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A Call for a Broader-based Geotechnical Education to Tackle Geological CO_2 Storage Site Selection Criteria in CO_2 EOR and Deep Saline Formation Injection

I. Introduction to the History of Captured Gases Stored Underground

Industrial gases have grown in use to become an essential part of modern society. From the most commonly utilized: methane, to nitrogen, hydrogen, propane, helium, and the noble gases, they are ubiquitous in their use even in the less technologically advanced societies. Energy supply, refrigerants, and fertilizers are three of the most important uses but there are many more. Manufacture, storage and transport of the gases is involved and is a large industry into itself.

Much attention has been focused on the gas emission streams caused in the production of industrial processes. Control of excess emissions has become a passion of society. Worries over breathing in of gases and the growing volumes of emissions from the earth's expanding population has led to curbs placed on the emissions from industrial companies providing the essential gases and other products for today's world.

Carbon dioxide (CO_2) emissions currently dominate the headlines and the focus usually comes back to the combustion of hydrocarbons, clearly an irreplaceable source of reliable energy for today's societies. The rapidly growing use of hydrocarbons is a direct function of their availability, mobility, their efficiency for creating heat, electricity and other forms of use. But combustion of hydrocarbons leads to the emission of CO_2 and those emissions are heightening the concentration of natural CO_2 in the atmosphere. The natural atmospheric CO_2 has always aided life by helping create a warming blanket in the earth's atmosphere. The gases that create that warming blanket are called greenhouse gases or GhGs. As populations and the enormity of energy uses have grown, the reduction of GhG emissions has become a worldwide priority.

There are several ways to approach limiting GhG emissions. The one receiving considerable public and governmental support in the form of subsidies is what is referred to as renewable energy replacements. These include wind turbines to capture energy from the atmospheric wind fluctuations and another form of the renewables is solar panels that convert the Sun's energy to electricity. Both capture the energy to be transported into the electric grid. Both are being scaled up with the help of governmental support in the developed nations. Direct carbon dioxide capture from the air is yet another approach and one that has seen limited industrial use for the last several decades. Scaling that use up to a meaningful size is beginning to be viewed as a viable and, perhaps, very economic approach for GhG emission reductions.

If one captures the CO_2, one must also find a permanent home out of the atmosphere. What to do with the captured CO_2 emission streams is the subject of this paper. Fortunately, there is a large precedent. Storage underground is not only being done today but has been done for a century. However, the capture volumes will be immense and coming quickly. A large scale-up of underground storage is a challenge and the lessons learned in storage of all gases underground needs to be reviewed and analyzed to provide a significant volumetric solution to mounting GhG emission streams. Education on the appropriate storage site attributes needs to happen very quickly.

II. Background on CO_2 EOR and Deep Saline Formation Injection

Carbon Dioxide Enhanced Oil Recovery: Fortunately, the experience of storing CO_2 underground has a long and successful history. CO_2 has been captured on the surface, transported via pipeline, and injected into underground oil reservoirs for over 50 years. The purpose of the industry was, and is, to produce more oil from an aging oilfield. The incidental effect of injecting CO_2 was storing the CO_2. A common misconception was present for many years that the process allowed venting of the CO_2 but the CO_2 enhanced oil recovery (CO_2 EOR) industry, as it is called, valued the commodity CO_2 so much that any returning (recycled) CO_2 was captured and returned to the reservoir to be used again.

CO_2 EOR thins and mobilizes the oil so that it can readily move within the reservoir and be produced at the surface. The implementation of the closed loop system was responsible for innovative treatment of purifying and compressing the CO_2 for transport that is an invaluable aid in today's industrial surface capture CO_2 industry. The CO_2 EOR industry is also responsible for insights related to the high-pressure CO_2 properties, movement and spread of CO_2 in the underground reservoirs (floods) that is also required for the broader CO_2 storage industry developing today.

One of the requirements of the project management within the CO_2 EOR industry is what they like to call reservoir surveillance. The professionals have to manage the reservoir pressures within close tolerances of the original bottomhole pressures originally present in the reservoir. As mentioned, the CO_2 is a valuable commodity and the largest expense in operating a flood so losing the CO_2 outside the flood boundaries can cause the project to be uneconomic. Loss of containment, as it is often called, can be a lateral phenomenon or it could be vertical. Since the buoyant oil was trapped in the earth by Mother Nature, the vertical containment is effectively assured. Risking a rupture of the seal would be unacceptable and is managed by controlling the pressures applied to move the oil in the flood.

Deep Saline Formation Injection and Storage: Unfortunately, surface carbon emission sources are ubiquitous and oil reservoirs are not. As a result, much attention is being given to what is most commonly called deep saline formation (DSF) storage or, less commonly called, CO_2 sequestration. Since in EOR, the injection process creates a product and the economics are assisted by sale of the product, in the case of DSF, there is no product produced. In addition, no producing well exists so the process can be called waste product injection. This distinction has given rise to the two terms, 1) carbon capture utilization and storage CCUS and 2) pure storage - or simply CCS.

Without producer wells, deep saline injection has the effect of increasing pressures within the reservoir past the original pressures prior to drilling. Most CCS projects will occur in formations that did not show entrapment of buoyant fluids like oil or gas hence signaling a possible concern for vertical containment, especially as reservoir pressures increase. There are also no large-scale precedents. The data base and history of DSF is recent and limited to small injection volumes. Many proposed that characterization of the DSF due to the above factors has to be very thorough. As a result, the Environmental Protection Agency (US EPA) ruled that injection permits for CCS need a new set of standards and passed these under the Underground Injection Control (UIC) Class VI guidelines. Since the pressures are managed within proven buoyant fluid entrapments and the CO_2 EOR industry had 50 years of successful operations, the EPA left CO_2 EOR and its incidental storage under Class II guidelines. Most oil producing States have primacy for UIC Class II injection well permits but did not require the detailed reporting that was necessary for documenting actual stored volumes of CO_2 so the EPA codified a procedure of reporting called SubPart RR to assure documentation of those volumes.

III. CO_2 Emissions as a Liability and Growing Numbers of Capture and Storage Projects

The perceptions of growing worldwide GhG emissions have reached a level that both governments and industries are taking actions to capture CO_2 emissions from the 'low-hanging fruit," i.e., relatively pure CO_2 compositions and large volume sources. Fig. 1 illustrates the common sources in the fruit tree metaphor while Table 1 documents the CO_2 capture projects in operation around the World.

Figure 1: Fruit Tree Metaphor for Ease of CO_2 Capture

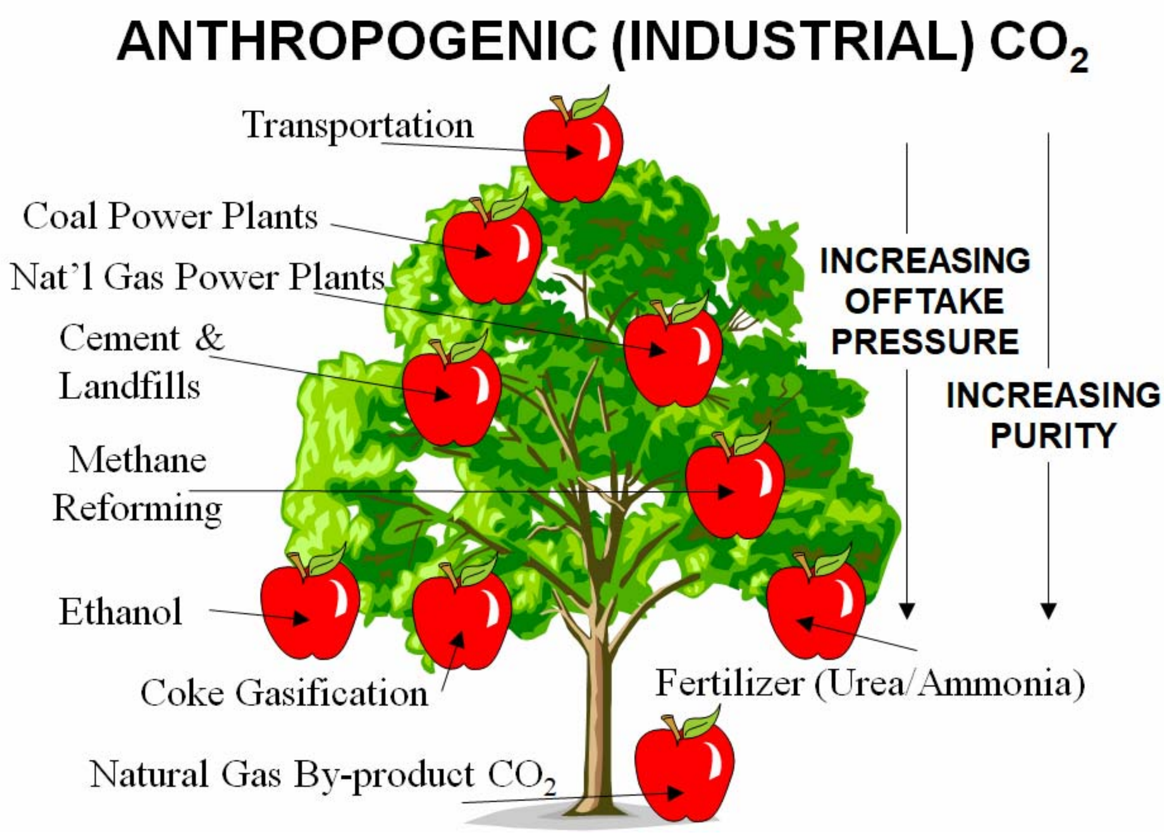


Table 1: Worldwide Commercial CCS and CCUS Facilities in Operation

COMMERCIAL FACILITIES IN OPERATION*

FACILITY TITLE	STATUS	COUNTRY	OPERATION DATE	INDUSTRY	CAPTURE CAPACITY (Mtpa) (MAX)	CAPTURE TYPE	STORAGE TYPE
Terrell Natural Gas Processing Plant (formerly Val Verde Natural Gas Plants)	Operational	United States	1972	Natural gas processing	0.40	Industrial Separation	Enhanced Oil Recovery
Enid Fertilizer	Operational	United States	1982	Fertiliser production	0.20	Industrial Separation	Enhanced Oil Recovery
Shute Creek Gas Processing Plant	Operational	United States	1986	Natural gas processing	7.00	Industrial Separation	Enhanced Oil Recovery
Sleipner CO_2 Storage	Operational	Norway	1996	Natural gas processing	1.00	Industrial Separation	Dedicated Geological Storage
Great Plains Synfuels Plant and Weyburn-Midale	Operational	United States	2000	Synthetic natural gas	3.00	Industrial Separation	Enhanced Oil Recovery
Core Energy CO_2-EOR	Operational	United States	2003	Natural gas processing	0.35	Industrial Separation	Enhanced Oil Recovery
Sinopec Zhongyuan Carbon Capture Utilisation and Storage	Operational	China	2006	Chemical production	0.12	Industrial Separation	Enhanced Oil Recovery
Snøhvit CO_2 Storage	Operational	Norway	2008	Natural gas processing	0.70	Industrial Separation	Dedicated Geological Storage
Arkalon CO_2 Compression Facility	Operational	United States	2009	Ethanol production	0.29	Industrial Separation	Enhanced Oil Recovery
Century Plant	Operational	United States	2010	Natural gas processing	5.00	Industrial Separation	Enhanced Oil Recovery & Gelogical Storage
Bonanza BioEnergy CCUS EOR	Operational	United States	2012	Ethanol production	0.10	Industrial Separation	Enhanced Oil Recovery
PCS Nitrogen	Operational	United States	2013	Fertiliser production	0.30	Industrial Separation	Enhanced Oil Recovery
Petrobras Santos Basin Pre-Salt Oil Field CCS	Operational	Brazil	2013	Natural gas processing	4.60	Industrial Separation	Enhanced Oil Recovery
Lost Cabin Gas Plant	Operation suspended	United States	2013	Natural gas processing	0.90	Industrial Separation	Enhanced Oil Recovery
Coffeyville Gasification Plant	Operational	United States	2013	Fertiliser production	1.00	Industrial Separation	Enhanced Oil Recovery
Air Products Steam Methane Reformer	Operational	United States	2013	Hydrogen production	1.00	Industrial Separation	Enhanced Oil Recovery
Boundary Dam Carbon Capture and Storage	Operational	Canada	2014	Power generation	1.00	Post-combustion capture	Enhanced Oil Recovery
Uthmaniyah CO_2-EOR Demonstration	Operational	Saudi Arabia	2015	Natural gas processing	0.80	Industrial Separation	Enhanced Oil Recovery
Quest	Operational	Canada	2015	Hydrogen Production Oil sands upgrading	1.20	Industrial Separation	Dedicated Geological Storage
Karamay Dunhua Oil Technology CCUS EOR	Operational	China	2015	Chemical production methanol	0.10	Industrial Separation	Enhanced Oil Recovery
Abu Dhabi CCS (Phase 1 being Emirates Steel Industries)	Operational	United Arab Emirates	2016	Iron and steel production	0.80	Industrial Separation	Enhanced Oil Recovery
Petra Nova Carbon Capture	Operation suspended	United States	2017	Power generation	1.40	Post-combustion capture	Enhanced Oil Recovery
Illinois Industrial Carbon Capture and Storage	Operational	United States	2017	Ethanol production – ethanol plant	1.00	Industrial Separation	Dedicated Geological Storage
CNPC Jilin Oil Field CO_2 EOR	Operational	China	2018	Natural gas processing	0.60	Industrial Separation	Enhanced Oil Recovery
Gorgon Carbon Dioxide Injection	Operational	Australia	2019	Natural gas processing	4.00	Industrial Separation	Dedicated Geological Storage
Qatar LNG CCS	Operational	Qatar	2019	Natural gas processing	2.10	Industrial Separation	Dedicated Geological Storage
Alberta Carbon Trunk Line (ACTL) with Nutrien CO_2 Stream	Operational	Canada	2020	Fertiliser production	0.30	Industrial Separation	Enhanced Oil Recovery
Alberta Carbon Trunk Line (ACTL) with North West Redwater Partnership's Sturgeon Refinery CO_2 Stream	Operational	Canada	2020	Oil refining	1.40	Industrial Separation	Enhanced Oil Recovery

* *Re: Appendix 6.1: Global Status of CCS https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Global-Status-of-CCS-Report-English.pdf*

Note that almost 80% of the 28 projects are injecting the CO_2 for EOR. The remaining are classified as dedicated geological storage with only one of those (ADM Ethanol) located in the U.S.

Carrots, Sticks, and Public Pressure In 2007 the US Supreme Court (SCOTUS) classified heat trapping emissions (including both methane and CO_2) as "air pollutants" and (under the Clean Air Act of 1970) the U.S. EPA was thereby given authority to pass regulations to curb GhG Emissions. It set into motion a series of actions that has resulted in the current movements to reduce the emissions. The pollutants became included in New Source Performance Standards (NSPS) and required emissions to be reportable at plants/projects exceeding certain threshold emissions. The new classification also placed GhGs into regulatory control under EPA's Federal Safe Drinking Water Act (SDWA {1974}).

Following the 2007 SCOTUS decision, in April 2009 - US EPA declared CO_2 a greenhouse gas and began crafting rules. This naturally occurring compound was now considered a pollutant and climate change initiatives at EPA set objectives to reduce atmospheric CO_2. They recognized that CO_2 used for EOR (CCUS) was being handled as a commodity and left it grandfathered into UIC Class II Wells for Injection. As discussed previously, CO_2 injected for permanent geologic storage (CCS aka DSF) needed special rules due to the volumes involved and its pollutant (waste) classification. A new UIC permit was codified and Class VI well rules were drafted and emplaced.

Many in the hydrocarbon related industries could see the emerging issues that CO_2 was falling into the same status of other pollutants to the atmosphere and began to move to capture their point source emissions. The Table 1 list shows those projects that have been implemented and are in operation. There are many more either in planning or construction phase. Helping accelerate that process is new Federal legislation referred to as 45Q. This is the U.S. Treasury Department's 45Q Tax Credit Incentive (a so-called "carrot") that was first passed in 2008. Through the provision, the U.S. Congress allowed parties to qualify their captured and injected emission streams and claim a tax credit on their Federal taxes of \$10/metric ton (~\$0.52/mcf) for their stored CO_2 in EOR (or enhanced gas recovery) and \$20/mt for pure geologic storage. The original 45Q credit was capped at 75 million metric tons so that new projects might not find the credit available once construction was complete and the qualifying injection began. This original 45Q was ineffective at creating new capture projects and was amended in Federal legislation in 2018 to \$35/mt for EOR, non-EOR utilization and direct air capture and was set at \$50/mt for CCS. A threshold CO_2 amount of 100,000 mt/year is needed to qualify with a higher threshold of 500,000 mt/year established for a power plant. The per metric ton credits starts at lower values and moves to the levels mentioned above in 2026 and beyond. The total amount of credits is not capped thus allowing a planned project to use the incentive in their economic justification and financing of the project.

In an alternative approach, some international bodies have chosen to use a carbon tax (aka "stick". That has also created some movement to capture and store CO_2. The Norwegian projects in Table 1 are two examples.

Another "driver" for CO_2 capture is the mounting pressures in boardrooms and stockholder meetings of many large GhG emitting companies. Some financial firms have publicly declared their avoidance of investments in companies that are not adopting emission reduction measures. Those forces are often referred to environment and social governance (ESG) pressures.

IV. Site Selection, Surveillance and Monitoring of Good Storage Sites

The U.S. CO_2 emitters are feeling the ESG pressures to capture and now are seeing the carrots of tax credits to take advantage of the incentives. What was once a marginal or uneconomic project might now work into a feasible one with the extra benefit of the tax credits. But these are complex projects to put together and the planners are generally unqualified to design the subsurface portion, especially for storing the large volumes they will end up capturing. The most qualified companies to help with the injection site selection are the oil companies that have the projects and experience in CO_2 EOR. Unfortunately, they have been the targets of much of the public's climate policy pressures. Consequently, they are often overlooked as the industry that is the most qualified to minimize the risks of a failed storage project. The results of this will be some poorly conceived projects that will be running into either permit dead-ends or find that the injection project is unsuccessful. The surface portion of the project cannot avoid the inevitable expensive capture and infrastructure investments so a low-risk site to store the long term captured CO_2 is essential.

What the oil and gas industry has learned about successful storage sites is not generally available in the public literature. Some of this is due to the fact that their experience is only indirect knowledge gained from oil and gas producing basins and some is due to the horizontal well revolution that has exploded knowledge about critical reservoir storage attributes. The new learnings are, of course, directly applicable to producing oil but many indirectly valuable for securely storing CO_2. The new knowledge gained about lateral reservoir characterization, geomechanics, and seismicity are three cases in point.

Picking the right storage site is critical but another field of experience invaluable to CO_2 storage is what is often called reservoir surveillance. Since the CO_2 emplaced into a reservoir is so valuable, the flooding industry has developed tools and expertise in locating and adjusting where the CO_2 is at work in a reservoir. The best CO_2 flood operators are constantly moving their injection volumes around and adjusting injection to maximize CO_2 contact with the oil in the reservoir. Knowledge of reservoir compartments, asymmetries, pressures and fractures are needed to optimize the flood economics and are the same attributes needed for a successful DSF storage project. Some reservoirs are inherently complex, can challenge the operators' plans, and lead to an unsuccessful project. It is also appropriate to say that poorly selected DSFs will challenge the injecting company in ways even beyond the historically studied and better-known oil fields. The tools for what the CCS industry calls monitoring, reporting and verification (of permanent storage) or MRV are quite analogous to the surveillance tools and methodology utilized in CO_2 flooding.

V. Basinal Storage Concepts (the "good, bad, and worrisome" sites to store)

It will seem obvious to a geologist, geophysicist, and reservoir engineers that there are unacceptable sites for storing CO_2. Formations at depth without a seal to cap buoyant fluids is a classic example. Sites that are prone to nearby earthquakes; especially where the faults continue to the near surface sediments are yet another. Those are just two of the criteria to examine. Hopefully, the regulators responsible for granting injection permits will have the expertise and management support to decline the awarding of injection permits to a highly risky site. And hopefully, those evaluations will occur in several stages of applicant's data presentation so that the capture project can make decisions on whether to proceed with site studies and data acquisition at the appropriate sequential stages.

As the idea of large volume CO_2 storage was emerging, some thoughtful international characterizations of the types of acceptable basins were documented[1]. The study was done on a regional scale. Figure 3 illustrates three very likely acceptable storage sites. It should be obvious to say that site specific studies or analogous reservoir experience is invaluable for confirming the acceptability. Note the foreland, cratonic and passive margin basins lead the list in acceptable regional basinal sites for storage. One, in particular, often has an advantage over the others in that the ideal sealing formation of salt beds often overly the deeper target injection intervals. Examples of that in the U.S. are the Michigan and Williston Basins, intermontane valleys of the Rockies, and the Permian Basin.

The work presented in the references goes on to characterize the key geological characteristics of basin settings suitable for geologic storage. These are as follows:

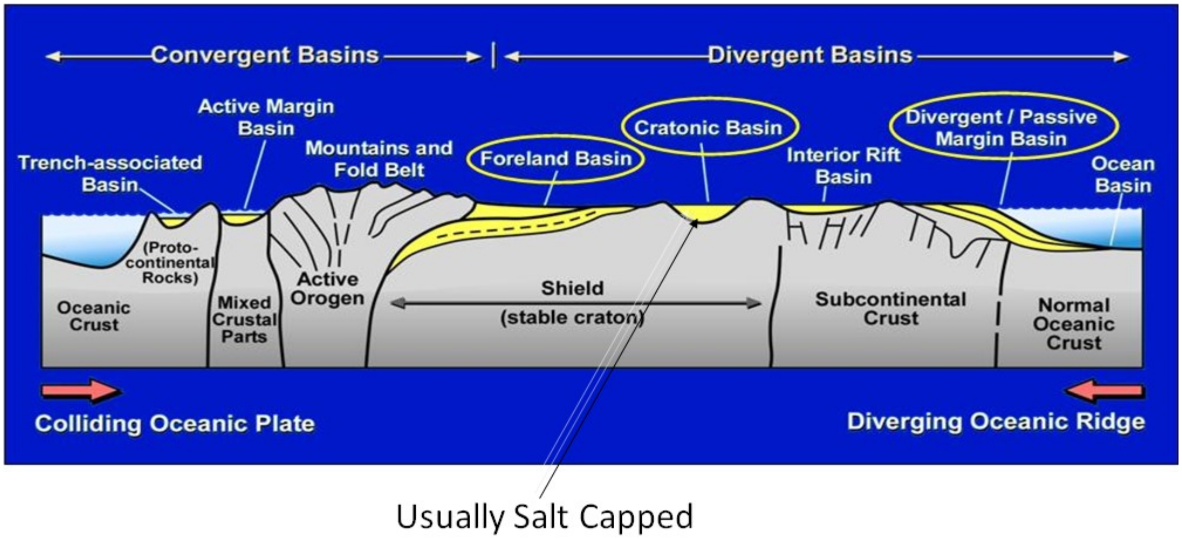
1. adequate depth to have the CO_2 in dense phase (>1000 meters for 95% or higher purity of CO_2),
2. strong confining seals,
3. minimally faulted fractured or folded beds.
4. Strongly harmonious (aka laterally continuous permeability) sedimentary sequences, and
5. well understood regional geological control.

[1] Hitchon et al, Dynamic basin analysis: an integrated approach with large data bases, Geological Society, London, Special Publications 1987, 34:31-44

Hitchon et al, The role of hydrogeological and geochemical trapping in sedimentary basins for secure geological storage of carbon dioxide, Geological Society, London, Special Publications 2004, 233:129-145

Hitchon B, Gunter WD, Gentzis T, Bailey RT (1999), "Sedimentary basins and greenhouse gases: a serendipitous association" Energy Convers Manage 40:825–843

Figure 2: Optimal Regional Basin Settings for CO2 Storage [1]



VI. Other Storage Case Histories, Successes and Failures

The natural gas, Strategic Petroleum Reserve, and hydrogen industries all have a long career is moving fluids in and out of storage. A few notable exceptions to the overwhelming success of underground storage have tarnished what is a long and credible service to the many industries that require underground storage.

There are approximately 400 active storage facilities in 30 states[2] and there are three principal types of underground storage sites used in the United States today: depleted natural gas or oil fields (80%), aquifers (10%) and salt formations (10%). The storage capacity is also expanding. Between 2002 and 2014, the capacity increased by a fifth to reach approximately 4 trillion cubic feet. The gas can be stored and withdrawn for residential and industrial use. Natural gas is one of the two primary storage gases (CO_2 being the other) but some other gases are also stored. Approximately 20 percent of all the natural gas consumed during the five-month winter heating season each year is supplied by underground storage.

Intrastate storage may fall under the regulatory authority of various state government entities depending upon the State. For example, underground storage in Texas is under the authority of the Texas Railroad Commission – Oil & Gas Division. State utility commissions as well as state environmental or natural resource agencies set the rules governing intrastate underground storage.

Beyond Federal and State regulation, the natural gas storage industry has taken the initiative to work with external stakeholders to develop two recommended practices (RPs)—accredited by the American National Standards Institute—for underground storage. RP 1170 and 1171 provide guidance to operators on how to design, and operate, and ensure the integrity of underground storage for natural gas. Many of the safeguards involve the combustible nature of the natural gas in combination with the loss of containment.

[2] American Petroleum Institute, https://energyinfrastructure.org/energy-101/natural-gas-storage

The next storage case histories belong to the CO_2 EOR industry. What was always an incidental side effect of CO_2 EOR has become a desired outcome. In this regard, the industry utilized a term they called reservoir retention and formula for retention in shown in Figure 3.

Figure 3: Definition of Reservoir Retention in CO_2 EOR Projects

CO_2 Retention is defined as the amount of CO_2 that has been injected* in a reservoir that has remained in the reservoir

$$CO_2 \text{ Retention} = \frac{(CO_2 \text{ Injected* } - CO_2 \text{ Produced})}{(CO_2 \text{ Injected*})}$$

$$CO_2 \text{ Retention (factor)} = \frac{CO_2 \text{ Produced}}{(CO_2 \text{ Injected*})}$$

Both can be defined as Instantaneous or Cumulative

* CO_2 Injected = Total CO_2 (New + Recyled)

Retention can vary widely with the type of reservoir and flood style of an operator and an average retention factor might be 50% or even less. However, one should not equate retention with storage. Stored volumes are very close to the volume of the total new CO_2 brought to a field less deminimis volumes that are lost during the closed cycle, recycle operations. For example, if the power to the field is lost for a short period of time and the recycle volumes have to be flared and some CO_2 is lost until producing wells are shut-in. CO_2 does not burn of course and, most often, natural gas has to be purchased and added to the venting stream causing not only a loss in value of the commodity CO_2 but the natural gas that had to be added. However, and fortunately, this is an uncommon occurrence and the amount of CO_2 that is stored in the reservoir is very close to the amount purchased. When one hears someone say only half of the CO_2 is stored in CO_2 EOR projects, they are misleading the audience in having them infer that half of the purchased CO_2 is "lost."

CO_2 EOR has been underway for 50 years, produced approximately 2 billion barrels of oil and estimates of purchased and stored CO_2 are very close to 20 trillion cubic feet (1 billion tons of CO_2). Some have estimated that to achieve net zero emissions the world needs to be capture and storing approximately 20 times the current rate of storage from EOR which is 2.5 billion cubic feet per day (50 million metric tons/year. Fortunately, targets for new CO_2 EOR projects are enormous but, quite naturally confined to oil producing basins like the ones identified in the previous section. Much of the infrastructure for EOR storage is in place already and the reservoir targets are expandable both vertically and laterally in many cases like the proven targets of residual oil zones (ROZs) in the Permian Basin. The bigger challenge are long-distance pipelines needed to get the CO_2 to the EOR fields in order to begin to store the large volumes.

VII. Critical Subsurface Storage Factors to Evaluate and Quantify:

Although storage of buoyant fluids in the subsurface has been a common practice, humankind is dealing with a new challenge of securing storage of volumes from CO_2 capture on a very large scale. For example, some emitting source areas active today desire to be capturing a billion cubic feet per day (20 million metric tons/year). Some extended source regions, like the Gulf Coastal areas, could collectively capture up to five times that amount (5 bcfpd or 100 million mt/yr)[3]. The infrastructure costs of such a challenge have been recently estimated to be $100 billion. Quite naturally, injecting that level of CO_2 into the subsurface will require multiple evaluations and quantification of some large risks that are involved. The risks can be generally categorized today but, with that high a level of investments, extreme confidence in the security of storage will be necessary.

Pressure Management Adding large volumes of CO_2 into reservoirs without the benefit of fluid removal will test the confidence of containment of fluids at depth. Adding additional formation pressures to the DSFs increases the possibility of rupturing caprock seals or generating flow in fault systems that heretofore provided barriers to fluid flow. As a result, careful site selection and very broad scale MRV will be necessary. Those risks can be mitigated through a process of fluid removal to increase formation pressures to tolerable levels.

Fortunately, the oil industry has a data base of projects to rely upon. The CO_2 EOR industry has effectively managed reservoir pressures by careful monitoring of fluids in and out of reservoirs. And, the scale of past and current CO_2 EOR operations makes that experience particularly germane to the volumetric challenges ahead. The cumulative two billion barrels of fluid (crude oil) removal and storage of 20 trillion cubic feet (1 billion metric tons) is directly applicable to the task of quantification of the risks.

Reservoir Seal Maintenance The aforementioned concerns of overpressured formations can provide a risk element that will have to be quantified. Unconsolidated formation seals are particularly worrisome since hydrofracturing can be accomplished with sometimes minimal overpressure gradients. Rapid dispersion of the fluids can minimize the overpressure and leave seals intact so a balance between the two factors can add the seal integrity confidence to proceed.

Certain type of formations are particularly excellent pressure seals. Halite and anhydrite are especially effective and cannot be hydrofractured easily when at depths greater than a thousand meters. As demonstrated in the earlier section on optimal storage types, many of the intra-cratonic basins were isolated from the oceans in their geologic past concentrating the salinities in the basin waters and causing deposition of capping salts. Sometimes these salts can occur in thickness of 100s of feet making the vertical upward movement of fluids in reservoirs beneath the salt sections impossible.

Wellbore Integrity: The presence of abandoned wellbores within the area of interest of injection is an example of mixed considerations. First, the wells provide ground truth to the nature and lateral continuity of the rocks in the area. Secondly and alternatively, they can represent a containment risk if fluids can find their way within or alongside the wellbore penetration.

Both the Class II and Class VI permit applications specifically call out examination of the area wellbores to assure the regulator that the risk is minimized. There are examples in the Gulf Coastal sediments where old wellbores provide a loss of containment of natural or injection fluids. Fortunately, the well bore situation can be mitigated. Leaky seals or faults can be another matter entirely.

In sediments that are un- or lightly consolidated, one can expect that fluid volume removal without compensating volume injection will often result in subsidence in the overlying sediments. There are many examples of subsidence in the literature in underground sources of drinking water and oil and gas

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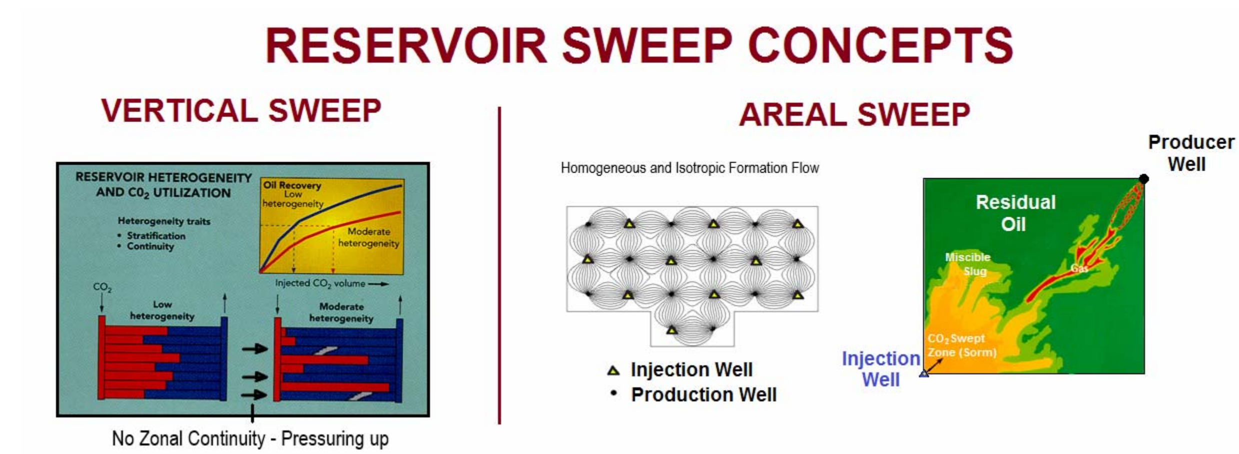
[3] https://www.forbes.com/sites/davidblackmon/2021/04/22/exxons-100-billion-carbon-capture-plan-big-challenging-and-needed/?sh=52ac470e417b

literature[4]. A wellbore in a vertical sequence of un- or lightly consolidated sediments, the stiff cement column will resist the shortening that the subsiding formations are experiencing. The relative displacements can provide a pathway for vertical movement of natural or injected formation fluids.

The rigidity of well-consolidated formations avoids both the compaction in the formation subject to fluid removal and anticipated subsidence of overlying formations.

Challenges in Determining Lateral Continuity of Reservoirs: In the world of successful flooding of a reservoir, the continuity of flow within zones is necessary. The oil community has learned (often the hard way) that sufficient continuity is not always present in spite of seismic and well-to-well correlations. One primary manifestation of the continuity problem is the full or partial pressuring up of an injection well. The left side of Figure 4 illustrates such an example in practice. If the entire vertical injection section, like the (arrow) highlighted ones, the well would soon overpressure the compartments of the reservoir and possibly rupture the seal or cause the well to be abandoned as an ineffective injection well. The best floods have only a few of these problems and the sweep efficiencies are high. Since CO_2 is expensive to bring to a flood, like CO_2 will be to deliver to a DSF injector, some confidence that the formation will have ample lateral continuity is paramount prior to making the project investments.

Figure 4: Concepts of Lateral Reservoir Continuity and Sweep Efficiency for Flooding



Horizontal Drilling and Transmissive Natural Fracture Lessons: Much has been made of "plume" modelling as a key requirement in obtaining permits for DSF project injection permits. Axisymmetric expansion of the modelled CO_2 plume is often the default simulation. Geologists and experienced reservoir engineers know that examples of homogeneous and isotropic formations are extremely rare in formations. Channels of permeability and natural fractures are extremely

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[4] https://www.usgs.gov/special-topic/water-science-school/science/land-subsidence?qt-science_center_objects=0#qt-science_center_objects

Nagel, N.B. (2001), "Compaction and subsidence issues within the petroleum industry: From Wilmington to Ekofisk and Beyond," https://www.sciencedirect.com/science/article/abs/pii/S1464189501000151 commonplace and, often, not visible with typical reservoir imaging prior to beginning injection. The right side of Figure 4 is a hypothetical example of an often encountered and real situation that could be due to either a high permeability zone or a fluid transmissive fracture.

In the age of vertical drilling, encountering a near-vertical fracture was rare. In the new age of horizontal drilling, the oil and gas industry's experience has been that near vertical natural fracturing is considerably more common than previously believed. Not all of the natural fractures are transmissive to fluid flow but evidence is accumulating that many can be transmissive. The flow can extend downward to the crustal rocks. If the basement faulting is episodic, vertical seals can be intermittently interrupted. The more ductile the sealing rocks, the quicker the sealing capacity is restored. The lessons being learned from the new horizontal age of drilling are many, very recent, and can impact the sealing capacity issues as well as the geometry of the modelled plume.

Today's Seismicity Lessons: Another new lesson of the age of horizontal drilling has been the lessons of induced seismicity[5]. Horizontal wells generally produce economic volumes of oil or gas while often producing large volumes of water. The wells rely on depressurizing the formation to allow the solution gas in the oil to expand and drive the oil, water and gas to the wellbore. Since the water will not be reinjected into the producing zone, disposal wells connected to other intervals are required. Examples of large volume water injection into the intervals can overpressure the formations and propagate fluid and pressure downward into the crustal rocks and lessen the frictional characteristics present in the fault planes and create earthquakes.

If similar conditions are present in a DSF disposal area, overpressured CO_2 in a formation at depth has nearly the same opportunity to create earthquake activity that the disposal water causes. The fluid transmissive connection to the crust is necessary for that to occur and the state of stress in the crust ('slippage' potential) is also a factor.

Strike Slip Faulting/Lineaments: One of the newly correlated crustal connections from the above-mentioned water injection intervals are the episodically active faults within the crust. One of the most common of these is strike-slip (aka transverse or "wrench") faulting. The San Andreas and Hayward fault zones in California are two such examples. Those, of course, display very recent movement but many others around the globe are believed to have been periodically active, both in modern times and, especially, in the geological past. For such faults, the causation is strike-slip movement within the crustal rocks. Overlying formations are also displacing if the movement post-dates the age of the formations. As mentioned in the last two sections, the transmissive nature of the fault zones in the disposal formation can be critical and overpressured fluids in the formations can propagate the pressures to the crust and provide the crustal slippage and earthquakes. Data also shows that effective sealing formations can confine vertical movement up and down leaving only lateral fluid transmission/flow.

VIII. Non-technical Factors Important for CO_2 Storage

Site characterization factors discussed in the last section are critical for any large volume injection project permitting. Class VI permits will likely be staged and be especially thorough and time consuming

[5] Rutqvist, J. (et al), (2016), "Fault activation and induced seismicity in geological carbon storage – Lessons learned from recent modeling studies," Journal of Rock Mechanics and Geotechnical Engineering, Vol 8, Issue 6, Dec 2016, Pgs 789-804, https://www.sciencedirect.com/science/article/pii/S167477551630049X

due to the inevitable lack of experience of the applicants and/or the reviewing parties. Large volume injection without plans for fluid removal and pressure balancing exacerbates the technical risks which, in turn, will affect the non-technical aspects of early project financing. The large volume project injection experience is needed to reduce the risks and the probability of considerable upfront capital costs of capture, processing, compression, and transport being lost via curtailed or terminated injection.

In particular, the long-distance transport of CO_2 has been viewed as a negative factor in project planning owed to the high costs of new pipelines. However, what is often overlooked are the high costs of proving an acceptable and secure site and the delays in receiving properly vetted injection permits.

Class II permits for CO_2 EOR have been reviewed and granted by various State Regulatory bodies for 30 years or more. They have historically been awarded in time frames of less than a year. The recent expansion of oil revenue driven CO_2 EOR projects into zones that were considered subeconomic projects in the past is changing now with CO_2 storage. When EOR income was the only driver, the marginal projects can be reconsidered now and viewed in a broader perspective with the passage of the new 45Q and other incentives. The residual oil zones of the Permian Basin with their enormous size and extent are a classic example. Other basins should have similar opportunities as well.

IX. Conclusions

Secure Storage in underground reservoirs has been demonstrated for 100 years. CO_2 has grown to become the largest volume gas being stored and has been underway for over 40 years. CO_2 is unique from other ideal gases in that it changes phase from a gas like material and takes on the density of a liquid when above 1300 psi in typical reservoir conditions. This allows a very efficient volumetric storage. It is also a very efficient material to transport in pipelines since it flows like a gas but, when pressurized above 1300 psi is dense like a liquid. The technological base, practical knowledge, and infrastructure buildout have all come from CO_2 enhanced oil recovery with the sole incentive being the produced oil. The infrastructure of CO_2 is present in several area of the world and U.S. with the most mature area being in the Permian Basin region of West Texas. Thirty 30 million tons of new CO_2 have been injected there each year since the mid-nineties and produced over 1 billion barrels of oil.

The Permian Basin is also an example of an optimally secure site for storage with large, laterally extensive reservoirs proven to have the best storage attributes and overlain with over 100 meters of the near-perfect sealing materials, halite and anhydrite.

The implementation of worldwide CO_2 EOR has been hampered by the availability of commercial supplies of CO_2 and the long distances from available sources to appropriate oil fields. As the economics of a CO_2 EOR project change today from either lower costs of CO_2 or the new carbon capture incentives, a robust opportunity and a shorter timeline for CO_2 emission reductions and storage will be ahead. As the world begins its transition to other forms of energy, carbon neutral or even carbon negative oil may prove economic and provide at least a short-term solution to continued use of needed supplies of crude oil. New small injection projects can be underway in a matter of two years or less. Very large ones can implement as fast or slow as large CO_2 emission sources can be augmented with CO_2 capture infrastructure and the resulting CO_2 pipelined to nearby acceptable secure storage sites or interconnects with existing CO_2 pipelines.