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Geologic carbon storage through enhanced oil recovery.

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Abstract

The advancement of carbon capture technology combined with carbon dioxide (CO_2) enhanced oil recovery (EOR) holds the promise of reducing the carbon footprint of coal-fired power plants and other industrial sources, while at the same time boosting production of oil. CO_2 injection in deep formations has a long track record. Tertiary EOR with CO_2 has its origins in West Texas in the 1970's, when CO_2 was first used at large scale at the SACROC field to produce stranded oil following primary and secondary production (water flooding). Because CO_2 mixes with oil and changes oil properties, CO_2 floods are effective at producing additional oil following water flooding. Carbon dioxide is a valuable commodity both because of its ability to stimulate oil production from depleted reservoirs, and because of the limited volumes of naturally-sourced CO_2 in the U.S. Therefore, during large-scale commercial floods, CO_2 that is produced with oil during EOR is separated, compressed and re-injected and recycled numerous times. Venting to the atmosphere is a rare event, quantifiable, and constitutes an insignificant fraction of the injected CO_2. The CO_2 purchased mass, net any venting during EOR activity is sequestered in the reservoir by a combination of capillary, solution and physical trapping mechanisms. Approximately 600 million metric tonnes of purchased CO_2 have been utilized in the southwest U.S. Permian Basin (PB) alone, the rough equivalent of 30 years worth of CO_2 from a half dozen medium-sized coal-fired power plants.

Although CO_2 EOR technology is mature in the U.S., many reservoir targets have not been flooded because of limited CO_2 supply. Moreover, very large newly discovered EOR resources, known as "residual oil zones" (ROZs) occur in naturally water-flooded intervals below the oil-water contact in reservoirs that possess pore space containing immobile oil. ROZs are also now being documented in geologic settings without overlying conventional oil and gas accumulations. ROZ exploration and production using CO_2 promises the supplemental capacity to accept very large volumes of CO_2 in order to access and produce the remaining immobilized oil.

Many existing EOR sites may be ideal for sequestration because they: 1) provide known traps that have held hydrocarbons over geologic time, 2) provide existing CO_2 transportation and injection infrastructure, 3) occur in areas where the general public widely accepts injection projects, 4) provide CO_2

commoditization capability for capturing companies, 5) facilitate management of underground CO_2 plumes, 6) have proven reservoir injectivity, 7) may offer additional stacked storage potential, and, 8) are advantageous for monitoring because of available well infrastructure, experienced service company presence, and dense pre-injection data.

Despite these advantages, in order to assure long-term containment of CO_2 for atmospheric purposes and related CO_2 reduction credits, the following best practices will ensure credit for captured and sequestered CO_2: 1) demonstrate the appropriateness of the reservoir and existing wells for long term CO_2 storage (integrity of the reservoir and seal, and identifying/remediating existing penetrations that are historically documented as the highest risk for unexpected pathways for CO_2 to the surface), 2) evaluate well construction practices to ensure they are compatible with long-term exposure to low pH fluids (carbonic acid), 3) account for the net CO_2 volumes stored- separately from the volumes purchased and recycled, and 4) demonstrate the long-term "permanence" of the CO_2 plume in the subsurface through flood surveillance, monitoring and careful site closure.

EOR provides a readily available pathway to large volume storage though oil production offsetting major capital costs of capture facility and pipeline construction, boosting public acceptance through experience and community benefits. Moreover, after completion of EOR operations, sequestration activities can be continued via maximizing CO_2 storage in the depleted field, and by injection into qualified and associated brine formations.

Keywords: carbon dioxide; carbon sequestration; geologic carbon storage; enhanced oil recovery; residual oil zones; monitoring verification and accounting.

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1. Introduction

Confidence that CO_2 can be injected into the subsurface in commercial volumes is gained through experience with a number of processes. Deep geologic injections and storage of wastewater, natural gas and for enhanced oil recovery (EOR) are commonplace in the U.S. Including geologic wastewater injections, billions of tonnes of fluids are injected each year in the U.S. [1] As an emissions reduction technology, EOR is already reducing the effective emissions from natural gas production. Natural gas plants in the Rocky Mountains and Southwest US are chief sources of CO_2 for tertiary EOR. For example, in Wyoming, the amount of CO_2 produced by natural gas processing plants is 716 trillion cubic feet (TCF), the amount of this CO_2 injected is 705 TCF, significantly reducing the emissions of the gas plants [2]. Core Energy in Michigan is also utilizing CO_2 that would be otherwise vented to the atmosphere for its EOR operations exploiting ancient carbonate reef deposits.

CO_2 injection technology is grounded in a nearly a half-century of oil industry CO_2 management expertise. Remaining oil not producible by primary or secondary techniques in several petroleum bearing regions of the United States have been successfully produced using CO_2 injections since its commercial-scale advent in West Texas in 1972. Since that time over 600 million metric tonnes of CO_2 shipped by pipeline to depleted oil fields in Texas and have produced 1.4 billion of barrels of oil. In the process, the recycled CO_2 is recaptured at the surface and injected so that almost all of the transported CO_2 ends up trapped by physical, solution and capillary trapping mechanisms and remains sequestered at depth.

Capacities for deep geological storage of CO_2 in the U.S. are now being recognized to accommodate hundreds of years of present day CO_2 emissions rates. The U.S. Department of Energy's North American Carbon Storage Atlas (NACSA) released in 2012 estimates that there are approximately 500 years of storage capacity for CO_2 emissions in North America [3][4]. Capacity and transportation and injection infrastructure currently available in EOR fields in the parts of the Rocky Mountains, Midwest, Southeast and parts of California provide a model for expansion. Where formations that have capacity for CO_2 don't exist, research suggests that the expansion and build-out of today's 4,000-mile CO_2 pipeline network is feasible and would reach much of the rest of the U.S.

This paper highlights that the demand for CO_2 supplies can boost domestic oil production in the U.S. and emphasizes the important role EOR can play in advancing carbon capture and sequestration technology [5]. If the oil produced during CO_2 EOR offsets imported sources of oil, the captured CO_2 emissions used for EOR will result in net reductions in greenhouse gases sequestered from the atmosphere, less any venting or leakage. There are a number of advantages to EOR-storage: 1) oil companies possess a long record of know-how to manage, inject and track CO_2, 2) depleted oil fields offer known reservoir capacities and injectivity and can--today--accept large volumes of CO_2 for tertiary oil production and subsequent storage, 3) EOR fields are equipped with the facilities to manage and inject CO_2, 4) oil fields are proven traps, known to hold oil and gas for millions of years, 5) occur in areas where the public is accustomed to oil and gas activities, 6) provide value to capturing companies through the sale of the CO_2, and 7) multiple injection and production wells offer the potential to manage the subsurface CO2 plume.

2. Tertiary CO_2 Enhanced Oil Recovery

2.1 Principles

In the primary phase of oil production, natural reservoir pressure helps drive oil out of the reservoir pore space to the pressure sink of the production wells and up to the surface. If the reservoir pressure declines to a point where fluids flow too slowly in the reservoir, some wells are converted to injection where, in the normal case, water is injected to rebuild the reservoir pressure and sweep oil to the producing wells. This stage of production is known as secondary oil recovery, or “water flooding”, and can provide an equal amount of oil as was produced during the primary phase [6]. As oil saturation in the reservoir declines, the mobility of the remaining oil decreases, as more of it is trapped by capillary forces, by “snap –off” or in dead-end pores. Significant oil remains in the pores, but it can no longer be made to migrate toward the production wells. At this point the field can be considered a candidate for an array of techniques, known as tertiary enhanced oil recovery (EOR), including CO_2 EOR. Injected carbon dioxide changes the properties of the residual oil in order to make it mobile and producible [7].

In the process of tertiary CO_2 flooding, compressed CO_2 is purchased from a pipeline and injected into the reservoir. There the CO_2 migrates though the reservoir, contacting the oil, some of which is produced with the oil at production wells. CO_2 EOR is typically developed in phases across a field, with areas of the field organized as sets of injection and production wells known as patterns. The process includes a complex group of interactions of CO_2 with the oil wherein oil mobility is increased, increasing the amount of oil that can be moved to the production wells. These processes include reducing the interfacial tension between the oil and rock, changing the oil’s viscosity, swelling the oil, and effectively releasing most of it from the rock pores.

At the surface the CO_2 is separated from the oil and water at a separation facility where the oil is sold, the water is recycled, and produced CO_2 is recompressed and readied for reinjection. Only a portion of the injected CO_2 is produced with the oil, as much of the injected CO_2 is exchanged for the displaced oil and water in the pores, and remains lodged in the formation. These CO_2 volumes remain in the reservoir via several mechanisms, including capillary, phase, solution, structural and stratigraphic trapping. Because CO_2 costs (purchase plus recycle) are in the range of 33-68 percent of the cost of EOR operations [8], combined with its scarcity in most places, operators take great care to ensure that CO_2 is not vented to the atmosphere after it is produced, except, for example, in the infrequent case of a power outage to the compressors. This CO_2 retention versus recycle process has been widely misunderstood. It has often led to misleading statements such as "only one third to one half of the CO_2 is retained," suggesting erroneously that significant amounts of CO_2 are lost from the system. A correct understanding is that: 1) the scarcity and cost of the CO_2 drives the operator to recapture and conserve all of the CO_2 and 2) the various operators design the CO_2 –EOR operations in a number of different ways to optimize the project, leading to different ratios of oil, water and recycled CO_2. During the entire life of the project, the retained volumes of CO_2 in the reservoir are the combined purchased volumes of CO_2 minus negligible losses.

Large volumes of CO_2 are essential to the tertiary oil recovery operation, with a wide spread of typical values ranging from 1-3 barrels of oil produced per metric ton of purchased CO_2 injected. CO_2 is currently very limited in supply with prices ranging from \$15 to \$40 per metric ton. This means that EOR can provide a revenue stream to offset the cost of upstream carbon capture technology at large industrial sources of CO_2.

2.2 EOR in the U.S.

Four decades of EOR illustrate the maturity of these processes [9]. The successful first experimental CO_2 injections go back nearly half a century, the first having taken place in 1964 at the Mead Strawn Field near Abilene, Texas. Results indicated that over 50% more oil was produced using CO_2 than by secondary waterflooding. Commercial CO_2 industry began with the first successful commercial scale CO_2 flooding that began in January 1972 at the SACROC field in west Texas and continues today. Initially the project was sourced by anthropogenic CO_2 separated at three southern Permian Basin gas plants and transported via two pipelines totalling 300 miles in length built specifically for CO_2 transport. Since this time it is estimated that approximately 600 million metric tonnes of CO_2 have been injected (much more considering recycle volumes) for tertiary EOR in the Permian Basin of Texas and more than 850 million metric tonnes in the United States. In early 2012 there were 127 U.S. CO_2 EOR projects with approximately 7,100 CO_2 injection wells and 10,500 producing wells. According to the National Petroleum Council [10], approximately 3 billion cubic feet per day of CO_2 (57 metric tonnes/yr) of newly purchased CO_2 are presently injected for tertiary EOR producing 286,000 barrels of oil per day (105 million barrels per year). Since the 1970s, the number of CO_2 EOR projects in the world has grown by nearly doubling each of the past three decades, with approximately 40 projects in 1984, 78 projects in 1994 and 142 projects in 2012[11]. CO_2 EOR now produces approximately 305,000 bbls worldwide with an accelerating growth rate. In the U.S. CO_2 EOR is focused in Wyoming, the Permian Basin region of West Texas and SE New Mexico and the Gulf Coast states of Texas, Louisiana and Mississippi. Other regions, such as the Mid-continent (Oklahoma in particular) and Michigan, are showing growth potential now as well.

In the U.S. enhanced oil recovery technologies hold the promise of providing infrastructure and capacity for long-term storage of commercial scale volumes of CO_2 and attendant revenue streams to offset the cost of capturing CO_2. With modest increases in surveillance and accounting, EOR can be utilized to store anthropogenic CO_2 [12]. In fact, in DOE "low" estimates, it is projected that approximately 136 million metric tonnes of CO_2 could be stored in EOR fields, not including the newly recognized residual oil zones (ROZ). The Texas Bureau of Economic Geology (BEG herein) estimates that there are 776 miscible oil and natural gas reservoirs in the Gulf Coast region that could be used first for EOR then for high volume storage. Many could also be used later in non-productive saline formations below the production interval [13] ("stacked storage").

2.3 Managing CO_2 *floods*

EOR operators design CO_2 EOR floods to minimize costs, such as the CO_2 expenses, and maximize (oil) revenue. Until recently enhancing the storing of CO_2 has never been a consideration in flood design. Minimizing cost relies on finding the optimal design of the recycle plant by considering the time profile of through-put capacity needed, by carefully monitoring the pressures along with injection and reservoir withdrawal volumes, by optimizing the type of lift to move fluids from the reservoir to surface, by minimizing the initial cost of the CO_2, by finding optimum solutions for water usage and/or disposal, carefully monitoring the production of oil, CO_2 and water volumes to control CO_2 breakthrough, and carefully planning the rate at which the areas under waterflood will be converted to CO_2 flood. Weighing these variables will lead the operator to manage the flood with spatial and temporal variations in the ratios of CO_2 and water injection leading to differing rates of CO2, water, and oil extraction. The mass of each fluid – oil, water and CO_2 - in the reservoir has to be monitored and will change over time. For example, during the early stages of a development of a pattern when CO_2 has not yet migrated to the offset production wells, all the CO_2 injected is retained in the reservoir. After a pattern has been in production for years, and because the CO_2 saturation in the flow units of the reservoir are high, larger amounts of CO_2 will be produced. Recycling produced CO_2 through the pore systems continue to process oil for decades. But, when the amount of oil produced in one part of the field declines to a marginal level, the recycled CO_2 will be moved to another part of the field. This can be referred to as a "taper-down" of the flood wherein less CO_2 and more water is gradually injected, or by quitting injection of CO_2 altogether and injecting all ("chase") water or, alternatively, cutting back on most or all injection wherein more fluids are extracted than are injected. This latter approach will cause the tapered areas to be depressured. However, it is important to note that during taper down, these volumes of CO_2 are not released to the atmosphere.

2.4 Reservoir retention of CO_2

Data on CO_2 retention is rarely found in the literature since it generally involves including two-party contractual information on CO_2 purchase volumes. Purchase and sale agreements are considered confidential business information. Thus retention and storage data generally remain unreferenced and unpublished. However, losses from venting and fugitive emissions are occasional reported in the literature and amount to a few percent or less of the purchased volumes of CO_2. Oxy's project overview for its Elk Hills CO_2 EOR project, states that, based on the performance of its Denver Unit, (a very large field) that, of 115 million tonnes supplied ("purchased"), there will be cumulatively 137 MMT produced and recycled for a total of 252 MMT injected, with 756,000 MT (0.3%) lost from the original purchased volume from fugitive and operating emissions [14].

3. Residual Oil Zones (ROZ): Potential for Increased U.S. Lower 48 State Oil Production and CO_2 Demand.

3.1 Principles.

Petroleum geologists and reservoir engineers have begun to identify previously unknown depleted oil-bearing reservoirs, in the naturally water flooded formations, below the oil-water contact in existing producing fields (Figure 1). These intervals have become known as residual oil zones (ROZs) [15].

Classically, CO_2 has been applied the "main pay zone" (MPZ) of reservoirs, where substantial portions of the mobile oil were recovered during primary and secondary production. Tertiary (enhanced oil) recovery was devised to mobilize the immobile fraction and has been traditionally called upon when the oil saturation drops toward the residual oil saturation where the remaining oil is immobile in waterflood.

The presence of significant shows of oil (i.e. residual oil) below the oil water contacts can be traced at least back to the 1960's wherein some authors reported oil presence below oilfields and some even displayed zones of partial oil saturation ("shows" of oil) between fields and apart from MPZs. In the past, a common explanation of these shows was to classify all of them as transition zones where oil saturations in the MPZ linearly decayed with distance depth from full to zero oil saturation because capillary and interfacial tension forces. Today, there is a growing recognition that many of these partial oil saturation below the oil-water contact are often better classified as ROZ and explained as petroleum-bearing formations that have been naturally water flooded. ROZs may result of one of three natural processes:

- Type 1: Regional tilt of an oil entrapment (illustrated in Figure 2),
- Type 2: Temporary breach and loss of oil through the reservoir seal,
- Type 3: Tectonic uplift and hydrodynamic flushing of a portion of a paleo oil entrapment by flow of meteorically driven water.

The residual oil saturations that remain in the reservoir rock are, in general, in the range of 20-40% of the total pore volume but can be as high as 60% in special circumstances. If the residual oil saturation is 20-25% or higher, the ROZ may be produced with the same success as tertiary CO_2 EOR of the MPZ. ROZs within the San Andres Formation of the West Texas Permian Basin are explained by the type 3 ROZ model, based on modelling of the paleo-hydrology of the natural sweep process [16]. Additionally, an extra stage of dolomitization has been identified within the San Andres ROZ intervals that make for a more uniform and permeable reservoir than the otherwise equivalent main pay zones.

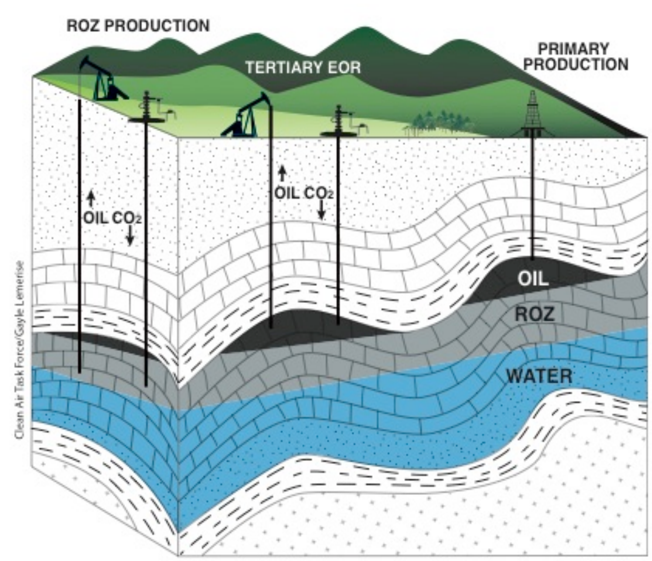

Figure 1. Relationship of ROZ production to primary and tertiary EOR. The ROZ is a naturally waterflooded reservoir below the MPZ, with residual oil that can be produced using same techniques as tertiary CO_2 EOR.

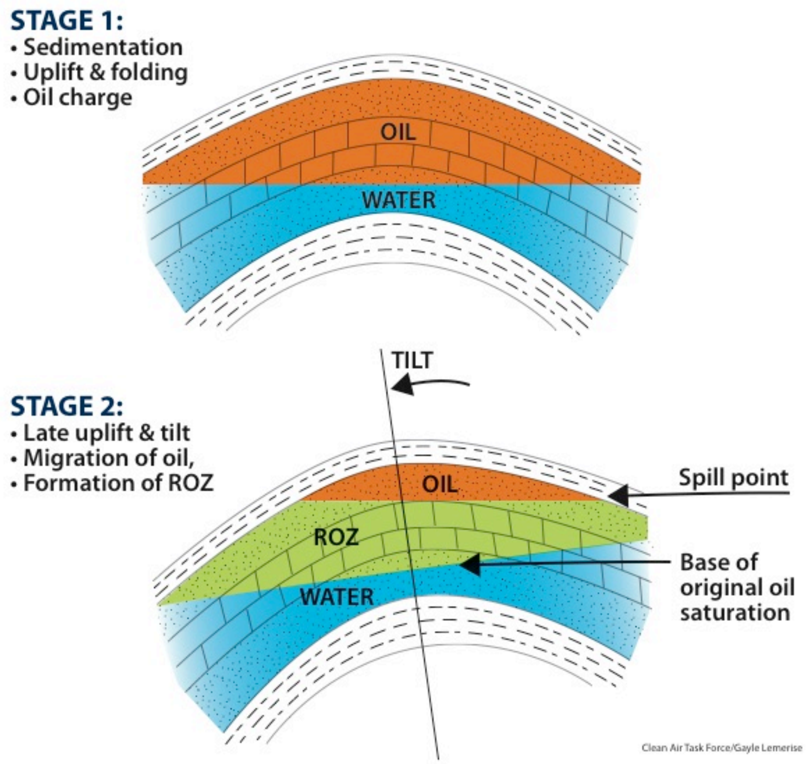

Figure 2. Formation of a type 1 ROZ during late-stage uplift and tilting.

3.2 Beyond tertiary EOR

Today, there is a growing recognition that post-waterflood MPZs are not the only targets for CO_2 EOR. The significance of these ROZs for geologic carbon storage is that they have the potential to boost CO_2 demand well beyond current volumes of CO_2 supply in the United States. Residual oil zones are being found and described in other regions of the U.S. including the Bighorn Basin of Wyoming and the Williston Basin of Montana [17]. Because they have been naturally waterflooded and oil can no longer be mobilized with additional water, production of these accumulations requires an enhanced oil recovery method. In fields where CO_2 EOR is already underway, the wells may be deepened and CO_2 flood applied to the ROZ as well as the ongoing or future developed depleted main pay zones. This next-generation EOR, including some estimates of ROZ production, may produce as much as 100 billion barrels of oil in the U.S., yet only a fraction of the associated CO_2 demand can come from existing CO_2 sources; Advanced Resources Inc. has estimated that next generation EOR combined with the limited estimates of ROZ production could produce a demand for approximately 33 billion tonnes of CO_2 [18].

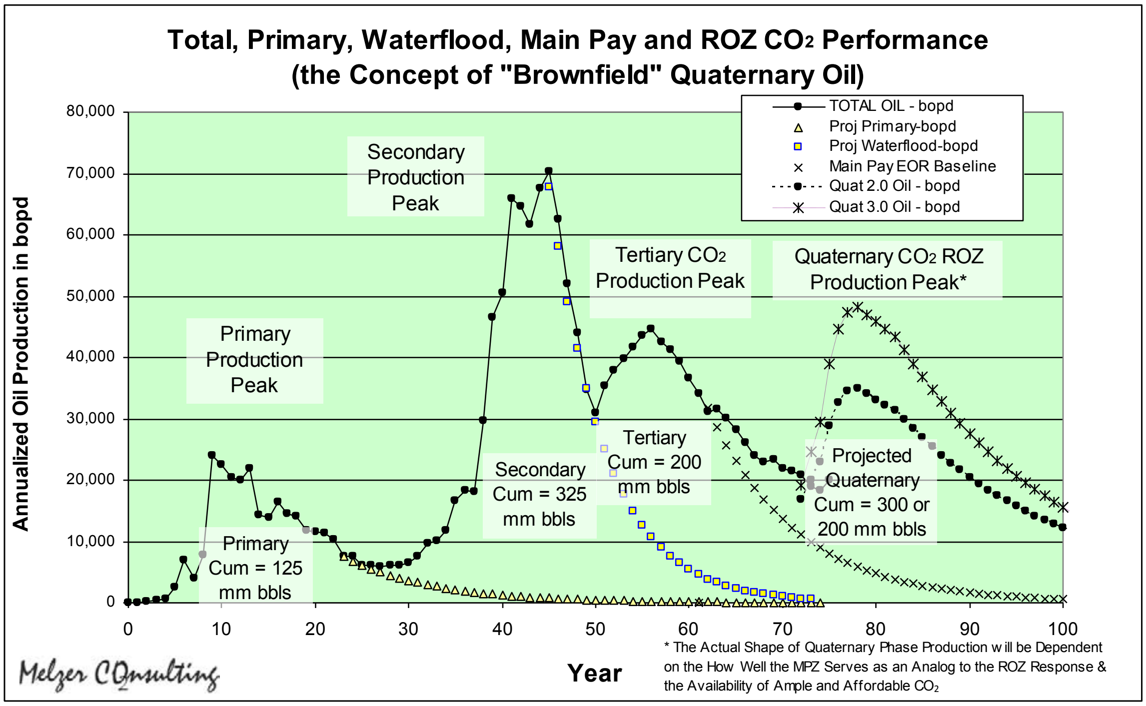

Figure 3. Oil Production performance from primary production, secondary and tertiary EOR and ROZ development.

Primary, Secondary, Tertiary Recovery	**Millions of barrels of oil (mm bbls)**	**Recovery Factor (% of OOIP)**
Main Pay Zone (MPZ) Original Oil in Place (OOIP)	1000	
Primary Recovery	200	20
Secondary Recovery	325	32.5
Primary + Secondary	525	
Tertiary Recovery	200	20
Total MPZ	725	72.5
Post Waterflood Recovery	200/(1000-(200+325))	42
Quaternary Recovery	**Millions of barrels of oil (mm bbls)**	**Recovery Factor (% of OIP)**
Total ROZ Oil in Place (OIP)	1000	
Conservative Estimate of ROZ Recovery	200	20
Alternative ROZ Recovery	300	30
MPZ analog Recovery @ 42% [19]	420	42

Table 1: An illustration of actual recoveries and comparative potential for ROZ recovery.

Figure 3 displays an illustration based on the production history of a large Permian Basin field that has progressed through a primary, secondary and tertiary (CO_2) phase of production. Also shown is what can be termed a "quaternary" or fourth phase of production that has extended the CO_2 EOR phase into a large target ROZ below the MPZ. What this chart demonstrates is that the response of the ROZ can be much like the CO_2 EOR response of the MPZ. Although the duration of the ongoing ROZ projects are insufficient to confidently establish a benchmark rule of thumb recovery factor, recoveries in the ROZ could approach 30%. Table 1 illustrates the potentail large volumes of oil that could be produced from the ROZ.

4. Stacked Storage

4.1 Stacked storage

As a CO_2 flood progresses, the efficiency of the CO_2 in producing the oil decreases, and with it, demand for CO_2. Where an operator may, in the future, contractually provide storage for a captured source of CO_2, the operator may opt to: a) divert the CO_2 to another field, b) "pack" the CO_2 into the depleted reservoir and plug and abandon it (staying below the any risk resulting from elevated pressure), or c) sequester the CO_2 in saline formations below the depleted producing zones. Therefore, CO_2 EOR can prepare the way for continued and larger volume storage in underlying saline formations. Where CO_2 is sequestered beneath the producing reservoir is called "stacked storage.". Many oil reservoirs are associated with large volumes of saline formation that forms the "water leg". These deeper formations may be connected to the EOR production zone so that fluids can flow into or out from the reservoir. Even deeper saline units with no oil and gas production may be also available for additional storage. The concept of using EOR to open the way to large volume saline storage; the saline injection can be designed to use the same surface footprint, infrastructure, characterization, and monitoring plan as the EOR project.

Several U.S. sites provide prototypes for stacked storage. For example, Denbury Onshore LLC in Mississippi has hosted a collaborative project with the University of Texas Gulf Coast Carbon Center at its Cranfield Mississippi EOR operation to assess monitoring and capacity estimation techniques for commercial volumes of stacked storage in the water leg of a producing formation. The Cranfield Mississippi oilfield geologic carbon storage project began injection operations in 2008 and had purchased, transported and injected 3.5 million metric tonnes of CO_2 into the Tuscaloosa Formation as of March 2012 and of this, 1.5 million tonnes have been produced and recycled, summing to 5 million tonnes injected. The Tuscaloosa Formation is a widespread oil producing formation in the Gulf Coast region with multiple overlying confining zones and underlying saline sections that could provide stacked storage.

5. Carbon Dioxide Supply and Demand

5.1 CO_2 Supply in the United States

Three quarters of all U.S. CO_2 supply today comes from natural CO_2 accumulations. In the U.S. there are reserves of approximately 2.2 billion metric tonnes (BMT) of natural CO_2 [20]. In North America, there are approximately 65 million metric (MMT) tonnes of annual supply, with 37 MMT supplied to the west Texas Permian Basin. As of 2010, approximately 75% of the North American CO_2 supply is from natural underground accumulations such as Mississippi's Jackson Dome. The remaining CO_2 is anthropogenic, supplied by natural gas plants, (19%), coal synfuel plants (5%), and ammonia plants (1%). Today, effectively all of the available CO_2 supply in the U.S. is under contract, while at the same time there is pent-up demand for $CO_2$for flooding conventional reservoirs and more yet from the large new targets, called residual oil zones, that have been piloted and proven commercial and more that have just been discovered that will require even more CO_2 to produce.

5.2 Meeting future CO_2 demand in the United States

Recent estimates of future CO_2 demand suggest that large volumes will be required to meet the promise of next generation EOR including the development of residual oil zones (Figure 4) [21]. According to a recent analysis by Advanced Resources International Inc (ARI) an additional 100 billion bbls of oil could be economically produced with advanced EOR, with adequate CO_2 supply, assuming $85 a barrel oil, including onshore U.S., including Alaska, offshore and residual oil zones. ARI estimates that this will require 33 billion tonnes of CO_2 to realize this volume of oil, of which approximately 2 billion tonnes can be supplied by underground natural sources, the remaining must be made up by captured anthropogenic sources such as natural gas plants, fertilizer plants and power plants. In order for this to happen, substantial new CO_2 sources must come online in coming years.

The insufficient supplies of CO_2 to undertake or expand EOR in the U.S. require substantial new volumes of anthropogenic CO_2. But while carbon capture technology has been tested at projects worldwide, the technology is expensive and the commercial scale development of CCS is just getting underway with projects such as Mississippi Power's Kemper County Plant under construction. One mechanism to help implement capture projects is to make multiple products for sale. This, in turn, may lead to better public acceptance and more expeditious regulatory approvals. For example, The Texas Clean Energy Project (TCEP) is an Integrated Gasification Combined Cycle (IGCC) facility will incorporate carbon capture and storage (CCS) technology [22]. TCEP will be a 400MW power/poly-gen project that will also produce urea for the U.S. fertilizer market and capture 90 percent of its carbon dioxide (CO_2), approximately 3 million tonnes per year, to be used for enhanced oil recovery (EOR) in the West Texas Permian Basin.

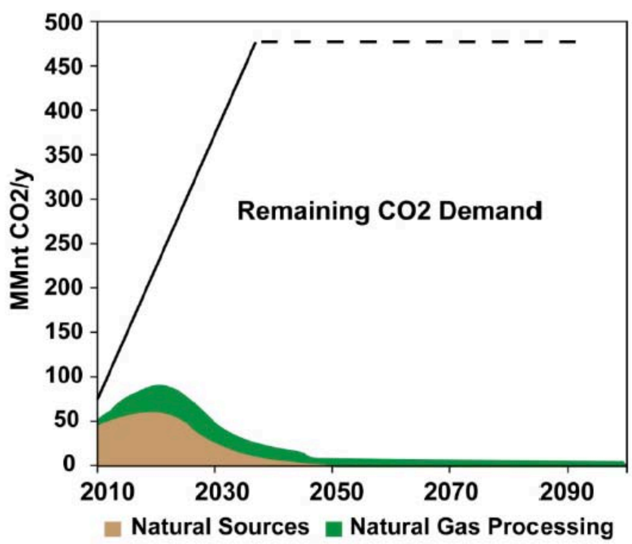

Figure 4. Schematic illustration of CO_2 supply and demand suggesting large volumes of anthropogenic CO_2 will be necessary to realize the estimated 100 billion bbls of economic stranded oil [23].

6. CO_2 Transport

6.1 CO_2 Pipelines in the United States

One consideration that has been widely used to favour CO_2 injection and sequestration into saline formations is that many CO_2 emissions sources, such as power plants are distant from favorable EOR fields. However, in many areas this may be addressed by systematic pipeline development. There are presently 4,000 miles of CO_2 pipeline connecting naturally mined and anthropogenic sources of CO_2 with enhanced oil recovery projects. In total there is approximately 50 million metric tonnes per year of CO_2 throughput. The Denbury "Green" pipeline, completed in 2009, extends existing pipeline system from Jackson Dome in Mississippi to south of Houston Texas and is designed to collect and deliver both CO_2 produced from subsurface " natural" geologic reservoirs and anthropogenic CO_2 [24]. The Green Pipeline is slated to begin collecting sources of anthropogenic later in 2012 from Air Products steam methane reformers in Port Arthur, Texas, and then in 2014 following the construction of the Leucadia Lake Charles Louisiana methanol plant in 2014 [25]. Denbury is taking a leading role in EOR CO_2 storage as it has planned for the possibility to continue to sequester CO_2 in its Oyster Bayou project following the commercial EOR production from the field [26]. A 320 mi extension of the Denbury Green pipeline to southern Illinois is under consideration and planning and would connect anthropogenic sources to fields in Mississippi, Louisiana and Texas [27]. Another Denbury Resources pipeline, the Greencore Pipeline, is currently under construction between the Denbury's Lost Cabin natural gas separation plant in Wyoming through the Powder River Basin to southeast Montana [28].

6.1 Pipeline development

With a growing demand for CO_2 for EOR and ROZ development, CO_2 pipeline development is critical factor. And while pipeline buildout appears to be a major challenge, there are nearly half a million miles of natural gas and hazardous liquids pipelines that could provide existing rights of way for the build out of CO_2 pipeline network. Such a network would supply captured CO_2 to EOR fields, which would inject it for oil production and, in the process store the CO2. The modelling work of Battelle's Joint Global Change Research Institute [29] suggests that building out a CO2 pipeline system under two hypothetical climate stabilization policies that would limit atmospheric build up of CO_2 levels to 450 or 550 ppm, would be a reasonable task. Between 11,000 and 23,000 additional miles of CO_2 pipelines might be needed by 2050 in these two cases. The analysis suggests that new CO_2 pipeline capacity "will unfold relatively slowly and in a geographically dispersed manner "as new CCS plants come online. From 2010-2030 the analysis estimated that a few hundred to less than 1,000 miles per year. The natural gas pipeline system from 1950-2000 grew at rates that were "far higher" than expected under Battelle's modelled scenarios. The paper concludes:

> "...the need to increase the size of the existing dedicated CO_2 pipeline system should not be seen as a major obstacle for the commercial deployment of CCS technologies in the United States."

In another analysis, Advanced Resources Inc. (2010) has estimated that three 800 mile-long pipelines could result in the storage of 30 years of Ohio River Valley EGU coal plant CO_2 [30].

7. Advantages of EOR Geologic Storage.

7.1 EOR storage

CO_2 -EOR sites can provide injection targets for early captured CO_2 because (See Table 2) they have proven reservoir injectivity, provide known traps that have held hydrocarbons over geologic time, facilitate management of underground CO_2 plumes, provide infrastructure, may offer additional stacked storage potential, and are advantageous for monitoring because of available well infrastructure and dense pre-injection data. Figure 5 illustrates a characterization and monitoring system for CO_2 retention in EOR including some of the advantages of the EOR storage setting: known capacity, provable seal and known injectivity, as discussed below. A damaged seal or inadequate storage capacity may result in rejection of an EOR field for storage. Leakage risk due to poor well integrity requires identification and potential corrective action on abandoned and orphaned wells, particularly in old fields. EOR storage benefits from plume and pressure management.

Use of captured CO_2 for EOR has additional benefits in that in many cases significant amount of infrastructure are in place, lowering barriers. Existing surface development of the site with roads and well pads may reduce environmental impact and decrease development costs. Exiting pipeline infrastructure and right-of ways may also be reused to benefit the project. Reuse of an existing (brownfield) site may also lower barriers to public acceptance. EOR can result in infusion of capital that allows clean up of historic infrastructure that may have degraded during periods of low revenue. Increase revenue and jobs generation from a successful EOR project oil production can also increase local acceptance.

However, is important to keep in mind and assess limitations in extrapolating the past performance of a field to future EOR-storage performance. It is therefore important to design the characterization and monitoring program to assess any limitations. Such limitations may exist in the following areas: the quality of historic production data, injection rates relative to initial reservoir charge, flaws in well construction, damage to the seal during past production.

Type	**Storage Only-Saline**	**EOR with Incremental Storage**
Land	Greenfield	Brownfield-already impacted by oil industry operations
CO_2 Management	CO_2 injection	CO_2 injection, production, recycle
Pressure Build-up Risk	Potential for large areas of pressure increase; pressure management may be needed	Pressure management is goal of EOR
CO_2 Trapping	Inferred trapping mechanisms	Demonstrated trapping
Solubility of CO_2 in Formation Fluid	CO_2 weakly soluble formation brine	High solubility of CO_2 in oil

Subsurface Information density	Few wells: sparse information	Many wells: subsurface well known
Mechanical Integrity/ Risk of Well Failure	Few wells, carefully drilled, cased and cemented	Many existing wells, some in unacceptable condition. Expense to remedy: identify, and re-enter to plug/repair
Pore space access	Variable by state; evolving	Existing legal framework
Revenues to offset CO_2 capture cost	No	Yes
Monitoring & verification, accounting (MVA)	MVA must be based on comprehensive geologic study.	Existing reservoir production and surveillance knowledge contributes to development of MVA; integrity of existing wells in the field a principal leakage concern.
Public Acceptance	Unknown.	Likely to be good. Public familiar / comfortable with oil production

Table 2: Comparison of EOR storage with saline storage

7.1 Storage Capacity: Limitations in Predicting EOR-Storage Performance from Past Performance

One advantage of EOR-storage is that performance data will help assess the field's capacity for CO_2 (Figure 5 top triangle). However, quality of data from historic production can contain significant uncertainty. It is important to assess the significance of this uncertainty on the assurance of retention. The amount of produced fluid may be incompletely recorded, particularly if gas was flared during production. Uncertainties in the original oil in place can be combined with difficulties in allocating produced fluids to the proper intervals can leave significant uncertainty in the amount and distribution of hydrocarbons remaining in the reservoir at the start of the CO_2 EOR project. This obviously constitutes an economic risk, but because of the strong solubility of oil and CO_2 under miscible conditions, could also lead to uncertainties in plume spread and pressure increase. In addition, complex miscibility functions, fluid density differences, and multiphase fluid interaction at the pore scale should be considered sources of uncertainty.

7.2 Confining system

Documenting the presence of adequate confinement is a critical go/no go decisions for a storage site (Figure 5, second triangle). In a previously undeveloped saline site, a lengthy, comprehensive screening process is needed to prepare for the decision [31]. A program of collection of seismic, wireline log, and core data are needed, followed by extensive hydrologic testing. Such activities will reduce risk that saline reservoir compartmentalization will limit capacity or that flaws in the confining system are present. Confidence that a saline site will accept the intended volumes of CO_2 and that the confining system operate as planned remains a significant uncertainty during the entire injection period. This is because in a saline storage project the area of the plume, area of pressure increase, and thickness of the plume will continue to increase, potentially adding stress to the containment system--depending upon the volume and geometry of the confining zone. A corollary issue in saline sites is prediction of the ultimate fate of CO_2. Some saline sites are identical to hydrocarbon traps, with a structural or stratigraphic closure that will limit lateral migration of the CO_2. However, others are more open with long flow paths that can be taken by buoyant fluids under gravitational forces and assessing final fate of the plume may require significant effort and lead to uncertainty [32][33].

One source of concern is possible geomechanical damage to the sealing formation during strong pressure depletion [34]. The mechanical integrity of the reservoir seal should be assessed for damage during injection. For example, is has been reported that the lower part of a thick shale seal at the In Salah saline storage site in Algeria may have incurred damage during injection [35]. Seal damage can occur when injection rapidly places surface temperature fluids into hot rocks at depth, and the attendant cooling can decrease the strength of seals and reservoir [36].

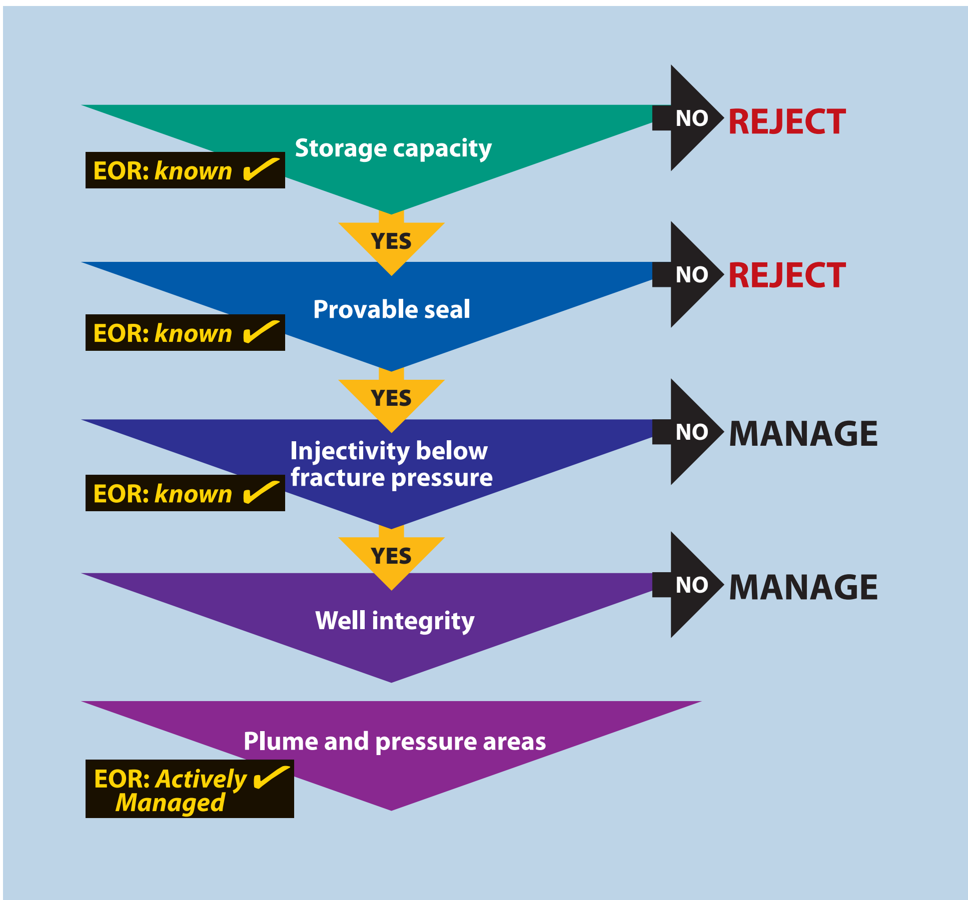

Figure 5. The characterization and monitoring system for CO_2 retention in EOR illustrates some of the advantages of the EOR storage setting: known capacity, provable seal and known injectivity. A damaged seal or inadequate storage capacity may result in rejection of an EOR field for storage. Leakage risk due to poor well integrity requires identification and potential corrective action particularly in old fields. EOR storage benefits from plume and pressure management.

7.3 Injectivity

In contrast, for a prospective CO_2 EOR site, the uncertainly of assuring adequate injectivity to accept all the planned volumes of CO_2 can be greatly reduced by analysis of data from past decades of production experience. Produced fluid reservoir volumes can be approximately equated to CO_2 injection capacity in a volume equivalent basis [37]. Another of the key issue tied to capacity is the rate at which CO_2 can be injected without unacceptably elevating pressure in the reservoir. Reservoir response to fluid extraction typically is predictive of the response to injection. In addition, many fields ready for CO_2 – EOR have undergone water flooding for secondary recovery, providing direct information about reservoir response to injection. The other key issue that is well established for a hydrocarbon field is that the top seal is sufficient to retain buoyant fluids (Figure 5, third triangle). Accumulation of oil eliminates the possibility that the top seal strata had major transmissive flaws prior to production. In addition, accumulation of oil provides direct evidence of where the CO_2 will accumulate at the end of injection. If properly designed, the lateral spread of CO_2 will be limited to the trap defined by the oil accumulation.

Another significant factor to be evaluated is that CO_2 injection occurs much more rapidly than natural hydrocarbon charge – the same approximate volume emplaced over decades during injection that was emplaced over geologic time periods. Therefore, pressure on the reservoir and seal is much greater during injection than the pressure exerted by the buoyant hydrocarbon column during natural charge. The adequacy of the seal to retain fluids at higher pressure should be assessed. If the seal is of adequate thickness, any increase in invasion because of elevated injection pressure will likely be offset by the short duration of injection. In addition, injected CO_2 will spread laterally, including downdip, under injection pressure. This effect will be naturally mitigated by pressure decrease with distance from the injection wells; at some point buoyancy will become the dominant force and CO_2 will migrate back toward the crest of a structure. A combination of pressure sinks at production wells and water injection “water curtains” to control lateral migration can also be utilized. It is important to assess the efficacy of these functions and assure that CO_2 does not cross structurally defined “spill points”. It is also important that CO_2 not migrate into the capture zones of pumping wells that are not connected to recycle, as this would result in rapid release to atmosphere as well as potential liability for interference with production on other leases. Monitoring can be used to determine that normal best practices of EOR operators is effective

7.4 Wellbore Integrity

Wellbore leakage historically has been an issue of concern for injection projects, both in oilfield and waste disposal context. (Figure 5, fourth triangle). Well construction is designed to limit fluid flow along the wells, however, flaws in construction are a well-known cause of failure in a number of situations. During production, pressure in the reservoir is decreased below discovery pressure, any flaws in well completion or plug and abandonment that allow flow along the well would allow water from normally pressured zones above the production zone to access the reservoir and appear as an increase in water cut in the reservoir which may or may not be detected. The same flaws, however, might become significant during injection, when pressure elevation near the injection wells increases so that gradients may drive flow from the reservoir to shallower zones. Leakage has been noted during water floods, when elevated pressure causes saline water to contaminate groundwater or migrate to the surface [38]. Inspection and remediation of wells is a regulatory requirement and thus part of any injection project, including CO_2. Well CO_2 leakage records are rare in the regulatory environment. A case of leakage was reported at Anadarko’s Salt Creek field in Wyoming where CO_2 migrated to the surface from inadequately plugged wells drilled very early in the 20th century [39][40]. The authors are also aware of a few unpublished cases where anomalous casing annulus pressures were noted or surface leakage was identified. Considerable work is underway to assess the issue of well performance during CO_2 injection [41][42][43].

As the field project is under development, the operator will prepare wells for injection and production and work-over any wells that will not perform adequately under elevated pressure and with changed fluid composition. This is a well-known operational activity, undertaken with apparent reasonable success by operators of existing floods. As described below, management of the risk is conducted during three stages:

1) Characterization,
2) Pre-injection remediation, and
3) During-and post-injection surveillance.

Characterization. Characterization starts with inspection of historical well completion records, which show construction details such as the amount and placement of cement as well as modifications to wells that have been made during operation. In some fields, historic operations leave uncertainty in the locations and total number of wells drilled. Historic air photographs and new surveys such as LIDAR (PCOR partnership at Bell Creek field) or ground based or airborne magnetics can be used to locate lost well casings for further investigation. Wells that are accessible can be further inspected with commercial tools for evaluating the quality of the cement and casing and the bond between them. Well that have been plugged & abandoned (P&A) are not accessible; in some cases the records are sufficient to document that the P&A meets the requirements of the flood (accept the increase in pressure). In other cases, uncertainty in the quality of the P&A remains, for example if the well was damaged limiting access and plugs were set at shallow depth, or the records are incomplete or missing. Operators and regulators must weigh risks and costs to determine in which cases best results will be obtained by closely monitoring of well performance during injection to determine if the completion is adequate, and which cases should be reentered and assessed prior to the start of injection. In some cases observations at the surface can provide clues to the conditions at depth, for example tapping into the casing with a pressure gauge can show that plugs designed to isolate the surface from reservoirs at depth are missing. Methane or saltwater anomalies at the surface are evidence that may indicate leakage from depth.

Remediation. A large number of options are commercially available for remediation. A well in unacceptable condition can be reentered to be plugged and abandoned, or it can be repaired by addition of new tubulars, placement of additional cement, or partly re-drilled or “sidetracked”. A questionably plugged and abandoned well can be re-entered, and repaired which includes “tie-back” of the cut off casings, using a well workover rig to drill out any plugs that are inside the well casing, and by repairing flaws in the casing, and resetting the plugs according to current standards. These activities are costly, with each well repair in the range $0.25 to $1 million.

Surveillance. A number of tools are available commercially for surveillance of well integrity during and post injection. Low cost standard options are to observe the pressure in different casing annuli as pressure in the reservoir changes, to identify flaws in well completions. This can be done to either open or P&A wells if the top of the casing is excavated. P&A wells can be tested by various types of gas sampling at the surface and above the well. Wells are traditionally tested by an array of mechanical integrity tests that can test the isolation inside the casing and as well as the important casing-rock bond. In addition, in gas storage sites, the overall integrity of system is tested by observation of pressure in transmissive zones above but isolated from the reservoir, above zone monitoring intervals (AZMI). No change in pressure in the AZMI documents no leakage toward the surface via wells that penetrate the AZMI. Other types of surveys for fluid migration from depth toward the surface include seismic surveys that are used to image gas accumulations, electrical surveys that can detect brine migration, natural or introduced tracer surveys to identify chemical constituents that migrate from depth.

7.5 Plume Management

Another risk abatement intrinsic to CO_2 EOR is active plume management (Figure 5, bottom triangle). Because the purpose of the project is to recover oil that is mobilized by interaction with CO_2, the project design will draw fluids toward production wells. Injection and production wells are organized in patterns designed to optimize this process. The extent of CO_2 migration is limited by this design. In addition, pressure is actively managed to a designed ratio between producers and injectors to sustain the circulation of CO_2 through the reservoir. The level of comfort with this design is such that proposals have been made to add production wells to saline projects to partly mimic EOR projects, for example the extraction planned at the Gorgon project, Australia [44]. However, the equivalent design in a saline project is limited by lack of ability to collect, recompress and recycle any CO_2 produced.

8. Monitoring, Verification and Accounting (MVA) for CO_2 storage in EOR

8.1 Regulatory Framework for Geologic Storage in the U.S

Secure geologic storage not only requires injection technology and capacity but it means careful site selection and surveillance to ensure that injected volumes remain out of the atmosphere and groundwater resources. CO_2 brine injection experience over the past ten years combined with industry experience in CO_2 EOR, over the past decade have begun to demonstrate methods to track and document storage of CO_2 in the subsurface during EOR. Department of Energy (DOE) National Energy Technology Laboratory (NETL) and its Research Carbon Sequestration Partnerships (RCSP) have characterized and developed a range of protocols, tools and experience in site characterization, monitoring, verification and accounting (MVA) to document that injected CO_2 remains confined in the subsurface and does not migrate and threaten aquifers or escape into the atmosphere [45]. Such protocols need to be tuneable to the reservoir environs; some reservoir/seal conditions are higher risk for leakage than others and MVA protocols will need to reflect site variability.

Federal regulations also now govern geologic CO_2 storage in the United States. The existing Underground Injection Control program (UIC) was promulgated by the U.S. Environmental Protection Agency's (EPA) under the Safe Drinking Water Act, and designates six categories of injection wells and attendant regulations to protect underground sources of drinking water (USDWs) [46]. In particular, the UIC Class II rules were designed to protect USDWs during injections associated with oil and gas production and therefore apply to EOR [47]. To supplement the UIC program, EPA promulgated a new well class, Class VI, finalized in 2010 to protect fresh water aquifers during saline geologic storage of CO_2 [48]. EPA is currently in the process of publishing guidance on implementation of MVA for Class VI wells. In addition to the UIC rules, EPA's Greenhouse Gas Reporting rule subpart RR lays out a framework for monitoring, reporting and verification of CO_2 volumes stored [49]. EOR operators that opt into CO_2 storage must comply with both the Greenhouse Gas Reporting Rule and the UIC Class II rules. Early EOR-storage projects are underway that will inform future development of monitoring plans for geologic storage and help provide a roadmap for compliance with subpart RR for future projects. In addition, U.S. CO_2 storage incentives under IRS 45Q require "secure geological storage" and thus "adequate security measures” (MVA) to prevent the escape of CO_2 to the atmosphere in order to qualify for the U.S. $10 per metric tonne tax credit available for EOR storage and U.S. $20 per tonne for saline storage [50].

8.2 MVA in EOR Settings

Table 3 shows carbon dioxide floods with concurrent MVA research and testing. For example, the Gulf Coast Carbon Center’s project at Denbury’s Cranfield field is using advanced MVA methods applicable in both saline reservoir and oilfield settings [51][52][53][54]. The goal of the project is to evaluate protocols that demonstrate that injected CO_2 is effectively retained, and to field test predictions of storage capacities. During the course of the project, a variety of methods have been tested focusing on optimizing MVA methods for commercial use. While recognizing that these methods are part of research programs, it should be noted that the methods are being evaluated for both technical and economic feasibility. Results are presently informing the development of MVA plans for CO_2 EOR projects planned in Texas.

Field name	**Location**	**Operator**	**Monitoring lead**	**Flood start date**	**Web resource**
Weyburn	Saskatchewan, Canada	Cenovus, Apache	Petroleum Technology Research Centre	2000	http://ptrc.ca/+pub/document/Summary_Report_2000_2004.pdf
West Pearl-Queen (huff-n-puff pilot)	New Mexico	Strata Production Co.	Los Alamos National Lab, Sandia 2003 National Lab, NETL	2002	http://www.es.ucsc.edu/~phlip/LDRD_ER/Pawar_EnvironmentalGeoscience.pdf
SACROC	Scurry County, Texas	Kinder Morgan	Bureau of Economic Geology, Southwest RCSP	1972	http://www.netl.doe.gov/publications/proceedings/08/rcsp/factsheets/10-SWP_SACROC%20EOR%20Sequestration_Oil.pdf
Zama	Alberta, Canada	Apache Canada	Energy & Environmental Research Center, PCOR RCSP	2006	http://www.netl.doe.gov/publications/proceedings/08/rcsp/factsheets/7-PCOR_Zama%20Field%20Validation.Oil.pdf
Louden Field (short huff-n-puff)	Fayette, Illinois	Petco	Illinois State Geological Survey, MGSC	2007	http://sequestration.org/resources/publish/MGSC_HuffnPuff_Loudon.pdf
Cranfield	Adams County, Mississippi	Denbury Onshore LLC	Bureau of Economic Geology, SECARB RCSP	2008	http://www.secarbon.org/files/early-test.pdf
Hastings	Alvin, Texas	Denbury onshore LLC	Bureau of Economic Geology, Denbury	2001	Hovorka unpublished
Bell Creek	Montana	Denbury Onshore LLC	Energy & Environmental Research Center, PCOR RCSP	planned 2012	http://www.undeerc.org/pcor/pdfs/FS17_Bell_Creek_Mar2012.pdf

Table 3. EOR fields undergoing CO_2 flood with monitoring programs designed to provide information about storage

Weyburn-Midale oil field is another example of an enhanced oil recovery and storage research project located in Saskatchewan Canada, the receptor site for captured CO_2 from the Beulah Dakota coal gasification site in the U.S. [55]. Over the life of the field, approximately 26 million tonnes (net) will be stored at Weyburn as a part of enhanced oil recovery at the field. Canada's non-profit Petroleum Technology Research Centre (PTRC) has conducted a monitoring research program to investigate the most effective methods for ensuring CO_2 injected for EOR remains sequestered at Weyburn.

8.3 Adaptation of Existing Subsurface Characterization, Planning and Surveillance Activities for EOR Storage MVA

A monitoring program designed to assure long-term containment of CO_2 reduction credits will include an overlay of MVA activities not normally conducted for CO_2 EOR. However, it is important to recognize that the risk profile at an EOR site is different from a saline site, therefore the spectrum of monitoring activities selected to optimize assurance will not be the same. In particular, the data available from the geologic history, the performance during production, and EOR surveillance for commercial purposes may cover much of the information that is assigned to MVA at saline sites.

Two major adaptations are needed to move from CO_2 EOR to CO_2 EOR plus CCS operations with storage assurance: 1) data traditionally collected privately to justify purchase, design the flood, and optimize operations needs to be reassessed to extract information relevant to storage permanence and this information provided to stakeholders who need this assurance, and 2) additional data collection should be targeted to the areas where uncertainties could lead to material failure to achieve goals of storage permanence. The cost of the adaptions need to be added into the business model, perhaps most easily conceptualized as additional monitoring costs being as part of the cost of obtaining the anthropogenic CO_2. The framework into which the storage assurance data from CO_2 EOR would be provided is evolving and presently immature and will likely vary across jurisdictions and geologic situations. However, we can explore some general ways in which monitoring to assure storage for EOR may be distinct from that planned for saline sites (Figure 6)

Data from field characterization during oilfield discovery and delineation can be mined to confirm the quality of the trap, especially to identify risks such as the mechanisms that limit the volume of hydrocarbon trapped, such as a spill point or hydrocarbon column height limit. As part of the commercial program, operational data from primary and secondary recovery will be assessed to plan the flood, likely via fluid flow models. The models will supply information to the planned the CO_2 purchase schedule, injection and production well build-out plan, plume area and thickness, CO_2 sweep efficiency, material balance and pressure increases. This planning will be reported for the CO_2 EOR program in much the same way that it is reported for a saline project, to obtain injection permits, which are public permit submittals. The EOR project will benefit from more data yielding higher confidence, however for both commercial and storage assurance purposes it is important to highlight uncertainties that could cause project failure via risk assessment and plan monitoring to avoid them. To assure sequestration, the risk findings and abatement plans will be made available to relevant stakeholders. It should be possible to negotiate avoiding release of competitive advantage information. For example an operator could make a public case using a standard approach, which can then be exceeded during operations by using a proprietary approach.

At the same time that the subsurface flood is being planned, the operator will be obtaining the needed surface rights (if necessary) and planning the surface infrastructure. If the project is supported by public funds, the surface activities may take on an additional regulatory burden. In the U.S. this takes the form of meeting the standards set by the National Environmental Policy Act [56]. Some other risk assessment and pubic assurance measures may be triggered by the mechanisms specific to the funding the CO_2 capture. In these cases, requirement for characterization of the near-surface beyond what is traditional for EOR will be added.

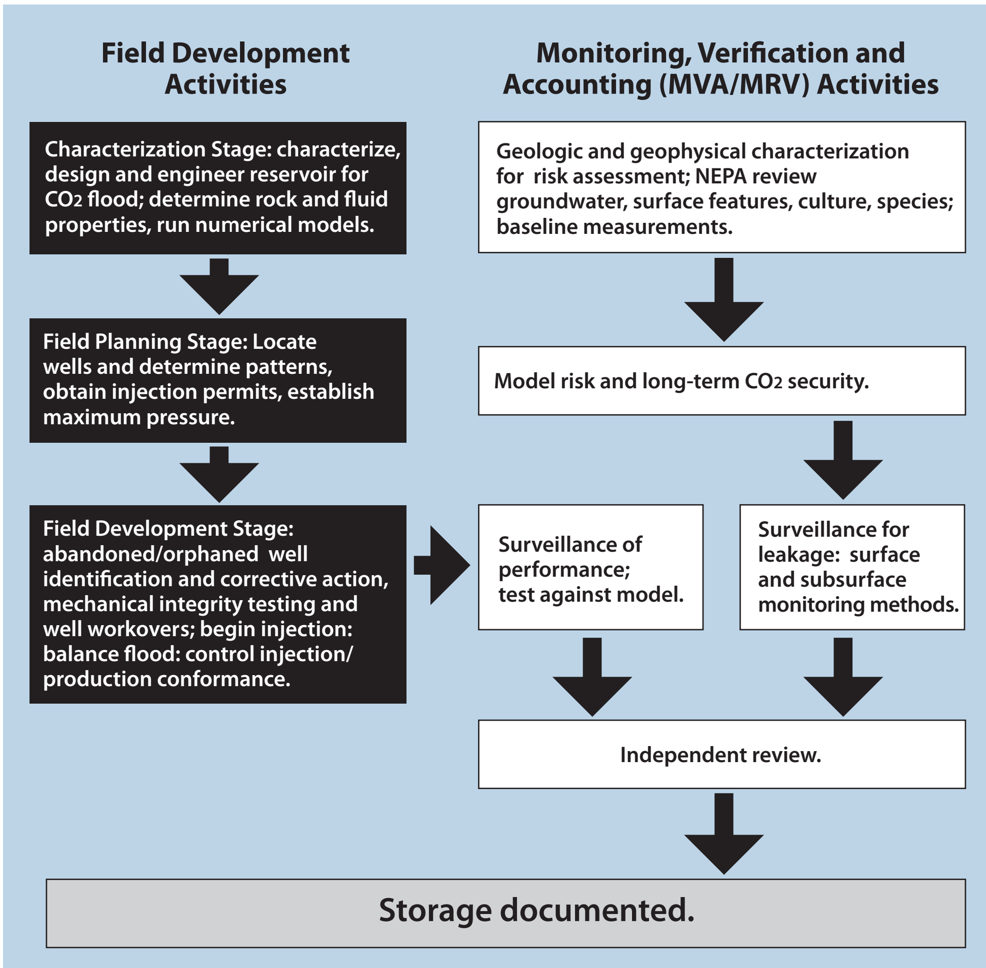

Figure 6. Field development activities provide the foundation for assuring injection is effective and safe; MVA activities are added to provide assurance of sequestration value.

During injection, data on performance of the CO_2-EOR flood will be much more abundant than an equivalent saline project. Production wells provide the operator with temporally (typically monthly) and spatially (typical well spacing 1 km or less) dense data on the reservoir response to flood. Surveillance via injection to withdrawal ratio, well head tubing and bottom hole pressure, and saturation logging with wireline tools are strong tools to assure that the reservoir is responding as planned. The variability in response in terms of rate and type of response from CO_2 EOR is valuable information that should be considered as a measure of uncertainty for saline project developers. Some discrepancies between modelled and observed reservoir response will always be present because of irreducible uncertainties in the characterization and modelling approximations of spatially varying reservoir data. In an EOR setting the active management provides ready opportunity to modify the flood to guide CO_2 in the intended parts of the reservoir, known as conformance. Additional surveillance tools, such as emplaced tracers or geophysical surveys for MVA purposes, may, at the same time, have the benefit of optimizing conformance and therefore maximizing oil yield.

Some information on well preparation is currently made public through existing permitting. However, to satisfy regulatory requirements of subpart RR and address public concern that may accompany EOR plus storage, supplemental data will be needed to demonstrate storage value. In particular, additional data will be needed to make long-term projections and subsequently verify that all wells can and do perform correctly and that the reservoir retains buoyant CO_2 long after the active injection period to assure CO_2 reductions are obtained. Additional research may be needed to develop methods and tools to achieve this goal efficiently and with adequate confidence.

Measuring vertical and areal conformance is also the core of assuring retention to gain storage value. However, the approaches used presently may not meet the standards set by the stakeholders in a capture project. Modification of the typical EOR tools may be used as needed to achieve the desired standards. For example, geophysics can be used to assure that CO_2 is not migrating to a spill point. Pressure and geochemical surveys can be deployed in units above, below, or adjacent to the injection area to assure that fluids are not migrating out of the project area in significant volumes. Soil and groundwater surveillance can be undertaken using much the same techniques as used for saline sites.

It is important to design the surveillance to work within the context of the field, which is intrinsically different than for a saline site. For example, seismic surveys may be of limited utility in areas where natural gas remains in the reservoir or overburden [57]. Similarly, biodegradation of natural or man-made hydrocarbon in near surface settings could be confused with or mask a leakage signal. Pressure and fluid chemistry perturbations may induce long-lived transients, rending some monitoring tools of limited use.

Adding operational surveillance to assure CO_2 retention requires thoughtful adaptation, especially to attain the desired standards showing long-term retention and permanence. However, when the techniques for assuring sequestration are added to field development and operational activities, a high standard of assurance is likely at low additional costs at a CO_2-EOR site compared to a saline storage-only site.

9. Conclusions

Enhanced oil recovery operations in the U.S. can accommodate and store substantial commercial volumes of CO_2 and provide attendant revenue streams to offset the costs of CO_2 capture from large industrial sources of CO_2. EOR provides several advantages over storage-only saline sequestration. EOR operations occur in brownfields with existing CO_2 infrastructure, known trapping, mass balance/pressure management, access to pore space, and likely public acceptance. In order to demonstrate long-term containment of CO_2volumes injected for EOR, operators will need to carefully address wellbore integrity in injection wells, and in nearby abandoned and orphaned wells, as well as ensure the mechanical integrity of the caprock and demonstrate stabilization of the CO_2 plume to include long-term containment after cessation of injection to ensure captured CO_2 does not pose a risk to USDWs or escape into the atmosphere. The recent recognition of residual oil zones, beneath the main pay zones of existing fields, and even in area where the main pay zone is absent, means that there is a potential for billions of tonnes of storage in addition to those provided by advanced CO_2 EOR. Storing CO_2 through EOR means that EOR fields opting into storage will need to develop and adopt monitoring verification and accounting methods. However MVA methods should be designed to complement the CO_2 surveillance and security that take place as a part of the existing field development and production operations. In most cases, the additional burden of MVA above and beyond field development and operations is likely to be comparatively low relative to saline storage-only sites.

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