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SITE CHARACTERIZATION AND SELECTION GUIDELINES FOR GEOLOGICAL CARBON SEQUESTRATION

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EXECUTIVE SUMMARY

Carbon capture and sequestration (CCS) is a key technology pathway to substantial reduction of greenhouse gas emissions for the state of California and the western region. Current estimates suggest that the sequestration resource of the state is large, and could safely and effectively accept all of the emissions from large CO_2 point sources for many decades and store them indefinitely. This process requires suitable sites to sequester large volumes of CO_2 for long periods of time. Site characterization is the first step in this process, and the state will ultimately face regulatory, legal, and technical questions as commercial CCS projects develop and commence operations.

The most important aspects of site characterizations are ***injectivity***, ***capacity***, and ***effectiveness***. A site can accept at a high rate a large volume of CO_2 and store it for a long time is likely to serve as a good site for geological carbon sequestration. At present, there are many conventional technologies and approaches that can be used to estimate, quantify, calculate, and assess the viability of a sequestration site. Any regulatory framework would need to rely on conventional, easily executed, repeatable methods to inform the site selection and permitting process.

The most important targets for long-term storage are deep saline formations and depleted oil and gas fields. The primary CO_2 storage mechanisms for these targets are well understood enough to plan operations and simulate injection and long-term fate of CO_2. There is also a strong understanding of potential geological and engineering hazards for CCS. These hazards are potential pathway to CO_2 leakage, which could conceivably result in negative consequences to health and the environmental. The risks of these effects are difficult to quantify; however, the hazards themselves are sufficiently well understood to identify, delineate, and manage those risks effectively. The primary hazard elements are wells and faults, but may include other concerns as well.

There is less clarity regarding the legal and regulatory issues around site characterization for large CCS injection volumes. In particular, it is not clear what would constitute due diligence for a potential selection and operation of a commercial site. This is complicated by a lack of clarity around permitting issues and subsurface ownership. However, there are many natural, industrial, regulatory, and legal analogs for these questions. However, solutions will need to evolve within the set of laws and practices current to the State.

The chief conclusion of this chapter is that there is enough knowledge today to characterize a site for geological carbon sequestration safely and effective permitting and operation. From this conclusion and others flow a set of recommendations that represent potential actions for decision makers.

INTRODUCTION

Carbon capture and storage (CCS) has emerged as a key technology pathway to substantial greenhouse gas reductions.[1] To achieve substantial reductions, it must be deployed commercially at large scale.[1,2] This will require many sites suitable for long-term injection and storage of large volumes of CO_2.[3] There are many available technologies and data sets that may be used for site selection and characterization. At present, however, there is no accepted set of practices to characterize a site for geological carbon storage (GCS). Within the US, there is no regulatory framework to define the minimum burden required of CO_2 storage operator in terms of pre-injection characterization, certification requirements, or abandonment.[3,4]

This chapter focuses on the critical needs and issues in characterization of potential geological sequestration sites. Site characterization is the first step to planning monitoring networks, locating potential injection projects, developing operational guidelines, seeking regulatory and public approval, and obtaining project financing.[5] It is also critical to the safe and effective long-term storage of carbon dioxide underground. As such, site characterization must play a central role in the commercialization and deployment of CCS technology

CURRENT UNDERSTANDING OF SEQUESTRATION RESOUCE

A number of geological reservoirs appear to have the potential to store many 100's – 1000's of Gt of CO_2.[4] The most promising reservoirs are porous and permeable rock bodies at depth.

- *Saline formations* contain brine in their pore volumes, commonly with salinities greater than 10,000 ppm.
- *Depleted oil and gas fields* have some combination of water and hydrocarbons in their pore volumes. In some cases, economic gains can be achieved through enhanced oil recovery or enhanced gas recovery. Substantial CO_2-enhanced oil recovery already occurs in the US with both natural and anthropogenic CO_2. These fields provide much of the knowledge base we have about the potential issues related to CO_2 sequestration.
- *Deep coal seams*, often called unmineable coal seams, are composed of organic minerals with brines and gases in their pore and fracture volumes that can preferentially adsorb and bind CO_2 as well as store it in pores and minor fractures. Due to the paucity of coal reserves in California, this reservoir class will not be considered in this document.

Because of their large storage potential and broad distribution, it is likely that most geological sequestration will occur in saline formations. However, initial projects have been proposed for depleted oil and gas fields, accompanying enhanced oil recovery, due to the high density and quality of subsurface data and the potential for economic return. Although there remains some economic potential for enhanced coal bed methane recovery much less is known about this style of sequestration.[4]

To achieve substantial reductions, it must be deployed at large scale.[1,2] This will require sites suitable for long-term injection and storage of large volumes of CO_2. These sites are a subset of a larger resource for sequestration of CO2.[3,6] Like other geological resources, these can be estimated through conventional geological analyses and approaches.[7,8,9,10] A number of national and global estimates have been published. Largely, these estimates are "top-down" estimates that do not analyze specific formations. It is important to understand that resources like storage capacity are not the same thing as proved or probable reserves, which can only be proved through exploration and detailed site characterization.

The Dept. of Energy recently published a Carbon Sequestration Atlas compiled by workers with the Regional Carbon Sequestration Partnerships.[11] At the time of publication, there was little individual formation analyses executed. However, ongoing work by the DOE, state geological surveys, The US

Geological Survey, and industrial actors continues to investigate individual formations in an effort to better understand the distribution of sequestration resource.

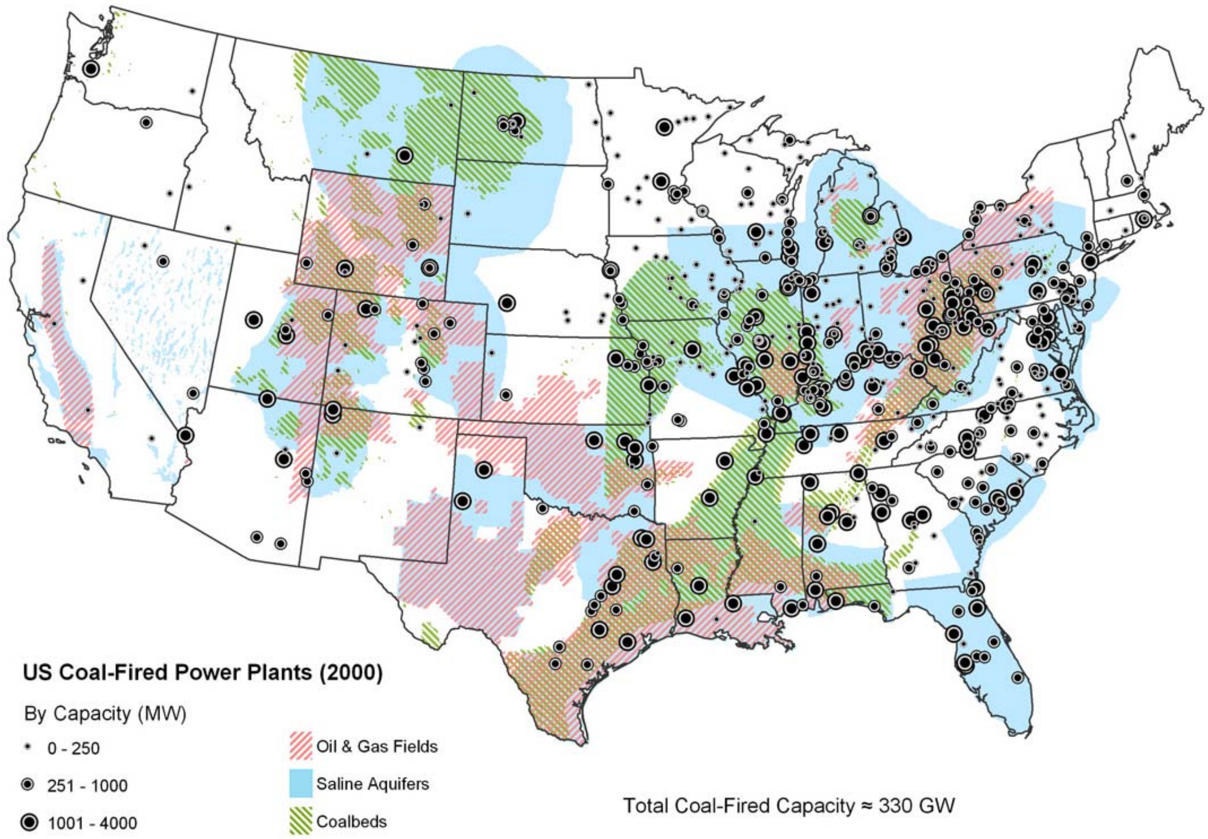

Figure 1: Preliminary map of coal-fired power plants and distribution of prospective sequestration resource distribution for the US. From MIT, 2007

At present, the sequestration resource is not well enough understood for two important tasks. The first is prospect ranking, which requires detailed maps of the resource for a region at the formation level. It also requires some understanding of potential risks to site effectiveness (see below). The second is for resource infrastructure development, chiefly pipeline networks, which also require detailed maps of storage potential. In order to help support commercialization of capture and sequestration plants in the state, the California Assembly should consider supporting more detailed and sustained GCS resource assessments. It is worth noting that the US Congress is currently considering bills that would authorize the US Geological Survey and the Dept. of Energy to begin detailed sequestration resource assessment nationally.

THE GOAL OF SITE CHARACTERIZATION

Siting viable geological storage projects requires substantial geological characterization. However, the detail, degree of quantification, and precision of characterization are limited by data and cost. In addition, perfect rendering of the subsurface is neither possible nor desirable. Rather, the degree of site characterization should reflect both the goals of the project stakeholders and the existing regulatory environment. Since these needs and goals will change as the project proceeds, this paper will discuss only the initial characterization, or that which might be needed for site permitting.

In this context, the goal of initial site characterization is NOT to ensure permanent CO_2 isolation. This may be a reasonable goal for the CO_2 injection project, but is not required in the initial steps for several reasons:

- The existing regulatory framework is not yet defined.[12]
- There is value in CO_2 storage even if its storage duration is less that 1000's of years.[13]
- The human health, safety, and environmental risks from CO_2 exposure require high concentrations;[14,15] slow or small leaks may not present substantial health, safety, or environmental risks.
- There are many viable strategies to detect leakage should it occur, and a suite of potential mitigation and remediation strategies.[4]

Instead, proper site characterization should serve the needs of all stakeholders in the project. As such, it must first and foremost select sites of low overall risk and high chance of success, short- and long-term. It must also provide a technical basis for decision making for secure storage, including financing & insurance. Finally, it must provide data for planning, including safe and successful operations, deployment of monitoring and verification (M&V) tools, and risk quantification and management. These goals may be readily met with existing tools and conventional data sets. It is also likely that our ability to select and operate a site effectively will improve through time, and that "learning by doing" will make it possible to store more CO_2 longer and more effectively.[16]

In considering a potential site, it is important to separate the goals of CO_2 storage site characterization (long-term separation of CO_2 from the atmosphere in safe underground locations) from that of nuclear waste storage. Ultimately, nuclear waste storage must isolate dynamic, highly lethal and carcinogenic materials from current and future human populations. The duration of isolation can be circumscribed by the half-lives of daughter products from radioactive decay. In addition, no nation has successfully disposed of high-level waste in a certified repository.[17] Carbon dioxide lacks these qualities. It is produced by human and all animal metabolisms. Also, the duration of necessary storage is not clear, since the goal is to serve as a bridging technology to a fully decarbonized energy infrastructure.[18] For these reasons, the term "effectiveness" as defined below is favored over the term "containment".

KEY TECHNICAL CONSIDERATIONS

To achieve substantial reductions, CCS must be deployed at large scale. This will require sites suitable for long-term injection and storage of large volumes of CO_2.[19] ***At present, however, there is no accepted set of practices to characterize a site for storage.*** Within the US, there is no regulatory framework to define the minimum burden required of CO_2 storage operator in terms of pre-injection characterization, certification requirements, or abandonment.[3,4] The guidelines here thus represent an attempt to provide a target for consideration rather than a consensus on approach. It is worth noting that several groups are working to produce this consensus and formal standards. These include the DOE's Fossil Energy program, largely through the Regional Partnerships program and collaboration with the EPA, as well as the International Energy Agency (IEA) and Carbon Sequestration Leadership Forum (CSLF).

Target formation attributes

To effectively sequester large volumes of CO2, three types of geological circumstances are required; targets, seals, and appropriate conditions. The first is a geological unit that can receive a large volume of CO2 quickly. These are called ***targets*** or reservoirs, and are the units into which a potential operator would inject CO2 volumes from a surface point source. These units must be porous and permeable, and have both high injectivity and capacity. These terms are described below in detail. Typically target formations are deep sandstones, conglomerates, limestones, or dolostones. Under the right circumstances, other kinds of formations might serve, such as deep coal seams, basalts, and evacuated salt caverns. These are not discussed in this chapter.

Second, a geological ***seal*** is required. Under all relevant crustal conditions, CO2 will be buoyant in the crust and gravitational (buoyant) forces will drive CO_2 upward from the injection point to the formation cap rock. A seal, also called a cap-rock, is an impermeable unit that can impede buoyant flow effectively, usually because it is very fine grained and as such has extremely small pore throats.[20,21] For a seal to be effective, it must be sufficiently continuous, laterally extensive, and thick to counter the total buoyant forces of a CO_2 accumulation at depth over the injection area. Marine and lacustrine shales and thick deposits of evaporites (e.g., gypsum, salts) are common cap-rocks.

Finally, a set of geological conditions must be met to ensure both effective use of the sequestration resource and the site safety and integrity.[4] The most important of these is that CO_2 must be a supercritical phase at depth. In a supercritical state, CO_2 is a dense, liquid-like fluid. Storage of large CO_2 volumes in geological formations requires that the CO_2 be relatively dense, so that storage capacity is efficiently used. Given typical geothermal gradients and hydrostatic loads, CO_2 is likely to be in a supercritical state at most target sites at depths greater than 800 m. At the likely range of injection pressures and temperatures, CO_2 density would range from 0.6 to 0.8 g/cm^3 and its viscosity will be less than most oils (~ a factor of 10).[22,23]

It should be noted that in some places, the geothermal gradient may be elevated or the water table far below the surface. In such cases, it is likely that injection must proceed at depths greater than 800 m. Similarly, it is not believed that injection will be allowed into fresh water bearing units. In parts of the US, some deep formation waters are fresh and as such may not accept CO_2. A commonly accepted cut-off for minimum formation salinity is 10,000 ppm total dissolved solids (TDS).

Storage Mechanisms

Finally, there needs to be some additional element of trapping. Since supercritical CO_2 is buoyant, it will seek the surface, some combination or forces are required to effectively immobilize the CO_2. These are called storage mechanisms. For a site to be considered viable, the sum of likely storage mechanisms must be sufficient to trap the CO_2 in the target over long time scales.

For saline formations and depleted oil and gas fields, expected CO_2 storage mechanisms are reasonably well defined and understood.[4,23] CO_2 sequestration targets will require *physical barriers* to CO_2 migration out of the crust to the surface. These barriers will commonly take the form of impermeable layers (e.g., shales, evaporites) overlying the sequestration target, although CO_2 may also be trapping dynamically by regional aquifer down-flow. This storage mechanism is highly or directly analogous to that of hydrocarbon trapping, natural gas storage, and natural CO_2 accumulations. Storage through physical trapping allows for very high fractions of CO_2 within pore volumes (80% or greater), and act immediately to limit vertical CO_2 migration. Physical trapping can be compromised or minimized by either a breach of the physical barrier (e.g., permeable fractures) or far-field migration away from an area lacking closure.

At the pore scale, *capillary forces* can immobilize a substantial fraction of a dispersed CO_2 bubble, commonly measured to be between 5 and 25% of the CO_2-bearing pore volume. The volume of CO_2 trapped as a residual phase is highly sensitive to pore geometry, and consequently is difficult to predict; however, standard techniques can measure residual phase trapping directly. This mechanism acts immediately and is sustained over long time scales and CO_2 trapped this way may be considered permanently trapped.

Once in the pore volume, the CO_2 will *dissolve* into other pore fluids, including hydrocarbon species (oil and gas) or brines. Depending on the fluid composition and reservoir condition, this may occur rapidly (seconds to minutes) or over a period of tens to hundreds of years. The volume of CO_2 that may be dissolved into brines commonly ranges from 1-4% of the pore volume – this mechanism and these ranges served as the basis for many of the earliest estimates of geological storage capacity potential.[24] Once dissolved, the CO_2–bearing brines are denser than the original brines, leading again to effectively permanent storage.

Over longer time scales (hundreds to thousands of years) the dissolved CO_2 may react with minerals in the rock volume to *dissolve or precipitate* new carbonate minerals. For the majority of the rock volume and major minerals, this process is slow, and may take hundreds to thousands of years to achieve substantial storage volumes.**Error! Bookmark not defined.** Precipitation of carbonate minerals permanently binds CO_2 in the subsurface; dissolution of minerals generally neutralizes carbonic acid species and increases local pH, buffering the solutions and trapping CO_2 as an ionic species (usually bicarbonate) in the pore volume. In both cases, the CO_2 is stored permanently and would require active intervention to bring to surface.

Although substantial work remains to characterize and quantify these mechanisms, the current level of understanding can be used today to develop estimates of the percentage of CO_2 that can be stored over some period of time. Confidence in these estimates is bolstered by studies of hydrocarbon systems, natural gas storage operations, hazardous waste injection, and CO_2-enhanced oil recovery. In the case of enhanced oil recovery, CO_2 has been injected underground for over 30 years. Although there are examples of CO_2 well-bore blowouts[25,26], there appear to be no cases of catastrophic or long-term leakage. Finally, the range of length and time scales on which trapping mechanisms act suggests that over time the system may become more effective at sequestering CO_2.

Site hazards, geological and engineered

The earth's crust is complex, heterogeneous media. Although the section above describes how the crust is well configured to store CO_2 for long periods, there are features, events, and processes that could potential lead to unintended CO_2 release from GCS sites. These features, events, and processes represent hazards that could compromise site storage integrity.[27] They form two categories: geological hazards that are naturally occurring, and engineered hazards that are man-made. This section focuses on the set of hazards of most immediate concern to GCS operations siting.

Wells

It is widely believed that wells represent the largest hazard to GCS. This is largely because deep well penetrations compromise the storage mechanisms of the earth's crust in order to bring fluids (oil, water, gas) to the surface rapidly. In order to maintain operational integrity, these wells are cased and cemented and, ultimately, plugged and abandoned.[28] Despite the long, successful history of well engineering, there are many potential failure mechanisms that could potentially allow CO_2 to escape from deep reservoirs.[29,30] Many conditions control the likelihood of well effectiveness, including the age and plugging mechanism, quality of completion, and post-closure history.[31]

In the context of site characterization, there are several approaches which can be employed to understand these hazards and mitigate potential risks. There have been several attempts to generate statistical and physical methods to quantify the risks well hazards present.[32]. Such methods can be used as a crude screening tool on a regional basis, and can be dramatically improved through careful review of public drilling and completion records. In addition, conventional geophysical tools can detect casing from wells, including buried, lost, and mislocated wells.[33] These surveys have increased in popularity due to their relatively low cost and utility. Finally, it is possible to monitor wells directly through regular surveys to detect leakage. In the event that leaks are detected, conventional approaches[34] can be used to re-complete and plug abandoned wells (see the chapter in this document on mitigation methods).

Cap Rock Integrity

All geological storage sites of interest require the presence of an effective top seal or cap-rock. There are many conventional approaches to assess potential cap-rock integrity. To begin, if that unit already traps hydrocarbons at depth, especially natural gas, then it is highly likely that it will also trap CO_2.[35] For example, the Kreyenhagen shale and shales of the Temblor Formation hold large accumulations of oil and gas over the San Joaquin basin, and as such should hold large CO_2 volumes as well. Thickness of a sealing unit can be assessed with conventional well-logging tools and techniques, and stratigraphic mapping and analysis can be used to assess likely later continuity. In addition, capillary entry pressure measurements on core samples can quantify the amount of buoyant force a cap-rock lithology can maintain before failure.[Error! Bookmark not defined.,36]

Finally, it has been suggested that some cap-rocks are inherently well suited for CO_2 storage due to their geochemistry. Such rocks appear to react to CO_2 so as to swell and close pore throats, thereby reducing porosity and transmissivity. This behavior has been observed in natural systems[37] and reproduced in simulations.[38] In considering potential sites for GCS, it may be advantageous to assess the mineralogy of target cap-rocks to understand the auto-sealing potential.

Transmissive faults

Faults may either serve as barriers or conduits to flow.[Error! Bookmark not defined.] Under the right circumstances, faults can provide transmissive or permeable pathways for fluids, and in some circumstances bring those fluids to the surface. This has been repeatedly seen in ancient and modern fault systems,[39] which serve as a locus for hydrocarbon seeps,[40] hot springs,[41] and cold springs. In some modern and ancient systems, CO_2 migrates along or very close to fault systems. These include the ancient Moab fault,[42] the modern Crystal geyser fault system,[43] and natural CO2 seeps at Latera, Italy near Rome.[44]

It is worth noting that faults only represent a substantial hazard if they can transmit large volumes of CO_2 at a high rate. Many of the modern and ancient fault systems are known to have very low flux rates for CO_2 and other gases. These include the site of the Oracle at Delphi,[45] the Crystal Geyser fault network,[46] and the Rome example.[44] There are no documented examples of catastrophic release of gases outside volcanic systems. In volcanic networks, gases such as steam and CO_2 combine with heat to rapidly expand causing eruptions.[47] Because it is important to avoid this response, it is not likely that sites of volcanism or high geothermal activity will be selected for CO_2 sequestration.

Induced seismicity

It has been known for roughly 40 years that, under some circumstances, injection of large fluid volumes can generate earthquakes. In most cases, these earthquakes will be quite small, but under the wrong circumstances may be quite large. The most spectacular example comes from the Rocky Mountain Arsenal. In that case, injection of large volumes of hazardous water produced earthquakes as large as magnitude 5.3.[48,49] It is important to note that at that site, the target rocks were completely impermeable, and as such sustained very large pressure build-ups. This is not likely to be true for most CO_2 injection sites.

One important case of induced earthquakes involves the Rangely oil field in northwestern Colorado.[50] This site was the target of a series of experiments led by Stanford University to generate earthquakes in the hope of preventing large events. Between 1969 and 1972, the researchers injected very large volumes of water into a fault in order to make earthquakes.[51] The fault was selected because it was thought to be close to failure. After several series of injections, the team was able to generate seismic events. However, the largest of these events was M3.1, which could barely be felt at the surface. The overwhelming majority of the earthquakes were less than M1 and too small to feel at the surface. After these experiments, the Rangely field became a site of active CO_2 injection. After 20 years of injection and nearly 50 million tons, there has been no detectable leakage at the surface.[52]

Injection Scale

A central concern of site characterization work is injection scale. In short, most commercial projects are highly likely to inject very large volumes of CO2 for a long time. Consider the volumes and rates needed for a reference plant, in this case a 800 MW natural-gas combined-cycle power plant (NGCC) with an

85% capacity factor and 90% capture injecting CO_2 for 60 years. Such a plant would produce over 2.5 million tons of CO_2/year, requiring the following parameters at a site of interest

- The ability to accept injection of ~30,000 – 50,000 reservoir barrels/day CO_2
- The ability to accept ~0.7 – 1.1 billion reservoir barrels (80 M tons) over 60 years plant operation
- Very high chance of effective storage well beyond those 50 years.

Another way to say this is that the reference plant, which is a large, gas-fired, highly efficient power plant would create a giant CO_2 field beneath it. This volume is similar to that emitted by a large cement plant or two large refineries today. For these reasons, injection scale must be central to considerations of plant siting, permitting, and regulation.

The potential consequences of failure at a site of this magnitude are likely to be small and readily managed. This point is discussed in depth in a later chapter on risk.

DEFINITIONS AND RELEVANT DATA

While many possible goals and terms may be pursued in site characterization, it is difficult to image the success of a large-scale injection project without knowledge of three parameters. These are *injectivity*, *capacity*, and *effectiveness*, or **ICE**. The following brief definitions serve as the basis of discussion:

- *Injectivity* is the rate at which CO_2 injection may be sustained over fairly long intervals of time (months to years).
- *Capacity* is the total volume of potential CO_2 storage CO_2 at a site or in a formation
- *Effectiveness* is the ability of the formation to store the injected CO_2 well beyond the lifetime of the project.

The simple definitions above in the introduction provide limited insight. An expanded explanation of these definitions below helps to point to the data needed to provide insight into necessary site characteristics. These definitions are provided in the context of the 800 MW natural-gas combined-cycle power plant described above. Basic data sets and analysis will constrain the site characteristics to determine if a project is feasible at scale. Table 1 outlines key information, data, and analyses needed to underlie **ICE** determination.

Injectivity

Injectivity, which is an effective rate term, may be described in various units (e.g., m^3/day/Pascal/m; barrels/day/psi/ft). This reveals some of the data required, including effective thickness (rock thickness, net:gross) over the injection footprint, local permeability, bulk connectivity, and down-hole pressure. Much of this data exists for oil and gas fields, but would be limited for other targets. However, conventional wells, geophysical surveys, and core analysis would be able to provide reasonable constraints for a project. Crucially, the injectivity depends on the length of the injection well; thus, injectivity may be increased through drilling long-reach horizontal wells or increasing well count. It may also be stimulated through hydrofracturing of rock, although the permitting will vary from state to state. For California, hydrofracturing a new or existing well requires a permit through the Division of Oil, Gas, and Geothermal Resources.

The amount of data needed to constrain injectivity may vary by site, but it is highly unlikely that one well and a limited geological or geophysical survey could alone provide enough data to reduce the necessary risk. In many commercial applications, the degree of connectivity is not well understood for many years. Since it is not considered practical to require years of study before siting a project, empirical and theoretical approaches will be needed to provide additional information, and multiple scenarios should be considered. In many cases, including those most relevant to California, injectivity data from neighboring oil, gas, and water wells plus information from analogous reservoirs can provide this information.

Capacity

The same will be likely of capacity estimation, which will be measured in units of volume (scf, barrels). The most important parameter to constrain is the pore volume. Again, this requires information on effective formation thickness and porosity; however, this is a bulk term and is not directly dependent on pore geometry or rate terms. This information may be constrained with conventional well data and geological and geophysical surveys. In some cases, 3D seismic surveys may be combined with well data to estimate the formation porosity directly.[53,54] Ultimately, it is likely that some sort of hydrodynamic simulation will be needed to estimate capacity well.

A second key parameter is the ***utilization factor***, or the effective pore volume. This is the fraction of the pore volume that would actually contact injected CO_2. Utilization factor is a function of the reservoir heterogeneity at all scales, ranging from pore-throat diameters to kilometer-scale connectivity, unit architecture, and residual phase trapping (hysteresis).[55,56] The utilization factor is also a function of the development strategy and well planning, such that capacity can be increased by more wells or better well design. Utilization factors vary from site to site, but commonly range from 5-50% of the pore volume.

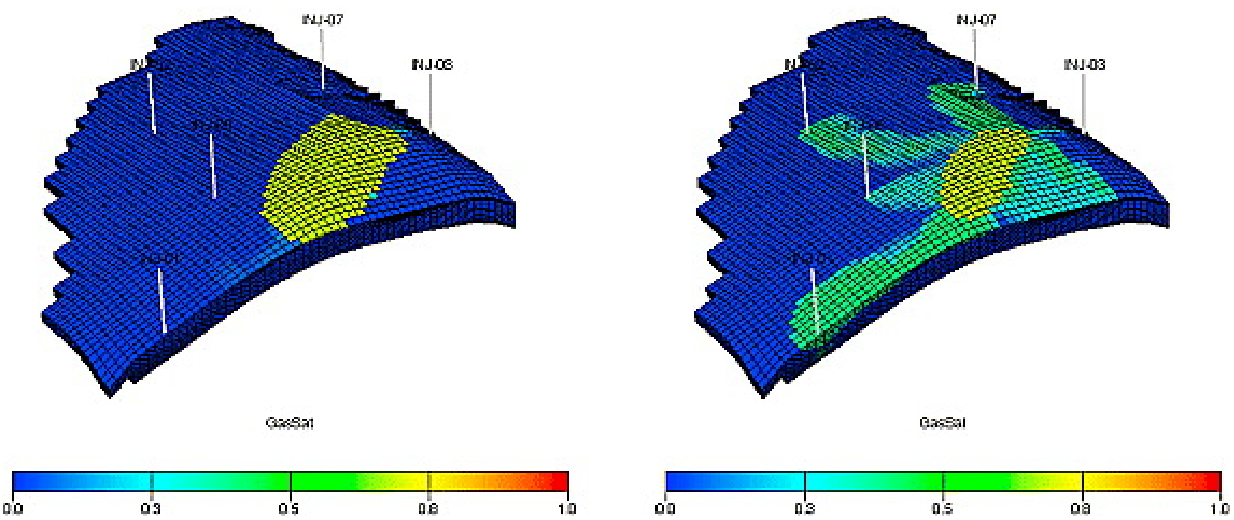

Figure 2. Impact of residual phase trapping on CO_2 storage volume and distribution. Colors show CO_2 saturation distributions after 500 years from the beginning of CO_2 injection, computed on the refined grid. (left) Results from case 1; no hysteresis. (right) Results from case 2 ; with hysteresis. After Juanes et al., 2006[Error! Bookmark not defined.]

Importantly, estimates of capacity require assumptions of the storage mechanism. Capacity assessments for saline aquifers sometime assume or calculate a dissolved fraction of 3-6%.[57] In the case of a structural or stratigraphic closure, a substantial fraction of the pore volume might be filled with CO_2 as a pure phase. Moreover, CO_2 buoyancy may make it difficult to store CO_2 in a substantial fraction of the available pore space. While some data (thickness, porosity) are relatively easy to characterize with conventional tools, the effective volume is often difficult to predict because the effective rock volume depends on questions of reservoir heterogeneity. Finally, it may be extremely difficult to predict the amount of residual phase trapping (capillary trapping) without extensive sampling and analysis.[58]

Site characterizations should define the volume that would be stored as a dissolved phase, as a trapped residual phase, or as a trapped contiguous, buoyant phase (these terms will also affect effectiveness). Statements of these assumptions would allow for easy updating of initial capacity estimates once new data or science becomes available. In practical terms, analog and empirical data sets should be considered in quantification of a defense of initial capacity estimates.

Effectiveness

Effectiveness is the trickiest term to define. Ultimately, characterizations of effectiveness must rely on estimates of geomechanical, hydrodynamic, and seal integrity for the rock system, fault system, and well system.[4,35] In all cases, at least one continuous cap rock (sealing unit) will be required for effectiveness. The more sealing units present, the greater their thickness and extent, and the better engineered the wells, the more likely the effectiveness for the storage site is likely to be. This consideration is part of the selection criteria for the FutureGen project site request for proposals, soon to be announced.

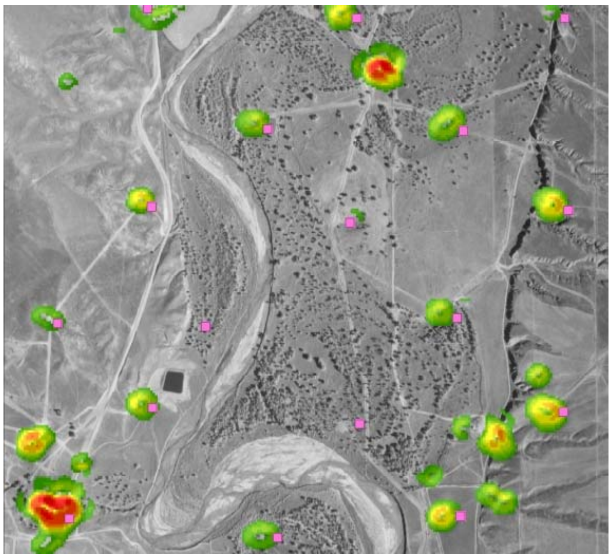

Figure 3. Helicopter magnetic data from study area plotted as color-scale, hill-shaded images. Wells (warm-colored dimples) can be identified by their distinctive monopole signature. From Veloski and Hammack[33]

Conventional data sets and analyses can and do underlie current characterizations of effectiveness. Some of these include depth-structure maps, well-log correlations, well completion records, 2D and 3D seismic volumes, and fault maps. Many of these data sources are ***interpretations*** and contain various degrees of certainty. As such, precise quantitative estimates may be difficult or impossible to provide. That precision, however, is not necessary to accurately characterize site effectiveness. For example, some aspects of effectiveness characterization (e.g. continuity and thickness of cap-rock, presence of multiple seals, structural closure) may be easily defined with limited data and analysis. Other aspects (e.g., Mohr failure criteria, capillary entry pressure) are straightforward but require basic analysis.[59] Some aspects are fairly straightforward but require a degree of geological sophistication (e.g., fault reactivation potential, fault-seal analysis, in-situ stress tensor characterization).[60,61,62] Some terms are extremely difficult to define (e.g., well behavior in 50-100 years) and cannot be unambiguously circumscribed in any reasonable operational context. However, relevant data sets can provide a technical basis for assessing the likely degree of efficacy and safety, and relevant procedures (e.g., aeromagnetic surveys)[33] could serve as a component of due diligence in relation to unexpected and difficult to define phenomena.

Again, relevant analogs and empirical characterization can be used to help determine effectiveness as appropriate until standard measures and best practices are broadly accepted. For example, if a regionally extensive shale unit is an effective regional hydrocarbon seal, that information should positively affect the determination of CO_2 storage effectiveness; if the hydrocarbon is natural gas, the likely effectiveness of the seal is greater.[Error! Bookmark not defined.,35] In some cases, this kind of data and analysis can provide the most important and most accurate information available to characterize likely site effectiveness.

Table 1: Information and data sources for ICE characterization of storage sites

Key term	Key information	Basic data sources	Basic analysis	Advanced analysis
Injectivity	Effective thickness and permeability, production/flow rate, delivery rate connectivity	Conventional core analysis, well-logs, production history, stem or leak-off tests, pressure	Stratigraphic analysis, population of static geological models, core plug analysis, conventional simulation, well pump tests/stem tests	Detailed stratigraphic characterization, hydro-fracture analysis, special core analysis
Capacity	Effective thickness, accessible pore-	Conventional core analysis, well-logs,	Stratigraphic analysis, structural analysis, static	Advanced simulation, fill-spill

	volume, area of injection, trapping mechanism constraint	reserves, structure maps, 3D seismic volumes	geomodels construction, simple calculation, conventional simulation, 3D seismic mapping	analysis, special core analysis
Effectiveness	Presence, number, continuity, thickness, and character of seal; fault azimuth and offset; basic failure criteria; surface and formation well density; well completion history	Cores, well-logs, structure maps, in-situ stress, well location maps, well completion records, 3D seismic volumes	Stratigraphic analysis, structural analysis, static geomodels construction, simple calculation, Mohr-Coulomb failure calculation, conventional simulation, special core analysis, well completion history, well location verification	Aeromagnetic surveys, capillary entry pressure tests, fault segmentation analysis, advanced simulation, well logging-through casing (e.g., cement bonding logs)

Basic ICE data integration and analysis

In reviewing the three terms of an **ICE** framework for detailed site characterization, a few points stand out:

- *In general, conventional data appear sufficient*. Absent a specific need, advanced tools or special measurements should not be required. Rather, well-log data, conventional core analysis, and basic geological maps are the primary data needs. This suggests that injectivity, capacity, and effectiveness can be defined and defended in many contexts. Several commercial projects nationwide and world-wide proceed on this basis.
- *There are some common work requirements*: For all terms, a basic static geological model based on stratigraphic and structural analysis is of basic value. The same is true for conventional multi-phase flow simulation. This may be information a regulator or financier may request to see.
- *Determinations should strive for accuracy rather than precision*. This point derives from the goals of initial characterization, which focus on determining whether a site appears suitable. Often, highly prospective sites lack data sufficient to make precise estimates of key parameters. However, there is often enough data to accurately assess site performance. As a development proceeds, more data will become available to provide both greater precision and accuracy.
- *The amount of data needed will vary on a case basis*. The density of data, the depth of prior operational knowledge, the number of wells likely to intersect the plume, and the local geology will all play a role in ICE determination. Operators, regulators, and stakeholders need to understand this basic condition and consider regulatory frameworks flexible enough to encompass many different geological settings and data sets.
- *Analog data is of value*. In many cases, certain kinds of data or data density may be absent. Where appropriate, analog information can serve to improve or condition injectivity, capacity, or effectiveness information. However, if local data is severely limited or if little is known about a particular province or play, new information is likely to be required.

POTENTIAL RISKS AND HAZARDS

Any viable site for storing CO_2 will consider some number of local hazards. If appropriately characterized and managed, the hazards for most sites will not present a substantial risk to the project operations or to the safety, health, environmental, or commercial concerns of local stakeholders. However, in order to avoid hazards and reduce potential risks, a set of concerns should be considered early in the process. Understanding of these hazards may also affect monitoring strategies for a given site.

Key site hazards

Several of the most important hazard elements have been discussed earlier in this chapter. These include wells, transmissive faults, cap-rock integrity, and induced seismicity. In considering these hazard elements, it is important to also consider the potential consequences of hazard failure, which will result in some leakage. In most cases, the likely fluxes associated with this leakage are small and the potential impacts limited. Nonetheless, it may also be that specific conditions at a site elevate the potential concern that a hazard may represent. Even in cases where it is not possible to quantify robustly the probability, consequences, or risks associated with hazard element failure, site characterization may be able to identify, address, and enable mitigation of CO_2 leakage impacts.[12]

Groundwater

The U.S. EPA's Underground Injection Control (UIC) regulations concentrate on the protection of public sources of drinking water. Potential risks to groundwater quality arise from CO_2's buoyancy, its potential to mobilize organic or inorganic compounds in aquifers, and its potential to displace subsurface fluids on a regional scale. While geological sequestration targets would be selected precisely because they are not potential drinking water sources, the risks of CO_2 migrating away from the injection zone into a potable aquifer needs to be assessed as part of site characterization. While upward migration into underground sources of drinking water is not allowed under UIC regulations, recent documented leakage in Florida's municipal wastewater injection wells has forced program modifications to allow for subsurface migration, specifically for Florida municipal injection wells and assuming that such migrations do not harm underground sources of drinking water.[63] This experience suggests that risks of migration should be considered under future regulatory regimes governing geologic sequestration.

Scientific studies bounding the potential harm to groundwater resources from CO_2 leakage would provide better constraints on the overall relevance of this risk. For example, if a site has high natural occurrences of toxic metals (e.g., arsenic) or high volatile organic carbon content due to prior use, it may be prudent for site assessors to analyze the site hydrology and geochemistry to understand potential health effects for a given CO_2 leakage rate and concentration.[12]

Atmospheric Release

Much attention and concern is focused on the health, safety, and environmental consequences of atmospheric CO_2 release, although several analyses and case histories suggest that such events are extremely unlikely to have negative consequences. This is because atmospheric mixing prevents high atmospheric CO_2 concentrations even in cases of large CO_2 volume and flux.[64] The only circumstances likely to produce high rates of CO_2 release and thus high concentrations are from uncontrolled venting from abandoned or orphaned wells.[31] Even those cases are not expected to result in substantial harm.[12]

In considering the potential hazards at a site, one can consider bounding analyses from existing cases of CO_2 well failure.[25,65] These can serve as the basis for scenarios to understand potential impact of site release. This approach was used by Bogen et al.,[64] who used a CO_2 settling model and high-resolution digital elevation model to generate maps reflecting zones of elevated risk for atmospheric release hazards. These maps can help potential operators plan monitoring schemes, aeromagnetic or shallow geophysical surveys, or mitigation plans for a site.

Active and ancient faults

Abundant current and prior tectonic activity in California has produced an abundance of natural fault networks. Some of these systems are active and generate small and large earthquakes today. Others are inactive, and in some cases have not slipped or deformed in many millions of years. Because of

California's geology, industry, regulators, media, and the public are aware of faults and recognize that a they can be a source of geological risk.

In the context of CO_2 sequestration, the presence of faults is neither good nor bad. Some faults are conduits for rapid fluid migration – others seal and prevent fluid migration.[66] In considering the role of faults at a potential site a few important points should be made:

The presence of seismically active faults does NOT exclude a site from either holding CO2 or being considered for storage. There are many places in the world where large volumes of buoyant fluids (e.g., oil, gas, and CO_2) are trapped indefinitely in the presence of seismic activity, including California, Wyoming, Alaska, Turkey, Western Australia, Papua New Guinea, Indonesia, and Iran.

Similarly, it is well established that earthquakes, even large earthquakes, do not release the buoyant fluids from their traps. For example, the large earthquakes in California over the last two centuries, including the 1906 and 1858 great earthquakes, did not compromise the effectiveness of oil and gas traps in the State. These events did not create new hydrocarbon seeps to the surface.

Many aspects of a fault affect its ability to trap CO_2 at a site. These include the geometry of the fault, its complexity, the orientation of the fault relative to regional stresses, the amount and distribution of fault gouge, and the occurrence of zone of either elevated or reduced pressure nearby.[67] In some cases, it is relatively straightforward to obtain key pieces of information that can be used to understand the potential risks presented by a fault or network of faults (Figure 4).

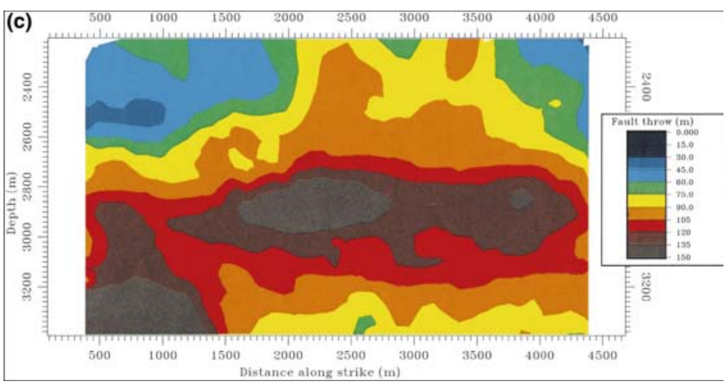

Figure 4. Map of displacement along a fault plan (m). The warm colors show where there is more displacement. This information is important to understanding fault leakage potential. From Yielding et al.[67]

Recently, Chiaramonte et al.[68] gathered this information to estimate the potential for faults within one oil field to fail and leak CO_2. In their calculation, one fault had a very low chance of failure, and would require injections well above reasonable operational pressures to induce failure. In contrast, another fault network in a different part of the field was very close to failure, and even a small injection could potential cause failure. If this were an operation site, the southern part of the field would be a good zone of storage, while the northern part would not. This example highlights the need for careful site characterization in selection and the importance of high quality data.

Injection of CO_2 near a fault will not automatically trigger a large earthquake. As discussed above, the case of Rangely demonstrates that large CO_2 injections do not necessarily induce large earthquakes.[51] Similarly, the history of water-flooding and brine injection in California oil fields also demonstrate that large volumes of fluid may be injected next to large faults without causing failure. However, those examples also highlight the importance of careful site characterization and operation.

In summary, the presence of large, active faults in California should in no way rule out prospective sites from storage. Rather, the complex nature of faults in and associated with potential injection sites must be characterized, considered, and managed carefully to avoid both CO_2 leakage and large seismic events.

Site risk screening

The list of potential earth and atmospheric hazards that present substantial risk to CCS operations is ultimately short. Each fundamental hazard—atmospheric release, groundwater contamination, and crustal deformation—is associated with a characteristic set of potential injection-triggered processes (risk elements) that may alone or in combination result in hazard realization. Table 2 summarizes these hazards and their risk elements.

Table2: CCS-Related Earth & Atmospheric Hazards & Component Risk Elements

Atmospheric release hazards	**Groundwater degradation hazard**	**Crustal deformation hazards**
Well leakage	Well leakage	Well failure
Fault leakage	Fault leakage	Fault slip/leakage
Cap-rock leakage	Cap-rock leakage	Cap-rock failure
Pipeline/ops leakage		
		Induced seismicity
		Subsidence/tilt

For each hazard class, the prioritization hierarchy assigned to developing protocols for underlying risk elements reflects *a priori* perception of relative importance, which has a significant component of site dependency. For example, a hypothetical CCS project in the Los Angeles basin would have different hazard priorities compared to cases in the Illinois basin or coastal Gulf of Mexico.[27]

Several components of risk cut across the different hazard classes, most notably wells, faults, and cap-rocks. There are also components unique to a given hazard class, such as induced seismicity. In some cases, the technical information needed to constrain one risk element can be applied to different hazards (e.g., in-situ stress state; completion history of wells). This kind of relationship will determine the nature of a best-practice recommendation and lead to formal protocols to quantify and potentially mitigate risk.

KEY NON-TECHNICALCONSIDERATIONS

Technical guidelines can help to advise both technical and no-technical considerations. This is particularly important in CCS, where many regulatory and legal questions have yet to be resolved and non-technical concerns involve property rights, environmental justice, and indemnification.[12,69] Careful site characterization can help advise many of these issues. However, given the uncertainties and sensitivities around key non-technical issues, it is premature to provide even draft guidelines. This section hopes to present some schools of thought around these issues and how they might be resolved at state or Federal level.

Subsurface ownership

In the case of sequestration into depleted oil and gas fields, ownership issues are clear. Specifically, the owner of the mineral rights for the unit of interest should have ownership of CO2 injection and storage rights. That clarity is absent in the case of saline formations. Currently, there are three fairly straightforward approaches to access and ownership for CO2 disposal into saline formations.

- The owner of the surface rights owns injection rights

- The injection rights are just like any other mineral right and can be purchased or leased accordingly, or condemned and captured by eminent domain.
- The water or hydrocarbon in the pores are owned by individual owners, but the pores are owned by the state and may be used and accessed for the public good.

In California, there appears to be precedent that water storage in depleted aquifer space is a valid exertion of a water district's police power to generally provide for the public.[70] The Interstate Oil and Gas Compact Commission has set out their own guidelines on the topic[71] and are planning another release in Sept. 2007.

Australia has taken the most substantial framework to date forward.[72] A draft set of regulatory principles for CO_2 'geo-sequestration' have been published by the Commonwealth government, whilst the Government of Western Australia has specifically created new regulations (in the Barrow Island Act, 2003) to accommodate proposed CCS operations (in the 'Gorgon' project). However, key legal and permitting issues arise in the case of multiple subsurface use, particularly where permits for different activities overlap (e.g. storing CO_2 versus hydrocarbon exploration). As such, clearly defined ownership and operational delimitation is required, and at present no jurisdiction currently provides legal clarity or precedence in this area. To help this point, the Australian Commonwealth government has prepared draft regulations that include consideration of this issue which will amend existing oil and gas regulations.

New Mexico's Governor signed Executive Order 2006-69 to "explore requirements needed to … geologically sequester significant amounts of anthropogenic carbon dioxide in the state, including but not limited to geologic surveys, infrastructure, and ownership of liabilities.[69] The three basic approaches above are discussed without a specific recommendation. Similar framing discussions are under consideration in California following the passage of AB1925, which request "recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide." Colorado and Montana are considering taking up the topic.

Ultimately, it is not clear how these issues will resolve themselves on a state-by-state or on a federal basis. In the short term, operators are served in all contexts by working in states with favorable treatment of the subject and around sites with small numbers of surface owners (e.g., large ranches, state land).

Pipeline routing and access

It is expected that for most CCS projects there will be a need to transport Co2 from the capture facility to the injection point. This distance may be short (10's of meters) but is likely to be 10's or even 100's of kilometers. For these projects, pipelines will provide CO_2 transport from source to sink. This technology is ultimately well developed and commercial, requiring little technical development. In addition, the regulatory framework for CO2 pipelines is well established and falls under the Dept. of Transportation within the US, covering such concerns as monitoring requirements, rupture management, and seismic hazard planning and engineering. However, because the routing is often contentious and may run through populated or sensitive areas, pipelines are a focal point for operational concern.

To help address potential public concerns and permit the pipeline, some characterization of potential risk and harm to the public or environment is needed. There are many simulators and approaches o this problem, which are regularly used by the differing agencies. The EPA has a list of simulators used to understand exposure hazards.(REF) These were named in the guidelines for environmental impact assessment for the FutureGen solicitation (REF) Lawrence Livermore National Laboratory operates the National Atmospheric Release Advisory Center (NARAC), a continuous operational facility that predicts dispersion of materials released into the atmosphere (REF). These tools can help predict the potential impact of CO2 releases from point sources (Figure 5),[64] providing information to potential regulators and stakeholders regarding concerns of pipeline siting.

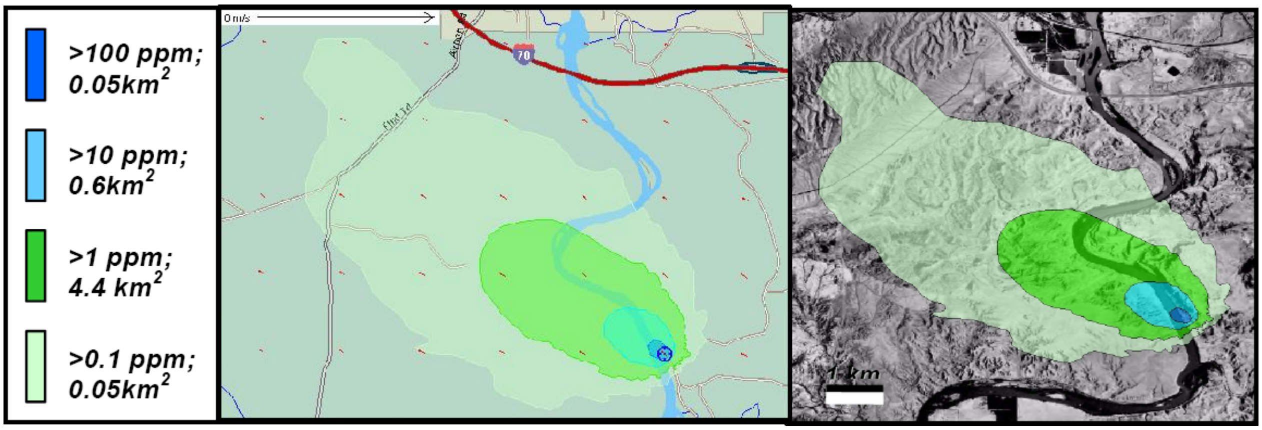

Figure 2 Plume model of atmospheric CO2 release from a 2-hour eruption at Crystal Geyser, UT.
Note that more than 100m from plume, concentrations are less than 100 ppm above background. Left map shows cultural data and wind vectors (red arrows) with black scale arrow at upper left = 10 m/s--most arrows <1 m/s. Right map shows plume draped over aerial photo showing topography. From Bogen et al. 2006

Well permitting and site characterization

At present, there is no institutional framework to govern geological sequestration of CO2 at large scale for a very long period of time.[72] In the United States, the body of federal and state law that governs underground injection to protect underground sources of drinking water. Under authority from the Safe Drinking Water Act, EPA created the Underground Injection Control (UIC) Program, requiring all underground injections to be authorized by permit or rule and prohibiting certain types of injection that may present an imminent and substantial danger to public health. However, there is no category specific to CO_2 sequestration. The EPA has been working with the DOE to develop practices that enables pilot programs[73] and has also issued a set of draft guidelines for consideration of well classes with respect to CO_2 injection wells although these guidelines reflect neither standards for operation nor formal regulatory practice.

While this mostly presents an operational challenge (see next chapter), it may present a challenge to wells used in site characterization. These wells may cost between $0.5-4 million each, and as such operators will be inclined to use pre-injection characterization wells again. However, it may be that some tasks of site characterization can inhibit permitting. For example, in order to collect in-situ stress information, it may be desirable to conduct a leak-off test. This requires fracturing of the rock to obtain stress tensor magnitude (REF!!!!). However, fracturing is prohibited under most readings of class 1 wells, either hazardous or non-hazardous. This may lead site investigators to propose a class V well, according to the current guidance. However, this classification may prevent using this well in the future to inject large volumes of CO2. At present, it is not clear how wells could be reclassified, and if the rock was fractured during site characterization that may prevent reclassification under UIC class I.

This subject requires a great deal more discussion, investigation, and consideration.

POTENTIAL DUE DILIGENCE

Ideally, project site selection and certification for injection would involve detailed characterization given the geological variation in the shallow crust. In many cases, this will require new geological and geophysical data sets. The specifics will vary as a function of site, target class, and richness of local data. In that context, each target class can be considered in the **ICE** framework in terms of what might constitute due diligence for an evolving regulatory framework.

Depleted oil and gas fields

A depleted oil or gas field has already held buoyant fluids in the crust for millions of years. In addition, multiple penetrations and production information exists due to commercial hydrocarbon exploitation and operation. These basic facts make it likely that one can characterize ICE readily. Oil and gas fields will have an advantage regarding effectiveness in that the trap and pore volume are well delineated and basic effectiveness is readily defended. However, greater due diligence may be needed to characterize effectiveness in terms of well age, width of completion zones, and plugging history. For depleted hydrocarbon fields, the key issues may involve incremental costs necessary to ensure well or field integrity; otherwise, the due diligence may be straightforward and the burden to operators relatively light.

Base Case

A depleted oil or gas field is likely to have well, core, production, and perhaps reflection seismic data that could be used to characterize ICE well in a fairly short time frame (order of months). Injectivity will be constrained by initial pressure, current pressure, and production history. Capacity will be defined by the pore volume and structural spill point, and current pressure. If such data sets are available, no additional data may be required to satisfy ICE characterization requirements. Effectiveness can be determined by the seal character and the structural configuration. In most cases, this can be readily augmented with available data regarding fault orientation and in-situ stress tensor calculation.[74] If the field was operated well, there may be information on borehole breakouts, well failure events, subsidence, water-floods, well recompletions, or other phenomena which could advise effectiveness determination. If not, some sort of in-situ stress characterization may be advised.

Because oil and gas fields have large numbers of well penetrations, it will be important to understand the well distribution and state as an effectiveness measure. This may involve a census of wells, confirmation of well location, aeromagnetic surveys, and review of completion records. Depending on the well number, density, age, and completion history, this may prove sufficient to understand well-bore failure hazards and determine effectiveness. In other cases, it may be necessary to re-enter wells and run wire-line tools to determine well conditions at depth for the critical intervals of interest.

Extended case

Conceivably, additional data (e.g., well-bore integrity analysis, capillary entry pressure data) may be required to satisfy regulators and stakeholders. For depleted oil and gas wells, this is likely to be cast in terms of effectiveness. If there are questions or concerns about injectivity or capacity, these may be addressed through production tests or conventional reservoir simulation. Depending on the completion and operation history of the field, it may be prudent to re-complete some or even all wells in the field to help demonstrate effectiveness.

Saline aquifers

In contrast to a depleted oil or gas field, a saline formation may have limited well data and lack core or seismic data altogether. Geological characterization of such a site may require new data to help constrain subsurface uncertainty, such as exploratory wells, new geophysical surveys, or regional hydrological analysis. For saline aquifers, key issues will involve appropriate mapping of potential permeability fast-paths out of the reservoir, accurate rendering of subsurface heterogeneity and uncertainty, and appropriate geomechanical characterization. However, existing science and technology exists and is well suited to defining ICE for all saline aquifer cases, and it is likely that the burden of proof would be manageable even in a cost-constrained environment.

Base Case

Injectivity may be readily constrained if the target formation is already receiving injected fluids under the UIC (e.g., portions of the Mt Simon aquifer or the Miocene of the Florida shelf). However, it is more likely that little will be known about the short or long term injectivity, and analog data may prove important. For example, if there are nearby natural gas storage sites or oil-fields in the target formation, production data might inform injectivity characterization. This was the case for several groups submitting environmental impact statements around FutureGen plant siting, and is the current strategy of several commercial power generators. However, the absence of reliable analog data may require injectivity tests from an exploratory well.

The key terms to define capacity as a function of pore volume might be readily calculated even in areas of poor data density. However, there may be surprises regarding local porosity, thickness, and net:gross or sand percent. In the absence of a well define closure, capacity estimates will derive from specific storage mechanisms (e.g. hydrodynamic, dissolution, or residual phase trapping). These might require special analysis and regional hydrological characterization. Effectiveness would require (at a minimum) strong analog arguments on the seal rock’s effectiveness (e.g., nearby hydrocarbon fields, well constrained seal-rock geological maps and correlations) and some effort to constrain the location of documented deep wells. Although circumstances may vary, it may be necessary to provide evidence of the absence of large-offset faults. Again, new data collected from at least one exploratory well, especially in-situ pressure and stress data, would improve the local case for effective storage.

Extended case

For cases where additional analysis is required to satisfy due diligence, injectivity characterization may require a new well and integration of appropriate analog data. Compared to the base case, some special core analyses might be requested by regulators, such as relative permeability curves. Capacity would also be readily calculated, but a great superabundance of capacity may be required to satisfy local concerns. For example, regulators may require a reasonable demonstration of five times the capacity needed to execute the project. In addition, some information on brine composition may be required to defend dissolution estimates, and conventional simulation needed to defend estimates of plume extent. In such cases, vertically stacked reservoir targets would have a distinct advantage in that the same injection volume would have a smaller aerial extend or footprint.

In contrast, determination of effectiveness may require some substantial characterization. In addition to one high-quality seal unit, multiple seals may be required, especially for first projects in a region. In-situ stress determination might be required, and perhaps special geomechanical analyses (e.g., leak-off tests, capillary entry pressure). In situations where there is little structural or geophysical information available, new geophysical surveys (e.g., 3D reflection seismic surveys of the central target area) may be required to demonstrate the absence of potentially leaky structures. To address questions of well integrity, aeromagnetic surveys might be required, as well as re-completion of some pre-existing wells (e.g., orphaned wells). Again, new data collected from at least one exploratory well, and new geophysical suites. Alternatively, an initial commitment to regular and comprehensive monitoring and verification may offset concerns about initial characterization, depending on the local geological or regulatory environment (see below).

MONITORING AND VERICATION (M&V) IN SITE CHARACTERIZATION

Many workers have described the likely role of M&V in geological sequestration.[4] This includes the DOE's current technology roadmap as well as working groups within the Regional Partnership program.[75] This document has a chapter devoted to M&V technology and its potential costs in deployment. However, the role monitoring might play in site characterization is less clear, since in most cases site characterization will be completed before gathering of baseline M&V data. Rather, it is generally thought that site characterization can determine the choice of monitoring suite and tool deployment, which are often sensitive to crustal physics, chemistry, reservoir geometry, and hazard distribution.[76] However, some M&V approaches provide crucial information on structure and stratigraphy relevant to characterization. In most cases, these are remote geophysical applications such as 3D reflection seismology. In some circumstances, geophysical potential field surveys (microgravity, aeromagnetic) may also provide key information such as shallow fault location or well distribution.

From the perspective of an operator or regulator, however, monitoring is likely to provide key information on the site after injection. This was demonstrated at both Sleipner and Weyburn, where the monitoring programs revealed important heterogeneities of the reservoir, persistent fracture networks, crustal velocity information, and permeable fast pathways.[76,77] This kind of information can serve to improve the understanding of the site substantially, and could improve predictions of plume geometry and extent as well as potential failure risks. Prudent operators would automatically update their reservoir characterizations with the new monitoring data. It may make sense for regulators to require some period of time after injection and monitoring begin to provide updated reservoir models as part of the permitting and approval process. These issues will be discussed under operational needs in the next chapter.

TECHNICAL GAPS AND NEEDS

The existing base on knowledge and expertise for CCS deployment is great. As such, we know enough to site a project, finance it, insure it, operated it, monitor it, and close it safely and effectively.[78] However, we do not yet know enough for a full national or worldwide deployment.[3] This is due to a number of technical gaps and needs that require further investigation. Some of the scientific gaps have been documented in recent publications.[Error! Bookmark not defined.,79,80] These gaps may ultimately limit the rate at which appropriate legislation and regulation can grow.[12] In order to develop the most appropriate framework for commercial CCS deployment, it is important to consider the most crucial gaps and how to address them.

Minimal Technical Constraints

For a given site, it is technically possible and reasonable to collect and analyze information that informs site characterization efforts and permitting. It is not clear, however, what minimal information is required to satisfactorily address the key concerns of potential operators, regulators, or public stakeholders. Said another way, this is no technical consensus or standard regarding what pieces of information are indispensable and what are merely helpful or illuminating. At present, there is neither a body of commercial CCS practice that can guide the technical standard development nor the decades of research focused on defining minimal technical constraints to adequately determine injectivity, capacity, and effectiveness for CO_2 sequestration.

As discussed above, there is a body of industrial practice in analog industries (e.g., oil production, natural gas storage) that can serve to guide and frame this technical discussion. Similarly, there is a large and growing body of literature focused on key questions of geological features, events, and processes that can be used to constrain and inform the formation of minimal technical constraints. It is likely that a focused scientific and technical effort aimed at drafting minimum technical constraints for site characterization can provide this information quickly and clearly. Such a program must be grounded in large injection projects with a large amount of data that could inform decisions on the minimal information and analysis necessary.[3,19]

Scale-up effects

Given our current understanding of the scope of large-scale, sustained CO_2 injection projects, it is unlikely that there will be substantial negative effects associated with a single well chosen site.[81] That is not as clear for multiple well chosen sites. Concerns have been raised regarding the potential effects of dozens of large projects sited within the same region, where the near and far-field effects of single projects might begin to interfere with each other or with regional systems. Some concerns include the effect on ground-water quality by displacement of large water volumes, changes in regional uplift or subsidence patterns, or changes in regional crustal stress orientations and magnitudes. These are issues that have been encountered in other large-scale injection or production deployments,[63,82,83] and as such are credible concerns. That said, these issue have also not prevented development of projects that are believed to be in the public good.

While it is not clear that these issues present a problem to regional CCS deployment, it is not clear that they do not. Very little scientific investigation has pursued geological or hydrological issues at the system scale. Since these concerns are defined around deployment of many large injection systems, they should not present an impediment to near-term development of commercial CCS projects. However, the state may decide to commence investigations into the potential effects that multiple project deployment might cause to reduce the chance of unintended consequences.

Human resources

In addition to the technical gaps mentioned above, there is a key technical need for commercial CCS deployment. It is anticipated that the growth of a CCS industrial sector will severely stress the availability of professionals with relevant experience, chiefly geoscientists and engineers.[80] In particular, the demand for reservoir geologists, geophysicsts, stratigraphers, reservoir engineers, chemical engineers, and mechanical engineers is expected to dramatically increase. These professionals are in equal if not greater demand in the conventional oil, gas, and power sectors, making the availability of key technical workers a greater problem. This is likely to create a shortage in human resources that will substantively impact the deployment of CCS on a national and even global level. While this shortage can eventually be addressed through professional re-training and development of academic resources, the immediate shortages may increase time to deployment, increase costs, and reduce technical quality of commercial project deployment. This trend is seen nationwide in other professions as well,[84] but is likely to hit California sooner due to increased demand for energy sector specialists.

CONCLUSIONS AND GUIDELINES

The observations of current technical knowledge around carbon capture and sequestration provide insight and potential recommendations for consideration by decision makers. The key observations are framed here as conclusions regarding the current state of knowledge needed to accurately characterize a site for safe, effective CO_2 storage projects.

- There is enough knowledge today to characterize a site for geological carbon sequestration safely and effective permitting and operation. This will improve with “learning by doing”.

- Site selection should proceed around three primary characterization parameters: Integrity, Capacity, and Effectiveness (ICE)

- Effectiveness is the most problematic to characterize, but there are many standard, commercial approaches and tools. Wells present the greatest hazard to effective storage, but appear readily managed through application of conventional industrial practice and tools.

- The presence of faults, even active faults, does not preclude a site from storing CO_2 effectively. The potential hazard presented by faults can be readily assessed with conventional geological and geophysical tools.

- What constitutes due diligence will change over time, but is likely to defined initially around repeatable, defensible, readily obtained measurements.

- The threshold for site characterization validation should differ for each site & reservoir class. Validation threshold can be considered a function of data availability and geological knowledge around a site.

- Policy is needed to establish a regulatory framework aimed at appropriate validation and certification of selected sites. This may include modification of existing regulatory frameworks (such as UIC)

- The presence of faults, even active faults, does not preclude a site from storing CO_2 effectively. The potential hazard presented by faults can be readily assessed with conventional geological and geophysical tools.

- There are important technical gaps and needs that persist and will affect the timing and costs of deployment. These gaps are well delineated and readily resolved.

These conclusions and the many points discussed above serve as a template for guidelines to effective storage site characterization and selection. The draft guidelines below are meant to provide operators with an understanding of what they must need to proceed in bringing a potential sequestration site forward. They are NOT meant to represent accepted standards or regulatory conformance.

Draft Guideline 1: Minimal site requirements
Any potential sequestration site must have viable sequestration resource present. There should be viable targets, seals, and appropriate conditions for CO_2 storage. Similarly, there must be minimal legal access to the sequestration resource. Absent these conditions, there should be no further work on site characterization.

Draft Guideline 2: ICE characterization
Any site must have sufficient injectivity, capacity and effectiveness to credibly plan and begin an injection program. These considerations can be expressed as follows:

- The minimal site injectivity should be able to accept 90% of the anticipated site volume.
- The minimal site capacity should be 4 times more than the site OR have alternate available sites prepared for storage that sum to 4 times.
- The minimal effectiveness should manifest in these ways:
    - It must have at least one and ideally several regionally continuous seals
    - It must identify and account for key potential hazards (see below)
    - It must identify and characterize other features of local importance that could compromise site effectiveness.

Draft Guideline 3: Hazard assessment
Operators should undertake serious site hazard assessment work. This should include both a consideration of key local impacts and features (e.g., faults, wells, lakes) as well as local conditions that may be of high relevance (e.g,, groundwater, induced seismicity). In general, geophysical and geological surveys or geochemical analyses that can identify the main hazards should be gathered and interpreted as a matter of

engineering design and operation prudence until operational standards are accepted. This hazard assessment should serve as the basis for risk assessment, operational parameters, and site regulatory requirements.

Draft Guideline 4:Regulatory framework
Those involved in site characterization must consider how to collect the most important geological information at their site in the context of existing regulations, particularly UIC. In cases where existing well classes or permitting process run counter to important data collection, it is prudent to approach State and federal regulators early to consider the approach which provides maximum geoscience insight, maximum operational flexibility, and maximum well utility.

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