

ENVISIONING A Carbon Management Business Park

An exploration of carbon management and clean energy industries, and their potential benefits and impacts if developed within a Carbon Management Business Park sited in Kern County.

Technical Report | June 2023

PREPARED BY *BLUE ENGINE* FOR THE Kern County Planning and Natural Resources Department



ENVISIONING A Carbon Management Business Park

This technical report supplements the informational website

cmbp.kernplanning.com

Technical report and website prepared for the Kern County Planning and Natural Resources Department

by Blue Engine and with Technical Assistance from the U.S. Department of Energy Communities-Local Energy Action Program (C-LEAP)

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Preface

What is a carbon management business park?

Carbon management industries are those that capture carbon dioxide (CO_2) for the purpose of removing it from the atmosphere or preventing its release to the atmosphere. The capture of CO_2 can be either the primary purpose of the industry – where a facility is built exclusively to capture gaseous CO_2 from the atmosphere, or a secondary goal – where CO_2 that is a byproduct of a primary industry process is captured. The Kern County Planning and Natural Resources Department has envisioned a conceptual Carbon Management Business Park, which could be developed as a large industrial park where one or several carbon management industries are located, with the aim of capturing CO_2 at the scale of millions of tons per year. Clean energy industries that support carbon management could be co-located within the park.

About Kern County Planning and Natural Resources Department

The Planning and Natural Resources Department (the Department) provides consolidated land use planning and community development programs for Kern County's residents, landowners and businesses. The Department's mission is to balance the county's economic vitality and resource conservation with the diverse needs of Kern County at large by preparing and implementing programs that are aligned with the county's General Plan. In 2021, with approval from the Kern County Board of Supervisors, the Planning and Natural Resource Department applied for the U.S. Department of Energy's (U.S. DOE) Communities Local Energy Action Plan (C-LEAP) Pilot Initiative. The Department's aim was

to secure expert technical assistance in order to better understand the nascent carbon management sector – what industries are involved, how they work, what they look like, and the potential benefits and impacts those industries could have if developed at a large scale in Kern County. The proposal was successful, and in 2022 Kern County became one of the 24 communities nationwide to be awarded a C-LEAP grant.

About the U.S. DOE Communities-Local Energy Action Program

C-LEAP is a pilot program developed by the U.S. Department of Energy (U.S. DOE) that is designed to facilitate community-driven clean energy transitions by providing supportive services valued at up to \$16 million USD. The program partners specifically with communities that are experiencing either direct environmental justice impacts, or direct economic impacts from a shift away from historical reliance on fossil fuels. Kern County faces both of these challenges. C-LEAP recipients are awarded up to 18 months of high-quality technical assistance from a network of national experts in order to help build community clean-energy related economic development action plans.

About Blue Engine

Blue Engine provides advisory services to local governments, communities, and companies or other organizations seeking to develop decarbonization strategies, with particular focus on identifying opportunities and mitigating impacts of the ongoing energy transformation. The team at Blue Engine works closely with its sister company, Climate Now, a multimedia educational resource that produces accessible, expert-driven content – including a weekly podcast, videos, and events across the United States – about how and why the climate is changing, the clean energy technologies available to address and mitigate climate change, and the role of policies, markets, and stakeholder communities in driving the transition to a net-zero emissions global economy. The combined capabilities of Climate Now and Blue Engine allow the team to manage projects that are highly interdisciplinary in nature, and to act as a communication bridge between project experts and stakeholder communities.

About this report

Kern County Planning and Natural Resources Department, in partnership with an executive committee of community leaders who represent the diverse stakeholders of Kern County, was awarded the C-LEAP grant to perform a pre-feasibility analysis for a conceptual carbon management industrial park that could serve as a Clean Energy and Carbon Management Hub for all of California. The envisioned park would comprise 30 million square feet of development on 4,000 acres, and could be supported by over 30,000 acres of solar power. The goal of the pre-feasibility analysis was to understand how much carbon could be

captured in such a facility, what kinds of industries would locate there, and how such a park might impact the surrounding community and environment of Kern County. This report, in conjunction with the website <u>cmbp.kernplanning.com</u>, addresses each of those questions. The website serves as an executive summary of this report, which is meant to provide a comprehensive review of the state of the art of carbon management technologies, and of the clean energy technologies most likely to support them in an industrial park situated in Kern County.

Disclaimer

This document was prepared by Blue Engine for the Kern County Planning and Natural Resources Department, and with support from the U.S. DOE Technical Assistance Team and other academic and industry experts. The purpose of the report is not to endorse or advise a specific strategy of development of a carbon management business park, but to provide a sufficient summary of publicly available information on these industries to allow area property owners, private investors, and the broader community to make their own well-informed strategic development plans. Any content or opinions expressed herein do not reflect the views of the U.S. Department of Energy or members of the U.S. DOE Technical Assistance Team, nor any of the other subject matter and industry experts who so generously contributed their time and knowledge.

Additionally, the research summarized within this report includes results that are experimental in nature, and neither Blue Engine, the Kern County Planning and Natural Resources Department, or any employees of either entity make any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information herein. Reference to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not constitute or imply an endorsement or recommendation by Blue Engine or the Kern County Planning and Natural Resources Department.

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Envisioning a Carbon Management Business Park

1. Introduction

It is not an overstatement to say that Kern County is integral to feeding and fueling the state of California, and by extension, the United States. Since the discovery of oil in the Kern River Field in 1899, Kern County has led California in oil and gas production.¹ Currently, it produces about 70% of the state's oil,² and is host to four of the top seven producing oil fields in the nation.³ As the southernmost county of California's Central Valley, which produces a quarter of the nation's food,⁴ Kern also leads California in the agricultural sector, producing over \$8 billion USD in goods from livestock and crops annually.⁵

These industries are important not only for what they export to the rest of the state and the nation, but for what they provide to the residents of Kern County. Nearly 1 in 5 county jobs are directly tied to the agriculture sector.⁶ Oil and gas also provides about 2% of jobs in the region,⁷ but more significantly, the sector is an important source of county tax revenue. The top ten property tax payers of Kern County are associated with either the extractive or energy sectors,⁸ and in total, the oil and gas industry accounts for about a quarter of the county's annual tax revenue.⁹ However, as policies are implemented to address climate

¹ Takahashi,K., D.L. Gautier (2007) <u>A brief history of oil and gas in San Joaquin Valley</u>. [12]

² Karlamangla (2022) If oil drilling ends in California, what happens to oil country? [7]

³ U.S. Bureau of Land Management (no date) <u>California Oil and Gas</u>. [1]

⁴ U.S. Geological Survey (no date) <u>California's Central Valley</u>. [17]

⁵ California Department of Food and Agriculture (no date) <u>County crop reports</u>. [2]

⁶ State of California Employment Development Department (no date) <u>Kern County, California Labor</u> <u>Market Information Resources and Data</u>. [11]

⁷ State of California Employment Development Department (no date) <u>Kern County, California Labor</u> <u>Market Information Resources and Data</u>. [11]

⁸ U.S. Department of the Interior (no date) <u>Natural Resources Revenue Data: Kern County</u>. [10]

⁹ Karlamangla (2022) If oil drilling ends in California, what happens to oil country? [7]

change, regional water supplies and global energy use patterns are evolving. As a result, the agriculture and oil and gas sectors of Kern County are also anticipating an evolution.

Decades of drought in the southwestern United States have led to increasing dependence on groundwater resources for irrigation of agricultural lands, resulting in over-depletion of subsurface aquifers and subsidence of the land in the Central Valley. It is anticipated that by 2040, average annual water supplies in the San Joaquin Valley (the southern portion of the Central Valley, where Kern is located) may need to decline by as much as 20%, as climate change drives increasing aridity and as policies such as the Sustainable Groundwater Management Act mandate reduced consumption of water from aquifers.¹⁰ The Public Policy Institute of California estimates that as much as 900,000 acres of farmland could be fallowed in the San Joaquin Valley in the next two decades. Landowners will need viable economic alternatives for creating revenue from their lands, and communities will need new industries that can provide alternative jobs and tax revenue.

The oil and gas industry is also experiencing a shift, as solar and wind become increasingly competitive energy markets,¹¹ and as focus grows among global, national and regional institutions to reduce the emission of greenhouse gases like carbon dioxide (CO₂). But the oil and gas industry, and in particular, the oil and gas industry *in Kern County*, is uniquely equipped to take the lead in a new market that has incredible growth potential: carbon dioxide removal.

The National Academy of Sciences, Engineering and Medicine estimates that by midcentury it will be necessary to remove 10 billion metric tons of CO₂ from the atmosphere every year to prevent global average temperatures from rising above 2°C.12 Carbon dioxide removal can be accomplished in a variety of ways - such as through significant reforestation efforts, through changing agricultural practices to enhance the drawdown and storage of CO_2 in soils, or through restoring wetlands and mangroves along coastal habitats, to name a few.¹³ Among the most effective methods of CO₂ removal however, is carbon capture and sequestration (CCS), or the process of trapping CO_2 from the atmosphere and from point sources of CO₂ emissions (like chimney stacks of large industrial facilities) and then pumping the CO₂ deep underground, into geologic layers in the subsurface that trap and hold the CO₂, much like it trapped and held the fossil fuels from which that CO_2 was derived. This technique is effective for two reasons: first, it is much easier to account for how much CO₂ is captured and sequestered via CCS than to estimate CO₂ drawdown from nature-based solutions like reforestation or soil regeneration, because gas pressures and flow rates of the CO₂ being pumped underground can be measured. Second, CO₂ that is pumped into well-characterized geologic layers of

¹⁰ Escriva-Bou, et al. (2023) <u>The future of agriculture in the San Joaquin Valley</u>. [6]

¹¹ Lazard (2021) <u>Levelized cost of energy</u>. [8]

¹² National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 9. [9]

¹³ Climate Now (2021) <u>Carbon Dioxide Removal (CDR)</u>. [3]

the subsurface is effectively trapped there indefinitely – it will be hundreds or thousands of years, at least, before that CO_2 returns to the atmosphere.¹⁴

CCS is a nascent industry – less than 100 million metric tons of CO₂ is injected in the subsurface globally, and almost all of that injection is for the purpose of enhanced oil recovery (in which injected CO₂ pressurizes oil-filled cracks and pore spaces, helping push oil out of the ground) rather than permanent underground storage.¹⁵ But new federal and state policies are incentivizing growth in CCS for the purpose of permanent CO₂ storage in the United States, and Kern County is extremely well positioned to benefit from those incentives. The geologic layers beneath Kern County that have allowed it to be such a prolific producer of oil and gas are the same kinds of layers that are perfectly suited for CO_2 storage. In fact, sediments underlying California's Central Valley have been identified as having among the highest CO_2 storage capacity in the nation, with storage potential of billions of tons of CO₂.¹⁶ Additionally, companies and employees within the oil and gas industry who have been established in Kern County for decades have the requisite knowledge to safely and effectively drill injection wells, transport CO_2 from sources of capture to injection sites, and sequester CO₂ underground. Kern County is home to more than 7,000 direct employees of the oil and gas sector,¹⁷ who already have the skillsets needed for carbon capture and storage. As of this report's publication, three companies in Kern County have begun the permitting process through the U.S. Environmental Protection Agency to develop the types of wells needed (called EPA Class VI wells) for CO₂ injection and permanent geologic storage.¹⁸ For those wells to be cost effective, there will need to be a significant source of CO_2 – on the scale of millions of metric tons annually – available for injection. Where all that CO_2 could come from has yet to be determined, but one possibility is a dedicated carbon management park, which would locate existing and new industries that capture or produce CO₂ in close proximity to the injection sites.

1.1 What is a carbon management park?

In Spring 2022, Kern County was among the inaugural group of recipients for the Communities LEAP (Local Energy Action Program, or C-LEAP) technical assistance grant from the U.S. Department of Energy.¹⁹ The Kern County Planning and Natural Resources Department's goal in obtaining this C-LEAP grant was to answer a question: could repurposing challenged agricultural lands with the development of one or several large-scale industrial parks designed for the express purpose of capturing CO₂ be an economically viable source of new jobs and revenue to Kern County over the coming

¹⁴ Climate Now (2021) Carbon Dioxide Removal: Carbon Capture and Storage, Part II. [5]

¹⁵ Climate Now (2021) <u>Carbon Dioxide Removal: Carbon Capture and Storage, Part I</u>. [4]

¹⁶ Teletzke, G. (2018) <u>Evaluation of Practicable Subsurface CO2 Storage</u>. [13]

¹⁷ U.S. Department of the Interior (no date) <u>Natural Resources Revenue Data: Kern County</u>. [10]

¹⁸ EPA (last updated May 19, 2023) <u>Class VI wells permitted by EPA</u>. [16]

¹⁹ U.S. Department of Energy (no date) <u>Communities LEAP Pilot</u>. [15]

decades? If so, what types of industries would be best suited for such a park, and what considerations should be taken in whether, where and how much to develop?

With technical assistance from the C-LEAP program, these questions are addressed through a Carbon Management Business Park pre-feasibility analysis, presented in the form of an interactive website hosted by the Kern County Planning and Natural Resources Department, and accompanied by this report. The analysis is designed to clarify the costs and benefits of a variety of emerging carbon management and clean energy industries, and based on these costs and benefits, to provide the necessary information for local residents and decision-makers to determine which carbon management technologies might be best suited for the region.

As principal investigator for the C-LEAP award, the Kern County Planning and Natural Resources Department developed a hypothetical framework for the carbon management park, envisioning a 30 million square foot park on 4,000 acres, with another 30,000 acres dedicated to solar power, that would be sited far from urban areas, in fallowed farmlands that are no longer viable for agriculture. The park would be closely situated to areas where EPA Class VI well permits for deep CO₂ storage are already being processed,²⁰ allowing regional infrastructure to work together. A variety of carbon management and clean energy technologies could be co-located within the park, and proximity to rail and interstate highways would provide connections with nearby transportation hubs like Los Angeles and Stockton that would expand the potential feedstock supply chains for the industrial park and potential end users for clean energy production.

Blue Engine Strategies was contracted by the Kern County Planning and Natural Resources Department to complete the pre-feasibility analysis, by gathering and synthesizing information about a suite of industries that could potentially be co-located on such a park. Each industry type was examined through a set of 4 lenses: technological, societal, environmental and economic. Information was collected through the following methods:

- Continuous research support and technical assistance from a team of experts from the U.S. Department of Energy through the C-LEAP Program
- Interviews with research experts at universities and national research laboratories, and with industry representatives
- Consultation with an Executive Committee of regional leaders, organized by the Planning and Natural Resources Department
- Independent scholarship of the latest published research, policies and regional data relevant to these technologies

This report provides a detailed summary of the pre-feasibility analysis. In addition, Blue Engine constructed a website, <u>cmbp.kernplanning.com</u>, that serves as an Executive Summary for this report. The website provides an interactive site map that can help users envision what such a park might look like, and explores a variety of the technologies that

²⁰ EPA (last updated May 19, 2023) Class VI wells permitted by EPA. [16]

could feasibly be incorporated into a carbon management and clean energy business park. The website provides an overview of how each technology investigated in this report works, how it might benefit from co-location with other technologies in a shared industrial space, and what impacts and benefits such a technology would have on the regional community and environment.

Please note, the purpose of this analysis is <u>not</u> to endorse any carbon management technology or specific business park configuration for development in Kern County. The purpose of the website and report is to provide a useful synthesis of relevant information about carbon management and clean energy to stakeholders, developers and planners in the Kern County community, to ensure that they have a holistic understanding of these novel industries. With such a resource, private investors and local stakeholders will be better equipped to plan how the region's energy economy should grow in a well-informed and transparent manner.

Any development of a carbon management business park in Kern County would be facilitated by private investors. Those investors would be required to submit a proposal to the Kern Planning and Natural Resources Department that would include a specified location and a Specific Plan designating the industries and land uses to be built. An Environmental Impact Report (EIR) would be required and the EIR and Specific Plan would go through a full public process.

1.2 How to read this report

This report is laid out in ten sections subsequent to this introduction. The first section (Section 2) provides a summary of the federal and state policy landscape that is relevant to all the carbon management industries examined here, and is intended as a general resource that is referred to in subsequent sections. Sections 3 through 5 examine industries whose primary or secondary purpose is to capture CO_2 for permanent underground storage, and Sections 6 through 10 examine industries that could support carbon management industries (e.g. energy storage or water treatment), could benefit from co-location with carbon management industries (e.g. hydrogen via electrolysis), and/or are tangential to carbon management industries (e.g. CO_2 transport and CO_2 utilization). The use of CO_2 for enhanced oil recovery is not examined in this report. Finally, Section 11 provides a brief examination of how carbon management industries might take advantage of partnerships with (and be a benefit for) the dominant regional industry of agriculture.

This report represents a synthesis of information derived from academic literature, publicly available data and subject matter and industry expertise. For each factor of analysis, the aim is to provide as quantitative an assessment of the state of the industry as possible. Where specific estimates of a variable were available (such as land use, energy or water use requirements) a specific value or range of values is given, with the range encompassing all published estimates that could be verified as reasonable based on corroborating reports or expert discussions. Because carbon management industries are novel and in a phase of

rapid growth and innovation, it is expected that all systems will become more efficient, smaller and less expensive in the coming decades than the technologies described here.

All costs listed in this report are given in U.S. dollars, and are reported as the dollar value used in the source material, unless explicitly noted otherwise in the text. That is, except for references in which cost estimates were older than 10 years or reported in a non-U.S. currency (noted in text), the dollar amount reported is the same as that reported in the referenced material and is not adjusted for inflation since the year of reference publication. This approach was taken for three reasons: (1) To maximize transparency with regards to how all calculations in this report were made and from where all information was obtained, and thus we avoided inflation corrections to reduce the possibility of confusion or miscalculation; (2) Most cost estimates are derived from references published within the last 5 years, which means inflation would increase the cost estimates by less than 20%.²¹ Nearly all technologies examined in this report have cost uncertainties much greater than 20%, and we report the full range of cost estimates aggregated from multiple sources; (3) Given the rapidity with which carbon management industries are growing, cost reductions that have likely occurred in the last 1-5 years from "learning by doing" may partially or completely offset the cost increases resulting from inflation.

A detailed techno-economic analysis of potential fiscal and economic benefits of the carbon management industry to Kern County was completed in parallel to the construction of this report by the Natelson Dale Group, Inc., and is appended at the end of the report.

²¹ U.S. Bureau of Labor Statistics (no date) <u>CPI Inflation Calculator</u>. [14]

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2. Policy Brief

International pressure to address climate change is spurring significant public and private interest in the development of carbon management technologies, and a variety national and state policies that enhance the benefits of deploying these technologies are making them particularly viable for development in Kern County. However, the building and operating of these technologies still must adhere to environmental, land use, and other existing policies if deployed.

In this report section, we endeavor to outline the topline general policy items that would impact carbon management implementation within Kern County. Thus, this section does not adhere to the lenses of analysis used throughout the rest of this report—this is intended as an informational addendum to the report at large.

- The first section explores the international case for limiting greenhouse gas concentrations in the atmosphere, as well as the natural and technological pathways available to remove carbon dioxide (CO₂) from the atmosphere.
- The second section outlines the United States' federal climate goals and California's state climate goals.
- The third section outlines the permitting and environmental requirements that projects looking to site in Kern County would need to adhere to in designing and constructing a carbon management facility, like the hypothetical carbon management business park.
- The fourth and final section outlines the subsidies and incentives available for implementing carbon management practices and related monetary benefits for emissions reduction.

2.1 International goals and the case for CCS

According to the IPCC, limiting global warming to 1.5°C is imperative to preserving the well-being of people and natural ecosystems.¹ It is considered a crucial target by the international community because climatic and environmental changes past that point become more drastic and unpredictable.² For example, limiting warming to 1.5°C is expected to lead to declines in coral reefs of 70-90% globally; however, warming of 2°C would lead to a near-total loss of coral reefs.³

Based upon the potential future pathways seen in Figure 2.1, meeting the future on the best possible terms relies upon not only rapidly lowering global emissions, but also removing more CO_2 from the atmosphere that we generate. The gray band at the bottom of the illustration demonstrates scenarios of net CO_2 removal. There are both natural and technological pathways to remove CO_2 from the atmosphere.



Figure 2.1. Illustration of CO₂ emissions pathways that could be employed to ensure global average temperatures remain below 2°C (green shaded region) or 1.5°C (blue shaded region). As temperatures rise, the cost of mitigating damages from extreme weather events like heat waves, floods and droughts will rise at a disproportionately higher rate.⁴ Each region represents an aggregate of multiple modeled pathways that could maintain the desired temperature limits. Nearly all pathways require global CO₂ emissions to become net-negative by mid- or end-century, which will require the employment of carbon management activities to remove CO₂ from the atmosphere.⁵ Adapted from Wikimedia commons: <u>Mitigation Pathways</u>.

¹ IPCC (October 8, 2018) <u>Summary for Policymakers</u>. [26]

² Nandi (August 9, 2021) World fails to meet key climate goal: IPCC. [32]

³ IPCC (October 8, 2018) <u>Summary for Policymakers</u>. [26]

⁴ Nuccitelli (September 19, 2021) <u>Can the economy afford NOT to fight climate change?</u> [34]

⁵ Rogelj, et al. (2018) Scenarios limiting global mean temperature increase below 1.5°C. [41]

Natural processes, such as plant growth in forests and wetlands or ocean acidification, serve to sequester atmospheric carbon, but can also have undesirable effects once they pass natural thresholds.⁶ For example, ocean acidification impacts the biodiversity of the ocean as it makes it difficult for coral and oysters to form their robust shells.⁷ Plant-based solutions—like afforestation and wetland restoration—are promising because they are not only beneficial for sequestering CO₂, but also serve to support climate resilience and ecosystem health in the region.⁸ However, these natural solutions — even when environmentally beneficial – can be problematic from a carbon management perspective, because it is difficult to assess how much CO₂ is being removed from the atmosphere from such interventions, and how long it will remain trapped in these organic reservoirs.⁹

Technological processes can also assist in removing CO_2 from the atmosphere and are generally termed carbon capture and storage (CCS). Many of the technological options available for capture—including DAC, BiCRS/BECCS, and point-source capture (with steel as an example industry)—are explored within this report at large, in Sections 3, 4, and 5, respectively. The primary value of these technologies is that they can prevent CO_2 from entering the atmosphere or remove it directly from the air.¹⁰ Furthermore, if scaled adequately, these systems have the potential to remove CO_2 at much faster rates than natural processes.¹¹ They also can remove CO_2 with a smaller land footprint than natural solutions like reforestation, though the costs are generally higher per ton of CO_2 removed for technological solutions.¹² Given the time-sensitive nature of climate change, technological processes may be necessary to slow the rise in atmospheric CO_2 before we reach critical tipping points.¹³ Achieving a global warming of under 2°C likely requires the use of carbon removal technologies *in addition to* substantial reductions in standard greenhouse gas emissions.¹⁴

2.2 Federal and state climate goals

The U.S. federal government has set ambitious targets for climate action in the coming decades. By 2030, the goal is to reduce greenhouse gas emissions to 50% of 2005 levels— by 2050, the target is to reach net-zero emissions.¹⁵

⁶ Sustainability for All – Acciona (no date) <u>What are carbon sinks?</u> [44]

⁷ NOAA (April 1, 2020) <u>Ocean Acidification</u>. [33]

⁸ Pfister (June 19, 2018) <u>Carbon Removal Strategies</u>. [38]

⁹ Climate Now (October 5, 2021) <u>Carbon Dioxide Removal: Forests</u>. [14]

¹⁰ Pfister (June 19, 2018) <u>Carbon Removal Strategies</u>. [38]

¹¹ Pfister (June 19, 2018) <u>Carbon Removal Strategies</u>. [38]

¹² Lebling, Leslie-Bole, *et al.* (May 2, 2022) <u>6 Things to Know About Direct Air Capture</u>. [30]

¹³ Mayewski, Beal (September 29, 2022) <u>We miscalculated our climate tipping points</u>. [31]

¹⁴ Pfister (June 19, 2018) <u>Carbon Removal Strategies</u>. [38]

¹⁵ The White House (no date) <u>National Climate Task Force</u>. [47]

In recent years, federal action on climate change has been supported by the Bipartisan Infrastructure Law (BIL) and the Inflation Reduction Act (IRA).¹⁶ The BIL package awarded funding for over 20,000 projects and supports efforts to modernize the electric grid, expand rail and other public transportation, as well as maintaining other key infrastructure like roads, bridges, and water treatment facilities.¹⁷ The IRA tackles climate more directly, with consumer rebates to install energy efficient appliances, tax credits for solar or electric vehicle purchases, and measures to directly reduce pollution and implement community-scale clean energy solutions.¹⁸ A full exploration of the IRA's climate-related provisions is included in the Subsidies & Incentives section below.

As a state, California has set goals that are more ambitious than federal goals. By 2045, California is aiming to be carbon neutral.¹⁹ This includes a goal to reduce natural gas consumption by 94% and greenhouse gas emissions by 85%.²⁰ These goals also rely upon ramping up carbon capture and sequestration efforts within California. In the most recent scoping plan announced by the California Air Resources Board (CARB), California targets to remove "20 million metric tons CO₂ equivalent (MMTCO₂e) by 2030 and 100 MMTCO₂e by 2045" from the atmosphere to meet its climate targets.²¹ This is aligned with the findings of other recent California-specific reports on reaching carbon neutrality, like Lawrence Livermore National Laboratory's Getting to Neutral.

2.3 Permits

2.3.1 Local land use

- Applicable for facilities with CO₂ capture, transport, or storage that takes physical place within, or in certain parts, of city or county boundaries.
- Agency level: local government
- Turnaround timeline: more than 18 months

The authorization of land use encompasses the physical footprint of the facility, from the types of activities allowed in certain areas, to the detailed aspects of facilities such as building height, traffic, noise, and other environmental impacts. Any planned CCS facilities must follow the city or county's zoning and land-use ordinance.

Carbon management projects on sites previously developed for similar purposes (like establishing a BiCRS facility by retrofitting a retired bioenergy plant, see Section 4) might

¹⁶ The White House (no date) <u>National Climate Task Force</u>. [47]

¹⁷ The White House (no date) <u>Building a Better America</u>. [45]

¹⁸ The White House (August 15, 2022) <u>The Inflation Reduction Act</u>. [46]

¹⁹ Office of Governor Newsom (November 16, 2022) <u>California Releases World's First Plan</u>. [36]

²⁰ Office of Governor Newsom (November 16, 2022) <u>California Releases World's First Plan</u>. [36]

²¹ Office of Governor Newsom (November 16, 2022) <u>California Releases World's First Plan</u>. [36]

face fewer hurdles, since some uses might have been allowed already for existing facilities—however, this is not always the case. For instance, the installation of tall columns for carbon capture solvent or a gas flare may face minimal review when placed at an existing refinery that would have been permitted for much taller distillation columns, but could face higher scrutiny at a former power plant site, where they might exceed specified height limits for the site.

Transportation via pipeline will likely face a high level of scrutiny and review, regardless of the existing right-of-ways (ROW) in place. One way to reach compliance is to seek amendment of a county's zoning map to allow uses or activities commonly related to carbon capture and storage.²² Such a measure would likely only be appropriate if it is in the county's long-term interests and economic plan, as opposed to authorizing a single project.

2.3.2 CO₂ Pipelines – Easements and ROWs

- Applicable for CO₂ transport.
- More than one agency could be involved and projects would generally involve private parties (including the pipeline owner and landowners)
- Timeline: more than 18 months

Permitting pipelines is often difficult and time consuming because most pipelines are sited across land held by a variety of owners. Thus, it is more attractive to route pipelines in such a way that it crosses large land holdings in the hands of fewer owners. Surface ownership of a pipeline might cross private, local government, state, federal, and tribal, as well as existing third-party easements. Under an easement—a legal agreement conferring to the pipeline owner the right to site, construct and operate the pipeline on a landowner's property—the holder is granted the right to travel over another's property.²³

Areas with existing pipelines run may offer potentially easier pathways to siting. Depending on the contract language, opportunities for new development may already exist under existing easements or ROW agreements. The success of this strategy hinges on how the existing easements are written and if they provide for addition of a new pipeline or for repurposing or modification of an existing one.

Regulation of any CO_2 pipelines constructed would fall under the purview of the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the federal level²⁴ and the Office of the State Fire Marshal (OSFM) at the state level.²⁵ A full exploration of the permitting and regulatory requirements for CO_2 pipelines can be found in Section 9.

²² World Bank (no date) <u>Zoning and Land Use Planning</u>. [51]

²³ Transportation Research Board of the National Academies of Sciences, Engineering, and Medicine (2004) <u>Transmission Pipelines and Land Use</u>. p. 34. [49]

 ²⁴ FECM (May 27, 2022) <u>Statement: DOE Welcomes New Carbon Dioxide Pipeline Safety Measures</u>.
 [35]

²⁵ OSFM (no date) <u>Pipeline Safety and CUPA</u>. [37]

2.3.3 Title V Air Permit

- Applicable for facilities with CO₂ capture, especially those that emit pollutants into the air
- Agency level: local air district, and potentially U.S. EPA
- Timeline: approximately 1 year

In California, air districts are the local regulators that implement federal Clean Air Act requirements, as well as other state-level regulations regarding emissions, for pollution sources within the region.²⁶ Any CCS project would likely have to engage these local air districts to receive air permits. Eastern Kern Air Pollution District (EKACPD) is the local regulator for eastern Kern County, while western Kern County falls under the authority of the San Joaquin Valley Air Pollution Control District (SJVAPCD).²⁷

To gain a Title V operating permit, an institution or person that is constructing, altering, replacing, or operating any source that emits, may emit, or may reduce emissions must obtain preconstruction permit authorization before commencing construction as well as a permit to operate from their local air district.²⁸ For projects built on Indian and tribal lands within the borders of the United States, the U.S. EPA is required to issue operating permits instead.²⁹ Exemptions are limited to very low-emitting, minor equipment, such as engines on compressors or emergency generators, but full requirements for non-major sources are laid out in Code 40 of Federal Regulations.³⁰ It's particularly applicable to carbon management industries that operate in the CO₂ capture stage, because these types of facilities may emit other air pollutants in addition to the CO₂ that they are capturing, such as NO_x or particulate emissions, and fugitive emissions from some kinds of amine-based CO₂ scrubbers could produce volatile organic compound (VOC) emissions.

California, as a state, is required to develop state implementation plans (SIPs) to achieve National Ambient Air Quality Standards (NAAQS), for six criteria pollutants: ground-level ozone, particulates, carbon monoxide, lead, sulfur dioxide and nitrogen dioxide.^{31, 32} Whether or not a state has achieved NAAQS attainment goals in a given pollution type determines the type of permit process that a new facility must pursue.

• Attainment areas: Prevention of Significant Deterioration (PSD) permits are required for new major sources or for making a major modification.³³

²⁶ CARB (no date) <u>Government Roles and Contracts</u>. [10]

²⁷ CARB (no date) <u>California Map for Local Air District Websites</u>. [8]

²⁸ EPA (November 29, 2022) <u>Air Emissions Monitoring</u>. [16]

²⁹ EPA (November 29, 2022) Air Emissions Monitoring. [16]

³⁰ EPA (May 25, 2022) <u>Who Has to Obtain a Title V Permit?</u> [23]

³¹ CARB (no date) <u>California State Implementation Plans</u>. [9]

³² EPA (January 20, 2023) <u>Basic Information about Air Quality SIPs</u>. [17]

³³ EPA (January 24, 2023) Prevention of Significant Deterioration Basic Information. [20]

 Non-attainment areas: Non-Attainment New Source Review (NNSR) permits are required for new major sources or for major sources making substantial modifications.³⁴

The required mitigation action is stricter in non-attainment areas and requires achieving the Lowest Achievable Emissions Rate (LAER), as well as the use of offsets to the extent allowed or available.³⁵ Offsets are specific to each pollutant category, but specialized cases outlined by the EPA allow offsets from alternate sources at a 2-to-1 ratio.³⁶ In attainment areas, the corresponding requirement is Best Available Control Technology (BACT) for any "major new or modified sources."³⁷

Pollutant	EKAPCD ^a		EKAPCD ^a SJVAPCD ^b		\PCD ^ь
	Federal	State	Federal	State	
Ozone (1 hour)	Attainment	Nonattainment	Attainment	Severe Nonattainment	
Ozone (8 hour)	Severe Nonattainment	Nonattainment	Extreme Nonattainment	Nonattainment	
PM10	Attainment	Nonattainment	Attainment	Nonattainment	
PM2.5	Attainment	Unclassified	Nonattainment	Nonattainment	
Carbon Monoxide	Attainment	Unclassified	Attainment	Attainment	
Nitrogen Dioxide	Unclassified	Attainment	Attainment	Attainment	
Sulfur Dioxide	Unclassified	Attainment	Attainment	Attainment	
Lead Particulates	Attainment	Attainment	Unclassified	Attainment	

Table 2.1. Air quality attainment data for Kern County

a. Eastern Kern Air Pollution Control District

b. San Joaquin Valley Air Pollution Control District

The California Ambient Air Quality Standards (CAAQS) are typically stricter than NAAQS requirements, but NAAQS attainment takes precedence "due to federal penalties for failure to meet federal attainment deadlines."^{38, 39} Both NAAQS and CAAQS use 'attainment' or 'unclassified' and 'non-attainment' designations—an attainment or unclassified designation means an area meets or exceeds the standard for that compound, whereas

³⁴ EPA (January 24, 2023) <u>Nonattainment NSR Basic Information</u>. [19]

³⁵ EPA (January 24, 2023) <u>Nonattainment NSR Basic Information</u>. [19]

³⁶ EPA (2013) <u>The Clean Air Act in a Nutshell: How It Works</u>. p. 7. [22]

³⁷ EPA (February 22, 2016) <u>RACT/BACT/LAER Clearinghouse: Basic Information</u>. [21]

³⁸ CARB (no date) <u>Ambient Air Quality Standards</u>. [6]

³⁹ CARB (no date) <u>California Ambient Air Quality Standards</u>. [7]

non-attainment is used for areas that fail to meet the standard.⁴⁰ Table 2.1 summarizes Kern County's current status for major pollutants.

In addition to PSD and NNSR permitting, installation of carbon management facilities and associated equipment will likely trigger additional Clean Air Act Title V permitting under the local air district. The Title requires major sources of air pollutants and certain other sources to obtain an operating permit, operate in compliance with it, and certify compliance at least annually.⁴¹

2.3.4 California Environmental Quality Act (CEQA) Guidelines

In California, CEQA requires a project to identify significant environmental impacts of their activities, and to avoid or mitigate those impacts.⁴² A project that may cause direct physical changes to the environment or an anticipated indirect change must comply with CEQA.⁴³ Most proposals for physical development need to comply with CEQA, but other projects which do not immediately result in physical development (like adopting a general or community plan) need to comply as well.⁴⁴

For every project, an initial review of potential environmental effects must be conducted.⁴⁵ Depending on the initial review of the potential impacts of a project, CEQA may require the project to conduct a full environmental impact report (EIR).⁴⁶ If there are feasible alternative options or mitigation strategies available for the project to notably reduce its environmental impact, then a project cannot be approved as originally submitted.⁴⁷

CEQA requires that an initial review determine the significance of a project's expected greenhouse gas emissions.⁴⁸ Under CEQA's definitions, greenhouse gasses "includes but is not limited to: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride."⁴⁹

Regulated air pollutants under CEQA include nitrogen oxides (NO_x) and volatile organic compounds (VOCs), ozone-depleting substances (CFC and HCFC), particulate matter, carbon monoxide (CO), sulfur dioxide (SO₂) and lead. CEQA also evaluates greenhouse gas (GHG) emissions,⁵⁰ in which project-specific GHG emissions must be analyzed for their

⁴⁰ EPA (November 29, 2022) <u>NAAQS Designations Process</u>. [18]

⁴¹ EPA (May 25, 2022) <u>Who Has to Obtain a Title V Permit?</u> [23]

⁴² Governor's Office of Planning and Research (no date) <u>Getting Started with CEOA</u>. [25]

⁴³ CNRA (no date) <u>FAQ about CEQA</u>. [13]

⁴⁴ CNRA (no date) <u>FAQ about CEQA</u>. [13]

⁴⁵ CNRA (no date) <u>FAQ about CEQA</u>. [13]

⁴⁶ CNRA (no date) <u>FAQ about CEQA</u>. [13]

⁴⁷ CNRA (no date) <u>FAO about CEOA</u>. [13]

⁴⁸ AER (January 1, 2023) <u>2023 CEOA</u>. p. 189. [1]

⁴⁹ AER (January 1, 2023) <u>2023 CEOA</u>. p. 317. [1]

⁵⁰ Governor's Office of Planning and Research (no date) <u>CEOA & Climate Change</u>. [24]

ability to contribute globally to climate change,⁵¹ unless the project is exempted from CEQA.

2.4 Subsidies & Incentives

2.4.1 California Low Carbon Fuel Standard (LCFS)

California's LCFS is a market-based policy, first adopted in 2009 and implemented in 2011, that aims to diversify California's energy mix by setting annual carbon intensity (CI) benchmarks and encouraging the adoption of low-CI fuels under the oversight of the California Air Resources Board (CARB).⁵² In 2018, the LCFS was extended by CARB from 2020 to 2030, with a goal of reaching a 20% CI reduction target from 2010 levels by 2030.⁵³

The system operates based on CI life cycle assessments conducted by CARB, which "examines the GHG emissions associated with the production, transportation, and use of a given fuel" along with notable indirect impacts, and then gives the fuel in question a CI score.⁵⁴ CARB's model does not rely just on carbon dioxide emissions, but also emissions of methane, nitrous oxide, and other greenhouse gases.⁵⁵ After each fuel is scored based on its lifetime emissions, it is compared to a CI benchmark set by CARB that declines each year.⁵⁶ Fuels with CI scores lower than the benchmark will generate LCFS credits that year, whilst fuels that exceed the CI benchmark generate deficits.⁵⁷

In short, the system grades fuels based on their relationship with the annual target—fuels that have a CI lower than the target will produce LCFS credits, while fuels that have a CI higher than the target have a deficit that must be fulfilled to meet the standard.⁵⁸ This deficit can be remedied by either generating LCFS credits directly or purchasing LCFS credits from another supplier in order to meet the annual target.⁵⁹ LCFS applies only for fuels used for transportation, including gasoline, diesel, and their alternatives.⁶⁰

Under the LCFS, all "petroleum importers, refiners, and wholesalers" selling fuels in the California market are regarded as Regulated Parties (RPs).⁶¹ Providers of clean, alternative fuels that already meet the relevant 2030 carbon intensity benchmark are exempt from the

⁵¹ Governor's Office of Planning and Research (no date) <u>CEOA & Climate Change</u>. [24]

⁵² CARB (no date) <u>About - Low Carbon Fuel Standard</u>. [5]

⁵³ UC Davis Institute of Transportation Studies (no date) <u>Status Review</u>. [50]

⁵⁴ CARB (no date) <u>About - Low Carbon Fuel Standard</u>. [5]

⁵⁵ CARB (no date) <u>About - Low Carbon Fuel Standard</u>. [5]

⁵⁶ CARB (no date) <u>About - Low Carbon Fuel Standard</u>. [5]

⁵⁷ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

⁵⁸ Boutwell (May 2, 2018) <u>LCFS 101 - An Update</u>. [4]

⁵⁹ Boutwell (May 2, 2018) <u>LCFS 101 - An Update</u>. [4]

⁶⁰ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

⁶¹ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

LCFS, but may opt-in to the program as RPs to receive credits for the fuels they sell in California.⁶² The LCFS system hinges on the LCFS Reporting Tool (LRT), which serves as a central database where RPs must record the transaction-level information anytime that "transportation fuels are imported, refined, or sold in California."⁶³ (The LRT may also be referred to as the LRT-CBTS, or the LCFS Reporting Tool and Credit Bank & Transfer System.)⁶⁴ The LRT serves to track all transactions, and also serves to sum the credits and deficits for a given RP to track their compliance status in relation to the annual CI target.⁶⁵ If credits are used in an annual compliance report to offset deficits for an RP, those credits are retired; otherwise, LCFS credits generated or acquired by an RP do not sunset or decline in value over time.⁶⁶ Owners of credits can only sell or trade credits to other RPs in the system currently at a deficit, and parties that are not recognized as RPs are forbidden from holding any LCFS credits.⁶⁷

In addition to credit generating fuels, the LCFS has provisions to generate credits through approved non-fuel activities that can help reduce transportation emissions at large.⁶⁸ This includes what CARB refers to as project-based crediting and capacity-based crediting under LCFS.⁶⁹ Project-based credit opportunities can include using renewable hydrogen at a facility generating transportation fuels, developing a direct air capture (DAC) facility to capture historic transportation emissions, and investments that reduce an existing transportation fuel facility's emissions, like using renewable energy or adopting carbon capture and storage (CCS).⁷⁰ Capacity-based credits are attainable by RPs that own hydrogen fueling equipment or zero-emission vehicle infrastructure.⁷¹

Starting in 2019, the LCFS began allowing the use of CCS technologies to "reduce emissions associated with the production of transport fuels" in California to generate LCFS credits—this included DAC projects.⁷² To qualify, projects must meet CCS Protocol requirements, which encompass a variety of carbon management projects, as long as they lead to storage of captured CO_2 in depleted oil and gas reservoirs or saline formations onshore *or* are used for enhanced oil recovery (EOR) in oil and gas reservoirs.⁷³ Table 2.2 shows different types of CCS projects that can qualify to generate credits under the LCFS.

⁶² Boutwell (May 2, 2018) <u>LCFS 101 - An Update</u>. [4]

⁶³ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

⁶⁴ CARB (no date) <u>LCFS Registration and Reporting</u>. [12]

⁶⁵ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

⁶⁶ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

⁶⁷ Boutwell (February 28, 2017) <u>A Beginner's Guide</u>. [3]

⁶⁸ CARB (no date) <u>LCFS Basics with Notes</u>. p. 11. [11]

⁶⁹ CARB (no date) <u>LCFS Basics with Notes</u>. p. 11. [11]

⁷⁰ CARB (no date) <u>LCFS Basics with Notes</u>. p. 28. [11]

⁷¹ CARB (no date) <u>LCFS Basics with Notes</u>. p. 33-35. [11]

⁷² Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 4. [48]

⁷³ Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 9. [48]

	Direct Air Capture Projects	CCS at Oil & Gas Production Facilities	CCS at Refineries Projects	All other CCS Projects (e.g. CCS with Ethanol)
Location of CCS project	Anywhere in the world	Anywhere, provided they sell the transportation fuel in California	Anywhere, provided they sell the transportation fuel in California	Anywhere, provided they sell the transportation fuel in California
Storage site	Onshore saline or depleted oil and gas reservoirs, or oil and gas reservoirs used for CO ₂ -EOR			
Credit method	Project- based	Project-based, under the Innovative Crude Provision	Project-based, under the Refinery Investment Credit Program	Project-based or fuel pathway
Earliest date which existing projects eligible	Any	2010	2016	Any
Requirements	Project must meet requirements specified in CCS Protocol			
Additional restrictions	None	Must achieve minimum Cl or emission reduction	None	None

Table 2.2. Qualifications for CCS projects to meet LCFS standards.⁷⁴

DAC facilities located anywhere in the world can generate LCFS credits by choosing to opt in to the LCFS program.⁷⁵ DAC projects are an exception to the general requirements of LCFS credits, as they are "not required to sell any transportation fuel into the California market to generate credits."⁷⁶ Even so, the rules around DAC project eligibility are tightly defined. If CO₂ captured by a DAC facility was used to create a synthetic fuel for sale in California, it wouldn't qualify for project-based crediting and would instead need to seek a separate fuel pathway in order to generate LCFS credits.⁷⁷

California's LCFS credits can also be stacked with federal 45Q tax credits (Section 2.4.3).⁷⁸ There are no restrictions on obtaining both incentives as long as the responsible party adheres to the rules and regulations of both systems.

2.4.2 Inflation Reduction Act (IRA)

The Inflation Reduction Act (IRA) was signed into law on August 16, 2022 and encompasses a wide range of new policy directives spanning healthcare, tax compliance, and energy and

⁷⁴ Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 9. [48]

⁷⁵ Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 9. [48]

⁷⁶ Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 9. [48]

⁷⁷ Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 9. [48]

⁷⁸ Townsend, Havercroft (2019) <u>The LCFS and CCS Protocol</u>. p. 20. [48]

environment issues (Figure 2.2).⁷⁹ Here, only the energy and environment directives are explored; other policy items included in the IRA are outside of the scope of this report.

Inflation Reduction Act investments by sector, \$ billion	Total =	393.7
Energy 250.6	Manufacturing 47.7	Transport + EVs 23.4
	Environment 46.4	Agri- culture 20.9
		Water 4.7

Figure 2.2. Scaled graphic indicating the amount of investment by sector, in billion USD, allocated under the Inflation Reduction Act.⁸⁰

The diversity of climate investments in the IRA, as seen below, is extensive. Funding will be disbursed through grants, loan guarantees, and tax incentives, with tax incentives being the largest share of available funding under the IRA.⁸¹ This includes tax credits for individuals associated with purchasing heat pumps and electric vehicles (new or used), as well as credits for businesses or utilities that are generating zero-carbon electricity, nuclear power, sustainable aviation fuels, or qualifying clean hydrogen.⁸² It is worth noting that the time horizons and credit amounts differ based on sector.

The IRA also incorporates provisions aimed to bolster domestic production of goods. Facilities must "meet prevailing wage and apprenticeship requirements" to attain full eligibility under the IRA's tax credit system.⁸³ These requirements also impose specific requirements, as applicable, to specific initiatives. For example, attaining the full consumer EV tax credit is dependent on a sliding scale of how many of the materials in the battery

⁷⁹ Badlam, Cox, *et al.* (October 24, 2022) <u>The Inflation Reduction Act</u>. [2]

⁸⁰ Badlam, Cox, *et al.* (October 24, 2022) <u>The Inflation Reduction Act</u>. [2]

⁸¹ Badlam, Cox, *et al.* (October 24, 2022) <u>The Inflation Reduction Act</u>. [2]

⁸² Badlam, Cox, *et al.* (October 24, 2022) <u>The Inflation Reduction Act</u>. [2]

⁸³ Badlam, Cox, *et al.* (October 24, 2022) <u>The Inflation Reduction Act</u>. [2]

were recycled within North America or extracted in countries with whom the U.S. maintains free-trade agreements.⁸⁴

Other provisions in the IRA are designed to aid in transitioning workers from fossil fuels to other energy industries. The IRA includes incentives for companies looking to develop solar or wind farms to locate in regions where coal facilities have recently discontinued operations.⁸⁵ It also includes some tailored worker benefits, like the development of a permanent federal trust aimed at supporting coal miners living with black lung disease.⁸⁶ Another angle of its transition-oriented policies is its expansion of support for hydrogen-based fuels and CCS, explored in the sections below.⁸⁷

2.4.3 45Q Federal Tax Credits

The 45Q tax credit was introduced in 2008 as an incentive to develop carbon capture, use, and sequestration projects within the United States.⁸⁸ Over time, the credit's value has increased—as of the end of 2022, due to the Inflation Reduction Act (IRA), these credits were valued at \$85/ton CO₂ permanently stored and \$60/ton CO₂ used for enhanced oil recovery (EOR).⁸⁹ The values are higher for carbon captured via direct air capture (DAC) processes, where the values rise to \$180/ton CO₂ permanently stored and \$130/ton CO, for use in EOR.⁹⁰

Changes in the IRA also extended the eligibility window for new projects to qualify.⁹¹ Now, projects must begin construction by January 2033 in order to qualify for 45Q credits.⁹² It also imposes updated minimums on the amount of CO_2 a facility must capture annually to qualify for credits: "18,750 tonnes per year for power plants (provided at least 75% of the CO2 is captured), 12,000 tonnes per year for other facilities, and 1,000 tonnes per year for DAC facilities."⁹³

2.4.3 45V Federal Tax Credits

The hydrogen fuel benefits are dispensed through the new tax incentive 45V, in which producers of hydrogen with 'near-zero emissions' can earn \$3 per kilogram of hydrogen produced with no cap on the number of kilograms the producer can receive the incentive

⁸⁴ Badlam, Cox, et al. (October 24, 2022) <u>The Inflation Reduction Act</u>. [2]

⁸⁵ Plumer, Friedman (July 30, 2022) <u>Democrats Got a Climate Bill</u>. [39]

⁸⁶ Plumer, Friedman (July 30, 2022) <u>Democrats Got a Climate Bill</u>. [39]

⁸⁷ Plumer, Friedman (July 30, 2022) <u>Democrats Got a Climate Bill</u>. [39t]

⁸⁸ IEA (November 4, 2022) <u>Section 450 Credit</u>. [29]

⁸⁹ IEA (November 4, 2022) <u>Section 450 Credit</u>. [29]

⁹⁰ IEA (November 4, 2022) <u>Section 450 Credit</u>. [29]

⁹¹ IEA (November 4, 2022) <u>Section 450 Credit</u>. [29]

⁹² IEA (November 4, 2022) <u>Section 450 Credit</u>. [29]

⁹³ IEA (November 4, 2022) <u>Section 450 Credit</u>. [29]

for.⁹⁴ The exact structure of these benefits, however, will depend on rules that are still being written by the Treasury Department; until they have developed a clear definition for 'nearzero emissions,' it is difficult to guess what standards a producer would need to meet to be eligible for the \$3/kilogram incentive.⁹⁵

2.5 Additional California-Specific Policies

In California, there are some specific policies that will impact the avenues of carbon management activity that can be pursued, which are external to the permitting requirements outlined above, nor do they constitute as incentives, at least at this moment.

First, a recent package of climate bills that was signed last fall by Governor Gavin Newsom included multiple state bills relevant to carbon management efforts. SB 1314 effectively bans the utilization of any captured CO₂ to be used for enhanced oil recovery (EOR) in the state.⁹⁶ As a result, carbon management entities will need to identify other avenues of utilization or storage for their captured CO₂. SB 905 requires that the California Air Resources Board (CARB) establishes a "Carbon Capture, Removal, Utilization, and Storage Program."⁹⁷ Under SB 905, CARB must also set up a unified permit for California-based carbon capture, utilization and storage (CCUS) projects, establish a centralized database for California-based carbon management projects, and implement financial responsibility regulations for CO₂ storage operators to retain responsibility for a minimum of 100 years following their most recent CO₂ injection at a well site.⁹⁸

Other statewide policies are likely to have indirect effects on carbon management efforts. California's Sustainable Groundwater Management Act (SGMA) from 2014 requires that state groundwater supplies be brought back into long-term balance by 2040,⁹⁹ which may limit the availability of freshwater supplies to Kern County and neighboring areas, depending on the region's hydrology over the coming decades. SGMA requires the development of local groundwater sustainability agencies (GSAs), formed as partnerships between city and/or county governments, irrigation districts, water districts, or other local bodies.¹⁰⁰ Each GSA submits plans to the state to meet SGMA's objectives, with a focus on implementing responsible groundwater management for their region.¹⁰¹ The California Department of Water Resources (DWR) oversees implementation, giving routine assessments and providing technical assistance, and the State Water Resources Control

⁹⁴ Pontecorvo (December 12, 2022) <u>Subsidy for 'green hydrogen' could set off a carbon bomb</u>. [40]

⁹⁵ Pontecorvo (December 12, 2022) <u>Subsidy for 'green hydrogen' could set off a carbon bomb</u>. [40]

⁹⁶ IEA (November 4, 2022) <u>SB 1314</u>. [28]

⁹⁷ IEA (November 4, 2022) <u>SB 905</u>. [27]

⁹⁸ IEA (November 4, 2022) <u>SB 905</u>. [27]

⁹⁹ SWRCB (no date) <u>SGMA</u>. [43]

¹⁰⁰ SWRCB (no date) <u>SGMA</u>. [43]

¹⁰¹ SWRCB (no date) <u>SGMA</u>. [43]

Board is entrusted with intervening in a basin's management if its sustainability plans fail.¹⁰² With regulations like SGMA in place to protect local water supplies, water-intensive industries—like liquid direct air capture (L-DAC) or hydrogen production via electrolysis—may find it more difficult to locate in water-stressed regions. Issues relating to available freshwater supplies in Kern County are explored more in Section 8.1.4.

¹⁰² SWRCB (no date) <u>SGMA</u>. [43]
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CARBON MANAGEMENT TECHNOLOGIES

3. Direct Air Capture

TECHNOLOGY AT A GLANCE

- Industry is in early commercial stages: Globally, a cumulative ~10,000 metric tons CO₂ are captured each year by other projects¹
- Current cost per metric ton CO₂ captured: \$94-877 USD/ton CO₂
- Projected cost per metric ton CO₂ captured at scale: \$60-200 USD/ton CO₂
- 200-240 acres of land use required per million metric tons CO₂ captured
- Key advantages of this technology in Kern County: minimal feedstock requirements or waste; solid-direct air capture (S-DAC) has the potential to capture water as well as CO₂
- Key concerns for this technology in Kern County: noise and vibration levels with large-scale projects, high energy demands, poor clarity on job creation potential

3.1 Technology Summary

Direct Air Capture (DAC) is a technology that captures carbon dioxide (CO_2) directly from the atmosphere, usually through a mechanical system, although some passive capture techniques are also being developed. In a mechanical system, fans or wind are used to drive ambient air through a contactor unit, where the air passes across a chemical sorbent

¹ Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

that selectively reacts with and traps CO_2 , allowing the other components of the air to pass through and exit the system. Currently, the most developed adsorbent materials are in liquid or solid forms.²

3.1.1 Description: How it Works

DAC can be thought of as an engineered equivalent to photosynthesizing plants, except that DAC captures CO_2 from the atmosphere at a faster rate and with a much smaller land footprint than biomass. Furthermore, DAC delivers CO_2 in a pure, compressed form. Captured atmospheric CO_2 can be permanently and safely stored in geologic reservoirs to deliver negative emissions, or be used to produce low carbon intensity products, such as synthetic fuels that work in existing vehicles and infrastructure.³

Current DAC technologies are primarily distinguished by using one of two types of sorbent: liquid solvents (L-DAC) and solid sorbents (S-DAC). In both techniques, DAC pulls air from the atmosphere and passes it over the sorbent material. The sorbent material captures the carbon dioxide, and the rest of the air passes through and exits the DAC unit. L-DAC typically uses hydroxide solutions (a liquid solvent) as the bonding sorbent, whereas S-DAC relies on a CO_2 "filter" or dry amine-based chemical sorbents.⁴ In both cases, the CO_2 from the air is chemically bound into a new compound, and then is subsequently broken down to release 1) a high-purity stream of CO_2 for storage, and 2) the original sorbent components for reuse. Figures 3.1 and 3.2 illustrate the multi-stage process of DAC's operational system, distinguished by the solid sorbent (S-DAC) and liquid solvent (L-DAC) technologies, respectively.



Figure 3.1. Schematic of S-DAC operation.⁵ Step 1: ambient air enters the air contactor unit and CO_2 is absorbed onto a solid sorbent. Step 2: Heat exposure (\pm vacuum pressure) releases CO_2 from sorbent material and a concentrated stream of CO_2 is produced. Step 3: Sorbent is cooled, thereby reactivating it for reuse in the air contactor.

² IEA (2022) <u>DAC Report</u>. [40]

³ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 149. [55]

⁴ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 82. [41]

⁵ Larsen *et al.* (2020) <u>Capturing New Business</u>. [44]



Figure 3.2. Schematic of L-DAC operation.⁶ Step 1: ambient air enters the contactor and CO₂ reacts with capture fluid to produce carbonate. Step 2: Carbonate reacts with hydroxide to form small pellets. Step 3: Pellets are heated to produce lime and a concentrated stream of CO₂. Step 4: Lime from the calciner reactivates capture solution for reuse in contactor.

Both technologies require electricity and heat to operate; the electricity drives the fans and controls inlet systems, while the heat releases the trapped CO_2 . However, S-DAC requires only temperatures of only ~100°C to break the chemical bonds linking the CO_2 to the sorbent material, whereas L-DAC requires temperatures around 900°C.^{7,8} Such temperatures are difficult to reach using renewable energy sources like wind or solar. If natural gas is used to attain the necessary heat, the associated CO_2 released from the use of L-DAC technology would need to be recaptured and stored to avoid counteracting the benefit of DAC.⁹

3.1.2 State of Development

DAC is a relatively new industry that is still in the early stages of development.^{10,11} As of the drafting of this report, large-scale commercial deployment of DAC does not exist, but several companies have developed pilot projects with limited commercialization that are capturing CO_2 on the scale of thousands of metric tons per year.¹² Some, but not all, of these pilot projects include geologic sequestration or utilization of the captured CO_2 .¹³ Because DAC technology is still in its infancy, there are few straightforward assessments of how the technology and business model of DAC will adapt to industrial scaling, although there is reason to expect that economies of scale and technological innovation will have

⁶ Larsen *et al.* (2020) <u>Capturing New Business</u>. [44]

⁷ IEA (2022) <u>DAC Report</u>. p. 10. [40]

⁸ Ghiat, Al-Ansari (2021) <u>A review of CCUS</u>. p. 4. [31]

⁹ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 82. [41]

¹⁰ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 189. [55]

¹¹ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 83. [41]

¹² Ozkan *et al.* (2022) <u>DAC Status Report</u>. [59]

¹³ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 83. [41]

positive effects.¹⁴ The earliest breakthrough paper describing a working direct air capture system was written by Geoffrey Holmes and David Keith of Carbon Engineering in 2012, specifically discussing an L-DAC system.¹⁵ The following year, the first pilot-scale deployment of DAC was launched by the Swiss company, Climeworks, which utilizes S-DAC technology.¹⁶ With only about a decade since its early breakthroughs, DAC technology still needs research, innovation, and further technological breakthroughs to reach its maturity at scale.

As of April 2022, there are 18 DAC plants currently operating worldwide, capturing approximately 0.01 Mt CO₂/year.¹⁷ Companies leading the industry with the most developed DAC technology are <u>Climeworks</u>, <u>Carbon Engineering</u> and <u>Global Thermostat</u>. These companies are primarily focused on developing megaton facilities: plants that will operate at the scale of capturing millions of metric tons of CO₂ annually (Mt CO₂/year), and have progressed the furthest towards opening commercial, large scale DAC plants.^{18,19}

Two commercial plants, developed by Climeworks, are currently operating in Switzerland and selling CO₂ to greenhouses and beverage companies for carbonation.²⁰ The latest plant to come online from Climeworks is Orca, launched in 2021 and capturing 4,000 metric tons of CO₂ per year for storage in basalt formations in Iceland.²¹ The Orca pilot plant is also a test facility for CO₂ mineralization, in which CO₂ is sequestered in porous basalt where it can react with host minerals and form the carbonate solid CaCO₃, precluding any risk of leakage.²² In North America, both Carbon Engineering and Global Thermostat have been operating a number of pilot plants, with Carbon Engineering, in collaboration with Occidental (Oxy), currently designing what would be the world's first megaton DAC facility, called 1pointfive, in the Permian Basin region of west Texas anticipated to be operational in 2024.^{23, 24}

¹⁴ Industry representative, personal communication, August 29, 2022.

¹⁵ Holmes, Keith (2012) Liquid DAC. [36]

¹⁶ McQueen *et al.* (2021) <u>DAC Review</u>. [51]

¹⁷ 1pointfive (n.d.) <u>DAC Technology</u>. [1]

¹⁸ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 193. [55]

¹⁹ Lebling *et al.* (May 2, 2022) <u>6 Things to Know about DAC</u>. [49]

²⁰ Climeworks (2015) <u>Capricorn</u>. [20]

²¹ Climeworks (2021) <u>Orca</u>. [23]

²² Reuters (September 13, 2021) <u>World's largest plant capturing carbon from air starts in Iceland</u>.

²³ 1pointfive (no date) <u>DAC Technology</u>. [1]

²⁴ GlobalNewsWire (2022) <u>Occidental, 1pointfive to begin construction</u>. [32]

3.1.2.1 Operational projects - examples

Orca Facility, Climeworks, Iceland

Launched in September of 2021, the Orca plant (Figure 3.3a) is currently the largest DAC plant in the world.²⁵ Located in Hellisheidi, Iceland, the plant has a carbon removal capacity of 4,000 metric tons per year.²⁶ The plant was developed as a collaboration between Climeworks (using their S-DAC technology) and Carbfix, an industry-research consortium that is piloting the development of underground storage of CO₂ through mineralization.²⁷ The facility consists of eight collector containers, with an annual CO₂ capture capacity of 500 metric tons each.²⁸ The containers are arranged around a central process hall that accommodate electrical and processing equipment, allowing the company to operate and control the facility remotely.²⁹ The DAC plant is strategically located in proximity with the Hellisheidi Geothermal Power Plant, which supplies the heat and electricity required to run the direct air capture process at low cost.³⁰ The Orca footprint is 8,600 square feet, equivalent to the square footage of approximately four urban houses.³¹ This translates to a per ton CO₂ land use requirement of 2.15 square feet per ton of CO₂ captured.



Figure 3.3. a) The four collectors of the Orca DAC facility in Hellisheidi, Iceland.³² The capture technology is S-DAC, from Climeworks. b) Conceptual plan for the in-development Mammoth DAC facility, also S-DAC and expected to be operational in 2024. Mammoth is co-located with the Orca facility, and is a scaled up equivalent of the first pilot facility.³³ Image credit: Climeworks.

²⁵ Climeworks (2021) <u>Orca</u>. [23]

²⁶ Climeworks (2021) <u>Orca</u>. [23]

²⁷ Climeworks (December 2, 2020) <u>The rapid construction of Climeworks' new DAC and storage</u> <u>plant Orca</u>. [24]

²⁸ Climeworks (2021) <u>Orca</u>. [23]

²⁹ Climeworks (2021) <u>Orca</u>. [23]

³⁰ Climeworks (2021) <u>Orca</u>. [23]

³¹ Ozkan *et al.* (2022) DAC Status Report. [59]

³² Climeworks (2021) <u>Orca</u>. [23]

³³ Climeworks (June 28, 2022) <u>Climeworks takes another major step</u>. [22]

The capital and operational costs of the Orca plant are covered in part by the sale of carbon credits in the voluntary carbon offset marketplace, where private buyers can purchase the capture and storage of CO₂ on a per-metric ton basis to offset their own emissions.³⁴ The Orca plant sells the most expensive carbon offset credits in the world, costing as much as €1,000 per metric ton of CO₂ removed.³⁵ Climeworks' clientele for carbon offset credits includes Microsoft, Swiss Re, Shopify and Audi.³⁶ Jan Wurzbacher, co-chief of Climeworks, said commercial demand had been so high that the plant was nearly sold out of credits for its entire 12-year lifespan, prompting the accelerated development of their next plan: the Mammoth DAC facility (Figure 3.3b).³⁷ Mammoth uses the same technological design as Orca, will also be sited in Hellisheidi, Iceland, and will also sequester the CO₂ via mineralization in Iceland's basalt-rock subsurface, but will have a nominal CO₂ capture capacity of 36,000 tons per year. The plant is expected to be operational in 2024.³⁸

DAC 1 Facility, Carbon Engineering, US

DAC 1 is a megaton DAC plant in development in west Texas by the companies 1pointfive and Carbon Engineering. Operation is expected to begin in 2024.³⁹ The plant will use Carbon Engineering's liquid solvent system (L-DAC), which uses a potassium hydroxide (KOH) solution as the sorbing fluid that binds the CO₂.⁴⁰ The facility will be assembled as "a scalable setup" consisting of modular contactors (Figure 3.4a, from Carbon Engineering's pilot facility in British Columbia) that will require a land size of 0.2 km², not including energy land use, to reach its 1 MtCO₂/yr capture target.⁴¹ High-temperature release and separation of the CO₂ and regeneration of the liquid solvent will be performed using natural gas as the thermal energy source.⁴² Because this facility will be sited in the Permian Basin region, which has ideal subsurface reservoirs for geological sequestration, transport of the separated CO₂ to a permanent storage site will be minimal.⁴³ The initial phase of DAC 1 is focused on a first capture train with a planned capture capacity of 0.5 MtCO₂/year; the total capacity of the project will subsequently increase to 1 MtCO₂/year.^{44,45}

³⁴ Favasuli, Sebastian (June 10, 2021) <u>Voluntary carbon markets</u>. [30]

³⁵ Hook (September 8, 2021) World's Biggest DAC Plant. [37]

³⁶ Milkywire (2022) <u>The Climate Transformation Fund: Milkywire Progress Report 2022</u>. p. 8. [53]

³⁷ Hook (September 8, 2021) World's Biggest DAC Plant. [37]

³⁸ Climeworks (June 28, 2022) <u>Climeworks takes another major step</u>. [22]

³⁹ GlobalNewsWire (2022) <u>Occidental, 1pointfive to begin construction</u>. [32]

⁴⁰ IEA (2021) <u>DAC 1</u>. [39]

⁴¹ Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 8.

⁴² Hook (September 8, 2021) <u>World's Biggest DAC Plant</u>. [37]

⁴³ Grover (July 8, 2021) <u>Old oil fields may be ideal for carbon sequestration</u>. [33]

⁴⁴ IEA (2022) <u>DAC Report</u>. p. 18. [40]

⁴⁵ IEA (2021) <u>DAC 1</u>. [39]

1pointfive and Carbon Engineering have raised money to cover the capital costs of this project from corporate sponsors, including a multi-million dollar direct investment from United Airlines, and hope to further offset costs by making the most of existing policy incentives, including the federal 45Q tax credit and California's Low Carbon Fuel Standard (LCFS) program.⁴⁶ More information about these policies and the incentives they provide for DAC can be found in Section 3.4 of this report.



Figure 3.4. a) Carbon Engineering Innovation Centre, R&D Facility, Squamish, British Columbia.⁴⁷ b) A conceptual aerial view of the megaton Carbon Engineering + 1pointfive facility, DAC 1 (in development).⁴⁸ Image credit: Carbon Engineering.

3.1.2.2. Technological innovations on the horizon

In terms of future development, technological designs that emphasize modular and relatively simple DAC approaches are generally favored because they allow for simplified mass production and can be scaled up easily for deployment.⁴⁹ Achieving economies of scale by producing large volumes of standard parts may also accelerate DAC's deployment and shorten technology learning curves, which will help to reduce costs. Additional technological trends that are being explored by many DAC startup companies include passive air contact and use of natural sorbents. Some notable start-ups in the DAC space that are indicative of these trends are <u>Carbon Capture Inc</u>, <u>Sustaera</u>, <u>Mission Zero</u>, and <u>Noya</u>. These companies are primarily in the design and development stage of their pilot projects.

Two startup companies are worth particular note for the innovative alternatives they are developing to traditional liquid-solvent or solid-sorbent based DAC systems, which may be

⁴⁶ IEA (2021) <u>DAC 1</u>. [39]

⁴⁷ Carbon Engineering (June 30, 2021) <u>Carbon Engineering Innovation Centre Update</u>. [13]

⁴⁸ 1pointfive (no date) <u>DAC Technology</u>. [1]

⁴⁹ Shayegh, Bosetti, Massimo (2021) <u>Future Prospects of DAC Technologies</u>. p. 3. [64]

critical for reducing the operational costs of DAC, and helping bring it to market more quickly.

Heirloom

Heirloom is a startup in the early phase of development. It has yet to deploy its first facility (slated for 2023), but is notable because it is attracting some of the largest investments in new carbon removal technologies from venture investment leaders like Microsoft cofounder Bill Gates's Breakthrough Energy Ventures, and because it has the lowest estimated cost of any direct air capture technology.^{50,51} Heirloom had developed an approach that optimizes passive carbon capture absorption using one of the most abundant natural resources on the surface of the earth: limestone. Limestone is composed of calcium carbonate, and is the primary feedstock for cement production.⁵² To produce cement, limestone is heated in the presence of water at high temperatures (~900°C) to form lime and a pure stream of CO₂, exactly the same process of solvent regeneration in L-DAC systems.^{53,54} The lime is then hydrated to form calcium hydroxide or slaked lime – the slaked lime, when exposed to air, will naturally react with CO₂ to re-form calcium carbonate.⁵⁵ Heirloom's technological innovation is to optimize natural carbonation of the lime during passive exposure to air, eliminating the need for fans or high-cost solvents.⁵⁶ The primary (and extremely inexpensive) feedstock of limestone, once converted to lime, can be re-used multiple times in a process of calcification (CO_2 absorption) and lime regeneration (CO_2 release).⁵⁷ Given the nascent stage of this company's development, specific information regarding the technical and operational requirements of such a process are not yet available, but with the exception of the high-cost solvent chemicals and water requirements for L-DAC, are likely to be similar.

Verdox

Another company in the early stages of development, called <u>Verdox</u>, is exploring a different alternative approach to liquid-solvent or solid-sorbent based DAC (L-DAC and S-DAC). Their Electro-swing Adsorption (ESA) technology is composed of a large, specialized battery that absorbs carbon dioxide from the air, or other gas stream, as it passes over charged electrodes.⁵⁸ When the electrodes are discharged, they release the concentrated carbon dioxide gas.⁵⁹ The technology works by alternating between charging and

⁵⁰ Cision PR Newswire (March 17, 2022) <u>DAC startup Heirloom raises \$53MM</u>. [16]

⁵¹ Olick (December 5, 2022) <u>Heirloom uses limestone to capture CO2</u>. [58]

⁵² PubChem (no date) <u>Limestone</u>. [61]

⁵³ McQueen *et al.* (2022) <u>A scalable DAC process</u>. p. 3. [52]

⁵⁴ Larsen et al. (2020) Capturing New Business. [44]

⁵⁵ McQueen *et al.* (2022) <u>A scalable DAC process</u>. p. 3. [52]

⁵⁶ McQueen *et al.* (2022) <u>A scalable DAC process</u>. p. 4. [52]

⁵⁷ McQueen *et al.* (2022) <u>A scalable DAC process</u>. p. 4. [52]

⁵⁸ Verdox (no date) <u>Breaking new ground</u>. [72]

⁵⁹ Verdox (no date) <u>Breaking new ground</u>. [72]

discharging, thus relying on only electricity to run—the process has no heat or water needs.⁶⁰ ESA is able to capture carbon dioxide from any concentration, down to roughly 400 parts per million currently found in the atmosphere.⁶¹ The technology is attractive for its high efficiency of raw materials and energy relative to more established direct air capture methods, using about 1GJ/tCO₂, or about 10-20% of the energy requirements for L-DAC and S-DAC (see Section 3.1.3.2).^{62,63} Verdox is still in the testing phase of technology development, having been awarded a Department of Energy Advanced Research Projects-Energy (ARPA-E) research grant in 2020.⁶⁴ Anticipated capital and operational costs of a pilot-scale project, once deployed, are projected to be ~ \$50-100 per metric ton of CO₂ captured.⁶⁵

3.1.3 Operational Needs

This section provides a synopsis of the land use, energy, feedstock, waste disposal and other operational needs of the representative technologies for this industry, aggregated from literature review and interviews with industry experts. Because L-DAC and S-DAC are the most advanced direct air capture technologies, these are the only two DAC approaches considered here and in subsequent sections. Alternative DAC technologies, such as passive air capture or ESA, may be appropriate candidates for a research and development incubator facility.

3.1.3.1 Land use requirements

One of the key benefits of DAC as a carbon management technology is that it can be sited in any location that is economical, because unlike point-source carbon capture technologies, which require concentrated CO_2 streams (such as those emitted from CO_2 emitting industries like steel or concrete manufacturing, see Section 5 of this report) the source of CO_2 - ambient air - is accessible anywhere. Thus, a DAC plant could be co-located next to a plant which requires CO_2 as a feedstock or on top of a geological storage site to minimize costs and secondary emissions associated with transporting the CO_2 via truck, rail or pipeline.⁶⁶ DAC can also be co-located with other types of CO_2 capture facilities.⁶⁷

A second benefit of DAC is that the direct land footprint of DAC is smaller than that of alternative carbon-removal processes. Land requirements for DAC are controlled by 1) the

⁶⁰ Verdox (no date) <u>Breaking new ground</u>. [72]

⁶¹ Chandler (2019) <u>New Technology: ESA</u>. [15]

⁶² Voskian, Hatton (2019) <u>Faradaic electro-swing reactive adsorption for CO₂ capture</u>. p. 3530. [73]

⁶³ Chandler (2019) <u>New Technology: ESA</u>. [15]

⁶⁴ ARPA-E (May 20, 2020) <u>Electro-swing adsorption for high efficiency DAC</u>. [2]

⁶⁵ Stauffer (September 2, 2020) <u>Electro-swing cell</u>. [67]

⁶⁶ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 189. [55]

⁶⁷ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 82. [41]

size of the contactor and 2) the spacing requirements of multiple contactors and contactor configuration.⁶⁸ Contactors are generally designed to be modular: easily transportable and stackable (e.g. Figures 3.3 and 3.5). Contactors from Carbon Engineering, a commercial L-DAC company, are about 23 ft long by 16 ft tall and 16 ft wide.⁶⁹ Climeworks, a commercial company with the largest existing capture capacity for S-DAC systems, has contactors the size of a standard shipping container, or about 40 ft long by 8 ft wide by 8.5 ft high.⁷⁰ Units cannot be too geographically concentrated within a site, as some units would be taking in air that has already been depleted in CO₂ by nearby contactor units.⁷¹ Although the actual footprint required for the contactors is small, there would need to be ample space between sets of contactors to build an effective facility.

Figure 3.5 is a schematic representation of the physical footprint of a 1 MTCO₂/year DAC facility. The size, height and orientation of the contactor arrays is based off the original design of solvent-based L-DAC by the company Carbon Engineering, with the crosssectional inlet of the contactor oriented normal to the land surface.⁷² More recent designs from this company have a configuration in which fans are parallel to the land surface (Figure 3.4). The height of the pictured tower, with four vertically stacked units, is approximately 65 feet (20 meters) and over 650 feet long, and could capture 50,000-100,000 metric tons of CO₂ annually.⁷³ To capture 1 MtCO₂/year, process engineer and DAC expert Howard Herzog estimates that you would need 25-30 of Carbon Engineering's contactor rows in a facility, and they would have to be spread far enough apart to ensure that the exhaust of one row of units does not interfere with the inlet of another row.⁷⁴ Given that no DAC facilities exist at a scale above *thousands* of metric tons of annual CO₂ capture, no field tests exist to determine the optimal spacing between contactor rows. In a schematic representation of a 1 MtCO₂/yr facility developed by the American Physical Society, contactor rows were spaced 250 m (820 ft) apart, to ensure that CO₂-depleted air exiting one contactor would be replenished before reaching the next.⁷⁵ Using the APS's spacing estimate, the land footprint of Carbon Engineering's original design for a 1 MtCO₂ capture facility (25-30 contactor rows) would be about 300-360 acres, or 1.2-1.5 km². If we created the same framework for an S-DAC system modeled after Climeworks' Orca facility in Iceland, also creating 40-unit long rows, one contactor row would be able to capture ~40,000 metric tons of CO₂ annually.⁷⁶ Scaling accordingly, the footprint of a 1 MtCO₂/yr facility would be 190-230 acres, or 0.8-0.95 km², assuming the same 66-80% efficiency that

⁶⁸ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 87-88. [41]

⁶⁹ Heidel *et al.* (2011) <u>Air contactor design</u>. [34]

⁷⁰ Climeworks (no date) <u>Capricorn</u>. [18]

⁷¹ Herzog (2021) <u>DAC: A Process Engineer's View</u>. 16:05-16:34. [35]

⁷² Heidel *et al.* (2011) <u>Air contactor design</u>. p. 2865. [34]

⁷³ Heidel *et al.* (2011) <u>Air contactor design</u>. p. 2866. [34]

⁷⁴ Herzog (2021) <u>DAC: A Process Engineer's View</u>. 15:52-16:05. [35]

⁷⁵ APS (2011) <u>DAC with Chemicals</u>. p. 7. [3]

⁷⁶ The <u>Orca facility in Iceland</u> contains 4 units of 2 stacked contactors, each ~40 ft long on the air inlet side, and ~ 8 ft deep. The facility captures approximately 4,000 metric tons of CO_2 annually.

Dr. Herzog estimated for L-DAC systems.⁷⁷ These numbers are comparable to published estimates of L-DAC and S-DAC land use requirements, which range from 0.2-7 km² and 0.2-2 km², respectively (Table 3.1).^{78,79,80,81} Further complicating land use estimates, DAC systems can make use of vertical space by stacking DAC contactors much higher than 2-4 units, and thus allowing for a far smaller footprint required for megaton-scale facilities.⁸²



Figure 3.5. A conceptual drawing of a $1MtCO_2$ DAC system, consisting of 10 m (33 ft) tall and 1 km (0.6 mile) long contactor structures and a facility for sorbent regeneration and CO_2 gas compression. Adapted from the American Physical Society⁸³ and Heidel et al. (2011).⁸⁴

Indirect land use, resulting from the energy source needed to provide heat and electricity to a DAC facility, is generally much more significant than direct land use itself, but is dependent on the type of DAC sorbent (L-DAC or S-DAC) and the type of energy source in question.⁸⁵ For an L-DAC plant capturing one million tons of CO₂ annually powered entirely by solar PV, around 34 km² of land would be needed, whereas natural gas only requires 0.4 km².⁸⁶ However, L-DAC systems require heating temperatures of ~900°C (Table 3.1), and as of the publication of this report, there is not an at-market tool for converting solar or wind energy into process heat at those temperatures.⁸⁷ Thus, published land use estimates for

⁷⁷ Herzog (2021) <u>DAC: A Process Engineer's View</u>. 15:52-16:05. [35]

⁷⁸ Lebling *et al.*, WRI (2022) <u>DAC: Assessing impacts to enable responsible scaling</u>. p. 2. [48]

⁷⁹ IEA (2022) <u>DAC Report</u>. p. 39. [40]

⁸⁰ APS (2011) <u>DAC with Chemicals</u>. p. 7. [3]

⁸¹ Lebling *et al.* (2022) <u>Building DAC</u>. [47]

⁸² Aines, R. *Personal communication* (2022).

⁸³ APS (2011) <u>DAC with Chemicals</u>. p. 7. [3]

⁸⁴ Heidel *et al.* (2011) <u>Air contactor design</u>. p. 2865. [34]

⁸⁵ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 78. [6]

⁸⁶ Lebling *et al.* (2022) <u>Building DAC</u>. [47]

⁸⁷ McMillan *et al.*, NREL (2021) <u>Opportunities for solar industrial process heat.</u> p. vi. [50]

energy demand as a function of energy source for L-DAC have generally assumed that heat energy is derived from natural gas or geothermal sources, but that alternative renewable energy sources like wind and solar could provide the power needed for electricity.⁸⁸ In contrast, S-DAC requires maximum sorbent regeneration temperatures of only ~80-100°C (Table 3.1), and thus both heat and electrical energy can be supplied by existing at-market wind or solar energy technologies. For a 1 million metric ton S-DAC plant, energy sourced from natural gas would require a 0.26km² footprint, whereas solar requirements would be about 21km² (Table 3.1).⁸⁹

Additional siting and footprint considerations

In addition to general land use considerations, attention needs to be paid to regional climate, dominant local airflows, and other meteorological conditions in the area, to identify preferred DAC technologies, optimal siting, and operational needs.⁹⁰ Humidity and average ambient temperatures are particularly important, because they can have large impacts on the capture productivity, energy efficiency, and water demands of DAC systems.

A recent study of S-DAC processes identified optimal capture productivity at low ambient temperatures, and much lower energy efficiency and capture productivity at higher ambient temperatures (Figure 3.6).⁹¹ This is because solid sorbent materials not only absorb CO₂, but also water vapor from the air.⁹² Although researchers agree that meteorological conditions will impact a DAC facility's effectiveness, findings are mixed as to these impacts. When looking specifically at Climeworks's S-DAC process, more water absorption from the atmosphere was found to reduce the sorbent's capacity for CO2 sorption.⁹³ In overarching studies of amine-based solid sorbents for DAC, higher humidity was found to increase the sorbent's CO₂ capture capacity but increase the energy use of the chemical process, while higher temperatures led to both higher energy demand and lower productivity—and these effects interact with one another.⁹⁴ As seen in Figure 3.6, at ambient temperatures above ~20°C (68°F), increases in relative humidity also begins to negatively impact capture productivity and energy efficiency.⁹⁵ In water scarce regions, however, sorption of both water and CO₂ may be considered a technological benefit, as captured water could be put to new use. Similarly, the company Carbon Engineering, which employs L-DAC systems, is avoiding places with colder climates to avoid unwanted viscosity of the liquid solvent, while at the same time avoiding dry and hot places to

⁸⁸ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 78-79. [6]

⁸⁹ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 79. [6]

⁹⁰ Herzog (2021) <u>DAC: A Process Engineer's View</u>. 27:24-27:35. [35]

⁹¹ Wiegner *et al.* (2022) <u>S-DAC optimization</u>. p. 12654. [75]

⁹² Wiegner *et al.* (2022) <u>S-DAC optimization</u>. p. 12650. [75]

⁹³ Herzog (2021) DAC: A Process Engineer's View. 27:35-28:06. [35]

⁹⁴ Wiegner *et al.* (2022) <u>S-DAC optimization</u>. p. 12650. [75]

⁹⁵ Wiegner *et al.* (2022) <u>S-DAC optimization</u>. p. 12654. [75]

minimize evaporation of the liquid solvent, which leads to constant water loss and an increased possibility of leaking some of the captured CO_2 .⁹⁶

Table 3.1.	Comparison	of S-DAC and	L-DAC key	features. ^a
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	S-DAC	L-DAC
CO₂ separation	Solid adsorbent	Liquid solvent
Specific energy consumption (GJ/tCO ₂)	3.4-5.9	5.3-12.4
Share as heat consumption (%)	75-80%	80-100%
Share as electricity consumption (%)	20-25%	0-20%
Regeneration temperature	80-120°C	Around 900°C
Regeneration pressure	Vacuum	Ambient
Capture capacity	Modular (e.g. 50 tCO ₂ /yr per unit)	Large-scale (e.g. 0.5 to 1 MtCO ₂ /yr)
Net water requirement (tH_2O/tCO_2)	-2 to none	0-50
Life cycle emissions (tCO _{2-emitted} /tCO _{2-captured})	0.03-0.91	0.1-0.4
Levelized cost of capture (USD/tCO ₂)	Up to \$540	Up to \$340
Main advantages	 Possible net water production Less capital-intensive Modular Operation can rely on low- carbon energy only Novel and therefore more likely to see cost reduction 	 Less energy-intensive Large-scale capture Operation relies on commercial solvents Technology adapted from existing commercial units
Main trade-offs	 More energy-intensive Manual maintenance required for adsorbent replacement 	 More capital-intensive Relies on natural gas combustion for solvent regeneration (with potential for full electrification in the future)
Land requirements	S-DAC	L-DAC
DAC footprint (km²/MtCO₂)	0.2-2 (Median = 1.0)	0.2-7 (Median – 0.8)
Natural gas energy source (km²/MtCO2)	0.26	0.43
Solar energy source (km ² /MtCO ₂) (with NG as a heat source – L-DAC only)	2	36 (5 + 0.37)
Wind energy source (km ² /MtCO ₂) (with NG as a heat source – L-DAC only)	217	364 (51 + 0.37)

a. Data from: IEA (2021) <u>DAC Report</u>, p. 23-24, Baker *et al.* (2020) <u>Getting to Neutral</u>, p. 79, APS (2011) <u>DAC with Chemicals</u>, p. 7., Lebling *et al.* (2022) <u>Building DAC</u>, p. 12, Ozkan *et al.* (2022) <u>Current DAC</u> <u>Status</u>, p. 2-8, National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>, and this study.

⁹⁶ Herzog (2021) <u>DAC: A Process Engineer's View</u>. 28:06-29:59. [35]

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Figure 3.6. Productivity and specific energy requirements for S-DAC as a function of ambient temperature and humidity. Reproduced with permission from Wiegner et al. (2022)⁹⁷.

Land use estimates also have to anticipate less than 100% operational efficiency. H. Herzog estimated 66-80% of total DAC capacity would be operational at any given time, and a life-cycle assessment of Climeworks technologies estimated a carbon capture efficiency of 85-93%.^{98,99} L-DAC contactors can "theoretically operate continuously at steady state without interruption" though they require regular maintenance.¹⁰⁰ However, S-DAC must operate using a batch operation which requires having multiple units in parallel.¹⁰¹ At any one time, some contactor units will be in operation capturing CO₂, while the remaining contactor units are in their regeneration state, releasing CO₂ from the filters.¹⁰²

3.1.3.2 Energy requirements

The energy requirement as well as per-ton cost of any carbon-dioxide removal technology is heavily influenced by the concentration of CO_2 in the main feedstock of the plant. For DAC, that feedstock is ambient air, which has CO_2 concentrations of a little over 400 parts per million, a small fraction of industrial-scale flue gas, which can be 5 to >90% CO_2 .^{103,104} The extremely dilute stream makes it difficult and energy-intensive to separate CO_2 from air relative to more established industrial point source carbon scrubbers.^{105,106}

⁹⁷ Wiegner *et al.* (2022) <u>S-DAC optimization</u>. [75]

⁹⁸ Herzog (2021) <u>DAC: A Process Engineer's View</u>. 15:52-16:05. [35]

⁹⁹ Deutz, Bardow (2021) Life-cycle assessment of an industrial DAC process. [25]

¹⁰⁰ IEA (2022) <u>DAC Report</u>. p. 22-23. [40]

¹⁰¹ IEA (2022) <u>DAC Report</u>. p. 22-23. [40]

¹⁰² IEA (2022) <u>DAC Report</u>. p. 22-23. [40]

¹⁰³ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>, p. 189. [55]

¹⁰⁴ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 101. [41]

¹⁰⁵ IEA (2022) <u>DAC Report</u>. p. 27. [40]

¹⁰⁶ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 82. [41]

The amount of energy needed for DAC also depends on the technology. For L-DAC, the most energy-intensive component of the capture process is the thermal regeneration step (Figure 3.2), in which the carbonate pellets holding the sorbed atmospheric CO_2 are combusted to release a stream of high-purity CO₂ and regenerate the lime solvent additive (CaO).¹⁰⁷ This process requires heating to temperatures up to 900°C.^{108,109} In comparison, the regeneration step for S-DAC sorbent only requires a temperature of 80–120°C.^{110,111} The result is that, while both technologies require about 80% of their energy for heating and 20% for electricity, estimates of the total energy need for L-DAC ranges from 5.3-10.7 gigajoules per ton of CO₂ captured (GJ/tCO₂), whereas S-DAC requires about 3.4 to 5.8 GJ/tCO₂ (Table 3.1), or 1.5-3.0 and 0.9-1.6 MWh/tCO₂, respectively.^{112,113} In existing pilot facilities, energy sources include geothermal (the Orca facility in Iceland), waste heat (Climeworks' first pilot plant in Hinwil, Switzerland) or natural gas with carbon capture (Carbon Engineering).^{114,115} Using solar power to supply both heat and electricity energy is a feasible option for S-DAC, given the lower required heat generation temperatures, but to deliver heat up to 900°C for L-DAC technologies, is not feasible unless paired with a hightemperature industrial battery solution (see Section 7 on energy storage industries).¹¹⁶ Estimates of the scale of solar installation required to supply 100% of the heat and electrical energy needs of a 1MtCO₂/yr DAC facility (assuming industrial battery use as needed) are provided in Table 3.2. Installed capacity for the solar fields were calculated following the equation:

MWh (energy supplied) = MW (installed capacity of facility) x (8760 hours in a year) x Capacity factor (E3.1)

where the capacity factor for solar panels in Kern County is 32.8%.^{117,118} Solar acreage is calculated on the basis of ~7 acres per MW installed solar capacity.^{119,120} With these values,

¹¹⁸ NREL (no date) <u>Utility-Scale PV</u>. [56]

¹⁰⁷ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 203. [55]

¹⁰⁸ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 196. [55]

¹⁰⁹ IEA (2022) <u>DAC Report</u>. p. 10. [40]

¹¹⁰ Beuttler *et al.* (2019) <u>The role of DAC in mitigation</u>. p. 2. [8]

¹¹¹ Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 2. [59]

¹¹² Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 79. [6]

¹¹³ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 222. [55]

¹¹⁴ Climeworks (2021) <u>Orca</u>. [23]

¹¹⁵ Climeworks (May 31, 2017) <u>Climeworks makes history</u>. [21]

¹¹⁶ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 211. [55]

¹¹⁷ Thomson Reuters Practical Law Glossary (no date) <u>Capacity factor</u>. [69]

¹¹⁹ Lorelei Oviatt, Kern County Department of Planning and Natural Resources, personal communication, September 21, 2022.

¹²⁰ SEIA (no date) <u>Land use and solar development</u>. [65]

a megaton L-DAC facility would require on average 830 MW installed solar capacity (range = 508-1034 MW), or a ~5800 acre solar field. S-DAC would require an average of 420 MW installed solar capacity (range = 329-561 MW), or ~2900 acres of solar panels.

3.1.3.3 Other operational needs

Waste disposal requirements

Because the only feedstock for DAC systems is air, and the only output is CO₂, there are no significant waste streams from DAC plants.¹²¹ Minor anticipated sources of waste are replacement of parts, and of the solid or liquid sorbent materials once their regenerative capacity has declined. It is not clear how many iterations of regeneration are possible before sorbents will need replacement, but may be on the scale of many dozens of capture cycles.¹²² L-DAC sorbents are primarily composed of strong bases such as NaOH or KOH.^{123,124} As standard industrial salts, these compounds have well established regulation and disposal procedures.^{125,126} Sorbent materials currently being tested for S-DAC technologies include metal–organic frameworks (MOFs), zeolites, activated carbon, silica materials, carbon nanotubes, porous organic polymers, and carbon molecular sieves.¹²⁷ These are solid, non-reactive and non-hazardous materials that are common in many chemical laboratories, and do not pose a hazardous waste risk.

Warehousing requirements

Warehousing could be minimal for DAC, as there's no feedstock related to the capture other than ambient air, which does not require storage.

Transportation & pipeline requirements

Transportation and pipeline needs for a site should be minimal—adsorbents or solvents may need to be moved in and out of the plant at regular intervals to ensure the contactors remain in working order, a process that would likely rely on trucks for transport. The most likely pipeline needs for any site would be a pipeline to move the CO_2 to storage or, for L-DAC, pipelines to bring in natural gas, hydrogen, or other materials to support its high thermal energy needs. Please refer to Section 9 of the full report for more information on transportation requirements for more information about pipelines and other transportation options for safely moving CO_2 offsite for geologic storage.

¹²¹ Simon Pang, DOE C-LEAP Technical Assistance, personal communication, September 29, 2022.

¹²² Industry representative, personal communication, November 11, 2022.

¹²³ McQueen *et al.* (2021) <u>DAC Review</u>. p. 3. [51]

¹²⁴ IEA (2021) <u>DAC 1</u>. [39]

 ¹²⁵ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. <u>Research Agenda</u>. p. 231. [55]
 ¹²⁶ EPA (no date) <u>Substance Registry Service: Sodium hydroxide</u>. [28]

¹²⁷ McQueen *et al.* (2021) <u>DAC Review</u>. p. 2. [51]

	Energy Requirements:		Solar Requirements for a 1 MtCO ₂ /yr Facility:			
L-DAC	GJ/t CO₂	J/t CO ₂ MWh/t CO ₂		Footprint (acres)	Footprint (km²)	
minimum	5.3	1.46	508	3553	14	
maximum	12.4	3.44	1199	8392	34	
mean	9.2	2.55	889	6224	25	
S-DAC						
minimum	3.4	0.94	329	2301	9	
maximum	5.9	1.64	570	3993	16	
mean	4.8	1.32	460	3223	13	

Table 3.2. Comparison of S-DAC and L-DAC energy requirements.¹²⁸

3.2 Societal Impacts

3.2.1 Job creation potential

3.2.1.1 Number and types of jobs

The largest existing DAC project is 0.0004% the size of a megaton (million ton) capture facility, meaning that estimates of the job creation potential of this industry is highly speculative and must be based on growth trajectories of similar industries. The United Kingdom, which aims to capture 20-30 MtCO₂/yr by 2030, is anticipating 50,000 carbon capture-related jobs, translating to ~2,000 jobs per million tons of CO₂ sequestered.¹²⁹ The Rhodium Group estimated that construction, engineering and equipment manufacturing sectors combined could see at least 3,000 new jobs for every one million ton DAC plant, though the bulk of these jobs are in the initial plant investment period.¹³⁰ The breakdown of those jobs are as follows:

- >1500 jobs created from the equipment manufacturing process
- 657 jobs created from the engineering and design phase
- 721 jobs created from the construction phase
- 278 jobs created from operation and maintenance activities

 ¹²⁸ Data from: Baker *et al.* (2020) <u>Getting to Neutral</u>, p. 78, National Academies of Sciences,
 Engineering, and Medicine (2019) <u>Negative Emissions Technologies and Reliable Sequestration: A</u>
 <u>Research Agenda</u>, p. 222, and this study.

 ¹²⁹ United Kingdom Department for International Trade (2022) <u>CCUS Investor Roadmap</u>. p. 4. [71]
 ¹³⁰ Larsen *et al.* (2020) <u>Capturing New Jobs</u>. p. 15. [45]

Additional job creation in supporting industries like the energy production sector.¹³¹

While it is not entirely clear how these estimates would scale, it is likely that some would grow more linearly than others. For example, operation and maintenance might not have significantly higher job creation potential at a 2 megaton DAC plant than a 1 megaton facility, but construction, manufacturing and supporting industries would.¹³²

For the DAC 1 facility led by 1pointfive and Carbon Engineering, planned to capture 1 megaton per year, the reported permanent job estimate is about 75, with ~1,000 on-site construction jobs.¹³³ CarbonCapture Inc.'s Project Bison, a DAC hub planned for Wyoming with a goal of creating a 5 megaton DAC facility by 2030, is estimating the plant will support "more than 200 permanent jobs" in the state.¹³⁴ When compared to the Rhodium Group figure for a 1 megaton facility, these real facility estimates appear to reflect how permanent job potential is unlikely to scale proportionally for larger DAC facilities.

It is also critical to note that the job opportunities in several categories of the Rhodium Group estimate are not guaranteed to directly benefit local communities where a DAC facility is sited. This is particularly true for equipment manufacturing, engineering, and design. If a facility scale is large enough, it could provide an economic incentive to co-locate equipment manufacturing in the region.¹³⁵ However, it is recommended that concrete actions are taken to prepare both the industry and potential local workers for these new jobs to be sited in the region. One such action is to develop legally binding mechanisms ensuring that communities have the opportunity to benefit from available jobs and negotiate for other types of benefits beyond jobs. These agreements could take the form of a Community Benefit Agreement, a negotiated legal agreement between community groups and project developers that guarantees community benefits in exchange for a community's agreement to accept the project, or a Project Labor Agreement, an agreement between contractors and unions laying out the terms for a project. Project Labor Agreements can include Community Workforce Agreements, which require that the contractor hire a negotiated percentage of local, low-income or other marginalized workers, or that they collaborate with local organizations to provide job training programs and provide job quality specifications.¹³⁶

3.2.2.2 Training pipelines

Direct jobs that would be based onsite—such as construction, operation and maintenance, and electricity generation and distribution—require skill sets that are transferable from

¹³¹ Larsen *et al.* (2020) <u>Capturing New Jobs</u>. p. 15. [45]

¹³² Roger Aines, DOE C-LEAP Technical Assistance, personal communication, September 28, 2022.

 ¹³³ Trendafilova, (August 26, 2022) <u>Occidental Starts Construction Of Its First Large-Scale DAC</u>
 <u>Plant</u>. [70]

¹³⁴ Arambel (October 7, 2022) <u>CarbonCapture Inc</u>. [5]

¹³⁵ Industry representative, personal communication, November 11, 2022.

¹³⁶ Lebling *et al.* (2022) <u>Building DAC</u>. [47]

other projects and industries, like fossil fuel and energy sectors.^{137,138} As mentioned above, facility developers can work with local organizations and institutions to provide relevant training to take on these roles. This collaboration with local organizations to provide job training can be seen in Project Bison, where developers are already working with local community colleges in Wyoming to set up training programs for new positions at DAC facilities.¹³⁹

3.2.2 Quality of Life

3.2.2.1 Location

The lack of dangerous feedstocks, waste streams or pollutants associated with DAC results in little to no health or environmental risk from the operation of DAC towards the local community. Key considerations that remain are:

- 1. Energy use: due to the enormous use of energy required to run DAC facilities, developers need to ensure that energy required for DAC doesn't compete with other existing uses, such as domestic and local industry.
- 2. Noise: a single DAC contactor unit operates much like a large fan or HVAC system, and thus is comparably loud.¹⁴⁰ One large HVAC air conditioner emits 50-70 decibels of sound, about the same as other home appliances (refrigerator, dishwasher, vacuum). This sound dissipates relatively quickly; 50 feet away from a unit the noise level would be about halved, to 25-45 decibels (comparable sounds are whispering, rustling leaves).¹⁴¹ However, further research is warranted to assess how sound levels increase as multiple contactor units are combined.
- 3. Vibration: there is no clear data or discussion on the vibrational impact of DAC, but a megaton facility would have tens of thousands of contactors with rotating fan blades, it is a consideration. Several solutions exist to reduce the impacts of industrial vibration, including hardware, pads and mats designed to absorb vibration.¹⁴²
- 4. Aesthetics: because DAC systems are modular, there is room for preference in whether towers are built very tall, to reduce the overall ground footprint, or kept low to minimize visual impact.

¹³⁷ Larsen *et al.* (2020) <u>Capturing New Jobs</u>. p. 23-24. [45]

¹³⁸ Pollack (October 10, 2022) <u>Firm has big plans for air capture</u>. [60]

¹³⁹ Arambel (October 7, 2022) <u>CarbonCapture Inc</u>. [5]

¹⁴⁰ Simon Pang, DOE C-LEAP Technical Assistance, personal communication, September 28, 2022.

¹⁴¹ WKC Group (no date) <u>Sound attenuation - inverse square law</u>. [76]

¹⁴² Sorbothane Inc. (no date) <u>Vibration Isolation in Industrial and Manufacturing Equipment</u>. [66]

5. Commuting considerations: new roads and increased commuting for employees could increase traffic, and thus road noise and pollution for nearby residents.¹⁴³

3.2.2.2 Multi-use potential

DAC contactors must be spaced far enough apart to prevent the CO₂-free exhaust from one contactor becoming the intake air for the next contactor.¹⁴⁴ The optimal configuration to prevent this is still in the design phase, and likely specific to the conditions of the facility site.¹⁴⁵ As a result, it is possible that there will be large swaths of available space between contactor rows that could have alternative uses, such as the siting of other facilities, part of the solar energy supply for the DAC units, or livestock grazing (depending on disruptiveness of noise and vibration of the contactor units).¹⁴⁶ Additionally, DAC can be placed on top of, or adjacent to other industrial facilities, as shown by Climeworks' DAC-1 plant, which is built on the roof of a municipal waste incinerator.¹⁴⁷

3.3 Environmental Impacts

3.3.1 Water requirements

3.3.1.1 Minimum volume requirements

Water requirements for DAC are highly dependent on the chosen technology. While L-DAC requires significant amounts of water to dilute the hydroxide solution, some S-DAC technologies produce water as a byproduct of CO₂ absorption.^{148, 149}

For L-DAC to capture one ton of CO_2 , various sources estimate as little as 1 to more than 20 tons of water is needed to dilute the hydroxide solution that binds CO_2 .^{150,151,152} Water is not actually a feedstock in the L-DAC process, but is a component in the circulating solvent solution. Although that solution can be repeatedly regenerated, water must be regularly added to compensate for evaporation loss and, to a lesser degree, drift loss that occurs

¹⁵⁰ Lebling *et al.* (May 2, 2022) <u>6 Things to Know about DAC</u>. [49]

¹⁴³ Lebling *et al.* (2022) <u>Building DAC</u>. [47]

¹⁴⁴ Herzog (February 4, 2021) <u>DAC: A Process Engineer's View</u>. 16:05-16:34. [35]

¹⁴⁵ APS (2011) <u>DAC with Chemicals</u>. p. 7. [3]

¹⁴⁶ Herzog (February 4, 2021) <u>DAC: A Process Engineer's View</u>. 32:05-32:32. [35]

¹⁴⁷ Evans (June 22, 2017) <u>The Swiss company hoping to capture 1% of global CO2 emissions by</u> <u>2025.</u> [27]

¹⁴⁸ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 88. [41]

¹⁴⁹ Breyer *et al.* (2019) <u>Direct air capture of CO₂</u>. p. 2053. [9]

¹⁵¹ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 199. [55]

¹⁵² An et al. (2022) <u>Impact of L-DAC</u>. p. 7. [4]

during the sorbent-air contacting process.¹⁵³ The intensity of evaporation, and thus the H_2O needed for CO_2 captured, depends on the molarity of the hydroxide solvent and the relative humidity of ambient air. More concentrated solutions of hydroxide result in less water loss, as does higher ambient humidity.¹⁵⁴ For example, experiments conducted at relative humidity levels above 65%, for solutions with a concentration of 7.2 M NaOH or 2 M KOH effectively mitigated evaporative water loss.^{155,156} In contrast, experiments conducted at ambient temperatures over 30°C and at relative humidity levels below 20%, water loss was higher than 20 metric tons of H_2O per ton CO_2 (Figure 3.7).¹⁵⁷

In the case of S-DAC, water is used, but is contained and continuously recycled within closed-loop systems.¹⁵⁸ Under specific operating conditions, S-DAC can also *produce* fresh water as a byproduct of the CO₂ capture. Climeworks' solid sorbent system is an example, yielding approximately 0.8-2 metric tons of water per metric ton of CO₂ captured.¹⁵⁹ Other S-DAC technologies, like the process used by Global Thermostat, use steam condensation for sorbent regeneration.¹⁶⁰ These S-DAC systems are more water intensive, requiring up to 1.6 tons of water per metric ton of CO₂ captured.¹⁶¹



Figure 3.7. Net water consumption per metric ton of CO_2 capture using L-DAC technology, as a function of climate conditions. Reproduced with permission from An et al. (2022).¹⁶² Kern County humidity and temperature highs in the summer and humidity and temperature lows in the winter winter are about 27% and 97°F (36°C), and 57% and 38°F (3°C), respectively,¹⁶³ meaning water consumption in Kern County would likely range from ~4-20 tons of water used per ton CO_2 captured.

 ¹⁵³ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 228. [55]

¹⁵⁴ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 199. [55]

¹⁵⁵ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 199. [55]

¹⁵⁶ Holmes, Keith (2012) <u>Liquid DAC</u>. p. 4395. [36]

¹⁵⁷ An *et al*. (2022) <u>Impact of L-DAC</u>. p. 7. [4]

¹⁵⁸ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 228-230. [55]

¹⁵⁹ Fasihi *et al.* (2019) <u>Techno-economic DAC</u>. [29]

¹⁶⁰ McQueen *et al.* (2021) <u>DAC Review</u>. p. 5. [51]

¹⁶¹ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 230. [55]

¹⁶² An *et al*. (2022) <u>Impact of L-DAC</u>. p. 7. [4]

¹⁶³ WeatherWX.com (no date) Kern County, California Climate Averages. [74]

3.3.2 Other potential impacts

DAC facilities are expected to produce zero or-near zero emissions onsite that could be hazardous to the environment or human health.¹⁶⁴ Hazardous waste is not a significant concern for DAC facilities, as reviewed in Section 3.1.3.2. Wastewater is also not generated in significant amounts in DAC processes, as the only water used is contained within close-loop systems. Solid waste buildup can occur in the CO₂ recovery equipment, as happens in traditional monoethanolamine (MEA) scrubbers that are used for point source carbon capture.¹⁶⁵ Similar environmental regulation and disposal guidelines would need to be followed. Chemicals used in sorbent plants would degrade over time as heat is applied to release captured CO₂, but those degradation products (e.g., ammonia) are expected to be contained within the DAC plant and not released into the environment, and have established regulation and disposal protocols (Section 3.1.3.2).¹⁶⁶

3.4 Economic Impacts

3.4.1 Business Model

There are two primary revenue streams possible for a DAC development: private carbon credits or benefits from federal and state incentives.

Selling carbon credits to the voluntary carbon offset market

DAC developers can either seek private companies to invest in their carbon removal project, allow carbon credits to be purchased to offset their CO₂ emissions, or both. Companies such as Stripe, Shopify, and SwissRe have purchased carbon credits from DAC facilities to offset their CO₂ emissions.¹⁶⁷ Other companies are helping develop capture projects. United Airlines is investing in DAC directly via funding on the 1pointfive and Carbon Engineering project, in line with its commitment to become carbon neutral by 2050.¹⁶⁸ And Microsoft is both purchasing DAC removal carbon credits from Climeworks and, through its Climate Innovation Fund, is investing in the Climeworks Orca facility in Iceland.¹⁶⁹

¹⁶⁴ Lebling *et al.* (2022) <u>Building DAC</u>. [47]

¹⁶⁵ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 231. [55]

¹⁶⁶ Lebling *et al.* (2022) <u>Building DAC</u>. [47]

¹⁶⁷ Clancy (April 13, 2022) <u>Stripe, Shopify, Alphabet, Meta and McKinsey will spend almost \$1</u> <u>billion on carbon removal</u>. [17]

¹⁶⁸ Rucinski (December 10, 2020) <u>United Airlines invests in a carbon-capture project</u>. [63]

¹⁶⁹ Climeworks (July 13, 2022) <u>Climeworks becomes first supplier of long-term, technology-based</u> <u>carbon removal</u>. [19]

Utilizing federal and state incentives

A DAC plant that sequesters captured CO₂ into saline or other geologic formations is also eligible to take advantage of the 45Q tax credit, which, since the adoption of the U.S. Inflation Reduction Act, provides \$180 per ton of CO₂ sequestered via DAC.¹⁷⁰ Moreover, DAC companies are eligible for the California Low Carbon Fuel Standard (LCFS) credit, which credits technologies that reduce transportation-derived greenhouse gas emissions.¹⁷¹ DAC is eligible under the program because it removes CO₂ produced by gaspowered cars and trucks.¹⁷² LCFS credits vary in price based on supply and demand within the credit marketplace, but from January 2018 to December 2022 ranged from \$62 to \$217 per metric ton CO₂.¹⁷³ 45Q and LCFS credits can be "stacked" (i.e. both credits given for one metric ton of carbon removed), such that, given historical LCFS prices, incentive revenue can be expected to be in the range of ~\$242-\$397 per metric ton CO₂.¹⁷⁴ Incentive credits cannot, however, be used in tandem with the voluntary carbon offset marketplace (for a summary of relevant policy and regulations pertaining to all carbon management industries, refer to Section 2 of this report).

3.4.2 Business Costs

Estimates of the current cost of carbon capture for DAC systems are highly variable, ranging in the published literature of the last decade from less than \$100 per metric ton CO₂ captured to more than \$1,000 per metric ton.¹⁷⁵ There are two reasons for the high variability. First, given the newness of the technology, all existing facilities are still in the testing or pilot scale. That means there are no large-scale facilities to directly assess cost, and ongoing research is continuously identifying lower-cost sorbent materials and optimal operating conditions.¹⁷⁶ Second, there are a large number of variables required for any techno-economic assessment of a new industry, and the assumptions used to determine each variable are different across different publications. In general, costs are assessed and reported through a 'Lifetime Cost Assessment' (LCA) model, or the summative cost per metric ton CO₂ of the capital costs (the prices of the equipment that make up the DAC facility), operational costs (including maintenance and labor), and energy costs (heat + electricity), normalized over the lifetime of the plant.^{177,178} In some cases, costs related to

¹⁷⁰ Carbon Capture Coalition (2022) <u>The Inflation Reduction Act (IRA) of 2022</u>. p. 2. [12]

¹⁷¹ CARB (no date) <u>About - Low Carbon Fuel Standard</u>. [10]

¹⁷² CARB (no date) <u>Low Carbon Fuel Standard Basics</u>. p. 11. [11]

¹⁷³ Neste (no date) <u>California Low Carbon Fuel Standard Credit price</u>. [57]

¹⁷⁴ Nagabhushan (November 10, 2018) <u>California's CO2 reduction program opens doors to CCS</u>.[54]

¹⁷⁵ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 190. [55]

¹⁷⁶ Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 9. [59]

¹⁷⁷ Fasihi *et al.* (2019) <u>Techno-economic DAC</u>. p. 965. [29]

¹⁷⁸ Carbonplan (no date) <u>DAC cost calculator</u>. [14]

the transport and permanent storage of captured CO_2 are also included (these are not accounted for here, but can be explored further in Section 9). Typically, the most significant drivers of cost uncertainty are the sorbent used and the source and cost of electricity.¹⁷⁹

A summary of recent published estimates for DAC costs are presented in Tables 3.3 and 3.4, and a breakdown of how capital, operational and energy costs are estimated is detailed in the following sections. Current levelized costs for net CO₂ removed for the solid sorbent–based approach (S-DAC) range from \$89 to \$600/tCO₂, with the greatest variable being the type of adsorbent and energy source.¹⁸⁰ The cost range for the solvent-based approach (L-DAC) is \$156 to \$506/tCO₂, with the strongest control on price being the source of thermal energy.¹⁸¹ Experts predict that these costs could fall significantly within the next decade, to ~\$100-200/tCO₂, and potentially as low as \$60/tCO₂ by 2040 or 2050, with the assumption that the technology will continue to grow and there will be cost reductions due to economies of scale (see Table 3.5, 'Future costs').^{182,183}

3.4.2.1 Cost to build (upfront costs)

Capital cost consists mostly of the construction expenses needed to establish the facility from scratch, including the procuring equipment and construction materials and the cost of labor. For S-DAC systems, the equipment components that comprise capital expenditures (CapEx) are the adsorbent material (>90% of total capital costs), and the blower, vacuum pump, condenser and contactor.¹⁸⁴ Adsorbent materials range enormously in cost and efficacy, drive the greatest uncertainty in cost for S-DAC systems, and have the greatest potential to drop in cost due to further innovation.¹⁸⁵ L-DAC facilities are more capital-intensive, with necessary equipment including the contactor array (~30% of CapEx), the slacker, causticizer and clarificator (how the liquid solvent is produced and regenerated, ~20% of CapEx), the oxy-fired calciner (how the CO₂ is released and the lime regenerated, ~40% of CapEx) and the air separation unit and condenser (provides oxygen to the calciner, ~10% of CapEx).^{186,187}

¹⁸⁷ Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 10. [59]

¹⁷⁹ Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 11. [59]

¹⁸⁰ Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 7-8. [59]

¹⁸¹ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 222. [55]

¹⁸² Ozkan *et al.* (2022) <u>Current DAC Status</u>. p. 10. [59]

¹⁸³ Sutherland, B. R. (2019) Pricing CO₂ Direct Air Capture. p. 1572. [68]

¹⁸⁴ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 221. [55]

¹⁸⁵ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. <u>Research Agenda</u>. p. 219. [55]

¹⁸⁶ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 206. [55]

For an average L-DAC system with a capacity of 1 million metric tons per year CO_2 removal, estimated upfront capital costs range from \$675 million to \$1.255 billion, if the building of clean energy infrastructure is not included (Table 4). Existing pilot L-DAC facilities are run with natural gas, which releases CO_2 that must also be captured. A 2019 study from the National Academy of Sciences, Engineering and Medicine (NASEM) included a technoeconomic analysis of co-locating a PV solar + battery system that supplied electricity directly to a putative million ton L-DAC facility and to an electrolyzer, which produces green hydrogen (H₂) via electrolysis (see Section 6) that can be combusted to drive the calciner operation. The added capital expense of these components leads to a net cost to build of \$1,921-3,045 million for a 1 million metric ton CO_2 capture facility.¹⁸⁸

An average S-DAC system with a 1 million metric ton CO₂ capture capacity is estimated to cost \$630-1,700 million to build (Table 3.3).¹⁸⁹ This does not include the cost of building any energy-supplying infrastructure.

Annualizing the total capital costs to a per ton CO_2 cost allows us to better assess total costs of varying carbon management industries by making it possible to calculate the collective cost of capital, operations and energy. Annualizing costs requires assumptions about the lifetime of the plant (typically estimated to be in operation for 20-30 years), and the weighted average cost of capital (WACC), or discount rate, which are used in combination to determine the capital recovery factor (also called the fixed charge rate or annuity factor) - an assessment of the combined cost of equity and debt over the lifetime of the facility.

The capital recovery factor (crf) is determined based on the following equation, where N = the facility lifetime in years: ^{190,191}

$$crf = (WACC \cdot (1 + WACC)^{N})/((1 + WACC)^{N} - 1).$$
 (E3.2)

Levelized capital costs, in turn can then be calculated as:

 $CapEx (\$/ton CO_2) = (Cost to Build Facility/Capture Capacity of Facility) \cdot crf$ (E3.3)

In Tables 3.3-3.5, capital recovery factors range from 7.5-12.5%. This leads to a levelized CapEx rate (or annualized rate) of \$76-205 per ton CO_2 for S-DAC, and \$52-365 per ton CO_2 for L-DAC.

¹⁸⁸ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. [55]

¹⁸⁹ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. 55]

¹⁹⁰ Fasihi *et al.* (2019) <u>Techno-economic DAC</u>. p. 958. [29]

¹⁹¹ Carbonplan (no date) <u>DAC cost calculator</u>. [14]

Table 3.3. Estimated costs of S-DAC per metric ton CO₂ captured.

S-DAC								
Cost to build a facility capturing 1 million metric tons CO ₂ annually								
\$630-1700 mi	Recovery Factor = 12%)							
~\$820 million		Fasihi <i>et al.</i> (2019 (Facility lifetime	9) <u>Techno-econc</u> = 20 yrs, Capital	emic DAC. Recovery Factor = 9.4%)				
CapEx (\$/ton CO₂)	OpEx+Energy (\$/ton CO₂)ª	Energy Source	Energy LCA Cost Source (\$/ton CO₂) ^b Reference					
\$135	\$93	Waste heat	\$228	Baker et al. (2020) Getting to Neutral.				
\$191-196	\$75-114	Geothermal	\$266-310	Baker et al. (2020) Getting to Neutral.				
\$76-205	\$11-22	Not included	Not included \$87-228° NASEM (2019) Research Agenda.					
		Waste heat	\$600 ^d	Ozkan <i>et al</i> . (2022) <u>Current DAC Status</u> .				
		Geothermal	\$205	McQueen et al. (2021) DAC Review.				
		Natural gas	\$223	McQueen et al. (2021) DAC Review.				
\$77	\$57-96	Grid electricity ± waste heat	\$134-174°	Fasihi <i>et al.</i> (2019) <u>Techno-economic DAC</u>				
			\$246	MEAN Levelized Cost				

a. Energy costs are highly variable due to market fluctuations. The values here reflect energy cost estimates from the sited references at time of publication.

- b. Some publications report only levelized cost analysis, without distinguishing capital and operational costs.
- c. Some computational inconsistencies are due to rounding.
- d. Reported operating cost of Climeworks pilot facility in Switzerland.
- e. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.¹⁹²

¹⁹² IRS (no date) <u>Yearly average currency exchange rates</u>. [38]

Table 3.4. Estimated costs of L-DAC per metric ton CO₂ captured.

L-DAC								
Cost to build a facility capturing 1 million metric tons CO ₂ annually								
\$694-1,146 m	illion	Keith et al. (2018 (Facility lifetime) <u>LDAC</u> . ¹⁹³ = 25 yrs, Capital	Recovery Factor = 7.5-12.5%)				
\$675-1,255 m	illion	NASEM (2019) <u>R</u> (Facility lifetime	<mark>esearch Agenda</mark> = 30 yrs, Capital	Recovery Factor = 12%, Natural gas)				
\$1,921-3,045	-3,045 million NASEM (2019) <u>Research Agenda</u> . (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%, H ₂ , Solar + batter							
~\$910 million		Fasihi <i>et al.</i> (2019) <u>Techno-economic DAC</u> . (Facility lifetime = 25 yrs, Capital Recovery Factor = 9.4%)						
CapEx (\$/ton CO ₂)	OpEx+Energy (\$/ton CO₂)ª	Energy Source	LCA Cost (\$/ton CO ₂) ^b	Reference				
\$52-87	\$61-76	Grid electricity + natural gas	\$113-163	Keith et al. (2018) <u>LDAC</u> .				
\$56-143	\$70-89	Natural gas	\$126-232	Keith et al. (2018) <u>LDAC</u> .				
\$81-151	\$66-113	Natural gas	\$199-357°	NASEM (2019) Research Agenda.				
\$230-365	\$87-136	Green H ₂ + \$317-501 NASEM (2019) <u>Research Agenda</u> .						
		Natural gas	Natural gas \$94-232 ^d Ozkan <i>et al.</i> (2022) Current DAC Status.					
\$87	\$121	Grid electricity	\$208 ^e	Fasihi <i>et al.</i> (2019) <u>Techno-economic DAC</u>				
			\$231	MEAN Levelized Cost				

a. Energy costs are highly variable due to market fluctuations. The values here reflect energy cost estimates from the sited references at time of publication.

b. Some publications report only levelized cost analysis, without distinguishing capital and operational costs.

- c. LCA is higher than CapEx+OpEx+Energy because it incorporates the cost factor resulting from emitting CO₂ from the natural gas energy source (i.e. every ton CO₂ captured by the process is partially offset by CO₂ emitted, and thus the *net* cost per ton CO₂ removed is greater).
- d. Reported operating cost of Carbon Engineering pilot facility in Canada.
- e. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.¹⁹⁴

¹⁹³ Keith *et al.* (2018) <u>A process for capturing CO₂ from the atmosphere</u>. p. 1581. [42]

¹⁹⁴ IRS (no date) <u>Yearly average currency exchange rates</u>. [38]

Anticipated Future LCA Cost (\$/ton CO₂)						
2035	\$100-200	Ozkan et al. (2022) <u>Current DAC Status</u>				
2050	\$60	Ozkan et al. (2022) <u>Current DAC Status</u>				
2050	\$60-80 ^b	Ozkan et al. (2022) <u>Current DAC Status</u>				

Table 3.5. Anticipated change in cost of DAC^a per metric ton CO₂ captured.

a. Includes both S-DAC and L-DAC.

b. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.¹⁹⁵

3.4.2.2 Operational costs

Operational costs involve the maintenance and labor for the various equipment pieces and the facility. NASEM (2019) provided a detailed breakdown of operational components for L-DAC facilities and Baker et al. (2020) does the same for S-DAC. Both are summarized in Table 3.6.

Table 3.6. Operational expenses for a 1 million ton CO₂ capture DAC facility.

L-DAC - from NASEM (2019) ¹⁹⁶							
Maintenance	\$18-33 million/yr ^a	Estimated as ~3% of total capital requirement					
Labor	\$6-10 million/yr	Estimated as 30% of maintenance cost					
Makeup and waste removal	\$5-7 million/yr	Includes replacement of hydroxide solution (\geq \$500/ton KOH), lime (\geq \$250/t Ca(OH) ₂), water (\geq \$0.30/t H ₂ O), waste disposal (\geq \$260/t)					
Energy Supply	See Section 2.4.2.3						
S-DAC - Baker et	S-DAC - Baker et al. (2020) Getting to Neutral. ¹⁹⁷						
Maintenance	~\$22 million/yr	~10-17% of total capital requirement (from Baker et al., Fig. 41)					
Labor	~\$7 million/yr	~30% of maintenance cost (from Baker et al., Fig. 41)					
Energy Supply	See Section 2.4.2.3						

a. For a megaton facility, this is equivalent to \$18-33/tCO₂, and so forth for each cost estimate.

3.4.2.3 Energy costs

A critical variable, and perhaps the most poorly constrained for DAC, is the cost of energy. This is because there is uncertainty about the amount of energy necessary (1.5-3.0 MWh/tCO_2 and 0.9-1.6 MWh/tCO_2 , for L-DAC and S-DAC, respectively, as shown in Table 1),

¹⁹⁵ IRS (no date) <u>Yearly average currency exchange rates</u>. [38]

¹⁹⁶ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 207. [55]

¹⁹⁷ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 86. [6]

how that energy could be sourced (published estimates consider a coal, natural gas, natural gas with CCS, solar, wind, nuclear, geothermal, waste heat or a combination of these), and then, for each of these, their local costs, given regional variability with capacity factor (particularly for solar and wind), and resource accessibility.

Existing pilot DAC facilities use natural gas (Carbon Engineering, L-DAC), geothermal heat (Climeworks Orca Facility, S-DAC) or waste heat (Climeworks pilot facility, S-DAC) as their energy source. With natural gas, or any fossil fuel, either the CO_2 emissions resulting from energy generation must be also captured - adding to the cost of the energy source, or the *net* CO_2 capture capacity of the facility decreases.¹⁹⁸ This is modeled by use of a cost factor, whereby:

```
Cost factor = 1/1-x
```

(E3.4)

And x is the amount of CO_2 emitted by the facility per ton of CO_2 captured. If x is near or greater than 1, and thus the cost factor approaches infinity, the facility can be considered uneconomical. If coal is the fuel source, the *net* capture capacity of a million ton facility drops to 0-0.11 million tons CO_2 per year (MtCO₂/yr), making it effectively useless. A natural gas facility has a net capacity of 0.11-0.42 MtCO₂/yr, and natural gas with CCS (as done by Carbon Engineering) has a net capacity of 0.49-0.99 MtCO₂/yr.¹⁹⁹ All non-fossil fuel sourced energy supplies (geothermal, waste heat, nuclear, green hydrogen, wind, solar) have a cost factor that approaches 1, and a net capacity that approaches its intended capacity.

To summarize the range of possibilities, Table 3.7 lists all energy sources considered in the references cited within Tables 3.3 and 3.4, and/or considered in this analysis. Note that for operations that use fossil fuels without carbon capture as their energy source, net capture capacity will be less than intended capacity.

L-DAC										
Energy Type		Energy Need (MWh/tCO ₂)		Levelized E (\$/M)	Total Energy					
Thermal	Electric	Thermal	Electric	Thermal	Cost (\$/tCO ₂)					
Natural gas (I	NG)	2.1-3.0	0.2-0.5	\$19-74		\$45-257				
NG + CCS (o>	(y-combustion)	2.1-3.0	0.2-0.5	\$50		\$117-174				
NG+CCS (oxy-comb.)	Solar PV + battery (elec.)	2.1-3.0	0.2-0.5	\$50	\$28-37 + \$15	\$151-231				
Green H₂	Solar PV + battery (elec.)	2.1-3.0	0.2-0.5	\$48-108	\$28-37 + \$15	\$109-350				

Table 3.7. Energy expenses for	а	1	million ton	CO_2	capture	DAC	facility.
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¹⁹⁸ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 194. [55]

¹⁹⁹ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 203. [55]

Envisioning a Carbon Management Business Park

S-DAC									
Energy Type		Energy Need (MWh/tCO ₂)		Levelized Energy Cost (\$/MWh) ^{a,b}		Total Energy			
The	rmal	Electric	Thermal	Electric	Thermal	Cost (\$/tCO ₂)			
Grid ele	ectricity	0.9-1.3	0.15-0.3	\$16	9 ²⁰⁰	\$185-278			
Wast	e heat	0.9-1.3	0.15-0.3	\$0-29 ²⁰¹		\$0-48			
Waste heat	Grid	0.9-1.3	0.15-0.3	\$0-29 \$169		\$26-91			
Geoth	iermal	0.9-1.3	0.15-0.3	\$56-93		\$61-153			
Natural	gas (NG)	0.9-1.3	0.15-0.3	\$45-74 ²⁰²		\$49-122			
NG + CCS (ox	y-combustion)	0.9-1.3	0.15-0.3	\$50		\$55-82			
Green H₂		0.9-1.3	0.15-0.3	\$48-108		\$50-173			
Solar PV + b	attery (elec.)	0.9-1.3	0.15-0.3	\$28-37	7 + \$15	\$47-86			

a. Cost estimates from: 1) Levelized cost of energy analysis - Version 15.0. Lazard. Published online, October 2021. 2) Moch, J.M., et al. <u>Carbon Capture, Utilization, and Storage: Technologies and Costs</u> in the U.S. Context. Harvard Kennedy School Belfer Center for Science and International Affairs. Published online January 2022. 3) NASEM (2019) <u>Research Agenda</u>, p. 211. Energy costs are subject to significant market fluctuations. 4. This study (Section 4)

b. Energy costs are subject to significant market fluctuations.

3.4.3 Regional benefits

3.4.3.1 Land availability and renewable energy potential

While the DAC technology itself represents one of the most efficient carbon management techniques available in terms of CO_2 -capture potential per acre, the enormous energy requirements of the technology will require a significant land footprint if energy is supplied entirely by renewable energy. Thus DAC facilities aiming to run entirely on fossil-free sources would benefit from locations with optimal solar potential and an abundance of available land (please see Section 3.1.1.2 for detailed analysis).

3.4.3.2 Proximity to optimal underground CO2 storage

For any carbon management technology, levelized cost per ton of CO₂ captured increases significantly as a function of distance from an underground storage site.²⁰³ Being located in

²⁰⁰ EIA (no date) <u>Average price of electricity monthly</u>. [26]

²⁰¹ Bertrand *et al.* (2019) <u>Regional waste heat valorisation</u>. p. 454-468. [7]

²⁰² Lazard (October 2021) <u>Lazard's levelized cost of energy analysis</u>. [46]

 ²⁰³ Larson *et al.* (2021) <u>Net-Zero America: Potential Pathways, Infrastructure, and Impacts</u>. p. 221-222.
 [43]
close proximity with established Class VI EPA wells should reduce operational costs, decrease planning, permitting and construction time for extensive pipeline infrastructure, and increase the business viability of a DAC plant.

3.4.3.3 Co-location advantages

L-DAC requires water and a high-temperature heat source to operate. As such, it would benefit from co-location with energy storage companies designed to provide industrial heat from clean energy—for example, green or blue hydrogen (Section 6) or heat batteries (Section 7), and potentially, water generating industries, such as S-DAC (Section 3.3.1) or some forms of BiCRS technologies (Section 4).

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4. Biomass CO₂ Removal and Storage

TECHNOLOGY AT A GLANCE:

- 2.5 million metric tons CO₂ captured annually by other projects, globally¹
- Estimated cost per metric ton CO₂ captured: \$30-400 USD/ton CO₂
- Projected cost per metric ton CO₂ captured at scale: \$61-288 USD/ton CO₂
- ~180-400 acres of land use required per million metric tons of CO₂ captured
- Key advantages of this technology in Kern County: around 470,000 tons of agricultural waste produced annually in Kern Co., close proximity to consumers of low-carbon fuels (including synthetic fuels and green hydrogen) due to California's Low Carbon Fuel Standard (LCFS).
- Key concerns for this technology in Kern County: Differences in potential air impacts from gasification/pyrolysis and combustion of biomass. Changes in biomass waste availability in the future due to climate change. Variable water requirements.

4.1 Technology Summary

Biomass Carbon Removal and Storage (BiCRS) encompasses a range of technologies that convert biomass into smaller molecular components, allowing CO₂ to be separated and sequestered, either through underground storage or in long-lived applications.² BiCRS is a

¹ Values in this section are summarized from the suite of references cited herein and are explained in further detail in each subsequent section.

² NETL (no date) <u>Carbon Dioxide Removal Program</u>. [64]

relatively new category of carbon management technologies,³ and is an umbrella term for any technology making use of biomass for the purposes of carbon capture, including Bioenergy with Carbon Capture and Storage (BECCS), one of the longest-established carbon management industries.⁴ BECCS is a distinct subcategory of BiCRS because it has a markedly different end goal, despite using the same technological processes. While the rest of BiCRS technologies prioritize CO₂ removal and storage as the primary technological aim, the focus of BECCS is fuel and energy production from biomass, and carbon capture and storage (CCS) represents an optional industrial component that neutralizes the carbon emissions of the primary commodity of power generation.

4.1.1 Description

BiCRS takes advantage of a natural mechanism of carbon dioxide removal: the storage of CO_2 in vegetation via photosynthesis. Rather than allowing stored CO_2 to return to the atmosphere as occurs when plants, trees and other organic matter die and decompose, these resources can be collected and chemically modified to produce clean CO_2 for underground storage \pm biofuels. Biomass can be sourced from agricultural, forest, industrial or municipal waste, or from dedicated crops, forestry, or cultivated algae.⁵ Generally, waste biomass is the preferred source of BiCRS feedstock because there are fewer competing uses (as in forestry and agriculture), and it typically costs less than biomass sources that require dedicated cultivation (like agriculture or algae).

There are a variety of processes used to convert biomass into CO_2 + other (potentially useful) organic compounds, which are generally divided into categories: biochemical and thermochemical conversion.⁶ Biochemical conversion involves using living microorganisms — typically yeast or bacteria — to convert biomass into biofuels, and the most commonly used and simplest biomass-to-energy process in the U.S. is biochemical conversion of corn to ethanol via fermentation.⁷ In fermentation, biomass feedstock is pretreated with an acid or base solution to break down biomass cell material into simple sugars.⁸ Yeast or bacteria is added to drive fermentation reactions that produce ethanol + CO_2 + residue materials (including water, solvents and residual solids), which are then separated from each other for various uses or sequestration.⁹

A simplified version of the biomass conversion reaction: ¹⁰

 $C_6H_{12}O_6 \text{ (glucose)} \rightarrow 2C_2H_5OH \text{ (ethanol)} + 2CO_2 \text{ (carbon dioxide)}$

(R4.1)

³ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. v. [80]

⁴ NETL (no date) <u>Carbon Dioxide Removal Program</u>. [64]

⁵ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 14-15. [80]

⁶ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 27-29. [80]

⁷ Sanchez *et al.* (2018) <u>Near-term deployment of CCS from biorefineries</u>. p. 4875. [79]

⁸ EERE (no date) <u>Biochemical conversion</u>. p. 2. [70]

⁹ EERE (no date) <u>Biochemical conversion</u>. p. 2. [70]

¹⁰ ETIP Bioenergy (no date) <u>Ethanol fact sheet</u>. [31]

Other biomass conversion processes add to or amend this process in order to utilize more complex plant structures, like agricultural residues (e.g. straw, corn stover, nut shells, fruit pits) or other lignocellulosic raw materials (e.g. wood chips, waste from forest management).¹¹ In low temperature deconstruction (also a form of biochemical conversion), enzymes or chemicals are used to break down the more starchy or woody materials into simple sugars in a process called hydrolysis (Figure 4.1).¹² High-temperature deconstruction comprises all *thermochemical* forms of biomass conversion, with the three primary methods being pyrolysis, gasification and hydrothermal liquefaction. Each of these methods use extreme heat and pressure to break down the biomass feedstocks into a suite of solid, liquid and gaseous components.

During pyrolysis, biomass is rapidly heated in an oxygen-free environment to temperatures of 500-700°C to produce gasses and a solid residue (biochar).¹³ The biochar is removed, and the gasses are cooled, causing some of the vapor to condense into a liquid "bio-crude" oil. The remaining gas, called syngas (a combination of CO_2 , CO, H_2 , and light hydrocarbons) can be further distilled to separate the CO_2 from the combustible gasses, which can be used to provide heat for the reaction.¹⁴



Figure 4.1. Summary of the potential feedstocks, processes, and products of biomass conversion. Adapted from Sandalow *et al.* (2021).¹⁵

¹¹ ETIP Bioenergy (no date) <u>Biochemical value chains</u>. [30]

¹² EERE (no date) <u>Biofuel Basics</u>. [71]

¹³ EERE (no date) <u>Biofuel Basics</u>. [71]

¹⁴ ARS (no date) <u>What is pyrolysis?</u> [2]

¹⁵ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 28. [80]

Gasification occurs under even higher temperature conditions, above 700°C, and in the presence of some oxygen, but the reaction is controlled so that – like pyrolysis – combustion does not take place.¹⁶ Instead, the biomass is converted into CO, H₂ and CO₂.¹⁷ In a second step called a water-gas shift reaction, the carbon monoxide is reacted with water to form more hydrogen gas and carbon dioxide: $CO + H_2O \rightarrow CO_2 + H_2$.¹⁸ The H₂ gas can then be sold as hydrogen fuel, known as green hydrogen.

Hydrothermal liquefaction is the preferred process when using wet feedstocks like algae¹⁹ or municipal solid waste.²⁰ Thermal conversion takes place under moderate temperatures (200-300°C) and elevated pressures to form liquid bio-crude oil and biochar.

Finally, biomass can be directly combusted to create steam or heat to be used as a direct source of energy. These types of bioenergy power plants can be fitted with post-combustion carbon capture technology that scrubs CO_2 from gaseous byproducts to form a bioenergy with carbon capture and storage (BECCS) power station.²¹ CO₂ capture rates can be as high as 90%²² and it can be retrofitted onto existing power stations.

Post-capture combustion works similarly to point-source capture. An advantage of the technology is that it could easily be retrofitted to existing power plants²³ and is now considered ready for massive-scale deployment.²⁴ Amine absorption technology is the most common carbon dioxide binding chemical to be used in CCS, but other chemicals such as hot potassium carbonate (HPC) could be viable as well.²⁵

Other capture technologies, such as oxy-fuel or pre-combustion technologies, are either relatively untested or inefficient.²⁶ Oxy-fuel combustion, as the name implies relies on combustion (rather than pyrolysis or gasification) in the presence of a pure or mostly-oxygen gas stream, rather than standard air.²⁷ The process relies on three primary components: an air separation unit to generate oxygen stream, an oxy-combustion boiler for the combustion itself, and then filtering the flue gas to remove pollutants and compress CO_2 for storage or use.²⁸ Compared to traditional combustion, oxy-fuel systems produce

¹⁶ EERE (no date) <u>Hydrogen Production: Biomass Gasification</u>. [72]

¹⁷ EERE (no date) <u>Hydrogen Production: Biomass Gasification</u>. [72]

¹⁸ EERE (no date) <u>Hydrogen Production: Biomass Gasification</u>. [72]

¹⁹ EERE (no date) <u>Biofuel Basics</u>. [71]

²⁰ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 28. [80]

²¹ Donnison *et al.* (2020) <u>BECCS win-wins</u>. [21]

²² Adams, Mac Dowell (2016) <u>Off-design point modeling of a 420 MW CCGT power plant</u> [1], as cited in Donnison *et al.* (2020) <u>BECCS win-wins</u>. [21]

²³ Mumford *et al.* (2015) <u>Review of solvent based carbon-dioxide capture technologies</u>. [60]

²⁴ Bui *et al.* (2018) Carbon capture and storage (CCS): the way forward. [12]

²⁵ Gustafsson *et al.* (2021) <u>BECCS energy penalty</u>. [43]

²⁶ Donnison *et al.* (2020) <u>BECCS win-wins</u>. [21]

²⁷ NETL (no date) <u>Oxy-combustion</u>. [65]

²⁸ NETL (no date) <u>Oxy-combustion</u>. [65]

about one-fourth the volume of flue gas emissions, making it easier to capture pollutants (including SO_x, NO_x, particulates, and mercury) from the gas, which is primarily composed of CO₂.²⁹ Furthermore, oxy-fuel pollution can reduce the amount of pollutants formed, such as NO_x.³⁰ This makes it far easier to purify and capture the CO₂ emissions to abate them.³¹ However, challenges—high capital costs, energy usage, and difficulty with oxygen separation—have made it difficult for oxy-fuel combustion systems to be cost-competitive.³²

4.1.2 State of Development

The key technological elements in BiCRS processes (biomass drying and pelletizing, gasification, anaerobic digestion, biomass boilers, CO₂ capture and separation, geologic storage and monitoring) are mature and commercially available at scale today in various industries, but have been combined for the explicit purpose of biomass carbon removal and storage in only a few instances.³³ 16 facilities are in operation at commercial-scale, though few are exercising their maximum capacity to store the carbon they are extracting from biomass.³⁴ However, several commercial-scale operations that emphasize carbon management are in the planning, development or pilot phase.^{35,36}

4.1.2.1 Commercial Scale Examples

Illinois Basin Decatur Project, Decatur, Illinois

This five-year pilot project is a collaboration of the Illinois State Geological Society (ISGS), the Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and other subcontractors.³⁷ CO₂ is sourced as a byproduct of ADM's corn ethanol facility.³⁸ The pilot plant successfully injected approximately 1 million metric tons of CO₂ derived from biofuel production into a saline reservoir from November 2011 to November 2014. The success of this pilot led to a second commercial scale project, called IL-CCS project, which began operation in 2016.³⁹

The IL-CCS project never met its stated aims of annually injecting one million tons of the carbon dioxide byproduct of the ethanol production process, to a depth of more than 7,000

²⁹ NETL (no date) <u>Oxy-combustion</u>. [65]

³⁰ NETL (no date) Oxy-combustion. [65]

³¹ NETL (no date) <u>Oxy-combustion</u>. [65]

³² NETL (no date) Oxy-combustion. [65]

³³ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 51. [80]

³⁴ EFI (2022) <u>Surveying the BECCS Landscape</u>. p. 3-4. [28]

³⁵ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 51. [80]

³⁶ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. p. 149. [62]

³⁷ Finley (2014) <u>An overview of the Illinois Basin – Decatur Project</u>. [33]

³⁸ Voegele (December 19, 2016) <u>EC approves state aid for third Drax unit conversion</u>. [93]

³⁹ Ahlberg (February 20, 2012) Innovation in CCS. [3]

feet in the Mt. Simon Sandstone saline aquifer of the Illinois basin.⁴⁰ According to the EPA, the plant's annual sequestered CO₂ emissions as of 2021 are less than 500 thousand tons,⁴¹ which is significantly less than what was projected.⁴² ADM receives tax credits of \$20 per ton of carbon sequestered, and as of 2020, has received \$281 million in total federal funding for both the Decatur and IL-CCS projects.^{43,44}

Drax Power Stations, North Yorkshire, UK

The Drax Power Station is a biomass-to-power plant working to transition into a bioenergy + carbon capture and storage (BECCS) facility as part of the Zero Carbon Humber industrial cluster in northern England.⁴⁵ The project is supported by the UK Government, with the stated goal of being the first net zero carbon industrial cluster in the nation, with Drax aiming to be carbon-negative by 2030.⁴⁶

Drax converted four out of six existing 645 MW coal power units to generate over 2.5 GW of electricity from biomass combustion.⁴⁷ They are in the process of piloting carbon capture and storage technologies to pair with the biomass facility, but cannot fully deploy CCS until transportation and storage infrastructure has been established and there is a policy framework or carbon marketplace in place that allows revenue generation for companies that produce negative emissions.⁴⁸ Drax uses wood pellets as the main feedstock of their power plant, primarily sourced from their factories in North America,⁴⁹ and estimates they will eventually be able to capture up to 8 million metric tons of carbon dioxide each year, starting with a first BECCS unit operational by 2027.⁵⁰

Kore Infrastructure, Los Angeles, California

Kore Infrastructure has designed a proprietary pyrolyzer unit that can be added to existing installations.⁵¹ Kore's process is a slow pyrolysis process operating at temperatures above 1000°F without oxygen, creating a biogas and carbon-rich biochar as products.⁵² Most of the energy requirements are met using the biogas generated by the pyrolysis process, and

⁴⁰ Ahlberg (February 20, 2012) <u>Innovation in CCS</u>. [3]

⁴¹ GHG Data – EPA (no date) <u>Archer Daniels Midland Co</u>. [40]

⁴² Hettinger (November 19, 2020) <u>ADM's carbon capture program</u>. [46]

 ⁴³ USASpending (no date, information through September 30, 2022) <u>FAIN DEFE0001547 Grant</u>
 <u>Summary</u>. [90]

⁴⁴ Hettinger (November 19, 2020) <u>ADM's carbon capture program</u>. [46]

⁴⁵ Drax (no date) <u>BECCS and negative emissions</u>. [23]

⁴⁶ Harris (2021) <u>Deployment of bio-CCS: Drax</u>. [45]

⁴⁷ Harris (2021) <u>Deployment of bio-CCS: Drax</u>. p. Summary-6. [45]

⁴⁸ Harris (2021) <u>Deployment of bio-CCS: Drax</u>. p. 6-7. [45]

⁴⁹ Drax (no date) <u>Our History</u>. [26]

⁵⁰ Frontier Economics (2021) <u>Supporting BECCS</u>. p. 4. [34]

⁵¹ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵² Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

the overall reaction generates more energy output than it consumes.⁵³ Once created, the generated biogas can be upgraded into renewable natural gas (RNG) or hydrogen.⁵⁴ Their business model is designed to meet multiple needs, either by setting up their system — along with biomass procurement and operation and maintenance assistance — for another company's onsite location, or by offering waste or energy services, by serving as waste disposal or as a source of natural gas, hydrogen, biogas, or biochar.⁵⁵ Currently, their largest operating facility is located in Los Angeles and serves SoCalGas, processing 24 tons of feedstock daily.⁵⁶ The SoCalGas facility opened in August 2021.⁵⁷

Their process is rated at technology readiness level 7,⁵⁸ meaning it had a successful operating pilot at commercial-scale.⁵⁹ Given the approval of strict air quality districts in California and their eligibility for LCFS credits for biogas, RNG, or hydrogen gas,⁶⁰ it can be reasonably expected that Kore expects their operations to be scalable in the California market.

4.1.2.2 Development Phase Examples

Clean Energy Systems, multiple sites in California

Rather than building facilities from scratch, Clean Energy Systems (hereafter CES) has been purchasing old biomass power plants throughout California and retrofitting them to bring them back online as BiCRS facilities.⁶¹ Within Kern County, CES has been running a biomass plant at Kimberlina as a 'proof of concept' facility,⁶² a 40-acre site for R&D, sub-commercial, and commercial activities and currently the world's largest oxy-fuel combustion plant.⁶³ Their largest project currently in permitting is the Mendota BiCRS Project.⁶⁴ At Mendota, CES plans to set up a 20-year commercial facility that will convert biomass into carbon-negative grid electricity using oxy-fuel combustion.⁶⁵

CES's oxy-fuel combustion system works by burning fuels (including, but not limited to, natural gas, gas generated on-site, synfuel, and landfill or bio-digester gas) alongside

⁵³ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵⁴ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵⁵ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵⁶ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵⁷ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵⁸ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁵⁹ GAO (2020) <u>Technology Readiness Assessment Guide</u>. p. 11. [42]

⁶⁰ Kore Infrastructure (no date) <u>A Fully Integrated System</u>. [55]

⁶¹ Industry representative, personal communication, October 4, 2022.

⁶² Industry representative, personal communication, October 4, 2022.

⁶³ Clean Energy Systems (no date) <u>Site Locations</u>. [19]

⁶⁴ Clean Energy Systems (no date) Mendota BiCRS. [17]

⁶⁵ Clean Energy Systems (no date) <u>Mendota BiCRS</u>. [17]

oxygen gas and water "at near-stoichiometric conditions."^{66*} Crucially, the water in question can be recycled or even untreated water without inhibiting the oxy-fuel combustion reaction.⁶⁷ The primary products of the reaction are CO₂ and steam, with CES reporting carbon capture rates of 100% for the produced CO₂.⁶⁸ However, how CES plans to store or use their captured CO₂ seems unclear. The EPA reports their Class VI well application was withdrawn,⁶⁹ and their website's suggestion of using captured CO₂ for enhanced oil recovery (EOR)⁷⁰ would violate language in California's SB 1314.⁷¹

Mote, Los Angeles, California

Mote, a Culver City-based cleantech startup, is planning to build a \$100 million biomass to hydrogen energy plant with carbon sequestration on 5 acres of unincorporated land in Kern County, pending securing financing, government approval and permits.⁷² The plant will extract carbon dioxide and hydrogen via gasification from wood waste from farms, forestry, and other resources.⁷³ The hydrogen gas will be sold to hydrogen fuel station operators, and the CO₂ will be sequestered into deep underground saline aquifers or retired oil wells.⁷⁴ Mote's first facility expects to produce approximately 60,000 kg of carbonnegative hydrogen (green hydrogen) per day, which translates to 450,000 tons of CO₂ captured per year from biomass and available for permanent sequestration.⁷⁵

Mote's business model will provide cost-competitive green hydrogen and carbon removal credits to the wide economy and take advantage of rebates from the federal tax credit for CCS projects (45Q) as well as California's Low Carbon Fuel Standard (LCFS).⁷⁶ In May 2022, Mote announced that they had secured commitments for over 450 thousand tons of feedstock for their production.⁷⁷ Working with Fluor, an industry leading engineering, procurement and construction (EPC) firm, to execute the Front-End Loading 2 (FEL-2), Mote plans to begin construction in 2023 and be fully operational by 2025.⁷⁸

⁷⁶ Mote Hydrogen (no date) <u>Mote</u>. [59]

⁶⁶ Clean Energy Systems (no date) <u>Oxy-Fuel Combustion</u>. [18]

^{*} Under stoichiometric conditions, the proportion of air (in this case, oxygen) to fuel is such that all of the combustible material will be completely combusted, leaving no oxygen remaining.

⁶⁷ Clean Energy Systems (no date) <u>Oxy-Fuel Combustion</u>. [18]

⁶⁸ Clean Energy Systems (no date) <u>Oxy-Fuel Combustion</u>. [18]

⁶⁹ EPA (April 24, 2023) <u>Class VI Wells Permitted by EPA</u>. [29]

⁷⁰ Clean Energy Systems (no date) <u>Oxy-Fuel Combustion</u>. [18]

⁷¹ IEA (November 4, 2022) <u>SB 1314</u>. [47]

⁷² Fine (January 3, 2022) <u>Mote unveils plans for carbon capture plant</u>. [32]

⁷³ Temple (February 15, 2022) <u>Fuel plant will use agricultural waste to combat climate change</u>. [87]

⁷⁴ Temple (February 15, 2022) <u>Fuel plant will use agricultural waste to combat climate change</u>. [87]

⁷⁵ Temple (February 15, 2022) <u>Fuel plant will use agricultural waste to combat climate change</u>. [87]

⁷⁷ BusinessWire (May 24, 2022) <u>Mote Enters Advanced Stage of Engineering Design</u>. [13]

⁷⁸ BusinessWire (May 24, 2022) <u>Mote Enters Advanced Stage of Engineering Design</u>. [13]



Figure 4.2. Digital rendering of a planned Mote Hydrogen facility in southern California, featuring a parking lot, office buildings, a gasifier building with conveyor belts for moving biomass, several large vertical tanks, and two evaporation ponds. Credit: Mote, Inc.

InterEarth, Australia

InterEarth is in the pilot phase of its operations, investigating the efficacy of shallow biomass burial. Their current model involves heavily trimming local trees, digging sixmeter deep pits into salty groundwater, burying the tree matter and monitoring equipment, and refilling the pit to test if the salty water will successfully prevent the organic materials from releasing their stored carbon dioxide.^{79*} Tests of the efficacy of their model are still ongoing, but they estimate that – if successful – the technology could be used to bury as much as 1 billion metric tons of carbon (nearly 4 billion metric tons of CO₂) annually, at a cost of less than \$50 USD per ton.⁸⁰ At least 4-5 more years of monitoring the pilot projects are necessary to establish the efficacy of the technique. For reference, globally, about 140 billion tons of biomass waste is produced each year.⁸¹

Charm Industrial, San Francisco, California

Charm Industrial is a new start-up utilizing a two-part pyrolysis processing model, which should reduce the physical footprint required for a facility.⁸² In general, pyrolysis generates biochar (or charcoal), bio-oil, and hydrogen gas, but the proportions of the products are dependent on the speed and heat of the pyrolysis process.⁸³ For their feedstock, Charm has

⁷⁹ Rathi (March 15, 2022) <u>Carbon Pickling</u>. [77]

^{*} The 'salty groundwater' in question here is not naturally formed saline aquifers, which would be found much deeper than 6 meters below ground, but salty groundwater formed after farming practices in the region disturbed the groundwater table and accelerated the accumulation of salt. See Rathi (March 15, 2022) <u>Carbon Pickling</u> [77] for more information.

⁸⁰ Rathi (March 15, 2022) Carbon Pickling. [77]

⁸¹ Tripathi *et al.* (2019) <u>Biomass waste utilisation in low-carbon products</u>. [88]

⁸² Pontecorvo (May 18, 2021) <u>Meet the startup producing oil to fight climate change</u>. [76]

⁸³ Bolan *et al.* (2022) <u>Applications of Biochar</u>. p. 151. [9]

been utilizing agricultural wastes from central California.⁸⁴ Charm has experimented with yielding a variety of pyrolysis products in their efforts to sequester carbon dioxideoriginally they looked at maximizing biochar yield, then pivoted to hydrogen production, and currently have found success in focusing on bio-oil.⁸⁵ Bio-oil is viscous and prone to solidifying, making it a weak fuel source but a promising candidate for carbon sequestration, as its tendency to solidify makes carbon dioxide leaks highly unlikely.⁸⁶ Furthermore, working with bio-oil has cost advantages over other forms of sequestration; bio-oil "would be cheaper to inject than CO2 gas captured from the air or from a power plant, since CO2 has to be compressed into a form that can be pumped underground."⁸⁷ However, financing larger projects using Charm's bio-oil process will likely rely on changes within the federal and state policy landscape. Bio-oil sequestration is currently not eligible for the federal 45Q tax credit program or recognized by California's Low Carbon Fuel Standard (LCFS), though Charm is pushing for policy changes to recognize the potential of bio-oil.⁸⁸ Charm is optimistic about scaling up their operations in the near future and Kern County could be a favorable location, as Charm indicates they are looking for new sites to operate with minimal transportation needs and available agricultural waste for feedstocks.89

4.1.2.3 Planning Phase Examples

San Joaquin Renewables Project, McFarland, California

The San Joaquin Renewables (hereafter SJR) project is a planned venture of Frontline Bioenergy, an lowa-based company currently operating a commercial-scale gasification plant in Montana and a demonstration pyrolysis plant in lowa.⁹⁰ According to SJR, the project will operate as a renewable natural gas (RNG) facility and could be considered either a BiCRS or BECCS project—they are aiming to maximize their potential bioenergy output from agricultural waste via gasification, but will also be sequestering carbon dioxide onsite "deep underground in an EPA class VI sequestration well."⁹¹ The SJR project is in permitting with the City of McFarland, California and has secured up to \$165 million in funding for development and construction from Cresta Fund Management and Silverpeak Energy Partners.⁹² SJR is also seeking permitting to site their class VI well for carbon

⁸⁴ Pontecorvo (May 18, 2021) <u>Meet the startup producing oil to fight climate change</u>. [76]

⁸⁵ Pontecorvo (May 18, 2021) <u>Meet the startup producing oil to fight climate change</u>. [76]

⁸⁶ Pontecorvo (May 18, 2021) <u>Meet the startup producing oil to fight climate change</u>. [76]

⁸⁷ Pontecorvo (May 18, 2021) <u>Meet the startup producing oil to fight climate change</u>. [76]

⁸⁸ Pontecorvo (May 18, 2021) <u>Meet the startup producing oil to fight climate change</u>. [76]

⁸⁹ Reinhardt (October 21, 2021) Largest Permanent Carbon Removal Delivery of All Time. [78]

⁹⁰ Frontline Bioenergy (no date) <u>Our Projects</u>. [35]

⁹¹ San Joaquin Renewables (no date) <u>The Project</u>. [81]

⁹² NewsWire (October 27, 2021) <u>San Joaquin Renewables Secures \$165 Million</u>. [69]

sequestration within the City of McFarland; their permit application is still undergoing review by the EPA.⁹³

SGH2 Energy, Lancaster, California

SGH2 Energy is a producer of green hydrogen using a patented "plasma-enhanced thermal catalytic conversion process" of gasification which operates at temperatures of 3500°-4000°C and produces a clean stream of hydrogen and carbon dioxide with reportedly "no toxins or pollution."⁹⁴ A plan for permanent CO₂ storage has not yet been specified by the company. According to SGH2's technical overview, "Lawrence Berkeley National Lab has found that for every ton of hydrogen produced, our process displaces 23 to 31 tons of carbon dioxide. That's 13 to 19 tons more carbon dioxide avoided than other fossil-free hydrogen production processes, which rely on electrolysis from renewable energy."95 Their process has yet to be tested at commercial scale. Costs per kilogram of hydrogen produced by this process are competitive relative to the existing hydrogen market, as they estimate a cost of \$2-3/kg hydrogen for their process compared to a \$10-13/kg hydrogen range for electrolysis-based blue hydrogen production.⁹⁶ SGH2 Energy is planning to build a facility in Lancaster, California, just south of Kern County's boundary with LA County. The Lancaster plant would generate 3.8 million kg of green hydrogen utilizing 42,000 tons of recyclable waste annually supplied by the City of Lancaster, saving the city an estimated \$50 to \$75 per ton of waste annually due to avoided landfill space and processing costs.⁹⁷ The City of Lancaster is required to sort and supply a feedstock of recyclables for use by SGH2 Energy, and in exchange, will receive co-ownership of the facility.⁹⁸ The Lancaster facility is designed for a 5-acre industrial lot scheduled to open in the first quarter of 2023, and is estimated to support the creation of 35 full-time positions once operational.⁹⁹

4.1.3 Operational Needs

4.1.3.1 Land use requirements

A BiCRS facility designed for commercial scale will likely have a large physical footprint, as the volumes of biomass to be sorted and converted will be extensive and need appropriate space to be stored and treated.¹⁰⁰ The overall land footprint for BECCS is estimated at between 1,000 and 17,000 km² per million tons of CO₂ removed, depending on location and the source for the biomass (e.g. forest and agricultural residues, and purpose-grown

⁹³ EPA (April 24, 2023) <u>Class VI Wells Permitted by EPA</u>. [29]

⁹⁴ SGH2 Energy (no date) <u>Technology</u>. [83]

⁹⁵ SGH2 Energy (no date) <u>Technology</u>. [83]

⁹⁶ SGH2 Energy (no date) <u>Technology</u>. [83]

⁹⁷ SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]

⁹⁸ SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]

⁹⁹ SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]

¹⁰⁰ Koornneef *et al.* (2012). <u>Global potential for biomass and carbon dioxide capture, transport and</u> <u>storage</u>. [54]

energy crops).¹⁰¹ Since we are focusing on scenarios where facilities could rely on existing waste biomass—rather than growing dedicated crops—we have chosen to emphasize the likely footprint of the facility itself where pyrolysis, gasification, or other biomass conversion would take place.

Based on scaling existing facility size estimates and interviews with industry representatives, the estimated physical footprint for a BiCRS facility capturing 1 million metric tons of CO_2 annually is 180 to 400 acres. The unscaled estimates, with their years indicated and estimated capture capacity represented by circle size, are illustrated in Figure 4.3. These estimated acreages do not account for land used to grow biomass for processing (as ideally, biomass will be sourced as waste from existing local agriculture and forestry partners) or external energy use needs, which will vary by plant design and efficiency.



Figure 4.3. Land use requirements of existing and planned BiCRS/BECCS facilities as a function of their CO₂ capture potential. Footprint sizes were either reported directly from operator data or were measured digitally using publicly available satellite imagery.

The plant itself will typically involve a small handful of buildings (3-5) with a conveyor belt to bring in biomass from outdoors, as well as piles of biomass for processing and (depending on the facility) evaporation ponds for wastewater.¹⁰² The tallest installation at a facility would be a gas flare, with an estimated height of 100 feet.¹⁰³ Typically, most of the acreage for a plant is dedicated to biomass storage and electricity generation.¹⁰⁴

¹⁰¹ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 87. [49]

¹⁰² Industry representative, personal communication, September 8, 2022.

¹⁰³ Industry representative, personal communication, September 8, 2022.

¹⁰⁴ Industry representative, personal communication, September 8, 2022.

4.1.3.2 Energy requirements

The energy requirements of a BiCRS facility are opaque. Based upon the variety of conversion methods available and the lack of commercial-scale facilities operating with the goal of sequestration, rather than bioenergy, there is a wide error range for any estimates about energy usage. As such, it is best to evaluate projects billed as BECCS projects on their energy requirements, as there is a greater availability of information to analyze.

As bioenergy facilities, BECCS facilities will have an energy-positive process—meaning they produce more energy output than they consume to process the biomass via pyrolysis or gasification. This energy output can be producing electricity for the grid or generating synthetic fuels for consumers. For every metric ton of CO₂ captured at a BECCS facility, the estimated energy output is 0.83 MWh.¹⁰⁵ This is simply a representative example for a woody biomass-based facility but other estimates may differ substantially, as many bioenergy projects only report their energy output, not the total energy generated or the amount used to sustain their pyrolysis or gasification reactions, and the energy content of the biomass material may differ.

Due to the high temperatures needed for pyrolysis or gasification, facilities require an energy source for heat. For BiCRS/BECCS, this energy is typically supplied by the biomass itself, which contains energy, or by the fuels (syngas, hydrogen, or other products) that are produced on-site as products by breaking down biomass. Depending on the model, some pyrolyzers need external fuel to start the process,¹⁰⁶ which can be supplied from renewable sources like green hydrogen, renewable natural gas (RNG), or biodiesel.

For BECCS, energy requirements will also depend greatly on the plant's thermal efficiency.^{*} Capturing carbon dioxide from the flue gas, which is commonly the source of carbon dioxide in post-combustion technology, of an energy conversion plant requires energy input.¹⁰⁷ As a result, the net energy efficiency of the plant is lowered. However, larger BECCS power stations are expected to have higher thermal efficiencies at 30% - 36%.¹⁰⁸ Higher thermal efficiency means the plant requires less energy to run the system, and subsequently lowering the cost of capital and operating expenses. Although current operational BECCS plants have yet to reach the million metric tons of CO₂ capture range, recent BECCS development shows that larger plant sizes are feasible.¹⁰⁹ For instance, Drax

¹⁰⁵ NREL (2022) <u>Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035</u>. p. 13. [66] In this report, the finding is reported as net negative emissions of 1.2 metric tons of CO_2 per MWh—converting to be in terms of per metric ton of CO_2 gives the 0.83 MWh figure reported above.

¹⁰⁶ Industry representative, personal communication, September 21, 2022.

^{*} Thermal efficiency is a performance measure of a device that uses thermal energy, which measures the ratio of the heat that becomes useful work.

¹⁰⁷ Bui *et al.* (2017) <u>Bio-energy with CCS (BECCS) performance evaluation</u> [11], as cited in Gustafsson *et al.*, (2021) <u>BECCS energy penalty</u>. [43]

 ¹⁰⁸ Austin (no date) <u>Size matters</u> [7], as cited in Donnison, *et al.* (2020) <u>BECCS win-wins</u>. [21]
 ¹⁰⁹ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. [49]

Power Station has a capacity from biomass of 2,595 MW¹¹⁰ and, as of 2018, operates with a thermal efficiency of 38% or more.¹¹¹ They estimate that the installation of CCS equipment in their power plant will decrease their thermal efficiency to 37%, so the change in efficiency due to the addition of carbon capture will be relatively small.¹¹²

4.1.3.3 Other operational requirements

Waste disposal requirements

The reaction products for biomass conversion and their disposal requirements will differ depending on the conversion process used by a given company. Reaction products outside of the main three—solid biochar, liquid bio-oil, and hydrogen gas—typically fall into the following categories.

Unless operating at extremely high temperatures, biomass processing generates ash and fine particulates, which can be accumulated and sold as a fertilizer product.¹¹³ Water is often used in these processes for cooling or scrubbing, generating varied qualities of wastewater—some processes generate water clean enough for direct reuse in agricultural irrigation, whilst others hold wastewater and sludge in on-site evaporation ponds until it can be sent for proper treatment.^{114, 115} Although some reaction products can be reused in other applications, non-hazardous industrial wastes will have to be landfilled. Items in this category include spent catalyst and any solid waste generated from spent material, like dolomite, silicates, or heavier ash.¹¹⁶

Of the standard three products generated via biomass pyrolysis, biochar is typically the least sought-after product, as bio-oil and hydrogen gas can both be upgraded into usable fuels. This means the solid biochar, or charcoal, generated by a pyrolysis-based biomass plant needs a designated end-of-life trajectory. Fortunately, biochar is both safe and more useful than most industrial waste products, and thus is less likely to be landfilled or otherwise discarded. A range of academic literature on biochar has identified uses including carbon storage, as a soil amendment, as a soil conditioner for contaminant immobilization, or as a catalyst for various uses.^{117,118} Resale of biochar for agricultural uses is the most common existing use, as it can be added in livestock feed, used as a treatment for increased soil fertility, or mixed in with compost or other organic materials to prevent

¹¹⁰ Drax (no date) <u>Drax Power Station</u>. [24]

¹¹¹ Drax (May 11, 2018) <u>Tweet</u>. [27]

¹¹² Donnison *et al.* (2020) <u>BECCS win-wins</u>. [21]

¹¹³ Industry representative, personal communication, September 8, 2022.

¹¹⁴ San Joaquin Renewables (no date) <u>The Project</u>. [81]

¹¹⁵ Industry representative, personal communication, September 8, 2022.

¹¹⁶ Industry representative, personal communication, September 8, 2022.

¹¹⁷ Bolan *et al.* (2022) <u>Applications of Biochar</u>. p. 151. [9]

¹¹⁸ Lee, Kim, Kwon (2017) <u>Biochar as a Catalyst</u>. p. 70. [58]

nutrient leaching.¹¹⁹ Biochar can also be used to remediate sites contaminated by oil and gas or mining operations, as its high porosity makes it a promising material to sequester chemicals from heavy metals to volatile organic carbons (VOCs).¹²⁰ There have also been studies conducted regarding the viability of using biochar as a cover for landfill waste disposal.¹²¹

Warehousing requirements

Warehousing for a BiCRS operation will likely need to be extensive, as any commercialscale facility would likely be dealing with thousands of tons of biomass daily for processing.¹²² The source and quality of the feedstocks-for example, if it's delivered already dehydrated or in its raw form-will likely dictate the amount of space needed for biomass storage. There will also need to be ample space for storing byproducts like biochar before their sale or disposal. In interviews with experts,¹²³ facility size was estimated to require approximately 80 acres of land to accommodate the storage of feedstocks, on-site electricity generation, and evaporation pools for wastewater, as well as necessary buildings for processing. Gas-fired facilities would be 3 stories tall and processing is estimated to require 3 of these buildings, though figures on estimated square footage are unavailable. Other facilities have had much smaller warehousing requirements - SGH2 Energy's entire Lancaster hydrogen plant fits on a 5 acre industrial lot because their feedstocks are regularly replenished under their agreement with the city, reducing the need to store large amounts of feedstock on-site.¹²⁴ Based upon this wide range of warehousing needs and total acreage presented by biomass firms, this requirement is likely flexible depending on contract terms and the feedstocks being processed.

Transportation requirements

In capturing carbon dioxide from biomass for sequestration, the most preferred facility sites are either co-located with a viable biomass source to eliminate transporting biomass, or located on-site with a sequestration well, to avoid needing to transport carbon dioxide for storage.¹²⁵ Transporting biomass often requires some pre-processing and is conducted using trains or trucks. When possible, rail is preferable to trucking, as it has lower costs – especially over longer distances—and lower externalities, according to the Government Accountability Office (GAO).¹²⁶ Rail can require upfront investments to build new tracks,

¹¹⁹ Usmani (August 25, 2021) <u>Things You Should Know About the Different Uses of Biochar</u>. [91]

¹²⁰ Simekin Inc. (no date) <u>Biochar</u>. [85]

¹²¹ Bordoloi *et al.* (2021) <u>Role of biochar as a cover material in landfill waste disposal system</u>. [10]

¹²² Approximately 1,000 tons per day biomass for a 400k CO₂/yr facility (According to data from an industry representative, personal communication, September 8, 2022).

¹²³ Industry representative, personal communication, September 8, 2022.

¹²⁴ SGH2 Energy (no date) <u>World's Largest Green Hydrogen Project</u>. [84]

¹²⁵ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 3. [86]

¹²⁶ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 3. [86]

depending on the region's existing infrastructure, so trucks are typically used for shorter distances.

Byproducts of BiCRS processes, from hydrocarbon fuels and grid electricity to biochar, would require transportation offsite to be used by customers. These transportation considerations should be taken seriously, as without proper planning, the carbon efficiencies of BiCRS could be lost in trying to sustain a market for related goods reliant on increased carbon emissions for transport.

Infrastructure & Pipeline requirements

Initial deployment of BiCRS should consider the availability of surrounding existing infrastructure to minimize the costs and complexities of long-distance transport of either carbon dioxide, biomass feedstock, and biofuel distributions.

Given that Kern County has appropriate geology for long-term carbon sequestration underground, any BiCRS facility should try to locate as close to an injection site as possible, limiting the need for extensive pipework to handle the supercritical carbon dioxide fluid. However, the pipeline requirements for carbon dioxide are not specialized—their requirements are well-understood due to decades of prior manufacturing and use in the U.S. For more details on carbon dioxide transport, particularly pipeline transport, please refer to Section 9 of this report.

Other requirements

Sequestering carbon underground requires clearing a number of legal and permitting hurdles. Although Kern County and other parts of California's Central Valley are seen as prime real estate for carbon sequestration from a geological perspective, it may be more complex to get all of the legal and regulatory matters aligned and have local landowners on board.¹²⁷

Another hurdle comes into play when using hydrogen as fuel: "There is very little refueling infrastructure and even fewer fuel cell-powered heavy duty vehicles" already in existence.¹²⁸ Ensuring biomass-to-hydrogen production timelines match up with the development and scale of hydrogen-fueled technology will be critical to the success of a green hydrogen project. For further exploration of biomass-based green hydrogen considerations, please see Section 6 of this report.

4.1.4 Carbon Capture Potential

The carbon capture potential of BiCRS and BECCS is highly promising, though restricted regionally based on resource use constraints. On average, "biomass is roughly half carbon by weight," so if processed efficiently the carbon removed from biomass is substantial.¹²⁹

¹²⁷ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 7. [8]

¹²⁸ Hanley (May 22, 2020) <u>Lancaster, California Will Be Home To World's Largest Renewable</u> <u>Hydrogen Plant</u>. [44]

¹²⁹ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 7. [80]

However, biomass can also be utilized for other applications in agriculture and construction that also repurposes or stores its carbon content—often the local context will determine if the financial cost and carbon benefits balance out in favor of a BiCRS or BECCS facility, or repurposing products for other uses.

Based upon the best estimates in the literature, experts posit that "roughly 2.5 to 5.0 GtCO₂/year could be removed from the atmosphere and stored by 2050 using biomass produced with minimal environmental impact."¹³⁰ Here, 'minimal environmental impact' means without repurposing other productive landscapes, like agricultural lands or forests, to grow biomass dedicated crops or using other carbon-rich materials like forests for biomass feedstocks.

Furthermore, biomass that decays anaerobically in other settings, like landfills, produces methane in addition to carbon dioxide, thus contributing multiple greenhouse gas emissions into the atmosphere.¹³¹ Thus for biomass-rich materials that are routinely landfilled, such as household organic wastes, the carbon removal potential could be even greater than expected as it would prevent the production of multiple forms of carbon-based pollutants.

However, quantifying the overall impacts of a BiCRS or BECCS facility will depend on the full life-cycle analysis (LCA) of a specific project. In a full LCA, it would be possible to identify how much carbon the plant material holds and the amount that could be captured in a given gasification or pyrolysis process, but also the carbon intensity of other steps, like transporting biomass, processing and/or dehydrating biomass, or sending finished products aside from CO_2 to market. Existing LCAs conducted for different BECCS models have indicated that net emissions can differ considerably depending upon the feedstock, conversion method, and carbon capture method used by a given facility.¹³²

4.2 Societal Impacts

4.2.1 Job creation potential

4.2.1.1 Number and types of jobs

Because BiCRS facilities at commercial scale are quite rare, the most relevant data to approximate job creation is to examine commercial-scale BECCS operations using likely BiCRS feedstocks available in Kern County, namely agricultural waste and municipal organic waste.

¹³⁰ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. vi. [80]

¹³¹ LMOP (April 21, 2023) <u>Basic Information About Landfill Gas</u>. [56]

¹³² Almena *et al.* (2022) <u>Carbon dioxide removal potential from decentralised bioenergy</u>. p. 9-11. [5]

Fulcrum Bioenergy's first commercial plant in Reno, NV, capable of processing 175,000 tons of landfill waste annually, supports over 100 permanent jobs.¹³³ Looking at estimates for upcoming projects under Fulcrum's umbrella, there is also a large requirement for construction workers to build these facilities—anywhere from 1,000 to 1,200 jobs created in the construction process, though these positions are not permanent.^{134,135} San Joaquin Renewables, who is planning to sequester carbon on-site though at a smaller facility, predicts its operation will sustain 45-50 full-time employees.¹³⁶ In industry interviews, some operators estimated smaller staff needs—closer to 25 for a full facility, even for a facility processing up to 219,000 tons of biomass annually.¹³⁷ Given this wide range of jobs figures across different biomass facility models, it appears that permanent job creation is not clearly correlated with facility capacity.

The Drax plant in the UK, as it converts from bioenergy to BECCS, is estimated to generate over 4,000 direct jobs annually during the CCS construction phase from 2024 to 2028.¹³⁸ Once Drax has been fully converted to BECCS, it is expected to support an estimated operations and maintenance staff of up to 800 employees.¹³⁹ After the facility is operational, it could further generate 2,300 indirect and 4,100 induced jobs.¹⁴⁰ Given that Drax claims that full BECCS operations at their facility would result in the removal of about 8 million metric tons of CO₂ per year, which would make it the largest CO₂ capture and storage project globally,¹⁴¹ it makes sense that these estimates are much higher than those of other BiCRS or BECCS facilities.

It is worth noting that scaled estimates for the million metric tons per year of CO_2 capture range for other facilities generate much smaller estimates, somewhere in the range of 45 to 150 full-time jobs created. Although some estimates range lower or higher, as seen in Table 4.1, the 45 to 150 range seems like the most consistent estimate based on both scaling existing facilities and any literature estimates, with an average of 102 jobs estimated per million metric tons of CO_2 captured annually. It is important to note that biomass facility jobs are not expected to necessarily scale linearly with plant size (in terms of CO_2 capture potential), as can be seen in the range of permanent jobs associated with already-existing facilities. Furthermore, the possibilities of increased automation and remote monitoring means that steps should be taken in the planning and permitting process to ensure jobs for any new carbon management facility benefits local communities.

¹³³ Fulcrum BioEnergy (no date) <u>Sierra BioFuels Plant & Feedstock Processing Facility</u>. [37]

¹³⁴ Fulcrum BioEnergy (no date) <u>Trinity Fuels Plant</u>. [38]

¹³⁵ Fulcrum BioEnergy (no date) <u>Centerpoint Biofuels Plant</u>. [36]

¹³⁶ San Joaquin Renewables (no date) <u>The Project</u>. [81]

¹³⁷ Industry representative, personal communication, October 4, 2022.

¹³⁸ Vivid Economics (2020) <u>Delivering Jobs at Drax</u>. p. 18. [92]

¹³⁹ Vivid Economics (2020) <u>Delivering Jobs at Drax</u>. p. 19. [92]

¹⁴⁰ Vivid Economics (2020) <u>Delivering Jobs at Drax</u>. p. 25. [92]

¹⁴¹ Drax (July 12, 2022) <u>Drax submits plans to build world's largest carbon capture and storage project</u>. [25]

Facility Name ^a	Year Operational	Annual CO₂ Capture ^ь	Reported Jobs		Scaled Employment (per 1MtCO₂/yr)	
			Perm.°	Const.d	Perm.°	Const.d
Drax Power Station, Humber, UK	2024-2028	8	800	4,000	100	500
Mendota BiCRS Project, Mendota, CA	Future	0.3	25		83	
Calgren Renewable Fuels, Pixley, CA	2015	0.15	20		133	
Mote, Los Angeles, CA	2024	0.438	100		228	
Stockholm Exergi, Stockholm, SE	2019	0.8	35		44	
Illinois Industrial CCS, Decatur, IL	2017	0.444	11		25	
AVERAGE					102	500

Table 4.1. Job creation estimates for planned and current BiCRS/BECCS facilities, globally.

a. Facility details are fully outlined in Appendices A-C.

b. In million metric tons (Mt). Where actual figures are available, they are used, otherwise data reported correspond with press releases or projections.

c. Permanent jobs.

d. Construction jobs.

4.2.2.2 Training pipelines

In conversations with industry experts, we found that oftentimes, facilities like to recruit locally where possible, though local hiring can be dependent on the specific skills needed. Some facilities that specialize in retrofitting old power plants or other infrastructure into BiCRS or BECCS facilities have found that since existing employees already know the plant well, they can be easily kept on and retrained as necessary, keeping all workforce demands local.¹⁴²

For the Drax plant, there are concerns regarding the challenges in labor and skills supply due to the lack of specialist skill in key manufacturing sectors as required by the plant.¹⁴³ This will need to be addressed with a combination of a direct apprenticeship scheme, early investment in the next generation of workers, and endorsement of vocational work at a local school.¹⁴⁴

¹⁴² Industry representative, personal communication, October 4, 2022.

¹⁴³ Vivid Economics (2020) <u>Delivering Jobs at Drax</u>. p. 29. [92]

¹⁴⁴ Vivid Economics (2020) <u>Delivering Jobs at Drax</u>. p. 29-30. [92]

4.2.2 Quality of Life

4.2.2.1 Location

At existing biomass-based plants, noise is a common concern for area residents. For example, a safety valve at the Drax Power Station, when opened, generates a sound so loud that residents 2.5 miles from the station reported that they were awoken by the noise.¹⁴⁵ It is anticipated that mitigation is possible with sound-dampening design within buildings.¹⁴⁶ Siting away from residential areas and incorporating sound dampening materials in construction would likely mitigate noise at nearby communities.

Given that burning is the traditional disposal method for agricultural and forestry wastes, moving to process agricultural waste at a BiCRS or BECCS facility could lead to lower emissions; potentially up to 95-99% lower than they would be if the biomass was burned instead.¹⁴⁷ Biomass-based facilities which produce emissions or pollutant discharge will need to adhere to a federal Title V operating permit. For Kern County, developers would need to obtain permit authorization to construct and operate before commencing construction, and a permit to operate from Eastern Kern Air Pollution Control District (EKAPCD) or San Joaquin Valley Air Pollution Control District (SJVAPCD).¹⁴⁸

4.2.2.2 Multi-use potential

There is multi-use potential for BECCS and BiCRS facilities, although examples are limited. Feedstock generation from nearby agricultural waste can be considered a multi-use byproduct of the primary agriculture industry. For the facilities themselves, noise pollution generated by biomass processing would need to be addressed, but co-locating community facilities with processing plants is possible. A waste-to-energy plant located in central Copenhagen, Denmark – called Amager Bakke – was designed to be a public recreational facility as well as a power plant.¹⁴⁹ The building, which converts municipal waste to electricity, is topped with a hiking trail and artificial ski slope. While Amager Bakke does not capture CO₂, it sets a precedent for the possibility of innovative proposals that could integrate other businesses or community facilities with BiCRS/BECCS facilities.

¹⁴⁵ The York Press (January 26, 2008) <u>Drax fault causes 'deafening' noise</u>. [89]

¹⁴⁶ Doyle (2015) <u>White Rose Carbon Capture and Storage (CCS) Project: Environmental Permit</u>. [22]

¹⁴⁷ San Joaquin Renewables (no date) <u>The Project</u>. [81]

¹⁴⁸ CARB (no date) <u>California Air Districts</u>. [14]

¹⁴⁹ Crook (October 8, 2019) <u>BIG opens Copenhill power plant topped with rooftop ski slope in</u> <u>Copenhagen</u>. [20]

4.3 Environmental Impacts

4.3.1 Water requirements

4.3.1.1 Minimum volume requirements

Water requirements vary depending on the conversion process used to process the biomass intake, but is low under every well-understood conversion pathway. The largest lifetime intake of water in the BiCRS life-cycle is that required for actually growing the biomass in question. As long as dedicated feedstock crops are not being grown to sustain the facility (i.e. the biomass in question is agricultural or forestry waste), it is likely the water would have been used anyway. In fact, biomass is frequently 'de-watered' before conversion, aside from supercritical water extraction,¹⁵⁰ so it's actually likely that facilities will be generating some volume of wastewater in the process.

However, in case there needs to be a dedicated feedstock crop to feed the facility, sustainable agriculture practices which reduce water consumption could reduce the additional water withdrawal.¹⁵¹ However, a study shows a potential tradeoff between land use pressure and water consumption. For instance, to reduce land use one might choose to grow crops with higher yields which require higher water volume. If we include the water consumption to grow the feedstock, the total amount of water to deliver 12 Gt carbon dioxide per year through BECCS would account for 3% of the total amount of water currently used by human activities.¹⁵²

Information about San Joaquin Renewable's current process appears to corroborate these assumptions. Their method requires some water vapor to gasify biomass, but also produces "irrigation-quality water" as a product of its conversion process, resulting in a net gain in water.¹⁵³ A diagram illustrating their model is included below in Figure 4.4.¹⁵⁴ With that said, these are assumptions—the water demands of any project may differ based upon their conversion method, kinetics, biomass source, or other factors.

4.3.1.2 Minimum quality requirements

As discussed above, water is not a necessary component to most BiCRS conversion processes, with some BiCRS processes even generating a net gain of water in the process. However, water availability issues in future projections are still poorly understood.¹⁵⁵

¹⁵⁰ Lee, Conradie, Lester (2021) <u>Review of supercritical water gasification</u>. p. 1. [57]

¹⁵¹ Ai *et al.* (2021) <u>Global bioenergy with carbon capture and storage potential</u>. [4]

¹⁵² National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. [62]

¹⁵³ San Joaquin Renewables (no date) <u>The Project</u>. [81]

¹⁵⁴ San Joaquin Renewables (no date) <u>The Project</u>. [81]

¹⁵⁵ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 18. [80]

Envisioning a Carbon Management Business Park



Figure 4.4. The biomass gasification process employed by San Joaquin Renewables.¹⁵⁶ Image credit: San Joaquin Renewables.

4.3.2 Air quality

Data availability for distinctions between biomass pyrolysis, gasification, and combustion with respect to emission impacts is limited, largely because most studies restrict themselves to a single type of biomass feedstock or single type of biomass conversion process, if not both. For this reason, we have chosen to highlight findings from coal, which is fossilized organic material from wetlands¹⁵⁷ and has clearly understood data due to decades of use with all three technologies. Although the comparison is imperfect, it provides useful insight into the differences between conversion types. The primary benefit of pyrolysis and gasification, from an emissions perspective, is the high temperatures and pressures of the biomass conversion generate a syngas stream of emissions that makes it simpler to separate out criteria air pollutants (including NO_x and SO_x) as well as trace contaminants including mercury, cadmium, arsenic, and selenium.¹⁵⁸

4.3.3 Other potential impacts

Some types of biomass production damage ecosystems, hurt local farmers, or increase emissions.¹⁵⁹ The American ethanol industry has been a notable offender, as its push to grow biofuel crops has contributed to deforestation with little to no clear carbon reduction benefits.¹⁶⁰

Any biomass plant will have to consider the land use impact associated with feedstock production. If there are no land use changes because biomass would be sourced from

¹⁵⁶ San Joaquin Renewables (no date) <u>The Project</u>. [81]

¹⁵⁷ Schweinfurth (November 23, 2016) <u>Coal—A Complex Natural Resource</u>. [82]

¹⁵⁸ NETL (no date) <u>6.5. EMISSIONS ADVANTAGES OF GASIFICATION</u>. [63]

¹⁵⁹ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 12. [80]

¹⁶⁰ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 12. [80]

waste and residues from existing land uses, the impact will be little to zero.¹⁶¹ If biomass feedstock needs are to come from dedicated agriculture soil, 380 to 700 Million hectares of land area is needed to deliver the global BiCRS sequestration potential of 12 GT per year carbon dioxide.¹⁶² Change in local land cover, or extensive withdrawal of water from irrigation sources, will impact the climate in regions as far as a few hundred kilometers downwind.¹⁶³

Land use change would also potentially cause indirect impacts, such as initiating new competition with other land uses, such as food-production, wood production, or residential land, which could lead to changes in the market for related commodity supplies and prices.¹⁶⁴ Given the abundance of potential biomass waste feedstocks in California in the form of agriculture waste, forest residues and municipal waste,¹⁶⁵ a significant volume of BiCRS facilities could be operational without the need to cultivate bioenergy crops – and their downstream effects – in the region.

4.4 Economic Impacts

4.4.1 Business Model

Whether a project defines itself as BiCRS or BECCS, the business model generally depends on the ability to outweigh fixed costs (i.e. levelized capital costs, labor expenses, taxes) and flexible costs (i.e. costs of energy use, biomass, transport) with income (i.e. selling products and/or carbon credits).

BiCRS and BECCS technologies have a number of revenue streams, depending on the outputs they prioritize in the gasification or pyrolysis process. All of these processes will generate CO₂ for permanent sequestration, and thus will be eligible for the 45Q federal tax credit.¹⁶⁶ As of 2022, the 45Q tax credit totaled \$85/ton CO₂ for every ton permanently stored and \$60/ton CO₂ for every ton used in enhanced oil recovery (EOR).¹⁶⁷ Due to California's SB 1314, captured CO₂ effectively cannot be used for EOR within the state.¹⁶⁸ Most biomass projects will also generate bioenergy products, which can be sold as electricity or fuel; BECCS processes will aim to maximize the potential bioenergy output. For gasification, the

¹⁶¹ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. [62]

¹⁶² National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. [62]

¹⁶³ Jia *et al.* (2019) <u>Land-climate interactions - Executive Summary</u>. [51]

¹⁶⁴ National Academies of Sciences, Engineering, and Medicine (2019) <u>Negative Emissions</u> <u>Technologies and Reliable Sequestration: A Research Agenda</u>. [62]

¹⁶⁵ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 4. [8]

¹⁶⁶ IEA (November 4, 2022) <u>Section 450 Credit</u>. [48]

¹⁶⁷ IEA (November 4, 2022) <u>Section 450 Credit</u>. [48]

¹⁶⁸ IEA (November 4, 2022) <u>SB 1314</u>. [47]

hydrogen gas created can be sold as a product—this economic opportunity is explored more in Section 6.4 of this report, which addresses the business of hydrogen production.

At the start of 2022, there were 16 operational facilities classified as BECCS facilities,¹⁶⁹ though some items on this list—like Charm Industrial—would likely be better described as BiCRS. An estimated 50 additional facilities are currently under development.¹⁷⁰ As for expanding the amount of BiCRS/BECCS facilities in the future, reduced costs in various technological pathways will help reduce the economic barriers, but the primary hurdle to scaling is anticipated to be generating new institutional arrangements and stakeholder consensus.¹⁷¹ In short, most of the expected barriers are political and institutional in nature, rather than economic or technical.¹⁷²

Most companies currently working on biomass facilities are working with large upfront capital investors and planning to fund their sequestration through a mixture of tax credits, selling carbon offsets, and/or selling byproducts (syngas, biochar, etc). Biomass conversion technologies can produce products aside from CO₂, including biochar and biofuels. As mentioned above, biochar can be used for a variety of agricultural and industrial applications. In recent years, biochar has sold for amounts ranging from \$9 to \$42 per cubic foot of biochar, with variations depending on the type, texture, quality, and sale venue.¹⁷³ Biofuels can vary considerably depending on the process in question: ethanol from fermentation,¹⁷⁴ hydrogen from gasification or fast pyrolysis,¹⁷⁵ or synthetic fuels generated by upgrading bio-oil.¹⁷⁶ For RNG and hydrogen fuel, the sale comes with additional benefits, as these fuels can often qualify for other state and federal subsidies.^{177,178} More details about these economic incentives established via policy for various lower-carbon fuels can be found in Section 2, and specific information for hydrogen incentives can be found in Section 6.

The other avenue of revenue is the carbon credit market, of which there are both governmental and private options available. For the government carbon market, there are benefits at the federal and state level, with the 45Q tax credit and depending on the products and their intended market, can also be eligible for California's LCFS credits. For BiCRS or BECCS projects that generate alternative fuels for sale in California—including renewable natural gas, hydrogen, or electricity¹⁷⁹—should be eligible for Low Carbon Fuel

¹⁶⁹ EFI (2022) <u>Surveying the BECCS Landscape</u>. p. 3-4. [28]

¹⁷⁰ GCCSI (no date) <u>CO₂RE Facilities Database</u>. [41] (See Appendices A-C).

¹⁷¹ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 2. [80]

¹⁷² Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 2. [80]

¹⁷³ Pokharel, Comer (December 7, 2021) <u>Economics of biochar</u>. [75]

¹⁷⁴ Sanchez, *et al.* (2018) <u>US Biorefineries</u>. p. 4875. [79]

¹⁷⁵ Arregi *et al.* (2016) <u>Hydrogen production from biomass by fast pyrolysis</u>. p. 25975. [6]

¹⁷⁶ Nanda *et al.* (2021) Catalytic and Noncatalytic Upgrading of Bio-Oil to Synthetic Fuels. p. 2. [61]

¹⁷⁷ Natural Gas Intelligence (no date) <u>How do you price RNG?</u> [67]

¹⁷⁸ Piper, Krause, Janzow (February 27, 2023) <u>The Hydrogen Credit Catalyst</u>. [73]

¹⁷⁹ Casetext (April 14, 2023) <u>Cal. Code Regs. tit. 17 § 95482</u>. [16]

Standard (LCFS) credits, though uses like electricity would need to demonstrate their contribution to lowering state transportation carbon intensity.¹⁸⁰ LCFS credits between 2018 and 2022 varied between \$62 and \$218 per ton of CO₂ reduced.¹⁸¹ The most recent price updates can be found on the California Air Resources Board <u>LCFS credit dashboard</u>, which posts LCFS price averages from the preceding week every Tuesday.

In speaking with industry experts, some BiCRS facilities have been selling their energy as electricity to the grid currently, but are planning to convert to more lucrative alternative energy sources, like selling hydrogen to consumers, once there is a sustained market and distribution network nearby.¹⁸² This reflects the adaptivity of biomass-based energy facilities—depending on the current energy market, the biomass content can be converted into different materials to meet local needs.

4.4.2 Business Costs

Combining the estimated capital and operational costs—capital costs, feedstock costs, fixed and variable operating costs—of BiCRS/BECCS, outlined below, results in an estimated cost per ton CO_2 of \$61-288, which aligns well with industry estimates of \$88-288.¹⁸³

4.4.2.1 Cost to build (upfront costs)

The estimated capital costs for constructing a BiCRS/BECCS facility capable of capturing 1 million metric tons of CO_2 annually ranges from \$350 million to \$1.2 billion, based on scaled estimates. This range has been corroborated by industry representatives. If a BiCRS/BECCS facility ran for 30 years, the average capital cost per metric ton of CO_2 would fall between \$30-189. Given that estimates in the academic literature for BECCS typically range from \$30 to \$400 per metric ton of CO_2 ,¹⁸⁴ the scaled estimates calculated in this study appear quite reasonable.

Costs can also vary depending on the inputs a facility requires, and between BiCRS and BECCS processes, the largest differences typically originate from energy needs. Biomass pyrolysis or gasification will generate thermal heat, and many facilities can be largely or fully energy self-sufficient by utilizing this heat to meet the plant's energy needs. For BECCS facilities, the process is optimized to maximize the bioenergy output—whether it be heat, electricity, or fuel—leaving excess energy available to sell. However, this often requires upfront investment to reuse process heat or build off-grid renewables of heat-to-electricity equipment to support any on-site electricity needs.

¹⁸⁰ CARB (October 2022) <u>Carbon Capture and Sequestration Project Eligibility FAO</u>. [15]

¹⁸¹ Neste (updated daily) <u>California Low Carbon Fuel Standard Credit price</u>. [68]

¹⁸² Industry representative, personal communication, October 4, 2022.

¹⁸³ Kalra *et al*. <u>Technical CO₂ Removals Market</u>. p. 10. [52]

¹⁸⁴ Fuss *et al.* (2018) <u>Negative emissions</u>. p. 12. [39]

4.4.2.2 Operational costs

Operational costs on-site will involve maintenance and repairs, staff, monitoring, and any taxes. In terms of fueling their conversion processes, facilities will also need access to biomass feedstocks, which vary in terms of seasonal availability and cost. Not only do these materials need to be purchased (or obtained through another standing arrangement) and then chipped and dried, they also must be transported to the facility via train or truck.¹⁸⁵ Feedstock costs are often the largest estimated category in assessing a facility's operational costs. However, costs can vary widely—items like municipal solid waste (MSW) or some agricultural residues, like pistachio shells or almond hulls, are already collected and processed, making them easy to purchase at relatively low additional cost.¹⁸⁶ Other materials that require collection directly from the field, or processing steps like chipping or drying for forestry waste, can increase the cost of biomass feedstocks.¹⁸⁷ In general, placing facilities within close proximity of CO₂ storage sites and large quantities of biomass to use results in lower overall costs per ton CO₂ by reducing the transportation burden at both ends.¹⁸⁸

Within the operational costs, there are fixed and variable expenses at play. Fixed operating costs—such as routine maintenance and labor costs—are typically estimated at 2-7% of the capital costs;¹⁸⁹ breaking down the estimated capital costs per ton CO_2 gives an estimated range from \$1-13 per ton of CO_2 in fixed operating costs. Variable operational costs—such as unplanned maintenance, waste disposal, or non-biomass feedstocks—range from \$10-27 per ton CO_2 .¹⁹⁰ As mentioned above, biomass feedstock costs are typically the largest cost category, and can vary considerably depending on the type of biomass and the distance it needs to be moved. Based on the estimates available, a good range is approximately \$20-60 per ton CO_2 .^{191,192} Combining these estimates, you would get a range of operating costs per ton CO_2 of \$31-100.

4.4.3 Regional benefits

Businesses looking to start commercial-scale BECCS and BiCRS operations are drawn to southern California locations, including operations eyeing Kern County specifically. Due to the region's promising geography for underground carbon sequestration and relative abundance of agricultural waste feedstocks, there are clear assets to siting a BiCRS or BECCS facility in Kern County. These benefits would also extend beyond the county: in a

¹⁸⁵ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 3. [86]

¹⁸⁶ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 3. [86]

¹⁸⁷ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 3. [86]

¹⁸⁸ Fuss *et al.* (2018) <u>Negative emissions</u>. p. 12. [39]

¹⁸⁹ IRENA (2012) <u>Biomass for Power Generation</u>. p. i. [50]

¹⁹⁰ IRENA (2012) Biomass for Power Generation. p. 35. [50]

¹⁹¹ IRENA (2012) <u>Biomass for Power Generation</u>. p. 28. [50]

¹⁹² NREL (2022) <u>Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035</u>. p. 109.[66]

study of CO₂ removal options for California at-large, experts found that "NNBFs [netnegative biofuels], and specifically biomass gasification to hydrogen, had the largest potential and among the lowest cost of carbon removal options for California."¹⁹³

4.4.3.1 Proximate feedstocks

Feedstocks for biomass carbon capture are abundantly available in Kern County, and the available feedstocks are highly preferred from a climate perspective. Both the area's high concentration of agricultural waste and steady supply of municipal organic waste could be used to fuel a BiCRS facility in the region. Within California, there is an estimated 55 million tons (Mt) of biomass available annually for energy applications, not including energy crops.¹⁹⁴ Within Kern County, the 2019 County Crop Report determined that 237,000 tons of almond hulls and shells and 236,000 tons of biomass were produced from the local agriculture industry.¹⁹⁵ The collective ~470,000 tons of biomass would be enough to support a ~620,000 ton CO_2 capture BiCRS facility—see Section 11 for more details about these calculations in relation to local agricultural waste.

4.4.3.2 Proximate consumers

Depending on the process used to extract carbon from oven-dried biomass, a byproduct of BiCRS facilities using slow pyrolysis processing is biochar—a material which can be applied to crop fields to improve soil fertility.¹⁹⁶ Given agriculture's large footprint in the area, this could produce a symbiotic relationship, with farms supplying agricultural waste feedstock and consuming the carbon-rich biochar produced by a local BiCRS facility.

There may also be proximate consumers for other biofuel or carbon offsets given the relative closeness of both Los Angeles and the Bay Area. Regional leaders in the digital technology space, such as Stripe in San Francisco, have been key investors in start-ups working towards carbon removal strategies.¹⁹⁷

4.4.3.3 Co-location advantages

The primary co-location advantage for biomass processing facilities is the ability to share infrastructure for common needs— CO_2 transport for sequestration or use, onsite water supplies, and the potential of using electricity from a shared solar array or other off-grid power source with other companies. Co-locating reduces the costs, and therefore risks, of each player within the carbon management park.

¹⁹³ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 2. [86]

¹⁹⁴ Stolaroff *et al.* (2021) <u>Transport for Carbon Removal Projects</u>. p. 2. [86]

¹⁹⁵ Kern County Department of Agriculture and Measurement Standards (2020) <u>2019 Kern County</u> <u>Agricultural Crop Report</u>. p. 10. [53]

¹⁹⁶ Sandalow *et al.* (2021) <u>BiCRS Roadmap</u>. p. 1. [80]

¹⁹⁷ Plumer, Flavelle (January 18, 2021) <u>Businesses Aim to Pull Greenhouse Gases From the Air</u>. [74]

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5. CO₂-emitting Industries

TECHNOLOGY AT A GLANCE:

- Point source carbon capture is a technique applied to industrial and energy facilities that emit large concentrations of CO₂. The technology is commercially available and used in over 30 energy plants and manufacturing facilities worldwide, but its cost (and thus level of deployment) varies as a function of facility type.¹
- Of the many industries that could use point source carbon capture, the steel industry was the most practical to investigate for purposes of location in Kern county.
- Carbon capture in the steel industry is in an early commercial stage: globally, there is 1 steel mill operating with carbon capture.
- Several techniques for producing low carbon steel are in the pilot or demonstration phase, and are explored briefly here, although they would not involve capture and storage of CO₂, and thus would not qualify as a carbon management technology.
- Current cost per metric ton CO₂ captured from steel: \$68-114 USD/ton CO₂.
- Projected cost per metric ton CO₂ captured at scale: \$40-90 USD/ton CO₂.
- Key advantages of this technology in Kern County: steel mills can provide hundreds of high paying jobs, many of which do not require post-secondary education.
- Key concerns for this technology in Kern County: steel mills do produce emissions, wastewater and solid byproducts that will have to be mitigated to meet regional environmental and safety standards.

¹ Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

5.1 Technology Summary

5.1.1 Description: How it Works

5.1.1.1 Point Source Carbon Capture

Many industries and energy facilities produce CO_2 as a byproduct of their processing activities, collectively accounting for about half of global greenhouse gas emissions.^{2,3} However, most of these industries and facilities can employ a technology called *point source carbon capture*, which scrubs CO_2 from significant points of exhaust before they are released to the atmosphere. In contrast to Direct Air Capture (DAC, Section 3) and Biomass with Carbon Removal and Storage (BiCRS, Section 4), which are designed to remove human-derived CO_2 emissions from the ambient air, point source capture prevents the release of CO_2 before it is emitted. Point source carbon capture is at an advanced state of technological development, and many techniques are commercially available today that can be used to trap CO_2 from the exhaust of coal and natural gas power plants and boilers, or in the industries of natural gas processing, petrochemical development, fertilizer development, iron and steel manufacture, cement production and paper mills.⁴ Despite this, only about 230 million metric tons of CO_2 are captured annually,⁵ less than 1% of the 28 billion metric tons of CO_2 emitted from these sectors globally each year.⁶

Of those facilities that do employ carbon capture, most in operation today use a solventbased approach, illustrated in Figure 5.1.⁷ Rather than directly emitting CO₂-bearing flue gas through exhaust chimneys of a plant or facility, the flue gas is diverted to a separate *absorption tower*, where it is mixed with a liquid solvent. The solvent has either chemical properties that cause the CO₂ to readily dissolve into the fluid (for example having a mildly basic pH),⁸ or a component of the solvent physically attracts the CO₂, such that it is drawn out of the flue gas and sorbs onto the surface of the molecular component in the capture fluid.⁹ The flue gas is returned to the chimney and released; the CO₂-rich capture fluid is transferred to a stripping tower (or capture tower), where the CO₂ is separated from the solvent. In chemical solvents, this is accomplished by increasing the temperature (making

² Ritchie, Roser, Rosado (February 15, 2023) <u>CO₂ and Greenhouse Gas Emissions</u>. [68]

³ Ge *et al.* (February 6, 2020) <u>GHG emissions by sector</u>. [35]

⁴ Bettenhausen (July 18, 2021) <u>Improving carbon capture</u>. [5]

⁵ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 109. [41]

⁶ Ge *et al.* (February 6, 2020) <u>GHG emissions by sector</u>. [35]

⁷ Kearns et al. (2021) <u>CCS readiness and costs</u>. p. 11-12. [45]

⁸ Carbon dioxide removal: Carbon capture and storage, Part I. Climate Now. Published online November 8, 2021. Accessed March 14, 2023 from <u>https://climatenow.com/video/carbon-capture-and-storage-part-i/</u>. 3:20.

⁹ Bettenhausen (July 18, 2021) <u>Improving carbon capture</u>. [5]

the CO_2 exolve as a gas). In physical solvents, pressure is decreased such that CO_2 is more stable as a gas than bound to the surface of the in-solvent physical adsorbents.¹⁰

A less common capture technique makes use of membranes (mostly used for natural gas processing). Membranes are permeable physical barriers that allow gasses to pass through at variable rates, effectively separating some gas molecules from others.¹¹ Like physical solvents, membranes are used in processes that have high concentrations of CO₂ in the flue gas stream, whereas chemical solvents are more efficient when CO₂ makes up less than 15% of the flue gas.¹²

The cost (and thus feasibility) of point source carbon capture is directly proportional to the concentration (or partial pressure) of CO_2 in the exhaust stream, and is therefore industry specific.¹³ Carbon capture technology for gas streams with CO_2 concentrations higher than 25% have been used in industrial applications since the 1940s¹⁴, and technologies currently exist that can capture CO_2 from gas streams with concentrations as low as hundreds of parts per million (as in the atmosphere). But to date, CO_2 point source capture has not been implemented on a large scale due to lack of financial or regulatory incentives.¹⁵



Figure 5.1. Generalized schematic of point source carbon capture. Adapted from Kearns et al. (2021).¹⁶

Industries for which point source capture is applicable for the purpose of carbon capture are summarized in Table 5.1. For the purposes of this analysis, our mandate was to explore industries for which there are existing or planned facilities in Kern County, and that might reasonably be included in a carbon management business park. According to the EPA

¹⁰ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 15. [45]

¹¹ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 16. [45]

¹² Bettenhausen (July 18, 2021) Improving carbon capture. [5]

¹³ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 3. [45]

¹⁴ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 10. [45]

¹⁵ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. [45]

¹⁶ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 13. [45]

Facility Level Information on GreenHouse gases Tool (FLIGHT), Kern County has 44 facilities that reported significant CO_2 emissions in 2021,¹⁷ and are divided into the following sectors:

- 15 Power plants
- 20 Petroleum and natural gas systems or refineries
- 4 Agriculture and/or food processing facilities
- 2 Waste facilities (Bakersfield and Clean Harbors landfills)
- 2 Cement facilities
- 1 Mine (Borax boron mine and refinery)

Agricultural facilities and landfills - while sources of emissions - are not viable candidates for point source capture because greenhouse gas emissions are diffuse, rather than concentrated from a single or few point(s) of exhaust (although waste could be diverted from landfills to a BiCRS facility, see Section 4). The cement and borax facilities are site dependent, meaning that although point source carbon capture could be a viable carbon management option in these industries, facilities are located adjacent to the mine or quarry from which raw material is extracted, and thus are not likely candidates for development in a dedicated carbon management park. Finally, because the business park under consideration would utilize renewable energy sources and is intended to be complementary rather than additive to the existing oil and gas sectors of Kern County, we have excluded investigation of power plants, natural gas processing, and petroleum refineries from this analysis. For additional information on the potential of point source capture for these CO₂-emitting industries, the interested reader is referred to two recent reports from the International Energy Agency on carbon capture utilization and storage (CCUS) in clean energy transitions¹⁸ and the role of CCUS in low-carbon power systems.¹⁹

Another CO₂-emitting industry is not yet operating in Kern County but may be in the future. The San Diego-based Pacific Steel Group announced in April 2022 that it plans to build a state-of-the-art steel plant in southeast Kern County, with construction beginning in 2025.²⁰ As of the publication of this report, Pacific Steel Group's proposal is under planning and permitting review by the county.

Steel mills are technologically diverse. Depending on the type of steel production employed, they can produce as much as 2.4 tons of CO_2 for every ton of steel produced (Table 5.2), or – with the most advanced technologies – no CO_2 .²¹ Here, we examine the

¹⁷ EPA (no date) <u>FLIGHT</u>. [27]

¹⁸ IEA (2020) <u>CCUS in clean energy transitions</u>. [41]

¹⁹ IEA (2020) <u>The role of CCUS in low-carbon power systems</u>. [42]

²⁰ Cox (March 14, 2022) <u>'Green steel' plant proposed for Mojave</u>. [21]

²¹ Soderpalm (August 19, 2021) <u>Sweden's HYBRIT delivers world's first fossil-free steel</u>. [72]

steel industry both as a potential carbon management industry and as an emerging clean energy technology.

Industry	CO ₂ Concentration in Exhaust ^a		Cost of Capture⁵	Commercial Facilities [®]	
	vol %	Partial Pressure ^d	(USD/mtCO₂)	Operational	In Development
Natural gas processing	2-65	0.05 - 5	\$15-25	15	12 (9) ^e
Fertilizer (ammonia) production	18-40	0.3 - 2.5 ^f	\$25-40	4	1 (7)
Bioethanol production ⁹	85-100	0.085 - 0.10	\$15-30	4	35 (3)
Production of other chemicals	7-92	0.2 - 0.27	\$25-40	4	2 (7)
Hydrogen production (Blue H ₂)	15-20	0.3 - 0.5	\$50-80	3	12 (18)
Power generation - coal	12-15	0.012 - 0.014	\$45-100	3	7 (4)
Power generation - NG	3-5	0.003 - 0.005	\$50-100	0	9 (14)
Waste to energy ^g	10-12	0.010 - 0.012	\$15-85	0	3 (3)
Iron and steel production	4-35	0.004 - 0.060	\$60-100	1	0 (1)
Cement production	14-33	0.014 - 0.033	\$60-120	0	2 (7)
TOTAL				34	83 (73)

Table 5.1. Industrial sources of emissions with commercial carbon capture facilities, globally.

a. Gale et al. (2005) IPCC Sources of CO2. p. 79-80., Kearns et al. (2021) CCS readiness and costs. p. 25.

b. Sources: Sanchez et al. (2017) <u>CCS from biorefineries</u>,²² Fuss et al. (2018) <u>Negative emissions</u>,²³ IEA (2020) <u>CCUS in clean energy transitions</u>.

- c. Global CCS Institute Facility Database.24
- d. Units are in MPa. (0.1 MPa = 1 bar = 0.99 atmospheres of pressure)
- e. Those in parentheses are in early development stages. All other facilities are in construction or advanced development. For details, see Appendices A-C.
- f. Up to 25% of captured CO₂ is used to convert produced ammonia to urea to create fertilizer.²⁵
- g. These industries can are examples of BiCRS/BECCS, and are discussed further in Section 4.

5.1.1.2 Steel Production and Carbon Emissions

There are a variety of production routes for steel, which vary as a function of the iron source material being used. Source materials include iron ore, the raw material mined from geologic deposits, direct reduced iron (DRI), which is formed by reducing iron ore in the presence of natural gas or a coal derivative, and recycled scrap steel. Integrated steel plants

²² Sanchez *et al.* (2017) <u>Near-term deployment of CCS from biorefineries</u>. [70]

²³ Fuss *et al.* (2018) <u>Negative emissions</u>. p. 20. [32]

²⁴ GCCSI (no date) <u>CO₂RE Facilities Database</u>. [36]

²⁵ TFI (no date) <u>State of the fertilizer industry: Environment & Energy</u>. [78]

can produce steel from any of these sources, typically using a *blast furnace* (BF) to convert iron ore to reduced iron, and using a *basic oxygen furnace* (BOF) to convert the reduced iron, DRI and/or scrap steel to new steel products.²⁶



Figure 5.2. Process pathways for the two main methods of iron and steel production, blast furnace + basic oxygen furnace (BF-BOF, typical in integrated steel mills) and the electric arc furnace (typical in mini mills that use scrap \pm direct reduced iron (DRI) as an iron source. Adapted from de Beer et al. (2003).²⁷

These types of steel facilities currently account for over 70% of global steel production,²⁸ but since the 1960's²⁹ a new type of mill, called mini mills, are becoming increasingly common and are now the predominant mill type in the United States.³⁰ Mini mills (and even more recently, micro mills)³¹ use a technology called *electric arc furnaces* to re-melt, refine and alloy scrap steel, or less commonly, DRI. Because they do not require the raw materials (iron sinter and/or pellets and coke) or extremely high heat needed to reduce iron ore in a

²⁶ de Beer *et al.* (2003) Emissions from iron and steel production. [24]

²⁷ de Beer *et al.* (2003) Emissions from iron and steel production. p. 14. [24]

²⁸ Kueppers *et al.* (2022) <u>Iron and Steel</u>. [49]

²⁹ Stubbles (2009) <u>The minimill story</u>. [76]

³⁰ CRU (2022) <u>Steelmaking emissions analysis</u>. [22]

³¹ Anderton (August 6, 2015) <u>Micro steel mills are competitive</u>. [3]

blast furnace, these smaller mills are able to produce steel at cost-competitive rates with the significantly larger integrated steel mills. Their growth potential is simply limited by the availability of scrap steel or DRI.³²

Process Step	Direct CO ₂ Emissionsª (tCO ₂ /t steel)	Capture Eligible? (tCO₂/t steel)	Energy Use (GJ/t steel)	CO ₂ from NG Energy Source ^b (tCO ₂ /t steel)				
Electric Arc Furnace + Scrap (EAF)								
Treatment of raw materials	0	N/A	N/A	N/A				
Iron making	N/A	N/A	N/A	N/A				
Steel making	0.04-0.12	No	1.3-3.3	0.06-0.15				
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10				
TOTAL	0.11-0.32	No	1.3-5.5	0.06-0.25				
Electric Arc Furnace + Direct Reduced Iron (DRI-EAF)								
Treatment of raw materials	0.02-0.05	No	1.9	0.09				
Iron making	0.52-1.05	Yes	10.9-16.1	0.5-0.74				
Steel making	0.04-0.12	No	1.3-3.3	0.06-0.15				
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10				
TOTAL	0.65-1.44	0.42-0.84	14.1-23.5	0.65-1.08				
Blast Furnace + Basic Oxygen Furnace (BF-BOF)								
Treatment of raw materials	0.05-0.5	Some	1.75-3.2	0.08-0.15				
Iron making	1.3-1.5	Yes	9.8-13.5	0.45-0.62				
Steel making	0.13-0.21	Yes	7.9-11	0.36-0.51				
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10				
TOTAL	1.55-2.43	0.92-1.12	19.5-29.9 °	0.89-1.38				

Fable 5.2. CO ₂ -equivalent emissions a	as a function of steel-making	process and process step.
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a. Data from de Beer et al. (2003) <u>Emissions from iron and steel production</u>, CRU (2022) <u>Steelmaking emissions analysis</u>, and Fan and Friedmann (2021) <u>Low-carbon production of iron and steel</u>, Fruehan et al. (2000) <u>Minimum energies to produce steel</u>.

b. Natural gas CO₂ emission factor from Our World in Data.³³

C. ~6 Gj of process heat are created per ton of steel produced, reducing this total value to ~13.5-24 Gj/ton of steel of net-energy requirements. (IEA (2020) <u>Iron and Steel Roadmap</u>.)

³² de Beer *et al.* (2003) Emissions from iron and steel production. [24]

³³ Our World in Data (no date) <u>Carbon dioxide emissions factor</u>. [63]

The intensity of CO₂ emissions produced during the steelmaking process is dependent on the steelmaking route used, and thus integrated steel mills, mini mills, and scrap-specific mini mills have very different emissions profiles.³⁴ To break down the sources of CO₂ emissions associated with each type of steelmaking process, and its potential for capture or mitigation, in the following sections we examine each step of steelmaking systematically. A flow chart outlining each step in steel making, and how those steps vary by process, is provided in Figure 5.2, and a summary of the sources and volume of greenhouse gas emissions from each step is provided in Table 5.2.

Treatment of raw materials

To make new steel, raw iron ore (the oxidized iron material mined from geologic formations) must be reduced to metallic iron,³⁵ which must then be treated by the addition or removal of carbon and other trace metals to achieve an alloy with the desired properties (i.e. strength, hardness, ductility, or weldability).³⁶ Luckily, once made, steel is an excellent candidate for recycling. Scrap steel, which is the steel discarded as waste either during manufacture or from products at the end of their useful life, can be repeatedly turned back into new steel, while retaining its original properties.³⁷

Every steel manufacturer uses some amount of scrap to produce new steel.³⁸ In dedicated scrap mini mills, scrap represents 100% of the raw material for steel production. In regions where scrap is scarce, mini mills will supplement scrap with metallic iron converted from ore via the direct reduction (direct reduced iron, or DRI) method.³⁹ In integrated steel mills, scrap is most commonly combined with pig iron, the material made from iron ore using a blast furnace (Figure 5.3).⁴⁰



Figure 5.3. a. Hot iron pellets. Pellets are generally ~1cm in diameter. b. Iron sinter, on A4 size paper, for scale. Image credits: Wikimedia commons, RobSimmons 223311, <u>CC BY-SA 4.0</u> and Borva53, <u>CC BY-SA 4.0</u>.

³⁴ de Beer *et al.* (2003) Emissions from iron and steel production. p. ii. [21]

³⁵ IIMA (no date) <u>About Metallics</u>. [43]

³⁶ Mar (September 28, 2017) <u>Chemical composition of steel</u>. [57]

³⁷ World Economic Forum (January 17, 2023) <u>Steel scrap and how it can help reach net zero.</u> [90]

³⁸ World Steel Association (2021) <u>Scrap use in the steel industry</u>. [91]

³⁹ de Beer *et al.* (2003) Emissions from iron and steel production. p. 21. [24]

⁴⁰ IIMA (no date) <u>About Metallics</u>. [43]

The preparation of scrap material for recycling into new steel products is relatively minimal - it involves collection, cleaning, and sorting.^{41,42} However, creation of metallic iron (either DRI or pig iron) requires the conversion of iron ore into a form that can be fed into the smelter or furnace. Two conversion processes are used: pelletization (for DRI and pig iron) and sinter plants (for pig iron only).⁴³ Pelletization occurs in a pellet plant, which can be cited at the ore mine or steel mill, and involves first crushing and grinding iron ore, and then forming 'green balls' of material by aggregating the iron grounds with crushed limestone, clays, and water. The balls are hardened for transport and loading through an *induration process*; they are dried, fired in a kiln at temperatures up to 1350°C, and cooled.⁴⁴ Sinter plants prepare iron ore by combusting it at ~1300-1480°C with limestone and coke breeze (used as the fuel) to produce a carbon-rich, porous clinker.⁴⁵ Formation of raw iron (pig iron or DRI) is often measured in 'tons of hot metal.'⁴⁶ For each ton of hot metal, about 1.5-1.7 tons of pellets or sinter is required.^{47,48}

In integrated mills, coke is another raw material that needs to be treated in preparation for iron making. Coking is the process of converting metallurgical coal to the porous, carbon-rich material 'coke.' Metallurgical coal is heated to temperatures up to 1125°C, melting and releasing any volatiles, and then re-solidifying as coke.⁴⁹ About 0.3-0.5 tons of metallurgical coal are used for each ton of hot metal produced.⁵⁰

Pelletization, sintering and coking all emit CO_2 - about 0.02-0.05, 0.3-0.4, and 0.03-0.10 tons CO_2 per ton hot metal, respectively.^{51,52} The combined impact of these emissions on the carbon intensity of final steel products derived from a given steel production pathway is detailed in Table 5.2.

Iron making

In integrated steel making, iron pellets, sinter, and coke are combined in a *blast furnace* (Figure 5.4) to form hot iron metal, or in its cooled form, pig iron. Coke is used as a fuel - combusting to help the furnace reach the melting temperatures of iron (as much as $2000^{\circ}C^{53}$), as a reductant - accepting oxygen from the iron oxides in the ore material to

⁴¹ Peters *et al.* (2021) Improve the EAF scrap route for a sustainable value chain. p. 10. [66]

⁴² de Beer *et al.* (2003) Emissions from iron and steel production. p. 14. [24]

⁴³ de Beer et al. (2003) Emissions from iron and steel production. p. 38-40. [24]

⁴⁴ de Moraes *et al.* (2018) <u>Iron ore pelletizing process: An overview</u>. [25]

⁴⁵ de Beer *et al.* (2003) Emissions from iron and steel production. p. 13-15. [24]

⁴⁶ Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. [30]

⁴⁷ Uys, Kirkpatrick (1963) <u>The beneficiation of raw materials in the steel industry</u>. [84]

⁴⁸ Van Wortswinkel, Nijs (2010) <u>ETSAP - Iron and Steel</u>. [86]

⁴⁹ Kentucky Geological Survey (no date) <u>Coal to make coke and steel</u>. [46]

⁵⁰ de Beer *et al.* (2003) Emissions from iron and steel production. p. 16. [24]

⁵¹ de Beer *et al.* (2003) Emissions from iron and steel production. p. 15-17. [24]

⁵² Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. p. 833. [30]

⁵³ IIMA (no date) <u>About Metallics</u>. [43]

produce metallic iron and CO₂, and as a charger - increasing the carbon content of the iron, which is critical for processing to steel in the *basic oxygen furnace*.⁵⁴ Within the steel making process, blast furnaces represent the largest source of CO₂ emissions, about 70% of emissions in an integrated plant.⁵⁵ For each ton of steel produced,⁵⁶ about 1.3-1.4 tons of CO₂ are released.⁵⁷



Figure 5.4. a. Schematic of iron production via blast furnace. b. Blast furnace, Port of Sagunto, Spain. Image credit: Wikimedia Commons, Diego Delso, <u>CC BY-SA 4.0</u>. c. Schematic of direct reduced iron production (modeled after the Midrex process, one of several flow processes for DRI). Adapted from <u>International Iron Metallics Association</u>. DRI facilities are of a similar scale to blast furnaces – the shaft furnace is a multi-story scaffolded building, with an attached conveying system for the iron ore pellet charge.

Direct reduced iron is an alternative to pig iron that can be used in *electric arc furnaces*. It has a significant advantage over the blast furnace in terms of emissions because it does not require coke as a fuel or additive. Rather, a natural gas- or coal-derived reducer, called syngas (CO + H_2), is used to remove oxygen from the pelletized iron ore. This process takes place in solid state; the ore never actually melts. Thus, required temperatures for the process are much lower, reaching only 900-1000°C. Because iron is not melted, impurities present in the ore are retained in the DRI product. This can mean additional additives will

⁵⁴ de Beer *et al.* (2003) Emissions from iron and steel production. p. 18-21. [24]

⁵⁵ Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. p. 831. [30]

⁵⁶ Some references report emissions in tons of hot metal (what emerges from the iron making process), whereas other references report emissions as a function of tons of steel. de Beer *et al.* (2003) <u>Emissions from iron and steel production</u> (p. 26) reports that hot metal comprises 65-90% of steel output, the balance being from scrap. To maintain continuity, we assume that 0.9 tons of hot metal are used to produce 1 ton of steel, with scrap steel comprising the remaining steel input.

⁵⁷ Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. p. 833. [30]

be needed in the steel-making step to extract unwanted impurities or to add underrepresented elements, like carbon, that control desired steel properties.^{58,59} The combustion of coal or natural gas to produce DRI emits between 0.5 and 1.0 tons of CO_2 per ton steel (Table 5.2).⁶⁰

Two other processes are worth noting briefly here: smelt reduction and hydrogen steel production. Smelt reduction is an alternative mechanism for producing pig iron that employs direct reduction of iron ore fines (omitting the pelletization or sintering step) in the presence of coal.⁶¹ The technology is mature, but has seen very little penetration in the global iron production market, likely because it is more expensive than conventional blast furnace-basic oxygen furnace (BF-BOF) production, but more carbon intensive than scrap-EAF or DRI-EAF processes.⁶²

Hydrogen-blended, or hydrogen fueled steel production are clean-energy alternatives to existing steel production, that are still in the early development or demonstration stages of technological readiness. These technologies would adapt existing BF, DRI, and smelting reduction reactors to operate with H₂ as part or all of the reducing agent and fuel source for the ironmaking step of steel production, resulting in reduced or eliminated process emissions of CO₂.⁶³

Steel making

Once crude iron has been produced, it is introduced into a furnace to further refine to steel. The purpose of this step is to remove any undesired impurities from the source iron, and to adjust the concentration of carbon and other desirable elements that imbue steel with specific properties optimized for its final intended use.⁶⁴ Basic oxygen furnaces (BOFs) are traditionally used in integrated mills, with iron sourced primarily from blast furnaces, with scrap and occasionally DRI to supplement.⁶⁵ The furnace is a large and pear-shaped reactor, where pure oxygen is blown into the vessel to react with the liquid iron metal. Carbon, and other impurities, are oxidized by the iron and separated, creating CO₂ gas and a metal-oxide-rich slag.⁶⁶ The molten and purified steel are separated and transported to a finishing facility for casting and rolling (Figure 5.2). BOFs are enormous, housed in buildings that can be as much as 80 meters (~260 feet) high. This is to accommodate the gravity feed equipment, oxygen lance and off-gas cooling systems.⁶⁷

⁵⁸ IIMA (no date) <u>About Metallics</u>. [43]

⁵⁹ de Beer *et al.* (2003) Emissions from iron and steel production. p. 21-23. [24]

⁶⁰ Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. p. 835. [30]

⁶¹ IEA (2020) <u>Iron and Steel Roadmap</u>. p. 91. [40]

⁶² IEA (2020) <u>CCUS in clean energy transitions</u>. p. 65. [41]

⁶³ IEA (2020) Iron and Steel Roadmap. p. 91. [40]

⁶⁴ de Beer *et al.* (2003) Emissions from iron and steel production. p. 26. [24]

⁶⁵ de Beer et al. (2003) Emissions from iron and steel production. p. 26-27. [24]

⁶⁶ Britannica.com (no date) Primary Steelmaking. [7]

⁶⁷ Britannica.com (no date) Primary Steelmaking. [7]

In mini steel mills (and some integrated mills), the electric arc furnace (EAF) is used in the steel making step. This process involves using a high-current electric arc to melt steel scrap (\pm DRI), which is chemically adjusted by varying the melting temperature and "charging" with DRI, pig iron and limestone (for slag formation). Because EAF is less oxidizing than BOF, steels made by this process typically have higher carbon contents than BOF steel, and CO₂ emissions from the EAF are lower - about 0.4 to 0.12 tons of CO₂ is released per ton of steel processed in an EAF, compared to 0.14 to 0.21 tons of CO₂ per ton steel in BOF processes (Table 5.2). An EAF furnace is much smaller than a BOF, with a shell diameter ranging from ~6-9 meters (20-30 feet), and able to process 100-300 tons of steel melt at a time.⁶⁸



Figure 5.5. a. Basic oxygen furnace being charged at the ThyssenKrupp steel mill in Duisburg. Image credit: Wikimedia Commons, Katpatuka, <u>CC BY-SA 3.0</u>. b. Electric arc furnace of the Georgsmarienhütte GmbH steel plant in Germany. Wikimedia Commons, GMH official, <u>CC BY-SA 3.0</u>.

Casting, rolling and finishing

Most steel facilities use continuous casting (rather than ingot casting) to cool and prepare steel for shaping into a range of final products.⁶⁹ In this process, liquid steel is continuously fed into short, vertical water-cooled copper molds. The outer most shell of the steel 'strand' is solidified, allowing them to be rolled out of the copper molds, as the inside continues to cool and solidify. Once solidified, the steel is cut into billets, blooms or slabs (distinguished by size), which are then shaped into finished products.⁷⁰ Such shaping takes place through rolling and finishing operations - hot rolling (done immediately after the slabs have been cast) and cold rolling (done once the slabs are cooler than their recrystallization

⁶⁸ Britannica.com (no date) <u>Primary Steelmaking</u>. [7]

⁶⁹ de Beer *et al.* (2003) Emissions from iron and steel production. p. 63. [24]

⁷⁰ de Beer *et al.* (2003) <u>Emissions from iron and steel production</u>. p. 31. [24]

temperature) are used to reduce slab thickness and ensure thickness uniformity,⁷¹ and further cutting to the preferred shape and size of the final steel product. An analysis performed for the Steel Manufacturers Association⁷² estimated that high-temperature heat emissions related to this portion of the steel making process was between 0.07 and 0.22 tons CO₂ per ton steel (Table 5.2), with lower values being associated with younger, more efficient facilities.

5.1.1.3 Carbon Capture in the Steel Industry

Pilot studies and research on the application of carbon capture as a decarbonization solution in the steel industry has been most closely applied to integrated mills, where blast furnaces produce ~80% of the mill's emissions (Table 5.2).⁷³ Retrofitted carbon capture devices on the blast furnace could capture as much as 65% of CO₂ emissions, and an additional ~10-20% could be conserved by adding oxygen and combusting the exhaust stream (composed of CO + CO₂) to provide heat energy to the furnace or other plant facilities.^{74,75} It is possible to apply commercially available carbon capture devices to other components of the integrated mill system (coke production, sinter production and the BOF), but as these produce a smaller fraction of total emissions, capturing CO₂ from these sources is likely not cost-effective for a globally-traded industry that must operate on tight profit margins.⁷⁶ For example, when blast furnace gas is combusted in the presence of air, the concentration of CO₂ in the exhaust is about 27 vol%. In contrast, the composition of offgas from a basic oxygen furnace includes only about 16 vol% CO₂.⁷⁷ Thus, the basic oxygen furnace produces less CO₂ to capture, and does so at a higher price per ton CO₂ captured.

DRI can also be designed or retrofitted with carbon capture, with the possibility of capturing as much as 80% of CO₂ emissions, although the lower concentrations of carbon in the flue gas make this process more challenging and expensive than carbon capture for BF-BOF.⁷⁸ The only commercially operating steel mill with carbon capture in the world - in Abu Dhabi, U.A.E. - captures carbon from the DRI process (see Section 5.1.2.2). An alternative decarbonization approach for DRI is using green hydrogen (produced via electrolysis or gasification of biomass, see Sections 6 and 4, respectively) as a carbon-free replacement fuel, but adapting the EAF technology for this fuel is far from technologically ready, and could be prohibitively expensive until the cost of producing green hydrogen decreases.^{79,80}

⁷¹ American Steel Products Company (January 5, 2017) <u>What is a rolling mill?</u> [2]

⁷² CRU (2022) <u>Steelmaking emissions analysis</u>. [22]

⁷³ CRU (2022) <u>Steelmaking emissions analysis</u>. [22]

⁷⁴ de Beer *et al.* (2003) Emissions from iron and steel production. p. 71. [24]

⁷⁵ EPRS (2021) <u>Carbon-free steel production</u>. p. 15-16. [28]

⁷⁶ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 64-65. [41]

⁷⁷ Gale *et al.* (2005) <u>Chapter 2: Sources of CO₂</u>. p. 80. [33]

⁷⁸ EPRS (2021) <u>Carbon-free steel production</u>. p. 15-16. [28]

⁷⁹ Liberty Steel Group (no date) <u>A direct reduced iron (DRI) plant</u>. [53]

⁸⁰ IEA (2020) Iron and Steel Roadmap. p. 91. [40]

EAF, like the blast furnace, emits an exhaust stream of $CO + CO_2$, which could be captured or re-used for its waste heat. However, even less CO_2 is emitted per ton of steel in this process than the BOF or raw material treatments (Table 5.2), making it unlikely that capture would ever be cost effective. In fact, for most EAFs, the emissions produced by creating the grid-sourced electricity needed to operate the facility are more than double the direct emissions from the furnace,⁸¹ and thus supplying an EAF mini mill with off-grid, carbonfree electricity would be the most efficient decarbonization approach for these kinds of facilities. While such a facility would produce low-carbon steel, it would not be considered a carbon management industry, as no appreciable carbon capture could take place.

Some researchers have proposed powering the EAF with natural gas via oxy-fuel combustion, rather than grid or renewable-sourced electricity.⁸² Oxy-fuel combustion combusts natural gas (or biomass-derived syngas, or renewable natural gas) in the presence of a pure oxygen stream, creating outputs of a pure stream of CO₂, water and electricity (see Section 4).⁸³ Thus, a mill could produce low-carbon steel and CO₂ for capture. If a scrap mini mill were powered entirely by natural gas with oxy-fuel combustion, approximately 0.06-0.25 (~0.15 on average) tons of CO₂ would be produced per ton of steel produced. Using oxy-fuel combustion from natural gas to power a DRI-EAF mini mill would produce about 0.65-1.08 tons of CO₂ per ton of steel, and for a BF-BOF mill it would produce about 0.89-1.38 tons of CO₂ per ton of steel (Table 5.2).⁸⁴

5.1.2 State of Development

The technological readiness of carbon capture in the steel industry is a two-part problem: first, what is the state of development of point source carbon capture technology? Second, to what extent is such technology (or other decarbonization technologies) ready to be implemented within the steel sector? Here, we will give a brief summary of the state of development of point source carbon capture, with a focus on the most developed approach: chemical solvents. Then we will highlight global examples of decarbonization efforts in the steel industry, with a focus on capture and green hydrogen substitution.

5.1.2.1 Point Source Carbon Capture

Chemical and physical solvents have been in commercial use for decades, and technological development in this space has been focused on reducing the costs of such solvents so that they can be used in industries that produce more diffuse gas streams, or where profit margins are tight.⁸⁵ Examples of cost-saving innovations include creation of water-lean solvents, which require a much lower energy input to regenerate the solvent (release the CO₂), simply because less water needs to be boiled. <u>Ion Clean Energy</u> is a

⁸¹ CRU (2022) <u>Steelmaking emissions analysis</u>. [22]

⁸² de Beer *et al.* (2003) Emissions from iron and steel production. p. 73. [24]

⁸³ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 99. [41]

⁸⁴ de Beer *et al.* (2003) Emissions from iron and steel production. p. 13-15. [24]

⁸⁵ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 12. [45]

commercial company that produces water-lean liquid solvent capture plants, and more recently, <u>Pacific Northwest National Lab</u> developed a technique that uses an oil-based instead of water based solvent, reducing water requirements by as much as 97%.^{86,87} Another next-generation solvent technology comes from the company <u>Saipem</u>. They have identified a biologically-derived enzyme that speeds a naturally slow carbonate salt solvent. The increased capture efficiency allows more CO_2 to be captured with a smaller stripper (and thus smaller footprint and lower capital costs), and the carbonate salt technology has the added benefits of being able to regenerate with hot water, rather than steam (so waste heat can be used as an energy source), and producing no hazardous waste byproducts.^{88,89}

Another company, <u>Carbon Clean</u>, is also driving cost savings by modularizing and reducing the physical footprint of their carbon capture technology. Their carbon capture system is the size of a shipping container, and can capture up to 35,000 metric tons of CO₂ annually. That is about one tenth the size of conventional carbon capture facilities.⁹⁰ Carbon Clean is developing a variety of projects in California, and globally. It is working with Cemex in Victorville, CA to capture carbon at a cement plant,⁹¹ and with Chevron to create a pilot facility in Kern County that would capture CO₂ from a gas turbine at the Kern River Eastridge cogeneration plant.^{92,93} They have also launched a demonstration facility in India, capturing 5 metric tons of CO₂ per day from the blast furnace of Tata Steel's Jamshedpur plant.⁹⁴

5.1.2.2 Example Projects in the Steel Industry

In the steel industry, scrap-based mini mills powered by carbon-free energy are the optimal solution for decarbonizing the sector. However, although ~85% of steel waste is recycled as scrap, it is not enough to meet the global demand for steel.⁹⁵ In terms of carbon capture as a decarbonization solution for ore-sourced steel making, DRI is the most technologically advanced. Carbon capture applied to smelt reduction or blast furnace process gas is still in the development to demonstration stages.⁹⁶ Replacing hydrocarbons (coke, coal and natural gas) with hydrogen as the reduction agent and/or fuel, is also still in development stages.⁹⁷ Below is a sample of key leaders in each of these innovations.

⁸⁶ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 13. [45]

⁸⁷ Clifford (January 24, 2023) <u>New technique from U.S. national lab promises to strip carbon</u> <u>dioxide</u>. [18]

⁸⁸ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 13. [45]

⁸⁹ Saipem (no date) <u>CO₂ Solutions</u>. [69]

⁹⁰ Clancy (May 18, 2022) <u>Meet the startup shrinking industrial carbon capture</u>. [16]

⁹¹ Carbon Clean (February 9, 2021) <u>CEMEX Awarded Grant from US Department of Energy</u>. [12]

⁹² Carbon Clean (February 24, 2022) <u>Chevron announces investment in Carbon Clean</u>. [13]

⁹³ Kumar (May 18, 2022) <u>Chevron to launch carbon capture project in San Joaquin Valley</u>. [50]

⁹⁴ Carbon Clean (September 14, 2021) India's first blast furnace carbon capture plant. [11]

⁹⁵ IEA (2020) Iron and Steel Roadmap. p. 62. [40]

⁹⁶ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 62. [41]

⁹⁷ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 62. [41]

Al Reyadah CCUS Project, Abu Dhabi, U.A. Emirates

The first (and as of this report's publication, only) fully commercial carbon capture and storage facility for the iron and steel industry is at a DRI plant in Abu Dhabi, where an existing facility was retrofitted with traditional liquid solvent capture technology (using monoethanolamine, or MEA, which is the industry leading solvent). The project was launched in 2016, and captures 800,000 metric tons of CO₂ annually, for enhanced oil recovery use (EOR) in nearby onshore oil fields. \$15 billion US of seed funding was supplied from the government of Abu Dhabi to launch the project.⁹⁸

CO2 Ultimate Reduction in the Steelmaking Process (COURSE50), Japan

Since 2008, a consortium of Japan's steel manufacturers has been working on experimental technologies to reduce emissions in BF-BOF steel plants through hydrogen reduction of iron in the blast furnace and capture of blast furnace off-gas. The project was commissioned and financed by the New Energy and Industrial Technology Development Organization.⁹⁹ So far, the project has been able to reduce blast furnace emissions by ~10% through supplementing coke with hydrogen. Continuing work focuses on development of novel chemical absorbents and physical adsorption technologies for BF carbon capture.¹⁰⁰

STEPWISE Project, Luleå, Sweden

Funded through the European Union's Horizon 2020 Low Carbon Energy programme, the STEPWISE Project aims to create a demonstration scale facility of sorption-enhanced water-gas shift (SEWGS) carbon capture for blast furnace gas. The pilot plant is a retrofit of the SSAB steel plant in Luleå, Sweden, and is able to capture 14 metric tons of CO₂ per day. The aim of the technology is to improve the efficiency of conversion of CO in the blast furnace off-gas to CO₂, which is currently a highly energy-intensive process. Such improvement has the potential to reduce BF emissions by 85%, reduce the energy requirement of capture by 60%, and the cost by 25%. While the pilot plant is operational, the extent to which these goals are achieved is still being investigated.^{101,102}

HYBRIT Project, Luleå, Sweden

Launched by three private companies in 2016 (SSAB, LKAB and Vattenfall), the HYBRIT initiative aims to develop a completely fossil-free value chain for steel production, using fossil-free pelletization, electricity and hydrogen. A pilot facility for producing fossil-free sponge iron (the output of DRI) was commissioned in 2020, and a pilot facility for hydrogen storage in a rock cavern facility launched in September 2022.¹⁰³ In August 2021, SSAB

⁹⁸ The University of Edinburgh (no date) <u>Al Reyadah: Project Details</u>. [79]

⁹⁹ Tonomura *et al.* (2016) <u>Concept and current state of CO₂ Ultimate Reduction</u>. [81]

¹⁰⁰ COURSE50 (no date) <u>To the future of the low carbon blast furnace</u>. [20]

¹⁰¹ Stepwise (no date) <u>STEPWISE: a H2020 Project</u>. [75]

¹⁰² van Dijk *et al.* (2017) <u>Cost effective CO₂ reduction in the iron & steel industry</u>. [85]

¹⁰³ HYBRIT (September 23, 2022) <u>HYBRIT: Milestone reached</u>. [39]

produced the world's first fossil-free steel using HYBRIT technology at its pilot facility - in which DRI is produced with 100% hydrogen as the fuel and reducing agent.¹⁰⁴

Boston Metal, United States

Boston Metal, a steel startup company in the United States, is developing an alternative technique for direct reduction of iron that uses *electricity* as the reducing agent, rather than hydrocarbons or hydrogen. Called Molten Oxide Electrolysis (MOE), the technology works by heating iron in a cell to 1600°C, in the presence of an electrolyte solution (i.e. water containing dissolved salts). The iron ore becomes molten, and an inert anode placed in the electrolyte solution is electrified, driving an electrical current through the molten iron that splits the bonds between iron and oxygen in the ore:

$$Fe_2O_3 + e^- \rightarrow Fe + O_2$$

(R5.1)

The process is anticipated to be cost competitive with traditional BF-BOF steel production, but is still being validated in the industrial environment. Demonstration facilities are planned for 2024, with the aim of commercial operation by 2026.¹⁰⁵

Rocky Mountain Steel, Colorado

Rocky Mountain Steel, based in Pueblo, Colorado was the first integrated steel mill built in the U.S. west of the Mississippi River, having been in operation since 1882.¹⁰⁶ Today, it no longer operates as an integrated mill, but rather a scrap steel mill - recycling scrap into rails for train tracks, pipes and re-bar.¹⁰⁷ In 2022, the company broke ground on developing the first steel mill to run almost entirely on solar power. Construction of the solar project that will power the mill is ongoing at the time of writing this report, but will use 750,000 solar panels, located on ~1,800 acres, to provide more than 90% of the mill's power needs.¹⁰⁸

Mojave Micro Mill, Kern County, California

In May 2022, the Pacific Steel Group announced plans to develop a state-of-the-art 'green steel' micro mill in the Mojave Desert of Kern County. The mill would be a 100% scrap-EAF mill, modeled after a similar mill that is in development in Mesa, Arizona, that has an expected opening date in 2023. The Mojave facility would be powered at least partially by local renewable energy (solar), and would produce up to 380,000 tons of steel annually.¹⁰⁹ It would use MIDA-Micromill technology from the company Danieli, which also produced the Mesa, Arizona facility, and a similar plant in Durant, Oklahoma.¹¹⁰ In terms of development status for the Mojave Micro Mill, the Pacific Steel Group has submitted a

¹⁰⁴ HYBRIT (no date) <u>HYBRIT Demonstration</u>. [38]

¹⁰⁵ Boston Metal (no date) <u>Molten Oxide Electrolysis for steel decarbonization</u>. [6]

¹⁰⁶ The Center for Land Use Interpretation (no date) <u>Rocky Mountain Steel, Colorado</u>. [77]

¹⁰⁷ EVRAZ North America (no date) <u>EVRAZ Rocky Mountain Steel</u>. [29]

¹⁰⁸ Lawrence (March 2, 2022) <u>World's largest solar-powered steel mill breaks ground in Colorado</u>.[51]

¹⁰⁹ Cox (May 13, 2022) <u>'Green steel' plant proposed for Mojave</u>. [21]

¹¹⁰ Danieli (July 29, 2015) <u>Danieli to supply second MIDA to CMC</u>. [23]

development proposal for the project, and the project is currently undergoing the public environmental review process pursuant to the California Environmental Quality Act.¹¹¹

5.1.3 Operational needs

This section provides a synopsis of the land use, energy, feedstock, waste disposal and other operational needs of the representative technologies for the steel industry that employs carbon management and/or clean energy technologies. Information was aggregated from literature review and interviews with industry experts.

Integrated steel mills that employ primarily BF-BOF steel making technology are quite distinct from mini mills in terms of their footprints, operational needs, and steel output. An integrated steel mill typically produces 3 million tons or more of steel annually, whereas mini mill production capacity is about 1 million tons per year.¹¹² Micro mills (and even nano mills), like the Mojave Micro Mill that is currently in development (see Section 5.1.2.2), produce even less - on the order of 200,000-500,000 tons of steel per year.¹¹³ Additionally, integrated mills are dependent on primary ores (iron ore and metallurgical coal for coke), and so have traditionally been located close to these natural resources and/or along major waterways where transport of raw materials is possible.¹¹⁴ Although located close to major rail and road transportation routes, Kern County is distantly located from any significant iron or coal natural resources, and is unlikely to be suitable for a large-scale integrated steel mill. Thus, for the purposes of this study, we will focus on the requirements and impacts of mini- and micro mills that use scrap as a primary feedstock, with DRI as a potential supplementary feedstock, if future regional demand outpaces the availability of scrap metal.

Considering that this industry is being evaluated in the context of its role as a carbon management industry, it is also worth noting the needs and impacts that such a facility will have in terms of its CO_2 output as well as its steel output. To this end, we considered three mini mill scenarios in the impact analyses that comprise the remainder of this report section. The scenarios are based on the direct and indirect (energy-sourced) CO_2 emissions profiles described in Table 5.2, and are as follows:

- 1. A scrap-based mini mill powered by solar energy, in which **0 tons of CO₂ can be captured per ton steel produced** (direct emissions are not easily captured, and the solar energy source is emission-free).
- A scrap based mini mill that utilizes oxy-fuel combustion of natural gas, producing an average of ~0.15 tons CO₂ that can be captured per ton of steel (full range is 0.06-0.25 tons CO₂ per ton steel).

¹¹¹ Kern County Planning and Natural Resources Department (October 28, 2022) <u>Notice of</u> <u>Preparation (NOP)</u>. [47]

¹¹² Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. p. 833. [30]

¹¹³ Millennium Steel (May 25, 2017) <u>Mini mills, micro mills, nano mills</u>. [58]

¹¹⁴ Anderton (August 6, 2015) <u>Micro steel mills are competitive</u>. [3]

3. A mini mill that utilizes DRI with point source capture for 100% of its iron source and oxyfuel combustion of natural gas as its energy source. Point source capture can capture up to 80% of DRI emissions,¹¹⁵ or ~0.42-0.84 tons CO₂ per ton steel produced. Combined with the CO₂ produced from oxy-fuel combustion (0.65-1.08 tons CO₂ per ton steel), this method would produce, on average, ~1.3 tons CO₂ per ton steel produced (full range is 1.07-1.50 tons CO₂ per ton steel).

A steel mill that utilized DRI and oxy-fuel combustion (the most emissions-intensive scenario) would need to produce about 770,000 tons of steel annually to emit 1 million tons of CO_2 . The same size facility utilizing only scrap and solar energy, or scrap and oxy-fuel combustion, would emit 0 tons CO_2 and ~115,000 tons CO_2 , respectively. For the purposes of understanding the impacts of a steel facility in Kern County, data from existing steel mills and published estimates are normalized both to a 1 million ton (Mton) steel production capacity (for consideration of impact per ton steel), and to a 770,000 ton (770 kton) steel production capacity (for consideration of impact per million tons CO_2 , noting that such a value is a *maximum* CO_2 output estimate).

5.1.3.1 Land use requirement

There are myriad existing examples of mini steel mills that can be utilized to approximate the land use requirements for this industry. As of 2022, 71% of the domestic U.S. steel supply was produced in 101 mini mills across the country.¹¹⁶ Table 5.3 provides a representative sampling of U.S. mini and micro mills, denoting their production capacity (in annual steel output) and land footprint. The footprint to steel output ratio for these facilities is diverse, suggesting flexibility in land use needs, depending on the cost and availability of land. The facilities investigated have annual steel outputs ranging from 350,000 tons to 1.2 million tons. For comparative purposes, the land use to output ratio was normalized, producing a range of 140 to 1,071 acres used per million tons (Mton) of steel production, with an average footprint of 663 acres/Mtons. Similarly, to a 770,000 ton steel mill, which could produce *up to* 1 million tons of CO₂ (see Section 5.1.3), would use 129 to 825 acres per million tons of CO₂ produced, with an average footprint of 510 acres per 770kton steel mill.

¹¹⁵ EPRS (2021) <u>Carbon-free steel production</u>. p. 15-16. [28]

¹¹⁶ Watson (2022) <u>Domestic Steel Manufacturing</u>. [88]

Facility Name ^a	Year Operational	Annual Steel Output	Facility Footprint		Normalized Footprint	
		(kton steel)	km²	Acres	(acres/ Mton steel)	(acres/770 kton steel)
Mojave Micro Mill, CA (proposed)	2025+	380	0.70	174	458	353
CMC Mesa Plant (II), AZ	2023	500	0.34	84	168	129
HighBar LLC, Osceola, AK	2024	600	2.43	600	1000	770
Nucor Steel, Brandenburg, KY	2022	1,200	3.64	900	750	578
CMC Durant Plant, OK	2017	350	1.52	375	1071	825
Nucor Steel, Davidson Co, NC	2024	430	0.93	229	533	410
MEAN		577	1.59	394	663	510

a. These six mills will be used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all future references to these sites, references are detailed in Table 5.7.

5.1.3.2 Energy Requirements

As detailed in Table 5.2, the primary energy needs for a scrap-based steel mill come from the electric arc furnace (EAF), which requires about 1.3-3.3 GJ (=0.4-0.9 MWh) of energy per ton of steel produced.^{117,118} Casting, rolling and finishing the hot steel that is made in the EAF into usable products requires another ~0.02-2.2 GJ (0.01-0.6 MWh)/ton steel.¹¹⁹ If DRI is made on site from pelletized iron ore feedstock, it would contribute an additional 10.9-16.1 GJ (3.0-4.5 MWh) of energy needs,¹²⁰ increasing the facility's energy requirements by an order of magnitude.¹²¹ It is important to note that DRI requires temperatures of 900-1000°C to reduce the iron ore in the presence of a reduction agent like natural gas, syngas or hydrogen. Such high temperatures cannot be directly supplied by solar-derived electricity without also utilizing a heat battery (see our section on energy storage). Capturing carbon from DRI requires additional energy input: point source capture using advanced chemical solvent technologies demands about 2.5-3 GJ (0.7-0.8 MWh) of energy per ton of CO₂ captured, which translates to an additional energy demand of about 1.1-1.3 GJ (0.3-0.35 MWh) per ton steel produced via DRI-EAF.¹²² Finally, Pelletization requires about 1.9 GJ (0.5 MWh) of energy per ton of steel, and while this step can be done at the

¹¹⁷ Fruehan *et al.* (2000) <u>Minimum energies to produce steel</u>. p. iii. [31]

¹¹⁸ Fan, Friedmann (2021) <u>Low-carbon production of iron and steel</u>. p. 835. [30]

¹¹⁹ Fruehan *et al.* (2000) Minimum energies to produce steel. p. iii. [31]

¹²⁰ de Beer *et al.* (2003) Emissions from iron and steel production. p. 22. [24]

¹²¹ IEA (2020) <u>Iron and Steel Roadmap</u>. p. 29 + 42. [40]

¹²² Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 36. [45]

steel mill site, it is more commonly done at the mine where iron is sourced,^{123,124} so is not included in the energy analysis here.

Estimates of the scale of solar installation required to supply 100% of the heat and electrical energy needs of a steel mill are calculated following the equation: ¹²⁵

MWh (energy supplied) = MW (installed capacity of facility) x (8760 hours in a year) x Capacity factor (E5.1)

where the capacity factor for solar panels in Kern County is 32.8%.¹²⁶ Solar acreage is calculated on the basis of ~7 acres per MW installed solar capacity.^{127,128} With these values, a 770,000 ton steel mini mill utilizing only scrap and solar energy would need about 690-2,900 acres of solar fields to supply the electricity demand. A 770,000 ton DRI mini mill using solar energy and only capturing CO₂ from process emissions of iron reduction would need 6,400-11,255 acres of solar fields (with heat battery storage) to operate. However, in this scenario, only 320,000 tons of CO₂ could be captured annually. A mini mill using oxyfuel combustion with carbon capture as the sole power supply would require no solar input.

In addition to solar energy, two other potential power supplies for mini mills are explored here: oxy-fuel combustion of natural gas (or alternatives like syngas or renewable natural gas) with carbon capture, and combustion of hydrogen gas.

Oxy-fuel Combustion

Oxy-fuel combustion is a process in which hydrocarbon-based fuels are combusted in a specialized chamber in the presence of a pure stream of oxygen (\pm an inert carrying agent, like purified CO₂). Normally, we combust fuels in the presence of air, which produces a series of partial reactions that convert the hydrocarbons to CO₂, CO, and a variety of unreacted residues that can be grouped as "volatile organic compounds" or VOCs. These products instantly mix with the surrounding air to produce a dilute stream of CO₂, making it difficult – and expensive – to separate the CO₂. In oxy-fuel combustion, the only inputs in the reaction are hydrocarbons and oxygen, and the reaction can be controlled so that the only products are H₂O (water) and CO₂. Because the reaction is taking place in a vacuum, rather than in the presence of air, the CO₂ product does not become diluted, and thus can easily (and cheaply) be separated for storage. Oxy-fuel combustion technology is generally at the large prototype or pre-demonstration stage of development.¹²⁹

Two examples of companies developing oxy-fuel combustion technologies are Clean Energy Systems and NET Power. Clean Energy Systems designs oxy-fuel turbines (the

¹²³ Carlson (no date) <u>Iron ore pellet production a bottleneck for steel producers</u>. [14]

¹²⁴ Cision PR Newswire (October 21, 2021) <u>Iron ore pellets demand to surpass 399 Mn tons in 2021</u>.[15]

¹²⁵ Thomson Reuters Practical Law Glossary (no date) <u>Capacity factor</u>. [80]

¹²⁶ NREL (no date) <u>Utility-Scale PV</u>. [59]

¹²⁷ Lorelei Oviatt (Kern County), personal communication, September 21, 2022.

¹²⁸ SEIA (no date) <u>Land use and solar development</u>. [73]

¹²⁹ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 99. [41]

reaction chambers for oxy-fuel combustion) using technology adapted from rocket engine design, to optimize the combustion reaction.¹³⁰ They have a pilot facility in Kern County and are in the process of converting several biomass power plants into Biomass Carbon Removal and Storage (BiCRS) facilities in California (see Section 4.1.2.4). NET Power has developed a form of oxy-fuel combustion called the Allam-Fetvedt power cycle, which uses the pure CO_2 produced from the combustion process as a streaming agent that carries heat energy and new pure CO_2 and H_2O streams, optimizing the efficiency of the process.^{131,132}

Hydrogen Fuel

Green hydrogen, or hydrogen that is derived from non-CO₂ emitting processes, like electrolysis (see Section 6) or biomass gasification with carbon capture (see Section 4), has enormous potential in helping to decarbonize iron and steel production, because it can work both as a fuel source, powering high-temperature operation of the DRI and EAF, and as an iron reducing agent, further reducing the necessity of coke or natural gas in the iron-refining process.¹³³ One company, SSAB in Sweden, has successfully fossil-free steel, using green hydrogen in the production process. Their work is currently at the demonstration stage (see Section 5.1.2.2). If hydrogen is used to power steel production and act as a reducing agent, the steel made will be carbon emissions free (a clean technology), but would not be a source of CO_2 for carbon capture.

5.1.3.2 Other Operational Requirements

Waste disposal requirements

Steel production from EAFs produce a variety of byproducts, including metal dusts, slag, wastewater, and gaseous emissions,¹³⁴ each of which needs to be handled appropriately on- or offsite, following state and federal regulations. Slag is relatively inert, and can be repurposed in other industrial applications, like construction.¹³⁵ Dust creation is a bigger issue, as on average, EAFs produce about 10 kilograms of dust per metric ton of steel, which can have a variety of heavy metals in it: zinc, lead, cadmium, chromium, and nickel. However, there are a variety of available mitigation measures that can minimize the hazard of dust creation, including: locating operational facilities inside enclosed buildings, selecting a feed quality (steel scrap or iron pellets) that have low concentrations of impurities or heavy metals, use fabric filters and other dry dust collection methods¹³⁶.

¹³⁰ Clean Energy Systems (no date) <u>Oxy-fuel Combustion</u>. [17]

¹³¹ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 17. [45]

¹³² Patel (November 10, 2022) <u>NET Power's first Allam Cycle 300-MW gas-fired project</u>. [64]

¹³³ Bartlett, Krupnick (February 18, 2021) <u>The potential of hydrogen for decarbonization</u>. [4]

¹³⁴ World Bank Group (1998) Mini Steel Mills. p. 341. [89]

¹³⁵ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 342. [89]

¹³⁶ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 342. [89]

In terms of wastewater, mini mills can produce up to 80 cubic meters (~21,000 gallons) of wastewater per metric ton of steel produced.¹³⁷ Like the dust, wastewater can have high concentrations of metals, totaling up to 3,000 milligrams per liter of water. That is about equivalent to 0.3% of the water being dissolved or suspended solids. These solids can be removed from settling, creating sludges that then need to be properly disposed of following environmental and safety guidelines. With proper treatment, the wastewater can be recycled to minimize the water demands of steel production.¹³⁸ Additionally, many of the metals that are concentrated in steel mill wastewater are of interest in development of clean energy technologies. Recovering critical metals from fluids, like waste waters of mining and industrial processes, is beginning to be explored,¹³⁹ and could warrant further investigation, both in its potential for an alternative revenue stream, and as a solution for waste mitigation.

The variety of methods described here (and for gas emissions, in Section 5.4.2) to manage and minimize waste from steel mills is not meant to be comprehensive, but is intended to illustrate that solutions already exist to address secondary products of steel production. Like any industrial facility hosted within a carbon management park, environmental and safety impacts of a steel mill would be assessed through a public process, and if approved, all facilities would be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

Warehousing requirements

Warehousing is a necessity at steel mills, both to hold a reserve of iron feedstock (whether steel scrap or iron pellets), and steel product. Although no explicit information could be found on storage requirements for feedstock or product, aerial and satellite imagery of existing steel mills suggests that whether storage is in enclosed warehouses or open air depends on regional preferences and regulation.

Transportation and pipeline requirements

Steel scrap and/or iron pellets will need to be delivered to a mini mill facility, and products will likely be sold nationally or internationally. Therefore, access to rail and shipping lanes are high priorities for steel industries. The availability of rail in Kern County, and its proximity to ports along the West Coast both make it an attractive site for steel production.

¹³⁷ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 341. [89]

¹³⁸ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 342. [89]

¹³⁹ Can Sener *et al.* (2021). <u>Recovery of critical metals from aqueous sources</u>. [9]

5.2 Societal Impacts

5.2.1 Job creation potential

5.2.1.1 Number and types of jobs

On average, it takes 1.5 man-hours to produce a ton of steel, with some mini mills able to produce a ton of steel with only 0.5 man-hours, due to increased efficiency and automation.¹⁴⁰ Given this range, a 770,000 ton steel mill could produce about 200-600 full-time equivalent jobs. This approximated range is consistent with job creation estimates reported from recently built U.S. micro mills, which, scaled to 770,000 ton steel production capacity, would produce on average ~400 permanent jobs. Details of these job estimates are given in Table 5.4.

Of the example steel mills examined in Table 5.4, two provide estimates of job growth in relation to facility construction. The 600,000 ton High Bar LLC steel mill in Arkansas, and the 430 thousand ton Nucor Steel mill being developed in North Carolina report generating 600 and 500 construction jobs, respectively. Scaled to a 770,000 ton facility, a steel mill could provide up to 900 short term jobs in construction. Additionally, such a facility would produce thousands of indirect jobs to support facility needs, such as solar and battery installation jobs.

According to a 2022 Congressional Research report,¹⁴¹ the average annual wage of steel workers in 2020 was \$88,325 USD, higher than both the national average in manufacturing (\$73,397 USD), and the median national household income across all sectors (\$71,186 USD)¹⁴² for that year. Steel product manufacturing (casting, rolling, and finishing steel into final products) accounted for about 40% of the job market in 2020, and had an average annual wage of \$68,585 USD.¹⁴³ Reported annual salary for the example steel micro mill manufacturing jobs support this average, with salaries ranging from \$60,000-\$140,000 plus benefits, with higher salaries associated with technical positions (see Appendix D for complete reference list).

5.2.2.2 Training pipelines

Most jobs in the iron and steel industry require a high school diploma or equivalent and may involve an apprenticeship training program. A significant amount of training is done on-the-job.¹⁴⁴ This is likely particularly true for steel product manufacturing. However, with sector wide goals of decarbonization and digital transformation, the steel industry is

¹⁴⁰ Perry (March 16, 2018) <u>Increased productivity is eliminating steel industry jobs, not imports</u>.[65]

¹⁴¹ Watson (2022) <u>Domestic Steel Manufacturing</u>. p. 9. [88]

¹⁴² U.S. Census Bureau (September 13, 2022) <u>Income in the United States</u>. [83]

¹⁴³ Watson (2022) <u>Domestic Steel Manufacturing</u>. p. 9. [88]

¹⁴⁴ Vault Firsthand (no date) <u>Steel industry workers</u>. [87]

increasingly looking for more trained or specialized workers.¹⁴⁵ The World Steel Association has a published fact sheet emphasizing the need for skilled workers in metallurgy, materials science, physics, chemistry, engineering, environment, mathematics, information technology and computer science, languages, business, and accountancy.¹⁴⁶

Facility Name ^a	Year Operational	Annual Steel Output	Facility Footprint		Normalized Jobs (per 770 kton steel)	
		(kton steel)	Perm. ^b	Const.º	Perm. ^ь	Const.°
Mojave Micro Mill, CA (proposed)	2025+	380	400		811	
CMC Mesa Plant (II), AZ	2023	500	186		286	
HighBar LLC, Osceola, AK	2024	600	200	600	257	770
Nucor Steel, Brandenburg, KY	2022	1,200	400		257	
CMC Durant Plant, OK	2017	350	225		495	
Nucor Steel, Davidson Co, NC	2024	430	200	500	358	895
MEAN		577			411	833

Table 5.4.	Reported	iob creation	estimates	for example	mini- and	micro-steel	mills in the U.S.

a. These six mills are used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all other references to these sites, references are detailed in Table 5.7.

b. Permanent jobs

c. Construction jobs

5.2.2 Quality of Life

5.2.2.1 Location

Steel mills do emit fine materials and gasses that can have harmful health effects, like particulate matter, lead, nitrous oxides (NO_x), and sulfur oxides (SO_x), although there are techniques mills can use to trap matter and minimize emissions¹⁴⁷ (see Section 5.3.2). Any mill developed within the carbon management park would be required to submit an environmental impact report and undergo pre-development review and operational monitoring to ensure emissions impacts remain within federal and state determined safety standards.

¹⁴⁵ Maldonado-Mariscal *et al.* (2023) <u>Skills intelligence in the steel sector</u>. [56]

¹⁴⁶ World Steel Association (2021) Working in the steel industry. [94]

¹⁴⁷ World Bank Group (1998) Mini Steel Mills. [89]

Steel mill operations are also loud^{148,149} – with most operational equipment emitting noise at levels that require hearing protection for workers.¹⁵⁰ It is possible to design steel mills in ways that diffuse noise levels to minimize noise pollution in the vicinity. One steel mill in New Zealand integrated several noise-minimizing solutions into their facility, and measured noise levels about 0.75 miles from the facility of ~45 decibels, a typical sound level for an urban neighborhood.¹⁵¹

5.2.2.2 Multi-use potential

Steel mills are among the most land intensive of the carbon management industries investigated in this report (Appendix D, Figure D.1), and as that land use involves warehousing of large volumes of feedstocks, enclosed buildings housing large manufacturing equipment, and warehousing (and treatment) of products and byproducts, it is unlikely that the land allocated to a steel mill would be well suited for multi-use potential. That being said, there is a plethora of opportunity in co-locating such an industry with other carbon management and clean energy technologies, explored in detail in Section 5.4.3.3.

5.3 Environmental Impacts

5.3.1 Water requirements

5.3.1.1 Minimum volume requirements

Steel mills require water to operate, primarily for cooling, but secondarily for equipment descaling, dust scrubbing and other processes. On average, steel mills that use electric arc furnaces require a water intake of 7,400 gallons of water per metric ton of steel produced, but discharge 7,000 gallons of water (about 94% of intake water), for a net water requirement of 400 gallons per metric ton of steel.¹⁵² It is also notable that the range in water use from plant to plant varies widely, suggesting that there are a variety of process configurations that can minimize water use and water waste. The most comprehensive publicly available assessment of water use in the steel industry was a report published by the World Steel Association (WSA) in 2011.¹⁵³ They examined water usage in 8 EAF steel plants (and 17 integrated plants, not discussed here), whose water intake ranged from 290 gallons of water per metric ton of steel produced, to over 18,000 gallons of water per metric

¹⁴⁸ Hojati *et al.* (2016) <u>Determining the noise exposure pattern in a steel company</u>. [37]

¹⁴⁹ Nyarubeli *et al.* (2018) <u>Variability and determinants of occupational noise exposure</u>. [61]

¹⁵⁰ OSHA (no date) <u>Occupational Noise Exposure</u>. [62]

¹⁵¹ New Zealand Steel (no date) <u>Reducing noise</u>. [60]

¹⁵² World Steel Association (2020) <u>Water management in the steel industry - Fact Sheet</u>. [93]

¹⁵³ World Steel Association (2011) <u>Water management in the steel industry - Full Report</u>. [92]

ton of steel.¹⁵⁴ The strongest control on water use intensity was whether water used for cooling was circulated or merely used one time ("once-through cooling"). In regions where water resources are abundant, once-through cooling can have minimal environmental impact, while also being cost effective, but given that only 25% of EAF plants examined by the WSA report used once-through cooling, water-circulation cooling appears to be a well-established technique in the industry.¹⁵⁵

Discharged water from steel mills can be treated and reused, or returned to the source.¹⁵⁶ The extent of treatment required will depend on the original water composition and its use in the steelmaking process. Water that is used for cooling never actually comes into contact with material or equipment, so does not require the same level of treatment as that used for descaling and dust scrubbing. Water used for these latter purposes could have a significant amount of dissolved solids, including metals and oil and gas residues,¹⁵⁷ that would need to be treated before water could be reused (see Section 8 for a summary of water treatment techniques and applications). If water is recirculated within the steel mill to minimize waste, it needs to be cooled and desalinated between uses. This could be energy and time intensive, but in the context of a carbon management business park, it is also a synergistic opportunity. If a thermal network were integrated into a carbon management park, waste heat in the form of hot process water from the steel mill could potentially supply heat energy to other co-located industries, and the cooled water could be circulated back to the steel mill for reuse.

5.3.1.2 Minimum quality requirements

Water for steel manufacturing can come from a variety of sources, with EAF mills examined by the World Steel Association using freshwater (potable water), groundwater, brackish water, seawater, and other non-potable water as sources.¹⁵⁸ Gray (reclaimed) water, of which there is an abundance in California (see Section 8), could be used similarly, minimizing the impact on local fresh water sources. Depending on the water source used, and its role in the steel making process, a variety of pre-treatment processes may be necessary, all of which are well established techniques. These include biological control or disinfection for reclaimed water, demineralization, desalination, distillation, filtration, reverse osmosis, and softening.¹⁵⁹ For further information, interested readers should refer to Section 8 of this report, as well as the WSA report on water use in the steel industry.

¹⁵⁴ World Steel Association (2011) <u>Water management in the steel industry - Full Report</u>. p. 31. [92]

¹⁵⁵ World Steel Association (2011) <u>Water management in the steel industry - Full Report</u>. p. 32. [92]

¹⁵⁶ World Steel Association (2020) <u>Water management in the steel industry - Fact Sheet</u>. [93]

¹⁵⁷ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 342. [89]

¹⁵⁸ World Steel Association (2011) <u>Water management in the steel industry - Full Report</u>. p. 32. [92] ¹⁵⁹ World Steel Association (2011) <u>Water management in the steel industry - Full Report</u> p. 20.40

¹⁵⁹ World Steel Association (2011) <u>Water management in the steel industry - Full Report</u>. p. 39-40.[92]

5.3.2 Other potential impacts

5.3.2.1 Criteria pollutants from operation

Two sources of atmospheric pollutants should be considered in the context of steel as a carbon management industry. First, there is the production of steel itself, and then there are emissions related to power generation for steel production, which - if it is in the form of oxy-fuel combustion with carbon capture, can have associated non- CO_2 emissions.

In the electric arc furnace (the steel making phase of production), scrap metal is "charged", or combined with DRI, pig iron (from integrated mills) and/or limestone, to add or remove impurities in the steel that control its properties (like strength and ductility). Elements that are separated out of the steel form a metal-oxide rich slag and small amounts of CO2 (not enough to be economically captured) and other gas or fine particulate emissions.¹⁶⁰ The slag is a waste byproduct that can typically be used in other industrial processes (see Section 5.1.3.2), and therefore poses little environmental risk.

Particulate emissions emitted from the EAF (and to a lesser degree from other steps in the steel making process) include particulate matter composed of iron and iron oxides, and depending on the composition of the source iron could also include heavy metals such as zinc, chromium, nickel, lead, and cadmium. Gaseous pollutants such as NO_x, CO, SO₂, and volatile organic compounds (VOCs) can also be emitted.^{161,162} These emissions can be captured and scrubbed from facility exhaust streams, to keep facility emissions under regulated limits. Techniques for trapping emissions include locating the EAF in an enclosed building, using hoods to evacuate dust into dust arrestment equipment, using scrubbers to attract gasses, and using equipment like cyclones, baghouses, and electrostatic precipitators to further attract and trap dust. However, regular maintenance and monitoring of facilities is critical to prevent fugitive emissions.¹⁶³

If natural gas (or synthetic natural gas or RNG) is used with oxy-fuel combustion and carbon capture and storage to power some or all of the steel-making processes, emissions associated with such combustion must also be considered. Thus far, this is difficult. There are few detailed studies of the emissions resulting from oxy-fuel combustion, and those emissions seem to be dependent on the fuel used (coal vs. natural gas vs. biomass), the oxygen/fuel ratio, and the combustion technique.¹⁶⁴ However, it appears that overall, gaseous emissions and particulate matter emissions from oxyfuel combustion are

¹⁶⁰ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 342. [89]

¹⁶¹ Environmental Protection Agency (EPA) (2009) <u>Emission factor documentation</u>. p. 5. [26]

¹⁶² Van Wortswinkel, Nijs (2010) ETSAP - Iron and Steel. p. 6. [86]

¹⁶³ World Bank Group (1998) <u>Mini Steel Mills</u>. p. 342. [89]

¹⁶⁴ Senior *et al.* (2013) <u>Emissions from oxyfuel combustion</u>. [71]

considerably lower than emissions related to traditional air-fired combustion.^{165,166} Integrating flue gas filtering processes into the oxy-fuel combustion process can also eliminate pollutants from any flue gas stream, as the Allam-Fedtvedt power cycle does for NO_x and SO_x .¹⁶⁷

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used in any given facility will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

5.4 Economic Impacts

5.4.1 Business Model

Unlike other carbon management industries investigated in this report (DAC and BiCRS, in Sections 3 and 4, respectively), the capture and sequestration of CO₂ is not a primary objective or product of CO₂-emitting industries. Thus, the only motivations that a CO₂-emitting industry will have to capture and store carbon are financial (if the CO₂ can be sold as a product or for a financial credit), or through pressure, whether regulatory or from consumers. A 2021 feasibility analysis by the Global CCS Institute examined the factors common to commercially operating point source capture facilities, that made them economically viable.¹⁶⁸ At the time, there were 28 operational facilities in the world (as of the writing of this report there are 35, according to the GCCSI facilities database, see Appendix A). Every single one of those operations had at least one of the following characteristics, and all but 1 had at least two:

- 1. They were capturing CO₂ from the lowest-cost point sources: natural gas processing, fertilizer production, bioethanol production, chemical manufacturing (23 facilities)
- 2. They sold their CO_2 to enhanced oil recovery (EOR) operations to offset costs (23 facilities).
- 3. Their country of operation provided grant support, tax credits, or had a government provision for carbon capture (17 facilities.)
- 4. Their country of operation was Norway, the only nation that implements a carbon tax (2 facilities).

¹⁶⁵ Senior *et al.* (2013) <u>Emissions from oxyfuel combustion</u>. [71]

¹⁶⁶ Kosowska-Golachowska, M. *et al.* (2022) <u>Pollutant emissions during oxy-fuel combustion of</u> <u>biomass</u>. [48]

¹⁶⁷ Allam, R. *et al.* (2017) <u>Demonstration of the Allam Cycle</u>. p. 5953-5954. [1]

¹⁶⁸ Rassool *et al.* (2021) <u>CCS in the circular carbon economy</u>. p. 7. [67]

Since the publication of GCCSI's report, the outlook for point source carbon capture has become more promising. Recent innovations in "water-lean" capture amine technology is helping the cost of capture decrease, even for industries with more dilute exhaust emissions.^{169,170} Additionally, the 2022 Inflation Reduction Act raised the amount of the 450 tax benefit for CO₂ capture and storage processes other than direct air capture (DAC) to \$85 per ton stored,¹⁷¹ meaning that even at the current state of technological development, every CO₂-emitting industry has the potential to entirely offset the cost of capture carbon with a tax credit (Table 5.1). This is particularly important for industries that are traded on international markets, like steel, in which the need to remain cost competitive allows for very low profit margins and little flexibility for added cost.¹⁷² Additional policies that could further encourage the purchase of low-carbon or clean energy products (e.g. Buy Clean incentives), thereby increasing their market demand, or those that would create a regulatory framework for allowable carbon-intensity of domestically manufactured or purchased products.¹⁷³

5.4.2 Business Costs

For point source carbon capture facilities, capture equipment is most commonly retrofitted onto existing infrastructure, adding to the baseline cost of producing the primary industry output. As mentioned in Section 5.1, the concentration of CO₂ within the gas stream emitted from an industrial facility is proportionally related to the cost of capture. This is illustrated in occurs for two reasons:

- More dilute streams require larger process equipment. This is because lower concentrations of CO₂ mean a higher total gas volume processed per ton of CO₂. Thus, the total size of equipment also needs to be larger to process the greater volume of gas. Additionally, higher CO₂ concentrations are more reactive the CO₂ will transfer more rapidly from the source gas to the solvent than at low CO₂ partial pressures thus speeding the time of the reaction. Faster reactions mean less necessary contact time between source gas and solvent, and thus smaller capture equipment, reducing capital costs.¹⁷⁴
- 2. More energy is required to capture more dilute CO₂. At high partial pressures, CO₂ can be captured using "physical" solvents those in which the CO₂ is bound to the surface of the a substance via electro-magnetic attraction, forming a weak bond (called van der Waals bonds) that is easily broken by modestly decreasing the

¹⁶⁹ Jiang, Y. *et al.* (2023) <u>Energy-effective and low-cost carbon capture from point-sources</u>. [44]
¹⁷⁰ Clifford (January 24, 2023) <u>New technique from U.S. national lab promises to strip carbon</u> <u>dioxide</u>. [18]

¹⁷¹ Carbon Capture Coalition (2022) <u>IRA</u>. p. 2. [10]

¹⁷² IEA (2020) <u>CCUS in clean energy transitions</u>. p. 159. [41]

¹⁷³ Watson (2022) <u>Domestic Steel Manufacturing</u>. p. 15. [88]

¹⁷⁴ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 26-27. [45]

pressure or increasing the temperature of the system. In contrast, low-concentration CO_2 generally requires selective "chemical" solvents to be use - those which trap CO_2 by forming stronger chemical bonds, that can only be broken by increasing temperatures significantly. The higher temperatures needed for solvent regeneration directly translate to higher energy needs, and therefore higher cost.¹⁷⁵

An additional relevant factor to the cost of carbon capture is the scale of deployment. An impact analysis by the Global Carbon Capture and Storage Institute determined that economies of scale could drive cost decreases considerably when moving from pilot scale (thousands of metric tons of capture annually) to commercial scale (hundreds of thousands of metric tons of capture annually), with costs reaching a minimum at capture rates above ~400 thousand metric tons of CO₂ capture per year.¹⁷⁶ In their analysis, economies of scale reduced carbon capture costs for natural gas and coal power generation by about 40% and 20%, respectively. Figure 5.6, adapted from the GCCSI report, illustrates both controls on the cost of point source carbon capture: the x-axis showing how increasing concentrations (partial pressures) of CO₂ in industry flue gas decreases the levelized cost of carbon capture, and the error bars reflecting the range in cost of capture at any given CO₂ concentration due to the scale of capture at any given facility.



FIGURE 5.6. Levelized cost of carbon capture per metric ton CO₂ as a function of CO₂ partial pressure and operational scale, with the largest capacity capture facilities demonstrating the lowest cost at any given partial pressure. Adapted from Kearns et al. (2021) <u>CCS readiness and costs</u>.

¹⁷⁵ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 26-27. [45]

¹⁷⁶ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 31. [45]
To compare the relative costs of different carbon management industries (DAC, BiCRS, or point source capture), a 'Lifetime Cost Assessment' (LCA) model is used. The LCA is the total cost per metric ton CO_2 resulting from the cost of building the facility (capital costs), the cost of maintenance and labor (operational costs), and the cost of energy (heat + electricity), over the lifetime of the plant. However, for a micro steel mill, the cost of carbon capture is a comparatively small addition to the cost of building the mill. For simplicity, we assess the costs of creating the mill, and of capturing carbon from the mill separately. A micro steel mill that uses scrap and clean energy (0 tons CO_2 emissions per ton steel) would cost about \$398-848 per ton steel produced. A scrap mill that used oxy-fuel combustion for energy would cost ~\$407-903 per ton steel produced, with the added cost of CO_2 capture being ~\$68-112 per ton CO_2 . A mill that used direct reduced iron (DRI) with point source carbon capture and oxy-fuel combustion would cost ~\$586-975 per ton steel produced, and the average cost of CO_2 capture would be \$75-114 per ton CO_2 . These estimated ranges are broken down in Table 5.5 and explained in detail below.

Cost (USD per ton steel)ª	Scrap-EAF + solar	Scrap-EAF + oxyfuel	DRI-EAF w. CCUS + oxyfuel	DRI-EAF + hydrogen
Cost to build steel mill (CapEx)	\$88-125	\$88-125	\$88-125	\$114-194
Feedstock (scrap steel or iron pellet)	\$192-557	\$192-557	\$81-154	\$157-267
Fixed operation & maintenance (OpEx)	\$77-116	\$77-116	\$77-116	\$90-153
Energy (solar, natural gas or green H_2)	\$41-50	\$40-88	\$243-433	\$226-508
Total Levelized Cost	\$398-848	\$397-886	\$489-828	\$587-1,122
Oxy-fuel combustion (Cap+OpEx)		\$10-17	\$59-97	
DRI point source capture (Cap+OpEx)			\$38-50	
Total Levelized Cost Including Capture	\$398-848	\$407-903	\$586-975	\$587-1,122

Table 5.5. Levelized cost per ton steel produced, by steel mill configuration.

a. See text for references for each estimated cost.

5.4.2.1 Cost to Build (upfront costs)

We can get a rough estimate of the capital expenditures, or cost to build a steel mini mill based on the six example mills listed in Table 5.5, which have been recently built, or are currently in development (detailed references for each of these sites is provided in Table 5.7). These mills, which produce between 350 and 1,200 thousand tons of steel annually, would cost \$250 million to \$1.7 billion dollars to construct. Normalizing those capital costs to the size of a steel mill that could capture up to 1 million tons of CO₂ annually (while producing ~770 thousand tons of steel), gives a range in capital costs between ~\$460 million and \$1.9 billion (average value is \$680 million USD). If we annualized these costs, assuming a facility lifetime of 30 years and a capital recovery factor of 12.5% (see Section

3.4.2.1 for a detailed explanation of this calculation), the levelized capital cost of these normalized facilities ranges from ~\$73-172 USD per ton steel produced. Such values closely approximate the estimated capital costs of DRI-EAF steel mills reported in the International Energy Agency (IEA)'s 2020 report on iron and steel technology.¹⁷⁷ They report a minimum CapEx for DRI-EAF of \$88 USD per ton steel produced, but include an ~40% uncertainty to account for cost variability across regions, resulting in a CapEx range of \$88-125. For the sake of consistency with the published literature, this is the CapEx range we employ in our levelized cost analysis (table 5.5). It is important to note that we approximate the same CapEx value for the scrap-EAF and DRI-EAF mills, and the added capital costs of CO₂ stemming from point source capture equipment (in the DRF-EAF with CCUS + oxy-fuel scenario) is accounted for separately.

Facility Name ^a	Year Operational	Annual Steel Output	Capital Costs (CapEx)	Normalized CapEx (per 770k tons steel)
		(kton steel)	million USD	million USD
Mojave Micro Mill, CA (proposed)	2025+	380	\$350	\$709
CMC Mesa Plant (II), AZ	2023	500	\$300	\$462
HighBar LLC, Osceola, AK	2024	600	\$500	\$642
Nucor Steel, Brandenburg, KY	2022	1,200	\$1,700	\$1,091
CMC Durant Plant, OK	2017	350	\$250	\$550
Nucor Steel, Davidson Co, NC	2024	430	\$350	\$627
MEAN		577		\$680

Table 5.6. Reported capital expenditures for new or developing EAF mills.

a. These six mills are used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all other references to these sites, references are detailed in Table 5.7.

5.4.2.2 Operational Costs

Operational costs fall into two categories: fixed costs (labor and maintenance) and variable costs (price of feedstocks). For scrap mills, the feedstock is steel scrap, which due to supply chain disruptions and the COVID-19 coronavirus, fluctuated significantly in recent years. Between January 2020 and March 2023, steel scrap ranged from \$192-557 USD per ton.¹⁷⁸ Iron ore, the raw material feedstock for DRI-EAF, has also fluctuated, ranging from \$81-154 USD in 2022 and 2023.¹⁷⁹ Reported fixed operational costs range from \$77-116 USD.^{180,181}

¹⁷⁷ IEA (2020) <u>Iron and Steel Roadmap</u>. p. 108. [40]

¹⁷⁸ SteelBenchmarker (April 24, 2023) Price History: Tables and Charts. [74]

¹⁷⁹ Trading Economics (no date) <u>Iron Ore</u>. [82]

¹⁸⁰ IEA (2020) <u>Iron and Steel Roadmap</u>. p. 108. [40]

¹⁸¹ M'barek *et al.* (2022) <u>Global steel production costs</u>. [54]

5.4.2.3 Energy Costs

Scrap-EAF mills require ~0.95MWh of energy production per ton steel (see Table 5.2), and DRI-EAF mills with point source capture require about 5 MWh per ton steel (see Section 5.1.3.2). If powered by solar with industrial scale battery storage, energy costs are estimated to be \$43-52 USD/MWh (\$28-37/MWh for solar energy + \$15/MWh for battery storage).¹⁸² Natural gas prices, based on a three year average, range from \$43-92/MWh.¹⁸³ Combining these rates, we obtain an estimated cost of energy of \$41-50 USD per ton steel for a scrap-EAF mill powered by solar, \$40-88 USD per ton for a scrap-EAF mill powered by natural gas. A steel mill powered by hydrogen would produce would not require the infrastructure or additional energy demand needed for point source capture. Thus, a DRI-EAF mill would require only about 4.7 MWh per ton steel produced. Costs for fossil-free green hydrogen range from ~\$1.60-3.60 USD per kg (Section 6), or about \$48-108 per MWh. Thus, green hydrogen energy costs for a scrap-EAF mill would be about \$46-103 USD per ton steel, and for a DRI-EAF mill would be about \$226-508.

5.4.2.4 Carbon Capture Costs

Finally, for mini-mills that are emitting appreciable CO₂, the capital and operational costs of capture via oxy-fuel combustion and point-source capture from DRI are additive to the costs of simply operating the mill. If these costs can remain under the \$85 USD federal tax credit 45Q,¹⁸⁴ then carbon capture can be cost-effective, or even serve as an additional form of revenue. In the IEA's 2020 economic analysis of steel production, they estimated the combined capital and operational costs of post-combustion point source carbon capture, when applied to a DRI-EAF mill, to range from \$38 to 50 USD per ton of steel. Given that about 0.42 tons of CO₂ can be captured via DRI point source capture per ton of steel made, the capture cost per ton CO₂ is \$90-119 USD, within the cost range reported by the GCCSI (Figure 5.6).¹⁸⁵ Separately, a 2017 European techno-economic study of oxy-fuel combustion provided an estimated cost range of €71-116 EUR per ton CO₂ captured in 2014 currency. Converting those values to 2023 USD,^{186,187} equates to an oxy-fuel combustion cost per ton of CO₂ captured of \$68-112 USD.

A scrap-EAF mill that uses oxy-fuel combustion with capture produces, on average, 0.15 tons of CO_2 per ton steel (Table 5.2). At a cost of \$68-112 USD per ton of CO_2 , there would be an added net levelized cost to steel production of \$10-17 USD per ton of steel (Table 5.5). A DRI-EAF mill, which is much more energy-intensive, would produce, on average, 0.87 tons of CO_2 via oxyfuel combustion, resulting in an added levelized cost to steel

¹⁸² Lazard (October 2021) <u>Levelized cost of energy analysis</u>. [52]

¹⁸³ Gamage *et al.* (March 9, 2023) Forging a clean steel economy in the United States. [34]

¹⁸⁴ Carbon Capture Coalition (2022) <u>IRA</u>. [10]

¹⁸⁵ Kearns *et al.* (2021) <u>CCS readiness and costs</u>. p. 31. [45]

¹⁸⁶ Macrotrends (no date) <u>Euro Dollar Exchange Rate</u>. [55]

¹⁸⁷ Bureau of Labor Statistics (no date) <u>CPI Inflation Calculator</u>. [8]

production of \$59-97 USD per ton steel. The additional 0.42 tons of CO_2 captured via point source capture in a DRI-EAF mill add \$38-50 USD per ton steel.¹⁸⁸ The total cost of carbon capture for a DRI-EAF mill with oxy-fuel combustion is \$97-147 USD per ton of steel produced, and an average cost of CO_2 capture of \$75-114 USD per ton CO_2 .

5.4.3 Regional benefits

5.4.3.1 Proximate feedstocks

The primary feedstocks for mini mills are scrap steel or pelletized iron ore. Kern County, while not rich in geologic iron resources, has an advantage in its location along major rail and interstate routes, and adjacent to the Pacific Coast and associated shipping lanes. Abundant domestic and international steel scrap could be readily available for processing in this region. Pelletized iron could be similarly shipped along such routes. Additionally, because steel-making is such an energy-intensive, close proximity to abundant clean energy, whether in the form of solar energy, green hydrogen, or oxy-fuel combustion of RNG or biomass-derived syngas, Kern County (and a potential carbon management park) offer significant opportunities for accessible clean energy.

5.4.3.2 Proximate consumers

The same proximity to highly populated areas, as well as rail, interstate and shipping routes are also advantageous for the sale of steel, a product that is traded on an international marketplace.

5.4.3.3 Co-location advantages

Steel produces a relatively smaller amount of CO_2 emissions than BiCRS/DAC - and thus development of dedicated CCUS compression, transport and storage infrastructure may not be economically viable for a stand-alone facility.¹⁸⁹ Co-location and sharing infrastructure with other industries that produce larger amounts of CO_2 could allow for cost-effective capture of CO_2 from steelmaking, even in smaller plants that produce significantly less than 1 million tons of CO_2 annually.

¹⁸⁸ IEA (2020) <u>Iron and Steel Roadmap</u>. p. 108. [40]

¹⁸⁹ IEA (2020) <u>CCUS in clean energy transitions</u>. p. 166. [41]

Table 5.7. References for representative micromill facilities in the U.S.

Facility Name	Year Operational
Mojave Micro Mill, CA (proposed)	Cox (2022) <u>'Green steel' plant proposed for Mojave</u> .
CMC Mesa Plant (II), AZ	SE Mesa plant double steel production. East Valley Tribune. Published online April 20, 2021. Accessed March 19, 2023 from <u>https://www.eastvalleytribune.com/money/se-mesa-plant-double-steel- production/article_78424896- a137-11eb-816a-d787277d5d29.html</u> .
	CMC Steel Arizona - Breaking Ground on the World's First Combination Micro Mill. Queen Creek Independent. Published online January 6, 2022. Accessed March 19, 2023 from <u>https://www.yourvalley.net/queen-creek-</u> <u>independent/stories/cmc-steel-arizona-breaking-ground-on-the-worlds-first-</u> <u>combination-micro-mill,279239</u> .
	CMC sees spring start for Arizona micro-mill. Association for Iron & Steel Technology. Published online January 12, 2023. Accessed March 30, 2023 from <u>https://www.aist.org/news/steel-news/2023/january/9-13-january-</u> 2023/cmc-sees-spring-start-for-arizona-micro-mill.
HighBar LLC, Osceola, AK	Chen, I. US' HighBar plans to invest rebar mill in Arkansas. Published online November 3, 2022. Accessed March 19, 2023 from https://yieh.com/en/Newsltem/137424 .
	Kamczyc, A. Highbar LLC announces site for first rebar mill. Recycling Today. Published online November 2, 2022. Accessed March 19, 2023 from <u>https:// www.recyclingtoday.com/news/highbar-llc-announces-site-for-first-rebar-mill/</u> .
Nucor Steel, Brandenburg, KY	Gregg, J. The New Steel City: Brandenburg Braces for Massive Steel Plant. Spectrum News 1. Published online July 19, 2019. Accessed March 19, 2023 from <u>https://spectrumnews1.com/ky/louisville/news/2019/07/19/small-kentucky-town-ready-for-big-steel-plant</u> .
	Otts, C., Ragsdale, T. Nucor starts work on Brandenburg, Ky. steel mill. WDRB.com. Published online Octobter 23, 2020. Accessed March 19, 2023 from <u>https://www.wdrb.com/in-depth/nucor-starts-work-on-brandenburg-ky-steel-mill/article_68b6530c-156b-11eb-8d81-ffc75a1b85c1.html</u> .
	New Nucor Steel Brandenburg Plate Mill Rolls First Plate. Nucor. Published online January 3, 2023. Accessed March 19, 2023 from https://nucor.com/news-release/19471 .
CMC Durant Plant, OK	Ground broken for new steel mill in Durant. News On 6. Published online April 30, 2016. Accessed March 19, 2023 from https://www.newson6.com/story/ 5e360f752f69d76f62039b57/ground- broken-for-new-steel-mill-in-durant.
	Commercial Metals Co. receives air permit. The Journal Record. Published online February 4, 2016. Accessed March 19, 2023 from <u>https://journalrecord.com/2016/02/04/commercial-metals-co-receives-air-permit/</u> .
	Commercial Metals Company selects Durant, Okla., for new micro mill. Oklahoma Commerce. Published online July 30, 2015. Accessed March 19, 2023 from <u>https://www.okcommerce.gov/commercial-metals-company-</u> selects-durant-okla-for-new-micro-mill/.

Facility Name	Year Operational
Nucor Steel, Davidson Co, NC	Doss-Raines, J. Nucor Steel to host two town hall meetings to get to know the Davidson County. The Dispatch. Published online February 8, 2023. Accessed March 19, 2023 from <u>https://www.the-dispatch.com/news/nucor- steel-to- host-two-town-hall-meetings-to-get-to-know-the-davidson- county/article_5165f657-eafe-56d5-a30e-eaa8d5d1e3b5.html.</u>
	Nucor to build new \$350 million micro mill in North Carolina. Industry Week. Published online April 11, 2022. Accessed March 19, 2023 from <u>https://www.industryweek.com/leadership/growth-</u> <u>strategies/article/21238679/nucor-to-build-new-350-million-micro-mill-in-</u> <u>north-carolina</u> .

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CLEAN ENERGY TECHNOLOGIES

6. Hydrogen Production

TECHNOLOGY AT A GLANCE

- There are many ways to produce hydrogen, which are at different degrees of technical readiness. Here we examine blue hydrogen (commercially operational), green hydrogen via electrolysis (commercial demonstration phase), and green hydrogen via biomass (pilot and early demonstration phase).¹
- Current costs per kilogram H₂ produced: \$1.30-10.60 USD/kg H₂
- Current cost of CO₂ capture: \$125-257 USD/ton CO₂ (green hydrogen from biomass), ~\$82 USD/ton CO₂ (blue hydrogen from steam methane reforming+carbon capture and storage [SMR+CCS])
- Projected costs reductions per kilogram H₂ produced at scale: 20-50%
- Key advantages of this technology in Kern County: close proximity to feedstocks for some production methods (agricultural waste for green hydrogen from biomass, natural gas for blue hydrogen from SMR+CCS), located within the largest hydrogen market in the U.S., abundant renewable energy can make green hydrogen via electrolysis cost-competitive with other techniques
- Key concerns for this technology in Kern County: high energy and water demands for green hydrogen via electrolysis, potential for air pollutants - particularly from blue hydrogen via SMR+CCS - warrants further investigation, the hydrogen market is still quite nascent and will require large infrastructure investments before it can scale significantly

¹ Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

6.1 Technology Summary

In looking for alternative fuels to traditional hydrocarbons (including gasoline and diesel), both scientific experts and policymakers have turned to hydrogen as a potential fuel of the future, as it does not generate carbon emissions when burned.² Hydrogen is highly abundant, but most commonly is chemically bound in the compounds of other familiar substances, like water (H₂O) or methane (CH₄, which is natural gas). To use hydrogen as a fuel, it must be isolated from those compounds.³ In this section, we present a brief overview of the variety of processes available to generate hydrogen gas (H₂), with a focus on two forms of hydrogen that are considered to produce little or no CO_2 emissions in their production: green and blue hydrogen.

6.1.1 Methods of Hydrogen Production

Hydrogen can be produced via several different methods, which for short-hand discussions have been categorized into a color key system, with each color indicating the production technique. Understanding this system is useful for research and discussions about the hydrogen industry and when thinking about the viability and trade-offs of given production methods. (Note, hydrogen itself is a colorless gas; the color system is simply a convenient notation device, but describes only the difference in hydrogen generation technique. There is no difference in the visual, physical, or chemical properties of hydrogen gas derived from these different production methods).⁴

While most applications of this color key system use commonly agreed upon definitions for each color, there is not a regulatory or industry standard, so some sources may have differences in what processes they include under each color. In this section, we provide a brief overview of the hydrogen labeling system, giving the commonly agreed upon definitions of each color. Then, we will examine the three forms of hydrogen production that would be most relevant for consideration in a carbon management and clean energy industrial park: green hydrogen via electrolysis, green hydrogen via biomass, and blue hydrogen.

6.1.1.1 The Hydrogen Color System

Unless otherwise noted, all definitions of the hydrogen color key system are derived from National Grid, an electricity distribution company operating in the United States and United Kingdom.⁵

Green hydrogen production refers to production techniques that generate no greenhouse gas byproducts. Most commonly, this is achieved via a process known as electrolysis,

² FuelCellWorks (November 28, 2022) <u>'Gold Hydrogen' Is an Untapped Resource</u>. [31]

³ EPA (September 13, 2022) <u>Green Vehicle Guide: Hydrogen Fuel Cell Vehicles</u>. [28]

⁴ National Grid (no date) <u>Hydrogen Colour Spectrum</u>. [50]

⁵ National Grid (no date) <u>Hydrogen Colour Spectrum</u>. [50]

wherein clean energy (like solar or wind) is used in an electrochemical reaction to split water molecules into hydrogen and oxygen. However, other non-carbon emitting techniques, such as gasification of biomass to form pure streams of H₂ and CO₂ gasses, combined with carbon capture, also qualify as green hydrogen.⁶

Blue hydrogen production refers to the conversion of methane (natural gas) to hydrogen via a process called steam reforming, which – like gasification from biomass – generates both hydrogen and carbon dioxide. In blue hydrogen generation, generated CO_2 is captured via point source capture technologies (see Section 5) reducing the carbon-intensity of hydrogen generation.

Gray hydrogen production also refers to steam reforming methane (natural gas), but does not incorporate the carbon capture processes necessary to reduce emissions. Currently, gray hydrogen is the most commonly used production process to generate hydrogen.

Black and brown hydrogen production relies on using pure coal or lignite (brown coal) to generate hydrogen, by gasification of the coal resulting in hydrogen as a byproduct. This is understood to be one of the most environmentally harmful ways to produce hydrogen.

Pink hydrogen production refers to the process of electrolysis, where water is split into hydrogen and oxygen, akin to green hydrogen. Unlike green hydrogen, though, it relies on nuclear power to sustain the electrochemical reaction. Some sources refer to this with other similar colors, like purple or red.⁷

Turquoise hydrogen production involves a process called methane pyrolysis, which converts methane to hydrogen and solid carbon, called "carbon black."⁸ Carbon black has many industrial uses, but this method of hydrogen production has yet to operate at a commercial scale.

Yellow hydrogen production is a less commonly used and newer term, referring specifically to hydrogen production via electrolysis fueled by solar power. As such, yellow hydrogen is a subcategory of green hydrogen.

White hydrogen refers to hydrogen that does not need to be produced, but that is naturally occurring in geologic formations and could be accessed via fracking. At present, there are no plans or strategies to mine hydrogen, and opinions are mixed as to whether naturally-occurring hydrogen gas even exists. The National Renewable Energy Laboratory (NREL) states that hydrogen gas is not naturally-occurring, but there is growing optimism from other scientists that naturally-occurring hydrogen may be abundant beneath the Earth's surface.⁹

⁶ Cormos (2023) <u>Green hydrogen production from decarbonized biomass gasification</u>. [20]

⁷ Willige (July 28, 2022) <u>The colors of hydrogen</u>. [84]

⁸ Willige (July 28, 2022) <u>The colors of hydrogen</u>. [84]

⁹ Coy (February 27, 2023) <u>A Gold Mine of Clean Energy May Be Hiding Under Our Feet</u>. [21]

6.1.1.2 Envisioning hydrogen production in Kern County

Given the current economy, climate, and resources of Kern County, and the developmental objectives of a carbon management and clean energy industrial park, only some hydrogen production approaches were identified as warranting exploration in this study. The following production methods were ruled out:

- Black/brown and pink hydrogen production make little sense to explore at this juncture, given Kern County's current and anticipated energy mix.
- White hydrogen production is still within very early stages of technological development and will require significant further research before it is ready for commercial demonstration.
- Turquoise hydrogen is still within very early stages of development. Although it is not examined extensively here, production is very similar to other forms of biomass gasification and pyrolysis, which are described in detail in Section 4.
- Yellow hydrogen is a type of green hydrogen, and thus will be examined briefly in the discussion of hydrogen via electrolysis.
- Gray hydrogen production, given its large, unmitigated greenhouse gas emissions footprint, is incompatible with the park's guiding principle of hosting carbon management and clean energy industries.

Green hydrogen (via electrolysis or biomass gasification) and blue hydrogen production are potential clean energy or carbon management technologies that could feasibly be adopted in a Kern County carbon management park, and we explore each of these in this report. Given that more than one production method can be classified as 'green hydrogen,' the nomenclature used in this report will always specify both the color key and the process of production, to avoid ambiguity: hydrogen via electrolysis (green), hydrogen via biomass gasification (green), and hydrogen via steam methane reforming (SMR) + CCS (blue). Finally, because hydrogen production via biomass gasification with carbon capture is a form of Biomass with Carbon Dioxide Removal and Storage (BiCRS), most of the information on this method of hydrogen production is also contained in the BiCRS/BECCS section of this report (Section 4) and is cross-referenced accordingly.

6.1.2 Green and Blue Hydrogen Description: How it Works

6.1.2.1 Green hydrogen via Electrolysis

Hydrogen production via electrolysis involves using an electric current to drive an electrochemical reaction in which water is split into its constituent elements, hydrogen and oxygen:¹⁰

 $H_2O \rightarrow H_2 + \frac{1}{2}O_2$

(R6.1)

¹⁰ AFDC (no date) <u>Hydrogen Production and Distribution</u>. [6]

(R6.3)

There are a variety of machines, called electrolyzers, that can sustain this electrochemical reaction to produce hydrogen, using varying techniques, which are reviewed here.



Figure 6.1. Schematic of the process of producing hydrogen via electrolysis: renewable energy provides electricity to power a cathode and anode placed in a water + dissolved salt solution. The electric current created breaks water (H_2O) molecules into hydrogen and oxygen.

The most well-established method, alkaline electrolysis, has existed for more than two centuries. Alkaline electrolysis uses an electrochemical cell, where a cathode and anode are placed in an electrolyte solution, which is a water-based solution with salts (Figure 6.1).¹¹ When voltage is applied to the cell, water molecules are reduced by electrons at the cathode to produce hydrogen gas and negatively charged hydroxide (OH⁻). The hydroxide ions will be electrically attracted to the anode, and by placing a membrane between the anode and cathode, the hydrogen gas molecules can be separated from the negatively charged hydroxide ions. At the anode, the hydroxide ions are oxidized, producing oxygen gas, and releasing water molecules and electrons back to the electrolyte solution (see reactions R6.2 + R6.3):¹²

Cathode reaction:
$$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$$
 (R6.2)

Anode reaction: 20H
$$^{\scriptscriptstyle -} \rightarrow {}^{1\!\!/_2}O_2$$
 + H_2O + 2e $^{\scriptscriptstyle -}$

Hydrogen gas is separated from the electrolyte solution to be dried (removing any H_2O vapor), cleaned (involving the removal of oxygen impurities),¹³ and depending on the end use, compressed.¹⁴ The reactions in the electrolyte solution (R6.2 + R6.3) generate heat; if this heat is harnessed during the process, it can help improve the cell's overall energy

¹¹ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

¹² Brauns, Turek (2020) <u>Electrolysis review</u>. [12]

¹³ Brauns, Turek (2020) <u>Electrolysis review</u>. [12]

¹⁴ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

efficiency.¹⁵ Alkaline electrolysis represents a *type* of electrochemical cell, which is often used as a kind of battery. For a general explanation of electrochemical cells and reduction-oxidation reactions, please see Section 7.1.1 of this report.

Most new hydrogen via electrolysis projects today use a different process that relies on a proton exchange membrane (PEM).¹⁶ Here, instead of a liquid electrolyte solution, water is pressed through a stack of two electrodes with a polymer membrane in between (Figure 6.2). At the anode, the water reacts to form oxygen, hydrogen ions (H⁺), and electrons; the hydrogen ions can then move selectively across the membrane, a specialty solid plastic material,¹⁷ towards the cathode.¹⁸ The electrons are moved to the cathode side as well through an external circuit, as they cannot pass through the membrane.¹⁹ On the cathode side, the hydrogen ions and electrons combine, forming hydrogen gas.²⁰



Figure 6.2. Schematic of a proton exchange membrane. Image credit: U.S. Department of Energy.²¹

There is a third electrolysis technology—solid oxide electrolysis (SOE)—that is rising in prominence, but alkaline and PEM systems are far more common for commercial applications. It is explored briefly here for comprehensiveness, but future sections on hydrogen via electrolysis primarily focus on alkaline and PEM systems. The electrolyte in these systems is a solid ceramic that selectively allows negatively charged ions to pass through at high temperatures—in this case, the negative ion is oxygen (O²⁻).²² Water enters at the cathode as steam, where it combines with negative ions brought in via the external

¹⁵ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

¹⁶ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

¹⁷ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

¹⁸ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

¹⁹ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

²⁰ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

²¹ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

²² EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

circuit to form hydrogen gas and O^{2-.23} Once formed, the oxygen ions pass through the solid ceramic membrane to the anion, where the oxygen ions react to form oxygen gas and electrons that will supply the external circuit.²⁴

Many projects currently emphasize "power-to-hydrogen" or "power-to-gas" initiatives, where excess renewable energy—when it is available from the grid—is channeled to electrolyzers to create hydrogen.^{25, 26}

6.1.2.2 Green Hydrogen via Biomass Gasification

There are a variety of ways to treat biomass in order to produce an energy-rich product and CO_2 byproduct that can be captured for permanent storage, which are detailed in Section 4 of this report. The most relevant in the context of hydrogen is a process called gasification, a two-step process in which first, biomass is reacted with steam and oxygen at high temperatures (>700°C) and pressure, converting it into gaseous components – primarily CO, CO_2 , and H_2 .²⁷ In the second step, called a water-gas shift reaction, the carbon monoxide (CO) is reacted with water to produce more CO_2 and H_2 , along with a small amount of heat.²⁸ The resulting products are two streams of high-purity gasses: CO_2 for permanent storage, and H_2 for fuel use. Pyrolysis, the high-pressure and high-temperature process used to create turquoise hydrogen from methane, is a technique that can also be applied to biomass to produce CO_2 and a variety of hydrocarbon byproducts, and is also detailed further in Section 4.

6.1.2.3 Blue Hydrogen via Steam Methane Reforming (SMR) + CCS

Hydrogen via steam methane reforming (SMR) + CCS relies on an interconnected series of processes to transform methane (CH₄) and water (H₂O) into hydrogen (H₂) and CO₂. In the initial SMR reaction, steam reacts with methane in a high-pressure container with a catalyst to produce syngas, a mixture of hydrogen, carbon monoxide, and carbon dioxide.²⁹ As an endothermic reaction, SMR requires heat for the reaction to proceed—requiring about 206 kJ of heat energy per mol of methane.^{30,31} (Steam reforming can be used to generate hydrogen from other hydrocarbon fuels, like propane or gasoline, but SMR is the most

²³ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

²⁴ EERE (no date) <u>Hydrogen Production: Electrolysis</u>. [58]

²⁵ AFDC (no date) <u>Hydrogen Production and Distribution</u>. [6]

²⁶ Shibata (2015) <u>Hydrogen Production from Variable Renewables</u>. p. 27-28. [70]

²⁷ EERE (no date) <u>Hydrogen Production: Biomass Gasification</u>. [57]

²⁸ EERE (no date) <u>Hydrogen Production: Biomass Gasification</u>. [57]

²⁹ Student Energy (no date) <u>Steam Methane Reforming</u>. [74]

³⁰ Student Energy (no date) <u>Steam Methane Reforming</u>. [74]

³¹ National Research Council and National Academy of Engineering (2004) <u>The Hydrogen</u> <u>Economy</u>. p. 199. [51]

common choice for hydrogen production, as it is the cheapest and most efficient.^{32,33}) Like gasification, the next step is typically a water-gas shift reaction, where the carbon monoxide generated in SMR is reacted with more steam in the presence of a catalyst to form more hydrogen, carbon dioxide, and a small amount of heat.³⁴ The final step, pressure-swing adsorption, removes the carbon dioxide and other gasses from the final products, leaving a pure stream of hydrogen gas.³⁵

Once separated from the hydrogen gas stream, the carbon dioxide generated in the SMR and water-gas shift steps can be purified, compressed, and transported for permanent underground storage, preventing it from entering the atmosphere and contributing to climate change. In gray hydrogen production (from SMR without CCS), for every kilogram of hydrogen produced, approximately 9 kilograms of CO₂ is generated.³⁶ With carbon capture and storage attached, the estimated emissions of SMR hydrogen production drops to 1-5 kilograms of CO₂ generated per kilogram of hydrogen.³⁷ Although this reduces the impacts of SMR, it does not make the process carbon-neutral—blue hydrogen still releases CO₂ into the atmosphere. This is explored in further detail in Section 6.3 on the environmental impacts of hydrogen production.

6.1.3 State of Development

Blue hydrogen via SMR + CCS, green hydrogen via electrolysis and green hydrogen from biomass are all commercially operational processes that are ready to be scaled up, but hydrogen production from electrolysis and biomass gasification in particular are currently deemed too costly to be competitive with less environmentally-friendly hydrogen production methods.

In addition to the hydrogen production methods detailed here, and in the color classification summary (Section 6.1.1.1), there are several emerging hydrogen production techniques that are still in the early research and development stage. It is beyond the scope of this study to detail each of these emerging technologies, but a list of their names is provided for the interested reader who would like to explore further. Hydrogen production techniques still in the experimental phase include processes like photo-electrochemical solar water splitting, solar high-temperature thermochemical cycles, high-temperature electrolysis, photo-biological conversion, bio-derived conversion, microbial conversion and generating hydrogen from aluminum scrap.³⁸

³² Student Energy (no date) <u>Steam Methane Reforming</u>. [74]

³³ AFDC (no date) <u>Hydrogen Production and Distribution</u>. [6]

³⁴ Student Energy (no date) <u>Steam Methane Reforming</u>. [74]

³⁵ Student Energy (no date) <u>Steam Methane Reforming</u>. [74]cf

³⁶ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

³⁷ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

³⁸ Bezdek (2019) <u>The hydrogen economy</u>. [8]

Below, we provide brief summaries of extant companies or projects that are representative of the three hydrogen production techniques explored here.

6.1.3.1 Example projects

Electrolysis: Air Liquide, Bécancour, Québec

Air Liquide's facility in Bécancour is discussed at length in Section 6.1.4, as a case study for operational needs of electrolysis. This facility has the largest operating electrolyzer of its kind in the world—a 20 MW PEM electrolyzer developed with Cummins technology.³⁹ This 20 MW capacity was obtained by a four-module configuration of HyLYZER 1000-30 units, which are 5 MW each.⁴⁰ The facility is run using grid hydropower resources from Hydro-Québec, an almost-all renewable source of energy.⁴¹



Figure 6.3. Digital rendering of the planned alkaline electrolysis facility in Lancaster, California, under construction by Element Resources. Image credit: Element Resources.

Electrolysis: Element Resources, Lancaster, California

At the planned Lancaster Energy Center, Element Resources intends to set up an electrolysis site on 1,165 acres with an electrical capacity of 135 MW using alkaline electrolysis.⁴² The primary reason for the large land footprint is the electricity demand, which will be met using solar photovoltaic (PV) panels installed on-site. Their estimated hydrogen output per year, once fully operational, is 18,750 metric tons per year.⁴³

³⁹ Air Liquide (February 8, 2021) <u>World's Largest PEM Electrolyzer</u>. [2]

⁴⁰ Collins (January 27, 2021) World's largest green-hydrogen plant inaugurated. [19]

⁴¹ Air Liquide (February 8, 2021) <u>World's Largest PEM Electrolyzer</u>. [2]

⁴² Element Resources (no date) <u>Lancaster Energy Center</u>. [24]

⁴³ Element Resources (no date) <u>Lancaster Energy Center</u>. [24]

Biomass Gasification: Mote, Los Angeles, California

Mote, a Culver City-based cleantech startup, is planning to build a \$100 million biomass to hydrogen energy plant with carbon sequestration on 5 acres of unincorporated land in Kern County, pending securing financing, government approval and permits.⁴⁴ The plant will extract carbon dioxide and hydrogen via gasification from wood waste from farms, forestry, and other resources.⁴⁵ The hydrogen gas will be sold to hydrogen fuel station operators, and the CO₂ will be sequestered into deep underground saline aquifers or retired oil wells. Mote expects to produce approximately 7,000 metric tons of carbon-negative hydrogen (green hydrogen) annually, which translates to ~150,000 metric tons of CO₂ captured from biomass and available for permanent sequestration.⁴⁶

Mote's business model will provide cost-competitive green hydrogen by partly offsetting their costs with income from the storage of CO₂. They will either take advantage of carbon removal credits in the voluntary carbon credit market, or of rebates from the federal tax credit for CCS projects (45Q) as well as California's Low Carbon Fuel Standard (LCFS).⁴⁷ In May 2022, Mote announced that they had secured commitments for over 450 thousand tons of feedstock for their production.⁴⁸ Working with Fluor, an industry leading engineering, procurement and construction (EPC) firm, to execute the Front-End Loading 2 (FEL-2), Mote plans to begin construction in 2023 and be fully operational by 2025.⁴⁹ A digital rendering of their planned facility is shown in Figure 6.4.

Steam Methane Reforming: Air Products, Texas & Louisiana

Air Products has deployed retrofitted carbon capture to two existing hydrogen via SMR facilities in Texas, and is now planning a more ambitious project: building the world's largest SMR + CCS facility in Louisiana, planned to go online in 2026.⁵⁰ The Louisiana Clean Energy Complex webpage states they expect to capture over 5 million tons of CO₂ annually from SMR + CCS hydrogen production, expecting that they'll capture 95% of the CO₂ generated during the process.⁵¹ According to Air Products, this would position them to be the largest CCS plant in the world. If they can attain this 95% capture rate in practice, it would be a higher capture rate than any reported estimates for SMR with CCS found in the literature during the preparation of this report. Total planned investment for the project amounts to \$4.5 billion, and the project would create an estimated 170 permanent jobs and another 2,000 positions during the construction phase.⁵²

⁴⁴ Fine (January 3, 2022) <u>Clean tech startup Mote unveils plans for \$100M plant</u>. [30]

⁴⁵ Temple (February 15, 2022) <u>Fuel plant will use agricultural waste to combat climate change</u>. [76]

⁴⁶ Temple (February 15, 2022) <u>Fuel plant will use agricultural waste to combat climate change</u>. [76]

⁴⁷ Temple (February 15, 2022) <u>Fuel plant will use agricultural waste to combat climate change</u>. [76]

⁴⁸ BusinessWire (May 24, 2022) <u>Mote Enters Advanced Stage of Engineering Design</u>. [14]

⁴⁹ BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [14]

⁵⁰ Air Products (no date) <u>Carbon Capture</u>. [3]

⁵¹ Air Products (no date) <u>Louisiana Clean Energy Complex</u>. [4]

⁵² Air Products (no date) Louisiana Clean Energy Complex. [4]



Figure 6.4. Digital rendering of a planned Mote Hydrogen facility in southern California, featuring a parking lot, office buildings, a gasifier building with conveyor belts for moving biomass, several large vertical tanks, rows of biomass feedstock, and two evaporation ponds. Image credit: Mote, Inc.

6.1.4 Operational Needs

6.1.4.1 Land use requirement

The scale of a commercial hydrogen facility is generally described in terms of how much energy it is able to produce annually (its MW capacity), rather than the physical footprint that it would occupy, meaning published descriptions of land use needs from operators are rare. Furthermore, given the rapid rate of technological innovation and plans to scale up production in this sector, most existing facilities are significantly smaller than planned future facilities. As such, experts have largely been approximating facility footprints based "on engineering estimates, rather than plot optimization based on real experience."⁵³

For hydrogen via electrolysis, the largest currently active site in the world is Air Liquide's site in Bécancour, Quebec, which began production in January 2021.⁵⁴ It has a capacity of 20 MW and can generate over 8.2 metric tons per day of hydrogen; their plant relies on hydropower from Hydro-Québec for its nearly-all renewable energy source.⁵⁵ The Bécancour facility relies on four proton exchange membrane (PEM) electrolyzers to generate its hydrogen, which are approximately the size and shape of very round water towers.⁵⁶

Estimates aggregated by the International Renewable Energy Agency (IRENA) can help refine size estimates for future hydrogen facilities that would be larger than Bécancour, as

⁵³ IRENA (2020) <u>Green Hydrogen Cost Reduction</u>. p. 41. [38]

⁵⁴ Air Liquide (February 8, 2021) <u>World's Largest PEM Electrolyzer</u>. [2]

⁵⁵ Air Liquide (February 8, 2021) <u>World's Largest PEM Electrolyzer</u>. [2]

⁵⁶ Air Liquide (February 8, 2021) <u>World's Largest PEM Electrolyzer</u>. [2]

is expected to become common if hydrogen is to be a widely-used fuel in the future. In a 2014 study, IRENA estimated that a 100 MW capacity electrolyzer would require ~6,300 m² (1.55 acres) of land.⁵⁷ For reference, a 100 MW electrolyzer would produce about 50,000 kilograms of H₂ per day⁵⁸ (that is the equivalent to about 50,000 gallons of gasoline production per day⁵⁹).

Later studies of 100 MW capacity facility designs generated smaller estimates than this initial figure, with a 2017 study estimating a footprint of 3,500 m² (0.86 acres) and a 2018 study estimating a footprint of 4,500 m² (1.11 acres).⁶⁰ In regards to even larger facilities, a 2017 study by Siemens predicted a 300 MW capacity electrolyzer facility would need 15,000 m² (3.71 acres).⁶¹ Relative to other industrial energy facilities that produce electricity or fuel, these are relatively modest land use requirements.^{62,63}

The accuracy of these estimates will be easier to determine moving forward, as companies have begun planning and constructing facilities in the hundreds of MW capacity range. A 100 MW hydrogen via electrolysis facility run by RWE Generation is planned for Lingen, Germany as part of the world's first publicly-accessible hydrogen network.⁶⁴

6.1.4.2 Energy requirements

Hydrogen production is an extremely energy intensive process, particularly for electrolysis, because of the strength of the chemical bonds that need to be broken between the hydrogen and oxygen ions within a water molecule. For hydrogen production via electrolysis, the efficiency of the reaction generally ranges between 60-81%, depending on the technology used.⁶⁵ This means that for every 100 MW of electricity used to drive an electrolysis reaction, about 60-81 MW of energy value is produced in the form of hydrogen fuel. That is equal to a production rate of about 43,600-58,900 kg of H₂ produced each day,⁶⁶ with one kg of H₂ having about the same energy content as one gallon of gasoline. If all of the hydrogen currently produced in the world (about 69 million metric tons annually) was

⁵⁷ IRENA (2020) <u>Green Hydrogen Cost Reduction</u>. p. 41. [38]

⁵⁸ EERE (August 2018) <u>Global Electrolyzer Sales Reach 100 MW per Year</u>. [55]

This DOE estimate assumes that the electrolyzer is running full-time with 50 kWh of electricity needed per kilogram of hydrogen produced to arrive at this estimate.

⁵⁹ Hydrogen Program (no date) <u>Hydrogen Conversion Factors</u>. p. 1. [35]

⁶⁰ IRENA (2020) <u>Green Hydrogen Cost Reduction</u>. p. 41. [38]

⁶¹ IRENA (2020) <u>Green Hydrogen Cost Reduction</u>. p. 41. [38]

⁶² Stevens *et al.* (2017) <u>The Footprint of Energy</u>. p. 1. [73]

⁶³ Boyett (January 27, 2023) <u>Henderson history: Third time wasn't the charm for local synthetic fuel</u> plants. [11]

⁶⁴ Celovic (March 19, 2020) <u>First Publicly Accessible Hydrogen Network</u>. [15]

⁶⁵ IEA (2019) <u>The Future of Hydrogen</u>. p. 43. [37]

⁶⁶ National Research Council and National Academy of Engineering (2004) <u>The Hydrogen</u> <u>Economy</u>. p. 240. [51]

^{*1}kg of hydrogen has an energy value ("lower heating value") of about 33.3 kWh, and 60-81MW of energy value translates to 525,600-700,800 MWh of energy production in a year.

generated using electrolysis, it would require 3,600 terawatt hours (TWh) of electricity, more than the total annual electrical output of the European Union—a staggering energy demand.⁶⁷ To put that energy demand in a domestic perspective, if hydrogen were to replace US gasoline consumption (requiring about 135 million tons of hydrogen annually⁶⁸), producing that hydrogen via electrolysis would use nearly twice the amount of electricity that currently powers the entire United States.^{69,70,71}

A biomass gasification facility producing 1 million tons of CO₂ for capture can produce about 70,000 tons of hydrogen if it is powered entirely through an external source of energy.⁷² For a facility to be self-sufficient (effectively needing no external energy input), about 30% of the syngas produced in the gasification step of hydrogen production is needed.⁷³ In this case, for every million tons of CO₂ produced, only about 50,000 tons of hydrogen is produced.⁷⁴ Whether and to what degree produced syngas or external energy sources are used depends on the relative cost of available energy sources, and the marketplace value of green hydrogen. If green hydrogen is far more valuable than other energy sources, facilities may use electricity or other fuels to produce the hydrogen, so they can sell as much of what they generate as possible. If prices are relatively equivalent, or green hydrogen prices decline to be cheaper than other fuels, facilities will likely opt to use some of the generated hydrogen to power the facility.

Most of the energy needs for biomass hydrogen production are used to attain the necessary heat and pressure to gasify the organic feedstock. The exact amount of required heat energy is difficult to ascertain, as the process is still relatively new, and most technical information regarding any individual gasification technique is proprietary. The fact that most facilities meet this energy need with their own supply of syngas, also leads to its often being unreported. Regardless of the scale of heat energy requirements, if solar-sourced energy were used, it would need to be paired with heat batteries, which likely would make it uneconomical compared to utilizing a portion of the syngas. As for the electricity demands, most facilities either pursue a grid connection as back-up or set up their own solar panels to meet any electrical demand. For a facility capturing 1 million metric tons of CO₂, the estimated solar capacity would be 135 MW, occupying ~945 acres, just to meet the electricity needs.⁷⁵

⁷⁴ This estimate is consistent with yield estimates from an industry representative, personal communication, September 8, 2022.

⁶⁷ IEA (2019) <u>The Future of Hydrogen</u>. p. 43. [37]

⁶⁸ EIA (May 1, 2023) <u>FAO: How much gasoline does the United States consume?</u> [25]

⁶⁹ IEA (2019) <u>The Future of Hydrogen</u>. p. 43. [37]

⁷⁰ Hydrogen Program (no date) <u>Hydrogen Conversion Factors</u>. p. 1. [35]

⁷¹ Our World in Data (no date) <u>USA Electricity Generation</u>. [60]

 ⁷² Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. Supplementary
 Table S4. [85]

⁷³ Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 3. [85]

⁷⁵ Industry representative, personal communication, September 8, 2022.

For SMR + CCS, there is no expected electricity demand, as the SMR process can be driven using internally generated waste heat, but there is a requirement of 3.4 kilograms of natural gas (methane) input per kilogram of hydrogen generated.⁷⁶ If waste heat is not employed to support the heat necessary for the SMR and water-gas shift reactions, then additional natural gas (methane) may be needed to meet the heat energy requirements.

6.1.4.3 Other operational requirements

Waste disposal requirements

During electrolysis, two gaseous products are created: hydrogen gas (H₂) and oxygen gas (O₂). Most electrolyzer plants choose to release their oxygen gas directly into the atmosphere,⁷⁷ but the oxygen could hypothetically be packaged and sold for use in metal processing, stone and glass production, chemical manufacturing, or for medical uses.⁷⁸ If these uses were pursued, the oxygen would likely need to be compressed and given warehouse space before it could be shipped to end users.

If the water source for electrolysis is not delivered at the necessary purity to go straight into an electrolyzer, then it may require additional on-site filtration, which produces minerals (mostly salt) that will need to be disposed of.⁷⁹ For a plant generating 45 metric tons of hydrogen gas daily using water directly from municipal supplies, the estimated weekly mineral production was about one dumpster worth of material for disposal.^{80,81} A 100 MW hydrogen electrolysis facility, which produces slightly more H₂ (about 50 metric tons daily),⁸² would need just over one dumpster per week. In the long term, another category of expected waste will be the electrolyzer stacks themselves, which typically require replacement on a 7 to 11 year timescale depending on the electrolyzer type.⁸³

For hydrogen production via biomass gasification, all of the reaction products—hydrogen, CO₂, biochar—can be sold for use or permanently sequestered. It is only equipment that should require a waste disposal strategy at end-of-life, which will be component specific, depending on whether it can be recycled or needs to be landfilled. Further information about gasification products and disposal can be found in Section 4.1.4.2 of this report.

For hydrogen production via SMR + CCS, the picture is similar to biomass gasification – once all of the steps have been completed, the only process outputs should be hydrogen,

⁷⁶ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

⁷⁷ Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 1. [64]

⁷⁸ Lenntech (no date) <u>Oxygen</u>. [44]

⁷⁹ Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 2. [64]

⁸⁰ Governor Kathy Hochul (October 20, 2021) <u>Construction Start at Largest Green Hydrogen Plant</u> <u>in North America</u>. [34]

⁸¹ Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 2. [64]

⁸² Hydrogen Program (no date) <u>Hydrogen Conversion Factors</u>. p. 1. [35]

 ⁸³ UK Department of Business, Energy & Industrial Strategy (2021) <u>Hydrogen Production Costs</u>. p.
 19. [77]

CO₂, and a small amount of heat.⁸⁴ None of these products require waste disposal, unless there are any impurities in the methane gas stream that would result in small amounts of gaseous waste.⁸⁵ The hydrogen and CO₂ can be packaged for sale or sequestration, and the heat would ideally be cycled back into the process or directed towards a co-located industry for use. Again, only equipment that requires replacement should need separate waste disposal practices.

Warehousing requirements

For all methods of hydrogen production, the most likely warehousing requirement will be a site to compress and store the hydrogen for transport once formed. Both hydrogen production via biomass gasification and via SMR + CCS will also create CO₂ that must be compressed and transported off-site, ideally to geologic storage, to minimize environmental impacts.

Hydrogen production via electrolysis may require similar infrastructure to store oxygen if they plan to sell it instead of releasing it.

For hydrogen production via biomass gasification, a facility will need biomass on hand to gasify (i.e. Figure 6.3), and these facilities often have drying warehouses on-site to prepare the biomass for processing.⁸⁶ Since these facilities will generate other byproducts, like biochar, that can be sold, it is likely that they will need other buildings to process and store these products for shipment.

Transportation requirements

Over short distances, hydrogen can be transported via pipeline, truck, or rail.⁸⁷ With that said, pure hydrogen gas is extremely hard to transport. It can be compressed, liquefied, or converted temporarily into a metal hydride (fuel cell) in order to be transported.⁸⁸ Given that hydrogen is the lightest and smallest element in the universe, hydrogen gas is the lowest density gas. Hydrogen gas is also extremely flammable when mixed with even small amounts of air, so leaks or other malfunctions in transport could be extremely hazardous.⁸⁹ As such, it would be an extensive challenge to retrofit existing transport methods for safe use with hydrogen. Rather, new, dedicated infrastructure (pipelines, hydrogen compression or conversion technologies, and appropriately designed tanker and shipping vessels) will need to be developed. Technologies to scale up the cooling and compressing of hydrogen for commercial-scale transport are still in the research and development phase.⁹⁰ Based on the current state of the industry, consensus is that mass transport of

⁸⁴ Student Energy (no date) <u>Steam Methane Reforming</u>. [74]

⁸⁵ EERE (no date) <u>Hydrogen Production: Natural Gas Reforming</u>. [59]

⁸⁶ Zafar (July 25, 2022) <u>Everything you should know about biomass storage methods</u>. [86]

⁸⁷ Pascal (June 20, 2022) <u>Different methods of storing, transporting, and distributing hydrogen</u>. [61]

⁸⁸ Brown (April 27, 2022) <u>The next frontier</u>. [13]

⁸⁹ Brown (April 27, 2022) <u>The next frontier</u>. [13]

⁹⁰ Brown (April 27, 2022) The next frontier. [13]

hydrogen by sea will not be commercially viable until the mid-2030s,⁹¹ limiting viable hydrogen markets over the next decade to those accessible by onland routes.

Currently, long-distance transport of hydrogen is conducted by converting hydrogen into chemical intermediates and then moving the intermediates to a final destination, where it can then be converted back into hydrogen gas for use. The intermediates used as energy carriers will likely be compounds like methylcyclohexane (organic hydride).⁹² Methylcyclohexane can be imported and exported globally and is less dangerous to transport than pure hydrogen, as it remains a liquid at standard temperature and pressure and is chemically stable.^{93, 94} The Chiyoda Corporation has already successfully demonstrated this process, using a mixture of toluene and hydrogen to generate methylcyclohexane in Brunei, transporting the methylcyclohexane over sea using a chemical tanker to Japan, and then using a dehydrogenation process on Japanese shores to supply the hydrogen for industrial facilities.⁹⁵

In short, because of its molecular structure, hydrogen gas will require development of entirely new transportation networks and usage infrastructure than that used in our existing natural gas economy.⁹⁶ This new infrastructure will need to develop at a significant pace in order to ensure the economic viability of any large-scale hydrogen production facility.

Pipeline requirements

In the United States, there are approximately 1,600 miles of hydrogen pipelines⁹⁷ under the regulation of the federal Pipeline & Hazardous Materials Safety Administration (PHMSA).⁹⁸ Regulating hydrogen pipelines in the United States has been under the purview of the U.S. Department of Transportation (DOT), PHMSA's parent agency, since 1970 due to 49 CFR Part 192.⁹⁹

Although hydrogen can be moved alongside natural gas at concentrations up to 15% hydrogen with only minor modifications required in a natural gas pipeline, moving hydrogen at higher concentrations of purity will require more substantial modifications or new pipeline infrastructure.¹⁰⁰

⁹¹ Brown (April 27, 2022) <u>The next frontier</u>. [13]

⁹² Shibata (2015) <u>Hydrogen Production from Variable Renewables</u>. p. 27. [70]

⁹³ Shibata (2015) <u>Hydrogen Production from Variable Renewables</u>. p. 27. [70]

⁹⁴ Kurosaki (2018) Introduction of Liquid Organic Hydrogen Carrier. p. 4. [43]

⁹⁵ FuelCellWorks (February 10, 2022) <u>Hydrogen Transportation in the Form of MCH by Chemical</u> <u>Tanker</u>. [32]

⁹⁶ Bossel, Eliasson (no date) <u>Energy and the Hydrogen Economy</u>. p. 1. [9]

⁹⁷ EERE (no date) <u>Hydrogen Pipelines</u>. [56]

⁹⁸ PHMSA (no date) <u>Hydrogen</u>. [63]

⁹⁹ PHMSA (no date) <u>Hydrogen</u>. [63]

¹⁰⁰ EERE (no date) <u>Hydrogen Pipelines</u>. [56]

6.1.5 Carbon Capture Potential

The carbon capture potential associated with hydrogen production differs depending on the process under consideration.

To generate hydrogen via electrolysis, no CO_2 should be produced unless the energy to sustain the reaction is sourced from a non-renewable resource. As we are only considering electrolysis conducted with renewable resources—like wind or solar—in this analysis, this production process should not be generating carbon for capture. It would exist as a clean energy industry, rather than a carbon management industry.

To generate hydrogen via biomass gasification, CO_2 will be created as a byproduct of hydrogen production. However, recovery rates of these carbon emissions are quite high (over 90%),¹⁰¹ allowing nearly all the CO_2 produced onsite to be compressed and transported for permanent underground storage. Between 50,000 to 70,000 tons of hydrogen can be generated via biomass gasification per every 1 million tons of CO_2 produced, depending on how the facility's energy needs are met.¹⁰²

To generate hydrogen via SMR + CCS, CO_2 will be created through multiple stages of production in both the initial SMR reaction and the subsequent water-gas shift reaction.¹⁰³ Given that gray hydrogen production (SMR without CCS) produces about 9 kilograms of CO_2 per kilogram hydrogen, while the estimate for blue hydrogen production (SMR + CCS) is 1-5 kilograms of CO_2 per kilogram hydrogen, the carbon capture and storage potential of SMR + CCS should range from 4-8 kilograms CO_2 per kilogram hydrogen produced.¹⁰⁴ This would correspond to a capture rate of 44-88% of the CO_2 emissions generated by hydrogen production via SMR. Some recent models have stated that carbon capture from SMR has a maximum removal capacity of 90%.¹⁰⁵

6.2 Societal Impacts

6.2.1 Job creation potential

6.2.1.1 Number and types of jobs

There are no average industry estimates across types of hydrogen production methods, and no public methodology for arriving at these estimates. Some studies have projected that nationwide, hydrogen-related jobs in the United States could number almost one million by 2030, but these jobs are expected to disproportionately benefit highly-skilled and

¹⁰¹ Patrizio *et al.* (2021) <u>CO₂ mitigation or removal</u>. p. 1-2. [62]

¹⁰² Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

¹⁰³ Student Energy (no date) <u>Steam Methane Reforming</u>. [74]

¹⁰⁴ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

¹⁰⁵ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

well-paid technical and professional workers.¹⁰⁶ Thus training workers to take on these new positions in the workforce will be essential to keeping jobs within local communities.

There are a few specific case studies we can use to approximate job creation potential in hydrogen production. Air Products, for their planned SMR + CCS facility in Louisiana designed to capture over 5 million tons of CO_2 annually, has projected the creation of 170 permanent jobs with an average salary of \$93,000.¹⁰⁷ For hydrogen production via biomass gasification, this study assumes that the number and type of jobs will not vary significantly from other biomass gasification facilities covered in Section 4 of this report—for specifics on those job figures, please see Section 4.2.1.1. A similar case study reporting jobs for a large scale electrolysis facility has not been found.

6.2.2.2 Training pipelines

A U.S. Department of Energy (DOE) study on the implementation of a hydrogen economy between 2020 and 2050 found that many American workers would need new skills for the hydrogen economy, and that training and retraining programs would need to be established to fill this gap.¹⁰⁸ Unfortunately, the DOE's reporting does not provide depth on what training would be necessary or the likely occupations (and anticipated earnings) associated with the growth of hydrogen production.¹⁰⁹

A wide range of skill levels are expected to engage with the hydrogen economy at-large (including hydrogen production, transport, and use), with experts anticipating that the hydrogen economy will include experts with graduate education, but also "include jobs that require associate's degrees, long-term on-the-job training, or trade certifications – and lead to jobs that pay higher than US average wages."¹¹⁰ Furthermore, Plug Power, a company currently constructing electrolyzer facilities in the United States, has specifically referenced that a skilled workforce in the region was desirable for planning where to locate electrolyzer plants.¹¹¹ Setting up programs at local community colleges and universities to provide specialized training to take on roles in hydrogen production is a crucial way to support these nascent industries and ensure new, high-paying jobs in the region benefit local community members. By establishing local programs to train workers in these skills, it could attract hydrogen investment opportunities to the overall region; existing regional benefits for Kern County specifically are explored in Section 6.4.3.

¹⁰⁶ Bezdek (2019) <u>The hydrogen economy</u>. [8]

¹⁰⁷ Air Products (no date) <u>Louisiana Clean Energy Complex</u>. [4]

¹⁰⁸ Bezdek (2019) <u>The hydrogen economy</u>. [8]

¹⁰⁹ Bezdek (2019) <u>The hydrogen economy</u>. [8]

¹¹⁰ Bezdek (2019) <u>The hydrogen economy</u>. [8]

¹¹¹ Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 1. [64]

6.2.2 Quality of Life

6.2.2.1 Location

Hydrogen production via electrolysis is generally a quiet process—a facility in western New York describes the actual electrolyzer as "silent."¹¹² The loudest equipment on site are the compressors, used to cool hydrogen post-production to prepare for transport. The impact of the compressor noise can be mitigated by placement inside a building far from the site boundary, allowing the sound to disperse over distance.¹¹³

Hydrogen generated via biomass gasification will have more components that can generate noise, as well as some outdoor equipment (ex. conveyor belts to transport biomass) that would be hard to dampen except with distance from population centers. The loudest components of the operation—such as the engine and compressor—should be housed in insulated materials to dampen the machinery noise.¹¹⁴ Other equipment like blowers and coolers inside the plant can also contribute noise, as well as any noise from equipment to transport biomass to the site and transport co-products off-site for distribution.¹¹⁵ For a facility capturing 1 million tons of CO₂ annually, about 1,800 tons of feedstock (~90 tractor-trailer truckloads) need to be delivered each day,¹¹⁶ which could contribute to noise and traffic in nearby communities. As a result, anticipated overall site noise can be a determining factor in siting a new biomass gasification facility.¹¹⁷

SMR processes can be quite loud, with on-site noise near the reformer loud enough to cause ear damage and fatigue to personnel.¹¹⁸ Ensuring there is adequate hearing protection available for workers, as well as that noise level surveys for the site and surrounding area do not exceed local regulations, is essential for any proposed SMR + CCS site.¹¹⁹

The full life-cycle of hydrogen production, transport, and use can generate a range of pollutants, which may have health impacts for nearby populations – the full spectrum of these emissions is explored in Section 6.3.2.

¹¹² Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 2. [64]

¹¹³ Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 2. [64]

¹¹⁴ IEE (2009) <u>Guideline for Safe and Eco-friendly Biomass Gasification</u>. p. 41. [36]

¹¹⁵ IEE (2009) <u>Guideline for Safe and Eco-friendly Biomass Gasification</u>. p. 22. [36]

¹¹⁶ EPA (no date) <u>Biomass Preparation</u>. p. 23. [26]

¹¹⁷ IEE (2009) <u>Guideline for Safe and Eco-friendly Biomass Gasification</u>. p. 29. [36]

¹¹⁸ EIGA (no date) <u>Combustion Safety for Steam Reformer Operation</u>. p. 13. [29]

¹¹⁹ EIGA (no date) <u>Combustion Safety for Steam Reformer Operation</u>. p. 13. [29]

6.2.2.2 Multi-use potential

Currently, most hydrogen is produced on the same site where it is used, making hydrogen a key co-location opportunity for heavy, heat-reliant industries and transportation hubs like train depots, airports, and shipping ports.

The multi-use potential of hydrogen production sites for community spaces is more narrow—with both biomass gasification and SMR + CCS being relatively hot and requiring stringently-controlled conditions to maximize efficiency, opportunities for community use on-site are unlikely. Hydrogen production via electrolysis may offer multi-use potential, as the production process is relatively quiet, making it potentially an attractive prospect for school field trips for scientific demonstration.

However, the risks of hydrogen could make such facilities intrinsically a poor candidate for multi-use opportunities. If handled improperly, hydrogen can cause fires or explosions, and since hydrogen gas is very light and odorless, leaks can be exceedingly difficult to detect before hydrogen concentrations exceed its lower flammability limit in air.¹²⁰ This risk can be reduced by designing hydrogen facilities with key features (like sloped and vented roofs) that leave hydrogen space to escape, so it is not trapped to mix with air in a sealed space.¹²¹ Overall, since hydrogen gas will need to be handled carefully on-site to protect workers, permitting other uses or untrained people to the site could be logistically difficult.

6.3 Environmental Impacts

The environmental impacts of hydrogen production are significant, particularly given that most hydrogen production taking place today is derived from natural gas and coal (gray, black and brown hydrogen). Annual global CO_2 emissions from hydrogen are equivalent to the combined annual CO_2 emissions of the United Kingdom and Indonesia, or approximately 830 million metric tons of CO_2 a year.¹²² For reference, in 2021, the United States emitted approximately 5 billion metric tons of CO_2 , ¹²³ so current hydrogen production would be equal to about 16.6% of annual CO_2 emissions in the United States. Implementing less carbon-intensive methods of hydrogen production is important for reducing emissions and air pollution, regardless of the potential uptake of hydrogen as a fuel. Building a sustainable future relies upon diversifying the energy sources used to generate hydrogen and utilizing less carbon-intensive production practices than the industry currently uses.¹²⁴

¹²⁰ OSHA (no date) <u>Green Job Hazards - Hydrogen Fuel Cells: Fire and Explosion</u>. [53]

¹²¹ Plug Power (no date) <u>STAMP Green Hydrogen Production Site</u>. p. 2. [64]

¹²² IEA (2019) <u>The Future of Hydrogen</u>. p. 14. [37]

¹²³ Richie, Roser (no date) <u>United States: CO₂ Country Profile</u>. [67]

¹²⁴ IEA (2019) <u>The Future of Hydrogen</u>. p. 17. [37]

6.3.1 Water requirements

6.3.1.1 Minimum volume requirements

For hydrogen production via electrolysis, the volume requirements of water are proportional to the output of hydrogen generated in the facility. As such, large hydrogen electrolyzers correspond to large water requirements by volume. For every two molecules of water put in an electrolyzer, two molecules of hydrogen (H₂) are created, assuming 100% efficiency.¹²⁵ However, real-world electrolyzers will suffer inefficiencies that means this 1:1 ratio will not hold in reality, and given the vast difference in molecular weight and size of a water molecule and a hydrogen gas molecule, put in terms of mass, water to hydrogen ratios are significantly higher than 1:1. Published estimates of the theoretical minimum water demand for electrolysis are as low as 9.1 liters (or 2.4 gallons) of water per kilogram of hydrogen.¹²⁶ In practice, electrolyzer operators have found that it takes approximately 12 liters (or 3 gallons) of water to produce every kilogram of hydrogen created via electrolysis.¹²⁷

Although experts are working to reduce the water requirements needed for hydrogen production via biomass gasification, currently, water is used to perform the water-gas shift reaction to generate hydrogen and purify the gaseous products. Some forms of gasification rely on steam or supercritical water, which can increase the overall water demand. The most conservative facilities use about equal quantities of biomass and water in their process.¹²⁸ There is some potential for water reuse; water is used to purify gas, allowing contaminants like SO_x or NO_x to dissolve into aqueous species. Once H₂ and CO₂ streams have been purified, the water is separated from them, carrying contaminants with them as dissolved components that can settle out. That water is typically stored in evaporation ponds on site, and could be treated for reuse with appropriate equipment.¹²⁹ Currently, the estimated water use for a biomass hydrogen facility capturing a million metric tons of CO₂ per year ranges between 266 and 1840 acre-feet of water each year.¹³⁰ That equates to about 15.0-103.6 liters (or about 3.9-27.4 gallons) of water needed to produce one kilogram of hydrogen via biomass gasification.^{*}

A full life-cycle analysis for hydrogen production via SMR + CCS found that per kilogram of hydrogen generated, the process consumed 6 to 13 liters (or 1.6-3.4 gallons) of water.¹³¹

¹²⁵ LibreTexts (August 9, 2022) <u>23.9: Electrolysis of Water</u>. [46]

¹²⁶ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 10. [41]

¹²⁷ Valdez (August 11, 2022) <u>Electrolyzers and Water</u>. [79]

¹²⁸ Industry representative, personal communication, September 8, 2022.

¹²⁹ Industry representative, personal communication, September 8, 2022.

¹³⁰ See the Comparative Analysis spreadsheet.

^{*} This calculation uses a ratio of estimated hydrogen output to water usage derived from data obtained in an interview with an industry representative, personal communication, September 8, 2022.

¹³¹ Valdez (August 11, 2022) <u>Electrolyzers and Water</u>. [79]

This is corroborated by other studies, which placed the water demand for SMR and the subsequent water-gas shift reaction combined at 9.7 liters (or 2.6 gallons) of water per kilogram of hydrogen produced.¹³²

Given these relatively high water use figures across production methods, hydrogen production may be a poor fit for water-stressed regions like Kern County, as freshwater is already overallocated.¹³³ The strain on local water resources could be reduced if highly purified, reclaimed or recycled water could help meet this need, a subject that is explored in Section 8 of this report on water treatment.

6.3.1.2 Minimum quality requirements

For electrolysis, the water quality threshold is extremely high—the water used in electrolyzers "needs to be as pure as possible."¹³⁴ The water used in an electrolyzer should be distilled and/or deionized, to preserve the efficiency and lifetime of the equipment.¹³⁵ Membrane-based electrolyzers require water to be of type II purity, though operate better with water of type I purity, which is even more filtered.¹³⁶

6.3.2 Air quality

An electrolyzer itself does not produce gaseous emissions other than H₂ and O₂. Any emissions associated with electrolysis will therefore come from its power supply. A full lifecycle analysis study of electrolyzer options fueled by different energy sources in Colombia found that wind-powered electrolysis was the most air quality-friendly option when looking at methane (CH₄), CO₂, NO_x, SO_x, and particulate matter emissions.¹³⁷ Any fossil-free, renewable energy supply will minimize emissions for electrolysis, with remaining life cycle emissions profiles reflecting third-order, upstream (manufacturing and construction) and downstream (end-of-life) related emissions.

In contrast, generating hydrogen via biomass gasification can create direct air pollutants, including carbon monoxide (CO), NO_x, methane (CH₄), and a small amount of soot (particulate matter¹³⁸),¹³⁹ although if the feedstock source for gasification is agricultural waste, forest waste or municipal waste that would otherwise have degraded through crop burning, wildfire or landfill decomposition, the net effect of using gasification on air quality

¹³² Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

¹³³ IEA (2019) <u>The Future of Hydrogen</u>. p. 43. [37]

¹³⁴ Valdez (August 11, 2022) <u>Electrolyzers and Water</u>. [79]

¹³⁵ Spiegel (November 7, 2017) <u>Introduction to Electrolyzers</u>. [72]

[[]Note: this information derives from a response provided in the comment section by the Fuel Cell Store account.]

¹³⁶ Jonsson, Mässgård (2021) <u>An Industrial Perspective on Ultrapure Water Production for</u> <u>Electrolysis</u>. p. 17. [40]

¹³⁷ Ullman, Kittner (2022) <u>Environmental impacts associated with hydrogen production</u>. [78]

¹³⁸ Weidman, Marshall (August 10, 2012) <u>Soot Pollution 101</u>. [83]

¹³⁹ Ahmed *et al.* (2019) <u>Emissions factors</u>. p. 221. [1]
is likely to be an improvement. There are few published studies comparing emissions from biomass gasification to combustion (what happens in bioenergy generation plants) or open burning, but what information is available suggests a significant reduction in criteria pollutants with gasification. Examples include a comparative study of coal gasification versus traditional coal-fired powerplants by the National Energy Technology Laboratory.¹⁴⁰ Their study showed a significant decrease in SO_x, NO_x, particulate matter and CO₂ emissions in gasification relative to traditional combustion. While the feedstock is different, the organic matter in coal and the organic matter in biomass can be expected to respond similarly to thermochemical processing. Another study found that less NO_x, CO, CH₄, CO₂ and soot was emitted from small scale biomass gasification plants, when compared to open burning.¹⁴¹ And finally, the planned San Joaquin Renewables facility (described in Section 4.1.2.7) anticipates the emissions impact of their gasification facility will be far more favorable than open pile burning (commonly employed in the San Joaquin Valley today) —with a minimum of a 95% reduction in VOCs, 96% reduction in NO_x, 99% reduction in CO, and 99% reduction in particulate matter released relative to biomass burning.¹⁴²

Blue hydrogen from SMR with CCS also produces both criteria air pollutants and greenhouse gasses aside from CO_2 .¹⁴³ These emissions included VOCs, NO_x , CO, SO_2 and both large (PM₁₀) and small (PM_{2.5}) particulate matter^{*} in the criteria air pollutants, and CH₄ and nitrous oxide (N₂O) as additional greenhouse gasses.¹⁴⁴ Researchers found that VOC, NO_x, and CO emissions per kilogram of hydrogen produced decreased as facility size increased, with an anticipated cause that larger facilities (in terms of expected hydrogen output) may have emissions control technologies that capture different pollutants.¹⁴⁵ Other emissions, though, showed little correlation with the facility size by anticipated hydrogen output, making it difficult to gauge how much other emissions categories can be effectively minimized.¹⁴⁶

Finally, recent has identified some risk of using hydrogen as a fossil-alternative fuel, due to hydrogen's ability to act as an indirect greenhouse gas, warming the atmosphere on short-term (years to decadal) timescales.¹⁴⁷ When combusted, hydrogen reacts with oxygen to form water vapor, which in the stratosphere, can trap heat. Hydrogen that leaks from operations or is offgassed can also drive production of other greenhouse gasses, including

¹⁴⁰ NETL (no date) Emissions advantages of gasification. [49]

¹⁴¹ Ahmed *et al.* (2019) <u>Emissions factors</u>. p. 221. [1]

¹⁴² San Joaquin Renewables (no date) <u>The Project</u>. [69]

¹⁴³ Sun *et al.* (2019) <u>Criteria Air Pollutants and Greenhouse Gas Emissions</u>. p. 4. [75]

^{*} Particulate matter emissions are often reported in terms of the size of the particles $-PM_{10}$ refers to particles smaller than 10 micrometers (μ m), and $PM_{2.5}$ to particles smaller than 2.5 μ m.

¹⁴⁴ Sun *et al.* (2019) <u>Criteria Air Pollutants and Greenhouse Gas Emissions</u>. p. 4. [75]

¹⁴⁵ Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 16. [75]

¹⁴⁶ Sun *et al.* (2019) <u>Criteria Air Pollutants and Greenhouse Gas Emissions</u>. p. 16. [75]

¹⁴⁷ Ocko, Hamburg (2022) <u>Climate consequences of hydrogen emissions</u>. p. 9349. [54]

methane, ozone, and water vapor in the atmosphere, mostly through indirect pathways.¹⁴⁸ Although both hydrogen via electrolysis and hydrogen via SMR + CCS will have significant climate benefits compared to fossil fuel systems on 100-year timescales by reducing the amount of CO_2 released to the atmosphere, some studies suggest that in the short term (first 20 years after adoption), green hydrogen via electrolysis may only halve the impact of emissions from fossil-fuel use and blue hydrogen via SMR + CCS could potentially worsen immediate climate impacts by increasing emissions of methane and hydrogen in the short term.¹⁴⁹

When used as a fuel, hydrogen can also generate NO_x in the atmosphere. During hydrogen combustion, enough heat is present to cause atmospheric nitrogen and oxygen to form NO_x in an endothermic reaction.¹⁵⁰ Atmospheric NO_x can have detrimental effects for humans, including respiratory symptoms like the development of asthma, as well as environmental harms, including acid rain and nutrient pollution in waterways and coastal areas.¹⁵¹ NO_x emissions from hydrogen boilers or engines can be minimized by controlling combustion conditions or by scrubbing NO_x from post-combustion flue gasses.¹⁵²

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used in any given facility will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

6.3.3 Other potential impacts

In many cases, hydrogen fuel is not the most effective solution for reducing greenhouse gas emissions—if a technology can run directly on clean energy or renewable electricity, that is typically a much more efficient power source.¹⁵³ However, for industries and processes that are difficult to electrify, hydrogen could be an excellent alternative to fossil fuels. Hydrogen has been explored as a fuel for heavy-duty transport (planes, freight rail, or trucking) or to produce the heat necessary to create products like ceramics, steel, and concrete.^{154,155,156} In the context of a carbon management business park, where several industries could be co-located, on-site production of hydrogen may provide a valuable industrial heat energy source. However, a detailed techno-economic and environmental

¹⁴⁸ Ocko, Hamburg (2022) <u>Climate consequences of hydrogen emissions</u>. p. 9350. [54]

¹⁴⁹ Ocko, Hamburg (2022) <u>Climate consequences of hydrogen emissions</u>. p. 9349. [54]

¹⁵⁰ Douglas *et al.* (2022) <u>NO_x Emissions from Hydrogen-Methane Fuel Blends</u>. p. 2. [23]

¹⁵¹ EPA (August 2, 2022) <u>Basic Information about NO2</u>. [27]

¹⁵² Lewis (2021) Optimising air quality co-benefits in a hydrogen economy. p. 201. [45]

¹⁵³ Bottorff (January 4, 2022) <u>Hydrogen: Future of Clean Energy or a False Solution?</u> [10]

¹⁵⁴ Gitlin (2022) <u>Forget passenger cars</u>. [33]

¹⁵⁵ Baxter *et al.* (November 16, 2020) Which sectors need Hydrogen, which don't. [7]

¹⁵⁶ Roberts (January 31, 2023) <u>This climate problem is bigger than cars and much harder to solve</u>.[68]

impact analysis will be crucial when considering whether hydrogen is the most costeffective and environmentally-efficient fuel option for such industries.

6.4 Economic Impacts

6.4.1 Business Model

Hydrogen is the primary product of electrolysis, biomass gasification and SMR with CCS, and in the future will most likely be sold primarily as a fuel product for transportation and industrial uses. Today, the infrastructure required for such end-use applications is not yet well established. Thus, most hydrogen currently produced goes to other purposes, such as in oil refining, to remove sulfur from natural gas distribution streams or in the production of synthetic fertilizers.^{157, 158} Global demand for hydrogen has been steadily rising since 1975, both for direct applications (in oil refining and ammonia production) and indirect applications (methanol, synthetic fuels, and direct reduced iron steel production).¹⁵⁹

Currently, the costs of hydrogen production are cheapest for more environmentally destructive processes like gray hydrogen, with blue and green forms of hydrogen being the most expensive. In 2020, the cost to generate a kilogram of hydrogen was \$0.70 for SMR with no CCS (gray hydrogen), \$1.30 for SMR with CCS (blue hydrogen), and \$3 for solar-powered electrolysis (green/yellow hydrogen).¹⁶⁰ The cost differential is primarily due to the significantly higher energy demand (and thus energy cost) of electrolysis relative to steam methane reforming.¹⁶¹ Any opportunities to lower the energy costs of electrolysis can therefore help this technique become cost competitive with gray hydrogen production. For example, when created using excess renewables from the grid, the production cost goes down to about \$1.60 per kilogram (in 2020 dollars).¹⁶² Depending on the availability of excess renewable resources in coming years, green hydrogen could become cost competitive with blue hydrogen within the next decade.¹⁶³ If a carbon tax were to be imposed, nationally or internationally, on CO₂ emitting power generation processes, like gray hydrogen, that could also equalize the cost differential between production.¹⁶⁴

Currently, the high cost of green hydrogen is considered to be the "brick wall" for global hydrogen production—it does not make sense to scale up production or end-use infrastructure until there are efficient and cheap ways to generate hydrogen that also do

¹⁵⁷ Cunningham (no date) <u>The economics of hydrogen in a carbon constrained world</u>. [22]

¹⁵⁸ IEA (2019) <u>The Future of Hydrogen</u>. p. 17. [37]

¹⁵⁹ IEA (2019) <u>The Future of Hydrogen</u>. p. 18. [37]

¹⁶⁰ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

¹⁶¹ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

¹⁶² Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

¹⁶³ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

¹⁶⁴ Climate Now (October 18, 2021) <u>Pricing carbon around the globe</u>. 01:21. [17]

not contribute to greenhouse gas emissions, and solutions to the barriers to reaching commercial scale and competitive market costs in this space have yet to be realized.¹⁶⁵ In the United States, a tax incentive designated in the Inflation Reduction Act (IRA) of 2022 could change this picture by making environmentally-friendly hydrogen production methods more economically favorable. Under the new tax incentive, producers of hydrogen with 'near-zero emissions' can earn \$3 per kilogram of hydrogen produced with no cap on the number of kilograms the producer can receive the incentive for.¹⁶⁶ This is exceptionally good news for hydrogen generated via electrolysis with renewable energy, as \$3/kilogram is about the average cost of production, so any sales of their hydrogen would be profit. The exact structure of these benefits, however, will depend on rules that are still being written by the Treasury Department; until they have developed a clear definition for 'near-zero emissions,' it is difficult to guess what standards a producer would need to meet to be eligible for the \$3/kilogram incentive.¹⁶⁷ In a worst-case scenario, the benefits could flow to companies that are still releasing large amounts of greenhouse gas emissions in the hydrogen production process, either via using methane as a feedstock or relying on grid electricity generated by fossil fuels to meet the high energy demands of electrolysis or gasification.¹⁶⁸

Two other potential revenue streams are worth noting. First, in California, Low Carbon Fuel Standard credits (LCFS, see Section 2) are designed to promote switching from fossil fuels to low-carbon fuels in the transportation sector, and could provide an additional revenue stream for green hydrogen projects (from electrolysis or biomass). However, any hydrogen produced from fossil fuels—including blue hydrogen formed from SMR + CCS—would be ineligible for LCFS credits.¹⁶⁹ From 2018-2022, the LCFS credit has ranged from \$62-218.¹⁷⁰ Second, federal incentive 45Q provides a tax benefit for CO₂ capture and storage processes other than direct air capture (DAC) of \$85 per ton stored, for which green hydrogen via biomass gasification and SMR + CCS could be eligible. Hydrogen producers would need to choose between the 45Q and 45V federal tax credits; they cannot receive both.¹⁷¹

6.4.2 Business Costs

6.4.2.1 Cost to build (upfront costs)

The cost and efficacy of electrolyzers is projected to become more favorable in the nearterm future, given that this field has seen greater investments in research and development

¹⁶⁵ Bezdek (2019) <u>The hydrogen economy</u>. [8]

¹⁶⁶ Pontecorvo (December 12, 2022) <u>Subsidy for 'green hydrogen' could set off a carbon bomb</u>. [65]

¹⁶⁷ Pontecorvo (December 12, 2022) <u>Subsidy for 'green hydrogen' could set off a carbon bomb</u>. [65]

¹⁶⁸ Pontecorvo (December 12, 2022) <u>Subsidy for 'green hydrogen' could set off a carbon bomb</u>. [65]
¹⁶⁹ Bezdek (2019) <u>The hydrogen economy</u>. [8]

¹⁷⁰ Neste (no date) <u>California Low Carbon Fuel Standard Credit price</u>. [52]

¹⁷¹ Webster (September 20, 2022) <u>The Inflation Reduction Act will accelerate clean hydrogen</u> <u>adoption</u>. [82]

and economies of scale.¹⁷² There are a wide range of levelized cost estimates available, but costs for large electrolysis facilities are poorly established. Additionally, these cost estimates vary widely based on capacity and the type of electrolyzer in question. A small PEM electrolyzer generating one cubic meter of hydrogen (\approx 11.126 kg H₂) per hour would likely be less than \$8,000, but a commercial-scale facility would require a much larger capacity, either by running a lot of small units or building specialized large electrolyzers.¹⁷³ A compilation from the International Council on Clean Transportation (ICCT) of levelized capital cost estimates for different types of electrolyzers as a function of their price per kW and price per kg H₂ is presented in Table 6.1.¹⁷⁴ In general, alkaline electrolyzers are the cheapest to purchase upfront, primarily because they do not require any precious metals to operate.^{175,176} Alkaline electrolyzers have a longer expected lifetime than PEM electrolyzers as well.¹⁷⁷

Another study, which focused only on PEM electrolyzers, is consistent with the ICCT's metaanalysis. They provide an estimated total levelized cost of production that incorporates capital and energy costs. Depending on whether grid energy, solar, or wind is used, production costs of electrolysis facilities with existing technology varied between \$4.22 and \$6.27 per kilogram of hydrogen produced.¹⁷⁸

For AE electrolyzers, the largest share of the capital cost is devoted to the electrolyzer stack, accounting for 50% of the estimated capital costs.¹⁷⁹ Although large alkaline electrolyzers have been built before in North America, Africa, Asia, and Europe, most large facilities were decommissioned in the late 20th century, so there are large uncertainties in projecting current costs for a new alkaline electrolyzer facility based on the costs of existing stock.¹⁸⁰ For PEM electrolyzers, about 60% of the capital cost is associated with the electrolyzer stack.¹⁸¹

Costs for electrolyzers are expected to decline sharply with advances in the electrode and membrane materials and improvements in manufacturing.^{182,183} Additional, economies of scale resulting from significant increases in production capacity are expected to further

¹⁷² IEA (2019) <u>The Future of Hydrogen</u>. p. 16. [37]

¹⁷³ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

¹⁷⁴ Christensen (2020) <u>Costs from Electrolysis</u>. p. 18. [16]

¹⁷⁵ IEA (2019) <u>The Future of Hydrogen</u>. p. 43. [37]

¹⁷⁶ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

¹⁷⁷ IEA (2019) <u>The Future of Hydrogen</u>. p. 44. [37]

¹⁷⁸ Vickers *et al.* (2020) <u>Cost of Electrolytic Hydrogen Production with Existing Technology</u>. p. 1.
[80]

¹⁷⁹ IEA (2019) <u>The Future of Hydrogen</u>. p. 46. [37]

¹⁸⁰ IEA (2019) <u>The Future of Hydrogen</u>. p. 43. [37]

¹⁸¹ IEA (2019) <u>The Future of Hydrogen</u>. p. 46. [37]

¹⁸² IEA (2019) <u>The Future of Hydrogen</u>. p. 46-47. [37]

¹⁸³ Vickers *et al.* (2020) <u>Cost of Electrolytic Hydrogen Production with Existing Technology</u>. p. 3.[80]

reduce electrolysis costs by 20-40%. The chart below illustrates the expected cost declines for both alkaline and PEM electrolyzers.¹⁸⁴

Fable 6.1. Anticipated ca	apital cost estimates fo	r hydrogen from	electrolysis. ^a
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Electrolyzer type	2020 \$/kW	2020 \$/kg H ₂ ^b	Sources		
Capital costs for development in 2020					
Alkaline electrolysis (AE)	\$500-1268	\$1.90-4.80	IEA (2019) The Future of Hydrogen, ¹⁸⁵		
Proton exchange membrane (PEM)	\$385-2068	\$1.50-7.90	Perspective, ¹⁸⁶ BloombergNEF (2019)		
Solid oxide electrolysis (SOE)	\$677-2800	\$2.60-10.60	Costs from Electrolysis. ¹⁸⁸		
Capital costs for development in 2030					
Alkaline electrolysis (AE)	\$400-1208	\$1.50-4.60	IEA (2019) The Future of Hydrogen,		
Proton exchange membrane (PEM)	\$365-1968	\$1.40-7.50	Perspective, BloombergNEF (2019) H2		
Solid oxide electrolysis (SOE)	\$647-2175	\$2.50-8.30	from Electrolysis.		
Capital costs for development in 2050°					
Alkaline electrolysis (AE)	\$80-1090	\$0.30-4.10	IEA (2019) The Future of Hydrogen,		
Proton exchange membrane (PEM)	\$150-1781	\$0.60-6.80	Perspective, BloombergNEF (2019) H2		
Solid oxide electrolysis (SOE)	\$500-1968	\$1.90-7.50	from Electrolysis.		

a. Adapted from ICCT (2020) Costs from Electrolysis.

b. $1kW \approx 263kg H_2$

c. For IEA (2019), cost estimates described as 'long term.'

For biomass gasification that generates hydrogen and CO_2 , the capital cost of a facility that could capture 1 million tons of CO_2 would be ~\$278 million to \$328 million.¹⁸⁹ If the facility operated for 30 years, the capital costs over the lifetime of the facility would be ~\$24-52 per

¹⁸⁴ IEA (2019) <u>The Future of Hydrogen</u>. p. 47. [37]

¹⁸⁵ IEA (2019) <u>The Future of Hydrogen</u>. [37]

¹⁸⁶ IRENA (2019) <u>Hydrogen: A renewable energy perspective</u>. [39]

¹⁸⁷ Hydrogen: The Economics of Production From Renewables. Bloomberg New Energy Finance, Technical Report, September 2019. (Data available through Christensen (2020) <u>Costs from</u> <u>Electrolysis</u>.)

¹⁸⁸ Christensen (2020) <u>Costs from Electrolysis</u>. p. 18. [16]

¹⁸⁹ Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 6. [85] Note: In figures in Wu, Lan, and Yao (2023), these estimates appear lower (approximately \$241 to \$285 million) as they correspond to a facility capturing 868,000 metric tons of CO_2 per year (see the supplementary material, Table S4 for CO_2 capture rates by scenario). In this report, all Wu, Lan, and Yao (2023) estimates are presented in-text as scaled figures for a million ton facility, to ensure consistency between carbon management industries when possible.

ton of CO₂ (assuming a capital recovery factor of 7.5-12.5%; see Section 3.4.3.1 for details).¹⁹⁰ Both capital and operating costs for biomass-based hydrogen production vary depending on the energy source, which varies across plant designs. In general, self-sustaining plants—which can meet their own energy needs—are the most expensive to build, but have the lowest operational costs.¹⁹¹ Plants that receive some or all of their energy from external sources are typically cheaper to construct, but more expensive to operate and maintain.¹⁹² It is worth noting that the cost range for most biomass plants, as outlined in Section 4.4, exceeds the range presented here. As the cost estimates here are derived from a single study, and it is likely that hydrogen production via biomass gasification will closely resemble other biomass-based plants, considering the larger variability in capital costs of biomass-conversion facilities in general may be worthwhile.

For SMR facilities in general (gray and blue hydrogen), there are a large number of constituent parts required to contain the entire reaction sequence and limit the escape of pollutants like particulate matter and NO_x.¹⁹³ Adding CCS equipment to the SMR process (blue hydrogen) generally results in an estimated capital cost increase of 50%.¹⁹⁴ When also accounting for the operation and maintenance of a facility over its lifetime, however, the distributed cost addition of carbon capture to SMR is anticipated to result in a ~13% increase in total levelized production cost.¹⁹⁵ A recent techno-economic study of hydrogen production for SMR + CCS estimated a levelized capital cost of \$0.28/kg hydrogen.¹⁹⁶ This model assumes that SMR without CCS emits 8.5 kilograms CO₂ per kilogram hydrogen but SMS with CCS emits only 1.2 kilograms of CO₂. Thus, we can estimate that for every kilogram of hydrogen produced via SMR + CCS, 7.3 kilograms of CO₂ will be captured.¹⁹⁷ If we assume a facility capturing 1 million metric tons of CO₂ per year, it will generate about 137,000 tons (or 137 million kg) of hydrogen per year. For a capital recovery factor (crf) between 7.5 and 12.5% (see Section 3.4.2.1),¹⁹⁸ the cost to build such a facility would be about \$300-510 million USD.

This estimate is relatively well-aligned with planned investment in the Air Products facility currently being constructed in Louisiana. Air Products states that it will cost about \$4.5 billion to build, own, and operate their facility with a capture capacity of over 5 million tons of CO_2 annually.¹⁹⁹ Scaling capital expenditures of \$300-510 million USD/ton CO_2 to a 5

¹⁹⁰ Adapted from: Carbonplan <u>DAC cost calculator</u>.

¹⁹¹ Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 6. [85]

¹⁹² Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 6. [85]

¹⁹³ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

¹⁹⁴ IEA (2019) <u>The Future of Hydrogen</u>. p. 42. [37]

¹⁹⁵ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

¹⁹⁶ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

¹⁹⁷ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

¹⁹⁸ Calculated using: Levelized capital expenditure $(k_H_2) = (Cost to build/Annual capacity of the facility)*crf$

¹⁹⁹ Air Products (no date) <u>Louisiana Clean Energy Complex</u>. [4]

million ton facility, suggests that capital costs will represent one third to over half of the total investment costs, the remainder presumably coming from operation, maintenance and the cost of the feedstock methane.

6.4.2.2 Operational costs

For an electrolyzer, the stacked membranes inside the machine must be replaced about every 7 to 10 years.²⁰⁰ The British government estimates the replacement period for electrolyzer membrane stacks varies with the technology type, with alkaline stacks requiring replacement every 9 years, PEM stacks requiring replacement every 11 years, and SOE stacks requiring replacement every 7 years, assuming a 30-year facility lifetime.²⁰¹ Fixed operational costs will also include labor, administrative costs, maintenance, insurance, and taxes.²⁰² Alkaline electrolysis systems also have relatively high maintenance costs throughout their lifetimes due to the variety of equipment needed to pump, clean, and store the electrolyte solution and to filter out and clean the hydrogen.²⁰³ The ICCT economic analysis of electrolysis states that most techno-economic models estimate fixed operational costs (labor and maintenance) as 1-3% of capital expenditures. Based on the range of capital costs summarized in Table 6.1, fixed operation costs of modern electrolyzers are about \$4-84 USD/kW (or \$0.02-\$0.32 USD/kg H₂), with their preferred operating cost estimate of \$40-50 USD/kW (\$0.15-0.19 USD/kg H₂).²⁰⁴ Variable costs will largely be electricity costs, which can vary considerably over time (and even be zero, if a facility is using excess energy from renewables or the grid). The ICCT model estimates variable operating costs of \$0.08 USD/kg H₂.²⁰⁵

For a biomass gasification plant, operational costs are expected to range from approximately \$60 million to \$101 million for a facility capable of capturing a million metric tons of CO_2 annually.²⁰⁶ The feedstock costs—amounting to approximately \$44 million annually—are the largest share of the operating costs.²⁰⁷ If these costs were reduced, it would lower the annual operating expenses notably. The next big cost categories come

²⁰⁰ Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

 ²⁰¹ UK Department of Business, Energy & Industrial Strategy (2021) <u>Hydrogen Production Costs</u>. p.
 19. [77]

 ²⁰² UK Department of Business, Energy & Industrial Strategy (2021) <u>Hydrogen Production Costs</u>. p.
 19. [77]

²⁰³ Lichner (March 26, 2020) <u>Electrolyzer overview</u>. [47]

²⁰⁴ Christensen (2020) Costs from Electrolysis. p. 18. [16]

²⁰⁵ Christensen (2020) Costs from Electrolysis. p. 18. [16]

²⁰⁶ Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 6. [85] Note: In figures in Wu, Lan, and Yao (2023), these estimates appear lower (approximately \$52 to \$88 million) as they correspond to a facility capturing 868,000 metric tons of CO_2 per year (see the supplementary material, Table S4 for CO_2 capture rates by scenario). In this report, all Wu, Lan, and Yao (2023) estimates are presented in-text as scaled figures for a 1 million ton facility, to ensure consistency between carbon management industries when possible.

²⁰⁷ Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 6. [85]

from chemical, material, and utility costs, while labor, maintenance, and waste treatment make up a relatively small amount of the operating expenses.²⁰⁸ These operational costs, combined with capital costs, result in a total levelized cost of about \$2.50-\$3.60 per kilogram of hydrogen produced, which translates to an estimated range of \$125-257 per metric ton of CO_2 captured.

Finally, for any SMR plant, the majority of operational costs are variable; they depend on the cost of methane (natural gas) in the market at a given time, and can account for 45-75% of overall production costs (including capital costs).²⁰⁹ However, the addition of a carbon capture component also adds additional operating costs and maintenance responsibilities for an operator.²¹⁰ In modeling SMR + CCS with a 90% carbon capture rate, the estimated variable operating cost (the energy costs for running the facility) amounted to \$0.88 per kilogram of hydrogen,²¹¹ and the additional costs for carbon capture, including separation, purification, compression, pipeline transport, and injection add up to about \$0.60/kg hydrogen,²¹² or \$82 USD/ton CO₂.²¹³ Translated to total annual operating costs for a facility capturing one million metric tons of CO₂ each year, these amounts should come out to approximately \$120 million USD and \$82 million USD, respectively, and combined with the estimated capital expenditures, the total levelized production cost of SMR + CCS is ~\$1.76 USD/kg H₂.

6.4.3 Regional benefits

California is already among the top three hydrogen-producing states in the U.S.²¹⁴ Additionally, the hydrogen market is strong in California—the state is home to 71% of all fuel cell EVs in the county and maintains the largest number of hydrogen fueling stations by far.²¹⁵ California also hosts a wide variety of industries that would be hard to fully electrify (such as cement and concrete manufacturing), thus making them prime candidates to transition to alternative fuels like hydrogen.²¹⁶ A large amount of credit for the growth of the hydrogen market in California is due to the state's carbon cap-and-trade program, which incentivizing the growth of hydrogen through a carbon credit marketplace.²¹⁷ With

²⁰⁸ Wu *et al.* (2023) <u>Carbon capture in hydrogen production by biomass gasification</u>. p. 6. [85]
²⁰⁹ IEA (2019) The Future of Hydrogen. p. 42. [37]

²¹⁰ IEA (2019) <u>The Future of Hydrogen</u>. p. 42. [37]

²¹⁰ IEA (2019) <u>The Future of Hydrogen</u>. p. 42. [37]

²¹¹ Katebah *et al.* (2022) <u>Analysis of production costs in Steam-Methane Reforming</u>. p. 9. [41]

²¹² Simon *et al.* (August 13, 2021) <u>Economics of Hydrogen Energy</u>. [71]

 $^{^{213}}$ Given the ratio of 1 kg H₂ production resulting in 7.3 kg CO₂ capture. From Katebah, Al-Rawashdeh, and Linke (2022) <u>Analysis of hydrogen production costs in Steam-Methane</u> <u>Reforming</u>.

²¹⁴ AFDC (no date) <u>Hydrogen Production and Distribution</u>. [6]

²¹⁵ AltaSea (October 28, 2022) <u>Sustainable Green Hydrogen Market</u>. [5]

²¹⁶ AltaSea (October 28, 2022) <u>Sustainable Green Hydrogen Market</u>. [5]

²¹⁷ Magill (February 23, 2021) <u>California And Texas Vie To Be America's Hydrogen Capital</u>. [48]

existing demand already in the region and sector-wide growth anticipated, Kern County is a promising locale for companies looking to develop hydrogen fuels.

6.4.3.1 Proximate feedstocks

For hydrogen produced via biomass gasification, Kern County's agricultural waste could become a supply of feedstock to generate hydrogen and capture CO₂. This theme is touched upon at greater length in Section 11.2.1 on the potential relationship between local agriculture and biomass-based carbon management facilities. For SMR+CCS, Kern County is home to the state's largest oil and gas fields and produces 78% of the state's total natural gas production.²¹⁸

6.4.3.2 Proximate consumers

As mentioned above, one of the strengths of locating in the region would be a proximate consumer base. All of the approximately 15,000 consumer cars in the U.S. that are fuel cell EVs are located in California, which is the only state with a network of retail hydrogen fueling stations to make them usable.²¹⁹ Kern County's proximity to the port of Los Angeles, the busiest shipping port in North America,²²⁰ also holds promise for the hydrogen industry - both as an access point for international trade, and because hydrogen holds potential as a fossil-free fuel source for the shipping industry.²²¹

6.4.3.3 Co-location advantages

Locating alongside carbon management industries could have benefits for a hydrogen production facility. If generating hydrogen via electrolysis, an electrolyzer could utilize water generated as a byproduct of some carbon management industries, such as S-DAC (Section 3), depending on the water quality.

If generating hydrogen via steam reforming and CCS, co-location could have multiple benefits. Steam reforming and the water-gas shift reaction could similarly use water generated from other industries in their production process, and the transport and sequestration needed for permanent underground storage of CO_2 could be shared infrastructure with other carbon management industries in the park.

6.4.3.4 Other

For hydrogen production via electrolysis, which relies on renewable energy to avoid carbon emissions, California and the American Southwest is a highly promising region to bring down production costs, given the extremely high solar and wind energy potential in the region (Figure 6.5). Given the significant impact that electricity costs have on the market

²¹⁸ KEDF (2021) <u>The economic contribution of the oil and gas industry in Kern County</u>. p. 1. [42]

²¹⁹ Voelcker (September 26, 2022) <u>Hydrogen Fuel-Cell Vehicles</u>. [81]

²²⁰ Port of Los Angeles (no date) <u>The Port of Los Angeles</u>. [66]

²²¹ Climate Now (May 2, 2022) <u>The bottom line on sustainable shipping</u>. 23:29. [18]

competitiveness of green hydrogen from electrolysis, the renewable energy potential of Kern County and the surrounding region is a remarkable asset for this industry.



Figure 6.5. Global map demonstrating the cost viability of locations where renewable energy generation (wind or solar energy) and hydrogen production via electrolysis are co-located.²²² The California coast, as well as the American Southwest, show promising cost estimates for electrolysis-generated hydrogen. Image credit: International Energy Agency.

²²² IEA (2019) <u>The Future of Hydrogen</u>. p. 49. [37]

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7. Battery and Energy Storage Solutions

TECHNOLOGY AT A GLANCE

- Energy storage solutions come in a wide variety of form, many of which are fully commercial, and others of which are still in early research and development stages.¹
- Lithium-ion batteries are currently the most widely used technology for utility-scale energy storage.
- Installation of large energy storage facilities is unlikely to create many jobs, but can produce a variety of societal benefits, like eliminating the need of fossil-based peaker power plants, and providing increased grid reliability.
- Adding energy storage to solar or wind power supplies increases the cost by ~\$5-39, but the cost of batteries has decreased 97% in the last 3 decades, and is projected to continue becoming less expensive.
- Key advantages of this technology to Kern County: it ensures a continuous clean energy supply to any industries sited in a carbon management park, and potentially to the local grid, and can provide a fossil-free source of industrial heat to industries that require it.
- Key concerns for this technology in Kern County: environmental and safety risks vary by battery type, and further assessment to identify the optimal storage approach for the region and needs of the carbon management park will be necessary.

¹ Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

7.1 Technology Summary

Since 2020, wind and solar energy have become the cheapest form of electricity generation in most parts of the world, and their costs have continued to decrease year over year.^{2,3} The sunny and arid climate of Kern County is particularly well suited for these renewable energy sources, and as such is host to the largest commercial solar project and among the largest commercial wind energy projects in the United States.⁴ Such abundant, fossil-free energy is particularly attractive to carbon management industries for two reasons. First, many carbon management industries are energy intensive, with energy costs representing their largest operational expense. Thus, minimizing the price per kWh of electricity used is critical to ensuring facilities are economically viable. Second, most carbon management industry's business model depends on the *net* amount of CO₂ removed or prevented from entering the atmosphere, which means that if such industries are powered by carbon-emitting fuels, their carbon capture efficiency (and thus potential for revenue) is reduced.⁵

Wind and solar are examples of variable renewable electricity (VRE) – they only generate electricity when the sun is shining or the wind is blowing, and the intensity of the electricity the generate depends on weather conditions.⁶ Battery storage solutions are a way to smooth fluctuations in energy supply, by storing excess energy generated by renewables during highly productive periods and then releasing that energy to meet electricity or heat demands during periods of lower productivity.⁷ For solar energy, for example, this could mean storing excess energy during the day and releasing it at night, when the sun is not out to generate additional power.

To support renewables and decarbonization objectives, the International Energy Agency (IEA) predicts that globally, energy storage will need to scale up to 266 GW of storage capacity by 2030—in 2017, global energy storage capacity was 176.5 GW—to keep climate change under 2°C of warming.⁸ To support the development of a clean energy and carbon management industrial park in Kern County, it is worth assessing the degree to which energy storage solutions would need to be integrated with local renewable energy generation in order to provide sufficient, continuous power that meets the needs of any industries locating within the park.

7.1.1 Description: How it works

In this report, we define energy storage technologies as devices that take in any form of renewable energy, store that energy in various forms, and then release energy as electricity

² Masterson (July 5, 2021) <u>Renewables were the world's cheapest source of energy in 2020</u>. [33]

³ Lazard (2021) <u>Levelized cost of energy</u>. [28]

⁴ CSUB (no date) <u>Energy in Kern County</u>. [5]

⁵ National Academies of Sciences, Engineering, and Medicine (2019) <u>Research Agenda</u>. p. 222. [36]

⁶ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 10. [26]

⁷ MIT (2022) <u>The Future of Energy Storage</u>. p. xi. [32]

⁸ EESI (February 22, 2019) <u>Fact Sheet | Energy Storage</u>. [20]

or heat to be used on demand. A summary of the more widely used energy storage technologies are listed in Table 7.1, along with the characteristics of each storage type that typically define its most suitable applications.

As the aim here is to understand storage solutions that could support a carbon management park in Kern County, we will focus on off-grid technologies with rechargeable, industrial-scale potential that can provide intermediate to longer-duration storage, and will produce energy in the form of electricity or in the form of heat. Some energy storage solutions are eliminated based on Kern's geography and resources. For example, pumped-storage hydropower (PSH) systems have been used in the United States for a century, and currently constitute 95% of energy storage facilities nationally, but are a poor fit for Kern given its largely arid climate.⁹ This section will also cover hydrogen-based batteries, with the assumption that the hydrogen utilized for this energy storage is produced through low-carbon processes—for more on hydrogen production, please refer to Section 6 of this report.

	Max Power Rating (MW)	Discharge Time	Max Cycles or Lifetime	Energy Density (Wh/I)	Round-Trip Efficiency
Pumped hydro	3,000	4h - 16h	30-60 years	0.2-2	70-85%
Compressed air	1,000	2h - 30h	20-40 years	2-6	40-70%
Molten salt (thermal)	150	hours	30 years	70-210	80-90%
Li-ion battery	100	1min - 8h	1,000-10,000 cycles	200-400	85-90%
Lead-acid battery	100	1min - 8h	6-40 years	50-80	80-90%
Flow battery	100	hours	12,000-14,000 cycles	20-70	60-85%
Hydrogen	100	mins - week	5-30 years	600 (at 200bar)	25-45%
Flywheel	20	secs - mins	20,000-100,000 cycles	20-80	70-95%

7.1.1.1 Electricity storage

Most of the batteries discussed in this report rely on the same basic electrochemical process: reduction-oxidation (redox) reactions. In redox reactions, electrons move between one molecule and another molecule; the substance losing electrons is oxidized and the substance gaining electrons is reduced.¹¹ It may sound counterintuitive that the substance

⁹ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

¹⁰ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

¹¹ Chemistry LibreTexts (July 1, 2019) <u>Batteries</u>. [9]

gaining electrons should be 'reduced', but reduction is referring to the overall charge of a particle, not how many electrons it has. Because electrons are negative, the overall charge of the substance gaining electrons will be a less positive number; it will be reduced.¹²

In a battery system, the site where oxidation (electron loss) occurs is called the anode, and the site where reduction (electron gain) occurs is called the cathode.¹³ These processes occur simultaneously in a redox reaction, and the electrons lost in one part of a battery system will be the same as the electrons gained in another part of the system. When these redox processes occur with a wire to capture the electric charge, it constitutes an electrochemical (or Galvanic) cell—the basic principle of most electric batteries.¹⁴ Here, we explore three types of electrochemical batteries: lithium-ion, flow, and molten salt. While the constituent parts of each of these electric batteries can look quite different, they all share the components shown in Figure 7.1: in addition to the cathode and anode, there is an electrolyte, separator, and two current collectors.¹⁵ The role of each of these components when a battery charges or discharges can be described in the context of each of the four battery types that are detailed below.



Figure 7.1. Schematic of lithium-ion electric battery storage.¹⁶

Lithium-ion batteries

Lithium-ion (Li-ion) batteries are what are typically used for mobile energy storage applications, such as in consumer electronics like cell phones, and in electric vehicles.¹⁷

¹² Chemistry LibreTexts (July 1, 2019) <u>Batteries</u>. [9]

¹³ Chemistry LibreTexts (July 1, 2019) <u>Batteries</u>. [9]

¹⁴ Chemistry LibreTexts (July 1, 2019) <u>Batteries</u>. [9]

¹⁵ Minos (February 28, 2023) <u>How lithium-ion batteries work</u>. [35]

¹⁶ Minos (February 28, 2023) <u>How lithium-ion batteries work</u>. [35]

¹⁷ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

(R7.1)

During a discharge cycle (when energy is being released from the battery), lithium that is stored in the anode gets ionized, meaning it converts to a lithium ion (Li^+) and an electron.

 $Li^{o} \rightarrow Li^{+} + e^{-}$

The lithium ion is carried through the battery via the electrolyte, a liquid solution containing dissolved salts, to the cathode. A porous separator allows the lithium ions to pass through the electrolyte solution towards the cathode, but prevents the passage of electrons within the battery structure. Thus, the cathode becomes concentrated with positively charged lithium ions, and the electrons collect near the negative current collector. The charge differential drives the electrons to travel along the external electrical circuit, creating an electric current that can provide electricity to an external device. Electrons are collected at the positive current collector, and recombined with the lithium ions, to form elemental lithium that is stored in the cathode. When all the lithium has migrated from the anode to the cathode, the battery is "empty" and needs to be recharged. Charging the battery works in the reverse direction of discharging: lithium ions are released by the cathode and received by the anode.^{18,19}

 $\mathsf{Li}^* + \mathscr{C} \to \mathsf{Li}^\circ \tag{R7.2}$

Advantages of the Li-ion battery is that it is highly efficient and energy dense (Table 7.1), being able to discharge as much as 90% of the energy used to charge, and able to provide a large amount of power from a relatively small battery, which is why these are particularly advantageous for mobile applications like phones, laptops and cars. Typically, these types of can supply a charge for a few hours, and they can go through the discharge/recharge cycle about 1,000-10,000 times,²⁰ meaning they usually need to be replaced within ~10 years.²¹

Flow batteries

Flow batteries can exist in a variety of forms and designs, but are primarily distinguished from standard rechargeable batteries (like Li-ion batteries) because the electroactive materials in a flow battery are dissolved within electrolyte solutions, rather than stored within one or the other electrode as they are in conventional rechargeable batteries (Figure 7.2).²²

In a flow battery, the electrolyte solution is stored in two separate tanks, with an anolyte tank replacing the anode and a catholyte tank replacing the cathode in a standard electrochemical cell.²³ These tanks are separate from regenerative cell stacks (or the reaction unit), wherein electrolytes are pumped in from the tanks to charge and discharge

¹⁸ Minos (February 28, 2023) <u>How lithium-ion batteries work</u>. [35]

¹⁹ Clean Energy Institute (no date) <u>What is a lithium-ion battery and how does it work?</u> [8]

²⁰ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

²¹ Le (August 4, 2020) <u>Flow Batteries</u>. [29]

²² IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 86. [26]

²³ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 86. [26]

the system using reversible chemical reactions.²⁴ The separate tanks can remain charged for long periods without experiencing degradative effects, making them an appealing solution for long-term energy storage.²⁵



Figure 7.2. Schematic of flow battery electricity storage.

A flow battery is considered 'pure flow' if both the anolyte and catholyte are stored outside the cell stacks and only flow in during operation; if one or more of the electrolyte materials are stored within the cell stacks, then the flow battery is considered to be a 'hybrid' flow battery.²⁶ Within this overarching split between pure and hybrid flow, there are other subcategories defined by the materials used or the physical state of the active materials, as seen in the IRENA categorization below (Figure 7.3).²⁷

Flow batteries are attractive for stationary applications as they are 100% recyclable, nonflammable, easily rechargeable, and approach the same high efficiency of Li-ion batteries, but with much longer lifetimes.²⁸ Many battery storage providers are looking to scale up their flow battery capacities, particularly flow batteries that rely on vanadium,²⁹ a material that is abundant and does not degrade through charge/recharge cycles.³⁰ Canadian company CellCube has deployed vanadium flow batteries in Australia, Vietnam, and South Africa, and British company Invinity is working with the Energy Superhub Oxford to create the UK's largest flow battery system.³¹

²⁴ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 86. [26]

²⁵ Le (August 4, 2020) <u>Flow Batteries</u>. [29]

²⁶ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 86-87. [26]

²⁷ IRENA (2017) Electricity Storage and Renewables. p. 87. [26]

²⁸ Le (August 4, 2020) <u>Flow Batteries</u>. [29]

²⁹ Le (August 4, 2020) <u>Flow Batteries</u>. [29]

³⁰ Rapier (October 24, 2020) <u>Why vanadium flow batteries may be the future</u>. [47]

³¹ Le (August 4, 2020) Flow Batteries. [29]

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Figure 7.3. Categories of flow battery systems. Image credit: IRENA (2017).³²

Molten salt batteries

As the name implies, molten salt batteries use a salt, in a liquid, molten state to act as the electrolyte in an electrochemical battery. These systems are often called high-temperature batteries, as high temperatures are necessary to keep the active materials in a liquid state.³³ When the temperature is lowered, the molten salt "freezes," or solidifies, allowing them to store their charge in an inactive state for up to months at a time.³⁴ Molten salt technologies are the most common kind of "thermal electricity storage", currently accounting for about 75% of global thermal storage capacity.³⁵ (Although these batteries operate at high temperatures, they deliver energy as electricity rather than heat, hence their categorization as electricity storage rather than as heat storage.)

In one example of the molten salt battery – the sodium beta battery – the anode is molten sodium while the cathode (and membrane) is constructed of beta-aluminum (β'' -Al₂O₃).³⁶ The system works by using sodium ion transport across the membrane to store or release energy from the battery.³⁷

A similar iteration of the high-temperature battery replaces the beta-aluminum with molten sulfur as the cathode and is known as the sodium sulfur (NaS) battery.^{38*} The anode and cathode are separated by a solid ceramic of sodium alumina, which only allows positively-

³² IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 87. [26]

³³ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 95. [26]

³⁴ Dhar (April 15, 2022) <u>Molten-salt battery freezes energy over a whole season</u>. [14]

³⁵ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 21. [26]

³⁶ IRENA (2017) Electricity Storage and Renewables. p. 95. [26]

³⁷ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 95. [26]

³⁸ IRENA (2017) <u>Electricity Storage and Renewables</u>. p. 95. [26]

^{*} Element S can be spelled as sulfur (American English) or sulphur (British English). In this report, all references have been standardized to American spelling, but the original source uses British spelling. Both spellings refer to the same element.

charged sodium ions to pass through its surface.³⁹ Operation relies on the system maintaining temperatures of 300-350°C to keep the active materials liquid, which can make it difficult for these batteries to operate intermittently.⁴⁰ However, these systems are highly efficient, with an average efficiency of 89%.⁴¹ Sodium sulfur batteries are already installed at dozens of sites in Japan and Abu Dhabi, assisting with voltage control and power reliability.⁴²

Currently, molten salt tanks (while molten) lose about 1% of their stored heat per day – after two weeks, their capacity has gone down to about 85%.⁴³ Research conducted at Pacific Northwest National Laboratory (PNNL) demonstrated that freezing and thawing molten salt creates a rechargeable battery that stores energy more effectively and inexpensively for weeks or months on end.⁴⁴ If scaled up, these research findings could help make the most of the high efficiency of these batteries by extending the timespan they can effectively store energy for future use.

7.1.1.2 Compressed Air Energy Storage (CAES)

Compressed air energy storage (CAES) systems do not rely on a chemical process, but rather in storing energy through pressurized air that can then be deployed as necessary. It does this by compressing ambient air (or another gas) and storing it at high pressure underground—when additional electricity generation is required, the compressed air is heated and expanded in a turbine connected to a generator, producing power.⁴⁵

Utility-scale CAES was first deployed in the 1970s, at capacities of around 290 MW, so the technology is well-established and understood even for large-scale storage needs.⁴⁶ CAES systems now encounter high costs associated with storing compressed air and relatively low capacities for these systems, with research and development efforts for this technology focused on addressing these obstacles.⁴⁷ Estimated efficiencies for CAES range from 40-70%.⁴⁸

7.1.1.3 Thermal/heat storage

Energy does not always need to be stored, or delivered, in the form of electricity. For some industrial and commercial facilities, storing heat energy is more important for sustaining

³⁹ ESA (no date) <u>Batteries</u>. [18]

⁴⁰ ESA (no date) <u>Batteries</u>. [18]

⁴¹ ESA (no date) <u>Batteries</u>. [18]

⁴² ESA (no date) <u>Batteries</u>. [18]

⁴³ MIT (2022) <u>The Future of Energy Storage</u>. p. 122. [32]

⁴⁴ Blaustein (May 6, 2022) <u>Rechargeable Molten Salt Battery</u>. [2]

⁴⁵ ESA (no date) <u>Why Energy Storage - CAES</u>. [19]

⁴⁶ ESA (no date) <u>Why Energy Storage - CAES</u>. [19]

⁴⁷ Xiaotao *et al.* (2017) <u>Performance Study of Salt Cavern Air Storage</u>. p. 1. [61]

⁴⁸ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

their operations. This includes steel, iron, cement, and chemical manufacturing, which all require high heat to fuel their primary processes.⁴⁹ Globally, about half of the world's energy consumption is in the form of heat energy.⁵⁰

Most thermal energy storage systems rely on heating a medium—like water, salt, or rocks—and then placing this material in an insulated environment so it retains heat.⁵¹ The type of medium used to store energy determines the system's classification: sensible (water and rock), latent (water, ice, or salt hydrates), and thermochemical reactions (i.e. chemical reactions and sorption processes).⁵² In sensible storage, when heat is needed, cold water is pumped onto the heated material to generate steam (Figure 7.4).^{53,54} Depending on the needed energy use, the steam can be used directly to heat a facility, or indirectly to turn turbines and generate electricity.⁵⁵ If the heat is converted back into electricity for use, the system averages only 47% round-trip efficiency (i.e. only 47% of the power put into the system as electricity will come back out as electricity).⁵⁶ In contrast, delivering stored energy in the form of heat can have a round-trip efficiency as high as 90%.⁵⁷ Thus, using the heat directly is ideal where possible, but relies on the industrial heat needs of co-located processes.



Figure 7.4. An example of sensible thermal storage, modeled after the operational design of Rondo Energy (see Section 7.1.2.1).

Whereas sensible storage relies on changing the temperature of the storage medium to release or absorb heat as needed, latent systems change the phase of the material without

⁴⁹ MIT (2022) <u>The Future of Energy Storage</u>. p. 4-5. [32]

⁵⁰ Celsius (August 17, 2020) <u>Thermal Energy Storage</u>. [7]

⁵¹ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

⁵² Celsius (August 17, 2020) Thermal Energy Storage. [7]

⁵³ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

⁵⁴ Celsius (August 17, 2020) <u>Thermal Energy Storage</u>. [7]

⁵⁵ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

⁵⁶ MIT (2022) <u>The Future of Energy Storage</u>. p. 114. [32]

⁵⁷ EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

changing the temperature to release energy—both a phase change and temperature change can occur in the same material concurrently, though.⁵⁸ The last system type, thermochemical, relies on chemical reactions taking place on the surface of a material to release or absorb heat. These systems can adapt renewable energy into heat to be stored and released, or capture waste heat for use in other processes.⁵⁹

Utility-scale heat storage systems can balance energy supply and demand across timescales from daily to seasonally,⁶⁰ making them a versatile solution for both short- and long-term needs. Since most of the processes addressed in this report require heat rather than cooling, we emphasize the capacity of this technology to store heat energy, but the process can work conversely, to provide residential or industrial cooling.⁶¹

7.1.1.4 Hydrogen Fuel Cells

Fuel cells are another energy storage solution that can be deployed to support energy needs in a range of sectors, including transportation, commercial and residential buildings, and for industrial-scale energy storage.⁶² Fuel cells operate similarly to batteries, but rather than cycling back and forth between discharging and recharging the energy stored, fuel cells thermochemically transform fuel to produce electricity and heat. Therefore, fuel cells – much like a gasoline-powered car – can only produce energy for as long as fuel is being supplied. Although fuel cells can use a wide range of fuels to operate, most focus has been directed towards the potential of using hydrogen in fuel cells, given that their only byproducts are electricity, heat, and water.⁶³

Like a standard chemical battery, fuel cells have an anode and a cathode placed on either side of an electrolyte.⁶⁴ Fuel is introduced at the anode and air is introduced at the cathode. The fuel molecules are separated to create positively charged ions (protons in the case of hydrogen) and electrons; the positively charged ions migrate across the electrolyte to the cathode, while the electrons move towards the cathode via an external circuit, creating an electric current. At the cathode, the positive ions and electrons reunite and react with oxygen from the air stream to form a new molecule in an exothermic (heat-generating) reaction.⁶⁵ For the case of hydrogen fuel, the reaction progresses as follows:

 $1/2O_2 + 2e^- + 2H^+ \rightarrow O^{2-} + 2H^+ \rightarrow H_2O + heat$

(R7.3)

⁵⁸ Celsius (August 17, 2020) <u>Thermal Energy Storage</u>. [7]

⁵⁹ Celsius (August 17, 2020) <u>Thermal Energy Storage</u>. [7]

⁶⁰ Celsius (August 17, 2020) <u>Thermal Energy Storage</u>. [7]

⁶¹ Celsius (August 17, 2020) <u>Thermal Energy Storage</u>. [7]

⁶² EERE (no date) <u>Fuel Cells</u>. [41]

⁶³ EERE (no date) <u>Fuel Cells</u>. [41]

⁶⁴ EERE (no date) Fuel Cells. [41]

⁶⁵ EERE (no date) Fuel Cells. [41]

Over traditional combustion engines, fuel cells have many advantages—they operate at higher efficiencies, have fewer (sometimes zero) emissions, are quiet to operate, and do not form air pollutants on-site that harm human health.⁶⁶

Currently, fuel cells are rarely used for utility-scale energy storage applications, although research and development programs, both publicly and privately supported, aim to increase the longevity and reliability of fuel cell systems, so that they can become a technologically and economically viable option.^{67,68} The primary area of interest for utility-scale storage with renewable energy sources is *reversible* hydrogen fuel cells. Just like other hydrogen fuel cells, they generate electricity and heat using air and hydrogen fuel.⁶⁹ However, the systems can also function in reverse — when there's excess renewable energy available, these cells can store that energy in the form of hydrogen by using the excess renewable energy to break apart water into hydrogen and oxygen, a process known as electrolysis.⁷⁰ Then, this hydrogen can be used to fuel the cell when the intermittent renewable energy source declines,⁷¹ helping to balance out energy production and energy use schedules. (A full exploration of hydrogen production via electrolysis is available in Section 6.1.1.2 of this report.)

Technological progress still needs to be made before reversible hydrogen fuel cells are commercially ready. One issue is that commercial-scale fuel cells and electrolyzers currently deploy different catalysts to support the electrolysis/combustion reactions. For one piece of equipment to do both jobs, a new device would need to be developed to get around these catalytic differences.⁷² One has been developed, called a proton conducting fuel cell (PCFC), but the device cannot yet maintain the power output needed for most practical applications.⁷³

7.1.2 State of Development

The state of development for these technologies is mixed, with some utility-scale batteries already having been commercially available for decades while others are still in the research and development space. Pumped hydropower storage and compressed air energy storage (CAES) are two examples of energy storage solutions that have existed for many decades.⁷⁴ The majority of newly-deployed utility-scale projects are focused on lithium-ion

⁶⁶ EERE (no date) Fuel Cells. [41]

⁶⁷ EERE (no date) <u>Fuel Cells</u>. [41]

 ⁶⁸ Service (March 12, 2019) <u>New fuel cell could help fix the renewable energy storage problem</u>. [53]
 ⁶⁹ EERE (no date) <u>Types of Fuel Cells</u>. [42]

⁷⁰ EERE (no date) <u>Types of Fuel Cells</u>. [42]

⁷¹ EERE (no date) Types of Fuel Cells. [42]

⁷² Service (March 12, 2019) <u>New fuel cell could help fix the renewable energy storage problem</u>. [53]

⁷³ Zhang, Hu (2021) <u>Progress in proton-conducting oxides as electrolytes</u>. p. 995-997. [62]

 ⁷⁴ Irving (April 29, 2021) <u>World's largest compressed air grid "batteries" will store up to 10GWh</u>.
 [27]

batteries.⁷⁵ For those technologies that are still in development, the U.S. Department of Energy (DOE) is working to accelerate innovation, so that they can quickly reach commercial scale operations and contribute to national and international goals of rapidly decarbonizing the economy.⁷⁶ A summary compiled by the Massachusetts Institute of Technology (MIT) of development statuses for a variety of energy storage technologies, as well as the ancillary industries that support them (mining and processing of critical minerals, battery recycling or up-cycling, and development of infrastructure to support the production and distribution of hydrogen for fuel cells) is given in Table 7.2. Most technologies fall in a range of developmental stages because of ongoing innovations aimed at optimizing and scaling energy storage.

	Current Innovation Status ^a				
Technology	Idea creation	R&D	Pilot scale	Demonstration	Deployment
Li-ion batteries					
Flow batteries (inorganic)					
Flow batteries (organic)					
NaS batteries					
Metal-air batteries					
Pumped hydro storage					
Thermal storage					
Hydrogen					
Ancillary Industries					
Critical materials supply chain					
Battery recycling					
H ₂ production, transport, storage					

Table 7.2. Status of development for	energy storage + ancillary industries,	as of 2022.77
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a. Shaded region(s) denote one or more technology types in the relevant stage of readiness. Because there are several battery types in each technology category, more than one current innovation status may exist.

One energy storage technology that we have not explored extensively in this report due to its still being in very early stages of development are metal-air batteries, in which electricity is released through the spontaneous oxidation of a common metal (i.e. zinc, iron,

⁷⁵ IEA (September 2022) <u>Grid-Scale Storage</u>. [25]

⁷⁶ Blaustein (May 6, 2022) <u>Rechargeable Molten Salt Battery</u>. [2]

⁷⁷ MIT (2022) <u>The Future of Energy Storage</u>. p. xiv. [32]

aluminum) by air.⁷⁸ A spontaneous reaction is one that is thermodynamically favorable - it will progress naturally without external forcing (like the addition of heat or pressure). As a corollary to other electro-chemical redox batteries, here the metal is the anode material during discharge and the cathode is a porous material that allows the air to pass through and react with the electrolyte to form hydroxyl ions. The hydroxyl ions react with the metal, producing oxidized metal and free electrons. For example:

 $FeO_{metal} + OH^- \rightarrow FeO(OH)_{goethite} + e^-$

(R7.4)

Although a zinc-based metal-air battery was first proposed in 1878, they are most commonly used today in small, often disposable, consumer electronics, and their deployment for utility-scale storage has yet to be proven.⁷⁹ If metal-air batteries can be scaled, they would have key advantages over other battery types: their theoretical specific energies exceed standard lithium-ion batteries by magnitudes of 5 to 50, depending on the type of metal used, and do not have the same overheating risks as lithium-ion battery cells (see Section 7.2.2).⁸⁰ While, attaining these high specific energies has not yet been achieved in practice, and currently, these systems are not cost-competitive with most other types of electrochemical battery storage,⁸¹ this example of the potential for innovation and development is worth keeping in mind. With the speed at which new technologies are evolving in the battery space, the utility-scale battery storage options that seem most practical now may look very different even in a few years.

7.1.2.1 Example projects

Electrical Storage: Fluence, headquarters in Arlington, Virginia

Fluence is an energy storage technology and service provider that is run by Siemens and AES. The company was launched in 2018.⁸² Fluence provides grid-scale and industrialstrength energy storage solutions, with scalable energy capability ranging from 2 MW to >500 MW and discharge duration of 6+ hours. Their advanced lithium ion sealed cells come in modular packaging, pre-installed with the necessary battery racks and modules, heating and cooling system, power supply, controllers, and safety components.⁸³ Fluence offers both short- and long-duration units ("cubes") that can be configured and combined on a site; a short-duration cube is approximately 2.5 x 2.5 x 2.2 m, while a long-duration cube is $2.5 \text{ m x } 2.5 \text{ m x } 2.1 \text{ m.}^{84}$

⁷⁸ MIT (2022) <u>The Future of Energy Storage</u>. p. 35. [32]

⁷⁹ MIT (2022) <u>The Future of Energy Storage</u>. p. 37. [32]

⁸⁰ MIT (2022) <u>The Future of Energy Storage</u>. p. 35-36. [32]

⁸¹ MIT (2022) <u>The Future of Energy Storage</u>. p. 36-37. [32]

⁸² Fluence (no date) <u>Fluence Energy</u>. [21]

⁸³ Fluence (2022) <u>Gridstack - Technical Specifications</u>. [22]

⁸⁴ Fluence (2022) <u>Gridstack - Technical Specifications</u>. [22]

Heat Storage: Rondo Energy, Alameda, California

Rondo Energy converts wind and solar energy—either directly from the source or indirectly through the grid—into heat energy that can be stored and deployed as needed (see Figure 7.4).⁸⁵ This is an example of a sensible thermal energy system. When wind or solar energy is available, either through the grid or in an off-grid system, Rondo's process uses electric heating elements (called Joule heaters) to turn that electrical energy into high-temperature heat energy. The heating elements are placed near bricks, warming them to temperatures up to 1500°C (~2730°F). These bricks can store heat very effectively for long periods, with thermal losses of less than 1% per day. To release the heat for use, air is directed through the heated bricks, where it rises to temperatures over 1000°C (~1830°F)—the release of heat into the system can be easily adjusted by controlling the air flow out of the brick stack. This heat can then be delivered to a facility as superheated air or superheated steam, with temperatures, pressures, and heat medium (air or water) optimized to meet a facility's specific needs.⁸⁶

7.1.3 Operational Needs

7.1.3.1 Physical footprint

Most energy storage sites report their size in terms of megawatt (MW) capacity, rather than a physical footprint. A good rule of thumb in the field is that per megawatt hour (MWh), the estimated land use for battery storage is 1,000 square feet.⁸⁷ The size will scale accordingly. Most energy storage applications require less than 10 acres of total land use.⁸⁸

A battery storage facility called Saticoy, opened by Averon Asset Management in Ventura County in 2021, represents what a typical battery storage site in southern California would look like (Figure 7.5). It houses a 100 MW (or 400 MWh) energy storage system, enough to power the entirety of Ventura County for half an hour or the city of Oxnard for four hours.⁸⁹ The system is made up of 142 Megapacks, Tesla's utility-scale battery units, with performance management software from Power Factors.⁹⁰

Another facility, Crimson Storage, is located on 2,000 acres of Bureau of Land Management (BLM) land in Riverside County, California (Figure 7.6).⁹¹ As of the writing of this report, it

⁸⁵ Rondo Energy (no date) <u>The Rondo Heat Battery</u>. [50]

⁸⁶ Rondo Energy (no date) <u>The Rondo Heat Battery</u>. [50]

⁸⁷ Convergent (no date) <u>Landowner Partnerships</u>. [12]

⁸⁸ Merritt (no date) Energy Storage Investment Opportunities. [34]

 ⁸⁹ Wagman (June 29, 2021) <u>Averon opens 100 MW/400 MWh battery energy storage facility in</u> <u>California</u>. [60] Note: For reference, Ventura County, California has a population of about 843,000 people, according to <u>the U.S. Census Bureau's 2020 Census figures</u>. Oxnard, California has a population of about 202,000 people, according to <u>the U.S. Census Bureau's 2020 Census figures</u>.
 ⁹⁰ Wagman (June 29, 2021) <u>Averon opens 100 MW/400 MWh battery energy storage facility in</u> <u>California</u>. [60]

⁹¹ Lewis (October 19, 2022) <u>The world's largest single-phase battery</u>. [30]

is the largest single-phase battery storage facility, and the second largest operating energy storage facility, in the world, with a capacity of 350 MW or 1400 MWh.⁹²



Figure 7.5. Saticoy 100 MW battery storage facility, Ventura County, California. Image credit: Averon Asset Management.⁹³



Figure 7.6. Crimson Storage 350 MW battery storage facility, Riverside County, California. Image credit: <u>Bureau</u> <u>of Land Management</u>.

⁹² Lewis (October 19, 2022) <u>The world's largest single-phase battery</u>. [30]

⁹³ Wagman (June 29, 2021) <u>Averon opens 100 MW/400 MWh battery energy storage facility in</u> <u>California</u>. [60]

The world's largest energy storage facility is Vistra Energy's Moss Landing Energy Storage Facility, with a capacity of 400 MW or 1600 MWh, also located in California (Monterey County).⁹⁴ In this project, battery units were stacked into a retrofitted turbine building in an old power plant that is approximately three football fields long.⁹⁵ Moss Landing is an interesting example of reusing existing energy infrastructure to meet new needs and the ability to stack battery units to reduce the land footprint of these facilities, both features that could inform the development of new energy storage projects.

7.1.3.2 Energy requirements

When assessing energy requirements for energy storage, the necessary metric to consider is round-trip efficiency. Not all of the energy that is stored in a battery can be used later — some amount of the energy is lost in the process. Depending on type of battery storage, the round-trip efficiency varies between 40-90% (Table 7.1), meaning that somewhere between 40% and 90% of the energy put into the battery can be withdrawn later for use.⁹⁶ Efficiencies can also alter over time for the same system. Aging systems generally have lower efficiencies due to degradation of the battery itself.⁹⁷ Systems can also decline in efficiency depending on the length of time that energy is stored in a particular medium before it is discharged; for example, molten salt batteries lose an estimated 1% of their stored energy every day.⁹⁸ For relatively short-term storage needs, molten salt could be incredibly efficient, but meeting longer-term needs could require other battery types or trying novel ideas, like freezing the entire molten salt system to hold the energy.⁹⁹ Thus, intended usage needs to be a determining factor for the type of storage chosen—large-scale battery storage systems are designed differently to meet short-term needs as opposed to long-term ones.

The storage duration – or how long an energy storage solution can supply energy to the user – depends upon the system's rated power capacity and the energy capacity. Most sites describe themselves in terms of rated power capacity, or the maximum rate of power discharge that a battery system can attain from a full charge expressed in kilowatts (kW) or megawatts (MW).¹⁰⁰ However, the total amount of power that can be stored by a battery system is the energy capacity, which is expressed in kilowatt-hours (kWh) or megawatt-hours (MWh). For a system rated 1 MW of power capacity storing 4 MWh of usable energy capacity (i.e. holding 4 MWh that can be released from the system with its efficiency), the

 ⁹⁴ Colthorpe (October 18, 2022) <u>Crimson Energy Storage 350MW/1,400MWh battery storage plant</u>.
 [11]

⁹⁵ Patel (January 14, 2021) <u>Vistra Energizes Massive 1.2-GWh Battery System at California Gas</u> <u>Plant</u>. [46]

⁹⁶ Roberts (July 21, 2018) <u>Batteries have a dirty secret</u>. [49]

⁹⁷ NREL (no date) <u>Battery Lifespan</u>. [37]

⁹⁸ MIT (2022) <u>The Future of Energy Storage</u>. p. 122. [32]

⁹⁹ Blaustein (May 6, 2022) <u>Rechargeable Molten Salt Battery</u>. [2]

¹⁰⁰ Greening the Grid (September 2019] <u>Grid-Scale Battery Storage</u>. p. 2. [24]

storage duration of the system would be 4 hours.^{101,102} Determining the correct battery storage system for different applications will rely on matching up typical energy usage with battery characteristics in terms of the rated power capacity and the energy capacity.

7.1.3.2 Other operational requirements

Waste disposal requirements

Day-to-day, waste disposal requirements are generally not needed for energy storage systems. Most systems can run and rerun using the same materials thousands or tens of thousands of times (Table 7.1). The end-of-life disposal for these systems is often opaque, though. For example, utility-scale use of lithium-ion batteries has been growing rapidly, but there are no standardized disposal guidelines for these batteries, which only have a 15-20 year lifetime.¹⁰³ These batteries also cannot be disposed of in traditional landfills; not only would it be wasteful of expensive and finite materials, but elements within the battery like cobalt, manganese, and nickel can harm soil and groundwater.¹⁰⁴ Battery recycling is not as advanced as battery production, but it is quickly growing into a large scale industry of itself, as demand for the critical materials that compose batteries increases. For example, in 2023, the U.S. Department of Energy granted Redwood Materials, a lithium-ion battery recycling company based in Carson City, Nevada, a conditional \$2 billion USD loan to build out its battery recycling campus. The expansion is expected to 1,600 full-time employees and support the production of more than 1 million electric vehicles per year.¹⁰⁵

Warehousing requirements

Energy storage technologies are essentially warehouses for electricity and/or heat. Some forms of energy storage may benefit from (or require) housing within a building, but as the only feedstock and product is energy, the need for ancillary on-site warehousing is highly unlikely.

Transportation requirements

Transportation requirements for battery energy storage systems should involve the transfer of electricity from a power source (e.g. wind or solar), and when needed, to an electricity or heat user. Electricity will be transported in the form of power lines. Heat can be transported as steam or hot air. The length of these transport lines is minimized the closer energy source, storage system, and end user are sited together, which is one of the key benefits of Kern County for carbon management industry development. High efficiency renewable energy and storage systems could be sited adjacent to a large-scale business park, reducing technical hurdles and costs of energy transfer.

¹⁰¹ Greening the Grid (September 2019] <u>Grid-Scale Battery Storage</u>. p. 2. [24]

¹⁰² NREL (2022) <u>Utility-Scale Battery Storage</u>. [38]

¹⁰³ Semeniuk (October 12, 2020) <u>The Future of Energy Storage Needs a Disposal Plan</u>. [52]

¹⁰⁴ Semeniuk (October 12, 2020) <u>The Future of Energy Storage Needs a Disposal Plan</u>. [52]

¹⁰⁵ LPO (February 9, 2023) <u>LPO offers conditional commitment to Redwood Materials</u>. [31]

7.1.3 Carbon Capture Potential

Energy storage systems do not capture or sequester carbon dioxide emissions. However, these technologies are expected to play a key role in transitioning from carbon-intensive energy sources—like coal, oil, and natural gas—to lower-carbon renewables like wind and solar. This is because traditional fossil fuel energy infrastructure can operate continuously and consistently, but renewable sources like wind and solar can be more intermittent in their supplies. To ensure reliable operation of any technology requiring heat or electricity, battery storage is required alongside renewables to sustain continuous or on-demand operations.

It is worth noting that battery storage is not inherently carbon-neutral, and over its life-cycle (manufacture to end-of-life) can emit CO₂ and other greenhouse gasses. How much it emits depends on the *indirect* emissions that occur during production of the energy that it stores (batteries can store energy indiscriminately of the source). If it's cheapest to store and then deploy energy that originates from a fossil fuel facility, then batteries will actually enable a very carbon-intensive energy mix. Currently, most incentives for battery storage expansion do not require the energy to be sourced from renewable resources, meaning that battery storage deployment has actually *increased* carbon emissions relative to a national grid with no storage.¹⁰⁶

This is relevant to a carbon management industry that uses CO₂ credits (either from public incentives like the federal 45Q tax credit, or from the private carbon credit market) for revenue, because they can only receive income for the *net* CO₂ that they remove from the atmosphere (or prevent from being emitted). If their energy source is carbon-emissions-intensive, that will reduce the viability of their business model. Thus, battery storage needs to be coupled with low-carbon energy sources—sources that are much less carbon-intensive than existing energy sources—to produce maximum revenue potential as well as maximum climate benefits.¹⁰⁷

7.2 Societal Impacts

7.2.1 Job creation potential

7.2.1.1 Number and types of jobs

By 2050, it is estimated that between research and development, manufacturing, installation, and operation and maintenance, the energy storage industry is expected to create 370,000-450,000 jobs in North America, or nearly 2,000 jobs for every GW of storage capacity installed.¹⁰⁸ Of these roles, only installation and maintenance jobs will be

¹⁰⁶ Roberts (July 21, 2018) <u>Batteries have a dirty secret</u>. [49]

¹⁰⁷ Roberts (July 21, 2018) <u>Batteries have a dirty secret</u>. [49]

¹⁰⁸ ACPA (2021) <u>Clean Energy Labor Supply</u>. p. 18. [1]
necessarily sited at energy storage facilities, and only maintenance jobs will be permanent, long-term, on-site roles. Given that a primary design goal for energy storage is high durability, and low maintenance, there would likely be very few permanent maintenance jobs created.

In terms of installation jobs, the Crimson Energy Storage Project - a 350MW battery storage facility in Riverside County (Figure 7.6) created 140 jobs during peak construction.¹⁰⁹ A 45MW energy storage facility planned in Massac County, Texas, anticipates the creation of 100 short-term jobs during construction.¹¹⁰

Sectors of the energy storage industry that have the largest growth potential are manufacturing (38% of all industry job growth) and project development (25%), which includes services like consulting, finance, research, legal support, architecture, engineering, and other specialized design services.¹¹¹ Battery recycling is also likely to experience significant growth (see Section 7.1.3.2). While project development jobs could locate onsite, local policies that incentivize or mandate energy storage companies to hire local workers to fill as many roles as possible is a strong driver for expanding the community benefits of these kinds of projects.¹¹² Manufacturing and recycling do not need to be co-located with installation sites, but given their job growth potential, an assessment of the benefits and risks of encouraging these types of facilities to locate in the region warrants further investigation.

7.2.2.2 Training pipelines

A training needs assessment for energy workforce development conducted by the New York State Energy Research and Development Authority (NYSERDA), identified a suite of thirteen technical, business, manufacturing, and general training needs to create a strong workforce in the energy storage sector.¹¹³ Most of these needs, such as fundamental knowledge of energy storage technology, technical skills training for installation and maintenance, electrician training, regulatory and permitting processes, advanced manufacturing skills, interconnection processes, and safety training, can be learned through on-the-job training, apprenticeships, professional association training programs, or trade schools. Some skills such as engineering, system design expertise, and business and finance modeling, will require advanced post-secondary degrees.

An assessment of job growth potential across the entire clean energy sector (wind, solar and storage) by the American Clean Power Association reported average wages for clean energy occupations to range from \$33,710-\$158,100 (in 2020 USD), with higher paying

¹⁰⁹ Denos (October 18, 2022) <u>BLM announces completion of Crimson Energy Storage Project</u>. [13]

¹¹⁰ Vistra (April 6, 2021) <u>Joppa power plant to close in 2022</u>. [58]

¹¹¹ ACPA (2021) <u>Clean Energy Labor Supply</u>. p. 18. [1]

¹¹² Garcia (October 6, 2021) <u>FAQ: Community-Level and Large-Scale Battery Energy Storage</u>. [23]

¹¹³ NYSERDA (2021) <u>Energy Storage Workforce Development</u>. [39]

positions requiring advanced degrees.¹¹⁴ They projected that 65% of job-years created across these occupations would have an annual average wage higher than the national average of \$56,310 (in 2020 USD).¹¹⁵

7.2.2 Quality of Life

7.2.2.1 Location

Battery storage facilities can be beneficial to communities, especially ones that are heavily reliant on variable energy sources, prone to extreme weather conditions, and/or suffer from transmission issues or grid unreliability. Battery storage facilities can replace "peaker plants"—typically fossil fuel-reliant power plants that run intermittently to meet peak demand on the grid.¹¹⁶ Peaker plants are frequently located in disadvantaged communities, where they release greenhouse gasses and other emissions, some of which harm human health. Energy storage facilities can also replace aging facilities on the grid in need of decommissioning (such as the Moss Landing Energy Storage Facility, Section 7.1.3.1), which reduces the burden for ratepayers on paying for necessary infrastructure updates.¹¹⁷ Because battery storage solutions can meet multiple needs, be deployed at a variety of scales, and utilize different storage technologies, there is a good deal of flexibility in ensuring the benefits of storage are realized by local communities.

Battery storage facilities do not locally emit any pollutants that cause harm to human health.¹¹⁸ This is part of why battery storage solutions generally make a favorable replacement to traditional peaker plants—they can help meet periods of high energy demand without emitting harmful pollutants into local communities.

In general, battery storage systems are described as being "no louder than the average residential home air conditioning system."¹¹⁹ The noise is derived from inverters, transformers, and fans needed to keep the equipment running,¹²⁰ though the exact equipment parts and their noise levels will differ between types of battery storage systems. With a planned 56 inverters, 56 transformers, and 40 HVAC units, the total noise level at a 1,000-foot distance from a 125MW facility operating at maximum sound level was 59.2 dB,¹²¹ about as loud as normal conversational voices when people are standing about 3 feet apart.¹²²

¹¹⁴ ACPA (2021) <u>Clean Energy Labor Supply</u>. p. 27-29. [1]

¹¹⁵ ACPA (2021) <u>Clean Energy Labor Supply</u>. p. 24. [1]

¹¹⁶ PNNL (no date) <u>Energy Storage for Social Equity Initiative</u>. [45]

¹¹⁷ PNNL (no date) <u>Energy Storage for Social Equity Initiative</u>. [45]

¹¹⁸ Garcia (October 6, 2021) <u>FAQ: Community-Level and Large-Scale Battery Energy Storage</u>. [23]

¹¹⁹ Convergent (no date) <u>Landowner Partnerships</u>. [12]

¹²⁰ Burns & McDonnell (2019) <u>Battery Energy Storage System Sound Study</u>. p. 23. [3]

¹²¹ Burns & McDonnell (2019) <u>Battery Energy Storage System Sound Study</u>. p. 23. [3]

¹²² OSHA (no date) <u>Occupational Noise Exposure</u>. [40]

Light pollution is uncommon for battery storage sites, but is something that would need to be evaluated based on the site-specific needs and the facility type.

Battery storage does come with some risks that will impact both on-site workers and, to a lesser extent, quality of life for nearby residents. Utility-scale battery storage sites can be a fire and explosion risk.¹²³ For example, with lithium-ion batteries, there is the risk of *thermal runaway*, wherein one battery pack overheats, leading to a domino effect causing other units to overheat, which can create a fire or explosion within or across battery packs. If the battery packs catch fire, toxic gasses including carbon monoxide, hydrogen fluoride, and hydrogen chlorine can be released. If batteries are damaged during disposal, they can have similar hazards. With diligent on-site management and strong federal and state regulation, these hazards can be minimized to protect workers and nearby communities.¹²⁴

7.2.2.2 Multi-use potential

Most battery storage systems can be easily co-located with other facilities, as exemplified by the diversity of sites upon which they already exist in urban, residential and remote environments, including private homes. One multi-use example comes from Duke Energy, which is planning to build a solar microgrid and battery storage facility next to Johns Hopkins Middle School in Pinellas County, Florida.¹²⁵ The 2.5 MW battery is designed to store energy from the solar microgrid to be deployed to support the school, which also acts as a hurricane shelter, or to the local power grid.

7.3 Environmental Impacts

7.3.1 Water requirements

7.3.1.1 Minimum volume requirements

Water intake amounts vary across battery types, and the relationship between water use (by volume) and capacity to store and release energy is not well reported, to the best of our knowledge, for any industry other than pumped hydropower storage facilities that rely on water from a nearby river being moved into a reservoir with a power station and then released back into the river (in this case, the net water use is very small).¹²⁶

Many energy storage systems require water as a solution medium—redox flow batteries rely on aqueous (water-based) solutions to store the salts needed to generate electricity,¹²⁷ but the extent to which that water needs to be replenished (and thus the water demand of

¹²³ Garcia (October 6, 2021) <u>FAQ: Community-Level and Large-Scale Battery Energy Storage</u>. [23]

¹²⁴ Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]

¹²⁵ Duke Energy (August 25, 2020) <u>Three new battery storage sites</u>. [15]

¹²⁶ Casey (November 30, 2022) <u>Underground Water Battery</u>. [6]

¹²⁷ MIT (2022) <u>The Future of Energy Storage</u>. p. 29. [32]

such batteries over time) is not well reported. CAES facilities often need water to be pumped underground to dissolve the salts in underground storage caverns, which become a reservoir to store the compressed air for the system.¹²⁸ This generates brackish water that needs to be removed from the ground and treated before reuse (see Section 8 on water treatment techniques).¹²⁹

Current lithium-ion batteries do not require water—in fact, most perform better in very dry conditions—but some teams are working on new lithium-ion batteries that can absorb water or use liquid materials instead of being a 'dry-cell' battery.¹³⁰

7.3.2 Other potential impacts

For an industry as diverse as this, it is not possible to clearly outline all potential environmental impacts (positive or negative) in a region that develops utility scale storage. Even within the same category, different battery types do not carry same risks or potential environmental impacts.

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

Two general points, however, can be made. First, battery and other energy storage systems do not generate criteria air pollutants.¹³¹ In fact, because battery storage facilities often replace emergency generators or traditional power plants that run on fossil fuels, battery storage can serve to improve local air quality by replacing energy facilities that do emit pollutants.¹³² Second, on a more global scale, battery production does have environmental impacts resulting from the extraction of critical materials (like lithium and cobalt) used to manufacture batteries, and from their disposal. As energy storage technologies scale up, a significant focus of research and development is on optimizing battery longevity and efficiency, and on improving mining practices and identifying raw materials that can replace critical minerals whose sourcing is often unsustainable and/or ethically fraught.¹³³

¹²⁸ MIT (2022) <u>The Future of Energy Storage</u>. p. 94. [32]

¹²⁹ MIT (2022) <u>The Future of Energy Storage</u>. p. 94. [32]

¹³⁰ Sagoff (May 2, 2022) <u>Water containing battery electrolyte</u>. [51]

¹³¹ Garcia (October 6, 2021) <u>FAQ: Community-Level and Large-Scale Battery Energy Storage</u>. [23]

¹³² Garcia (October 6, 2021) <u>FAQ: Community-Level and Large-Scale Battery Energy Storage</u>. [23]

¹³³ Le (August 4, 2020) <u>Flow Batteries</u>. [29]

7.4 Economic Impacts

7.4.1 Business Model

The global energy storage market size is currently valued at \$59 billion, and is anticipated to grow by at least 900% by 2035.¹³⁴ This is due primarily to the dramatic increase expected in our reliance on variable renewable energy (VRE) sources like wind and solar. In 2020, VREs provided 9% of global energy supplies. It is projected to rise to almost 70% of global energy supplies by 2050,¹³⁵ due both to commitments by nations and municipalities to reduce their carbon emissions, and to the fact that since 2020, onshore wind and solar power have been the least expensive forms of energy generation to build.¹³⁶

Business models for utility-scale battery storage typically relies on the mismatch between energy supply and demand. With variable renewable electricity (VRE) sources like wind and solar, energy production highs and lows are based on the weather. Battery facilities buy electricity during periods of high VRE availability, when electricity is the cheapest, and then sell and distribute the electricity when VRE availability is low for a higher price.¹³⁷ This system enables battery facilities to generate consistent profits, while also providing a few co-benefits. First, implementing battery storage reduces demand for peaker plants, which are typically sustained using fossil fuels, to meet peak periods of electricity demand, thereby reducing CO₂ and other types of emissions. Second, it levels out energy costs for ratepayers from industrial to household scale. In California, as more battery facilities have come online, the variability between minimum and maximum energy prices has decreased, introducing greater consistency to energy pricing (Figure 7.7).¹³⁸

The build-out of energy storage systems is not always driven by pure economics—rebates and other government incentives can drive additional uptake by making the economics more favorable, and mandates can ensure broad uptake, even when the economics are unfavorable. For example, in 2018, the Federal Energy Regulatory Commission (FERC) mandated that regional transmission organizations (RTOs) begin to adopt energy storage practices and that energy storage facilities are classed as "generation facilities."¹³⁹ In December 2020, the U.S. Congress passed the Better Energy Storage Technology Act, authorizing over USD 1 billion over five years to support the research and commercialisation of a range of storage technologies, with a focus on multi-hour distribution (balancing daily variation in VRE availability, and long-duration storage, that addresses seasonal VRE variability.¹⁴⁰ Although more regulatory changes will be necessary

¹³⁴ Le (August 4, 2020) <u>Flow Batteries</u>. [29]

¹³⁵ MIT (2022) <u>The Future of Energy Storage</u>. p. 271. [32]

¹³⁶ Lazard (2021) <u>Levelized cost of energy</u>. [28]

¹³⁷ CEC (November 2021) <u>Buy Low, Sell High</u>. [4]

¹³⁸ CEC (November 2021) <u>Buy Low, Sell High</u>. [4]

¹³⁹ Shim (November 13, 2018) <u>Enthusiasm for Energy Storage</u>. [54]

¹⁴⁰ St. John (December 22, 2020) <u>Congress passes spending bill</u>. [55]

to keep pace with expected changes in the energy grid, these policies offer a promising groundwork to remove unnecessary regulatory barriers and encourage greater participation of energy storage in the national electricity market.¹⁴¹



Figure 7.7. As more batteries have entered the California energy market, the highest and lowest energy prices have both moderated. Image credit: California Energy Commission.¹⁴²

7.4.2 Business Costs

7.4.2.1 Cost of energy: Installed cost of storage

When considering the cost of energy storage, there are a few key takeaways:

- 1. Storage cost is dependent on the storage technology and energy capacity.
- 2. The price of energy has dropped significantly in the last few decades, and is expected to continue dropping.
- 3. The capital and operational costs associated with storage development do not translate to a levelized cost of energy in the same way that other energy commodities do, because energy storage is not a stand alone energy provider - it only operates in conjunction with an energy source.

We will unpack these takeaways in this, and the following section.

¹⁴¹ Shim (November 13, 2018) <u>Enthusiasm for Energy Storage</u>. [54]

¹⁴² CEC (November 2021) <u>Buy Low, Sell High</u>. [4]

Determinants of installed cost of storage

A 2022 study undertaken by the Pacific Northwest National Laboratory (PNNL)¹⁴³ examined commercially available energy storage technologies, with the aim of assessing how their costs varied as a function of power capacity (the amount of energy they can provide at a given time, in MW or kW) and energy capacity (the total amount of energy they can store on a single charge, in MWh or kWh), and how these costs are likely to evolve by 2030. Their comparison was across two variables: installed cost and levelized cost of storage (LCOS). Installed cost is addressed here, and LCOS is discussed in Section 7.4.2.2.

Battery Type ^a	Power Capacity Range (MW)	Installed Cost (\$/kWh)	Installed Cost (\$/kW)	Operating Costs (\$/kW-yr)	Decommis- sioning Costs (\$/kWh)
Lithium-Ion (LFP) ^b	1-10	\$360-519	\$922-9,128	\$2.79-23.30	\$2.65
Lithium-ion (NMC)°	1-10	\$410-576	\$1,031-10,405	\$6.18-29.59	
Lead Acid	1-10	\$412-607	\$1,090-10,457	\$4.05-31.46	\$16.89-33.28
Vanadium Redox Flow	1-10	\$356-836	\$1,522-\$9,054	\$4.85-26.48	\$22.95-59.27
Zinc	1-10	\$440-631	\$1,172-10,798	\$10.56-27.65	
CAES	100-1,000	\$16-295	\$1,087-1,784	\$9.82-18.56	
Pumped storage hydropower	100-1,000	\$221-511	\$1,716-2,625	\$15.58-28.19	
Gravitational	100-1,000	\$190-731	\$1,706-7,600	\$14.28-34.37	
Thermal	100-1,000	\$130-595	\$1,568-3,944	\$6.95-42.77	
Hydrogen	100-1,000	\$126-295	\$2,949-3,033	\$16.89-23.90	

Table 7.3. Installed cost of energy storage in 2021.¹⁴⁴

a. The most commonly utilized battery types are described in this report. For details on all battery types, see Viswanathan et al. (2022) <u>PNNL energy storage cost assessment</u>.

b. Lithium-ferrophosphate

c. Nickel-manganese-cobalt

Installed costs comprise the net of capital expenses (raw materials, project development, engineering, procurement, construction and grid integration). These costs are detailed in Table 7.3, along with operating costs (fixed operations and maintenance, losses associated with round-trip efficiency (RTE),¹⁴⁵ and in some cases a warranty) and decommissioning costs (disconnection, removal, site remediation and recycling/disposal), and are given as

¹⁴³ Viswanathan *et al.* (2022) <u>PNNL energy storage cost assessment</u>. [59]

¹⁴⁴ Viswanathan *et al.* (2022) <u>PNNL energy storage cost assessment</u>. [59]

¹⁴⁵ Note: round-trip efficiency (RTE) is the percentage of the energy used to charge a storage system that is released during discharge. See Table 7.1 for typical RTEs by battery type.

ranges that reflect cost variation as function of power capacity (specified by storage type) and storage duration, in hours.

For any of these technologies, installation costs in terms of energy capacity (\$/kWh) decrease with increasing storage duration (see Figure 7.8), but in terms of power capacity (\$/kW) and operating costs, they increase with storage duration.¹⁴⁶ Installation costs also decrease with increasing power capacity, due to economies of scale.¹⁴⁷

Projected decreases in battery costs

The outlook for rapidly decreasing costs for energy storage is quite promising, on the basis of historical trends. Since 1991, the price of lithium-ion batteries has decreased 97%.¹⁴⁸ Like other technological innovations (such as solar and wind power), economies of scale and learning by doing have driven significant, systematic decreases in the cost of production with every doubling of installed capacity. For lithium-ion batteries, this 'learning rate' has been a price decline of about 18.9% for every cumulative capacity doubling.¹⁴⁹ Using this learning rate, as well as anticipated growth in energy storage installation capacity, it is possible to make projected estimates of what costs will be in the future. A cost analysis from MIT estimated that by 2050, lithium ion batteries may have decreased an additional 37-74% in price, while less developed technologies could see even greater cost decreases (up to 91% for flow batteries and up to 97% for metal-air batteries).¹⁵⁰

7.4.2.2 Cost of energy storage: Levelized cost of storage

The cost of energy is often assessed as a levelized cost, that is incorporating capital, operational, labor and feedstock costs, what is the total cost of producing energy (\$/kWh or \$/MWh) for a given facility, over the lifetime of that facility?¹⁵¹ Assessing the levelized cost of storage is slightly more complicated, as it requires not only consideration of the above factors, but also how much the storage system would be used annually (annual hours discharged), the cost of energy needed to charge the energy storage system and the round-trip efficiency (RTE). These variables are combined to calculate the levelized cost of storage (LCOS) as follows:

 $LCOS = [(fcr x CapEx) + O&M_{fixed})/AH + ECC,$

(E7.1)

where fcr = the fixed charge rate (%), CapEx is the present value of capital expenditures, $O&M_{fixed}$ are fixed operating and maintenance costs, AH is the annual hours discharged, and ECC is the electricity charging cost (purchased energy [\$/kWh] divided by RTE [%]).¹⁵²

¹⁴⁶ NREL (2022) <u>Utility-Scale Battery Storage</u>. [38]

¹⁴⁷ Viswanathan et al. (2022) PNNL energy storage cost assessment. f.ex. p. 24-25. [59]

¹⁴⁸ Ritchie (2021) <u>Price of batteries has declined by 97%</u>. [48]

¹⁴⁹ Ritchie (2021) <u>Price of batteries has declined by 97%</u>. [48]

¹⁵⁰ MIT (2022) <u>The Future of Energy Storage</u>. p. 19. [32]

¹⁵¹ Lazard (2021) <u>Levelized cost of energy</u>. [28]

¹⁵² Viswanathan *et al.* (2022) <u>PNNL energy storage cost assessment</u>. p. 120-121. [59]



Figure 7.8. Total installed cost of energy solutions, as a function of storage duration and power capacity, showing estimated 2021 values (a) and projected 2030 values (b). Values are shown for power capacities of 100 and 1,000 MW. Data and image credit: Pacific Northwest National Laboratory.¹⁵³

The energy system cost assessment from PNNL (2022) included an LCOS analysis of all studied energy storage systems, and found that levelized costs ranged from about \$0.10-1.30 USD/kWh for large (100-1,000 MW) storage systems, with most costs falling between \$0.10 and \$0.40 (the higher costs were associated with systems that had 100 hr storage duration).¹⁵⁴ For comparison, grid electricity in California is about \$0.12-0.65 USD/kWh.¹⁵⁵ It is also important to note that battery storage does not work alone - it operates in tandem with an energy source, like wind or solar - with the direct energy source supplying power sometimes (to the grid and the storage system) and the energy storage system supplying

¹⁵³ Viswanathan *et al.* (2022) <u>PNNL energy storage cost assessment</u>. p. ix-x. [59]

¹⁵⁴ Viswanathan *et al.* (2022) <u>PNNL energy storage cost assessment</u>. p. 130. [59]

¹⁵⁵ EIA (February 2023) <u>Average price of electricity</u>. [16]

power other times. Therefore it is most useful to think of how energy storage adds to the levelized cost of energy production from wind or solar, which is about \$0.03-0.05 USD/kWh.¹⁵⁶

The National Renewable Energy Laboratory reports added costs per MWh (= 1,000 x kWh) of \$5-39 for energy storage (from their own models and the published literature), with much of the range reflecting the inclusion or omission of tax credits. In a practical example, during a 2018 bidding war for new energy capacity for electricity provider Xcel Energy in Colorado, the median price for energy storage and wind was \$21/MWh, and it was \$36/MWh for solar and storage. This compares to \$18/MWh and \$29.50/MWh, respectively, for wind and solar solutions without storage.¹⁵⁷

7.4.3 Regional benefits

California leads the nation in energy storage, with 215 operational projects providing ~4,200 MW of energy,¹⁵⁸ and plans to grow. Among utility-scale facilities, about 75% of planned development between 2022 and 2025 is concentrated in California and Texas.¹⁵⁹ As such, there are already companies active in the energy storage space with a sizable presence in the California market.

Local laws and regulations in California also make it an attractive location for utility-scale energy storage projects. The California Energy Commission (CEC) predicts that to meet the requirement of Senate Bill 100 for a carbon-free electricity system by 2045, 49,000 MW of battery storage capacity will need to be integrated into the electricity grid.¹⁶⁰ To reach these goals, new state legislation has removed some of the subdivision and zoning requirements that extended project timelines, making it more straightforward to develop a battery energy storage facility in California.¹⁶¹

7.4.3.1 Proximate feedstocks

Battery storage systems have minimal feedstocks in the traditional sense. These systems need inputs and catalysts to fuel the redox reactions that support most electrical storage, but these materials can often be reused for many charge/discharge cycles. Thus, having local supplies of materials to meet this need is not a major concern—depending on the battery type, replacement of component chemicals may not be necessary for a decade or longer.

Depending on the system type, water intake will be the most important feedstock consideration. For aqueous systems like redox flow batteries, water is necessary for

¹⁵⁶ Lazard (2021) <u>Levelized cost of energy</u>. p. 9. [28]

¹⁵⁷ Svaldi (January 16, 2018) <u>Xcel Energy receives shockingly low bids</u>. [56]

¹⁵⁸ University of Michigan (no date) <u>U.S. grid energy storage factsheet</u>. [57]

¹⁵⁹ EIA (December 8, 2022) <u>U.S. battery storage capacity will increase significantly by 2025</u>. [17]

¹⁶⁰ CEC (November 2021) <u>Buy Low, Sell High</u>. [4]

¹⁶¹ Colthorpe (August 31, 2022) <u>California zoning exemption granted</u>. [10]

sustained operation. However, some forms of redox flow batteries have optimized reuse of the liquid electrolyte solutions, with vanadium redox flow batteries having a liquid electrolyte with near-100% recyclability.¹⁶² As a result, this water requirement can vary greatly, even within the same family of batteries, due to the material differences between electrolyte solutions, catalysts, and other components.

Other battery types—like standard dry-cell lithium-ion batteries—are corroded by water,¹⁶³ so locating them in arid regions, a common feature in Kern County, could be a great locational fit based on the region's climate and the battery's optimal operating conditions.

7.4.3.2 Proximate consumers

Battery storage has multiple benefits for carbon management and clean energy industries. Many of these processes require energy input to capture carbon or generate other products, but given the goals of the carbon management park, would need to find ways to meet this energy demand while minimizing their operational carbon output. Battery storage can serve to smooth out energy supply availability by storing solar energy during peak production periods and releasing it while the solar supply is negligible (i.e. at night), so facilities can maintain continuous operation. Thermal batteries can also convert renewable energy solar and wind energy into high temperature heat, which is needed in some carbon management industries, particularly L-DAC (Section 3) and steel (Section 5).

7.4.3.3 Co-location advantages

There will already be a large amount of renewable energy resources around to support the carbon management and clean energy industries on-site; batteries bridge the gap between supply and need imbalances.

If the system is entirely off-grid, a battery storage provider could secure procurement agreements directly with park facilities. If the system has a grid connection, the battery storage provider could also secure procurement agreements with local utility companies.

¹⁶² Ondrey (April 1, 2021) <u>Recycling electrolyte from vanadium RFBs</u>. [43]

¹⁶³ Sagoff (May 2, 2022) <u>Water containing battery electrolyte</u>. [51]

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8. Water Treatment

TECHNOLOGY AT A GLANCE

- Industry has wide-scale public implementation: globally, 48% of wastewater is treated, with 11% destined for reuse.¹ In the U.S., an estimated 91.1% of wastewater is safely treated.²
- Water treatment is energy-intensive³ and varies in size and complexity based on the amount and quality of water received and the necessary quality for use after treatment.⁴
- Key advantages of this technology in Kern County: regional water supply is already overallocated⁵ and subject to frequent drought conditions.⁶ Water reclamation and reuse could support new industries while minimizing impacts on existing agricultural and residential water use.
- Key concerns of this technology in Kern County: Water treatment is well-understood and highly regulated for safety. Facilities should be sited where odors, light, and noise pollution will not bother communities and implemented in the context of a sustainable regional water use plan.

¹ Utrecht University (February 8, 2021) <u>Half of global wastewater treated</u>. [79]

² Alabaster *et al.* (2021) Progress on Wastewater Treatment. p. 92. [1]

³ Lund (September 2017) Plant Earns LEED Recognition. [55]

⁴ CDC (no date) <u>Water Treatment</u>. [16]

⁵ Grantham, Viers (2014) <u>California's water rights system</u>. p. 5. [41]

⁶ NDMC (October 13, 2022) Kern County, California. [57]

8.1 Technology Summary

Water use is a critical consideration in the design of any new industrial center, especially in California, which is in the midst of a multi-decadal megadrought.⁷ State policies require restoration of the groundwater aquifers⁸ that have been traditionally relied upon to compensate for shortages in surface water resources, further exacerbating the need for water conservation.⁹ In Kern County, industries requiring abundant fresh water would directly compete with regional agriculture, municipalities and existing industries. However, the state of California produces more than 3.4 million acre-feet of wastewater annually¹⁰ (see below for definitions) that has the potential to be remediated and repurposed for industrial use. The viability of such an option is dependent upon interest, cost, and needs of the envisioned park, which will vary depending upon the types of industries that choose to locate on-site. In this section, we provide a general overview of water treatment facilities, and how they differ as a function of the purity needs of treated water. For readers unfamiliar with industrial scale water treatment and use, relevant key terms and policies are outlined here.

Acre-foot is a standard measurement for large volumes, representing the amount of water needed to cover one acre of land with one foot of water. One acre-foot is equivalent to 326,000 gallons of water.¹¹ For reference, it would take the average household in California between six months and two years to use this volume of water.¹²

Alternative water is a catch-all term for water sources that are not surface or standard groundwater collection. According to the U.S. Department of Energy (DOE), this includes "Harvested rainwater, stormwater, sump-pump (foundation) water; Graywater [also spelled greywater or grey water]; Air-cooling condensate; Rejected water from water purification systems; Reclaimed wastewater; [and] Water derived from other water reuse strategies."¹³ Graywater and reclaimed wastewater are of particular interest here. **Graywater** constitutes water lightly used for domestic or industrial use aside from toilets, and typically requires less processing than wastewater.¹⁴ **Wastewater** is a broader category, including sewage, water used in heavier industrial processes, and stormwater as

⁷ James (February 14, 2022) <u>Western megadrought is worst in 1,200 years</u>. [48]

⁸ Escriva-Bou *et al.* (2021) <u>Groundwater recharge in California</u>. [33]

⁹ Chappelle *et al.* (2017) <u>Groundwater in California</u>. [17]

¹⁰ California Water Boards (no date) <u>Volumetric annual reporting of waste water and recycled</u> <u>water</u>. [15]

¹¹ Bland (August 4, 2021) <u>Water is life</u>. [9]

¹² Bland (August 4, 2021) <u>Water is life</u>. [9]

¹³ EERE (no date) <u>Net Zero Water Building Strategies</u>. [58]

¹⁴ Ghaly *et al.* (2021) Greywater Sources, Characteristics, Utilization and Management Guidelines.

p. 128. [39]

well as graywater; it can contain a wider range of pollutants and thus requires more processing, depending on the quality necessary for reuse.¹⁵

Influent refers to the water entering a treatment plant, and **effluent** refers to the same water after it has undergone treatment and is leaving a treatment plant.¹⁶ The quality and volume of influent and effluent will vary across facilities.

8.1.1 Description: How it Works

Wastewater processing works utilizing a well-established model, though the steps may differ based on the quality of the influent, amount of water processed, and age of the facility. There are a few consistent steps across models, however, with one exception that distinguishes the two primary types of plants: conventional treatment, in which a sedimentation tank is part of the treatment process, or direct filtration, which does not use a sedimentation step.¹⁷ The list below describes **primary treatment**, typical for all wastewater treatment plants. Depending on the quality of the influent water and the necessary quality of effluent flow, secondary or tertiary systems can be implemented to further clean the supply.

- **Preliminary treatment**: influent water passes through coarse screening and grit removal processes to remove large materials, like manmade objects, rocks, or gravel.¹⁸
- **Coagulation**: chemicals are added to the water to "stick" small particulates together.¹⁹
- **Flocculation**: as particulates begin to clump together, water is added to large tanks with slowly-mixing paddles, which bring particles together to form floc.²⁰
- **Sedimentation**: the water slowly passes through a sedimentation tank, where the floc settles at the bottom of the tank to be pumped out while the water moves out of the tank.^{21,22} Direct filtration systems skip this step.²³
- **Filtration**: the water enters a filter, typically a concrete box with sand and gravel supported on an underdrain structure, which removes remaining suspended particles.²⁴

¹⁵ DES – Queensland (no date) <u>Wastewater</u>. [24]

¹⁶ Pulsar Measurement (no date) <u>Influent and Effluent Flow Monitoring</u>. [61]

¹⁷ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

¹⁸ Pescod (1992) <u>Wastewater treatment</u>. [60]

¹⁹ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

²⁰ College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]

²¹ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

²² EPA (1998) <u>How Wastewater Treatment Works</u>. p. 3. [29]

²³ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

²⁴ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

Disinfection: prior to discharge, water is often treated with chlorine gas or a mix of chlorine and ammonia in a process called chloramination to kill microorganisms.²⁵ The maximum residual disinfectant level (MRDL) for effluent water leaving the plant is 4.0mg/L, and most effluent averages free and total chlorine concentrations "between 2.5 and 3.5 mg/L" when leaving a treatment facility.²⁶

While these steps are common to nearly all water treatment facilities, some can be removed or other steps can be introduced, depending on the water quality and planned destination for effluent flow. The flowchart in Figure 8.1 provides an example, demonstrating the water treatment process used at the Granollers Wastewater Treatment Plant, built in Spain in 1992.²⁷ This system includes far more intermediary steps to clean its water before discharge. The figure also details the steps necessary to process sludge (raw primary biosolids), a byproduct of water treatment.²⁸



Figure 8.1. Flow chart demonstrating some typical steps of a wastewater treatment process; adapted from Vidal et al. (2002) and other sources.²⁹

Cleaning water for industrial use may be less intensive than is required for a wastewater treatment plant producing drinking water quality effluent. The European Union's guidelines for water reuse, which draws on existing best practice, outlines that "industrial water reuse

²⁵ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

²⁶ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

²⁷ Vidal et al. (2002) Design of Wastewater Treatment Plants. p. 4994. [81]

²⁸ EPA (1998) <u>How Wastewater Treatment Works</u>. p. 3. [29]

²⁹ Vidal *et al.* (2002) <u>Design of Wastewater Treatment Plants</u>. p. 4994. [81]

is highly determined by the exact quality needs of the individual industrial process and/or product as well as the costs of producing water of the required quality compared to other suitable sources."³⁰ Thus, there are few 'industry standards' that can be used to define the necessary processes (and costs) of industrial water reuse—it will depend on the types of industries that could be located within the park and the water volume and quality necessary to operate a given facility.

Another freshwater alternative for industrial water (or drinking or irrigation water) is desalination, which is the process of stripping dissolved salts from seawater or other brines. As Kern County is within 100 miles of the Pacific Ocean, desalination of seawater would provide an effectively limitless volume of water for industrial development, albeit at a high price. Desalination is up to four or five times the cost per gallon for treatment, when compared to graywater or wastewater treatment plants.³¹ It is considered in this study for the purpose of comparison with treatment of graywater or wastewater, and as a point of consideration for future development in the region, given that freshwater resources are anticipated to become ever more scarce with climate change.³²

There are two main techniques for desalination, each reviewed briefly here. In reverse osmosis (RO), influent is passed through a series of semi-permeable membranes in order to remove the salts and other impurities found in seawater, as shown schematically in Figure 8.2.^{33,34}



Figure 8.2. Thermal desalination and reverse osmosis are two techniques for producing fresh water from saline waters like seawater or brines. Adapted from the Texas Comptroller of Public Accounts.³⁵

³⁰ EU Water Directors (no date) <u>Common Implementation Strategy</u>. p. 24. [35]

³¹ Climate Now (April 19, 2022) <u>Solve the Global Water Crisis?</u> 6:30-6:42. [20]

³² Hanak (January 9, 2023) <u>Adapting to a Water-Scarce California</u>. [44]

³³ IDE Technologies (no date) <u>What is Desalination?</u> [46]

³⁴ Ang *et al.* (2015) <u>Integrated/Hybrid Membrane Processes</u>. [3]

³⁵ Texas Comptroller of Public Accounts (no date) <u>Texas Water Tour: Desalination</u>. [73]

In thermal desalination, heat is used to evaporate seawater, creating pure water vapor and a briny residue. The vapor is subsequently condensed into fresh liquid water. Waste heat from power plants or refineries is often used to supply the heat source.³⁶ Thermal desalination can be accomplished through vapor compression (VC), in which heat derived from mechanically compressed vapor is used to drive evaporation of the seawater influent. Alternatively, multi-stage flash distillation (MSF) and multi-effect distillation (MED) employ multi-step evaporation/condensation processes, taking advantage of how the boiling point of water varies as a function of salinity to optimize energy efficiency. Steam or the seawater influent itself is used as the carrying agent for the heat, which boils seawater in a series of vessels (or "effects"), producing vapor and a more salty brine. The brine is moved to the next vessel, which induces boiling at a higher temperature, producing more vapor and a saltier brine, that is transferred to the next vessel, and so forth, iterating as many times as is desired.^{37,38}

8.1.2 State of Development

Water treatment and transport has been employed for centuries,³⁹ and are a common feature of public drinking water systems throughout the United States⁴⁰ (and the world). But new technologies that are particularly important in water-scarce regions like Kern County, such as desalination of seawater or wastewater treatment that provides water effluent that is clean enough for irrigation or drinking purposes, are not yet widely used on a commercial scale in the United States. Only about 1% of water is recycled in the U.S.,^{41,42} and less than 3 gallons of every 1 million gallons of water used each day in the U.S. comes from desalination.⁴³

For the purposes of this investigation, we have examined two water treatment facilities that are typical for water reuse in irrigation or landscaping, and a small set of facilities across the nation that fall within the 1% of plants that are designed to generate usable water to directly meet local needs and increase water circularity. Water treatment facilities specifically designed to meet the needs of an industrial park are not well-covered in the literature, given the vast diversity of requirements that might entail. However, lessons gleaned from existing facilities can provide a general sense of the parameters, needs, impacts and benefits of a water treatment or desalination facility to nearby industries or communities.

³⁶ IDE Technologies (no date) <u>What is Desalination?</u> [46]

³⁷ IDE Technologies (no date) <u>What is Desalination?</u> [46]

³⁸ Tzen (no date) <u>Desalination Technologies (I)</u>. [75]

³⁹ EPA (2000) <u>The history of drinking water</u>. [31]

⁴⁰ CDC (no date) <u>Water treatment</u>. [16]

⁴¹ WaterReuse.org (no date) <u>Water Reuse 101</u>. [84]

⁴² USGS (no date) <u>How much water is used by people in the United States?</u> [77]

⁴³ Tonner (November 2, 2021) <u>Desalination in America</u>. [74]

8.1.2.1 Example projects

Bee Ridge Water Reclamation Facility, Sarasota County, Florida⁴⁴

This facility in Sarasota County has a capacity of 12 million gallons per day (GPD), making it the largest of the county's water treatment plants. Wastewater is moved to the site through a series of underground pumps and lifting stations. Once at the site, the influent water goes through four major cleaning steps: screening for inorganic materials, biological processing, filtration, and disinfection. Biosolids removed during the treatment process are separated out and composted.

Effluent water that leaves the Bee Ridge facility after processing is reclaimed water that is suitable to meet commercial and residential needs for landscaping and irrigation. This reduces the demand to use potable water—which could be used in homes for cooking and cleaning—for outdoor use.

Lancaster Water Reclamation Plant, Lancaster, California⁴⁵

This facility in Lancaster, just south of Kern County, has a capacity of 18 million GPD. It employs primary, secondary, and tertiary processing, so the facility can generate reclaimed water suitable for agricultural, municipal, industrial, and parkland uses, including maintenance of water levels in regional parks and migratory bird ponds. An estimated 12.6 million gallons per day of reclaimed water is used from the Lancaster facility every day.

The Lancaster facility also saves its byproducts; biosolids are dried and can be used for compost or soil additives. The methane (biogas) generated on-site from processing wastewater is used to meet the heat requirements of the anaerobic digesters.

Direct potable reuse (DPR) water treatment demonstration facilities, United States

Although it is possible to generate reused water at the quality necessary for safe drinking water, few states allow treated wastewater to be pumped directly into homes—currently, only Texas and (on a case-by-case basis) Arizona allow direct distribution of treated water as potable tap water (direct potable reuse, or DPR).⁴⁶ Both Big Spring and Wichita Falls, in Texas, have used DPR to support local water supplies, with Wichita Falls relying on the practice to generate 5 million gallons of treated water per day to support the city during the end of a 5-year drought.⁴⁷

In California, cities like San Diego and Los Angeles have begun to consider the implementation of DPR to diversify their own water supplies.⁴⁸ The State Water Control Resources Board is expected to release updated regulations this year that would allow DPR

⁴⁴ Sarasota County (no date) <u>Bee Ridge Water Reclamation Facility</u>. [68]

⁴⁵ LACSD (no date) <u>Lancaster Water Reclamation Plant</u>. [54]

⁴⁶ Constantino (August 19, 2022) <u>What's in your drinking water?</u> [23]

⁴⁷ Constantino (August 19, 2022) <u>What's in your drinking water?</u> [23]

⁴⁸ Constantino (August 19, 2022) <u>What's in your drinking water?</u> [23]

in the state.⁴⁹ To prove the viability and safety of DPR to the public, San Diego ran a demonstration advanced purification facility from 2009 to 2013 allowing the public to tour the plant and try the water, but avoided any legal trouble by not sending any of the DPR water to taps.⁵⁰ Los Angeles plans to undertake a similar demonstration facility in 2024 to act as "proof of concept" for city residents about the safety of DPR.⁵¹ Experts estimate that California has the potential to triple its current water reuse rate to 2.8 million acre-feet annually.⁵²

8.1.3 Operational Needs

8.1.3.1 Land use requirements

Water treatment plants can have large land use requirements. The physical footprint of a facility can comprise a series of open ponds and/or buildings, depending on facility scale and local regulations.⁵³ Quality of the influent and effluent can also shape facility size — more intensive treatment can introduce additional filtration steps requiring extra equipment or ponds — and facilities often locate, when possible, on larger sites than needed to both leave room for future expansion and avoid bothering nearby communities with any noise, light, or odor pollution from the treatment plant.⁵⁴

It is important to note that facility acreage and facility capacity (the amount of water a treatment plant can process) are not strongly correlated. In the United States, the largest treatment plants by capacity have maximum physical footprints of about one square kilometer (~247 acres), with an average size of around 0.6 square kilometers (~148 acres).⁵⁵ For a regionally representative example, the Bakersfield Wastewater Treatment Plant No. 2, processing 13.7 million gallons per day or about 15,345 acre-feet of water per year,⁵⁶ occupies ~645 acres of land.⁵⁷

Design plans also differ considerably, depending on how much of the processing equipment is visible from the outside of the facility. An advantage of water treatment facilities relative to other industries included in this report, is the wide potential for alternative uses, including natural or open spaces, or public use spaces (see Section 8.2.2). An image demonstrating the potential appeal in the landscape and for nearby residents is shown in Figure 8.3.

⁴⁹ Water Education Foundation (no date) <u>Water Recycling</u>. [83]

⁵⁰ Constantino (August 19, 2022) <u>What's in your drinking water?</u> [23]

⁵¹ Constantino (August 19, 2022) <u>What's in your drinking water?</u> [23]

⁵² Water Education Foundation (no date) Water Recycling. [83]

⁵³ USA SHADE (no date) <u>Water Treatment Facility Design Guide</u>. [76]

⁵⁴ USA SHADE (no date) Water Treatment Facility Design Guide. [76]

⁵⁵ Wikipedia (August 2, 2022) <u>List of largest wastewater treatment plants</u>. [86]

⁵⁶ City of Bakersfield (no date) <u>Wastewater Treatment Plants</u>. [18]

⁵⁷ Measured via Google Earth.



Figure 8.3. The Newtown Creek Wastewater Treatment Plant in is located on a 52-acre site and has been designed to exist alongside residential development.⁵⁸ Blue and white lighting at the plant seek to provide enough light to work safely at night, without constituting an ecological or community hazard of light pollution.⁵⁹ Image credit: <u>Victoria Belanger / Flickr</u>

8.1.3.2 Energy requirements

Water treatment is an extremely energy-intensive process, using approximately 650 MWh per acre-foot of treated water.⁶⁰ Electricity costs alone can account for 25% to 40% of a water treatment facility's annual operating budget,⁶¹ and within most municipal areas, wastewater treatment facilities are the largest single electricity consumer.⁶² Energy requirements for water treatment depend on the quality of influent water being processed, considering both the type of contaminants involved, and their concentration in the influent. These factors determine the technologies and methods used to treat the water and are thus highly correlated with energy consumption.⁶³ The most energy intensive practices are generally also the most expensive, with seawater desalination requiring more electricity than cleaning wastewater or graywater.⁶⁴

Aside from treatment facilities themselves, transporting water before or after treatment also requires a great deal of energy, simply because water is heavy to move. For reference, one acre-foot of water weighs 1,360 U.S. tons (~1,233 metric tons).⁶⁵ In California, the State Water Project – a suite of canals, pipelines, reservoirs, and hydroelectric power facilities that serve as a freshwater delivery system across the state⁶⁶ – is "the state's single largest user of electricity" as the infrastructure needed to support pumping water between regions is highly energy intensive.⁶⁷

⁵⁸ L'Observatoire International (no date) <u>Newtown Creek</u>. [53]

⁵⁹ L'Observatoire International (no date) <u>Newtown Creek</u>. [53]

⁶⁰ Hamilton *et al.* (2009) <u>Driving energy efficiency in the U.S. water & wastewater industry</u>. [43]

⁶¹ Lemar, de Fontaine (2017) <u>Energy Data Management Manual</u>. p. 2. [51]

⁶² Lemar, de Fontaine (2017) Energy Data Management Manual. p. 5. [51]

⁶³ Energy Star (no date) <u>Energy Use in Wastewater Treatment Plants</u>. p. 2. [26]

⁶⁴ Fort, Nelson (2012) <u>Pipe Dreams</u>. p. 21. [36]

⁶⁵ Fort, Nelson (2012) <u>Pipe Dreams</u>. p. 3. [36]

⁶⁶ California Department of Water Resources (no date) <u>State Water Project</u>. [14]

⁶⁷ Fort, Nelson (2012) <u>Pipe Dreams</u>. p. 3. [36]

Innovative state and federal programs are helping facilities to reduce their energy consumption through improvements in energy recovery, benchmarking usage, and efficiency upgrades to onsite equipment.⁶⁸ Scientists and engineers are even optimistic that ambitious wastewater treatment plants could become net energy creators, rather than users, in the future.⁶⁹ This is primarily due to their ability to use the biogas and thermal heat produced on-site more efficiently with measures like co-digestion and fuel cell systems.⁷⁰ However, given the present average energy requirements of water treatment facilities (650 MWh/acre-foot), approximately 1.6 acres of solar energy would be required to treat an acrefoot of water.^{*} Water needs from the various carbon management systems explored in this report range from less than 0 acre-feet per million metric tons of CO₂ captured (S-DAC and some forms of BiCRS), to as much as ~16,000 acre-feet of water needed per million tons CO₂ (L-DAC, see Figure 8.4). The high-end estimate translates to about 25,312 acres of solar panels needed to support sufficient water treatment.



Figure 8.4. Water use across carbon management industries, based on this study (see Sections 3, 4 and 5). Hydrogen production via biomass, steel and particularly L-DAC technologies are water-intensive practices, using as much as 16,200 acre-feet of water annually, that could be sourced from treated graywater or (less economically) desalinated seawater.

⁶⁸ Lemar, de Fontaine (2017) <u>Energy Data Management Manual</u>. p. 4. [51]

⁶⁹ Gandiglio *et al.* (2017) Enhancing the Energy Efficiency of Wastewater Treatment. p. 1. [38]

⁷⁰ Gandiglio *et al.* (2017) Enhancing the Energy Efficiency of Wastewater Treatment. p. 1-2. [38]

^{*} Please see Section 3.1.3.2 of this report to see the equation and solar capacity factor used to derive this estimate.

8.1.3.3 Other operational needs

Waste disposal requirements

Wastewater treatment plants generate bio-solids and methane gas as byproducts of the water purification process.⁷¹ According to the EPA, the methane produced on-site is frequently used by water treatment plants as fuel, rather than being disposed of or sold.⁷² However, the methane produced can be sold as renewable natural gas (RNG) to other firms as long as its production and storage meets necessary federal and state standards.⁷³ This could encourage circularity within a water treatment plant or within a carbon management industrial park at large, particularly given the potential for generating electricity plus CO₂, or hydrogen fuel plus CO₂, through oxy-fuel combustion or methane steam reforming, respectively (see Sections 4 and 6).

Biosolids are another byproduct that are produced by physically and chemically treating the solids separated out during the water purification process to generate a nutrient-rich, semisolid product.⁷⁴ These solids can be used productively on agricultural and mining sites to improve soil structure, add nutrients, and improve water reuse, with secondary benefits including reduced landfilling and reduced use of synthetic fertilizers.⁷⁵ If not reused, biosolids must be disposed of by surface disposal methods, such as landfilling or incineration.⁷⁶

Warehousing requirements

To store influent prior to treatment and effluent before it is sent to customers, water treatment facilities typically require a large amount of onsite storage. Water awaiting treatment is often held in ground lakes or pools.⁷⁷

Because treated water is also often stored onsite until it can be transported to a customer, facilities can require millions of gallons worth of space to store cleaned water.⁷⁸ Onsite storage helps to regulate water supply to align with demand, both of which can vary seasonally.⁷⁹ Furthermore, onsite storage serves to further reduce the amount of nitrogen, microorganisms, and suspended solids present in treated water, so water leaving storage can also be cleaner than when it first leaves the treatment plant.⁸⁰ Depending on the

⁷¹ City of Bakersfield (no date) <u>Wastewater Treatment Plants</u>. [18]

⁷² EPA (no date) <u>Methane Generated on Site</u>. [30]

⁷³ EPA (no date) <u>Methane Generated on Site</u>. [30]

⁷⁴ EPA (no date) <u>Basic Information about Biosolids</u>. [28]

⁷⁵ EPA (no date) <u>Basic Information about Biosolids</u>. [28]

⁷⁶ EPA (no date) <u>Basic Information about Biosolids</u>. [28]

⁷⁷ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

⁷⁸ College of the Canyons (November 22, 2020) <u>Water Treatment Facilities</u>. [22]

⁷⁹ Pescod (1992) <u>Wastewater treatment</u>. [60]

⁸⁰ Pescod (1992) <u>Wastewater treatment</u>. [60]

location and quality, effluent can be directly discharged into 'receiving waters' such as nearby rivers or streams, removing the need to store effluent flow for distribution.⁸¹

Transportation requirements

The influent and effluent from any water treatment plant would need to move between potential sources – agricultural fields, commercial or industrial facilities, or the ocean – to the plant, and then into the carbon management park. Depending on the yield of the plant and the park's water usage, additional infrastructure may be necessary to transport water to alternate consumers or to nearby aquifers in need of replenishment.

In California, water is typically transported using open canals, aqueducts, or pipelines.⁸² The size of this equipment, as well as its operating needs and costs, will depend on the anticipated load.⁸³ Moving water can be energy-intensive over any topographical features, as pumps will be necessary to accommodate any increases in altitude along the route; as a result, the most efficient pipelines would move water near flat or declining geography to benefit from gravity.⁸⁴ A good example of this type of infrastructure operating without energy-intensive pumps is the nearby Los Angeles aqueduct, which runs through the eastern portion of Kern County.^{85, 86}

Pipeline requirements

Pipeline requirements would depend upon a facility's size and anticipated influent and effluent flows. A low intensity project may only require polyvinyl chloride (PVC) pipes, while larger projects would require steel pipes.⁸⁷ Investing in durable and easily-repairable equipment is generally the most cost-effective option in the long run by minimizing future repair and maintenance costs.⁸⁸

8.1.4 Local Context - Current Water Use

Given the overall focus of this report on the potential development of a carbon management industrial park, an entire segment on water use—including the viability of onsite water treatment options—may appear to be out of scope. However, water is often critical to ensuring sustained and successful facility operations, thus the local context of water availability in Kern County is worth examining.

⁸¹ EPA (1998) <u>How Wastewater Treatment Works</u>. p. 4-5. [29]

⁸² Bland (August 4, 2021) <u>Water is life</u>. [9]

⁸³ Resourcefulness (no date) <u>Transporting Water</u>. [64]

⁸⁴ Resourcefulness (no date) <u>Transporting Water</u>. [64]

⁸⁵ Fort, Nelson (2012) <u>Pipe Dreams</u>. p. 23. [36]

⁸⁶ Library of Congress (1908) <u>Topographic map of the Los Angeles aqueduct and adjacent territory</u>.[52]

⁸⁷ Frankel (November 10, 2021) <u>Wastewater Treatment System Cost?</u> [37]

⁸⁸ Frankel (November 10, 2021) <u>Wastewater Treatment System Cost?</u> [37]

California is in a state of drought, having experienced a series of such dry years since at least 2000, that the few wet years in between have not been enough to replenish groundwater or support plant regeneration.⁸⁹ Currently, over 80% of Kern County is experiencing 'exceptional drought' conditions.⁹⁰

In Kern County, precipitation is low due to the arid climate — the county seat of Bakersfield receives an average of 6.49 inches of rain per year.⁹¹ Yet the area uses water to support a diverse range of communities, industries, and farms; in an average year, agriculture receives 2,294,000 acre-feet of water and municipalities and industry receive 166,000 acre-feet of water across Kern County.⁹² Only about one-quarter of the water used originates from local surface sources, like the Kern River or smaller streams.⁹³ Most of the region's water is derived from underground reservoirs or is brought in from the State Water Project (via the California Aqueduct) or the federal Central Valley Project (via the Friant-Kern Canal).⁹⁴

Water is overallocated across California when compared to supply, with a 2014 study from University of California researchers finding that "[in] the state's major river basins, water rights account for up to 1000% of natural surface water supplies."⁹⁵ For the Kern River, this figure stood at 631%.⁹⁶ Additionally, overpumping of underground aquifers as an alternative water source has led to land subsidence, with approximately half the land in the San Joaquin Valley experiencing significant land subsidence (over one foot in surface ground level change) by 1970.⁹⁷ In this context, land subsidence occurs when water is removed from under the ground and the land at the surface drops down as a result.⁹⁸ These environmental changes have caused significant concern, and the state has sought to resolve these impacts of reduced aquifer replenishment and land subsidence with laws like the Sustainable Groundwater Management Act (SGMA) of 2014.⁹⁹

Given this regional context, any ways in which newly developing industries in Kern County can make use of non-freshwater sources, like treated graywater or desalinated seawater, or in which industries that produce water as a byproduct of carbon management (S-DAC and some forms of BiCRS) could co-locate with more water intensive industries, warrant examination.

⁸⁹ Wigglesworth (April 18, 2021) <u>Is California suffering a decades-long megadrought?</u> [85]

⁹⁰ NDMC (October 13, 2022) <u>Kern County, California</u>. [57]

⁹¹ WAKC (no date) <u>Water in Kern County</u>. [82]

⁹² WAKC (no date) Water in Kern County. [82]

⁹³ WAKC (no date) <u>Water in Kern County</u>. [82]

⁹⁴ WAKC (no date) <u>Water in Kern County</u>. [82]

⁹⁵ Grantham, Viers (2014) <u>California's water rights system</u>. p. 1. [41]

⁹⁶ Grantham, Viers (2014) <u>California's water rights system</u>. p. 5. [41]

⁹⁷ USGS (October 17, 2018) Land Subsidence. [78]

⁹⁸ USGS (October 17, 2018) Land Subsidence. [78]

⁹⁹ SWRCB (no date) <u>The Sustainable Groundwater Management Act</u>. [71]



Figure 8.5. Image of the Los Angeles Aqueduct, which does not require energy for pumping, demonstrating what large-scale water pipelines look like in the local environment. Image credit: <u>Mavens Notebook / Flickr</u>.

8.2 Societal Impacts

8.2.1 Job creation potential

8.2.1.1 Number and types of jobs

Water management will likely generate relatively few jobs past any necessary construction phases; however, the initial construction of any treatment facilities or canals would be labor-intensive endeavors.¹⁰⁰

California's water supply is heavily monitored and managed by existing staff attempting to balance demands from industry, agriculture, and power generators, in addition to communities and natural habitats.¹⁰¹ Any additional permanent jobs created in this sector will likely be skilled jobs to remotely manage flows, supplies, and make executive decisions during periods of drought.¹⁰²

There could be some full-time, on-site jobs generated by a water treatment facility. The majority of these would likely require vocational training, but would not require extensive secondary education, as 85% of national water-related occupations are filled by workers

¹⁰⁰ Kane, Tomer (2018) <u>Renewing the water workforce</u>. p. 17. [50]

¹⁰¹ Escriva-Bou, A. *et al.* (2019) <u>Dams in California</u>. p. 1. [34]

¹⁰² California Department of Water Resources (no date) <u>Careers</u>. [13]

who have less than a bachelors degree.^{103,104} Furthermore, water infrastructure jobs are generally good jobs, with an average wage that exceeds the national average and equates to a livable wage in most of the country.¹⁰⁵

For a large water treatment facility, staffing needs would likely be around a few dozen employees. For reference, Bakersfield's Wastewater Treatment Plants 2 and 3, processing 13.7 and 17.3 million gallons per day of influent water (or approximately 15,346 and 19,378 acre-feet per year), support 11 and 19 jobs, respectively.¹⁰⁶

8.2.2.2 Training pipelines

Anyone with a high school diploma or GED with appropriate experience can become certified to fill most water treatment roles.¹⁰⁷ All states set their own guidelines for certification for water operators.¹⁰⁸

Most training for working with water infrastructure relies on developing skills and knowledge through applied learning, rather than emphasizing traditional postsecondary education.¹⁰⁹ Some specialized jobs within the water workforce—including architects, environmental engineers, and computer systems managers—typically require a postsecondary degree and earn higher pay.¹¹⁰

8.2.2 Quality of Life

8.2.2.1 Location

Light pollution is a frequent complaint regarding water treatment sites close to communities.¹¹¹ Since the facilities process water continuously, the site must be well-lit at all hours of the day for the safety of its employees, who are walking around and operating large equipment. Newly-designed plants have taken on a variety of innovative features to try and address light pollution concerns. The Newtown Creek plant (seen in Figure 8.3) has used a mixture of blue and white lighting to provide both an artistic and safe amount of light without disturbing residents.¹¹² A LEED-certified wastewater treatment plant located in Dryden, Ontario optimized their design to use the lowest possible light levels whilst still

¹⁰³ Bureau of Labor Statistics (October 4, 2022) <u>Water and Wastewater Treatment Plant</u>. [12]

¹⁰⁴ Kane, Tomer (2018) <u>Renewing the water workforce</u>. p. 21. [50]

¹⁰⁵ Kane, Tomer (2018) <u>Renewing the water workforce</u>. p. 19-20. [50]

¹⁰⁶ City of Bakersfield (no date) <u>Wastewater Treatment Plants</u>. [18]

¹⁰⁷ AWWA (no date) <u>Water Operator Certification Explained</u>. p. 13. [2]

¹⁰⁸ AWWA (no date) <u>Water Operator Certification Explained</u>. p. 13-14. [2]

¹⁰⁹ Kane, Tomer (2018) <u>Renewing the water workforce</u>. p. 22. [50]

¹¹⁰ Kane, Tomer (2018) <u>Renewing the water workforce</u>. p. 20. [50]

¹¹¹ ACE (2005) <u>Washington Aqueduct: Environmental Impact Statement</u>. p. 5-13. [4]

¹¹² L'Observatoire International (no date) <u>Newtown Creek</u>. [53]

meeting security requirements.¹¹³ Another facility in Adelaide, Australia is using infrared lighting to monitor all the external features and security gates of their water plant, so only the inside of buildings require visible lighting for operation.¹¹⁴ Although light pollution is a serious concern, there are innovative options available to protect worker safety and reduce light pollution for any nearby residents.

Noise complaints are another frequent issue with locating water treatment plants close to residential areas.¹¹⁵ Given the fans, motors, pumps, and compressors needed to run the plant, noise can build up.¹¹⁶ The most common problem is not just an increase in ambient noise, but different parts of equipment that produce unique but similar tones, creating a 'pulsating' effect for human ears that can be perceived as doubling the sound coming from the plant.¹¹⁷ Designing the plant to accommodate for noise can resolve most of these problems. Construction plans should locate large equipment away from residential areas, minimize the potential openings in the building for sound to escape, and include necessary sound-dampening materials like acoustical louvers and HVAC duct silencers.¹¹⁸ Recent software developments, namely variable frequency drives (VFD), can adjust the speed of rotation for devices based upon the required load, which can dramatically lower the sound pressure generated.¹¹⁹

If the water being processed involves any raw sewage, as is true of most wastewater plants, odor becomes another concern for the plant. Depending on the chemicals and processes used to cope with biological waste, the resulting biosolids may also release a noticeable smell, typically due to "ammonia, amines, and reduced sulfur-containing compounds" present in the biosolids.¹²⁰ Odors can be mitigated with intentional design. At the Dryden plant (Figure 8.4), a fan is placed over the influent flow entrance to draw off air into a set of biofilters and charcoal, leaving most of the facility odor-free to house offices and other space for workers.¹²¹

8.2.2.2 Multi-use potential

Multi-use projects with water treatment plants are rare, likely due to their size and high potential for noise pollution. Although plants like the Newtown Creek treatment facility have been designed with unique tanks, lighting, and glass walkways to draw visual interest

¹¹³ Lund (September 2017) <u>Plant Earns LEED Recognition</u>. [55]

¹¹⁴ Raytec (July 14, 2014) <u>RAYMAX IR Protects Australian Water Plant</u>. [63]

¹¹⁵ Goodfriend, Bontomase (June 1, 2007) <u>Can Water Treatment Plants be Quiet?</u> [40]

¹¹⁶ Goodfriend, Bontomase (June 1, 2007) <u>Can Water Treatment Plants be Quiet?</u> [40]

¹¹⁷ Goodfriend, Bontomase (June 1, 2007) <u>Can Water Treatment Plants be Quiet?</u> [40]

¹¹⁸ Goodfriend, Bontomase (June 1, 2007) <u>Can Water Treatment Plants be Quiet?</u> [40]

¹¹⁹ Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]

¹²⁰ EPA (no date) <u>Basic Information about Biosolids</u>. [28]

¹²¹ Lund (September 2017) <u>Plant Earns LEED Recognition</u>. [55]

from passersby, akin to an art exhibit, these designs are uncommon and do not involve any nontraditional users on the actual site.

There are some unique water treatment facilities that have evolved for multi-use purposes. The R.C. Harris Water Treatment Plant in Toronto, Ontario processes about 30% of the city's drinking water, but also is a notable Art Deco building with public access to the grounds and has served as a frequent filming location for TV and movies.¹²² The plant used to be fully open for public access until security concerns arose in the early 2000s, but still allows some public access for special events.¹²³ Similarly, water treatment plants in China and the United States have managed to incorporate both indoor and outdoor botanical gardens for public enjoyment.^{124,125}

8.3 Environmental Impacts

8.3.1 Water requirements

8.3.1.1 Minimum volume requirements

For graywater and wastewater treatment plants, the volume of influent and effluent hardly differs. By weight, wastewater is 99.9% water, with only the remaining 0.1% of organic and inorganic compounds, as well as microorganisms, being removed by the filtration process.¹²⁶ Thus the yield of water that will be released as effluent is quite high. There is no minimum volume requirement to operate a water treatment plant, though efficiency varies—both in terms of maximizing water reuse and equipment lifetime—if the plant is processing much more or much less water than it was designed to handle.¹²⁷

For desalination specifically, the technology used to remove salts from seawater will determine the minimum volume requirements necessary. Using reverse osmosis (RO), approximately half of the initial volume of water run through the process can be desalinated—the remainder is returned to the water source.¹²⁸ This is considered a relatively good yield for desalination processes.

The salient question for volume requirements—what will the average daily water needs of the carbon management park look like—is also the most difficult to answer, as different technologies exhibit a vast range of water consumption patterns. For biomass-based

¹²² City of Toronto (no date) <u>Fast Facts about the City's Water Treatment Plants</u>. [19]

¹²³ Mok (no date) <u>The historic R.C. Harris Water Treatment Plant</u>. [56]

¹²⁴ Engineering News-Record (September 25, 2019) <u>Wusong Wastewater Plant Upgrade - Botanical</u> <u>Garden</u>. [27]

¹²⁵ Smith (June 2019) <u>Landscape With a Purpose</u>. [69]

¹²⁶ Buchanan, J. R. (no date) <u>Wastewater Basics 101</u>. [11]

 ¹²⁷ Tchobanoglous, G. *et al.* (2021) <u>Rationale for constant flow to optimize wastewater treatment</u>. p.
1238-1239. [72]

¹²⁸ Beswick *et al.* (2021) <u>Does the Green Hydrogen Economy Have a Water Problem?</u> p. 3168. [8]

processes (BiCRS and BECCS), facilities can typically run close to neutral on water use. Some processes are even net-positive on water and can generate water as a reaction byproduct at a quality suitable for agricultural use.¹²⁹ Other technologies, like hydrogen production via electrolysis, require water to generate any output. 9 kg of water must be used to generate a single kg of hydrogen fuel (Section 6), with some companies reporting that in the field, the best estimate is 12 kg per kg of hydrogen produced due to water vapor loss.^{130, 131}

8.3.1.2 Minimum quality requirements

Water quality needs are dependent on the intended use of the treated water. For agricultural uses or industrial cooling needs, water can typically be less filtered than would be necessary for drinking water. To use water in chemical processes like electrolysis, the water must meet high standards of purity (i.e. be distilled and/or deionized) to preserve the efficiency and lifetime of the equipment.¹³² Membrane-based electrolyzers require water to be of type II purity, though operate better with water of type I purity, which is even more filtered.¹³³

8.3.3 Other potential impacts

Redirecting water use in any way may impact existing usage covenants, or harm the wellbeing of local communities, farms, or wildlife. Given the exceptional drought conditions in Kern County discussed in Section 8.1.4, directing already-purified water for industrial use from existing sources that are already stretched for existing and new housing would be difficult.

In terms of environmental impact, generating more usable water for the park from otherwise undesirable sources, including graywater, stormwater, seawater, or wastewater, can be construed as a net positive. If a water treatment facility can purify otherwise unusable water to be clean enough for industrial, agricultural, or residential uses, and in excess of the quantities needed by members of the carbon management park, this water can help alleviate shortages in the county's current supplies. Excess purified water could be traded through California's water markets to help keep agricultural producers in business during dry years. It could even be stored in the area's underground aquifers to replenish the over-drained supply and prevent continued land subsidence in the southern San Joaquin Valley. Further, excess energy generation from other industries (such as electricity from oxyfuel combustion of biomass, or waste heat from BiCRS or steel

¹²⁹ San Joaquin Renewables (no date) <u>The Project</u>. [67]

¹³⁰ Beswick *et al.* (2021) <u>Does the Green Hydrogen Economy Have a Water Problem?</u> p. 3167. [8]

¹³¹ Valdez (August 11, 2022) <u>Electrolyzers and Water</u>. [80]

¹³² Spiegel (October 18, 2022) <u>Introduction to Electrolyzers</u>. [70]

Note: this information derives from a response provided in the comment section by the Fuel Cell Store account.

¹³³ Jonsson, Mässgård (2021) <u>An Industrial Perspective on Ultrapure Water Production</u>. p. 17. [49]

industries) could be used as a cost-effective and carbon-free energy source for treating alternative waters for regional use.

8.4 Economic Impacts

8.4.1 Business Model

The profitability of water is a complex question due to the array of existing regulations and allocations involved and the unusually low price of water.¹³⁴ Low tariffs on water use are intended to protect economically vulnerable residential consumers, but also effectively undercharge all users—including those in industry and agriculture—for their current water use.¹³⁵ This system means that despite scarcity, water is generally undervalued, and thus rarely conserved or reused.¹³⁶ At the macro scale, investing in large facilities for generating more clean water from less pure sources is seen as an expensive and unnecessary investment when water access is currently cheap in monetary terms. However, as scarcity increases, there is a "huge opportunity" to adopt reuse and recycling practices for industrial water that will mitigate risks associated with climate change as the American West becomes more arid.¹³⁷

Because of the high costs associated with these projects, the federal government offers a range of funds, loan guarantees, and grant programs that can provide funding for projects aiming to increase water reuse, reclamation, and efficiency.¹³⁸ Most programs emphasize community or local government leadership, and may be ineffective options for an industrial park—more research would be needed to determine the viability of pursuing federal water reuse funding for a specific project. Likely, policy intervention or necessity due to scarcity will be the levers that encourage more widespread adoption of water conservation, reuse, and desalination within California.¹³⁹

Finally, under California law, water is a public resource, although its use can be subject to private rights.¹⁴⁰ Presumably, the revenue potential of a water treatment facility within a carbon management industrial park would depend on how projects were permitted and funded. If the County itself owned a water treatment plant, it could presumably sell the water (within the park or outside of it) or store it in aquifers. It is less clear whether there is a profitable model for a privately owned and operated water treatment plant. California does operate a water market where a purifier could recuperate costs by selling water,

¹³⁴ Climate Now (November 16, 2021) <u>Water Strategy</u>. 9:25-9:55. [21]

¹³⁵ Climate Now (November 16, 2021) <u>Water Strategy</u>. 11:07-11:58. [21]

¹³⁶ Climate Now (November 16, 2021) <u>Water Strategy</u>. 11:07-11:58. [21]

¹³⁷ Climate Now (2022) Solve the Global Water Crisis? 4:42-6:10. [20]

¹³⁸ EPA (no date) <u>Water Reuse Infrastructure Funding Programs</u>. [32]

¹³⁹ James (August 11, 2022) <u>California expected to lose 10% of its water within 20 years</u>. [48]

¹⁴⁰ Green (no date) <u>A Primer on California's Water Issues</u>. [42]
though most of the water traded in California originates from surface sources.¹⁴¹ 46% of all water traded in California is done between buyers and sellers in the same county.¹⁴² In the last decade, farmers in the San Joaquin Valley and cities have been the largest buyers in the water trading market, so it is likely that there would be substantial interest in Kern County around purchasing any water generated from industrial park activity or from treatment of alternative waters, not to mention the potential of selling to industrial players within the park to support their operations.¹⁴³

8.4.2 Business Costs

Capital and operational costs for water treatment can be difficult to ascertain. First, there is currently no federal or non-federal standard for what factors should be included or excluded when reporting estimated capital or operating expenses.¹⁴⁴ Furthermore, both the capital and operational costs are dependent upon changeable factors; for example, for capital costs, this includes the volume and quality of the influent water and for operating costs, this includes the costs of labor and electricity.

8.4.2.1 Cost to build (upfront costs)

Costs to build a facility depend upon its capacity (usually measured in gallons per day, hereafter GPD) and purity of the influent. Wastewater treatment centers capable of processing 150,000 GPD for industrial use typically cost \$500,000 to \$1.5 million upfront.¹⁴⁵ For reference, 150,000 GPD is equivalent to 168 acre-feet of water treated per year, and water-intensive carbon management facilities investigated in this report could require up to 16,200 acre-feet per million tons of CO₂ captured (Figure 8.4).

Depending on the other technologies needed to filter and process the water and the level of purity required for the effluent, costs can grow significantly—up to many millions in additional upfront costs. Reverse osmosis (RO), a desalination process, and ion exchange (IX), which can remove minerals and ions to generate deionized water for chemical processes like electrolysis,¹⁴⁶ both would add an estimated capital cost of under \$5 million for smaller GPD systems.¹⁴⁷ Complete distillation and purification via zero liquid discharge (ZLD)—essentially, a water treatment plant that does not release water with any solid or liquid contaminants into the natural environment, like streams or groundwater, instead

¹⁴¹ Hanak et al. (2021) California's Water Market. p. 1. [45]

¹⁴² Hanak *et al.* (2021) <u>California's Water Market</u>. p. 1. [45]

¹⁴³ Hanak *et al.* (2021) <u>California's Water Market</u>. p. 2. [45]

¹⁴⁴ Dundorf et al. (2017) <u>Quantifying the Cost of Water Treatment</u>. [25]

¹⁴⁵ SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]

¹⁴⁶ Atlas Scientific (October 31, 2022) <u>Ion Exchange in Water Treatment</u>. [5]

¹⁴⁷ SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]

recycling the water routinely on-site¹⁴⁸—would be considerably more expensive, running up to \$10 million for systems capable of handling GPD in the thousands.¹⁴⁹

8.4.2.2 Operational costs

Operational costs for water treatment vary considerably based upon influent quality,¹⁵⁰ and are dependent upon material costs, electricity costs, labor costs, and costs from third-party services.¹⁵¹

Treating graywater and other wastewater is less cost-intensive than treating seawater or other brackish water via desalination. To generate the same quantity of usable water, the costs of operation for desalination are typically two to four times higher than for wastewater treatment.¹⁵² In a study of treatments to recycle irrigation water for greenhouses, researchers found that the costs ranged from \$0.07 to \$1.00 to treat 1,000 gallons of water, depending on the treatment method,¹⁵³ equating to between \$38,325 and \$547,500 per year for a 150,000 GPD facility. That's over a tenfold increase between the lowest and highest cost treatment option, and irrigation water generally has less impurities requiring treatment compared to wastewater or seawater, suggesting operational costs would be higher for a wastewater treatment facility or desalination plant.

8.4.3 Regional benefits

With population increases and a decades-long cycle of droughts afflicting the American West, innovative projects to generate more usable water should be drawn to locations like Kern County, with its abundance of open land to locate a facility and steady mix of agricultural, industrial, and residential water consumers.

8.4.3.1 Proximate feedstocks

Within Kern County, the largest water users are in the agricultural sector.¹⁵⁴ Agriculture produces substantial runoff of graywater, as up to half of the water used in crop irrigation evaporates or becomes runoff.¹⁵⁵ If captured and reused, this graywater would constitute an existing and accessible source of water for the carbon management park.

The western edge of Kern County is located less than 100 miles from the Pacific coastline, making it a potential site for desalination projects. A desalination facility could also be

¹⁴⁸ Saltworks (January 15, 2018) <u>What is Zero Liquid Discharge & Why is it Important?</u> [65]

¹⁴⁹ SAMCO (October 12, 2017) <u>Industrial Water Treatment System Cost?</u> [66]

¹⁵⁰ Frankel (November 10, 2021) <u>Wastewater Treatment System Cost?</u> [37]

¹⁵¹ Bluefield Research (October 9, 2018) <u>Operating Expenditures</u>. [10]

¹⁵² Climate Now (April 19, 2022) <u>Solve the Global Water Crisis?</u> 6:30-6:42. [20]

¹⁵³ Raudales *et al.* (2017) <u>How much does it cost to sanitize your water?</u> [62]

¹⁵⁴ WAKC (no date) <u>Water in Kern County</u>. [82]

¹⁵⁵ Balsom (September 28, 2020) <u>Water Usage In The Agricultural Industry</u>. [7]

located on the coast and utilize pipelines or canals to transport water into Kern County for industrial or agricultural uses.

8.4.3.2 Proximate consumers

In addition to potential users within a carbon management industrial park, treated water could be utilized by residents as drinking water or for agricultural use, depending on the quality of water available and the amount produced in excess of the carbon management park's needs. For water that is not purified to drinking water standards, underground storage to replenish regional aquifers would be an option. As groundwater, the water would be purified further within the aquifers, making it usable to consumers above the surface in the future.¹⁵⁶

8.4.3.3 Co-location advantages

Kern's existing supply of clean energy from wind and solar—amounting to over half of California's total renewable energy supply—may be appealing for water treatment plants, which are energy-intensive operations.¹⁵⁷ Similarly, depending on the energy and heating needs of a facility, locating on-site in the carbon management park may be a good way to reuse heat or energy that would otherwise be lost from other processes, like converting biomass or steel production.

¹⁵⁶ Balke, Zhu (2008) <u>Natural water purification and water management by artificial groundwater</u> recharge. [6]

¹⁵⁷ Oviatt (July 15, 2022) <u>Why is California punishing our alternative energy leader?</u> [59]

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9. Carbon Dioxide Transport

TECHNOLOGY AT A GLANCE

- Industry is well established: CO₂ pipelines have been in operation in the U.S. for more than 50 years.¹
- Pipelines are typically the most cost-effective option for overland transport of CO₂. Average levelized cost for pipeline transport is \$10-20 per metric ton CO₂, but values can be higher or lower depending on length of pipeline, pipeline capacity, and siting logistics (terrain, securing rights-of-way, urbanization, etc.).
- CO₂ pipelines are typically constructed ~3 feet below the surface, so they do not create a visual or sound impact at the surface, and can co-locate with other land uses.
- Key advantages of this technology in Kern County: Would provide a cost-effective solution for transporting CO₂ between producer(s) in the region and sites that are permitted for injecting CO₂ underground for the purpose of permanent geologic storage.
- Key concerns for this technology in Kern County: Safety hazards related to leaks or ruptures of pipelines are exceedingly rare, but if a large rupture occurs, CO₂ can pose a health risk in the immediate vicinity. Siting pipelines in remote areas and following all federal and state regulations regarding monitoring and emergency response protocols in event of a leak are critical. Additionally, regulatory

¹ Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

frameworks for construction of CO_2 pipelines in California are not yet well-established.

9.1 Technology Summary

Between any potential carbon dioxide source or production and sequestration, safe transport is required. Pipelines, rail cars, trucks, and ships are all available forms of transport for carbon dioxide. In most cases, pipelines are the most cost-efficient choice,² especially for moving long or routine distances over land. These pipelines compress the carbon dioxide into a single phase (it can be gaseous, liquid, dense-phase or supercritical, depending on pipeline specifications) and then maintain controlled temperature and pressure conditions to safely deliver the carbon dioxide to its end use.³ For the carbon management industrial park being examined here, that end use would be permanent geologic storage, taking place deep underground in nearby sequestration sites that have been appropriately permitted for such use, with the possible exception of some CO₂ utilized by other co-located industries (see Section 10).

9.1.1 Description: How It Works

Pipelines are the standard transportation choice for moving large volumes of carbon dioxide for extended distances (on the order of hundreds to thousands of miles) along overland routes,⁴ especially when the sources and sinks are located at fixed points, as they are intended to be for proposed projects in Kern County. CO₂ pipelines are made from externally coated steel line pipe⁵ and operate at high pressures to transport carbon dioxide between sources and sequestration sites.⁶ There is also an external cathodic protection applied to prevent corrosion on the outside of the pipe.⁷

Because impure CO₂ streams (containing traces of NO_x, SO_x, O₂ or H₂O) can have corrosive effects on alloys and polymers,⁸ non-steel or composite metal pipelines are not permissible to transport carbon dioxide under California law without an exemption approved by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).⁹ Pipelines are more complex than a single steel tube, though. They have a range of parts, including "valves, compressors, booster pumps, pig launchers and receivers, batching stations and instrumentation, metering stations, and Supervisory Control and Data Acquisition (SCADA)

² Roussanaly *et al.* (2021) <u>Comparison of CO₂ shipping options</u>. p. 20-22. [31]

³ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 5-6. [19]

⁴ Roussanaly *et al.* (2021) <u>Comparison of CO₂ shipping options</u>. p. 20-22. [31]

⁵ EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]

⁶ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 7. [19]

⁷ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 4. [7]

⁸ Paul *et al.* (2012) <u>Selection of materials for high pressure CO2 transport</u>. [23]

⁹ PSD (June 8, 2022) <u>Carbon Dioxide Pipeline FAOs</u>. [28]

systems."¹⁰ The number and complexity of these constituent parts is dependent on the pipeline's length, topography of the pipeline route, the need to adjust for pressure along-route pressure variability, and safety monitoring requirements.

Before pipeline transport, carbon dioxide must be dehydrated and not surpass certain oxygen or hydrogen sulfide (H₂S) concentrations to avoid internal corrosion of the pipeline or constituent parts, or cause stress cracking in the steel.¹¹ When necessary, there are coatings designed for the inside of pipelines in addition to the standard external coating.¹² Theoretically, corrosion-resistant pipeline could be designed that allowed for the transportation of carbon dioxide with higher concentrations of water or H₂S present.¹³ However, given the high risks of H₂S to human health if a pipeline were to rupture or leak, purifying the carbon dioxide prior to transport is likely to remain a necessity.¹⁴



Figure 9.1. Installation of the Cortez Pipeline, a 30" diameter carbon dioxide pipeline located in New Mexico, during a maintenance upgrade conducted and documented by STATS Group. Image credit: <u>STATS Group</u>.

Finally, carbon dioxide needs to be condensed prior to transport, which requires specialized compressors.¹⁵ Although similar compressors have been utilized in the natural gas industry, the unique properties of carbon dioxide require some design, material and sizing modifications.¹⁶ Once compressed, carbon dioxide can be transported as a gas, liquid,

¹⁰ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 46. [12]

¹¹ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 4. [7]

¹² Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 46. [12]

¹³ Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 181. [6]

¹⁴ Pipeline Safety Trust (2022) <u>CO₂ Pipelines</u>. p. 4. [29]

¹⁵ EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

¹⁶ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 3. [7]

solid, dense phase substance, or supercritical fluid (Figure 9.2), depending on the pipeline length, requirements, and location.¹⁷ The most common pipelines constructed in the United States are intended for liquid or dense phase carbon dioxide transport, with liquid being more common near population centers and dense phase more common in sparsely populated regions.¹⁸ Although it can be transported in a variety of physical states, for a given pipeline, operators need to keep the carbon dioxide in the same state for all steps of transportation, as two-phase flows can interfere with compressors or other key equipment, increasing the odds of pipeline failure.¹⁹ Optimizing CO₂ pipeline transport relies upon reducing impurities and controlling temperature and pressure to avoid unexpected pressure drops.²⁰ Since carbon dioxide exhibits nonlinear patterns of compressibility and density, pipeline operators typically develop point-by-point estimations of fluid properties along the pipeline's length using computational modeling.²¹



Figure 9.2. CO_2 is a gas at standard surface temperatures and pressures. When transported for permanent underground storage via pipeline, pipeline pressure and temperature is controlled to keep CO_2 in a denser phase. Dense phase liquids and supercritical fluids demonstrate properties of both a fluid and a gas - they can flow easily like a gas, but their high density allows for high flow capacity. Adapted from Paul et al. (2012).²²

Commercial carbon dioxide pipelines, in which CO₂ is in a dense liquid phase or supercritical fluid phase for the entire journey, typically operate at pressures between 1,200 pounds per square inch gauge (psig) and 2,200 psig (83-152 bar), though some pipelines have higher maximum pressures in the 2,500 to 2,800 psig (172-193 bar) range.²³ These higher pressures allow the operator to minimize costs by increasing flow capacity for the

¹⁷ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 5. [19]

¹⁸ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 6. [19]

¹⁹ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 44. [12]

^{*}For reference, a *two-phase flow* occurs when the carbon dioxide in the pipeline exists at two physical states simultaneously (ex. liquid and gas).

²⁰ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 5. [19]

²¹ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 45. [12]

²² Paul *et al.* (2012) <u>Selection of materials for high pressure CO2 transport</u>. [23]

²³ EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

pipeline.²⁴ To ensure that the CO₂ remains in a dense phase state along the entire pipeline length, pumps are used to recover any pressure losses that can occur due to friction of elevation changes.²⁵ The allowable temperature range for the pipeline will differ between projects, with the minimum set based upon the winter ground temperature and the maximum set by the compressor-station output temperature and any temperature limits imposed by the pipeline coating composition.²⁶ A standard temperature range for carbon dioxide pipeline operation falls between 55 and 110°F.²⁷

Pressure and temperature are not the only factors which impact carbon dioxide behavior. For example, the fluid flow rate responds to changes in pipeline diameter—for larger pipeline diameters, the fluid flow rate decreases, which should result in fewer pressure drops within the pipeline.²⁸ Extensive modeling is required to determine the most efficient and cost-effective balance of pipeline size, number of compressors, and route design.²⁹

In general, CO₂ pipelines will need to be purpose-built to handle carbon dioxide, especially when intended for transporting large quantities of carbon dioxide or covering long distances. Pipelines designed to transport natural gas, for example, are in a different class according to the American National Standards Institute (ANSI)—they are not built to the same maximum pressure rating necessary for transporting carbon dioxide.³⁰ Some pipelines built for other energy purposes have been retooled to transport carbon dioxide at lower flow rates and/or for distances shorter than 100 miles.³¹ Federal requirements for pipeline construction are set by PHMSA and are covered at greater length in Section 9.1.4.

9.1.2 State of Development

Carbon dioxide pipelines already constitute a small but growing industry. The United States is a global leader in the area, having established some of the first carbon pipelines in the 1970s.³² As of 2015, the U.S. had over 4,400 miles of active carbon dioxide pipelines, with that figure growing every year.³³

The vast majority of carbon dioxide pipeline projects support enhanced oil recovery (EOR) in Texas and the American West; the number currently deployed for sequestration is

²⁴ EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

²⁵ EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

²⁶ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 44. [12]

²⁷ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 44. [12]

²⁸ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 45. [12]

²⁹ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 45. [12]

³⁰ EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]

³¹ EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]

³² Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 182. [6]

³³ Peletiri *et a*l. (2018) <u>CO₂ Pipeline Design</u>. p. 3. [24]

^{*} This figure has been converted to miles; in Peletiri et al., this figure is given as 7200 kilometers.

smaller.³⁴ However, because the technical and regulatory requirements for safely and efficiently moving carbon dioxide are the same regardless of end use, pipelines developed for EOR can be used as a case study for new pipeline systems being constructed for permanent CO₂ sequestration.

9.1.2.1 Example projects

Pipeline companies: Kinder Morgan, Houston, TX and Trimeric, Buda, TX

Installation of pipelines are typically performed by third parties, rather than carbon management companies, sequestration companies, or even pipeline operators.³⁵ Kinder Morgan is the largest transporter of carbon dioxide in North America, although they also operate many of their pipeline systems. They have capacity to transport as much as 1.5 billion cubic feet (>77,000 metric tons) of CO₂ daily.³⁶ Although their operations are mostly sourcing CO₂ from natural source fields and delivering it to oil and gas operations for the purpose of enhanced oil recovery, the logistics of pipeline transport are the same for CO₂ sourced from capture industries and transported for the purpose of injection and permanent storage. Kinder Morgan's largest pipeline is 500 miles long and spans from Colorado to Texas.

Trimeric is another example of a third party company that could support pipeline development. They design CO₂ purification and compression facilities, and their company has served as technical experts and design engineers on a wide range of research programs supported by the U.S. Department of Energy, and for carbon dioxide pipeline projects in the United States.³⁷ Their process engineers have worked on all stages of the CO₂ transportation and storage process, including dehydration, cooling, pumping, liquefaction, compression, purification, and sequestration pumping.³⁸

South West Hub Project, Western Australia

The South West Hub project, which broke ground in 2012, is designed to connect point source carbon emissions in industrial centers south of Perth to sequestration sites underneath the Lesueur sandstone formation in saline aquifers.³⁹ Publicly available video and conference papers largely emphasize the research conducted on validating Lesueur's feasibility as a sequestration site—the pipeline infrastructure needed for the project is less emphasized.⁴⁰ However, its overall model matches well with Kern's potential projects, where a number of known carbon producing or capturing sites within a carbon

³⁴ Jones, Lawson (2022) <u>Carbon Capture and Sequestration (CCS) in the United States</u>. p. 8. [16]

³⁵ George Peridas (LLNL) personal communication, July 6, 2022.

³⁶ Kinder Morgan (no date) <u>CO₂ operations overview</u>. [18]

³⁷ Trimeric (no date) <u>CO₂ Capabilities</u>. [38]

³⁸ Trimeric (no date) <u>CO₂ Capabilities</u>. [38]

³⁹ Sharma, Van Gent (2018) <u>The Australian South West Hub Project</u>. p. 2. [32]

⁴⁰ Sharma, Van Gent (2018) <u>The Australian South West Hub Project</u>. p. 12-14. [32]

management park will be directly connected with a sequestration site using the same pipeline infrastructure.

The South West Hub also presents an interesting form of management, as the project originated as a collaboration between the Western Australia Department of Mines, Industry Regulation and Safety, acting as the project lead, and industrial producers in the energy and chemicals space.⁴¹ This project may be valuable as a type example for private-public partnership in carbon management projects.

9.1.3 Operational Needs

9.1.3.1 Land use requirement

Most carbon dioxide pipelines are relatively small, ranging from 12-28 inches in diameter,⁴² and operate similarly to pipelines used for decades in the oil and natural gas industries, though they often operate at higher pressures.⁴³ On land, pipelines are typically buried 3 to 4 feet beneath ground level—thus at surface level, the physical footprint of the pipeline is invisible, except at metering or pumping stations.⁴⁴

The siting of a pipeline is determined by state authorities; federal authorities are only implicated if a project crosses federal lands, uses federal funding, or if a project sought federal intervention to grant eminent domain.⁴⁵ Pipeline operators who operate as public utilities or common carriers may have greater flexibility over their siting options, as state and federal authorities can grant the powers of eminent domain to these projects to acquire land,⁴⁶ and because of existing rights-of-way utilities possess for other pipeline systems, like natural gas.⁴⁷ In lengthy pipeline projects, it is near impossible to site a project without exercising eminent domain.⁴⁸

9.1.3.2 Energy requirements

Condensing the carbon dioxide gas into a dense state for transport requires a large energy input to reach appropriate pressurization, ranging from 90-120 kWh per metric ton of CO_2 ,⁴⁹ about the same amount of energy needed to power a home for 3-4 days.⁵⁰ CO₂ compressors can be fueled by "electricity, natural gas or diesel engines, steam, or a combination of

⁴¹ Department of Mines, Industry Regulation, and Safety (no date) <u>South West Hub Project</u>. [5]

⁴² Molag, Dam (2011) <u>Modelling accidental CO₂ pipeline release</u>. p. 2301. [21]

⁴³ EEIA (no date) Key Excerpts on CO2 Transport. p. 3-4. [7]

⁴⁴ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 46. [12]

⁴⁵ DOE (2017) <u>Siting and Regulating Carbon Capture</u>. p. 31. [4]

⁴⁶ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 49. [12]

⁴⁷ Industry representative, personal communication, February 10, 2023.

⁴⁸ Fish, Martin (2010) <u>California Carbon Capture and Storage Review Panel</u>. p. 2. [11]

⁴⁹ Jackson, Brodal (2018) <u>A comparison of the energy consumption for CO₂ compression process</u> <u>alternatives</u>. p. 1. [15]

⁵⁰ EIA (October 12, 2022) <u>How much electricity does an American home use?</u> [8]

these,"⁵¹ and could be the responsibility of either the pipeline operator or the capturing industry. For industries like DAC and steel, compression represents between 25% and <1% of the energy needs for CO_2 capture.⁵²

Maintaining constant pressure and flow specifications along the length of the pipeline also requires energy input (using compression or pumps), although it is a small fraction of the energy needed for compression, and can be minimized through intentional route designs that take advantage of gravity to maintain flow through the pipeline.^{53,54} Choosing between compressors or pumps to maintain constant pressure conditions within the pipeline depends on the intended physical state for transport—compressors are needed for gas, whereas pumps can be used for liquid or dense phase carbon dioxide.^{55,56} Given the park's goal of carbon management, using low-carbon energy sources to power initial CO₂ compression and any additional pumps or compressors along the length of the pipeline should be a priority.

9.1.3.3 Other operational needs

Waste disposal requirements

There should be no waste disposal requirements for regular operation and maintenance of CO_2 pipelines, unless the pipeline or monitoring equipment requires replacement. Then, the old equipment would need to be disposed of or recycled accordingly.

The carbon dioxide itself often needs to be dehydrated and treated to reach a certain purity percentage (generally 95%) for efficient and safe transport, so preparing CO₂ for transport will likely produce some byproducts to dispose or reuse, like water and hydrogen sulfide (H₂S).⁵⁷ It is important to remove water from CO₂ streams because it can react with carbon dioxide to form carbonic acid (H₂CO₃) in the pipeline, which can cause corrosion. Similarly, hydrogen sulfide can interact with any remaining water to form sulfuric acid, another corrosive compound. Additionally, because H₂S is toxic to humans at any concentration exceeding 200 parts per million (ppm), for the safety of any communities located near a CO₂ pipeline, both water and H₂S should be restricted to reduce the likelihood and resulting risk of a pipeline rupture.⁵⁸ Water could be filtered and reused onsite in the industrial park (see Section 8). The most common disposal method for hydrogen sulfide is injection into deep geologic storage, as surface storage of sulfur generally constitutes a liability for the

⁵¹ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 3. [7]

⁵² Appendix D

⁵³ Suter *et al.* (2022) <u>Carbon Capture, Transport, & Storage</u>. p. 21. [35]

⁵⁴ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 3. [7]

⁵⁵ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 6. [19]

⁵⁶ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 5. [19]

⁵⁷ Pipeline Safety Trust (2022) <u>CO₂ Pipelines</u>. p. 4. [29]

⁵⁸ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 43. [12]

producer.⁵⁹ However, this purification process would likely be the responsibility of a different party—i.e. the company capturing or generating carbon dioxide within the carbon management park—rather than the pipeline operator, and for many types of CO₂ capture explored in this report (BiCRS, DAC, oxy-fuel combustion), H₂S is not known to be a significant contaminant.

Warehousing requirements

There are no inherent warehousing requirements for transporting carbon dioxide, but the value of housing some carbon outside of the pipeline to maintain a constant supply, and therefore pressure, is likely advantageous.

9.2 Societal Impacts

9.2.1 Job creation potential

9.2.1.1 Number and types of jobs

Monitoring and upkeep of a local pipeline network will likely create between 8-20 highwage permanent jobs.⁶⁰ CCS initiatives are also projected to generate indirect employment, as new pipeline manufacturing projects and administrative staff will be necessary in addition to jobs created on-site.⁶¹ These indirect jobs may not be locally concentrated, however.

9.2.1.2 Training pipelines

Jobs in CO₂ transport require a mix of skill levels but overlap considerably with skills in other pipeline management or engineering jobs (like those in the oil and gas industry) and other heavy industries.⁶²

9.2.2 Quality of Life

9.2.2.1 Location

Unlike transport via rail, truck, or ship, there is no noise or light pollution from a pipeline that would disturb nearby communities. Additionally, because CO₂ pipelines are buried, they produce no significant visual disturbances to the landscape. The primary issue relevant to locational justice is both the real and perceived risks of a pipeline leak or rupture.

⁵⁹ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 43. [12]

⁶⁰ Carbon Capture Coalition (no date) <u>Jobs and Project Development Status</u>. p. 4. [3]

⁶¹ Townsend *et al.* (2020) <u>Thought Leadership</u>. p. 15. [37]

⁶² Carbon Capture Coalition (no date) <u>Jobs and Project Development Status</u>. p. 4. [3]

We explore this issue here, first in the context of general public's attitudes towards pipeline safety, and then with a focus on the actual risks associated with transporting CO_2 .

Pipelines related to the energy sector have a long history of generating locational justice concerns, primarily for the environmental, health and safety hazards that they can bring. Some key examples from the oil and gas sector where locational justice has become a widespread public concern because of risk to local ecosystems, water resources and safety include the Dakota Access Pipeline,⁶³ Enbridge's Line 3,⁶⁴ and the Coastal GasLink project in Canada.⁶⁵ Given the historically large public debates around these major pipeline projects, the idea of placing any new pipelines in or near a community could drive resistance among local residents and environmental groups, even though piping carbon dioxide has a different purpose, and carries different risks (and safety mitigation measures) than piping oil or natural gas. For example, regional chapters of environmental organizations are already organizing against the construction of new carbon dioxide pipelines in other parts of the country. The lowa chapter of the Sierra Club has been resisting three proposed pipelines primarily because the carbon transported has an unclear end-of-life—there has been varied messaging about whether it will be sequestered or used for EOR.⁶⁶

Addressing the general public's hesitancy or resistance to development of pipeline networks requires open communication and education about the real hazards associated with CO₂ pipelines, how they differ from other types of pipelines, what mitigation strategies ensure low safety risks associated with these kinds of pipeline, and the current and developing regulatory frameworks that are designed to assess and monitor pipeline safety standards.

Safety risks associated with CO₂ pipelines

Unlike natural gas and other fossil fuels, carbon dioxide is not flammable or explosive, and if leaked in small quantities, will dissipate into the air without creating a hazardous situation.⁶⁷ But, in large quantities (over 40,000 ppm, or comprising more than 4% of inhaled air) it acts as an asphyxiant,⁶⁸ and if released quickly from the pressurized conditions of a dense phase or supercritical phase pipeline, can cause flash freezing - producing temperatures immediately around a pipeline rupture that are well below freezing, which can cause brittle failure of the remaining pipeline and exacerbate further

⁶³ Environmental & Energy Law Program (no date) <u>The Dakota Access Pipeline (DAPL)</u>. [9]

⁶⁴ MPR News (October 1, 2021) <u>The Line 3 oil pipeline project: What you need to know</u>. [20]

⁶⁵ Simmons (November 8, 2022) <u>'You will be arrested'</u>. [34]

⁶⁶ Sierra Club Iowa Chapter (no date) <u>Carbon Dioxide Pipelines - Say NO to CO2 pipeline projects</u>.[33]

⁶⁷ Thomley, Kammer (2023) <u>CO₂ pipeline safety</u>. [36]

⁶⁸ FSIS (2020) <u>Carbon dioxide health hazard information sheet</u>. [13]

rupturing.⁶⁹ This means that small leaks present little health or safety risk,⁷⁰ and in fact, over the 50 years that CO_2 pipelines have operated in the U.S. there has been only one reported injury and no deaths related to pipeline operation.^{71,72} A significant pipeline rupture, however, could pose a safety hazard. If a breach were to occur, carbon dioxide could be released into the atmosphere in high concentrations; because CO_2 is more dense than ambient air, rather than dissipating as it is released, it can concentrate in low-lying areas, risking the health of any residents in the area.⁷³

Although leaks are uncommon, a significant event did occur near a population center in 2020. That year, a carbon dioxide pipeline ruptured near Satartia, Mississippi, sending 49 residents to the hospital. Residents reported seeing an eerie green cloud that left them "nauseated and dazed."⁷⁴ Carbon dioxide itself is odorless and colorless—the green shade of the gas reported in Satartia is thought to be due to high amounts of hydrogen sulfide in the supply, which likely worsened the health impacts on residents.⁷⁵ The Satartia rupture is thought to be the first outdoor CO₂ mass exposure event resulting from a pipeline failure globally.⁷⁶ However, as pipeline mileage increases in the future, potential for these types of accidents could grow. The federal Pipeline and Hazardous Materials Safety Administration, or PHMSA (responsible for pipeline safety and monitoring), has responded to the Satartia leak by promising additional regulations for CO₂ pipeline safety, with a focus on emergency preparedness.⁷⁷

Mitigation options for CO₂ pipelines

To reduce public concerns about pipelines in general, other hazardous materials transported via pipeline – like natural gas – are typically odorized, so residents can identify a gas leak and evacuate. In theory, the same practice is possible for carbon dioxide moved through pipelines, although there are currently no requirements in place to odorize carbon dioxide prior to transport for the purpose of public safety.⁷⁸ There are some promising contenders for odorants, like disulfides or thioethers, although they increase pipeline operation costs and dilute the purity of the carbon dioxide stream.⁷⁹

Compared to other types of pipelines, carbon dioxide pipelines are more susceptible to longitudinal running fractures, which can be a brittle or ductile weakness in the pipeline,

⁶⁹ Vree *et al.* (2015) <u>Rapid depressurization of a CO₂ pipeline</u>. [39]

⁷⁰ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 48-49. [12]

⁷¹ Thomley, Kammer (2023) <u>CO₂ pipeline safety</u>. [36]

⁷² Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 182. [6]

⁷³ Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 188. [6]

⁷⁴ Zegart (August 26, 2021) <u>Gassing Satartia</u>. [40]

⁷⁵ Zegart (August 26, 2021) <u>Gassing Satartia</u>. [40]

⁷⁶ Zegart (August 26, 2021) <u>Gassing Satartia</u>. [40]

⁷⁷ PHMSA (May 26, 2022) <u>New Safety Measures</u>. [27]

⁷⁸ Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 190. [6]

⁷⁹ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 48. [12]

causing it to "unzip" several hundred meters.⁸⁰ To mitigate the severity of a potential rupture, propagation of these kinds of fractures can be inhibited with the placement of fracture arrestors along the pipeline. The arrestors are typically placed every 500 meters (545 yards) along the length of the pipeline, minimizing the distance a fracture can spread.^{81,82}

Additionally, a variety of monitoring fixtures, both internal and external, can be used to ensure the pipeline is secure, or provide warning for emergency response if a rupture occurs. Meters can be placed along the pipeline to conduct computational pipeline monitoring (CPM) leak-detection, though this is not yet a regulatory requirement as it can be technically difficult to implement.⁸³ Other types of monitoring – including pressure point analysis or aerial and visual surveys—can also be used to identify potential leaks.⁸⁴

Finally, the most effective safety measure for CO_2 pipelines is siting them far from urban or residential areas. Because CO_2 settles rather than dissipates, any impact from a pipeline leak will occur in the vicinity of the pipeline, although determination of safe distances from pipelines that experience an accidental rupture remains ongoing.⁸⁵

Regulatory authority and monitoring

The Occupational Health and Safety Administration (OSHA) imposes safety regulations that impact carbon dioxide pipeline operators, including workplace safety laws that ban carbon dioxide exposure exceeding 5,000 ppm.⁸⁶ Requirements for pipeline construction and management have also been standardized by PHMSA within the U.S. Department of Transportation,⁸⁷ and operators that fail to meet standards of environmental safety can be issued with notices and fined.⁸⁸

In response to the Satartia pipeline rupture, PHMSA initiated new rulemaking processes to strengthen regulations on carbon dioxide pipeline safety, including updating standards on emergency preparations and response, that may impose new requirements for the safe construction, maintenance, and operation of future pipelines.⁸⁹ As of the writing of this report, PHMSA has not released any new regulations determined from this rulemaking process. Currently, PHMSA regulations only apply to pipelines transporting supercritical carbon dioxide at a minimum of 90% purity. Projects where the carbon dioxide is in a liquid

⁸⁰ Lu *et al.* (2020) <u>Carbon dioxide transport via pipelines</u>. p. 4. [19]

⁸¹ Doctor et al. (2018) <u>Transport of CO₂</u>. p. 184. [6]

⁸² Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 46. [12]

⁸³ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 46. [12]

⁸⁴ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 46. [12]

⁸⁵ Molag, Dam (2011) <u>Modelling accidental CO₂ pipeline release</u>. p. 2301. [21]

⁸⁶ Forbes *et al.* (2008) <u>CCS Guidelines</u>. p. 47. [12]

⁸⁷ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 3. [7]

⁸⁸ PHMSA (May 26, 2022) <u>New Safety Measures</u>. [27]

⁸⁹ PHMSA (May 26, 2022) <u>New Safety Measures</u>. [27]

or gas state, as well as lower-purity pipelines, remain less regulated.⁹⁰ Furthermore, PHMSA's current guidelines do not regulate maximum concentrations of water or hydrogen sulfide contaminants in CO₂,⁹¹ despite their presence making pipelines more susceptible to corrosion and failure, and the added health risk of H₂S if a leak occurs.

In the state of California, the Pipeline Safety Division (PSD) of the Office of State Fire Marshal regulates supercritical and hazardous liquid pipelines (including CO₂ pipelines) following the 49 Code of Federal Regulation (CFR), Part 195 and the Elder California Pipeline Safety of 1981.⁹² However, in 2022, the California state legislature passed law SB-905, stating that no new CO₂ pipelines can be built until the federal government updates its CO₂ pipeline policies with stronger safety regulations, or until state lawmakers can develop their own pipeline standards, based on recommendations from the California Natural Resources Agency (CNRA).⁹³ To this end, CNRA submitted a proposal to the California legislature in March 2023 for establishing a state framework and standards for intrastate CO₂ pipelines, which is now being considered.⁹⁴ Such a framework is critical not only for ensuring the safe handling and transportation of CO₂ for permanent industries.

9.2.2.2 Multi-use potential

Since onshore pipelines are typically beneath the surface once installed, the land surface above a pipeline can still be used for a variety of purposes. Some forms of agriculture that require ample underground space for plant roots may be inappropriate, but myriad other applications should be sustainable on overlapping land, while keeping in mind the advantage of siting CO_2 far from human activity for safety reasons.

9.3 Environmental Impacts

9.3.1 Water requirements

No references were found identifying any water requirements for the operation of CO₂ pipelines. Given the technology, it is unlikely that water is necessary for operation beyond that generally required for construction.

⁹⁰ Pipeline Safety Trust (2022) <u>CO₂ Pipelines</u>. p. 2. [29]

⁹¹ Pipeline Safety Trust (2022) <u>CO₂ Pipelines</u>. p. 5. [29]

⁹² OSFM (no date) <u>Carbon Dioxide Pipeline</u>. [22]

 ⁹³ Phillis, Ronayne (February 23, 2023) <u>Pipeline debate at center of California carbon capture plans</u>.
 [25]

⁹⁴ CNRA (2023) <u>Proposal for CO₂ pipeline state policy framework</u>. [2]

9.3.2 Other potential impacts

California's Central Valley is naturally susceptible to seismic activity, and small earthquakes in the region are common and larger-scale seismic events are possible. This environmental stressor will exacerbate external pressure on any pipelines constructed and will need to be accounted for in construction and operational monitoring plans, as is done for all pipeline systems in the region.

9.4 Economic Impacts

9.4.1 Business Model

Business models for the operation of carbon dioxide pipelines can be flexible from project to project, based upon the operator's structure. For example, the owner or operator of the transport infrastructure could charge either CO_2 suppliers or CO_2 purchasers a tariff for using the pipeline network.⁹⁵ Given the proposed setup of a carbon management park as a putative CO_2 source and a sequestration well operator as a CO_2 "purchaser," both avenues of tariffs seem possible—either charging a tariff to members of the park to sequester their carbon dioxide off-site, or a transport tariff being covered as part of a carbon offset payment or other arrangement where an external company would act as a carbon purchaser.

Under either scheme, the pipeline operator can choose between different tariff calculation models. The two most common options are charging based upon the distance moved, by summing the specific costs per segment of pipeline traveled, or determining a system average cost to charge all users of the network (i.e. a flat rate per ton CO₂).⁹⁶ Based upon the current end-to-end structure of the pipeline that would be built for this project (modeled as a single business park producing CO₂ and supplying it to a single site for sequestration), a system average cost and total distance traveled would likely come out to near-identical tariffs. However, if the carbon management park model proves successful, there could be multiple parks in different locations, sharing a single pipeline system, in which case a preferred tariff model would have to be determined across parties.

The time horizon for profitability of a CO_2 pipeline network will depend upon the tariff rate and the total capital cost—without external incentives, it would likely take a few years before tariffs offset the millions spent on permitting, construction, and monitoring.

⁹⁵ Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. 31. [1]

⁹⁶ Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. 31. [1]

9.4.2 Business Costs

9.4.2.1 Cost to build (upfront costs)

Upfront costs are a substantial hurdle to constructing CO₂ pipelines. In general, costs depend on the terrain, environment, and existing regulations around right-of-way.⁹⁷ Shorter pipelines requiring few bends and avoiding existing features in the built environment constitute the cheapest conditions for pipeline construction,⁹⁸ as does avoiding heavily built areas like cities and suburbs. The Greencore Pipeline in Montana, which spans private ranches as well as state and federal public lands was built for \$68,635 per diameter inch mile; meanwhile, the Webster Pipeline built in the industrial and suburban districts south of Houston, Texas cost \$199,176 per diameter inch mile to construct.⁹⁹ According to a 2018 IPCC report, population density and terrain are the largest determinants of cost: "Onshore pipeline costs may increase by 50 to 100% or more when the pipeline route is congested and heavily populated. Costs also increase in mountains, in nature reserve areas, in areas with obstacles such as rivers and freeways, and in heavily urbanized areas because of accessibility to construction and additional required safety measures."¹⁰⁰ Pipeline right-of-ways can amount to 4%-25% of the overall pipeline construction costs, with estimates at the lower end of this range in rural areas and higher end of this range in suburban or urban areas.¹⁰¹

In 2020, the Great Plains Institute developed a techno-economic analysis of building national CO_2 transport infrastructure to support near- and medium-term carbon capture and storage capacity at a national scale. They modeled how much of a variety of pipelines (distinguished by diameter, and therefore CO_2 flow rate capacity) would be necessary to capture CO_2 from the most economically feasible point sources of carbon dioxide existing today, and determined capital, labor and operation and maintenance costs of pipeline infrastructure as a function of pipe diameter and length. A summary of their analysis is detailed in Table 9.1, for the purpose of illustrating a few key points.

First, reducing the pipeline's length by siting the carbon source (like a carbon management park) and sequestration well projects close together, drastically lowers all costs (capital, labor and maintenance) for the pipeline operator.¹⁰² Second, while smaller pipe diameters do result in lower costs per mile, due to lower material costs, large diameter pipelines are ultimately more cost efficient, as long as they are operating at capacity. The more CO₂ that is transported through the pipeline systems, the lower the effective cost per ton of CO₂.¹⁰³ The calculated costs of CO₂ transport per ton-mile (how much it costs to move one ton of

⁹⁷ Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 189-190. [6]

⁹⁸ Peletiri *et al.* (2018) <u>CO₂ Pipeline Design</u>. p. 4. [24]

⁹⁹ EEIA (no date) <u>Key Excerpts on CO2 Transport</u>. p. 3. [7]

¹⁰⁰ Doctor *et al.* (2018) <u>Transport of CO₂</u>. p. 190. [6]

¹⁰¹ Peletiri *et a*l. (2018) <u>CO₂ Pipeline Design</u>. p. 4. [24]

¹⁰² Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. 23. [1]

¹⁰³ Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. 29. [1]

 CO_2 one mile) is lower than most summative estimates of the levelized cost of CO_2 transport (usually ~ \$10-20 per ton of CO_2 from source to sink, see below), because most point sources of carbon would be unable to provide enough CO_2 for the pipeline to operate at capacity. For example, the calculations in Table 9.1 indicate that a 100 mile, 24" pipeline operating at full capacity would cost \$1 per ton of CO_2 transported. However, that requires that the pipeline is transporting 25 million tons of CO_2 annually. The largest facility capturing CO_2 for the purpose of sequestration (not EOR) in the US today is the Illinois Industrial ethanol plant (operated by Archer Daniels Midland Co.),¹⁰⁴ which is capturing CO_2 at a rate of about 500,000 tons annually.¹⁰⁵ At that rate, it would cost over \$50 per ton of CO_2 to pipe it for 100 miles in a 24" pipeline, and \$15 per ton of CO_2 in an 8" pipeline. Such sensitivity to CO_2 capacity demonstrates the value of developing concentrated sources for large amounts of CO_2 , such as could be achieved by co-locating CO_2 -emitting industries and/or carbon removal industries like DAC or BiCRS/BECCS in a single business park.

Pipe diameter	Segment capacity	Segment length	Capital costs	Labor costs	Annual O&M costs	Cost per Mileª	Cost per tCO₂-mile ^ь
(inches)	(MtCO₂/yr)	(miles)	(million USD)			(million USD)	(US cents)
8″	<5	8,560	\$3,436	\$3,672	\$72.6	\$1.1	1.8 ¢
12″	3-7	5,834	\$4,195	\$2.928	\$49.5	\$1.5	1.6 ¢
16″	6-11	2,675	\$2,888	\$1,777	\$22.7	\$2.0	1.5 ¢
20″	10-16	1,790	\$2,704	\$1,498	\$15.2	\$2.6	1.4 ¢
24″	15-25	59	\$99	\$63	\$0.5	\$3.0	1.0 ¢
30″	24-33	16	\$34	\$23	\$0.1	\$3.8	0.97 ¢

Table 9.1. Capital	and operating	costs of CO ₂	pipelines a	as a function	of pipe diameter an	d
segment length ¹⁰⁶	\$					

a. The sum of capital, labor and annual O&M costs (assuming a 30 year lifespan), divided by segment length.

b. The sum of labor and annual O&M costs normalized to maximum segment capacity and pipeline lifespan with the levelized capital cost, divided by the segment length. (Modeled for a 30 year lifespan and capital recovery factor of 12.5%.)

Another report which performed cost-benefit analyses of nation-wide decarbonization plans - Princeton's Net-Zero America report - calculated regionally specific building costs for CO₂ pipeline networks. To build a main CO₂ pipeline fully across the region of southern California, the report estimates a cost of \$1.2 billion for 239 miles¹⁰⁷ of a 36" diameter

¹⁰⁴ Rassool *et al.* (2021) <u>CCS in the circular carbon economy</u>. [30]

¹⁰⁵ EPA (no date) <u>Archer Daniels Midland Co. Emissions Data</u>. [10]

¹⁰⁶ Data from Abramson et al. (2020) <u>Transport Infrastructure for CCS</u>. p. 23, 29. [1]

¹⁰⁷ Email correspondence with Chris Greig and Andrew Pascale, January 24-25, 2023.

pipeline, or \$139,470 per diameter inch mile.^{108,109} The cost per user (whether CO_2 supplier or buyer) for this pipeline could be reduced by incorporating other carbon dioxide pipelines into this system, creating a regional network in southern California to connect carbon producers or capture sites to sequestration sites in Kern County. The best layout for a hypothetical hub system to connect multiple sources with a single sink—whether it be "tree with branches" or "hub and spoke" (Figure 9.3)—would depend upon angles the pipelines from the sources are placed at relative to each other.¹¹⁰

Innovative financing could also reduce the overall capital needed to sustain regional scale pipeline networks. Financing options, including private activity bonds (PAB) or master limited partnerships (MLP), should be explored by any potential operator to reduce the direct capital required to start up operations.¹¹¹

In addition to construction costs, it is also critical to consider the time needed for an onshore pipeline to go from development to deployment – estimated at four to six years.¹¹² Opening of a pipeline this decade, for instance, would require setting an ambitious project timeline now to be able to clear all the regulatory requirements needed, complete construction, and pass safety and environmental quality checks prior to deployment.



Figure 9.3. CO_2 transport pipelines are most cost-effective when built as a network, connecting multiple CO_2 sources to an underground storage site. The two most common pipeline network designs are a 'tree with branches' model, which has a single main line with many small, single-input offshoots, and a 'hub and spoke' model, where CO_2 sourced from several small facilities ('spokes') are combined in a 'hub' before being joined to a main pipeline.

¹⁰⁸ Greig, Pascale, Wagner (2021) <u>Net-Zero America Annex I</u>. p. 25-26. [14]

¹⁰⁹ The conversion to diameter inch miles was possible due to additional information provided by the primary authors on Net-Zero America Annex I via email on January 25, 2023.

¹¹⁰ Peletiri *et al.* (2018) <u>CO₂ Pipeline Design</u>. p. 6. [24]

¹¹¹ Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. 29. [1]

¹¹² ZEP (no date) <u>The Costs of CO2 Transport</u>. [41]

Finally, it is worth noting that the expense of building and maintaining a CO_2 pipeline is not typically a significant portion of the cost of carbon capture and storage projects. Up to 90% of carbon management project costs come from the capture process itself, and the energy needed for CO_2 compression.¹¹³ Transport is a relatively small portion of the overall cost of capturing CO_2 for the purpose of permanent underground storage.

9.4.2.2 Operational costs

Operation and management (O&M) costs of a pipeline vary by industry, as they are dependent on the required maintenance and monitoring technology. One estimate of O&M and labor costs – from the Great Plains Institute¹¹⁴ – is given in Table 9.1. Such costs are often estimated to be between 4 and 7% of the original capital cost.¹¹⁵ In scenarios explored by Princeton's Net-Zero America study, which looked at potential paths to get to net-zero nationwide by 2050, the estimated average cost to move a ton of CO_2 – considering capital as well as O&M costs – would range between \$10-20, depending on the location.¹¹⁶ For long distances or CO_2 derived from low-capacity sources (see Section 9.4.2.1), the cost would increase, but approximately 90% of carbon dioxide moved throughout this hypothetical national network could be moved for under \$20/ton CO_2 .¹¹⁷

As discussed above, there are additional safety considerations for an operator with locating pipelines near population centers, thus siting pipelines too close to communities can result in both higher upfront and heavier monitoring costs for operators.

9.4.3 Regional benefits

Any carbon management business park of the form considered in this study would likely find pipelines to be the most cost-effective form of CO₂ transport to locations suited for permanent underground storage. Additionally, regions like Kern County, where there is suitable geology and growing industry interest in developing CO₂ sequestration sites (as of the writing of this report, three companies have applied for permits from the EPA to construct Class VI wells for the purpose of CO₂ sequestration), development of a pipeline network is crucial. If a large carbon management park was developed within Kern County to act as the primary CO₂ source, pipeline distances could be exceptionally short by industry terms, requiring tens to a few hundred miles of pipeline, rather than hundreds to thousands (the county is 180 miles across at its widest point). Not only would short distances reduce the costs of construction and maintenance, but all of construction, monitoring, and taxation would fall under the same set of state and county regulations for the entire length of the pipeline, reducing regulatory or bureaucratic hurdles.

¹¹³ Peletiri *et al.* (2018) <u>CO₂ Pipeline Design</u>. p. 2. [24]

¹¹⁴ Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. 23. [1]

¹¹⁵ Abramson *et al.* (2020) <u>Transport Infrastructure for CCS</u>. p. A6. [1]

¹¹⁶ Greig, Pascale, Wagner (2021) <u>Net-Zero America Annex I</u>. p. 34. [14]

¹¹⁷ Greig, Pascale, Wagner (2021) <u>Net-Zero America Annex I</u>. p. 33-34. [14]

9.4.3.1 Proximate consumers

As Kern County is already pursuing permits for a sequestration site and investigating the feasibility of a carbon management park, transport of carbon dioxide will be necessary to link these two distinct projects to fulfill their potential.

When applying for LCFS (Low Carbon Fuel Standard) or CARB (California Air Resources Board offset) credits, there will need to be a new legal arrangement drawn up between the supplier, the sequesterer, and the transporter about who will claim the credits and how they will be divided amongst parties within this relationship.¹¹⁸

9.4.3.2 Co-location advantages

The primary advantage of a carbon management park that can act as a 'hub' is particularly evident when dealing with transport. Pipelines are time-consuming to design and permit, expensive to safely build and monitor, and require meeting a range of regulations and environmental quality checks. Any company developing a pipeline project would want to ensure that there would be steady interest in carbon dioxide transport; the occupants of a carbon management park, who are either generating or capturing carbon dioxide, would be of substantial appeal because they would constitute a reliable source of carbon to transport. As for members of the industrial park, having another player provide the pipeline infrastructure can reduce overall costs and risks of their operation, as they can focus on the carbon capture and purification, but leave the transportation and sequestration portion to other companies. Thus co-locating has the appeal of distributing risk across a set of players.

9.4.3.3 Other

Although technically tricky to accomplish due to the differences between the material and safety requirements of oil pipelines versus carbon dioxide pipelines, there are operational projects that have retrofitted existing oil pipelines to transport carbon dioxide. In the Netherlands, the OCAP pipeline has been transporting carbon dioxide since 2004 using a retrofitted oil pipeline that had been out of commission for 25 years.¹¹⁹ The right pipeline operator may be able to reuse existing oil and natural gas pipelines¹²⁰ in Kern County by upgrading them to the necessary specifications to safely move carbon dioxide, which could be less costly than constructing a new pipeline and reduce the burdens of permitting and obtaining right-of-ways. If such re-purposing is deemed unsafe for CO₂ transport be the ongoing assessment of state safety regulations,¹²¹ it is worth investigating whether existing right-of-ways for these pipeline systems could be used for CO₂ transport as well, minimizing the time and expense of identifying and purchasing rights to new right-of-ways.

¹¹⁸ Internal conversation with DOE Technical Team, August 29, 2022.

¹¹⁹ Kenton, Silton (no date) <u>Repurposing Natural Gas Lines</u>. [17]

¹²⁰ PHMSA (no date) <u>National Pipeline Mapping System</u>. [26]

¹²¹ CNRA (2023) <u>Proposal for CO₂ pipeline state policy framework</u>. [2]

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10. Carbon Dioxide Utilizing Industries

TECHNOLOGY AT A GLANCE

- There are a diverse suite of industries that can incorporate CO₂ into their production process or their final products. Most industries are in pilot or early demonstration phases of CO₂ integration. The exception is the food and beverage industry, which uses about 15 million tons of CO₂ annually.¹
- The most promising industries for scaling up CO₂ utilization to the million-ton scale are in cement and concrete manufacturing, building materials manufacturing, synthetic carbon fuels, and plastics, polymers and other chemical manufacturing.
- Significant investment in research and development (± policy incentives) will be needed to bring costs down relative to competing, non-CO₂ utilizing products.
- Key advantages of these technologies to Kern County: co-location within a carbon management industrial park and near abundant clean solar and wind power will reduce operational costs and make CO₂-utilizing products more economically viable.
- Key concerns for this technology in Kern County: each CO₂-utilizing industry has its own suite of impacts and benefits, which warrant further investigation. Additionally, most CO₂-utilizing industries do not permanently store CO₂; it is (re)-released to the atmosphere on the order of months to years. Case by case life cycle analyses of the carbon removal benefit of a CO₂-utilizing practice will be necessary to understand whether it provides any climate benefit, and whether it is eligible for state or federal carbon removal incentives.

¹ Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

10.1 Technology Summary

Interest from governments,² companies³ and scientists⁴ around the growth of the carbon management industry is primarily for the purpose of carbon dioxide removal: pulling CO₂ from the atmosphere (through processes like DAC or BiCRS) or preventing CO₂ emissions from point sources (like steel mills), and storing that CO₂ permanently and safely underground to reduce the impacts and mitigate the costs of climate change. However, until the U.S. Inflation Reduction Act that passed in 2022 increased financial incentives for carbon sequestration, carbon capture for the purpose of permanent storage was, for the most part, not financially feasible.⁵ As an alternative, several researchers and companies have explored options for using CO₂ in products, in ways that would either remove it from the atmosphere on timescales of decades to centuries, or replace products or feedstocks that would otherwise produce more greenhouse gas emissions.⁶

Even with the increased cost effectiveness of carbon management for the purpose of removal and storage, the research and innovations of recent decades in CO_2 utilization has seeded or expanded potential commercial markets for CO_2 that could complement sequestration programs, and those markets could grow in scale to using as much as tens of millions of tons of CO_2 annually by mid-century.⁷

The primary industries expected to use CO₂ are food & beverages, concrete & other building materials, fuels, and chemical manufacturing opportunities, and in this section, we provide a review of each of these sectors and how CO₂-utilization can be integrated into their products or supply chains. Because this section is an examination of several different nascent industries, and detailed evaluation of each is beyond the scope of this report, rather than presenting CO₂-utilizing industries in the format common to other industries examined here (through technological, societal, environmental and economic lenses), we will provide brief descriptions of each category of CO₂-utilizing industries, examining their state of development and describing example projects (Section 10.1), and then will consider the potential of these industries from a business model standpoint (Sections 10.2 and 10.3).

Note that the industries described in this section are not necessarily exhaustive examples of uses for CO_2 . For example, it can be used to increase agricultural productivity or in cleaning or medical processes – but these uses are either addressed in other sections of the larger report or are negligible in the context of how much CO_2 they would utilize. As such, these uses are not explored in this section. Finally, one application of CO_2 -utilization

² WRI (December 22, 2022) <u>Carbon removal in the BIL and IRA</u>. [57]

³ Brigham (June 28, 2022) <u>Why Big Tech is pouring money into carbon removal</u>. [5]

⁴ Harvey (April 5, 2022) <u>Carbon removal 'unavoidable' as climate dangers grow, new IPCC report</u> says. [26]

⁵ Climate Now (February 18, 2022) <u>How to scale up carbon capture and storage with Sheila</u> <u>Olmstead</u>. [18]

⁶ IEA (2019) <u>Putting CO₂ to Use</u>. [34]

⁷ IEA (2019) <u>Putting CO₂ to Use</u>. p. 1. [34]

is not addressed in this section at all: Enhanced Oil Recovery, or EOR. While globally, EOR is by far the largest market for CO₂, it is not a relevant market to consider for the purpose of a carbon management business park in Kern County, given that state law SB-905 prohibits operators from injecting CO₂ produced in a carbon management project into the subsurface for the purpose of enhanced oil recovery.⁸

10.1.1 Types of Industries

 CO_2 can be used in its pure state for several purposes – an example many are familiar with is beverage carbonation. Currently, most commercial processes that rely on CO_2 use it directly.⁹ However, if the goal of CO_2 utilization is to create a measurable impact in the reduction of atmospheric greenhouse gases, it will have to be adopted by industries that would use tens or hundreds of millions of tons of CO_2 annually. These types of industries – concrete, fuels, plastics and polymers, and other chemicals – require chemical or biological conversion of the CO_2 into usable products, which can be technologically complex and energy intensive. A summary of the wide range of industrial applications for CO_2 is shown in Figure 10.1, adapted from a comprehensive report on CO_2 utilization from the International Energy Agency (IEA),¹⁰ to which the reader is referred for further information on the topic.

The CO₂ utilization market is relatively small (currently, about 25-35 million tons of CO₂ are used in non-EOR industries),^{11,12} and likely to remain so in the short term, as carbon management companies that could cost-effectively source CO₂ are still in nascent stages of development, and the markets most likely to be large consumers of CO₂ (building materials and fuels) will require years of testing to ensure they meet regulatory and safety standards.¹³ Additionally, adoption of CO₂ utilization practices will require either 1) a clear economic benefit compared to current techniques for an industrial activity or product development, or 2) a clear and measurable climate benefit to the utilization of CO₂ that adds enough value to its use that additional costs can be offset. For most CO₂-utilizing industries, neither of these goals has been clearly achieved yet – more expansive and improved methods to analyze the life-cycle emissions of CO₂-utilizing products will be necessary to inform the best policy and investment decisions for the future.¹⁴ In the following sections, we provide a brief summary of the state of the art for CO₂ utilization in the food and beverage, concrete, building material, fuel, plastic & polymer, and chemical industries.

⁸ OpenStates (no date) <u>SB 905</u>. [48]

⁹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 3. [34]

¹⁰ IEA (2019) <u>Putting CO₂ to Use</u>. [34]

¹¹ IEA (2020) <u>CCUS in Clean Energy Transitions</u>. p. 109. [36]

¹² Note: About 70-80 million tons of CO_2 is used for EOR, and ~125 MtCO₂/yr is used by the fertilizer industry. However, fertilizer facilities produce and use their own CO_2 , so they do not need to buy it externally. (IEA (2020) <u>CCUS in Clean Energy Transitions</u>. [36])

¹³ IEA (2019) <u>Putting CO₂ to Use</u>. p. 1. [34]

¹⁴ IEA (2019) <u>Putting CO₂ to Use</u>. p. 2. [34]


Figure 1. A summary of direct uses of CO_2 (including in greenhouses, in food and beverages and solvents) and indirect uses of CO_2 (including fuels, plastics, and building materials). Adapted from IEA (2019).¹⁵

10.1.1.1 Food & Beverages

Currently, the largest industry for CO_2 utilization (excluding EOR and fertilizers, see notes above) is the food and beverage industry, which purchases about half of the CO_2 on the market – approximately 15 million tons in 2015.^{16,17} Carbonated beverages comprise about half of the use in the food and beverage industry,¹⁸ but CO_2 is also used as a produce preservative, a freezing agent for meat, or to keep food items cold in transport as dry ice.¹⁹ Food and beverage opportunities for CO_2 utilization are among the least useful in terms of atmospheric carbon dioxide removal; the CO_2 that is utilized will only be stored temporarily in the product before returning to the atmosphere.²⁰ However, it is one of the more well-established CO_2 -utilization industries, with captured CO_2 already used on a commercial scale.

Another promising avenue of food and beverage applications is associated with chemical manufacturing opportunities. For example, sodium bicarbonate, or baking soda, can be formed through the chemical conversion of CO₂ (its chemical formula is Na₂CO₃). Baking soda is both widely used in commercial baked goods and sold directly to consumers.²¹

¹⁵ IEA (2019) <u>Putting CO₂ to Use</u>. p. 7-8. [34]

¹⁶ GlobalNewsWire (January 7, 2021) <u>The Largest User Of The Carbon Dioxide Market</u>. [25]

¹⁷ IEA (2019) <u>Putting CO₂ to Use</u>. p. 6. [34]

¹⁸ IEA (2019) <u>Putting CO₂ to Use</u>. p. 6. [34]

¹⁹ nexAir (no date) <u>Carbon Dioxide in Food and Beverage</u>. [44]

²⁰ Budinis (January 31, 2020) <u>Going carbon negative</u>. [6]

²¹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 49. [34]

Chemical compounds formed by converting CO_2 are explored at large in Section 10.1.1.6 on chemical manufacturing.

Example Project: Coca-Cola HBC Switzerland, Switzerland

A Coca-Cola franchised bottler in Switzerland purchased captured CO₂ from the first commercially operating DAC facility in the world for use in beverage carbonation for its Valser sparkling water.²² Climeworks' first generation Hinwil DAC facility supplied CO₂ to the bottling company from 2017 until the retirement of the facility in January 2023.²³ Presently, Coca-Cola is considering ways to expand its use of captured CO₂ across its products and Climeworks is looking to expand their CO₂ utilization offerings beyond Switzerland as their operations grow.^{24, 25}

Example Project: Air Company, New York, New York

Air Company is a carbon utilization company that uses CO₂ conversion technology to produce carbon negative alcohol products, such as vodka, as well as personal care products including perfume and hand sanitizer.²⁶ Air Company's technology obtains CO₂ from point-source capture sources, then combines that CO₂ with green hydrogen (hydrogen via electrolysis) to create an alcohol mixture that is distilled and forms the basis for their product offerings.²⁷ They also rely wholly on clean energy (wind and solar) to support their processes.²⁸

Air Company is planning to add fuel products to their commercial-scale offerings, namely sustainable aviation fuels, ethanol, and methanol (see Section 10.1.1.4).²⁹ Their aviation fuels have been successfully used by the U.S. Air Force in pilot-scale tests, and the company is currently in the process of scaling their operation to a commercial demonstration phase.³⁰ If expanded to all potential areas of business that Air Company has scoped (food, personal care and fuels), they anticipate their technology "could avoid 10.8% of global CO₂ emissions, the equivalent of more than 4.6 billion tons of CO₂ annually."³¹

²² Johnston (September 6, 2021) <u>Inside the Facility</u>. [37]

²³ Climeworks (January 24, 2023) <u>Climeworks completes the commercial operation of its 1st gen</u> technology. [20]

²⁴ Johnston (September 6, 2021) <u>Inside the Facility</u>. [37]

²⁵ Kotecki (January 15, 2019) <u>Sparkling water made with carbon dioxide captured from the atmosphere</u>. [39]

²⁶ Air Company (no date) <u>Transforming CO₂</u>. [3]

²⁷ Air Company (no date) <u>AIR Eau de Parfum</u>. [1]

²⁸ Air Company (no date) <u>AIR Eau de Parfum</u>. [1]

²⁹ Air Company (no date) <u>Transforming CO₂</u>. [3]

³⁰ Air Company (no date) <u>AIRMADE[™] SAF</u>. [2]

³¹ Air Company (no date) <u>Transforming CO₂</u>. [3]

10.1.1.2 Concrete

Concrete production is very carbon-intensive, accounting for at least 8% of global CO2 emissions.³² Moreover, concrete demand is quickly accelerating—we use three times more concrete than we did 40 years ago, and as more nations industrialize, demand growth is expected to continue.³³ Thus decarbonizing concrete production has a clear positive impact on reducing global greenhouse gas emissions. There are already small-scale manufacturing facilities developing lower-carbon concrete, but it will require immense scaling and regulatory reforms before these products can replace traditional concrete.³⁴

In general, CO_2 utilization in concrete production falls into two categories: 1) replacing water for curing, or 2) as a raw material within the concrete mixture. Both uses represent examples of CO_2 utilization that provide sequestration on the order of decades, so could benefit from carbon offset marketplaces or regulatory incentives for CO_2 storage.³⁵ CO_2 curing is both a mature and particularly promising avenue for CO_2 use, as it provides the co-benefits of decreasing water use, decreasing the production time for curing, and producing a higher-strength concrete. Additionally, the amount of CO_2 necessary for concrete curing is relatively minimal, so does not add significant manufacturing costs to cement production, even with the still relatively high costs of capture CO_2 . Meanwhile, using CO_2 directly in the production process is a developing area of technology. Injecting CO_2 directly into concrete changes its material composition and could affect its properties—at this early stage of development, it is not yet clear to what degree. CO_2 -rich concrete could have material properties that are essentially the same – or better – than conventional concrete.³⁶

In terms of market readiness, barriers for CO_2 -rich concrete are cost- and policy-related. One way to keep costs low while the industry (and availability of CO_2) evolves, is by injecting CO_2 into precast concrete materials, like concrete bricks, at a central facility rather than incorporating captured CO_2 into onsite concrete mixing or curing of concrete at building sites (see example projects below).³⁷

In terms of policy barriers, all types of concrete are highly regulated for safety reasons. As such, extensive testing and regulatory reforms are necessary before any CO₂-utilizing concrete could be used for high-stability purposes. Thus, early market opportunities will likely rely on less-intensive concrete uses, like paving roads or poured concrete floors.³⁸

³² *Nature* (September 28, 2021) <u>Concrete's colossal carbon footprint</u>. [43]

³³ *Nature* (September 28, 2021) <u>Concrete's colossal carbon footprint</u>. [43]

³⁴ IEA (2019) <u>Putting CO₂ to Use</u>. p. 12. [34]

 $^{^{35}}$ The federal tax credits 45Q provides a reduced tax-credit for industrial uses of CO₂ (compared to permanent storage) as long as emissions reductions can be clearly demonstrated. From: IEA (November 4, 2022) <u>Section 45Q credit for carbon oxide sequestration</u>. [35]

³⁶ IEA (2019) Putting CO₂ to Use. p. 12, 54-55. [34]

³⁷ IEA (2019) <u>Putting CO₂ to Use</u>. p. 55-56. [34]

³⁸ IEA (2019) <u>Putting CO₂ to Use</u>. p. 12. [34]

Although developers are working on promising new industrial processes in this field, experts anticipate that the hurdles in scaling and deploying CO₂-utilizing concrete will be regulatory, rather than technical, in nature.³⁹

Example Project: Carbicrete, Montreal, Quebec

Canadian company Carbicrete has developed a new process to reduce their carbon emissions that both changes the constituent parts of the concrete to be less carbon intensive and relies on CO₂ to cure its final concrete product.⁴⁰ Rather than mixing cement with aggregates and water to generate their concrete, they replace the cement with steel slag, which is incorporated into the mixture on industry standard equipment—removing the requirement for cement altogether.⁴¹ Then, they mold precast concrete blocks that are cured with CO₂ in a specialized chamber, taking 24 hours to reach their full strength.⁴² In testing, they have found their concrete has up to 30% higher compressive strength, improved freezing and thawing resistance, and the same water absorption properties of traditional concrete.⁴³

Across Carbicrete's production process, more CO_2 is absorbed in the concrete than is emitted in manufacturing, making their concrete production carbon negative.⁴⁴ Currently, Carbicrete relies on captured industrial point-source emissions for its CO_2 , but it is hoping to move to using CO_2 from Direct Air Capture (DAC) facilities in the future so they are actively removing existing CO_2 from the atmosphere.⁴⁵

Example Project: CarbonCure, Halifax, Nova Scotia

CarbonCure's process relies on incorporating CO_2 directly into the concrete mix, where the CO_2 reacts with calcium ions within the cement (composed primarily of lime, or CaO and $Ca(OH)_2$) in order to form calcium carbonate ($CaCO_3$).⁴⁶ They market a range of products from their technology, including ready concrete mix, concrete bricks, precast concrete, and reclaimed water.⁴⁷ Their technology decreases both the water and carbon intensity of their concrete in comparison to traditional concrete.⁴⁸

It's expected that over the next 30 years, about half of the emissions from new construction will come from embodied carbon, which is the carbon emitted during the manufacture of

³⁹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 58. [34]

⁴⁰ Carbicrete (no date) <u>Technology</u>. [11]

⁴¹ Carbicrete (no date) <u>Technology</u>. [11]

⁴² Carbicrete (no date) <u>Technology</u>. [11]

⁴³ Carbicrete (no date) End Users. [10]

⁴⁴ Carbicrete (no date) <u>Carbicrete - About the Process Video</u>. 0:31-0:36. [9]

⁴⁵ Fairs (June 27, 2021) <u>Carbon Revolution</u>. [24]

⁴⁶ CarbonCure (no date) <u>Innovative CO₂ Technologies</u>. [14]

⁴⁷ CarbonCure (no date) <u>Innovative CO₂ Technologies</u>. [14]

⁴⁸ CarbonCure (no date) <u>Innovative CO₂ Technologies</u>. [14]

building materials.⁴⁹ CarbonCure's goal is that with their associated products, they could remove 500 million metric tons of embodied CO_2 from the environment by 2030, equivalent to taking 100 million cars off the road.⁵⁰

Example Project: Solidia Technologies, San Antonio, Texas

Solidia Technologies is developing two processes for reducing CO₂ emissions associated with concrete production: one is to adjust the chemistry of the cement mix and the other - like other companies - is to use a CO₂ curing process.⁵¹ Their cement formula is more silicarich and less lime-rich than the most common cement recipe, Portland cement. Because lime production (converting limestone rock (CaCO₃) to lime (CaO and Ca(OH)₂) is an energy intensive process that releases CO₂ in the atmosphere, a cement chemistry with less lime has the effect of lowering the CO₂ emissions, energy requirements, and raw materials intensity of the cement and subsequent concrete products.⁵²

The lime-poor cement is combined with sand granules to generate their concrete, which undergoes CO_2 curing. In the CO_2 curing process, the CO_2 reacts with the cement in the concrete to form calcium carbonate (CaCO₃), strengthening the material and chemically trapping the CO_2 .⁵³ This process makes the concrete higher performing, reduces production costs, and drastically reduces the curing time to less than 24 hours, compared to a full 4 weeks for traditional concrete.⁵⁴

If implemented globally, Solidia anticipates that their technologies could reduce carbon emissions from concrete production by up to 70%.⁵⁵

10.1.1.3 Building Materials

 CO_2 can be utilized for building materials other than concrete as well, with most applications involving the remediation of metal waste materials into carbonates that can be used as aggregates in construction.⁵⁶ Fly ash and steel slag are two examples of alkaline wastes - materials that have high concentrations of reactive metals like calcium and magnesium. These kinds of metals chemically bond with CO_2 to form solid carbonate materials (CaCO₃ and MgCO₃) that permanently bind the carbon. Carbonation of 1 ton of fly ash can sequester about 0.07-0.25 tons CO_2 , and carbonation of 1 ton of blast furnace slag from steel operations requires about 0.26-0.38 tons CO_2 . Not all of the CO_2 used is bound up in the product, but the cost of CO_2 input encourages recycling the CO_2 such that the majority of the CO_2 input will be sequestered. Producing carbonates from metal waste is a

⁴⁹ CarbonCure (no date) <u>500 Million Tonne CO₂ Reduction</u>. [13]

⁵⁰ CarbonCure (no date) <u>500 Million Tonne CO₂ Reduction</u>. [13]

⁵¹ Solidia Technologies (no date) <u>Solutions</u>. [52]

⁵² Solidia Technologies (May 2021) <u>The Science Behind Solidia</u>. [53]

⁵³ Solidia Technologies (no date) <u>Solutions</u>. [52]

⁵⁴ Solidia Technologies (no date) <u>Solutions</u>. [52]

⁵⁵ Solidia Technologies (no date) <u>Impact</u>. [51]

⁵⁶ IEA (2019) <u>Putting CO₂ to Use</u>. p. 59. [34]

relatively new industry, and life-cycle assessments of the CO₂-reduction potential of carbonated waste products are limited and often not transparent – substantial analytical work is still needed to establish the climate benefits possible from these processes.⁵⁷

However, a co-benefit of metal-waste carbonation is that it binds harmful metals that could leach into the environment and cause harm, and it helps eliminate the costs of tailings or hazardous waste disposal in mining and industrial applications.⁵⁸ Thus, these practices have the potential to reduce the environmental impact of existing industrial sites requiring remediation and protect industrial communities from future environmental harm.

Carbonation of metallic wastes for construction aggregates does face economic hurdles before significant scaling can take place. Since building materials are readily and cheaply available, it is difficult for materials generated from waste to be economically competitive in the marketplace.⁵⁹ As a result, early markets are likely to appear only where there are large amounts of waste to process and tightening regulations incentivize safe remediation of that waste. Examples include regions around the world that are increasing regulations around disposing bauxite residue (informally called "red mud") from aluminum production,⁶⁰ and regions where industrial waste disposal is expensive, like the European Union (EU).⁶¹ Regulations can also present hurdles, however; for example, EU law currently prohibits the integration of waste into commercial products, which could present challenges for bringing a carbonated aggregate generated from waste into the European market.⁶²

Example Project: Carbon8, United Kingdom

In the UK, Carbon8 works to capture CO₂ from industrial sources and then, at the same site, react that CO₂ with residues and byproducts that would otherwise be destined for landfilling.⁶³ Once formed, these carbonated materials can be used for "a variety of applications including in cement blocks, road filler and green roofing substrate."⁶⁴ Carbon8's technology is notable because it can sequester CO₂ for long periods and has a relatively short production time, with an estimated time for its carbon capture and storage process of 20 minutes.⁶⁵

⁵⁷ IEA (2019) <u>Putting CO₂ to Use</u>. p. 59-62. [34]

⁵⁸ IEA (2019) <u>Putting CO₂ to Use</u>. p. 59. [34]

⁵⁹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 60. [34]

 ⁶⁰ Srivastava *et al.* (2023) <u>Challenges, regulations, and case studies on sustainable management</u>.
 [54]

⁶¹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 61. [34]

⁶² IEA (2019) <u>Putting CO₂ to Use</u>. p. 62. [34]

⁶³ Carbon8 (no date) Our Solution. [12]

⁶⁴ Carbon8 (no date) <u>Our Solution</u>. [12]

⁶⁵ Carbon8 (no date) <u>Our Solution</u>. [12]

10.1.1.4 Synthetic Carbon Fuels

Another budding industrial opportunity for CO_2 use is to incorporate captured CO_2 into new carbon fuels. These fuels could replace conventional fuels in use today, including gasoline, aviation fuels, methane, and methanol.⁶⁶ This prospect has clear potential: by volume, synthetic carbon fuels rank as the biggest use potential for CO_2 , with the ability to provide a lower-carbon fuel option for industries with few non-carbon fuel alternatives, like the aviation industry, or by replacing fossil fuels with an option that is simpler to use and store than pure hydrogen fuels. However, synthetic carbon fuels come with challenges as well: generating fuels from CO_2 is very energy-intensive, and existing fuel standards may be difficult to meet with synthetic CO_2 -derived fuels. Additionally, upon combustion of these fuels, CO_2 will be re-released into the atmosphere, and so these products are not pathways for permanent CO_2 removal and storage, and thus not eligible for carbon credits, or policies that incentivize carbon removal.⁶⁷

Production of synthetic carbon fuels can be carried out through one of two pathways, either direct or indirect.⁶⁸ Both pathways involve combining CO₂ and H₂ for chemical conversion, summarized by this simplified reaction:

$$CO_2 + H_2$$
 (or H_2O) + energy \rightarrow Hydrocarbon fuel + O_2 (R10.1)

The direct pathway relies on hydrogenation, and the indirect pathway on a reverse gaswater shift process followed either by a Fischer-Tropsch (FT) or methanol synthesis process. Not all of these processes are equally ready for commercial deployment. Hydrogenation, FT, and methanol synthesis are all mature processes, but the reverse water-gas shift is still at the demonstration scale.⁶⁹ Other processes that develop CO₂derived fuels via chemical or biological pathways are still in the research and development phase.⁷⁰

Regardless of production pathway, producing synthetic carbon fuels is an energy intensive process, which significantly contributes to their high cost relative to fossil fuels. For example, in creating CO_2 -derived methane and methanol, electricity accounts for 40-70% of production costs and is the primary reason that production costs exceed traditional methane and methanol by 2 to 7 times.⁷¹ With improvement, CO_2 -derived methanol may become price-competitive in the marketplace, but other fuels produced from CO_2 – methane, diesel, gasoline, and aviation fuel – are expected to require policy interventions

⁶⁶ IEA (2019) Putting CO₂ to Use. p. 9. [34]

⁶⁷ IEA (2019) <u>Putting CO₂ to Use</u>. p. 7-10. [34]

⁶⁸ IEA (2019) Putting CO₂ to Use. p. 10. [34]

⁶⁹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 18. [34]

⁷⁰ IEA (2019) <u>Putting CO₂ to Use</u>. p. 9. [34]

⁷¹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 10. [34]

to compete with traditional fuels.⁷² Some of the policy avenues that could precipitate this change in demand are explored in Section 10.3.2.

The energy demand of synthetic carbon fuels is intuitive - production of these fuels is essentially a reversal of the combustion reaction we use to obtain energy:

Hydrocarbon fuel +
$$O_2 \rightarrow CO_2$$
 + H_2O (or H_2) + energy (R10.2)

Thus, synthetic carbon fuels will only have value if the energy used to create them produces less CO_2 than would come from simply combusting fossil fuels. For example, using electricity generated from a coal-fired power plant to create synthetic carbon fuel could emit more CO_2 than it avoids. Thus, for any production facility, a full life-cycle analysis would be necessary to examine how beneficial these CO_2 -derived fuels are when compared to traditional fuels.

Example Project: Carbon Engineering - Air to Fuels, British Columbia, Canada

Carbon Engineering is one of two leading companies in the development of Direct Air Capture (the other being ClimeWorks, see Section 3), having operated a pilot Liquid Direct Air Capture (L-DAC) facility in Sqamish, British Columbia since 2015.⁷³ In addition to their work in capturing CO₂ for the purposes of underground sequestration, the company's Air to Fuels program develops synthetic fuels that are drop-in compatible with existing infrastructure and engines. Their process involves reacting CO₂ captured from the air with green hydrogen derived from electrolysis (see Section 6) to create hydrocarbons that can be converted into synthetic gasoline, diesel or jet fuel.⁷⁴ In 2019, the reported cost to produce these fuels was ~ \$4 USD per gallon.⁷⁵

Example Project: George Olah Renewable Methanol, Svartsengi, Iceland

The George Olah Renewable Methanol facility, located in Svartsengi, Iceland, is the first industrial scale operation converting captured CO_2 to methanol fuel.⁷⁶ The facility was commissioned in 2011 and reuses 5,500 metric tons of CO_2 annually. It relies on captured CO_2 from a nearby geothermal power plant (point-source capture) to synthesize methanol via a catalytic reaction with H₂.⁷⁷

Example Project: Air Company, New York, New York

Air Company is developing a variety of products utilizing CO₂, including alternative fuels, and is described in detail in Section 10.1.1.1.

⁷² IEA (2019) <u>Putting CO₂ to Use</u>. p. 10. [34]

⁷³ Carbon Engineering (no date) <u>Our Story</u>. [16]

⁷⁴ Carbon Engineering (no date) <u>Air to Fuels[™]</u>. [15]

 ⁷⁵ Conca (October 8, 2019) <u>Carbon Engineering – Taking CO₂ right out of the air to make gasoline</u>.
 [21]

⁷⁶ IEA (2019) <u>Putting CO₂ to Use</u>. p. 18. [34]

⁷⁷ Carbon Recycling International (no date) <u>George Olah renewable methanol plant</u>. [17]

10.1.1.5 Plastics & Polymers

Today, fossil fuels are not only used for energy production, but are a primary feedstock in the production of a variety of plastics, polymers and their derivatives: materials that are collectively described as the *petrochemical* industry. In the long term, decarbonization efforts would ideally reduce fossil fuel use in petrochemicals in addition to the energy sector, and to this end, plastics and polymer production is an industry with a strong potential for reusing captured CO₂ to create new products.⁷⁸

A clear benefit to incorporating CO_2 into plastics and polymers is that it requires relatively low energy input, making it cost-competitive with many traditional manufacturing practices, and it reduces the raw materials necessary from fossil fuels.⁷⁹ However, this is not a fix-all solution—at least currently, CO_2 can only replace part of the raw material from fossil fuels necessary to form plastics or polymers, up to approximately 50% of the final products' mass.⁸⁰ Full life-cycle analyses would be necessary to quantify the degree to which CO_2 -utilization reduces the emissions associated with polymer production. Additionally, while the longevity of CO_2 -derived plastics and polymers could provide an environmental benefit in the form of long-term storage sites for CO_2 , the accumulation of non-degradable plastic waste creates a different environmental hazard that needs to be considered.⁸¹

Example Project: Econic, United Kingdom

UK manufacturer Econic is using CO₂ to produce polyurethane, which is used in foam, coatings, sealants, elastomers and other products.⁸² Their process relies on replacing a percentage of the material's polyols—cross-linking agents—with carbon dioxide, which serves not only to bind the CO₂ but also replaces a highly expensive standard polyol material, propylene oxide.⁸³ As a result, Econic estimates that their process will not only lower carbon emissions, but also save money for manufacturers.⁸⁴ Econic products are in development - with full scale production of their polyol technology planned to begin in 2024.⁸⁵

10.1.1.6 Chemical Development

Most of the products discussed in the previous sections involved some form of chemical conversion of CO_2 into a new product. However, there are other ways to chemically convert CO_2 that does not fit clearly into these large, existing industrial sectors, like fuels, building

⁷⁸ Vilcinskas (March 2020) <u>Carbon dioxide-based polymers</u>. [56]

⁷⁹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 11. [34]

⁸⁰ IEA (2019) <u>Putting CO₂ to Use</u>. p. 11. [34]

⁸¹ Parker (June 7, 2019) <u>The world's plastic pollution crisis explained</u>. [49]

⁸² Cormier (no date) <u>Turning carbon emissions into plastic</u>. [22]

⁸³ Cormier (no date) <u>Turning carbon emissions into plastic</u>. [22]

⁸⁴ Cormier (no date) <u>Turning carbon emissions into plastic</u>. [22]

⁸⁵ Econic (January 12, 2023) <u>Econic Technologies Named on the 2023 Global Cleantech 100</u>. [23]

materials or plastics. This section encompasses products of CO₂-conversion that are outside of the previously described sectors, as well as some processes of chemical conversion that are in early stages of laboratory testing, but could have promising future applications.

Through processes described as biological conversion, CO₂ can be converted into fatty acids, amino acids, and proteins.⁸⁶ Synthetic amino acids and proteins can be used in animal feed or, in the future, to generate meat alternative products.⁸⁷

Electrochemical conversion of CO₂ could produce a wide variety of products, including carbon monoxide and carbon nanomaterials.⁸⁸ Some products, like methanol and formic acid, can be generated through thermochemical or electrochemical conversion of CO₂.⁸⁹ These products are exceedingly versatile and useful. Carbon monoxide is used in the formation of an array of other chemical materials, including long-chain hydrocarbons for fuel and methanol. Carbon nanomaterials, depending on their specific shape and characteristics, can be used in fuel cells, batteries, automotives, and water treatment.

Methanol can be formed with CO₂, CO, and H₂ molecules, and serves as a reactant for forming other chemical compounds, including acetic acid, formaldehyde, and long-chain hydrocarbons. It can also be used as a fuel (see Example Project: George Olah Renewable Methanol in Section 10.1.1.4) – although less energy-dense than gasoline, methanol can be used in some gas-powered engines with minor modifications.⁹⁰ Lastly, formic acid can be formed through a multi-step process, but has thus far been rarely commercialized as it relies on an expensive catalyst and can be difficult to separate out at the product end.⁹¹ Formic acid (or CH_2O_2) can be used as a food additive, pesticide (depending on local regulations), in cleaning products, in dyeing or treating fabric and paper products, and as an organic reagent for chemists.⁹²

10.2 Growth in CO₂-Utilizing Industries: Obstacles and Opportunities

The International Energy Agency (IEA) has identified four primary factors that will determine the market viability of a CO₂-utilizing technology: scalability, competitiveness, climate benefits, and the policy & regulatory framework in place.⁹³ The IEA's analysis of

⁸⁶ ten Have (December 20, 2022) <u>Don't bury money</u>. [55]

⁸⁷ ten Have (December 20, 2022) <u>Don't bury money</u>. [55]

⁸⁸ ten Have (December 20, 2022) <u>Don't bury money</u>. [55]

⁸⁹ ten Have (December 20, 2022) Don't bury money. [55]

⁹⁰ ten Have (December 20, 2022) <u>Don't bury money</u>. [55]

⁹¹ ten Have (December 20, 2022) <u>Don't bury money</u>. [55]

⁹² PubChem (no date) Formic Acid (Compound). [50]

⁹³ IEA (2019) <u>Putting CO₂ to Use</u>. p. 28. [34]

each of these factors are summarized briefly here, with additional focus given to national and state policies and funding opportunities that could impact growth of CO₂-utilizing industries in California.

10.2.1 Scalability

For new technologies, supply chains and infrastructure to produce new products take time to develop. In terms of CO₂-utilizing industries, key supply inputs are CO₂ and clean energy (and in some cases, hydrogen). For projects to grow from R&D testing scale to commercial production, large supplies of these inputs will be necessary, which requires either siting such industries close to input sources, or developing significant infrastructure (100% utility-scale energy and a large CO₂ (\pm H₂) pipeline networks). While these supply frameworks are in development, it will likely be several decades before such inputs are widely available.⁹⁴ Co-locating CO₂-utilizing industries in regions close to points of CO₂ capture, green hydrogen production, and abundant potential for clean, renewable energy, as would be the case in a carbon management business park in Kern County, would be highly advantageous, particularly before the infrastructure to support national supply chains is available.

Another critical determinant to scalability is marketplace demand, which varies widely across the products examined here. For example, demand for some of the sophisticated chemicals made with CO_2 will likely be constrained to chemical engineering firms, specialized labs, and other chemical industries. Meanwhile, demand for a product like concrete has grown exponentially over the last century,⁹⁵ and with applications across a wide variety of sectors that grow in tandem with population growth and social-economic development (residential, industrial, municipal, and commercial), is likely to continue such growth. Demand is also not fixed – new technologies may shift what materials are most in demand in ways that have not been considered here – but the ability to project future demand and revenue potential will certainly shape the types of initiatives that are pursued and funded within this early, exploratory phase. The IEA estimates that the five largest potential CO_2 -utilization markets (fuels, chemicals, building materials from waste, building materials from minerals – essentially, concrete and cement, and CO_2 to boost plant yields – discussed in Section 11) each have the potential to scale up to tens of millions of tons of CO_2 use annually, on a global scale.⁹⁶

10.2.2 Competitiveness

 CO_2 -utilizing products that will see success at a commercial scale are those whose use or CO_2 -based production pathway can be easily implemented and have the lowest production costs, especially when ranked against alternatives. This will depend on the costs of the technology itself, the market price, and the cost of inputs—material, energy, labor. For

⁹⁴ Larson *et al.* <u>Net-Zero America: Final Report Summary</u>. [40]

⁹⁵ Andrew (2018) <u>Global CO2 emissions from cement production</u>. [4]

⁹⁶ IEA (2019) Putting CO₂ to Use. p. 1. [34]

example, plastics and polymers made with CO_2 reuse are expected to be quite competitive, as there's little additional equipment needed for production, the process can actually save money in material cost for manufacturers, and these products could be sold near the existing average market price for these plastic and polymer products.

In contrast, carbon-based synthetic fuels will need to compete against fossil fuels that have been historically abundant and heavily subsidized.⁹⁷ Building materials, like concrete, will need to compete on a global market where profit margins are low, so additional production costs are difficult to absorb without some kind of policy incentives.⁹⁸ Both of these types of CO₂-utilizing industries will likely need some kind of policy intervention to support their adoption during early stages of development (see Section 10.2.4).

10.2.3 Climate benefits

Life cycle emissions and other environmental benefits associated with products that utilize captured CO_2 is often difficult to characterize, but will be essential for quantifying the impact and cost-benefit of adopting products that utilize CO_2 , as is determining the life cycle emissions of the products they displace. For example, for building aggregates that are developed from combining industrial waste (slag and tailings) with CO_2 , there are clear benefits—not only does the construction industry have new aggregates to work with, the technology reduces wastes that could leach harmful metals into the environment. However, for an item like plastics or polymers, addition of CO_2 into the production process does not displace the need for raw materials from fossil fuels to create these products—the impacts are limited as current technologies do not fully displace the reliance on fossil fuels.

Benefits are also enhanced when the necessary energy to complete these processes is reduced through in the CO_2 -utilization process compared to traditional methods, and/or if it supplied through clean sources near the production site. Depending on the region, this could include solar, wind, hydropower, geothermal, and/or nuclear energy sources.

Finally, the benefits of CO_2 reuse will be driven by the amount of time that the CO_2 is stored within the product. For building materials and concrete, this is on the order of years or decades; for beverages and fuels, this could be only a few weeks or months. Longer storage of the CO_2 within the product enhances the climate benefits by acting more as a CO_2 removal solution, whereas products with short storage spans only serve to recycle existing atmospheric CO_2 , avoiding further CO_2 additions from fossil sources.

10.2.4 Funding Opportunities & Policy Support

To date, most of the investment in CO_2 -utilization technologies has come from the private sector. Between 2008 and 2018, private investment in the form of venture capital and

⁹⁷ IEA (February 2023) <u>Fossil Fuels Consumption Subsidies 2022</u>. [32]

⁹⁸ Khung, Crete (2022) <u>Life cycle assessment (LCA) and cost-benefit analysis for low carbon</u> <u>concrete</u>. [38]

growth equity for start-ups in the CO₂-use space reached nearly \$1 billion USD, globally.⁹⁹ It is worth noting that level of investment pales in comparison to other clean energy sectors. Global investment in electrified transport topped \$139 billion dollars USD in 2020 alone, and \$304 billion dollars USD were invested in renewable energy in the same year.¹⁰⁰ However, public funding and policy support is beginning to gain momentum within state and federal governments. The simplest and most direct policy support for CO₂-utilization is the development of incentives, guidelines or policies for using low-carbon products, or requiring products to stay below a maximum carbon-intensity (i.e. limit of how much CO₂ per unit product was emitted).¹⁰¹ While politically less popular, another effective policy strategy is placing a price on carbon (a carbon tax), that reflects the cost of – and provides revenue for – mitigating climate change, while also encouraging the use of carbon-negative materials over carbon-intensive materials.¹⁰²

As a climate leader within the nation, California has some statewide policies already informing practices in some CO_2 utilization areas. Federally, the United States supported research and development of CO_2 use through a variety of grant programs, and is beginning to develop additional policy incentives.

10.2.4.1 Relevant California State Policies

With a state-wide commitment to be carbon-neutral by 2045,¹⁰³ laws are being developed to directly address CO₂-emitting industries, many of which are industries that can use CO₂ (concrete and cement, fuels, plastics and chemicals). For example, California's SB 596, passed in 2021, requires the cement industry to reach net-zero carbon emissions by 2045, are changing the landscape by making climate improvements a necessity.^{104,105} However, the high costs of decarbonizing some processes—like creating cement and concrete—have led operators to seek ways to work with the government to lower emissions.¹⁰⁶ California's Air Resources Board (CARB) is scheduled to release a comprehensive strategy to guide the state's cement industry to meet this goal by July 1, 2023, including defining metrics for greenhouse gas intensity, coordinating strategy with other state agencies, and incorporating ways to leverage state and federal incentives and market demand to promote low-carbon cement.¹⁰⁷

⁹⁹ IEA (2019) Putting CO₂ to Use. p. 25. [34]

¹⁰⁰ Bullard (January 28, 2021) In the race for investment dollars, cars are pulling ahead. [7]

¹⁰¹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 5. [34]

¹⁰² Climate Now (October 18, 2021) <u>Pricing carbon around the globe</u>. [19]

 ¹⁰³ Office of Governor Gavin Newsom (November 16, 2022) <u>California releases world's first plan</u>.
 [46]

¹⁰⁴ Office of Governor Gavin Newsom (September 23, 2021) <u>Governor Newsom Signs Climate</u> <u>Action Bills</u>. [47]

¹⁰⁵ Lopez (June 27, 2022) <u>Climate-friendly cement?</u> [41]

¹⁰⁶ Lopez (June 27, 2022) <u>Climate-friendly cement?</u> [41]

¹⁰⁷ CARB (2022) <u>SCOPING PLAN FOR ACHIEVING CARBON NEUTRALITY</u>. p. 48. [8]

California's climate policies have also prevented the use of CO_2 for certain uses. SB 905 (2022) bans the use of captured CO_2 for enhanced oil recovery (EOR),¹⁰⁸ a process where CO_2 is injected into existing oil fields to extract hard-to-reach deposits, thereby extending the lifetime of oil fields.¹⁰⁹ SB 1314 (2022) effectively bans the use of CO_2 injection for EOR, explicitly citing that the state's support of CCUS technologies is driven by a desire to advance towards a carbon-neutral society rather than extending the lifetime of fossil fuel production facilities.¹¹⁰

10.2.4.2 Relevant United States Federal Funding Programs and Policies

At the federal level, funding in CO₂ utilization has primarily been in the form of grants for early-phase research and development (R&D). The 2009 American Reinvestment and Recovery Act (ARRA) invested \$100 million USD in R&D projects focused on innovative CO₂ conversion projects,¹¹¹ notably in the building materials and chemical production industries.¹¹² From 2012-2017, a portion of the U.S. Department of Energy (DOE)'s Carbon Storage Program (between ~\$1 and 10 million USD annually) funded an R&D portfolio of projects specifically in the space of carbon use and reuse.¹¹³ A similar program (the Climate Innovation Research Opportunity investment program) launched in 2021, providing another \$100 million USD grant program for low-carbon energy technologies, including those in the field of carbon capture and utilization.¹¹⁴ The 2020 Energy Act authorized the Department of Energy to allocate nearly \$7 billion USD in funds for various carbon management and removal programs, including carbon utilization.¹¹⁵ Additional funding is planned from the 2021 Infrastructure Investment and Jobs Act, with \$12 billion USD earmarked for investments in carbon capture, utilization and storage technology.¹¹⁶

Section 45Q in the tax code provides a credit for qualified uses of CO_2 , most commonly used for EOR in the oil and gas sector, but other uses can qualify if they fall into certain categories. The language of Section 45Q(f)(5)(A) permits 45Q credits for processes that fix CO_2 via photosynthesis or chemosynthesis or chemical conversion that securely stores carbon, but other uses could become eligible if a commercial market exists and the use of qualified CO_2 is determined to be eligible for 45Q by the Secretary of Energy.¹¹⁷

In general, experts agree that governments need to develop more incentive structures to encourage CO_2 utilization, as well as more robust policies in place to quantify reduced or

¹⁰⁸ OpenStates (no date) <u>SB 905</u>. [48]

¹⁰⁹ FECM (no date) <u>Enhanced Oil Recovery</u>. [45]

¹¹⁰ IEA (November 4, 2022) <u>Enhanced Oil Recovery and CCUS (SB 1314)</u>. [31]

¹¹¹ IEA (August 24, 2021) <u>American Reinvestment and Recovery Act - CCUS elements</u>. [28]

¹¹² IEA (August 24, 2021) <u>American Reinvestment and Recovery Act - CCUS elements</u>. [28]

¹¹³ NETL (2017) <u>Carbon use and reuse program overview briefing</u>. [42]

¹¹⁴ IEA (July 8, 2021) <u>Climate Innovation Research Opportunity investment program</u>. [29]

¹¹⁵ IEA (March 10, 2022) <u>Energy Act of 2020</u>. [30]

¹¹⁶ IEA (April 18, 2022) <u>Infrastructure and Jobs act</u>. [33]

¹¹⁷ IRS (no date) <u>Request for Comments on Credit for Carbon Oxide Sequestration</u>. p. 5-6. [27]

avoided emissions resulting from CO₂-utilizing products or production pathways. Underpinning any policies or incentives with transparent measurement, reporting, and verification standards will be crucial to ensuring that development of CO₂ utilization programs results in meaningful emissions reductions or carbon removal.¹¹⁸ Although this sounds straightforward, developing these standards is difficult due to the range of products that can be developed utilizing CO₂, and the need to assess the life cycle impacts of CO₂-utilizing products as compared traditional manufacturing methods for those same kinds of products.¹¹⁹

Finally, adaptations in existing legislation and regulations will also be required for the widespread adoption of CO₂-utilizing materials, especially in long-lived products like concrete and building materials that, for public health and safety reasons, are highly regulated. Without a clear regulatory pathway to the adoption of CO₂-utilizing materials as replacements for the carbon-intensive products used today, continued development and commercial scaling of these technologies will not be possible.

¹¹⁸ IEA (2019) <u>Putting CO₂ to Use</u>. p. 67. [34]

¹¹⁹ IEA (2019) <u>Putting CO₂ to Use</u>. p. 67. [34]

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11. Connections with Regional Agriculture

OPPORTUNITIES AT A GLANCE

- Kern County's agricultural sector emits over 2 million tons of CO₂ annually, 65% of which comes from the degradation of agricultural waste, including livestock waste.¹
- 482,000 tons of agricultural waste and 625,000 tons of livestock manure are produced in Kern County annually, and could be converted into renewable fuels, pure streams of CO₂, and/or a source of water.
- Conversion of 100% of Kern County's biomass waste could produce over 900 thousand metric tons of CO_2 annually.
- Biochar is a byproduct of BiCRS + BECCS processes, which could serve as a nutrientadding alternative to fertilizer for regional croplands.
- Additional products of carbon management industries that could be useful to regional agriculture are water (depending on carbon management technology) and CO₂, which can be used to enhance greenhouse production.

¹ Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

11.1 Kern County's Agricultural Sector

Agriculture is a major industry throughout California's Central Valley, a region that produces about a quarter of the nation's food.² In Kern County alone, agricultural output is valued at over \$8 billion annually,³ making it the highest producing agricultural county in California by value in 2021.⁴ The agriculture sector also leads the county in land use,⁵ water use,⁶ and employment,⁷ providing nearly 1 in 5 county jobs directly, and supporting a variety of indirect jobs (i.e. sales of equipment, fertilizers, feed, and other supplies, or supplying food an beverage processing facilities). As such, understanding the ways in which carbon management and clean energy technologies can enhance, benefit from, or compete with this sector are worth considering.

A full examination of agriculture and its projected development in Kern County is beyond the scope of this report. Rather, in this section we will provide a brief overview of the current state of the industry, highlighting strengths, challenges and potential synergistic pathways between agriculture and the development of one or more carbon management business parks in the region.

11.1.1 The Current Agriculture Industry

Kern County's farmland is expansive, covering 2,295,497 acres of land according to the USDA's 2017 Census of Agriculture.⁸ That means that farmland accounts for 44% of Kern county's land area of 5,206,176 acres.⁹ Although over 80% of the county's sales are in crops, land use is more evenly distributed between livestock and crops, with 53% of farmland designated as pastureland and 42% of farmland designated as cropland.¹⁰

Agriculture requires more than land to flourish, though, and the water needed to irrigate Kern County's croplands is in jeopardy. In Kern County today, 2,294,000 million acre-feet of water is devoted to the agriculture industry.¹¹ That represents 93% of total municipal,

² U.S. Geological Survey (no date) <u>California's Central Valley</u>. [45]

³ Kern County Department of Agriculture and Measurement Standards (2022) <u>2021 Kern</u> <u>Agricultural Crop Report</u>. [23]

⁴ When compared to other county crop reports from the California Department of Food and Agriculture; accessed March 4, 2023 from

https://www.cdfa.ca.gov/exec/county/CountyCropReports.html.

⁵ NASS (no date) <u>Agriculture Census: Kern County</u>. [32]

⁶ WAKC (no date) <u>Water in Kern County</u>. [47]

⁷ State of California EDD (no date) <u>California Labor Market Information Resources and Data</u>. [42]

⁸ NASS (no date) <u>Agriculture Census: Kern County</u>. [32]

⁹ U.S. Census Bureau (no date) <u>QuickFacts: Kern County, California</u>. [44] (In this source, land area is given in square miles and has been presented here converted to acres.)

 ¹⁰ NASS (no date) <u>Agriculture Census: Kern County</u>. [32] These percentages do not add to 100% as the Agriculture Census recognizes other categories (woodland, other) that are not discussed here.
 ¹¹ WAKC (no date) <u>Water in Kern County</u>. [47]

industrial and agricultural water use in the county. More than 70% of that water is sourced from reservoirs to the north of the county, or from groundwater in subsurface aquifers.¹² With more frequent droughts impacting the region and the implementation of laws like the 2014 Sustainable Groundwater Management Act (SGMA), which requires local water users to achieve sustainable groundwater use by 2040,¹³ less water will be available for irrigation from rain and snowfall, and significantly less water will be available from underground aquifers.^{14,15} The Public Policy Institute of California estimates the combined impact of climate change and the SGMA could result in as much as 900,000 acres of fallowed farmland in the San Joaquin Valley by 2040. The number can be lessened (but not eliminated) with improved water trading rules, infrastructure investments, and improved agricultural productivity.¹⁶

Development of carbon management business parks like that considered here, provide a potential revenue-generating alternative to agriculture in fallowed croplands, while carbon management itself directly combats the primary driver of climate change-induced droughts. Below, we explore how principles of carbon management – both in collaboration with some of the carbon management industries described in this report and applied directly to agricultural practices – could help farms transition under these new circumstances.

Emissions Source	Kern 2005 ^ь	CA 2005°	CA 2020°	% Change ^d
Livestock enteric fermentation	633,214	10.5 million	11.0 million	+5%
Livestock manure management	741,173	10.4 million	11.6 million	+12%
Crop growing & harvesting	575,572	8.2 million	6.8 million	-17%
Fuel combustion	74,511	4.6 million	2.3 million	-50%
TOTAL	2,024,470	33.7 million	31.7 million	-6%

Table 11.1. Agriculture-related emissions in Kern County and California^a

a. In metric tons CO_2 -equivalent.

b. Kern County Planning and Natural Resources Department (2012) <u>Community GHG emission</u> <u>inventory final report</u>.

c. CARB (2022) California greenhouse gas emissions for 2000 to 2020.

d. Relative change in state-wide emissions from 2005 to 2020.

¹² WAKC (no date) <u>Water in Kern County</u>. [47]

¹³ Escriva-Bou *et al.* (2023) <u>The future of agriculture in the San Joaquin Valley</u>. [15]

¹⁴ California Department of Water Resources (no date) <u>Climate Change Basics</u>. [9]

¹⁵ Escriva-Bou *et al.* (May 14, 2020) <u>Sinking Lands, Damaged Infrastructure</u>. [16]

¹⁶ Escriva-Bou *et al.* (2023) <u>The future of agriculture in the San Joaquin Valley</u>. [15]

11.1.2 Carbon Capture Potential

In 2012, the Kern County Department of Planning and Community Development created an inventory of community-wide greenhouse gas emissions, estimating the county's sector by sector emissions impact in 2005, in units of metric tons CO₂-equivalent (CO_{2e}). The agriculture sector sequestered ~400,000 metric tons of CO_{2e}, annually, through the process of photosynthesis and plant growth, but released over 2 million tons of CO_{2e} through enteric fermentation (digestive gasses of livestock), manure management, crop growing and harvesting, and fuel combustion (Table 11.1).¹⁷ The report forecasted an ~30% increase in emissions by 2020, but no subsequent studies have been undertaken at the county level. At the state level, livestock related emissions have increased 5-12%, crop-related emissions have decreased 17%, and fuel combustion-related emissions have decreased 50%, with the net effect being very little change in agriculture sector emissions since 2020.¹⁸ Of these emissions, some can be reduced through partnerships with biomass with carbon dioxide removal (BiCRS) technologies, detailed in Section 11.2, while others can be reduced through low carbon farming techniques, which are introduced briefly here. With sustainable practices and low-carbon techniques, farms can reduce their overall impacts on the environment. From low-till farms and crop cover to technical systems equipped to monitor water and nutrient levels, there are a variety of potential avenues to reduce the carbon intensity of farming.

About 28% of Kern County's agricultural emissions come from crop growing and harvesting, which includes fertilizer use, soil preparation and disturbance, and crop residue burning.¹⁹ Many of these emissions can be reduced through the practice of *carbon farming*, a set of farming tactics that sequester carbon or reduce the GHG emissions of agriculture by focusing on the importance of CO₂ drawdown via photosynthesis as a carbon removal strategy.²⁰ An example is no-till farming practices, in which the topsoil is left undisturbed, preventing it from releasing its stored carbon into the atmosphere.²¹ Other practices, like cover cropping, also serve to sequester carbon in soils and keep the ground nutrient-rich for other crops. With cover crops, new roots help feed the soil's ecosystem of fungi, bacteria, and other organisms over time, gradually increasing the soil's carbon levels.²²

Currently, these practices are not standard for agricultural land in the region—the USDA found that in Kern County, less than 10% of farms are no-till or reduced-till and that only 2% of farms have cover crops.²³ However, interest has been rising in these practices nationally, and many feel there could be economic benefits as well as climate benefits

¹⁷ Kern County Planning and Natural Resources Department (2012) <u>Community GHG emission</u> <u>inventory</u>. [24]

¹⁸ CARB (2022) <u>California greenhouse gas emissions for 2000 to 2020</u>. [5]

¹⁹ CARB (2022) <u>California greenhouse gas emissions for 2000 to 2020</u>. [5]

²⁰ Carbon Cycle Institute (no date) <u>What is Carbon Farming?</u> [10]

²¹ Spears (June 24, 2018) <u>What is No-Till Farming?</u> [41]

²² Clark (2015) <u>Cover Crops and Carbon Sequestration</u>. [11]

²³ NASS (no date) <u>Agriculture Census: Kern County</u>. [32]

associated with their adoption. Reporting from the USDA indicates that shifting from conventional to continuous no-till farming uses a third of the amount of diesel for farm equipment per acre, saves time in field maintenance, and can save money in future years as the more nutrient-dense soil requires less water and fertilizer to thrive.²⁴ Agricultural planners in Minnesota have reported that the net profit from farms earning \$5.25 per acre with conventional farming can increase up to \$112 per acre with a combination of no-till and cover cropping practices.²⁵

More technologically driven carbon farming techniques include implementation of advanced monitoring equipment and automated systems, which can also help reduce water and fertilizer usage on agricultural lands. A variety of sensors are available to monitor farmland conditions: temperature sensors, electrochemical sensors for nutrient levels and pH, mechanical sensors to monitor soil compression or displacement, airflow sensors to test soil air penetration, and dielectric sensors for calculating soil moisture levels.²⁶ These systems can also be equipped to identify environmental threats like drought stress early, giving farmers more time to plan and mitigate such risks to their livelihood.²⁷

11.2 Potential Relationships with a Carbon Management Business Park: Feedstocks and Products

11.2.1 Agricultural Waste as Carbon Management Feedstocks

Industries under the carbon management umbrella, though they all aim to sequester carbon, utilize different feedstocks and produce varied byproducts of capture. For biomass with carbon dioxide removal or biomass-to-energy with carbon capture and storage processes (collectively referred to as BiCRS, see Section 4), the feedstock is biomass. From an environmental perspective, the biomass source is ideally waste from existing agriculture or forest management practices. Examples specific to agriculture include plant residues (stalks, pits, shells) from harvest seasons, tree trimmings, or other discarded organic material. Obtaining BiCRS feedstocks from such sources solve two problems: they reduce the potential land and water use impacts of BiCRS that would result from producing dedicated feedstock crops, and they prevent the release of CO_2 that has already been trapped in that biomass material back to the atmosphere. Often, agricultural residues are left to decompose on the cropland,²⁸ releasing their carbon content as either methane (CH₄)

²⁴ Creech (August 3, 2021) <u>Saving Money, Time and Soil</u>. [14]

²⁵ Scharpe (January 11, 2020) <u>Economics of no-till and cover crop; does it really pay off?</u> [39]

²⁶ GeoPard Agriculture (no date) <u>What types of sensors are used in precision agriculture?</u> [17]

 ²⁷ GlobalNewsWire (February 12, 2020) <u>Agricultural Sensors Market To Reach USD 2.56 Billion By</u>
 <u>2026</u>. [18]

²⁸ Lal (2005) <u>World crop residues production and implications of its use as a biofuel</u>. [26]

or CO_2 into the atmosphere, or are they burned.²⁹ The latter technique, common in orchards and vineyards, also releases air pollutants like SO_2 , nitrous oxides, and particulate matter,³⁰ and are a particular health hazard to the regional community.³¹

In Kern County in 2021, 482,000 tons of almond hulls, almond shells and crop biomass were produced.³² From 2000-2020, between 200,000 and 1,200,000 tons of agricultural waste were burned in the San Joaquin Valley each year.³³ The variation is due to increasing burn prohibitions from 2003-2011, which were relaxed over the following decade in response to drought-related fallowing of croplands. In 2021, the California Air Resources Board (CARB) renewed their plan to phase out agricultural burning entirely by 2024,³⁴ meaning disposal alternatives will be required for the region's agricultural waste. Currently, CARB is offering a grant program that incentivizes 'whole orchard recycling' as an alternative to burning.^{35,36} Whole orchard recycling involves the chipping and grinding of waste material, which is then re-incorporated into the soil. It has the advantage of restoring soil nutrients, but may still release greenhouse gasses to the atmosphere as it decomposes into the soil. Another disadvantage is that it is a tax-funded program that may not run indefinitely. A more ideal solution to agricultural waste removal is identifying a buyer, for which BiCRS industries would be strong candidates.

Based on the average amount of carbon in organic feedstocks (~49% by mass of the dry tonnage),³⁷ the agriculture waste in Kern County alone could produce as much as 860,000 metric tons of CO₂ for geologic storage, depending on the BiCRS technique applied. If all of the San Joaquin Valley's agricultural waste were used for carbon management (approximating from the maximum rate of annual burning), as much as 2 million metric tons of CO₂ could be produced for geologic storage.

11.2.2 Renewable Natural Gas (RNG)

Another industry that relies heavily on biomass inputs is the renewable natural gas (RNG) industry. RNG relies on capturing the biomethane released from decomposing biomass, which can then be captured and compressed for use as natural gas.³⁸ A wide variety of

²⁹ CARB (2021) <u>San Joaquin Valley agriculture burning assessment</u>. [6]

³⁰ Andini *et al.* (2018) Impact of crop residue burning on air pollution and climate change. [3]

³¹ Vaughan, Klein (September 6, 2022) <u>Smoke from ag burning contributes to long-term health</u> <u>effects</u>. [46]

³² Kern County Department of Agriculture and Measurement Standards (2022) <u>2021 Kern</u> <u>Agricultural Crop Report</u>. [23]

³³ CARB (2021) <u>San Joaquin Valley agriculture burning assessment</u>. [6]

³⁴ CARB (no date) <u>San Joaquin Valley agricultural burning phase down</u>. [7]

³⁵ Mayer (September 10, 2022) <u>The goal is to end open-field burning by growers</u>. [29]

³⁶ Klein, Vaughan (September 8, 2021) <u>As air regulators phase out ag burning, what's the</u> <u>alternative?</u> [25]

³⁷ Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 31. [4]

³⁸ Murillo (August 8, 2022) <u>A RNG Facility Will Be Opening Soon in Lost Hills</u>. [31]

biomass can be used for RNG–agriculture waste and dairy manure are the most relevant for this section, but waste from food, wastewater, and landfills can also be used for RNG.³⁹

Over the last decade, RNG has already been making inroads within Kern County. The CalBioGas cluster in Kern County is a joint venture wherein local dairy farmers use onsite dairy digesters to capture methane (CH₄), which is then shipped to a central upgrading facility run by California BioEnergy and Chevron that converts the methane into RNG.⁴⁰ A company described in detail in the BiCRS section of this report (Section 4), San Joaquin Renewables, is planning to site its first waste biomass-to-RNG facility in McFarland and will be producing RNG alongside its plans to capture and sequester CO₂.⁴¹ Once active, their RNG will be transported using pipelines from regional energy provider SoCalGas.⁴² SoCalGas has been actively embracing RNG as an energy alternative, with nine RNG projects currently connected to their system.⁴³ By 2030, SoCalGas is aiming to have 20% RNG in the natural gas supply that it sends to core customers.⁴⁴ Given these recent and upcoming projects, it appears that there is substantial interest in future RNG expansion in Kern County.

A significant contribution to the enthusiasm for RNG comes from economic incentives – under California's Low Carbon Fuel Standard (LCFS) program, in effect until at least 2030, RNG can qualify for LCFS credits in any situation where RNG is replacing "conventional transportation fuel in California,"⁴⁵ significantly subsidizing the cost of production (see Section 4). But there are carbon management incentives worth considering as well.

Anaerobic digestors, which are a typical first step in the conversion of biomass waste (particularly livestock manure) to RNG, produce *biogas*, which is a mixture of methane, CO_2 and other trace gasses.⁴⁶ About 18-27% of livestock manure solids (dry weight) will be converted to biogas.⁴⁷ Biogas is then *upgraded* to produce RNG (Figure 11.1),⁴⁸ by stripping the CO_2 and other gasses, leaving pure biologically-derived methane that can serve as a drop-in replacement anywhere methane is used. The ratio of CO_2 to CH_4 in the biogas is about 30-40 mol% CO_2 and 60-70 mol% CH_4 .⁴⁹ That means that for the 625,000 tons of

³⁹ Murillo (August 8, 2022) <u>A RNG Facility Will Be Opening Soon in Lost Hills</u>. [31]

⁴⁰ California Climate Investments (2021) <u>Capturing Methane to Create Renewable Fuels in Kern</u> <u>County</u>. [8]

⁴¹ San Joaquin Renewables (no date) <u>The Project</u>. [38]

⁴² San Joaquin Renewables (no date) <u>The Project</u>. [38]

⁴³ SEMPRA (February 24, 2022) <u>RNG in SoCalGas Pipelines</u>. [40]

⁴⁴ SEMPRA (February 24, 2022) <u>RNG in SoCalGas Pipelines</u>. [40]

⁴⁵ Psihoules, Toro, Gamache (December 8, 2021) <u>LCFS credit for renewable natural gas</u>. [37]

⁴⁶ Yentekakis, Goula (2017) <u>Biogas management</u>. [48]

 ⁴⁷ PennState Extension (March 12, 2012) <u>Biogas from manure</u>. [36] ~15% of livestock manure are solids. Of those, 91% are volatile (can be converted to biogas), and conversion efficacy is 20-30%.
 ⁴⁸ IEA (no date) <u>Introduction to biogas and methane</u>. [21]

⁴⁹ Yentekakis, Goula (2017) <u>Biogas management</u>. p. 3. [48]

livestock manure produced by Kern County in 2021,⁵⁰ about 150,000 tons of biogas can be produced, which can be separated into about 4 million cubic feet of RNG as well as 85,000 tons of CO₂ for geologic storage.⁵¹



Figure 11.1. Schematic of RNG production. Image credit: International Energy Agency (IEA).52

11.2.2 Carbon Management Byproducts as Agricultural Supplements

Some BiCRS process used to convert biomass also generate useful byproducts for agriculture. For example, biomass processed via pyrolysis and gasification produces biochar, a soil additive that can support soil microorganisms, mitigate heavy metal toxicity, and raise soil pH.^{53,54} Biochar can often be applied in place of traditional fertilizers, which has downstream benefits for the environment, as it prevents nitrogen runoff into

⁵⁰ Kern County Department of Agriculture and Measurement Standards (2022) <u>2021 Kern</u> <u>Agricultural Crop Report</u>. [23] (Note: we are assuming dry tons. This is not explicitly stated in the report, but is consistent with the fraction of California's livestock farms located in Kern County and the state-wide dairy manure biomass estimate in Baker *et al.* (2020) <u>Getting to Neutral</u>. p. 32., which is listed in bone-dry tons.)

⁵¹ Assumptions made in this calculation: Livestock manure was reported as dry tons, conversion factor to biogas is 25%, molar ratio of CO_2 to CH_4 is 30%:70%, 1 metric ton of methane at atmospheric pressure is 57,800 cubic feet.

⁵² IEA (no date) <u>Introduction to biogas and methane</u>. [21]

⁵³ ARS (no date) <u>What is Pyrolysis?</u> [2]

⁵⁴ ARS (no date) <u>Exploring the Benefits of Biochar</u>. [1]

waterways and the release of excess nitrous oxide (N₂O) into the atmosphere—a greenhouse gas that warms the planet 300 times as much as CO_2 .⁵⁵

Additionally, some biomass gasification processes and S-DAC facilities generate water as a byproduct. The biomass gasification for San Joaquin Renewables uses local wood waste and nut shells to generate water along with biochar, renewable natural gas (RNG), and CO₂ for sequestration.⁵⁶ Clean Energy Systems, which has an existing test facility at Kimberlina in Kern County,⁵⁷ and purchased the idle Delano biomass facility, also in Kern, with plans to develop it into a BiCRS facility (still in the pre-permitting and assessment phase),⁵⁸ also produces water as a byproduct of their oxy-fuel combustion system (Section 4). Though utilizing an entirely different process, Climeworks' solid direct air capture (S-DAC) system also generates water alongside CO₂, generating 0.8-2 tons of water per ton of CO₂ captured.⁵⁹

11.3 Other Collaborative Opportunities

11.3.1 Multi-Use Potential

Another potential opportunity for symbiosis between regional agriculture and carbon management industries is to share resources—primarily land, but potentially water as well—with local agriculture.

If water resources become increasingly scarce and farmers are being required by new groundwater policies to make decisions to permanently fallow unproductive land, then land could be rented or sold to carbon management companies, who may have large land use requirements to operate facilities (especially if they rely on solar power). In this arrangement, the land would continue to be profitable through the rents paid. Additional funding could be raised if farmers sold water to carbon management industries to operate. Some companies in the green energy and carbon management space are explicitly looking for landowners to partner with to deploy their processes, including NovoHydrogen, a company planning to develop local hydrogen fuels without degrading the land,⁶⁰ and InterEarth, looking for sites appropriate for their direct biomass burial method.⁶¹

Some technologies hold the promise of being able to operate with high mobility or to be decentralized, with nodal facilities spread out over large areas. In terms of high mobility, one example is Charm Industrial—their biomass pyrolyzer equipment can fit in the back of

⁵⁵ Manthiram, Gribkoff (July 15, 2021) <u>Explainer - Fertilizer and Climate Change</u>. [28]

⁵⁶ San Joaquin Renewables (no date) <u>The Project</u>. [38]

⁵⁷ Clean Energy Systems (no date) <u>Site Locations</u>. [12]

⁵⁸ Cox (December 4, 2021) <u>Idle biomass plant near Delano would reopen</u>. [13]

⁵⁹ Lebling *et al.* (May 2, 2022) <u>6 Things to Know About Direct Air Capture</u>. [27]

⁶⁰ NovoHydrogen (no date) <u>Partner with Us</u>. [33]

⁶¹ InterEarth (no date) <u>For Farmers</u>. [20]

a semi-trailer and can be driven directly to a site, so biomass doesn't have to be transported to a central processing facility.⁶² Charm also pays farmers to be able to collect their biomass, and their unit can be temporarily stationed on the edge of a field during harvest season, when there is an abundance of waste biomass, and then offsite the rest of the year.⁶³ In terms of diffuse land use, direct air capture (DAC) is a prime example of technology that works well spread out across the land. Although DAC contactors can be placed anywhere (see Section 3), there is likely a minimum spacing of several hundred yards between contactors, to ensure the CO₂-free exhaust of one contactor fan does not directly feed into the next.⁶⁴ The space between contactors could be used for other land-intensive purposes, like farming or solar panels. However, there are uncertainties about how well crops would handle growing in between units that absorb CO₂ from the atmosphere, as plants also need to absorb CO₂ from the atmosphere to grow successfully.⁶⁵ This issue warrants further investigation.

11.3.2 Greenhouses

Greenhouses are experiencing a period of growth in California, driven primarily by drought conditions and an increasing consumer demand for organic and locally-grown produce.⁶⁶ This is because greenhouses promote higher productivity, even in less optimal environments: farming can take place on a smaller land footprint with lower water usage while still obtaining high crop yields.⁶⁷ Innovations like UC Santa Cruz's solar greenhouse, which uses transparent solar panels to filter light and help offset operational costs, are working towards the development of greenhouses that could be used "in most of California" rather than just along the coast.⁶⁸ Although these developments are still in precommercial stages, it presents another opportunity for the long-term future of agriculture in Kern County and California at large.

If greenhouses were implemented in Kern County, some of the CO_2 captured by carbon management industries could be supplied to the greenhouses to encourage plant growth. CO_2 must be very pure to not damage the plants,⁶⁹ but increasing the CO_2 concentration of the ambient air inside greenhouses can increase yields of some crops by up to 25-30% with CO_2 application.⁷⁰ Typically, greenhouses obtain CO_2 from combustion of natural gas, which also serves as a heat source for the facility. A retrofitted oil pipeline in the

⁶² Temple (May 26, 2022) <u>Charm Industrial's big bet</u>. [43]

⁶³ Temple (May 26, 2022) <u>Charm Industrial's big bet</u>. [43]

⁶⁴ Herzog (February 4, 2021) <u>Direct air capture: A process engineer's view</u>. 16:05-16:34. [19]

⁶⁵ Ontario Ministry of Agriculture, Food, and Rural Affairs (August 2009) <u>Carbon Dioxide in</u> <u>Greenhouses</u>. [35]

⁶⁶ Murdock (July 23, 2018) <u>Solar Greenhouse</u>. [30]

⁶⁷ Murdock (July 23, 2018) <u>Solar Greenhouse</u>. [30]

⁶⁸ Murdock (July 23, 2018) <u>Solar Greenhouse</u>. [30]

⁶⁹ IEA (2019) <u>Putting CO₂ to Use</u>. [22]

⁷⁰ IEA (2019) <u>Putting CO₂ to Use</u>. [22]

Netherlands spanning over 180 miles demonstrates a viable alternative: the pipeline supplies 500,000 metric tons of CO_2 annually (captured from hydrogen production) to over 600 greenhouses in the region, and without the need of producing CO_2 from natural gas combustion, the greenhouses are able to switch to more sustainable heat sources.⁷¹

11.3.3 Other Potential Opportunities

This report is not comprehensive. There are other opportunities in the agribusiness space that may work symbiotically with carbon management technologies but were not identified to be good fits for Kern County at this time, and thus were not explored further here, although some examples are discussed in greater detail in other sections of the report. These include developing dedicated biomass crops to sustain BiCRS operations (also addressed in Section 3) or using CO_2 to promote algae growth to generate petroleum substitutes⁷² (also addressed in Section 10).

A proposed component of the Carbon Management Business Park is a dedicated Research and Development Incubator, which would be an ideal setting for the exploration of new ways that local agriculture and carbon management industries could serve one another.

⁷¹ OCAP (no date) <u>Factsheet: Pure CO2 for Greenhouses</u>. [34]

⁷² IEA (2019) <u>Putting CO₂ to Use</u>. [22]

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Appendices

Appendix A. Existing commercial and industrial power facilities with CCS

Appendix B. Commercial and industrial power facilities with CCS in advanced development

Appendix C. Commercial and industrial power facilities with CCS in early development

Appendices A-C are summarized from the Global CCS Institute (GCCSI) CO₂RE Facilities Database, a list of all historical, active, and developing carbon-capture related projects worldwide. The database is maintained, and updated regularly to reflect status updates and new projects. The lists represented by Appendices A-C represent the status of the global carbon management industry as of the publication of this report. The database was sampled for this report on March 18, 2023.¹

Appendix D. Comparative analysis of carbon management industries

A primary objective of this report is to provide an accessible resource for cost-benefit analysis of a variety of carbon management technologies that could hypothetically be developed in Kern County. We developed quantitative estimates of 6 key metrics across all 5 carbon management technologies examined in detail (L-DAC, S-DAC, BiCRS, green hydrogen from biomass, and steel with point source carbon capture):

- Land use
- Energy use
- Water use
- Job growth potential
- Cost to build (a proxy for potential county tax revenue)

¹ Global CCS Institute (GCCSI). CO₂RE Facilities Database. Published (no date). Accessed March 18, 2023 from <u>https://co2re.co/FacilityData</u>.
- Cost per ton CO_2 (a reflection of the competitiveness of the industry in the emerging carbon market)

Details of how each estimate was determined is given in the relevant section of the report, but how each industry compares with each other across these six metrics is shown visually in Appendix D across a suite of Figures D.1- D.6. The same figures are provided in the Comparative Analysis section of the companion website, at <u>cmbp.kernplanning.com</u>.

Appendix A. Existing commercial and industrial power facilities with CCS

Facility Name	Country	Operational	Industry	
Terrell Natural Gas Processing Plant (formerly Val Verde)	USA	1972	Natural gas processing	
Enid Fertilizer	USA	1982	Fertilizer production	
Shute Creek Gas Processing Plant	USA	1986	Natural gas processing	
MOL Szank field CO2 EOR	Hungary	1992	Natural gas processing	
Sleipner CCS Project	Norway	1996	Natural gas processing	
Great Plains Synfuels Plant and Wayburn- Midale	USA	2000	Chemical production	
Core Energy	USA	2003	Natural gas processing	
In Salah CO2 Storage	Algeria	2004	Natural gas processing	
Petrobras Santos Basin Pre-Salt Oil Field	Brazil	2008	Natural gas processing	
Snohvit CO2 Storage	Norway	2008	Natural gas processing	
Arkalon CO2 Compression Facility	USA	2009	Ethanol production	
Century Plant	USA	2010	Natural gas processing	
Bonanza BioEnergy	USA	2012	Ethanol production	
Yanchang Integrated CCS Demonstration	China	2012	Chemical production	
Air Products Steam Methane Reformer	USA	2013	Hydrogen production	
Coffeyville Gasification Plant	USA	2013	Fertilizer production	
Lost Cabin Gas Plant	USA	2013	Natural gas processing	
PCS Nitrogen	USA	2013	Fertilizer production	
Boundary Dam Unit 3	Canada	2014	Power plant - coal	
Karamay Dunhua Oil Technology	China	2015	Chemical production (Methanol)	
Quest	Canada	2015	Hydrogen production	
Uthmaniyah CO2-EOR Demonstration	Saudia Arabia	2015	Natural gas processing	
Abu Dhabi CCS (Emirates Steel Industries)	UAE	2016	Iron/steel production	
Illinois Industrial Carbon Capture and Storage	USA	2017	Ethanol production	
Petra Nova Carbon Capture	USA	2017	Power plant - coal	
CNPC Jilin Oil Field CO2 EOR	China	2018	Natural gas processing	
Gorgon Carbon Dioxide Injection	Australia	2019	Natural gas processing	
Qatar LNG	Qatar	2019	Natural gas processing	
Alberta Carbon Trunk Line (ACTL) - Nutrien	Canada	2020	Fertilizer production	
Alberta Carbon Trunk Line (ACTL) - Sturgeon Refinery	Canada	2020	Hydrogen production	
Guohua Jinjie	China	2020	Power plant - coal	
Orca	lceland	2021	Direct air capture	
Glacier Gas Plant	Canada	2022	Natural gas processing	
Red Trail Energy	USA	2022	Ethanol production	
Sinopec Qilu-Shengli CCUS	China	2022	Chemical production	

Appendix B.

Commercial and industrial power facilities with CCS in advanced development

Facility Name	Country	Operational	Industry
Stockholm Exergi BECCS	Sweden	2025	BiCRS/BECCS
HeidelbergCement	USA	2023	Cement production (incl. lime)
Norcem Brevik Cement Plant	Norway	2024	Cement production (incl. lime)
Antwerp@C - BASF Antwerp	Belgium	2030	Chemical production
Lake Charles Methanol	USA	2025	Chemical production
Farley DAC	USA		Direct air capture
Mammoth	lceland	2024	Direct air capture
Occidental, 1PointFive	USA	2024	Direct air capture
Aberdeen Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Atkinson Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Bushmills Biorefinery CCS	USA	2024	Ethanol production
Casselton Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Central City Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Fairmont Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Federated Co-operatives Limited	Canada	2024	Ethanol production
Galva Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Goldfield Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Grand Junction Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Granite Falls Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Heron Lake Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Huron Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Lamberton Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Lawler Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Marcus Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Mason Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Merrill Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Mina Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Nevada Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Norfolk Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
One Earth Energy facility	USA	2025	Ethanol production
Onida Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production

Facility Name	Country	Operational	Industry	
Otter Tail Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Plainview Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Project Interseqt - Plainview Ethanol Plant	USA	2024	Ethanol production	
Redfield Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Shenandoah Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Sioux Center Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Steamboat Rock Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Superior Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Watertown Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Wentworth Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Wood River Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
York Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production	
Wabash CO2 Sequestration	USA	2022	Fertilizer production	
Air Liquide Refinery Rotterdam	Netherlands	2024	Hydrogen production	
Air Products Net-Zero Hydrogen Energy Complex	Canada	2024	Hydrogen production	
Air Products Refinery Rotterdam	Netherlands	2024	Hydrogen production	
Baytown Low Carbon Hydrogen	USA	2027	Hydrogen production	
Cliff Head CCS Project (Mid West Clean Energy Project)	Australia	2025	Hydrogen production	
ExxonMobil Benelux Refinery	Netherlands	2024	Hydrogen production	
Phillips 66 Humber Refinery	UK	2028	Hydrogen production	
Polaris Carbon Storage	Norway	2024	Hydrogen production	
Shell Refinery Rotterdam CCS	Netherlands	2024	Hydrogen production	
Louisiana Clean Energy Complex	USA	2026	Hydrogen production	
Federated Co-operatives Limited	Canada	2026	Hydrogen production (Oil refining)	
Prax Lindsey Carbon Capture Project	UK	2028	Hydrogen production (Oil refining)	
Abu Dhabi CCS (Natural gas processing plant)	UAE	2025	Natural gas processing	
Bayu-Undan CCS	Timor-Leste	2027	Natural gas processing	
Ghasha Concession Fields	UAE	2025	Natural gas processing	
Lang Lebah	Malaysia	2026	Natural gas processing	
Northern Delaware Basin	USA	2023	Natural gas processing	
PTTEP Arthit	Thailand	2026	Natural gas processing	
Guodian Taizhou Power Station	China	2023	Power plant - coal	
Cal Capture	USA	Mid-2020's	Power plant - NG	
Capital Power Genesee	Canada	2026	Power plant - NG	

Facility Name	Country	Operational	Industry
Coyote Clean Power Project	USA	2025	Power plant - NG
Deer Park Energy Centre	USA		Power plant - NG
James M. Barry Electric Generating Plant	USA	2030	Power plant - NG
Mustang Station of Golden Spread Electric Cooperative	USA		Power plant - NG
Peterhead CCS Power Station	United Kingdom	2026	Power plant - NG
Plant Daniel Carbon Capture	USA		Power plant - NG
VPI Immingham power plant	United Kingdom	2027	Power plant - NG
Acorn Storage Site	United Kingdom	2025	Infrastructure
Bayou Bend CCS	USA	2025	Infrastructure
Bridgeport Energy Moonie CCUS Project	Australia	2023	Infrastructure
CODA Shipping	lceland	2026	Infrastructure
CODA Terminal Onshore Infrastructure	lceland	2026	Infrastructure
CODA Terminal Pipeline	lceland	2026	Infrastructure
CODA Terminal Storage	lceland	2026	Infrastructure
East Coast Cluster	United Kingdom	2025	Infrastructure
East Coast Cluster Humber Pipeline	United Kingdom	2025	Infrastructure
East Coast Cluster Teesside Pipeline	United Kingdom	Mid-2020's	Infrastructure
Endurance Storage Site	United Kingdom	2025	Infrastructure
Porthos - Compressor Station	Netherlands	2024	Infrastructure
Porthos - Offshore Pipeline	Netherlands	2024	Infrastructure
Porthos Storage	Netherlands	2025	Infrastructure
Project Greensand	Denmark	2025	Infrastructure
Prothos - Onshore Pipeline	Netherlands	2024	Infrastructure
Southeast Saskatchewan CCUS Hub - Storage	Canada		Infrastructure
Stockholm Exergi BECCS - Shipping Route	Sweden	2025	Infrastructure
Summit Pipeline	USA	2024	Infrastructure
Viking CCS Pipeline	United Kingdom	2027	Infrastructure
Viking CCS Storage Site	United Kingdom	2027	Infrastructure
Norcem Brevik - Shipping Route	Norway	2024	Infrastructure
Northern Lights - Storage	Norway	2024	Infrastructure
Copenhill (Amager Bakke)	Denmark	2025	Waste-to-energy
Hafslund Oslo Celsio-Truck Route	Norway	2025	Waste-to-energy
Hafslund Oslo Celsio	Norway	2024	Waste-to-energy

Appendix C.

Commercial and industrial power facilities with CCS in early development

Facility Name	Country	Operational	Industry
Clean Energy Systems BiCRS Plant - Madera County	USA	2027	BiCRS/BECCS
Clean Energy Systems Carbon Negative Energy Plant	USA	2025	BiCRS/BECCS
Cyclus Power Generation	USA		BiCRS/BECCS
Drax BECCS Project	UK	2027	BiCRS/BECCS
Mendota BECCS	USA	2025	BiCRS/BECCS
Air Liquide CalCC	France	2028	Cement production
CEMEX	Germany	2026	Cement production
GO4ECOPLANET	Poland		Cement production
HyNet North West - Hanson Cement	UK	2026	Cement production
K6	France		Cement production
LafargeHolcim Cement Carbon Capture	USA	Mid-2020's	Cement production
LafargeHolcim Ste. Genevieve Cement Plant	USA		Cement production
Antwerp@C - Borealis Antwerp	Belgium	2030	Chemical production
Antwerp@C - Exxonmobil Antwerp Refinery	Belgium	2030	Chemical production
Antwerp@C - Ineos Antwerp	Belgium	2030	Chemical production
Hackberry Carbon Sequestration Project (Sempra)	USA		Chemical production
The Illinois Clean Fuels Project	USA	2025	Chemical production
Velocys' Bayou Fuels Negative Emission Project	USA	2026	Chemical production
Nauticol Energy Net Zero Methanol	Canada	Mid-2020's	Chemical production (Methanol)
Acorn Direct Air Capture Facility	UK	2026	Direct air capture
FS Lucas do Rio Verde	Brazil		Ethanol production
Midwest AgEnergy Blue Flint Ethanol	USA	2022	Ethanol production
Project Interseqt - Hereford Ethanol Plant	USA	2023	Ethanol production
Barents Blue	Norway	Mid-2020's	Fertilizer production
CF Fertilisers Billingham Ammonia CCS	UK	2023	Fertilizer production
El Dorado	USA	2024	Fertilizer production
ExxonMobil Donaldsonville	USA	2025	Fertilizer production
PAU Central Sulawesi Clean Fuel Ammonia Production	Indonesia	Mid-2020's	Fertilizer production
Project Pouakai Hydrogen Production	New Zealand	2024	Fertilizer production
Yara Sluiskil	Netherlands	2025	Fertilizer production
Acorn Hydrogen	UK	2025	Hydrogen production
Air Liquide Normandy CCS	France	2025	Hydrogen production
Buxton Lime Net Zero	UK	2024	Hydrogen production
H2NorthEast	UK	2027	Hydrogen production
Hydrogen 2 Magnum	Netherlands	2024	Hydrogen production
Hydrogen to Humber Saltend	UK	2027	Hydrogen production

Facility Name	Country	Operational	Industry	
HyNet Hydrogen Production	UK	2025	Hydrogen production	
HyNet North West	UK	Mid-2020's	Hydrogen production	
Killinholme Power Station	UK	2027	Hydrogen production	
L10 Carbon Capture and Storage	Netherlands	2026	Hydrogen production	
Net Zero Teesside	UK	2027	Hydrogen production	
Northern Gas Network H21	UK	2026	Hydrogen production	
Polaris CCS	Canada	Mid-2020's	Hydrogen production	
Preem Refinery	Sweden	2025	Hydrogen production	
Project Pouakai Hydrogen Production	New Zealand	2024	Hydrogen production	
Zeeland Refinery Azur	Netherlands	2026	Hydrogen production	
Sukowati CCUS	Indonesia	2028	Hydrogen production (Oil refining)	
Vertex Hydrogen	UK	2025	Hydrogen production (Oil refining)	
ArcelorMittal Texas (formerly voestalpine Texas)	USA		Iron/steel production	
Caroline Carbon Capture Power Complex	Canada	Mid-2020's	Natural gas processing	
G2 Net-Zero LNG	USA		Natural gas processing	
Grand Forks Blue Ammonia Capture plant	USA		Natural gas processing	
INPEX CCS Project Darwin	Australia	2026	Natural gas processing	
NextDecade Rio Grande LNG	USA	2025	Natural gas processing	
Novatek Yamal LNG	Russia	Late 2020's	Natural gas processing	
Otway Natural Gas Plant	Australia	2026	Natural gas processing	
Repsol Sakakemang Carbon Capture and Injection	Indonesia	2026	Natural gas processing	
South East Australia Carbon Capture Hub	Australia	2025	Natural gas processing	
Dave Johnston Plant	USA	2020's	Power plant - coal	
Diamond Vault CCS	USA	2028	Power plant - coal	
Dry Fork Integrated CCS	USA	2025	Power plant - coal	
Korea-CCS 1&2	South Korea	2020's	Power plant - coal	
Caledonia Clean Energy	UK	2025	Power plant - NG	
Caroline Carbon Capture Power Complex	Canada	Mid-2020's	Power plant - NG	
Damhead Powerstation	UK		Power plant - NG	
Ervia Cork CCS	Ireland	2028	Power plant - NG	
Illinois Allam-Fetvedt cycle power plant	USA	2025	Power plant - NG	
Keady 3 CCS Power Station	UK	2027	Power plant - NG	
Medway Power Station	UK Power plant - N		Power plant - NG	
Net Zero Teesside - NET Power Plant	UK	Mid-2020's	Power plant - NG	
Net Zero Teesside CCGT Facility	UK	2025	Power plant - NG	
Pembroke Power Station	UK	2030	Power plant - NG	
Project Pouakai Hydrogen Production	New Zealand	2024	Power plant - NG	
Saskatchewan NET power plant	Canada	Mid-2020's	Power plant - NG	
Whitetail Clean Energy	UK		Power plant - NG	

Facility Name	Country	Operational	Industry
Cane Run CCS	USA		Power plant - NG
Acorn	UK	Mid-2020's	Infrastructure
Acorn CO2 Pipeline	UK	2026	Infrastructure
Arun CCS Hub	Indonesia	2029	Infrastructure
Borg CO2	Norway		Infrastructure
Burrup CCS Hub	Australia		Infrastructure
Carbon TerraVault I	USA	2025	Infrastructure
Cinfracap - Pipeline	Sweden	2026	Infrastructure
Cinfracap - Shipping Route	Sweden	2026	Infrastructure
Coastal Bend CCS	USA	2026	Infrastructure
Damhead Pipeline	UK		Infrastructure
Delta Corridor Pipeline Network	Netherlands	2026	Infrastructure
Fortum Oslo Varme - Shipping Route	Norway	2025	Infrastructure
Heartland Greenway Storage	USA	2025	Infrastructure
HyNet Pipeline	UK	2025	Infrastructure
Hynet Storage Site	UK	2025	Infrastructure
Isle of Grain LNG Terminal	UK	2026	Infrastructure
Jubail CCS	Saudia Arabia	2027	Infrastructure
Medway Hub - Esmond and Forbes Carbon Storage	UK		Infrastructure
Medway Hub Shipping	UK		Infrastructure
Northern Lights - Pipeline	Norway	2024	Infrastructure
Origins Project Carbon Storage Hub	Canada	2026	Infrastructure
Ravenna CCS Hub	Italy	2027	Infrastructure
River Bend CCS Louisiana Pipeline	USA	2026	Infrastructure
Net Zero Teesside	UK	2027	Waste-to-energy
Runcorn Carbon Capture	UK		Waste-to-energy
Tees Valley Energy Recovery Facility Project	UK	2026	Waste-to-energy



Appendix D. Comparative analysis of carbon management industries

Figure D.1. Land Use. To capture 1 million metric tons of CO_2 , the land use requirements of facilities vary considerably. Across the examined industries, estimated footprints range from 0.08 to 2.73 square miles (49-1730 acres). In cases where there is not an operational facility with the capacity to capture carbon at the million ton scale (L-DAC, S-DAC and green hydrogen from biomass) these footprints are industry-provided estimates of needed space. For established industries (steel and BiCRS), the range of values reflects the variability of existing facility footprints, most of which are not actively capturing CO_2 . The range in land use is mostly due to availability and affordability of land, and the retrofitting of these types of facilities with carbon capture equipment would likely not result in a significant change in areal footprint. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2 , but it depends on the source of iron and type of energy used.



Figure D.2. Energy Use. Most carbon management industries (L-DAC, S-DAC, green hydrogen from biomass, and steel) are energy intensive, requiring both electricity and heat energy. DAC technologies require the largest amounts of energy per ton of CO₂ captured, whereas most of the energy demand for steel goes into steel production (the light shaded region) rather than CO₂ capture (the dark shaded region). Green hydrogen from biomass is less energy-intensive, and like steel, the energy needs also generate a different primary output: production of H₂ gas. Other forms of BiCRS (including BECCS) generate more energy than they consume, and are thus able to power their own production, with some facilities also selling energy to the grid. As a result, BiCRS facilities do not require an external energy supply unless it is more profitable to sell their output (i.e. biofuel, syngas) than to use it to operate the facility. An additional critical factor to note is that any facility using solar PV for their energy needs will also require electricity and heat storage (batteries) to ensure uninterrupted supply of electricity and that heat is provided at the required temperatures (100-1000°C, depending on industry). *A steel facility of the size modeled here could produce up to 1 million tons of CO₂, but it depends on the source of iron and type of energy used. The more power supplied by solar energy, the less CO₂ the steel mill would produce.



Figure D.3. Water Use. Water use is one of the most variable categories across carbon management industries. Hydrogen production via biomass, steel and particularly L-DAC technologies are water-intensive practices, using as much as 16,200 acre feet of water annually. Meanwhile, BiCRS and S-DAC technologies can actually generate excess water by capturing it from biomass feedstocks or the atmosphere. This water yield depends on the specific process a facility uses, but could be as much as 1,650 acre feet annually. Due to the arid environment in large parts of Kern County, mindfulness about the water intensity of these industries is crucial to ensure supplies can continue to meet a mixture of residential, agricultural, and industrial demands for decades to come. *A steel facility of the size modeled here could produce up to 1 million tons of CO₂, but it depends on the source of iron and type of energy used.



Figure D.4. Job Development Potential. The job growth potential of carbon management facilities can be difficult to quantify, as different companies rely on different processes—even within the same industry—that shapes their labor demands. Industries like BiCRS and hydrogen production via biomass expect to have lower labor demands, similar to that required to operate bioenergy power plants that do not utilize carbon capture. L-DAC and S-DAC have larger expected labor demands, mainly to monitor and maintain contactor units, although it is possible that some of these jobs could be performed remotely, and would not necessarily benefit the host community. Steel is likely to provide the most jobs. It is important to note that job growth potential for many of these industries was determined from the number of jobs at smaller facilities, and because the need for workers does not scale linearly with facility size, these are rough estimates. Furthermore, the possibilities of increased automation and remote monitoring means that steps should be taken in the planning and permitting process to ensure jobs for any new carbon management facility benefits local communities. *A steel facility of the size modeled here could produce up to 1 million tons of CO₂, but it depends on the source of iron and type of energy used.



Figure D.5. Cost to Build. Building a new carbon management site comes with considerable expense—securing land, planning, engineering, permitting and zoning, environmental assessments, and other details will need to be handled before construction even begins. Across all of these carbon management industries, upfront costs range from \$278 million to 1.7 billion. Costs are generally expected to be higher for the direct air capture industries (L-DAC and S-DAC) than for the biomass-based hydrogen production, BiCRS and steel facilities. However, many of these industries have never been built at a scale that could capture 1 million metric tons of CO₂ per year, which accounts for the large ranges of uncertainty in their upfront costs. *A steel facility of the size modeled here could produce up to 1 million tons of CO₂, but it depends on the source of iron and type of energy used.



Figure D.6. Cost to Capture. The levelized cost per metric ton of CO_2 is a good way to consider overall costs – it accounts for the cost of building the facility (capital costs), the cost of maintenance and labor (operational costs), and the cost of energy (heat + electricity) over the lifetime of the plant. In these estimates, the plant lifetime has been fixed at 30 years to standardize estimates, though some of these facilities may have longer or shorter lifetimes. The cost of carbon capture is lowest for steel emissions, given the relatively high concentration of CO_2 in exhaust gases from this kind of facility, as well as the maturity of the technology. Biomass-based carbon capture (BiCRS or biomass hydrogen production) also generally have lower levelized cost estimate ranges than direct air capture (L-DAC and S-DAC). However, it is worth noting that 1) all of these costs are likely to decrease as carbon capture technologies mature, and 2) which of these industries is economically viable depends both on the levelized cost and on the potential sources of revenue to recoup that cost, which varies across industries. *The cost to capture CO_2 for the steel facility only considers the cost of building and operating the capture equipment. It does not incorporate the capital and operational costs of the steel mill itself.



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ANALYSIS OF POTENTIAL FISCAL AND ECONOMIC BENEFITS OF KERN COUNTY CARBON MANAGEMENT INDUSTRY

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1.0 INTRODUCTION

This report evaluates the potential fiscal and economic benefits that would be created by the development of a carbon management industry in Kern County. Specifically, the report quantifies the direct fiscal and economic impacts of the proposed Carbon Management Business Park (CMBP), and the indirect impacts that would be generated by related firms that the CMBP would support elsewhere in Kern County.

1.1. Categories of Benefits Evaluated

The study considers the following categories of fiscal and economic benefits:

Fiscal Benefits

- Property tax revenue accruing to the County of Kern General Fund and Fire Fund
- Sales tax revenue accruing to the County of Kern General Fund
- Property tax revenue accruing to city General Funds
- Sales tax revenue accruing to city General Funds

Broader Economic Benefits

- Jobs created
- Payroll created
- Total business activity (the dollar volume of "output") supported

Given the undefined nature of the indirect (offsite) benefits of the CMBP, the study does not attempt to quantify potential benefits to individual/specific cities (since the specific locations of supported businesses are unknown). Instead, potential city-level benefits are shown as aggregate numbers (i.e., for all cities combined).

1.2. Profile of Business Types in CMBP

As conceived by the Kern County Planning and Natural Resources Department, the proposed CMBP would encompass 4,200 acres in unincorporated Kern County. Although a specific site has not been identified yet, it is anticipated that the park would be developed on agricultural land that would be rezoned for industrial uses and the location would generally be west of Interstate 5.

The assumed mix of carbon management and related activities within the CMBP is as follows:

Business Type (Carbon Capture Technology)	Area
Liquid Direct Air Capture (L-DAC)	400 acres
Solid Direct Air Capture (S-DAC)	500 acres
Biomass Carbon Removal and Storage (BiCRS)	600 acres
Green Hydrogen (H2)	600 acres
Steel Micro Mill	600 acres
Research & Development Incubator Site	500 acres
Administrative Offices + Ancillary Clean Energy Industries	1,000 acres
Total (with 31 million square feet of industrial building space)	4,200 acres

1.3. Overview of Study Scope and Methodology

In completing this study, The Natelson Dale Group, Inc. (TNDG) has relied on industry profiles (for each of the above business types) prepared by Blue Engine for the CMBP project. In particular, the Blue Engine team has quantified the following economic variables for each CMBP component:

- Permanent (operational) jobs
- Operations and maintenance costs
- Capital costs

Blue Engine has also provided general descriptions of the types of carbon capture businesses that might be the "tenants" within each component of the park. From these descriptions, TNDG has selected specific industries (i.e., NAICS codes) representative of these business types for purposes of evaluating the projects fiscal and economic impacts.

The direct property tax impacts of the CMBP have been estimated by TNDG based on projected land reassessment (from converting the underlying land from agricultural and industrial uses) plus anticipated improvement costs (based on the Blue Engine data). Indirect property taxes (i.e., from offsite businesses that would be developed as part of a countywide carbon management industry anchored by the CMBP) have been estimated using the IMPLAN model¹.

The IMPAN model has also been used to estimate direct and indirect sales tax revenue, as well as broader economic impacts such as job creation, payroll, and supported countywide business activity.

Due to the somewhat speculative nature of the CMBP (composed of industries that in many cases are still in early stages of development globally), the Blue Engine research is understood to provide general/

¹ This model was developed by researchers at the University of Minnesota and is widely used in economic impact analysis throughout the Country. This software is classified as an "Input-Output" (IO) model that computes all of the economic impacts of industries in a user-defined region (in this case, Kern County), including the estimated local expenditures of employees of both project-direct and supplier firms. The current version of the IMPLAN model divides the economy into 546 sectors that correspond to 4-digit and 5-digit NAICS codes.

approximate estimates of costs and employment. As such, the Blue Engine numbers are often expressed in broad ranges (e.g., the Liquid Direct Air Capture operation would support 75 to 270 permanent jobs per 1 million in CO2 captured annually). Since TNDG's analysis stems from the Blue Engine estimates, TNDG's numbers are expressed in terms of a "Low Scenario" and a "High Scenario" corresponding the Blue Engine's ranges.

2.0 EXECUTIVE SUMMARY

2.1. Fiscal Benefits of Carbon Management Industry

Table II-1, on the following page, summarizes the potential fiscal benefits of the proposed CMBP and the related countywide carbon management industry. All dollar amounts are expressed in 2023 dollars.

Fiscal Benefits to County of Kern. At full buildout, the CMBP and related offsite industries would generate total <u>property tax income</u> (General Fund plus Fire Fund) of \$24.2 million (Low Scenario) to \$56.2 million (High Scenario) per year.²

Total <u>sales tax income</u> to the County's General Fund is projected to range between \$4.2 million and \$7.9 million per year.³

Fiscal Benefits to Incorporated Cities. Whereas the direct impacts of the CMBP would occur in unincorporated Kern County (where the park would be located), the indirect impacts associated with the overall carbon management industry would potentially be spread throughout the county. Given the undefined nature of these indirect benefits, the study does not quantify potential benefits to individual/ specific cities (since the specific locations of supported businesses are unknown). Instead, potential city-level benefits are shown as aggregate numbers (i.e., for all cities combined).

The CMBP and related offsite industries would generate total <u>property tax income</u> to city General Funds of \$4.5 million (Low Scenario) to \$8.4 million (High Scenario) per year.

Total <u>sales tax income</u> (to city General Funds) is projected to range between \$8.4 million and \$15.6 million per year.⁴

² The projections of property tax generation are largely driven by the very substantial capital facility investments associated with carbon management projects. For purposes of this study, assessed valuation has been estimated based on total capital investments at the time facilities are completed and put into operation. To the extent these capital facility values are depreciated without offsetting capital reinvestments, property tax revenues from these facilities could decline over time.

³ The sales tax projections are derived from the IMPLAN model; the IMPLAN estimates for Kern County have been adjusted by TNDG to reflect the recent passage of Measure K, which effectively doubles the County's local sales tax rate.

⁴ A significant portion of the sales tax revenue projected in this analysis would be derived from indirect impacts (i.e., CMBP businesses making purchases at other Kern County firms) and induced impacts (i.e., CMBP employees spending their payroll incomes at local businesses). Since many of these indirect/induced expenditures would occur in incorporated cities, the CMBP would create larger sales tax impacts to city General Funds than to the County's General Fund.

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION KERN CARBON MANAGEMENT BUSINESS PARK (CMBP) INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

LOW SCENARIO					
	Cour	nty	Citie	es	
Project Component	Sales Tax	Property Tax	Sales Tax	Property Tax	
Liquid Direct Air Capture	\$669,000	\$3,163,700	\$1,316,700	\$709,500	
Solid Direct Air Capture	\$130,500	\$4,326,800	\$256,800	\$138,400	
Biomass Carbon Removal & Storage	\$261,300	\$1,836,800	\$514,300	\$277,200	
Green Hydrogen	\$84,600	\$3,148,100	\$166,400	\$89,700	
Steel Micro Mill	\$111,800	\$1,936,400	\$220,000	\$118,500	
R&D Incubator Site	\$581,400	\$1,863,300	\$1,144,200	\$616,600	
Ancillary Clean Energy Industries	\$2,439,500	\$7,895,100	\$4,801,200	\$2,587,200	
Total CMBP and Offsite Support	\$4,278,100	\$24,170,200	\$8,419,600	\$4,537,100	

HIGH SCENARIO					
	Cour	nty	Citie	es	
-	Sales	Property	Sales	Property	
Project Component	Тах	Тах	Тах	Тах	
Liquid Direct Air Capture	\$1,226,500	\$8,599,900	\$2,413,900	\$1,300,700	
Solid Direct Air Capture	\$344,000	\$11,659,400	\$677,000	\$364,800	
Biomass Carbon Removal & Storage	\$1,835,900	\$13,841,200	\$3,613,300	\$1,947,100	
Green Hydrogen	\$301,200	\$4,124,200	\$592,900	\$319,500	
Steel Micro Mill	\$168,400	\$4,406,800	\$331,400	\$178,600	
R&D Incubator Site	\$775,300	\$2,681,300	\$1,525,800	\$822,200	
Ancillary Clean Energy Industries	\$3,252,600	\$10,920,300	\$6,401,400	\$3,449,500	
Total CMBP and Offsite Support	\$7,903,900	\$56,233,100	\$15,555,700	\$8,382,400	

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Property Tax includes General Fund and County Fire Fund.

2.2. Broader Economic Benefits

Table II-2, on the following page, summarizes the broader economic benefits of the proposed CMBP and the related countywide carbon management industry. All dollar amounts are expressed in 2023 dollars.

Total business activity supported. The potential volume ("output") associated with the CMBP and related offsite activities is projected to range from \$4.5 billion (Low Scenario) to \$6.9 billion (High Scenario) per year.

Total jobs supported. At full buildout, the CMBP and related offsite activities would directly and indirectly support 13,500 to 22,000 permanent jobs.

Total payroll generated. The total direct and indirect payroll associated with these jobs is projected to range from \$1.1 billion to \$1.8 billion per year, representing an average annual wage of approximately \$80,000.

POTENTIAL ECONOMIC IMPACTS KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

LOW SCENARIO

		Employee		Output
Impact Measure	Employment	Compensation	Value Added	
	_		\$000s	
Liquid Direct Air Capture	197	\$16.524	\$117.945	\$184.594
Solid Direct Air Capture	280	23,463	23,004	36,002
Biomass Carbon Removal & Storage	186	20,355	29,577	64,855
Green Hydrogen	368	43,675	32,989	74,886
Steel Micro Mill	500	36,999	30,400	119,439
R&D Incubator Site	325	30,073	47,059	85,755
Ancillary Clean Energy Industries	11,682	888,418	1,564,302	3,975,561
Total CMBP	13,540	\$1,059,508	\$1,845,277	\$4,541,092

HIGH SCENARIO

		Employee		Output
Impact Measure	Employment	Compensation	Value Added	
			\$000s	
Liquid Direct Air Capture	711	\$59,485	\$184,714	\$338,423
Solid Direct Air Capture	756	63,230	48,574	94,915
Biomass Carbon Removal & Storage	1,368	149,670	149,168	455,611
Green Hydrogen	1,228	145,583	88,822	266,780
Steel Micro Mill	1,501	110,998	37,973	179,934
R&D Incubator Site	876	81,043	99,760	231,094
Ancillary Clean Energy Industries	15,575	1,184,478	1,859,499	5,300,389
Total CMBP	22,014	\$1,794,487	\$2,468,510	\$6,867,148

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

3.0 DETAILED SUMMARY OF FISCAL AND ECONOMIC IMPACTS

This section provides a detailed summary of the ongoing fiscal and economic impacts associated with the CMBP. For fiscal impacts, the analysis shows the ongoing property tax and sales tax revenues that would be generated for the County and incorporated cities in the County. For economic impacts, the analysis shows annually-recurring impacts related to employment, employee compensation, value added, and output (i.e., total dollar volume of business activity).

3.1. CMBP Sales Tax and Property Tax Impacts

Tables III-1 and III-2 (pages 9 and 10) show the direct and indirect sales tax and property tax impacts associated with each proposed CMBP component, along with the total for the entire proposed CMBP. Table III-1 shows the "low" scenario (reflecting more conservative direct employment and operating cost estimates), while Table III-2 shows the "high" scenario (reflecting higher direct employment and operating cost estimates).

3.2. CMBP Economic Impacts

Tables III-3 and III-4 (pages 11 and 12) show the direct and indirect/induced economic impacts associated with each proposed CMBP component, along with the total for the entire proposed CMBP. Table III-1 shows the "low" scenario (reflecting more conservative direct employment and operating cost estimates), while Table III-2 shows the "high" scenario (reflecting higher direct employment and operating cost estimates).

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION KERN CARBON MANAGEMENT BUSINESS PARK (CMBP) INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

LOW SCENARIO				
	Col	unty	Cities	
-	Sales	Property	Sales	Property
Impact Measure	Тах	Тах	Тах	Тах
Liquid Direct Air Capture				
Direct	\$627,912	\$3,014,656	\$1,235,790	\$665,920
Indirect	\$41,089	\$149,067	\$80,867	\$43,576
Total	\$669,001	\$3,163,723	\$1,316,657	\$709,496
Solid Direct Air Capture				
Direct	\$122,465	\$4,297,682	\$241,023	\$129,878
Indirect	\$8,014	\$29,073	\$15,772	\$8,499
Total	\$130,479	\$4,326,755	\$256,795	\$138,377
Biomass Carbon Removal & Storage				
Direct	\$220,881	\$1,689,984	\$434,714	\$234,251
Indirect	\$40,461	\$146,788	\$79,631	\$42,910
Total	\$261,342	\$1,836,772	\$514,345	\$277,161
<u>Green Hydrogen</u>				
Direct	\$36,931	\$2,975,317	\$72,685	\$39,167
Indirect	\$47,626	\$172,782	\$93,732	\$50,509
Total	\$84,557	\$3,148,099	\$166,417	\$89,676
<u>Steel Micro Mill</u>				
Direct	\$58,109	\$1,741,749	\$114,364	\$61,626
Indirect	\$53,664	\$194,688	\$105,616	\$56,912
Total	\$111,773	\$1,936,436	\$219,980	\$118,539
R&D Incubator Site				
Direct	\$393,307	\$1,180,952	\$774,066	\$417,115
Indirect	\$188,070	\$682,298	\$370,140	\$199,454
Total	\$581,377	\$1,863,251	\$1,144,206	\$616,569
Ancillary Clean Energy Industries				
Direct	\$914,321	\$2,361,905	\$1,799,471	\$969,666
Indirect	\$1,525,172	\$5,533,164	\$3,001,683	\$1,617,493
Total	\$2,439,493	\$7,895,069	\$4,801,154	\$2,587,159
Total Business Park Components				
Direct	\$2,373,926	\$17,262,245	\$4,672,112	\$2,517,624
Indirect	\$1,904,095	\$6,907,860	\$3,747,441	\$2,019,353
Total	\$4,278,021	\$24,170,105	\$8,419,553	\$4,536,977

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Direct Property Tax includes General Fund and County Fire Fund.

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION KERN CARBON MANAGEMENT BUSINESS PARK (CMBP) INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

HIGH SCENARIO				
	County		Cities	
-	Sales	Property	Sales	Property
Impact Measure	Тах	Тах	Тах	Тах
Liquid Direct Air Capture				
Direct	\$1,151,171	\$8,326,656	\$2,265,614	\$1,220,853
Indirect	\$75,330	\$273,290	\$148,257	\$79,890
Total	\$1,226,501	\$8,599,946	\$2,413,871	\$1,300,743
Solid Direct Air Capture				
Direct	\$322,862	\$11,582,788	\$635,424	\$342,406
Indirect	\$21,127	\$76,648	\$41,581	\$22,406
Total	\$343,990	\$11,659,436	\$677,004	\$364,812
Biomass Carbon Removal & Storage				
Direct	\$1,551,707	\$12,809,984	\$3,053,907	\$1,645,634
Indirect	\$284,241	\$1,031,197	\$559,414	\$301,447
Total	\$1,835,948	\$13,841,181	\$3,613,320	\$1,947,081
<u>Green Hydrogen</u>				
Direct	\$131,568	\$3,508,651	\$258,939	\$139,532
Indirect	\$169,667	\$615,535	\$333,921	\$179,937
Total	\$301,236	\$4,124,185	\$592,860	\$319,470
<u>Steel Micro Mill</u>				
Direct	\$87,540	\$4,113,513	\$172,288	\$92,839
Indirect	\$80,845	\$293,296	\$159,110	\$85,738
Total	\$168,385	\$4,406,809	\$331,398	\$178,578
R&D Incubator Site				
Direct	\$524,473	\$1,771,429	\$1,032,214	\$556,221
Indirect	\$250,790	\$909,841	\$493,579	\$265,971
Total	\$775,264	\$2,681,270	\$1,525,793	\$822,192
Ancillary Clean Energy Industries				
Direct	\$1,219,061	\$3,542,857	\$2,399,229	\$1,292,853
Indirect	\$2,033,529	\$7,377,432	\$4,002,179	\$2,156,622
Total	\$3,252,590	\$10,920,289	\$6,401,407	\$3,449,475
Total Business Park Components				
Direct	\$4,988,384	\$45,655,878	\$9,817,614	\$5,290,339
Indirect	\$2,915,530	\$10,577,239	\$5,738,040	\$3,092,012
Total	\$7,903,914	\$56,233,117	\$15,555,654	\$8,382,351

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Direct Property Tax includes General Fund and County Fire Fund.

POTENTIAL ECONOMIC IMPACTS KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

LOW SCENARIO				
Impact Measure	Employment	Employee Compensation	Value Added \$000s	Output
Liquid Direct Air Capture				
Direct	150	\$12,163	\$80,122	\$120,000
Indirect/Induced	47	4,361	37,823	64,594
Total	197	\$16,524	\$117,945	\$184,594
Solid Direct Air Capture				
Direct	213	\$17,271	\$15,627	\$23,404
Indirect/Induced	67	6,192	7,377	12,598
Total	280	\$23,463	\$23,004	\$36,002
Biomass Carbon Removal & Storage				
Direct	68	\$10,986	\$19,849	\$46,500
Indirect/Induced	118	9,370	9,729	18,355
Total	186	\$20,355	\$29,577	\$64,855
<u>Green Hydrogen</u>				
Direct	150	\$25,978	\$21,788	\$53,333
Indirect/Induced	218	17,697	11,201	21,552
Total	368	\$43,675	\$32,989	\$74,886
<u>Steel Micro Mill</u>				
Direct	235	\$17,259	\$14,950	\$90,588
Indirect/Induced	265	19,741	15,450	28,851
Total	500	\$36,999	\$30,400	\$119,439
R&D Incubator Site				
Direct	213	\$21,587	\$31,095	\$57,322
Indirect/Induced	112	8,486	15,964	28,433
Total	325	\$30,073	\$47,059	\$85,755
Ancillary Clean Energy Industries				
Direct	7,382	\$563,778	\$885,833	\$2,727,538
Indirect/Induced	4,300	324,640	678,469	1,248,023
Total	11,682	\$888,418	\$1,564,302	\$3,975,561
Total CMBP Components				
Direct	8,411	\$669,022	\$1,069,264	\$3,118,686
Indirect/Induced	5,128	390,486	776,013	1,422,406
Total	13,540	\$1,059,508	\$1,845,277	\$4,541,092

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

POTENTIAL ECONOMIC IMPACTS KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

HIGH SCENARIO					
Impact Measure	Employment	Employee Compensation	Value Added \$000s	Output	
Liquid Direct Air Capture					
Direct	540	\$43.786	\$146.891	\$220.000	
Indirect/Induced	171	15,698	37,823	118,423	
Total	711	\$59,485	\$184,714	\$338,423	
Solid Direct Air Capture					
Direct	574	\$46,543	\$41,198	\$61,702	
Indirect/Induced	182	16,687	7,377	33,213	
Total	756	\$63,230	\$48,574	\$94,915	
Biomass Carbon Removal & Storage					
Direct	500	\$80,777	\$139,439	\$326,667	
Indirect/Induced	868	68,894	9,729	128,945	
Total	1,368	\$149,670	\$149,168	\$455,611	
<u>Green Hydrogen</u>					
Direct	500	\$86,594	\$77,620	\$190,000	
Indirect/Induced	728	58,989	11,201	76,780	
Total	1,228	\$145,583	\$88,822	\$266,780	
<u>Steel Micro Mill</u>					
Direct	706	\$51,776	\$22,523	\$136,471	
Indirect/Induced	795	59,222	15,450	43,464	
Total	1,501	\$110,998	\$37,973	\$179,934	
R&D Incubator Site					
Direct	574	\$58,174	\$83,796	\$154,472	
Indirect/Induced	302	22,868	15,964	76,622	
Total	876	\$81,043	\$99,760	\$231,094	
Ancillary Clean Energy Industries					
Direct	9,842	\$751,653	\$1,181,030	\$3,636,471	
Indirect/Induced	5,733	432,824	678,469	1,663,918	
Total	15,575	\$1,184,478	\$1,859,499	\$5,300,389	
Total CMBP Components					
Direct	13,236	\$1,119,305	\$1,692,497	\$4,725,783	
Indirect/Induced	8,778	675,182	776,013	2,141,365	
Total	22,014	\$1,794,487	\$2,468,510	\$6,867,148	

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park