Title

West Coast Regional Carbon Sequestration Partnership (WESTCARB) Down-Select Report for Task 7: The King Island Characterization Well at King Island, San Joaquin County, California.

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West Coast Regional Carbon Sequestration Partnership (WESTCARB)

Down-Select Report for Task 7: The King Island Characterization Well at King Island, San Joaquin County, California

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Executive Summary

As outlined in WESTCARB's SOPO, WESTCARB will use preliminary collection of available geologic and nontechnical data to select two top-ranked candidate sites for its Phase III field characterization projects: a preferred site and a backup location. WESTCARB has reached Decision Points 1 & 2 for these tasks for the California project (Task 7). This report provides a summary of the data and criteria that were used to support down-selection to the King Island site, with the Kimberlina site as a back-up. This report fulfills the deliverable to DOE as the go/no-go decision report for Task 7 to enable the DOE to determine if there is sufficient evidence including favorable geology to support a decision to proceed with the installation of the test borings. Additional information on access and permitting is also provided.

Under its new Phase III directive, WESTCARB will not be performing an injection at any scale; thus, the major technical objective of its site selection process is to find a site which would allow sample and data collection from as many of the key storage and sealing formations of the Sacramento-San Joaquin Basin as possible, the same formations which were targets for injection at the Phase II and Phase III candidate sites.

WESTCARB developed a set of geologic and geographic criteria and nontechnical/logistical criteria to rank potential characterization well sites. In addition, the site was evaluated to assure that the well plan would be able to meet the scientific objectives of the characterization well project.

WESTCARB has been performing site characterization work in California in collaboration with the California State Geologic Survey, with various industry partners with interest in CCS development, and in preparing for its Phase II pilot injection and Phase III large volume storage test phases. The knowledge gained in these endeavors was reviewed and used as a starting point for the characterization well down-selection.

Four sites were considered: King Island, Thornton, Kimberlina and Montezuma Hills. As is explained below, all sites met the geologic/geographic criteria, however the geology at King Island and available data offer some advantages over the other sites. King Island site meets the scientific objectives better than the other three sites considered. Furthermore, King Island is the only site that completely fulfills the nontechnical/ logistical criteria. Kimberlina is a close second based on these criteria and was chosen as a back-up on that basis. King Island meets the criteria, related to liability, permitting, site access and other non-technical factors necessary to assure successful completion of the project. In the case of the other sites selected, as is described in more detail below, these non-technical factors were the criteria eliminated the sites from further consideration.

1.0 Definition and Objectives of the Characterization Study

The overall goal of the California Characterization Well project is to gain practical experience with subsurface characterization, and demonstrate the potential for safe CO_2 storage in deep underground geologic formations in a location near large CO_2 sources and with large CO_2 storage resource potential. In addition, the project should define characterization approaches and provide technology and knowledge transfer to governmental agencies and the public. The project has three defining themes:

1) Demonstrate and test methods for acquiring high-quality data and samples for characterizing potential CO_2 storage sites in geologic formations;
2) Evaluate laboratory testing techniques and numerical modeling codes capabilities to predict the location, movement, and fate of CO_2 in storage reservoirs; and
3) Provide knowledge sharing to the public, policymakers, and permitting agencies through project-related outreach.

The primary scientific objectives of the project, and the activities planned to address these objectives, are summarized in Table 1.

Table 1. Summary of the scientific objectives and proposed test plan elements

Scientific Objective	**Measurement Approach**
Demonstrate site characterization techniques	• Geologic analysis of existing well data • Baseline characterization data from new well • Numerical simulation modeling of CO_2 plume using existing data
Assess the storage formation	• Collection and testing of whole and rotary core from the reservoir formation • Collection of geophysical log and wireline formation(s) testing data from the reservoir formation(s)
Assess the spatial extent and behavior of injected CO_2 scenarios	• Numerical modeling of hypothetical CO_2 injection scenarios to mimic small pilot or large-scale injections
Assess seal integrity	• Collection and testing of whole and rotary core from the seal formation • Collection of geophysical log and wireline formation test data from sealing formations
Assess formation fluids	• Collection of formation fluid samples • Geochemical testing and modeling

2.0 Methodology

The methods for site down-selection for a characterization well include developing criteria for site selection and collecting relevant available data that address those criteria. Based on these data, a ranking of sites can be made. Criteria include elements of the geology and geography that define the suitability of the site for geologic storage including location relative to sources and presence of storage and sealing formations, how representative the formations at the site are of the major geologic storage targets in the region, as well as non-geologic criteria that must be met to assure a successful project. Such criteria include site access, liability assumption, and permitting constraints. Table 2 lists these criteria by category.

Table 2. Characterization well site selection criteria

Category	Criteria Description
Geologic and Geographic Criteria	Well-defined stratigraphy or structure that should minimize CO_2 leakage
	No impact on 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
	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 yet not so much as to make characterization well unnecessary to fill knowledge gaps
	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 feet) to keep CO_2 in dense supercritical state
	Potential for CO_2 utilization at site improve likelihood of early CCS development opportunities
Non-technical/ 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

The criteria that sites be within reasonable proximity to large volume CO_2 sources was addressed through use of the GIS NATCARB databases, which WESTCARB has assembled. Urbanization is concentrated on the coasts, predominantly in the San Francisco Bay Area and Los Angeles Basin and many large CO_2 sources are also within these regions. 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 greater than 500 years of California's current large-point source CO_2 emissions.

The formations of interest in California for geologic storage have been the subject of many previous investigations by WESTCARB and its partners. These formations include the Mokelumne, Starkey, Winters, Domengine, and Vedder sandstones. The methodologies used to assess these units as potential storage resource 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 carbon sequestration potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin (Downey & 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 square miles are underlain by Mokelumne River sandstones, 920 square miles by Starkey Formation sandstones, and 1,454 square miles by Winters sandstones, which meet minimum depth requirements of 1,000 meters (3,280 feet) and seal thickness of over 100 feet and may be suitable for carbon sequestration. Since the formations are vertically stacked, only 2,019 net surface square miles 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 Gigatons of CO_2.

Given that early opportunities for commercial-scale CCS are likely to be linked to opportunities for CO_2-EOR or other CO_2 utilization, such as enhanced gas recovery, cushion gas for natural gas storage or as compression gas for energy storage, another criteria used for site screening was to look for sites where such opportunities were available. 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 EOR using injected CO_2 to swell and mobilize oil from the reservoir toward a production well is well known. Enhanced gas recovery (EGR) involves a similar CO_2 injection process, but relies on sweep and methane displacement. CO_2 injection may enhance methane production by reservoir re-pressurization or pressure maintenance of pressure-depleted natural gas reservoirs or by preferential desorbing more methane in any gas-bearing formation. Thus, potential sites that are near oil fields, gas fields, natural gas storage sites, or areas being studied for compressed gas energy storage were given preference in the ranking process.

Another criterion was to locate an area where the data gathered by a characterization well would have high value through filling knowledge gaps balanced against the need to have sufficient data available for selected sites for informed decision-making. In other words, areas that were already rich in subsurface data would rank lower than areas where a characterization well would significantly improve knowledge of the character of storage formations and sealing units. However, this automatically did not preclude selecting sites in the oil and gas-bearing regions of the state. Although the oil and gas regions in California have been extensively drilled and studied, the focus of data gathering 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 CCS 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 enhanced natural gas recovery 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 geohydrologic 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. For example, being able to use existing well pads and roads may favor one site for well drilling within a field over another site where formations are predicted to be of greater thickness. Side-tracking the well might be used to plan a project to balance these competing objectives. Similarly, a field where the owner may be willing to take liability and obtain permits would rank more highly than one where WESTCARB would have to purchase an insurance bond or take permitting responsibility.

Final ranking criteria used include reviewing well plan scenarios of the potential sites for compatibility with the scientific objectives of the project given logistical and budgetary limitations. For example, a site where formations of interest were shallower might be preferred over one where they were deeper because the savings in drilling costs could be used to acquire more logging data or a greater number of core or fluid samples.

3.0 Down-Select Results

WESTCARB has been in the process of identifying sites in California for pilot tests under Phase II since 2005 and Phase III since 2008. The down-select process which resulted in selection of the King Island site for a characterization well study built on the extensive work WESTCARB did in Phase II to select a site for a small-scale CO_2 injection and in Phase III to select a site for a large-volume storage test. It is important to note that prior to the selection of each of the Phase II or III sites, independent down-selection processes were undertaken by and with the industry partners to establish a preferred site.

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 selection details and history of site down-selection for Thornton are reported in the WESTCARB Phase II Final Report (pp. 45-53). C6 Resources, LLC performed its own proprietary evaluation of over 100 potential sites before selecting the Montezuma Hills site. WESTCARB geologists concurred with the

C6 Resources conclusions regarding the suitability of the site for a small-scale pilot and potentially for a large-scale Phase III WESTCARB project.

For a characterization well, the King Island site meets the geologic criteria and provides equivalent or better scientific opportunities compared to the Thornton and Montezuma Hills sites. Much of the geologic data acquired for the Thornton sites, and to some extent at the Montezuma Hills site, are applicable to the King Island site, which is 12 miles to the south of Thornton and about 15 miles to the east of Montezuma Hills. King Island also meets the nontechnical/logistical criteria whereas the Thornton and Montezuma Hills sites do not. Kimberlina was selected as a back-up site, meeting geologic and non-technical/logistical criteria but was judged to provide less knowledge gain and fewer scientific opportunities than King Island.

3.1 Geologic and Geographic Criteria

Based on the methods described above, WESTCARB has identified the characterization site area with the highest potential in California as the Sacramento-San Joaquin Basin. The target storage formations are the extensive sedimentary deposits in the Sacramento-San Joaquin Basin, associated with gas-bearing and oil-bearing formations and the underlying saline units.

There are over 11 megatonnes per year of CO_2 emissions from sources within the southern Sacramento Basin alone, and the area lies in close proximity to numerous power plants and large industrial sources in the San Francisco Bay Area, the California Delta, Stockton, and Sacramento areas. In addition to saline formation storage opportunities, there is the possibility for enhanced hydrocarbon recovery or CO_2 utilization in gas storage or energy storage. The southern Sacramento-northern San Joaquin basin contains producing gas fields and gas storage reservoirs. Thornton, King Island, and Montezuma Hills are within this gas-bearing region. The oil fields in the southern San Joaquin Basin (as well as the nearby Ventura oilfields) are close to large sources, and some are suitable for CO_2-enhanced oil recovery. The Kimberlina site, which is near Bakersfield, is in the oil region.

The California Geological Survey divides California into 11 Geomorphic Provinces based on a common geologic record, landscape, or landform. Each province represents a unique area of the state with distinct geology, structure (i.e., faulting), topographic relief and climate. The candidate sites are located in the Great Valley Geomorphic Province, a structural trough or basin filled with up to 40,000 ft (12.2 km) of Jurassic to Holocene marine and nonmarine clastic sediments. Marine and deltaic sediments were deposited along the western convergent margin of the Cordilleran Mountains, which underwent rapid uplift and erosion during the Late Jurassic to Late Cretaceous Cordilleran Orogeny.

Thick marine sediments continued to accumulate along the Farallon-North American Plate boundary during the early Cenozoic era before the California Coastal Range began its rapid uplift during the middle Cenozoic. Cenozoic evolution of the Coastal Range, characterized by intense faulting and alternating periods of uplift and subsidence, created the western boundary of the structural trough. Corresponding uplift and subsidence of the Central Valley resulted in deposition of alternating layers of undifferentiated nonmarine and marine sediments, respectively, across the Sacramento-San Joaquin Basin (Figures 1 and 2).

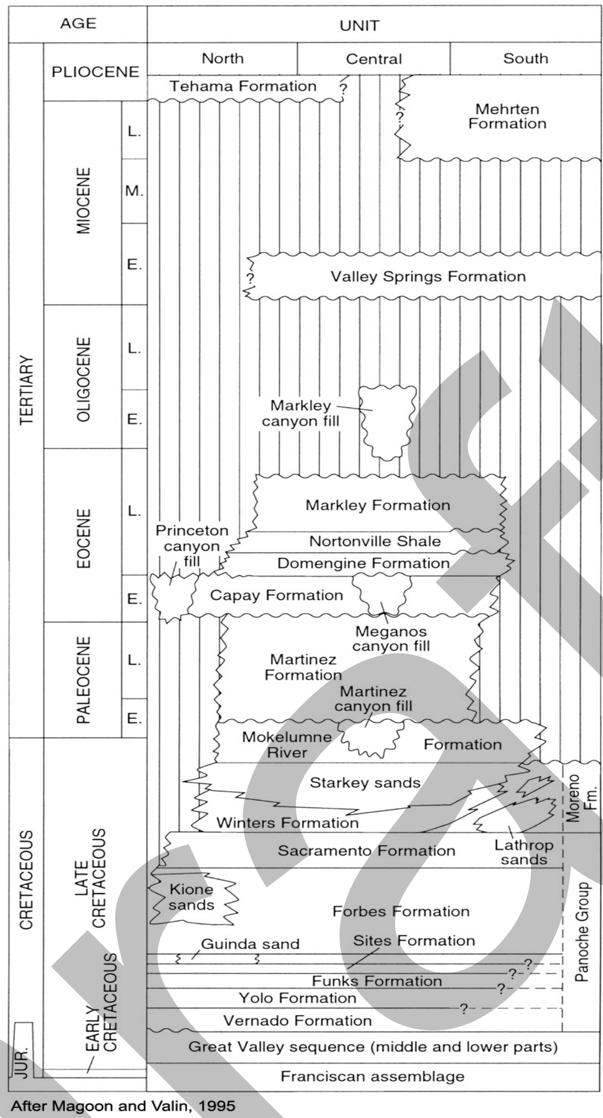


Figure 1. General stratigraphic section for the Sacramento Basin, California.

The Kimberlina site lies within the southern part of the San Joaquin Basin. The southern part of the San Joaquin basin is filled by more than 7000 m of Tertiary marine and nonmarine sediments that bury the downwarped western margin of the Sierra Nevada metamorphic-plutonic terrane. The stratigraphic section is generally thin and predominately continental on the east side of the basin, but it thickens into largely deepwater marine facies to the west. The structure is basically a monocline dipping toward the west, characterized by block faulting and broad, open folds. A major feature of the basin is the Bakersfield Arch, a westward-plunging structural bowing on the east side of the basin. This structure plunges south-southwest into the basin for approximately 25 km, separating the basin into 2 sub-basins. The structural feature is the site of several major oil fields.

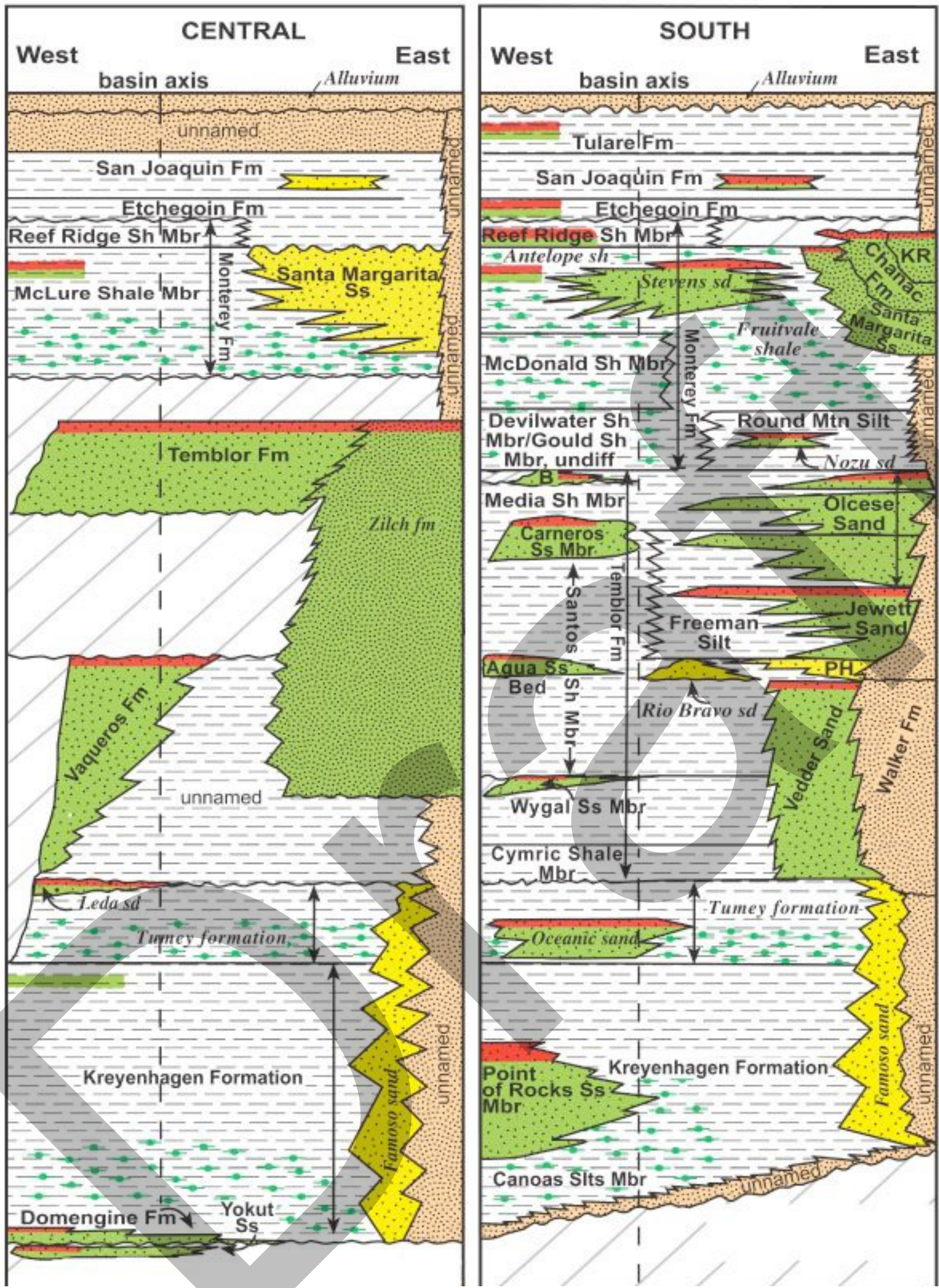


Figure 2. Generalized stratigraphic section for the southern San Joaquin basin (Scheirer and Magoon, 2007).

Because Kimberlina was a candidate site for a Phase III large volume storage test, WESTCARB constructed a regional 3D geologic model of the southern San Joaquin basin encompassing an area within a 50 km radius of the Kimberlina site (Figure 3). This regional model was developed to improve our understanding of the location and character of potential sequestration targets in this part of the basin. This model provides a framework for constructing smaller, more detailed models of potential injection sites. The regional framework model is approximately 84 km x 112 km in size. Mapped geologic units included Quaternary basin fill, Tertiary marine and continental deposits, and pre-Tertiary basement rocks. Detailed geologic data, including surface geologic maps, borehole data, and geophysical surveys, were used to define the geologic framework. Fifteen time-stratigraphic formations were mapped, as well as >140 faults. The free surface is based on a 10 m lateral resolution DEM. Most of the geologic information integrated into this model originated from the oil and gas industry and is now available from the California Division of Oil, Gas and Geothermal Resources (DOGGR). Individual fault data are taken from DOGGR documents on specific oil and gas fields in the basin. Our current understanding of the faulting between the oil and gas fields is poor, and this is an area in which more work is required.

Definition of the lithology and lithologic properties was provided by well logs from a reference well, Kimberlina 1-25 ls. Based on this well, target sequestration formations were identified and capacity estimates were made (Table 3). The Phase III plan was to inject 250,000 tons of CO_2 per year for four years into the saline formations fluids beneath the Kimberlina site. Storage formations identified were the Stevens, Olcese, and Vedder formations at 7,000 ft, 8000 ft, and 9000 ft, respectively. The geology, structure, tectonics, and reservoir properties of this subsurface area are broadly recognized from drilling and production data from nearby oilfields. This geology makes prediction of injectivity, injection-induced pressure increases, brine flow pathways, CO_2 migration, and trapping behavior relatively straightforward, and general effects and potential impacts of the injection of CO_2 can be anticipated. However, the acquisition of seismic survey data will greatly improve subsurface understanding.

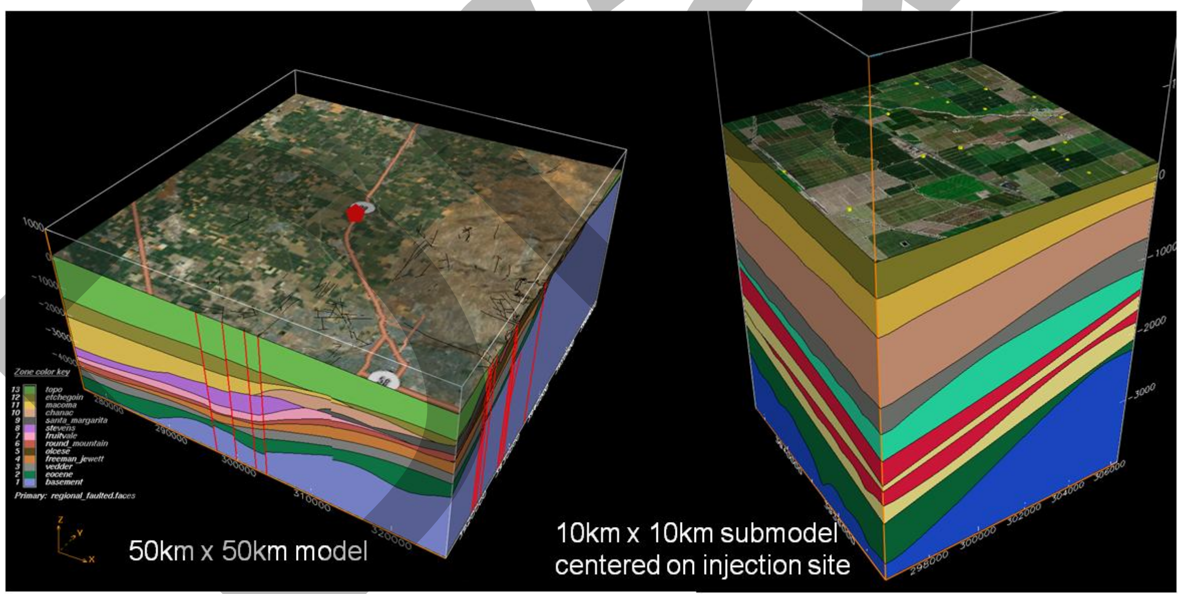


Figure 3. Kimberlina geologic framework model at 50 km scale and 10 km scale showing stratigraphy of southern San Joaquin basin. Well locations used to inform the model are shown as red vertical lines in the lefthand model.

The shallowest injection target is the 400-foot thick Stevens Sandstone located at about 7000 ft depth. The depositional environment for the Stevens is a deep-water fan. Below the Stevens is the Olcese, at a depth of about 8000 ft. The Olcese is a regionally continuous, fluvial-estuarine unit of moderate injectivity. Its thickness at the site is on the order of 800 ft. The lowest unit at a depth of about 9000 ft, is the Vedder, which is also regionally continuous. At the site, the Vedder is a braided stream unit with a thickness of about 500 ft. Thick shale units provide good overlying seals at the site and surrounding areas.

Storage capacity of the target formations were made assuming that 5% of the pore volume contained dissolved fraction CO_2, 8% contained residual phase-trapped CO_2, and 65% was available for free phase trapped by physical processes (seals). Injectivity measures are high (20-300 mD). These initial estimates show a very significant and effective (due to stratal continuity and functional seals) potential in the Kimberlina region of up to 800M tons of CO_2. While the data obtained during Phase II activities and prior data from the literature and from the USGS are sufficient to proceed with confidence, the geological characterization must be considerably refined and risk reduced through the acquisition of seismic surveys.

Table 3. Capacity estimates for Kimberlina formations

Formation	Capacity Type	Capacity (M tonnes CO2)
Vedder	Dissolved & Residual	207
	Physical	715
Olcese	Dissolved & Residual	214
	Physical	739
Stevens	Dissolved & Residual	382
	Physical	1,320
Total	Dissolved & Residual	c. 800
	Physical	c. 2,800

The Sacramento Basin Province is a gas-producing province with 73 gas fields throughout the province and two small oil fields in the southern part of the basin. The Domengine Formation, a late Eocene sandstone, provides most of the gas production in the southern Sacramento Basin; however, other reservoir rocks include sandstones in the Winters Formation, Starkey sands, Mokelumne River Formation, Martinez Formation, Capay Formation, Nortonville Shale, Markley Formation, Lathrop sands, Tracy sands, Blewett sands, Azevedo sands and Garzas sand. Most of these sandstones are of marine origin, ranging in thickness from 4 to 550 ft (1.2–168 m) and having porosities and permeabilities ranging from 10 to 34% and 5 to 2406 milliDarcy (mD; 4.9E-15–2.37E-12 m^2). The DOGGR reports pool data for the Mokelumne River Formation ranging from 31-35% for porosity, 40-45% for water saturation, 55-60% for gas saturations, and water salinity (NaCl) of 14,379 parts per million. Organics in the Winters Shale or Sacramento Shale are suspected of being the source of hydrocarbons for the gas pools within the Winters through the Domengine formations.

These formations are the producing zones for dozens of gas-producing fields in California, including King Island (Figure 4). The cumulative storage capacity of these fields is estimated at 1.7 gigatonnes CO_2. Storage capacity of the largest, the Rio Vista field, is estimated to be over 300 megatonnes CO_2, sufficient to accommodate CO_2 emissions for over 80 years from the nearest large (650 MW) gas-fired power plant. 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 Mokelumne River Formation consists of a series of interbedded sands and shales deposited in a deltaic system. The Molelumne is the producing formation at King Island. The lower Capay Shale was deposited in an outer neritic environment and the upper Capay was deposited in an inner-neritic to brackish water environment, implying a partial shoaling of the basin during the Eocene. The Domengine Sand consists of alternating layers of marine sand and shale with sand being the dominant lithology. The Markley sand is a poorly consolidated deltaic deposit containing interbedded sand and shale (Johnson, 1990). The Eocene sediments are unconformably overlain by approximately 2,000 to 2,300 ft (610–701 m) of Miocene and Pliocene undifferentiated nonmarine strata.

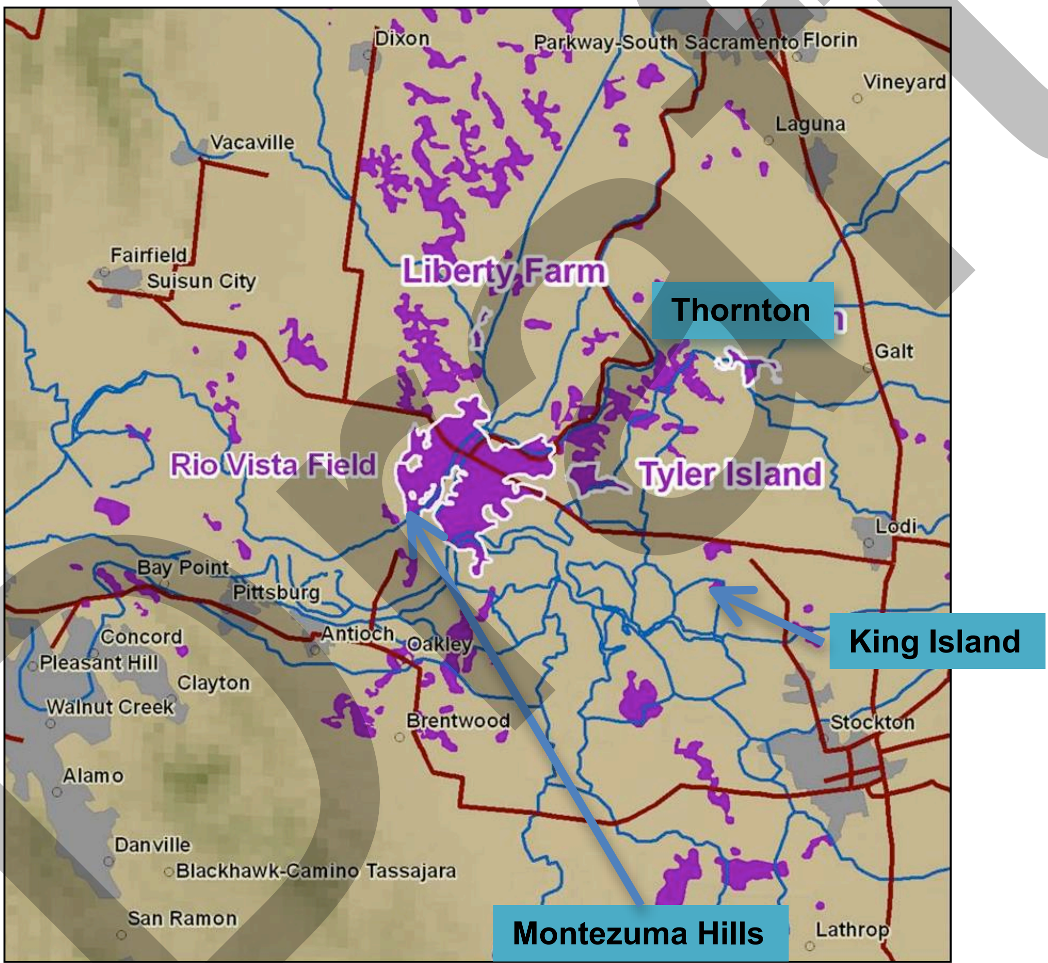


Figure 4. Gas fields of the southern Sacramento-northern San Joaquin Basins and locations of the WESTCARB candidate sites: Thornton Gas Field, King Island Gas Field, and Montezuma Hills area.

Structural and stratigraphic information for King Island is provided by two wells in the King Island gas field and two in the nearby East Island gas field, which provide logging data (Figure 5), and a 3D seismic survey of the King Island field. The King Island field is in a northeast-southwest trending structure with a seal provided by a mudstone-filled gorge cut. King Island Field has produced 10.3 bcf of gas, with an EUR of about 11 bcf (California Department of Conservation—Division of Oil and Gas). Natural gas was produced primarily from the top of the Mokelumne

River Formation. Additional sequestration potential may be present in the overlying Domengine sandstone and the underlying Starkey sandstones.

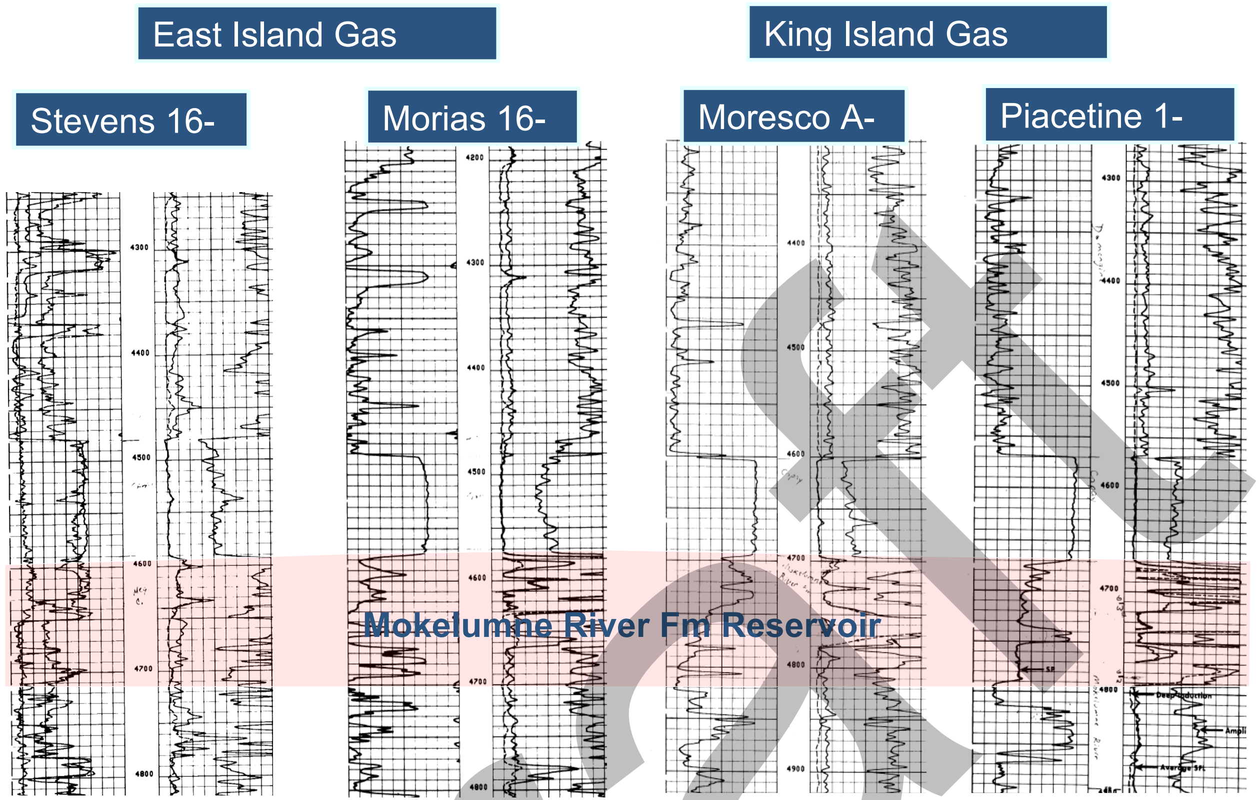


Figure 5. Stratigraphic cross section through East Island and King Island Gas Fields.

The Thornton Gas Field consists of an east-west trending anticline structure with an estimated maximum productive area of approximately five square miles. 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 x 109 m3) of natural gas through the 1980s from approximately 15 now abandoned wells. In Phase II, geologic logs and electrical logs were reviewed by WESTCARB from these wells to look for CO_2 injection intervals within a gas-bearing zone and a saline zone beneath a competent shale layer located below the original gas-water contact (-3,360 ft; -1,024 m) (Figure 6). Estimated depth to the bottom of the shale unit is 3410 ft (1039 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 (4.5E-14–1.65E-12 m2) and porosities ranging from 26.5 to 28.8% for the sands in the upper Mokelumne River Formation. Geologic logs 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.

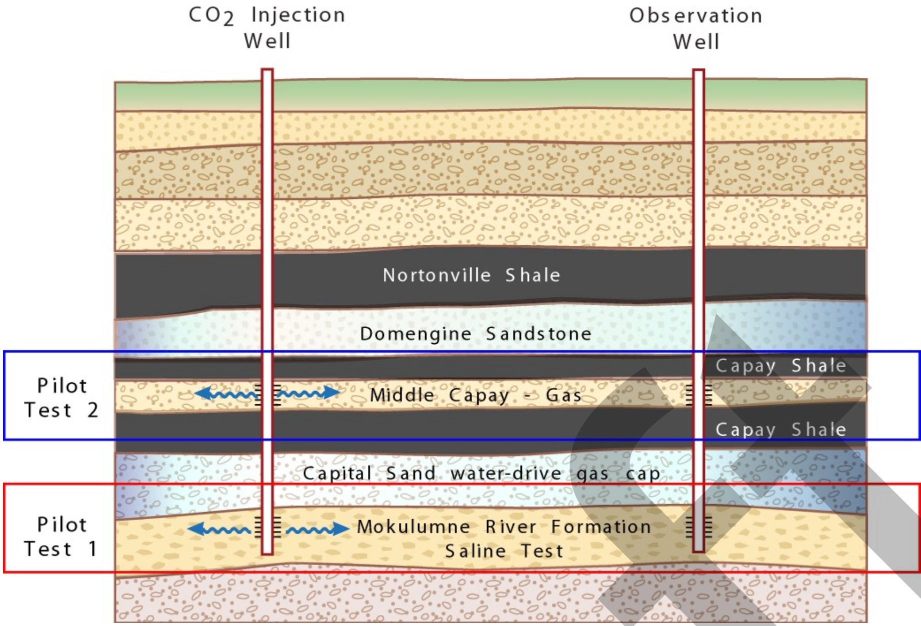


Figure 6. Proposed pilot test configuration for Thornton when it was a potential Phase II injection pilot site, with injection planned in the gas-bearing and saline units. The stratigraphy shown is equivalent to the upper section that will be drilled and sampled at King Island.

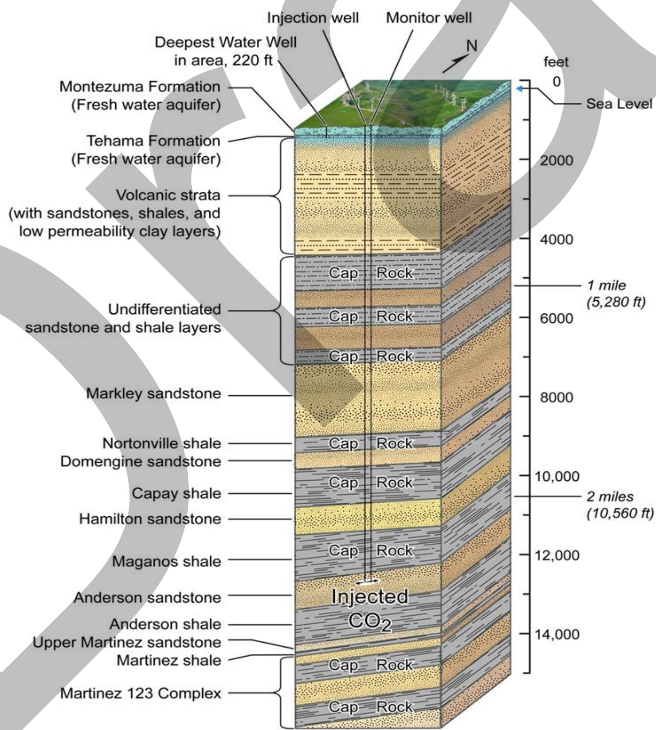


Figure 7. General Stratigraphy at the Montezuma Hills site. The Domengine, Capay and Maganos are present, but are significantly deeper than to the east at the King Island and Thornton sites.

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 bottom hole pressures, and the natural gas was assumed to be ideal and flowing under isothermal conditions. Therefore, the permeability value of 4 mD (4E-15 m2) determined using this approach should be considered a rough estimate of the Capay's true 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 7). A characterization well at Montezuma Hills would have required 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 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 trend or 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 Tertiary 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/year (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 synclinal. 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 DOGGR structural contour map of the top of the Capital Sand in the Thornton field and these faults are located outside 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 Phase II 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 a 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 miles 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 miles (10 km) and 10 miles (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 site of microearthquakes as large as magnitude 3.7 over the past 32 years. Most of these small events occurred 9-17 miles (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 injection well, the azimuth of the mean maximum horizontal stress is estimated at 41° and it is consistent with strike-slip faulting on the Kirby Hills Fault, 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.

The Phase II pilot would have injected about 6000 metric tons of CO_2 at about two miles depth. This injection would result in a reservoir fluid pressure increase greatest at the well and 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 metric tons 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 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.

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, 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, provided the acoustic source. The source spacing and group interval were both 220 ft. The spread was eight lines with 120 channels each, for a total of 960 channels. The sample rate was two ms down to eight s. Two companies processed the data, producing numerous versions of the volume. Processing parameters include DMO gathers, DMO, migration, spectral whitening, TVF, FXY, and trace equalization by Matrix Geophysical; and prestack migrated gathers and an enhanced migration (DMO prestack) 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 8) (May et al., 2007).

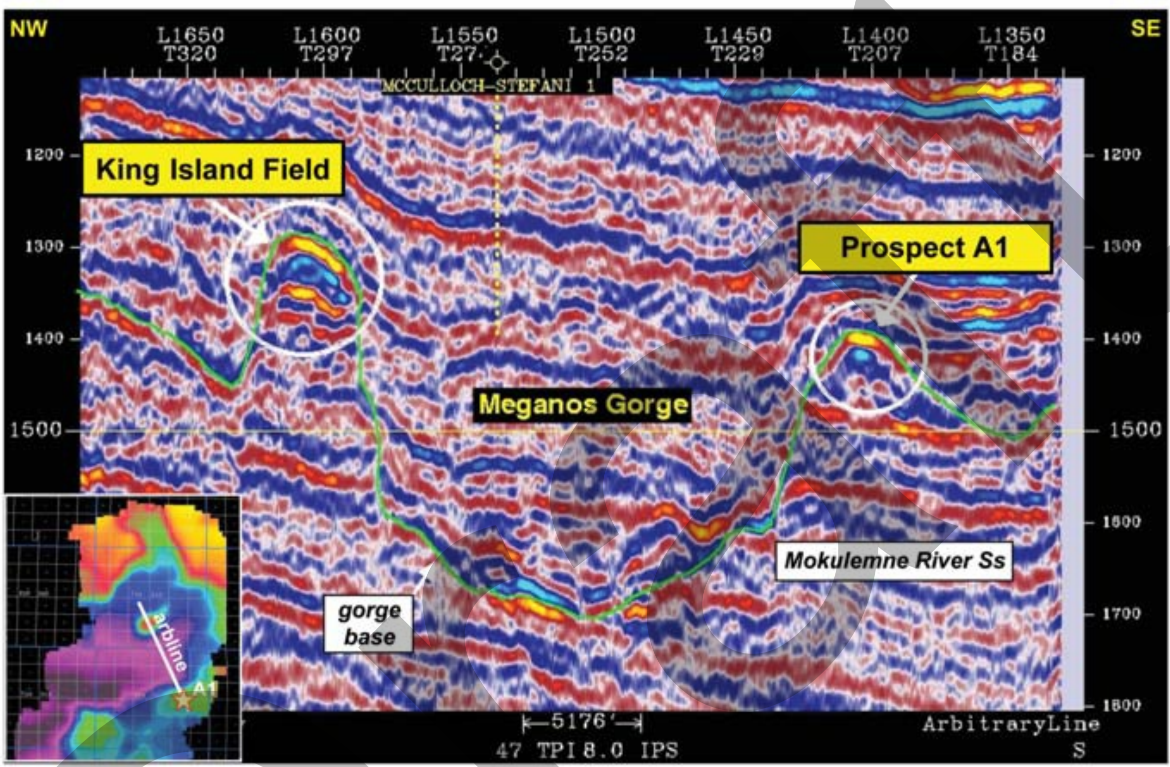


Figure 8. Seismic line extending from King Island gas field across the Meganos stratigraphic gorge to another potential gas play in the region (also shown on the inset map). In this variable-density display, the seismic troughs are presented in red, grading though white at the zero crossing, with the peaks in blue. The strongest trough amplitudes are highlighted in yellow and the strongest peak amplitudes are in cyan. From May et al, 2007.

Because of the availability of the three-dimensional seismic survey data, WESTCARB decided that pursuing the subtasks to obtain additional seismic data through purchase or new shoots was unnecessary as part of the down-selection process to determine a well location or deviation at the King Island site. In this respect, King Island outranks the Kimberlina site where three dimensional seismic data are lacking. The specific site for the King Island well location is constrained by surface issues rather than subsurface, and the seismic data were included in the data used in well planning to determine the optimum drilling angle to intersect the formations of interest. 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 will be addressed after the data from the well have been analyzed and during construction of the simulation models.

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, 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 sub-basin 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 older 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 sub-basin 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 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 (California Department Water Resources 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.

3.2 Nontechnical/Logistical Criteria

Nontechnical and logistical issues proved to be the critical risk elements in WESTCARB's Phase II and Phase III pilot test projects. 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. Subsequently, C6 Resources, LLC, a Shell Oil Company subsidiary, approached WESTCARB about the possibility of performing a pilot test at another site in the Montezuma Hills, but also subsequently withdrew from the project for business reasons. For Phase III, WESTCARB collaborated with Clean Energy Systems (CES) in preliminary characterization of the Kimberlina site, but business reasons also precluded CES from continuing as a WESTCARB 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 (6000 metric tons) CO_2 injection pilot to a Phase III large volume (several 100,000 metric tons) injection project to a commercial-scale (1 million tons per year). Outreach activities and permitting applications were pursued successfully for the 6000 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.

Due to such nontechnical factors, WESTCARB does not have site access to Thornton or Montezuma Hills, so neither of these sites currently pass the criteria for a characterization well project in Phase III. CES has agreed verbally to provide site access to Kimberlina for WESTCARB to drill a characterization well. This site was determined to be suitable as an alternate site for a characterization well project.

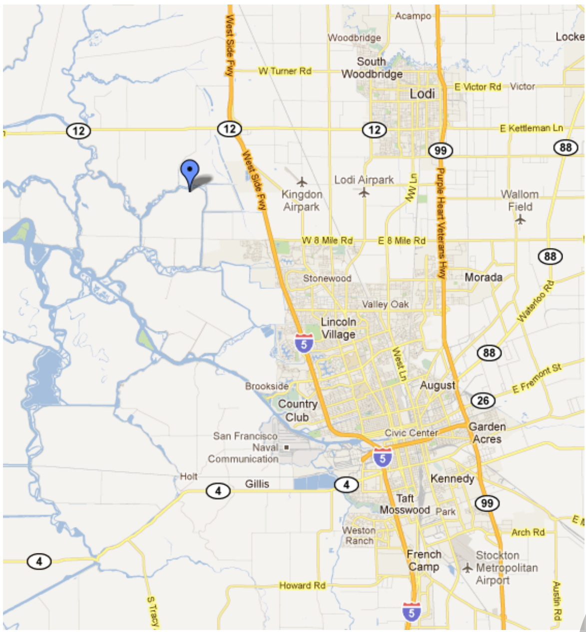
At King Island, WESTCARB has site access permission from both the well and mineral rights owner and, through that company, the land owner. The mineral rights beneath the King Island site and the well are owned by WESTCARB's key collaborator (Princeton Natural Gas), who is providing free access to the well and the rights. The landowner has given permission to access the extant well pad, which is on un-improved, private roads.

King Island is "drill-ready" in that it has existing gas wells, well pads and access roads, and is in a rural agricultural area. The Kimberlina site is located at the CES power plant facility, in a rural agricultural area, but is not "drill-ready."

The mineral rights and well owner has procured the drilling permit at his own expense and has taken the legal liability for the well. The owner will also assume ownership and responsibility for the well after completion of the WESTCARB project.

In the area near King Island, demographic highlights from the 2000 U.S. Census indicate that the population is about 50% Hispanic or Latino, 45 % White, 3% Asian, 2% Black or African American, and <1% American Indian and Alaska Native. The King Island site is located west of the Interstate 5 and south of Kettleman Lane (State Highway 12). The nearest communities are Stockton (290,000), about 8 miles away, and Lodi (63,000), about 5 miles away (Figure 9). The immediate vicinity is a rural area. The Thornton site is approximately

23 miles north of Stockton, but only two miles north of the unincorporated town of Thornton California, (population 1467). It is about 12 miles north of the King Island site.



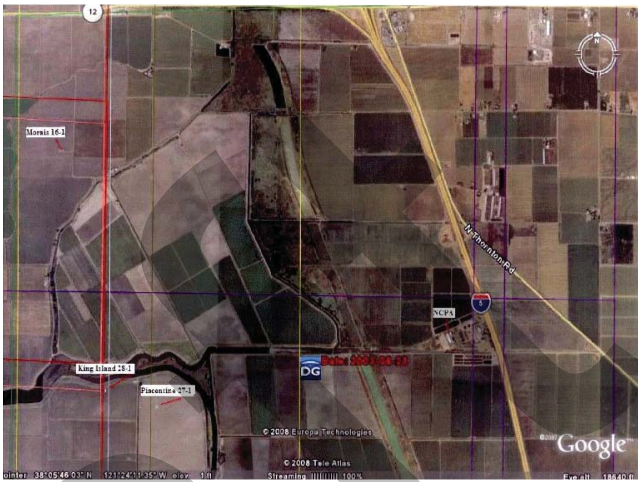


Figure 9. Map and aerial photograph of King Island area showing Stockton and Lodi, Interstate 5, and surrounding agricultural areas. The location of King Island (marked at blue balloon on the map) is northwest of the city of Stockton and southwest of Lodi, close to the Interstate 5. King Island is an island which was formed during the dredging and channeling of the Sacramento-San Joaquin Delta into a system of sloughs for agriculture and flood control over the last 150 years.

The King Island site is at an elevation of minus 6 ft below mean sea level. The site is located within the Sacramento River drainage basin, which joins the San Joaquin River (which drains the southern part of the Central Valley) to form the Sacramento-San Joaquin River Delta system. The project site is located in a low-lying area protected by levees that have been installed along the rivers to prevent the property from flooding during winter and spring, when peak precipitation and surface runoff occur.

The King Island well will be drilled as a deviation in order to take advantage of an existing well pad from an operational but no longer productive well, the Source Energy Corporation's "King Island" 1-28 well (Figure 10 and lower left of aerial photo in Figure 9). There are no residences anywhere near the well pad and the surrounding fields are planted in bell peppers, corn or fruit trees. The existing well pad is 240 ft by 120 ft. This is more than sufficient space to accommodate well operations without any need for new surface construction. All facilities for fueling, waste storage tanks, power generators, and so on, will be brought by trailer to the site for temporary use during the project and will fit within the footprint of the existing well pad. The well pad is accessible by all equipment by existing private and levee roads.

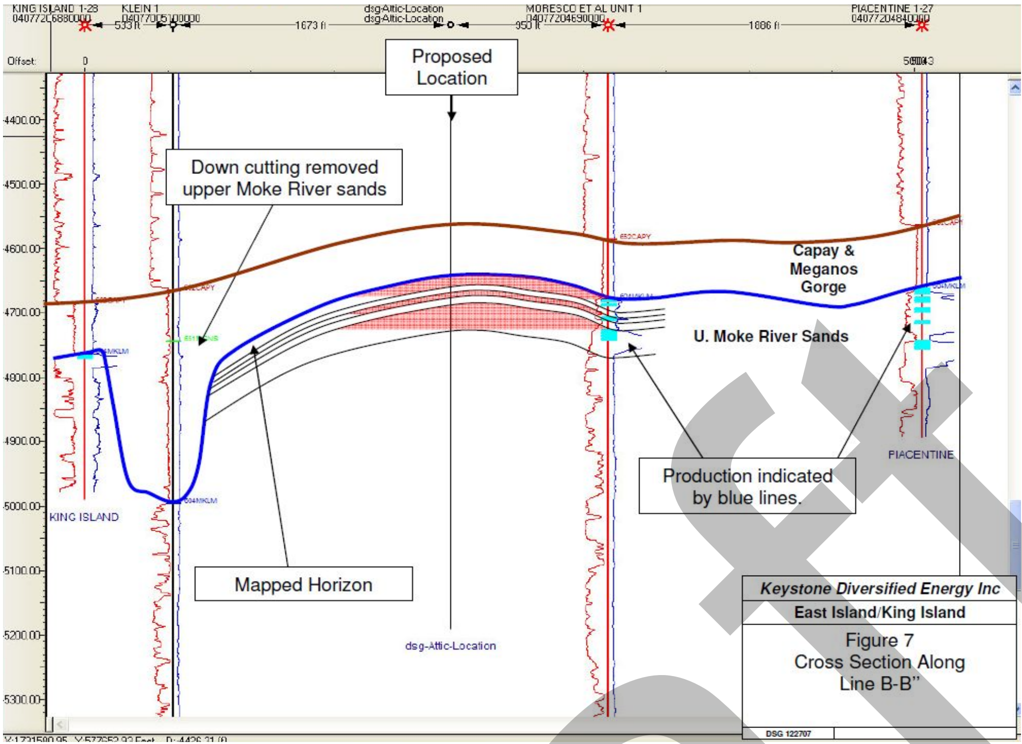


Figure 10: Cross-section of the East Island-King Island gas fields showing inferred formation tops from resistivity logs of several gas wells within these fields. The proposed characterization well site is shown as a vertical well, however, to avoid surface disturbance, the project team decided to drill a deviated well to utilize and existing well pad and well head.

Permitting has been facilitated at the King Island site by the well owner. A California DOGGR permit for drilling the characterization well was obtained. DOGGR has developed regulations governing the drilling, disposition or abandonment of oil, gas, geothermal, and injection wells in compliance with CEQA, NEPA and EPA UIC regulations as applicable. The California Code of Regulations specifies the requirements.

The well is permitted to a target depth of 8,500 ft (2,500 m). A service rig will be deployed to pull old casing over the interval necessary for subsequent deviated drilling (approximately 500-700 ft) and to plug back the existing well. The integrity of the cement plug and the surface casing (0 to 500 ft) will be tested in compliance with DOGGR permitting requirements.

WESTCARB was unable to pursue a large volume test at the Kimberlina site because CES could not complete construction of the power plant that would have provided the CO_2 for the large-volume test planned in time. However, the site passes the geologic and geographic criteria and non-technical/logistical criteria to be a characterization site. Seismic data would likely be required to better establish any faulting in the area, as noted above.

4.0 Scientific Objectives

WESTCARB technical staff and scientists at LBNL worked to assure that the down-selection process resulted in a well site and test plan that would be able to meet the scientific objectives for the Phase III characterization well projects. Even though CO_2 injection in the field is not part of the Phase III project, a test plan was developed to include field measurements, sample collection, laboratory measurements and testing, and development of simulations that could be used to provide information about the formations' suitability for a large volume CO_2 storage project.

Both core samples from gas-bearing and saline units will be collected at King Island. These samples will undergo laboratory testing at LBNL to obtain some of the information about CO_2-rock interactions that would have been gathered through field tests. While field tests are arguably the only method for testing and verifying monitoring techniques, LBNL will be able to perform some laboratory tests on the King Island samples to test petrophysical responses to injected CO_2 which will contribute critical information to developing some new monitoring tools.

The scientific test plan developed for Thornton included CO_2 injection under Phase II. The plan for the Thornton site called for two wells to be installed, perforated, and utilized for both pilot tests. One of the wells was to be used as a CO_2 injection well and the second as an observation well. Both wells were to be drilled from a single drill pad at land surface to a maximum depth of 4,000 ft (1,220 m). Drill core was to be collected during drilling for subsequent off-site testing and mud logging was to be conducted on-site for each hole to provide input to a site geologic conceptual model. Open and cased well logs were to be run to further characterize site geology and to determine reservoir conditions and parameters. Baseline site characterization activities were to consist of geophysical measurements, pressure-transient testing, and baseline monitoring of reservoir fluid composition, reservoir static pressure and temperature, shallow groundwater quality and water level, and leak detection around a now-abandoned nearby gas production well. Upon completing the baseline activities, up to 2,000 tonnes of CO_2 were to have been injected into the saline formation at an anticipated depth of 3,400-3,500 ft (1,035-1,065 m) (Pilot Test 1). The injection period would be approximately 10-14 days in duration with a series of measurements performed to track the spread of CO_2 as it moves through the formation. Post-injection monitoring of the horizontal CO_2 plume would be conducted for a three-six month period following injection to look for CO_2 leakage from the saline formation into overlying formations and to track the movement of the buoyant CO_2 after injection ends. The well perforations were to be cemented shut after the saline formation pilot test was completed and new perforations shot through the well casing across the targeted gas reservoir in preparation for the gas reservoir pilot test (Pilot Test 2). Up to 2,000 tonnes of CO_2 were to be injected into the gas reservoir at an anticipated depth of 3,045-3,050 ft (~930 m). Again, the injection period would be approximately 10-14 days in duration. Monitoring of CO_2 was to be repeated for the gas reservoir to characterize and track CO_2 movement over a second three-six month period. Commercial grade, manufactured CO_2 was to be trucked in and used for both pilots. Upon completion of the project, the wells were to be abandoned in accordance with California State law and the site restored.

The King Island characterization well will provide core and fluid samples from the same zones that were identified for the Phase II pilot injections at the Thornton site as well as additional zones at greater depths. Fluid sampling and analysis of deep and shallow hydrocarbon and aqueous gas and liquid phases will be useful to establish whether flow paths exist from the deep subsurface to shallower formations. Fluid analyses may include bulk composition, trace gases, and isotopic composition to establish relationships between the fluids, their origins, and their ages. Shale cap rock and storage sandstones will be included in the coring program. The samples will be transported to laboratory test facilities at LBNL where CO_2 injection tests will be done to provide data on CO_2-rock-fluid interactions at the core scale, to provide data for geohydrologic simulations of CO_2 fate and transport, and to inform development of new monitoring techniques. At Sandia National

Laboratory, shale samples will be tested to improve understanding of the geomechanical behavior of cap rocks. Other samples will be analyzed at commercial laboratories to acquire specific data to inform simulation activities. Part of the research outcome of the King Island studies will be to improve understanding of the scalability of laboratory and field logging data.

In addition, earth science researchers at LBNL will use sophisticated numerical codes, TOUGH2 and TOUGHREACT, for modeling the movement of fluids in geologic formations (Pruess, 2004; Xu et al. 2006). Simulation of the CO_2 injection and storage based on detailed site-specific hydrogeological models will be performed. The well constrained stratigraphy and structure from nearby wells and seismic surveys, multiple stacked sands, including gas-bearing and saline zones, and the acquisition of a robust set of petrophysical and geochemical data from the characterization well logs and samples will allow for a significant simulation effort. A geologically realistic mathematical model of the multiphase, multi-component fluid flow produced by CO_2 injection is indispensable for determining the viability of a potential storage site, because capacity and trapping ability are both strongly impacted by the coupling between buoyancy flow, geologic heterogeneity, and history-dependent multi-phase flow effects, which is impossible to calculate by simpler means. Modeling may also be used to: 1) optimize CO_2 injection by assessing the impact of various rates, volumes, and depths; 2) choose monitoring sensitivity and range by providing the expected formation response to CO_2 injection; and 3) assess the state of understanding by comparing model predictions to field observations.

LBNL also will undertake a preliminary leakage risk assessment for King Island. Such an assessment was performed for the Montezuma Hills and Kimberlina sites using the Certification Framework methodology. In the absence of a long track record, leakage risk assessment methods are needed to address concerns by the various stakeholders about the effectiveness of CO_2 trapping and the environmental impacts resulting from CO_2 injection. For the last two years, investigators at the LBNL, the University of Texas at Austin (UT), and the Texas Bureau of Economic Geology (TBEG) have been developing a framework called the Certification Framework (CF) for estimating CO_2-leakage risk for GCS sites. Risk assessment methods such as the CF rely on site characterization, predictive models, and various methods of addressing the uncertainty inherent in subsurface systems. The King Island dataset can be used to perform sensitivity analyses of the CF.

5.0 Conclusions

The down select history for the California characterization well (Task 7) incorporates new information as well as substantial site information WESTCARB compiled during its attempts to find locations for its Phase II pilot injection well and Phase III large volume storage tests. Locations generally passed geologic and geographic criteria, but failed to meet nontechnical/logistical criteria.

King Island was selected as the best site to meet site down-select criteria and the scientific objectives of the project. Kimberlina was selected as a back-up.

King Island.

WESTCARB has been in discussions with a gas operator in the southern Sacramento Basin since about 2006. The King Island Gas Field, near the Thornton site, would permit characterization of both the gas-bearing and saline formations of importance in the southern Sacramento-northern San Joaquin Basin. The general geology of the site is very similar to the original Thornton site, which lies 12 miles 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. Thus, King Island is the best site at meeting the geologic and geographic criteria outlined by the down-select process.

The site is located within a couple of miles of U.S. 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 serving power to these areas and to industrial sources such as Bay area refineries. The site presents no problems with regard to site access. WESTCARB will be able to use an existing as well as a re-entry point to drill a deeper well so that WESTCARB activities can be performed without new surface construction or disturbance, saving budget for the scientific program and streamlining permitting with the California DOGGR , CEQA, and NEPA.

Kimberlina

An alternate site was identified in the southern part of the San Joaquin Valley, near Bakersfield, in the oil-bearing part of the state. A geological assessment, construction of a static geomodel, dynamic simulations, and a thorough risk assessment were undertaken for this site because it was a strong candidate for a Phase III LVST. Given the lack of seismic data specific to the Kimberlina area to constrain structure and the greater general availability of data surrounding Kimberlina in the oil-producing areas because of extensive oil exploration and production nearby, it was felt that at this time, Kimberlina would not be our top choice for a characterization well.

Because of a lack of industry matching funds to provide a CO_2 source, however, this site could not be implemented as a primary candidate for a small-scale CO_2 injection test or LVST. The industry partner also is reconsidering its interest in CCS development at the Kimberlina site since it has acquired another site for some of its CCS-relevant operations recently so it does not rank as highly as a potential early commercial CCS opportunity.

Thornton

The original site selected for the Northern California Pilot Storage Test Phase II project, for which a test scale CO_2 injection was planned, was near Thornton, California. 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, 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 gigatonnes CO_2.

The proposed site was about two miles north of the unincorporated town of Thornton California, (population 1467), so it is less isolated from residences than the King Island site. However, the industry partner for this project was unable to proceed with the Phase II project, and WESTCARB did not re-establish access to the site for a characterization well.

Montezuma Hills

A second industry partner offered to partner with WESTCARB on the Northern California Pilot Storage Test Phase II project, but in this case C6 Resources determined the precise location based mostly upon their extensive proprietary subsurface geological analysis. This site was in the Montezuma Hills, approximately 20 miles northwest of the Thornton site and 15 miles west of the King Island site. This site lay on the west side of the Central Valley and was structurally somewhat different than the Thornton site. However, this site would have suited WESTCARB's scientific objectives, although target formations are considerably deeper and therefore more expensive to drill.

C6 was responsible for procuring access rights and all state and county permits, which were submitted. Unfortunately, C6 made a decision to withdraw from pursuing CCS projects in California in 2010 in this area. The easement on the site remains with C6, and cannot be used by WESTCARB to drill a characterization well.

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