California CO_2 Storage Assurance Facility Enterprise (C2SAFE)

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Principal Investigator: Robert C. Trautz

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Name and Address of Submitting Organization

Electric Power Research Institute
3420 Hillview Avenue
Palo Alto, California, 94304

Prepared by
Electric Power Research Institute
3420 Hillview Avenue
Palo Alto, California, 94304

DISCLAIMER

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The following organizations were involved in the preparation of this report:

Clean Energy Systems, Inc.
3035 Prospect Park Drive, Suite 120
Rancho Cordova, California 95670

Contributors
R. Hollis
J. Perron
K. Pronske

California State University Bakersfield
64 SCI, 9001 Stockdale Highway
Bakersfield, CA 93311

Contributors
D. Saini

Electric Power Research Institute
3420 Hillview Ave.
Palo Alto, CA 94304

Contributors
L. Chiaramonte
J. Swisher
R. Trautz, Principal Investigator

Frontier Energy
1000 Broadway #410
Oakland, CA 94607

Contributors
R. Myhre
M. Stone

Lawrence Berkeley National Laboratory
1 Cyclotron Road
Berkeley, CA 94720

Contributor
P. Jordan

Lawrence Livermore National Laboratory
P.O. Box 808, L-052
Livermore, CA 94551

Contributor
J. Wagoner

Sempra Energy Utilities; Southern California Gas Co.
555 West 5th Street
Los Angeles, CA 90013

Contributor
R. Kent
P. Bauer

EXECUTIVE SUMMARY

The California CO_2 Storage Assurance Facility Enterprise (C2SAFE) project, led by the Electric Power Research Institute (EPRI), has conducted a preliminary study into the feasibility of a commercial-scale carbon dioxide (CO_2) storage complex located in the southernmost portion of California's Central Valley. The work represents the first phase of a multi-phased development approach outlined by the United States Department of Energy's (DOE's) Carbon Storage Assurance and Facility Enterprise (CarbonSAFE) program meant to develop carbon storage sites capable of permanently storing 50 million metric tonnes of CO_2, or greater, injected over a typical facility life of 20 to 30 years.

Project work was conducted across several tasks including: CO_2 source characterization and capture techno-economics, sub-basin storage assessment and storage economics, pipeline routing, scenario analysis, and preliminary site screening/risk assessment. This report represents the culmination of work performed under C2SAFE and outlines a phased implementation plan for large-scale, industrial carbon capture and permanent storage in California's Southern San Joaquin Valley (SSJV). The report is meant to be a standalone document and as such provides high-level summaries of all tasks of the project, but is also meant to complement the other three topical reports issued by the project – reports referenced herein.

The study considered multiple scenarios including an east-side storage facility, a west-side storage facility, and potential multi-site storage facilities. The east-side storage facility is to be located at Clean Energy Systems, Inc.'s (CES's) Kimberlina Power Plant (KPP), or nearby, and the west-side facility will be located at the California Resources Corporation's (CRC's) Elk Hills oil field. The majority of carbon emissions are planned to be captured from existing sources and transported to the selected and verified storage site(s). Capture from the single closest source to the eastern storage facility and the sources within the Elk Hills field would meet the CarbonSAFE storage goal of 50 million tonnes. The study has shown there is sufficient storage capacity to meet this requirement and more; thus, capture from any of the numerous additional large nearby sources would substantially leverage the CarbonSAFE investment. A comparison of preliminary CO_2 capture, transportation, and storage costs to economic value and incentives in the state shows current market conditions make it economically feasible to develop large-scale industrial storage sites in California's SSJV.

The business case for Carbon Capture and Storage (CCS) in California's SSJV appears economically viable today for large CO_2 point sources involved in the production of transportation fuels, such as oilfield cogeneration units and steam boilers. The overall levelized CCS cost is estimated at roughly $125 per tonne of CO_2, which includes CO_2 amine-solvent post-combustion capture, transportation, and storage. The levelized CO_2 capture cost is based on today's technology, with no future cost reduction factored in for technology improvement. The sum of the value of incentives and revenue from California Low Carbon Fuel Standard (LCFS) credits (discounted roughly 20% from their current transaction value), sale of California cap-and-trade emission allowances, and Section 45Q tax credits—either for saline storage or the Enhanced Oil Recovery (EOR) credit plus CO_2 sales revenue—is about \$165/tonne-CO_2.

The economic viability of CCS for Natural Gas Combined Cycle (NGCC) power plants in the SSJV is more site-specific. A plant providing power solely to the electric grid, if it added CCS, should be eligible for Section 45Q tax credits and could sell its excess cap-and-trade emission allowances, but it would not generate LCFS credits. Using the cost and incentive values detailed in this report, it would not be economical for such a plant to add CCS today, barring other considerations. An NGCC plant within an oilfield (e.g., CRC Elk Hills and NRG Sunrise) that provides power to the oilfield as well as to the grid should receive "partial credit" in terms of generating LCFS credits if it added CCS (pro-rated for the fraction of power going to the oilfield). Such a plant should also be eligible for Section 45Q tax credits and garner revenue from selling its excess cap-and-trade emission allowances. Using the cost and incentive values described in this report, the economic viability of adding CCS today would depend on the relative fractions of electricity supplied to the oilfield and the grid. As the value of cap-and-trade emission allowances grows over time (either by market forces or the escalating floor price), the relative fraction of power needing to remain in the oilfield to achieve "breakeven" would diminish. At some point, even plants providing all of their power to the grid would be candidates for economical CCS application.

The C2SAFE team has proposed to expand upon the knowledge gained during this study by conducting a detailed feasibility assessment under a follow-on phase of the program, Phase II – Feasibility. This would include detailed data collection at the two sites, analysis, reporting, stakeholder outreach, and risk mitigation activities to support the development of a commercial carbon storage complex in the SSJV.

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NOMENCLATURE

BECCS	Biomass Energy combined with Carbon Capture and Storage
BEST	Brine Extraction Storage Test; EPRI project
BioCCS	Biomass industrial process with Carbon Capture and Storage
BOE	Barrels of Oil Equivalent
C2SAFE	California CO_2 Storage Assurance Facility Enterprise; EPRI project
CARB	California Air Resources Board
CarbonSAFE	Carbon Storage Assurance Facility Enterprise; DOE program
CCS	Carbon Capture and Sequestration
CCUS	Carbon Capture Utilization and storage
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CES	Clean Energy Systems, Inc.
CHP	Combined Heat and Power (plants)
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CRC	California Resources Corporation
CSUB	California State University Bakersfield
DOE	United States Department of Energy
DOGGR	California Division of Oil, Gas, and Geothermal Resources
EGU	Electricity Generating Unit
EIA	United States Energy Information Administration
EJ	Environmental Justice
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency
EPIC	Electric Program Investment Charge; California Energy Commission program

EPRI	Electric Power Research Institute
GGRF	Greenhouse Gas Reduction Fund; California program
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
HRSG	Heat Recovery Steam Generator
KPP	CES' Kimberlina Power Plant
LBNL	Lawrence Berkeley National Laboratory
LCFS	California Low Carbon Fuel Standard (for fuels used in the transportation sector)
LLNL	Lawrence Livermore National Laboratories
NATCARB	National Carbon database
NEPA	National Environmental Policy Act
NETL	DOE's National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle (power plants)
NGO	Non-Government Organizations
NRAP	National Risk Assessment Partnership
OTSG	Once-Through Steam Generators
PIER	Public Interest Energy Research
POGG	Pressurized Oxy Gas Generator
RNG	Renewable Natural Gas
ROW	Rights-of Way (typically referring to pipeline routings)
SoCalGas	Southern California Gas Company (a Sempra Energy Utility)
SSJV	Southern San Joaquin Valley
Tonne	Metric ton = 1,000 kg
UIC	Underground Injection Control; US Environmental Protection Agency permit
USDW	Underground Source of Drinking Water
WESTCARB	West Coast Regional Carbon Sequestration Partnership

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INTRODUCTION

California represents a unique confluence of the required attributes necessary to make commercial carbon capture, utilization and storage (CCUS) projects technically and economically feasible. Specifically, California offers:

1. Highly-developed energy and transportation sectors,
2. Major oil and gas reserves, most significantly in the SSJV (Kern County),
3. Large potential for onshore (and offshore) carbon storage,
4. Robust carbon pricing and trading network, and
5. Strong government support and commitment to a low carbon future.

Many of these items, or the combination thereof, are not found anywhere else in the world, and significantly improve the C2SAFE project's likelihood of success.

1.1 Project Summary and Goals

The C2SAFE project team consists of multiple private and public organizations with a common vision of developing commercial-scale CO_2 CCUS projects that can store greater than 50 million metric tonnes of CO_2 emitted by one or more industrial facilities in the SSVJ, California (Figure 1–1) over decadal time scales. C2SAFE's vision for the Phase I (pre-feasibility) study included identifying storage hubs on the east and west sides of the SSJV where numerous CO_2 sources are located and the emissions could be safely aggregated together and stored at a common location, phased-in over time. Excepting the greater Bakersfield metropolitan area, the flanks and center of the valley are mostly rural, supporting farming, ranching, and oil and gas operations central to the economy of Kern County.

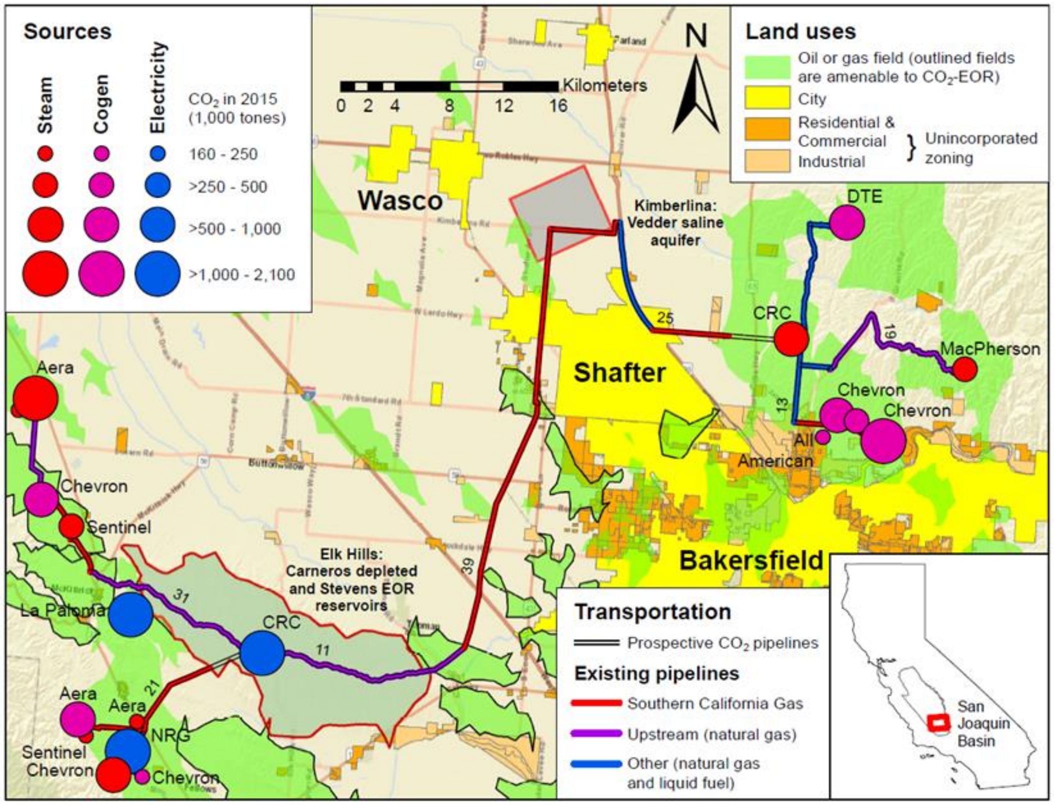

Figure 1-1
Map of the Kimberlina and Elk Hills CO_2 Storage Complex Locations, Major CO_2 Point Sources, Select Land Uses, and Potential Pipeline Routings within the SSJV

C2SAFE has teamed with two industrial site hosts on the east and west sides of the SSJV (Figure 1–1) who have committed to assessing the feasibility of developing CO_2 storage hubs at their facilities – work to be conducted during the second phase of the project. The Clean Energy Systems feasibility study site is located on the eastern side of the valley at the Kimberlina Power Plant and the California Resources Corporation feasibility study site is found on the western side at the Elk Hills Oilfield. Should one of the site hosts decide at a future date not to pursue the opportunity further, or through exploration the geology is found not to be suitable for safe, reliable storage, then C2SAFE has a backup site for continued development.

C2SAFE project development plans to follow the four-phase approach outlined by the DOE's CarbonSAFE program (Figure 1–2). The four phases include:

Phase 1—Integrated CCS Pre-Feasibility (2017–2018)

- Focused on high-level technical and economic analyses of a large-scale commercial carbon storage complex in California's SSJV, team formation, and planning.

Phase II—Storage Complex Feasibility Study (Proposed 2018–2020)

- Characterization wells at the Kimberlina (east-side) and Elk Hills (west-side) sites, and the identification and solutions for regulatory and contractual requirements

Phase III—Site Characterization (2020–2022)

- Detailed characterization needed to qualify site(s) to apply for U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class VI permits, National Environmental Policy Act (NEPA)/California Environmental Quality Act (CEQA) determinations, and other legal and regulatory filings.

Phase IV—Permitting and Construction (2022–2025)

- Final work before commercial operation; analytical models updated, permits submitted and obtained, Class VI injection and monitoring wells installed.

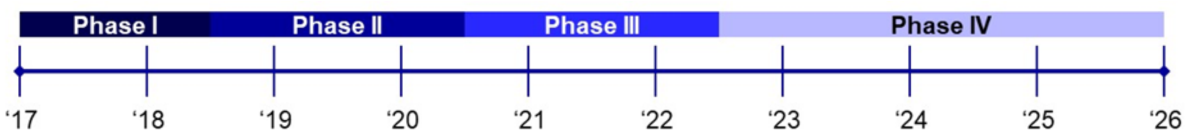

Figure 1-2
C2SAFE Project Implementation Timeline by Phase

1.2 Project Team

During Phase I, C2SAFE assembled a large team of expert scientists and engineers from a research institute (EPRI), national laboratories (Lawrence Berkeley National Laboratory, LBNL, and Lawrence Livermore National Laboratories, LLNL), academia (California State University Bakersfield, CSUB), government (California Division of Oil, Gas, and Geothermal Resources, DOGGR), a technology provider (CES), an energy company (CRC), subsurface service companies (Geostock Sandia and Schlumberger), and an energy analysis consultancy (Frontier Energy), all committed to seeing CCS deployed on a commercial scale within California.

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SCENARIO ANALYSIS

During Phase I, the C2SAFE project evaluated four commercial-scale carbon capture and storage (CCS) scenarios in California's SSJV to serve existing and future CO_2 industrial emission point sources:

1. East-side hub – Clean Energy Systems (CES) Kimberlina Power Plant (KPP) site
2. West-side hub – California Resources Corporation (CRC) Elk Hills oil field
3. Linked east-side and west-side hubs (by trunk pipeline)
4. Dispersed source/sink model (i.e., injection at or very near each major CO_2 point source)

The scenarios are not mutually exclusive, and the C2SAFE team believes some combination of the options would be best suited for the SSJV. The C2SAFE Phase I screening analyses found only the fourth option, distributed CO_2 storage directly beneath or near each major point source, to be problematic, because storage-suitable formations beneath point sources in the eastern portion of the SSJV are too shallow for dense-phase storage and most point sources in the western portion of the SSJV overlie undesirably complex geologic structures resulting from proximity to the San Andreas Fault.

Instead, under scenario 1, an east-side storage facility would start with CO_2 injection from a small point source located on the CES' KPP site. A considerable number of large-scale emitters, mainly used for heavy oil production, are located in the eastern SSJV foothills (Figure 1–1). CO_2 could be captured at these sites and transported via pipeline to the eastern valley floor (e.g., the Kimberlina site), where shale-sealed sandstone strata are sufficiently deep to provide storage. The primary saline storage target at Kimberlina or other nearby east-side injection locations is the Vedder Formation, with the Olcese Formation as a backup target. These formations have been extensively geomodeled by Lawrence Livermore National Laboratory (LLNL), with various CO_2 injection simulations conducted by LBNL. Kimberlina was a focus site for many studies, including the DOE National Energy Technology Laboratory's (NETL's) National Risk Assessment Partnership (NRAP), West Coast Regional Carbon Sequestration Partnership (WESTCARB), and California Energy Commission (CEC) funded studies. Proposed Phase II work will install a stratigraphic (or Class II) well at Kimberlina to investigate the dynamic storage capacity, injectivity, residual trapping, and compartmentalization of both the Olcese and Vedder formations as potential CO_2 storage reservoirs.

The C2SAFE west-side SSJV location in the Elk Hills is vast, remote from other land uses, and well understood given its long history as a major oil and natural gas producing field and naval petroleum reserve. One of the SSJV's largest CO_2 emitters, the 550 MW Elk Hills natural gas combined cycle (NGCC) power plant, lies within the oil field, as does a 45 MW cogeneration plant, both operated by the oil field operator, CRC. These CO_2 sources could be logical primary customers for a commercial CO_2 storage operation in the Elk Hills oil field, with the prospect of

CO_2 storage in conjunction with CO_2-enhanced oil recovery (EOR) as a means of improving storage economics and drawing in private-sector investment. Storage targets in the Elk Hills are the Stevens Sand (tertiary oil recovery) and the depleted Carneros Sandstone. Proposed Phase II activities will collect overlying shale core samples to validate seals.

The third C2SAFE commercial development scenario assumes that both scenarios 1 (east-side hub) and 2 (west-side hub) proceed to fruition, and an interconnecting “trunk” pipeline is installed to connect the two CO_2 storage hubs. This scenario would enhance storage operation reliability and flexibility, and minimize risk should one storage site need to be shut down for unforeseen reasons.

The fourth scenario of locating storage sites as close as is practical to sources (to minimize CO_2 transportation) may be viable for the Calpine Pastoria NGCC plant[1] and several large west-side oil field sources (as the basin is deeper on the west) and may be especially applicable to other oil field operators considering CO_2-EOR. This option will not be explored specifically in Phase II, but results from the work could inform the potential for this scenario in future phases of the project.

2.1 Project Sites

Two of the industry partners, CES and CRC, have made an initial commitment to host the Phase II (Feasibility) project at their facilities to determine the efficacy and technical viability of storing CO_2 at an east and west hub located at Kimberlina and Elk Hills, California, respectively (Figure 1–1). Construction and operation of CO_2 storage facilities is expected to concentrate initially on one side of the SSJV, either east or west, depending on results of the feasibility study and where entities willing to invest in CO_2 capture facilities are ready to proceed. Ultimately, the goal is to have C2SAFE storage operations growing on both sides of the SSJV. Note, that the midpoint between the east and west source clusters is farther from the western sources and would require transport through Bakersfield from the eastern sources and storage just adjacent to Bakersfield; thus, a single, central hub is not envisioned.

CO_2 storage customers are expected to come initially from oil field operators and later from electric power producers, given the differing regulatory requirements and available incentives, with the possible exception of the CRC Elk Hills and CES KPP, which could host early CO_2 capture retrofits. Depending on the established capacity and redundancy/perceived reliability of east-side and west-side storage complexes, an interconnecting pipeline across the SSJV floor may or may not be economically justified.

2.1.1 Clean Energy Systems Kimberlina Power Plant (East Hub)

The KPP site is located on the east of the SSJV, about 17 miles (27 km) north of Bakersfield, near the intersection of Highway 99 and Kimberlina Road. Built in the early 1980s, the KPP was originally a 5 MWe biomass-fired plant but only ran for a few years before shutting down. CES acquired the facility in 2003 and has converted the 37-acre site into a research, development, and demonstration site for their pressurized oxy-combustion technologies. The oxy-combustion system uses natural gas or synthesis gas and oxygen to generate steam (when fired indirectly) or a steam-CO_2 working fluid (when fired directly) for electric power generation or combined heat

[1] Geologic CO_2 Sequestration Potential of 42 California Power Plant Sites: A Status Report to WESTCARB, LLNL-TR-489273, June 2011.

and power applications. The combustion process generates wet-CO_2 that can be dehydrated, producing water that may be put to beneficial reuse or recycled to produce more steam. After dehydration, the CO_2 can be compressed allowing it to be injected and stored deep underground. When combined with a biomass derived fuel source, the process has the potential to produce electricity and/or steam for heavy oil production and have net negative CO_2 emissions. The California Air Resources Board (CARB) and local air quality pollution control district have expressed keen interest in the biomass-gasification process because of the potential health benefits that result from reducing criteria pollutants (e.g., NOx, particulate matter) associated with open burning of agricultural wastes in the valley. The co-benefits of reducing criteria pollutants and producing negative CO_2 emissions power is an attractive proposition.

CES is currently installing a biomass gasifier at KPP to produce either: 1) renewable natural gas (RNG) for pipeline export; and/or 2) synthesis gas for use as a fuel in its oxy-combustion power system for electricity sales to the grid. Pilot testing of the biomass-gasifier is planned for 2019. Once up and operating, the KPP emissions are expected to be less than 100,000 tonnes of CO_2 per year for the foreseeable future, but there are numerous existing emitters on the east side of the SSJV. These include numerous oil field operators that use natural gas-fired steam generators and combined heat and power (co-gen) plants to produce steam for thermal EOR. Plants at these heavy oil production sites emit an aggregate mass exceeding 3 million tonnes/yr (Figure 1–1). Existing equipment may be retrofitted for post-combustion carbon capture using commercially available equipment or aging equipment may be replaced with new or novel systems to enable CO_2 capture at a lower cost. Once captured the CO_2 must be transported to a nearby carbon storage field through pressurized pipelines.

During Phase I, C2SAFE examined the cost and routing of new CO_2 pipelines from these sources to the KPP storage hub and determined the most effective approach was to follow existing natural gas and hazardous liquid product pipeline rights-of-way (ROW) as shown on Figure 1–1. So-called “brownfield” pipelines are often easier to permit and less costly to construct compared to “greenfield” pipelines where new pipeline ROW must be negotiated, obtained, and permitted. Natural gas pipelines exist to every source either for supplying fuel or taking away produced gas. The Southern California Gas Company (SoCalGas) has expressed interest in partnering with hub and sources owners to build out the CO_2 pipeline infrastructure using its extensive natural pipeline ROW network. Most large industrial emitters in the SSJV have natural gas pipelines either leading to the facility for use in their process or leading from oil and gas fields to distribution pipelines owned by groups like SoCalGas.

WESTCARB performed an extensive assessment of geologic storage focused on the KPP site, including development of a lithofacies model (Wagoner 2009), simulation of a large pilot injection, and risk assessment (Oldenburg, et al. 2009). The KPP site subsequently became a test site for tool development by the NRAP. As part of this work, a regional static geologic model was created and reservoir simulations were conducted to assess the nature and extent of the CO_2 plume that resulted from a 250M tonne injection (five times the target goal identified in the CarbonSAFE program) vicinity of KPP. WESTCARB identified the Vedder and Olcese geologic formations as possible targets for CO_2 storage. The entities and most of the personnel that conducted this WESTCARB and NRAP work are also C2SAFE members. As discussed below, reservoir simulations conducted by Wainwright et al. (2013) indicate there is sufficient storage resource capacity in the portion of the Vedder Formation selected for injection at the tonnage needed to meet the DOE minimum requirements (50M tonnes).

Conceptually, the KPP project would be advanced as a saline storage complex. A CO_2 injection well was planned as part of WESTCARB Phase III drilling effort at KPP that was never installed but would have provided valuable geologic data/information on the reservoirs and seals that are essential for ground-truthing the prior models and risk assessment. C2SAFE is proposing a stratigraphic well at KPP as part of the Phase II feasibility study to fill the data gap that still exists.

2.1.2 California Resources Corporation (CRC) Elk Hills Oilfield (West Hub)

CRC is an oil and natural gas exploration and production company operating high-growth, high-return conventional and unconventional assets exclusively in California. CRC is one of the largest oil and natural gas producers and privately-held mineral acreage owners in California (2.3 million net acres). CRC is the majority mineral rights owner and operator of the Elk Hills field; the second location of the C2SAFE feasibility study.

The Elk Hills Oilfield is located 35 km (22 miles) west of Bakersfield in Kern County, California. Discovered in the early 1900s, the field encompasses 75 square miles and has produced over 2 billion barrels of oil equivalent (BOE). It is one of the most productive oil fields in the United States. CRC operates gas processing facilities in the field, including the largest cryogenic gas plant in California; the Elk Hills Power Plant, a 550 MW natural gas, combined-cycle power plant that supplies electricity to the Elk Hills Field and excess power to the California electric grid; and a 45 MW cogeneration plant that provides steam and electricity to the field. The total 2016 annual GHG emissions reported in the EPA's Facility Level Information on GreenHouse Gases (FLIGHT) database for the CRC Elk Hills operations was 1.37M tonnes. Emissions from non-CRC sources on the west side of the valley totaled over 4M tonnes in 2016.

Several depleted oil and gas reservoirs amenable to storage, and active oil production intervals amenable to CO_2-EOR exist in the Elk Hills Oilfield. The field has storage potential in stacked reservoirs ranging from down-dip saline water legs to depleted intervals to active oil and gas production intervals. The anticlinal structures within the Elk Hills field provide added security with respect to permanently trapping and storing CO_2. The Stevens and Carneros Sandstone Members represent two potential targets for EOR and depleted storage, respectively. Static CO_2 storage estimates based on total historical fluid production (oil, gas and produced water) equals 120M tonnes for the Stevens and 4.5M tonnes for the Carneros reservoirs proposed for storage to refill the voidage from hydrocarbon production. The Stevens estimate does not account for future production of oil, gas, and produced water.

Conceptually, the Elk Hills project would be advanced as a hybrid storage complex with CO_2-EOR occurring in one of the Stevens reservoirs in the field and additional secondary or surge capacity in a depleted Carneros reservoir. Given that oil and gas production from the Elk Hills field has been ongoing for over a century, a great deal is known about the stratigraphy and reservoir properties. In contrast, little is known about the sealing properties of the shales and mudstones that make up the caprock overlying the reservoirs, which for most oil and gas projects is of little to no interest to the operator. Therefore, the primary focus of the C2SAFE feasibility study will be to assess the sealing properties of the Reef Ridge shale, which is the regional confining unit overlying the shallower Stevens sand, and the deeper Media shale above the Carneros sand. C2SAFE is proposing to side-track existing CRC wells or extend new wells to collect core from the caprocks for laboratory testing and conduct in situ tests to assess seal integrity.

3
HIGH-LEVEL CO_2 SOURCE CHARACTERIZATION

The high-level CO_2 source characterization within the SSJV, as well as the assessment of capture technologies and economics, was performed under Task 2 of the project SOPO. The SSJV was the target of this study due to its geology, which may be favorable for the storage of CO_2, and its role as a center of both thermally-enhanced heavy oil and electricity production in California. The geographic extent of the study area comprised those portions of Kern, Tulare, Kings, and Fresno Counties within the San Joaquin Basin Province. Emitters in the study area were identified by the data in the US EPA's Greenhouse Gas Reporting Program (GHGRP) database, Energy Information Administration's (EIA's) data reported on Forms EIA-860 and EIA-923, and the NETL's National Carbon (NATCARB) database. High-level summary of results are provided here; for more information see the project's (Task 2) Topical Report on CO_2 Source Characterization and Capture Techno-Economics.

According to GHGRP data, large facilities in California emitted about 105.9 M tonnes of CO_2 in 2015 across all facility types[2]. The majority of these emissions was attributed to facilities reporting under stationary combustion and electricity generation subparts, contributing 41.9 M tonnes (40%) and 38.8 M tonnes (37%), respectively, to the total.

3.1 Summary of the Types of Large CO_2 Point Sources in the SSJV

The SSJV is an active center of oil production in California. Due to the prevalence of heavy oil at relatively shallow depths, production is dependent on extensive steam flooding for thermally enhanced extraction.[3] The heat needed to produce the large quantities of steam required is largely provided by combustion of natural gas, either in combined heat and power (CHP or cogeneration) facilities or in once-through steam generators (OTSG). In the SSJV, these stationary sources reported a total of 13.0 M tonnes of CO_2 emitted in 2015. In addition to oil production facilities, the SSJV is home to four NGCC power plants, typically in a 2 x 1 (nominally 550 MW) configuration. These sources collectively reported emitting 7.3 M tonnes of CO_2 in 2015. These two types of sources combine for over 20 M tonnes of CO_2 emissions annually and were the focus of CO_2 capture analyses in C2SAFE Phase I.

3.1.1 Oilfield Cogeneration Units

Oilfield cogeneration units are similar to small-scale NGCC plants except that steam raised in the heat recovery steam generator (HRSG) is directed to the oil field rather than to a steam turbine power cycle. Produced steam is not taken to full saturation (i.e., it remains wet), allowing for

[2] According to California Air Resources Board (ARB) data, California emitted 369.9 M tonnes of CO_2 across all sectors of the economy in 2015. This total includes estimated emissions from combustion of transportation fuels and attributed emissions from imported electricity.

[3] With this technique, large quantities of steam are raised and injected into target formations for oil production. Heat transferred by the steam reduces the viscosity of the heavy oil and helps to sweep it toward production wells. When the oil-water mixture reaches the surface, the water is separated from the oil and then treated and recycled to heaters for further steam generation.

impurities concentration in the blowdown stream and allowing for use of poorer quality feedwater, such as separated produced water. The post-HRSG exhaust is similar in composition to NGCC exhaust, but may be relatively enriched in CO_2 if supplementary (duct) firing is used to increase steam output.

3.1.2 Steam Boilers

The simplest equipment for generating large quantities of steam is an OTSG. These are typically horizontally oriented vessels with both radiant and convective sections. Standard capacities of oil field OTSG are 62.5 and 85 MMBtu/hr, although in principle any size of burner can be built. To take advantage of common infrastructure, OTSG units are often arranged into banks of 2 to 10 units feeding a single primary steam header line. Common exhaust ducting to a CO_2 absorber would provide economies of scale for capture.

3.2 Average Gas Properties for the Different Emitter Types

The majority of the largest emitters in the SSJV exclusively burn natural gas. As a consequence, the exhaust gases produced by the emitters of interest should have similar compositions. The primary distinguishing factor is the amount of excess air used for combustion. Typical estimations of compositions and conditions are shown in Table 3–1. The exhaust of all these sources also contains various NOx species, although at levels much lower than those of the other primary constituents.

Table 3-1
Representative Exhaust Gas Properties for Large SSJV CO_2 Emitters

	OTSG (single unit)	CHP[1,2,3]	NGCC[4]
Property			
Mole fractions			
CO_2	0.0621	0.0292	0.0391
H_2O	0.1288	0.0655	0.0841
N_2	0.7730	0.7731	0.7442
O_2	0.0270	0.1230	0.1238
Ar	0.0092	0.0092	0.0089
Flow rate range, kg/hr	35,000 – 50,000	100,000 – 400,000	1,000,000 – 4,000,000
Temperature, °C	180	149 – 160	117
Pressure, MPa	0.1	0.1	0.1

1 I. S. Ondryas, C.O. Myers, and W.E. Hauhe. "Omar Hill-300 MW Cogeneration Plant for Enhanced Oil Recovery." International Gas Turbine Conference and Exhibit, Dusseldorf, West Germany, June 8, 1986.

2 Catalog of CHP Technologies, Section 3. Technology Characterization – Combustion Turbines. U.S. EPA, March 2015.

3 Based on an air-to-fuel mass ratio of 60.

4 Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3. National Energy Technology Laboratory, Morgantown, WV: 2015. DOE/NETL-2015/1723.

3.3 Summary of Model Capture Process: Cansolv Amine Scrubber

C2SAFE Phase I analyses assumed that CO_2 would be captured from flue gas streams using Cansolv's amine-based post-combustion capture process. This process is the current reference process used by NETL for its "Baseline" report series on state-of-the-art fossil power plants with CCS. The NETL reference process also includes drying of product CO_2 and multi-stage centrifugal compression to transport pipeline pressure. Because of the nature of the process, the properties of the CO_2 product stream are relatively insensitive to the CO_2 composition of the inlet flue gas.

3.4 Quantities of CO_2 from Different Sources

To determine the potential quantities of CO_2 from large point sources in the SSJV, C2SAFE researchers analyzed EPA's Envirofacts Database, the US EIA's data on generators and fuel consumption, and the NETL NATCARB database. All emissions data used in this analysis were from reporting year 2015. An initial screening examined facilities emitting at least 200,000 tonnes annually of CO_2. Because some reporting entities aggregate individual adjacent combustion stacks, individual combustion sources at the facilities were reviewed to identify those emitting at least 100,000 tonnes of CO_2 annually. From this analysis, a list of 42 point-source emitters was developed, representing over 30 businesses in the SSJV. Table 3–2 shows summary information of the number of different units of emitters and a range of their annual emissions. Note that for OTSG units, data are reported only in aggregate in the Envirofacts database, so the ranges below represent multiple banks of OTSG units.

Table 3-2
Number of Large CO_2 Emitters by Source Type in the SSJV (2015)

Emitter type	Number of emitters	Range of annual CO_2 emissions, tonnes
OTSG	18	101,657 – 969,570
Cogeneration units	9	198,161 – 785,403
NGCC	15	110,873 – 730,979

3.5 Geographic Distribution of CO_2 Emitters

The data were used to map the geographic location of the large point sources of CO_2 emissions in the SSJV (Figure 1–1). Within the figure, different colors indicate different combustion equipment types and the size of the circle indicate the quantity of CO_2 emitted in 2015. Each source is then labeled with its parent company. The map was then overlaid on the areas land use profile to show relative proximity to oil and gas field, cities, and industrial and non-industrial areas.

3.6 CO_2 Transportation via Pipeline

C2SAFE Phase I analyses suggest that the largest CO_2 point sources on the east side of the SSJV are oilfield cogeneration units and steam generators in the foothills to the east of the valley floor. These could be linked to the candidate east-side storage complex at, or just west of, the

Kimberlina power plant with four pipeline segments following established natural gas and liquid fuel pipeline corridors (see Figure 3–1) and totaling about 45 miles (72 km) in length.

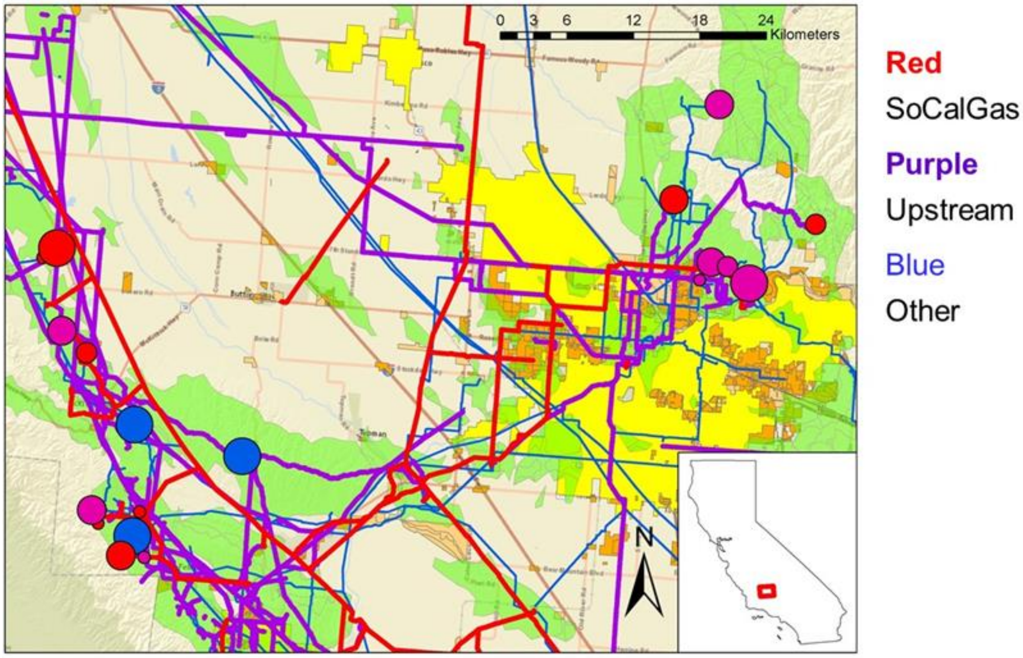


Figure 3-1
Pipelines in the SSJV Overlaid on Map of CO_2 Sources by Type and Size

The largest CO_2 point sources on the west side of the SSJV are a mixture of NGCC plants and oilfield cogeneration units and steam generators, mostly in the foothills rising to the west of the valley floor. These could be linked to the candidate west-side storage complex and/or CO_2-EOR injection wells in the Elk Hills oilfield with three pipeline segments totaling about 40 miles (64 km). Not included in this pipeline length estimate is a line connecting the Calpine Pastoria NGCC power plant at the very southern tip of the SSJV to the west-side hub. A cursory analysis by Lawrence Livermore National Laboratory suggests that the Pastoria plant's location offers the possibility of on-site or nearby CO_2 injection for saline formation storage,[4] and thus a pipeline connecting it to the west-side hub would presumably be built only if a storage site at or near the plant could not be feasibly developed or if the prospect of CO_2 sales to oilfield operators for EOR was a strong enough economic driver to justify the connecting pipeline. Were this pipeline segment to be included in the analysis, it would add roughly 40 miles (64 km), doubling the overall length of the west-side pipeline segments to about 80 miles (128 km).

To connect the proposed east-side storage hub at the Kimberlina power plant with the west-side Elk Hills oilfield storage hub would require a pipeline of about 25 miles (40 km), again following established natural gas and liquid fuel pipeline corridors.

[4] Geologic CO_2 Sequestration Potential of 42 California Power Plant Sites: A Status Report to WESTCARB, LLNL-TR-489273, June 2011.

Summing the aforementioned segment lengths, the envisioned C2SAFE pipeline network would be about 110 miles (176 km) in total without a connecting line from the Pastoria NGCC plant and about 150 miles (240 km) with one.

C2SAFE Phase I analyses using the FE/NETL CO_2 Transport Cost Model[5] as well as other analyses by Southern California Gas suggest that an 8-inch (200 mm) diameter pipeline could accommodate the anticipated ultimate capacity of east-side CO_2 point sources transporting CO_2 to an east-side hub at or near the Kimberlina power plant. Some spur pipelines collecting CO_2 from individual CO_2 capture process units could be smaller.

The anticipated ultimate capacity of CO_2 that could be captured from west-side point sources is greater than from east-side point sources. However, one of the largest source pairs—the Elk Hills power plant and a nearby cogeneration plant—are very near to the saline storage/EOR sites in the Elk Hills oilfield and thus would not contribute significantly to overall pipeline frictional losses (i.e., pressure drop). C2SAFE intends to analyze west-side pipeline sizes in more detail in C2SAFE Phase II.

C2SAFE envisions that a trunk pipeline connecting the east-side and west-side storage hubs—if built—would come in a relatively late implementation phase when transport capacities and the business drivers affecting primary directional flow (e.g., saline formation storage management versus CO_2-EOR operations supply) were better known, allowing for more refined sizing calculations. However, a cursory analysis by Southern California Gas suggested that an 8-inch (200 mm) diameter pipeline would be suitable for the hub interconnecting pipeline segment. Because the west-side storage hub is at a higher elevation than the east-side storage hub (by perhaps as much as 800 feet or 260 m), a boost pump station could potentially be needed for transferring CO_2 from east to west. Although the cost of a pump station was not estimated by Southern California Gas, the FE/NETL CO_2 Transport Cost Model suggests that the capital cost of such a station would be modest relative to the cost of the pipeline itself. C2SAFE Phase I analyses also identified additional potential CO_2 offtakes at oilfields amenable to CO_2-EOR along the western half of the pipeline, but at elevations lower than the Elk Hills oilfield (see Figure 3–2), which would reduce pipeline frictional losses relative to transporting all the CO_2 to the pipeline terminus at the west-side storage hub.

Pipeline material is assumed to be carbon steel, consistent with the materials used in other commercial pipelines transporting supercritical natural source and anthropogenic CO_2.[6]

[5] https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/CO_2-transp-cost-model-desc-user-man-v1-2014-07-11.pdf

[6] Yong Xiang, Minghe Xu, and Yoon-Seok Choi (2017): State-of-the-art overview of pipeline steel corrosion in impure dense CO_2 for CCS transportation: mechanisms and models, Corrosion Engineering, Science and Technology, DOI: 10.1080/1478422X.2017.1304690.

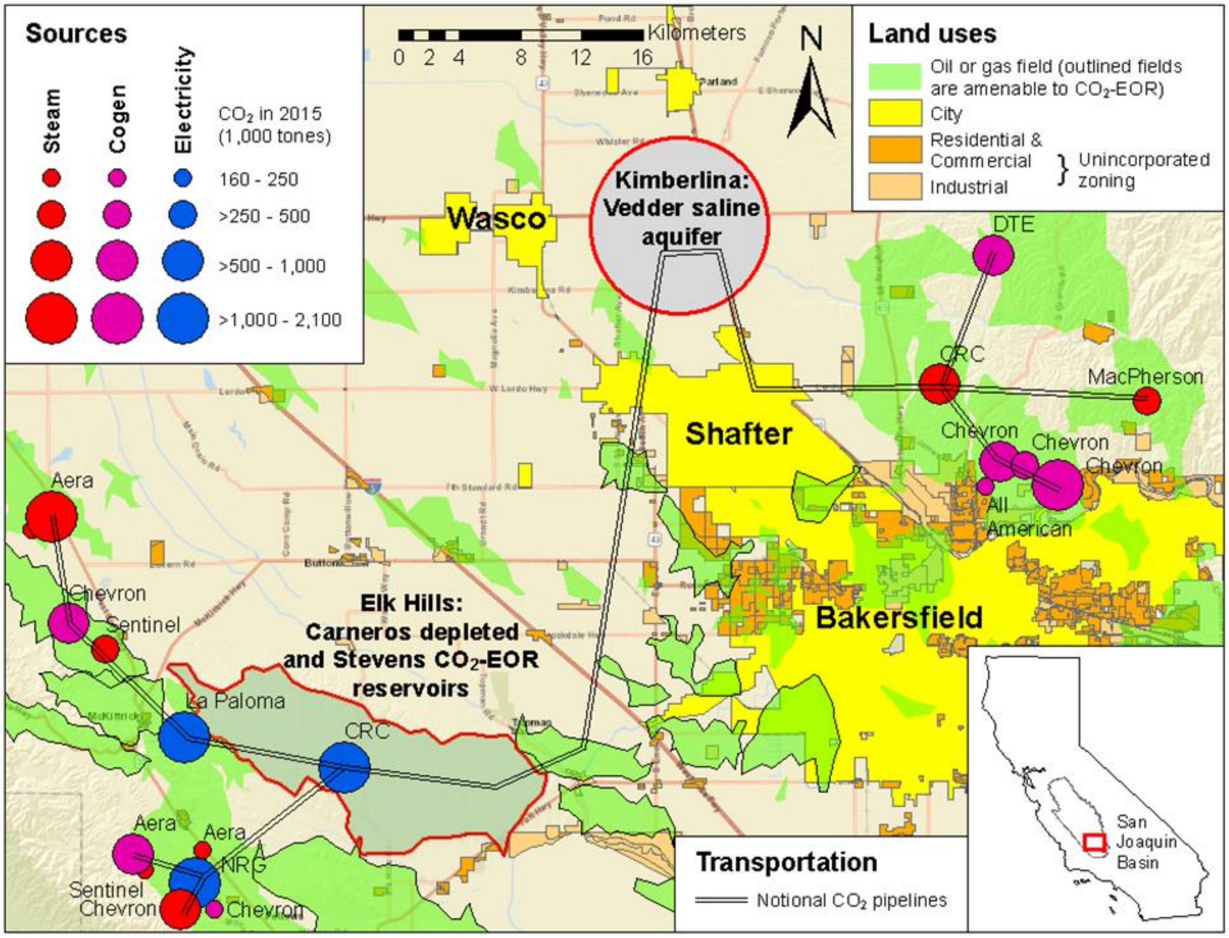


Figure 3-2
Hypothetical CO_2 Pipeline Routings Linking Southern San Joaquin Valley CO_2 Point Sources and the C2SAFE East-Side and West-Side Storage Hubs

3.6.1 CO_2 Pipeline Rights-of Way Analysis

The C2SAFE project team has mapped the natural gas and liquid fuel transmission pipelines in the SSJV from the National Pipeline Mapping System GIS layer (see Figure 3–1), with the notion that CO_2 pipelines could follow these corridors where practical, to leverage pipeline ROW held by prospective C2SAFE project partners or customers. Note, many of the SSJV large CO_2 emission point sources are at power plants (blue circles) or oil field facilities (red circles for OTSG and purple circles for CHP) are already connected by these existing pipelines.

3.6.2 CO_2 Pipeline Construction and Protection

The vast network of natural gas pipelines in the SSJV shown in Figure 3–1 provides robust information for pipeline designers on soil properties, the effectiveness of cathodic and other pipeline protection measures, approved means of crossing rivers/streams and irrigation aqueducts or agricultural drainage channels, highway and railroad crossings, environmentally sensitive areas, and other restricted spaces. Terrain in the center of the SSJV is flat and still wind days are rare, aiding natural CO_2 dispersion in the event of a pipeline leak and moderating the risk of an accumulation in a low-lying area.

In addition, the ROWs proposed for pipeline construction were selected to minimize human exposure in the event of a rupture. The proposed network to all the sources avoids suburban/urban residential areas except for a 2.6 km (1.6 mile) segment of the east-west hub connector through or along a current residential area in Shafter along an existing natural gas transmission ROW. This length could extend if this residential area grows. The proposed east side pipeline from Kern Front to the east hub also passes through Shafter, however this area is agricultural and industrial.

3.7 Reliability of Sources of CO_2

Almost all the largest SSJV point sources of CO_2 fire natural gas or associated gas. Natural gas has been gaining market share in the power generation sector and the ultimate application of CCUS to NGCC plants or the use of gas-fired oxy-combustion plants with inherent CO_2 capture is viewed as vital future technology for emissions reduction and competitive export markets – especially in California. Oil producers in the SSJV employing thermally enhanced production operations report decades of reserves and have long-term production plans.

3.7.1 Electric Generating Units

The SSJV's four NGCC electricity generating units (EGUs) are some of the largest point sources of CO_2, and thus make excellent candidates for CO_2 capture retrofit due to economies of scale in CO_2 capture and compression process units/equipment. The Elk Hills NGCC plant is sited within the CO_2-EOR suitable Elk Hills oil field and is operated by the oil field operator CRC. Thus, it is a particularly attractive candidate for a CO_2 capture retrofit. In competitive power markets, concern has been expressed that the addition of CO_2 capture would increase the variable operating cost of the plant, and absent any other incentives or policies, reduce its position in the dispatch order. However, the California Independent System Operator has provisions for must-run status and thus offers state regulators an option to help assure a high capacity factor to a plant operator investing in CO_2 capture and compression. This approach can also reduce the risk that lower energy market prices for electricity, driven by increasing mandatory procurement/production of renewable generation, would undermine out-year capacity factors. For reference, the capacity factors for the utility-scale California generating units studied by C2SAFE ranged from 26% to 86% in 2015. For 2017, the Elk Hills NGCC plant remains at the high end of the range. Pastoria and Sunrise are above average. Only La Paloma, which in 2017 was in bankruptcy proceedings, was below average.

3.7.2 Oilfield Steam Operations

Cogeneration units and once-through steam generators are typically operated to match the demand for steam in the oil fields, which is contingent on well production response to steam stimulation and long-term production plans influenced by the expected price of oil. Unlike EGUs, there is not an instantaneous demand for oil that must be followed in real time, hence demand for steam can be planned for longer operational periods and further in advance. The typical capacity factor for oil field steam producing units is high and they tend to operate steadily, thus providing a reliable source of CO_2.

The addition of post-combustion CO_2 capture equipment will increase the cost of making steam. However, this can be offset by California's unique incentives and carbon credit and trading economy. Discussions with oil producers suggest a business case can be made at current market values. Further, some CHP units and OTSGs are near their replacement age, opening the prospect for novel/advanced generation technologies such as pressurized oxy-combustion with CO_2 capture. Such repowering options offer the prospect of lower-cost capture, reduced criteria pollutant emissions and enabling produced water cleanup, which would likely win favor with local populations and air regulators.

4
HIGH-LEVEL SUB-BASINAL EVALUATION

The high-level sub-basinal evaluation of the SSJV and CO_2 storage economics were performed under Task 3 of the project SOPO. The SSJV is one of the country's most productive oil basins. However, as is typical, proven oil resources occupy only a small portion of the basin's area. Less than 18% of the SSJV in Kern County, where almost all the production is located, contains oil wells that have been, or are now, productive (and much of this area is located on the margins of the basin where the deepest strata are too shallow for efficient storage). As a marine siliciclastic basin, this suggests there is a tremendous amount of storage capacity in the saline formations between the oil fields, while the history of oil production provides a substantial body of data from which to characterize target formations. A high-level summary of the region's sub-basin is provided here; for more information refer to the project's (Tasks 3 and 5) Topical Report on Sub-Basin Storage and Preliminary Risk Assessment.

4.1 CO_2 Storage Reservoirs

The proposed storage complex consists of three reservoirs: a saline formation on the east side of the basin, and two separate depleted and tertiary oil recovery reservoirs on the west side of the basin. Table 4–1 provides information regarding these reservoirs at the proposed storage locations. Pressure and temperature conditions at the minimum proposed storage depths are considerably more than the critical point pressure and temperature for CO_2.

The Vedder Formation, located on the east-side of the SSJV, consists of extensive massive sandstone interbedded with shale. The sandstone was deposited in a marine shelf environment (Wagoner, 2009; Johnson and Graham, 2007). The portion of the Vedder Formation proposed for storage consists of a homocline.

On the west-side of the SSJV, the Carneros Sandstone Member of the Temblor Formation is a shelf-basin floor turbidite (Johnson and Graham, 2007), as is the Stevens Sand (Lamb et al., 2003). The sand bodies proposed for storage in both units occur in doubly plunging anticlines in the Elk Hills oil field.

Table 4-1
Properties of Proposed Storage Reservoirs

Type of reservoir	Geologic unit	Location in SSJV	Shallowest storage depth (mi/km)	Average temperature at minimum depth (°F/°C)	Average net sand thickness (ft/m)	Average porosity (%)	Average permeability (md)
Saline aquifer	Vedder Formation	East-side	0.9/1.5[1]	131/55[2]	525/160[3]	22[4]	220[4]
Depleted reservoir	Carneros Sandstone Member	West-side	1.4/2.3[5]	212/100[6]	246/75[7]	16[7]	6[7]
Tertiary oil recovery	Stevens Sand	West-side	1.1/1.7[7]	176/80[8]	295/90[7]	21[7]	150[7]

[1] From Wagoner (2009) at up dip plume limit in Wainwright et al. (2013)
[2] Jordan and Doughty (2009)
[3] Total thickness from Wagoner (2009); Vsand of 0.5 estimated from Wagoner (2009)
[4] Wainwright et al. (2013)
[5] CRC confidential business information
[6] CRC confidential business information, depth adjusted
[7] California Division of Oil, Gas, and Geothermal Resources (1998)
[8] California Division of Oil, Gas, and Geothermal Resources (1998), depth adjusted

4.2 Prospective Storage Resources

4.2.1 East-Side Storage Resources: Vedder Sandstone

Wainwright et al. (2013) simulated injection of 250 million tonnes of CO_2 over 50 years into the east-side Vedder Formation, including sensitivity analysis. The 95% confidence interval plume area 200 years after commencement of injection was 12–27 square miles (30–70 km^2). Compared with Wagoner (2009), the shallowest depth of the CO_2 plume at its up dip extent in Wainwright et al. (2013) is approximately one mile (1.6 km). As the CO_2 injection studied by Wainwright et al. (2013) is five times the total CarbonSAFE target, and is injected over a period twice as long, the results of Wainwright et al. (2013) indicate there is sufficient storage resource in the portion of the Vedder Formation selected by C2SAFE for the injection rate and total mass targeted by CarbonSAFE.

Jordan and Gillespie (2013) concluded that the reservoir-scale productivity index for the Vedder Formation in the two fields studied indicated it is compartmented by barriers at larger spacing than the length of the fields. In contrast, the study in Wainwright et al. (2013) was based on only partial compartmentalization by regional faults at an even larger spacing. The two results are orders of magnitude different with regard to likely pressure response to CO_2 injection. The fields studied by Jordan and Gillespie (2013) were located south to southwest of the proposed storage site in an area with a higher fault density according to Jordan et al. (2012). Consequently, the results of Jordan and Gillespie (2013) may be conservative with regard to injectivity at the proposed storage site relative at the mid to end period of the injection. If this is the case, active pressure management via brine extraction may be required depending upon the amount of CO_2 to be injected to this reservoir relative to the other two reservoirs forming the proposed storage complex.

4.2.2 West-Side Storage Resources: Carneros Sandstone

The proposed west-side storage in the depleted Carneros Sandstone Member would take advantage of historic voidage resulting from production of 85.1 Bcf of gas, 2.2 million barrels of oil, and 0.8 million barrels of water. Pressure decline and water production indicate a gas drive with little to no water drive. CRC estimates 4.4 million tonnes of CO_2 to refill the volume voided, restoring original pressure. From the database of production through 2010 utilized in Jordan and Gillespie (2013), the estimated total voidage at reservoir conditions was approximately 7,300 acre-feet (9 million m^3). CRC provided an initial reservoir pressure of 4,160 psia (287 bara). This is considerably lower than the estimated value in DOGGR (1998). That published value is almost twice hydrostatic and consequently appears too high. At the initial pressure provided by CRC and the reservoir temperature of 252°F (122°C) from DOGGR (1998), the density of CO_2 is a bit greater than 0.5 tonne/cubic meter (specific gravity >0.5). This yields an independent estimate of 4.5 million tonnes to refill the voidage. The average production rate from this Carneros reservoir during the peak 15-year period was equivalent to more 200,000 tonnes of CO_2 per year. The peak annual rate was 300,000 tonnes.

Jordan and Gillespie (2013) studied the Carneros reservoir in a field immediately west of Elk Hills and concluded it was compartmented based on several lines of evidence. Compartmenting was by both lateral facies change, attendant upon the Carneros Sandstone Member being comprised of turbidite deposits, and faulting. The gas-expansion drive in the Carneros reservoir for the proposed storage complex indicates it is compartmented as well. As such, further study may determine it is possible to store CO_2 up to a pressure greater than initial without damaging the seal or exceeding the footprint of the original hydrocarbon accumulation. Storage up to a pressure gradient of 0.7 psi/ft (16 kPa/m) would result in a CO_2 density over 0.6 tonne/cubic meter (specific gravity = 0.6). At this density, the prior voidage would contain 5.5 million tonnes of CO_2, more than 10% of the CarbonSAFE goal of 50 million tonnes stored.

4.2.3 West-Side Storage Resources: Stevens Sand

Voidage from the west-side's Stevens Sand proposed for CO_2-EOR was estimated from the database described in Jordan and Gillespie (2013) as greater than 162,000 acre-feet (200 million m^3). At the midpoint of the average pressure and temperature for the Stevens in the Elk Hills field given in DOGGR (1998), CO_2 has a density of 0.6 tonne/cubic meter (specific gravity = 0.6). This indicates 120 million tonnes of CO_2 would refill the voidage, without accounting for additional voidage due to enhanced oil production. Jordan and Gillespie (2013) studied two Stevens reservoirs immediately east of the Elk Hills field and adjacent to each other and found gas-expansion to be the predominant drive in those reservoirs. Additionally, each reservoir was concluded to be a separate compartment but with no compartment barriers within each. Production from the Stevens in the proposed structure has averaged 2 million tonnes per year CO_2 equivalent, and peaked at an annual rate of over 9 million tonnes equivalent.

4.3 Confining System

Each of the three reservoirs proposed in the storage complex has multiple overlying seals.

4.3.1 East-Side Confinement

The first seal overlying the Vedder Formation is the Freeman silt. The proposed storage site is near the center of the Freeman silt's mapped extent according to Scheirer and Magoon (2007), and extends tens of kilometers in every direction beyond the limits of the CO_2 plume simulated in Wainwright et al. (2013). In addition, oil was produced from the Vedder in the closest structural folds, which are in the Mount Poso field 10 km east (up dip, and therefore at lower stress) and the Rio Bravo field 7.5 miles (12 km) southwest. Geophysical log analysis by Wagoner (2009) found the Freeman silt continuous as a fine-grained unit in the prospective CO_2 plume area.

Overlying the Freeman silt is the Olcese Formation, which, like the Vedder, contains extensive marine shelf sands with net thickness of several tens of meters (Johnson and Graham, 2007; Scheirer and Magoon, 2007). The Olcese is overlain by the Round Mountain silt, which is overlain by the Fruitvale shale. Together these units provide secondary containment should CO_2 leak through the primary seal. The Olcese Formation would dissipate overpressure from the leakage, reducing the driving force for further upward advection. The Round Mountain and Fruitvale provide secondary seals beneath which any leaked CO_2 would accumulate, providing an opportunity to detect the leakage through geophysical monitoring.

The Pond-Poso Fault passes east of the proposed storage site in the Vedder Formation. As indicated by Wainwright et al. (2013), the CO_2 plume resulting from injection of 250 M tonnes over 50 years might encounter the fault in the scenario studied, which included an uncompartmented conceptual model. The permeability structure of this fault through the Freeman silt is unknown. According to Wagoner (2009), the fault does not fully offset the Freeman silt. Consequently, it is unlikely to be conductive through this primary seal. However, whether or not to design the storage project to minimize the probability of the plume encountering this structure requires further study.

Jordan and Wagoner (2017) found there are several uncased exploratory borings to the Vedder within the CO_2 plume footprint of Wainwright (2013) that have plugs above the base of the Underground Source of Drinking Water (USDW). Most of these are on the east side of the Pond-Poso fault. Others are at the southeastern margin of that plume footprint. Just one is adjacent to the fault to its west. The difficulty of re-entering these uncased borings to plug them across the primary and secondary seals suggests engineering the CO_2 storage so as to minimize the probability of the CO_2 plume encountering them. This goal is synergistic with the designing the project to also avoid CO_2 encountering the fault as suggested above. One available measure is to move injection down dip from the location simulated in Wainwright et al. (2013). The shallow dip and extent of the Vedder provides for moving this location as much as 6 miles (10 km) down dip to the west.

Jordan and Wagoner (2017) also identified a boring to the Vedder cased to the base of the seal over the Olcese, and uncased below, which is more centrally located relative to the prospective CO_2 storage plume. Consequently, it is unlikely the plume footprint could be engineered to avoid this well. One alternate approach is to anticipate and accept some movement of CO_2 into the Olcese via this boring. This would provide a useful field study of CO_2 migration via uncased exploratory borings. Another approach is to inject water into the top of the Vedder near this boring via a new well to create a local water flood that excludes CO_2 from this location.

There are likely no unknown borings to the Vedder within the CO_2 plume footprint. Oldenburg et al. (2017) found the deepest prospect wells in California at the time that the state oil and gas agency was founded were 1.1 miles (1.7 km), and the deepest hydrocarbon accumulations being produced had an average depth of 0.8 mile (1.3 km). As one of the agency's main purposes was to collect statewide data and oversee well construction, the number of undocumented wells advanced to the proposed storage depths appears to be minimal.

4.3.2 West-Side Confinement

Regarding the two proposed reservoirs in Elk Hills on the west side of the SSJV, there is virtually no USDW, or the relevant state agencies have concurred that only the unconfined aquifer contains USDW (see aquifer exemption application documents for Elk Hills Phase 1 and Phase 2 aquifer exemption application documents).[7]

The top seal of the proposed Stevens reservoir is the Reef Ridge Shale Member of the Monterey Formation, which extends tens of kilometers in every direction from this location (Scheirer and Magoon, 2007). Its integrity in the proposed storage area is demonstrated by the hydrocarbon accumulations retained in the Stevens. There are a number of seals and reservoirs between the Reef Ridge and the base of unconfined aquifer that contains the only USDW. Most significantly, there is a shallow oil production zone in the Etchegoin Formation throughout almost the entirety of the Elk Hills field in this interval. This zone and its overlying seal provide secondary containment for CO_2 leaking from the primary Stevens storage zone. In addition, this zone is actively produced, so it is both a pressure sink, making for even more effective secondary containment, and fluids from the zone are monitored, providing greater likelihood of early warning if there is a leak.

The proposed Carneros reservoir has the same overlying seals at the Stevens reservoir plus additional seals. In order from the Carneros, these include the Media Shale Member of the Temblor and the Gould, Devilwater, and McDonald Shale Members of the Monterey. The Carneros reservoir also has two overlying production zones/pressure sinks: the Stevens and the Shallow Oil Zone in the Etchegoin.

The Carneros and Stevens reservoirs proposed as part of the storage complex are at the deepest substantial production intervals in each of their respective parts of the Elk Hills field. As such, there are few wells that extend through them. Although a review of the completion of each well to and through these reservoirs has not been completed, the original existence of a gas cap in each suggests that all these wells at least have an annular seal at the base of the caprock overlying each reservoir.

[7] http://www.conservation.ca.gov/dog/Pages/Aquifer_Exemptions.aspx)

5
HIGH-LEVEL ECONOMIC ANALYSIS

The high-level economic analysis integrates CO_2 capture, transportation and storage assessment into an overall estimate of the cost of the CCS chain for the SSJV and was performed under Task 4 of the project SOPO. C2SAFE estimated the capital, operating, and levelized costs of prospective commercial CCS facilities and operations in the SSJV. It also examined prospective revenue from CO_2 use for EOR in SSJV oil fields as an intermediate beneficial use prior to long-term storage and the potential value of federal tax credits and California greenhouse gas compliance instruments. The latter makes California unique in the nation and provides some of the world's strongest incentives for undertaking CCS. High level findings of the economic analysis are provided here; for more information see the project's (Task 4) Topical Report on Integrated Scenario Analysis.

5.1 CO_2 Capture Technology and Economics

5.1.1 SSJV Point Source Screening for CO_2 Capture Potential

C2SAFE deemed the point sources most likely to adopt CO_2 capture technology to be those planning to operate for decades to come and those large enough to reap the economies of scale in CO_2 capture equipment.

With respect to future electric grid needs, natural gas plants have been gaining market share nationally and have long been the predominant fossil power plant type in California. Despite California policies to increase the number of renewables in the generation mix and to add grid-scale energy storage, the retirement of California nuclear plants, the reduction in imported power from coal plants in neighboring states, and grid reliability/security needs suggest that natural gas power plants will continue to be a vital generation resource in California for decades. To meet long-term greenhouse gas reduction goals, existing NGCC plants can be retrofit with post-combustion CO_2 capture systems or, in some cases, replaced with oxy-combustion power plants (with inherent CO_2 capture) firing natural gas or biogas. Oil producers in the SSJV report decades of reserves and long-term operating plans for steamflood-assisted oil production.

With respect to point source size, C2SAFE's initial screening examined facilities emitting at least 200,000 tonnes of CO_2 annually. Because some reporting entities aggregate individual adjacent combustion stacks, individual combustion sources at the facilities were reviewed to identify those emitting at least 100,000 tonnes CO_2 annually.

To match the SSJV point sources with potential CO_2 storage sites, the emitters were further classified as to whether they were located on the east or west side of the SSJV. Figure 5–1 shows a dot plot of the potential annual CO_2 capture quantities (assuming 90% capture and 2015 emissions rate) by source type (i.e., CHP, NGCC, or OSTG) and valley location. As depicted, the largest individual emitter is a bank of steam boilers on the east side of the SSJV, but overall, more large emitters are found on the west side of the SSJV. Note that the NGCC emissions are shown per combustion turbine unit, but each of the four NGCC plants in the SSJV has multiple combustion turbines, so a larger quantity of CO_2 could be captured from multiple exhaust ducts close to a given plant site.

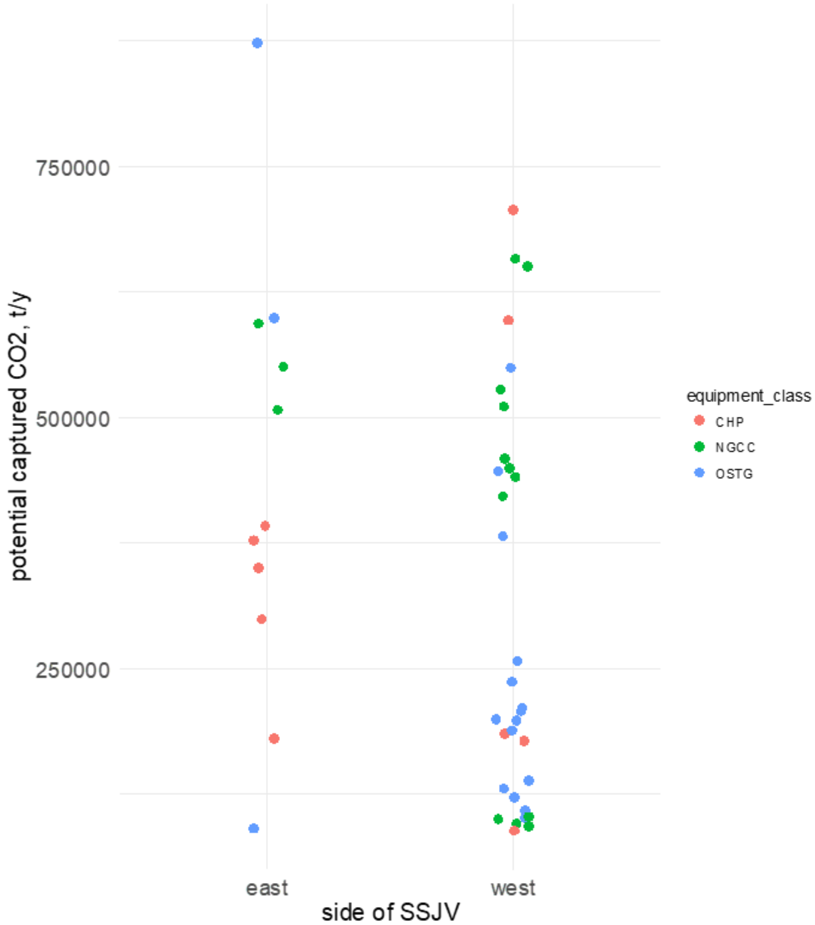


Figure 5-1
Dot plot showing the distribution of potential quantities of captured CO_2 from the large point sources on the east and west sides of the SSJV

5.1.1.1 Source-Specific Retrofit Considerations for NGCC Units

The Elk Hills NGCC plant is sited within the CO_2-EOR suitable Elk Hills oilfield and is operated by the oilfield operator, CRC. Thus, it is a particularly attractive candidate for a CO_2 capture and compression retrofit. For power producers operating in competitive regional markets, concern has been expressed that the addition of CO_2 capture to a given generating unit would increase its variable operating cost, and absent any other incentives or policies, reduce its position in the dispatch order. However, the California Independent System Operator has provisions for designating units as “must run” and thus offers state regulators an option to help assure a plant operator investing in CO_2 capture and compression that its retrofit unit could be dispatched at a high capacity factor. A must-run designation (or comparable preferential dispatch mechanism) can also reduce the risk that lower market prices for electricity, driven by increasing mandatory procurement/production of renewable generation, would undermine future-year capacity factors before the capital investment in CO_2 capture equipment could be recouped. [Note: At present, the capacity factors for the four NGCC units studied by C2SAFE ranged from 26% to 86% in 2015, with the Elk Hills plant is at the high end of the range.]

5.1.1.2 Source-Specific CO_2 Capture Considerations for Oilfield Steamflood Operations

Cogeneration units and once-through steam generators are typically operated to match the demand for steam in the oilfields, which is contingent on well production response to steam stimulation and long-term production plans influenced by the expected price of oil. Unlike power plants dispatched by electric grid operators, there is not an instantaneous demand for oil that must be followed in real time. Hence, demand for steam can be planned for longer operational periods and farther in advance. Addition of CO_2 capture to steam boilers and cogeneration units will increase the net cost of making steam, which oil producers would look to offset by generating salable low carbon fuel standard (LCFS) credits or avoiding the need to purchase LCFS credits as well as through other federal and state incentives. Discussions with oil producers suggest a business case can be made by “stacking” current incentive values. The typical capacity factor for oilfield steam producing units is high and they tend to operate steadily, condition conducive to economical CO_2 capture application.

5.1.2 CO_2 Capture Economics

C2SAFE economic analyses assumed that CO_2 would be captured from SSJV point sources using the Shell Cansolv amine-based post-combustion capture process. This process is the current reference process used by NETL for its “Baseline” report series on state-of-the-art fossil power plants with CCS. The NETL reference process also includes drying of product CO_2 and multi-stage centrifugal compression to transport pipeline pressure. Because of the nature of the process, the properties of the CO_2 product stream are relatively insensitive to the CO_2 composition of the inlet flue gas.

Using FE/NETL costing tools for post-combustion CO_2 capture from coal and natural gas power plants and applying NETL scaling factors for the source sizes found in SSJV oilfield steamflood operations, C2SAFE estimated the 30-year levelized cost of CO_2 capture and compression for a “Cansolv type” process to be about $100 per tonne-$CO_2$ for large oilfield cogeneration units, and slightly less for utility-scale NGCC units (see Figure 5–2). The levelized cost of CO_2 capture and compression for oilfield steam boilers is estimated to be somewhat higher due to fewer economies of scale at their smaller unit sizes. C2SAFE examined the effect of the discount rate on the estimated levelized cost by running analyses at discount rates of 5% and 10%.

As shown in Figure 5–2, there is a strong relationship between the levelized cost of CO_2 capture per tonne and the size of the CO_2 capture system. The observed economies of scale for CO_2 capture systems justify C2SAFE’s focus on point sources emitting more than 200,000 tonnes of CO_2 annually.

An examination of the composition of the levelized cost results finds capital cost to be the primary cost component, or roughly 50–60% of the overall 30-year levelized cost (see Table 5–1). The predominance of the capital cost is the reason that the discount rate has such a strong effect on the overall levelized cost. This suggests that government loan guarantees or other programs that reduce the cost of capital to SSJV point source operators will be important to making a business case for investment in CCS. Fixed operating and maintenance costs represent about one-third of the 30-year levelized cost, and variable operating and maintenance costs make up about 10% of the 30-year levelized cost.

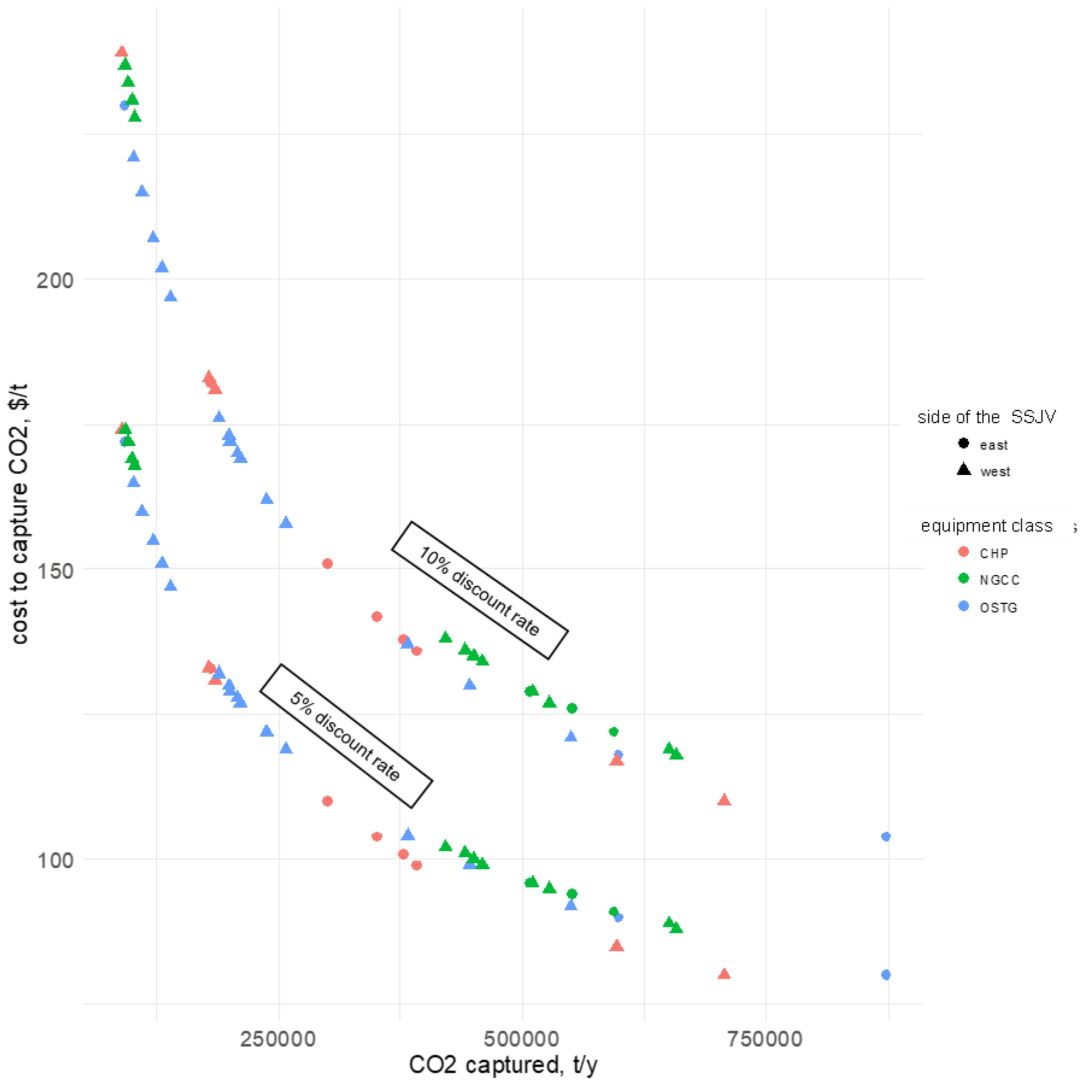


Figure 5-2
Plot of the estimated 30-year levelized cost per tonne of CO_2 captured for SSJV point sources, identified by equipment type (color) and location in the SSJV (shape)

Table 5–1 and Figure 5–2 show that the levelized cost of CO_2 capture and compression is relatively insensitive to the type of SSJV point source for modest point source sizes. Even though there are differences in the CO_2 concentration between the source types (see Table 3–1), all the CO_2 concentrations are dilute, and for modest size sources the differences are not significant. Thus, for the many SSJV sources in this size range, factors other than source type will determine the most economical projects.

For SSJV point sources overall, the most economical projects will be those with large CO_2 capture systems (which require the point source to be large), high capacity factors, and low costs of capital (discount rate).

Table 5-1
Breakdown of the contributors to the 30-year levelized cost to capture CO_2 for oilfield point source types of similar size (discount rate = 5%)

Emitter type	OSTG		CHP		Small NGCC	
Capacity	500 MMBtu/hr		40 MW_e		75 MW_e	
CO_2 captured, t/y	104,601		107,867		117,676	
Annual cost contributions	\$/t CO_2	%	\$/t CO_2	%	\$/t CO_2	%
Fixed operating costs	56	34	61	38	58	36
Variable operating costs	24	15	9	6	15	9
Capital charge (discount rate = 5%)	84	51	91	57	87	55
Total capture cost	164		161		159	

5.2 CO_2 Pipeline Cost Analysis

A C2SAFE analysis by Southern California Gas compared six CO_2 pipeline capital cost estimating methods. The formulas examined included those by Kinder Morgan, a leading developer of pipelines linking natural CO_2 sources with oilfield EOR operators; NRG, the power company that co-developed the Petra Nova coal power plant CCS to oilfield EOR project; the University of California–Davis (two versions); Carnegie Mellon University; and the University of Alaska–Fairbanks. The latter three formulas are embodied in the FE/NETL CO_2 Transport Cost Model. The various methods yielded capital cost estimates varying by a factor of two (see Table 5–2). The NRG formula, which drew upon cost data for the Petra Nova project, yielded the highest estimated cost, at nominally $100,000 per pipeline diameter-inch per mile. However, this pipeline resembles several characteristics of the envisioned C2SAFE pipeline network, namely the nature of the CO_2 as industrially captured, its approximate length, and its route through relatively flat rural/agricultural terrain.

Using the NRG formula, Southern California Gas estimated the capital cost of an 8-inch (200 mm) pipeline spanning the eastern portion of the C2SAFE network and hub interconnecting pipeline totaling 60 miles (96 km) to be about $48 million. A linearly proportional extrapolation of this result to the envisioned 110-mile (176 km) C2SAFE pipeline network boosts the capital cost estimate to $88 million.

Table 5-2
Comparison of CO_2 Pipeline Capital Cost Estimating Methods

Cost Estimating Method	Relative Pipeline Cost (Kinder Morgan = 1.0)
UC Davis (Parker) Formula[8]	1.7
CMU (McCoy & Rubin) Formula[9]	1.3
UAF (Rui et al.) Formula[10]	1.0
Kinder Morgan Formula	1.0
NRG Formula	2.0
UC Davis (alternate) Formula	0.98

Note: The named "formulas" are derived formulas based on research associated with these companies and have not been approved by these individuals or companies and were used solely for C2SAFE cost sensitivity insights.

The FE/NETL CO_2 Transport Cost Model estimates capital costs, operating costs (in nominal and present value terms), and 30-year levelized costs on a \$/tonne-CO_2 transported basis. Using the model's standard financial parameters (for the western region) and inputting the C2SAFE pipeline network distance of 110 miles (176 km) and an annual CO_2 transportation quantity of 2.0 million tonnes yields capital costs for an 8-inch (200 mm) diameter pipeline ranging from roughly \$40 million to \$100 million (when adjusted to 2018 dollars), depending on the equation set selected, and \$55 million to \$125 million for a 12-inch (300 mm) diameter pipeline. Although the model's solution algorithm does not select a 10-inch (250 mm) diameter pipeline, manual entry of this size yields a capital cost range about halfway between the cost ranges for the 8-inch (200 mm) and 12-inch (300 mm) diameter pipelines.

Levelized costs range from \$2.50 to \$5 per tonne of CO_2 when using the 10-inch (250 mm) pipeline, again depending on the equation set selected. Within the levelized cost analysis, capital costs are the dominant cost element, accounting for 72%–86% of the total transportation costs on a net present value basis. When levelized costs are driven chiefly by capital costs, the levelized cost is very sensitive to the quantity of CO_2 transported (i.e., the tonnes of CO_2 over which the capital costs can be amortized). The business implication of this situation is that securing a certain minimum quantity of CO_2 to be transported from "anchor" users will be needed to justify the investment in pipeline construction. However, once this business hurdle is met and the pipeline is built, the incremental cost of transporting additional CO_2 (up to the pipeline's maximum capacity) is very low, suggesting that transportation costs should not be an impediment to rapid expansion of C2SAFE complex use once the complex has achieved commercial status.

[8] Using natural gas transmission pipeline costs to estimate hydrogen pipeline costs. Nathan Parker, Institute of Transportation Studies, University of California, UCD-ITS-RR-04-35, 2004.
[9] An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage. Sean T. McCoy, Edward S. Rubin; International Journal of Greenhouse Gas Control 2 (2008), 219–229.
[10] Regression models estimate pipeline construction costs. Zhenhua Rui; Paul A Metz; Douglas B Reynolds; Gang Chen; Xiyu Zhou; Oil & Gas Journal; July 4, 2011; 109, 14; ABI/INFORM Global pg. 120.

5.3 Geologic CO_2 Storage Technology and Economics

As noted, of the three storage targets evaluated by C2SAFE, two are located in the western side of the basin in the Elk Hills oilfield (western storage hub): the Stevens Sandstone and the Carneros Sandstone reservoirs. The Stevens, which is an upper unit in the Monterey Formation, would be coincident with a CO_2-EOR project owned and operated by CRC. The other reservoir in the Elk Hills field is a depleted gas zone in the Carneros Sandstone of the Temblor Formation. The third C2SAFE storage target, in the eastern side of the basin, is the Vedder Formation (eastern storage hub).

C2SAFE analysis of sources and storage target properties led to the following assumption of how a nominal 2 million tonnes of CO_2 captured annually would be injected among the three storage targets: 400,000 tonnes into the Vedder, 200,000 tonnes into the Carneros, and 1.4 million tonnes into the Stevens. Injection of the nominal 2 million tonnes per year for 30 years (the operating period used for cost estimating), results in a total nominal storage volume of 60 million tonnes. (Refer to the Task 3 Topical Report on Sub-Basin Storage and Preliminary Risk Assessment for the modeling details on well injectivity).

5.3.1 Economic Analysis Methodology

To evaluate the cost of storing CO_2 in the three formations described above, C2SAFE used the FE/NETL CO_2 Saline Storage Cost Model[11] that estimates the break-even price (in the first year) of CO_2 storage in a deep saline formation[12] such that the Net Present Value (NPV) of the project is 0. The model also estimates capital costs and operating costs, both in real, nominal as well as present value terms. The model follows EPA's Class VI regulatory requirements.

Although the model allows for estimation of the reservoir values needed to evaluate costs (i.e. CO_2 plume area and number of injection wells), C2SAFE generated those inputs separately (see Table 5–3), estimated from numerical simulation and historical data analysis of production data from the C2SAFE sub-basin assessment. C2SAFE used the financial assumptions embedded in the FE/NETL model (see Table 5–4). Additional information detailing the number of observation wells, seismic surveys, etc. assumed in the cost analysis can be found the Task 4 C2SAFE Integrated Scenario Analysis Report.

Table 5-3
Injection wells, average rates, CO_2 plume area, and pressure area for each C2SAFE reservoir

Reservoir	# of injectors	Rate/injector (CO_2 tonnes/yr)	Maximum CO_2 plume area (km^2)	Maximum pressurized area (km^2)
Vedder (saline)	2	200,000	12	72
Carneros (depleted)	4	50,000	9	18
Stevens (CO_2 EOR)	7	200,000	23	23

[11] National Energy Technology Laboratory (2017). FE/NETL CO_2 Saline Storage Cost Model. U.S. Department of Energy. Last Update: Sept. 2017 (Version 3).
[12] National Energy Technology Laboratory. FE/NETL CO_2 Saline Storage Cost Model: User's Manual. U.S. Department of Energy, Pittsburgh, PA, 2017.

Table 5-4
Financial assumptions used in economic analysis of CO_2 storage in the SSJV

Financial Item	Value	Units/ Comments
Percent Equity (remainder is debt)	55.0%	Capitalization
Cost of Equity	10.0%	
Cost of Debt	5.5%	Interest rate
Tax Rate	21.0%	Matches PSFM
Escalation Rate	3.0%	
General and Administrative (G&A) Factor	20%	Assessed on all labor costs
Site Selection & Site Characterization Failure Contingency	0%	Assessed to account for sites failing
Process Contingency Factor	20%	Assessed on all monitoring costs
Project Contingency Factor	15%	Assessed on all capital costs
Lease bonus	$ 50.00	$/acre
Injection Fee (for lease holders)	$0.25	$/tonne
Long-term Stewardship Trust Fund (State)	$0.07	$/tonne
Operational Oversight Fund (State)	$0.01	$/tonne

5.3.2 Summary of Storage Economic Analysis

According to C2SAFE analyses performed using the FE/NETL CO_2 Saline Storage Cost Model, the levelized cost of storing a tonne of CO_2 (see Table 5–5) three formations in the San Joaquin Valley was found to range from ~$8/tonne in the Stevens Sand to ~$36/tonne in the Carneros Sandstone.

One of the main cost drivers is the cost of drilling and completing wells, which is consistent with reports in the literature. Therefore, it is not surprising that the Carneros, the deepest of the three cases and having a lower injectivity than the other cases, displays the highest cost. Similarly, the lowest cost case, the Stevens, is the shallowest of the cases analyzed and has an injectivity that allows for injection of four times more CO_2 per well than in the Carneros.

Table 5-5
Summary of levelized cost of CO_2 storage in the three hubs considered for the San Joaquin Valley

Storage Reservoir	Case	Total CO_2 injected/yr	# of Inj.	Depth [ft]	Levelized cost [$/tonne of CO_2]
Stevens		1,400,000	7	7,000	8
Carneros		200,000	4	10,000	36
Vedder	Minimum 3D seismic monitoring	400,000	2	9,000	15.89
	Regular 3D seismic monitoring				16.26
	With water extraction - sold after treatment				20.67
	With water extraction - reinjected in shallower unit				22.08

5.4 Incentives and Legal/Regulatory Issues

California greenhouse gas regulations and prospective federal regulations have created the market for CCS, and federal and state incentives are available to help offset the cost of CCS.

California's various greenhouse gas regulations has resulted in market mechanisms, such as tradeable cap-and-trade emission allowances and LCFS credits, that collectively provide one of the world's greatest economic incentives for CCS.

Additional limited or one-time incentives may be available to accelerate scale-up R&D and demonstrations or first-of-a-kind commercial systems. NETL's CarbonSAFE program is an example for CO_2 storage. The State of California accumulates cap-and-trade CO_2 emission allowance auction revenue into a Greenhouse Gas Reduction Fund (GGRF), for which the California Air Resources Board (CARB) establishes a triennial investment plan for approval by the legislature and governor. The GGRF's authorizing legislation expanded the fund's mission in 2016–17 to include greenhouse gas-reducing R&D projects. Stakeholders could potentially voice support for funding of C2SAFE or other CCS projects with GGRF funds at future CARB public workshops. California legislation also provides for collection of a "public goods charge" from investor-owned natural gas utility customers to fund R&D benefitting ratepayers, including projects furthering greenhouse gas reductions. Administered by the California Energy Commission (CEC), the Public Interest Energy Research (PIER) program also holds annual public workshops on its proposed investment plan. At the 2018 workshop, CCS posed a question for stakeholders on the need for funding CCS R&D projects.

5.4.1 IRS section 45Q tax credits

At the federal level, the most significant incentive for CCS is the Internal Revenue Service (IRS) tax credit known as Section 45Q, credit for carbon dioxide sequestration, initially enacted as part of the Energy Improvement and Extension Act of 2008. It covers "qualified" CO_2 captured at "qualified" facilities, stored securely in U.S. geologic formations. The qualifications essentially amount to capturing CO_2 at an industrial point source that would otherwise be emitted to the atmosphere at a rate of at least 500,000 tonnes per year. The original program limited the overall cumulative quantity of stored CO_2 that could receive the tax credit at 75 million tonnes. To be securely stored, CO_2 could be injected into saline formations or into hydrocarbon reservoirs for EOR, with residual permanent storage. The initial credit value differed depending on the type of storage used, and were indexed for inflation. Credits were received for the tax years in which the CO_2 was injected.

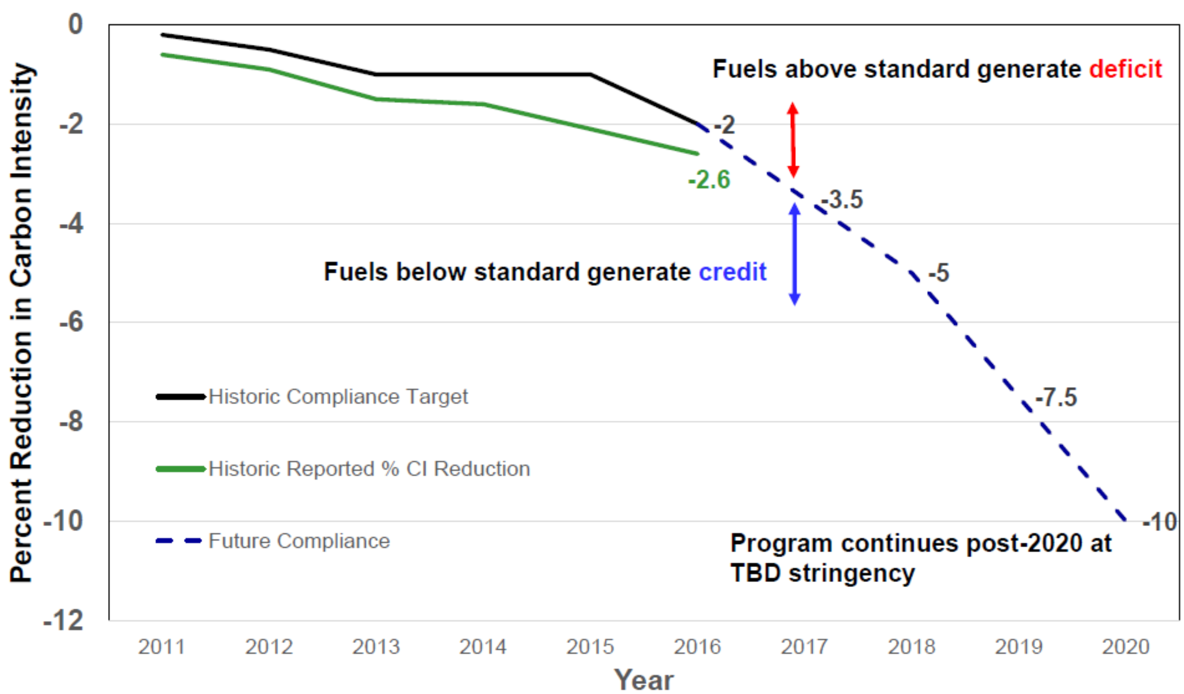
The Bipartisan Budget Act of 2018, enacted in February, significantly expanded the Section 45Q tax credit program.[13] The program cap of 75 million tonnes was removed. The period of program eligibility was established to be 12 years from commercial startup. The qualifying capture rates were adjusted for different source types and capture technologies. Specifically, industrial facilities emitting less than 500,000 tonnes of CO_2 per year (i.e., small relative to utility fossil fuel power plants) would be eligible if deploying systems capturing at least 25,000 tonnes of CO_2 per year. Some SSJV oilfield cogeneration units and steam boilers fall in this size category. Direct air capture of at least 100,000 tonnes of CO_2 per year would also qualify. Utility power plants still need to capture at least 500,000 tonnes per year. A schedule to increase the value of tax credits linearly from 2017 to 2026 was established, with the credit for saline formation storage rising from $22.66 to $50 per tonne and the credit for CO_2 injected for EOR with residual storage rising from $12.83 to $35 per tonne.

[13] http://uscode.house.gov/view.xhtml?req=(title:26%20section:45Q%20edition:prelim)

In terms of C2SAFE economic analyses, the 45Q tax credit values will reach their new maximum levels at about the time of the envisioned commercial C2SAFE startup, so the values of $35 and $50 per tonne were used, respectively, for EOR and saline/depleted reservoir storage projects.

5.4.2 California low-carbon fuel standard credits

The LCFS was launched in 2009 to implement AB 32, the California Global Warming Solutions Act of 2006. CARB assigns transportation fuels a life-cycle greenhouse gas emissions value (known as a carbon intensity) and requires producers of California transportation fuels to reduce their average carbon intensity to the level of a benchmark that declines in prescribed annual increments. Fuels with carbon intensities below the benchmark generate credits; fuels with carbon intensities above the benchmark generate deficits. Unlike cap-and-trade emission allowances, there is no distribution or auction of LCFS credits. The original LCFS program culminated in a reduction in the benchmark by 10% by 2020, relative to a 2010 baseline (see Figure 5-3 5–3).



Credit: California Air Resource Board presentation

Figure 5-3
Original LCFS Compliance Targets Through 2020

Table 5-6
CARB Staff-Proposed LCFS Schedule for Percentage Reduction in Carbon Intensity

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
6.25 %	7.50 %	8.75 %	10.00 %	11.25 %	12.50 %	13.75 %	15.00 %	16.25 %	17.50 %	18.75 %	20.00 %

With legislation in 2017 extending the LCFS program to 2030, CARB staff in March 2018 proposed that the benchmark continue to decline 1.25% per year linearly to reach a 20% reduction (relative to the 2010 benchmark) by 2030 (see Table 5–6).[14]

CARB facilitates transactions of credits among entities regulated by AB 32's low-carbon fuel standard to meet their compliance obligations. Over the course of the LCFS program, the price of credits rose in the early years, but fell in 2015–2016 when the program was subject to legal challenges and other uncertainties. The passage of AB 398 and AB 617 in 2017 by two-thirds majorities not only codified the LCFS into law and extended the program to 2030, it also eliminated the primary basis of the legal challenges. Since then, credit prices have been less volatile and have risen steadily. The credit price for transactions for the period of January through March 2018 averaged \$124/tonne-CO_2.[15]

CARB modeled "illustrative, marginal" future LCFS credit prices through 2030 on the basis of its original program and the CARB staff-proposed amendments issued in March 2018 (see Figure 5–4).[16] Modeling results suggest that CARB aims to stabilize the LCFS credit price at an annual maximum value of about \$125 per tonne-CO_2.

The CARB staff amendments to the LCFS proposed in March 2018 also include accounting and permanence protocols for geologically sequestered CO_2, allowing CCS projects related to transportation fuel production to generate LCFS credits. The amendments also allow direct air capture projects to generate credits.

Because the LCFS credit transaction market has no price floor, financial analysts typically discount the market price to account for uncertainty. Even discounted, the value of an LCFS credit is among the highest CCS incentives in the world on a dollar per tonne of CO_2 basis. In its integrated economic analysis, C2SAFE discounted the value of an LCFS credit to \$100 per tonne.

[14] https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf
[15] https://www.arb.ca.gov/fuels/lcfs/credit/20180410_marcreditreport.pdf
[16] https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf

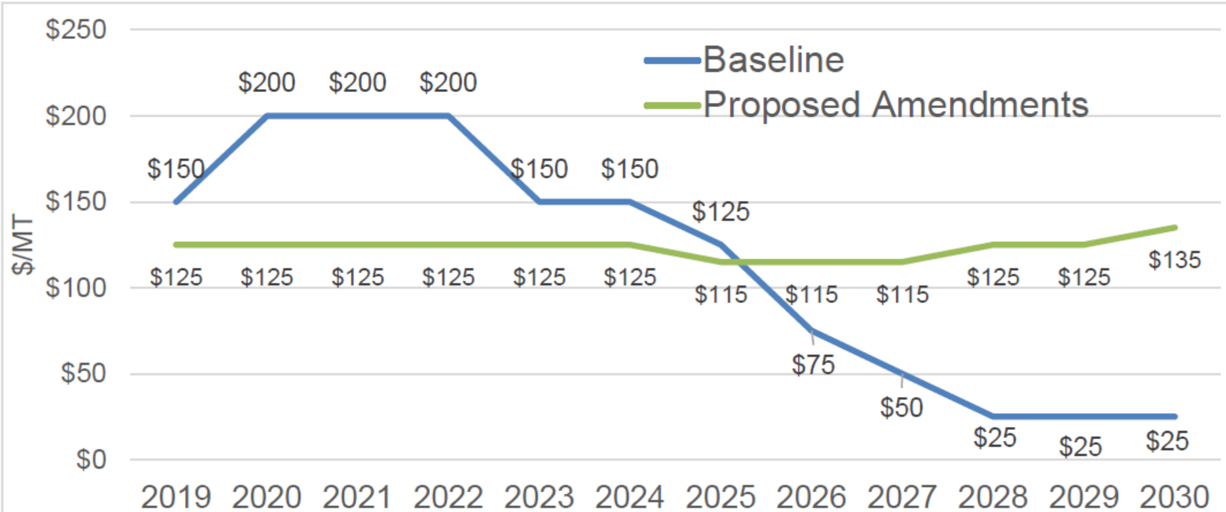


Figure 5-4
CARB Projected LCFS Credit Prices under the Baseline Program and Staff-Proposed Amendments

5.4.3 California, Quebec, and Ontario Cap-and-Trade Emission Allowances

The "covered entities" required to participate in California's cap-and-trade program include power producers and transportation fuel producers, which are by far the two largest point source types in the SSJV.

In 2017, California's cap-and-trade program was also extended to 2030. The Province of Ontario's cap-and-trade program is now holding joint auctions with California and Quebec.

The February 2018 emission allowance auction price was about $15/tonne-$CO_2$. Although the value of a cap-and-trade emission allowance is significantly lower than an LCFS credit, the cap-and-trade program has a floor price, which in 2018 is about $14.50/tonne. The floor price increases by 5% per year plus inflation.

The Ontario Energy Board published in 2017 a long-term forecast of cap-and-trade allowance prices reaching a mid-range value of CAD$57/tonne-$CO_2$ by 2028 (in 2017 dollars),[17] which is about $45/tonne using an April 2018 exchange rate.

Once the CARB accounting and permanence protocols for geologically sequestered CO_2 are approved by its Board of Directors for the LCFS program, CARB staff intend to introduce them as amendments to the cap-and-trade program.

5.4.4 Legal and Regulatory Issues

Although California is not presently among the 11 states that have passed CCS-specific legislation, several California Assembly and Senate bills have explicitly identified CCS as a greenhouse gas mitigation measure and authorized regulators to develop CCS rules. For example, SB 1368, an emission performance standard for baseload power generation or procurement, enacted in 2006 along with the landmark AB 32 bill, identifies CO_2 capture and geologic storage as an allowable compliance measure.

[17] https://www.oeb.ca/sites/default/files/uploads/OEB-LTCPF-Report-20170531.pdf

5.4.5 Pore Space Ownership and Rights Acquisition

Although legislation specific to ownership of pore space rights in the subsurface outside of a mineral estate has not been enacted in California, there is a general consensus that the surface owner retains all rights not held by a mineral estate owner. Thus, the pore space owner with respect to CO_2 storage in saline formations is expected to be the surface owner.

As CO_2 injection for storage has not been practiced in California, there are no in-state data for estimating the cost of pore space rights acquisition. C2SAFE reviewed the reported cost of securing pore space rights from the FutureGen 2.0 project in Illinois, which was on the order of $50 million. The prospective CO_2 plume for the C2SAFE east-side hub (in the Vedder Formation) would reside almost entirely under agricultural land between Shafter and McFarland, east of Wasco. This setting seems similar in land use to the agricultural area in Illinois where FutureGen 2.0 secured pore space rights, and thus the FutureGen cost may be appropriate for order-of-magnitude cost estimating. When the FutureGen 2.0 cost is compared with the minimum of 50 million tonnes of CO_2 targeted for storage by C2SAFE, the levelized cost of pore space rights acquisition appears to be on the order of $1 per tonne-$CO_2$.

For the C2SAFE west-side hubs, the prospective CO_2 plumes in the two reservoirs in the Elk Hills oilfield would entirely underlie the field itself. The land use in the field area is oil production, gas processing, modest CRC office space and industrial facilities, and a power plant. There are no co-located land uses other than conservation areas. CRC owns or co-owns the mineral rights in the Elk Hills oilfield. Consequently, it likely has authority to inject CO_2 for enhanced oil recovery with incidental storage in the Stevens reservoir hub. It also owns the surface over the Carneros depleted reservoir, and so has authority to inject CO_2 into that reservoir as well. Thus, the cost of pore space rights acquisition for the west-side hubs could be minimal.

C2SAFE has obtained parcel ownership data for the area around the CES Kimberlina power plant. Analyses suggest that, in general, the areal extent of prospective plume for injection at Kimberlina involves a relatively small number of affected landowners. However, a small portion of the prospective plume area is occupied by a large number of small parcel owners. It might be possible to engineer the plume to avoid some of these areas if agreements cannot be secured.

CRC owns mineral rights in areas to the northwest of the Kimberlina plant site, which could be reached by the prospective CO_2 plume in the Vedder Formation, depending on east-side hub injection well placement. However, there is no active resource development in many of the areas for which CRC holds rights. The only active production is in the immediate vicinity of the North Shafter oilfield. The Vedder Formation is below the deepest productive zone in this field, so subsurface interaction such as pressure interference is unlikely. The well density in the North Shafter field is moderate, so even if CO_2 injection or brine production wells were needed in that area, they could likely be designed and installed in a manner that would not create conflict. Mineral rights in the up-dip portion of the prospective CO_2 plume at Kimberlina (to the northeast) have not been separated from surface ownership.

5.4.6 Liability for Stored CO_2

Liability for potential CO_2 leakage and remediation during the time period covered by an EPA Underground Injection Control Class VI permit is addressed by a requirement to demonstrate financial responsibility (e.g., posting a bond). C2SAFE reviewed the cost for demonstrating financial responsibility reported by the FutureGen 2.0 and other projects and estimated the levelized cost of such liability protection for C2SAFE storage quantities to be less than $1 per tonne-$CO_2$.

Long-term liability for the CO_2 storage sites remains an undefined and open-ended issue in California. The California CCS bills introduced in the late 2000s and early 2010s, which did not proceed to floor votes, did not address the issue of long-term liability. C2SAFE has reviewed the various insurance type, bond type, fee type, and future year transfer type approaches used in other states, but has not seen a preference by state agencies for any given approach. In the absence of legislation addressing this issue, long-term liability risk must be evaluated on a project-by-project basis and risks assumed or protections negotiated.

Given the large areal extent and remote location of the Elk Hills oilfield, CRC will accept long-term liability for CO_2 it captures at the Elk Hills power plant and/or cogeneration plant and injects in operating reservoirs for EOR (with residual storage) or depleted reservoirs for storage. Clean Energy Systems will accept liability for CO_2 captured and injected at the Kimberlina power plant as part of its BioCCS operations (which are expected to be small in scale). There is scant data on the cost of insurance or other programs to cover long-term liability for CO_2. In its economic analyses, C2SAFE estimates the levelized cost of addressing liability to be on the order of a few dollars per tonne of CO_2.

5.5 Integrated Economic Summary

The business case for CCS in California's southern San Joaquin Valley appears economically viable today for large CO_2 point sources involved in the production of transportation fuels, such as oilfield cogeneration units and steam boilers (see Figure 5–5). As shown, the overall levelized CCS cost is estimated at roughly $125 per tonne of CO_2, estimated from summing the aforementioned economic analyses of CO_2 capture, transportation, and storage. The levelized CO_2 capture cost is based on today's amine-solvent post-combustion capture technology, with no future cost reduction factored in for technology improvement. By the time of C2SAFE commercial operation in 2025 and beyond, such technology improvement and learning-by-doing knowledge could yield significant cost reductions, but the C2SAFE economic analysis has not assumed such savings. The sum of the value of incentives and revenue from California LCFS credits (discounted roughly 20% from their current transaction value), sale of California cap-and-trade emission allowances, and Section 45Q tax credits—either for saline storage or the EOR credit plus CO_2 sales revenue—is about $165/tonne-$CO_2$.

The economic viability of CCS for NGCC power plants in the SSJV is more site-specific. A plant providing power solely to the electric grid (e.g., Calpine Pastoria), if it added CCS, should be eligible for Section 45Q tax credits and could sell its excess cap-and-trade emission allowances, but it would not generate LCFS credits. Using the cost and incentive values shown in Figure 5–5, it would not be economical for such a plant to add CCS today, barring other considerations. An NGCC plant within an oilfield (e.g., CRC Elk Hills and NRG Sunrise) that provides power to the oilfield as well as to the grid should receive "partial credit" in terms of generating LCFS credits if it added CCS (pro-rated for the fraction of power going to the oilfield). Such a plant should also be eligible for Section 45Q tax credits and garner revenue from selling its excess cap-and-trade emission allowances. Using the cost and incentive values shown in Figure 5–5, the economic viability of adding CCS today would depend on the relative fractions of electricity supplied to the oilfield and the grid. As the value of cap-and-trade emission allowances grows over time (either by market forces or the escalating floor price), the relative fraction of power needing to remain in the oilfield to achieve "breakeven" would diminish. At some point, even plants providing all their power to the grid would be candidates for economical CCS application.

In situations where a point source operator has made an investment decision in repowering, the incremental cost of incorporating CCS should be less than the cost of a CCS retrofit, and the level of incentives needed to achieve economic viability would be lower. Thus, such situations are an opportune time for evaluating CCS business cases.

For situations where the point source owner/operator is also an oilfield operator seeking CO_2 for EOR, a project-specific economic analysis could incorporate revenue from sale of the incremental oil produced by CO_2-EOR operations. Given the extent of oilfield-specific (and often proprietary) data involved in such an incremental production analyses, C2SAFE instead has chosen to evaluate EOR situations on the basis of expected revenue from a CO_2 sales transaction to an EOR operator. Although California has oilfields suitable for CO_2-EOR and research-scale injections have been conducted, CO_2-EOR is not a commercial practice in California (in part because there are no natural sources or CO_2 pipelines in the state). Thus, California-specific CO_2 sales price data are not available. An analysis by the Global Carbon Capture and Storage Institute (GCCSI) of data on CO_2 sales for EOR in other locations, and of projections of CO_2 sales prices once numerous CO_2 capture projects are applied to large point sources, suggests that the longer-term CO_2 price may be equal to just the cost of CO_2 compression and transportation, which GCCSI estimates at roughly \$15/tonne-CO_2.[18] Using such a CO_2 sales value, coincidentally, results in the combination of the Section 45Q tax credit for EOR (\$35/tonne) and the CO_2 sales revenue (\$15/tonne) equaling the Section 45Q tax credit for saline formation storage, as shown in Figure 5–5.

[18] https://hub.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-CO2-enhanced-oil-recovery-10

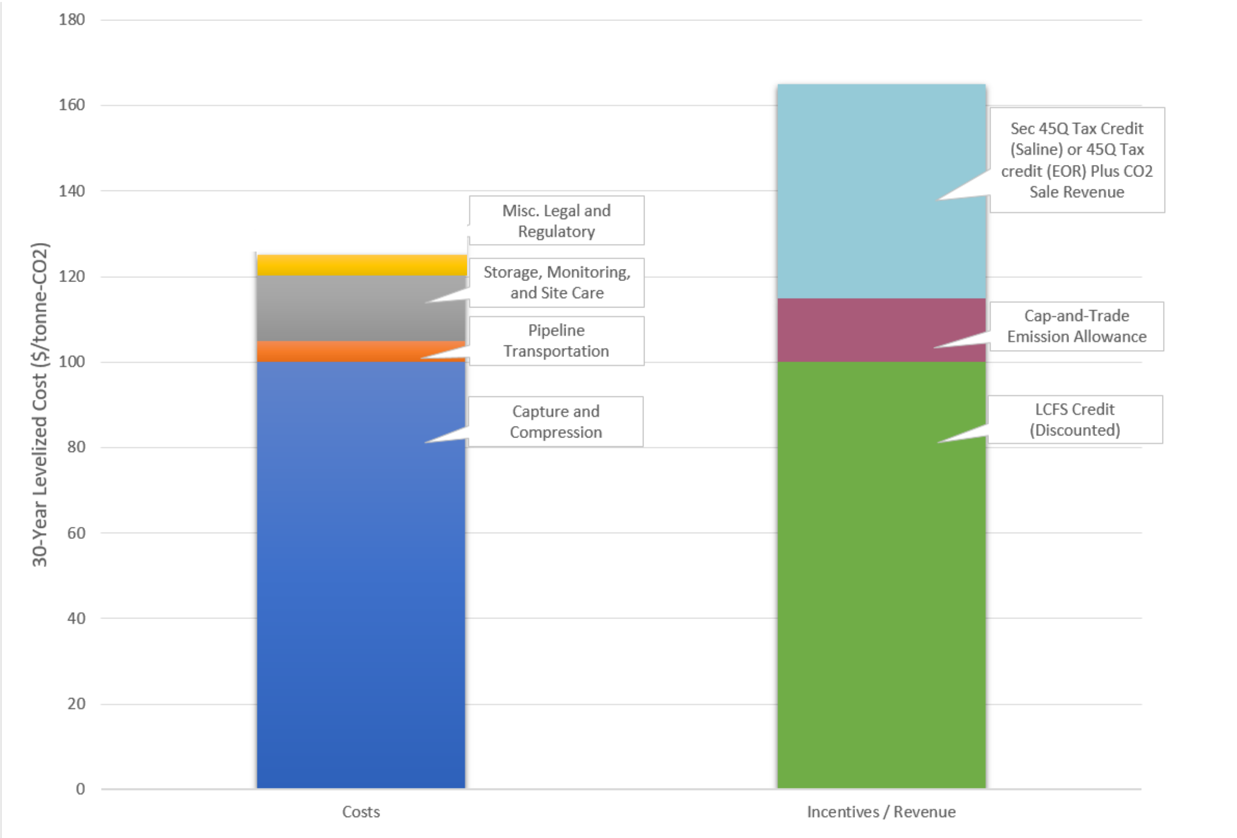


Figure 5-5
Estimated Costs and Incentives (and Revenue if EOR) for CCS Application to a Large SSJV Point Source Engaged in the Production of Transportation Fuels

6
HIGH-LEVEL REGIONAL ANALYSIS

6.1 Land Uses

The east-side site is the 37-acre (15 hectare) CES Kimberlina Power Plant, located about 17 miles (27 km) north of Bakersfield, near Highway 99 and Kimberlina Road. C2SAFE team member CES owns the land, which houses a 5 MW power plant and CES' pressurized oxy-combustion demonstration systems in the southwest corner of the property. The eastern portion of the site is occupied by linear concentrating solar demonstration arrays that are no longer in service (Figure 6–1, left photo). There is sufficient space in the northwestern portion of the property for a well drilling rig and associated pipe laydown areas, water tanks, mud mixing and storage areas, operations and mudlogging trailers, vehicle parking, etc., as shown in Figure 6–1 (right photo). In subsequent C2SAFE phases, this area's characterization well could be designed for conversion to an injection well or a monitoring well in commercial operations.

Figure 6-1
Aerial View of the Kimberlina Site (Left) and Area Available for Well Drilling at CES KPP (Right)

The Kimberlina site, Kern County APN 073-210-19, is zoned A, Exclusive Agriculture District. The power generation activities are permitted under approved Conditional Use Permits. The level and graded site is on a designated flood plain and facilities on the site must be designated to accommodate or mitigate flooding. The underlying groundwater is brackish and at 1,000 ft (300 m) depth. There are no natural water bodies or ecosystems that could be affected by drainage runoff.

The site is surrounded by large agricultural operations, primarily almond orchards. SunWorld International's fruit packaging facility is the immediate neighbor to the south. The property to the north is unoccupied and zoned for M2, industrial. A north-south branch of the Southern Pacific railroad passes along the eastern boundary of the property (which could support rail delivery of CO_2 captured at ethanol plants to the north along the rail line as early commercial customers). Adjacent to the railroad tracks is U.S. Route 99, a major north-south highway that links the major Central Valley cities of Sacramento, Modesto, Merced, Fresno, and Bakersfield. Driver Road runs along the western side of the property.

The west-side Elk Hills is 22 miles (35 km) from Bakersfield and occupies about 75 square miles (190 km^2) of industrial/rural land. Structures include over 2,000 oil/gas wells, pipelines, and gas/oil processing and power generation facilities. Future phases of C2SAFE activities will only take place on a fraction of this site, consisting of existing oil field roads for access an existing oil or gas well, which will be used for sidetrack drilling or an extension to carry out the testing and sampling program, or extension of new wells that would otherwise be installed by CRC.

6.2 Protected and Sensitive Areas

Both the east- and west-side sites are on land currently being used for industrial purposes: power generation on the east side and oil and gas production and power generation on the west side. Given these land uses, activities in subsequent phases are not expected to entail any conflicts with protected or environmentally sensitive areas.

The Kimberlina site was originally cleared and graded in 1981. There is no natural vegetation. A biology survey conducted by ENSR Corporation in 2008 did not identify any biota of concern on the site. There are also no known cultural resources within the site boundary. As the estimated size and location of the CO_2 plume under commercial-scale storage operations becomes better known during the Phase II study, further assessment of an expanded area is expected to be undertaken.

As shown in Figure 6–2, CRC has established an 8,000-acre (3,200 hectare) habitat conservation area and has received a 50-year state permit that will preserve an additional 17,500 acres (7000 hectares), for a total conservation area equivalent to over half of the surface area of the Elk Hills oil field. CRC’s habitat conservation program, which is certified by the Wildlife Habitat Council, also includes operating practices to protect unique plant and animal species and cultural resources at Elk Hills.

6.3 Population Centers and Pore Space Ownership

Bakersfield, with a population of ~347,000, is the largest community in the SSJV. Smaller communities include Shafter, Wasco, McFarland, and Taft. Significant population centers are not expected to be impacted by surface or pore space rights acquisition for a commercial CO_2 storage complex in the locations under investigation by C2SAFE. However, outreach to towns nearest the project sites will be part of the C2SAFE Phase II outreach activities, as discussed in the Stakeholder Analysis section below.

The prospective CO_2 plume in the Vedder Formation would reside almost entirely under agricultural land between Shafter and McFarland east of Wasco. As such, the injection wells—and production wells, if needed—can be sited at considerable distance from urban areas; CO_2 plume monitoring, such as seismic reflection, would not be deployed within those urban areas. The only moderately developed area the plume may underlie, according to the Kern County General Plan, is about 0.5 square mile (1.4 km2) near the intersection of Highway 46/Famoso Road and Highway 99. This is comprised of “service industrial,” “light industrial,” and “highway commercial,” but no residential, land uses.

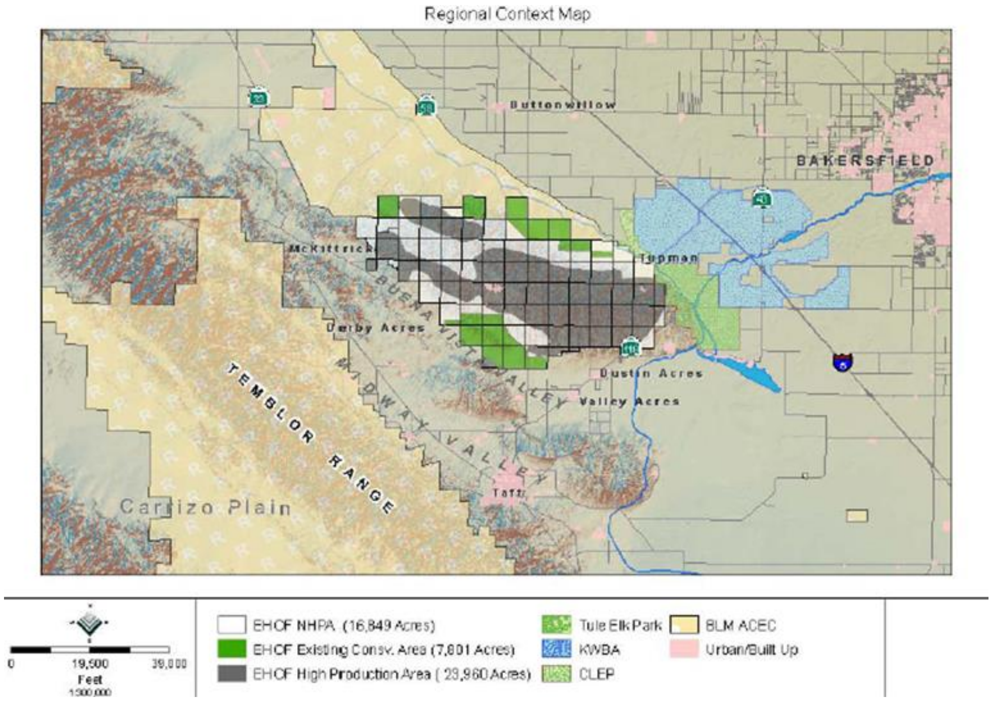


Figure 6-2
Land Designations in and Near the Elk Hills

The only resource development in the immediate vicinity of prospective storage in the Vedder Formation is the North Shafter field, which is owned by CRC. The Vedder Formation is below the deepest productive zone in this field, so subsurface interaction such as pressure interference is unlikely. The well density in the North Shafter field is moderate, so even if CO_2 injection or brine production wells were needed in that area, they could likely be designed and installed in a manner that would not conflict.

Further from the prospective Vedder storage area are fields with production from the Vedder, as mentioned. However, Jordan and Gillespie (2013) did not find any evidence of pressure interference from activity in the Vedder in one field to the next. Thus, conflicts are not anticipated to occur as a result of the proposed storage in the Vedder.

CRC owns the mineral rights in most of the area the prospective CO_2 plume in the Vedder Formation would occupy. Mineral rights in the up-dip portion of this area have not been separated from surface ownership. To the extent there is potentially relevant case law though, it suggests that pore space ownership goes with surface rather than mineral rights ownership. If this is in fact the case, surface storage agreements with the owner of each parcel overlying the prospective CO_2 plume would be required.

Figure 6–3 shows the land ownership parcels around the potential east-side Kimberlina hub. Each entity indicated by a different color. Light pink areas are owned by entities holding fewer than 5 km^2 in total each within Kern County. In general, the areal extent of the prospective plume from injection at Kimberlina involves a relatively small number of affected landowners. However, a small portion of the prospective plume area is occupied by a large number of small parcel owners. It might be possible to engineer the plume to avoid some of these areas if agreements cannot be secured. As failure to reach agreements with all necessary surface owners has the potential to adversely affect the project under the current understanding of law, securing pore space rights is an identified project risk. "Unitization" legislation for CO_2 storage will be a topic for discussion with state agency team members and stakeholders in Phase II.

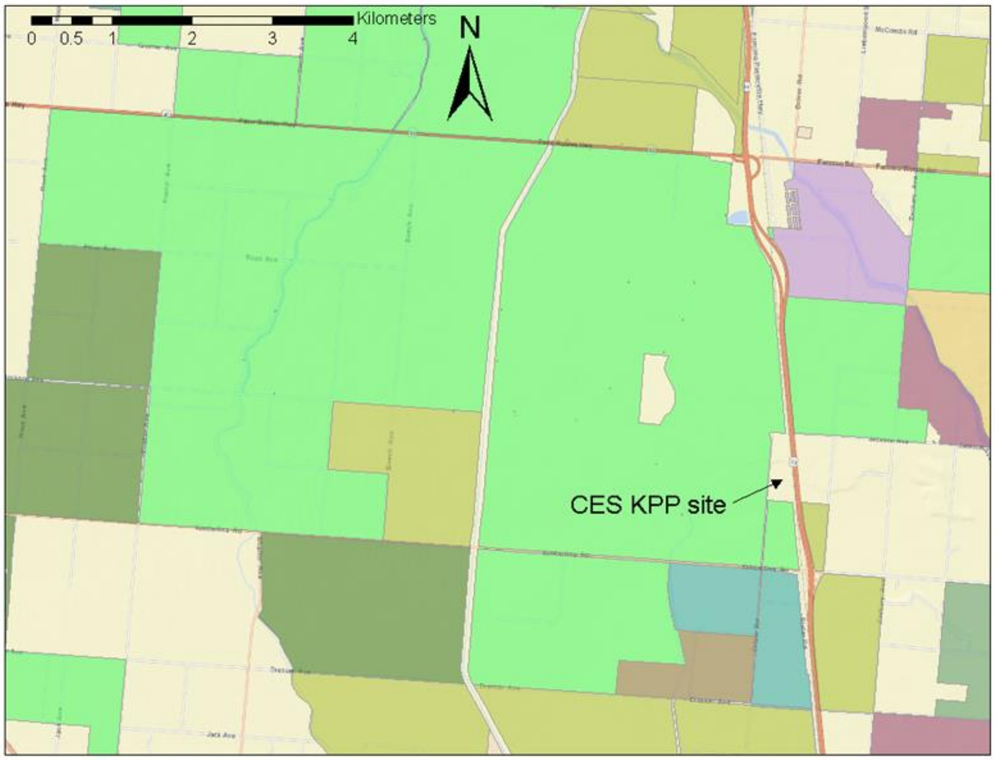


Figure 6-3
Ownership of Land Parcels around the East-Side Kimberlina Site

The prospective CO_2 plumes in the two reservoirs in the Elk Hills oil field would entirely underlie the field itself. The land use in the field area is oil production. In other words, although there is office space and industrial facilities, such as a power plant and gas processing facilities within the field, there are no co-located land uses other than conservation areas.

CRC owns most of the mineral rights in the Elk Hills oil field and operates the field under agreement with the other owners. Consequently, it likely has authority to inject CO_2 for enhanced oil recovery with incidental storage in the Stevens reservoir selected. It also owns the surface over the Carneros depleted reservoir, and so has authority to inject CO_2 into that reservoir under any interpretation. As CRC controls production of all zones in the field and all surface infrastructure, it can optimize surface and subsurface activities to avoid most conflicts, and where they occur, prioritize use and task sequencing.

7
CARBON STORAGE FACILITY IMPLEMENTATION

During Phase I, the C2SAFE team developed a preliminary implementation plan for the commercial-scale geological CO_2 storage sites as part of Task 6 of the SOPO. This includes a phased approach where an initial small-scale CO_2 capture and storage (approximately 100,000 tonnes per year) is conducted at CES' Kimberlina site to develop tools and best practices, while minimizing capital at risk, before scaling the project to reach commercial targets. Note, for the goal of 50 M tonnes of CO_2 captured over a 20-to 30-year facility life, between 1.67 M and 2.5 M tonnes of CO_2 must be stored on average, annually. The 2015 emissions suggest this amount could be captured from the source closest to the eastern storage hub and the source in the western storage hub alone, as discussed below. The initial CarbonSAFE investments in storage from these sources could be substantially leveraged by capture from the large number of additional sources on both sides of the SSJV.

Aside from the onsite CO_2 sources, i.e. CES KPP and the CRC Elk Hills facilities, initial storage "customers" are expected to be oil field sites using thermally-enhanced oil recovery that are currently subject to the state's LCFS program and therefore have the largest economic incentive to reduce CO_2 emissions (at current credit transaction prices). There are numerous fields in operation across the SSJV in Kern County Figure 7–1 is a map of the relevant oil field in DOGGR's fourth District (Kern County). Fields on the east side of the valley – north of Bakersfield – near the KPP site are the Kern River, Kern Front, and Poso Creek fields. On the west side of the SSJV – west of Bakersfield- large oil fields include the Elk Hills, Buena Vista, and Cymric fields, and smaller fields such as the McKittrick and Railroad Gap. Initial discussions with oil field operators have indicated an interest in a large-scale industrial CO_2 storage hub in the SSJV to mitigate compliance costs and risks to their operations supplying the Californian market, however concerns have been raised about long-term liability for CO_2 storage. This issue has been noted as a project risk and will be investigated in future phases of the program.

The pre-feasibility study also showed economies of scale can reduce the per unit cost of adding carbon capture systems to existing steam or power generating equipment. As such, large-scale NGCCs are also seen as potential customers for the C2SAFE storage complex, although at the current market prices, the incentives may not outweigh the costs.

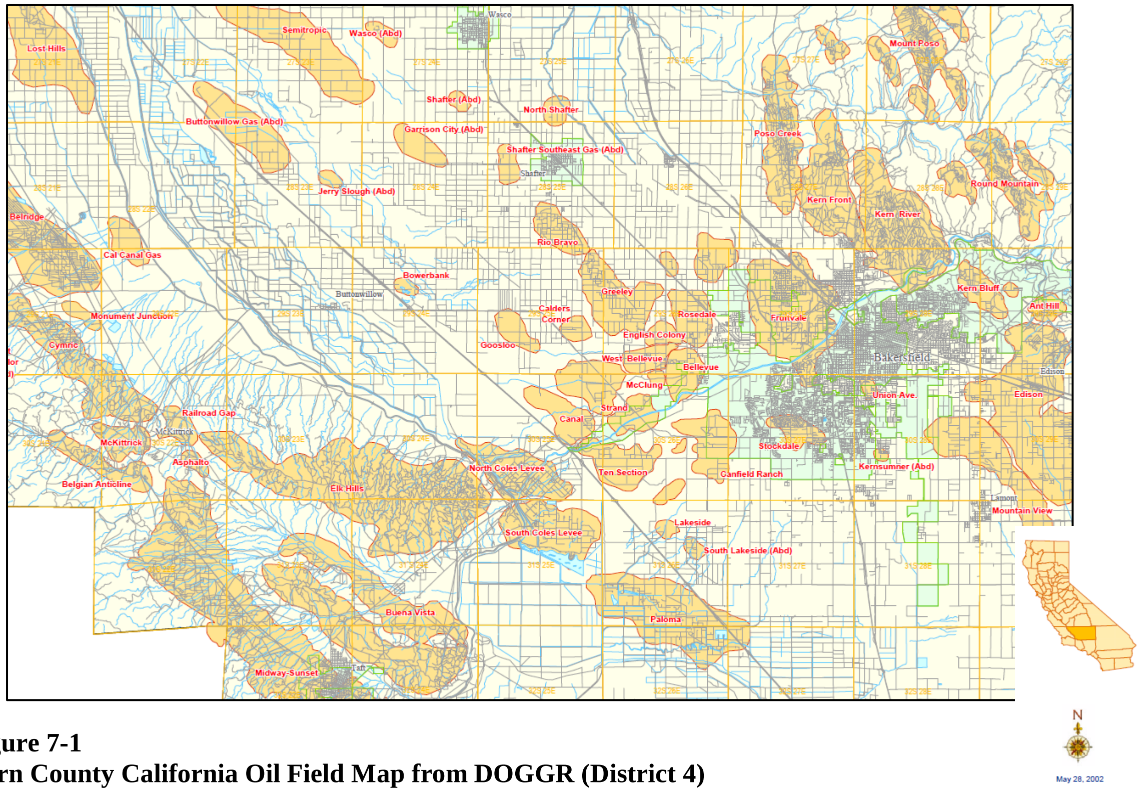


Figure 7-1
Kern County California Oil Field Map from DOGGR (District 4)

7.1 East-Side Hub—Kimberlina Power Plant

7.1.1 Kimberlina Site Description

Clean Energy Systems' Kimberlina Power Plant sits on 37 acres in Kern County, California, about 17 miles (27 km) north of Bakersfield, along State Highway 99; Assessor's Parcel Number (APN) 07321029. Specifically, the plant is located at 16000 Driver Road, Bakersfield, California, 93308, at geographic coordinates:

- Latitude 35.5666 N
- Longitude 119.2036 W
- Elevation 492 feet (150 m)

The site is nestled in the rural agricultural region of California's Southern San Joaquin Valley, surrounded by hundreds of acres of fruit and nut orchards and a processing plant. The plant itself sits atop the Vedder saline formation that has shown early indications of large-volume CO_2 storage capabilities. To the east and west of the plant are actively producing oil fields, many using steam injection for enhanced extraction. Figure 7–2 shows a map of California's sedimentary basins with the KPP site identified on a satellite image in the inset.

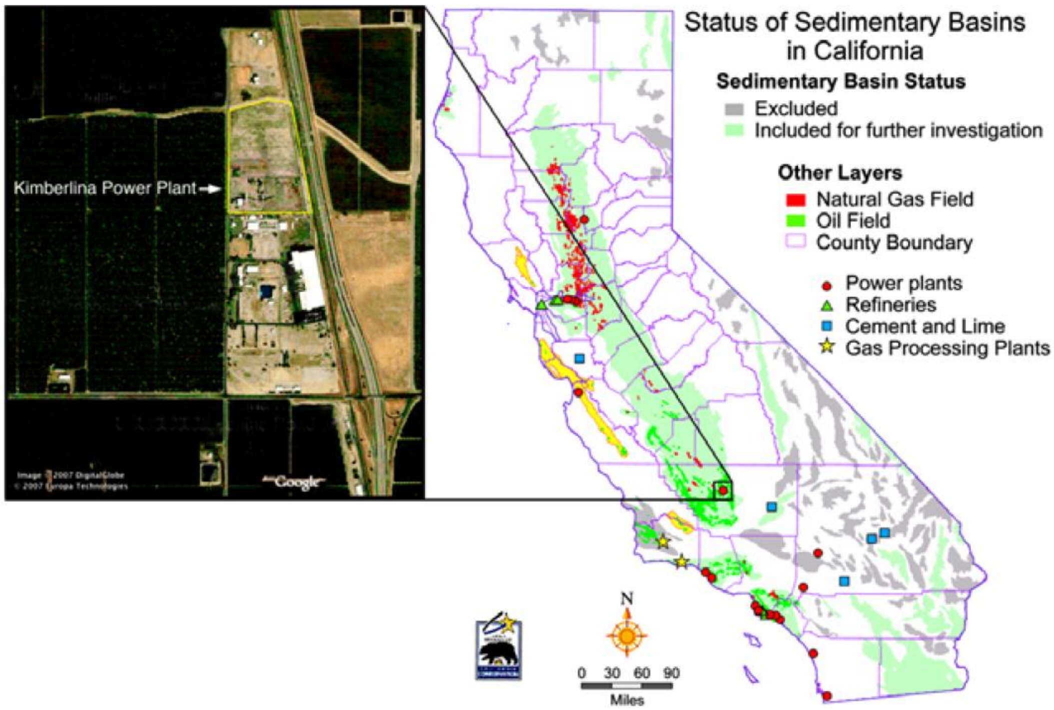


Figure 7-2: Location of Kimberlina Power Plant among California's Sedimentary Basins

The region has a moderate to warm climate with ambient conditions of:

- Temperature (min, max, ave) 27°, 109°, 65.4° F (-2.8°, 42.8°, 18.5° C)
- Pressure (min, max, ave)* 14.43, 14.55, 14.43 psia (0.99, 1.0, 0.995 bara)
- Relative Humidity (min, max, ave) 12%, 100%, 50%

Source: ASHRAE Fundamentals Handbook, 2005 Edition

And low levels of precipitation:

- Annual average 5.14 inch (13.1 cm)
- Monthly average (min, max) 0.0, 5.82 inch (0.0, 14.8 cm)
- 24 hour maximum, 100 year storm 2.90 inch (7.4 cm)
- Monthly average (April - September) 1.09 inch (2.8 cm)
- Snow Loads None
- Frost Line N/A

Source: NOAA National Weather Service Forecast Office

The site is on dry, flat land and is easily accessible by truck, and rail access is nearby; Figure 7-3. Pipeline natural gas, provided by Shell Energy North America, is delivered to the site via a two-inch diameter supply line. Depending on the time of year, nominal pressures range from 350-390 psig (24-27 barg) at 35-60°F (1.7-15.6°C) and approximately 1,000 SCFM. A 12 kV pole-line provides a maximum of 1.3 MW from the nearby Pacific Gas and Electric substation, while the export interconnect is capable of handling 4.2 MW (however, CES' current power export agreement is limited to 3.25 MW).

The Kimberlina plant was formerly a 5 MWe biomass plant, built in the early 1980s by AES Corporation. CES acquired the facility in 2003 and since that time has modified and upgraded the plant to support demonstration testing of their clean-burning, pressurized oxy-combustion power systems. Today KPP is the world's largest pressurized oxy-combustion demonstration facility.

Figure 7-3: Aerial Photograph of the Kimberlina Power Plant

7.1.2 CES Oxy-Combustion Process Description

Since its inception in 1996, CES has been working to develop and deploy advanced technologies to enable clean burning power plants that emit nearly zero harmful emissions to the atmosphere. These state-of-the-art power systems make use of adapted, proven aerospace technologies to combust natural gas, synthesis gas (syngas), and/or other hydrocarbon-based fuels with high purity oxygen to produce a high pressure, high temperature drive gas that can be used to power turbines either directly or indirectly. Because the generated working fluid is comprised of primarily steam and CO_2, the CO_2 is easily separated in the plant's condenser and captured for sequestration or use in EOR or enhanced gas recovery applications. To date, with the support of development partners, CES has successfully demonstrated oxy-combustion direct steam gas generators, reheat combustors, oxy turbines, heat exchangers, and a zero-emission power plant complete with full carbon capture at the Kimberlina site, all with the goal of making hydrocarbon-fueled power plant with greater than 99% carbon capture both technically and economically feasible.

A simplified schematic of the proposed process is shown in Figure 7-4Figure 7–4. Major components or systems include: the air separation unit (ASU), fuel processing/biomass gasification system, pressurized oxy gas generator (POGG) power block, and plant exports (power, water, CO_2, and possibly nitrogen and biochar). The majority of the plant equipment is readily available, off-the-shelf technology (shown in grey in the figure). The novel component of the power block is the CES POGG system (shown in green in the figure). The POGG is comprised of an oxy-fuel burner, compact platelet heat exchangers, and a working fluid recirculation system (blower). The burner combusts a biomass derived syngas in the presence of high purity oxygen (≥93% purity) to produce a pressurized working fluid, typically 20 and 25 bar (290 and 363 psi), comprised of primarily steam and CO_2. The resulting high-temperature combustion gas is used to heat water across a series of heat exchangers that is then used to power a traditional steam turbine. A portion of the steam-CO_2 working fluid is exhausted, condensed, and thereby separated into streams of pressurized CO_2 and pure water. The CO_2 can then be cleaned and further compressed for sequestration or use in industrial applications. The remainder of the working fluid is recycled back to the POGG combustion system to control flame and hardware metal temperatures. This process is readily scalable from 3 to 300 MWe net and can handle a variety of fuel gases ranging from high quality pipeline natural gas to impure gases with up to 80% non-combustibles (typically CO_2).

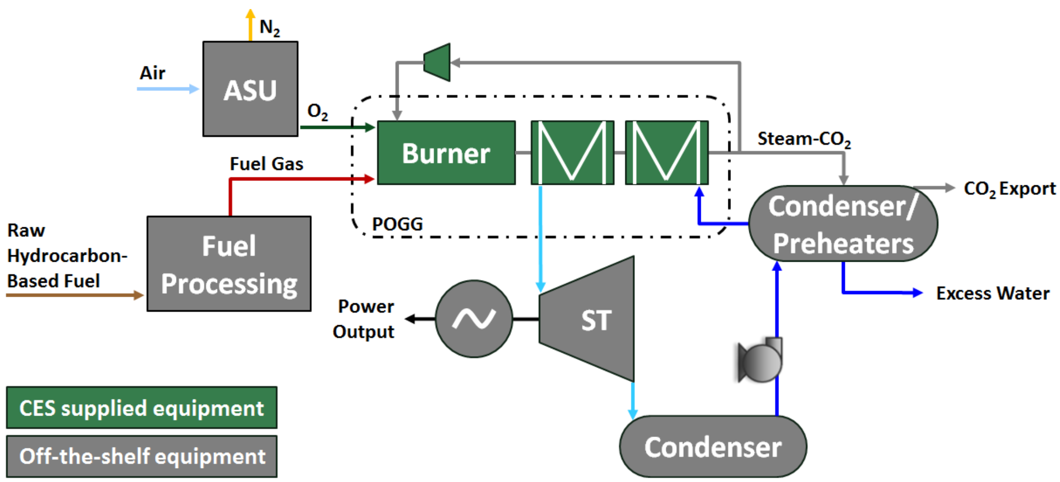


Figure 7-4: Simplified Schematic of CES' Oxy-Fuel Power and Gas Generation Process

CES is now working to deploy next-generation biomass power plants capable of producing electricity and other renewable fuels such as RNG or hydrogen with net negative carbon emission (Figure 7–5), with the first pilot project to be installed and operated at KPP in 2019. Through the use of biomass gasification and carbon capture and storage, these "bioCCS" plants will revolutionize the power industry by offering the world's first commercial carbon negative power cycle. Ideally suited for the California market, these plants can be deployed on a retrofit basis and are profitable when taking advantage of available federal and state incentives. By using a woody biomass fuel that consumes CO_2 throughout its lifetime, the small-scale Kimberlina bioCCS plant will effectively pull up to 100,000 tonnes of CO_2 out of the air annually and safely store it underground. That equates to approximately two million tonnes of CO_2 removed from the atmosphere over a 20-year operating life. When the electricity is directly sold to the transportation industry, the resulting negative-emissions vehicles effectively remove carbon from the atmosphere with each mile driven—a game changing technology for California's transportation sector.

CES' pressurized oxy-combustion systems may also be used for clean steam generation for industrial processes. For example, many oil field operators in California's Southern San Joaquin Valley would benefit from a process that readily produces high-temperature, high-pressure steam with zero-carbon emissions. This would reduce their compliance costs with the state's LCFS as well as their water treatment costs as the process can make use of oil field produced water, and is a net producer of water.

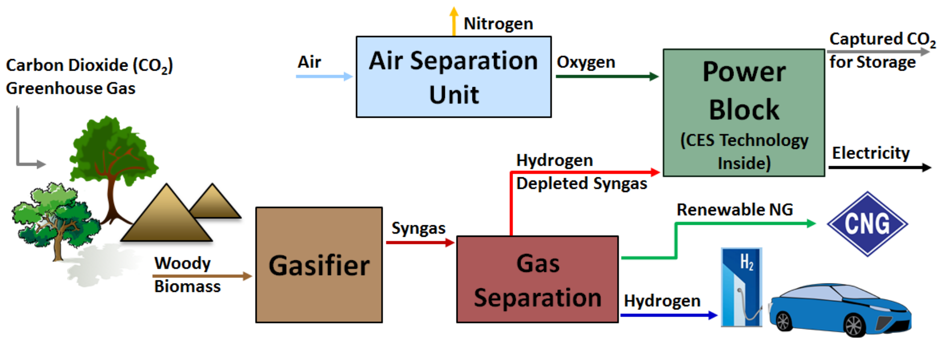


Figure 7-5: Simplified Schematic of CES' Next Generation Biomass "BioCCS" Plants

7.1.3 Kimberlina Small-Scale Capture Project Permitting

In late 2017, CES prepared documentation and submitted applications for air and conditional use permits. CES has received an initial review and continues to work with the San Joaquin Valley Air Pollution Control District and Kern County to gather and develop additional information requests. Permit processing can take up to six months to complete the necessary reviews and public comment periods. CES permits should be issued in the second half of 2018 for the waste-to-energy project.

Project UIC permitting will benefit from work CES conducted in 2008, when it prepared a Class V well permit application for up to 1 million tonnes of CO_2 sequestration beneath the Kimberlina site. Although US EPA did not complete processing of the permit application, its feedback on additional requested information suggested that an acceptable permit application could have been prepared if the project had moved forward. Recently, CES reviewed the Class V permit application, and determined that "upgrading" it for a Class VI geologic sequestration permit application could be accomplished within a reasonable level of effort.

7.1.4 Kimberlina Small-Scale Capture Project Funding

For the small-scale waste-to-energy plant, CES worked with its project partner to secure bond funding through the California Pollution Control Financing Authority Bond Financing Program. Release of funds is conditional upon receipt of project permits from Kern County.

Other funding opportunities may be available from state resources such as the CEC and CARB. From the CEC, Grant Funding Opportunities are offered through the Electric Program Investment Charge (EPIC) and Public Interest Energy Research (PIER-Natural Gas) programs for the development of technologies providing ratepayer benefits, including lower-cost and reliable energy and reduced environmental impacts. CES will work with development partners to identify and apply for suitable grant opportunities to support the project. Also, the State of California now allows cap-and-trade allowance auction revenue to be applied to demonstrations of innovative greenhouse gas-reducing technologies.

For commercial implementation of the process on a large scale, CES has confirmed project financing funds are available under the DOE's existing loan guarantee programs. The objective is to develop a commercially viable demonstration plant, capable of operating for 20 to 30 years, while sequestering in excess of one million tons of CO_2 over that time period. The plant would become a "model" for larger, commercial-scale BioCCS plants CES plans to deploy on a repower basis throughout California's Central Valley.

7.2 East-Side Capture and Transport Implementation

7.2.1 Kern River Oil Field

On the east-side of the SSJV the greatest amount of CO_2 emissions comes from a cluster of three industrial processes at the Kern River Oil Field. Wholly owned by Chevron Corporation, the site is used for crude petroleum and natural gas extraction and emits more than 2.5 M tonnes of CO_2 annually (2015 data). Three fossil fuel cogeneration plants are located on the field, the largest of which emits 1.2 M tonnes of CO_2 annually. Significant carbon capture from this site alone would enable the C2SAFE team to reach its goal of 50 M tonnes of CO_2 captured over a 20-to 30-year facility life.

CO_2 captured at the Kern River oil field must then be dried, compressed to at least 11 MPa (1,600 psi), and transported to the Kimberlina storage hub (CO_2 must be dried in order to prevent the formation of carbonic acid in the carbon steel pipeline). C2SAFE estimates approximately 13 km (8 miles) of pipeline connecting to the Kern Front plant would be required to transport the CO_2 along new and existing pipeline ROWs (Figure 3–1). CO_2 pipeline operators consulted during the Phase I study note a pressure drop of only 4 to 5 psi per mile, so it is unlikely that intermediate compressor stations will be needed. Pipelines would be sized for the ultimate expected capacity of the CO_2 transportation network—C2SAFE calculated an 8-inch carbon steel line would be sufficient—and must be considered as raw materials can comprise 30% of total pipeline costs. A typical CapEx breakdown for rural/flat terrain pipeline build includes:

- 40% construction labor
- 30% raw materials
- 20% miscellaneous, such as permitting, engineering, and surveying
- (5% to) 10% ROW

7.2.2 Kern Front Oil Field

The next identified oil field on the SSJV's east-side is the Kern Front Field, owned by C2SAFE project team member CRC. This source, which produces steam for heavy oil recovery, generated over three quarters of a million tonnes of CO_2 in 2015. As the closest facility to the Kimberlina site, and a source whose emissions are entirely related to oil production and so fully eligible for LCFS credits, capture from Kern Front steam plant is a likely first step. A pipeline from this plant to the Kimberlina site would be approximately 19 km (12 miles) and would follow ROW of both a natural gas and liquid fuel delivery line; Figure 3–1. Another 5 km (3 miles) of pipeline west from the Kimberlina site may be needed to reach injection wells downdip of the site geologically, where the storage reservoirs are deeper and underlie larger land holdings.

7.2.3 Other East-Side Potential Customers

After engaging the “major” oil field operators, C2SAFE will invite smaller operators at fields a greater distance from the Kimberlina storage hub. For example, an additional 19 km (12 miles) of pressurized CO_2 pipeline could connect the Macpherson Oil Company’s steam plant serving the Round Mountain field to the pipeline network. This plant emitted over a quarter of a million tonnes of CO_2 emissions in 2015. Also, the Mt. Poso cogeneration plant, run by a subsidiary of DTE Power and Industrial, could be connected with an additional 13 km (8 miles) of pipeline. This site already uses a biomass feedstock so its net emissions are relatively low. However, capture and storage of these emissions would qualify for LCFS credits and could potentially make the facility carbon negative.

7.3 West-Side Capture and Transport Implementation

7.3.1 Elk Hills Oil Field

The Elk Hills oil field is located 35 km (22 miles) west of Bakersfield in Kern County, California. The field encompasses 75 square miles and has produced over 2 billion BOE. CRC operates gas processing facilities in the Elk Hills field, including the largest cryogenic industrial gas plant in California; the Elk Hills Power Plant, a 550 MW natural gas, combined-cycle power plant that supplies electricity to the Elk Hills Field and excess power to the California electric grid; and a 45 MW cogeneration plant that provides steam and electricity to the field. In 2015, annual CO_2 emissions from CRC equipment at the site was 1.4 M tonnes.

Conceptually, the Elk Hills project would be advanced as a hybrid storage complex with CO_2-EOR occurring in one of the Stevens reservoirs in the field and additional secondary or surge capacity in a depleted Carneros reservoir. CO_2 captured from the Elk Hills sources could be transported to both the Stevens Sand and Carneros Sandstone reservoirs selected via a 16 km (10 mile) long pipeline; 5 km (3 miles) is needed to reach the Carneros.

7.3.2 Buena Vista Oil Field

From the Elk Hills storage hub, a 21 km (13 mile) pipeline could be built to the southwest to connect a cluster of CO_2 sources operating at the Buena Vista oil field; Figures 3–2 and 7–1. All three types of generating equipment studied can be found here, steam generators, cogeneration plants, and EGUs. Both Chevron and Aera Energy have oil operations here that would be eligible for credits under the LCFS if CCS was incorporated.

Aera Energy is one of California’s largest oil and gas producers. Jointly owned by Shell Oil Company and the Exxon Mobil Corporation, the company accounts for nearly 25% of the state’s production. During the Phase I pre-feasibility study, C2SAFE categorized at least 8 CO_2 sources operated by Aera in the SSJV that emitted more than 2.8 M tonnes of CO_2 in 2015. The Aera Energy Belridge plant, located near McKittrick, is the third largest emitter in the SSJV, having emitted over 1.5 M tonnes of CO_2 in 2015. As a California based company, the firm is intimately familiar with the state’s regulations for carbon reductions.

Also in the southwest region of the SSJV it the Sunrise Power Plant, wholly owned and operated by NRG Energy, Inc. In 2015, this NGCC power plant was one of the largest emitters of CO_2, emitting over 1 million tonnes that year. As an EGU, the plant is likely only eligible for California's cap and trade incentives, so is likely a longer-term prospect for the storage complex. Because the plant is sited atop the major Buena Vista oil and gas field it may be amenable to CO_2 capture and injection at the site. However, this option will not be considered in the next phase of the C2SAFE project.

7.3.3 Cymric and Surrounding Oil Fields

While only the 14th-largest oil field in California in terms of size, the Cymric oil field is the fifth largest in terms total remaining reserves, with more than 100 million BOE still in the ground. Production at Cymric field has been increasing faster than at any other California oil field. As with the Buena Vista oil field, both Aera and Chevron have crude petroleum and natural gas extraction operations in the area. A CO_2 transport pipeline extending northwest of the Elk Hills storage hub could reach these sources approximately 31 km (19 miles) away—technical only 26 km (16 miles) since the first 5 km (3 miles) is needed to reach the Carneros under the first mover Elk Hills capture plant.

Like on the east-side of the SSJV, Chevron Corp. has multiple oil and gas operations, and therefore, sources of CO_2, on the west-side of the SSJV. These include cogeneration and steam generation facilities located to the southwest and northwest of the Elk Hills field. In the SSJV, Chevron represents the largest emitter of CO_2, with over 4.5 M tonnes of CO_2 released to the atmosphere in 2015. The company could implement carbon capture across their facilities in a phased approach, taking advantage of lessons learned along the way and eventually capturing the economies of scale to drive down capture costs.

7.3.4 Other West-Side Potential Customers

Other potential customers of a west-side industrial CO_2 storage hub include the two largest single point emitters in the SSJV, the La Paloma Generating Plant and the Pastoria Energy Facility. Both NGCC EGUs, these plants combined for nearly 4 M tonnes of CO_2 emissions in 2015. The La Paloma Generating Plant has the largest nameplate capacity of the NGCC plants in the SSJV and in 2015 was also the largest emitter with over 2 M tonnes of CO_2 released to the atmosphere. With its current bankruptcy proceedings, generation is reduced, and consideration of capital investment for post-combustion carbon capture technology will need to await a new owner. Calpine's Pastoria NGCC plant was the second greatest emitter of CO_2 in the SSJV in 2015, with over 1.8 M tonnes emitted. Located at the southernmost tip of the SSJV, the facility operates at a fairly high capacity factor so could benefit from economies of scale to reduce the cost of capture (unit-based cost). However due to its location it would require a longer connecting pipeline, and thus would realistically only be a longer-term prospect.

7.4 East-West Interconnection

A possible cross-valley pipeline system to connect the east and west side hubs would enhance storage operation reliability and flexibility, and minimize risk should one storage site need to be shut down for unforeseen reasons, as well as provide access to new storage resources. However, at 39 km (24 miles), the pipeline would be a significant undertaking. Consequently, this would likely be a later stage development as more capture from more CO_2 sources come on line and so greater storage balancing capability is needed. It would also overlie additional storage resources, and pass through or by many fields with oil pools appropriate for CO_2-EOR, providing access to more storage capacity as capture from new sources on either basin margin commences.

8
HIGH-LEVEL STAKHOLDER ANALYSIS

The C2SAFE team is familiar with many stakeholders in the SSJV because of previous work under the WESTCARB, NRAP, and GEO-SEQ projects, familiarity with the Hydrogen Energy California project, as well as C2SAFE Phase I stakeholder meetings. Additionally, the insights provided by local team members CRC, CES, and CSUB help inform stakeholder analysis in the area and facilitate outreach through established relations and channels.

All members of the C2SAFE team played a role in stakeholder identification and outreach during Phase I. Stakeholder analysis yields the following groups, which have been shown to have specialized interests in regard to CCS:

- Industry stakeholders – oil and gas producers; electric utilities; other CO_2 source owner/operators
- Policy makers and regulators
- Local landowners and mineral rights owners
- Local elected planning and safety officials
- Local communities
- Environmental NGOs and environmental/social justice groups
- The "general public"

Stakeholder engagement during Phase I was focused on industry and California regulatory/resource management agencies. The C2SAFE team established or renewed relationships, and held meetings to introduce them to the project, gain their input, and invite their participation. This yielded new project partners and support for Phase II.

8.1 Analysis of Communities

Kern County, at the heart of the SSJV, has a long history of agricultural interests co-existing with oil and gas exploration and production operations. For Kern County, employment in the oil and gas industry accounted for 4.5% of total employment as of 2014.[19] Notably, these are generally higher-than-average paying jobs.[20] In addition to generating employment, the oil and gas industry contributes property tax revenues that account for about 15% of Kern County's discretionary revenue (also 2014 timeframe). The importance of this industry is reflected in a generally supportive business community and strong programs at CSUB for petroleum engineering and petroleum geology.

[19] https://www.doi.gov/sites/doi.gov/files/uploads/06102016_useiti_county_case_study_updates-kern_county.pdf
[20] https://datausa.io/profile/geo/bakersfield-ca/#economy

As the C2SAFE project matures, community analysis and outreach for the Kimberlina site will be weighted toward: 1) immediate neighbors, 2) smaller nearby communities, and 3) general Kern County and Bakersfield. Bakersfield, located about 17 miles (27 km) from Kimberlina and 22 miles (35 km) from the Elk Hills, is the largest community in the SSJV, with a population of about 347,000. Nearby smaller towns around the KPP are: Shafter (pop. ~19,000) to the southwest at about 6 miles (9.5 km); Wasco (pop. ~26,000) to the northwest at about 8 miles (13 km), and McFarland (pop. ~15,000) to the north at about 14 miles (23 km).

CES has owned the KPP since 2003 and in the past, has received favorable feedback from meeting with its immediate neighbors about activities there. Also, CES has had discussions with the head of the environmental justice (EJ) group the Association of Irritated Residents of Kern County (headquartered in Shafter) and members of the Coalition for Clean Air & Central Valley Air Quality Coalition, all of whom showed a positive response to plans for a biomass project at KPP. Additional exchanges with local air quality districts and the local chapter of the Air & Waste Management Association have had similar results, as the work would reduce atmospheric emission in the area known for some of the worst air quality in the nation. Broader outreach to nongovernment organizations (NGOs) such as the Natural Resources Defense Council and the Center for Carbon Removal have shown strong support for the potential of carbon-negative power plants that result from biomass combined with CCUS technologies—a process sometimes referred to as BioCCS or BECCS (Bio-Energy with CCS).

Activities for Phase II are not expected to affect the nearby communities. The increase in traffic to and from the project site will likely go unnoticed apart from the immediate neighbors, who are in the fruit processing business—which itself entails frequent truck traffic—and are accustomed to operating next to a power plant. These neighbors will be informed of project plans and the possibility of increased traffic and noise during drilling. In particular, the team anticipates taking precautions during the arrival and departure of the drill rig as it travels down Kimberlina Road and onto the access road shared by the fruit processing facility and the power plant.

The west-side hub will be included in outreach to the broader Kern County community. The more remote site location in the Elk Hills and the use of this area as a working oil field may reduce the scope of outreach to neighboring communities (i.e., Taft, pop. ~9,300; Tupman, pop. ~160) relative to the east side of the SSJV; however, this issue will be assessed in conjunction with project partner California Resources Corporation.

As noted, the C2SAFE project envisions using existing natural gas pipeline ROW for CO_2 pipelines on both the east and west sides of the SSJV. Discussion of potential routes and CO_2 pipeline safety will be included in project presentations to community groups and local elected and safety officials.

Based on past outreach meetings for CCS projects in Kern County, chief community and environmental concerns are related to groundwater and air quality. EJ groups objected to the HECA project because of expected impacts to air quality from the proposed IGCC power plant and associated coal delivery trucks. For Phase II, the project team anticipates addressing questions on whether the C2SAFE project could affect local groundwater and air quality (in addition to safety-related questions for CO_2 storage per se). Because the C2SAFE project is focused on CO_2 sources already in place, the team will seek to understand how co-benefits from

CCS such as reduced NO_X and particulate matter emissions and produced water could be used to build a supportive coalition among environmental and agricultural stakeholders.

8.2 Community Outreach Plans

The C2SAFE community outreach program seeks to: 1) improve understanding of and gain acceptance for the C2SAFE project among stakeholders who could either become future customers, be affected by the project, or influence the project outcome, and 2) support community and public education by providing factual information about the potential benefits and risks of commercial-scale CO_2 capture, transportation, and geologic storage in the SSJV.

In keeping with the best practices from the Regional Carbon Sequestration Partnership program, outreach planning will be integral with overall Phase II project planning. Outreach planning will cover team member roles and responsibilities, stakeholder analysis and engagement strategies, outreach activities, and outreach materials. Key elements will include: maintain and expand C2SAFE stakeholder contacts among industry, regulatory, and resource management agencies; update talking points/key messages and hone benefits assessment/business proposition; create and maintain a project website and outreach materials (factsheets/FAQ, presentations, posters, etc., in English and Spanish); assess social media and develop channels, if needed; formulate a crisis communications plan; conduct targeted outreach to landowners and agricultural/water resource organizations, local elected and safety officials and staff, and EJ groups/NGOs; hold public meeting(s) and tours of drill site(s).

For each of the stakeholder segments identified in the planning subtask, the C2SAFE team will establish (or build upon existing) relationships to identify invitees to a series of in-person meetings or webcasts to review C2SAFE objectives, activities, and vision for commercialization, and to allow for feedback, teaming opportunities, and other forms on involvement. Based on stakeholder preferences, C2SAFE will establish the means and channels for follow-on dialogue. For the key stakeholder segments of government and the oil and gas and associated support industries, C2SAFE will establish informal, but regularly convening, working groups to provide more in-depth guidance to the project. Stakeholder engagement activities will be structured to collect input from key stakeholders and promote knowledge sharing for CCS and the C2SAFE project.

The C2SAFE team will plan and hold an annual R&D forum and business meeting, which will be open to the public. The event will feature technical updates of project progress and interim findings, poster sessions on CCS-related technology advances applicable to C2SAFE, and ample time for questions and discussions. Regulators, policy makers, NGOs, industry, and civic personnel will be invited to participate and contribute to community-suitable solutions to siting, construction, operational, environment, health and safety, and other issues for commercial-scale CCS.

9
HIGH-LEVEL RISK ASSESSMENT

The C2SAFE team completed a high-level assessment of the technical and non-technical challenges the project may encounter throughout the various stages of development.

9.1 Technical Challenges

The technical challenges that were identified during the Phase I pre-feasibility study for the KPP and Elk Hills sites include:

- The lack of site-specific data on the storage target reservoirs including the shallower Olcese Sand, deeper Vedder Sand, and the confining units at the KPP site
- The lack of site-specific data for the confining units at the Elk Hills site including the regional Ridge Reef shale above the Stevens Sand and the Media shale above the Carneros Sand
- Lack of data/information on aquifers and confining units above and below the storage reservoirs needed to demonstrate pressure dissipation required by rules being developed by CARB that will likely be finalized in 2018, and submitted for Board approval in 2019
- The limited availability of hydrologic and geomechanical data for the caprock and how to extrapolate these data across a broad regional area, such that one can demonstrate CO_2 containment
- The degree to which the reservoirs are compartmentalized, which could limit CO_2 injection and/or require costly brine extraction, treatment and/or re-injection to increase dynamic CO_2 storage capacity

As mentioned above, the KPP site represents a greenfield site that has never been drilled, therefore, site-specific data does not exist for the Olcese and Vedder Sands and the confining units at this location. The project team will overcome this technical challenge in Phase II by installing a stratigraphic well to collect the data needed to ground-truth the site-specific models developed by WESTCARB.

The Elk Hills Oilfield is a brownfield site with excellent well control, known structure and stratigraphy, and reservoirs that are well characterized. Other than the depth, thickness and occurrence, little is known about the properties of the regionally extensive, primary confining unit, the Reef Ridge shale, and a localized deeper confining unit, the Media shale. As noted, these shales lie stratigraphically above the Stevens Sand and the secondary storage zone in the Carneros. During Phase II, the project team will deepen or sidetrack an existing well to gain access to these shales to overcome this technical challenge.

CARB is in the process of developing final rules for storage requirements that must be met for owners/operators to receive LCFS credits for storing CO_2 (and will be the basis for future rules regarding receiving cap and trade allowances from storage). The state's so-called "Permanence

Protocol" for CCS contains special standards that are not contained in Federal rules. The Permanence Protocol requires that a project developer demonstrate that there is a permeable layer above the primary caprock and an intervening confining unit and permeable layer between the lowermost CO_2 storage interval and the basement. The purpose of this requirement is to ensure that layers are present that will allow any injection pressure escaping the permitted storage reservoir to dissipate above and below the reservoir. Pressure dissipation below the storage horizon is especially important because of the potential for pressure propagation into basement where basement faults (if present) might be reactivated. Collection of data from reservoirs and confining units above and below the storage complex at both project sites will help overcome this technical challenge.

Another challenge associated specifically with the Permanence Protocol is the requirement to characterize the geomechanical properties of the caprock to show what the integrity of the seal will be if induced seismicity occurs. Similar to saline reservoirs that have no economic value and little to no available petrophysical or hydrologic data, scarcity of information on the confining units is a recognized technical gap. The scarcity of data makes it difficult to scale up and extrapolate across a broader region to make the safety case for seal integrity and storage security. C2SAFE hopes to address this challenge using 3D seismic data to determine the velocity of the confining unit and correlating these widely distributed velocity measurements to detail velocities from well logs and geomechanical properties (e.g., ductility) obtained from laboratory tests on shale samples (core) collected from each site.

Compartmentalization of reservoirs caused by faulting in tectonically active California is a potential challenge that CO_2 storage developers may face in the SSJV. Reservoir-scale productivity indices studied by Jordan and Gillespie (2013) indicate for two fields in the Vedder Formation that compartmentalization does exist and that barriers occur at spacings larger than the length of the fields. Continuous injection of large volumes of CO_2 over decadal time scales into compartmentalized reservoirs will likely result in elevated pressures, reduced storage capacity, and a long-term decline in injection rates unless pressures are activity managed. This could require the use of pressure relief wells and/or active brine extraction. C2SAFE team members including EPRI and LBNL are actively engaged in research in this area and are developing adaptive management computer algorithms and monitoring strategies that optimize injection pressures and rates, and minimize plume migration. The EPRI-led Brine Extraction Storage Test (BEST) hosted by Gulf Power Company at Plant Smith near Panama City, Florida, is the site where the pressure and plume management strategies will be field tested at a scale that approaches that of a CCS project. (Large-scale wastewater injection is being used as a proxy for CO_2 to manipulate subsurface pressures at the BEST site). In addition, EPRI is building a water treatment user facility at Plant Smith, where interested parties can evaluate the performance of their treatment technologies under realistic conditions using produced, high salinity brines. Cost-effective treatment technologies may potentially be commercialized and deployed at CCS sites in the future. The applications and lessons learned from the BEST project can and will be used to address the technical challenge of compartmentalization and project scale up.

9.2 Non-Technical Challenges and Advantages

California's SSJV offers numerous non-technical advantages for commercial-scale CCS operations, as well as some challenges.

Advantages include:

- An experienced oil and gas industry workforce and supporting drilling and testing services
- Power generation/oil production/renewable methane projects amenable to CO_2 capture
- Flat, mostly rural terrain with existing natural gas pipeline corridors that align well with a source-sink analysis of desired CO_2 pipeline routes
- A state government committed to greenhouse gas emission reductions with programs offering some of the world's highest CO_2 sequestration credit values
- Venture capitalists and other investors experienced in clean energy technology
- An economy strong enough to accommodate the modest increases in energy prices that accompany CCS application

Challenges include:

- Uncertainty over and the number of neighboring landowners from whom pore space rights need to be acquired
- The availability of suitable and affordable insurance given the lack of a state or federal program to assume long-term liability for geologically stored CO_2
- Potential opposition from environmental justice and other activists who believe CCS primarily benefits oil companies and other businesses or practices they find objectionable
- Potential skepticism over the ability of subsurface operators and regulators to assure CO_2 storage security given the SSJV's relative proximity to the highly publicized Aliso Canyon natural gas storage reservoir leak in 2015-16.

The C2SAFE project team will assess the logistics of pore space rights acquisition through established and new lines of communication with the owners of the neighboring parcels (generally agricultural properties). Phase II activities will sharpen estimates of the plume size for commercial CO_2 storage operations, which in turn will allow the team to better define the number of parcels that would be involved with scale-up.

Engagement with state policy makers and industry stakeholders will aim to build consensus on potential solutions for long-term liability. The C2SAFE team will hold direct meetings with skeptical members of the EJ community and engage environmental NGOs and local social justice groups supportive of the project's air quality and local employment benefits.

10 SUMMARY AND CONCLUSIONS

The EPRI-led, C2SAFE project team has conducted a preliminary study into the feasibility of a commercial-scale CO_2 storage complex located in the southernmost portion of California's Central Valley. The work represents the first phase of a four-phase development approach outlined by the DOE's CarbonSAFE program meant to develop carbon storage sites capable of permanently storing 50 million metric tonnes of CO_2, or greater, injected over a typical facility life of 20 to 30 years. The report provides high level summaries of the work performed across several Phase I pre-feasibility tasks including: CO_2 source characterization and capture techno-economics (Task 2), sub-basin storage assessment and storage economics (Task 3), pipeline routing, scenario analysis (Task 4), and preliminary site screening/risk assessment (Task 5). For more information on these topics, one should consult the project's other reports.

The study considered multiple scenarios including an east-side storage facility, a west-side storage facility, and potential multi-site storage facilities. The east-side storage facility is to be located at Clean Energy Systems, Inc.'s (CES's) Kimberlina Power Plant (KPP), or nearby, and the west-side facility will be located at the California Resources Corporation's (CRC's) Elk Hills oil field. Most of the carbon emissions are planned to be captured from existing sources and transported to the selected and verified storage site(s). Capture from the single closest source to the eastern storage facility and the sources within the Elk Hills field would meet the CarbonSAFE storage goal of 50 million tonnes. The study has shown there is sufficient storage capacity to meet this requirement and more; thus, capture from any of the numerous additional large nearby sources would substantially leverage the CarbonSAFE investment. A comparison of preliminary CO_2 capture, transportation, and storage costs to economic value and incentives in the state shows current market conditions make it economically feasible to develop large-scale industrial storage sites in California's SSJV.

The C2SAFE team has proposed to expand upon the knowledge gained during this study by conducting a detailed feasibility assessment under a follow-on phase of the program, Phase II—Feasibility. This would include detailed data collection at the two sites, analysis, reporting, stakeholder outreach, and risk mitigation activities to support the development of a commercial carbon storage complex in the SSJV.