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Recommendations for

Geologic Carbon Sequestration in California:

I. Siting Criteria and Monitoring Approaches,

II. Example Application Case Study

Final Report
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Prepared for the California Air Resources Board and the California Environmental Protection Agency

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DISCLAIMERS

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ABSTRACT

In order to certify that carbon dioxide (CO_2) emissions are avoided through application of carbon dioxide capture and storage (CCS), the California Air Resources Board (ARB) is developing a quantification methodology (QM). In this report, we provide recommendations on site selection and monitoring approaches for consideration in developing the QM. Wells and boreholes are the main potential causes of CO_2 surface leakage risk from geologic carbon sequestration (GCS) sites in sedimentary basins. The most effective mitigation of the risk of CO_2 surface leakage by transmissive wells, and/or transmissive faults and fractures, is to avoid the causal features altogether through careful site selection. We find that areas with hydrocarbons discovered prior to 1921 in California have the highest likelihood of unknown wells, although few of these appear to extend deeper than 1.5 km (5,000 ft). While we find that minimum storage depth alone is an unnecessary requirement insofar as CO_2 storage efficiency is concerned, establishing a minimum storage depth could serve to reduce the likelihood that injected CO_2 could encounter unknown wells and borings. A minimum depth requirement will not preclude CO_2 from encountering uncased exploratory borings with only shallow plugs, typically those abandoned prior to 1981, because these borings extend to considerable depths, even to basement in many locations. Transmissive faults and fractures are best avoided by selecting sites with ductile seals. Cap-rock seal property requirements, with regard to leakage through the seal matrix, depend on the proposed mechanism of cap-rock sealing, i.e., capillary trapping or attenuated advection. For GCS projects in reservoirs without existing hydrocarbon accumulations, we recommend reservoir characterization that establishes a high probability of cap-rock continuity.

Besides selecting sites to avoid features that might allow leakage, we recommend sites with a pressure-dissipation interval between the storage zone and the base of underground sources of drinking water (USDW). This interval will attenuate leakage of CO_2 to USDW and the surface via most types of leakage paths, and create a secondary accumulation of CO_2 that may be detected if leakage along one of those paths occurs. Consequently, we recommend monitoring plans be developed to detect secondary accumulations, as well as surface leakage, using appropriate approaches and technologies, and to quantify such leakage. We recommend focusing monitoring on the free-phase CO_2 plume and overlying area, which suggests targeted surface leakage monitoring (e.g., near abandoned wells that penetrate to the depth of the storage interval). We recommend that GCS sites be located in areas of low population density to reduce the likelihood of impacts to people from storage activities (e.g., monitoring, injection, and pipeline transportation) or accidents. Baseline data are important for lowering the detection limits for most monitoring approaches. We recommend quantifying the mass of CO_2 stored by subtracting either the detected leakage or the leakage detection limit from the mass injected, rather than by attempting to measure the mass present in the storage reservoir. We recommend conducting three-dimensional (3D) time-lapse seismic at regular intervals using the same seismic network and monitoring for changes in pressure in the dissipation interval as methods to monitor for secondary accumulations.

In addition to pore-space capacity, a minimum injectivity is needed for any successful GCS site. This should be estimated during project design at a scale relevant to the proposed project to assure that injection pressures will stay below the seal-fracturing pressure, that CO_2 pressure on the base of the seal will not exceed the seal capillary entry pressure for CO_2, and that such

pressure will not result in unacceptably large flow rates through the seal matrix. Alternatively, pressure management via brine extraction or CO_2 injection in backup (contingency) intervals can be proposed. Seismic hazard needs to be considered for safety and nuisance reasons, but not for surface leakage risk.

Example case studies of the application of our site-screening and monitoring recommendations were carried out. In earlier studies by WESTCARB, four sites were screened for feasibility, King Island, Thornton, Kimberlina, and Montezuma Hills. King Island and Kimberlina emerged as the preferred sites. At King Island, unknown wells are considered low-risk for loss-of-containment, but further detailed evaluation and potential remediation of known uncased borings and wells are required. As for geologic pathways, the seal appears to be sufficiently ductile to reduce fault and fracture transmissivity to preclude detectable leakage. Measurements of the seal's capillary entry pressure and permeability are needed to determine if leakage through the seal matrix will be sufficiently low. Finally, a pressure-dissipation interval exists above the Mokelumne River target reservoir at King Island, and gas production data indicate injectivity is likely to be sufficient. The free-phase CO_2 plume area may extend into city limits, complicating monitoring and increasing the consequences of accidents or surface leakage, if they were to occur.

The Kimberlina site has uncased borings that need to be evaluated and monitored as potential leakage pathways. The area of review for the free-phase CO_2 plume at the Kimberlina site may include a portion of an oil field with both known and unknown wells. The area of these potential wells would probably not be encountered until decades after injection ceases, by which time further characterization and remediation would need to be completed. While the seal has retained oil in fields surrounding the site at some distance, there are currently insufficient data to determine if the seal is sufficiently ductile to preclude leakage via faults and fractures. It is also unknown whether it has sufficiently high capillary entry pressure or low enough permeability to effectively limit leakage through the seal matrix. A dissipation interval exists that could provide a monitoring opportunity for subsurface migration. Data from oil production in nearby fields indicate the injectivity is limited, suggesting a project at this site would likely require pressure management by brine extraction.

EXECUTIVE SUMMARY

Introduction

In order to certify carbon dioxide (CO_2) is sequestered by carbon dioxide capture and storage (CCS), the California Air Resources Board (ARB) is developing a quantification methodology (QM) for CCS projects. The QM will provide standard accounting and reporting methods for quantifying CO_2 sequestered from CCS projects with an emphasis on the geologic storage component, along with protocols for storage site selection and monitoring to ensure the CO_2 emissions sequestered are real, permanent, quantifiable, and verifiable. The QM and relevant regulations will need to accurately account for CO_2 sequestered and provide confidence in the permanency of the sequestration. The US Environmental Protection Agency (EPA) Class VI regulation protects underground sources of drinking water (USDW) but does not contain requirements directly addressing the rare but possible scenario in which CO_2 leaks from the reservoir upward to the ground surface without threatening USDW. It also does not address storage concurrent with enhanced oil recovery (EOR). We concluded in an earlier review of worldwide CO_2 storage accounting protocols that no single existing monitoring, verification, and accounting (MVA) protocol was fully appropriate for potential inclusion in California's climate programs.

The purpose of the present study is to build upon the prior report completed under ARB Agreement No. 12-411 in two primary areas: (1) recommend storage siting criteria and favorable properties of geologic carbon sequestration (GCS) sites, and (2) evaluate monitoring approaches aimed at ensuring sequestration permanence under ARB's CCS program. In this report, we provide recommendations on GCS siting criteria and other favorable properties of GCS sites that will maximize likelihood of achieving real and permanent CO_2 sequestration by means of CCS. Note the focus of this study is on siting and monitoring to minimize the risk of loss of CO_2 containment, relative to meeting compliance obligations or carbon intensity goals. We do not focus on health, safety, and environment (HSE) risk, which has been the subject of most other GCS risk-based site-selection studies, although such concerns are one factor in the population density site-selection criteria we recommend.

PART I. Risk-Based Site Selection, Monitoring, and Criteria for Siting

The properties of geologic materials relevant to GCS vary considerably, and can do so over short distances. For instance, the permeability of clay shale (i.e., cap rock, or seal) can be as little as one billionth the permeability of a subjacent sandstone (storage reservoir). Because it is not possible to measure these properties throughout all points in the subsurface relevant to GCS, site selection is always based on limited knowledge. This suggests a risk-based approach is needed to select storage sites to minimize the probability of leakage of injected CO_2.

Risk-based site selection utilizes the methods of risk assessment, an approach that considers the likelihood and consequences of hypothetical series of events referred to as failure scenarios. For instance, wells and boreholes are widely recognized as the most likely potential leakage pathways. Information typically exists to estimate the probability of well leakage based upon the number of wells and how they are constructed and/or abandoned.

Previous studies have determined both high-quality storage reservoirs and cap rocks exist in California. Cap rock needs to have sufficient thickness throughout the area overlying the ultimate extent of free-phase CO_2 (not be too thin or pinch out in some locations). In addition, any faults or fractures through the cap rock need to have sufficiently low conductivity to preclude detectable leakage.

Assuming an effective seal exists to contain the injected CO_2, a secondary requirement arising in the QM context is that the CO_2 containment be verifiable, e.g., through monitoring of injected CO_2, and its migration and trapping over time, including the possible leakage out of the complex while remaining within the deep subsurface. In the context of the QM, monitoring is focused on the CO_2 plume footprint, including the area occupied by both the free-phase CO_2 plume and brine (or any other groundwater) containing injected CO_2 in its dissolved form.

Failure Scenarios Relevant to Surface Leakage

It was recognized early in GCS feasibility studies that wells and boreholes were the main source of loss-of-containment risk for CO_2 injected into sedimentary basins. Orphan and abandoned wells are a particular concern for well integrity. This is primarily because well construction and plugging requirements have evolved and improved over time to reduce the likelihood of leakage. It is also, to a lesser degree, due to the time since abandonment, which is often decades, during which processes could occur that degrade a well's ability to contain fluids and fluid pressure. For instance, steel well casings are subject to corrosion and well cements may degrade over time, either of which could increase leakage risk.

Wells that predate a GCS project and are deep enough to penetrate into the proposed storage reservoir are a potential hazard for surface leakage, and motivate locating GCS sites elsewhere. If such wells cannot be avoided, well workovers may be effective in bringing them up to recent plug-and-abandonment requirements, and/or surface and atmospheric monitoring targeted to detect well leakage can be implemented. Because deep wells of varying age and condition are common in the California sedimentary basins that are excellent prospective GCS sites, we assert that these wells are the likeliest path for CO_2 leakage to the surface. This may or may not be the case for GCS outside of California, such as may be carried out under the low-carbon fuel standard (LCFS) program to lower the carbon intensity of fuel used in California.

For GCS surface leakage risk, both faults and fractures are also hazards for containment. Documented cases of fault-related gas leakage to the surface include the LeRoy natural gas storage site in Wyoming. At the In Salah GCS site in Algeria, monitoring data and analysis indicated potential migration of CO_2 into a fault or fracture in the lower-most cap rock. This finding led to shutdown of the project, although the CO_2 remains contained in the storage complex with no evidence of surface leakage. However, faults can also act as traps by virtue of having reduced permeability or higher gas entry pressure, evidence of which is provided by the common occurrence of fault traps that have held oil and natural gas for millions of years.

In the context of GCS, induced seismicity is another recognized hazard. Such seismicity is not normally considered a hazard for fluid leakage or contamination of water, soil, or air. Because large active faults will be avoided in siting GCS sites, we assert that induced seismicity itself is not a significant hazard for CO_2 containment in California.

The most effective mitigation of the risk of surface leakage of CO_2 by the above failure scenarios is to avoid the causal features altogether, i.e., to select a site without potentially leaky wells or faults, and to operate the site such that fractures are not opened by overpressure to create flow pathways. Industry has decades of experience in well construction, well control, and well integrity-assurance worldwide, on- and offshore, which can be taken advantage of for reducing surface leakage risk at GCS sites in California.

Monitoring Technologies and Approaches

Significant effort in the research community has gone into review and development of monitoring technologies and strategies for GCS sites. Through the process of site selection, investment, permitting, and licensing, GCS sites will be expected to perform as required to meet the many objectives of the project including long-term containment of CO_2. Therefore the focus of monitoring is on detecting, diagnosing, and efficiently correcting or managing unexpected or off-normal behavior. For the QM, i.e., in the carbon credits and accounting (CCA) context, the ultimate concern is about surface leakage. But in order to anticipate and address unexpected behavior that could lead to surface leakage, monitoring of the injection and storage process in the reservoir and in other deep locations is necessary. Modeling provides a picture of the system and how it is expected to perform and thus is an important tool for developing the monitoring program.

Practical Monitoring of GCS for Containment Assurance

The deployment of monitoring equipment and effort needs to be distributed both temporally and spatially, and be potentially adjusted depending on the results of ongoing monitoring. Many deep subsurface monitoring approaches are not precise enough to produce absolute images of subsurface properties, but they are good at indicating differences in properties from one time to the next, i.e., monitoring in so-called time-lapse mode. Different monitoring activities need to be carried out depending on the state of GCS operation, e.g., standard operational monitoring when injection is proceeding as planned, contingency monitoring when there are indications of off-normal behavior, and surface leakage detection and quantification when surface leakage is suspected or detected. Monitoring plans are needed to identify, locate, and quantify leakage, if any, from wells, faults, and fracture networks.

Most of the regions broadly recommended for GCS in California have a Mediterranean climate, low topographic relief, low-population density, and agricultural land use. The California climate results in essentially no snow coverage that could interfere with some monitoring methods. The low-population density and agricultural land use results in relatively few structures and little infrastructure that could interfere with monitoring methods. All of these factors result in few restrictions on the use of many of the most effective monitoring activities, both in terms of quality of the resulting data and cost of the methods.

Monitoring for Specific California Failure Scenarios

Surface Leakage

The well leakage failure scenario is by far the biggest threat to CO_2 containment in California, particularly from unknown wells. Conveniently, monitoring for such leakage largely uses the same methods and technologies as the monitoring used to address potential leakage from transmissive faults and fracture networks. This is because the first challenge for surface leakage is *detecting* it. Surface leakage relevant to the QM may involve methane (CH_4) or other reservoir gases with lower detection limits than CO_2. Leakage fluxes may be very low and potentially derive from undocumented wells and faults at unknown locations. In order to detect such a leak, broad aerial monitoring focused on the footprint of the free-phase CO_2 plume is required, e.g., using large-scale open-path laser infrared or other remote sensing methods.

Subsurface Migration

Surface and borehole seismic surveys, and possibly electrical resistivity tomography (ERT), are the standard approaches to monitoring migration of the injected CO_2 plume in the storage reservoir. Seismic methods are based upon the difference in the velocity of sound, and ERT is based on the difference in electrical conductivity between injected CO_2 and the water previously occupying the storage reservoir. In the Sacramento and San Joaquin Valleys, lands managed for agriculture should provide a good number of permanent radar reflectors for interferometric synthetic aperture radar (InSAR). This method consists of a satellite repeatedly emitting a radar signal toward the study area and processing the reflections to image uplift or subsidence caused by injection or other processes.

Strategy for Detecting Baseline Levels

In the storage complex and overburden, measuring the baseline equates with determining pre-injection characteristics that are needed to allow simple differencing between monitoring results over time and the pre-injection baseline (so-called time-lapse). In the shallow subsurface, changes in ecological processes arising from changes in season, moisture, weather, land-surface disturbance, and many other factors can affect carbon cycling, which gives rise to the need for attribution assessment in monitoring plans.

Sensitivity and Accuracy

All monitoring approaches have sensitivity and accuracy limitations. While there is no substitute for seismic methods, the resolution available in that method is not sufficient for quantifying the mass of CO_2 in the storage reservoir with accuracy that may be needed for CCA purposes. We recommend use of "negative accounting," an approach whereby the amount of stored CO_2 is estimated as the smaller of (i) the difference between the amount injected and the amount detected to have leaked, or (ii) the difference between the amount injected and the non-zero detection limit. In general, multiple monitoring approaches are needed to confirm CO_2 containment, and the chosen approaches should be rationally defended with consideration of sensitivity and accuracy. We recommend that monitoring plans be considered living documents insofar as improvements in monitoring technologies are expected over time, and the plans should allow for substitutions to improve the efficiency of the QM in the future.

Area to Monitor

With respect to area to monitor for the QM, the footprint of the free-phase plume is the primary target area. The footprint will grow with time until post-injection plume stabilization occurs.

Frequency of Measurement

As for frequency, there is no general rule because each monitoring objective and technique has its own inherent optimal frequency from continuous monitoring to annual or less frequent. A general philosophy is that when a particular monitoring target reveals large changes in measured parameters, higher frequency monitoring of that target is indicated, and vice versa. Leakage via most paths will commence with the arrival of CO_2 at that location so that monitoring at any particular location needs to commence prior to arrival, and can reduce in frequency over time after that arrival as long as leakage of CO_2 is under control or ceases (is no longer detected).

Spatial Coverage in Terms of Where and How Much Density

Monitoring density is also site-specific, and in some places in California, GCS monitoring will need to be designed to match the leakage likelihood, e.g., with relatively high density monitoring at oil or gas fields with a high spatial density of wells. In contrast, for sites with few known wells, the intensity of such surface monitoring could be drastically reduced.

Schedule and Phasing of Monitoring

Regarding the scheduling and phasing of monitoring, activities will evolve as the project proceeds. We recommend that monitoring at the outset of injection be frequent and intensive to catch unexpected behaviors early. As the project progresses successfully as designed over six months to a year, monitoring can be less frequent while also expanding in size as the plume grows.

Proxy or Companion Gases

Gases, such as CH_4, that may accompany CO_2 during leakage are excellent indicators of deep gas migration, especially in hydrocarbon reservoir environments. The early indication provided by anomalous CH_4, or some other low-solubility companion gas species, could provide an opportunity for stopping or reducing leakage before CO_2 reaches the surface.

Attribution

CO_2 and CH_4 are ubiquitous gases in the environment. For this reason, it is now appreciated that variations in CO_2 or CH_4 in the near-surface environment should not be taken at face value as indicators of deep-sourced leakage, but rather, any variations need to be explained as part of the QM. Because processes affecting the oxidation of CH_4 to form CO_2 are less variable in the deep subsurface than in the near-surface aerobic environment, the need for attribution is less for anomalous CO_2 observed in deep fluid sampling campaigns than in the shallow subsurface or atmosphere.

Use of Tracers

Tracers fall into two broad categories: natural and artificial (those added). Natural tracer analysis of gas samples can be a useful practice, and we recommend that it be considered part of the wide array of approaches applicable to monitoring within the QM. In general, we do not recommend continuous use of artificial tracers, because we do not believe they are needed in routine injection operations.

Monitoring Workflow to Inform Annual Quantification

Monitoring for CO_2 containment is not always a simple process involving static protocols, routine field campaigns, and checking boxes on forms. Instead, monitoring of GCS sites involves an assortment of methods and approaches, many with significant data analysis and interpretation components. As such, there needs to be a reasonable time period built into the reporting requirement following data collection to allow for data analysis and interpretation.

Assessment of Plume Stability

The injected free-phase CO_2 plume can be considered stable if post-injection monitoring over multiyear intervals, e.g., by 3D seismic surveys or other approved monitoring approaches, shows that the free-phase CO_2 is stationary in all directions (not moving upward or downward, or spreading laterally). Because plume velocity can be quite slow, we recommend that the plume show no movement for five consecutive years as a default period for post-injection monitoring subject to change depending on the specifics of the injection design, site, and approval by ARB. For instance, if there are potential leakage pathways whose character suggests they might become more permeable with time, such as well segments with uncemented casing exposed to the storage reservoir, these could warrant a longer post-injection monitoring period.

Evaluation of Siting Criteria

Historical use considerations

The presence of a hydrocarbon accumulation beneath a geologic seal (without evidence for surface seepage) provides evidence of the seal's ability to retain buoyant fluids in the reservoir over millions of years. Past experience, such as underground natural gas storage, supports the advantage of storage in depleted oil and gas fields. Prior hydrocarbon production from a proposed storage reservoir provides a basis for estimating the injectivity and, to a lesser extent, capacity of the proposed storage target. Results from prior hydrocarbon production suggest that there are caveats to the potential benefits in understanding the performance of the geologic components in the proposed storage system. For example, the likelihood of legacy borings intersecting the storage zone is much higher in hydrocarbon-producing regions than in areas where hydrocarbon exploration and production have not occurred. These legacy borings are potential pathways for leakage of fluids out of the storage zone. For inactive wells, leakage appears to occur most typically as a result of defects present in the well at or after the end of its operation. Older exploration borings are potentially an even greater concern for leakage as they typically are only plugged at a depth above the base of underground sources of drinking water, if at all.

Minimum injection depth

The rationale for previously suggested minimum storage depths (typically ranging from 800 m to 1 km (2,600 to 3,300 ft) for GCS arises from the use of depth as a proxy for specifying the minimum pressure and temperature combination that will maintain CO_2 in a dense, fluid (i.e. supercritical) phase. The purpose of this is to efficiently use the available pore space. However, setting a simple metric for the ideal CO_2 properties, such as a minimum storage depth, is difficult in practice because the pressure and temperature at a given depth vary widely from location to location, and there is no distinct phase (density) change when CO_2 transitions from its gaseous to its supercritical form.

Although efficient use of pore space is important, the larger concern for permanence is ensuring the CO_2 remains underground. Therefore, we recommend that instead of a minimum depth criterion, ARB require a pressure-dissipation interval, or "thief zone," above the target storage formation to effectively dissipate overpressure along leakage paths exposed to the interval. This virtually eliminates the driving force for brine leakage outside of the CO_2 plume and reduces the driving force for CO_2 and brine leakage within the CO_2 plume. Past and ongoing research indicate that the presence of even a relatively small net thickness of permeable strata between the CO_2 storage reservoir and the base of USDW will have this effect, substantially reducing brine, and to a lesser extent CO_2, flux to the USDW and atmosphere via most potential leakage paths. We suggest referring to these zones as "dissipation intervals" to emphasize that their purpose is to effectively dissipate overpressure along leakage paths.

Minimum cap-rock thickness, spatial variability, and quality of cap rock

Leakage risk does not decrease continuously with increasing seal or cap-rock thickness. If a project proposes that CO_2 be retained under a seal by its capillary entry pressure, seal thickness is less of a concern if the seal is water-saturated. If a project proposes capillary trapping, we recommend requiring the applicant to provide data regarding the capillary-trapping aspects of the seal. For an attenuated-advection seal, the operator would provide a statistical and geostatistical understanding of the flow rates of CO_2 out of the top of the seal, given the evolution of the CO_2 plume. Characterizing and defending an attenuated-advection sealing mechanism requires developing statistics and geostatistics regarding both seal permeability and thickness. Hybrids of capillary exclusion and attenuated-advection sealing mechanisms are also possible. If the operator proposes allowing some CO_2 to flow through the seal, or if the flow is into a dissipation interval and ARB allows its inclusion in the defined storage complex, the operator could perform an analysis of the seal over the dissipation interval to demonstrate effective sealing of the dissipation interval.

Delineation of an area of review (AoR); tiered or temporally variable AoR

The AoR is defined in US EPA Class VI injection well regulations as the area where the driving forces resulting from injection are sufficient to cause fluids in the storage zone to flow to USDW via a hypothetical previously fluid-filled conduit that hydraulically connects each zone without pressure dissipation in between the zones. The *Zone of Endangering Influence* approach to AoR definition for Class II injection wells is substantially similar. Class II wells are alternately allowed to be permitted using an AoR based on a ¼-mile radius around the proposed well without analysis of the area over which driving forces are present that could cause leakage. The requirements of the Class II and VI well regulations are sufficient for protecting USDW, as long as the *Zone of Endangering Influence* approach is used to define the Class II well AoR.

For CCA, we recommend that ARB focus its requirements and review on the anticipated free-phase CO_2 plume, both for the purpose of quantifying and verifying storage, and for appropriately regulating surface leakage risk in the near term (during the injection period). In order to distinguish the AoR as defined in Class VI injection well regulations, we recommend use of the term AoRc to refer to an area of review based upon the CO_2 plume. We further recommend that project applicants be required to provide a projection of the area to be occupied by the free-phase CO_2 plume at the time it stabilizes after injection ceases, as well as at the next time of substantial monitoring effort (e.g., by 3D seismic) of the storage complex and overlying materials. These projected areas should be appropriately buffered by safety factors to account for uncertainty in these projections to establish the AoRc.

Minimum pore-space capacity and injectivity

Pore-space capacity and residual saturations themselves are not germane to ARB's goal of quantifying the amount of CO_2 stored. First, these properties are implicitly included in the AoRc calculation. Second, actual-less-than-predicted pore-space capacity or residual saturation alone does not translate into a CO_2 storage failure.

Injectivity is the reservoir property that we suggest is the most pertinent for ARB to include in its primary list of information requested from potential GCS site operators, both at the proposed injection wells and over the entire storage volume to be perturbed. A study of injectivity in the geologic strata with the most apparent storage capacity based on pore space in the southern San Joaquin Valley indicates injecting industrially-relevant quantities of CO_2 in that basin would require well fields over large areas if storage is not accompanied by brine extraction.

We recommend ARB require project applications to include the applicant's approach to managing injectivity risk. We are aware of three approaches a project may take to managing this risk: (1) evaluating (estimating or measuring) injectivity at relevant injection rates and spatial extents, (2) including backup (contingency) injection intervals to adapt to lower-than-anticipated injectivity in the primary interval, and (3) deploying active pressure management (brine extraction from a saline aquifer storage reservoir, or brine and oil production) to accommodate the injected CO_2 volume.

Identification of potential leakage pathways for CO_2

The main potential leakage pathways identified for storage sites are wells and faults, and to a lesser extent fractures and facies changes in seals. The risk of leakage via wells can be classified on the basis of well type and well age, with two significant breakpoints within California being 1920, which is five years after the regulatory body for recording well drilling was established, and 1981, before which plugs in cased and uncased borings tended to be at shallow depths. A survey of records of deep wells indicates that CO_2 stored deeper than 1.5 km (4,920 ft) anywhere in the major basins of California is substantially less likely to encounter wells whose locations are unknown than is shallower storage.

The other main leakage pathways of concern are discontinuities (faults and fractures) in the seal. For projects proposing to store CO_2 entirely within a reservoir volume that contained hydrocarbon accumulations, relying on this prior evidence of seal capacity requires demonstrating that the injection pressures will be below the seal fracture-opening pressure and that the CO_2 pressure on the base of the seal will not be higher than the seal's capillary entry pressure for CO_2. For GCS projects in reservoirs without existing hydrocarbon accumulations, we recommend reservoir characterization that establishes a high likelihood of cap-rock continuity and low likelihood of permeable fault or fracture zones that compromise cap-rock integrity. Consequently, we additionally recommend a preference for sites with seals of sufficiently high ductility (low strength) so that they creep under the *in-situ* stresses imposed upon them, because this tends to seal any pre-existing faults and fractures created by natural stresses.

Proximity to emission sources and potential of source for CO_2 capture

We recommend measuring the mass of CO_2 potentially stored in the subsurface by flow metering at the storage facility injection points. The proximity of the source(s) to a storage project site therefore is not relevant to the geologic storage part of the QM. However, to minimize the potential for leakage during transport from source points to injection points, it is desirable to identify the shortest routes for pipeline, rail, or truck transport. Consideration of the modes of failure for leakage in pipelines, and other transport options, via features such as valves, bad welds, and by processes such as transfer operations, etc., are beyond the scope of this study.

Proximity to population centers

We recommend that GCS projects initially be located such that the projected AoRc does not extend into designated urban areas as defined by existing city boundaries within which near-term future population growth will likely occur. Selecting sites outside of these areas minimizes the risk of leakage that affects people, but also has a nexus with the QM in that low population density areas create fewer problems for the deployment of monitoring technologies, e.g., 3D seismic data collection. Given that city planning boundaries and population densities may change over the life of a project, it may be that at the time of site closure, this criterion is no longer met. This suggests the importance of establishing agreements with county and urban planners such that future access for monitoring be retained.

Seismic hazard considerations

The main hazard of concern with regard to seismicity is not leakage due to damaging cap rocks or wells, which would be relevant to quantification, but rather damage to surface structures caused by ground shaking from larger events, and potentially nuisance shaking from smaller events. Basement faults are generally more capable of such events owing to their larger size ("basement" refers to the metamorphic or igneous rock below the sedimentary rock in a sedimentary basin). Consequently we recommend a preference for sites with a pressure-dissipation interval below the injection zone to reduce the probability of inducing seismic activity in basement faults.

Establishing pipeline or other transportation rights-of-way

The location of pipeline or other transportation rights-of-way is not relevant to quantifying the amount of CO_2 stored if the flow meter is at the storage facility, rather than the source facility, as we recommend. A flow meter may be required at the source facility for other purposes.

Setting requirements for baseline data collection, including levels and other sources of CO_2 emissions, groundwater chemistry, and microseismicity

Rather than a matter of site selection for the QM, collecting baseline data is more a matter of monitoring once a site is selected based on other criteria. Given natural variability in most of the monitoring targets, such as atmospheric gas concentrations, groundwater quality, and microseismicity, the more baseline data collected, the lower the detection limit is for an anomaly caused by storage. The plans for baseline data collection should be included and evaluated by ARB. The wide variability of sites does not lend itself to prescriptive time periods for baseline data collection, but one year would seem to be the shortest meaningful period due to the seasonal variation of many relevant parameters.

Necessary geologic models and CO_2 flow simulations

We do not find simulation of surface leakage is needed as a direct component of the QM. As mentioned in the AoR discussion, a prediction of the area occupied by the free-phase CO_2 plume is needed to define the AoRc.

PART II: Site-selection Case Study

Previous California GCS Site-Screening Studies

GCS site-screening studies have been undertaken at several levels of detail in California, ranging from state-wide screening of the potential for major geologic formations to pass general site criteria, to studies of specific sites as candidates for pilot- or commercial-scale GCS projects. The Central Valley of California, composed of the Sacramento Basin in the north and San Joaquin Basin in the south, contains numerous saline formations and oil and gas reservoirs that are the state's major geologic storage resources. The saline formations alone are estimated to have a storage capacity of 100 to 500 Gt CO_2, representing a potential CO_2 sink equivalent to more than 500 years of California's current large-point source CO_2 emissions. Depleted petroleum reservoirs are especially promising early-opportunity targets for CO_2 storage because of the potential to use CO_2 to extract additional oil or natural gas.

Attributes of Broadly Representative Sites

Prior studies considered geologic and geographic criteria related to the ability to store CO_2, avoidance of impact to USDW, locations unlikely to cause public or environmental impacts unrelated to USDW, proximity to source(s) of CO_2, potential for utilization of CO_2, etc. Nontechnical criteria included access to surface and/or subsurface rights, existence of roads and/or well pads to minimize disturbance, and ease of permitting.

In these prior studies, four sites were screened: King Island, Thornton, Kimberlina, and Montezuma Hills. All of these sites met the geologic/geographic criteria. King Island was the only site that completely fulfilled the nontechnical criteria, while Kimberlina was a close second. Based on the initial screening, we focused attention for the case study on King Island and Kimberlina.

Site-selection Criteria Applied to Two Candidate Sites

King Island

The King Island site is located west of Lodi in the Sacramento-San Joaquin River delta. It includes a natural gas field of the same name. The formations of interest for storage at King Island are sands in the Mokelumne River, Starkey, and Winters formations. These were formed from sediments that were part of a dynamic coastal environment subject to high rates of localized deposition and erosion. After deposition, the rocks were eroded by strong currents in coastal and nearshore river systems, resulting in deep gorges cut down through the section, which were later infilled with muds and became good seals. The King Island site generally meets all criteria as applied to GCS in the Mokelumne sands. However, data are insufficient to assess whether formations above the Domengine and below the Starkey might also meet all criteria.

Likelihood of leakage via unknown wells: There are no historical records indicating that any exploration for oil or gas was done in this area prior to 1920.

Likelihood of leakage via exploration borings: Based on the California Division of Oil, Gas, and Geothermal Resources (DOGGR) records, there are uncased borings that intersect the Mokelumne River formation within the likely AoRc, and a review of their records indicates they are only plugged more than 1 km above the storage reservoir.

Likelihood of leakage via known wells: There are five wells within the likely AoRc that extend to the Mokelumne River formation, three of which are operating (active or idle) and two of which have been plugged and abandoned.

Likelihood of leakage via geologic pathways (ductility): Based on offsets observed in 3D seismic surveys, there are two faults within the likely AoRc. There may also be faults with total offset too small to be detected by 3D seismic, and fractures as well. The seismic wave velocity in the cap rock indicates it is ductile under the *in-situ* stresses such that faults and fractures in the cap rock are closed (will not leak).

Likelihood of leakage via geologic pathways (overpressure): There are no capillary entry pressure measurements on samples of the cap rock available. The minimum cap-rock capillary entry pressure implied by natural gas accumulation at the site is substantially lower than the maximum-allowable CO_2 injection pressure. There are no permeability measurements of the cap rock available. In the absence of these data, the maximum likely permeability of the cap rock is too high to preclude prohibitively large leakage. Consequently the capillary entry pressure and the permeability of the cap rock need to be measured.

Magnitude and detectability of leakage: The Domengine formation immediately overlying the Capay shale (the primary storage seal) and underlying its own seal (the Nortonville formation) provides a dissipation interval between the storage zone and the base of USDW.

Risk of induced seismicity: The Starkey formation underlies a seal below the storage target. The transmissivity of this unit is sufficient to dissipate any downward propagating overpressure, precluding it from entering basement.

Likelihood of damaging seal: The pressure response to gas production, which occurred from the top of the Mokelumne River formation, indicates there is sufficient injectivity for commercial-size storage injection.

Likelihood of lethal concentration for someone in a building is less than a hundredth of a percent: The AoRc likely includes areas within the Lodi and Stockton city limits.

Likelihood of collapse impact and surface monitoring interference: There has been no active or past surface or subsurface mining within the King Island area.

Kimberlina

The Kimberlina site is located in the southern San Joaquin Valley, northwest of Bakersfield. The geologic strata of primary interest for GCS at the Kimberlina site is the Oligocene Vedder formation. The Vedder formation is capped by the Freeman-Jewitt formation, a unit that can reach thicknesses of 300 m (1,000 ft) or more and is composed of over 90% shale (seal rock), with minor interbedded siltstones and sandstones. Overlying the Freeman-Jewett is the Olcese formation, a locally continuous, fluvial-estuarine sand package. The sedimentary section has been tectonically tilted toward the west, and is characterized by block faulting with broad, open folds. There is a mapped normal fault in the area called the Pond fault, which apparently propagates to the land surface and is expressed as a 3.4 km-long (2.1 mi) scarp, with up to 1.5 m (5 ft) of surface displacement.

Likelihood of leakage via unknown wells: The AoRc likely includes a portion of the Poso Creek oil field, which was discovered prior to 1920. Therefore, this area may contain unknown wells that intersect the proposed storage reservoir, which is considerably shallower in the Poso Creek field than in the proposed injection location.

Likelihood of leakage via uncased borings: Numerous, uncased borings with only shallow plugs intersect the Vedder formation within any AoRc for commercial-scale storage.

Likelihood of leakage via known wells: The only known wells intersecting the Vedder formation within a likely AoRc are in the Poso Creek oil field to the east. While assessing the seal and plug depth of each of these wells was beyond the scope of this study, it is likely they are of sufficient depth to intersect the Vedder formation because the formation is the deepest pool in the field, and so no wells are likely to extend through it to access a deeper zone. Additionally, production from this pool commenced about 1980, so seals and plugs would have been required immediately above the Vedder formation.

Likelihood of leakage via geologic pathways (ductility): Data indicate there are numerous faults within the likely AoRc. Quantitative measurements bearing on the ductility of the seal could not be identified, so the transmissivity of these faults, and consequently whether this criterion is met or not, cannot be judged at this time.

Likelihood of leakage via geologic pathways (overpressure): The Freeman-Jewett has not been found to have retained hydrocarbons at the site, and we could not identify any capillary entry pressure or permeability measurements on the seal rock. Consequently whether the site meets this criterion could not be determined.

Magnitude and detectability of leakage: Available data indicate the Olcese formation, a sandstone unit immediately overlying the Freeman-Jewett primary seal, is itself overlain by a seal, and lies between the storage target and the base of USDW. Therefore, the Olcese formation has sufficient transmissivity to provide a dissipation interval above the target reservoir.

Risk of induced seismicity: The Famoso formation underlies the seal below the storage target and has sufficient transmissivity to preclude any downward propagating overpressure from entering basement.

Likelihood of damaging seal: The pressure response to oil production from the Vedder formation in nearby fields suggests its injectivity is likely too low for storage by injection only into this target. Because this estimate of injectivity was performed over an area equivalent to a substantial portion of the AoRc, any project proposal will need to include an approach for appropriately managing the injectivity risk (such as injection into an additional geologic unit or extraction of brine during injection).

Likelihood of lethal concentration for someone in a building is less than a hundredth of a percent: The AoRc likely includes a portion of the City of Shafter.

Likelihood of collapse impact and surface monitoring interference: There has been no active or past surface or subsurface mining within the Kimberlina area.

Recommendations for Monitoring Approaches at the Case Study Sites

The scope of this project did not allow development of a detailed example monitoring plan for the case study sites. Nevertheless, we can make some broad comments on monitoring at the two prospective sites, King Island, and Kimberlina. 3D time-lapse seismic using the same seismic network for each site should be carried out at regular intervals at both of these sites and above-zone intervals should be monitored for pressure change. Pressure in the injection formation should be monitored in wells at various distances from the injection well. In addition, a microseismic array should be deployed to monitor microseismicity with sufficient resolution that hypocenters could be located to within 100 m (0.06 mi). InSAR data should be analyzed to observe pressure propagation and anticipate plume migration. Because the overall expectation is that no leakage will occur for well-characterized and screened sites that receive US EPA Class VI injection permits, standard operational monitoring is all that is expected to be required. The monitoring plan should spell out potential additional modeling activities that would be deployed if the system deviates from expected behavior.

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1. PART I. EVALUATION OF SITE-SELECTION CRITERIA AND MONITORING APPROACHES

1.1 INTRODUCTION

The California Air Resources Board (ARB) is developing a quantification methodology (QM) for carbon dioxide capture and storage (CCS) projects in order to certify that carbon dioxide (CO_2) is sequestered. The QM will provide standard accounting and reporting methods for quantifying CO_2 sequestered from CCS projects with an emphasis on the geologic carbon sequestration (GCS) component (e.g., Intergovernmental Panel on Climate Change (IPCC), 2005), consisting of protocols for GCS site selection and monitoring to ensure the CO_2 emissions reductions by means of GCS are real, permanent, quantifiable, and verifiable.

The QM and relevant regulations will need to establish a protocol that accurately accounts for CO_2 sequestered and provides confidence in the permanency of sequestration. To achieve this, the QM will need to include criteria, specifications, or other requirements to ensure selection of an effective CO_2 injection site that minimizes the likelihood of potential CO_2 surface leakage and maximizes CO_2 trapping in the underground target storage complex, defined here as the storage reservoir and surrounding geological domain, which can have an effect on overall storage integrity and security, e.g., by providing secondary containment of CO_2. The monitoring protocol will specify the minimum requirements of a monitoring plan including active site management, while acknowledging that every GCS monitoring protocol will need to be site-specific and flexible to allow changes as monitoring practice and technology, along with understanding of site performance, can be expected to change over time. Importantly, the monitoring protocol will need to incorporate techniques to detect and quantify potential CO_2 leakage out of the storage complex including surface leakage, and provide the methods for understanding ongoing CO_2 migration in the storage complex. Insofar as methane (CH_4) is an important greenhouse gas (GHG) that may also leak from GCS sites in the subsurface along with CO_2, its emissions to the atmosphere associated with GCS should also be quantified. However, our focus in this report is on the QM for CO_2 surface leakage. We recommend that additional studies be carried out with focus on other GHG emissions that might be associated with GCS (such as CH_4), which may have deep and shallow natural sources that may or may not be related to any given GCS project.

In 2013-14, we (Oldenburg and Birkholzer, 2014) completed a literature review of worldwide publications and reports on GHG reduction protocols, monitoring approaches, and regulations associated with CO_2 injection under an agreement with ARB (ARB Agreement No. 12-411). The stated purpose of the agreement was "to review existing monitoring, verification, and accounting (MVA) protocols, evaluate their various components, and recommend specific elements of surface leakage MVA protocols that would be particularly appropriate for implementation in California's Cap-and-Trade and LCFS programs." One conclusion of the study was the need for a "sufficiently detailed" monitoring approach such that an expert in GCS monitoring can review the plan, understand the monitoring rationale, and confirm its intended effectiveness. This conclusion is consistent with ARB's need to require a monitoring, reporting, and verification (MRV) protocol that is specific enough to meet the requirements of California's rulemaking procedures and standards; however, the MRV will also need to be appropriately flexible to address site-specific factors and their effects on monitoring technology applications, both of which may change over time.

A prior study (Oldenburg and Birkholzer, 2014) summarized the US Environmental Protection Agency's (EPA) Class VI well regulation for CO_2 injection for GCS aimed at preventing contamination of underground sources of drinking water (USDW) (e.g., US EPA, 2012). The Class VI regulation protects USDW, but does not contain requirements directly addressing the rare but possible scenario in which CO_2 leaks from the reservoir upward to the ground surface without threatening USDW. This scenario could occur in areas that do not have USDW, e.g., at oil fields or regions with only high-salinity groundwater, such as might exist in portions of the southwestern margin of the San Joaquin basin. It could also occur if CO_2 leaks up a well without contacting or impacting USDW and then leaks into the shallow subsurface or into the atmosphere near or at the wellhead, such as seems to have occurred via leakage from a vandalized wellhead of a shut-in well at the In Salah project in Algeria (Ringrose et al., 2013). EPA's GHG reporting Subparts UU and RR together promote avoidance of both USDW contamination and surface leakage of CO_2 through their requirements of reporting, which depends on monitoring that allows detection and mitigation of leakage. But UU and RR only require reporting, and do not compel the operator to remedy or mitigate surface leakage. Furthermore, Subpart UU does not specify a provision for discounts in GHG reduction crediting based on the degree of certainty or precision in monitoring. For these reasons, we concluded in our earlier study that no one existing MVA protocol was fully appropriate for ARB's climate programs.

The purpose of the present study is to build upon the prior report completed under Agreement No. 12-411 in two primary areas: (1) recommend injection siting criteria and favorable properties of GCS sites, and (2) evaluate monitoring schemes aimed at ensuring permanence under ARB's CCS program. In this report, we provide recommendations on GCS siting criteria and other favorable properties of GCS sites that will maximize likelihood of achieving real and permanent CO_2 sequestration by means of CCS. Additionally, the report evaluates monitoring approaches and provides recommendations on the appropriate techniques, tools, monitoring technology/equipment, reporting parameters, and other methods for evaluating containment of CO_2 to maximize likelihood of quantifying and verifying the permanence of stored CO_2. We present tables and figures to summarize the utility and relative merits of various tools and technologies and their applications. The recommended monitoring approaches will be discussed briefly in light of the merits or challenges of different techniques or monitoring approaches when paired with California's climate, topography, geology, and land use characteristics (e.g., CO_2 injection in mature oil and gas fields where well density can be very high). To demonstrate the recommendations on siting and monitoring, we present in the second part of this report a case study on site-screening and site selection in California.

In order to make the present study concise and readable, we focus our reviews of prior literature relatively narrowly and refer readers to more detailed review papers where appropriate. Our goal is not to thoroughly review the entire field of GCS risk-based site selection and monitoring, but rather to target our review toward what is relevant and significant for onshore (non-marine) California GCS opportunities, so that we can make practical recommendations pertinent to California appropriate for ARB to use in its development of the QM.

1.2 RISK-BASED SITE SELECTION

1.2.1 Introduction

Assuming the existence of a high-pressure pipeline source of anthropogenic CO_2, a GCS complex comprises three basic components: (1) one or more cased injection wells open to a deep subsurface reservoir with (2) sufficient capacity to store the required amount of CO_2 and sufficient injectivity to inject CO_2 at the same rate as CO_2 is supplied through the pipeline, and (3) a cap rock to contain buoyant CO_2 permanently (for hundreds to thousands of years). Although when stripped to its essentials, GCS site selection may appear to be a simple matter of optimizing the above three components, the fact is that the process of site selection involves assessment of a large number of site characteristics that are never knowable with 100% certainty. These include:

- Storage reservoir capacity, lithology, heterogeneity (e.g., compartmentalization of high-permeability regions), and structure (e.g., anticline or dome structure to contain the CO_2, or a long dipping reservoir for residual gas trapping in an open structure);
- Cap-rock lithology, mechanism for CO_2 exclusion (low-permeability or capillary exclusion), thickness, continuity, extent;
- Presence of secondary containment reservoir with its own cap rock, e.g., above-zone monitoring interval (AZMI) (Meckel and Hovorka, 2010; Hovorka et al., 2013; Kim and Hosseini, 2014), or pressure-dissipation interval;
- Locations and characteristics of wells and boreholes that could serve as migration pathways;
- Locations and characteristics of faults and fractures that could serve as migration pathways; and
- Locations and characteristics of subsurface resources that could be impacted by CO_2 or injection-induced brine leakage and migration.

Site characterization information is used to choose a site with the greatest likelihood of meeting the essential requirements of a GCS site, i.e., sufficient injectivity and capacity, along with capability of containing injected CO_2 for hundreds to thousands of years. By analogy with oil migration (e.g., Schowalter, 1979), CO_2 buoyancy is the underlying driving force that threatens long-term containment, the failure of which could lead to surface leakage. To counter upward buoyancy-driven CO_2 migration, cap rock or other sealing features are essential to CO_2 containment. Figure 1.1, taken from the report on cap-rock seals by The International Energy Agency Greenhouse Gas Program (IEAGHG, 2011), shows various sealing cap-rock lithologies with a qualitative scale showing degree of effectiveness to serve as a cap-rock seal. We have augmented the cap-rock seal figure by adding some indication of lithology typical of California cap rocks in the Sacramento and San Joaquin Valleys, which suggests high-quality cap rocks are available in the state.

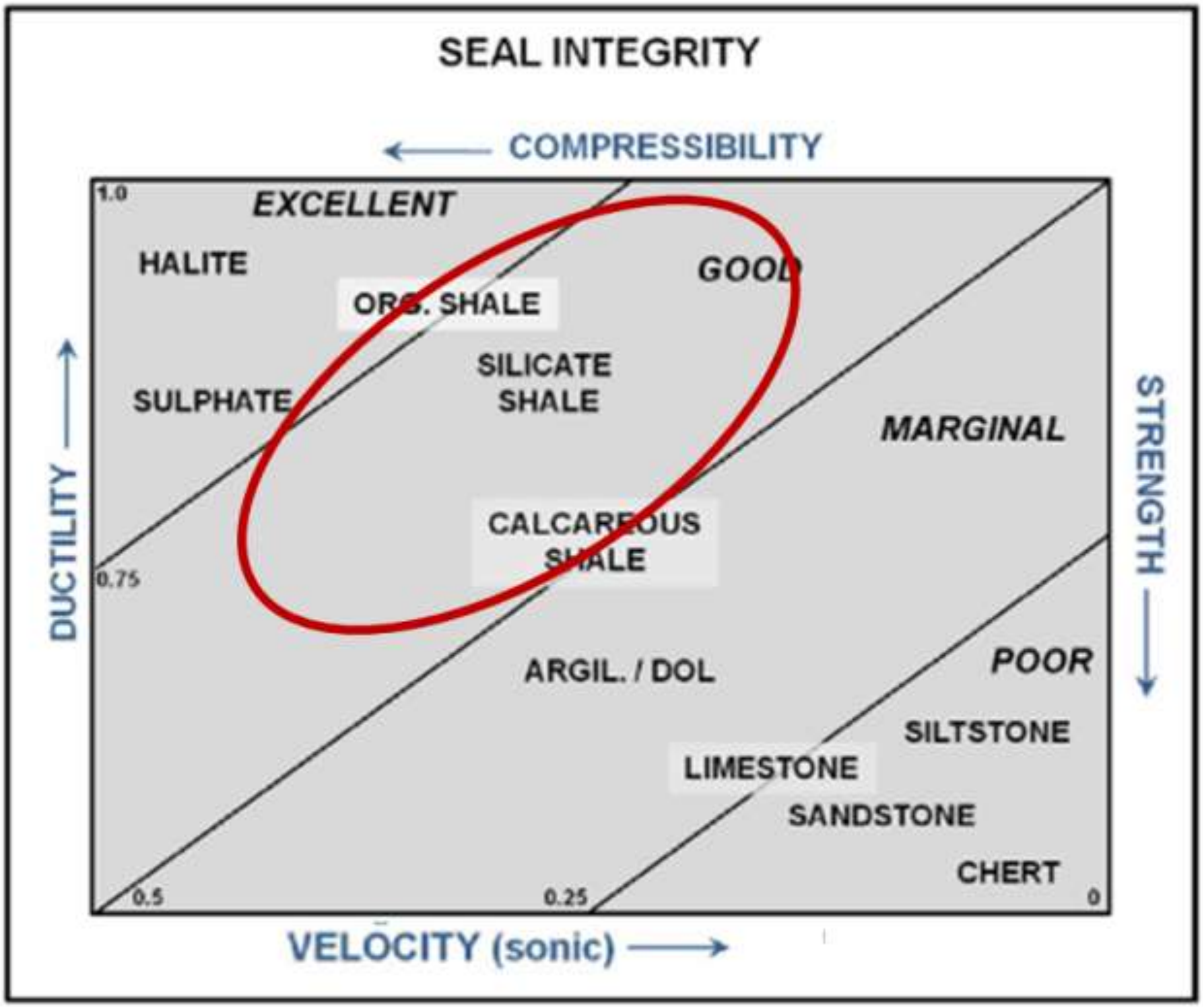


Figure 1.1. *Schematic showing relative ductility and strength (vertical axes) versus velocity and compressibility (horizontal axes) for various lithologies along with general quality of cap rock from a GCS perspective superimposed as diagonally oriented fields of excellent, good, marginal, and poor (modified from IEAGHG (2011) in which document the figure appeared with inadvertently transposed STRENGTH and VELOCITY labels on the axes). We have superimposed the red oval to indicate approximate lithologic characteristics of typical California cap rocks. We note also that siltstone should probably be plotted in the excellent region insofar as siltstone in California is commonly clay-rich, which makes it an excellent cap rock.*

But cap-rock effectiveness relies on much more than lithology and the properties plotted in Figure 1.1. For example, a cap rock needs to have sufficient thickness throughout the domain overlying the ultimate extent of free-phase CO_2 (e.g., not be too thin or pinch out in some locations). Aside from the cap rock, the other main potential leakage pathway is deep wells with either insufficiently constructed, degraded, or absent cement plugs and seals, either between the casing and formation, or within the well absent casing. And of course, over very long time scales and in certain conditions, groundwater containing injected CO_2 in its dissolved form may migrate around or through cap rock to a depth that allows it to degas into the atmosphere. These processes are sketched in Figure 1.2.

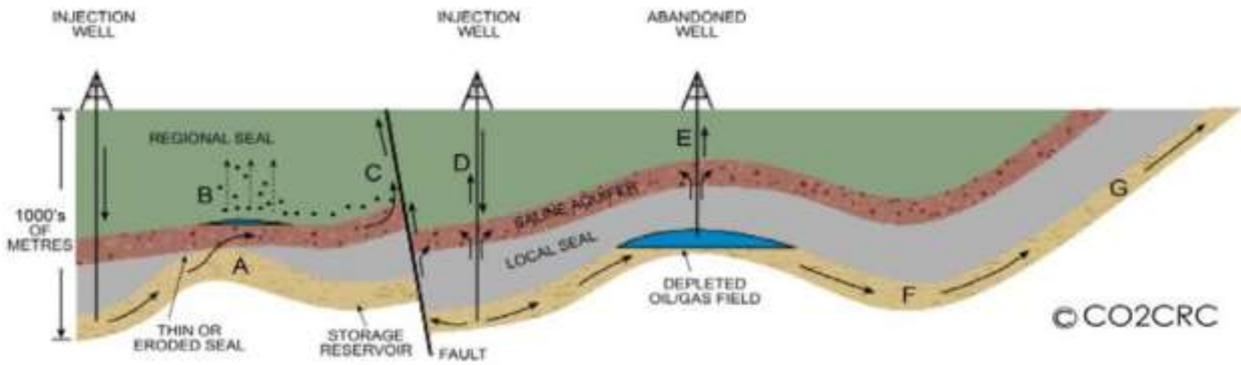


Figure 1.2. *Generic cross-section showing two CO_2 injection wells into a GCS reservoir (beige, bottom layer) underlying a cap-rock seal (gray) underlying an above-zone saline aquifer (brown) underlying a regional sealing overburden (green). Potential CO_2 leakage pathways and mechanisms are indicated by the letters A-G as follows: (A) CO_2 leaks out of the reservoir through an eroded gap (missing local seal), (B) the gas pressure of CO_2 accumulated in the above-zone saline reservoir exceeds the capillary entry pressure in the regional seal and leaks upwards, (C) CO_2 leaks upwards along a conductive normal fault, (D) CO_2 leaks up a poorly cemented annulus of a CO_2 injection well, (E) CO_2 leaks up a poorly plugged abandoned well, (F) regional groundwater flow transports dissolved CO_2 out of the structural closure, and (G) once out of the closure, groundwater transports CO_2 to surface springs and into the atmosphere. (Diagram from IEAGHG (2011) which was a modification from the original by Benson et al., (2005)).*

Assuming an effective seal exists to contain the injected CO_2, a secondary requirement arising in the QM context is that the CO_2 containment be verifiable, e.g., through monitoring the injected CO_2, its migration and trapping over time, and leakage out of the complex into, but still contained within, the deep subsurface. Of course, monitoring to detect explicit surface leakage of CO_2 from potential leakage pathways, e.g., wells or permeable faults or fractures, within the free-phase or dissolved CO_2 plume footprint is also an essential part of verification. Any such detection would be followed by monitoring to quantify the leakage. In the context of the QM, the plume footprint should include both the extent of injected CO_2 that is dissolved in brine (or any groundwater) in the storage complex, as well as the free-phase CO_2 plume. The reason for this is that CO_2 dissolved in groundwater in the deep subsurface may degas upon leaking upward to lower pressures (e.g., Oldenburg and Lewicki, 2006). In a subsequent section of this report, we will discuss this point further and delineate two plumes (free-phase and dissolved) for consideration.

An excellent GCS site will be one with mostly favorable features for meeting the essential requirements of a GCS site and very few if any of the undesirable features that could be antithetical to the storage objective. But the desirable features of good GCS sites are never known with 100% certainty. This is because the subsurface is highly heterogeneous over both small and large scales, and because the limited access to image, examine, or sample rock in the deep subsurface results in uncertainty in characterization. Therefore, site selection is inherently a risk-based undertaking where site data are inherently limited and uncertain.

Throughout this report, we use the term risk under its formal definition where it refers to the product of likelihood and consequences. For example, if we refer to surface leakage risk, we are referring to the multiplicative combination of a certain likelihood (e.g., frequency, or number of times per year) that a given surface leakage rate (e.g., in kg CO_2/day) will occur. So the term surface leakage risk carries with it both elements of likelihood and consequences.

Furthermore, the kind of risk that we are concerned with is technical risk. In this report, technical risk pertains to performance elements in the areas of containment of CO_2 within the storage complex, such as well integrity, and it also pertains to performance elements such as induced seismicity and fracturing. This is in contrast to project risk elements which involve the areas of finance, public support, government support, land access, legal and regulatory restrictions, among others.

By focusing on the technical risk of loss of CO_2 containment for the QM, we do not focus on health, safety, and environment (HSE) risk that has been the subject of most other GCS risk-based site selection studies. The distinction in objective is important because the threshold for CO_2 surface leakage relevant to the QM may be much smaller than it is for HSE risk. In other words, very small leakage rates or fluxes over many years can impact carbon credits and accounting (CCA), whereas these small leakage rates may not impact HSE significantly. For example, HSE impacts above ground typically require surface leakage, with a rate and duration sufficient to cause relatively high concentrations (>10–100 times background) that lead to exposures causing detectable and measurable harm. For the QM, surface leakage of concern may raise ambient CO_2 concentrations only slightly due to a large area of surface leakage or lack of sensitive flora or fauna in the area. Therefore, the surface leakage risk of concern relevant to the QM may not trigger any measurable consequences or impacts to HSE. On the other hand, the failure scenarios and leakage flow pathways (e.g., loss of well integrity in abandoned wells) may be the same, as might the likelihoods of various failure scenarios.

The perspective in this study is that the most important feature of a GCS site is its ability to contain CO_2 for hundreds to thousands of years. To further restrict the scope and purpose of the discussion and recommendations, we point out that it is surface leakage that is most relevant to the QM. However, it is important to recognize that subsurface leakage out of the storage complex can lead to surface leakage over centuries, and therefore deep subsurface monitoring is relevant to the QM, insofar as early warning of potential future surface leakage is necessary to allow mitigation of such leakage before it occurs at the surface. On the other hand, there are other forms of subsurface migration that will lead to either verifiable secondary trapping or indeterminately long migration time to the surface along very slow flow paths, neither of which is expected to lead to measurable surface leakage within a thousand years.

1.2.2 Review of Approaches to Risk-Based Site Selection

Geologic carbon sequestration (GCS) is generally proposed as a large-scale, carefully planned and permitted approach to reducing effective emissions of CO_2 from industrial operations that produce CO_2. Far from simply injecting CO_2 haphazardly into wells in the subsurface, GCS entails injecting CO_2 into targeted formations chosen for their sufficient capacity and injectivity to accommodate CO_2 at the required injection rate over time and for their top-boundary containment provided by effectively impermeable cap rock to contain the buoyant CO_2. The target for storage is often a primary clastic sandstone reservoir rock that may contain low-permeability shale or mudstone formations that act as baffles that spread buoyant CO_2 laterally as it slowly migrates upwards toward the uppermost cap-rock seal of the storage complex, such as at Sleipner (Chadwick et al., 2010). Such a target can be called a storage complex because it recognizes migration may occur laterally and upward within a sedimentary unit consisting of both reservoir and low permeability rocks. Note that the storage complex includes the cap rock, providing a definition for leakage as migration out of the storage complex.

In all cases, the complex must have an upper boundary cap rock that provides a top seal or barrier to upward migration. By this design, in which CO_2 partially or fully occupies small pores in rock deep underground in a storage complex, CO_2 is effectively trapped. Simply put, in the absence of a leaking well or a fault or fracture zone that compromises the integrity of the cap rock above the storage complex, there is no mechanism for CO_2 to escape back to the atmosphere over hundreds to thousands of years following injection. This understanding is backed up by studies of offshore hydrocarbon seepage rates which suggest very long natural residence times (many tens of millions of years) and very small natural seepage rates for buoyant and mobile oil and gas reserves (Kvenvolden and Harbaugh, 1983).

Capacity and Injectivity. Although the main characteristic of a suitable geologic carbon storage site is capacity, that is, the ability of the pore space in a volume of geologic material to accommodate and retain a large amount of injected CO_2, an equally important quality of GCS sites is injectivity. The sequestration objective cannot be met unless CO_2 can be injected through an economically feasible number of wells. Defined as the amount of CO_2 mass injected per unit pressure rise, injectivity describes the ease with which CO_2 injection can be carried out. While porosity volume may be sufficient to store a planned amount of CO_2, the injectivity may not be sufficient to do so as a result of volume-average permeability being too low.

For example, there are many highly compartmentalized oil and gas reservoirs with high permeability within compartments, but very limited hydraulic connectivity between compartments. Low-connectivity between compartments can be caused by low-permeability faults that cut through the formation, or by lateral lithologic variation, forming boundaries between compartments. The implication of low-connectivity for GCS is that a project may be more expensive because of the need to use multiple wells, or long-reach horizontal wells, to meet the injection needs of a large CCS project. A recent study by Jordan and Gillespie (2013) on injectivity in California suggests the geologic units with the most capacity in the southern San Joaquin basin are compartmentalized in a manner that would reduce large-scale injectivity.

On the other hand, large reservoirs without strong compartmentalization also exist, and individual nearly vertical wells completed in single reservoir intervals, such as the Mt. Simon, have been demonstrated to sustain an injection rate of ~0.4 $MtCO_2$/yr (Finley, 2014), and are planned to sustain a rate of 1 $MtCO_2$/yr in the same reservoir in the upcoming Illinois Basin Industrial Scale CCS project.

The main widely recognized potential failure scenario for well-chosen GCS sites worldwide is failure of well integrity (Gasda et al., 2004; Friedmann, 2007). For GCS surface leakage risk, both faults and fractures are also hazards for containment. The impacts of well-, fault-, or fracture-based leakage include impacts to adjacent or superjacent hydrocarbon resources (Oldenburg et al., 2008), groundwater degradation (e.g., Siirila et al., 2012), impacts to vegetation in the root zone, and surface leakage including health hazard (e.g., Oldenburg, 2007). The overall effectiveness (performance requirement) of GCS from a life-cycle emissions perspective was investigated by Hepple and Benson (2005), who determined that the average annual surface leakage rate must be less than 0.01% of injected CO_2 if GCS is to be an effective climate-change mitigation strategy. The Hepple and Benson (2005) study did not evaluate specific leakage pathways or suggest site-selection criteria beyond the need for capability to meet the overall performance requirement.

Despite the numerous variations in approaches proposed by researchers over the years on how to do risk-based site selection for GCS, all risk-based approaches stem from the same fundamental concepts. Specifically, risk-based approaches consider the likelihood and consequences of the hypothetical series of events referred to as failure scenarios. Estimates are made of the likelihood of the occurrence of the failure scenario or the existence of some property or feature that leads to the failure scenario. Risk is calculated as the product of the estimate of likelihood of the failure scenario and model- or experience-based estimates of the degree of impact or consequence that a given failure scenario will have on a resource or receptor. Risk assessment is carried out for prospective GCS sites as one part of the site-selection process. In actual GCS site selection and decision making, numerous considerations beyond optimal risk reduction (e.g., property ownership, proximity to source, etc.) will be involved. Here we focus only on risk-based site selection for surface leakage risk reduction.

Risk-based site selection utilizes risk assessment to select sites that present the lowest risk. Important foundational work for risk assessment of GCS was carried out in the mid-2000's. For example, a comprehensive features, events, and processes (FEP) database that is useful for identifying the totality of FEPs that contribute to a multitude of possible failure modes was presented by Savage et al. (2004) and Maul et al. (2005). Wildenborg et al. (2005) presented a scenario approach for GCS risk assessment and management. In the FEP-scenario approach, risk analysts develop simple narrative failure scenarios for systems comprising FEPs that lead to failure. By this approach, the likelihood of occurrence of various triggers and/or likelihood of the presence of various features can be evaluated in isolation. The total likelihood of the failure scenario can then be evaluated using Fault Tree Analysis, while the consequences can be analyzed using models and prior experience. Examples of the FEP-scenario approach for low-probability, high-consequence (LPHC) CO_2 pipeline and well-failure risk assessment associated with GCS are presented in Oldenburg and Budnitz (2016). In 2008, the US EPA proposed an overarching framework for identifying specific aspects of GCS projects that could lead to failure and associated impacts called the Vulnerabilty Evaluation Framework (VEF; Karimjee and Bacanskas, 2008). The US EPA suggested that stakeholders evaluate sites using the VEF to point to areas of concern where actual quantitative risk assessment should be carried out. The above examples of risk assessment approaches take advantage of dividing the potential failure into discrete pieces that can be analyzed and mitigated in relative isolation.

As stated above, most GCS risk assessment studies in the literature focus on HSE risk, and several variations in approach to leakage risk-based site selection have been proposed. For example, Bowden and Rigg (2005) applied an existing framework that utilizes Boston-Squares-type representations for quantitative risk assessment to HSE risk in GCS. Other early efforts in this field are Oldenburg (2008) who proposed a spreadsheet-based Screening and Ranking Framework (SRF) approach that considered secondary trapping and/or attenuation of leakage as significant and favorable impact-reducing properties of a site. The SRF approach with some modifications has been recently applied to the Shenhua site in China (Li et al., 2013). The Certification Framework (CF) laid out a risk assessment approach based on compartments to simplify and clarify the evaluation of impacts due to CO_2 leakage from the storage system (Oldenburg et al., 2009). Recognizing the need to consider uncertainty and variability in GCS systems, deLary et al. (2015) demonstrated the use of probability distributions for parameters in evaluation of GCS feasibility. In full recognition of the importance of uncertainty and variability in subsurface systems, the Department of Energy (DOE) sponsors a project called the National

Risk Assessment Partnership (NRAP) that is developing probabilistic approaches for evaluating leakage and induced seismicity risk for large-scale GCS projects (e.g., Pawar et al., 2016). While NRAP and many other researchers use proxies for risk such as concentration of leached metals in groundwater (e.g., Carroll et al., 2014), other researchers have considered exposure and modeled human health risk (e.g., Siirila et al., 2012).

As the above review suggests, the numerous efforts related to leakage risk assessment have emphasized HSE risk rather than loss-of-containment risk. One could argue that loss-of-containment is the first step in the chain of processes that would lead to leakage of sufficient magnitude to trigger HSE impacts, and therefore that loss-of-containment risk is implicitly part of HSE risk assessment. But the direct linkage of risk assessment of what could be very small-scale (small leakage rate) CO_2 leakage relevant to the QM to larger-scale CO_2 leakage relevant to measurable HSE impacts is not necessarily justified. For example, there could be CO_2 surface leakage occurring in a windy and unpopulated area with no protected groundwater such as at an existing oil field. In this environment, there may be no direct HSE risk due to CO_2 leakage, and yet from a CCA perspective, the leak could be very significant. On the other hand, the same features of well integrity and cap-rock effectiveness that control HSE risk assessment are also critical for CCA risk.

1.2.3 Risk-Based Site Selection in the California Context

Prospective sites for GCS in California are in sedimentary basins such as those in the Sacramento and San Joaquin valleys, and include the Santa Maria, Ventura, and the Los Angeles sedimentary basins. These sedimentary basins have a proven history of trapping buoyant fluids in certain structures such as those bounded by steeply dipping sealing faults and up-warped cap rock and combinations thereof as evidenced by California's large-scale hydrocarbon (oil and gas) accumulations. The Mediterranean climate coupled with the long history of oil and gas production, along with groundwater extraction, in these basins means there is a wealth of knowledge about the subsurface and characterization and monitoring programs are relatively easily carried out. This is not to say that all sites will be promising for GCS; California projects will have to deal with many existing wells and some faults, but will on the other hand have the advantage of year-round monitoring opportunities without interference of snow or ice cover or extreme weather. We recommend that risk-based site selection be based on failure scenarios developed using the FEP-scenario approach utilizing California's long experience and large existing knowledge base, and that site screening begin on multiple candidate sites using existing site characterization data (e.g., extensive oil and gas well database, and exploration seismic data sets that are available). The top candidate sites from screening can then be subject to more detailed assessments involving characterization wells until a final site is selected. It should be acknowledged that every site will have strengths and weaknesses. Shortcomings in various features of a site can be accommodated by site-specific operational design and careful monitoring plan development and implementation.

1.3 FAILURE SCENARIOS RELEVANT TO SURFACE LEAKAGE

1.3.1 Well-integrity failure

In the context of this report, wells are defined as manmade deep borings drilled into rock and used for one or more of the following purposes: (1) characterizing stratigraphy and pore fluids, i.e., exploration or characterization well, (2) monitoring fluid composition over time, or hosting monitoring equipment, i.e., monitoring well, (3) producing water from aquifers for beneficial use, i.e., water well, (4) producing water from aquifers for reducing aquifer pressure, i.e., a pressure control well, (5) producing oil or gas, i.e., an oil or gas well, (6) injecting or producing oil or gas for storage, i.e., an oil or gas storage well, (7) injecting fluids for disposal, e.g., liquid disposal well, (8) injecting water or steam for enhancing oil or gas recovery, e.g., a steam (or water) injection well, or (9) a CO_2 injection well.

Depending on the intended use of the well and other factors, wells may consist of various combinations of open hole (the boring in the rock), steel casings, cement (used to bond steel to the formation, and steel to steel), along with tubing (internal pipe) for injection and production of fluids, and possibly plugs and packers to isolate different regions of the well. Wells may also contain a wide variety of pumps, valves, down-hole mixers, monitoring probes, and other devices in the deep parts of the well. Probably the most significant wells contributing to loss-of-CO_2-containment risk are orphan, abandoned, or semi-permanently shut-in (suspended) wells. Orphan or abandoned wells may be filled only with mud, or filled with cement, or plugged in other ways over all or part of their extent. Many orphan wells were drilled decades ago using substandard methods and without documentation, may never have been plugged, and have over the years been forgotten and/or covered over by more recent agricultural fields, roads, or other development. Old wells which were plugged and abandoned according to regulations also present risk to GCS, especially those predating more stringent US EPA requirements, and because well plugs and casings degrade over time.

The main features of wells relevant to GCS site selection are (1) the depth extent of the wells that penetrate through cap rock, and thereby (2) provide a potential leakage pathway for subsurface fluids that compromises cap-rock integrity. To avoid such leakage, wells must maintain well integrity which can be defined as, "the application of technical, operational, and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well" (Norsk Sokkels Konkuranseposisjon (NORSOK), 2004; Corneliussen et al., 2007). In other words, well integrity is the condition of the well that prevents vertical migration of fluids, often referred to as zonal isolation. Many people refer to this as *wellbore integrity*, but insofar as the wellbore is the cylindrical cavity in the rock formed by the drilling process, the term *wellbore integrity* does not make sense and we recommend the use of the term *well integrity* instead. Well integrity ensures that (1) fluids cannot migrate through the well from one formation to another one higher or lower in the geologic section, and (2) fluids can only migrate from the subsurface to the ground surface under the control of the operator.

Well-Integrity Failure There are many documented examples of well-integrity failures relevant to the QM. One recent example is the blowout of the SS-25 well at the Aliso Canyon natural gas storage facility on October 23, 2015 (e.g., Conley et al., 2016). Although the investigation is not complete at the time of the writing of this report, there is suspicion that corrosion of casing led to the uncontrolled flow of high-pressure natural gas into the formation at a depth of approximately 500 ft (152 m). From that shallow depth, natural gas migrated through the overburden and leaked out into the atmosphere through the ground surface over a relatively wide area. Most of this migration appears to have occurred via fractures created in the overburden by the high pressure of the gas itself. Subsequent attempts to kill the well led to fluid entrainment which may have contributed to the formation of two craters around the well from which natural gas flowed into the atmosphere for nearly four months. Stopping the flow ultimately required intercepting SS-25 with a relief well at its perforation interval in the storage reservoir. The average leakage rate during the blowout was ~10^3 tonnes CH_4/d for a total leakage of ~10^5 tonnes CH_4 (California ARB, 2016).

Drilling Mud During the drilling of a deep well, pressure control is maintained by the driller through careful control of drilling mud density, which is evaluated and circulated in the hole to ensure that the pressure of the mud in the wellbore is a certain degree higher than the pressure in the formation. If the drilling mud is too dense, it can cause the formation to fracture; if too light, formation fluids can flow up the well. Failure to properly control mud weight can lead to blowouts.

CO_2 Well Blowout Case Study A CO_2 well-integrity failure occurred at Sheep Mountain, Colorado, site of a natural CO_2 dome (natural accumulation of CO_2). At Sheep Mountain, the CO_2 reservoir is contained within the Dakota sandstone with the Graneros shale acting as the cap rock at a depth of 3,400 ft (1,000 m). On March 17, 1982, a blowout occurred from a boring being drilled into the dome for well installation. Gas was observed leaking out of nearby wells and fractures in the ground. Estimates were made that indicated CO_2 gas leakage was occurring at a rate of 5.6×10^6 scmd ($\sim 10^4$ t/d = 35 million bbl/d). The leakage included dry ice chunks formed by decompression cooling being flung into the air. The release lasted 17 days as engineers tried various kill approaches until finally a dynamic kill succeeded (Lynch et al., 1985).

Deep wells are common in the same sedimentary basin environments that offer promise as excellent GCS sites because alternating sandstones and shales often contain trapped oil and gas, which are targets for exploration and production well-drilling activity. The canonical sketch of the plugged well showing various integrity failure mechanisms is shown in Figure 1.3 from Gasda et al. (2004). Orphan and old abandoned wells are a particular concern for well integrity because they are either lack documentation altogether or have inconsistent or very poor documentation of plugging and abandonment procedures. In addition, their age has allowed many decades of time over which processes could degrade their ability to contain fluids and fluid pressure.

Steel well casings are subject to corrosion in the deep subsurface and well cements may degrade over time leading to well integrity problems as sketched in Figure 1.3. Corrosion may be enhanced by carbonic acid created when CO_2 dissolves into water. Experimental research suggests that secondary minerals forming as a result of cement carbonation can plug voids between cement and steel (Carey et al., 2009), but one cannot generalize these laboratory results broadly to field situations. In general, cement degradation and steel corrosion must be considered potential contributing factors to well integrity failure. Geomechanical failure of wells is also possible if the well is sheared or compressed due to land subsidence or fault shear effects acting directly on the casing (e.g., Blanco-Martin et al., 2016). Finally, there are often very old wells with or without casing that were orphan or abandoned without sufficient care to prevent leakage, and these must be considered hazards to surface leakage of CO_2 also. Some orphan or abandoned wells may not be known or documented within well databases. When such wells penetrate to depths below regional cap rock, they are a particular hazard for surface leakage and motivate avoiding GCS in such areas, undertaking a well workover program, and/or implementing large-area monitoring for surface leakage at GCS sites in such areas.

Pressure Control in Wells Fluid pressure in the deep subsurface is commonly equal to approximately the hydrostatic pressure in sedimentary basins. When a fluid such as oil or natural gas or CO_2, all of which are less dense than water, occupies the well volume from bottom to ground surface, the pressure exerted by the fluid in the well at any depth is greater than the hydrostatic pressure in the formation around the well at that depth, and greater than the atmospheric pressure at the top of the well. This overpressure would cause the fluid in the well to flow into the rock or atmosphere in the absence of a sufficient well seal (casing or cemented annulus).

To prevent such flow, wells must be capable of containing the effective overpressure. Wells contain pressure by relying on steel casings, cement seals between casings and between casing and formation rock, and/or emplacement of specialized fluids (e.g., drilling muds with precisely defined density) for pressure control. Failure of any one of these pressure control features can lead to leakage up wells, potentially to the ground surface, or leakage into the formation through failed or casing or casing seals.

Water wells typically do not flow upward naturally because the density of fluid (water) in the well is approximately the same as the density of water in the formation surrounding the well along its length. In contrast, natural gas flows up the well without pumping, as does oil in the early phases of production from an oil accumulation because both natural gas and oil are less dense than water. CO_2 is also less dense than water, so pressure control or other barriers are needed for well integrity at GCS sites.

1.3.2 Well Leakage in the California Context

We assert that well-integrity failure is the main failure mode that could lead to surface leakage of CO_2 at GCS sites because (1) deep wells are common in California sedimentary basins in the same places that are excellent prospective GCS sites, (2) there are wells of varying age and condition, and (3) there is the possibility that undocumented wells will exist within the footprint of future GCS CO_2 plumes (free-phase and dissolved plumes). This assertion applies to both saline and enhanced oil recovery (EOR) sites for GCS. In fact, the failure mode whereby CO_2 leaks directly up the inside of a well bypassing underground sources of drinking water (USDW) is the very reason that the US EPA's Class VI (applicable to GCS for both saline and EOR sites) well designation and related requirements does not protect in every case against surface leakage. To state this differently, Class VI regulations protect USDW from degradation by CO_2 and displaced brine. However, some orphan, abandoned, or poorly maintained wells may be capable of sustaining CO_2 leakage from the reservoir to the ground surface without threatening USDW, either because USDW is bypassed or because it is absent, as occurs in some California oil fields. In addition, wellheads, or the tops of shallowly buried abandoned wells, could be vandalized or damaged leading to surface leakage up wells. Finally, the amount of CO_2 needed to materially and/or detectably impact USDW may be higher than the amount of interest to the QM for CCA. Hence there is the need for overlay regulations and monitoring protocols beyond Class VI for surface leakage risk mitigation in the context of the QM.

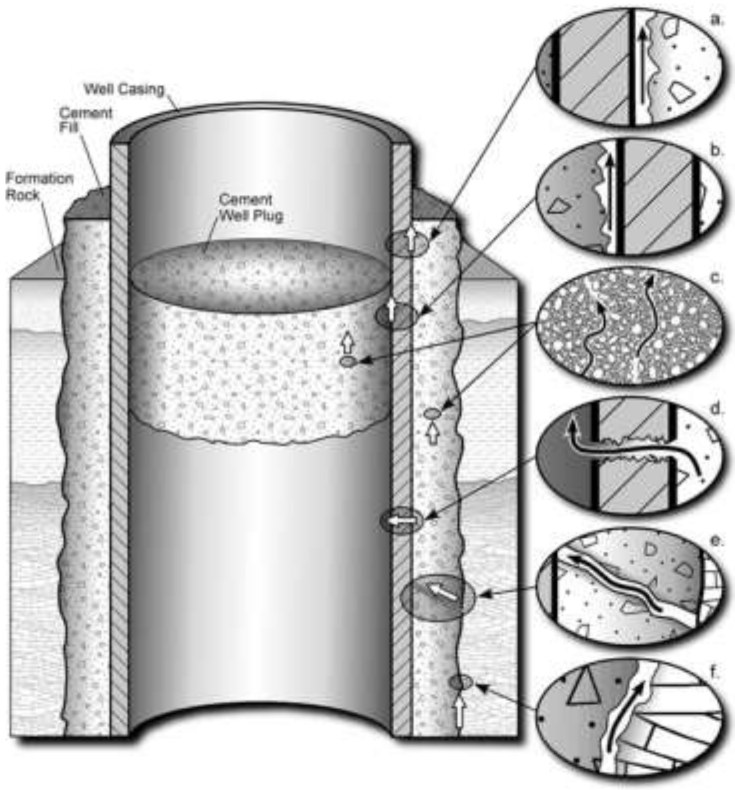


Figure 1.3. *Three-dimensional cross-section of a generic plugged well showing cement plug, production well casing, cement, and formation along with various failure modes (a) bad seal between casing and cement, (b) bad seal between cement plug and casing, (c) leakage through the cement pore space as a result of cement degradation, (d) leakage through casing as a result of corrosion, (e) leakage through fractures in cement, and (f) leakage between cement and rock. (From Gasda et al., 2004; drawing by Dan Magee, Alberta Geological Survey).*

1.3.3 Faults and Fractures

Faults are generally planar, large-scale (> 100 m) features over which adjacent rock masses have been displaced parallel to the feature. Normal and thrust faults sustain vertical displacement, while horizontal motion occurs on strike-slip faults. Fault planes can be discreet and narrow in width, or they can comprise many discreet subparallel slip planes with associated gouge and damage zones to form a fault zone of larger width. A sketch of normal faults with various features relevant to fluid-flow pathways is shown in Figure 1.4. Earthquake compressional and shear waves are the result of the sudden episodic movement of rock masses along faults, with larger earthquakes occurring on larger faults and on larger rupture areas over the fault “plane.” Fractures are generally planar discontinuities in rock that range from cm to 100 m in length and show no significant parallel displacement between adjacent rock masses. Fractures are generally smaller-scale features than mappable faults. Fractures do not include gouge or damage zones.

Because faults are breaks in what were originally continuous rock layers, they generally cause increased permeability relative to the permeability of the intact rock. But there are many exceptions to this owing to changes in rock properties that occur due to slip and fluid flow within faults. For example, rock slip tends to break up and grind rock into finer materials that can be further altered by reactive fluids at high pressures and temperatures, leading to low permeability. In addition, clay minerals from offset shale or mudstone horizons can smear in the fault zone creating a fine-grained, low-permeability barrier to flow. The result is often the formation of fault gouge and/or clay smear, which can have lower effective permeability and/or higher gas entry pressure than the rock from which it forms (Yielding et al., 1997). Fault permeability and potential for faults to serve as seals for storing buoyant, non-wetting fluids (e.g., oil, natural gas, and CO_2) can be estimated from the shale-gouge ratio (SGR) which quantifies the ratios of fine material (with high gas entry pressure) to coarser clastic material (with lower gas entry pressure) in the fault zone (e.g., Bretan et al., 2011).

Fractures, on the other hand, do not involve gouge or smearing. In fact, they are often propped open by asperities or infill material which leads to larger bulk permeability than the adjacent unfractured rock masses of the same rock type, unless the fractures become filled with new minerals (e.g., calcite veins), in which case they are no longer fractures but rather filled-fractures. The limited lengths of fractures relative to faults make them less likely to transect the entire thickness of cap rock. However, fractures induced by injection overpressure can propagate great distances, so one cannot ignore fractures in the context of GCS leakage risk.

For GCS surface leakage risk, both faults and fractures are hazards for containment. But unlike wells which always create a loss-of-containment risk, faults can be of different kinds and many act as traps by virtue of having reduced permeability or higher gas entry pressure, evidence of which is provided by the common occurrence of fault traps that have held oil and natural gas for millions of years. For example in California, the Midland fault and related normal faults in the Rio Vista area are very likely sealing faults that form effective traps for numerous large, natural gas reservoirs (Johnson, 1990). As for small faults and fractures, these need to be connected in an extended network to create flow paths across thick cap-rock seals (e.g., Sibson, 1996; Mazzoldi et al., 2012).

In summary, the existence of faults and fractures does not rule out a site for GCS (e.g., Kaldi et al., 2013), but rather means that careful consideration of faults and fractures is necessary in order to evaluate the loss-of-containment risk at each site. One of the main ways to reduce risk of fault leakage is to avoid locating GCS sites in areas of major or active faults. This includes making projections of plume migration so that faults are avoided throughout the evolution of the CO_2 plume trapping process (Jordan et al., 2011), and estimating whether connected pathways could exist for fractures and faults (Zhang et al., 2009). However avoiding such sites may be difficult in California given its existence at the margin between tectonic plates. Consequently assessment of the hydraulic properties of the faults within a proposed storage site is a necessary component of GCS project applications.

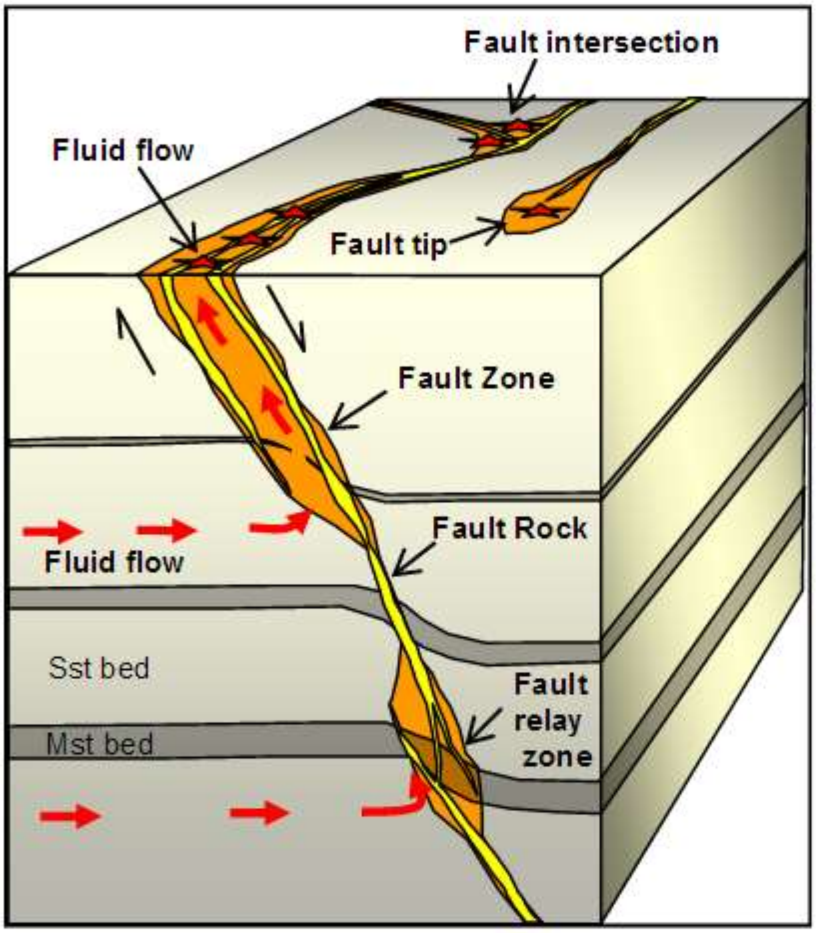


Figure 1.4. *Schematic block diagram of generalized fault zones (yellow fault cores and orange damage zones) and potential fluid-flow paths (red arrows) within permeable reservoir rocks and within fractures in fault zones. Fault relay zone refers to region where displacement transitions from one fault to another. Sst – sandstone, Mst – mudstone. (Figure is from IEAGHG, 2011).*

Significant research has been carried out relevant to the risk of fault-related leakage of buoyant CO_2. Several efforts have centered on the natural analogue site near Crystal Geyser on the Colorado Plateau in southern Utah where natural CO_2 leaks to the surface. Crystal Geyser itself is the most dramatic feature consisting of a periodically erupting cold-water CO_2 geyser that erupts through an improperly abandoned exploration borehole that penetrates a CO_2-charged aquifer and provides an apparently open pathway to the surface. Ancient travertine at the site provides evidence that a natural CO_2-charged spring existed prior to drilling of the exploration well. The other features in the area are fault-related surface manifestation of CO_2-charged water emissions in the form of travertine mounds and bubbling cold-water springs. Researchers have documented elevated overall CO_2 fluxes in the area with much of the flux likely originating from degassing of CO_2-charged water migrating upward from depth (Allis et al., 2005). The study by Heath et al. (2009) found that faults impeded horizontal flow but not vertical flow, and that despite significant formation of travertine in the area, self-sealing of the fault-flow paths does not occur. Shipton et al. (2004) documented clay-rich fault gouge in the faults that is usually associated with sealing faults, but near the Crystal Geyser system, such faults do not provide sealing against upward CO_2-charged spring waters. Despite some researchers finding anomalous CO_2 seepage fluxes associated with faults (Jung et al., 2014), other field campaigns attempting to document fault-related CO_2 gas emissions found limited elevated gas seepage along mapped fault zones (Allis et al., 2005).

Documented cases of fault- or fracture-related gas leakage include the LeRoy natural gas storage site in Wyoming, and the In Salah GCS site in Algeria. At LeRoy, it is believed that natural gas leaked to the surface through a known normal fault due to high pressure in the storage reservoir (Araktingi et al., 1984), although it is possible that a leaking well played a part (e.g., Chen et al., 2013). Regardless of the flow pathway, the gas leakage rate was reduced by limiting the pressure in the gas storage reservoir, and the facility continued to operate. The In Salah GCS site stored approximately 4 million tonnes of CO_2 (stripped from natural gas produced in the area) in a fractured sandstone reservoir 1,800 m (5,900 ft) deep in the Sahara Desert of Algeria from 2004 until 2011 (e.g., White et al., 2014; Rinaldi and Rutqvist, 2013). Multiple surface deformation monitoring approaches showed uplift above the horizontal injection wells, and a double-lobed uplift pattern above one of the wells (Vasco et al., 2010). Three-dimensional (3D) seismic imaging showed a possible fracture zone above the reservoir extending into the cap rock below the double-lobed uplift (Zhang et al., 2015). The most plausible explanation for the observations at In Salah is that high-pressure injection of CO_2 into the thin reservoir fractured the lowermost parts of the cap rock, allowing CO_2 to move upward within a fracture (Oldenburg et al., 2011; Rinaldi et al., 2014; White et al., 2014). With 950 m (3,120 ft) of cap rock above the reservoir, there is no compromise in cap-rock integrity at In Salah, but the case has served as a very useful example of the need to carefully consider geomechanical effects during the injection process.

1.3.4 Induced seismicity

Induced Seismicity from Waste-Water Injection While it has been well-known for several decades that fluid injection can cause earthquakes (e.g., Hsieh and Bredehoeft, 1981), it is only recently that this phenomenon is garnering worldwide attention, e.g., in Oklahoma due to large-scale injection of oil- and gas-production-related wastewater (Ellsworth, 2013). Much of the growth in production-related wastewater has accompanied growth in the use of hydraulic fracturing to produce oil and gas. It is important to note that the largest hazard of induced seismicity comes not from the hydraulic fracturing itself but rather from the disposal of wastewater through injection wells typically in deep bedrock formations (Ellsworth, 2013).

In the context of GCS, induced seismicity is a well-recognized hazard (e.g., Sminchak and Gupta, 2003; Rutqvist et al., 2008; Rutqvist, 2012). Injection-related induced seismicity most often causes microseismicity that does not cause any known damage nor is felt by the public. However, the few felt earthquakes, such as those in Oklahoma, some of which have also caused building damage, are a hazard for safety and public acceptance of disposal activities. Such seismicity is not normally considered a hazard for fluid leakage or contamination of water, soil, or air. In the GCS context, Mazzoldi et al. (2012) considered the potential for induced seismicity related to GCS to lead to CO_2 leakage from the storage complex. The Mazzoldi et al. (2012) study concluded that faults large enough to provide leakage pathways from deep reservoirs to the surface would be easily detectable during site characterization and could therefore be avoided, whereas smaller faults that were not detectable could provide only a short leakage flow path if reactivated, but this flow path likely would not extend very far above the reservoir.

1.3.5 Fault Leakage in the California Context

Because large conductive faults will be avoided in siting GCS sites, we assert that induced seismicity itself is not a hazard for CO_2 containment in the CCA context in California. Furthermore, some of the most promising GCS sites in California are in the San Joaquin Valley, which is relatively devoid of large faults, historic seismicity, and seismic hazard as shown in Figure 1.5. But leaky faults, whatever their cause, are a concern for CO_2 containment that must be addressed.

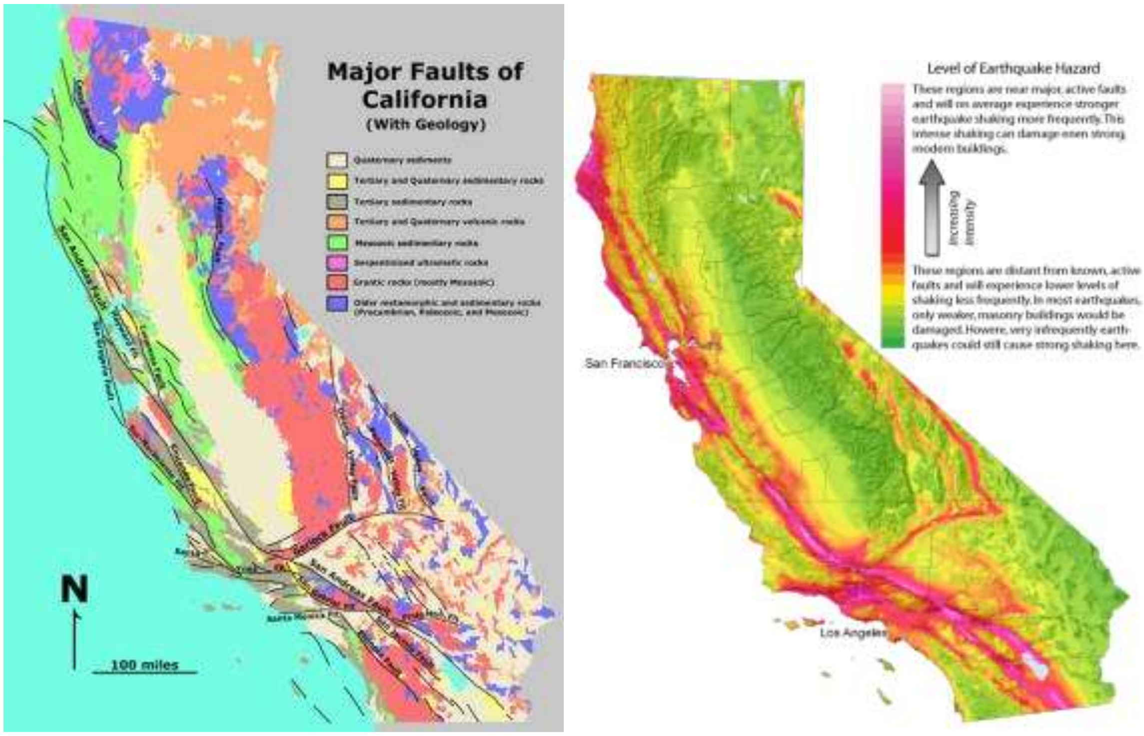


Figure 1.5. *(a) Major faults and general geology of California (source: http://geologycafe.com/erosion/tectonics.html accessed 10/15/16). (b) Earthquake hazard in California (source: http://usgsprojects.org/erol/California/index.html accessed 10/15/16).*

1.3.6 Well, Fault, and Fracture Surface Leakage Risk Mitigation

As discussed above, the main failure modes of concern in the CCA context are related to leaky wells, faults, and fractures. Among these three failure scenarios, well integrity is by far the main concern. The risk (likelihood multiplied by consequence) of fault and fracture leakage to surface is much smaller than well leakage risk. To summarize, the main failure modes relevant to CCA are in order:

1. **Leaky wells**. Leaks in wells can arise from orphan wells, improperly plugged and abandoned wells, old wells that have suffered corrosion or cement degradation, or they can arise in modern wells that suffer from defects, accelerated corrosion or cement degradation, geomechanical impacts, accidents at the well head, or human error in pressure control.
2. **Leaky fault(s)**. In the event that a free-phase or dissolved CO_2 plume encounters a large fault that extends through the cap rock, and even less likely that it extends to surface or shallow subsurface, there is the possibility that upward leakage of CO_2 could occur. Therefore, characterization of the fault is required to determine potential transmissivity. We suggest that the best mitigation of fault leakage risk is to avoid altogether sites with large faults, especially faults that extend from the reservoir to USDW or to the ground surface. Another possible configuration for leaky faults is a series of connected smaller-transmissivity faults that together produce a flow pathway

through cap rock that will ultimately lead to surface leakage. This can be mitigated by selecting sites with at least one ductile seal through which smaller faults will have low transmissivity. We emphasize again, that fault leakage risk is much lower than well leakage risk, and many faults are sealing faults.

3. **Fracture opening or fracture creation**. Fractures that produce a flow path through cap rock can ultimately lead to surface leakage. However, natural fractures in typical shales and mudstones are not likely to provide a connected flow path through the cap rock. On the other hand, fractures induced by overpressure related to injection can grow to large sizes (see Oldenburg et al., 2014) for theoretical treatment of this possibility, including the effects of buoyant fracture fluid). Therefore, the best way to mitigate fracture leakage risk is to avoid generating fractures by overpressure during injection.

1.3.7 Summary

The most effective mitigation of the risk of CO_2 surface leakage by the failure scenarios listed above is to avoid altogether the causal features, i.e., to select a site without leaking wells or leaking faults, and to operate the site such that fractures are not opened to create flow pathways for surface leakage. This strategy of avoidance of features that can lead to surface leakage as a way of mitigating risk does so by reducing the likelihood part of the risk equation. To maximize the chances of avoiding features that contribute to the likelihood of these failure modes, careful site selection is critical, and this topic will be covered below and in Part 2, where we discuss a site-selection case study.

To finish with the discussion of mitigating risk of the failure modes discussed here, we mention that well construction, well control, and well-integrity assurance are large industrial-scale technologies that have been in existence for decades and applied worldwide to all kinds of wells on and offshore for deep oil and gas exploration (e.g., Grace, 1994; King and King, 2013). The issues that will confront large-scale GCS in the area of well integrity have been anticipated (e.g., Gasda et al., 2004). If and when the need arises, service companies will be ready with effective technologies to mitigate the consequences of well leakage related to GCS. The goal of effective site selection and careful GCS monitoring is to mitigate risk by reducing the likelihood of leakage events, thereby avoiding ever having to mitigate consequences.

In contrast to mitigation of well-integrity failures, technology and experience in mitigating fault and fracture surface leakage consequences are non-existent. Some well-blowout scenarios involve what is called a breach blowout in which gas or oil leaks from cracks and fissures in the ground. We note that the 1984 Sheep Mountain CO_2 well blowout was a breach blowout that was ultimately killed by a dynamic kill approach, which stopped the flow of CO_2 from the reservoir (Lynch et al., 1985). Readers may recall that the concern for the Macondo well in 2010 was that installation of the capping stack would cause a subsurface well rupture and breaching of the seafloor, with associated oil and gas release no longer occurring only through the well but also through cracks in the seafloor, making it all but impossible to kill the well by any means except by relief well. Instead, the Macondo well held (did not rupture at depth to create a breach blowout) and the capping stack succeeded in stopping the flow of oil and gas into the Gulf of Mexico. This was two months prior to formally killing the well at reservoir level using a relief well (Hickman et al., 2012). To our knowledge, surface leakage during breach blowouts has never been mitigated by any means except by killing the well from the bottom by use of a relief well, i.e., stopping the flow from below rather than plugging the fissure(s). On the other hand, there has been success in minimizing subsurface fault leakage. The case of the Le Roy natural gas storage facility involved surface leakage of CH_4, and subsequent elimination of this leakage was done by limiting the storage reservoir pressure to levels that did not activate the fault flow path (Araktingi et al., 1984; Chen et al., 2013).

1.4 MONITORING TECHNOLOGIES AND APPROACHES

1.4.1 Introduction

Significant effort in the research community has gone into review and development of monitoring technologies and strategies for GCS sites. Excellent reviews are provided by the US DOE (Plasynski et al., 2011), IEAGHG (IEAGHG, 2012), the European Union (EU) (Rütters et al., 2013), and most recently by Jenkins et al. (2015) and Harbert et al. (2016). Even prior to these reviews and recent studies, it was noted that the toolbox of potential monitoring methods is large, and that the challenge lies in finding cost-effective approaches that are fit-for-purpose (Benson, 2006). In this section, we focus attention on recommending monitoring and verification strategies and technologies to address well integrity and fault surface leakage risk from the CCA perspective, which involves concern for potentially very small leakage rates, fluxes, and total amounts. In short, the context for monitoring as discussed in this report is the QM, as opposed to assuring health and safety, which would only be impacted above a threshold that may be much larger than the threshold of relevance for the QM.

Through the process of site selection, investment, permitting, and licensing, GCS sites will be expected to perform as required to meet the many objectives of the project, including long-term containment of CO_2. Therefore the focus of monitoring is on detecting, diagnosing, and efficiently correcting or managing unexpected behavior. Unexpected behavior can occur from failures involving known FEPs, but it can also involve unknown FEPs. For example, there may be unknown orphan or abandoned wells in the footprint of the pressure or free-phase CO_2 plume. The key for the QM is to account for unknown hazards in a practical and cost-effective way.

For the QM, i.e., in the CCA context, the ultimate concern is about surface leakage. But in order to anticipate and address unexpected behavior that could lead to surface leakage, monitoring of the injection and storage process in the reservoir and in other deep locations is necessary. An overriding objective of GCS is to avoid failure by diagnosing problems early so that appropriate operational and possibly remedial actions can be taken to address the unexpected behavior.

In order to estimate emissions from GCS sites, we recommend that modeling be used as a complement to monitoring. As described by Eggleston (2006) for the IPCC guidelines for national GHG inventories, there are four key steps:

1. Properly and thoroughly characterize the geology of the storage site and surrounding strata,
2. Model the injection of CO_2 into the storage reservoir and the future behavior of the storage system,
3. Monitor the storage system, and

4. Use the results of the monitoring to validate and/or update the models of the storage system.

The above basic workflow has been described in numerous figures and flowcharts (e.g., Plasynski et al., 2011). The heavy reliance on modeling comes from the fact that GCS involves a large degree of uncertainty. The modeling studies provide a degree of confirmation of the conceptual understanding of system performance. When the models match observations, there is confidence that the system is performing as it was designed. When the models disagree with observations, effort must be expended to understand why, and appropriate changes in conceptual and numerical models may need to be made.

In this section, we review monitoring technologies and approaches with a focus on the three main CCA-relevant failure modes (leaky wells, fault leakage, and fracture leakage), and with California's geography in mind.

1.4.2 Practical Monitoring of GCS for Containment Assurance

The deployment of monitoring equipment and monitoring effort needs to be distributed both temporally and spatially, and the approach and strategy should be flexible so that it can be potentially changed depending on the results of ongoing monitoring. First, as part of site characterization and/or before injection occurs, baseline monitoring needs to be carried out to develop an understanding of the storage complex, local groundwater composition, and ambient atmospheric GHG fluxes in the pre-injection condition. Baseline monitoring should also be used to establish whether there are other sources in the area of positive readings and to establish background levels of other sources of GHGs. Baseline data may be critical to avoid false positive and false negative readings after project operations have begun.

Many deep subsurface monitoring approaches are not precise enough to produce absolute images of subsurface properties, but they are good at indicating differences in properties from one time to the next, i.e., monitoring in so-called, time-lapse mode. For example, surface and borehole seismic surveys rely on models of the seismic velocity structure of the geologic units. The arbitrariness in velocity model makes any one seismic image uncertain in an absolute sense. But when one compares one seismic image taken pre-injection and another taken post-CO_2-injection using the same seismic network and same velocity model and with injected CO_2 affecting seismic wave speed, the difference between the two images can show the location of injected CO_2.

In fact, time-lapse comparisons and baseline pre-injection data are important for many monitoring approaches. Simply put, uncertainty in the subsurface is large enough that it is much more effective to look for changes away from the baseline related to CO_2 injection, than it is to try to discern absolute signals at discrete times. But in some monitoring approaches, baseline information is less important. For example, if tracers not found in the subsurface are injected with CO_2 as indicators of CO_2 leakage, clearly there is no need for a baseline sampling campaign. In the case of CO_2 captured from fossil fuels, the absence of ^{14}C in the injected CO_2 relative to the ^{14}C content of CO_2 in shallow fluid samples, can be a useful tracer of injected CO_2 (Oldenburg et al., 2003). Similarly, if monitoring, coupled with analysis of oxidation processes that consume and produce CH_4 and CO_2 is carried out on near-surface soil gas samples, baseline sampling is theoretically not needed (Romanak et al., 2012). We recommend flexibility in the

QM with respect to baseline monitoring data collection as long as the plan describes a defensible approach to leakage detection. The wide variability of sites does not lend itself to prescriptive time periods for baseline data collection, but one year would seem to be the shortest meaningful period.

Following baseline monitoring and during early phases of CO_2 injection, the focus of monitoring should be on the injection well and the reservoir near the injection well. Ensuring the integrity of the injection well should be a priority, because the well is subject to high pressures related to early phases of injection of CO_2, and off-normal effects due to any defects in well construction that allow leakage will tend to manifest early. Distant wells and areas far from the injection well(s) are not a priority at the initial stage of CO_2 injection because CO_2 and pressure will not have propagated very far this early in time. By the same logic, the pressure and free-phase CO_2 plume movement over the first year should be monitored to assure that the complex is behaving as designed. As time goes on and the plume and pressure footprint become larger, we recommend that the monitored area expand, while areas nearer the injection well may require less-frequent monitoring. At very late times and provided the storage complex has performed effectively as anticipated, the frequency of monitoring could be reduced as understanding and confidence in storage containment grow.

In general, we recommend that monitoring be divided into three main categories based on different objectives:

1. Standard operational monitoring: The purpose of standard operational monitoring is to verify that the storage complex is behaving as expected based on site characterization and design modeling and simulation. Operational monitoring is aimed at locating and tracking the migration of CO_2 and pressure within the storage complex. If CO_2 or fluid pressures show benign excursions from expected behavior, then operational monitoring should be focused on understanding why, and evaluating whether the behavior represents a threat to containment.
2. Contingency monitoring: The purpose of contingency monitoring is to alert the operator when the storage complex is not performing satisfactorily, and to indicate how it is deviating from plan. Contingencies include early signs that containment features (e.g., well cement, well casing, or cap rock) are failing. The purpose of contingency monitoring is to provide the indication of potential failure or early indications of failure so that mitigations and corrective actions can be taken to avoid progression of the failure. Contingency monitoring is focused on the known containment barriers and system elements such as wells and cap rocks.
3. Surface leakage detection and quantification: The purpose of surface leakage detection and quantification is to locate and assess the rates and/or amounts of leakage that occur. The detection part of this kind of monitoring is particularly challenging because it involves addressing unknowns such as unidentified orphaned or abandoned wells, faults, and fracture systems. The quantification part of this kind of modeling is also very challenging, especially in the QM context, because CO_2 is naturally present in the shallow crust, groundwater, soil, and atmosphere, and special analyses or approaches must be taken to quantify leakage of injected CO_2 as distinguished from natural CO_2. In addition, the leakage amounts and fluxes may be

very small, on the order of natural fluxes in the environment, e.g., drawdowns due to photosynthesis or efflux due to soil respiration.

In Figure 1.6 we present recommended approaches to monitoring divided into the three categories listed above. We do not recommend that all approaches be required at all times, but rather that project operators consider these approaches and develop a sufficiently detailed monitoring plan such that an expert in GCS monitoring can review the plan, understand the monitoring rationale, and confirm its intended effectiveness. These approaches should be applied in different regions both on the land surface and in the subsurface, and at different times as needed. The ability to be flexible, as well as persistent, is critical to monitoring success and containment assurance. Table 1.1 provides general details on the various monitoring approaches and technologies. Again, our recommendation is not that every approach needs to be followed, but rather that the monitoring plan be tailored to the site and stage of injection progress with appropriate use of technologies such as those listed in Table 1.1 to satisfy the needs of the QM as required by ARB.

	2D, 3D surface seismic	Cross-hole seismic	Electrical resistivity	Seismic monitoring network	InSAR, tilt	Formation pressure, temperature	Fluid sampling for composition and/or saturation	Tracer analysis (natural and introduced)	Well logging	Well integrity monitoring	Well-pad-based surface monitoring	Broad-area surface monitoring (AC, EC, open-path IR)	Vadose zone monitoring	Vegetative stress and related direct observations	
Location of injected CO2 plume	X	X	X				X		X						
Injection pressure propagation				X	X	X									
Fluid migration into above-zone interval(s)	X	X	X			X	X	X	X	X	X				
Well integrity									X	X					
Seismicity				X											
Deep fluid leakage up well(s)					X	X	X	X	X	X	X				
Deep fluid leakage up fault(s)/fracture(s)					X	X	X	X							
Fluid migration into USDW						X	X	X							
CO2 migration into shallow subsurface						X	X	X	X	X			X	X	*
CO2 leakage into surface water							X	X	X	X		X			*
CO2 surface leakage (to atmosphere)							X	X	X	X	X	X	X	X	*

(green) standard operational monitoring

(yellow) contingencies, early warning that surface leakage may occur

(pink) surface leakage detection and quantification

* attribution may be necessary

Figure 1.6. *Classes of monitoring objectives (rows) and technologies (columns) organized by purpose of monitoring (assurance, early warning, surface leakage). Note that different processes occur over different time scales, and that the frequency of monitoring must be sufficient to ensure effective observation of the dynamics of system behavior.*

Table 1.1. *Monitoring tools and technologies for the three main classes of monitoring objective, Standard operations (green), Contingency (yellow), and Surface leakage (pink). Layout is for 11 × 17 inch paper.*

Class	Monitoring approach	Property Measured	Technology/instrumentation	Property Interpreted	Sensitivity	Depth of Investigation	Radius of Investigation	Reliability	Repeatability	False Positives	False Negatives	Cost
Standard operational monitoring	2D-3D Surface Seismic	Seismic wave velocity is a function of fluid/phase composition	Accelerometers, geophones, hydrophones	Volume or fraction of CO_2 in the pore space	can show large volumes, dependent of rock/fluid properties for small leaks	3D	3D	Established technology	Variable, experience in quantifying 4D 'noise'	possible within 4D noise level	possible within 4D noise	expensive; $$/square km
	Crosswell seismic	Seismic wave velocity is a function of fluid/phase composition	Accelerometers, geophones, hydrophones	Volume or fraction of CO_2 in the pore space	sensitive to changes in moduli	well depths	well spacing	varies with rock properties	generally good	possible within 4D noise level	possible within 4D noise	$200K and up per well pair
	Electrical Resistivity (surface or borehole)	Electrical resistivity is a function of fluid/phase composition	Electrodes	Volume or fraction of CO_2 in the pore space	sensitive to changes in fluid conductivity	reservoir depths	depends on acquisition geometry	varies with rock properties	good	possible within 4D noise level	possible within 4D noise	
	Seismic monitoring network, microseismicity (MEQ)	Seismic wave arrivals/speed	Accelerometers, geophones, hydrophones	detect and locate fracturing near wells and shearing at faults	variable	depth of fracturing	km's	Established technology	depends on fracturing/shearing	can have events without fluid flow	can have fluid flow without events	variable after initial deployment cost
Contingency monitoring	InSAR (satellite-based)	Monthly observation of surface defomation	Satellite based synthetic aperture radar	Invert with coupled geomechanical modeling to interpret depth of pressure-related surface deformation	senstive to large-scale deformations with mm-scale uplift/subsidence	With interpretation, depth range extends to reservoir	Unlimited areal extent	good	good with point scatterer	possible due to non-uniqueness	possible due to non-uniqueness	generally low cost
	Tilt (surface and well-based)	cumulative shearing and deformation	MEMS inclinometer	pore pressure change, uplift	good for small-creeping and large-sudden shearing of the rock	3D but non-unique with depth/magnitude	3D	Established technology	good repeatability	possible due to non-uniqueness	possible due to non-uniqueness	variable, large initial deployment cost
Surface leakage detection	Distributed temperature sensor (DTS)	sharp change in temperature at specific depth and time, showing leaks	Fiberoptics	inverting depth/time of leaks	Sensitive to flow rate of leaks and well breaks, can be coupled with modeling	Along the wells	at wells	Very relieable for shallow reservoirs, may have some noise for steam-stimulated high-T conditions	Real-time data with operation			not expensive
	P/T/S profiles	sharp change in P/T/S may show well leaks	Various transducers, thermisters, well logging tools	inverting depth/time of leaks, also calibrating reservoir model	Sensitive to leaks	along wells	at wells	may be continuous or at survey times				not expensive
	Fluid phase composition	Fluid composition between non-leak and leak conditions	Analytical chemistry, ICPMS, etc.	May indicate leaks by changes in fluid compositions	High sensitivity but must be careful to avoid interpreting natural changes as being leak-related.	Multiple depths depending on results of well inspection	Near-well region	Basic/routine monitoring tools for normal or anormalous operations	Repeatable notwithstanding evolution of flow and failure mechanisms			Cheap
	Routine Field Inspection and fluid sampling	CO_2/CH_4/oil/bubble expressions (location, composition, flow rate) at ground surface	Field survey/inspection, drone photography, etc.	Direct evidence of reservoir leakage to surface. May be able to back-track flowpaths to shallow aquifer, and to the nearby wells with monitoring	Directly shows leaks with known location, fluid composition, and flow rate.	Ground surface	areal extent of the GCS site	Reliable. Most important to large leaks	Leak-specific events; repeatable with synthetical examples			Cheap
	Tracer analysis	Composition of fluid samples, concentration of tracer (natural or artificial) in the fluid)	Analytical chemistry, ICPMS, etc.	Indicates injectate	Variable depending on choice of tracer	Multiple depths depending on where sample was taken	areal extent of the GCS site	Variable depending on choice of tracer	Variable			
	Well Logs	many properties	Induction tools, neutron capture, acoustic, sonic	many properties	variable	well depths	typically 1 m	good	good	variable	variable with log type	variable with log type
	Continuous P/T monitoring in wells	Continuous P/T data may show P/T anormalies with time showing leaks	Various transducers, thermisters, well logging tools	Rate/depth/time of well leaks and well/reservoir rock properties	Sensitive to failure scenarios (e.g., slow or suddent well breaks), coupled with reservoir/leakage modeling	Better to position above and below the known shear zone	at wellbore showing anormalies in vertical flow	P/T data should be precise, but inversion of leaks based on their anormalies needs good inversion framework for leakage detection				cheap
	P/T at gauges	Anormalous signals showing well leaks		Rate/depth/time of well leaks and well/reservoir rock properties	High	Along full length of well	Local to well	Basic and routine monitoring tools with long record of reliability	Repeatable notwithstanding evolution of flow and failure mechanisms			Cheap
	Atmospheric monitoring	CO_2 or other gases associated with storage complex (e.g., CH_4 in the case of injection into hydrocarbon reservoir)	Open-path laser (IR absorption), Fourier Transfor IR (FTIR) spectrometry, FLIR Cameras	Evidence of reservoir leakage to surface. May be able to back-track flowpaths to shallow aquifer, and the nearby wells with monitoring.	Directly shows leaks with known location, fluid composition, and flow rate.	near-surface	areal extent of the GCS site					
	Soil Gas Measurement	CO_2/CH_4 gas composition	Accumulation chamber, direct sampling, closed-path IR absorption	Detect anomalous CO_2/CH_4 concentrations. May be able to back-track the leak path to nearby leaking wells	Directly shows leaks with known location, fluid composition, and flow rate. Can be incorporated into leakage model	shallow subsurface	Small region around soil-gas sampling port. Campaign can be carried out at scale of areal extent of the GCS site.					
	Camera or spectral imager	Change in color or light absorbance	Satellite, plane, or drone-based spectral analysis	Root-zone soil CO_2 (stresses plant) or increased free-air CO_2 (fertilizes plant)	variable	Root zone (up to approximately 2 m)	Foot print of plant(s)	High	May be seasonal or meteorological overprint			

1.4.3 Monitoring for Specific California Failure Scenarios

1.4.3.1 Introduction

California's Mediterranean climate coupled with large-scale agricultural activities, low topographic relief, and low population density in the regions broadly amenable to GCS provide excellent opportunities for year-round monitoring. In this section we discuss some specific approaches that might be applicable for various monitoring objectives. Through analogy with natural gas storage, we first describe advantages of so-called negative accounting as the overall concept for quantifying CO_2 storage. The significance of the ability to precisely account for stored CO_2 is that uncertainty in accounting can lead to loss of storage credit. This is followed by a discussion of the timing of leakage relative to arrival of the separate-phase CO_2 plume, which informs the spatial and temporal distribution of monitoring.

1.4.3.2 Positive accounting

One commonly proposed conceptual approach to storage accounting is to quantify the amount of CO_2 stored in the reservoir. We term this "positive accounting." This involves calculating the amount of CO_2 stored in the reservoir from measurements, such as pressure in wells accessing the reservoir and changes in seismic reflection characteristics.

To explain positive accounting, we present here the approach as it is used in underground natural gas (CH_4) storage. Positive accounting is performed using the non-ideal gas equation

$$PV = znRT \tag{1}$$

where *P* is the average gas pressure in the storage reservoir, *V* is the void volume in the reservoir occupied by gas, *z* is the (non-ideal) compressibility factor, *n* is the number of moles, *R* is the universal gas constant, and *T* is the average absolute temperature in the reservoir volume occupied by gas. The number of moles *n* is directly proportional to the gas inventory. Rearranging the equation to solve for *n* yields

$$n = zRT/PV \tag{2}$$

The inventory uncertainty based upon this equation, modified from Tek (1991), is

$$\frac{\Delta n}{n} = \frac{\Delta z}{z} + \frac{\Delta T}{T} + \frac{\Delta P}{P} + \frac{\Delta V}{V} \tag{3}$$

where each term represents the relative uncertainty in that parameter. The uncertainty in *z* is small (<1%) given the detail with which the composition of the stored gas is known, and the relatively small range over which *z* varies. The uncertainty in *T* is larger because it is an average over the reservoir based on point measurements. However *T* is a spatially continuous parameter that can be measured ahead of gas storage, and is only moderately altered by the storage process itself given the density and heat capacity of the gas relative to the reservoir matrix and residual fluid saturations. So uncertainty in the estimate of *T* should be on the order of 1%.

Uncertainty in *P* is larger still, because it is substantially altered by the storage process. Pressures for inventory measurement are typically taken after shutting in the storage field wells for some period of time to allow the pressure at the wells to equilibrate with pressures in the reservoir. During active production or injection, these pressures are necessarily out of equilibrium, as that is what causes the gas to move out from or into the wells. Unless there are a sufficient number of observation wells, the average pressure across the reservoir volume calculated from storage well pressures will be biased low if they have been on production and high if they have been on injection.

Recent experience examining reservoir operations associated with the Aliso Canyon underground gas storage facility Standard Sesnon-25 well blowout provides perspective on the uncertainty in average reservoir pressure due to the duration of the shut-in time. According to monthly data available from the California Division of Oil, Gas, and Geothermal Resources (DOGGR), there was almost no gas produced from the field from February through May 2016 (~24 billion cubic feet (bcf) produced in January versus less than 20 million cubic feet, which is less than 0.1% of the January production, in each of the following months). However, the average tubing pressure for wells with non-zero data from February to May increased by 11.5%, 12.6%, and 13.3% in March, April, and May, respectively, relative to the average pressure in February. This indicates that even with approximately 100 wells in which to measure pressure in that field, the equilibration time is at least one month for 2% uncertainty.

The largest uncertainty is likely the estimation of the void space in the reservoir occupied by stored gas. This term involves porosity, saturation (residual) by oil and water, and reservoir volume. For instance, there are about 600 core porosity measurements in the records held by DOGGR for the approximately 100 gas storage wells in the Aliso Canyon field. These measurements indicate a 2% uncertainty in this parameter. Increasing the number of measurements into the thousands, for instance, by including log porosity measurements, would decrease this uncertainty to 1%. The uncertainty in liquid saturation is likely to be at least as large, because it is more difficult to measure accurately in core samples due to the potential for evaporation, and in logs due to calibration uncertainty. Finally, at Aliso Canyon, the uncertainty in reservoir thickness is greater than 5% when taking the true vertical distance from the top to the bottom perforation of wells extending through the gas storage reservoir.

Table 1.2 summarizes the uncertainties discussed for the Aliso Canyon gas storage volume. This table indicates that even for a facility with a larger number of wells than typically envisioned for a geologic carbon storage facility and a greater degree of operational control and data, the uncertainty in positive accounting is sufficiently large to substantially reduce the amount of injected CO_2 that is considered permanently sequestered relative to the amount of CO_2 injected.

Table 1.2. *Uncertainty in positive accounting of natural gas stored in the Aliso Canyon field.*

Parameter	**Uncertainty**
Non ideal gas constant (z)	<1%
Temperature (T)	1%
Pressure (P)	2%
Porosity (ϕ)	2%
Residual liquid saturation (S_r)	>2%
Reservoir thickness (t)	>5%
Volume (V; subtotal ϕ, S_r, t)	10%
Total	13%

Further, the discussion above pertains to only the CO_2 forming a separate phase. With increasing time, a growing fraction of the CO_2 is dissolved in the brine and, if present, in the oil in the storage reservoir. Quantifying this portion of the stored CO_2 is even more difficult because the physical properties of these liquids contrast less with the liquids in the formation prior to storage than does the separate phase CO_2. Consequently, inclusion of the dissolved CO_2 increases rather than decreases uncertainty, and therefore affects the potential reduction in the amount of CO_2 considered permanently sequestered relative to CO_2 injected.

1.4.3.3 Negative accounting

Another conceptual approach to accounting is to quantify the amount of CO_2 leaked from the storage reservoir, and subtract this from the amount injected. We term this “negative accounting.” This is akin to the approach specified in 40 CFR §98.443 (in Subpart RR). Equations RR-11 and RR-12 govern the annual reporting of the amount of CO_2 sequestered. These equations subtract surface leakage, as well as leakage from surface equipment between the flow meter and the well along with some other terms, from the total volume injected.

Instead of subtracting surface leakage, we recommend subtracting leakage out of the storage complex (which includes both the storage reservoir and the overlying primary seal), because monitoring the fate of this indefinitely is outside the scope of the project plan and is likely not cost-effective relative to the credit value of the leaked CO_2. We also recommend that project applicants submit the detection limit for each potential pathway based on the monitoring proposed, and that ARB review these limits. In the absence of any detected leaks, we recommend using these detection limits to quantify the amount of CO_2 to subtract from the amount injected and determine the amount stored. This is a refinement to the approach in Subpart RR, which does not discuss detection limits.

We recommend the use of the negative accounting method, because monitoring detection limits are sufficiently low that negative accounting will result in a considerably smaller reduction in the quantifiably stored CO_2 than that of positive accounting, with its large uncertainty values. For example, Hoversten et al. (2005) determined that subsurface accumulations considerably less than 10,000 tonnes (1 tonne = 1 Metric ton = 1 Mt = 1.1 ton) can readily be detected in seismic reflection data. Consequently if no such secondary accumulation is detected in an area monitored by seismic reflection five years after the passage of the free-phase plume front in the storage reservoir below, the detection limit is less than 2,000 tonnes per year (assuming fast transport from the storage reservoir to the pressure-dissipation interval recommended in the site-selection section). This detection limit indicates that the amount of injected CO_2 that cannot be verified as sequestered in the negative accounting approach would be substantially smaller than in the positive accounting approach.

The above is not to suggest that the use of seismic reflection should be mandated. Rather we recommend leaving the choice of method(s) up to the applicant (and as approved by ARB), so the applicant can optimize the cost of monitoring against the amount of CO_2 that cannot be verified as sequestered as controlled by the detection limit for each method.

Also, the detection limit for a particular method is not necessarily the detection limit of that method as applied to an entire project. For instance, for seismic reflection, the detection limit is based in part on the accumulation area in the dissipation interval. Thus, there could be numerous sub-detection limit accumulations that total to more mass than the detection limit. In addition, if the frequency of measurement is too low, the effective monitoring detection limit could be compromised if episodic leakage is occurring. Although we expect sub-detection limit leakage to be low for approved monitoring plans, we recommend that ARB direct further research at quantifying how much surface leakage can reasonably be expected to occur from leakage values below various detection limits.

1.4.3.4 Leakage Timing

As discussed in the site-selection section below, leakage from natural gas storage facilities in aquifers provides information regarding when such leaks occur relative to the project history. Of the two underground gas storage facilities in aquifers in Illinois, for which the timing of surface leak detection relative to project initiation is available in Buschback and Bond (1973), both detections were less than a year after the initiation of storage. Surface leak detection at the LeRoy natural gas storage facility was detected six years after initiation of storage, which is three years after the first inventory peak followed by winter drawdown, and two years after the largest inventory prior to leak detection. The study concluded the leak likely started at the time of either the first inventory peak or the largest inventory peak, two to three years prior to detection. Tracer studies indicated the leakage time from storage reservoir to surface was less than one year (Araktingi et al., 1984).

In each of these cases, the leakage path likely involved geologic pathways, at least in part, because investigations of potential leakage via wells were followed by workovers to preclude well leakage, and these did not stop the leakage. Consequently, the leakage timing in these cases suggests that if leakage occurs via a geologic pathway, it is likely to commence relatively shortly after free-phase CO_2 encounters the leakage path.

Research has shown a similar result for leakage via inactive wells (idle or abandoned). Watson and Bachu (2007) concluded that well leakage was correlated to initial construction details rather than age. This suggests that if leakage along wells occurs, it is most likely to occur when free-phase CO_2 encounters the well. Jordan and Carey (2016) found most blowouts from inactive wells in the southern San Joaquin Valley involving steam, which is another buoyant fluid, occurred when the steam encountered the well, providing further support to the findings of Watson and Bachu (2007).

1.4.3.5 Surface Leakage

Monitoring plans are needed to identify, locate, and quantify leakage, if any, from leaky wells, leaky faults, and leaky fracture networks. Although the well leakage failure scenario is by far the biggest threat to CO_2 containment in California, the monitoring plan for such leakage, insofar as it considers unknown wells, can largely be used as-is to monitor for leakage from leaky faults and fracture networks. This is because the same challenge of unknown leakage location exists for unknown wells as it does for unknown faults and fracture networks. In both cases, the monitoring approach needs to have a large spatial sampling area in order to detect what may be small and localized leakage sources from within a much larger area.

In the case of leakage from unknown wells, faults, or fractures, one has to assume there will be no subsurface detection and the first manifestation of leakage may be at the ground surface. In order to detect such leakage, we recommend broad aerial monitoring focused on the footprint of the free-phase plume, e.g., using large-scale, open-path laser infrared (IR) methods (e.g., Trottier et al., 2009) or other remote sensing methods such as vegetative stress, spectrographic, or thermal. All of these methods require careful baseline measurements to establish pre-project conditions and anomalies unrelated to GCS activities. To the extent possible, monitoring should be continuous. For the inherently intermittent methods, the periodicity of monitoring should be proposed, defended, and approved as part of the monitoring plan. If hints of potential surface leakage are found, we recommend that the locations with anomalous readings be visited on the ground for more detailed investigation, e.g., using accumulation chamber, eddy-covariance, or handheld thermal IR (so-called forward looking infrared (FLIR)) cameras to precisely locate leakage sources. These same instruments can then be used to *quantify* leakage rates. Note that leaky wells may be indicated by flowing brine, water, or associated deep reservoir gases such as CH_4, or hydrogen sulfide (H_2S), in addition to CO_2.

In the case of potential leakage via known wells, faults, fracture zones, and other features, more intensive and periodic monitoring methods should also be deployed at the surface and near surface. For instance, eddy covariance towers can be used in areas with multiple wells and vadose zone gas monitoring can be used adjacent to isolated wells. Unlike the broad area methods recommended above to monitor for leakage from unknown features, monitoring for leakage from known features can step out sufficiently ahead of the leading edge of the free-phase plume, to provide a baseline, and stop at a specified time after the passage of the plume front. The timing of leakage via wells and geologic pathways discussed above suggests that monitoring for two years after passage of the plume front should be sufficient.

1.4.3.6 Subsurface Migration

As shown in Table 1.1, surface and borehole seismic surveys, and possibly electrical resistivity tomography (ERT), are the standard approaches to locating the injected CO_2 plume in the storage complex. Subsurface migration away from the storage complex (i.e., leakage) may be detectable if it is above a certain volume and mass, for instance as indicated by Hoversten et al. (2005) and discussed above with regard to negative accounting. Deep well monitoring of P, T, and X (concentration or phase saturation) can also indicate deep subsurface migration. In the San

Joaquin Valley, lands managed for agriculture should provide a good number of permanent radar reflection scatterers for interferometric synthetic aperture radar (InSAR), by which ground deformation can be detected and modeled to indicate unexpected subsurface migration, insofar as the overpressure that causes ground uplift represents hydraulic connectivity and potential for fluid flow.

There are two goals for subsurface monitoring. The first goal is to detect the location of the free-phase plume, and particularly the front of the plume. This information tests predictions of plume propagation and allows those predictions to be improved. The predictions in turn inform where to deploy surface and near-surface monitoring technology at specific potential pathways, as discussed above. The history of the actual location of the plume front informs when to cease such path-specific monitoring at the surface and near-surface. Both uses of the information resulting from subsurface monitoring indicate this monitoring method can focus on the plume front rather than the entire plume.

The second goal is to detect CO_2 accumulations in the dissipation interval discussed in the site-selection section. Such an accumulation will form for any leakage pathway hydraulically connected to the dissipation interval, such as annular pathways in wells. Because leakage via such pathways are likely to commence at the time they are encountered by the plume, monitoring for dissipation interval accumulations can also be focused at, and just behind, the plume front. The longer monitoring occurs in a location after passage of a plume front, the lower the detection limit is on a leakage-rate basis. For instance if repeat seismic reflection surveys are designed to detect any such accumulation greater than 10,000 tonnes, and the final survey at a location is conducted five years after the passage of the plume front, the detection limit is 2,000 tonnes/year discounting the initial, likely short, increment of time for the leakage front to reach the dissipation interval.

1.4.3.7 Strategy for Detecting Baseline Levels

In the storage complex and overburden, the baseline equates with pre-injection characteristics. As discussed above, simple differencing of monitoring and characterization results with time as more CO_2 is injected during the GCS project (so-called time-lapse) reveals change over time. In the shallow subsurface, changes in ecological processes arising from changes in season, moisture, weather, land surface disturbance and many other factors can affect carbon cycling, and therefore the concentrations and ecological fluxes of CO_2 and CH_4. False conclusions about leakage could be made if careful consideration of the actual source of the detected carbon is not accounted for (e.g., Romanak et al., 2014). We recommend that monitoring plans include discussion of the possibility of changes in ecological fluxes of CO_2 that could complicate direct CO_2 flux and concentration measurements, and that consideration be given to attribution assessment (Romanak et al., 2012; 2014) to clarify the cause of observed changes in carbon fluxes in the near-surface environment.

As mentioned in the discussion of surface and subsurface monitoring above, we recommend that baseline data collection step out ahead of the free-phase plume front arrival, rather than cover the entire anticipated final plume extent at the outset. This both limits cost and allows for lessons learned from earlier baseline monitoring to be incorporated into later baseline monitoring. The amount of time required for baseline monitoring prior to the plume arrival is predicated on the method. For subsurface methods, such as reflection seismic, the baseline area should extend from the current plume front to the predicted location of the front at the time of the next seismic reflection survey, plus a buffer sufficient to cover uncertainty in plume front propagation. For surface and near-surface methods, monitoring for at least a year ahead of the plume front arrival is likely needed to capture seasonal variations.

1.4.3.8 Sensitivity and Accuracy

Monitoring is inherently challenging and entails uncertainty. The methods in Table 1.1 involve uncertainty and may require varying levels of interpretation by modeling to obtain maximum value from the approach. While there is no substitute for seismic methods, they are subject to limitations in terms of resolution (e.g., Hoversten et al., 2005). Under the negative accounting approach we recommend, these limits could translate directly into a reduction in the amount of CO_2 that can be verified as sequestered relative to the amount of CO_2 injected. This connects the choice of monitoring methods by an applicant to the economic fundamentals of a project, which provides an incentive for applicants to devote more effort to developing the monitoring plan, as opposed to an approach where monitoring is a check box necessary for the project to proceed, and otherwise only weakly related to project economics. This in turn allows a more performance-based, rather than prescriptive, approach to regulating the monitoring methods deployed. This approach would require ARB to closely validate the detection limits proposed by the applicant.

In general, multiple monitoring approaches are needed to confirm CO_2 containment, and the chosen approaches should be rationally defended with consideration of sensitivity and accuracy. We recommend that monitoring plans be considered living documents insofar as improvements in monitoring technologies are expected over time, and the plans should allow for substitutions to improve the efficiency of the QM (same or greater effectiveness for less cost) in the future.

1.4.3.9 Area to Monitor

As discussed above, the area we recommend for monitoring is determined by the type and utility of a monitoring method. Remote sensing methods that are relatively inexpensive should cover the entire AoR. Surface and near-surface methods should be deployed where potential leakage pathways intersect the surface ahead and behind the plume front for some distance based upon the speed of the front. Subsurface methods should cover some distance behind the plume front to the predicted location of the plume front at the next survey, buffered by a safety factor to account for prediction uncertainty, as discussed further below.

1.4.3.10 Frequency of Measurement

The various monitoring approaches in Figure 1.1 and Table 1.1 have different inherent deployment frequencies, from continuous to annual or less frequent monitoring. Taking the long-established Sleipner project as an example, an acceptable record of plume migration was produced via 3D surface seismic carried out every two years since 2002 (Chadwick et al., 2010).

Barring detecting leakage at some unknown location, the measurement frequency proposed by the applicant will have a direct effect on the detection limit for a particular monitoring method. Consequently, under the accounting approach we recommend, the frequency with which measurements are made can be left to the applicant, again with the caveat that this requires ARB review of the detection limits proposed by the operator.

If a particular monitoring target reveals large changes in measured parameters, then a shift to higher-frequency monitoring of that target is indicated as necessary to attribute that change to either leakage, some other project aspect, or to phenomena unrelated to the project.

1.4.3.11 Spatial Coverage in Terms of Where and How Much Density

The specific properties and characteristics of the GCS project site will dictate the appropriate spatial coverage and the density of measurements with consideration of plume migration as discussed above. In California, it is likely that some GCS sites will have a relatively high density of existing oil or gas wells within the AoR. As such, we recommend that surface monitoring of well integrity failure be carried out with commensurate intensity. In contrast, for sites with few known wells, the intensity of such surface monitoring could be drastically reduced or eliminated altogether, as defended and justified in the monitoring plan. Here as in other areas of monitoring specification, site-specific properties and characteristics control the monitoring plan, and no general recommendation is possible.

1.4.3.12 Schedule and Phasing of Monitoring

It is clear that activities around monitoring evolve as the project proceeds. We recommend that monitoring in the vicinity of the dissolved and free-phase CO_2 plume fronts be frequent (once a year or more) and intensive to catch unexpected behaviors early. As the plumes expand successfully as designed, monitoring in the areas the plume has occupied for some time can be less frequent. Birkholzer et al. (2014) expressed a philosophy that a tiered approach to treatment of existing wells should be adopted as a modification for Class VI requirements. The idea is that the free-phase CO_2 plume presents different leakage risks to USDW than does the pressure plume. We concur with this general philosophy and recommend that monitoring be risk-based, and that the monitoring rationale should be spelled out in the monitoring plan approved by ARB.

1.4.3.13 Attribution

CO_2 and CH_4 are ubiquitous gases in the environment. As such, anomalous CO_2 or CH_4 concentrations or fluxes in near-surface environments may arise for ecological reasons (e.g., changes in moisture, season, plant cover, etc.) unrelated to deep subsurface processes. For this reason, it is now appreciated that variations in CO_2 or CH_4 in the near-surface environment should not be taken at face value as indicators of deep-sourced leakage, but rather such variations need to be explained as part of the QM. The determination that anomalies in CO_2 or CH_4 fluxes or concentrations are related to loss of containment related to GCS must be made by the process of attribution assessment (Romanak et al., 2012; 2014). As explained by Romanak et al. (2012, 2014), plots of oxygen (O_2) versus CO_2 concentrations in gas samples, and plots of CO_2 concentration versus the ratio of nitrogen (N_2) to O_2 can be used to ascertain the likely origins of the measured CO_2, e.g., whether it is due to oxidation of CH_4 or whether it is sourced externally, e.g., from leakage up a well.

Because processes affecting CH_4 oxidation are less variable in the deep subsurface than in the near-surface environment (aerobic), attribution is less relevant for anomalous CO_2 observed in deep fluid sampling campaigns than in the shallow subsurface or atmosphere. Nevertheless, accounting for all potential sources of anomalous gas concentration needs to be part of every geochemical monitoring and analysis campaign (and plan).

1.4.3.14 Proxy or Companion Gases

Gas transport from the deep subsurface, regardless of flow path or mechanism, will involve a mixture of gases, e.g., CO_2 and other species in the injected CO_2 stream, including CH_4 and other hydrocarbons, H_2S, etc., that are native to the storage complex. It has been noted that CH_4 is an excellent indicator of deep gas migration, especially in hydrocarbon reservoir environments (Klusman, 2003), as well as being an important GHG in its own right that we recommend be monitored as part of the QM. Different gas species have different solubilities in water, which can give rise to so-called chromatographic separation during upward flow, the analysis of which can be potentially useful for quantifying aqueous phase saturation and other properties along the flow path (Bachu and Bennion, 2009). Methane, in particular, is much less soluble in water than CO_2, and occurs in lower background concentrations above ground, making any change in CH_4 concentration above the storage complex or in the air at the GCS site (e.g., Trottier et al., 2009) an effective indicator of potential CO_2 and CH_4 leakage from the storage complex. The early indication provided by anomalous CH_4, or some other low-solubility gas species, in gas samples could provide an opportunity for stopping or reducing the leakage process. The first step would be to try to confirm by other means whether leakage is occurring and, if so, by what mechanism, e.g., well integrity failure. If leakage is suggested by other monitoring evidence, it might be possible to stop the leakage through well workovers to re-cement a well, or through operational changes such as lowered injection rate. We recommend that any monitoring plan development include consideration of the use of proxy gases as complements to direct CO_2 monitoring approaches.

1.4.3.15 Use of Tracers

Tracers fall into two broad categories: natural, and artificial (added). We consider the natural isotopic variability, if any, of captured carbon relative to the reservoir carbon, along with co-mingled gases in the captured CO_2 stream as natural tracers (e.g., Flude et al., 2016). Artificial tracers include substances like perfluorocarbon tracers (PFTs), sulfur hexafluoride (SF_6), and others that are deliberately added. Challenges in the use of tracers include differing behaviors arising from inherent differences in solubility, adsorption, and reactivity with subsurface fluids relative to CO_2 (e.g., Myers et al., 2013). Another challenge for tracers such as PFTs is their very low detectability levels (10^{-15} L/L air; Wells et al., 2007), which require unusually rigorous care by technicians in avoiding cross-contamination of clothing, vehicles, and instrumentation that can lead to false positives. In addition, PFTs and SF_6 tracers are used for other studies by other agencies, e.g., air-quality management agencies, so false-positives are also an issue from that standpoint. Cost is another factor. In general, we do not recommend continuous use of artificial tracers because we do not believe they are needed in routine injection operations. On the other hand, added tracers may be useful for diagnosing particular unexpected behavior, in which case they can be added to the injection stream periodically or at any time; this was done at In Salah to prove the source of leaking CO_2 at a compromised wellhead (Ringrose et al., 2009; Stalker et al., 2015).

Natural tracer analysis of gas samples can be a useful practice and we recommend that it be considered part of the wide array of approaches applicable to monitoring within the QM.

1.4.3.16 Monitoring Workflow to Inform Annual Quantification

Monitoring for CO_2 containment is not always a simple process involving static protocols, routine field campaigns, and checking boxes on forms. Instead, monitoring of GCS sites involves an assortment of methods and approaches, many with significant data analysis and interpretation components. As such, there needs to be a time period built into the reporting requirement following data collection to allow for data analysis and interpretation. If annual reporting of CO_2 plume migration and storage complex integrity are required, reports on conditions of the plume, obtained by methods such as 3D seismic or others that require analysis and inversions, will lag actual field conditions by at least one quarter (three months). Other methods such as fluid sampling and continuous monitoring of pressure, temperature, and above-ground concentrations can be reported with less lag time. In general, we point out that compulsory annual reporting at a fixed date each year may reflect conditions of the plume and complex integrity at an earlier time, and that these times may vary from year to year depending on how much analysis needs to be done since the last collection campaign. We recommend that the award (or deduction) of credit for CO_2 storage (or surface leakage) needs to reflect the lag time in analysis and reporting of monitoring and the QM activities.

1.4.3.17 Assessment of Plume Stability

The injected CO_2 free-phase plume can be considered stable if post-injection monitoring over multiyear intervals by 3D seismic surveys, or other approved monitoring approaches, shows that the free-phase CO_2 is stationary in all directions (not moving upward, downward, or spreading laterally). Because plume velocity can be quite slow, we recommend that the plume show no movement for five consecutive years as a default period for post-injection monitoring. Implicit in this recommendation is that monitoring of above-zone intervals and wells shows no significant changes and no indications of integrity failures.

The recommended post-injection monitoring period could be shortened or lengthened depending on details of the duration of injection, size of plume, site conditions, and plume monitoring resolution. For instance, if there are potential leakage pathways whose character suggests they might become more permeable with time, such as well segments with uncemented casing exposed to the storage reservoir, these could warrant a longer post-injection monitoring period.

1.5 EVALUATION OF SITING CRITERIA

1.5.1 Historical use considerations (e.g., oil and gas production)

Natural gas and oil generation rates are sufficiently low that the presence of a hydrocarbon accumulation beneath a geologic seal provides evidence of the seal’s ability to retain far more than 99% of the volume of such fluids in the reservoir over a 1,000-year period, which is one published metric for the necessary retention capacity of CO_2 storage facilities (Miller, 1992, California Carbon Capture and Review Panel, 2010). This stated CO_2 “column retention height” differs from that for oil or natural gas due to differences in density and surface tension between CO_2 and oil or CH_4. Therefore, care must be taken to appropriately calculate the column retention height for CO_2, even in the case of GCS in a depleted oil or gas field.

Industrial experience supports the advantage of storage in depleted fields. Figure 1.7 shows the underground natural gas storage facilities in Illinois as of 1973 (Buschback and Bond, 1973).

Storage facilities were developed in depleted natural gas reservoirs in the southern portion of the state and in aquifers in the northern portion of the state. As of 1973, none of the 13 facilities developed in natural gas fields had been reported to have leaked, while four of the 24 facilities in aquifers leaked during operations, two above the storage zone and two to surface, as shown in Table 1.3. The two that leaked to surface did so within a year of the start of gas injection. Ongoing dynamic measures, such as installation of wells to collect leaking gas, were subsequently implemented at three of the facilities, including one of the two that leaked to surface, which allowed continued operation. Subsequent investigations were unable to determine the cause of the leaks to the surface. Operators at both facilities that experienced surface leaks subsequently developed storage in a deeper reservoir that did not leak.

Figure 1.7. *Underground natural gas storage facilities in Illinois as of 1973 (modified from Buschback and Bond, 1973).*

__Table 1.3.__ Underground natural gas storage facilities in aquifers in Illinois that leaked (from Buschback and Bond, 1973)

Facility	Storage depth (m)	Time to leak detection	Detection location	Response
Herscher	530	4 months	Groundwater wells	Ongoing measures and deeper reservoir development
Manlove	1200	<9 months	Glacial drift	Deeper reservoir development
Troy Grove	430	NA	Between primary and secondary seals	Ongoing measures
Waverly	550	NA	Between primary and secondary seals	Ongoing measures

In contrast to aquifer natural gas storage, prior hydrocarbon production from a proposed storage reservoir provides a basis for estimating the injectivity and, to a lesser extent, capacity of the proposed storage target. This provides information on the performance of the target closer to the scale of GCS than is likely to result from any tests conducted in an aquifer that has not been subjected to any large-scale injections prior to full-scale CO_2 injection operations.

There are caveats to the potential benefits in understanding of the performance of the geologic components of the proposed storage system that result from prior hydrocarbon production. These activities, and to a lesser extent activities related to exploration, result in legacy borings that intersect the storage zone, which were not designed for the needs of CO_2 containment. These legacy borings are potential pathways for leakage of fluids out of the storage zone. Borings are most typically sealed sufficiently with cement to prevent leakage of quantities of fluid that would have detectable impacts to HSE or CCA, but a fraction of legacy borings, particularly the older ones, will most likely not be sufficiently sealed.

Leakage via active wells can occur due to either defects in the original construction of the well seal or degradation of the seal and other well components during well use. For inactive wells, leakage appears to occur most typically as a result of defects present in the well at the end of its operation, typically dating from the construction of the well, but in some cases due to degradation during operation, particularly for wells with alternating injection and production (Watson and Bachu, 2007; Jordan and Carey, 2016).

Older exploration borings are perhaps an even greater concern for leakage as they are typically only plugged at a depth above the base of USDW (Jordan and Wagoner, 2017). There has been little research at this time regarding the leakage potential of these pathways. On the one hand, the geologic material around the boring may collapse or squeeze into the void over time, reducing its permeability. And if the borings remain open, the fluid filling the boring may prevent or substantially reduce the leakage depending upon the conditions where the boring intersects the storage target. For instance, exploratory borings are typically left filled with drilling mud. This is a dense fluid at the time the boring is abandoned, but over time can age to become a material with some shear resistance due to flocculation (Johnston and Knape, 1986). This age-related rheology would substantially prevent leakage up to some threshold pressure, above which it would fracture. But on the other hand, legacy borings could also provide fast-flow paths through cap-rock seals all the way to the base of USDW, and potentially beyond depending on the integrity of the plug.

The above discussion has focused on the advantages and disadvantages of prior hydrocarbon exploration and production from a proposed storage zone. Other mineral resource production activities can also result in subsurface voids that can either create leakage pathways or otherwise diminish the integrity of a proposed GCS site. While the authors are not aware of such activities co-located or near to sites potentially suitable for storage in California, such co-location does occur outside California. For instance, salt caverns have been created in locations in the vicinity of the coast of the Gulf of Mexico, which also have reservoirs that could store CO_2. Some of these caverns have collapsed in a manner that would cause any sufficiently nearby storage wells to leak. For example, the collapse of a salt cavern near the town of Bayou Corne in Louisiana threatened the stability of other storage caverns in the area (Louisiana Department of Natural Resources, 2013). Consequently, considerable attention and care to risk mitigation should be exercised regarding GCS projects proposed in areas with any prior surface or subsurface mineral resource extraction activities.

1.5.2 Minimum injection depth

The minimum depth for GCS suggested in most references ranges from 800 m to 1 km (2,600–3,280 ft; e.g., Benson et al., 2005). The rationale for this suggestion arises from the use of depth as a proxy for the minimum subsurface pressure and temperature that is considered “optimal” for storage where optimal in this case refers to the efficient use of pore space for storage, rather than minimizing surface leakage risk.

As shown on Figure 1.8, there is no distinct phase (density) change with increasing pressure for temperatures greater than the critical temperature, which are common at storage depths in the subsurface. Rather, CO_2 density increases continuously with increasing pressure. However, the density increases nonlinearly with the increasing pressure and temperature that occurs with depth in the subsurface. As a result, substantially more CO_2 can be stored in a given pore volume at pressures above the region of rapid nonlinear density increase, such as 8 MPa in the example in Figure 1.8, as compared to pressures within or below the region of rapid nonlinear increase with depth.

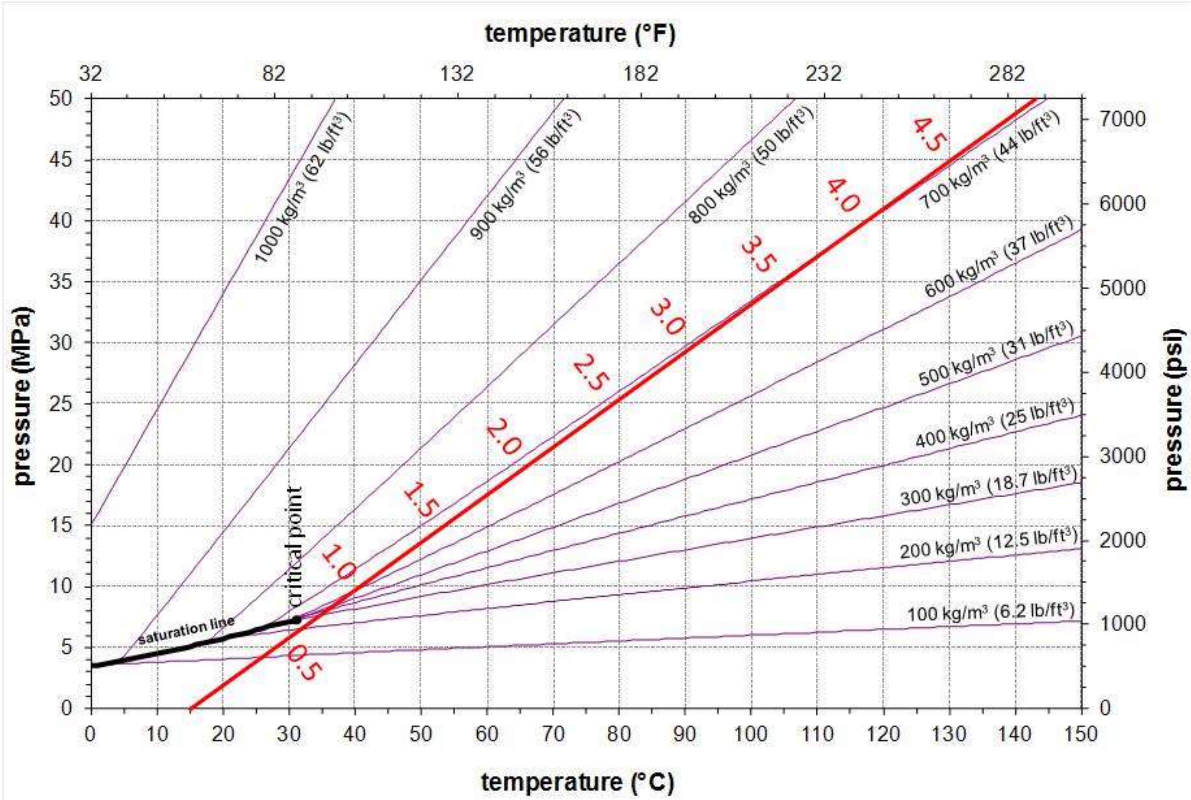


Figure 1.8. *CO_2 isopycnics (contours of equal density) with a depth profile (in km) based on a 15° C (59° F) average surface temperature, 25° C/km (23.5° F/1000 ft) geothermal (temperature) gradient, and a hydrostatic pressure gradient.*

In practice, fluid pressure commonly varies significantly from that predicted by a hydrostatic gradient plotted in Figure 1.8, as shown on Figure 1.9 for a location in a California sedimentary basin suitable for GCS. Figure 1.9 shows temperatures also do not conform to a uniform geothermal gradient. As a result, it is not possible to determine *a priori* an optimal minimum depth at any particular site. Furthermore, Figure 1.8 shows that at higher temperatures the pressure-density nonlinearity is weak to non-existent.

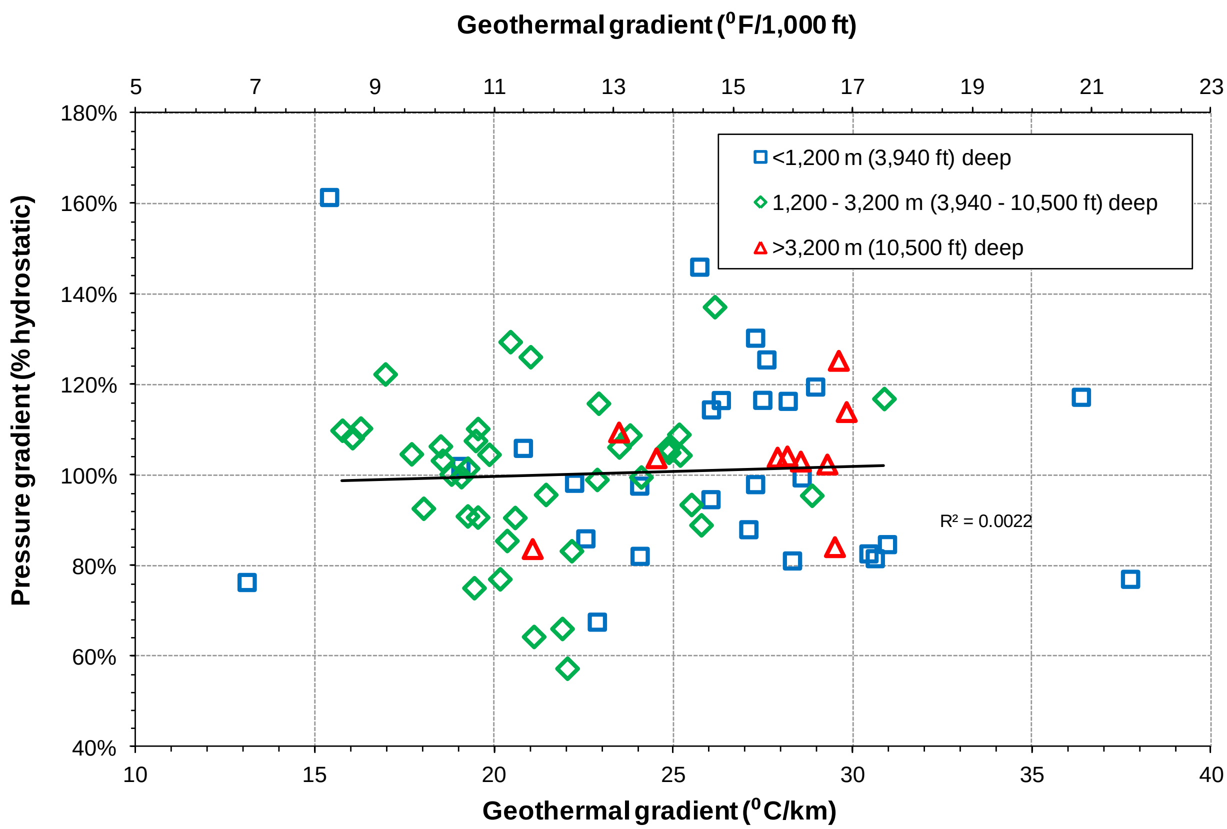
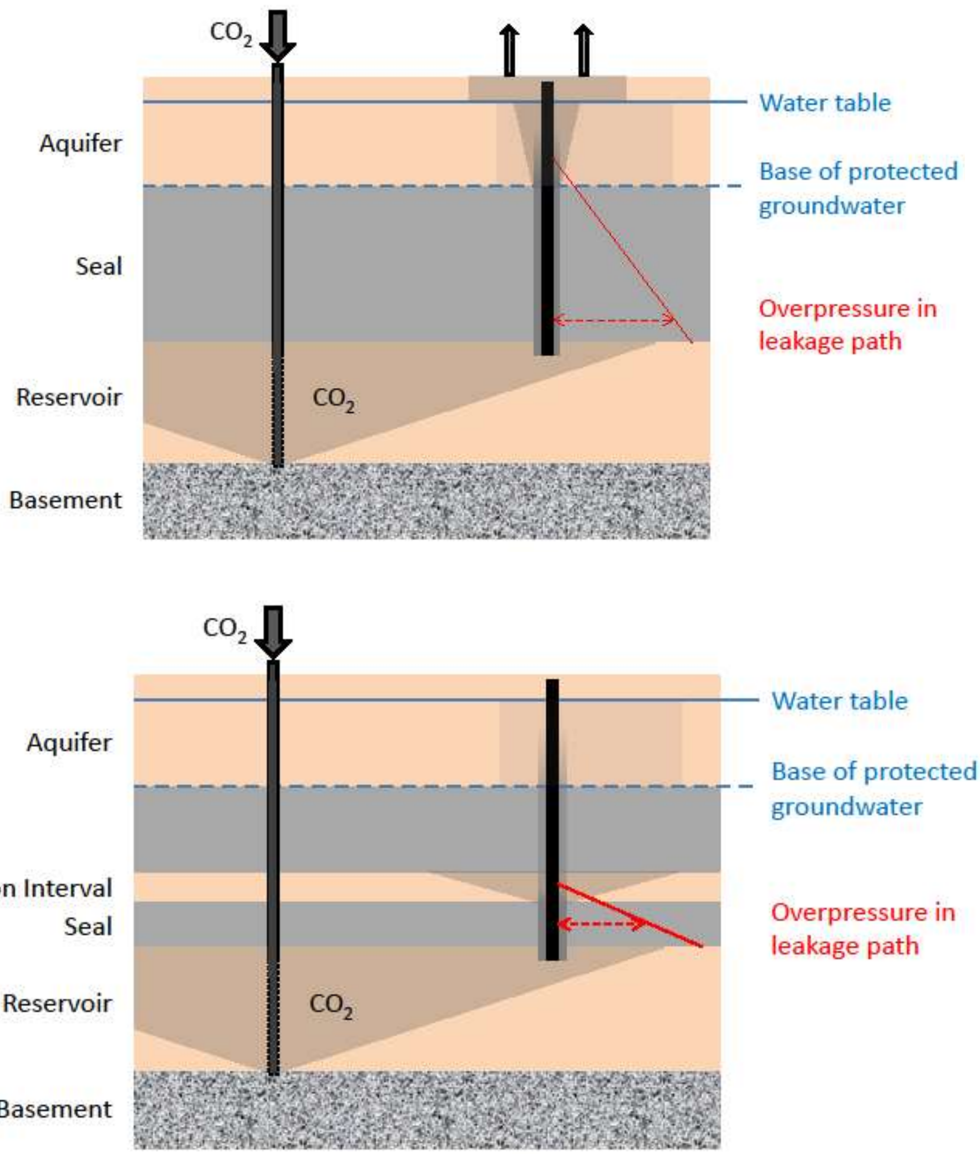


Figure 1.9. *Pressure and geothermal gradients calculated from pressures and temperatures reported in oil and gas reservoirs in the southeastern portion of the San Joaquin Valley near the intersection of Kimberlina Road and Highway 99 (data from DOGGR, 1998; figure modified from Jordan and Doughty, 2009).*

There is an inverse correlation between reservoir fluid density and leakage risk. For instance, in the southern San Joaquin Valley, blowouts from non-associated (i.e., no associated oil present, or "dry") gas wells have been more frequent on a per-well basis than from oil wells in thermally-enhanced oil recovery areas (which involve steam injection). The steam blowout frequency from these wells has in turn been greater than that from oil production wells without steam injection, which generally produce mostly water in California (Jordan and Benson, 2008).

These observations led to an alternative approach to adopting a specific minimum depth criterion in the past, and that was to consider specifying a minimum density at which CO_2 would be stored. However, from a technical perspective, there is no threshold density below which a discontinuous increase in risk occurs. Furthermore, there may be operators in the future that would like to collect carbon credits for storing CO_2 at low densities as a result of immiscible CO_2-EOR (this involves injection of gaseous rather than liquid or supercritical CO_2).

As a result of the considerations above, we recommend ARB not establish minimum depth, pressure-temperature, or CO_2 density criteria. On the other hand, there is a nominally depth-related criterion we recommend ARB does establish. Specifically, past and ongoing research indicate that the presence of a permeable stratum (thief zone(s)) between the storage reservoir and the base of USDW will substantially reduce brine, and to a lesser extent CO_2 flux, to the USDW and atmosphere via most potential leakage paths, even if the thickness of the stratum is relatively small (e.g., Harp et al., 2016). These studies indicate the reduction in flow in the leakage path above the thief zone is because excess pressure dissipates into the zone, as illustrated schematically in Figure 1.10. This virtually eliminates the driving force for brine leakage outside of the CO_2 plume and reduces the driving force for CO_2 and brine leakage within the CO_2 plume.



a)

b)

Figure 1.10. *Schematic sections showing overpressure profiles (red) for (a) overpressure along a leakage path in a system with no dissipation interval, and (b) overpressure along a leakage path hydraulically connected to a dissipation interval (thief zone).*

We recommend that ARB require the existence of an interval, or intervals in aggregate, sufficient to effectively dissipate overpressure of any leakage passing through them. We suggest referring to these zones as "dissipation intervals" to emphasize that their purpose is to dissipate overpressure along leakage paths that pass through and are hydraulically connected to them. This is a more stringent definition than that for an AZMI (Meckel and Hovorka, 2010; Hovorka et al., 2013; Kim and Hosseini, 2014) whose purpose is to provide an effective monitoring interval but not necessarily to have properties sufficient to effectively dissipate overpressure.

The dissipation interval requirement would not apply to high-flow-rate leakage such as that which would occur in an open boring, because the flow rates would likely be too high for a sufficient amount of the flow to divert into the dissipation interval to eliminate the overpressure given realistic open-boring flow resistance. Compliance with this criterion could be demonstrated either through numerical simulations or use of reduced-order well leakage models, e.g., such as those developed by NRAP.

If ARB implements this suggested criterion, we recommend that consideration be given as to whether the dissipation interval(s) should be considered part of the storage complex or not. Considering them part of the storage complex would have the benefit of providing secondary containment that serves as additional CO_2 storage volume. This would have to be coupled with requiring a robust increase in monitoring and investigation if CO_2 is suspected of entering the dissipation interval(s), because there is substantial likelihood in that event that CO_2 leakage above the dissipation interval(s) could also occur.

We recognize that non-technical factors may lead ARB to adopt a minimum depth criterion. One such factor might be public acceptance related to the sense of safety arising from greater distance to the storage reservoir. We recommend that if ARB does adopt a minimum depth criterion, it will also include the dissipation interval criterion.

1.5.3 Minimum cap-rock thickness, spatial variability, and quality of cap rock

Leakage risk does not decrease continuously with increasing seal (cap-rock) thickness. Rather cap-rock containment is primarily dependent upon which property of the seal the project proposes will retain the CO_2: capillary trapping or advective attenuation. Capillary trapping occurs when CO_2 cannot enter the cap rock by overcoming the surface tension of the water already in the pores of the cap rock. Advective attenuation occurs when CO_2 can enter the cap rock, but the flow rate is so low due to the low permeability of the cap rock that CO_2 cannot be detected. If a project proposes that CO_2 is retained under a seal by its capillary entry pressure, the requirement for seal thickness is less important than for advective attenuation, because even relatively thin cap rocks can contain CO_2 if the cap rock is water-saturated.

Water saturation of seals is common in California because most seal rocks were deposited in marine environments and are generally not source rocks (source rocks are the strata within which oil and gas has been, and potentially is being, generated, and so may not be water-saturated). This is because source rocks in the state have generally not been uplifted, and so reside sufficiently deep that they do not, or would not have to, provide the primary seal for storage. In other words, even where source rocks are present above the proposed storage reservoir, some other strata are likely available that could and should be defined as the seal given the stratigraphy of California's sedimentary basins with CO_2 storage potential.

If a project proposes capillary trapping, the applicant should be required to provide data regarding the capillary-trapping aspects of the seal. These include enough measurements to provide a statistical and geostatistical understanding of the distribution of the capillary entry pressure and the thickness of the seal. In particular, capillary entry pressure should be discussed with respect to the anticipated pressure in the CO_2 plume at the base of the seal. Statistics and geostatistics regarding the thickness of the seal would also be required, with the focus on establishing a negligible probability of the seal being entirely missing (i.e., having zero thickness) over some portion of the projected CO_2 plume.

The benefit to the operator of a capillary seal is that it provides a more lenient seal-thickness criterion than an attenuated-advection seal, which is essentially relying on a low permeability-thickness product to trap CO_2. A capillary seal may be quite appropriate for some storage approaches. For instance, storage in a geologic homocline (uniformly dipping or “tilted” strata) tends to result in relatively small column heights of CO_2 beneath the seal due to buoyant flow. This in turn results in a relatively small pressure imposed on the seal, which requires only a small capillary entry pressure for sealing.

For an attenuated-advection seal, the applicant would be required to provide a statistical and geostatistical understanding of the flow rates of CO_2 out of the top of the seal given the evolution of the CO_2 plume. We recommend flow out of the top of the seal as the metric, because there are far fewer methods for monitoring flow in a seal than in a permeable zone. Consequently excluding the seal from the storage complex would require calculating the quantity of CO_2 entering the seal, the result of which would largely be untestable with monitoring data. Implicit to the specification of attenuated advection as the sealing mechanism is the recommendation that the seal be considered part of the storage complex.

Characterizing and defending an attenuated-advection sealing mechanism requires developing statistics and geostatistics regarding both seal permeability and thickness because together these define the transmissivity of the seal, which in turn controls the amount of CO_2 that would flow through the seal. The degree of correlation between seal thickness and permeability must also be determined in order to develop accurate statistics and geostatistics regarding the transmissivity.

Hybrids of capillary exclusion and attenuated-advection sealing mechanisms are also possible. For instance the applicant might determine that part of the seal area is unlikely to have capillary entry pressure above the predicted CO_2 pressure, and in those areas an attenuated-advection mechanism could be proposed. Attenuated-advection fluxes could be calculated near the injection well due to the high pressures in that area. Attenuated-advection fluxes could also be calculated for the percentage of area away from the injection well where the capillary entry pressure is estimated to be too low to preclude CO_2 entry given predicted pressures.

If the applicant proposes allowing some CO_2 to flow through the seal, this can either be discounted from the amount of CO_2 considered permanently sequestered, or if the flow is into a pressure-dissipation interval and ARB allows its inclusion in the defined storage complex, the operator could perform an analysis of the seal over the dissipation interval.

1.5.4 Delineation of an area of review (AoR); tiered or temporally variable AoR

The AoR is defined in the US EPA Class VI injection well regulations as the area where the driving forces resulting from injection are sufficient to cause fluids in the storage zone to flow to USDW via a hypothetical conduit that hydraulically connects each zone without pressure dissipation in between the zones. The *Zone of Endangering Influence* approach to defining the AoR for Class II injection wells is substantially similar. In these cases, almost any pressure increase in the injection zone can cause such flow (Nicot et al., 2009). For storage without active pressure management, most of the area with pressure sufficient to cause such hypothetical flow is outside of the plume of separate phase CO_2, as discussed by Birkholzer et al. (2014). While it is important to manage leakage risk in the area beyond the CO_2 plume, we find the requirements of the Class II and VI well regulations are sufficient in this regard for the purposes of CCA-related leakage risk, as long as the *Zone of Endangering Influence* AoR definition is used for Class II wells rather than the alternative AoR of a ¼-mile radius around the proposed well without analysis of the area over which driving forces are present that could cause leakage.

Another potential source of risk beyond the free-phase CO_2 plume is migration (leakage) of brine into which CO_2 has dissolved. Brine saturated with CO_2 is denser than unsaturated brine. This difference induces density currents that tend to move CO_2 away from, and downward relative to, the free-phase plume. Overpressure during injection could cause upward flow of dissolved CO_2, but because the density difference between saturated and unsaturated brine is small, the density-driven flow velocities are small relative to the velocity of the free-phase CO_2 front. Consequently, the dissolved CO_2 plume is nearly coincident with the free-phase CO_2 plume during injection, and the following period of overpressure dissipation.

Consequently, we recommend that both for the purpose of quantifying and verifying CO_2 storage, and appropriately regulating risk in the near term (during the injection period), ARB should focus its requirements and review on the anticipated free-phase CO_2 plume. In order to distinguish this area from the (pressure) AoR as defined in Class VI injection well regulations, we recommend use of the term AoRc to refer to an area of review based upon the free-phase CO_2 plume, and AoRd to refer to the area of review based on the dissolved CO_2 plume. Over the long term (e.g., during the decades following injection), the dissolved-CO_2 plume could become larger than the free-phase CO_2 plume, and both free-phase and dissolved CO_2 would need to be considered as potential sources of surface CO_2 leakage relevant to the QM.

We recommend that project applicants be required to provide a projection of the area to be occupied by the free-phase CO_2 plume at the next time of substantial monitoring effort (e.g., by 3D seismic) of the storage complex and overlying materials, and the maximum extent of the plume after cessation of injection. The projections should be appropriately buffered by safety factors to account for uncertainty in these projections to establish the AoRc. The safety factor from any point on the projected plume margin should generally be a multiple of the distance from that point to the previous closest margin of the plume based on monitoring results (or the injection well in the case of the first time step), as shown on Figure 1.11. For storage proposed in structures with closure at times when the plume has reached the crest of the structure, the safety factor should be as low as 0.1. For storage in structures with no closure and no dip, the safety factor should be as high as two. The predicted maximum plume extent should be used to perform or update a preliminary search for leakage pathways that are a substantial hazard for storage.

Note that the safety factors recommended here are based on expert opinion, rather than a quantitative analysis of plume predictions versus actual plume development across all commercial storage projects in the world. This approach was taken because there are relatively few such projects with sufficient operational history for a statistically meaningful assessment of the accuracy of prediction relative to results. If a sufficient number of projects are operated for a sufficient period of time globally at some time in the future, such a statistical analysis should be undertaken, and the suggested safety factors should be updated based upon the results.

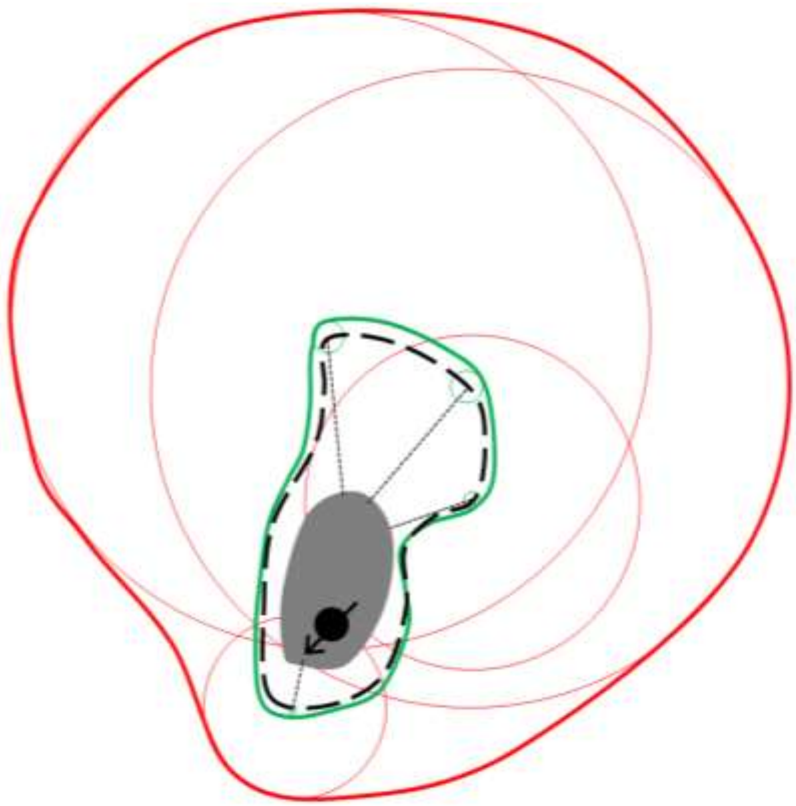


Figure 1.11. *Schematic representation of AoRc construction using safety factors. Gray area is the free-phase CO_2 plume extent at the time the future plume evolution is projected (e.g., by simulation). The black dashed line is the simulated position of the plume front at the time of the next periodic monitoring. The dotted black lines are the shortest distance from the projected to current plume extent. The green circles are a 0.1x buffer based on these distances, which is the recommended safety factor for plume fronts predicted to reach the crest of a closed geologic structure. The green line is AoRc based on the 0.1x buffered area. The red circles are a 2x buffer based on these distances, which is the recommended factor for plume fronts in nearly flat geologic structures. The red line is the AoRc based on the 2x buffered area.*

1.5.5 Minimum pore-space capacity and injectivity

Project proponents will estimate pore-space capacity as part of project development and permitting, e.g., in the delineation of AoR. This estimate of pore-space capacity should be reviewed for accuracy. It should also consider residual saturation and other parameters key to determining the AoRc as well, such as sweep efficiency and the detailed configuration of relief of the base of the seal. Actual-less-than-predicted pore-space capacity or residual saturation alone does not necessarily translate into a CO_2 storage project failure. The operator has a few choices after such a discovery. The operator could cease to inject additional CO_2 because doing so will now be uneconomic given the ratio of monitoring and potential well-remediation effort per unit of CO_2 injected. The operator could inject only an amount of CO_2 that will occupy the footprint for which it has designed the project. Or the operator could acquire additional pore space to provide more capacity, potentially up to that which would allow the originally planned amount of CO_2 injection volume.

The matching of planned injection volume and pore-space capacity with full consideration of residual saturation is a necessary but not sufficient condition for feasibility of the project. The reservoir property that is less appreciated but that we recommend is most pertinent for ARB to include in its primary list of information to be requested from operators is injectivity, sometimes referred to as dynamic capacity. We define injectivity as the injection rate per increment of pressure increase above the original reservoir pressure. Injectivity is dependent on both the microscopic configuration of the reservoir, quantified as permeability, as well as its macroscopic configuration, such as the reservoir thickness and the existence and position of relatively lower-permeability features that compartmentalize the reservoir, such as shale baffles or sealing faults.

We recommend focusing on injectivity because both worldwide experience to date and prospective study suggest it is a main project risk factor for storage (injection) failure. According to the index maintained by the Global CCS Institute, only four projects storing on the order of a million tonnes of per year in saline storage reservoirs have operated as of the date of this report. These are listed in Table 1.4.

Table 1.4. *Geologic carbon storage projects to date that have injected on the order of one million tonnes (1 tonne = 1 Metric ton = 1 Mt = 1.1 ton) of CO_2 per year (Global CCS Institute, 2016).*

Project	Country	Start year	Injection rate (Mtpa)
Sleipner	Norway	1996	0.9
In Salah	Algeria	2004	0.0 (injection suspended)
Snøhvit	Norway	2008	0.7
Quest	Canada	2015	1.0

The performance of these projects indicates that less injectivity is a project risk in practice relative to that estimated from other data prior to project commencement. The Sleipner and Quest projects have proceeded without injectivity problems to date, although the Quest project has been in operation for only a year at this time. The Snøhvit project initially injected into a storage interval that had insufficient injectivity, but the project was designed with a backup (contingency) injection zone which is now being utilized without injectivity limitations (Grudea et al., 2014).

The storage interval targeted by the In Salah project also had less than projected injectivity, and this project was not designed with a backup zone. As a result, the total CO_2 injected annually was less than the design target (less than 0.5 million tonnes per year versus a planned injection rate of 0.6 to 0.8 million tonnes per year), and even that was at pressures that later had to be reduced (Ringrose et al., 2013; Oldenburg et al., 2010). Not long afterward, the results of a repeat 3D seismic reflection survey suggested the injection had disrupted the lower portion of the seal, possibly by fracturing it (White et al., 2014). Injection was subsequently terminated (Ringrose et al., 2013).

Less-than-anticipated injectivity creates conditions that tend to promote exceeding the injection pressure threshold set in advance of the project, which increases the risk of leakage. This can occur simply by exceeding the threshold established prior to the project (operation outside of requirements) or by increasing the allowable threshold and raising the pressure to the new threshold. Even the latter method is difficult to undertake in an objective manner, especially when the economic viability of an expensive project already being implemented is on the line.

The Gorgon project in northwest Australia has not commenced operation at the time of writing this report, but is anticipated to do so within months. At the time it commences operation, its anticipated injection rate into a saline storage target is planned to be many times that of the next largest such project in operation. Attaining this rate has required the project to include brine extraction from the storage target in order to maintain pressures below the predetermined acceptable design threshold chosen to minimize seal failure risk (Trupp et al., 2012).

A study of injectivity in the geologic units with the most apparent storage capacity in the southern San Joaquin Valley indicates injecting industrially-relevant quantities in that basin would require well fields over quite large areas if storage is not accompanied by brine extraction, as shown in Table 1.5 (Jordan and Gillespie, 2013). As this is one of the main storage basins in the state, this finding further supports our recommendation for ARB to include injectivity in its primary list of site-selection considerations. In Table 1.5, the injectivities were derived by dividing the injectivity values for each of the six fields in Jordan and Gillespie (2013) by the area of each field. The maximum injection rates were calculated by multiplying the average for each unit by maximum allowable pressure increase of 1.4 MPa/100 m of depth (Guerard, 1984) and a CO_2 density of 0.6 tonnes/m^3, which is the approximate density in the reservoirs at their initial pressure (equilibrium after pressure dissipation following completion of injection).

Table 1.5. *Areal injectivity calculated from the pressure response to oil production in a pair of fields in each of three main potential storage units in the southern San Joaquin Valley, and the maximum injection rates implied by these units. (1 tonne = 1 Metric ton = 1 Mt = 1.1 ton)*

Potential storage unit	**Oil field**	**Areal injectivity (m^3/yr/MPa/km^2)**	**Maximum injection rate without brine extraction (million tons per year per 100 km^2)**
Stevens Sandstone	North Coles Levee	2,417	~0.5
	South Coles Levee	2,906	
Temblor formation	McKittrick, Northeast	703	~1.5
	Railroad Gap	667	
Vedder formation	Greeley	4,740	~2.5
	Rio Bravo	5,021	

The rate of encounter of injectivity difficulties described above for injecting CO_2 volumes produced by large industrial facilities is higher than the rate at which such difficulties have been encountered in smaller pilot projects. Given the size of the experience sets involved at this time, this could be happenstance. However, there are two physical reasons this could be occurring, which further support our recommendation that ARB focus on injectivity in considering project applications. First, there is a step change in the manner in which CO_2 spreads in a reservoir. At low injection rates, CO_2 buoyancy dominates and it overrides the denser brine in the reservoir. This is characterized by a somewhat linear pressure response to the injection rate. However, as the rate increases, at a certain rate, the viscous force involved in pushing away the brine in the reservoir dominates over the CO_2 buoyant force. Above this rate, the CO_2 sweeps the brine away from the well across substantially more of the reservoir thickness. This results in a greater rate of pressure increase at the injection well per increase in injection rate (Bachu et al., 2004). Pilot injections have been designed without consideration of this effect, and because of their relatively small injection rates, have likely been in the buoyant-force dominated regime, while industrial-size injections will more often, or perhaps mostly, be in the viscous-force dominated regime (e.g., Jordan and Doughty, 2009). We note in passing that different modeling approaches have been applied to the various regimes because of variation in the dominant flow processes as sketched in Figure 1.12 from Oldenburg et al. (2016).

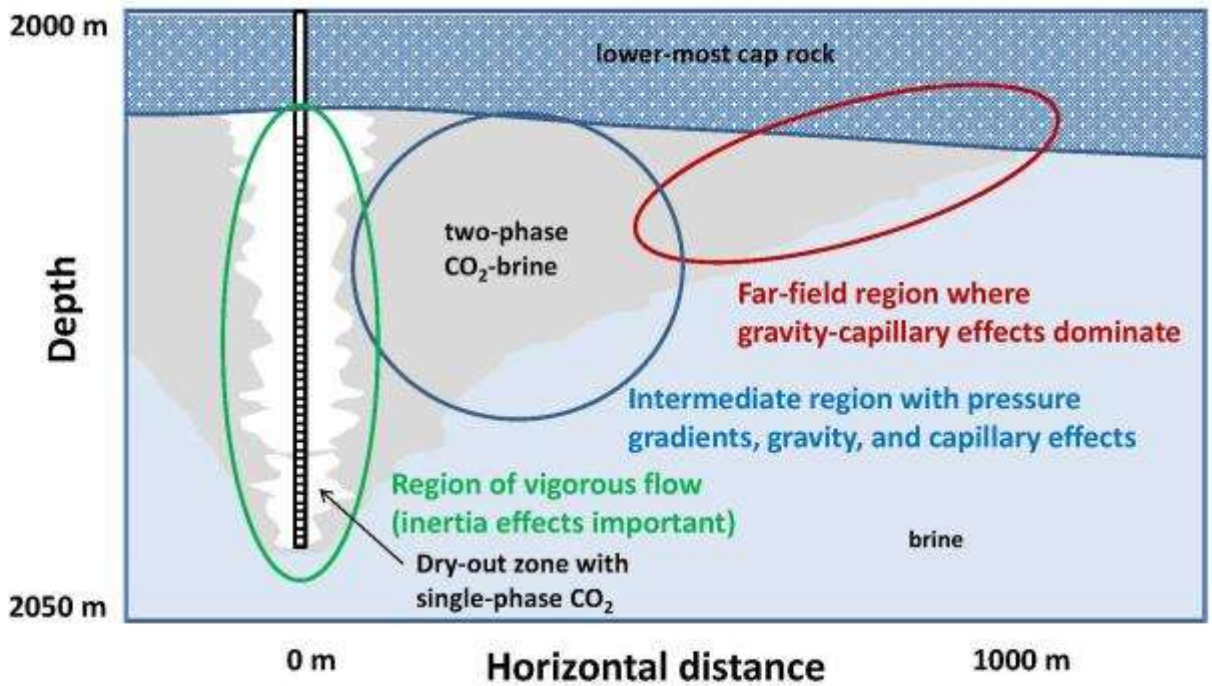


Figure 1.12. *Schematic regions around a CO_2 injection well roughly indicating locations of approximately radially symmetric dominant flow mechanisms, starting with vigorous flow near the well, to two-phase CO_2-brine flow where pressure, gravity, and capillary effects control flow, to the outer edge of the plume where gravity and capillary effects dominate (Oldenburg et al., 2016).*

The second possible reason that injectivity issues have arisen in large-scale projects is that injectivity over areas relevant to GCS has not typically been estimated. For instance, reservoir engineering tends to rely on permeability measurements on core samples and in single wells. These small-scale measurements do not stress the potential reservoir-scale hydraulic barriers, such as facies changes and faults, within reservoirs that reduce injectivity at the size of large-scale GCS projects. This is understandable because oil and gas production typically involves closer well spacing than envisioned for GCS in order to maximize net present value. Production is typically managed over lengths of hundreds of meters rather than the tens of kilometers, over which pressure increases from GCS projects might occur. Also, oil production typically involves injection to increase production by maintaining reservoir pressure and sweeping oil from injection to production wells. Consequently, measuring and accounting for the productivity, which is the inverse of injectivity, across entire fields as a unit rather than individual wells or well clusters, is not as germane to oil and gas production as it is to GCS.

However, it is possible to measure injectivity across larger areas using data from hydrocarbon production, as was done in Jordan and Gillespie (2013). For proposed storage in units from which hydrocarbon production has occurred, ARB could require such calculations as a test of the feasibility of the proposed relationship between injection rate and pressure. There are other approaches for proposed storage in units from which such production has not occurred. For units that have internal barriers, such as shale baffles or faults, the best approach is to design a test in the viscous-force dominated regime by focusing a smaller injection on a small portion of the reservoir. This could be tested by injecting into one of the thinner sand intervals or smaller fault compartments, for example. This injection could be performed using water as a CO_2 surrogate, as long as the lower injection pressure due to lack of a CO_2-brine interface is accounted for.

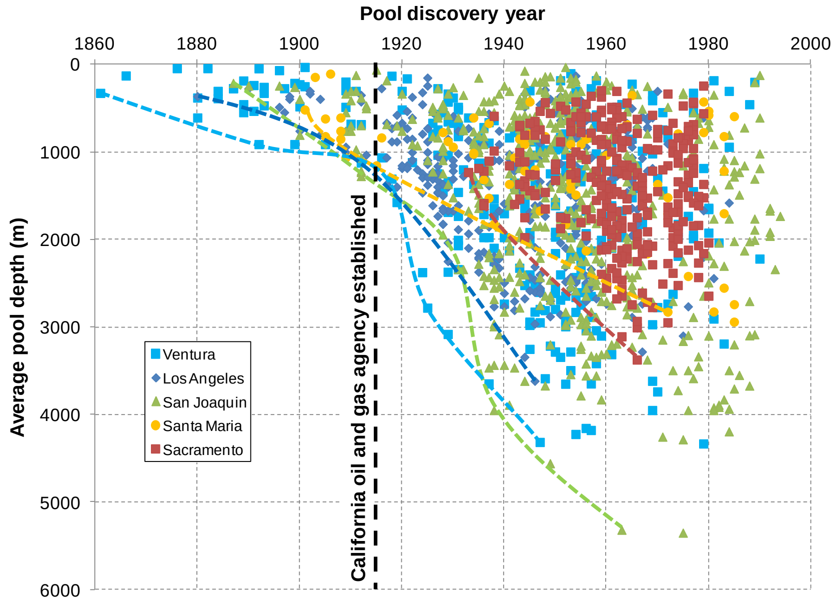
There are three approaches to managing the project-risk of low injectivity: (1) evaluating (estimating or measuring) injectivity at relevant injection rates and spatial extents, (2) including backup (contingency) injection intervals to adapt to lower-than-anticipated injectivity in the primary interval, and (3) deploying active pressure management (brine extraction from a saline aquifer storage reservoir, or brine and oil production during EOR). The Snøhvit project is a precedent for the second approach, the Gorgon project is a precedent for the third with regard to saline aquifer storage, and the Weyburn project is a precedent for the third with regard to EOR.

1.5.6 Identification of potential leakage pathways for CO_2

The main potential leakage pathways identified for storage sites are wells and faults, and to a lesser extent fractures and facies changes in seals. The risk of leakage via wells can be classified on the basis of well age and type. Research indicates that well age alone is not a significant determinant of leakage risk, but rather well construction standards and the quality of well construction in effect at the time are determinants of leakage likelihood (Watson and Bachu, 2007; Jordan and Carey, 2016). The two most salient aspects of wells with regard to GCS are whether the locations of wells that intersect the proposed storage unit are known and the purpose of the boring.

In California, DOGGR was created as the Department of Petroleum and Gas in 1915 in response to legislation. One of the agency's primary charges from the outset was to regulate well construction, specifically to manage vertical migration of water from shallow zones into oil production intervals (Rintoul, 1990; California Department of Petroleum and Gas, 1917). Consequently, there is a high probability that the location and depth of wells installed after that date are available in information held by the agency, and that the wells constructed after this date have seals. Figure 1.13 shows all the average depth-discovery year pairs listed for hydrocarbon pools in DOG/DOGGR (1982a; 1992; 1998), and total measured depths of exploration wells with drilling year listed in DOG (1982b), DOG (1982-1992), and DOGGR (1993-2010). (DOG is the Department of Oil and Gas, an earlier name for DOGGR.)

(a)



(b)

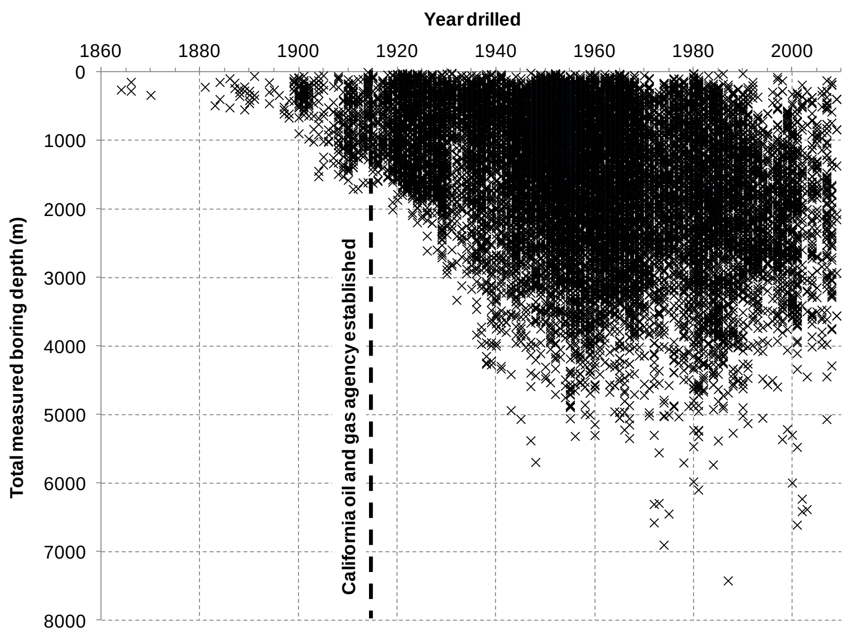
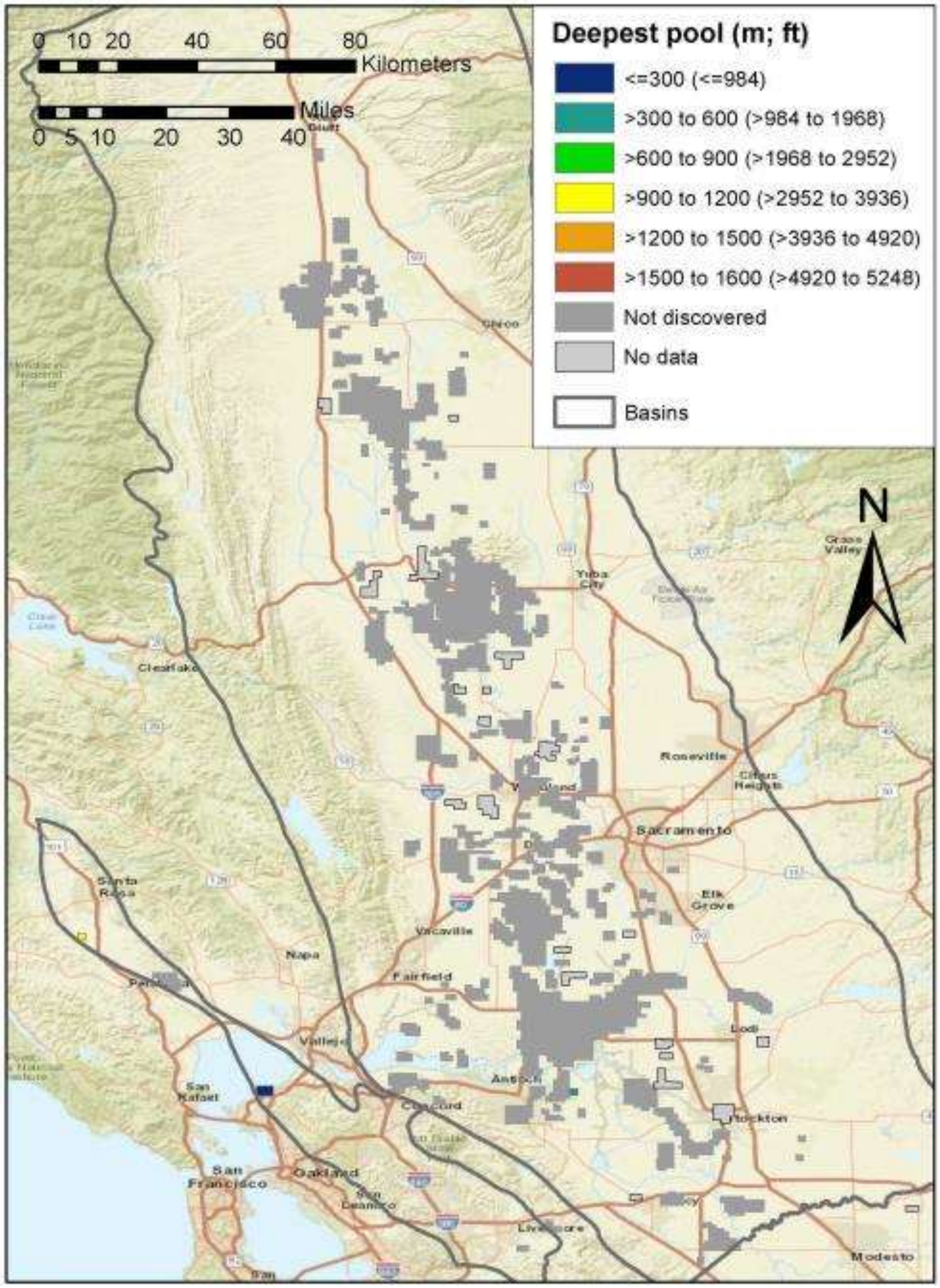
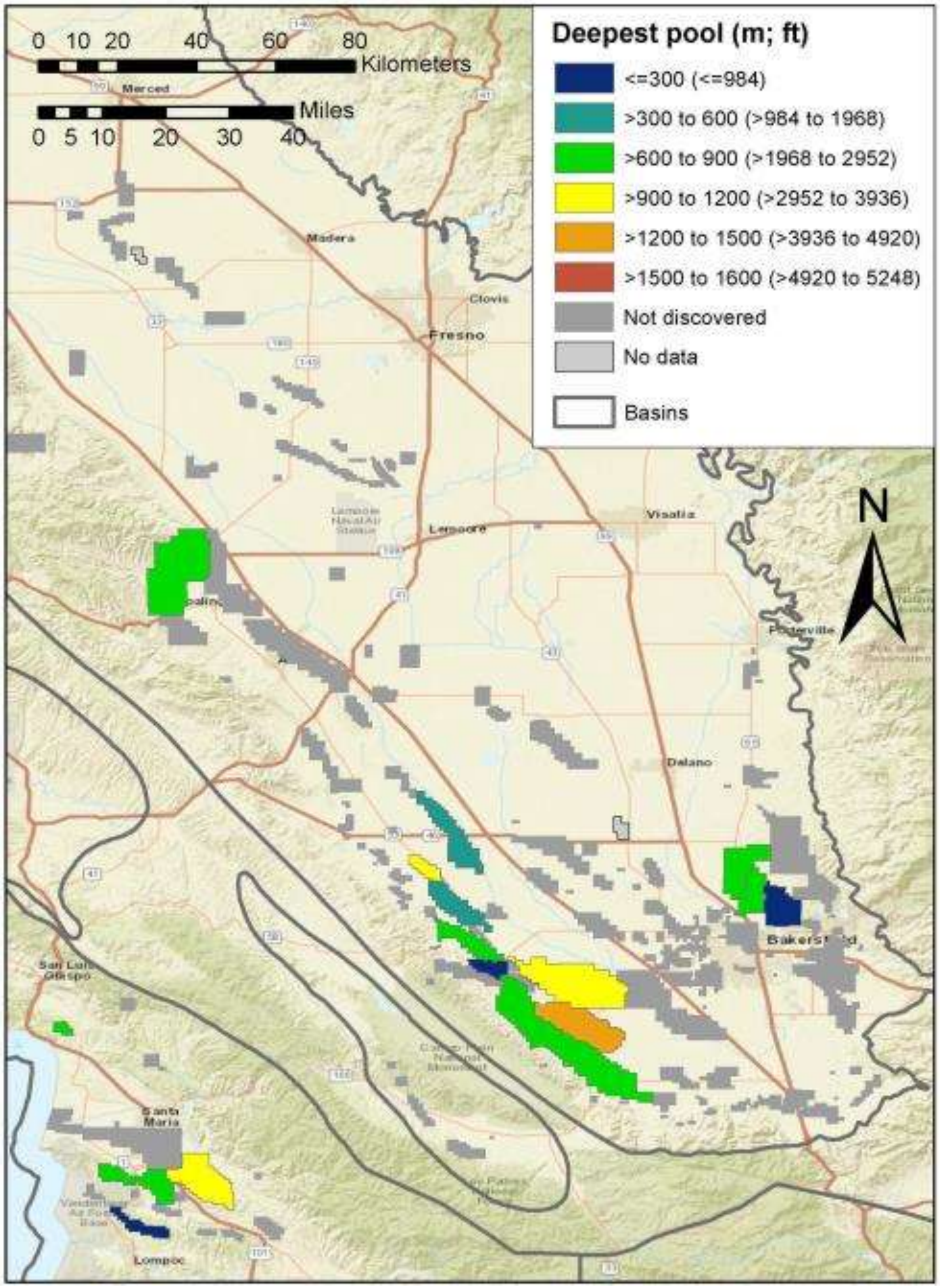


Figure 1.13. *(a) Average hydrocarbon pool depth-discovery year pairs in each major oil and gas basin in California listed in DOG (1982a and 1992) and DOGGR (1998). Dashed lines interpolate deepest pools discovered in each basin through time. (b) Total measured depth of prospect (also known as exploration or wildcat) wells with drilling year listed in DOG (1982b), DOG (1982 to 1992), and DOGGR (1993 to 2010). The first reference lists the year drilling commenced and others list the year the operation was completed.*

Figure 1.13 indicates that CO_2 stored deeper than 1.5 km (4,920 ft) anywhere in the major basins is substantially less likely to encounter wells whose locations are unknown than is shallower storage. Of course, shallower storage may also not encounter such wells depending upon the portion of the basin within which it occurs, but this requires a location-specific assessment. Figure 1.14 maps the average depth of the deepest pool in each field as of 1920 listed in DOG (1982a and 1992) and DOGGR (1998).



(a)



Deepest pool (m; ft)
<=300 (<=984)
>300 to 600 (>984 to 1968)
>600 to 900 (>1968 to 2952)
>900 to 1200 (>2952 to 3936)
>1200 to 1500 (>3936 to 4920)
>1500 to 1600 (>4920 to 5248)
Not discovered
No data
Basins
0 10 20 40 60 80 Kilometers
0 5 10 20 30 40 Miles
N
Fresno
Visalia
Bakersfield
Lompoc

(b)

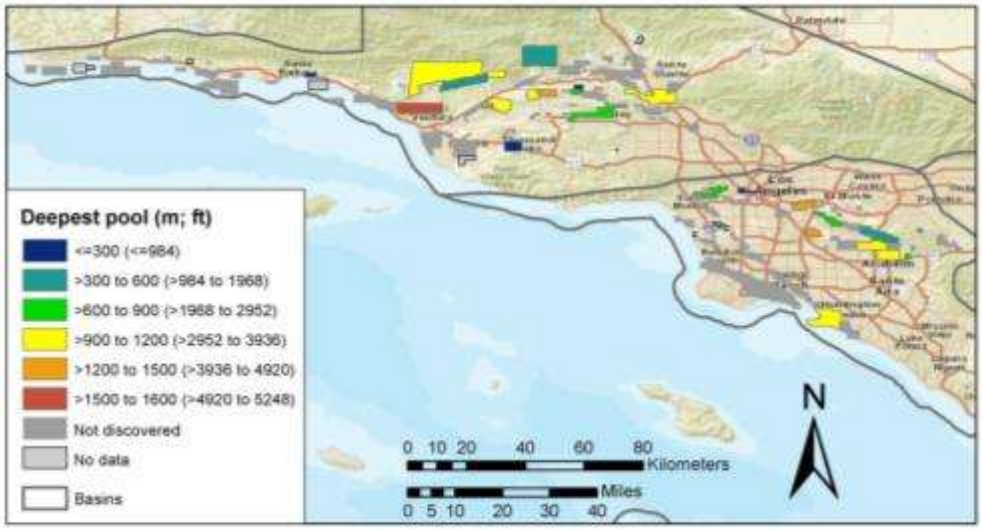
(c) 

Figure 1.14. *Deepest average hydrocarbon pool depth in each field discovered before 1921 in each major oil and gas basin in California listed in DOG (1982a and 1992) and DOGGR (1998): (a) Sacramento Basin, (b) Santa Maria Basin to the southwest and central and southern portion of the San Joaquin Basin to the northeast (there are no fields in the northern San Joaquin Basin, which extends north to the southern margin of figure (a), and (c) Santa Barbara-Ventura Basin to the north and Los Angeles Basin to the southeast.*

As indicated in Figure 1.13 and shown in Figure 1.14a no pools were discovered in the Sacramento Basin prior to the operation of California's oil and gas regulatory agency. Some pools had been discovered in the central portion of the Santa Maria Basin and the western and southeastern margins of the San Joaquin Basin by that time, and some of these are deeper than 1 km (3,280 ft). Pools had been discovered across the Ventura Basin and around the inland margins of the Los Angeles Basin by that time, including pools deeper than 1 km (3,280 ft) in most fields.

The next substantial change in the construction of wells in oil and gas fields occurred in the late 1970s following passage of the Safe Drinking Water Act (SDWA) in 1974. The SDWA required protection from degradation by injection of groundwater that could potentially be used for drinking water supply (USDW). The resulting regulations required injection wells associated with oil and gas production to have cement seals to prevent the movement of fluids into or between USDWs. Analysis of the documented placement of the deepest cement seal in wells related to oil and gas production in a portion of the southeastern San Joaquin Valley suggests this resulted in a step increase in the depth of deepest seal in dry prospect borings a few years after the passage of the SDWA, as shown on Figure 1.15 ("dry" refers to borings that do not encounter economically-producible accumulations of oil or gas; "prospect" refers to exploratory, also known as wildcat, borings). DOGGR also increased the requirement for the length of the cemented annulus above zones with economically relevant oil and gas accumulations from 100 to 500 ft (30.5–152 m) in 1978.

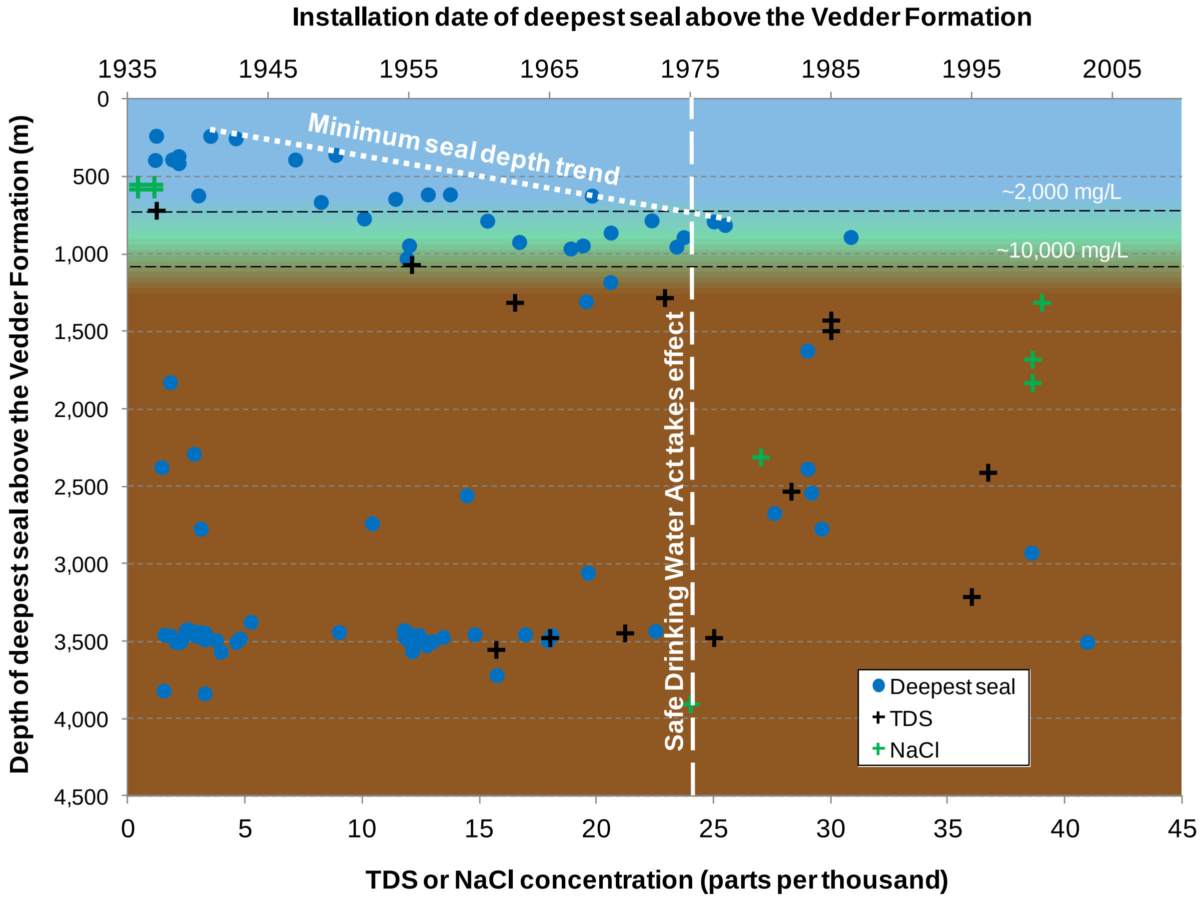
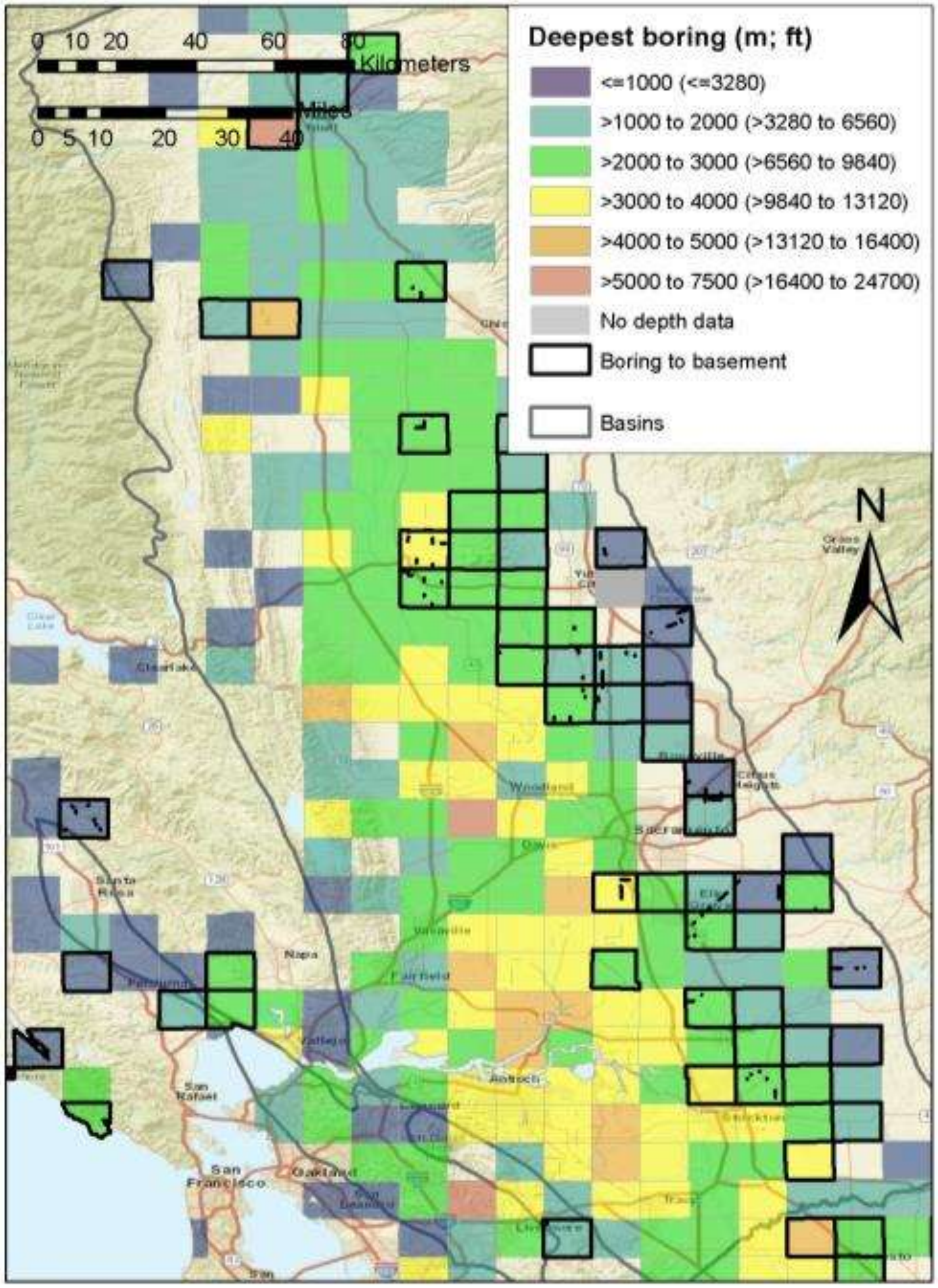
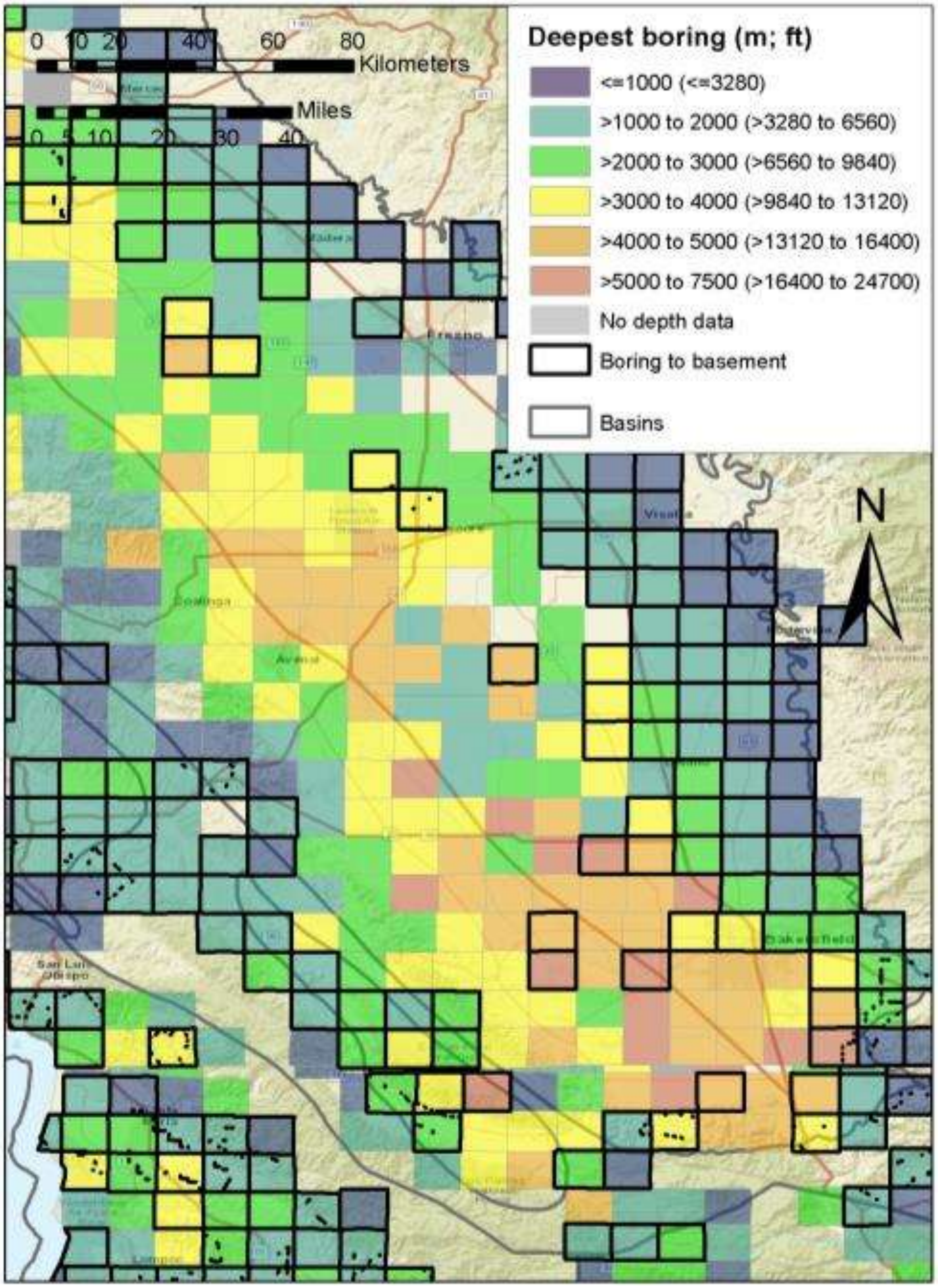


Figure 1.15. *Installation date and depth of the deepest seal against the borehole wall of wells intersecting the Vedder formation in a portion of the southeastern San Joaquin Valley (Jordan and Wagoner, 2017). If this seal is cemented to casing, the spud date is plotted. If the deepest seal is a plug, its date of installation is plotted. Total dissolved solids (TDS) and NaCl groundwater concentrations (mg/L) in the area listed in DOGGR (1998) are also plotted.*

Figure 1.16 shows the maximum measured depth (MD) of a prospect boring completed prior to 1981 in each township, along with whether any prospect borings encountered basement. These maps are based on the surface location from which the boring was drilled. For borings advanced directionally, the boring may be in a different township at depth and the true vertical depth TVD is less than the MD for borings advanced directionally. In general, the denser the surface infrastructure and structures not related to oil and gas production, the greater the difference between the plan location from which the boring was drilled and its base, and therefore its total MD and TVD. Prospect borings are typically advanced directionally because the land surface over the exploration target is not available, typically because it is already occupied by some engineered structure. The more engineered structures that are present in an area, the more likely the drilling site will have to be further removed from the exploration target. Review of a sample of records for directional wells in the San Joaquin Basin indicates MD is generally only a hundred meters or so greater than TVD. Consequently the maximum MD shown for a township on Figure 1.16 is likely a relatively accurate estimate of depth in less densely populated areas, and less inaccurate for more densely populated areas, as shown on Figure 1.17 below.


0 10 20 40 60 80 Kilometers
0 5 10 20 30 40 Miles
Deepest boring (m; ft)
<=1000 (<=3280)
>1000 to 2000 (>3280 to 6560)
>2000 to 3000 (>6560 to 9840)
>3000 to 4000 (>9840 to 13120)
>4000 to 5000 (>13120 to 16400)
>5000 to 7500 (>16400 to 24700)
No depth data
Boring to basement
Basins
N

(a)

(b) 
0 10 20 40 60 80
Kilometers
Miles
0 5 10 20 30 40
Deepest boring (m; ft)
<=1000 (<=3280)
>1000 to 2000 (>3280 to 6560)
>2000 to 3000 (>6560 to 9840)
>3000 to 4000 (>9840 to 13120)
>4000 to 5000 (>13120 to 16400)
>5000 to 7500 (>16400 to 24700)
No depth data
Boring to basement
Basins
N

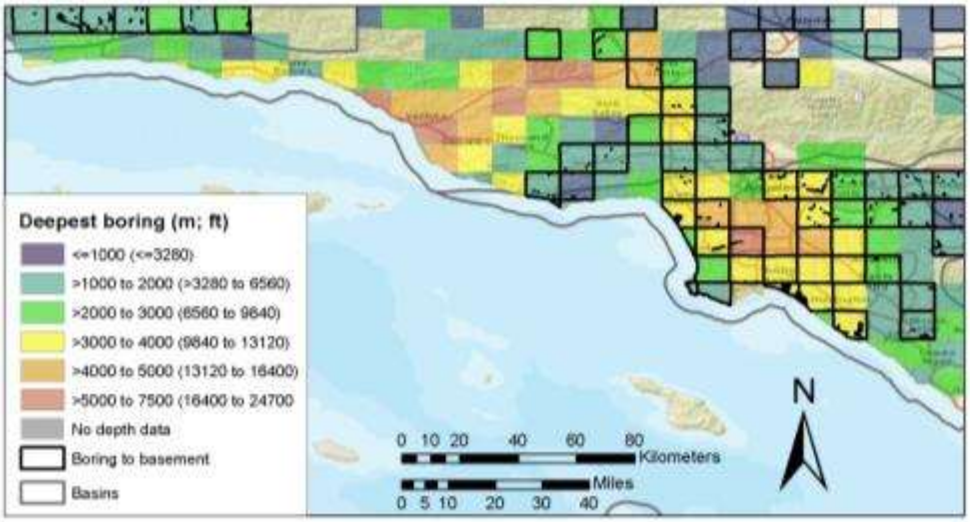
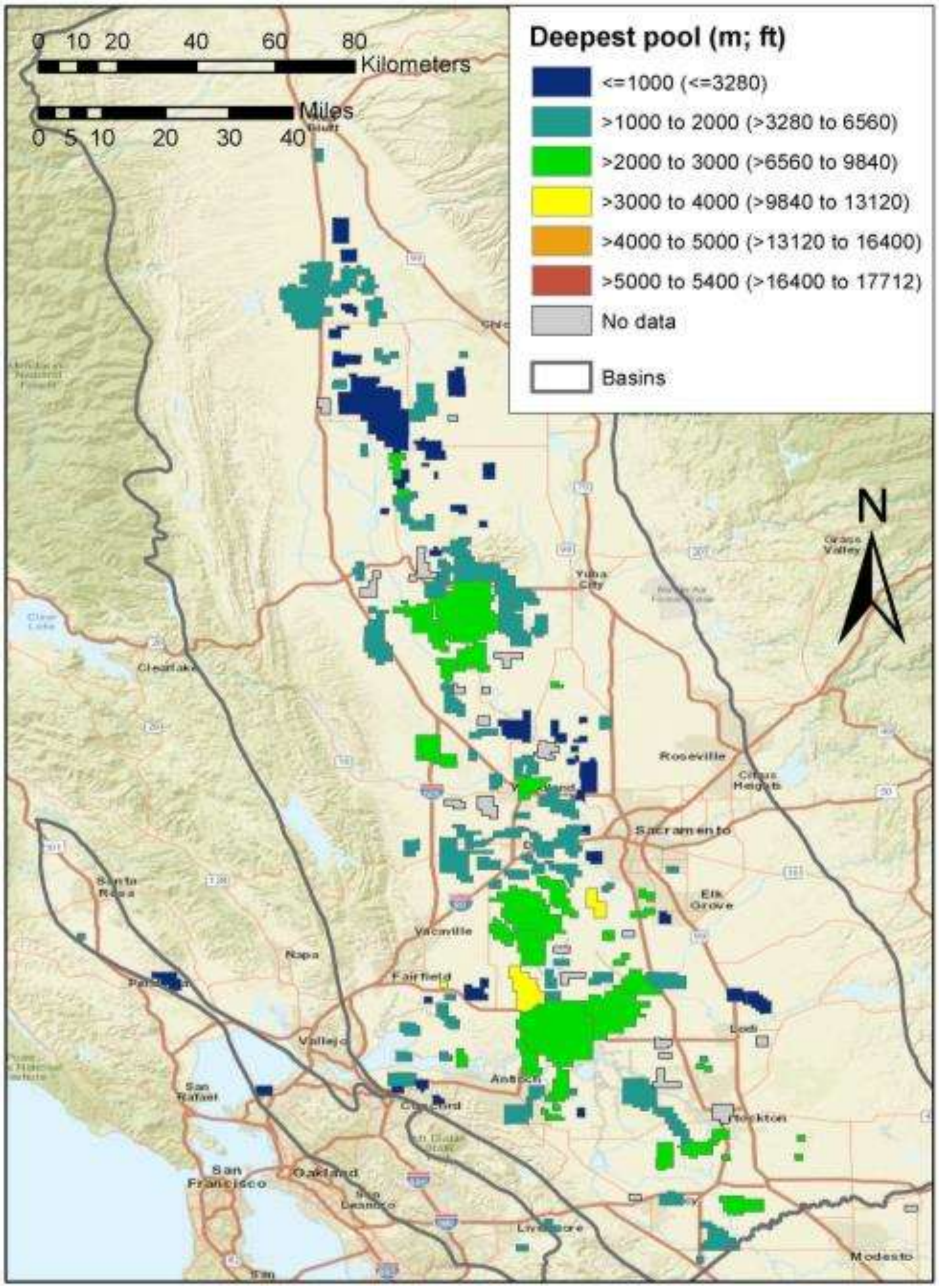
(c) 

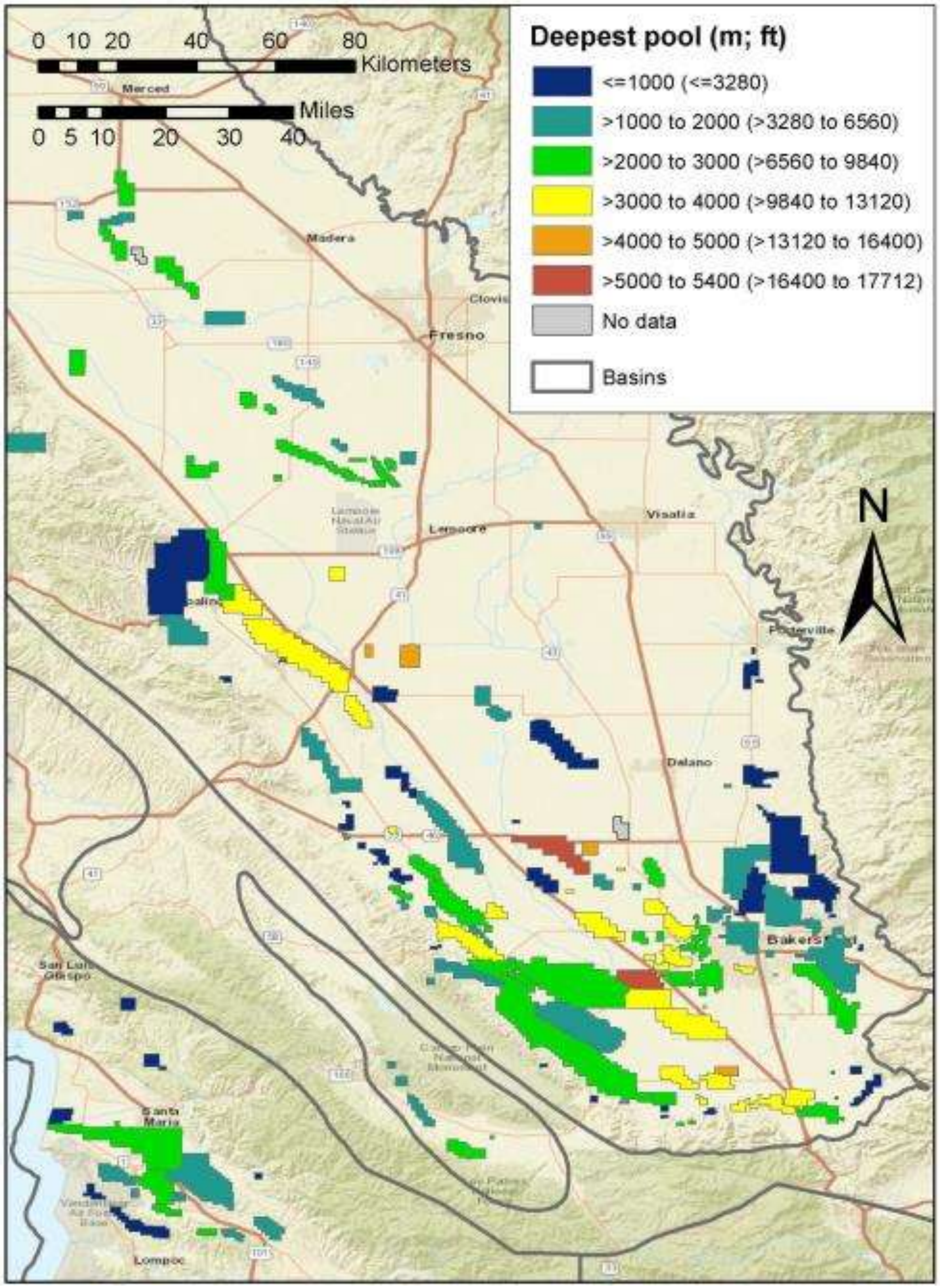
Figure 1.16. *Deepest prospect well and whether a prospect well encountered basement in each township prior to 1981 (data from DOG 1982b): (a) Sacramento Basin, (b) Santa Maria Basin to the southwest and central and southern portion of the San Joaquin Basin to the northeast, and (c) Santa Barbara-Ventura Basin to the north and Los Angeles Basin to the southeast.*

Figure 1.17 shows the average depth of the deepest pool available in DOG (1982a and 1992) and DOGGR (1998) for reference in considering potential CO_2 storage with regard to all known production and injection wells related to oil and gas. Figure 1.18 shows the maximum prospect boring MD and prospect borings to bedrock by township as of 2010 for reference.



Deepest pool (m; ft)
<=1000 (<=3280)
>1000 to 2000 (>3280 to 6560)
>2000 to 3000 (>6560 to 9840)
>3000 to 4000 (>9840 to 13120)
>4000 to 5000 (>13120 to 16400)
>5000 to 5400 (>16400 to 17712)
No data
Basins
0 10 20 40 60 80
Kilometers
Miles
0 5 10 20 30 40
N
Yuba City
Roseville
Sacramento
Elk Grove
Vacaville
Napa
Fairfield
Vallejo
Antioch
Concord
Lodi
Stockton
San Francisco
Oakland
Livermore
Modesto

(a)

(b) 
Deepest pool (m; ft)
<=1000 (<=3280)
>1000 to 2000 (>3280 to 6560)
>2000 to 3000 (>6560 to 9840)
>3000 to 4000 (>9840 to 13120)
>4000 to 5000 (>13120 to 16400)
>5000 to 5400 (>16400 to 17712)
No data
Basins
0 10 20 40 60 80
Kilometers
Miles
0 5 10 20 30 40
N
Merced
Madera
Clovis
Fresno
Lemoore
Visalia
Porterville
Delano
Bakersfield
San Luis Obispo
Santa Maria
Lompoc

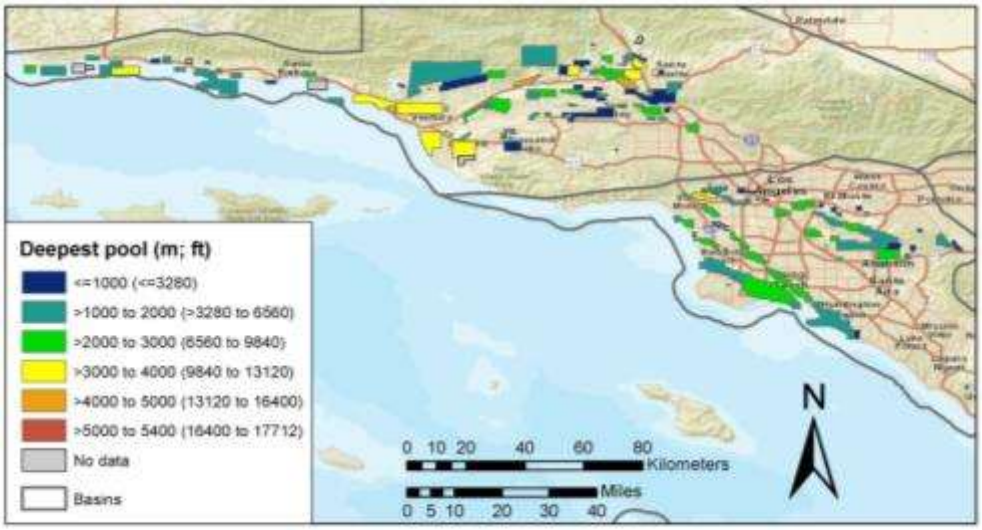
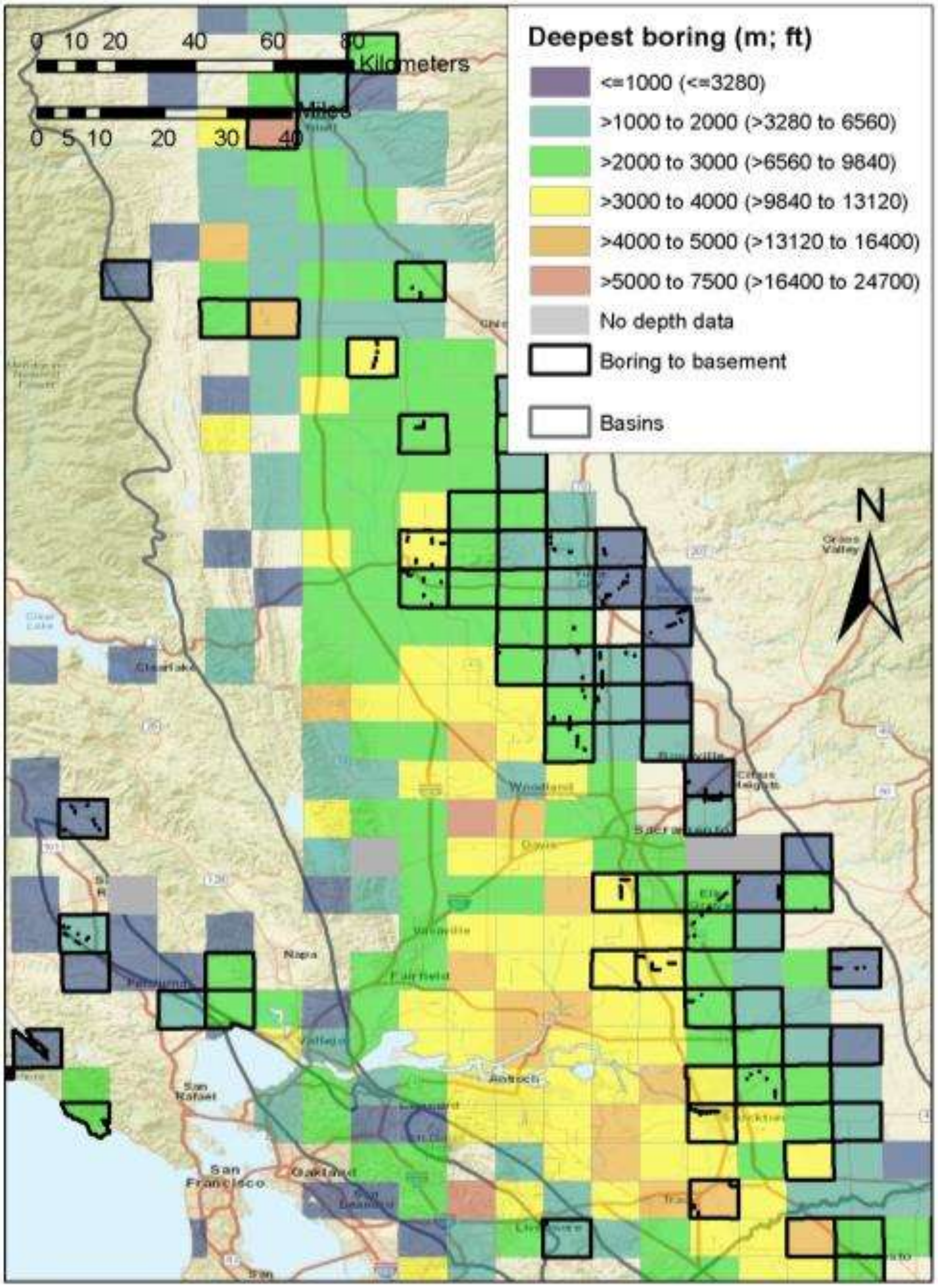
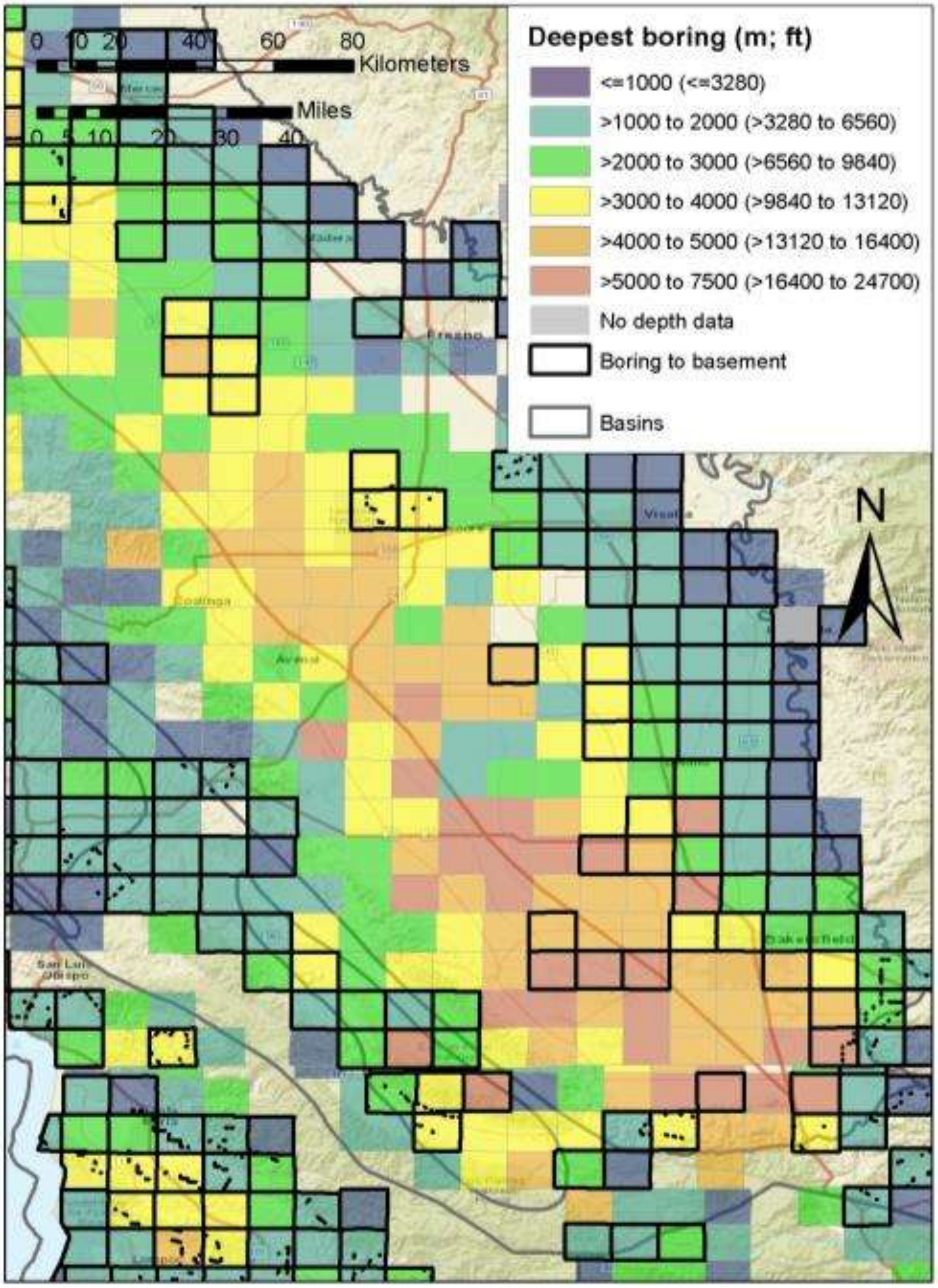
(c) 

Figure 1.17. *Deepest average hydrocarbon pool depth in each field in each major oil and gas basin in California listed in DOG (1982a and 1992) and DOGGR (1998): (a) Sacramento Basin, (b) Santa Maria Basin to the southwest and central and southern portion of the San Joaquin Basin to the northeast, and (c) Santa Barbara-Ventura Basin to the north and Los Angeles Basin to the southeast.*


Deepest boring (m; ft)
<=1000 (<=3280)
>1000 to 2000 (>3280 to 6560)
>2000 to 3000 (>6560 to 9840)
>3000 to 4000 (>9840 to 13120)
>4000 to 5000 (>13120 to 16400)
>5000 to 7500 (>16400 to 24700)
No depth data
Boring to basement
Basins
0 10 20 40 60 80 Kilometers
0 5 10 20 30 40 Miles
N
(a)

(b) 

0 10 20 40 60 80
Kilometers
0 5 10 20 30 40
Miles
Deepest boring (m; ft)
<=1000 (<=3280)
>1000 to 2000 (>3280 to 6560)
>2000 to 3000 (>6560 to 9840)
>3000 to 4000 (>9840 to 13120)
>4000 to 5000 (>13120 to 16400)
>5000 to 7500 (>16400 to 24700)
No depth data
Boring to basement
Basins
N

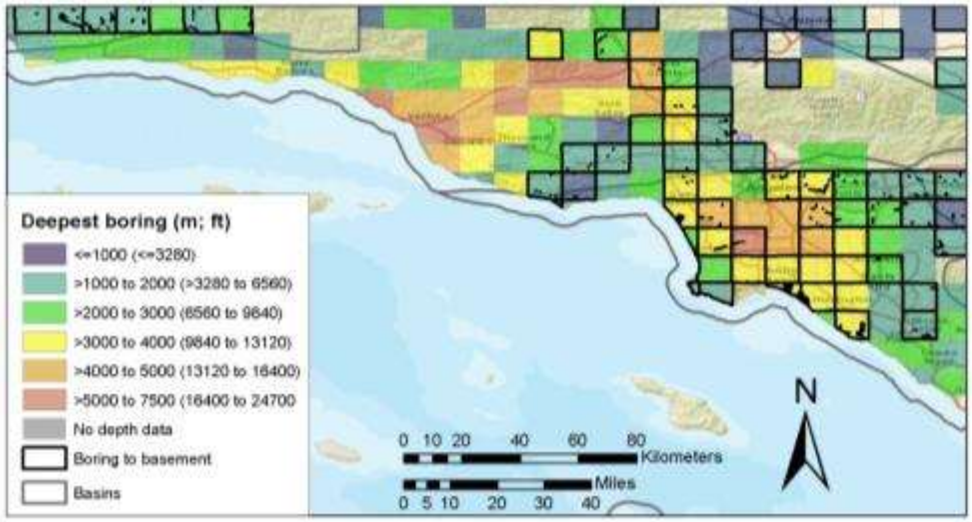
(c) 

Figure 1.18. *Deepest prospect boring and whether a prospect boring encountered basement in each township prior to 2010 (data from DOG 1982b and 1982-1992, and DOGGR 1993-2010): (a) Sacramento Basin, (b) Santa Maria Basin to the southwest and central and southern portion of the San Joaquin Basin to the northeast, and (c) Santa Barbara-Ventura Basin to the north and Los Angeles Basin to the southeast.*

The other main leakage pathways of concern are discontinuities (faults and fractures) in the seal rock and related uncertainties (e.g., Rohmer and Bouc, 2010). We recommend two means for applicants to manage this risk through site selection. Previous retention of hydrocarbons by a seal provides the most definitive evidence of its integrity with regard to retaining CO_2. For projects proposing to store CO_2 entirely within a reservoir volume that contained hydrocarbon accumulations, relying on this prior evidence of seal capacity only requires demonstrating that the injection pressures will be below the seal fracture opening pressure and that the CO_2 pressure on the base of the seal will not be higher than the seal's capillary entry pressure for CO_2 if capillary sealing is the proposed sealing mechanism, as opposed to attenuated advection.

For storage in reservoir volumes that did not contain hydrocarbons, seal integrity cannot be presumed *a priori*, as illustrated by the experience of natural gas storage in Illinois discussed above. For GCS projects in reservoirs without existing hydrocarbon accumulations, we recommend reservoir characterization that establishes very strong likelihood of cap-rock continuity and very low likelihood of permeable fault or fracture zones that compromise cap-rock integrity. While substantial discontinuities, such as seal-offsets by faults, can be large enough to be detected by 3D seismic reflection survey data, no consistently accurate method for assessing the hydraulic properties of these features with regard to leakage potential is currently available. As evidenced by hydrocarbon accumulations against faults, or seepage along others, it is apparent that these features can form either seals or leakage pathways, respectively.

There are also discontinuities that cannot be consistently detected, such as bedding-parallel open fracture zones and displacement on faults. Such features likely allowed leakage at some of the natural gas storage facilities developed in aquifers in Illinois mentioned above, and may have also allowed leakage at the LeRoy facility in Wyoming.

While we do recommend that ARB require applicants to provide information regarding detectable discontinuities and any evidence regarding their hydraulic properties, this is not sufficient alone, as indicated above. Consequently, we additionally recommend a preference for sites with seals whose strength is sufficiently low that they creep under the *in-situ* stresses imposed upon them (Sone and Zoback, 2013). Discontinuities in such seals will tend to be annealed (closed), such that they do not allow substantial leakage (Bourg, 2015).

Seals that are normally consolidated, meaning that their current depth is the maximum depth to which they have been buried, can be presumed to lack transmissive discontinuities if they have not experienced secondary cementation throughout (Ingram and Urai, 1999). This can be evaluated through study of the geologic history of the site and petrographic assessment of samples of the seal.

If the geologic history or petrographic analysis indicate some ambiguity regarding whether the seal is over-consolidated, i.e., the seal is stronger than it would be if only buried to its current depth and is without secondary cementation, the seal's ductility can be quantitatively evaluated using the following brittleness index (*BRI*):

$$BRI = \frac{UCS}{UCS_{NC}} \tag{4}$$

Where UCS is the seal's unconfined compressive strength and UCS_{NC} is the seal's compressive strength if it was normally consolidated. UCS can be measured from intact samples, and UCS_{NC} can be measured from a remolded (completely disaggregated) sample that is then normally reconsolidated. The UCS can also be estimated from the pressure wave velocity (V_p) through intact samples or preferably measured across the seal in a boring as

$$\log(UCS) = -6.36 + \log(0.86V_p - 1172) \tag{5}$$

where UCS is in MPa and Vp is in m/s. The UCS_{NC} can be estimated from the vertical effective stress σ', which is the pressure exerted by the weight of the rock above the seal minus the pressure of the water in the seal (Ingram and Urai, 1999):

$$UCS_{NC} = 0.5\sigma' \tag{6}$$

If $BRI < 2$, the seal is sufficiently ductile to anneal any discontinuities. If $BRI > 2$, discontinuities may be open. This does not necessarily mean the seal does not have sufficient capacity to trap CO_2, because such discontinuities may not exist, or they may not connect all the way through the seal if they do exist, or they may have other properties precluding substantial leakage if they do connect all the way through the seal (Ingram and Urai, 1999). For instance, if the seal is in a thrust fault stress regime (horizontal stresses are greater than vertical stress) the discontinuities will be nearly horizontal. This makes it sufficiently unlikely that there are connections across the entire seal and, if there are, the path lengths are sufficiently long enough to substantially slow down and reduce upward leakage to below detection limits.

If *BRI* > 2, and the seal is not in a thrust fault stress regime, determining if there are discontinuities cross-cutting the seal that could result in leakage above the detection limit requires substantially more detailed geologic and geomechanical characterization.

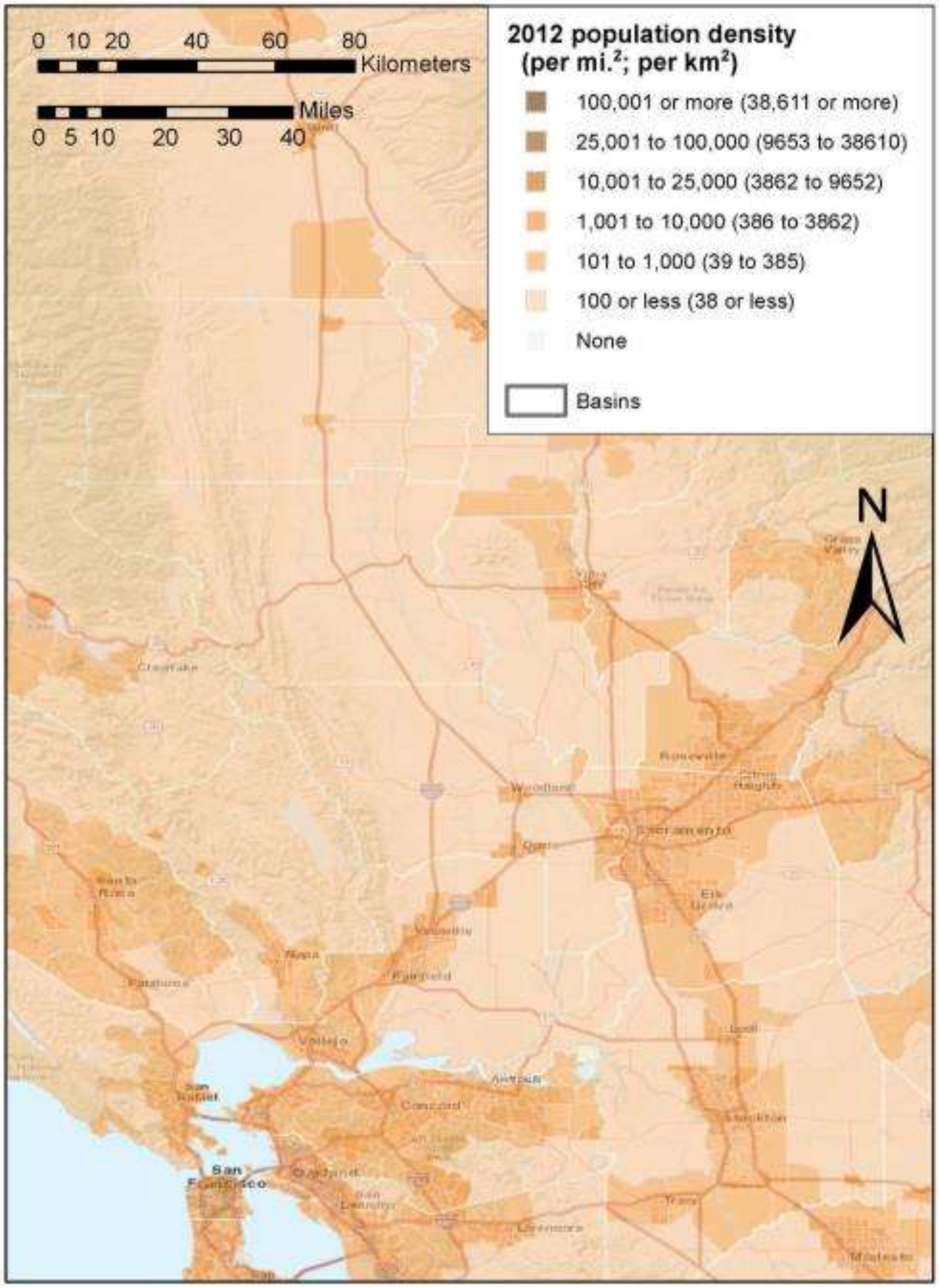
1.5.7 Proximity to emission sources and potential for CO_2 capture

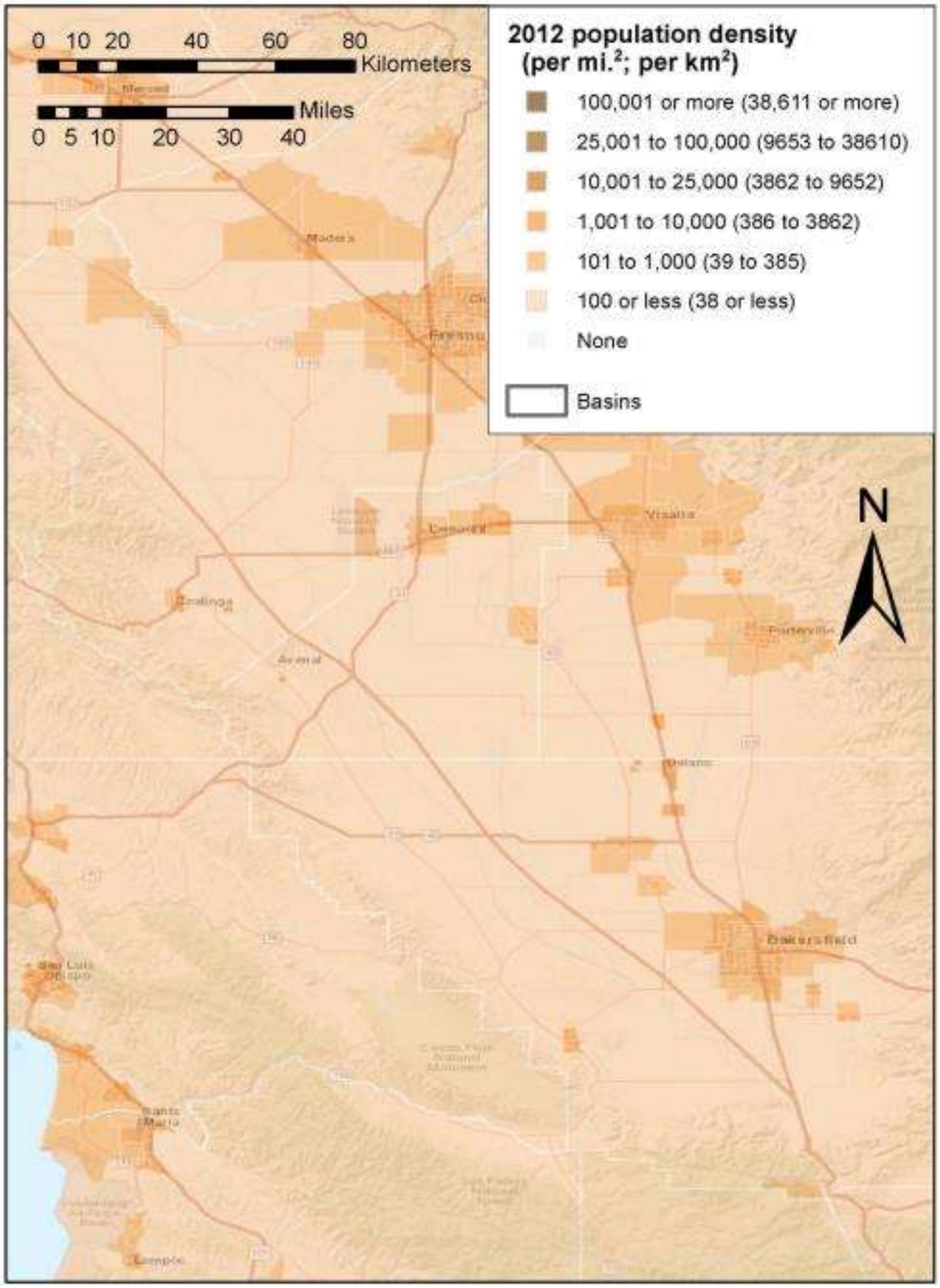
We recommend measuring the mass of CO_2 potentially stored in the subsurface by flow metering at the storage facility inlet, rather than the source facility outlet, although metering of flow from the source facility may be desirable for purposes other than quantifying the mass stored. Consequently, the proximity of the source to a storage project is not relevant to the geologic storage part of the QM although CO_2 pipeline transport is still going to be an important element of the QM overall. On this basis, we recommend not including source-to-storage proximity as a site-selection criterion. Optimizing the economic aspect of source-to-storage proximity can be left to market mechanisms. Various agencies already oversee risk management of transportation between sources and storage facilities. The experience base of some of these agencies includes overseeing transportation of CO_2 by pipeline, rail, and truck given the current active market for this commodity. While there may be some unique aspects of transportation for storage, and there may be a need to build transportation capacity to oversee larger volumes of transported CO_2 if carbon capture and storage becomes a significant industry, the agencies with current experience and jurisdiction are best positioned to meet these societal needs.

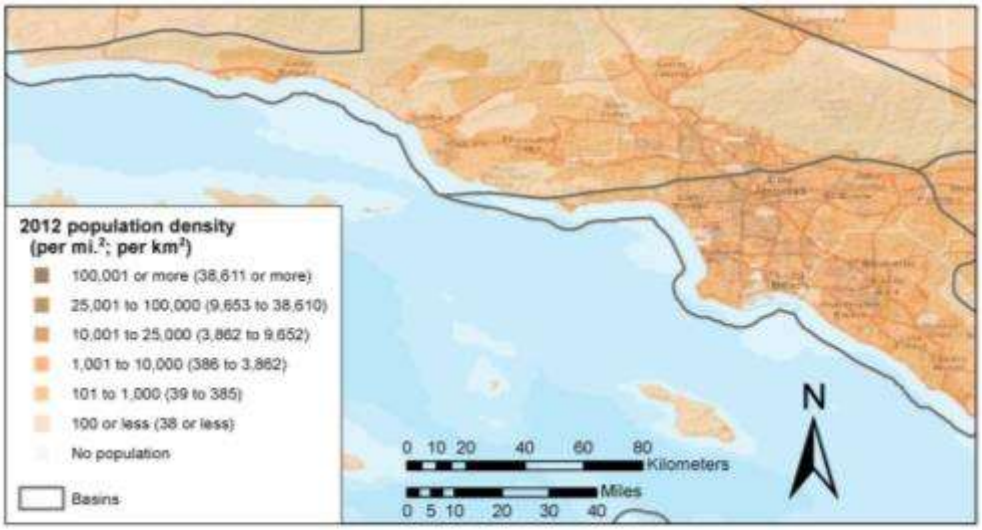
To minimize the potential for leakage during transport from source points to injection points, it is obviously desirable to identify the shortest routes for pipelines, rail, or truck transport. Consideration of the modes of failure for leakage in pipelines, and other transport options, via features such as valves, seams, and processes such as transfer operations, etc., are beyond the scope of this study.

1.5.8 Proximity to population centers

We recommend that GCS projects be located such that the projected AoRc does not extend into areas within urban limits, as defined by existing city boundaries, within which near-term future population growth can be assumed. The city boundary criterion motivates requiring extra scrutiny of proposed storage facilities within areas that are likely to experience increases in population density during the active injection phase, and ideally during post-injection site care as well. Selecting sites outside of these areas minimizes the risk of leakage that may affect people, but also has a nexus with the QM. In particular, the infrastructure and surface structures associated with suburban and urban areas makes application of some monitoring techniques, such as 3D seismic reflection, practically untenable, and substantially increases the cost and/or detection limits of others, such as groundwater quality and atmospheric gas monitoring. For reference, we show in Figure 1.19 the population density in the relevant parts of the state as a guide for locating low-population-density areas. Given that city planning boundaries and population densities may expand onto a site or its monitoring footprint, it may be that at the time of site closure, city boundaries and population densities have changed. This advocates for the importance of establishing with county and urban planners that future access to the site for monitoring be retained for time periods long enough to assure project monitoring objectives for the QM and long-term stewardship can be met.

(a) 
0 10 20 40 60 80
Kilometers
Miles
0 5 10 20 30 40
2012 population density
(per mi.²; per km²)
100,001 or more (38,611 or more)
25,001 to 100,000 (9653 to 38610)
10,001 to 25,000 (3862 to 9652)
1,001 to 10,000 (386 to 3862)
101 to 1,000 (39 to 385)
100 or less (38 or less)
None
Basins
N
Roseville
Woodland
Sacramento
Davis
Elk Grove
Santa Rosa
Napa
Vacaville
Fairfield
Petaluma
Vallejo
Lodi
Antioch
San Rafael
Concord
Stockton
San Francisco
Oakland
Tracy
Livermore
Modesto

(b) 
0 10 20 40 60 80
Kilometers
Miles
0 5 10 20 30 40
2012 population density
(per mi.²; per km²)
100,001 or more (38,611 or more)
25,001 to 100,000 (9653 to 38610)
10,001 to 25,000 (3862 to 9652)
1,001 to 10,000 (386 to 3862)
101 to 1,000 (39 to 385)
100 or less (38 or less)
None
Basins
N
Madera
Fresno
Visalia
Porterville
Coalinga
Bakersfield



(c)

Figure 1.19. *Population density from the 2012 Census via an Environmental Systems Research Institute (ESRI) service layer: (a) Sacramento Basin, (b) Santa Maria Basin to the southwest and central and southern portion of the San Joaquin Basin to the northeast, and (c) Santa Barbara-Ventura Basin to the north and Los Angeles Basin to the southeast.*

For areas outside city limits, we recommend a preference for sites where the likelihood of CO_2 from a well blowout entering a building is less than one hundredth of one percent (10^{-4}) for the life of the project (e.g., 20 years injection, plus the post-injection site-care period). This probability was selected because economic modeling suggests a few thousand storage projects are needed by 2050 (IEA, 2016). Thus, a 10^{-4} probability across all projects would result in less than 50% chance that anyone would be exposed a CO_2 well blowout into a building they occupy. A CO_2 well blowout into a building is particularly likely to result in high concentrations of CO_2 and related injuries or fatalities. The probability of this scenario occurring can be approximated by the following formula:

$$\Pr(\mathrm{y}) = t * f * \Pr(x) \tag{7}$$

where y is a person exposed to a blowout into a building, t is the time-averaged occupancy of buildings in areas where a blowout could occur (generally less than one per individual occupant because they are not in the building 24 hours a day), f is the proportion of area where a blowout could occur that is covered by buildings, which are occupied at some time, and $Pr(x)$ is the probability of the well blowout scenario x at a specific location.

1.5.9 Seismic hazard considerations

While the supposition has been published that seismic fault ruptures intersecting free-phase CO_2 plumes could result in leakage, this was based upon rupture through brittle rock (Zoback and Gorelick, 2012) rather than the ductile cap rocks we recommend as seals. Consequently, the main hazard of concern with regard to seismicity is not leakage related to quantification, but rather damage to surface infrastructure caused by ground shaking from larger events, and potentially nuisance from smaller events (although for projects in California, ground shaking from small events is less likely to be a nuisance because of the familiarity of the population with these phenomena due to California's high rate of natural seismicity).

Available research suggests that controlling the extent of downward pressure propagation limits the probability of potentially damaging earthquakes. For example, in Oklahoma, seismic events within basement rock faults are hypothesized to occur due to pressurization of the sedimentary interval immediately overlying the basement, as shown in Figure 1.20 (Keranen et al., 2013).

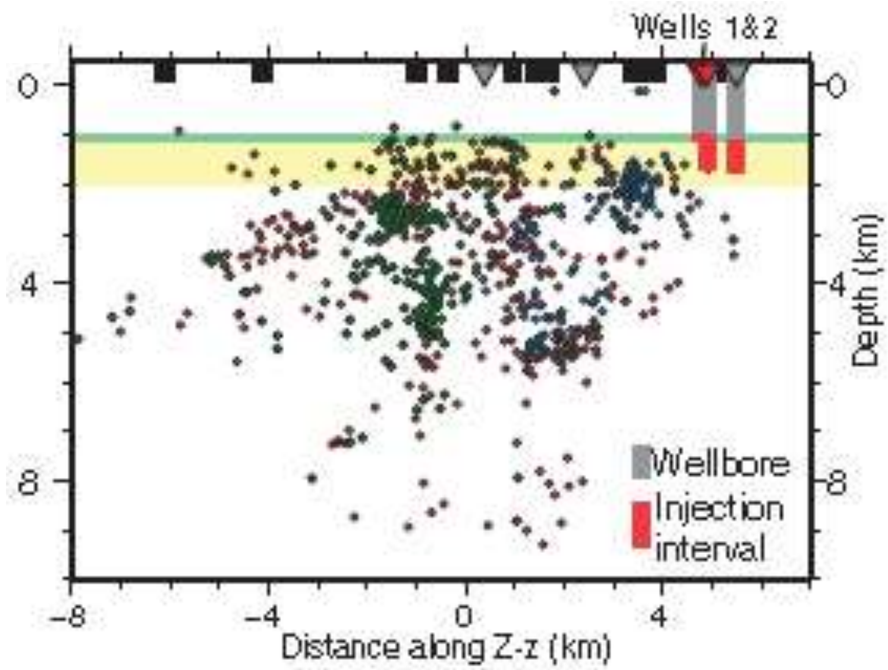


Figure 1.20. *Cross-section through a volume showing projected hypocenters of seismic events (shown as diamonds in the figure) in Oklahoma posited to result from increased pressures in the sedimentary unit (shown in light orange) capped by the seal (green). Most of the events are in the basement rock (no color) (Keranen et al., 2013).*

This same mechanism has been proposed to have induced an earthquake sequence including three > 4 magnitude events near the southern margin of the San Joaquin Valley, as shown in Figure 1.21 (Goebel et al., 2016). However in this case, wastewater injection occurred within a sedimentary unit several kilometers above the top of the basement, and up to 10 km shallower than the three largest events in the earthquake sequence. Simulation of the pressure propagation from the injection well indicated that the permeability of the wall rock, along a hypothetical permeable pathway connecting the injection interval to the hypocenter of the largest event, had to be 0.1 nD in order to prevent dissipation of the overpressure prior to reaching the hypocentral depth of the main shock. The existence of such low permeability continuously over such distances is not hydrologically or geologically reasonable, particularly through the several-kilometer-thickness of sediments between the injection interval and the top of basement. Therefore, we assert that this study failed to link fluid injection to the subject seismicity.

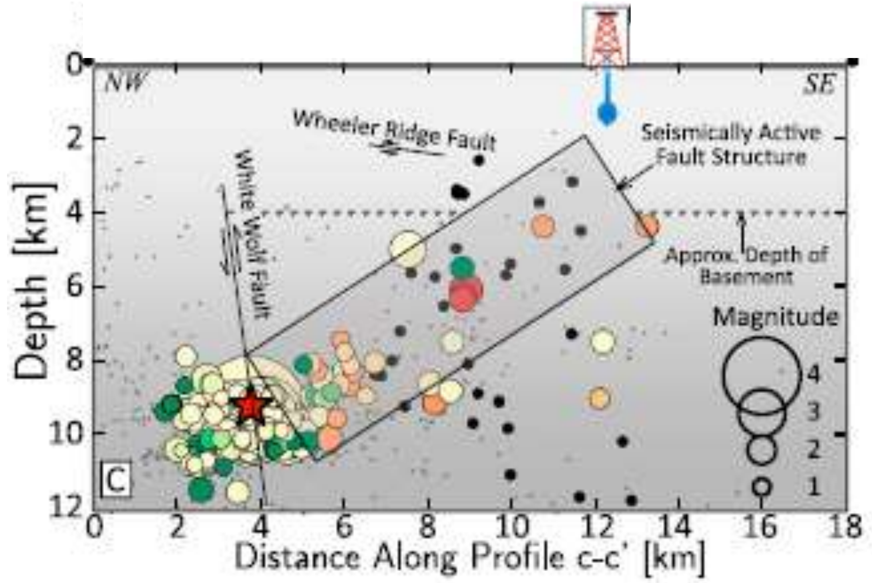


Figure 1.21. *Cross-section through a rock volume with an earthquake sequence posited to be induced by wastewater injection into a well near the southern margin of the San Joaquin Valley (Goebel et al., 2016). Note that while the depth of the well is shown as approximately 1.5 km, its public record data indicates it is actually less than 1 km in depth.*

The two studies cited above indicate that selecting sites with a dissipation interval below the proposed storage zone will limit the potential for induced seismicity, as shown in Figure 1.22, similar to the role dissipation intervals play in limiting upward leakage. Consequently we recommend including the presence of dissipation intervals as a site-selection criterion to manage the risk of induced seismicity, even though the risk of induced seismicity is not demonstrably related to leakage, and therefore quantification, at this time.

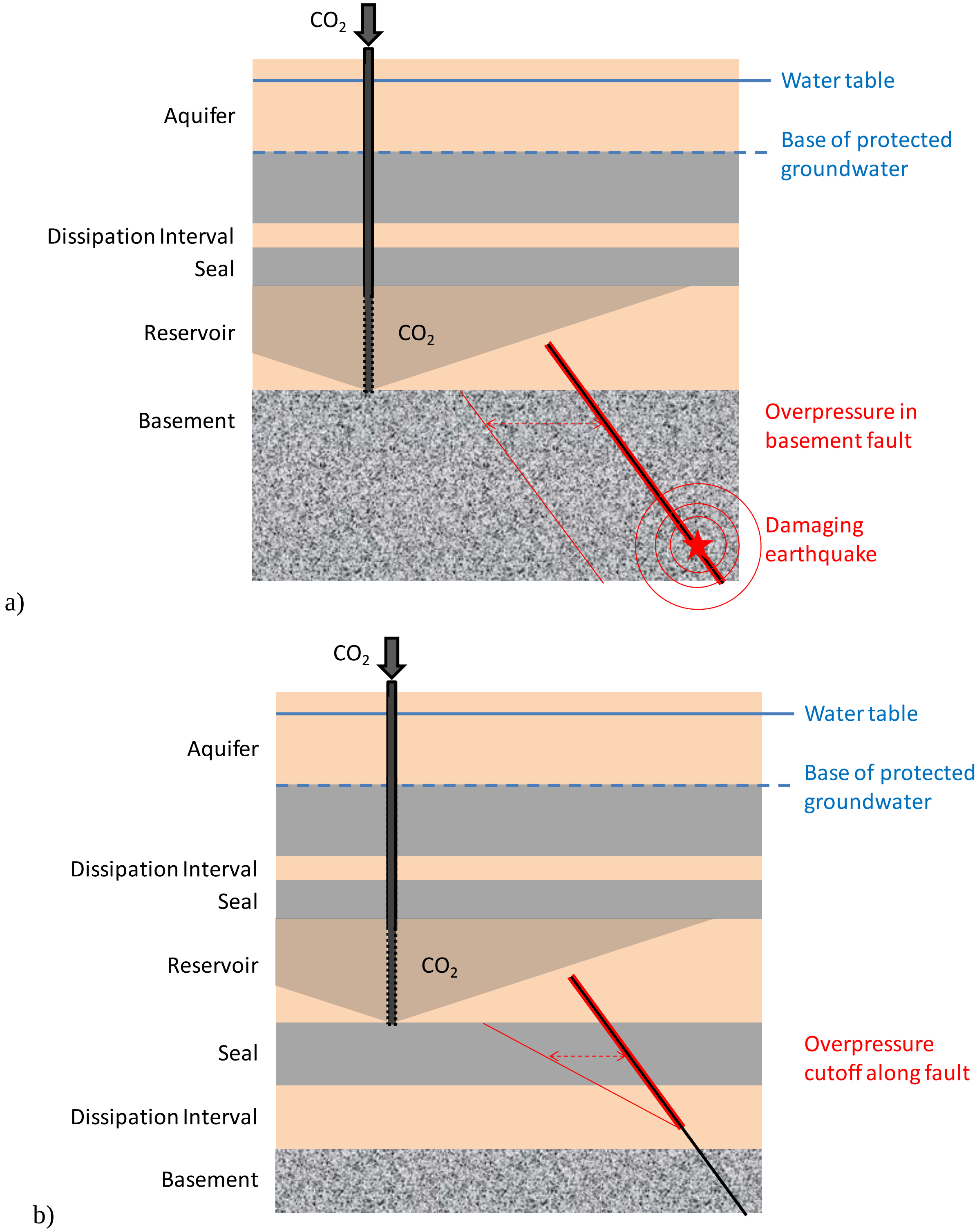


Figure 1.22. *Schematic cross-section showing a leakage pathway (black diagonal line) and pressure propagation (red) for (a) the propagation of overpressure from injection into a storage interval immediately overlying basement rock, and (b) the result of having the recommended pressure-dissipation interval between the proposed storage reservoir and the top of basement rock, i.e., reduced likelihood of inducing damaging earthquakes.*

1.5.10 Establishing pipeline or other transportation rights-of-way

The location of pipeline or other transportation rights-of-way is not relevant to quantifying the amount of CO_2 stored if the flow meter making the measurements upon which the credit calculation is based is located at the storage facility, rather than the source (capture) facility, as discussed above. With regard to managing transportation risk, there are other permitting and risk-management processes for new pipelines or other transportation modes, such as review required by the California Environmental Quality Act. Therefore, we recommend excluding consideration of new transportation facilities in the site-selection criteria with regard to the QM related to GCS.

1.5.11 Setting requirements for baseline data collection, including levels and other sources of CO_2 emissions, groundwater chemistry, and microseismicity

Rather than a matter of site selection for quantification, collecting baseline data is more a matter of monitoring once a site is selected, based on other criteria. Baseline data collection will impact the detection limit for the monitoring methods proposed, and thus the credit accounting, as discussed elsewhere in this report. Given natural variability in most of the monitoring targets, such as atmospheric gas concentrations, groundwater quality, and microseismicity, the more baseline data that are collected, the lower the detection limit for a perturbation caused by storage. Consequently, the extent of baseline data collection may be driven by the economics resulting from credit quantification, and so can be left to some degree to the applicant's discretion, subject to the condition that an agency such as ARB reviews the credibility of the monitoring method detection limits proposed by the applicant. Furthermore, we recommend collection of as much baseline data as are needed to understand system behavior, and to lower leakage detection limits.

1.5.12 Necessary geologic models and CO_2 flow simulations

1.5.12.1 Surface leakage of CO_2

We do not find simulation of surface leakage is needed as a direct component of the QM. Such simulations may be needed to determine or support the detection limits of surface monitoring methods the project applicant proposes to deploy. These limits are required for the negative accounting quantification approach that we recommend, as described above.

1.5.12.2 Subsurface migration and trapping of CO_2

As mentioned in the AoR discussion, a prediction of the area occupied by the free-phase CO_2 plume is needed to define the AoRc. Based on our recommendation of a monitoring cycle in the AoR and monitoring section, a prediction of the free-phase CO_2 plume extent at the next interim monitoring phase as well as its final extent are needed to define the interim and final AoRc. Making this prediction will most likely require simulating plume evolution using software capable of modeling multiphase fluid flow through porous media. In some rare cases, it might be possible to make the necessary predictions using analytical or semi-analytical approaches.

1.5.13 Summary of recommended site-selection criteria

The above discussion leads to the recommended site-selection criteria listed in Table 1.6 to increase the probability of containment and facilitate quantification.

Table 1.6. *Summary of site-selection criteria checklist (Met and Not Met left blank) to increase the probability of containment and facilitate storage quantification*

Criteria to reduce likelihood of leakage and facilitate quantification	**Met**	**Not Met**
Likelihood of leakage via unknown wells and uncased borings: No oil or gas was discovered in the AoRc and within or deeper than the proposed storage zone prior to five years after establishment of the oil and gas regulatory agency (1920 in California).		
Likelihood of leakage via known uncased borings (for instance "dry" exploration borings): For the portion of storage proposed in a saline aquifer, all borings that intersect the storage zone within the AoRc need to have plugs within the primary seal. (Plugs in these borings may be shallower than the seal, particularly if the boring was advanced prior to 1981, which is five years after passage of the SDWA, and so there is a higher risk of leakage via these borings.)		
Likelihood of leakage via known wells: All known active or idle wells intersecting or passing through the storage zone within the AoRc have annular seals and all abandoned wells have plugs immediately above the reservoir.		
Likelihood of leakage via geologic pathways through the seal (low brittleness): For the portion of storage proposed in a saline aquifer, the proposed seal is normally consolidated, sufficiently ductile that potential fractures and faults are annealed, and/or is in a thrust-fault stress regime.		
Likelihood of leakage through intact seal (overpressure): Capillary trapping and slow advection combined have a 99% probability of retaining 99% of the stored CO_2 for 1,000 years in the storage reservoir, given pressures at the base of the seal related to injection and buoyancy forces.		
Magnitude and detectability of leakage: An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and the base of USDW over the AoRc.		
Risk of induced seismicity: An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and basement rock over the AoRc.		
Likelihood of damaging seal: Dynamic capacity will be managed by one of the following: 1. Measured by perturbing a contiguous reservoir area at least one tenth the area of the AoRc. 2. Backup (contingency) injection intervals are proposed. 3. Pressure management via fluid extraction is proposed.		
Likelihood of lethal CO_2 concentration for someone in a building is less than a hundredth of a percent per project: AoRc is outside city limits and the probability of someone being in a structure over a well blowout is 10^{-4} per project over the life of the project (e.g., 20 years injection, plus post-injection site-care period).		
Likelihood of collapse impact and surface monitoring interference: No surface or subsurface mining activities have occurred or are planned to occur within the AoRc.		

These criteria are intended as an initial screen. Sites that meet all the criteria are preferred because they will have a lower probability of containment failure than other sites. A site that does not meet a particular criterion may still be acceptable. For sites that do not meet every criteria, demonstrating acceptability will require more detailed characterization of the site relative to any criteria that are not met, assessment of the containment risk based on the more detailed characterization, and, if indicated by the assessment, establishing mitigations to decrease the risk of loss of containment to acceptable levels. For instance, Figure 1.18 suggests there are few sites in California that would not include prospect borings drilled prior to 1981 in their AoRc. Consequently, further analysis of the location and depth of such prospect borings could determine that none of these borings encounter the storage target within the AoRc, or that borings that encounter the target were plugged at a depth appropriate for maintaining storage containment. Either of these could allow the project to proceed at the proposed site.

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PART II: SITE-SELECTION CASE STUDY

2.1 INTRODUCTION

In Part II of this report, we apply the findings and recommendations of Part I to two potential storage sites upon which a considerable amount of public domain research has already been conducted. Specifically, a previous site-screening study by WESTCARB (2011) was carried out that considered four sites in California. The results of WESTCARB's study was the emergence of the two sites discussed below, King Island and Kimberlina. The WESTCARB study is summarized in Appendix A.

King Island is located in the delta of the San Joaquin and Sacramento Rivers. The Kimberlina site is located at the intersection of Kimberlina Road and State Highway 99, in the eastern side of the southern San Joaquin Valley. Initial research regarding storage at each site was conducted by WESTCARB. Subsequent research funded by other sources leveraged this initial research (e.g. Foxall et al., 2017). The sites are also covered by various regional storage studies that provide further context for the following case studies (Downey and Clinkenbeard, 2005; 2006; 2010; 2011).

2.2 SITE-SELECTION CRITERIA APPLIED TO CANDIDATE SITES

2.2.1 King Island

2.2.1.1 Overview

The King Island site is located in the south-central portion of the Sacramento sedimentary basin. The deepest sediments in this basin were deposited in a marine environment. This typically results in the deposition of a variety of geologic units, some of which function as seals overlying others that possess sufficient permeability and porosity to store CO_2.

The Sacramento Basin is dominated by siliciclastic sediments. The maximum depth to the bottom of the basin is in the range of 6,710 m (22,000 ft) (Downey and Clinkenbeard, 2006), and there are a number of extensive units consisting predominantly of marine shale and sandstone, as shown in the cross-section on Figure 2.1. The formations of interest for storage at King Island, the Mokelumne River, the Starkey, and the Winters formations (Figure 2.1), have been identified as the most widespread potential storage units in the Sacramento Basin (Downey and Clinkenbeard, 2010).

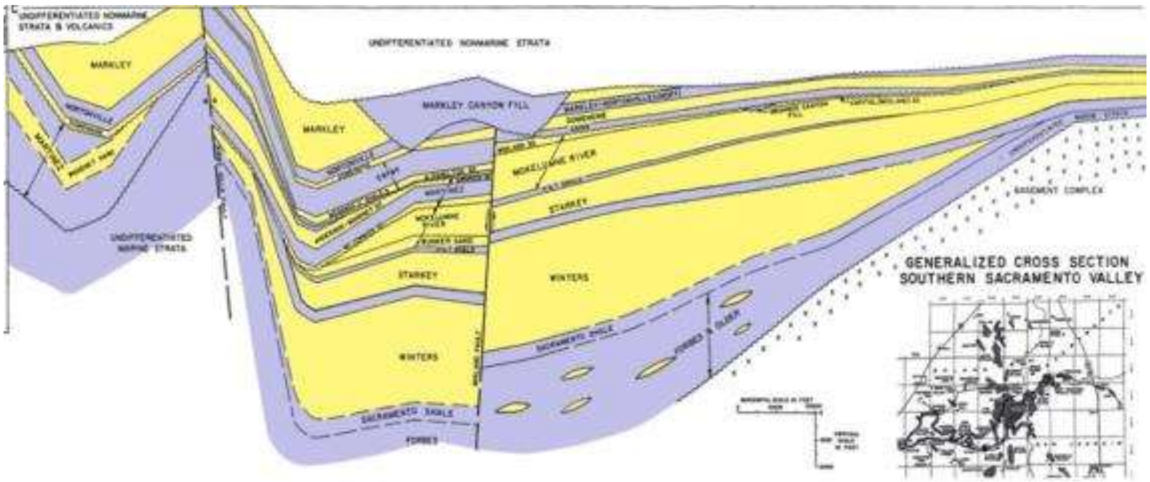


Figure 2.1. *Cross-section interpretation of the stratigraphy in the southern Sacramento Basin, showing geologic units consisting of predominantly sandstone (in yellow) and shale (in gray). (Downey and Clinkenbeard, 2005).*

The methodologies used to evaluate the geologic units at King Island as potential storage resources are based on DOGGR public well records, as well as a dataset obtained from a characterization well advanced at the site, the Citizen Green #1 storage characterization well. Well logs are used to determine the depth and thicknesses of formations, and the permeability of potential reservoir sandstones and sealing formation shales.

The material within each geologic formation shown on Figure 2.1 is not uniform. Rather, units that are predominantly sandstone reservoirs typically contain some shale layers and units that are predominantly shale seals contain some sandstone layers. The sediments in these formations were deposited in dynamic coastal and marine environments with high and low rates of localized deposition and erosion, resulting in deposition of both sandstone and shale in each formation at various times and locations. These formations were subsequently eroded by strong currents in coastal and nearshore river systems, resulting in deep gorges cut down through the section. The gorges were later infilled with muds that later became favorable seals, preventing the lateral migration of gas produced from source rocks at depth, which subsequently became trapped by the King Island structure. The gas in the King Island field resided in a pinnacle consisting, in part, of the Mokelumne River formation within the Meganos Gorge fill, which acts as the seal (Figure 2.2).

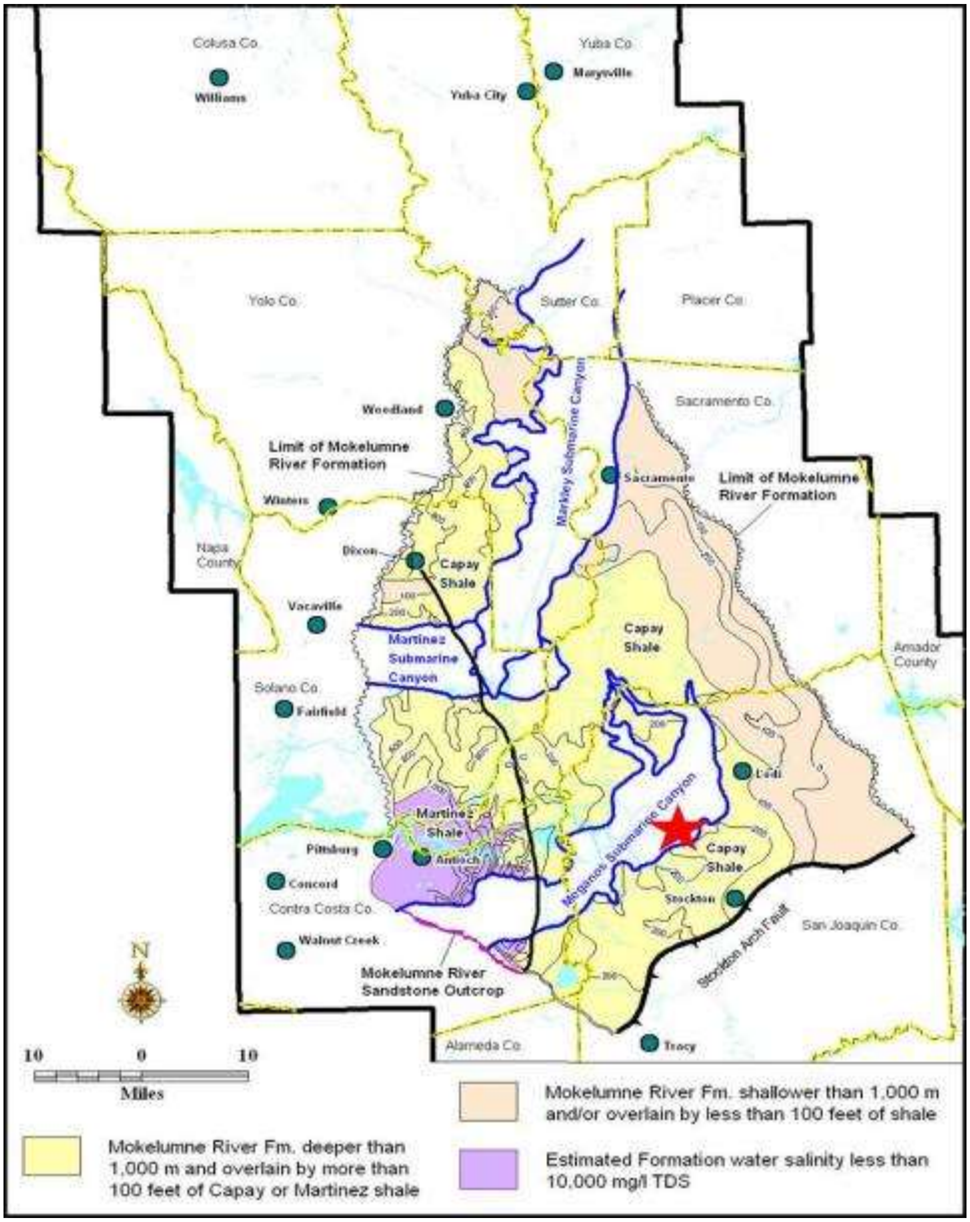


Figure 2.2. *Regional map showing areal extent, depth, and thickness of the Mokelumne River formation (contour lines). Formation water may be less than 10,000 mg/L TDS in areas near surface outcrops of the formation. Approximate King Island site location is shown by the red star. (Modified from Downey and Clinkenbeard, 2010).*

In spite of such heterogeneities, a cross-section made by connecting log data from local wells (as shown by the red dashed line in Figure 2.3) suggests that the storage and sealing formations are laterally continuous and the confining layers maintain the same approximate thickness within the King Island pinnacle (Figure 2.).

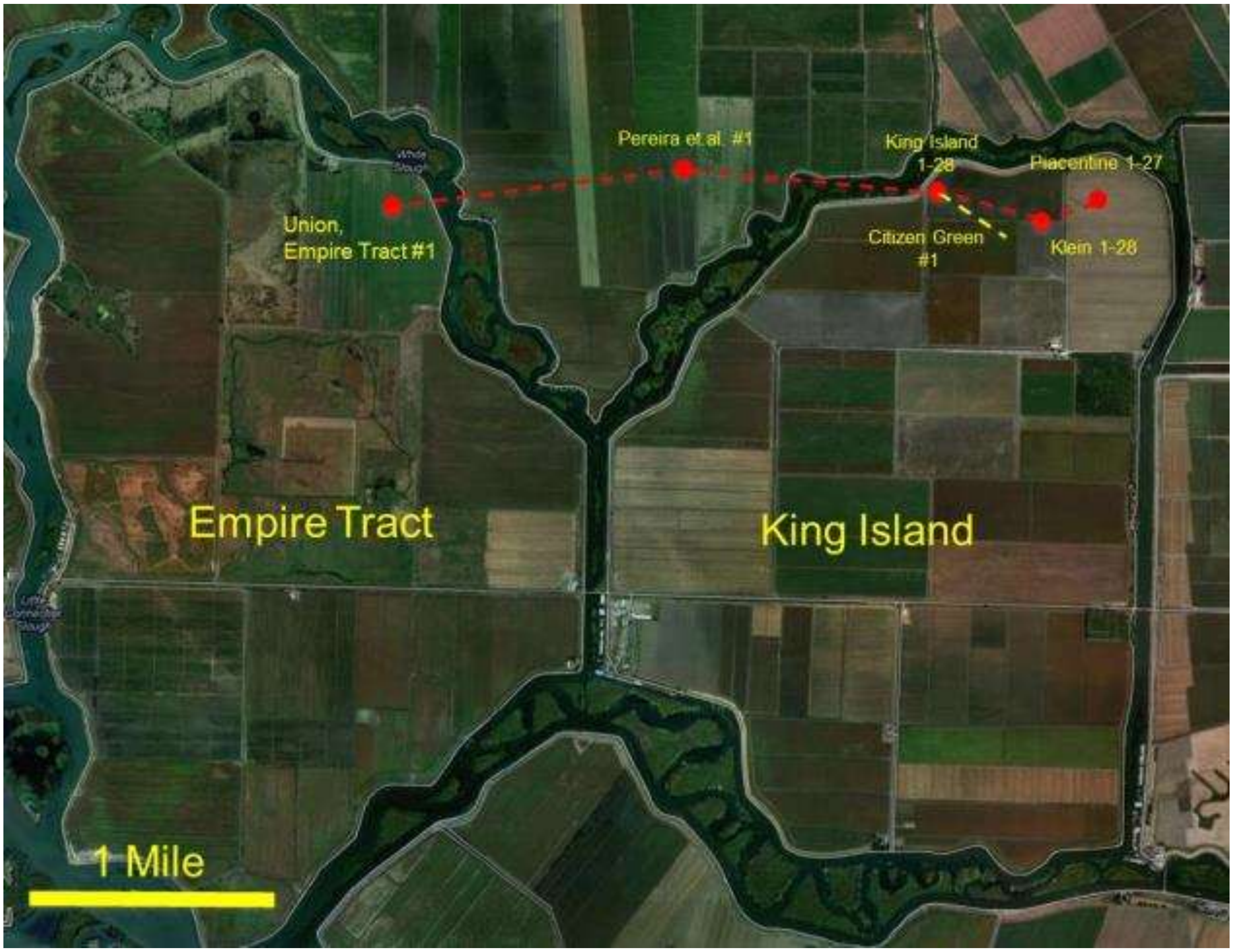
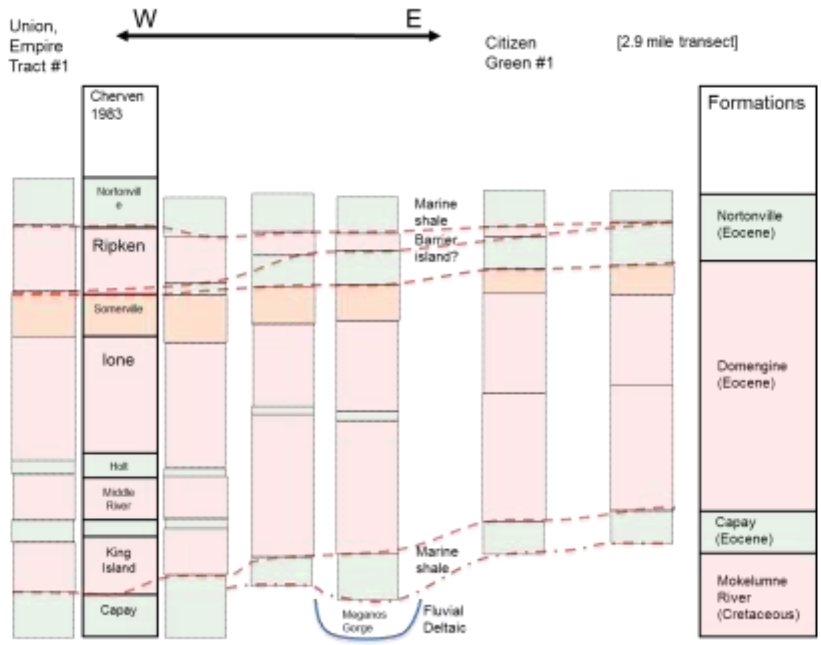
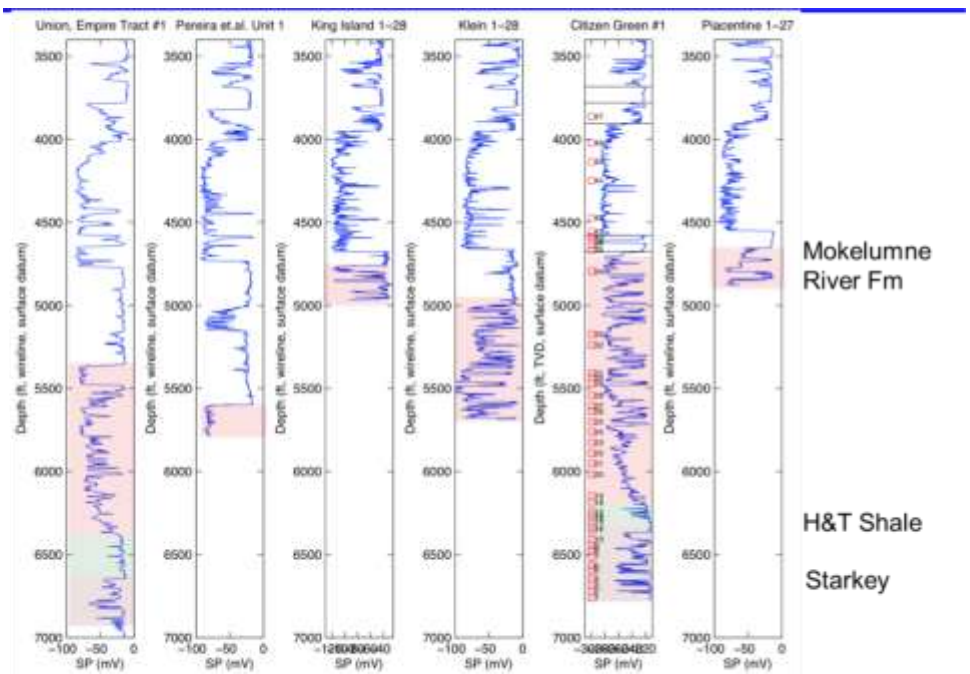


Figure 2.3. *Google map view of King Island showing locations of five wells. Directionally drilled Citizen Green #1 characterization well is shown by the yellow dashed line and gas production wells are shown as red dots. The red dashed line shows the east-west strike of stratigraphy as interpreted from well logs shown in Figure 2.4.*


Union, Empire Tract #1
W
E
Citizen Green #1
[2.9 mile transect]
Cherven 1983
Formations
Ripken
Somerville
Ione
Holt
Middle River
King Island
Capay
Marine shale
Barrier island?
Marine shale
Meganos Gorge
Fluvial Deltaic
Nortonville (Eocene)
Domengine (Eocene)
Capay (Eocene)
Mokelumne River (Cretaceous)


Union, Empire Tract #1
Pereira et.al. Unit 1
King Island 1-28
Klein 1-28
Citizen Green #1
Piacentine 1-27
SP (mV)
Mokelumne River Fm
H&T Shale
Starkey

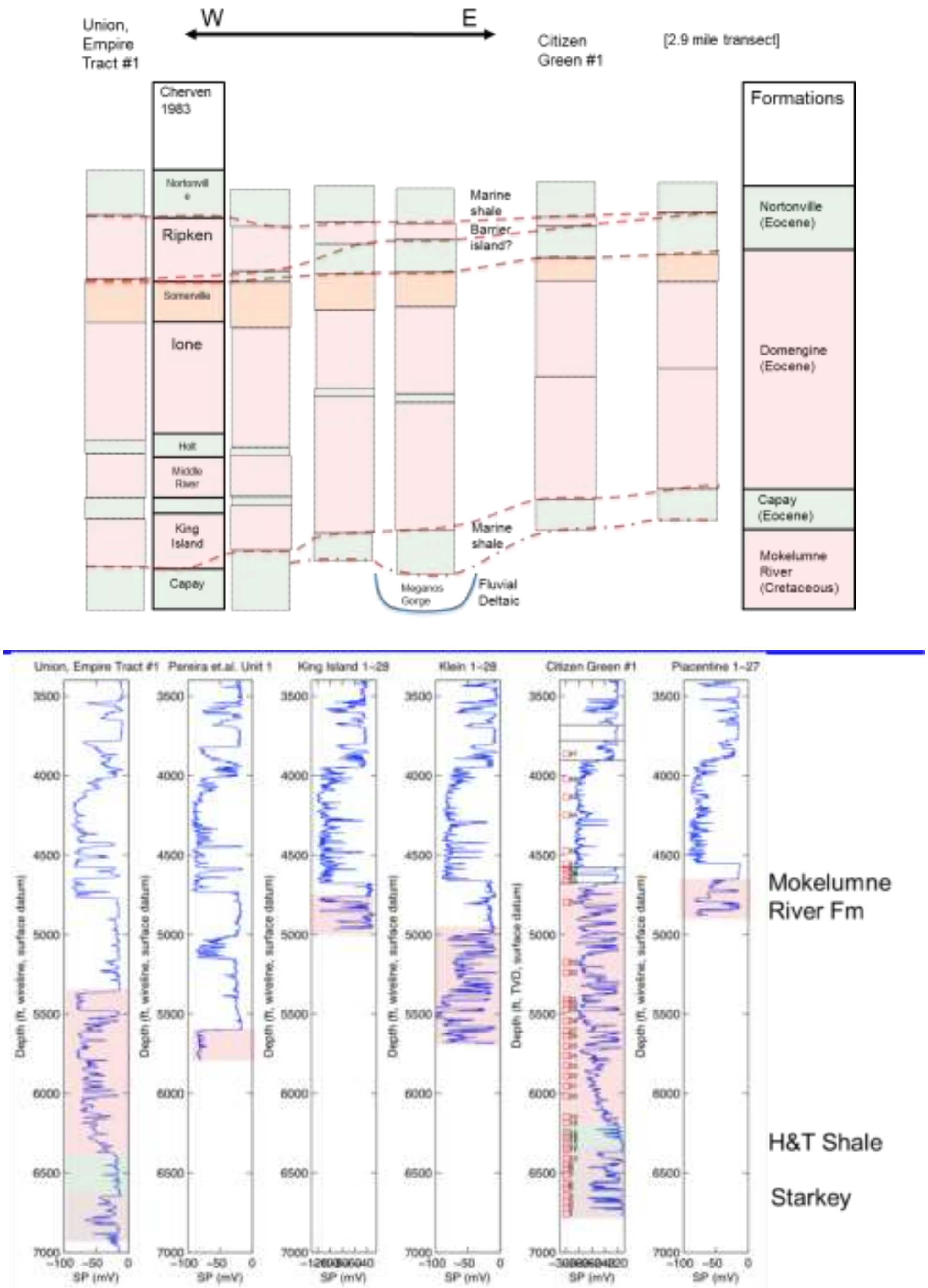


Figure 2.4. *Cross-sections showing local stratigraphy at King Island. Upper figure shows the section nearby and in the King Island field above the Mokelumne River formation as interpreted from gas production well logs of the spontaneous potential (SP), lower figure. Location of wells and transect are shown in Figure 2.3.*

While all logs include the top of the Mokelumne River formation (top of pink bars in Figure 2.4, lower figure), only two of the well logs, Citizen Green #1 and Union Empire Tract #1, were drilled deep enough to capture the base of the Mokelumne River formation (base of pink bars).

Although there is no water composition data from these formations in the King Island field itself, salinities in the Mokelumne River formation are thought to be, based on log data and a few samples, far higher than the cutoff for USDW (defined as any water resources less than 10,000 mg/L TDS).

2.2.1.2 Application of recommended site-selection criteria

Table 2.1 summarizes the application of the site-selection criteria proposed in Section 1.5 of this report to the King Island site. This presumes injection into the Mokelumne River formation of more than a million tonnes per year of CO_2. Such a project at this site would meet six of nine of the site-selection criteria. There are insufficient data to determine whether or not one of the critera is met.

To reiterate, the failure to meet a criterion does not necessarily mean the site is inappropriate for storage from a quantification standpoint. Rather more work is required to assess the site relative to those criteria not met.

The evaluations entered into Table 2.1 are further described and justified below.

Table 2.1. *Summary of site-selection criteria as applied to the King Island site given available data*

Criteria to reduce likelihood of leakage and facilitate quantification	Met	Not Met
Likelihood of leakage via unknown wells and uncased borings: No oil or gas was discovered in the AoRc and within or deeper than the proposed storage zone prior to five years after establishment of the oil and gas regulatory agency (1920 in California).	x	
Likelihood of leakage via known uncased borings (for instance "dry" exploration borings): For the portion of storage proposed in a saline aquifer, all borings that intersect the storage zone within the AoRc need to have plugs within the primary seal. (Plugs in these borings may be shallower than the seal, particularly if the boring was advanced prior to 1981, which is five years after passage of the SDWA, and so there is a higher risk of leakage via these borings.)		x
Likelihood of leakage via known wells: All known active or idle wells intersecting or passing through the storage zone within the AoRc have annular seals and all abandoned wells have plugs immediately above the reservoir.		x
Likelihood of leakage via geologic pathways through the seal (low brittleness): For the portion of storage proposed in a saline aquifer, the proposed seal is normally consolidated, sufficiently ductile that potential fractures and faults are annealed, and/or is in a thrust-fault stress regime.	x	
Likelihood of leakage through intact seal (overpressure): Capillary trapping and slow advection combined have a 99% probability of retaining 99% of the stored CO_2 for 1,000 years in the storage reservoir, given pressures at the base of the seal related to injection and buoyancy forces.	?	?
Magnitude and detectability of leakage: An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and the base of USDW over the AoRc.	x	
Risk of induced seismicity: An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and basement rock over the AoRc.	x	
Likelihood of damaging seal: Dynamic capacity will be managed by one of the following: 1. Measured by perturbing a contiguous reservoir area at least one tenth the area of the AoRc. 2. Backup (contingency) injection intervals are proposed. 3. Pressure management via fluid extraction is proposed.	x	
Likelihood of lethal CO_2 concentration for someone in a building is less than a hundredth of a percent per project: AoRc is outside city limits and the probability of someone being in a structure over a well blowout is 10^{-4} per project over the life of the project (e.g., 20 years injection, plus post-injection site-care period).		x
Likelihood of collapse impact and surface monitoring interference: No surface or subsurface mining activities have occurred or are planned to occur within the AoRc.	x	

2.2.1.3 Likelihood of leakage via unknown wells and uncased borings

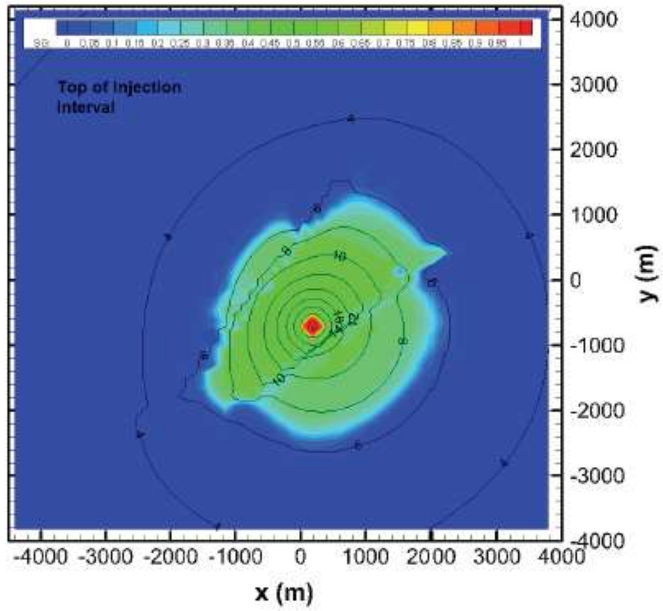
No oil or gas was discovered in the AoRc and within or deeper than the proposed storage zone prior to five years after establishment of the oil and gas regulatory agency (1920 in California).

There are no historical records indicating that oil or gas was discovered in this area prior to 1921. According to records available from DOGGR, g production in the King Island field commenced in 1986.

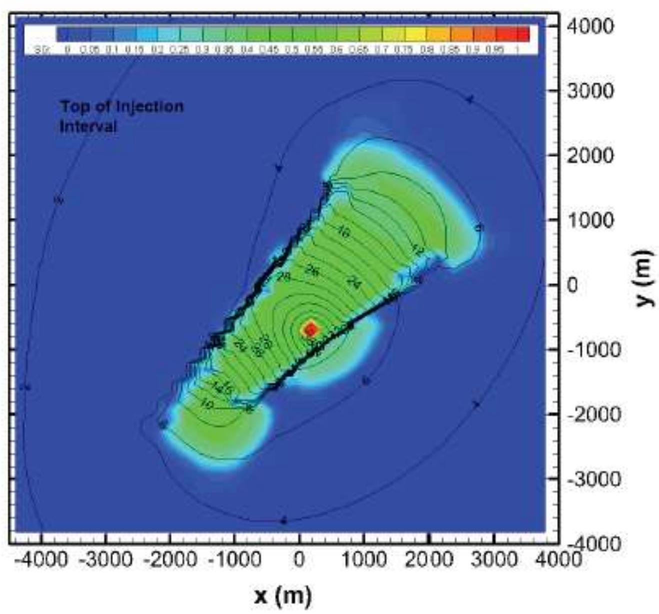
2.2.1.4 Likelihood of leakage via known uncased borings

For the portion of storage proposed in a saline aquifer, all borings that intersect the storage zone within the AoRc need to have plugs within the primary seal. (Plugs in these borings may be shallower than the seal, particularly if the boring was advanced prior to 1981, which is five years after passage of the SDWA, and so there is a higher risk of leakage via these borings.)

The plume resulting from the injection of eight million tonnes of CO_2 per year for 20 years at the King Island site has been simulated by Foxall et al. (2017). The predicted plume footprint from two scenarios is shown on Figure 2.5. While this is likely more CO_2 per year than would be injected by a project at this location, it is also likely a shorter injection duration. Injection of four million tonnes per year for 40 years is closer to the likely rate and duration. Consequently, the approximately 10 km^2 plume area shown in Figure 2.5 is reasonable.



(a)



(b)

Figure 2.5. *Simulated CO_2 plumes at the cessation of injecting eight million tonnes of CO_2 per year for 20 years at King Island. (a) Higher injection modeled with h permeability bounding faults. (b) Injection modeled with low permeability bounding faults. Note that the faults are not actually interpreted as existing, but were included in the model in order to explore potential leakage and induced seismicity (Foxall et al., 2017).*

As of the end of 2016, approximately 11 Bcf of gas had been produced from the King Island field. Based on the reservoir pressure and temperature, the gas formation volume factor (bbl/Mcf) is estimated as 0.0012 and the specific gravity of stored CO_2 as 0.65. The assessed pore space evacuated could store about 1.3 million tonnes of CO_2. The administrative field area is a section and a half (4 km^2). All of this information indicates any commercial storage project at the site will extend into the saline aquifer portions of the Mokelumne River formation outside of the gas accumulation footprint.

A map of known well and uncased boring locations is shown in Figure 2.6. Table 2.2 lists uncased borings that were drilled to the Mokelumne River formation, and Table 2.3 lists wells in the King Island gas field. The deepest plugs in these borings are more than a 1,000 m (3,300 ft) above the top of the storage target, which is also above the primary seal. Consequently, the King Island site does not meet this criterion.

Figure 2.6. *Well and uncased boring map of King Island. Records for these are summarized in Tables 2.2 and 2.3 and provided in Appendix A. Source:* [*http://www.conservation.ca.gov/dog/Pages/WellFinder.aspx*](http://www.conservation.ca.gov/dog/Pages/WellFinder.aspx) *(accessed on 4 May 2017).*

Table 2.2. *Known uncased borings in the vicinity of the King Island field*

Well Name	Year drilling commenced	Total depth (ft)	Year plugged and abandoned	Plug depth(s) (ft)
Klein 1-28	1961	5,702	1961	326–520
Piacentine 1	1962	10,500	1962	728–950
Rio Blanco 1	1972	5,450	1972	15–40, 360–557
King Island 33-1	2007	5,500	2007	270–624

2.2.1.5 Likelihood of leakage via known wells

All known active or idle wells intersecting or passing through the storage zone within the AoRc have annular seals and all abandoned wells have plugs immediately above the reservoir.

There are five known wells, three of which are operating (active or idle) and two of which have been plugged and abandoned. All of these wells are or were open to the Mokelumne River formation.

Table 2.3. *King Island field wells*

Well Name	Year drilling commenced	Shallowest perforation measured depth (ft)	Measured top depth of annular seal above perforations (ft)	Year plugged	Measured depth interval of plug at/above target (ft)
King Island 1-28 (KI) Citizen Green 1 (CG: sidetracked from King Island 1-28)	KI: 2005 CG: 2011	KI: 4772 CG: 5216	KI: 3880 CG: 3700	KI: 2011	KI: 4572–4888
Piacentine 1-27	1986	4670	3896		
Piacentine 2-27	2013	None	0		
PG&E Test Injection/With-drawal Well 1	2014	4716 (top of liner screen with gravel pack)	0	Shown as plugged, but not according to records	
Moresco et al. Unit A 1	1985	4700	3965	1997	4602–4758

2.2.1.6 Likelihood of leakage via geologic pathways through seal (low brittleness)

For the portion of storage proposed in a saline aquifer, the proposed seal is normally consolidated, sufficiently ductile that potential fractures and faults are annealed, and/or is in a thrust-fault stress regime..

If storage in the King Island Field were restricted to the depleted gas reservoirs, this criterion would not be necessary or applicable. As noted in the discussion of the rationale for this particular criterion, the presence of gas or oil demonstrates that any fractures or faults present in sealing units have annealed. However, as discussed above, commercial injection at King Island would result in storage in the saline aquifer portion of the reservoir also. Laboratory testing of a Capay shale seal rock analog indicated it would be ductile under *in-situ* conditions, and therefore any faults or other discontinuities would be annealed (Foxall et al., 2017).

The general configuration of the Sacramento Basin, as shown in Figure 2.1, suggests that the Capay shale is currently at or near the greatest depth in its history, in which case it would be normally consolidated. However, there are substantial regions at the site with no strata in the section, so uplift cannot be ruled out. Consequently, the *BRI* approach is utilized. The approximate average V_p of the Capay shale is derived from sonic logging of Citizen Green #1 is 2,600 m/s with minima of approximately 2,400 m/s (from data provided by Jonathan Ajo-Franklin). From Equation 5, this implies an average *UCS* of 11 MPa with minima of 7 MPa.

The lithostatic stress at the top of the Capay shale is about 25 MPa (Jonathan Ajo-Franklin, personal communication). We did not identify initial fluid pressure data for the King Island field. However, the Capay and Mokelumne River are normally pressured (water is at hydrostatic pressure) in the Harte and Lodi Airport fields to the east, McDonald Island field to the southwest, and River Island field to the northwest (DOG, 1982a). The depth of the top of the Capay shale in these fields is the same or slightly deeper than it is in the King Island field. True vertical depth to the top of the Capay shale is about 1.25 km (4,100 ft) in Citizen Green #1 (Jonathan Ajo-Franklin, personal communication). Hydrostatic pressure at this depth is about 12 MPa. Therefore, σ' is about 14 MPa. By Equation 3, this implies a *UCS* for the Capay of 7 MPa. Using Equation 4, the *BRI* < 2. Consequently, the Capay shale is ductile, so fractures and faults will anneal.

2.2.1.7 Likelihood of leakage through intact seal (overpressure)

Capillary trapping and slow advection combined have a 99% probability of retaining 99% of the stored CO_2 for 1,000 years in the storage reservoir given pressures at the base of the seal related to injection and buoyancy forces.

The minimum capillary entry pressure can be calculated from the estimate of the original gas in place, the Mokelumne River formation porosity, and the field area. The original gas in place is estimated as 13.8 Bcf. Given the gas formation volume factor above, this equates to 93 million scf of volume occupied in the reservoir. The Mokelumne River formation porosity, at the same approximate depth in surrounding fields, is approximately 0.30 (DOG, 1982a). Using the administrative field area, this gives an average original gas column height of just more than 7 ft. Given specific gravity and the gas formation volume factor above, the initial density of the gas in the reservoir was about 110 kg/m^3. These yield an original buoyancy pressure on the base of the seal of 20 kPa. Taking the gas accumulation area as half the administrative field area increases this to 40 kPa. Considering a conical accumulation, the peak buoyancy pressure on the base of the seal would be 120 kPa, or 0.12 MPa. Allowable injection pressure increments are typically at least half of hydrostatic pressure, or 7 MPa (1,000 psi), as calculated above. Consequently, the minimum capillary entry pressure implied by natural gas accumulation is insufficient to prevent the stored CO_2 from entering the seal during injection. Therefore, meeting this criterion requires sampling and measuring the entry pressure for Capay shale.

Because the minimum capillary entry pressure implied by gas accumulation is insufficient to conclude CO_2 will be prohibited from entering the seal, this criterion can be judged via a bounding advection calculation. Citizen Green #1 encountered approximately 30 m (100 ft) of the Capay shale seal (Jonathan Ajo-Franklin, personal communication). The upper limit permeability for shale is 10 μD (10^{-17} m^2) (Neuzil, 1994). The allowable pressure increase of 7 MPa (1,000 psi) is greater than the average pressure increase over the plume area at any given time. Taking the CO_2 viscosity as 5×10^{-5} Pa s, based on the initial reservoir pressure and temperature, the ultimate plume area as 10 km^2, CO_2 specific gravity as 0.65 (as discussed above), and the average pressure in the CO_2 plume equal to the allowable injection pressure increment, yields a maximum annual advective flux through the seal of about 10 million tonnes of CO_2 per year during the last year of injection, discounting any time lag for the CO_2 to reach the top of the seal. As this upper bound leakage for just one year is considerably more than 1% of the total injected mass, this criterion cannot be met through attenuated advection with available data. This suggests measuring the permeability of samples from the Capay shale would be essential to further constrain the potential magnitude of this leakage mode.

2.2.1.8 Magnitude and detectability of leakage

An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and the base of USDW over the AoRc.

USDW in this area are found in the shallower, non-marine deposits above the Nortonville formation. Thus, the Nortonville, Domengine, and Capay formations occur between the USDW and the Mokelumne River formation storage target. According to DOG (1982a), the Domengine formation has substantial permeability in nearby fields (frequently greater than 1 D) and underlies the Nortonville formation, which acts as a seal in various nearby fields. An approximately 200 m (700 ft) thickness of Domengine formation was encountered in Citizen Green #1 (Jonathan Ajo-Franklin, personal communication). Consequently, the Domengine formation provides a sufficient dissipation interval over the primary seal.

2.2.1.9 Risk of induced seismicity

An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and basement rock over the AoR.

There is one reservoir unit beneath the seal below the Mokelumne River storage target at King Island: the Starkey formation. The permeability of this unit is 10 to 100 mD. However it is more than 300 m (1,000 ft) thick (Downey and Clinkenbeard, 2010), and so has sufficient transmissivity to effectively attenuate downward propagating overpressure, should that occur.

2.2.1.10 Likelihood of damaging seal

Dynamic capacity will be managed by one of the following:

1. *Measured by perturbing a contiguous reservoir area at least one tenth the area of the AoRc.*
2. *Backup (contingency) injection intervals are proposed.*
3. *Pressure management via fluid extraction is proposed.*

Gas production versus tubing pressure in King Island field wells provides some perspective of dynamic capacity. Assuming initial hydrostatic pressure, the average productivity index for wells Piacentine 1-27 and Moresco #1 over the first year was equivalent to 70,000 and 80,000 tonnes of CO_2 per year per MPa, respectively. If the allowable injection pressure is 150% of the hydrostatic pressure, the allowable injection rates would be 500,000 and 600,000 tonnes per year, respectively, through the relatively thin portion of the Mokelumne River formation perforated in each well.

These dynamic capacity estimates are for the portion of the reservoir near the well. Estimating a storage field dynamic capacity would require pressures from an observation well, which does not appear to be available. Nonetheless, the near well results from relatively short perforation intervals toward the top of the storage target suggests there is likely to be sufficient injectivity to meet commercial storage needs.

2.2.1.11 Likelihood of lethal concentration for someone in a building is less than a hundredth of a percent

AoRc is outside city limits and the probability of someone being in a structure over a well blowout is 10^{-4} per project over the life of the project (e.g., 20 years injection, plus post-injection site-care period).

The AoRc may extend into the western isolated portion of the City of Lodi, specifically the area containing the Lodi Energy Center and the White Slough Water Pollution Control Facility. The AoRc may also extend into the very northwestern portion of the City of Stockton. While review of 2017 aerial imagery available through Google maps does not show residences in these areas, their inclusion within each City indicates such development could readily occur. The imagery for the relevant portion of Stockton, in particular, indicates it may have been graded for development that has yet to occur. So this criterion is not met.

2.2.1.12 Likelihood of collapse impact and surface monitoring interference

No surface or subsurface mining activities have occurred or are planned to occur within the AoRc.

There has been no active or past surface or subsurface mining within the likely AoRc.

2.2.2 Kimberlina

2.2.2.1 Overview

The Kimberlina site is located in the southeastern portion of the San Joaquin sedimentary basin, approximately 25 km northwest of Bakersfield at the Kimberlina Road exit off US 99 (Figure 2.7). Like the Sacramento Basin, the sediments in this basin are siliciclastic and deposited in a marine environment, resulting in numerous zones suitable for GCS.

Land use around the Kimberlina site is agricultural. The site owner, Clean Energy Systems, runs an experimental facility for high-temperature oxycombustion power plant design. The site also hosts other experimental energy technologies, including solar.

Figure 2.7. *Aerial view of Kimberlina site adjacent to US 99 with the location of a prospective power plant shown. The existing experimental power generation facilities are visible in the southern portion of the site.*

The geologic unit of primary interest for geologic carbon storage at the Kimberlina location is the Oligocene Vedder formation. A schematic cross-section of the stratigraphy of the southern San Joaquin Basin from west to east shows target storage formations and sealing units (Figure 2.8). The Freeman-Jewett unit provides a seal over the Vedder formation.

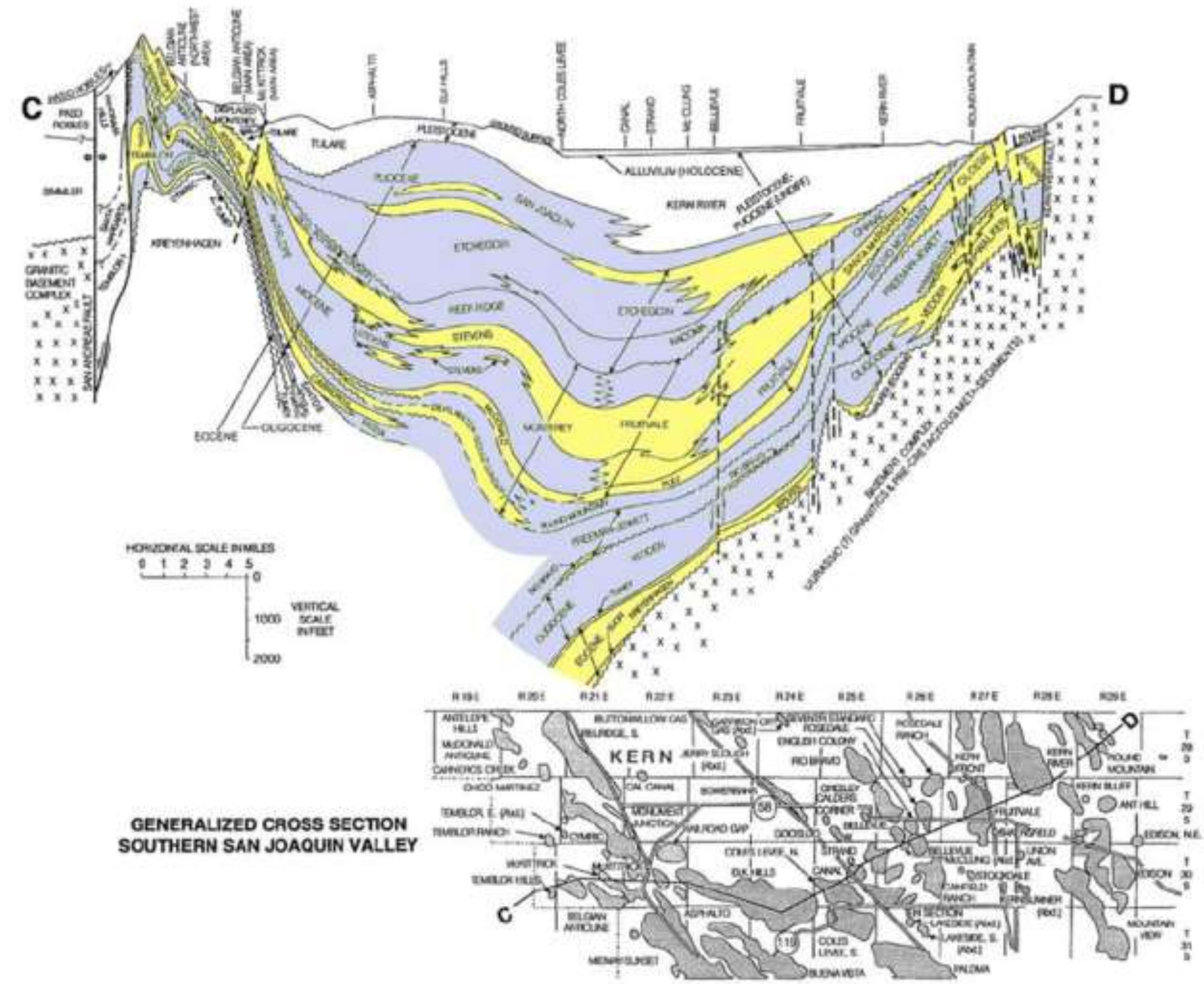


Figure 2.8. *Cross-section interpretation of southern San Joaquin Basin stratigraphy, showing geologic units that consist predominantly of sandstone (in yellow) and shale (in gray) (Downey and Clinkenbeard, 2005).*

Figure 2.9 shows an east-west cross-section through the region near Kimberlina. The Vedder formation is regionally extensive and thick enough to potentially contain millions of tonnes of CO_2. It is capped by low-permeability shale of the Freeman-Jewett formation. The Freeman-Jewett formation can reach thicknesses of 300 m (1,000 ft) or more and is composed of over 90% shale (seal rock), with minor interbedded siltstones and sandstones. The Freeman-Jewett sandstones are not particularly thick, generally averaging between 1.5 and 3 m (5 and 10 ft). In most cases these sandstones are encased in, or overlain by, thick shales. The Freeman-Jewett units are 245 m (800 ft) thick at the Kimberlina site.

Overlying the Freeman-Jewett, sandstone in the Olcese formation provides a dissipation interval or a secondary storage target. The Fruitvale formation, which overlies the Olcese formation, consists of deep water marine deposits of the middle Miocene. At Kimberlina, it is 275 m (900 ft) thick and occurs at a depth below 1,650 m (5,400 ft).

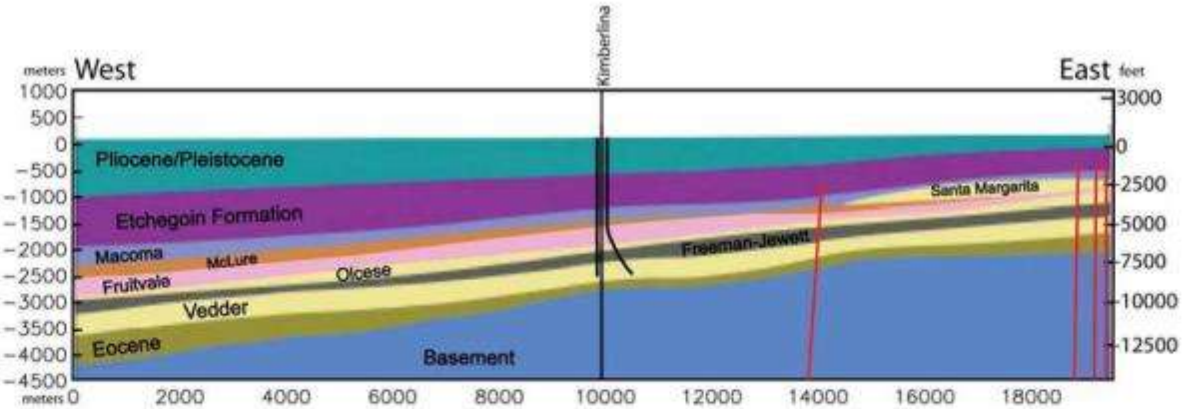


Figure 2.9. *Simplified cross-section of stratigraphy from west to east through Kimberlina site, showing target storage formations and sealing units.*

The sedimentary section has been tectonically tilted toward the west, as well as faulted and broadly folded in some locations. A major feature of the basin is the Bakersfield Arch, located south of the Kimberlina site. It is a westward-plunging structural bowing on the east side of the basin. This structure extends for approximately 25 km (15 mi), separating the basin into two subbasins (Figure 2.10). This structural feature is the site of several major oil fields.

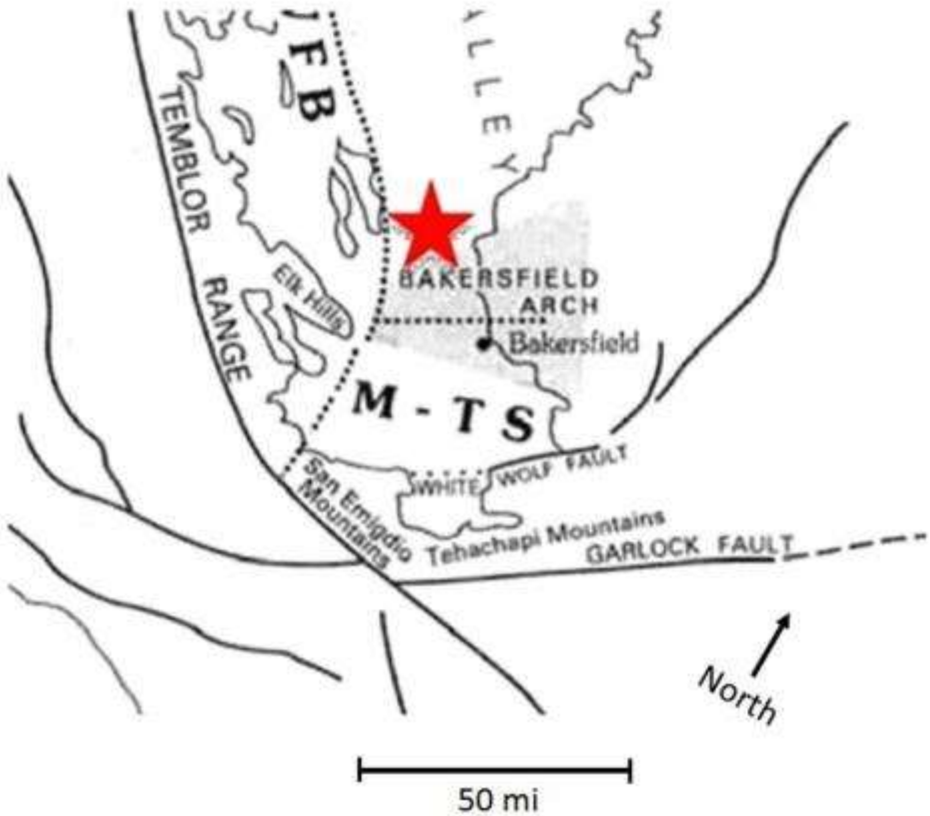


Figure 2.10. *Structural map of Bakersfield area. Kimberlina site is shown by the red star.*

Wagoner (2009) used well logs and seismic line data to build a geologic model of the Kimberlina site. Figure 2.11 shows the locations of the seismic lines and the wells used to construct the model, and Figure 2.12 shows the stratigraphic cross-section interpreted from the data.

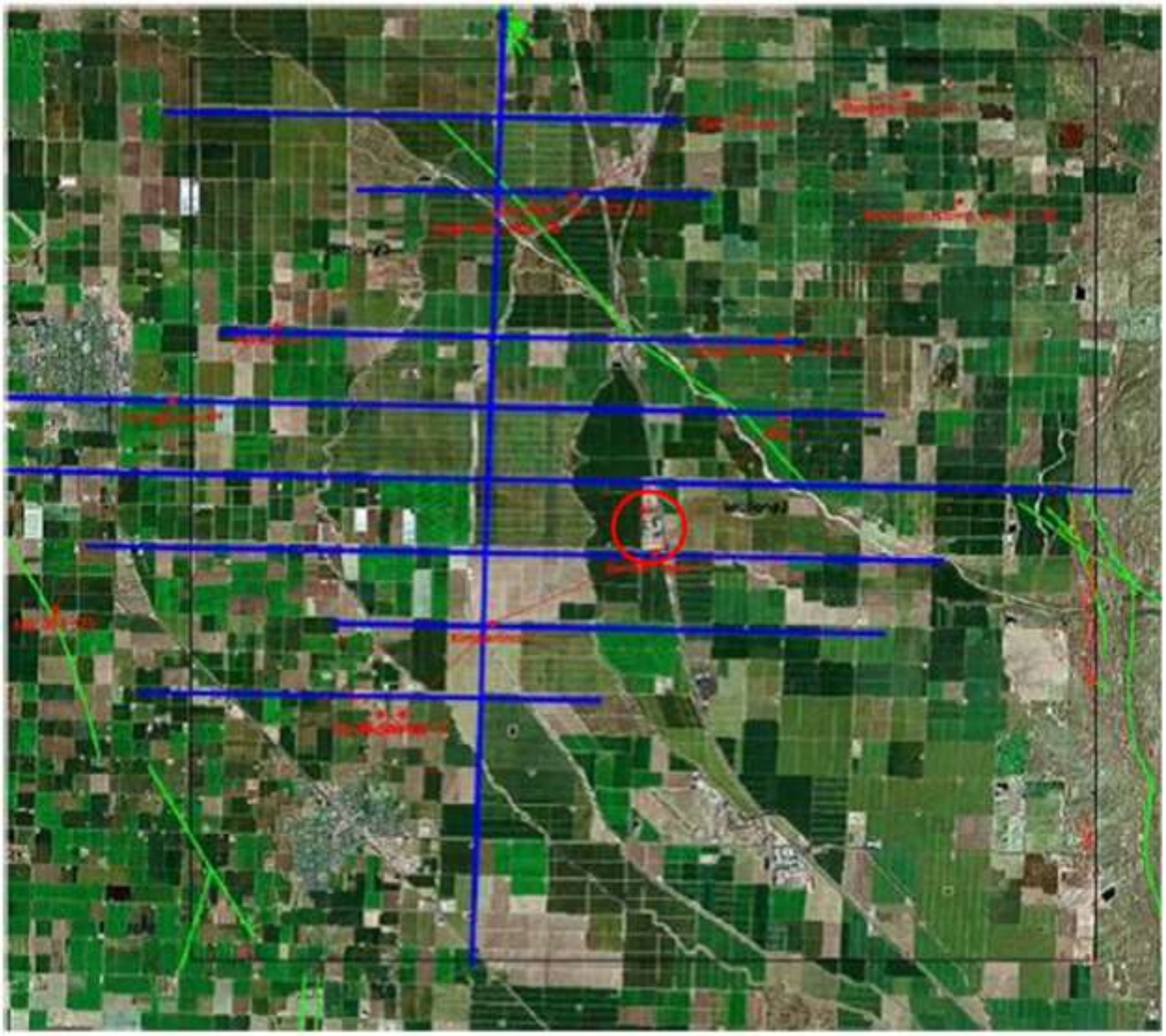


Figure 2.11. *Aerial plan view of the Kimberlina site, showing seismic survey lines (blue) and cross-section lines (faint red) for projecting well log and seismic data. The Kimberlina power plant is located in the circle near the center of the map. Stratigraphic tops were interpreted by EOG Resources, Inc., using the blue seismic lines. Well locations are shown as red dots connected by the red cross-section lines. The black outline square denotes the range of the 20 km x 20 km model. The green lines indicate approximate fault locations (Wagoner, 2009).*

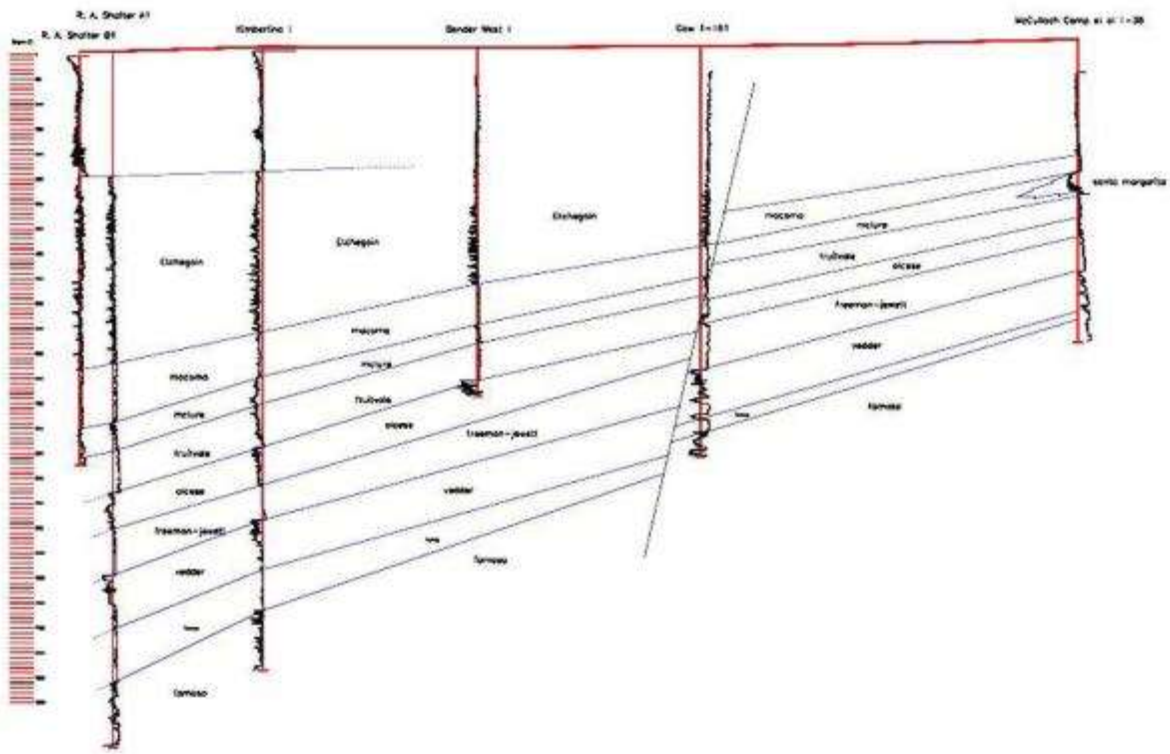


Figure 2.12. *Cross-section #3 on Figure 2.11 showing interpreted stratigraphy under the Kimberlina site.*

The southwesterly-dipping fault shown in Figure 2.12 is the Pond fault. The location of this structure is inferred from seismic reflection interpretations provided by EOG Resources, Inc. and earlier geotechnical studies (Los Angeles Department of Water and Power (LADWP), 1974; Holzer, 1980; Smith, 1983). The Pond fault apparently propagates to the land surface and is expressed as a 3.4 km-long (2.1 mi) scarp, with up to 1.5 m (5 ft) surface displacement, possibly due to differential subsidence from groundwater withdrawal (Holzer, 1980). The LADWP originally investigated this feature as part of the potential siting of a nuclear power plant in the 1970’s, concluding that the fault is a kilometer-wide zone of northwesterly-striking normal faults, dipping to the southwest at 50–70 degrees. LADWP also concluded that the Pond fault was an extension of the Poso Creek fault, located on the west edge of the Poso Creek Field.

Figure 2.13 shows a cut-away view of the regional geologic model from Wagoner (2009), which extends about 84 × 112 km (52 × 70 mi). The legend on the left-hand side of the figure identifies the colors of the individual stratigraphic units. Note that stratigraphic control decreases toward the center of the basin, thus the tops of the units are much less well-constrained, especially deeper in the section. The structural dip to the west discussed above is supported by the well and seismic picks. Figure 2.14 shows a sub-model that is 10 × 10 km (6 × 6 mi), centered on the Kimberlina site, showing the closest known oil and gas exploration wells.

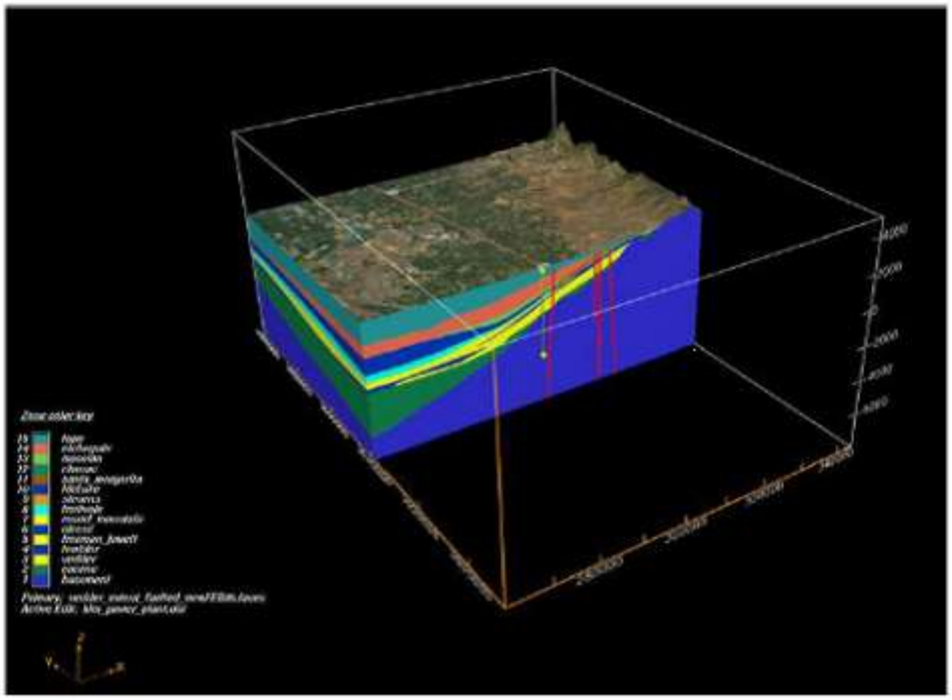


Figure 2.13. *Geologic framework model of the Kimberlina site (vertical yellow line). Faults are shown as subvertical red lines. (4x vertical exaggeration; Wagoner, 2009).*

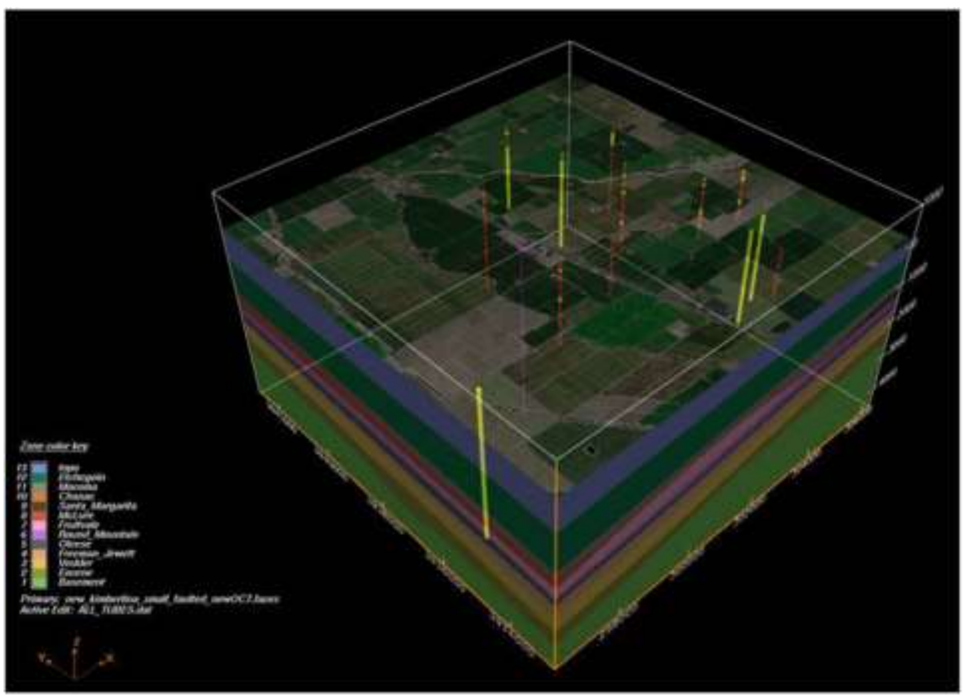


Figure 2.14. *Sub-model centered on the Kimberlina site, extending 10 x 10 km (6 x 6 mi).The yellow vertical lines are cemented boring segments and the red vertical lines are uncemented segments. (Wagoner, 2009).*

Based on the local stratigraphic framework, the predicted stratigraphic section that may be encountered at the Kimberlina power plant site is shown in Figure 2.15. USDW occurs only in the Kern River and Etchegoin formations (Oldenburg et al., 2008).

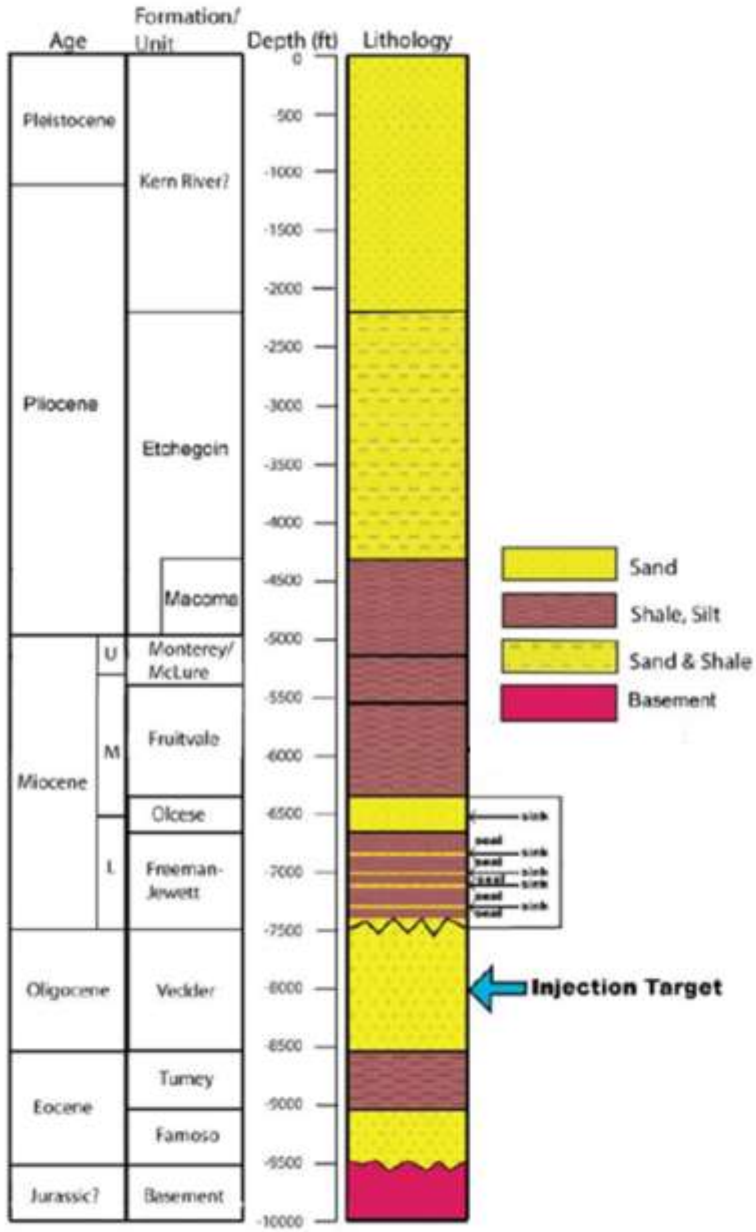


Figure 2.15. *Inferred stratigraphy at the Kimberlina site. The Vedder is designated as the injection target, with the Freeman-Jewett acting as a seal and the Olcese acting as a dissipation interval.*

Although less of a concern than oil and gas wells, groundwater wells must also be considered as potential leakage pathways, and these types of wells are common in the Kimberlina area.

Groundwater wells in California are generally much shallower than oil and gas wells, and thus do not approach the injection zone and will not penetrate the seal above the reservoir. However, this might not be the case in the future as shallow aquifers become depleted and as water tables decline.

2.2.2.2 Application of recommended site-selection criteria

Table 2.4 summarizes the site-selection criteria application to the Kimberlina site proposed in Section 1.5 of this report. This presumes injection into the Vedder formation of more than 1 million tonnes per year of CO_2. Such a project at this site would meet six of the site-selection criteria, but not the other four. This does not necessarily mean the site is inappropriate for storage from a quantification standpoint. Rather, more work is required to assess the site relative to these criteria. The values entered in the table are further described and justified below.

Table 2.4. *Summary of site-selection criteria as applied to the Kimberlina site given available data*

Criteria to reduce likelihood of leakage and facilitate quantification	Met	Not Met
Likelihood of leakage via unknown wells and uncased borings: No oil or gas was discovered in the AoRc and within or deeper than the proposed storage zone prior to five years after establishment of the oil and gas regulatory agency (1920 in California).	**?**	**?**
Likelihood of leakage via known uncased borings (for instance "dry" exploration borings): For the portion of storage proposed in a saline aquifer, all borings that intersect the storage zone within the AoRc need to have plugs within the primary seal. (Plugs in these borings may be shallower than the seal, particularly if the boring was advanced prior to 1981, which is five years after passage of the SDWA, and so there is a higher risk of leakage via these borings.)		**x**
Likelihood of leakage via known wells: All known active or idle wells intersecting or passing through the storage zone within the AoRc have annular seals and all abandoned wells have plugs immediately above the reservoir.	**?**	**?**
Likelihood of leakage via geologic pathways through the seal (low brittleness): For the portion of storage proposed in a saline aquifer, the proposed seal is normally consolidated, sufficiently ductile that potential fractures and faults are annealed, and/or is in a thrust-fault stress regime.	**?**	**?**
Likelihood of leakage through intact seal (overpressure): Capillary trapping and slow advection combined have a 99% probability of retaining 99% of the stored CO_2 for 1,000 years in the storage reservoir, given pressures at the base of the seal related to injection and buoyancy forces.	**?**	**?**
Magnitude and detectability of leakage: An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and the base of USDW over the AoRc.	**x**	
Risk of induced seismicity: An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and basement rock over the AoRc.	**x**	
Likelihood of damaging seal: Dynamic capacity will be managed by one of the following: 1. Measured by perturbing a contiguous reservoir area at least one tenth the area of the AoRc. 2. Backup (contingency) injection intervals are proposed. 3. Pressure management via fluid extraction is proposed.	**x**	
Likelihood of lethal CO_2 concentration for someone in a building is less than a hundredth of a percent per project: AoRc is outside city limits and the probability of someone being in a structure over a well blowout is 10^{-4} per project over the life of the project (e.g., 20 years injection, plus post-injection site-care period).		**x**
Likelihood of collapse impact and surface monitoring interference: No surface or subsurface mining activities have occurred or are planned to occur within the AoRc.	**x**	

2.2.2.3 Likelihood of leakage via unknown wells and uncased borings

No oil or gas was discovered in the AoRc and within or deeper than the proposed storage zone prior to five years after establishment of the oil and gas regulatory agency (1920 in California).

As described, the strata at the Kimberlina site tilt to the west. Consequently, the buffer factor for constructing the AoRc is less than two because the strata are not near horizontal. Because of the tilted strata, CO_2 will tend to migrate to the east due to its buoyancy. No geologic structure that would cause the CO_2 to accumulate in one location and the migration to cease (a geologic structure with “closure”) has been detected in this direction. Consequently a reasonable buffer factor for constructing the AoRc is equal to 1.

The distance from the Kimberlina site to the closest wells in the Poso Creek oil field to the east is 9 km (6 mi.). This may be within the AoRc. As shown on Figure 1.14b, oil was discovered in the Poso Creek field prior to 1921. DOGGR’s production and injection data indicates there has been activity in the Vedder formation in this field, but discovery dates are not available. The earliest activity listed in these pools occurred in 1979. However, while it appears injection is assigned to specific pools, production is not so assigned. Consequently, production in these pools may have commenced earlier than 1979. It appears these pools may be in whole or in part shallower than 1.5 km (4,900 ft), suggested above as the maximum depth of unknown wells. Consequently, there may be unknown wells within this portion of the AoRc.

2.2.2.4 Likelihood of leakage via known uncased borings

For the portion of storage proposed in a saline aquifer, all borings that intersect the storage zone within the AoRc need to have plugs within the primary seal. (Plugs in these borings may be shallower than the seal, particularly if the boring was advanced prior to 1981, which is five years after passage of the SDWA, and so there is a higher risk of leakage via these borings.)

As shown on Figure 1.16b, prospect borings drilled prior to 1981 exist within any likely AoRc. The figure also shows that at least some of these borings extend to basement, and thus through the storage target. Documented exploration borings and known wells within a 5 km (3 mi) radius of the Kimberlina site are listed in Table 2.5. As shown in Table 2.5, all but two of these 13 borings and wells were drilled prior to 1981.

__Table 2.5.__ Known borings and wells in the vicinity of Kimberlina site

easting	northing	well name	Distance from power plant (m)	Elevation (m)	TD (m)	Spud date
300591	3937093	Bender West 1	1007	135	2129	12/12/48
301837	3936957	Woodward-Sheedy 1	1868	136	1390	?
301267	3940312	KCL-A 58-8	2431	135	2831	10/8/38
303406	3940068	Gow 1	3666	148	2506	2/15/61
304178	3938830	Coberly West Co. 15-1	3918	150	2437	11/25/83
296994	3935532	Kimberlina 1-25	4194	121	3956	8/29/83
305004	3937209	C.W.O.D. 87	4747	144	1597	12/26/54
304168	3935237	Union-Mattei 1-34	4764	150	2437	8/12/74
303327	3941905	Steele Pet CO 4-1	4867	153	2281	12/1/56
305090	3940092	Kuhn 81	5168	169	2356	6/8/47
304795	3935419	MobilFlorida 1-27	5187	153	2239	2/21/75
304134	3934438	Mattei 1	5254	147	1289	7/25/28
305845	3936789	McCulloch/IDS-Vignoloetal 1-26	5656	146	1288	9/19/72

easting	northing	well name	Abandonmen t date	Cement plugs	Junk left in hole	Measured depth to Vedder (m)
300591	3937093	Bender West 1	12/30/48	yes	yes	n/a
301837	3936957	Woodward-Sheedy 1	?	no?	?	n/a
301267	3940312	KCL-A 58-8	12/9/38	yes	none	2177
303406	3940068	Gow 1	?	yes	none	1978
304178	3938830	Coberly West Co. 15-1	12/19/83	yes	none	2012
296994	3935532	Kimberlina 1-25	12/10/83	yes	none	2869
305004	3937209	C.W.O.D. 87	1/11/55	yes	none	n/a
304168	3935237	Union-Mattei 1-34	8/27/84	yes	none	2168
303327	3941905	Steele Pet CO 4-1	12/18/56	yes	none	1868
305090	3940092	Kuhn 81	7/10/47	yes	none	1787
304795	3935419	MobilFlorida 1-27	3/2/75	yes	none	2107
304134	3934438	Mattei 1	9/21/28	no	none	n/a
305845	3936789	McCulloch/IDS-Vignoloetal 1-26	10/3/72	yes	none	n/a

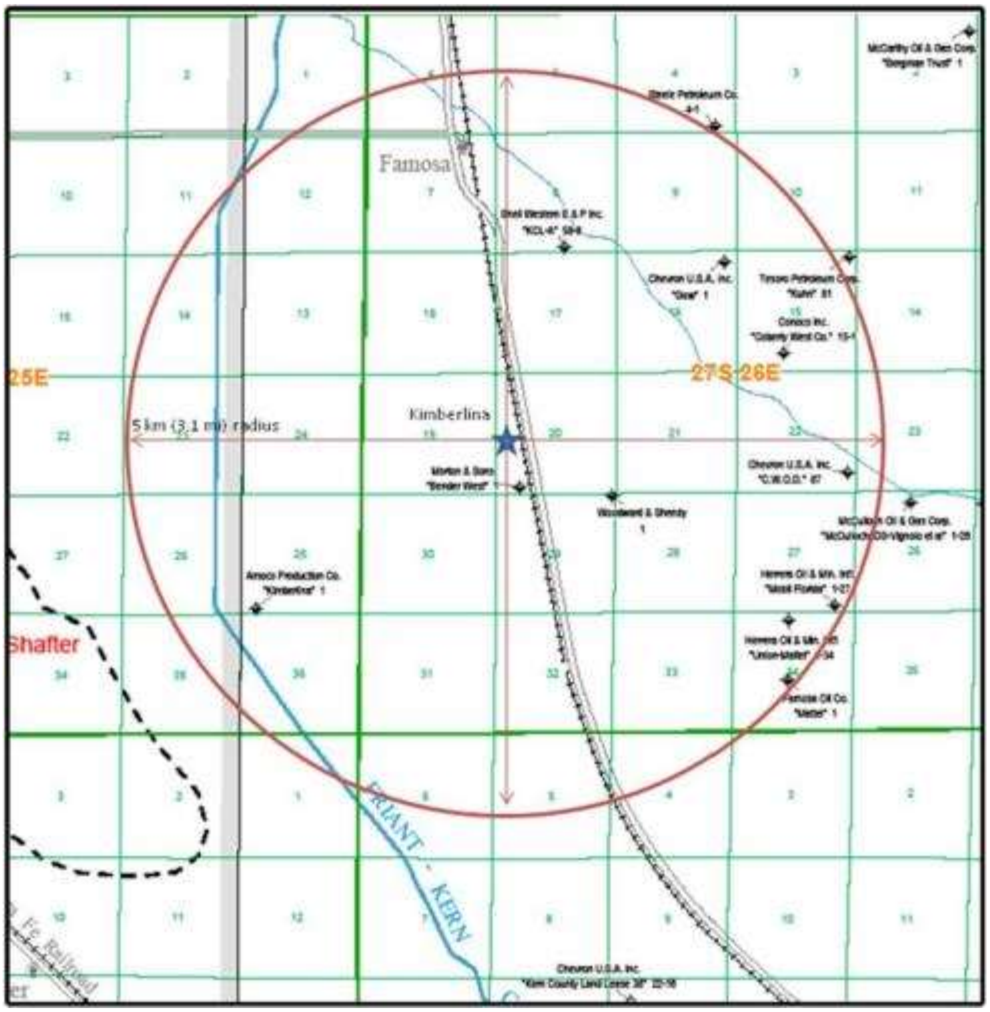


Figure 2.16. *Locations of known exploration borings and active wells within a 5 km radius of the Kimberlina site.*

The boreholes are all abandoned oil and gas exploration borings drilled starting in 1928. The available completion reports detail the method of abandonment and how and where the holes were plugged. There is uncertainty on the plugging of some of the wells, partly because the wells are old and some of the completion and abandonment reports are incomplete.

Figure 2.16 shows the locations of known borings and wells in the Kimberlina area, while Figure 2.17 shows borings that intersect the Vedder formation within a likely AoRc east and northeast of the site, which is the direction stored CO_2 is likely to flow. As shown, these borings are mostly uncased, and most have plugs far above the Vedder formation, and so also the primary seal. Consequently, the site does not meet this criterion, necessitating detailed assessment of each uncased boring.

2.2.2.5 Likelihood of leakage via known wells

All known active or idle wells intersecting or passing through the storage zone within the AoRc have annular seals and all abandoned wells have plugs immediately above the reservoir.

The only known wells that intersect the Vedder formation within the likely AoRc are in the Poso Creek field. DOGGR's production and injection database lists open wells within the Vedder formation in the Premier area, and in the Vedder-Walker combined strata in the McVan area (which is located further east, and may be outside the AoRc). Review of the construction schematics of each of these wells to determine if they have annular seals immediately above Vedder formation, or plugs in this position for those that are abandoned, is beyond the scope of this study. However, it is likely that they have annular seals immediately above the Vedder formation because it was the target strata for these wells. It is also likely that any abandoned wells have sufficiently deep plugs because DOGGR's production and injection database indicates activity in these zones took place from 1979 to 1981, so abandonments would have occurred after 1981, when the general practice shifted to include setting both deep and shallow plugs. Finally, there are no deeper pools in the Poso Creek field to which wells might extend through the Vedder.

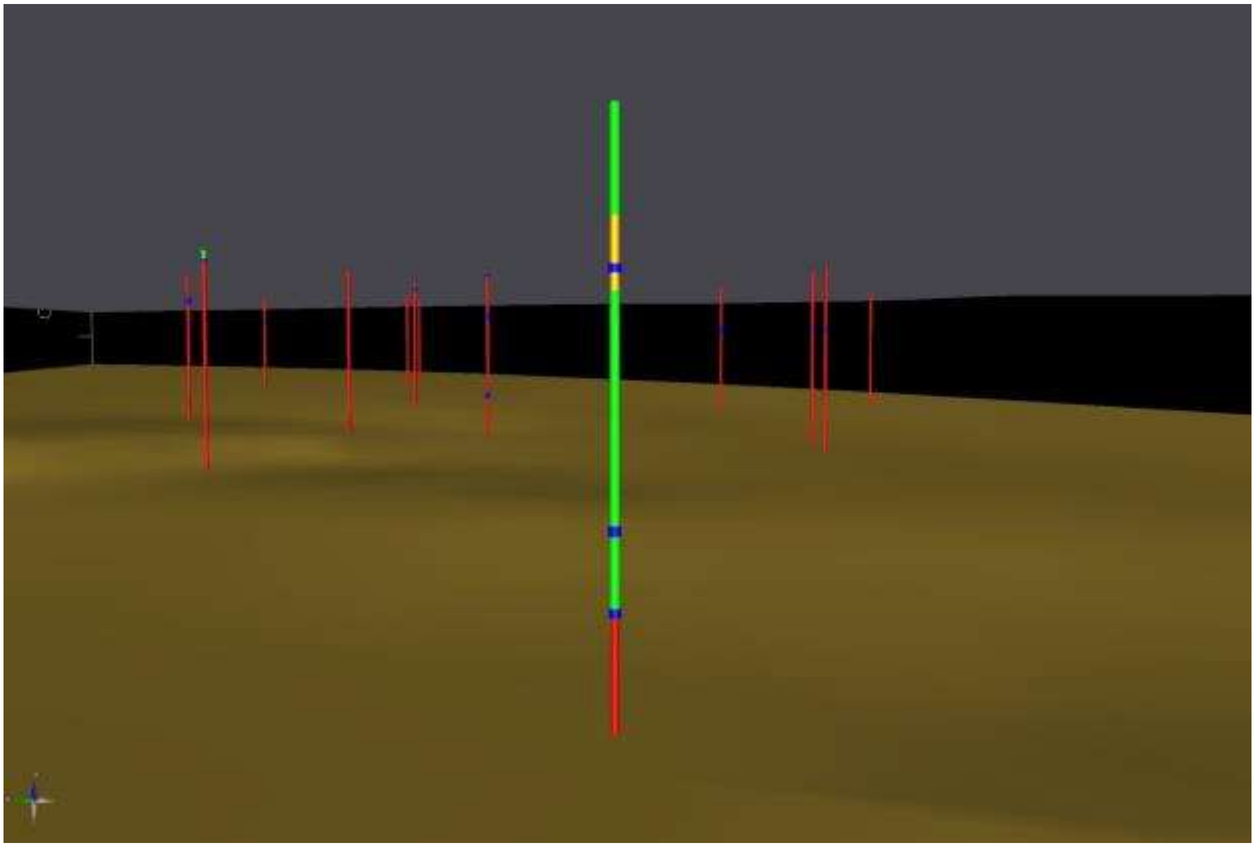


__Figure 2.17.__ Borings and wells in the vicinity of the Kimberlina site, with the top of the Vedder formation from the geologic model shown. View is from the south-southwest of the Kimberlina site towards the east-northeast, in the direction stored CO_2 is likely to flow. The gray surface at the top of the image is positioned at a depth of 300 m to give some impression of well conditions relative to potable groundwater aquifers. The well borings are colorized by construction as follows: red – unsealed boring, yellow – uncemented casing, green – cement (outside casing), and blue – cement plugs (shown on the outside for visualization). The exposed portion of the boring in the foreground is approximately 2.5 km in length.

2.2.2.6 Likelihood of leakage via geologic pathways through the seal (low brittleness)

For the portion of storage proposed in a saline aquifer, the proposed seal is normally consolidated, sufficiently ductile that potential fractures and faults are annealed, and/or is in a thrust-fault stress regime.

The Pond-Poso fault occurs in the northeast of the site (Wagoner, 2009). Simulation of commercial-scale injection 3 km (2 mi) southwest of the site found the resulting CO_2 plume would likely migrate to this fault (Wainwright et al., 2013). There are also faults mapped in the portion of the Poso Creek field (DOGGR, 1998) that is likely within the AoRc. Finally, fault population statistics indicate the plume is likely to encounter numerous faults prior to encountering the Pond-Poso fault (Jordan et al., 2012). In the region surrounding the Kimberlina site, faults often provide the structural traps for many of the oilfields present. This suggests that annealing of faults is common. In addition, the significant percentage of swelling clays in the shale units in this region suggests that faults cross-cutting these formations would likely be annealed. However, quantitative measurements bearing on the ductility of the seal, such as those regarding the seal at King Island, could not be identified. Consequently, whether this criterion is met or not cannot be judged at this time.

2.2.2.7 Likelihood of leakage through intact seal (overpressure)

Capillary trapping and slow advection combined have a 99% probability of retaining 99% of the stored CO_2 for 1,000 years in the storage reservoir given pressures at the base of the seal related to injection and buoyancy forces.

The Freeman-Jewett formation has not been found to have retained hydrocarbons at the site or anywhere within the base-case simulated plume area in Wainwright et al. (2013), which considered injection of five million tonnes per year of CO_2 for 50 years. Hydrocarbons were retained by this seal in numerous locations beyond the simulated plume, suggesting the seal has capacity to retain buoyant fluids. However, this cannot be assumed at the site, and we could not identify any capillary entry pressure or permeability measurements on the seal rock at the site or elsewhere nearby. Consequently, whether the site meets this criterion could not be determined.

2.2.2.8 Magnitude and detectability of leakage

An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and the base of USDW over the AoRc.

Salinities and total dissolved solids (TDS) concentrations reported for pools in the oil fields surrounding the site (DOGGR, 1998) indicate that the base of USDW (water with < 10,000 mg/L) is no deeper than the base of the Etchegoin formation (Oldenburg et al., 2008), shown on Figure 2.15. Consequently, the Olcese formation, which consists primarily of sandstone, intervenes between the proposed Vedder storage zone and the base of USDW. The Olcese is in turn separated from the base of USDW by numerous seals. As the Olcese is estimated to be 75 m (250 ft) thick at the site, it provides an adequate dissipation interval. Thus, this criterion is met.

2.2.2.9 Risk of induced seismicity

An interval with sufficient transmissivity and capillary entry pressure to effectively dissipate overpressure along any hypothetical leakage path hydraulically connected to it exists between the storage zone and basement rock over the AoR.

As shown on Figure 2.15, the Famoso formation consists predominantly of sandstone and is located below the lower seal and above basement. It is approximately 125 m (400 ft) thick, and so provides a dissipation interval for dissipating overpressure that might propagate downward, preventing them from reaching basement. Consequently, this criterion is met.

2.2.2.10 Likelihood of damaging seal

Dynamic capacity will be managed by one of the following:

1. *Measured by perturbing a contiguous reservoir area at least one tenth the area of the AoRc.*

2. *Backup (contingency) injection intervals are proposed.*
3. *Pressure management via fluid extraction is proposed.*

Table 1.5 indicates the injectivity to the Vedder storage target is ~2.5 million tons per 100 km^2 (40 mi^2) based on the pressure response to oil production in two fields to the south to southwest of the site. Combined, these fields have an area of 22 km^2 (8 mi^2). Consequently, they cover an area greater than one tenth of the estimated area needed to inject 5 million tons per year. The injectivity estimate indicates doing so over the necessary reservoir area from the proposed surface site would require wells reaching 8 km (5 mi) in depth. This may be less economically feasible than drilling wells from pads outside the surface site or extracting brine to increase CO_2 injectivity. Whatever approach is determined to be most economically feasible, this criterion is met because the necessary injectivity estimate is available.

2.2.1.11 Likelihood of lethal concentration for someone in a building is less than a hundredth of a percent

AoRc is outside city limits and the probability of someone being in a structure over a well blowout is 10^{-4} over the life of the project (e.g., 20 years of injection, plus post-injection site care).

The AoRc likely extends into the City of Shafter, specifically that portion to the south where an airport and various surrounding businesses are located. So this criterion is not met.

2.2.2.12 Likelihood of collapse impact and surface monitoring interference

No surface or subsurface mining activities have occurred or are planned to occur within the AoRc.

There has been no active or past surface or subsurface mining within the likely AoRc.

2.3 RECOMMENDATIONS FOR MONITORING APPROACHES

In Part 1, we presented potential monitoring approaches for different broad objectives, namely routine operational monitoring, contingency monitoring, and surface leakage detection and quantification. The scope of this project did not allow development of a detailed example monitoring plan for our case studies. Nevertheless, we can make some broad comments on monitoring at the two prospective sites, King Island and Kimberlina. We assume commercial-scale injections of over 1 million tonnes over time periods of decades at both sites. In all cases, we recommend baseline monitoring using appropriate techniques, ideally for at least a year prior to injection.

First, we recommend that 3D time-lapse seismic using the same seismic network surveys be carried out at both of these sites. Intervals for operational seismic surveys should be frequent in the initial stages of site activity (e.g., annually for two years), and then every other year for the next four years, followed by every four years for the remainder of the injection period, assuming expectations were being met for plume evolution. We recommend determination of the repeat survey interval after cessation of injection should be based on the prior results and simulations of the rate of plume migration toward stabilization.

Second, we recommend that above-zone dissipation intervals be monitored for pressure change with the possibility of fluid sampling if pressure differences suggested potential leakage was occurring.

Third, we recommend that pressure in the injection formation be monitored in wells at various distances from the injection well(s).

Fourth, we recommend that a microseismic array be deployed to monitor microseismicity with sufficient resolution that hypocenters could be located to within 100 m (330 ft), which would be useful for monitoring pressure and fluid compositional changes.

Fifth, we recommend that InSAR data be analyzed to observe pressure propagation to anticipate plume migration.

Depending on the results, and specifically on the agreement between observations and expectations, additional monitoring could be carried out. But overall, the expectation is that for well-characterized and screened sites that receive US EPA Class VI injection permits, standard operational monitoring is all that will be required. The monitoring plan should spell out potential additional monitoring activities that would be deployed if the system deviates from projected behavior. It is beyond the scope of this project to lay out every scenario for off-normal behaviors and corresponding monitoring recommendations, but generally, we recommend that the monitoring plan be consistent with the suggested approaches presented in Figure 1.6 and Table 1.1.

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3.0 SUMMARY OF RECOMMENDATIONS

3.1 Risk-Based Site Selection

- The well leakage failure scenario is by far the biggest threat to CO_2 containment in California. Wells that predate the GCS project and are deep enough to penetrate into the proposed storage reservoir are a particular concern. If such wells cannot be avoided, well workovers may be effective in bringing them up to recent plug-and-abandonment requirements, and/or surface and atmospheric monitoring can be targeted at detecting well leakage.
- In the context of the QM, the plume footprint should include both the extent of injected CO_2 that is dissolved in brine (or any groundwater) in the storage complex, as well as the free-phase CO_2 plume.
- It should be acknowledged that every site will have strengths and weaknesses. Shortcomings in various features of a site can be accommodated by site-specific operational design, along with careful monitoring plan development and implementation to minimize and monitor potential leakage.
- We recommend that risk-based site selection be based on failure scenarios developed using the FEP-scenario approach utilizing the long experience and large existing knowledge base, and that site screening begin on multiple candidate sites using existing site-characterization data (e.g., extensive oil and gas well database, and exploration seismic data sets that are available).

3.2 Failure Scenarios Relevant to Surface Leakage

- We recommend that the best mitigation of fault leakage risk is to avoid altogether sites with large faults, especially faults that extend from the reservoir to USDW or to the ground surface, and to select sites with ductile cap rocks that will tend to seal any smaller cap-rock faults or fractures within them.

3.3 Monitoring Technologies and Approaches

- In order to estimate emissions from GCS sites, we recommend that modeling be used both to assist determining the area to monitor (AoRc) and to assist in interpreting monitoring results. We recommend project applicants be required to provide a projection of the area that will be occupied by the free-phase CO_2 plume at the next time of substantial monitoring effort (e.g., by 3D seismic) of the storage volume and overlying materials, and the maximum extent of the plume after cessation of injection. Making this prediction will typically require simulating the plume evolution using software capable of modeling multiphase fluid flow through porous media. We do not find simulation of surface leakage is needed as a direct component of the QM.
- We recommend the deployment of monitoring equipment and effort be distributed both temporally and spatially, and be potentially changed depending on the results of ongoing monitoring.
- We recommend that baseline monitoring be carried out with a degree of flexibility in the QM with respect to its extent, as long as the plan describes a defensible approach to leakage detection.

- In general, we recommend that monitoring be divided into three main categories based on different objectives: (1) standard operational monitoring, (2) contingency monitoring, and (3) surface leakage detection and quantification.
- Following baseline monitoring, we recommend focusing monitoring during early phases of CO_2 injection on the injection well and the reservoir adjacent to the injection well. This is because off-normal effects due to any defects in well construction that allow leakage will tend to manifest early, and the injection well is subjected to higher pressures in the early phases of CO_2 injection if the injection rate is constant. Distant wells and areas far from the injection well(s) are not a priority at early time because CO_2 and pressure will not have propagated far at the beginning of injection. By the same logic, the pressure and free-phase CO_2 plume movement over the first year should be monitored to assure that the complex is behaving as designed. As time goes on and the plume and pressure footprint become larger, we recommend that the monitored area expand, while areas nearer the injection well may require less-frequent monitoring. At very late times and provided the storage complex has performed effectively as anticipated, the frequency of monitoring could be reduced as understanding and confidence in storage containment grow.
- Regarding monitoring, our recommendation is that not every approach needs to be followed, and that the monitoring plan be tailored to the site and stage of injection progress, with appropriate use of technologies to satisfy the needs of the QM as required by ARB.
- To the extent possible, we recommend monitoring be continuous. For the inherently intermittent methods, the periodicity of monitoring should be proposed, defended, and approved as part of the monitoring plan. If hints of potential surface leakage are found, we recommend that the locations with anomalous readings be visited on the ground for more detailed investigation, e.g., using an accumulation chamber, eddy-covariance, or a FLIR camera to precisely locate leakage sources.
- We recommend that monitoring plans include discussion of possible causes of anomalous gas concentrations in addition to leakage, such as changes in ecological CO_2 flux, and include a description of the attribution assessment that will follow detection of an anomaly to determine if the observed change is due to leakage or some other cause.
- We recommend that monitoring plans be considered living documents, insofar as improvements in monitoring technologies are expected over time, and the plans should allow for substitutions to improve the efficiency of the QM (with the same or greater effectiveness and/or less cost) in the future. Note that for observing changes over time, repeatability of measurement method is critical, e.g., the same seismic network should be used over time for time-lapse seismic monitoring.
- We recommend that monitoring in the vicinity of the dissolved and free-phase CO_2 plume fronts be frequent (e.g., once a year or more frequently) and intensive in order to detect unexpected behaviors early. We recommend this include focused surface monitoring at wells as the plume front arrives and for some time (e.g., on the order of a year) after it passes.
- It has been noted that CH_4 is an excellent indicator of deep gas migration, especially in hydrocarbon reservoir environments, as well as being an important GHG in its own right. Therefore, we recommend CH_4 be monitored as part of the QM.

- In general, we do not recommend continuous use of artificial tracers because we do not believe they are needed in routine injection operations. On the other hand, added tracers may be useful for diagnosing particular unexpected behavior, in which case they can be added to the injection stream at any time or periodically.
- Natural tracer analysis of gas samples can be a useful practice and we recommend that it be considered part of the wide array of approaches applicable to monitoring within the QM.
- Because plume velocity can be quite slow, we recommend that for the establishment of plume stability, the plume show no movement for five consecutive years as a default period for monitoring, but this could be shortened or lengthened depending on details of the duration of injection, size of the plume, specific site conditions, and the plume monitoring resolution.

3.4 Evaluation of Siting Criteria

- Considerable attention to, and care, regarding risk mitigation should be exercised for GCS projects proposed in areas with any prior surface or subsurface mining activities.
- We recommend ARB not establish minimum depth, pressure-temperature, or CO_2-density criteria, notwithstanding non-technical reasons for minimum depth requirements, and considerations of the depths of existing wells that could provide leakage pathways.
- We recommend that ARB require the existence of a geologic unit(s) equivalent to an interval, or intervals in aggregate, sufficient to effectively dissipate overpressure of any leakage passing through the interval(s) via leakage path(s) that are hydraulically connected to the interval(s). We suggest referring to these zones as "dissipation intervals" to emphasize that their purpose is to dissipate leakage overpressure.
- If ARB implements the dissipation interval criterion, we recommend that consideration be given as to whether the dissipation interval(s) should be considered part of the storage complex or not.
- If a project proposes capillary exclusion as the storage mechanism, we recommend requiring the applicant to provide data regarding the capillary-exclusion aspects of the seal. These include enough measurements to provide a statistical and geostatistical understanding of the distribution of the capillary entry pressure and the thickness of the seal. In particular, capillary entry pressure should be discussed with respect to the anticipated pressure in the CO_2 plume at the base of the seal. Statistics and geostatistics regarding the thickness of the seal would also be required, with the focus on establishing a negligible probability of the seal being entirely missing (i.e., having zero thickness) over some portion of the projected CO_2 plume).
- For an attenuated-advection seal, we recommend requiring the operator provide a statistical and geostatistical understanding of the flow rates of CO_2 out of the top of the seal given the evolution of the CO_2 plume.
- We recommend defining the top of the seal as the boundary across which CO_2 flow is considered because there are far fewer methods for monitoring flow in a seal than in the permeable interval above the seal.

- We recommend that both for the purpose of quantifying and verifying storage, and appropriately regulating risk in the near term (during the injection period), ARB should focus its requirements and review on the anticipated free-phase CO_2 plume. In order to distinguish this area from the (pressure) AoR as defined in Class VI injection well regulations, we recommend use of the term AoRc to refer to an area of review based upon the free-phase CO_2 plume, and AoRd to refer to the area of review based on the dissolved CO_2 plume. Over the long term (e.g., during the decades following injection), the dissolved-CO_2 plume could become larger than that of the free-phase, and both free-phase and dissolved CO_2 need to be considered as potential sources of surface CO_2 leakage relevant to the QM.
- We recommend basing the AoRc on buffering of the modeled projections of the plume extent by the appropriate safety factors to account for uncertainty.
- We do not find that pore-space capacity and residual saturations themselves are germane to ARB's goal of quantifying the amount of CO_2 stored. There are two reasons for this conclusion. First, these properties are implicitly included in the AoRc calculation. As such, they should certainly be reviewed for reasonable accuracy as part of the review of that calculation discussed above. This review should consider other parameters key to determining the AoRc, such as sweep efficiency and the detailed configuration of the reservoir structural closure, etc. Second, actual-less-than-predicted pore-space capacity or residual saturation alone does not translate into a CO_2 storage failure because an alternate reservoir may be available or the project plan could be altered.
- The reservoir property that we recommend is most pertinent for ARB to include in its primary list of information requested from operators is measurement of injectivity, sometimes referred to as dynamic capacity, over a substantial portion of the storage volume, or injectivity management via backup injection intervals or brine extraction.
- We recommend two means for applicants to manage the risk of leakage through cap rock as part of site selection:
    - (1) Previous retention of hydrocarbons by a seal provides the most definitive evidence of its integrity with regard to retaining CO_2. For projects proposing to store CO_2 entirely within a reservoir volume that contained hydrocarbon accumulations, relying on this prior evidence of seal capacity only requires demonstrating that the injection pressures will be below the seal fracture opening pressure and that the CO_2 pressure on the base of the seal will not be higher than the seal's capillary entry pressure for CO_2 if capillary sealing, rather than advection attenuation, is the proposed sealing mechanism.
    - (2) For storage in reservoir volumes that did not contain hydrocarbons, seal integrity cannot be presumed *a priori*, as illustrated by the experience of natural gas storage in Illinois. For GCS projects in reservoirs without existing hydrocarbon accumulations, we recommend characterization that establishes a high probability of cap-rock continuity and low probability of permeable fault or fracture zones that compromise cap-rock integrity.

- While we do recommend that ARB require applicants to provide information regarding detectable discontinuities and any evidence regarding their hydraulic properties, this is not sufficient alone. Consequently, we additionally recommend a preference for sites with seals whose strength is sufficiently low (high ductility) that they creep under the *in-situ* stresses imposed upon them such that openings tend to anneal.
- We recommend measuring the mass of CO_2 potentially stored in the subsurface by flow metering at the storage facility inlet, rather than the source facility outlet. Consequently the proximity of the source to a storage project is not strictly relevant to the geologic storage part of the QM, although it is relevant to the QM generally including emissions and leakage from CO_2 pipeline transport.
- We recommend that GCS projects be located such that the projected AoRc does not extend into areas within urban limits as defined by existing city boundaries, within which near-term future population growth can be assumed.
- We recommend including the presence of dissipation interval(s) between the storage reservoir and basement as a site-selection criterion to manage the risk of induced seismicity, even though the risk of induced seismicity is not demonstrably related to leakage and therefore quantification at this time.
- With regard to managing transportation risks, there are other regulatory requirements for new pipelines or other transportation modes, such as review required by the California Environmental Quality Act. Therefore we recommend not including consideration of new transportation facilities in the site selection criteria with regard to the QM related to GCS.

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GLOSSARY AND DEFINITIONS

Abandoned well

A well that is no longer in use and may or may not be plugged.

Above-Zone Monitoring Interval (AZMI)

Geologic unit above the cap rock with sufficient permeability and porosity to serve as a secondary reservoir in which monitoring, e.g., for pressure change, can be carried out to detect cap-rock leakage.

Area of Review (AoR)

Area around an injection well in which the pressure rise in the reservoir due to injection is predicted to be large enough to cause fluid to flow upward from the storage reservoir to USDW in a hypothetical open pathway that is filled with fluid and that is not connected to any intervening zone. Under Class VI regulations, all artificial penetrations (e.g., wells) within the AoR must be located, mapped, evaluated, and treated to prevent leakage.

Area of Review for free-phase CO_2 (AoRc)

Area around an injection well in the reservoir that is predicted to be occupied by the free-phase CO_2 plume plus an additional safety factor (buffer). This safety factor is recommended to be 0.1 times the distance from the injection well to the predicted free-phase CO_2 plume front for storage in closed geologic structures, and 2.0 times the same distance for storage under primary seals with a nearly horizontal base (approx. zero dip of cap-rock contact with reservoir).

Area of Review for dissolved CO_2 (AoRd)

Area around an injection well in the reservoir extending out to the limit of the predicted leading edge of the dissolved CO_2 plume.

Basement rock

Older (often crystalline) rock underlying younger sediments in a sedimentary basin.

Boring, borehole

Cylindrical hole cut into rock or soil by drilling. Casing, cement, and other well components may be inserted into the boring to construct a well.

Brittleness

Property of rock in which failure under load occurs by fracturing rather than by plastic deformation.

Cap rock, confining layer

Laterally extensive and low-permeability and/or high capillary entry-pressure formation (e.g., clay shale or mudstone) above a storage reservoir capable of impeding upward migration of fluid. Synonymous with seal.

Capillarity, capillary pressure

The surface-tension forces that hold a wetting phase (e.g., water) in the pores of a rock relative to the non-wetting phase (e.g., CO_2). Capillary pressure is the non-wetting phase pressure minus the wetting phase pressure.

Capillary entry pressure

The pressure that a non-wetting fluid (e.g., CO_2) must overcome to displace water held tightly by capillary forces in the pores of a cap rock.

Casing

Pipe (typically made of steel as used in oil and gas wells) placed into a boring to allow conveyance of fluids to/from the surface from/to a specific location in the subsurface.

Consequences

Quantified negative effect of a failure scenario (e.g., evacuations of people due to a well blowout).

Dip moveout correction (DMO)

Moveout is the effect that distance from source to receiver has on arrival time in seismic reflection surveys. DMO is the effect of dip of the bedding on arrival time. The DMO is the correction made so that seismograms can be stacked as if the bedding had zero dip.

Directional drilling

Controlled drilling of boreholes that are intentionally deviated from the vertical including fully horizontal boreholes.

Dissipation interval

A stratigraphic interval with properties sufficient to effectively dissipate overpressure in a leakage pathway that passes through and is hydraulically connected to the interval.

Ductility

Property of rock by which the rock plastically deforms under load rather than breaking by fracturing.

Electrical Resistivity Tomography (ERT)

Geophysical approach to map spatial variations in electrical resistivity of rock by recording voltage changes at multiple locations along electrodes and fitting the data by inverse modeling to map electrical resistivity.

Enhanced Gas Recovery (EGR)

The approach by which fluids such as CO_2 are injected into a gas reservoir to improve gas production by increasing reservoir pressure and potentially by sweeping gas toward production wells.

Enhanced Oil Recovery (EOR)

The approach by which fluids such as CO_2 are injected into an oil reservoir to improve oil production by increasing reservoir pressure, increasing the mobility (e.g., decrease the viscosity and density) of oil by CO_2 dissolution into the oil, and sweeping oil toward production wells.

Failure scenario

Sequence of events involving a component or system malfunction that results in consequences.

Fault Tree Analysis (FTA)

An approach to estimating likelihood of failure scenarios by breaking the scenario up into multiple contributing events whose likelihoods are easier to estimate.

Features, Events, and Processes (FEPs)

In risk assessment, FEPs comprise all of the elements potentially relevant to failure scenarios. Catalogues of FEPs can be analyzed to aid in generating a complete and accurate set of failure scenarios.

Forward Looking Infrared (FLIR)

Infrared imaging of objects in front of the device rather than alongside the device as in sideways tracking systems.

Free-phase plume

Portion of the storage zone that contains CO_2 in supercritical, gaseous, or liquid phase rather than as a dissolved component in native fluid (e.g., dissolved in brine).

Hazard

A potential source of harm to humans, other animals, plants, environment, or infrastructure. Synonymous with threat.

Interferometric Synthetic Aperture Radar (InSAR)

An approach that measures the distance from a radar source (e.g., mounted on a satellite) and an object or surface (e.g., the ground surface). The approach uses differences in the phase of waves reflecting from the same object over time to calculate changes in distance over time.

Light Detection And Ranging (LIDAR)

An approach to measuring distance that uses laser light.

Likelihood

Probability per unit time (e.g., per year), per component, or quantitative or semi-quantitative chance (or expected frequency) of occurrence of a failure scenario.

Low-Probability High-Consequence (LPHC)

A descriptor of a class of failure modes that is very unlikely but has large consequences.

Measured Depth (MD)

The length of the well. This may be larger than the depth of the well if the well is not vertical.

Normally consolidated

Sediments that have consolidated or lithified consistent with the conditions (e.g., P, T) of their current depth of burial.

Orphan well

A well without any known owner and which is very likely to be improperly plugged.

Overpressure

Fluid pressure above the hydrostatic pressure, e.g., as caused by injection.

Perfluorocarbon Tracers (PFTs)

Organic fluorine compounds that are detectable at trace levels in gas samples by gas chromatography making them useful in tracer studies.

Pinnacle

A roughly columnar mass of permeable sedimentary rock within other sedimentary rock with low permeability capable of holding a buoyant fluid. Such structures are created by certain processes, such as growth of carbonate reefs (e.g. coral reefs).

Risk

Likelihood (of failure scenario) multiplied by consequences (of failure scenario).

Seal

Laterally extensive and low-permeability and/or high capillary entry-pressure formation (e.g., clay shale or mudstone) above a storage reservoir capable of impeding upward migration of fluid. Synonymous with cap rock.

Seismic hazard

Likelihood that an earthquake will occur in a given location or along a given fault, within a given window of time, and with ground motion intensity exceeding a given threshold. Although the term *hazard* is used here, its meaning in this context is different from the standard use of the term in risk assessment (see Hazard).

Seismic risk

Risk (seismic hazard multiplied by consequences, e.g., collapse of building(s) in the area) of an earthquake in a given window of time.

Seismic troughs, peaks

Descriptive term for acoustic energy reflection when wave goes from lower to higher impedance at a boundary (trough) and from higher to lower impedance (peak).

Shale-Gouge Ratio (SGR)

The shale/clay content of the rock (percentage of that rock that is shale/clay) that has slipped past any point along a fault.

Standard cubic feet per day, standard cubic meters per day (scfd, scmd)

Volumes of measurement for compressible fluids such as oil and gas at standard conditions of 1 atm (1.01325 bar) and 60°F (15.5°C).

Storage complex

The storage zone and surrounding geological domain which can have an effect on overall storage integrity and security, i.e., potentially comprises storage zone, cap rock, and secondary containment formations.

Storage zone

The reservoir into which CO_2 is injected for geologic storage/sequestration.

Threat

A potential source of harm to humans, other animals, plants, environment, or infrastructure. Synonymous with hazard.

Time Variable Filtering (TVF)

An approach to smoothing a signal (e.g., seismic wave arrival) by removing noise and higher modes using time-frequency filtering.

Total Dissolved Solids (TDS)

The sum of the masses of salts and minerals dissolved in groundwater per unit volume of groundwater, e.g., in milligrams per unit volume of water (mg/L) although it is also often referred to as parts per million (ppm).

Transmissivity

A measure of flow resistance and capacity of a permeable pathway. Transmissivity can be thought of as the product of pathway fluid conductivity and the minimum pathway dimension perpendicular to flow (e.g., the aperture of a fracture).

True Vertical Depth (TVD)

The vertical distance measured from a point in the well (e.g., the current or final depth) to a point at the ground surface. This is in contrast to the measured depth which is equal to the length of the well and maybe be much larger than the TVD in the case of horizontal wells.

Unconfined Compressive Strength (UCS)

Maximum compressive stress that can be sustained by a cylindrical sample of rock under unconfined (zero lateral (confining) stress) conditions (MPa).

Underground Source of Drinking Water (USDW)

An aquifer or part of an aquifer that supplies any public water system, or contains a sufficient quantity of groundwater to supply a public water system, and currently supplies drinking water for human consumption, or contains fewer than 10,000 mg/L of Total Dissolved Solids (TDS).

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ABBREVIATIONS

3D	Three-dimensional
AMI	area of mutual interest
AoR	Area of Review, area on ground surface within above-threshold overpressure
AoRc	Area on ground surface under which lies the free-phase CO_2 plume
AoRd	Area on ground surface under which lies the dissolved CO_2 plume
ARB	Air Resources Board
AZMI	Above-Zone Monitoring Interval
bbl	Barrel, 42 gallons
bcf	billion cubic feet
BRI	Brittleness Index (-)
CCA	Carbon Credits and Accounting
CCS	Carbon Dioxide (CO_2) Capture and Storage
CES	Clean Energy Systems
CF	Certification Framework
CGS	California Geological Survey
d	day
DMO	Dip Moveout correction
DOG	Department of Oil and Gas
DOGGR	Division of Oil, Gas, and Geothermal Resources
DWR	Department of Water Resources
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
ERT	Electrical Resistivity Tomography
ESRI	Environmental Systems Research Institute
EU	European Union
FEP	Features, Events, and Processes
FLIR or IR	Forward Looking Infrared
FXY	Frequency and X- Y- (domain)
GCS	Geologic Carbon Sequestration
GHG	Greenhouse Gas
GIS	Geographic Information System
Gt	Gigatonne (10^9 tonnes)
HSE	Health, Safety, and Environment
IEAGHG	International Energy Agency Greenhouse Gas
InSAR	Interferometric Synthetic Aperture Radar
IPCC	Intergovernmental Panel on Climate Change
IR	Infrared
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory

LCFS	Low-Carbon Fuel Standard
LIDAR	Light Detection And Ranging
LLNL	Lawrence Livermore National Laboratory
LPHC	Low-Probability High-Consequence
Mcf	Thousand cubic feet at 1 atm (1.01325 bar) and 60°F (15.5°C)
MD	Measured Depth
MPa	Megapascal = 10^6 Pa
MRV	Monitoring, Reporting, and Verification
Mtpa	Metric ton per annum (year)
MVA	Monitoring, Verification, and Accounting
NATCARB	National Carbon Sequestration Database
NORSOK	Norsk Sokkels Konkuranseposisjon
NRAP	National Risk Assessment Partnership
P	Pressure (Pa)
Pa	Pascal (1 bar = 10^5 Pa)
PFTs	Perfluorocarbon Tracers
psi	pounds per square inch
QM	Quantification Methodology
Scfd, scmd	Standard cubic feet per day, standard cubic meters per day
SDWA	Safe Drinking Water Act
SGR	Shale-Gouge Ratio
SP	Spontaneous Potential
SRF	Screening and Ranking Framework
t	tonne (1 tonne = 1 Metric ton = 1 Mt = 1.1 tons)
T	Temperature (°F or °C)
TDS	Total Dissolved Solids
TVD	True Vertical Depth
TVF	Time Variable Filtering
US DOE	Department of Energy
US EPA	United States Environmental Protection Agency
UCS	Unconfined Compressive Strength (MPa)
UCS_{NC}	Unconfined Compressive Strength under normally consolidated conditions (MPa)
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
VEF	Vulnerabilty Evaluation Framework
WESTCARB	West Coast Regional Carbon Sequestration Partnership

APPENDIX A. PREVIOUS CALIFORNIA SITE-SCREENING STUDIES

A.1 WESTCARB SITE SCREENING

A.1.1 Overview

Geologic carbon sequestration (GCS) site-screening studies have been undertaken at several levels of detail in California, ranging from state-wide screening of the potential for major geologic formations to pass general site criteria to studies of specific sites as candidates for pilot- or commercial-scale CCS projects (WESTCARB, 2011).

The California Geological Survey (GCS) performed a state-wide screening of sedimentary basins. Where California basins extended offshore, only the onshore portions were considered. This resulted in an inventory of 104 sedimentary basins, outlines of which were digitized to produce a California sedimentary basin geographic information system (GIS) layer. This layer was combined with a California oil and gas field layer to create the map shown in Figure A1.

Basins were screened to determine preliminary suitability for potential CO_2 sequestration, with those basins not meeting the screening criteria being excluded from further consideration. Screening involved literature searches and analysis of available well logs. Criteria included the presence of significant porous and permeable strata, thick and pervasive seals, and sufficient overburden sediment thickness to provide critical state pressures for CO_2 injection (> 800 m, or 2,625 ft). Accessibility was also considered, with basins overlain by national and state parks and monuments, wilderness areas, lands administered by the Bureau of Indian Affairs, and military installations being excluded. Screening and follow-up geologic reviews resulted in 27 of the original 104 basins being identified as having geologic sequestration potential. The remaining 77 basins failed to meet at least one of the screening criteria. Most of these basins are shallow non-marine basins that lack sufficient fill, are too small, or are overlain by national parks, military installations, or Indian reservations. The majority of these rejected basins are located in the arid desert regions of the Mojave Desert and Basin and Range provinces.

The reconnaissance nature of this study precluded a systematic effort to map the many potential aquifers, reservoirs, and sealing formations, or to prepare basin-wide, sand-shale ratio maps. Instead, to identify areas of thick sand development in basins with adequate well log control, a single gross sandstone isopach map was constructed for the interval between 800 and 3,050 m (2,625 and 10,000 ft; or basement if shallower than 3,050 m (10,000 ft)). The upper isopach limit comprises the minimum depth for critical state CO_2 injection that many studies use as a depth threshold, while the lower limit was selected to incorporate a reasonable number of deeper well logs in the larger Sacramento, San Joaquin, Los Angeles, and Ventura basins. Although this approach lumps many disparate sand bodies and is not accurate from a depositional or sequence-stratigraphic standpoint, it does provide a broad measure of the more sand-rich areas.

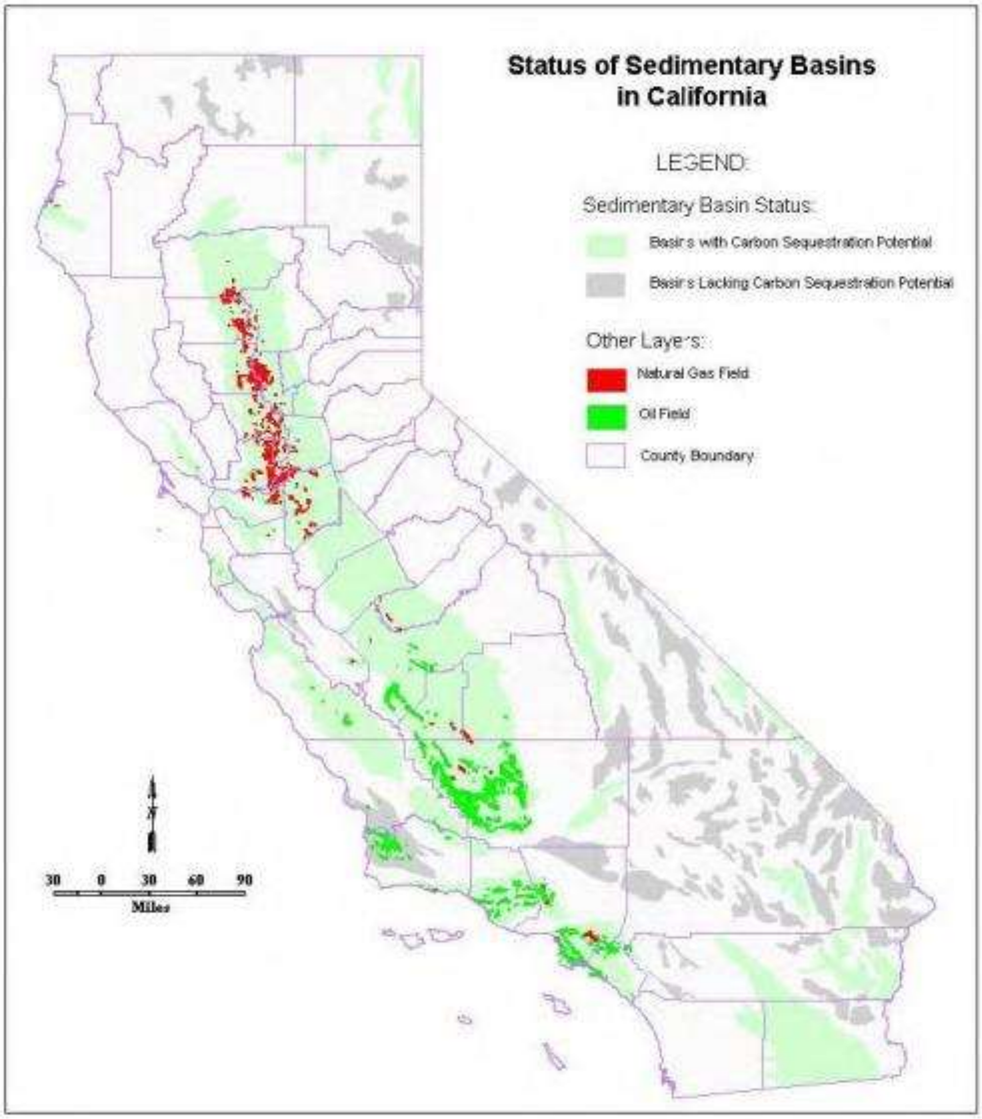

Figure A1. *California sedimentary basins screened by the California Geological Survey (CGS). Gray basins do not pass screening; green basins pass screening. Oil and gas fields are overlain in red and dark green, respectively.*

Of the 27 basins that met the screening criteria, the most promising are the larger Cenozoic marine basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda. Favorable attributes of these basins include: (1) wide spatial distribution around the state, (2) thick sedimentary fill with multiple porous and permeable aquifers and hydrocarbon reservoirs, (3) thick, laterally persistent marine shale seals, (4) locally abundant geological, petrophysical, and fluid data from oil and gas operations, and (5) numerous abandoned or mature oil and gas fields which might be utilized for CO_2 sequestration or which might benefit from CO_2-enhanced (oil or gas) recovery operations. Most of these basins contain multiple oil and gas reservoirs and saline aquifers that met the initial screening criteria, the most important of which are discussed in the following sections. The zones were selected for their greater areal distributions and/or thicknesses, significant sealing formations, and hydrocarbon production.

The Central Valley of California, composed of the Sacramento Basin in the north and San Joaquin Basin in the south, contains numerous saline formations and oil and gas reservoirs that are the state's major geologic storage resources. The saline formations alone are estimated to have a storage capacity of 100 to 500 Gt CO_2, representing a potential CO_2 sink equivalent to more than 500 years of California's current large-point source CO_2 emissions. The formations with the greatest potential in the Central Valley include the Mokelumne, Starkey, Winters, Domengine, and Vedder sandstones.

The methodologies used to assess these units as potential storage resources are exemplified by a WESTCARB study done by the California Department of Conservation, California Geological Survey (CGS), which conducted a preliminary regional geologic assessment of the GCS potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin (Downey and Clinkenbeard, 2010).

Approximately 6,200 gas well logs were used to prepare a series of three maps for each formation. Gross sandstone isopach (thickness) maps were prepared to define the regional extent and thickness of porous and permeable sandstone available within each formation. Depth-to-sandstone maps were then generated and used to identify areas of shallow sandstone that might not be suitable for supercritical-state CO_2 injection. Finally, isopach maps of overlying shale units were prepared for each formation to identify areas of thin seals. The maps were digitized and GIS overlays were used to eliminate areas where sandstone has been eroded by younger Paleocene submarine canyons, areas of shallow sandstone, and areas exhibiting a thin overlying seal, to arrive at an estimate for each formation meeting minimum depth and seal parameters. The maps reveal that approximately 1,045 mi^2 (2,700 km^2) are underlain by Mokelumne River sandstones, 920 mi^2 (2,380 km^2) by Starkey formation sandstones, and 1,454 mi^2 (3,770 km^2) by Winters sandstones, which meet the nominal minimum depth requirements of 1,000 m (3,280 ft) considered important and seal thickness of over 100 ft (30 m). Because the formations are vertically stacked, only 2,019 net surface mi^2 (5,230 km^2) meet depth and seal criteria. However, stacking provides the potential for much thicker total sandstone sequences than individual formations. The estimated storage resource for the portions of the three formations meeting depth and seal criteria is 3.5 to 14.1 Gt of CO_2.

Early opportunities for commercial-scale CCS are likely to be linked to opportunities for CO_2-enhanced oil recovery (EOR) or other CO_2 utilization, such as enhanced gas recovery (EGR), cushion gas for natural gas storage (Oldenburg, 2003), or as compression gas for energy storage (Oldenburg and Pan, 2013). Depleted petroleum reservoirs are especially promising targets for CO_2 storage because of the potential to use CO_2 to extract additional oil or natural gas. The benefit of using injected CO_2 to swell and mobilize oil from the reservoir toward a production well is well-known and widely practiced. EGR involves a similar CO_2 injection process, but relies on sweep and methane displacement and is not practiced anywhere to our knowledge. CO_2 injection may enhance methane production by reservoir re-pressurization or pressure maintenance of pressure-depleted natural gas reservoirs, or by preferentially desorbing methane from certain kinds of gas-bearing formations.

A.2 ATTRIBUTES OF BROADLY REPRESENTATIVE SITES

A.2.1 Introduction

Sites that are representative of prospective GCS sites in California should meet a number of geological and geographic criteria, as well as nontechnical criteria necessary to host a CCS project. Criteria include elements of the geology and geography that define the suitability of the site for geologic storage, including location relative to sources, presence of storage and sealing formations, and how representative the formations at the site are of the major geologic storage targets in the region. In addition there are non-geologic criteria that must be met to assure a successful storage project. Such criteria include site access, liability assumption, and permitting constraints. Table A1 lists these criteria by category. Note that these are different from the criteria developed by this project for evaluating a specific GCS site for qualification for the QM described in the body of this report. The list in Table A1 focuses on pre-screening criteria that affect the practicality of undertaking a project given the geologic and non-geologic attributes of a site. This list provides a business-case screening to down-select to viable sites at which the QM leakage risk criteria would then be applied. We emphasize that this is the process by which WESTCARB screened sites in 2011 and differs from our current recommendations but we include the information in this appendix as a review (see scope of work in Appendix B).

With respect to location, GCS sites should be within reasonable proximity to large-volume CO_2 sources. GIS National Carbon Sequestration Database (NATCARB) provides a database of CO_2 source locations and characteristics which can be used to find source-sink matches. Urbanization and industrialization, including many large CO_2 sources such as power plants and refineries, are concentrated along the coast, predominantly in the San Francisco Bay Area and Los Angeles Basin.

__Table A.1.__ Representative site-selection criteria used in WESTCARB study (WESTCARB, 2011).

Category	**Criteria Description**
Geologic and Geographic Criteria	Well-defined stratigraphy or structure that should minimize CO_2 leakage
	No impact on USDW (low-salinity (<10,000 mg/L TDS) aquifers); minor impact on a deep, high-salinity aquifer beneath a confining seal formations
	Location is unlikely to cause public nuisance (noise, traffic, dust, night work, etc.) and does not disturb environmentally protected or other sensitive areas
	Well will intersect formations identified as potential major storage resources for the region—i.e., case study sites typical of California storage resource
	Area is in sufficiently close proximity to large-volume CO_2 sources
	Sufficient preliminary geologic data (hydrogeologic data, well logs, seismic surveys, rock and fluid properties) available to inform site down select process
	Major faults in area are known and can be assessed for their potential as leakage pathways
	Depth of storage formations are greater than 800 m (~2,600 ft) to keep CO_2 in dense, supercritical state
	Potential for CO_2 utilization at site to improve likelihood of early CCS development opportunities
Nontechnical/ Logistical	Surface owner grants project access
	Subsurface (mineral rights or well) owner grants project access and accepts well liability
	Pre-existing roads and easy access for heavy equipment
	Pre-existing well pad or well to eliminate or minimize surface disturbance and easy access for heavy equipment
	Ease of permitting process

Another criterion worthy of mention is the desire to locate a prospective GCS study site where additional data collection or drilling would have high value through filling knowledge gaps. Interestingly, application of this criterion in earlier studies led to inclusion of sites in the oil- and gas-bearing regions of the state that have been extensively drilled and studied. But the focus of data gathering in oil and gas areas has been on the hydrocarbon-bearing formations that typically overlie the deep saline formations of interest for CO_2 storage. Of the gas exploration wells drilled to the depths needed for GCS site characterization, few have collected sampling and logging data for these deep formations. In addition, the characteristics of the sealing units are typically neglected in traditional oil and gas exploration. Because CO_2 for EGR remains experimental, the types of data needed for dynamic modeling of CO_2 behavior are not typically collected in the gas-bearing formations.

At the field level, criteria include establishing that storage and sealing formations meet general thickness requirements, incorporating any data on hydrogeologic properties, including permeability and formation water salinities, and examination of the properties of any faults in the area. Methods include reviewing existing well or seismic data to create a preliminary geologic model. However, at this level, other criteria related to site access, permitting, liability, and minimizing new construction activities also are part of the ranking.

A.3 INITIAL SCREENING OF FOUR CANDIDATE SITES

The sites that were short-listed in the down-select process were the King Island Gas Field, the Thornton Gas Field, and the Montezuma Hills sites in the southern Sacramento Basin, and the Kimberlina site in the southern San Joaquin Basin. The King Island site met the geologic criteria better than the Thornton and Montezuma Hills sites. Much of the geologic data acquired for the Thornton site, and to some extent at the Montezuma Hills site, are applicable to the King Island site, which is 12 mi (19 km) to the south of Thornton and about 15 mi (24 km) to the east of Montezuma Hills. King Island also meets the nontechnical/logistical criteria whereas the Thornton and Montezuma Hills sites do not. The Kimberlina site was selected as a back-up site, meeting geologic and nontechnical/logistical criteria.

A.3.1 King Island

The King Island Gas Field, near the Thornton site, permits characterization of both the gas-bearing and saline formations of importance in the southern Sacramento-northern San Joaquin Basins. The general geology of the site is very similar to the Thornton site, which lies 12 mi (19 km) to the north, but includes the ability to access deeper sand units and shales. It also includes some of the formations of interest at the Montezuma Hills site, but which occur at shallower depths at King Island.

The site is located within a couple of miles of US Interstate 5, providing ready access to California's major ground transportation corridors, serving the San Francisco Bay, Sacramento, and Stockton metropolitan areas, and is close to significant CO_2 sources that provide power to these areas and to industrial sources such as Bay Area refineries. The site presents no particular problems with regard to site access.

A robust dataset exists because WESTCARB performed a research project at the site, drilling a characterization well and performing extensive laboratory and simulation studies (WESTCARB, 2016).

A.3.2 Kimberlina

The Kimberlina site is in the southern part of the San Joaquin Valley, near Bakersfield, in a region of oil resources. A geological assessment, construction of a static geomodel, dynamic simulations, and a thorough risk assessment were undertaken for this site by WESTCARB. There is a lack of seismic data specific to the Kimberlina area to constrain structure although there is general availability of data surrounding Kimberlina in the oil-producing areas because of extensive oil exploration and production nearby.

A.3.3 Thornton

The Thornton site contains saline formations and gas reservoirs that could be used for geologic storage of CO_2. Depleted gas reservoirs are especially promising targets for CO_2 storage because of the potential to use CO_2 to extract additional natural gas through EGR. Based on favorable results of numerous EGR modeling studies, the Thornton Gas Field (abandoned) was selected for the purpose of studying EGR processes. Depleted natural gas reservoirs are attractive targets for sequestration of CO_2 because of their demonstrated ability to trap gas, proven record of gas recovery (i.e., sufficient permeability), existing infrastructure of wells and pipelines, and land use history of gas production and transportation. The formations at the Thornton Gas Field are representative of dozens of gas-producing fields in California, the cumulative storage capacity of which is estimated at 1.7 Gt CO_2. The site is about two miles north of the unincorporated town of Thornton, California (population 1,467), so it is less isolated from residences than the King Island site.

A.3.4 Montezuma Hills

The Montezuma Hills site (Figure A2) is approximately 20 mi (32 km) northwest of the Thornton site and 15 mi (24 km) west of the King Island site. This site is on the west side of the Central Valley and is a monocline, rather than a pinnacle structure as present at the Thornton and King Island sites. Target formations are considerably deeper and therefore more expensive to drill.

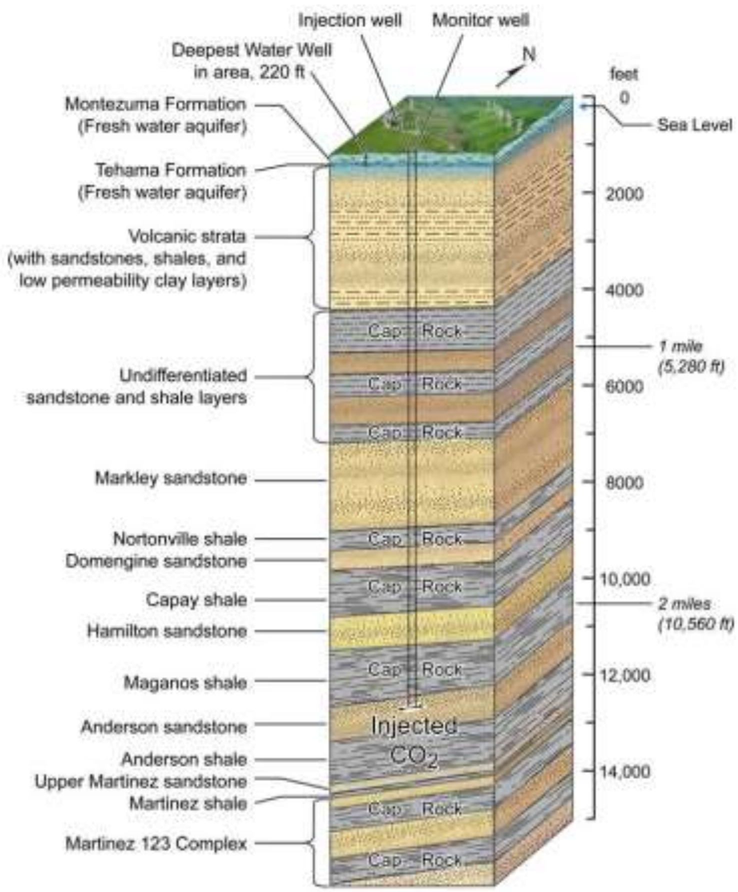

Figure A2. *General Stratigraphy at the Montezuma Hills site. The Domengine, Capay and Maganos are present, but are significantly deeper than to the east at the King Island and Thornton sites.*

A.4 APPLICATION OF GEOLOGIC CRITERIA TO THE FOUR SITES

The Thornton Gas Field consists of an east-west trending anticline structure with an estimated maximum productive area of approximately 5 mi^2. The original gas-water contact was reportedly at a depth of 3,360 ft (1,024 m). Natural gas was produced primarily from the top of the Mokelumne River formation (known locally as the Capital Sand) with smaller localized plays found in the overlying Domengine sandstone (known locally as the Emigh) and sand stringers in the Capay Shale and Nortonville Shale. Production began in the mid-1940s, producing nearly 53.6 billion cubic feet (bcf; 1.52×10^9 m^3) of natural gas through the 1980s from approximately 15 wells (now abandoned).

Geologic and electrical logs from these wells show a gas-bearing zone and a saline zone beneath a competent shale layer located below the original gas-water contact depth (3,360 ft; 1,024 m; Figure A3). Estimated depth to the bottom of the shale unit is 3,410 ft (1,039 m). Core samples collected from deviated well, Bender #1, at a true vertical depth of approximately 3,330–3,400 ft (1,015–1,036 m) have permeabilities ranging from 46 to 1,670 mD (4.65×10^{-14}–1.6765×10^{-12} m^2) and porosities ranging from 26.5 to 28.8% for the sands in the upper Mokelumne River formation. Geologic and electrical logs were also consulted to look for a thin sand stringer or layer in the middle Capay shale where gas was produced from abandoned production well Capital Co. 2. This thin sandy unit is continuous across the section, expressing itself in several well logs throughout the area.

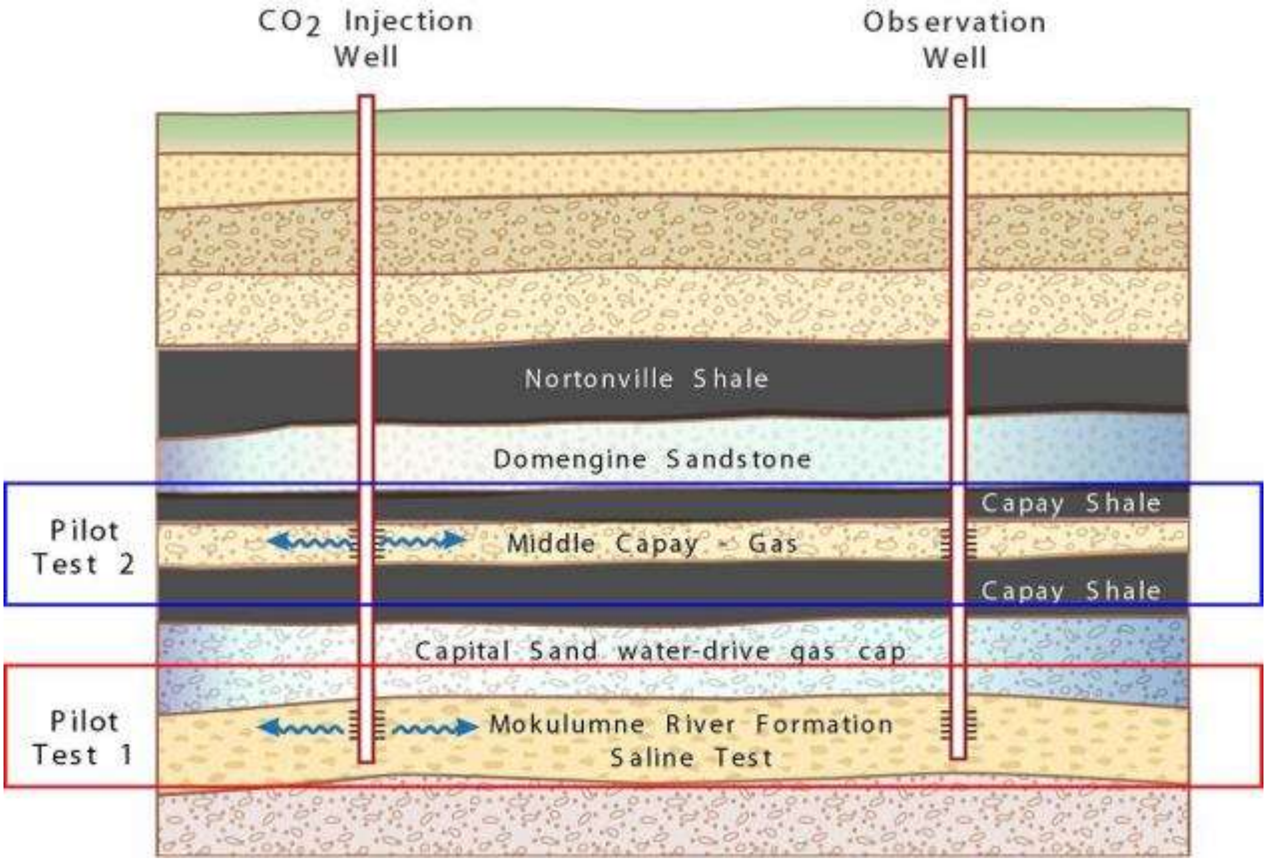

Figure A3. *Proposed pilot test configuration for Thornton when it was a potential WESTCARB injection pilot site, with injection planned in the gas-bearing and saline units. The stratigraphy shown is equivalent to the upper section that will be drilled and sampled at King Island.*

Data on reservoir properties could not be found for the Capay Shale, so production data were analyzed using the transient wellhead pressure response matched to the Theis (1935) type curve (i.e., exponential integral solution). The wellhead pressures were not converted to equivalent bottomhole pressures, and the natural gas was assumed to be ideal and flowing under isothermal conditions. Therefore, the permeability value of 4 mD (4×10^{-15} m^2) determined using this approach should be considered a rough estimate of Capay permeability.

A regional unconformity separates the Mokelumne River formation from the younger Eocene Capay shale. The intervening Paleocene sediments including the McCormick sand, Anderson and Hamilton sands and Martinez and Meganos shales are missing from the stratigraphic column and were either removed by erosion or not deposited when the Midland fault was active up through the early Eocene.

The stratigraphy at the Montezuma Hills site has similarities with that further eastward at King Island and Thornton. Some of the same sandstone and shale formations occur, but here they are significantly deeper (Figure A2). Performing further work for a case study at Montezuma Hills would require drilling to about 11,000 ft (3 km) in order to obtain information on the formations of interest.

The Midland fault is the closest major fault zone to the gas fields of the southern San Joaquin Basin. It is located approximately 10 to 15 mi (16–24 km) west of Thornton and King Island and east of the Montezuma Hills. The Midland fault does not exhibit a surface trace; rather it is thought to be a blind, high-angle, west-dipping normal fault with a north-northwest strike. The Midland fault trace was identified and mapped using subsurface correlation between stratigraphic units and seismic reflection data derived from wells and geophysical surveys collected during gas exploration. The Midland fault accommodated extension and subsidence that occurred in the late Cretaceous to early Paleogene Sacramento Valley forearc basin. Normal displacement along the fault ended by the Eocene epoch; however, minor normal displacement may have occurred in late Miocene time. Seismic reflection data indicates that post-Miocene reactivation of the Midland fault occurred to accommodate reverse slip caused by horizontal shortening of the crust. Estimates for the long-term average slip rate for the Midland fault range between 0.004–0.02 in/yr (0.1–0.5 mm/yr).

It is important to note that the gas zones in much of the Sacramento Basin are structural traps against sealing faults; however at King Island, the trap is stratigraphic, Thornton is at the top of an anticline, and Montezuma Hills is monoclinal. There are very few faults identified in the immediate vicinity of the candidate sites, but some specific issues arose during activities associated with WESTCARB's Phase II and Phase III site planning.

Two minor faults are identified on the Division of Oil, Gas, and Geothermal Resources (DOGGR) structural contour map of the top of the Capital sand in the Thornton field and these faults are located outside of the productive area. The faults have normal displacement and strike north-south. These faults were not considered to be an issue for the planned CO_2 injection at that site.

Faulting became a permitting issue, however, for a pilot-scale CO_2 injection proposed for the Montezuma Hills site. Researchers at the Lawrence Berkeley National Laboratory (LBNL) and the Lawrence Livermore National Laboratory (LLNL) prepared seismic hazard reports for Solano County to address concerns (Daley et al., 2010; Myer et al., 2010; Oldenburg et al., 2010). The closest known fault to the proposed injection site is the Kirby Hills fault. Shell's proprietary seismic survey data also indicated two unnamed faults more than 3 mi east of the project site. These faults do not reach the surface as they are truncated by an unconformity at a depth of about 2,000 ft (610 m). The unconformity is identified as occurring during the Oligocene Epoch, 33.9–23.03 million years ago, which indicates that these faults are not currently active. Farther east are the Rio Vista fault and Midland fault at distances of about 6 mi (10 km) and 10 mi (16 km), respectively. These faults have been identified as active during the Quaternary (last 1.6 million years), but without evidence of displacement during the Holocene (the last 11,700 years).

The Kirby Hills fault is probably the source of microearthquakes, and earthquakes as large as magnitude 3.7, over the past 32 years. Most of these small events occurred 9–17 mi (15–28 km) below the surface, which is deep for this part of California. However, attributing recorded earthquakes to specific faults using data from events in the standard seismicity catalog for the area is subject to considerable uncertainty because of the lack of nearby seismic stations. Installation of local seismic monitoring stations near the site would greatly improve earthquake location accuracy.

The stress state (both magnitude and direction) in the region is an important parameter in assessing earthquake potential from injection activities. Although the available information regarding the stress state is limited in the area surrounding the proposed injection well, the azimuth of the mean maximum horizontal stress is estimated at 041° and it is consistent with strike-slip faulting on the Kirby Hills fault, the unnamed fault segments to the south, and the Rio Vista fault. However, there are large variations (uncertainty) in stress estimates, leading to low confidence in these conclusions regarding which fault segments are optimally oriented for potential slip induced by pressure changes. Uncertainty in the stress state could be substantially reduced by measurements planned when wells are drilled at the site.

If it had gone forward, the WESTCARB pilot project would have injected about 6,000 tonnes of CO_2 at about 2 mi (3.2 km) depth. This injection would result in a reservoir fluid pressure increase greatest at the well, decreasing with distance from the well. After the injection stops, reservoir fluid pressures would decrease rapidly. Pressure changes have been predicted quantitatively by numerical simulation models of the injection. Based on these models, the pressure increase on the Kirby Hills fault at its closest approach to the well due to the injection of 6,000 tonnes of CO_2 would be a few pounds per square inch (psi), which is a tiny fraction of the natural pressure of approximately 5,000 psi (34 MPa) at that depth. The likelihood of such a small pressure increase triggering a slip event is very small. It is even more unlikely that events would be induced at the significantly greater depths where most of the recorded earthquakes are concentrated, because it is unlikely that such a small pressure pulse would propagate downwards any appreciable distance without dissipation.

Therefore, in response to the regulatory agency's specific question of the likelihood of the CO_2 injection causing a magnitude 3.0 (or larger) event, the preliminary analysis suggested that no such induced or triggered events would be expected. However, it is possible that a fault, too small to be detected by the existing seismic data (e.g., Mazzoldi et al., 2012), yet sufficiently large to cause a magnitude 3.0 event, could exist in close proximity to the injection point where the pressure increase could cause slippage. However, the existence of any such faults would be detectable by data collection from the well prior to injection. It should be noted that natural earthquake events of up to 3.7 in magnitude have occurred in this area and would be expected to occur again regardless of the proposed CO_2 injection.

There appear to be no major faults and no minor ones in the King Island field at the resolution of a recent seismic survey of the area. During early 1999, Eagle Geophysical acquired a 250 mi 3D seismic survey in western San Joaquin County, including King Island. DDD Energy and Enron Oil and Gas formed an area of mutual interest (AMI) and underwrote the proprietary shoot. OXY USA later acquired Enron's position as part of a larger trade of property and data. The seismic survey targeted multiple stratigraphic and structural objectives that extend from Cretaceous submarine fans and channels deep in the basin up through fluvial-deltaic reservoirs in the shallow Cenozoic section. Three-pound dynamite charges, inserted at depths of 20 ft (6.1 m), provided the acoustic source. The source spacing and group interval were both 220 ft (67 m). The spread was eight lines with 120 channels each, for a total of 960 channels. The sample rate was 2 ms down to 8 s. Two companies processed the data, producing numerous versions of the volume. Processing parameters include dip movement correction (DMO) gathers, DMO, migration, spectral whitening, time variable filtering (TVF), frequency and X- Y- domain (FXY), and trace equalization by Matrix Geophysical; pre-stack migrated gathers and an enhanced migration (DMO pre-stack) were performed by Vector Geophysical. These data are the basis for a research publication providing a structural-stratigraphic interpretation of King Island and surrounding potential gas plays (Figure A4; May et al., 2007).

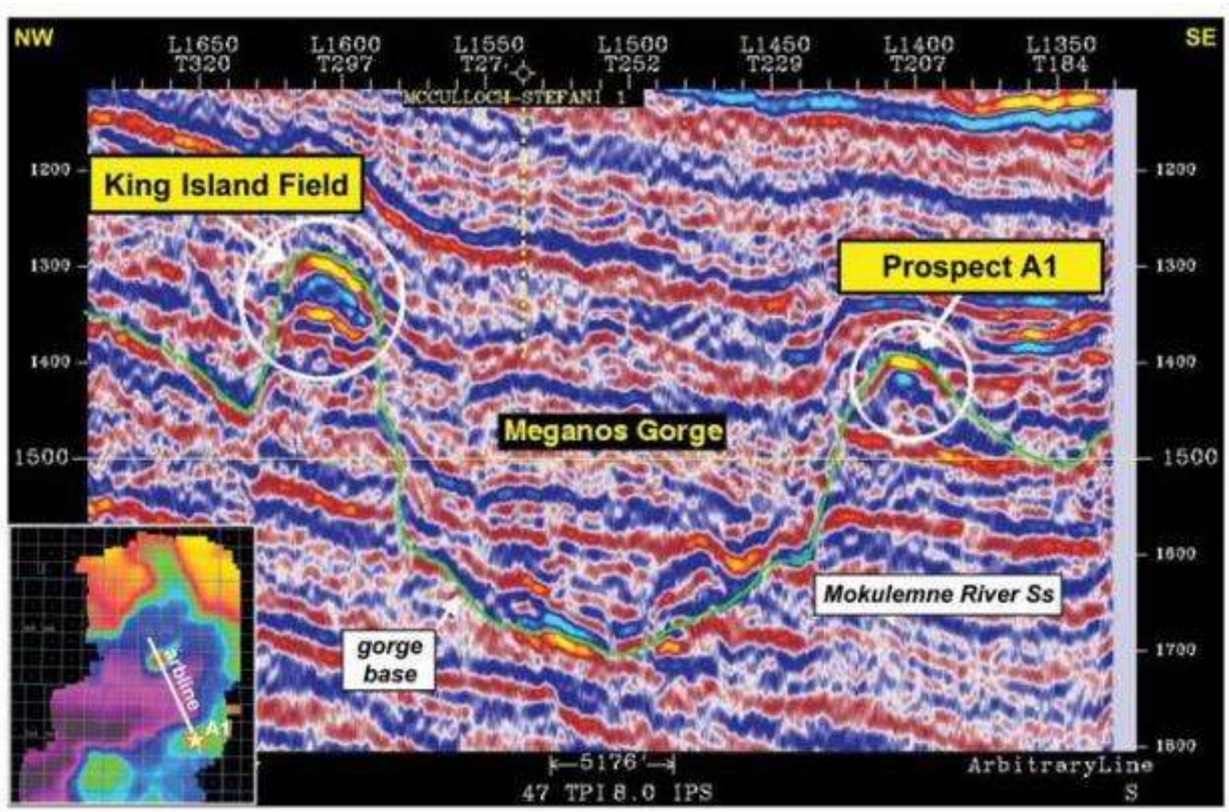

Figure A4. *Seismic line extending from King Island gas field across the Meganos stratigraphic gorge to another potential gas play in the region (also shown on the inset map). In this variable-density display, the seismic troughs are presented in red, grading through white at the zero crossing, with the peaks in blue. The strongest trough amplitudes are highlighted in yellow and the strongest peak amplitudes are in cyan. (From May et al. (2007)).*

King Island is preferable to the other sites because 3D seismic data are lacking at the other sites. An assessment of the need to purchase additional seismic data that may be available in adjacent areas to assist in developing commercial-scale CO_2 injection simulations should be done as part of site selection and well placement planning, using existing data for construction of simulation models to determine likely CO_2 migration scenarios.

Regional groundwater elevations in the adjacent Sacramento Valley Groundwater Basin indicate that a steep hydraulic gradient exists at the margins of the Central Valley and Sierra Nevada mountains, where valley recharge takes place. Groundwater discharges near the axis of the Central Valley as base flow, adding to the overland component of the surface water runoff derived from snow pack and precipitation originating in the adjacent Sierra Nevada Mountains. The Thornton and King Island field sites are located in a low-lying swampy area with groundwater elevations near land surface, characteristic of a regional groundwater discharge location. The Montezuma Hills site is slightly higher, in the foothills of the Coast Range to the west.

The Thornton and King Island sites lie within the Central Valley Hydrogeologic Province in the Cosumnes Subbasin (groundwater basin 5-22.16, Department of Water Resources (DWR), 2003). The Cosumnes Subbasin is defined by the aerial extent of unconsolidated to semi-consolidated sedimentary deposits that are bounded on the north and west by the Cosumnes River, on the south by the Mokelumne River, and on the east by consolidated bedrock of the Sierra Nevada Mountains. Annual precipitation ranges from approximately 15 in (0.38 m) on the west side of the subbasin to 22 in (0.56 m) to the east. The Cosumnes Subbasin aquifer system is made up of three types of deposits including younger alluvium, older Pliocene/Pleistocene alluvium, and Miocene/Pliocene volcanics of the Mehrten formation (DWR, 2003). The cumulative thickness of these deposits ranges from a few hundred feet near the Sierra foothills to nearly 2,500 ft (762 m) at the western boundary of the subbasin. The Mehrten consists of alternating layers of “black” sand, stream gravels, silt and clay, with interbedded layers of tuff breccia. The gravel aquifers are highly permeable and the interbedded tuffs serve as confining layers. Wells completed in this unit typically have high yield. The deposit ranges in thickness from 200 to 1,200 ft (61–366 m) and forms a discontinuous band of outcrops along the eastern margin of the basin. Specific yields range from 6 to 12%. The younger Pliocene/Pleistocene sediments were deposited as alluvial fans along the eastern margin of the Central Valley. These sediments consist of loosely to moderately consolidated silt, sand, and gravel deposits ranging from 100 to 650 ft (30.5–198 m) thick. The older alluvial sediments are exposed between the foothills of the Sierra Nevada and the overlying younger alluvium near the western margin of the subbasin and valley center. Calculated specific yields are about 6 to 7% and the aquifers in this unit exhibit moderate permeability. The younger alluvial deposits include recent sediments deposited in active stream channels, overbank deposits and terraces along the Cosumnes, Dry Creek, and Mokelumne Rivers. These unconsolidated sediments primarily consist of silt, fine to medium sand, and gravel with the maximum thickness approaching 100 ft (30.5 m). The courser sand and gravel are highly permeable and produce significant quantities of water. Calculated specific yields for the younger alluvial deposits range from 6% for the alluvium to 12% for the channel deposits.

Data for groundwater wells near King Island and Thornton (e.g., State Well Number 05N05E28L003M; DWR monitoring network) indicate that depth to groundwater ranges from 1.5 to 12 ft (0.46–3.6 m) below ground level, depending upon the time of year. Shallow groundwater at the King Island site is also expected to be within a few feet of land surface and expected to respond to seasonal changes in surface water levels in the adjacent rivers and sloughs.

A.5 APPLICATION OF NONTECHNICAL/LOGISTICAL CRITERIA TO THE FOUR SITES

Nontechnical and logistical issues proved to be the critical elements for site selection. For example, WESTCARB attempts to site a northern California Phase II pilot injection test with Rosetta Resources, Inc., at Thornton were aborted by internal decisions at Rosetta that resulted in the company being unable to continue as WESTCARB's industry partner.

Following the withdrawal of Rosetta Resources from the Northern California CO_2 Storage Project, a partnership with C6 Resources, LLC, an affiliate of Shell Oil Company, was discussed and WESTCARB's intended pilot test site was shifted to the Montezuma Hills of Solano County, California. C6 Resources was interested in evaluating the site's potential for a commercial-scale CCS project to sequester captured CO_2 from Shell's Martinez refinery. WESTCARB and C6 planned to jointly (1) undertake a pilot injection test and supporting outreach and permitting activities, (2) coordinate geophysical, hydrological, geochemical, and geomechanical characterization work, and (3) explore options and perform background work to support a possible scale-up from a small-volume (6,000 tonnes) CO_2 injection pilot to a Phase III large volume (several 100,000 tonnes) injection project to a commercial-scale (1 million tonnes per year). Outreach activities and permitting applications were pursued successfully for the 6,000 metric ton test. However, in mid-August 2010, C6 informed WESTCARB that a corporate decision had been made not to pursue CCS activities further at the Montezuma site, citing reasons such as a continued lack of clarity in California regarding the status of CCS in the GHG regulatory framework and the outcome of corporate strategic business decisions.

Subsequently, WESTCARB collaborated with Clean Energy Systems (CES) in preliminary characterization of the Kimberlina site, but business reasons also precluded CES from continuing with installation of an injection well.

A.6 CONCLUSION OF PREVIOUS SITE SCREENING

All four sites met the geologic/geographic criteria; however, the geology at King Island offers some advantages over the other sites. King Island also was the only site that completely fulfilled the nontechnical/logistical criteria. Kimberlina was a close second based on these criteria. King Island met the criteria related to liability, permitting, site access, and other nontechnical factors.