Sharing the Benefits

How the Economics of Carbon Capture and Storage Projects in California Can Serve Communities, the Economy and the Climate

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Authors

Benjamin Grove, Clean Air Task Force

George Peridas, Lawrence Livermore National Laboratory

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EXECUTIVE SUMMARY

To reach its ambitious goal of economy-wide carbon neutrality no later than 2045, California will have to capture, transport, and geologically store tens of millions of tons of carbon dioxide (CO_2) per year. This CO_2 will come from the atmosphere and from large stationary sources that have no other options for eliminating emissions. The needed technologies are available today and have been successfully demonstrated at multiple U.S. and international sites; California will need to host several of these carbon capture and storage (CCS) and carbon dioxide removal (CDR) projects to achieve its climate goals.

For CCS and CDR projects to succeed in California, they must concurrently serve three needs and interests: (1) the need to reduce emissions and atmospheric CO_2, (2) the need for projects to make economic sense for developers, and (3) the economic, social and environmental needs of local landowners and host communities. Without serving all three, we anticipate CCS and CDR projects to face significant obstacles, jeopardizing the state's ability to meet its climate goals.

In this report, we study the economics of different classes of CCS projects in California to assess their broad economic viability, the potential need for additional policy support, and their potential for local landowner and community benefits. We find that they broadly fit into three categories. A first, small set of applications that includes ethanol and some refinery applications is readily economical, needs no additional policy support, and holds considerable potential for local benefits. A second, large class of applications includes less amenable refinery applications and possibly some low-hanging fruit natural gas power plant applications, and can range from reasonably profitable to questionable, with economics that will depend heavily on project and local specifics. The final class of applications includes most natural gas power plants and cement plants, and will likely need additional revenue streams and/or policy support to become viable.

BOX ES-1

KEY FINDINGS

- Eligibility for incentives – such as the Federal 45Q tax credit and California's Low Carbon Fuel Standard (LCFS) credits – is essential for project viability.
- Projects that are eligible for both 45Q and LCFS range from clearly economical (e.g., ethanol), to likely economical (e.g., refinery fluid catalytic crackers and steam methane reformers) depending on project and local specifics. On balance, these hold meaningful potential for landowner and local community benefits.
- Projects that are not eligible for LCFS (e.g., most natural gas-fired combined cycle power plants and cement plants) face challenging economics. Absent additional policy support or new revenue streams, these projects may not materialize.
- The concentration of CO_2 in the flue gas stream, the ability to use pipelines for transporting CO_2 – or, in some cases, marine transport – and proximity to good geologic storage are key determinants of project viability and potential for landowner and local community benefits.
- Where pipelines are not feasible, trucking and railing offer alternative transportation options but often at a sizeable cost, which may still be within reasonable policy support ranges, however.
- Project specifics and local factors beyond those that are covered in this report can have a distinct effect on project costs and must be considered. Such factors may include plant location, age and configuration, access to low-cost energy, challenging pipeline routings, supply-chain constraints and inflation.
- Several economically viable classes of projects offer a potentially sizeable upside for landowners and host communities. A compensation structure that considers individual project profitability, and that grows or shrinks compensation commensurate with actual project revenues, would spread the benefits most fairly without exposing the developer to undue risks and would likely result in broader project acceptance and proliferation.

We examine a number of factors that affect project economics, but project specifics and local factors beyond those that are covered in this report can have a distinct effect on project costs and must also be considered. Such factors may include plant location, age and configuration, access to low-cost energy, challenging pipeline routings, supply-chain constraints, and inflation. The report is not meant to serve as a comprehensive cost-lookup table or a definitive reference on individual project costs. The result is intended to enhance the reader's understanding of the factors that govern costs, as well as provide a general sense of where costs for different classes of application may lie.

This report focuses on economics. As with any energy infrastructure development, CCS projects may have potential environmental, public health, and local impacts that must be considered and mitigated through project design, operation, and regulatory enforcement. These potential impacts should be examined thoroughly at the individual project proposal level.

We use the terms *landowner* and *community member* interchangeably in this report. The potential impacts and mitigation measures of a project may extend beyond the landowners whose property overlies the injected CO_2. As such, benefits likely need to extend beyond direct landowner compensation and may include workforce agreements, community investments and other potential community benefits approaches. The exact nature of these is beyond the scope of the report and our expertise.

Introduction

This report summarizes cost estimates for CO_2 capture, transport, and storage from published literature and models. We then modify these cost numbers where needed, based on assessing their applicability to current California conditions and on multiple interviews with project developers in the state. The generic cost numbers presented represent, unless otherwise stated, actual costs. In other words, we have not attempted to factor in the cost of capital, time value of money, target rate of return under a project finance scenario, target profit margin by the operator, or other factors that may affect the price that an entity may charge to third parties, for example, for CO_2 storage or other services. In our case-studies chapter, however, we do include finance costs and examine some representative examples in a go/no-go marketplace context.

All **TONS** referenced in this report are **METRIC.** All **COSTS** presented are in **REAL 2022 $.**

Case Studies

We assembled theoretical but indicative project case studies based on existing types of facilities in California. We use the case studies to examine the likely range of project benefits or needs. Those values are principally a function of project costs, which we sourced from a number of recent studies and then adapted as necessary for California conditions, and revenue, for which we only considered policy support mechanisms and not commodity sales.

We present the project surplus and deficit results here and the underlying cost and revenue assumptions subsequently.

The case studies are:

- An **ETHANOL PLANT** in the vicinity of Stockton that captures 500,000tCO_2/y (100% capture rate); compressing and dehydrating it; and transporting it via barge over 10 miles to a storage site in the Delta.
- A **BAY AREA REFINERY** that captures 900,000tCO_2/y from a 1MtCO_2/y flue gas stream (90% capture rage) belonging to a **FLUID CATALYTIC CRACKER** or **STEAM METHANE REFORMER** using amine scrubbing; and transporting it via pipeline over 60 miles to a storage site in the Delta.
- A **NATURAL GAS COMBINED CYCLE POWER PLANT** in the vicinity of Tracy that captures 900,000tCO_2/y from a 1MtCO_2/y flue gas stream (90% capture rage) using amine scrubbing; and transporting it via pipeline over 35 miles to a storage site in the Modesto area.

- A **CEMENT PLANT** in the vicinity of Mojave or Tehachapi that captures 900,000tCO_2/y from a 1MtCO_2/y combined flue gas stream (90% capture rage) using amine scrubbing; and transporting it via rail using intermodal containers over 60 miles to a storage site in Kern County.

We used both the low-end and high-end capture cost estimates to model an 8% cash-on-cash rate of return for each case, using the following, generally conservative, assumptions:

- A *capital outlay over the first 3 years,* with revenues accruing thereafter.
- A *45Q and LCFS revenue window and project lifetime of 12 years.*
- An *LCFS credit price of \$125/tCO_2.*
- A *generic reduction of 10% in LCFS credits* due to parasitic loads, fugitive and upstream emissions, and other factors.
- An *8% contribution of generated credits to the LCFS Buffer Account.*
- An *annual insurance expenditure equal to 3% of revenues.*
- A *terminal enterprise value* at the end of project operations *equal to 6x* the free cash flow during the last year of project operations.
- No taxes: the numbers presented are pre-tax.

Under these assumptions, we obtain the following results for the project surplus or revenue using both the low-end and high-end capture cost estimates from our survey.

BOX ES-2

PROJECT SURPLUS/ DEFICIT

The project surplus or deficit presented here is a per-ton of CO_2 metric of the project's economic viability under the project finance assumptions above. A surplus indicates economic viability and is a measure of how much "headroom" may be available for landowner compensation and community benefits. A "deficit" indicates that the project is not profitable and is a measure of how much additional assistance, at a minimum, would have to be provided through new policies to make the project viable.

Table ES-1. Project surplus or deficit for case study base cases. *A positive value indicates a surplus and a negative value indicates a deficit.*

	UNDER LOW END CAPTURE COSTS		UNDER HIGH END CAPTURE COSTS	
Case Study	Project Surplus (\$/tCO_2)	Project Deficit (\$/tCO_2)	Project Surplus (\$/tCO_2)	Project Deficit (\$/tCO_2)
Ethanol	114		93	
Refinery (FCC)	87		33	
Refinery (SMR)	90		17	
NGCC		-27		-104
Cement		-155		-224

We then model sensitivities whereby we vary one parameter at a time from these base cases in order to isolate its effect on the results.

Table ES-2. Sensitivities on case study base cases. *Green text indicates use of low-end capture cost assumptions, and red text use of high-end capture cost assumptions. The arrow flows from the base-case value (in parentheses) to the sensitivity result* **(in bold)**.

	SENSITIVITY	UNDER LOW/HIGH END CAPTURE COSTS	
CASE STUDY		Project Surplus ($/tCO$_2$)	Project Deficit ($/tCO$_2$)
Ethanol	Use pipeline instead of barge	(93→) **106**	
Refinery (SMR) #1	Use tanker trucks instead of pipeline	(17→)	**-45**
Refinery (SMR) #2	Use barges instead of pipeline	(90→) 76	
Refinery (SMR) #3	Increase incentive period to 20 years	(17→) **24**	
Refinery (SMR) #4	Increase LCFS credit price to $175/tCO$_2$	(17→) **57**	
Refinery (SMR) #5	Increase target rate of return to 15%	(17→)	**-23**
NGCC	Increase incentive period to 20 years		(-104→) **-97**
Cement	Use pipeline instead of rail		(-224→) **-84**

Findings

Despite the seemingly wide range of these results, and the fact that they represent theoretical cases and not real-life projects whose costs may be affected by several more factors, a coherent picture emerges, and conclusions can be drawn.

Some factors are *major determinants of economics.* These include:

- The *CO_2 concentration* in the flue gas stream (the higher it is, the cheaper the project).
- The *ability to transport CO_2 via pipeline* decreases the economic demands on the project significantly, *unless marine transport is an option.* Having to resort to trucking or railing instead of pipeline can significantly increase project costs.
- The *ability to tap a second incentive strea*m on top of federal 45Q tax credits, such as LCFS credits.

Thus, projects that are eligible for both 45Q and LCFS range from clearly economical (e.g., ethanol), to likely economical (e.g., refinery fluid catalytic crackers and steam methane reformers) depending on project and local specifics.

Projects that are not eligible for LCFS (e.g., natural gas-fired combined cycle power plants and cement plants) face challenging economics. Absent additional policy support or new revenue streams, these projects are unlikely to materialize except in select circumstances. Additional support through premium offtake agreements for dispatchable low-carbon power, recognition of CCS under California's Cap-and-Trade program and new cement incentives under SB 596 (statutes of 2022) may tip the balance in favor of projects.

Where pipelines are not feasible, trucking and railing offer alternative transportation options but often at a sizeable cost, which may still be within reasonable policy support ranges, however.

CCS projects are complex undertakings that are often challenging to put together due to a combination of overarching and local factors. On balance, we find that a meaningful number of projects are likely viable currently, and that they are capable of concurrently serving California's climate goals, the developers' need for a return on investment, and local landowner and community benefits. This necessitates an appreciation for the complexity of the undertaking that is each project. It also necessitates revenue-sharing arrangements between developers and local actors that are commensurate with project revenues, without precluding these local hosts from a potential project up-side while at the same time not exposing the project developer to undue risks. This likely requires more transparent sharing of project economics to enable an informed discussion of costs and headroom. It also necessitates the development of project revenue or profitability metrics that are transparent, objective, and available to all parties in the transaction.

We believe that the circumstances exist for good-faith approach from all parties involved is required to enable such mutually beneficial projects to materialize.

Cost Estimates

CO_2 Capture Costs

Capture is typically the most expensive and capital-intensive step in CCS. We source and synthesize capture cost estimates for the following types of facility:

- Cement plants (we assume amine capture from a common stack that includes emissions from the pre-heater, calciner, combustor, and kiln).
- Refinery fluid catalytic crackers (FCCs – we assume post-combustion capture using amines).
- Refinery steam methane reformers (SMRs – we assume post-combustion capture using amines).
- Natural gas combined-cycle power plants (NGCCs – we assume post-combustion capture using amines).
- Ethanol plants (the very highly concentrated CO_2 stream produced only requires dehydration and compression).

Generally, capture costs are higher for sources with dilute CO_2 streams (e.g., NGCCs) and lower for sources with highly concentrated CO_2 streams (e.g., ethanol). Our sources include published costs from the Great Plains Institute (GPI), the National Energy Technology Laboratory (NETL), the International Energy Agency (IEA), the National Petroleum Council (NPC), other published literature, and private conversations with industry actors who are considering or developing CCS projects in California.

Table ES-3. Capture cost ranges from surveyed sources.

APPLICATION	ASSUMED ANNUAL EMISSION RATE (tCO_2/y)	COST RANGE ($/$tCO_2$ CAPTURED)	SOURCES
Cement Plants	1,000,000	55-120	GPI ($55-69), NETL ($64), IEA ($60-120), industry survey (81), NPC ($64-95)
Refinery FCCs	1,000,000	55-150	GPI ($55-71), industry survey ($100), ($97-150 assuming only 374,000 tCO2/y)
Refinery SMRs	1,000,000	50-111	IEA ($50-80), industry survey ($111), NPC ($61-88)
NGCCs	1,000,000	76-140	GPI ($76-104), Rubin/Herzog ($74 avg), industry survey ($132), NPC ($93-140)
Ethanol Plants	500,000	16-35	GPI ($16-19), NETL ($17-37), IEA ($25-35), industry survey ($30), NPC ($24-34)

Published capture cost estimates are generally lower than private industry estimates, since the latter likely take into account post-pandemic inflation and higher cost of materials, the generally higher cost of doing business in California due to longer permitting timelines, higher electricity costs and other factors. We expect project costs in California to generally – but not always – trend to the higher side of these cost ranges.

CO_2 Transport Costs

We examine transport via pipeline, barge, truck and rail. Pipelines are a mature technology that have been used in the U.S. since the 1970s, with thousands of miles of existing pipe in operation. Barge, truck and rail transport rely on tanks of intermodal containers to transport CO_2 over, generally, shorter distances. A pipeline is typically the preferred way to transport CO_2, but can be complicated, time-consuming and controversial to site. Barge transport is not always an option but, where available, can offer a more expeditious alternative to pipelines at a modest cost. Truck and rail transport can be feasible where no other options exist but may impose significant additional costs to a project. Whether these costs can be covered depends on the policy framework for each CCS project.

Pipeline transportation costs are largely controlled by the volume of CO_2 transported and the distance, which distance dictate the minimum diameter of pipeline that is required and hence capital and operating costs. Economies of scale can be realized when transporting large volumes of CO_2. *For a generic single-source pipeline* of 60 miles in length transporting approximately 1 million tCO_2/y, *the capital cost of pipeline transport is just over \$1 million per mile,* and the *operating cost just over \$1/tCO_2.* Routing or siting complexities may increase this cost.

In California, at the scales considered in this study and *for distances shorter than 100 miles, trucks carrying tanks and intermodals can transport CO_2 for <\$50/tCO_2.* When financing costs are included, intermodal transport by truck remains ~\$50/tCO_2 while tank-based transport increases to ~\$80/tCO_2.

Rail transportation costs show only modest increases with distance, and rail is thus the preferred mode over larger distances. *Rail costs start slightly above \$100/tCO_2* regardless of whether tankers or intermodals are used. The bulk of this cost comes from rates set by the rail companies. For transport using intermodals, costs may be up to ~\$30–40/tCO_2 less for sites where existing intermodal rail facilities and workforce can be fully applied to CO_2 transport.

Barge transport typically costs approximately *\$25 million of capital for each barge,* with an *operating cost of \$5-7/tCO_2,* depending on the degree of utilization of the barges.

Geologic CO_2 Storage Costs

For storage cost estimates, we used the National Energy Technology Laboratory's Saline Storage Cost Model, which is a widely-used, open-source model for estimating the cost of storing CO_2 in saline formations. The model provides total capital and operating cost estimates for the entire value chain of a saline storage project, including feasibility and geologic characterization, construction, injection operations, monitoring, site closure, and post-injection monitoring and site care. It also incorporates the labor, equipment, technology, and financial instruments that are needed to meet the requirements of EPA Class VI permits and includes cost estimates for monitoring and reporting requirements under the Subpart RR of the Greenhouse Gas Reporting Rule.

For a typical project injecting approximately 1 million tCO_2/y using 3 injection wells and 1 monitoring well, *the capital cost is just under \$100 million,* and the *operating cost about \$8/tCO_2.* Acquisition and processing costs of 3D seismic data for site characterization are included, as are repeat 3D seismic surveys for subsequent monitoring of the CO_2 plume in the subsurface. These costs constitute a significant portion of the total project storage cost, generally 20-30%.

Incentives and Revenue Sources

CCS and CDR projects in California today have to rely primarily on two incentive programs: the *California Low Carbon Fuel Standard (LCFS),* and the f*ederal 45Q tax credit.* In addition, *federal funding* may also be available through a variety of Funding Opportunity Announcements that the U.S. Department of Energy is administering under the federal Bipartisan Infrastructure Law (2021) and the Inflation Reduction Act (2022). Finally, CCS projects earn *revenues from the products or commodities* that they produce. The price of these, which include electricity, cement, fuels, chemicals or other products, can be subject to varying market conditions, which are beyond the scope of this report to analyze.

California Low Carbon Fuel Standard

The *LCFS* aims to reduce the carbon intensity (CI – measured in gCO_2e/MJ) of California's transportation fuels. The program's current target is a 20% CI reduction by 2030. Low carbon fuels below the benchmark generate credits, while fuels above the CI benchmark generate deficits. Credits and deficits are denominated in metric tons of GHG emissions. Regulated entities under the LCFS include producers, processors and importers of transportation fuels. Such entities can buy credits commensurate with their compliance obligation in the market and/or undertake their own credit-generating projects. A CCS Protocol in the LCFS regulation awards credits to certain types of CCS projects – those that affect the lifecycle CI of transportation fuels used in California – and to Direct Air Capture projects around the world.

The LCFS is a variable-price instrument: credits are traded and their value changes. LCFS credit prices have historically undergone significant fluctuations, as shown in Figure 1.

Figure ES 1. *Historical LCFS credit prices.*[01]

At the time of this writing (early 2023), CARB is preparing to revise the LCFS 2030 target, and also to set a longer-term (2045) target. The scenarios currently in discussion for 2030 span the 25-35% CI reduction range for 2030, compared to the existing 20% reduction target.[02] As a result of these upcoming regulatory changes, which we anticipate will be adopted in 2023, an upward pressure in LCFS credit prices will almost certainly follow. CARB's own preliminary credit price estimates show price levels jumping to over $450/ tCO_2 before the end of the decade.

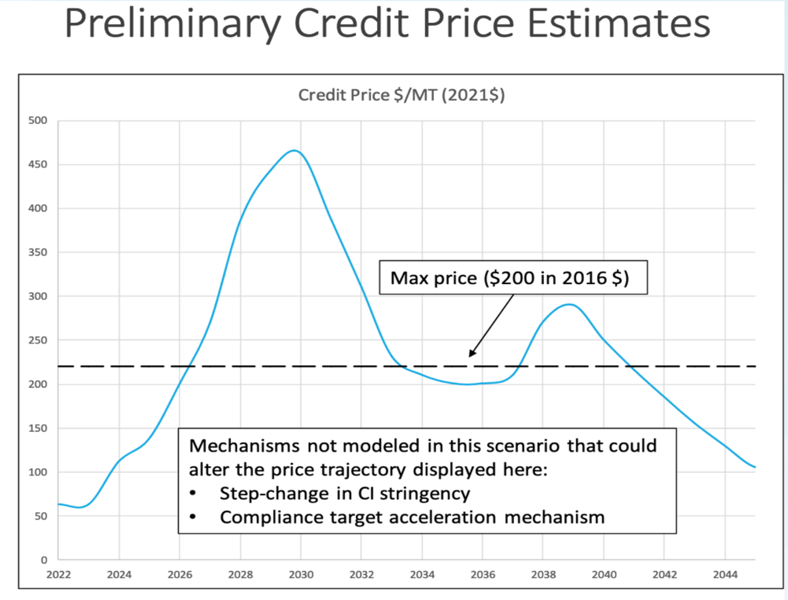


Figure ES 2. *California Air Resources Board preliminary LCFS credit price estimates as a result of the program amendments under consideration in early 2023. Source: CARB staff presentation at Feb22, 2023 virtual public workshop to discuss potential changes to the Low Carbon Fuel Standard.*[03]

One LCFS credit is equal to 1 metric ton CO_2-equivalent, as determined on a life-cycle basis. Some deductions will be made to account for the amount of energy (parasitic load) required to capture the CO_2 in the CCS process, transport it, etc. CARB's CCS Protocol under the LCFS also requires CCS project operators to contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by CARB. The minimum contribution is ~8%, while the maximum is ~16.5% of credits generated.

01 Source: https://www.neste.com/investors/market-data/lcfs-credit-price

02 For the latest proposals under consideration in public workshops held by CARB, as well as history, see: https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops

03 Source: https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/LCFSpresentation_02222023.pdf

California Cap-and-Trade Program

CARB's CCS Protocol has not been incorporated into the Cap-and-Trade program. Thus, an entity like a power plant that is covered under Cap-and-Trade cannot deduct from its compliance obligation even if it captures and sequesters CO_2 to the letter of the CCS Protocol. This may change in the future.

Federal 45Q Tax Credit

The federal 45Q tax credit, as amended by the Inflation Reduction Act (2022), now awards from \$50 to \$85/tCO_2 for storing CO_2 from industrial and power generation facilities in saline geologic formations, and from \$50 to \$180/tCO_2 for storage in saline geologic formations from direct air capture facilities (i.e., capturing CO_2 directly from ambient air). The credit can still be realized for 12 years after the carbon capture equipment is placed in service. And will be inflation-adjusted beginning in 2027 and indexed to base-year 2025. The commence construction window was also extended seven years to January 1, 2033. In addition, the Act gave a direct payment option for receiving the credit, extended broad transferability provisions for the credit value, and broadened the definition of qualified facilities by lowering minimum capture volumes and percentages. In general, the tax credit level that applies to facilities reflects the status quo of the 45Q tax credit at the time when the carbon capture equipment was placed in service and not the latest and highest available credit level.

CHAPTER 1

Report Background and Purpose

Background

Carbon Capture & Storage (CCS) and Carbon Dioxide Removal (CDR) refer to a family of technologies that remove carbon dioxide (CO_2) from industrial point sources or from the atmosphere respectively, transport it (commonly by pipeline, truck, rail, or barge), and then inject it thousands of feet underground in rock formations selected for their proven ability to hold fluids for millions of years.[04] Geologic storage is key to CCS permanently returning millions of tons of fossil and atmospheric CO_2 safely underground, whence it originated. The technologies involved in CCS are not new, and a sizeable array of demonstration and early commercial-scale projects have emerged around the world over the past two or more decades.[05, 06] CCS is an emissions-reduction strategy in itself when applied to existing emission sources. It is also a key component and enabler of CO_2 removal from the atmosphere (negative emissions) to compensate for residual emissions that cannot be abated, and to remove legacy carbon that is already in the atmosphere.

California has now set a goal by statute to become carbon-neutral no later than 2045, and to reduce statewide anthropogenic emissions by 85% from 1990 levels by that date.[07] California's progress in decarbonizing its economy over the past two decades, combined with coincidental emission reductions due to economic downturns and other circumstances beyond its control, has enabled the state to meet its climate goals to date. However, for the state to achieve its new mid-century goals, it must both intensify existing mitigation efforts and expand its climate toolkit to include CCS and CDR. These technologies are a complement – not a threat – to other mitigation approaches. The latest Scoping Plan adopted by the California Air Resources Board (CARB) reached the same widely-held conclusion.[08]

In addition, recent legislation (SB9 905, statutes of 2022) has also authorized CARB to "[e]valuate the efficacy, safety, and viability of [carbon capture, utilization and storage] CCUS and CDR technologies and facilitate the capture and sequestration of carbon dioxide from these technologies, where appropriate."[09] (emphasis added)

Meanwhile, the nature, risks and benefits CCS and CDR technologies are not widely understood by the public. Recent polling and interviews in the California Delta and Kern County revealed differing but generally low levels of

04 Other approaches of storing CO_2 also exist, such as mineralization as conversion to durable products, as well as approaches that convert CO_2 to products that substitute or avoid fossil fuel use. Due to the nascent nature of a lot of these approaches and limits to their scalability, in this report we focus on what is widely anticipated to be the largest pathway for storing CO_2 that has been removed from the atmosphere: geologic storage.

05 Global CCS Institute, "Global Status of CCS Report 2022". https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/

06 Global CCS Institute, Facilities Database, accessed April 2023: https://CO2re.co/FacilityData

07 Assembly Bill 1279, statutes of 2022.

08 California Air Resources Board, "2022 Scoping Plan for Achieving Carbon Neutrality", November 16, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf

09 Senate Bill 905, statutes of 2022.

understanding, and a desire for additional knowledge and information.[10]

Purpose of This Report

This report has a dual purpose:

First, to *inform California state agencies' efforts* to implement SB905, the state's new CCS/CDR statute, which calls for several rulemakings and a new program to facilitate the adoption of these technologies, where appropriate. A thorough understanding of projects' economic viability or lack thereof is crucial to the design of an appropriate program.

Second, to *facilitate discussions between pore space owners and project developers,* both by highlighting the factors that affect project costs and the available headroom for community benefits and income, and by bounding the feasible range for some indicative project types. Even though oil and gas leases are common in California, pore space leases for the purpose of CO_2 injection are a brand new proposition with no precedent. A more informed discussion between interested parties is conducive to maximizing the public benefit of projects – which is central to their ultimate acceptance and success – and to avoiding protracted negotiations that can jeopardize project development and viability.

Methods Used

This report examines the economics of CCS and CDR technologies in California. We start with published literature and models and modify these cost numbers where needed based on assessing their applicability to current California conditions, and also on multiple interviews with project developers in the state. Although we have to maintain the anonymity of these sources, we have endeavored to be objective, and the final results do not radically deviate from published literature. They merely add a layer of practicality and local applicability.

The numbers presented in the Capture, Transport, and Storage chapters of this report represent, unless otherwise stated, actual costs. In other words, we have not factored in the cost of capital, time value of money, target rate of return under a project finance scenario, target profit margin by the operator, or other factors that may affect the *price* that an entity may charge to third parties, for example, for CO_2 storage or other services. The exception is the rail transport section, since we do not consider it realistic for a project developer to develop new rail infrastructure afresh, and thus the fees charged by existing rail operators need to be factored in. However, we have tried to consider and present costs and not prices where possible.

In our *Indicative Case Studies* chapter, however, we do include finance costs and examine some representative examples in a go/no-go marketplace context.

How to Interpret this Report

The report is not meant to serve as a comprehensive cost-lookup table or a definitive reference on individual project costs. Instead, we summarize today's quoted cost ranges by type of application and apply a filter of practical and local industry estimates. The result is intended to enhance the reader's understanding of the *factors that govern costs,* as well as provide a general sense of where costs for different classes of application may lie.

A number of other highly-individual and/or local factors are likely to affect a specific project's costs, and it is neither within our scope to capture all of these, nor our intent to present definitive project cost estimates. Please refer to the *Discussion and Findings* chapter for further details.

This report focuses on economics. As with any energy infrastructure development, CCS projects may have potential environmental, public health and local impacts that must be considered and mitigated through project design, operation and regulatory enforcement. These potential impacts should be examined thoroughly at the individual project proposal level.

We use the terms landowner and community member interchangeably in this report. The potential impacts and mitigation measures of a project may extend beyond the landowners whose property overlies the injected CO_2. As such, benefits likely need to extend beyond direct landowner compensation and may include workforce agreements, community investments and other potential community benefits approaches. The exact nature of these is beyond the scope of the report and our expertise.

Conventions

All **TONS** referenced in this report are **METRIC.** All **COSTS** presented are in real **2022 $.**

10 For a presentation of this research, see: https://youtu.be/UTuUxRUZTuk?t=2636

CHAPTER 2

Incentives and Revenue Sources

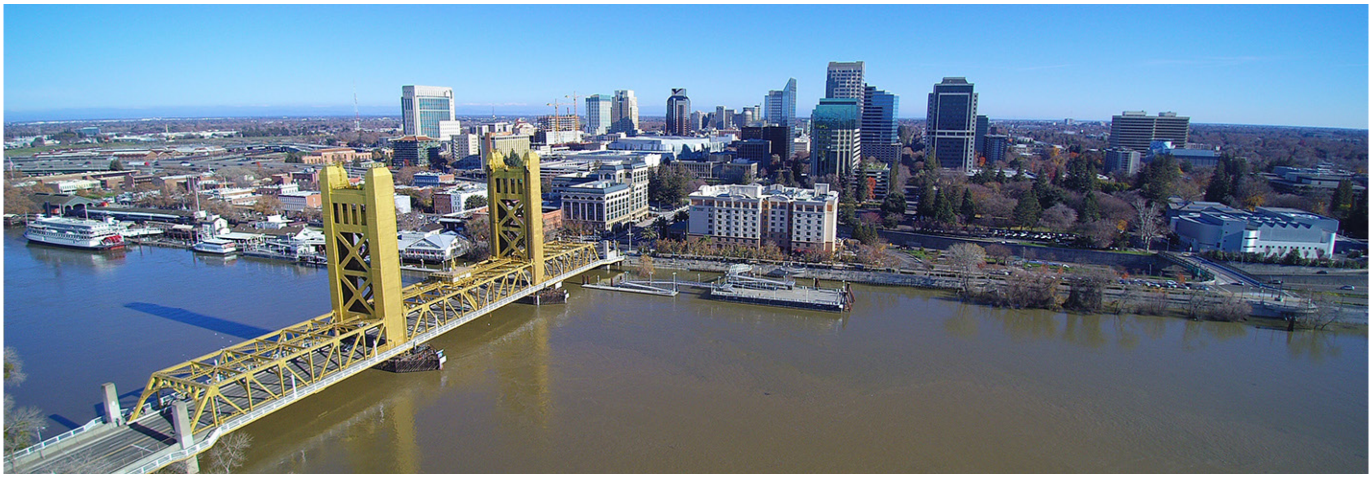
Due to the added cost of capturing, transporting and injecting CO_2, projects are not currently viable in general without incentives or policies that encourage the use of the technology. No mandates for CCS use or CDR deployment exist federally, and to date no state – not even California – mandates the use of CCS for particular types of industrial or other facility. CCS and CDR projects in California today have to rely primarily on two programs: the *California Low Carbon Fuel Standard (LCFS),* and the *federal 45Q tax credit.* We examine these in more detail below.

Federal funding may also be available through a variety of Funding Opportunity Announcements that the U.S. Department of Energy is administering under the federal Bipartisan Infrastructure Law (2021) and the Inflation Reduction Act (2022). These statutes authorized significant cumulative amounts for a variety of projects, including CCS and related applications. Total award amounts are in the tens of billions of dollars nationwide, with individual awards ranging from tens of thousands of dollars to almost a billion dollars annually. Because of the very high variability in the size of these awards, we cannot factor them into our analysis generically. However, the existence or absence of such federal funding for specific projects should be factored into calculations of economic viability and headroom for these projects.

In addition, in cases where CCS is being installed as a retrofit, the *revenues from* these *products or commodities* are already factored into the economics of the existing, pre-CCS facility. Therefore, we do not net out these revenues from the CCS costs we present, but instead recommend a consideration of market conditions and trends in the case of specific projects when assessing economic viability and headroom.

California Low Carbon Fuel Standard Program

California's LCFS was instituted in response to the state's first overarching climate statute: the Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB 32).[11] The LCFS is part of the portfolio of tools under AB 32, and it aims to reduce the carbon intensity (CI – measured in gCO_2e/MJ) of California's transportation fuels. The California Air Resources Board (CARB) first approved the LCFS regulation in 2009 with a target of decreasing transportation fuel CI by at least 10% by 2020 compared to a 2010 baseline. The regulation was amended in 2018 (effective Jan. 1, 2019) with an updated target of a 20% CI reduction by 2030. Low carbon fuels below the benchmark generate credits, while fuels above the CI benchmark generate deficits. Credits and deficits are denominated in metric tons of GHG emissions. Regulated entities under the LCFS include producers, processors, and importers of transportation fuels. Such entities can buy credits commensurate with their compliance obligation in the market and/or undertake their own credit-generating projects.[12]



11 "Global Warming Solutions Act of 2006." California Air Resources Board. Accessed November 2020. https://ww2.arb.ca.gov/resources/fact-sheets/ab-32-global-warming-solutions-act-2006

12 "Low Carbon Fuel Standard: About", California Air Resources Board, accessed April 2023. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about

Figure 1. *Historical LCFS credit prices. Source:* https://www.neste.com/investors/market-data/lcfs-credit-price

In the 2018 LCFS regulation amendments, CARB also adopted a CCS Protocol[13] and opened eligibility for credit generation under the program to certain types of CCS projects – those that affect the lifecycle CI of transportation fuels used in California – and to Direct Air Capture projects around the world.[14]

LCFS credit prices

The LCFS is a variable-price instrument: Credits are traded and their value changes. LCFS credit prices have historically undergone significant fluctuations. In recent years, they hit their historical maximum about a year after the 2018 amendments of just approximately $220/t$CO_2$ and have exhibited a steady decline since then to levels of approximately $60/t$CO_2$ in January 2023. At the time of this writing, prices had rebounded to nearly the $80/t$CO_2$ level (May 2023).

At the time of this writing (early 2023), CARB is preparing to revise the LCFS 2030 target, and set a longer-term (2045) target. The scenarios currently in discussion for the 2030 target range from 25-35% CI reduction, compared to the existing 20% reduction target.[15] As a result of these upcoming regulatory changes, which we anticipate will be adopted in 2023, an upward pressure in LCFS credit prices will almost certainly follow. CARB's own preliminary credit price estimates show levels jumping to over $450/t$CO_2$ before the end of the decade.[16]

LCFS credit generation mechanisms

Choosing to pursue certification under the LCFS for CCS projects is voluntary. Two basic steps are required for CCS projects to generate credits under the LCFS:

Preliminary Credit Price Estimates

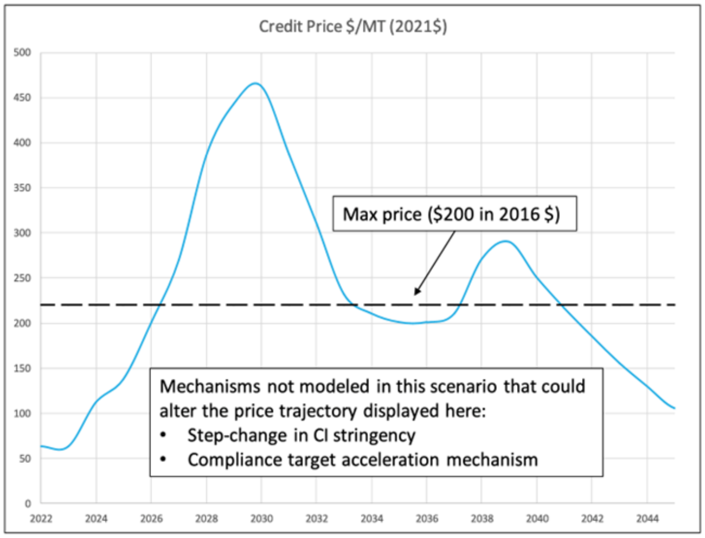


Figure 2. *California Air Resources Board preliminary LCFS credit price estimates as a result of the program amendments under consideration in early 2023.*

Source: CARB staff presentation at Feb22, 2023 virtual public workshop to discuss potential changes to the Low Carbon Fuel Standard (https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/LCFSpresentation_02222023.pdf).

13 https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf

14 Direct Air Capture refers to the practice of removing CO_2 from the ambient air using purpose-built machines.

15 For the latest proposals under consideration in public workshops held by CARB, as well as history, see: https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops

16 Note that the LCFS currently features a price cap, i.e. a maximum price for credits acquired, purchased or transferred in the Credit Clearance Market (CCM). The CCM is a mechanism that provides additional compliance flexibility to regulated parties who have not met their previous year-end obligation, which aims to increase market certainty regarding maximum compliance costs, strengthen incentives to invest in and produce low-CI fuels, and reduce the probability of credit shortfalls and price spikes. The maximum price for credits acquired, purchased or transferred in the CCM is currently set at $200 in 2016 $, and this price is adjusted by a Consumer Price Index (CPI) deflator in all subsequent years. See: https://ww2.arb.ca.gov/resources/documents/lcfs-credit-clearance-market

Table 1. California Low Carbon Fuel Standard crediting options.

Fuel Pathway-Based Crediting	Tier 1: most common fuels, not applicable to CCS; simplified carbon intensity calculation
	Tier 2: innovative, next-generation fuel pathways, including CCS; full lifecycle analysis for calculating carbon intensity
Project-Based Crediting	Refinery investment credits (incl. CCS)
	Innovative crude credits (incl. CCS)
	CCS projects that use direct air capture
Capacity-Based Crediting	Does not currently apply to CCS

- Certification of a fuel pathway under the program for the project type in question, if none already exists or if the project does not fall under one of the types explicitly listed in the program.
- Certification under the CCS Protocol.

The LCFS allows for credit generation in three main ways, shown in Table 1: fuel pathway–based crediting, project-based crediting, and capacity-based crediting.[17] Currently, capacity-based crediting does not apply to CCS. Under fuel pathway crediting, applicants obtain a certified CI score for their fuel, which is based on a lifecycle analysis of the process for producing and supplying the fuel to the California market. Fuel pathways fall under two tiers: Tier 1 comprises the most commonly-encountered applications and fuel types and includes a pre-approved look-up table for these pathways, whereas Tier 2 comprises the less common and more complicated pathways that CARB evaluates and certifies individually.

CCS pathways are not currently included in Tier 1, and the LCFS regulation requires CCS fuel pathways to be Tier 2. New Tier 2 fuel pathways are typically submitted to CARB for informal review while in the draft stage, and they eventually undergo formal review and are subject to public comment when the details have been refined. The public comment window is usually 10 business days or 45 days for some pathway types. Verification occurs after credits have been issued, and credits are calculated relative to annual CI benchmarks. The 2018 LCFS amendments also introduced a design-based pathway as a special circumstance for fuel pathway applications.[18] Generally, LCFS fuel pathways are developed based on 24 months of operational data. To encourage development of innovative fuel and other technologies, CARB now allows a design-based pathway for a fully engineered and designed facility with no operational data. After a design-based pathway has been in production for at least three months, it is eligible to report and generate credits following the completion of a provisional pathway application. Approval of a provisional pathway application allows a transportation fuel or project to generate credits during its 24-month period of developing operational data.[19]

Under project-based crediting, CARB allows for certain types of explicitly listed projects to generate credits. These project types include emission-reduction actions at refineries, crude oil production and transportation facilities, as well as direct air capture projects. Verification occurs before credits are issued, and the credits are equal to the lifecycle GHG emission reductions.

How many LCFS credits does a CCS project generate?

The number of credits that a CCS project generates under the LCFS will always be smaller than the number of tons that the project injects, for two main reasons.

First, one LCFS credit is equal to 1 metric ton CO_2-equivalent, as determined on a life-cycle basis which takes into account the emissions during raw material extraction or recovery, feedstock cultivation, fuel production, transport, processing and use of the fuel.[20] The LCFS considers the entire lifecycle of the project and transportation fuel in question. As such, some deductions will be made to account for the amount of energy (parasitic load) required to capture the CO_2 in the CCS process, transport it, etc.

17 "Low Carbon Fuel Standard." California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf

18 17 CCR 95488.9(e).

19 17 CCR 95488.9(c).

20 https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

Second, CARB's CCS Protocol under the LCFS requires CCS project operators to contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance. The account is a mechanism to set aside a pool of credits to act as an insurance pool for CCS projects and keep the program whole in the event of reversals (CO_2 leakage). The percentage of credits that CCS projects must deposit in the Buffer Account depends on their risk rating under CARB's CCS Protocol, which is determined through a number of factors, including financial, social, management, site, and well integrity risks.[21] The minimum contribution is ~8%, while the maximum is ~16.5%.

California Cap-and-Trade Program

In addition to the LCFS, California has a Cap-and-Trade program that covers entities in the power, industry and fuel distribution sectors. However, CARB's CCS Protocol has not been incorporated into this program. Thus, an entity like a power plant that is covered under Cap-and-Trade cannot deduct from its compliance obligation even if it captures and sequesters CO_2 to the letter of the CCS Protocol.[22] This may change in the future.

Federal 45Q Tax Credit

In 2008, Congress enacted a tax credit for CO_2 sequestration under Section 45Q of the Internal Revenue Code.[23] The credit amounted to \$20/ton CO_2 for pure storage and \$10/ton CO_2 for settings in which CO_2 was being injected with enhanced hydrocarbon recovery. The credit soon proved too low to incentivize any new CCS projects.

Congress amended the 45Q tax credit in the Bipartisan Budget Act of 2018, increasing its value up to \$50/ton CO_2 for pure storage, up to \$35/ton CO_2 for settings in which CO_2 was being injected with enhanced hydrocarbon recovery, and also allowed other types of CO_2 utilization. The credit pool was no longer finite, and different types of eligible facilities had minimum capture amounts. The credit could only be claimed for up to a 12-year period, and project construction had to begin by a certain date: The original deadline of January 1, 2024,

set in 2018, was extended by two years to *December 31, 2025,* in the federal omnibus spending package of December 2020.

The 45Q tax credit was further amended by the Inflation Reduction Act (2022). Now, provided prevailing wage and apprenticeship requirements are met, the credit value has increased from \$50 to \$85/tCO_2 for storing CO_2 from industrial and power generation facilities in saline geologic formations, and from \$50 to \$180/tCO_2 for storage in saline geologic formations from direct air capture facilities (i.e., capturing CO_2 directly from ambient air). The credit can still be realized for 12 years after the carbon capture equipment is placed in service and will be inflation-adjusted beginning in 2027 and indexed to base-year 2025. The commence construction window was extended seven years to January 1, 2033, and the Act gave a direct payment option for receiving the credit. This option extended broad transferability provisions for the credit value and broadened the definition of qualified facilities by lowering minimum capture volumes and percentages.[24]

In general, the tax credit level that applies to facilities reflects the status quo of the 45Q tax credit at the time when the carbon capture equipment was placed in service and not the latest and highest available credit level. For example, a power plant that began capturing carbon in 2019 would today still be receiving a maximum credit level of \$50/ton or \$35/ton credit rather than the increased credit value of \$85/ton.

21 CARB CCS Protocol, Appendix G.

22 Energy Futures Initiatives and Stanford University "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions." October 2020, p.85. https://sccs.stanford.edu/sites/g/files/sbiybj17761/files/media/file/EFI-Stanford-CA-CCS-FULL-rev2-12.11.20_0.pdf

23 26 USC § 45Q.

24 For more details, see Clean Air Task Force, "Carbon Capture Provisions in the Inflation Reduction Act of 2022": https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf

CHAPTER 3

CO_2 Capture Costs

Capture is typically the most expensive and capital-intensive step in CCS. In this chapter we synthesize costs for 5 types of facility that are present in California and are good targets for CCS due to the magnitude of their emissions and/or the ease of capture, and therefore make likely first-mover projects.

Application Types Considered

- ***Cement plants:*** These plants feature a number of CO_2 sources that can be retrofitted with amine carbon capture systems. We assume capture from a common stack that includes emissions from the pre-heater, calciner, combustor, and kiln. The CO_2 stream concentration at cement plants is low-medium (~16%).[25] Capture can also be done from a dedicated calciner that produces a pure CO_2 stream, and so avoids the use of amines or other sorbents. We do not cover the dedicated calciner option in this report, which is covered in detail in a report by Project 2030.[26]
- ***Refinery fluid catalytic crackers (FCCs):*** FCCs can account for a sizeable portion of total refinery emissions (typically 20-35%, but as high as 50% in some cases) and represent a prime capture opportunity in refineries. The CO_2 stream concentration in FCCs is low (~10%) to medium (~20%).[27] Here, we assume that post-combustion capture is used.
- ***Refinery steam methane reformers for hydrogen production (SMRs):*** SMRs produce hydrogen for use in refining and can also account for sizeable portions of total refinery emissions (as high as 20%). The CO_2 concentration in SMRs is low (~16%) to medium (~47%) and can be captured using post-combustion systems or through pressure/vacuum swing adsorption.[28]
- ***Natural Gas Combined Cycle power plants (NGCCs):*** These plants produce a low-concentration (~5%) CO_2

Image source: https://www.powermag.com/saskpower-carbon-capture-facility-operating-more-reliably/

25 For an example of a project that is in development in this sector, see: https://www.heidelbergmaterials.com/en/carbon-capture-and-storage-ccs (accessed April, 2023).

26 "The Economic Case for Two Emerging Decarbonization Options for Cement Production Evaluating LEILAC's Direct CO_2 Separation Pre-Calciner and Rondo's Thermal Energy Storage", Project 2030, December 27, 2022. Available here: https://project2030.blog/reports/

27 https://doi.org/10.3389/fenrg.2020.00062

28 https://arpa-e.energy.gov/sites/default/files/2021-01/05%20OK%20-%20ARPA-E%20Air%20Liquide%20SMR%20decarbonization%20%28Jan%202021%29.pdf

stream and are typical targets for post-combustion capture systems such as amines.[29]

- ***Ethanol plants:*** The fermentation of grain produces a very high-concentration CO_2 stream that only requires dehydration and compression, making these plants one of the cheapest CO_2 capture opportunities.

Factors that Affect Capture Costs

Processes to separate dilute CO_2 from other industrial facility exhaust gases generally use amine absorption technology, which is effective on a wide range of CO_2 concentrations and industrial sources. Amine absorption technology is expected to be the most widely used capture technology in the near- and mid-term, and has been the primary method of CO_2 separation from industrial gas mixtures over the last 40 years.

Capture cost estimates included in this report are based on amine absorption technology, except for ethanol (which only requires dehydration and compression), and refinery steam methane reformers (where vacuum swing adsorption is commercially available in addition to amine absorption). The application of amine absorption technology is similar across the sources included in this report; however, the costs can vary significantly depending on the concentration of CO_2 relative to other gases in the emissions streams of various sources.

Generally, capture costs are higher for sources with dilute CO_2 streams (e.g., NGCCs) and lower for sources with highly concentrated CO_2 streams (e.g., ethanol). Ethanol plants typically have highly concentrated CO_2 streams, upwards of 99% CO_2, which only require dehydration and compression for CO_2 capture. NGCCs, on the other hand, have very dilute CO_2 concentrations in the flue gas (roughly 5%) that necessitate large absorption columns to separate and purify CO_2 and regenerate the scrubber solvent, resulting in significantly higher costs. CO_2 concentrations in SMR and FCC applications can range from low (low teens %) to medium (approaching 50%).

Sources Used

Our sources include published costs from the Great Plains Institute,[30] the National Energy Technology Laboratory,[31] the International Energy Agency[32], the National Petroleum Council,[33] other published literature,[34,35] and private conversations with industry actors who are considering or developing CCS projects in California. The aforementioned sources are based on assessments of historical studies, industry insight, and published industry experience.

Capture cost estimates by source type, summarized in Table 2 on the following page, include total capital and operating costs for separation, dehydration, and compression in terms of annualized $/ton of CO_2 captured. Cost estimates are based on an assumed 20-year project lifespan, which is a typical length of a commercial carbon capture project. The costs presented exclude financing considerations, such as the cost of capital and time value of money.

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29 https://doi.org/10.1016/j.egypro.2009.01.121

30 E. Abramson, D. McFarlane and J. Brown, “Transport Infrastructure for Carbon Capture and Storage – Whitepaper on Regional Infrastructure for Midcentury Decarbonization”, June 2020. Available at: https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf

31 National Energy Technology Laboratory, “Cost of Capturing CO_2 from Industrial Sources”, 2022. Available at: https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources_011014.pdf

32 International Energy Agency, “Levelised Cost of CO_2 Capture by Sector and Initial CO_2 Concentration”, 2019. Available at: https://www.iea.org/data-and-statistics/charts/levelised-cost-of-CO2-capture-by-sector-and-initial-CO2-concentration-2019

33 National Petroleum Council, “Meeting the Dual Challenge – A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage”, 2019. Available at: https://dualchallenge.npc.org/downloads.php

34 E. Rubin, J. Davidson, and H. Herzog, “The Cost of CO_2 Capture and Storage,” 2015. Available at: https://www.sciencedirect.com/science/article/pii/S1750583615001814

35 Bechtel National, Inc, “Comparison of FEED Results from Mustang Station and Panda Power”, 2022. Available at: https://netl.doe.gov/projects/files/Comparison%20of%20FEED%20Results%20from%20Mustang%20Station%20and%20Panda%20Power.pdf

Table 2. Capture cost ranges from surveyed sources.

APPLICATION	ASSUMED ANNUAL EMISSION RATE (tCO_2/y)	COST RANGE ($\$/tCO_2$ CAPTURED)	SOURCES
Cement Plants	1,000,000	55-120	GPI ($55-69), NETL ($64), IEA ($60-120), industry survey (81), NPC ($64-95)
Refinery FCCs	1,000,000	55-150	GPI ($55-71), industry survey ($100), ($97-150 assuming only 374,000 tCO2/y)
Refinery SMRs	1,000,000	50-111	IEA ($50-80), industry survey ($111), NPC ($61-88)
NGCCs	1,000,000	76-140	GPI ($76-104), Rubin/Herzog ($74 avg), industry survey ($132), NPC ($93-140)
Ethanol Plants	500,000	16-35	GPI ($16-19), NETL ($17-37), IEA ($25-35), industry survey ($30), NPC ($24-34)

Explaining Cost Ranges and Variation

Capture cost estimates from published literature are generally lower than, or overlap with, the lower- or mid-range private industry estimates. The higher end of industry estimates is likely due a combination of factors:

- Post-pandemic inflation and higher cost of materials.
- Their estimates are largely based on actual vendor quotes specific to California where the cost of doing business is generally higher due to longer permitting timelines and other factors.
- Higher electricity costs than in other states, and because these electricity costs can account for the majority of capture OpEx.
- Site-specific considerations that can lead to higher costs, e.g. increased installation costs due to legacy materials on site, existing pipelines, or regulations that place limits on plant design.

For projects in California, we expect costs to trend to the higher side of the cost ranges indicated.

CHAPTER 4

CO_2 Transport Costs

Carbon dioxide transportation cost estimates are provided for four distinct methods of transportation: CO_2 pipeline, rail, truck, and barge. In this chapter, we discuss the methods used to estimate transportation costs for each method of transportation represented in the case studies.

Pipeline

Pipelines are currently the most common method of transporting large volumes of CO_2 for CCS, and more than 5,000 miles of CO_2 pipeline exist in the U.S. Pipeline transportation of CO_2 is most efficient when CO_2 is in a compressed phase at ambient temperature,[36] which requires pipelines to operate at higher pressures than in gaseous phase transport (which only makes sense for short distances). Pipelines have significant economic benefits over alternative transportation methods because they can offer significant economies of scale, especially for large volumes of CO_2 transported over long distances.

Pipeline transportation costs are largely controlled by the volume of CO_2 being transported and distance of transportation. The volume of CO_2 transported in a pipeline and the transportation distance dictate the minimum diameter of pipeline that is required, which significantly impacts costs. Economies of scale can be realized when transporting large volumes of CO_2 from multiple sources via a network of pipelines that feed into a larger trunk line. For this study, however, we consider single-source to single-sink scenarios in the case studies presented. For a generic single-source pipeline of 60 miles in length transporting approximately 1 million tCO_2/y, the capital cost of pipeline transport is just over \$1 million per mile, and the operating cost just over \$1/tCO_2. Routing or siting complexities may increase this cost.

Pipeline cost estimates for this study were generated using the National Energy Technology Laboratory's (NETL) CO_2 Transport Cost Model.[37] The NETL CO_2 Transport Cost Model is an Excel-based tool that estimates capital and operating costs of transporting CO_2 by pipeline and assumes a single, point-to-point pipeline. Key input assumptions used in this report for each case study include CO_2 mass flow rate, duration of operations, pipeline length, inlet and outlet pressures, number of booster pumps, and region.

36 This is known as the *supercritical* phase, whereby CO_2 has the density of a liquid but behaves like a gas. The *critical point* for a substance is the combination of pressure and temperature above which the liquid and vapor forms of the substance become indistinguishable.

37 https://netl.doe.gov/projects/files/FENETLCO2TransportCostModel2018_050118.xlsm

Truck & Rail

When pipelines are unavailable or too complicated to site and permit, transporting CO_2 by truck is potentially a viable alternative – provided the distances are not too long, for reasons that we explain below. Currently, liquified CO_2 shipping is done commercially, mostly for the food and beverage industry, at relatively small volumes compared to what will be needed for CCS.

Truck transport may be able to serve a larger variety of locations and can typically be implemented faster than pipelines. Rail is the preferred mode of transport over longer distances.

This section is based on a recent analysis of Corey Myers and Wenqin Li at Lawrence Livermore National Laboratory.[38]

Both trucks and rail can carry CO_2 in two ways: tankers and intermodals.[39] In both truck and rail transport, CO_2 is converted to a cryogenic liquid prior to transportation to increase its density and reduce the number of shipments. It is subsequently converted back to an ambient temperature liquid before underground injection.

Distance

In California, at the scales considered in this study and for distances shorter than 100 miles, trucks carrying tanks and intermodals can transport CO_2 for <\$50/tCO_2. When financing costs are included, intermodal transport by truck remains ~\$50/tCO_2 while tank-based transport increases to ~\$80/tCO_2.

Truck transportation costs increase steeply with distance, becoming more expensive than rail transportation at ~300-500 miles. The main reason for the price increase is that more than 50% of pre-financing costs increase with travel distance; namely, truck drivers, trucks, fuel, maintenance, and CO_2 emissions (fuel usage, materials production, and pressure-regulating CO_2 boil-off gas). These cost increases are particularly pronounced for tanker trucks due to the regulatory requirement for multiple drivers for longer routes.

Rail transportation costs show only modest increases with distance due to the only distance-proportional costs being fuel surcharges, and increased CO_2 boil-off. Rail is thus the preferred mode over longer distances, but costs start slightly above \$100/tCO_2 regardless of whether tankers or intermodals are used. The bulk of this cost comes from rates set by the rail companies, and as such

38 Publication pending, expected in Q3 of 2023.

39 Intermodals are large, standardized containers that can be loaded and transported by a variety of means, including truck, rail and ship. Intermodals lower transportation costs by avoiding repackaging and offloading of the cargo.

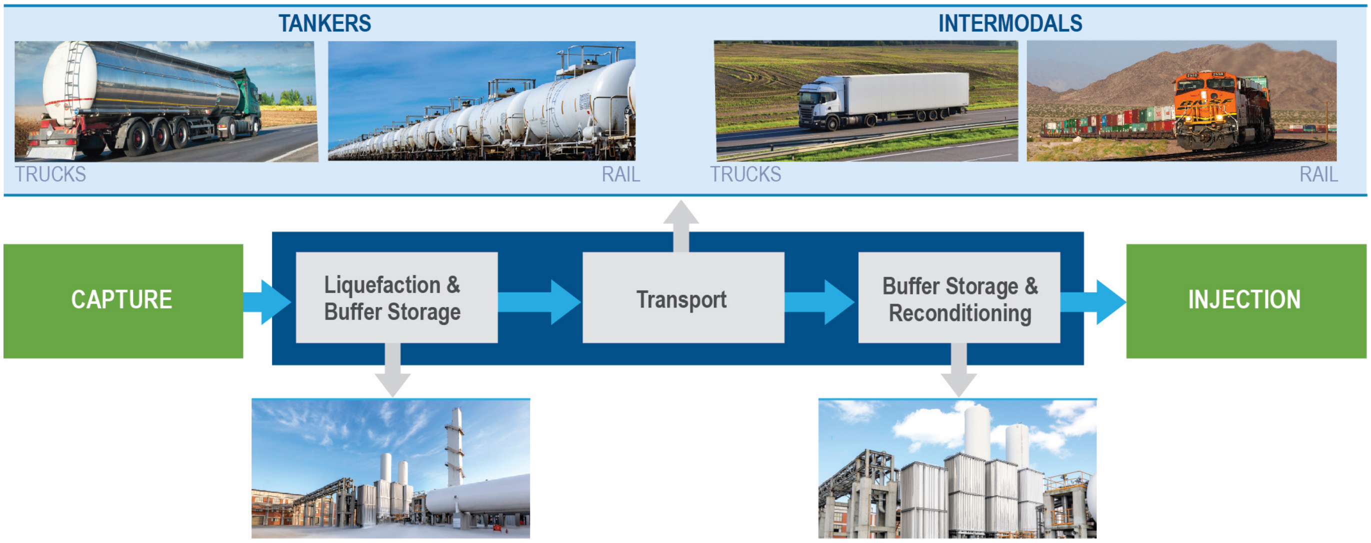


Figure 3. *The CO_2 transportation chain by truck or rail. Source: Myers and Li, 2023 (publication pending).*

is dependent on commercial considerations and not amenable to engineering improvements.

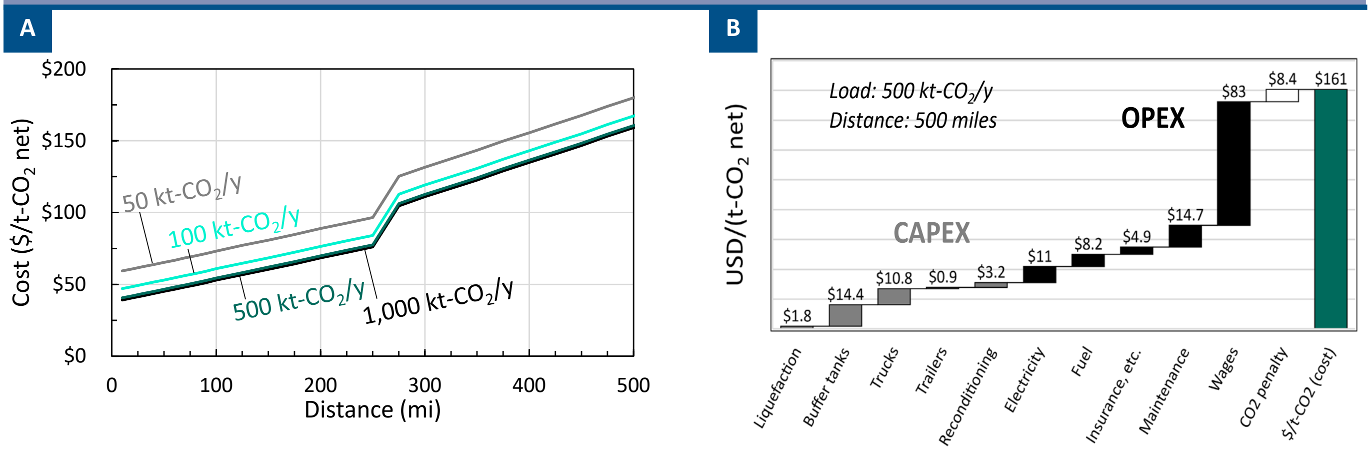
Rail intermodals have the advantage over tanker cars that they can be filled up before the rail car arrives on site. Thus, the filling of intermodals can be carried out separately from the loading of the intermodal onto the train, which saves time, reduces boiloff, and lowers logistical risk. For greenfield projects, tankers and intermodals end up being equally viable. But if a rail-loading facility exists on-site already (including cranes, workers etc.), intermodals end up being advantageous. Transport costs may be up to ~$30-40/t$CO_2$ less for sites where the existing intermodal rail facilities and workforce can be fully applied to CO_2 transport (i.e., reported costs assume no transfer of existing assets or labor to CO_2 transport).

It is also possible that intermodals can command a more competitive base rate on rail due to insurance considerations. A tanker car holds four times more CO_2 (~80tCO_2) than an intermodal container (~20tCO_2). Therefore, a potential release event involves less CO_2 for an intermodal and it is less likely for four intermodals to be punctured than one rail car tanker.

Size

A sizeable portion of the transportation cost for both truck and rail is due to the large equipment that is needed to store CO_2 at either end of the route, convert the CO_2 to a cryogenic liquid for transportation, and convert it back to a room temperature liquid for injection. Therefore, larger is cheaper for both truck and rail: The higher the volume of CO_2 to be transported, the lower the $/t$CO_2$ cost will be for the project because the CapEx for this equipment is spread over a larger CO_2 volume. However, transporting large volumes by truck may run into limitations on how much added traffic the route can support. In addition, financing costs for very large (or very small) projects may increase. It may be possible to reduce costs further by developing equipment to transport CO_2 as a room-temperature liquid and avoid the multiple conversion steps and dedicated CapEx.

TANKER TRUCK



INTERMODAL TRUCK

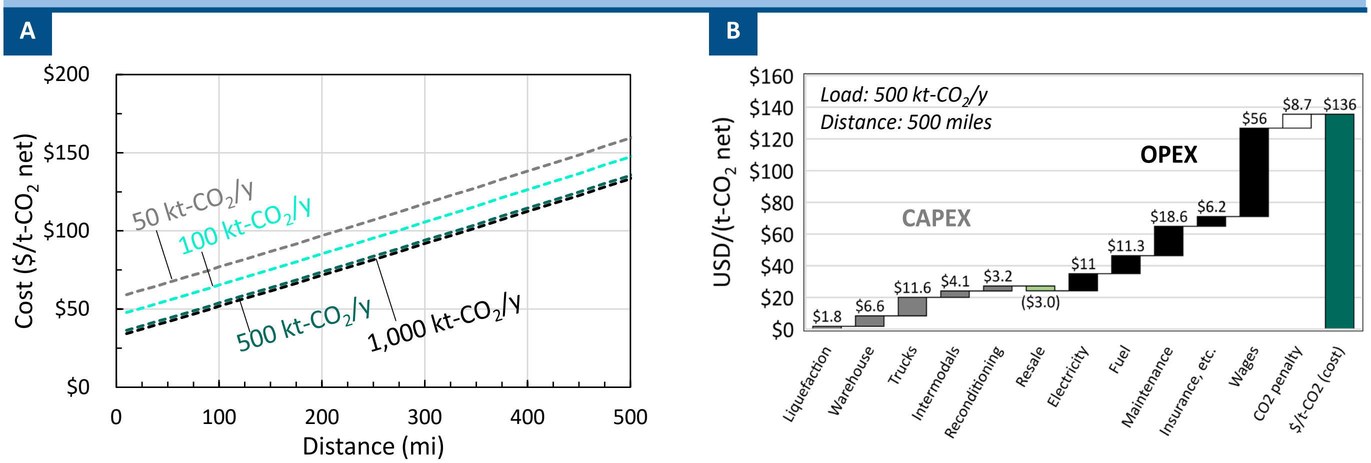
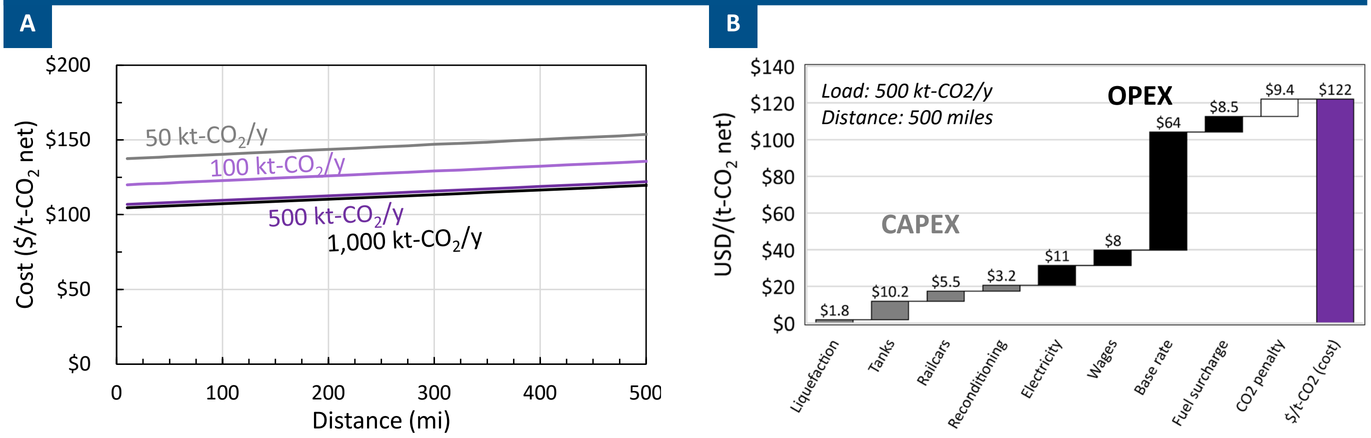


Figure 4. *Cost with distance and cost breakdown for 4 variations of transport: tanker trucks, truck intermodals, rail tankers and intermodal rail. Source: Myers and Li, 2023.*

RAIL TANKER



INTERMODAL RAIL

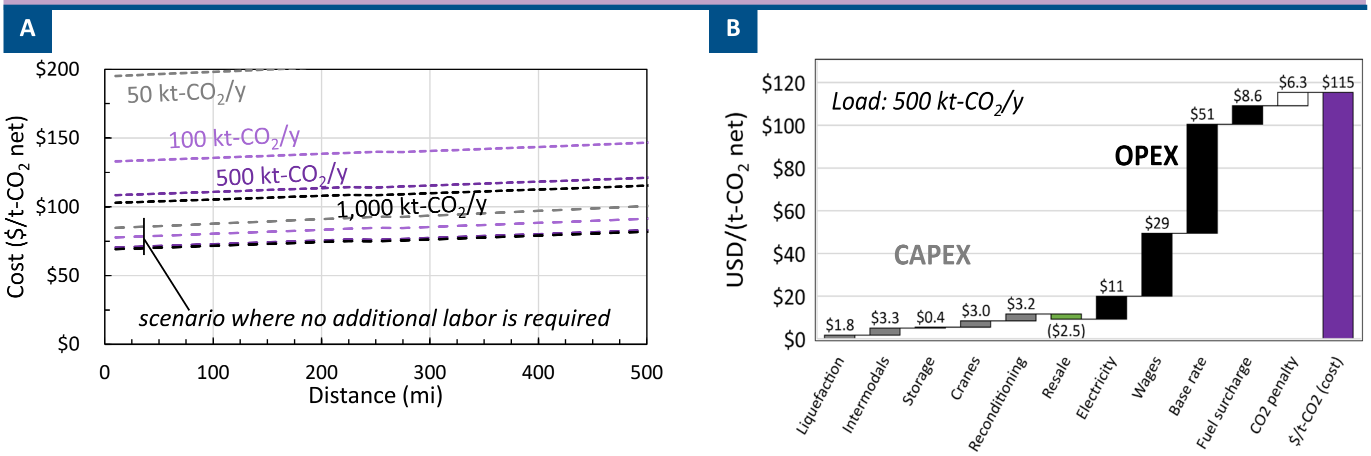


Figure 4, continued.

Barge

Inland transportation of CO_2 via barge is a potentially viable option where appropriate waterways exist, and can offer a more expeditious CO_2 transport option where pipelines are not feasible or timely to site, permit, and construct. Liquified CO_2 shipping is currently done commercially, mostly for the food and beverage industry, at relatively small volumes compared to what will be needed for CCS.

Some companies are designing specialized ocean-going vessels (ships) to transport CO_2 over long distances. However, for the purposes of this report, we focus on inland barges that can carry CO_2 using the same type of containers that are used on trucks and rail and discussed above: Liquid tanks and intermodals.

In the sense that they each use tanks and intermodals, barge transport is similar to truck and rail transport. However, barge transport does not suffer from some of the same limitations that are responsible for bulk of the cost of truck and rail: Labor costs are cheaper than tanker trucks, barges avoid road traffic or rail-route delays, there is no rail base rate charged, and barges can carry much higher-weight containers with the only constraint being the container volume.

In addition to a loading and unloading dock at either end of the waterway, barge transport will typically need the same equipment as truck and rail to liquefy and/or store CO_2 at either end of the route.

There is limited activity and published literature for barge transport, and our cost estimates originate solely from an industry survey of market participants. This information points to an estimate of $25 million CapEx per barge. The OpEx for barges goes towards crew costs, fuel costs, and fees to maintain proper licensing. These costs and fees on a per-ton of CO_2 basis will depend heavily on the degree of utilization of the barge, i.e. whether the barge will be in transit or loading continuously, or whether it will remain idle for longer periods. For a project of 500,000tCO_2/y, a representative OpEx would be $5-7/t$CO_2$ for two barges, which offer a degree of redundancy.

Overall, we expect barging, where available, to be more economical than trucking or railing. Pipeline transport will always be economically preferrable to barging, but the lead time and complexity involved in siting pipelines may render barging a valuable option in certain locales.

Geologic CO_2 Storage Costs

Geologic storage of captured carbon dioxide constitutes the final piece of the CCS value chain. In this chapter, we discuss the key elements of geologic storage and the methodology used to generate storage cost estimates for each case study in this report.

Geologic storage of carbon dioxide is a mature technology, and underground injection of CO_2 has been in commercial application since the 1970s. Geologic storage can take place either in oil fields (during CO_2 enhanced oil recovery (CO_2-EOR) if they still producing, or in depleted fields) or as pure storage in saline aquifers, referred to as saline storage. In this study, we solely consider pure storage without concurrent oil production because California recently enacted a statewide ban on CO_2-EOR.[40] Most of California's geologic storage potential lies deep underneath the Central Valley, and we consider three indicative storage locations for our case studies:

- Storage near Stockton in the Southern Sacramento Basin;
- Storage near Modesto in the Northern San Joaquin Basin;
- Storage in Kern County in the Southern San Joaquin Basin.

CO_2 storage costs presented in this report cover the total cost of storage from geologic characterization through post-injection monitoring. Developers typically carry out geologic storage projects in a phased manner with the intent to reduce risk and increase investment with each subsequent phase. Figure 4 illustrates an ideal commercial CCS project. Storage projects begin with initial geologic feasibility assessments, and it can take multiple years to complete the characterization and permitting phases before construction and injection can commence. This idealized timeline is a general representation of CCS projects and individual projects will each have their unique timelines and structures. The timing of developer acquisition of pore space rights to inject CO_2 and pore space leasing structures, for instance, can vary project to project.

Based on existing projects and cost modeling, the U.S. Department of Energy estimates costs of geologic storage to range from \$7-13 per metric ton of CO_2.[41] The wide range of costs is due to the site-specific nature of geologic storage projects. The key factors that influence the cost of geologic storage projects include geologic reservoir characteristics (i.e., depth, thickness, porosity, permeability), the amount of CO_2 that is being stored at a

40 Senate Bill 1314, statutes of 2022.

41 https://dualchallenge.npc.org/files/CCUS-Chap_7-030521.pdf

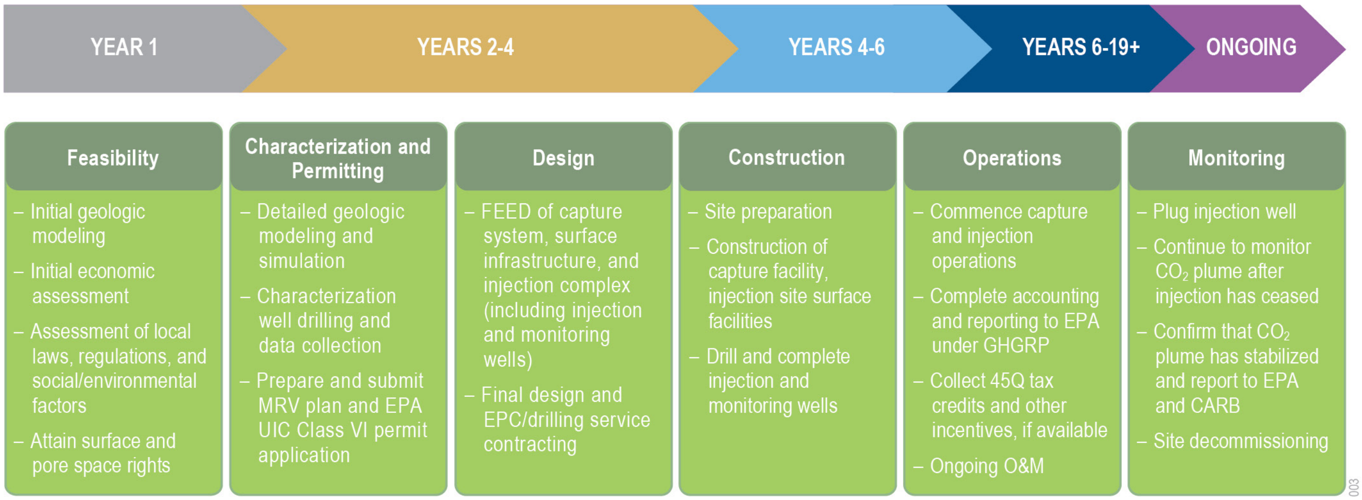


Figure 5. *Geologic CO_2 storage timeline schematic.*

given site, the number of injection and monitoring wells, and the duration of monitoring. For example, a 1 million ton per year storage project will carry a higher total cost than a 500,000 ton per year storage project because the injected CO_2 will spread over a larger footprint in the higher volume project – corresponding to increased monitoring costs. In this example, the smaller, 500,000 ton per year storage project may have a higher cost per ton of CO_2 injected, because the total cost, despite being lower, is spread across fewer tons of CO_2. Similarly, the duration of injection operations influences the per ton cost of storage (generally, the longer the injection period, the lower the cost per ton of injected CO_2). Most literature-based cost estimates for carbon storage assume injection durations typical of commercial projects (i.e., 20-30 years). Storage cost estimates in this report carry higher cost per ton due to our assumed injection duration being limited to 12 years (the current duration of the 45Q tax credit).

The cost estimates provided in the following case studies of this report were generated using the NETL Saline Storage Cost Model,[42] which is a widely-used, open-source model for estimating the cost of storing CO_2 in saline formations. The NETL Saline Storage Cost Model provides total capital and operating cost estimates for the entire value chain of a saline storage project, including feasibility and geologic characterization, construction, injection operations, monitoring, site closure, and post-injection monitoring and site care. The model incorporates the labor, equipment, technology, and financial instruments that are needed to meet the requirements of EPA Class VI permits and includes cost estimates for monitoring and reporting requirements under the Subpart RR of the Greenhouse Gas Reporting Rule.

The NETL Saline Storage Cost Model allows users flexibility to tailor it to the specific characteristics of a given saline storage project. Below are the key input assumptions that were used across the case studies in the following chapter (where we present storage costs in context):

- 1 stratigraphic characterization well, converted to a dual-completed monitoring well.
- 2-3 injection wells.
- 1 additional dual-completed monitoring well.
- 100-year duration of post-injection monitoring (this is both the period mandated by CARB under the current CCS Protocol if the project is eligible for LCFS credits, and the minimum period required by recent legislation (SB 905, statutes of 2022) for carbon dioxide capture, removal, or sequestration projects).

42 https://edx.netl.doe.gov/dataset/fe-netl-CO_2-saline-storage-cost-model-2017

- Repeat 3D seismic monitoring for the CO_2 plume. Although it is not certain whether such monitoring will be required for all projects or if it will be informative in all geologic settings, we make the conservative assumption that it will be required. This increases total storage costs: Seismic costs generally constitute 20-30% of the total project storage cost.
- 12-year injection duration.
- $0.07/ton long-term stewardship trust fund fee.
- Financing costs are not included in the NETL model, although we do model these in the case studies that follow in this report.
- Initial and ongoing land and pore space acquisition or leasing costs are also not included.

Site specific geologic input parameters (i.e., geologic formation, depth, thickness) for each modeled storage location were derived from WestCARB.[43]

43 https://www.westcarb.org/pdfs/geologic_CO_2_sequestration%20_potential_hq.pdf

CHAPTER 6

Indicative Case Studies

In this chapter we present indicative project case studies around California. These are not meant to replicate real projects that are already under consideration, but are chosen so as to represent likely or logical developments, to demonstrate the effect and relative role of various factors on total project costs (e.g., concentration of CO_2 in flue gas, transportation means and distance, etc.), and to cover different areas of the state.

General Case Study Assumptions and Methods

To present project practical and useful cost numbers, we use a simple cash-flow calculation, which is typically used in project finance. The base-case for the calculation assumes:

- A *capital outlay over the first 3 years* of the project, with revenues accruing after those 3 years.
- A *45Q revenue window of 12 years.* We consider this to be a very conservative assumption, because it is likely that the 45Q credit will be extended once this window expires.
- Since 45Q is a major source of income for all projects, we assume a *12-year project lifetime* and calculate the rate of return based on this period. We anticipate the LCFS credit-generation window to be longer, in practice. Although certain types of LCFS-eligible projects are periodically identified by CARB as mature and are "graduated" from the program (thus terminating credit generation), there are no CCS projects generating credits at the time of this writing, and we expect the credit generation window of future projects to last for quite some time. Nonetheless, projects that are economical only under a combination of 45Q and LCFS will likely discontinue operations after 45Q revenues terminate.
- An *LCFS credit price of \$125/tCO_2.*
- An *annual insurance expenditure equal to 3%* of revenues.
- A target *cash-on-cash rate of return of 8%.* The rate of return will be dependent on the size, capitalization, balance sheet, degree of integration and other metrics related to the project developer.
- We assume a *terminal enterprise value*[44] at the end of project operations *equal to 6x* the free cash flow during the last year of project operations. We also consider this value to be a conservative assumption.
- No taxes: The numbers presented are pre-tax.

We present sensitivities to this base case in the case studies that follow to showcase the effect of varying some of these assumptions.

Pipeline costs used in the case studies, where applicable, *are generic and do not correspond to a specific route.*

We do not attempt an exact calculation of the number of LCFS credits that projects in the case studies below may be able to generate. However, one LCFS credit corresponds to one ton of CO_2 reduction, and thus the maximum number of LCFS credits (over and above what a project may be generating without CCS) will be equal to the number of CO_2 tons being injected. This theoretical maximum needs to be reduced to take into account lifecycle emissions that result from the CCS process, such as transportation emissions, parasitic loads for capture, and other factors that may affect the overall carbon footprint of the project. Determining this exact reduction would necessitate the use of lifecycle models for emissions and carbon intensity. Exact reductions are calculated by CARB and project applicants, but are outside the scope of this study. Instead, here we assume a generic reduction of 10% in LCFS credits due to parasitic loads, fugitive and upstream emissions, and other factors.

For LCFS-eligible projects, a small portion of credits will also need to be placed into the Buffer Account, as described in the *Incentives and Revenue Sources* chapter earlier. Here, *we subtract 8% of issued LCFS credits from project revenues due to Buffer Account contributions,* which is on the low end of the range specified in CARB's CCS Protocol.

On balance, *we consider our base-case assumptions to be conservative,* particularly the revenues. We also present sensitivities to some of these assumptions to showcase their effect and relative importance below.

44 This is typically calculated as *(Net Debt + Market Capitalization of Equity) / EBITDA.*

Summary of Case Studies

- *Case Study #1:*
  - — Capture from corn ethanol plant.
  - — Theoretical location: Stockton.
  - — Transport means: barge over 10 miles.
  - — Theoretical storage location: Delta.
  - — Sensitivity:
    - – Change transport means to pipeline over the same distance.
- *Case Study #2:*
  - — Capture from refinery steam methane reformer and fluid catalytic cracker.
  - — Theoretical location: Bay Area.
  - — Transport means: pipeline over 60 miles.
  - — Theoretical storage location: Delta.
  - — Sensitivity #1:
    - – Transport means: tanker trucks over 60mi for steam methane reformer.
    - – High end of capture-cost range.
  - — Sensitivity #2:
    - – Transport means: barge over 60 miles for steam methane reformer.
    - – Low end of capture-cost range.
  - — Sensitivity #3:
    - – Increase 45Q eligibility and LCFS credit generation period to 20 years for steam methane reformer.
    - – High end of capture-cost range.
  - — Sensitivity #4:
    - – Increase LCFS credit price to \$175/tCO_2 for steam methane reformer.
    - – High end of capture-cost range.
  - — Sensitivity #5:
    - – Increase target rate of return from 8% to 15% for steam methane reformer.
    - – High end of capture-cost range.
- *Case Study #3:*
  - — Capture from natural gas combined cycle power plant.
  - — Theoretical location: Tracy.
  - — Transport means: pipeline over 35 miles.
  - — Theoretical storage location: Modesto area.
  - — Sensitivity:
    - – Increase 45Q eligibility period to 20 years.
- *Case Study #4:*
  - — Capture from cement plant.
  - — Theoretical location: Tehachapi or Mojave.
  - — Transport means: rail over 60 miles.
  - — Theoretical storage location: Kern County.
  - — Sensitivity:
    - – Change transport means to pipeline over the same distance.

CASE STUDY #1:

Ethanol plant, barge transport, storage in the California Delta

In this case study, we consider CO_2 capture from a nameplate ethanol plant in Stockton with geologic storage nearby in the Sacramento-San Joaquin Delta. We assume that the plant sources its electricity from the grid at present-day costs even though dedicated renewable generation may be available nearby or on-site.

SIGNIFICANCE: This represents a low-hanging-fruit case due to the very high degree of purity of CO_2 in the emissions stream and the access to a wide range of geologic storage options within a very short distance.

We assume capturable annual emissions of 500,000 tons with a 100% capture rate using only dehydration and compression. We model transportation via barge on the river over a 10-mile distance. We assume 2 injection wells, 12 years of operation, totaling 6,000,000 tons of CO_2 captured, transported, and stored, and 100 years of post-injection monitoring. The project would be eligible both for 45Q tax credits and for LCFS credits.

ANNUAL EMISSIONS STREAM PROCESSED (tCO_2/y)	CAPTURE METHOD	CAPTURE RATE	DISTANCE TO STORAGE, TRANSPORT MEANS	INJECTION WELLS (#)	POST-INJECTION MONITORING (YEARS)
500,000	Dehydration, compression	100%	10mi, barge	2	100

The table below shows the estimated costs for capture, transport, and storage:

	COSTS (LOW/HIGH)		COST per ton ($/$tCO_2$) (LOW/HIGH)	
Capture CapEx	21M	47M		
Capture OpEx			14	30
Transport CapEx	50M			
Transport OpEx			6	
Storage CapEx	85M			
Storage OpEx			13	
45Q	ELIGIBLE			
LCFS	ELIGIBLE			

Using these cost estimates and the finance assumptions below, we obtain the following results for the project surplus:

Target Rate of Return	8%	
Years of operation	12	
LCFS credit price	$125/$tCO_2$	
Project Surplus/Deficit (Low Costs/High Costs)	$114/$tCO_2$	$93/$tCO_2$

ETHANOL SENSITIVITY

To showcase the differences between barge and pipeline transport over short distances, we modeled a pipeline of the same distance from source to sink while using the high-end cost estimates for capture from the plant.

PARAMETER CHANGED	MEANS OF TRANSPORT → PIPELINE	
	Cost ($)	Cost per ton ($/$tCO_2$)
New Transport CapEx	12M	
New Transport OpEx		0.8

We obtain the following results for the ***project surplus*** under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	$114/$tCO_2$	$93/$tCO_2$

ETHANOL CONCLUSIONS

With low capture costs and both 45Q and LCFS eligibility, ethanol CCS looks comfortably economical. Utilizing barge transport, the project surplus ranges between $93-114/$tCO_2$ in the high- and low-cost cases respectively. Using a dedicated pipeline for transporting the CO_2 over the 10 miles increases the project surplus to $106/$tCO_2$ under the high-cost case, which represents fairly small savings.

CASE STUDY #2:

Petroleum refinery sources (steam methane reformer and fluid catalytic cracker), pipeline transport, storage in the California Delta

In this case study, we consider CO_2 capture from two types of refinery applications in the Bay Area: a steam methane reformer (SMR) and a fluid catalytic cracker (FCC). CO_2 storage would take place in the Sacramento-San Joaquin Delta at a nominal distance of 60mi away, and the CO_2 would be transported by pipeline.

SIGNIFICANCE: The Bay Area is home to 5 refineries, which are major CO_2 sources statewide. Some of these are reconfiguring their operations to process bio-feedstock instead of/alongside fossil feedstock. Due to the quantity and somewhat elevated concentration of CO_2 in SMRs and FCCs, these represent prime CCS targets. In addition, these pieces of equipment will likely remain operational if refineries switch from crude oil to bio-feedstock. The relative proximity to a wide range of geologic storage options in the Delta also helps these projects.

We assume a capturable annual emissions of 1,000,000 tons with a 90% capture rate using amine scrubbing. We model transportation via pipeline over a 60-mile distance. We assume 3 injection wells, 12 years of operation, totaling 10,800,000 tons of CO_2 captured, transported and stored, and 100 years of post-injection monitoring. The project would be eligible both for 45Q tax credits and for LCFS credits.

ANNUAL EMISSIONS STREAM PROCESSED (tCO_2/y)	CAPTURE METHOD	CAPTURE RATE	DISTANCE TO STORAGE, TRANSPORT MEANS	INJECTION WELLS (#)	POST-INJECTION MONITORING (YEARS)
1,000,000	Amines (post-combustion capture), compression	90%	60mi, pipline	3	100

FLUID CATALYTIC CRACKER (FCC)

The table below shows the estimated costs for capture, transport, and storage:

	COSTS (LOW/HIGH)		COST per ton ($/tCO₂) (LOW/HIGH)	
Capture CapEx	158M	288M		
Capture OpEx			46	84
Transport CapEx	68M			
Transport OpEx			1.3	
Storage CapEx	98M			
Storage OpEx			8	
45Q	ELIGIBLE			
LCFS	ELIGIBLE			

Using these cost estimates and the finance assumptions below, we obtain the following results for the *project surplus:*

Target Rate of Return	8%	
Years of operation	12	
LCFS credit price	$125/tCO₂	
Project Surplus/Deficit (Low Costs/High Costs)	$87/tCO₂	$33/tCO₂

STEAM METHANE REFORMER (SMR)

The table below shows the estimated costs for capture, transport, and storage:

	COSTS (LOW/HIGH)		COST per ton ($/tCO₂) (LOW/HIGH)	
Capture CapEx	171M	376M		
Capture OpEx			41	89
Transport CapEx	68M			
Transport OpEx			1.3	
Storage CapEx	98M			
Storage OpEx			8	
45Q	ELIGIBLE			
LCFS	ELIGIBLE			

Using these cost estimates and the finance assumptions below, we obtain the following results for the project surplus:

Target Rate of Return	8%	
Years of operation	12	
LCFS credit price	$125/tCO₂	
Project Surplus/Deficit (Low Costs/High Costs)	$90/tCO₂	$17/tCO₂

SMR Sensitivity #1

To showcase the favorable economics and importance of pipeline transport, even for relatively short distances, we also modeled *transport using tanker trucks* over the same distance from source to sink while using the high-end cost estimates for capture from the plant.

PARAMETER CHANGED	MEANS OF TRANSPORT → TANKER TRUCKS	
	Cost ($)	Cost per ton ($/t$CO_2$)
New Transport CapEx	201M	
New Transport OpEx		47

We obtain the following results for the ***project deficit*** under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	**\$17/tCO_2**	**–\$45/tCO_2**

The implication of this sensitivity is that trucking over modest distances but large volumes – even if feasible – places a marked strain on project economics.

SMR Sensitivity #2

To demonstrate the potential advantages of maritime transport where the option is available, we modeled *transport using barges* over the same distance from source to sink while using the low-end cost estimates for capture from the plant. For the volume considered, we estimate that 6 barges would be required. The OpEx is slightly lower than in the ethanol case study due to the larger volumes involved, hence there is a higher degree of utilization for the barges.

PARAMETER CHANGED	MEANS OF TRANSPORT → BARGES	
	Cost ($)	Cost per ton ($/t$CO_2$)
New Transport CapEx	150M	
New Transport OpEx		5

We obtain the following results for the ***project surplus*** under this sensitivity:

Project Surplus/Deficit (Base Case Low Costs/Sensitivity)	**\$90/tCO_2**	**\$76/tCO_2**

The implication of this sensitivity is that marine transport, where available, can offer a viable transport option, even for large volumes. Marine transport avoids the complications of siting pipelines without straining project economics in the same way that truck transport does.

SMR Sensitivity #3

In this sensitivity, we consider the effect of a *longer eligibility period for 45Q and LCFS credits of 20 years (from 12 years)* while using the high-end cost estimates for capture from the plant. Thus, the plant would earn revenue and operate for an additional 8 years.

PARAMETER CHANGED	45Q & LCFS: 12 → 20 YEARS

We obtain the following results for the project surplus under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	**\$17/tCO_2**	**\$24/tCO_2**

The implication of this sensitivity is that a longer incentive eligibility period has a small positive effect on overall project economics because it counterbalances the initial capital expenditure with positive revenues over a longer period.

SMR Sensitivity #4

In this sensitivity, we consider the effect of a higher *LCFS credit price of \$175/tCO_2* while using the high-end cost estimates for capture from the plant.

PARAMETER CHANGED	LCFS CREDIT PRICE: $125/tCO_2 → $175/tCO_2

We obtain the following results for the project surplus under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	$17/tCO_2	$57/tCO_2

The implication of this sensitivity is that LCFS credit prices have a marked effect on project economics.

SMR Sensitivity #5

In this sensitivity, we consider the effect of a higher target rate of return of 15%, instead of 8%, while using the high-end cost estimates for capture from the plant.

PARAMETER CHANGED	TARGET RATE OF RETURN: 8% → 15%

We obtain the following results for the ***project deficit*** under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	$17/tCO_2	–$23/tCO_2

REFINERY (FCC & SMR) CONCLUSIONS

The cases and sensitivities considered above reaffirm the generally held belief that high-concentration refinery components such as fluid catalytic crackers and steam methane reformers present good targets for CCS. At the lower end of their respective capture cost ranges, and using a pipeline for CO_2 transport, both applications show healthy surpluses: \$87/tCO_2 (FCC) and \$90/tCO_2 (FCC). At the high end of the cost range, and using a pipeline for CO_2 transport, these surpluses shrink to \$33/tCO_2 (FCC) and \$17/tCO_2 (SMR).

Resorting to tanker trucks due to the inability to site a pipeline has a marked economic impact on project economics, turning the SMR high-capture cost case from a \$17/tCO_2 surplus to a-\$45/tCO_2 deficit. This underscores the importance of pipelines in aggregating and transporting CO_2 from a cluster of sources. However, barge transport, if available, can accomplish the task with a much smaller economic hit. The SMR low-capture cost case using pipeline transport only shrinks the \$90/tCO_2 surplus to \$76/tCO_2.

A longer, 20-year incentive eligibility period (both 45Q and LCFS) improves project economics marginally: Foe example, it increases the SMR high-capture cost case from a \$17/tCO_2 surplus to a \$24/tCO_2 surplus.

An increase in LCFS credit prices from \$125/tCO_2 to \$175/tCO_2 has a profound effect on project economics, increasing the SMR high-capture cost case surplus from \$17/tCO_2 to \$57/tCO_2, demonstrating the importance of the LCFS program going forward.

Finally, a target rate of return of 15% instead of 8%, as may apply, for example, to a project developer that is not as well capitalized or integrated, turns the SMR high-capture cost case from a \$17/tCO_2 surplus to a-\$23/tCO_2 deficit. In other words, to achieve that rate of return, an additional \$23/tCO_2 incentive would be required.

Overall, given the conservative nature of our assumptions, we conclude that these two refinery CCS applications are likely to be economically viable with a potentially sizeable margin for local benefits. However, projects and costs will need to be evaluated individually based on their own particular characteristics.

CASE STUDY #3:

Natural gas combined-cycle power plant, pipeline transport, storage in the Modesto area

In this case study, we consider CO_2 capture from a natural gas-fired, combined-cycle power plant (NGCC) in the Tracy area. The distance to storage, which we assume to be in the vicinity of Modesto, is 35 miles.

SIGNIFICANCE: NGCCs are a common type of power plant in California. Even under a very renewables-heavy grid, it is likely that some of these plants will need to remain online into mid-century to safeguard grid stability and reliability, and to provide dispatchable and/or baseload power in some cases.

ANNUAL EMISSIONS STREAM PROCESSED (tCO_2/y)	CAPTURE METHOD	CAPTURE RATE	DISTANCE TO STORAGE, TRANSPORT MEANS	INJECTION WELLS (#)	POST-INJECTION MONITORING (YEARS)
1,000,000	Amines (post-combustion capture), compression	90%	35mi, pipline	3	100

The table below shows the estimated costs for capture, transport, and storage:

	COSTS (LOW/HIGH)		COST per ton ($/tCO₂) (LOW/HIGH)	
Capture CapEx	233M	428M		
Capture OpEx			63	116
Transport CapEx	37M			
Transport OpEx			1.0	
Storage CapEx	77M			
Storage OpEx			4	
45Q	ELIGIBLE			
LCFS	TYPICALLY NOT ELIGIBLE[45]			

Using these cost estimates and the finance assumptions below, we obtain the following results for the *project deficit:*

Target Rate of Return	8%	
Years of operation	12	
LCFS credit price	NA	
Project Surplus/Deficit (Low Costs/High Costs)	−$27/tCO₂	−$104/tCO₂

NGCC SENSITIVITY

In this sensitivity, we consider the effect of a *longer eligibility period for 45Q of 20 years* (from 12 years) while using the high-end cost estimates for capture from the plant. Thus, the plant would earn revenue and operate for an additional 8 years.

PARAMETER CHANGED	45Q: 12 → 20 YEARS

We obtain the following results for the *project surplus* under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	−$104/tCO₂	−$97/tCO₂

NGCC CONCLUSIONS

CCS at an NGCC plant faces challenging economics, due to the dilute nature of the flue gas stream being captured and the lack of an incentive program like the LCFS that can support the plant in addition to 45Q. Lengthening the eligibility period for 45Q from 12 years to 20 years marginally improves the project's deficit, which remains close to the-$100/ tCO_2 under the high-end cost estimates for capture.

Under the low-end cost estimates for capture, the project appears closer to viability with a deficit of-27/tCO_2. Such a deficit may be covered in several ways, for example through a marked-up power purchase agreement for low-carbon dispatchable power. In addition, a plant could be LCFS-eligible if it happens to supply the electricity needs of an oil field (which is the exception and not the rule). NGCCs are also subject to California's Cap-and-Trade program, so recognition of CCS under that program could tilt project economics in favor of project development if the allowance price is high enough.

The viability of NGCC CCS projects will depend on future policy developments that affect the sector.

CASE STUDY #4:

Cement plant, rail transport, storage in Kern County

In this case study, we consider CO_2 capture from a common stack at a cement plant in California's Central Valley – for example in the vicinity of Tehachapi or Mojave where plants exist today – that includes emissions from the pre-heater, calciner, combustor, and kiln. We assume transportation by rail over a 60-mile route, and present sensitivities related to other means of transport.

SIGNIFICANCE: California is one of the largest cement producers in the U.S. and features 7 operating cement plants, which emit just under 10 million tons of CO_2 per year.[45] Cement will continue to be needed in California's economy for decades to come. Cement plant technology is generally fairly rudimentary, with large heat requirements, and finding ways to decarbonize cement is important to achieving California's climate goals. In addition to the capture application discussed here, a dedicated calciner approach is also possible, but we do not discuss that configuration in this report.[46]

ANNUAL EMISSIONS STREAM PROCESSED (tCO_2/y)	CAPTURE METHOD	CAPTURE RATE	DISTANCE TO STORAGE, TRANSPORT MEANS	INJECTION WELLS (#)	POST-INJECTION MONITORING (YEARS)
1,000,000	Amines (post-combustion capture), compression	90%	60mi, intermodals on rail	3	100

45 Ali Hasanbeigi & Cecilia Springer, "California's Cement Industry: Failing the Climate Challenge", February 2019. Available at: https://www.climateworks.org/wp-content/uploads/2019/02/CA-Cement-benchmarking-report-Rev-Final.pdf Note that the Lehigh Hanson plant in Cupertino is not operational at the time of this writing after the owner announced in late 2022 suspension of plant operations.

46 See Project 2030 (2022).

The table below shows the estimated costs for capture, transport, and storage:

	COSTS (LOW/HIGH)		COST per ton (\$/tCO_2) (LOW/HIGH)	
Capture CapEx	130M	259M		
Capture OpEx			53	106
Transport CapEx				
Transport OpEx				
Storage CapEx	96			
Storage OpEx			8	
45Q	ELIGIBLE			
LCFS	NOT ELIGIBLE			

Using these cost estimates and the finance assumptions below, we obtain the following results for the *project deficit:*

Target Rate of Return	8%	
Years of operation	12	
LCFS credit price	N/A	
Project Surplus/Deficit (Low Costs/High Costs)	−\$155/tCO_2	−\$224/tCO_2

CEMENT SENSITIVITY

In this sensitivity we examine the effect of having a dedicated pipeline to the storage site rather than relying on rail to transport intermodal CO_2 containers.

PARAMETER CHANGED	MEANS OF TRANSPORT → PIPELINE	
	Cost (\$)	Cost per ton (\$/tCO_2)
New Transport CapEx	68M	
New Transport OpEx		1.3

We obtain the following results for the *project deficit* under this sensitivity:

Project Surplus/Deficit (Base Case High Costs/Sensitivity)	−\$224/tCO_2	−\$84/tCO_2

This sensitivity shows, once again, the importance of CO_2 pipelines in transporting CO_2 economically from its source to a suitable geologic storage location.

CEMENT CONCLUSIONS

Both the low and the high end of the cost range for this cement plant application with rail transport appear uneconomical. Even though rail is technically and logistically feasible, it places a strain on project economics. Despite the 45Q tax credit, the cement plant generates a deficit between-\$155/tCO_2 and-\$224/tCO_2 under low- and high-end capture cost estimates respectively.

The option to use a CO_2 pipeline could reduce the high-end deficit significantly to-\$84/tCO_2, further demonstrating the utility of such pipelines.

Much like NGCC plants, the viability of CCS applications in cement production will depend on future policy developments that affect the sector.

Cement production is not eligible for LCFS credits. However, recent legislation[47] calls for, inter alia, CARB to develop and implement a comprehensive strategy for the state's cement sector to achieve net-zero emissions, encourage the production and use of cement with low greenhouse gas intensity, interim targets for reductions in the greenhouse gas intensity of cement used within California with the goal of reducing the greenhouse gas intensity of cement used within the state to 40% below the 2019 average levels by December 31, 2035. This means that additional incentives for carbon capture in cement will likely be available in the future.

47 SB 596, statutes of 2022.

CHAPTER 7

Discussion and Findings

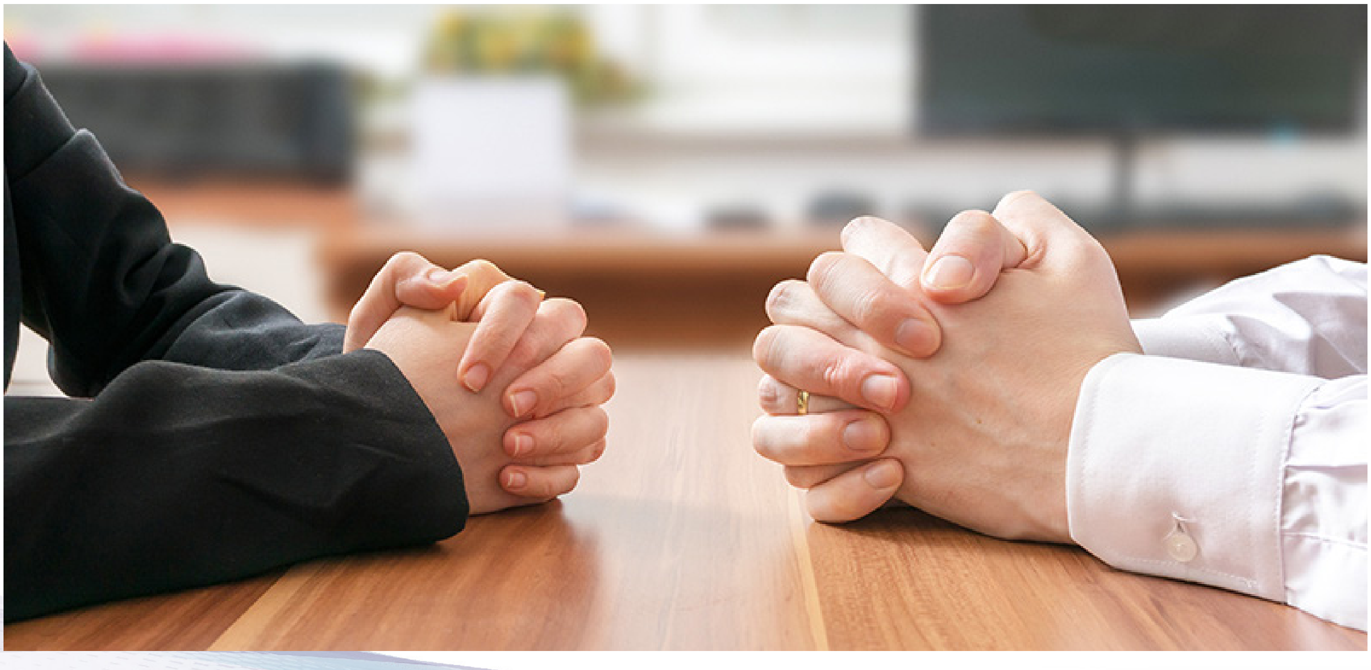
The previous chapters may seem to paint a confusing picture regarding CCS costs. Cost ranges from a single published source can be wide, sources may differ between each other, and many parameters – which can come together in numerous permutations – control project costs in a significant way. In addition, local factors such as regulations (e.g., height of structures, noise, etc.), and the lack or presence of existing infrastructure (e.g., existing connections to power and natural gas supply, existing pipelines that have to be avoided when digging, etc.) can also have a smaller effect on costs, but one that may still cause deviations from academic estimates.

Despite this picture, there are useful and material conclusions to be drawn, both for policy makers and for landowners.

Cost-determining Factors

A useful starting point when assessing a project's economics is to establish where it stands in relation to the main factors that affect cost:

- Major cost-determining factors:
  - The CO_2 concentration in the emissions stream to be captured. This depends on the type of application and economic sector, as well as, importantly, plant specifics. Some sectors exhibit larger variations than others in how plants are configured.
  - The ability to transport CO_2 via pipeline decreases the economic demands on the project significantly, unless marine transport is an option. Having to resort to trucking or railing instead of a pipeline can significantly increase project costs, sometimes even double them or more for lower-capture cost projects.
  - For truck transport projects, labor costs are a major factor and the distance traveled has a significant effect on overall costs, with shorter distances being cheaper.
  - Eligibility for LCFS credits or lack thereof significantly affects project revenues, despite the price variability inherent in the program.
  - Eligibility for 45Q tax credits, and which vintage in particular the plant qualifies for. For all new capture facilities that were not in operation prior to the enactment of the Inflation Reduction Act of 2022, the latest and highest level of credit would apply for a period of 12 years.
- Moderate cost-determining factors:
  - The annual and total quantity of CO_2 to be captured, transported, and stored can affect economies of scale for projects and hence the $/t$CO_2$ cost. A larger project, for example, can



- spread minimum needed capital costs such as injection and monitoring wells, compressors, pipeline expenses, rail or truck transportation equipment etc., more easily than a smaller project.
- Unless intermodal containers are used, truck transportation projects exceeding a distance of ~250mi can result in a step-change increase in costs due to the additional labor requirements and costs for longer routes.

- Minor cost-determining factors:
  - For rail transport projects, the distance traveled does not affect overall cost significantly.
  - For pipeline transportation projects, longer transport distances are feasible at only a modest increase in overall costs.

As a result of these factors, some project types clearly make economic sense. These will typically have very high CO_2 concentrations and, hence, low capture costs – e.g., ethanol – or be located close to viable geologic storage. These projects need no additional policy support and hold a sizeable potential for local and community benefits.

At the other end of the spectrum, projects that feature dilute sources with a high capture cost and that are not eligible for LCFS credits will typically not be economic with 45Q tax credits alone, particularly if they lack viable geologic storage on site. Such projects, which include most natural gas-fired combined cycle plants and cement plants, may become economically viable under certain conditions. These conditions include if they are eligible for LCFS, if CCS is recognized under California's Cap-and-Trade program, and/or if they receive additional federal or state funding, favorable offtake agreements, or other grants or incentives.

In between these two ends of the economic spectrum are projects whose viability will depend on plant specifics. This category includes several large LCFS-eligible refinery sources of CO_2 with elevated CO_2 concentrations such as fluid catalytic crackers and steam methane reformers. The economic viability of CCS and the potential for local and community benefits needs to be examined at each specific facility individually, and our results show a range of possible outcomes. Despite stacking several conservative assumptions in our modeling of refinery projects, we generally note a favorable picture of 10s of $/t$CO_2$ of project surplus. This is consistent with reported values of recent pore-space leasing agreements and proposals from the U.S. Gulf Coast.[48]

While this economic picture is representative of first-of-a-kind (FOAK) and early-adopter projects, we expect that costs for subsequent, Nth-of-a-kind (NOAK) projects will decline and become more economically favorable as these technologies are deployed more broadly commercially.

It is also important to note that the economics represented in this report are for single-source to single-sink projects. Multi-source projects that utilize common transport and storage infrastructure can achieve economies of scale that will make their economics more favorable.

Implications for Policy Makers, Landowners and Project Developers

A clear conclusion from this study is that no two projects are the same. All project specifics need to be taken into account when assessing a project's true cost, not just the sector from which CO_2 is captured. These factors include the plant's age, configuration, proximity to suitable geologic storage, viability of cheap CO_2 transport, transport routings through areas of different sensitivity or logistical complexity, and more. Two similar-looking projects may have materially different economics depending on their location, plant configuration, and other factors. This report attempts to illustrate the effect of some of these factors, but many more exist at the individual project level.

The implication for policy makers is that a one-size-fits all policy instrument is not well suited for driving deployment in an entire sector. A fixed-price incentive may be insufficient for some projects, while more than sufficient for others. This issue can be avoided if the incentive is made large enough, but that likely results in the inefficient use of public funding. Some policy instruments, such as reverse auctions, can avoid overspending while avoiding a case in which a blanket incentive fails to make a deep enough impact on a sector by covering only the easiest and cheapest projects.

The implication for landowners and project developers is that a thorough discussion needs to take place that

48 Private communications with consultants involved in Gulf Coast CCS projects.

is based on project specifics and detailed economics. Without examining these details, it is virtually impossible to arrive at a reasonable figure that respects both the genuine difficulty that is often inherent in putting CCS projects together and the legitimate desire of landowners and host communities to realize a fair portion of the benefits that may flow from a project in their area. This may require a depth of conversation that has been traditionally absent from most oil and gas lease negotiations: one that delves into the project's economic models.

A typical oil and gas lease includes a royalty component that is indexed to the price of the produced oil or gas. As such, the revenue for the land/mineral owner will fluctuate downwards or upwards as the price of the produced fuel drops or rises respectively. Based on private conversations with a small number of mineral owners, typical values are approximately 1/7th – 1/6th of a particular well's revenue from oil or gas in California's Central Valley. Such indexing in the oil and gas context is commonplace nowadays and straightforward to structure in a deal or agreement, as market prices are well understood and published. It is worth noting that such structures took some time to emerge since the early days of hydrocarbon exploration.

It is logical and fair to expect a similar structure with CO_2 storage – especially given the wide possible range of project revenues – whereby the payment to the land owner is commensurate with the (fixed and variable) revenue that the project earns. Without such a structure, landowners and local communities are precluded from the potential economic up-side of CCS which, as this report has shown, can range from meaningful to very significant for several project classes. Conversely, an unduly high fixed payment demand may impose unreasonable risks on projects and render them uneconomical.

Such agreements may necessitate accounting innovation or creativity to structure, as there is no single metric that quantifies CO_2-related revenues. The revenue streams may change over time (if tax credits or incentive programs are amended), the CO_2 being injected in a single sink (site) may originate from several different capture sources, and the number of LCFS credits earned for similar applications may be different if their lifecycle emissions differ.

However, such metrics and arrangements appear feasible to devise if there is a shared desire and commitment to do so, and we are not aware of any legal or other fundamental limitations that preclude their development and use. In addition, recent statute (SB 905, 2022) directs the Secretary of the Natural Resources Agency to "On or before July 1, 2025, […] publish a framework for governing agreements regarding two or more tracts of land overlying the same geologic storage reservoir or reservoirs for purposes of managing, developing, and operating a carbon dioxide capture, removal, or sequestration project. […] The framework shall include […] [s]tandards to determine fair and reasonable compensation for owners of surface, mineral, and subsurface rights whose use of their property will be infringed upon by the geologic storage reservoir." We thus expect considerable evolution in the space of landowner compensation in the coming years.

There is no unique structure to these agreements. A variety of different structures could be implemented in a way that satisfies the needs of both developers and landowners. A transparent, proactive and inclusive discussion with members of the host community based on project specifics and economics must take place to achieve a fair, viable and sustainable outcome that sets a positive precedent and paves the way for more successful projects.

While the practice of sharing and discussing individual project economics may not be common today, we believe that it is ultimately in the interest of both landowners and project developers, in that it leaves room for negotiation, expedites project development, and results in genuine and material local benefits.

The future of CCS and CDR in California hinges on finding ways to deploy projects that concurrently serve the climate, the project developer, and the host landowners and communities. A good-faith approach from all parties involved is required to enable such projects to materialize.