other geotechnical people. A notice for a speech by Teletzke, while he was a 2018–2019 SPE Distinguished Lecturer, said, “Geologic and reservoir engineering studies will be essential for identifying storage sites having adequate capacity, containment, and injectivity.”

Evaluating the risk of injection-induced earthquakes should also be on that list. Zoback explained that risk factor at the CO_2 Conference in Midland during a presentation titled “Earthquake Triggering and Large-Scale Geologic Storage of Carbon Dioxide.”

The geophysics expert, whose work helped explain why high levels of water injection in certain places in Oklahoma caused a surge in earthquakes, showed in his presentation how carbon dioxide storage could have the same effect in places with the same risk factors, including in the Permian Basin.

Both water and CO_2 injected into deep formations can migrate down to basement rock where they can add the relatively small amount of pressure needed to activate those faults that are “critically stressed,” Zoback said.

Zoback has been making a point of speaking out on the potential risks dating back to a 2012 paper that forecast what could happen when developers fail to thoroughly evaluate the geology of storage sites—it could be an “expensive and risky strategy.”

Reducing that risk by doing the testing needed to evaluate deep saline reservoirs won’t be cheap because little is known about spaces that have never offered an economic reason to perform detailed studies. But Zoback said the risks of climate change justify moving forward with carbon sequestration.

“It is not just one of the options; it is a critical component for large-scale decarbonization,” he said.

He advises those getting into storage to start with oil and gas reservoirs which are better understood. For example, old fields have been depressurized by production, which is not the case in saline aquifers. Still, those older fields come with risks as well.

“Existing oil and gas reservoirs have a lot of old wells, many with unknown location and/or condition, which provide the highest risk of potential leakage to the surface,” Teletzke said.

All of which will create more work for asset teams and service companies. While this article focuses on the work by engineers, the evaluations also will require geologists, geophysicists, and chemists, plus an array of experts in legal and government relations issues.

While this can be slow going during the learning stage, Zoback said, “The pump-and-pray guys will have to pause.”

High-Stakes Decisions

ExxonMobil’s site in the Gulf of Mexico may lower some of the risks. For one, Zoback noted that the depleted reservoirs and saline aquifers there are “relatively well characterized.”

Also, offshore storage reduces the risks of earthquakes because the “weakly cemented sands are not likely to produce earthquakes,” he said.

Teletzke explained that the highly permeable zones under consideration are better described as sediments than rock. The “squishier nature” of these aquifers reduces the risk of seismic activity and opportunities, just as independents have long done in the oil business. A large onshore gas-processing unit could provide a low-cost source of captured CO_2, which would best be injected at a nearby site to limit the cost of transporting it.

When CO_2 is used for EOR in the Permian, the pressure risks are limited by the fact that the injections of the costly gas are restricted to the volumes needed for efficient production, and production wells are used to manage the downhole pressure. With storage, the goal is to inject as much CO_2 as possible without any production wells.

Zoback said the earthquake risk at storage sites can be managed in places such as Oklahoma and Texas, but detailed subsurface work will be required. And the data needed may not be readily available.

Oklahoma's subsurface has been explored by the oil industry for more than 100 years, but many fractures were not mapped until the tremors prompted a rapid expansion of the state's seismic monitoring network. Data gathering during those seismically active periods also led to more accurate measures of local stresses, which also are a consideration, Zoback said.

While many of the earthquakes in Texas and Oklahoma were small compared to the ones that cause major disasters, they resulted in long-lasting lawsuits and significant damage to the industry's reputation in a place where oil is a pillar of the local economies.

"If CO_2 is associated with earthquakes, it will be perceived by the public as a hazardous activity and there will be pushback," Zoback said.

Dynamic Injection Criteria

The ExxonMobil paper highlighted how dynamic injection criteria can affect storage performance.

Those simulations drew on what has been learned from EOR injection over the years by experts such as Larry Lake, a professor in the department of petroleum and geosystems engineering at The University of Texas at Austin (UT). Lake concluded an online presentation hosted by SPE's Gulf Coast Section by stating "injectors should behave the same in CCS and CO_2 EOR."

And that point is likely to include reservoir changes that affect the injections. He noted that the lack of

Large-scale storage management is still at the development stage, and government-backed projects such as Shell's Quest CCS venture have observed some puzzling injection behaviors.

Shell described how the technical team at the Quest CCS project in northern Alberta realized that "the standard models of CO_2 injectivity leave out some important physics," according to a paper in the *International Journal of Greenhouse Gas Control.*

Before injection began, they predicted that CO_2 chilled by frigid winter weather was likely to reduce injection rates by 5 to 8% because the cooling would make the CO_2 more viscous.

Based on the team's injection data, the opposite has been the case—the winter gas injection rate was up to 10% higher. Other cold-weather storage sites have observed increases as well during winter.

This odd outcome led to an investigation seeking an explanation for the improved injection rate. The authors considered a handful of possibilities and ultimately concluded the most plausible explanation for the higher injection rate was that the colder fluid created "thermally induced micro fractures" which allowed greater inflow. The paper said further work is needed to understand injection during the warmer months.

There are multiple papers published on the topic of whether injecting large volumes of CO2 in water containing high levels of salts will cause precipitation of the salt, and if so, whether the injection rate will be altered.

In a 2020 paper (SPE 200632), researchers at the University of Salford in Manchester, UK, said their coreflood testing concluded that "porosity and permeability decreased drastically" as salinity increased. They also found that the higher the injection rate of CO_2, the greater the reduction.

However, the UT coauthors of a 2008 paper (SPE 113937) came to the opposite conclusion. "If the mobility of CO_2 in the dry region exceeds the mobility of the brine in the undisturbed aquifer, as will be the case in most formations, the injectivity will increase steadily" over time as the dry region expands.

Another study from UT, whose coauthors included Lake, warned against taking data from old oil wells at face value when evaluating an injection site (SPE 205995).

The analysis of 9,000 whole cores from 42 wells in the San Andres formation found that in about one-quarter of the cores, the vertical permeability exceeded the horizontal permeability, contradicting a widely used rule of thumb that assumes that vertical permeability is usually only a fraction of the horizontal permeability, Ren said.

Permeability is an important factor in models used to predict injection performance and CO_2 migration because these values determine where and how much fluid flows, and they can be extremely variable.

"You cannot just accept the rule of thumb," Ren said. Core measurements are needed to ensure accurate measurements at various points within a reservoir.

While a lot of data are gathered in producing oil fields, Ren said they "are often insufficiently sampled. We have even fewer measurements for storage aquifers."

For Further Reading

Evaluation of Practicable Subsurface CO_2 Storage Capacity and Potential CO_2 Transportation Networks, Onshore North America *by G. Teletzke, J. Palmer, E. Drueppel, et al., ExxonMobil Upstream Research Co. 14th Greenhouse Gas Control Technologies Conference, Melbourne, October 2018.*

CO2 Injectivity Behaviour Under Nonisothermal Conditions—Field Observations and Assessments From the Quest CCS Operation *by P. Tawiah and J. Duer, Shell Canada Ltd.; and S.L. Byrant, University of Calgary. International Journal of Greenhouse Gas Control.*

SPE 200632 Experimental Investigation of the Extent of the Impact of Halite Precipitation on CO2 Injection in Deep Saline Aquifers *by D. Edem, M. Abba, A. Nourian, et al., University of Salford.*

SPE 113937 Time-Dependent Injectivity During CO_2 Storage in Aquifers *by B. McMillan, N. Kumar, and S.L. Bryant, The University of Texas at Austin.*

SPE 205995 Analysis of Vertical Permeability and Its Influence on CO2 EOR and Storage in a Carbonate Reservoir *by B. Ren, J. Jensen, L. Lake, et al., The University of Texas at Austin.*

At the University of Houston (UH) there is growing demand for executive education courses on carbon capture, utilization, and storage (CCUS).

Many of the students are mid-career oil industry professionals whose job title now includes CCUS and who are interested in learning more about it, said Charles McConnell, Energy Center officer at the UH Center for Carbon Management in Energy.

"What am I going to do?" It is a question from the students that educators are addressing in a variety of ways.

The growth potential for CCUS is significant. Plans to offset carbon emissions by capturing massive amounts of carbon and injecting it into underground storage could be a huge business. It is a slowly developing trend however, and details are sketchy as to who will foot the bill.

Teaching carbon capture and storage (CCS) is a labor-intensive process because there is no textbook approach for this emerging business and set of technologies.

The UH classes are taught by a team of eight, half from the university faculty, including McConnell, and the other half by experts from BP and McKinsey & Co.

CCUS is also creeping into the offerings of petroleum engineering programs in a variety of ways.

At the University of Wyoming, students are involved in government-backed work related to storage site development, and at Texas Tech they are working on a CO_2 sequestration research project in Illinois that is evaluating the integrity of wells to assess storage leak paths. The Colorado School of Mines (CSM) has established an interdisciplinary CCUS online certificate.

"There is lots of room for retaining (or rethinking)," said Jennifer Miskimins, department head and professor in the Colorado School of Mines petroleum engineering program.

Words such as "interdisciplinary" and "rethinking" say a lot about the nature of this training challenge. A carbon storage project is a massive startup business. Those involved will need a plan that delivers a reliable, cost-effective means of capturing and storing the carbon, building partnerships, raising money, the carbon components, Miskimins said.

When explaining how the UH program addresses the engineering of carbon storage, McConnell acknowledged that while engineers will benefit from the program, it is not "engineering engineering."

The focus is on understanding the business, government, and technical variables that must come together for a storage project, rather than the engineering of the facility's construction and its operation.

For most of his career as a professor at The University of Texas at Austin, Larry Lake said he has been involved in work related to CO_2 enhanced oil recovery.

In a recent online presentation for SPE's Gulf Coast Section he talked about what has been learned in CO_2 EOR, which suggested that adapting those techniques to CCS long-term storage is a manageable engineering challenge.

Lake noted that using CO_2 for EOR would leave a large amount of the carbon in the ground while also generating cash flow from selling the oil produced.

But in Washington, DC, policymakers frequently leave the U out of the CCUS abbreviation because they are trying to reduce carbon emissions on a far larger scale than EOR utilization can offer.

Recently passed legislative bills offering tax credits for carbon capture provide significantly more incentives for those doing storage, but it is far short of the cost of the amount of storage needed on a global scale to slow climate change.

"There has been a lot of work going on to this point with technology proving out things. Is it commercial? Of course it is not commercial. We do not have a construct in this country to provide commerciality for CO_2 reduction," McConnell said.

While there are tax credits allowed for those who capture carbon from exhaust streams or from the atmosphere and then inject it into the ground, the billions of dollars going into those projects have barely moved the volume of storage above the zero line on the global storage chart.

Given the political obstacles to passing laws that would pay for storage at that scale, the future may play engineers paid to find and produce hydrocarbons will also need to focus more on managing carbon emissions.

So far, this pressure has been leveraged on large, public oil companies by investors who are evaluating the companies' environmental, social, and governance (ESG) performance. Based on a recent survey of oil companies in Texas and adjoining states, smaller operators are not as urgent about it.

When small oil firms (producing less than 10,000 B/D) were asked how much they expect to reduce carbon emissions between 2020 and 2025, 25% estimated their reduction at 0%; only 8% said more than 10%, according to a Federal Reserve Bank of Dallas energy survey.

Larger firms are more focused on reductions—only 5% estimated they would not reduce carbon emissions and 38% would cut them more than 10%. An identical response came from the large and small companies: 38% of each category said they did not know how much they planned to reduce carbon.

Chances are that any company that is still in business by 2025 will have reduced its emissions by reducing flaring and maximizing sales of its natural gas or by cutting its costs by switching some operations from diesel to electric power.

Those teaching CCS classes are trying to encourage students to begin thinking in terms of carbon-based performance, such as emissions per BOE produced—the unit used in the Federal Reserve Bank of Dallas survey.

In the UH classes, student teams are asked to figure out the best option for adding 200 MW of electricity capacity. The educators are looking for an answer that goes beyond the cost and reliability of the source to promote the consideration of a variety of options and the larger impacts they may have.

Those within petroleum engineering (PE) programs see increasing interest among students who are hoping to make a career in carbon capture and storage. While administrators in the programs are working to increase offerings in that field, they warn that this is still an industry of the future when it comes to hiring PE graduates.

"Bottom line, the world needs training and education at both the university and post-degree areas—a

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Stephen Rassenfoss covers a range of novel ideas that engineers may find promising but are not sure work. His reporting has also been devoted to the industry's response to price crashes and the outlook for its engineers. He can be reached at srassenfoss@spe.org.

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