PATHWAYS TO CARBON NEUTRALITY IN CALIFORNIA

Decarbonizing the Industrial Sector

May 2022

Stanford
Center for Carbon Storage
Carbon Removal Initiative

About

About the Stanford Center for Carbon Storage

Carbon Capture, Utilization, and Storage is a key technology for achieving net-zero greenhouse gas emissions. The Stanford Center for Carbon Storage (SCCS) uses a multidisciplinary approach to address critical questions related to flow physics, monitoring, geochemistry, geomechanics and simulation of the transport and fate of CO_2 stored in partially to fully depleted oil & gas fields and saline reservoirs. SCCS is an affiliates program associated with the Stanford University School of Earth, Energy and Environmental Sciences.

About the Stanford Carbon Removal Initiative

The Stanford Carbon Removal Initiative (SCRI) seeks to create science-based opportunities and solutions for gigaton-scale negative emissions and atmospheric carbon removal. The initiative helps to enable removal of atmospheric greenhouse gasses at scale by generating and integrating knowledge, creating scalable solutions, informing policies for technology deployment and governance, and demonstrating approaches and solutions with industry collaborators. All of this is done with a focus on social acceptance and equity, as well as environmental, economic, and social costs. SCRI is an affiliates program associated with the Precourt Institute for Energy and the Woods Institute for the Environment.

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California State Building and Construction Trades Council

International Brotherhood of Boilermakers

Western States Petroleum Association

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Acronyms

BBLS	barrels
BOE	barrels of oil equivalent
BPD	barrels per day
CO_2e	carbon dioxide global warming equivalent
CCS	carbon capture and storage
CARB	California Air Resources Board
CH_4	methane
CHP	combined heat and power facility
CSP	concentrated solar power
eGRID	EPA emissions and Generation Resource Integrated Database
EPA	U.S. Environmental Protection Agency
FCC	fluidized catalytic cracker
FLIGHT	EPA Facility Level Information on Greenhouse gases Tool
GHG	greenhouse gas
GHGRP	EPA Greenhouse Gas Reporting Program
LCOC	levelized cost of carbon
MBBLS	millions of barrels
MBOE	millions of barrels of oil equivalent
MBTU	millions of British thermal units
Mcfd	million cubic feet per day
MRR	CARB Mandatory Reporting of GHG Emissions database
Mt	million metric tonnes
MWh	megawatt-hours
NPV	net present value
O&M	operations and maintenance
scf	standard cubic feet
SG	steam generator
SMR	steam methane reforming
UTO	useful thermal output
VRU	vapor recovery unit

Key Findings

- The **Industrial sector** is responsible for nearly 25% of California's CO_2e emissions primarily due to the combustion of fossil fuels for process heat. This emissions level has not changed significantly over the past 20 years.
- Steamflood operations are the primary source of emissions in the **Oil & Gas subsector**. These emissions occur from steam generation units, of which there are estimated ~750 (+/- 20%) in the state, as well as much larger CHP units. Technoeconomic modeling of CCS retrofits on both types of facilities show positive cash flow, while other decarbonization options (e.g., concentrated solar power) would require additional incentives.
- Fluidized catalytic crackers, hydrogen SMRs, and CHPs are responsible for the majority of the emissions in the **Refining & Hydrogen subsector**. Technoeconomic modeling of CCS retrofits on all of these types of facilities show positive cash flow.
- Fuel combustion for process heat and the chemical reaction that occurs when making clinker are the primary sources of CO_2e emissions in the **Cement subsector**. Technoeconomic modeling of CCS retrofits, electrification, and a fuel switch to hydrogen are all cash-flow negative, with CCS both costing the least and abating the highest volume of CO_2.
- The **Manufacturing & Mining** subsectors use process heat at different temperatures to produce thousands of different products fabricated by hundreds of facilities in California. CCS retrofits at the largest 5 mining and petrochemical products facilities and largest 3 food products facilities can reduce emissions by 60% and 29%, respectively. Notably, the high concentration of food manufacturers located over suitable geologic CO_2 storage sites may reduce barriers to CO_2 transport for sequestration.
- **Biogenic** emissions are not included in California's emission reduction targets, yet these emissions (e.g., wood and furniture products which utilize heat generated from the combustion of wood-based residue left over from the wood manufacturing process) can be significant and may be more cost-effective to abate than other sources of industrial emissions.
- The **Transmission & Distribution** subsector has fuel combustion emissions at over 100 compressor stations located across the state but CO_2e emissions are dominated by fugitive methane emissions (78% of total CO_2e) associated with natural gas conveyance through over 200,000+ miles of pipeline. The most expensive abatement options when adjusted for inflation to 2025 yield a levelized cost of carbon (LCOC) of \$53/t CO_2e, and many options can actually make money.

Introduction

In 2019, the Industrial sector emitted 100 Mt of CO_2e or 23.9% of California's total emissions (Figure 1) [1]. Emissions are heavily weighted to the Refining & Hydrogen, Oil & Gas, and Manufacturing & Mining subsectors, which require substantial amounts of process heat for their operations. The sources of these emissions over time are shown in Figure 2.

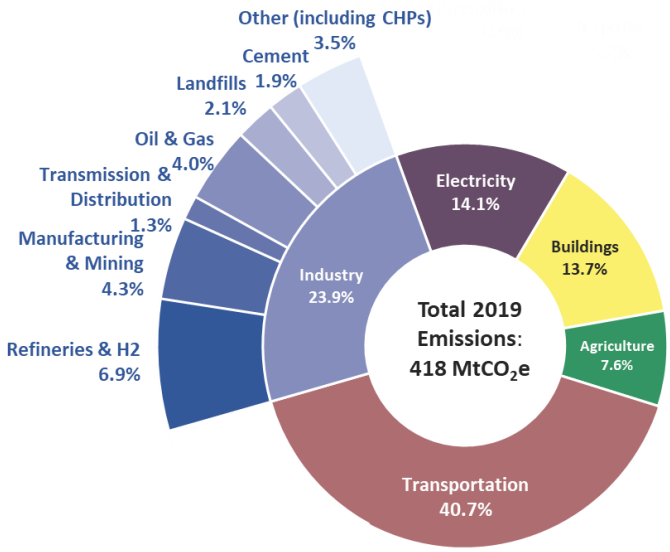


Figure 1: California 2019 emissions. Adapted from CARB GHG Emissions Inventory (2021) [1].

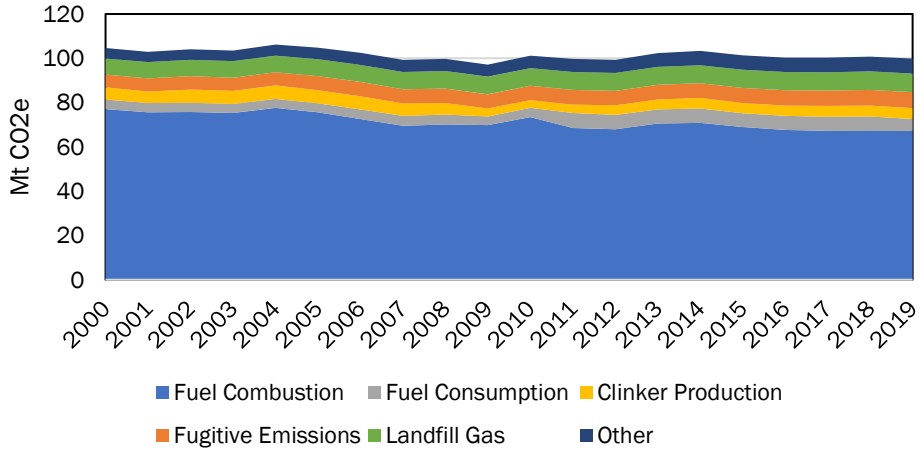


Figure 2: Sources of California Industrial sector emissions. Adapted from CARB GHG Emissions Inventory (2021) [1].

Note that the level of emissions has not changed substantially over the past 20 years (decrease of <5%) and that emissions are dominated by fuel combustion. In Figure 3 below, the majority of the emissions from fuel combustion come from natural gas followed by refinery gas and catalyst coke (which is a build-up by-product in the refining process which needs to be burned off in order to regenerate the catalyst [2] [3]).

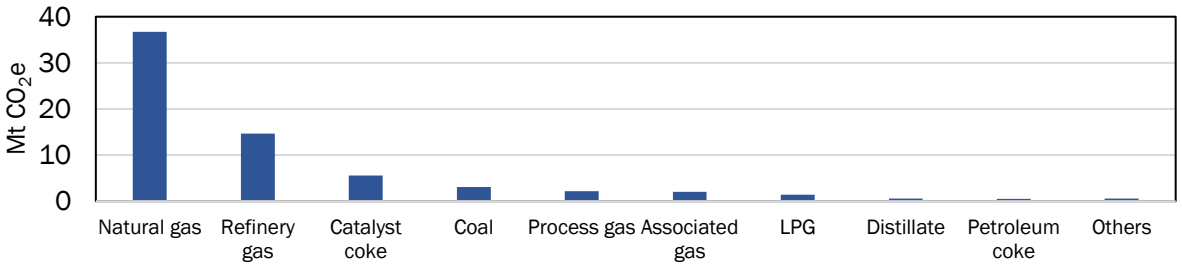


Figure 3: Sources of California 2019 Industrial sector fuel combustion emissions. Adapted from CARB GHG Emissions Inventory (2021) [1].

In this study, a bottom-up approach was taken to identify the individual sources of industrial emissions and then commercially-available technologies were evaluated to decarbonize these facilities. Facility-level emissions data came primarily from 3 sources:

- California Air Resources Board (CARB) Mandatory Reporting of Greenhouse Gas Emissions (**MRR**) [4] which contains annual GHG emissions for facilities subject to the California Cap-and-Trade Program.
- EPA Facility Level Information on Greenhouse Gases Tool (**FLIGHT**) [5] which contains GHG emissions from large facilities in the US. These facilities are required to report annual data on GHG emissions to EPA as part of the Greenhouse Gas Reporting Program (GHGRP)
- EPA Emissions and Generation Resource Integrated Database (**eGRID**) [6] which contains emissions, emission rates, generation, heat input, resource mix, and many other attributes of almost all electric power generated in the United States.

Identified emissions were then compared to CARB total emissions for each subsector to assess which major subsectors should be evaluated in this study, as shown in Figure 4. Note that CARB combines some emissions into a category labeled 'CHP Industrial'. In this study, those emissions have been (where possible) disaggregated and moved into the proper sub-sectoral category. CARB also groups Cement within the Manufacturing subsector and treats Mining as a separate subsector. Due to the large volume of emissions from the cement industry in the state, this study has chosen to treat cement as a separate subsector. In addition, given the difficulty of determining whether a specific facility identifies as Mining or Manufacturing, these two subsectors have been merged in this study.

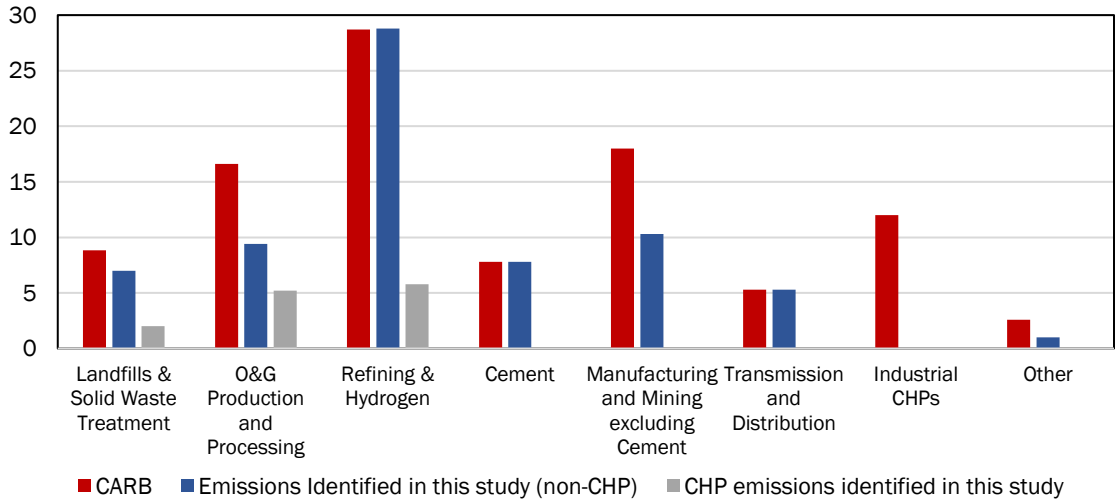


Figure 4: 2019 Emissions identified in this study [4] [5] [6] *compared to those from CARB GHG Emissions Inventory* [1]*. Emissions associated with CARB's category entitled "CHP: Industrial" emissions have been assigned to their subsector, if known, and are identified by the gray bar.*

The bottom-up approach used in this study identified entities responsible for approximately 80% of the industrial sector emissions in California. Remaining emissions are below CARB's reporting threshold.

This study focuses on the following 5 subsectors:

- Oil and Gas Production and Processing
- Refining and Hydrogen
- Cement
- Manufacturing (excluding cement) and Mining (merged for this analysis)
- Transmission and Distribution (of natural gas)

While landfills and solid waste treatment are significant sources of emissions in the state, these are addressed in the companion study "Pathways to Carbon Neutrality in California: The Bioenergy Opportunity" [7].

For each subsector analyzed in this study, the individual (entity or facility) level emissions were evaluated to understand the number and magnitude of different emitting sources as well as their locations. These factors impact decarbonization options. Different decarbonization technologies were evaluated for each subsector, including CCS, hydrogen and electricity fuel switching, and heat pump usage, along with technoeconomic analysis to compare economic feasibility for each of the technology options.

Technoeconomic analysis was specific to each subsector, yet some common modeling assumptions were utilized across subsectors, as outlined in Table 1.

Parameter	Value	Unit
Discount Rate	10	%
Inflation	2	%

Natural Gas Price	7.28	$/MBTU
Electricity Price	144.20	$/MWh
Hydrogen Price	3.50	$/kg
Common assumptions for technoeconomics involving CCS		
45Q Incentive	50	$/t CO_2e captured & stored
45Q Duration	12	Years
LCFS Incentive	100	$/t CO_2e captured & stored
CO_2 Transport Cost	5 (unless collocated with storage)	$/t CO_2e
CO_2 Storage Cost	10	$/t CO_2e

Table 1: List of common assumptions used for technoeconomic modeling for all subsectors in this study.

Oil and Gas Subsector

According to the EIA, California is the 7th largest crude oil producer and the 14th largest natural gas producer [8] [9] in the United States. Oil and gas production in California has been decreasing steadily since the 1980s as shown in Figure 5. CARB has estimated a total of approximately 16.7 Mt of CO_2e emissions in 2019 from the Oil and Gas Production and Processing subsector [1]. In April of 2021, California Governor Newsom requested that CARB analyze pathways to phase out oil extraction across the state by no later than 2045.

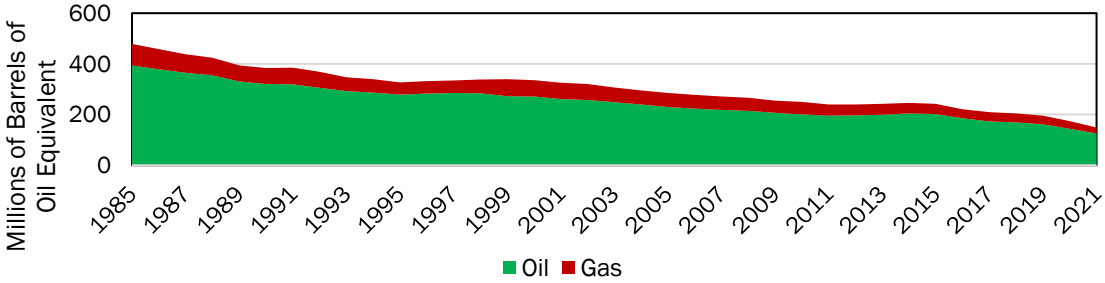


Figure 5: California production of oil and gas production as reported by the EIA [10] [11].

CARB also provides an emissions breakdown of the 16.7 Mt of CO_2e emissions [1]. The two primary sources of emissions are fuel combustion and fugitive emissions. Fuel combustion emissions account for 86% (14.3 Mt of CO_2e emissions), while fugitive emissions make up the remaining 14% (2.3 MtCO_2e emissions). Fuel combustion emissions are either categorized as deriving from natural gas combustion (86%) or associated gas combustion (13%). There are very small amounts of emissions from distillates.

Data from CARB's MRR database, EPA's Flight database, and EPA's eGRID database were utilized to develop a bottom-up list of all emitting entities for the Oil and Gas subsector. This analysis identified entities emitting a total of 14.6 Mt CO_2/yr, including CHP facilities contributing thermal energy to oil and gas production.

Emissions from Cyclic Steam and Steamflood Operations

California's oil mostly comes from the decay of dead organic matter laid down in the relatively recent Miocene epoch. Much of this oil is dense, viscous, and has a high carbon-to-hydrogen ratio ("heavy oil"). This heavy oil is challenging and costly to produce, transport, and refine. For this reason, California produces much of its oil through thermal recovery operations including cyclic steam injection and steamflooding. Both operations inject steam

into the reservoirs, so that crude oil is loosened and warmed. The oil viscosity drops due to heating, and it can then flow to production wells, as shown in Figure 6. To generate the steam utilized for these operations, natural gas is combusted to boil water. Some oil fields rely on series of steam generators (SGs) to produce the steam, others have a combined heat and power plant (CHP), and some utilize both.

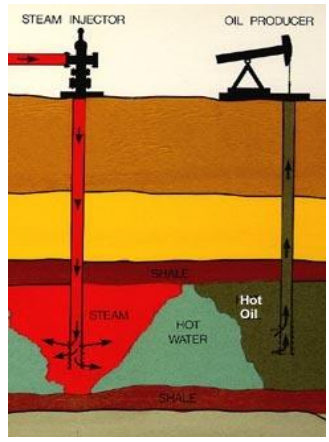


Figure 6: Diagram of steam injection operation where steam warms and loosens the crude oil and pushes the oil up to the surface [12].

To assess pathways for decarbonizing the oil and gas sector, it was necessary to estimate the total number of SGs in the state, as each one is a source of emissions that will require abatement. Conversely, the individual CHP facilities are known, as most are large enough such that their emissions are reported to either CARB or the EPA. The procedure used to estimate the number of SGs is outlined in Box 1 and yields a count of 750 (+/- 20%).

Box 1

Estimating Number of Steam Generators used in Oil Production Operations

The following procedure was used to estimate the number of SGs in California:

1. Download steam injection volumes from the California Department of Conservation's WellSTAR database [13] for each operating company in the state.
2. Tabulate emissions from all companies that report emissions using the sources discussed in Introduction.
3. Subtract out the CHP emissions from the total emissions for each company. It is assumed that the "useful thermal output" (UTO) emissions, which are noted separately for entities in eGRID [6], represent CHP emissions for each company.
4. Assume that the remaining emissions for each company are due to SGs.
5. For entities with both SGs and CHPs, assume the ratio of emissions from SGs/CHPs is the same as the ratio of steam injection volume from SGs/CHPs.
6. Test results by cross-plotting 2019 CO_2e emissions (steam generators and CHPs individually) vs. 2019 steamflood and cyclic steam injection volumes (Figure 7).
7. SG counts were obtained from 4 entities (some dated) from public sources [14], [15], [16], [17]. These SG counts were then compared with the 2019 steam injection volumes found through WellSTAR for those same entities and an average injection volume per SG of 550,000 barrels steam/yr was calculated.
8. Based on the total 2019 SG injection volume in California (415 MBBLS), it is estimated that there are 750 (+/- 20%) SGs used in oil field operations in California.

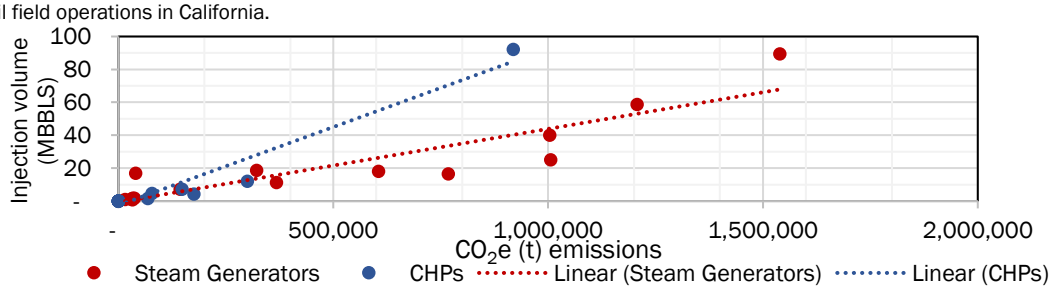


Figure 7: Plot of 2019 CO_2e emissions from steam generators and CHP facilities vs 2019 steam injection volumes. Note linear trend for both steam generators and CHP facilities [1] [13].

Decarbonization Options and Technoeconomics

Options for decarbonizing the Oil and Gas subsector include CCS retrofits for both SGs and CHPs as well as new-build concentrated solar power (CSP) to replace existing SGs. CSP uses multiple mirrors to concentrate solar energy for thermal storage and utilization.

Steam Generators

This study assumes that decarbonizing SGs will occur "in bulk" by operating companies and therefore the technoeconomic modeling compared CCS retrofits on 100 SG units versus a new-build CSP replacing 100 SG units. It is acknowledged that CCS retrofits on such a large array of SGs is perhaps a novel concept. Generalized technoeconomic assumptions were previously outlined in Table 1, and specific assumptions for SGs with these two decarbonization pathways are shown in Table 2, the resulting cash flows are shown in Figures 8 and 9.

Project Assumptions	CCS retrofit	New-build CSP
Number of SGs	100	100
Production associated with SGs	18 MBOE	18 MBOE
Model Assumptions		
CapEx ($M)	700 (Assumes $7 M per generator*)	3500 (Source: [18])
CapEx Duration (yr)	2	3
Non-energy OpEx as % of CapEx (%)	7	1
Energy OpEx ($M/yr)	54	27
Incentives applied	45Q, LCFS	LCFS
Model Results		
Levelized Cost of Carbon ($/t CO_2e)	$13.07 (revenue)	$219.87 (cost)
Levelized Additional Cost per BOE ($/BOE)	$0.89 (revenue)	$14.89 (cost)

Table 2: Comparison of CCS retrofit and new-build CSP technoeconomic assumptions and results.

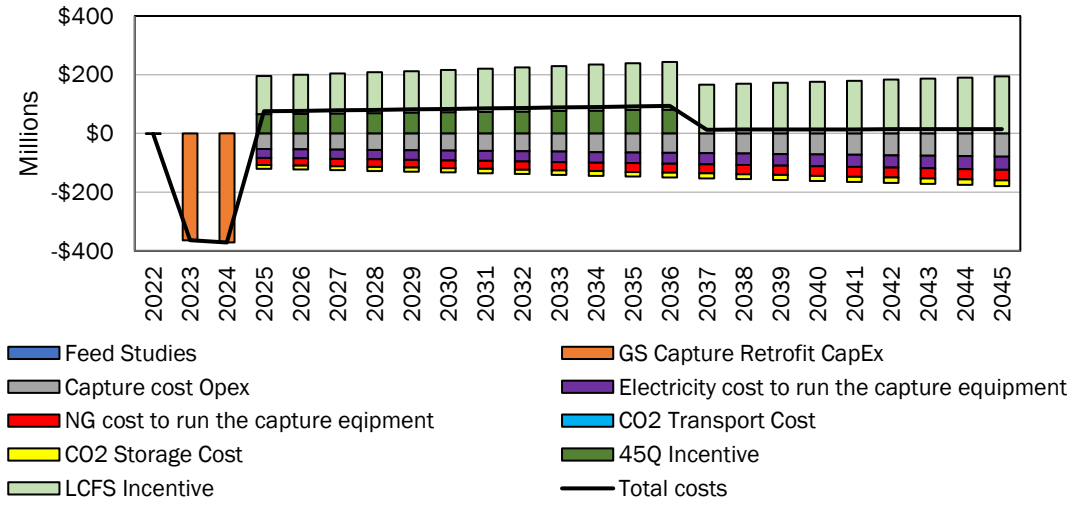


Figure 8: Cashflow for CCS retrofit on 100 SGs.

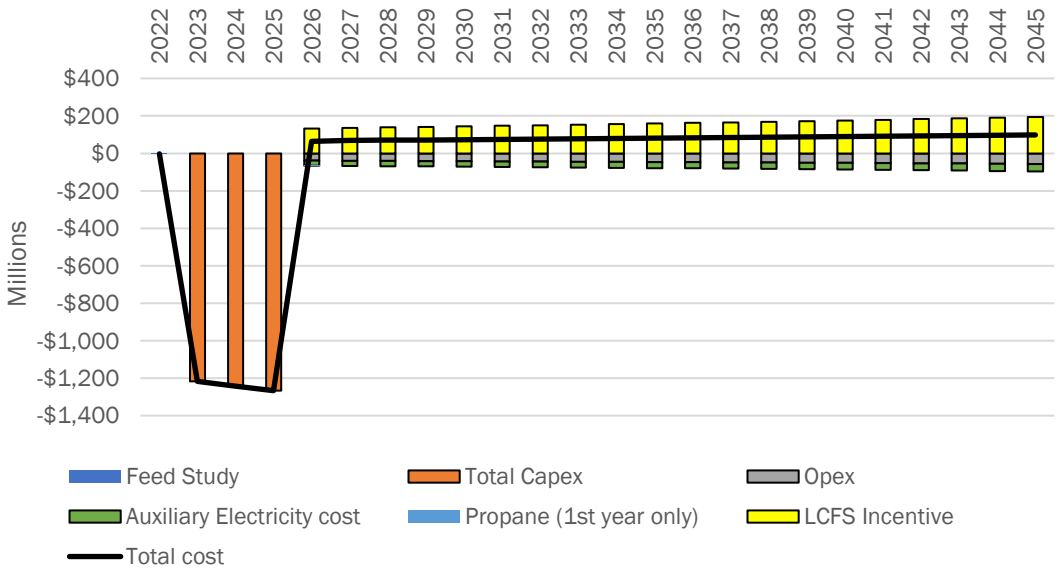


Figure 9: Cashflow for new-build CSP to replace 100 SGs.

As is clear from the results in Table 2 and Figures 8 and 9, CCS retrofits (at this time) appear to be a much more cost-effective way to decarbonize SG units. In fact, the cash flows and levelized cost analysis suggest that CCS retrofits can result in net revenue generation for the operating entity.

CHP Facilities

CCS retrofits were the only technology that was considered for decarbonizing CHPs facilities involved in oil and gas production operations. Generalized technoeconomic assumptions were previously outlined in Table 1, specific assumptions for CHPs with CCS retrofit are shown in Table 3, and the resulting cash flows are shown in Figure 10.

Project Assumptions	CCS retrofit
CHP emissions (t/yr)	300,000
Production associated with CHP	2 MBOE
Model Assumptions	
CapEx ($M)	126
CapEx Duration (yr)	2
OpEx Non-energy as % of CapEx (%)	5
OpEx Energy ($M/yr)	12
Incentives applied	45Q, LCFS (50 %)
Model Results	
Levelized Cost of Carbon ($/t CO_2e)	15.93 (revenue)
Levelized Additional Cost per BOE ($/BOE)	2.15 (revenue)

Table 3: CCS retrofit technoeconomic inputs and results.

Given that CHP units deliver useful thermal output (UTO) for steamflood operations as well as power to the grid, it was assumed that only 50% of the captured CO_2 emissions would be eligible for the LCFS incentive.

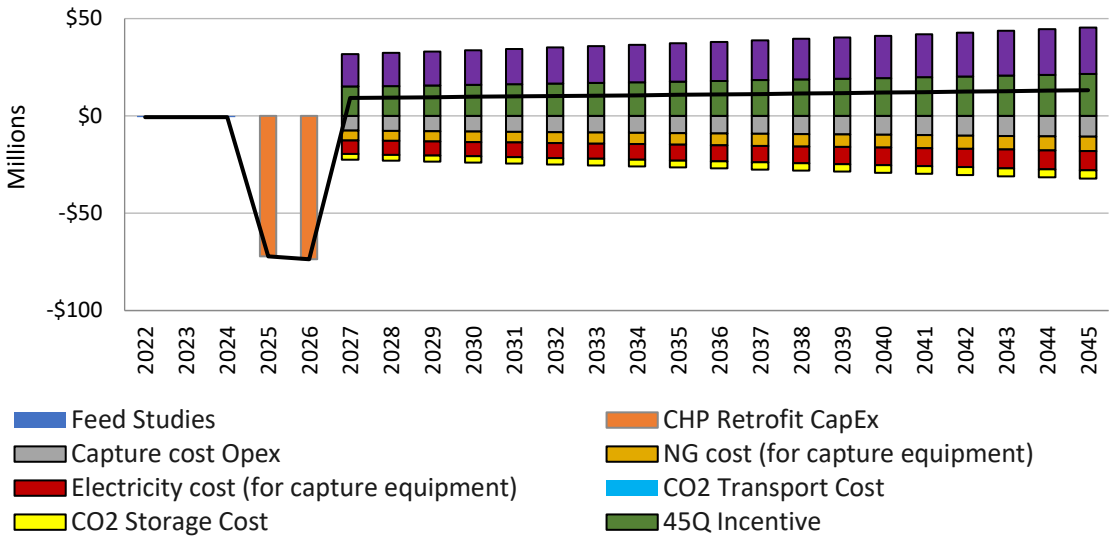


Figure 10: Cashflow for CCS retrofit on CHP unit.

This analysis suggests that CCS retrofits on CHPs providing steam for oilfield steam injection operations can generate positive revenue.

Refining and Hydrogen Subsector

As of 2019, there were 18 refineries and 19 hydrogen steam methane reforming (SMR) plants operating in California that reported emissions. Many of the larger refineries have their own hydrogen SMR unit, but there are also a number of merchant SMRs typically located outside the fence line of the refineries. Most of the SMRs are providing hydrogen for the refining process.

Refineries consist of several different processing units producing a multitude of products. Though the slate of products may differ by refinery and by year, each refinery has the ability to separate, convert, and treat processed crude oil. **Separation** involves crude oil passing

through hot furnaces to separate the oil at different boiling points. The separated oil is referred to as fractions [19]. In the **conversion** stage, the fractions are processed into products such as gasoline [19]. There are a variety of methods refineries use in the conversion stage. *Cracking* uses heat and pressure to break down heavy hydrocarbon molecules into lighter ones [19]. Other methods such as *alkylation* and *reforming* are also used at different refineries. Figure 11 shows the temperature ranges required for the processing of different products [19]. The final stage, **treatment,** involves addition of additives to create the final product.

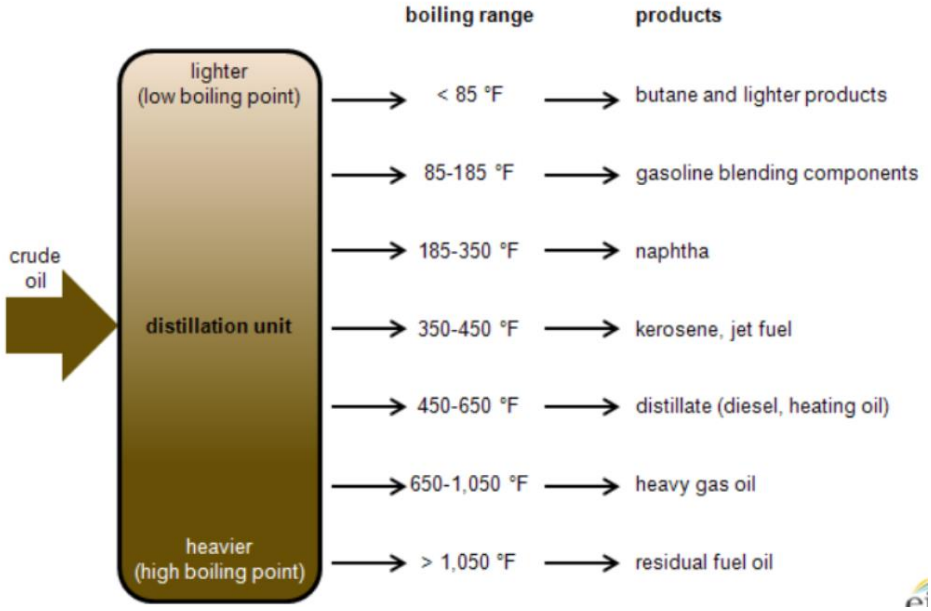


Figure 11: Crude oil distillation unit and products along with their temperature range. Source: U.S. Energy Information Administration [19].

Emissions from Refining and Hydrogen SMR Operations

CARB reports 2019 emissions in this subsector of 28.75 Mt [1]. Over the past 20 years, the Refining and Hydrogen subsector annual emissions have fluctuated between 28 and 31 Mt. Most the emissions are due to fuel combustion and fuel consumption with other smaller emission sources associated with acid gas control, flaring, process emissions, and fugitive emissions, as shown in Figure 12 [1]. Fuel combustion involves fuel to generate heat whereas fuel consumption involves use of fuel to create another product.

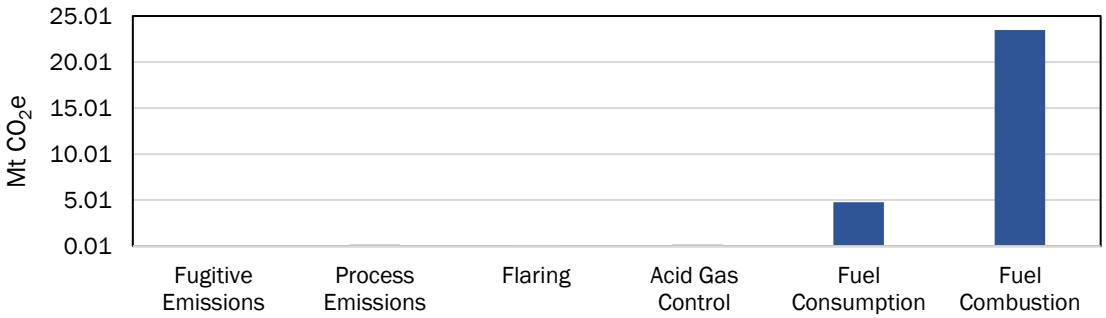


Figure 12: 2019 sources of emissions in the Refining and Hydrogen subsector [1].

Sources of fuel for both consumption and combustion are shown in Figure 13 [1].

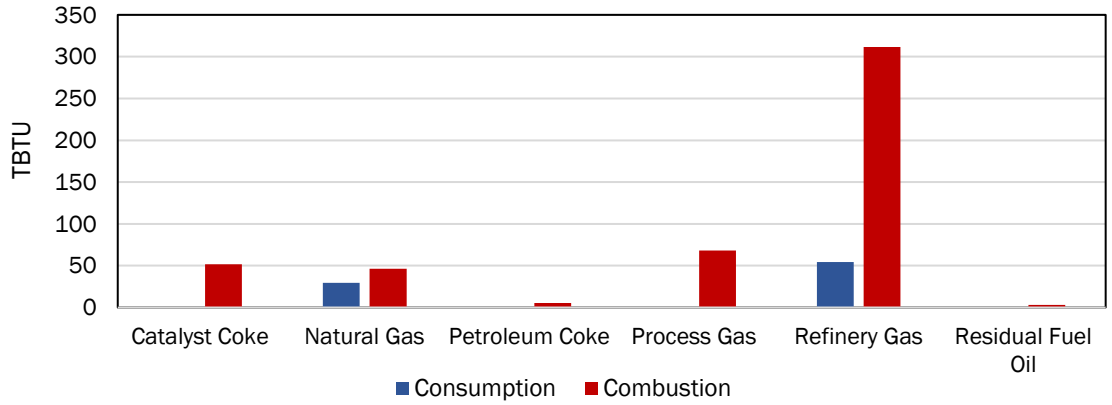


Figure 13: 2019 sources of fuel for consumption and combustion in the Refining and Hydrogen subsector [1].

Refinery gas, which is the major fuel responsible for the emissions from both combustion and consumption activities, is a byproduct of the refining processes [20] and has a higher emissions content due to a higher level of sulfur as well as higher flame temperature. Because refinery gas is generated as a byproduct, refineries utilize it for both fuel combustion and consumption to recover the energy content as well as to eliminate its disposal as a waste stream [20].

Within a refinery, the largest emitting units are the fluidized catalytic cracker (FCC), the hydrogen SMR, and to a lesser extent (typically) CHPs which are located within the refinery providing process heat for the refining operations, as shown in Figure 14.

As described in the Introduction, a compilation of CARB's MRR database, EPA's FLIGHT database, and EPA's eGRID database were utilized to develop a bottom-up list of all emitting entities for the Refining and Hydrogen subsector. This analysis identified entities emitting a total of 34.7 Mt CO_2/yr. Note, however, that this analysis includes 5.8 Mt/yr of emissions from CHPs, which CARB classifies in the "CHP: Industrial" subsector. The difference between these two numbers (28.9 Mt CO_2/yr) is quite close to the 2019 emissions reported by CARB for the Refining and Hydrogen subsector of 28.75 Mt/yr [1].

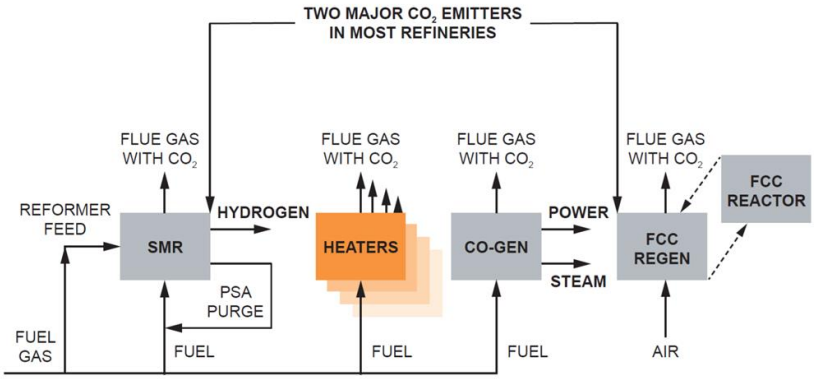


Figure 14: Refinery layout showing emission sources including SMR, heaters, CHP (labeled co-gen in figure) and fluidized cat cracker (labeled FCC Regen in figure). Source: EPRI.

Decarbonization Options and Technoeconomics

As noted in Figure 14 above, refinery gas is an unavoidable byproduct from refining, and decarbonization options that do not involve the combustion of this gas are unrealistic. For example, even if fuel switching and/or electrification were viable, refineries would only be able to use those technologies to address 30% of both fuel combustion and consumption emissions. Other options such as switching feedstocks (to plant oil and animal fats) to produce renewable diesel are also acknowledged as potential actions for future decarbonization pathways [21]. This option is discussed in more detail in the companion study "*Pathways to Decarbonization in California: The Bioenergy Opportunity*" [7]. However, for existing refineries to continue to make the current slate of products, the only technology abatement option that is considered for this analysis is CCS retrofits as it can also reduce emissions from refinery fuel gas combustion. Note that a CCS retrofit can be done separately for the FCC, the SMR, and the CHP(s) at a refinery. The refinery model project assumptions and model results for a large California Refinery with each of these types of units is shown in Table 4 and an example combined cash flow is shown in Figure 15.

Project Assumptions	FCC	H_2 SMR	CHP
Plant Emissions (Mt CO_2e/yr)	930,000	1,300,000	600,000
Carbon Capture %	90	90	90
CapEx ($M)	$200	$220	$218
CapEx Duration (yr)	2	2	2
OpEx Non-energy as % of CapEx (%)	4	7	5
OpEx Energy ($M/yr)	$32	$60	$21
Incentives applied	45Q, LCFS	45Q, LCFS	45Q, LCFS (50%)
Model Results			
Levelized Cost of Capture ($/t CO_2e)	36.49 (revenue)	28.26 (revenue)	12.98 (revenue)

Table 4: Project assumptions and model results for a large complex refinery in California. Assumptions are based on EFI/Stanford (2020) reference case facilities [22].

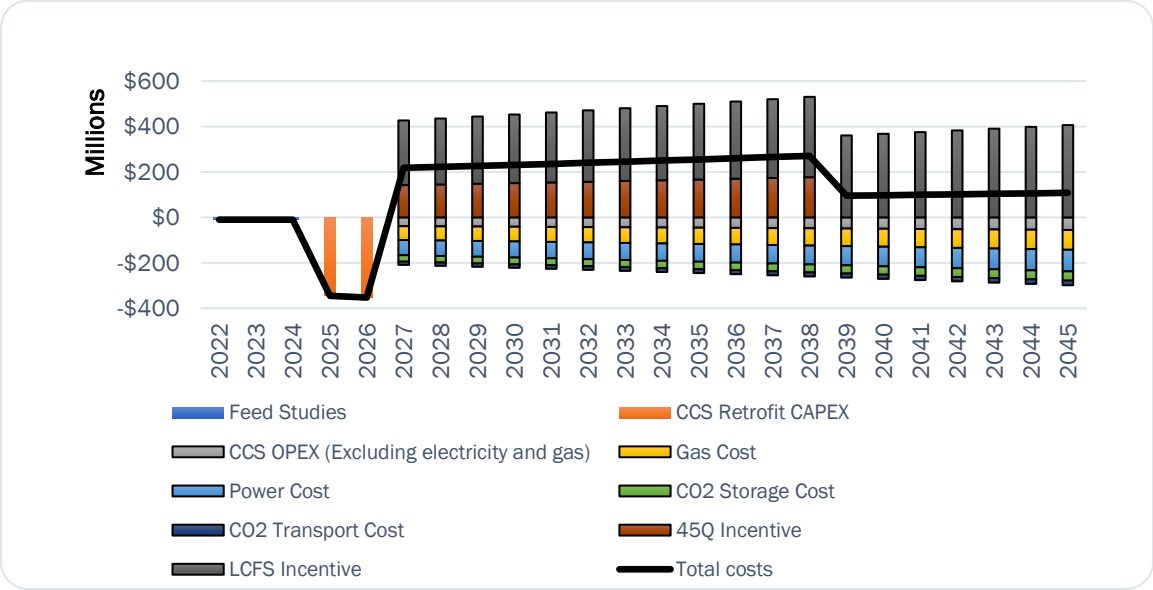


Figure 15: Modeled cash flow for a large California refinery with an FCU, H_2 SMR, and CHP.

These results are consistent with previous studies indicating that CCS retrofits at California refineries can generate positive net revenue.

Cement Subsector

California is the 2nd largest cement producer in the United States [23], producing approximately 10 Mt/yr of product. In 2019, CARB reported 7.78 Mt of CO_2e emissions from in-state cement production from 8 different cement production facilities (one has since ceased operations). The cement industry is expected to grow in the future, both in the US and globally.

Cement production can be simplified into three major steps. **Step 1** involves excavation and crushing of limestone (the calcium source) as shown in Figure 16. Other materials such as silicon, aluminum, and iron are also gathered for the process. These raw materials are crushed and mixed into the proper proportions and then ground to produce very fine particles. These mixed fine particles are then pushed into a preheater to dry the mix.

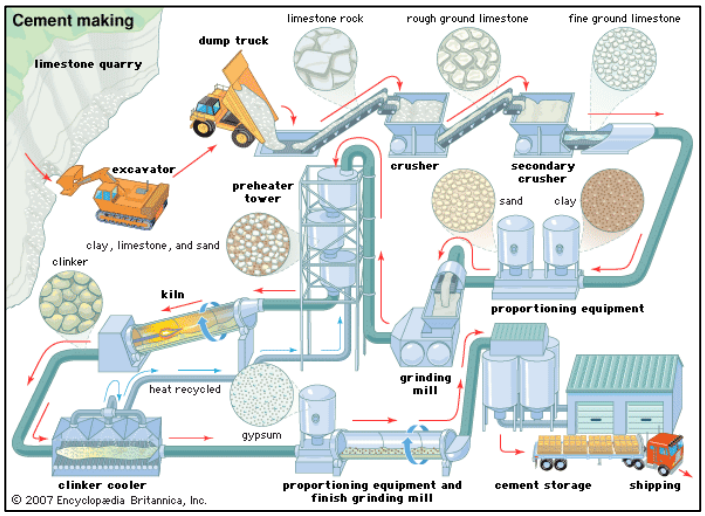


Figure 6: Diagram detailing the cement production operation. Source: https://theconstructor.org/building/manufacture-of-cement/13709/ [24].

Step 2 involves heating and drying the mix of crushed limestone and other materials in a preheater at temperatures around 450 °C. The purpose of the preheating stage is to reduce the water content in the mix. The dried mix then enters the rotary kiln. Three temperature zones exist in the kiln. Zone 1 at the upper end is where the raw meal is added and moisture is evaporated and has temperatures ranging from ambient up to 600 °C. Zone 2 is the calcining zone. Calcination is the process where calcium carbonate ($CaCO_3$) turns into calcium oxide (CaO) and CO_2. Temperatures in zone 2 range from 600 °C to 900 °C. Zone 3 is the burning or sintering zone with temperatures in excess of 1,500 °C which induces the calcium oxide to react with silicates, iron and aluminum in the raw materials to form clinker. In zone 3, temperatures can reach as high as 1800 °C [25]. To reach these high temperatures, multiple fuels are burned. California cement producers currently use coal as the primary combustion fuel followed by petroleum coke, natural gas, and other fuels, respectively.

In **step 3,** the small stone clinkers are rapidly cooled. Note that waste heat produced from the clinkers can be captured for use in the preheater stage. After the clinkers are cooled, they are ground one more time. While grinding, a small percentage of gypsum is added to the mix. The gypsum is used to prevent the ground clinkers from stiffening. The final product is cement which is either stored or shipped.

Emissions from Cement Manufacturing Operations

Emissions from the manufacture of cement are due to 3 main activities: fuel combustion, fuel storage, and clinker production (see Figure 17). Clinker production accounts for the majority of the emissions (immutable emissions released by the chemical process of limestone calcination) [26].

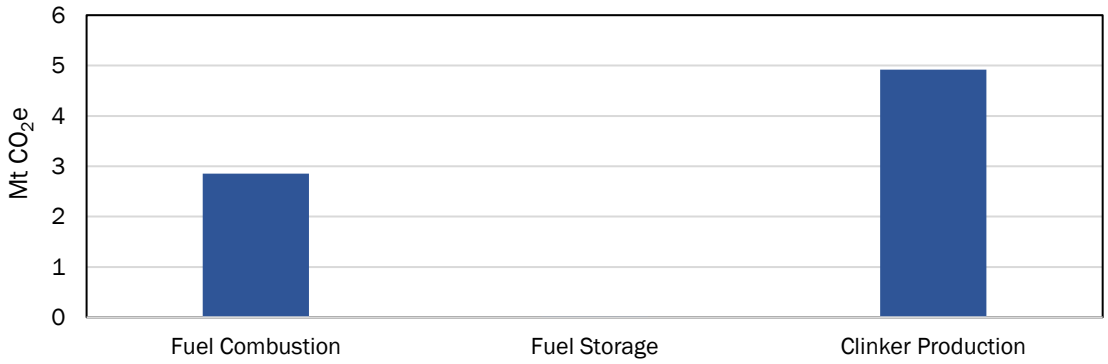


Figure 17: 2019 sources of emissions in the Refining and Hydrogen subsector [1].

As shown in Figure 18, fuel combustion is also a significant source of emissions in the cement industry. Fuel is combusted in the making of cement for process heat for the endothermic calcination reaction. Figure 18 shows the variety of the sources of fuel that are combusted in the cement industry as well as the volume of clinker that is produced.

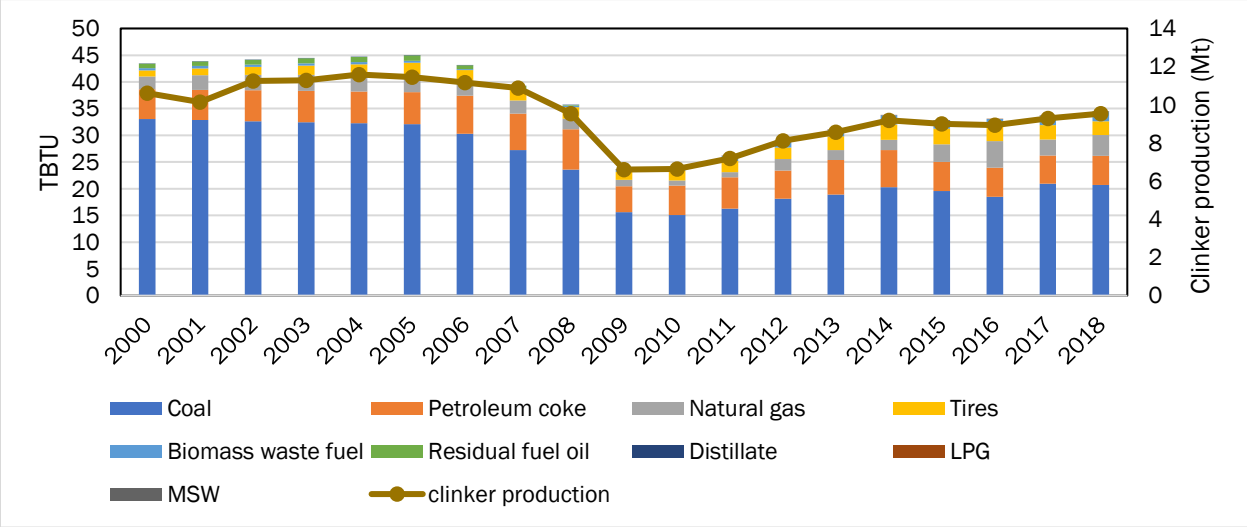


Figure 18: Sources of fuel for combustion in the cement industry from 2000 to 2018. Clinker production levels indicated by brown line and right axis [1] [27].

Decarbonization Options and Technoeconomics

The California Nevada Cement Association recently published a study entitled "Achieving Carbon Neutrality in the California Cement Industry" [26] which lays out decarbonization pathways for the industry. For this study, three options were considered for decarbonizing the cement industry: CCS retrofits, electrification, and a fuel switch to hydrogen. Note that CCS has the potential to abate approximately 90% of the cement emissions from both clinker production and fuel combustion emissions; however, electrification (plasma) and fuel switching options are only able to abate the fuel combustion emissions (approximately 37% of the total cement industry emissions). A fuel switch to natural gas (with CCS) was not considered as a decarbonization option. Discussion with cement industry contacts indicates that while plants start their kilns using natural gas, they lack the supply of natural gas for full plant operations, and permitting a pipeline extension from a trunk line to a cement plant is not seen as a viable option.

Manufacture of cement requires a heat input of 1800 ºC [28] as shown in Figure 19. Biomass, electricity, and hydrogen could potentially be used as alternative fuels. Biomass has been excluded from this analysis due to infrastructure limitations in piping biofuel to cement production facilities.

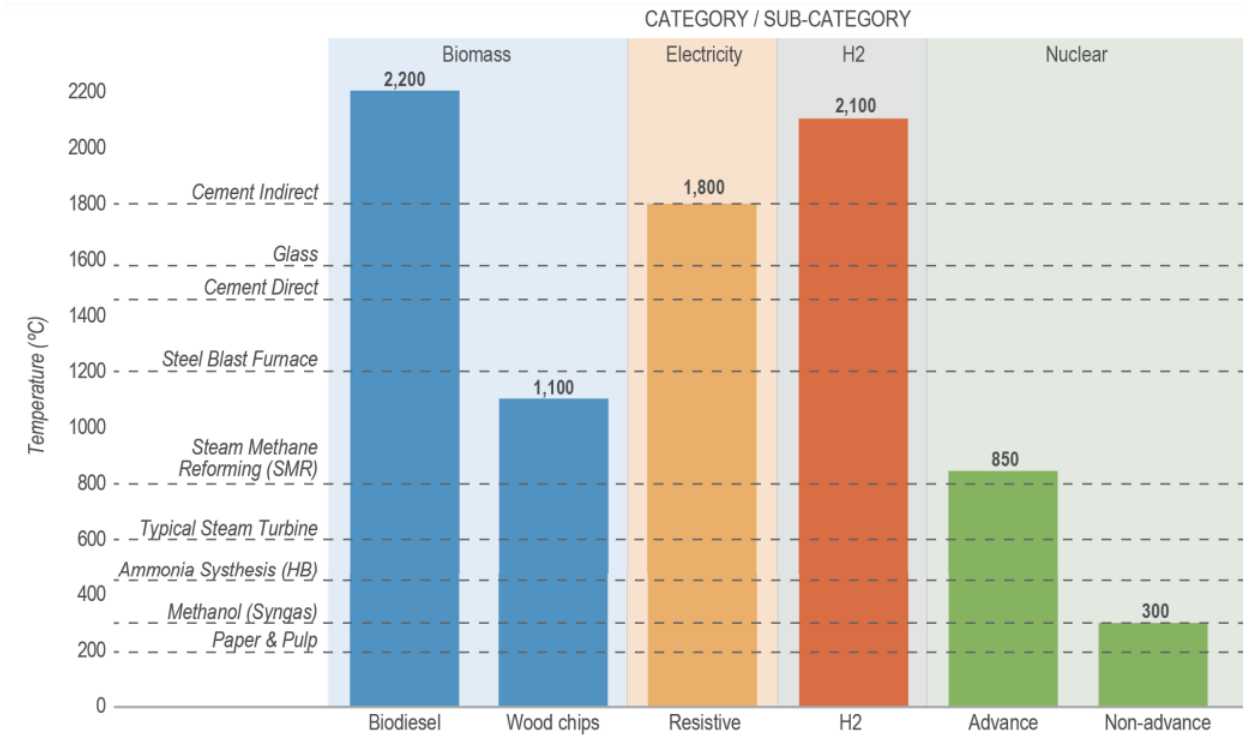


Figure 19: Temperature requirements of different industry processes and fuel temperature limitations. Source: Sandalow et. al.(2019) [29].

For this study, the generalized technoeconomic assumptions were previously outlined in Table 1, and specific assumptions for the cement industry are listed in Table 5 below.

Project Model Assumptions	
Cement Production (Mt/yr)	1.5
Plant Emissions (Mt CO_2e/yr)	1
CapEx Duration (yr)	3
Additional OpEx as % of Capex (%)	7

Table 5: Model inputs for a cement plant.

Carbon Capture and Storage

Cement plants are relatively attractive candidates for industrial CCS, as emissions are co-located and concentrated at two primary sources: the pre-calciner and the kiln. A 2020 study by the Energy Future Initiative and Stanford University estimated CO_2e capture costs for cement in California to range from $48 - $75 per ton of CO_2 [22]. Additional assumptions for a CCS retrofit and technoeconomic model results are shown in Table 6 below.

CCS Assumptions	
CapEx ($M)	187
Yearly OpEx ($M)	28
Incentives	45Q
Model Results	
Volume of CO_2 abated (t/yr)	900,000
Levelized Cost of Abated CO_2 ($/t CO_2e)	38.93
Levelized Cost per Ton of Cement ($/t)	25.96
% Of Abated Emissions	90

Table 6: Technoeconomic model assumptions and model results for CCS retrofit of cement plant described in Table 5 [22].

Although cement capture costs are relatively low compared to other industrial emission sources, cement is not eligible for the California Low Carbon Fuel Standard (LCFS), and the only available incentives are from the federal 45Q tax credit which is currently $50 per ton of CO_2.

The resulting cash flow using the assumptions in Tables 1,6, and 7 is shown in Figure 20. As observed in the bar chart, the revenue from the 45Q incentive is not enough to offset the total capture costs plus storage and transportation costs. Although cement carbon capture retrofit projects are not currently revenue generating, if future legislation were to allow additional incentives such as LCFS or if AB-32 were to become applicable to CCS projects, the economic outlook would significantly shift. With current assumptions alone, a CCS retrofit on a cement plant would likely add $25.96 to the cost per ton of cement. (current cement cost is $125/t of cement).

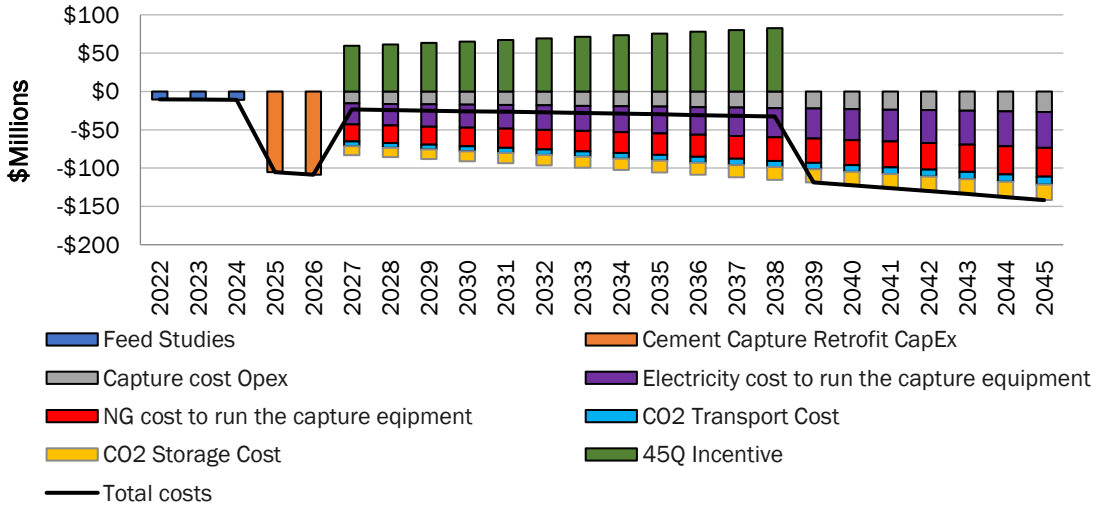


Figure 20: Modeled cash flow for cement plant with 1.5 Mt of cement production per year with CCS retrofit.

Electrification

One option for electrification involves the utilization of plasma generators. This method is currently being piloted by Vattenfall and Cementa on cement plants in Sweden. Sweden predicts this technology could reduce their emissions by 5% by 2030 [30]. The thermal plasma generators for the pilot project are built by ScanArc Plasma Technologies AB and

utilize a technology that has the capacity to reach temperatures of up to 5000 ºC as shown in Figure 21. One benefit of this technology is the low maintenance cost due to lack of moving parts. However, each individual generator has the capacity of only 2 MW which means that a series of generators are necessary to create enough energy for a typical cement plant at 120 MW total.

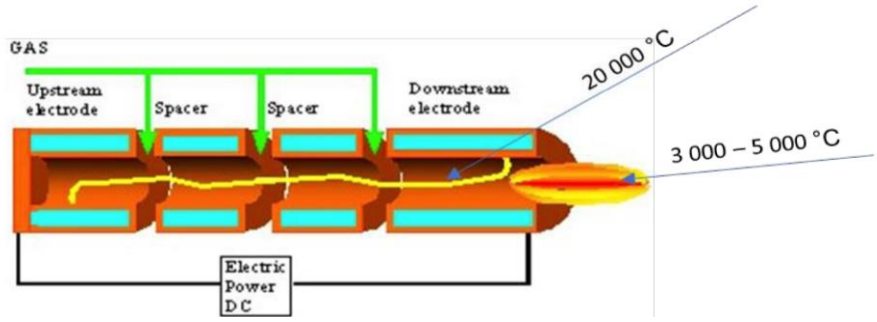


Figure 21: Diagram of a ScanArc plasma generator [31] [30] .

Other electrification methods have also been considered (but neither tested nor implemented) including electrical flow heaters, microwave heating, and resistive heating. It remains to be seen whether these other electrification options have the feasibility to reach the necessary temperature for production.

The additional assumptions and model results for electrification of a cement plant using ScanArc plasma generators are listed below in Table 7, and the resulting cash flow is shown in Figure 22. With current assumptions, electrification of a cement plant would likely add $93.79 to the cost per ton of cement.

Electrification Assumptions	
Annual run time hr/yr	7,500
Plasma Generator [2 MW] (5 units)	6,851,675
Number of generators required	60
Control and instrumentation ($)	5,225,854
Cooling water system ($)	870,976
Civil modification ($)	1,500,000
Electrical energy supply cost for 140 MW	151,410,000
Gas supply	8,709,756
Shield gas	870,975
Expandable materials (electrodes, etc.)	3,483,902
Maintenance	870,975
Incentives	None
Model Results	
Volume of CO_2 abated (t/yr)	370,000
Levelized Cost of Abated CO_2 ($/t CO_2e)	380.22
Levelized Cost per Ton of Cement ($/t)	93.79
% Of Abated Emissions	37%

Table 7: Technoeconomic model assumptions and model results for electrification of a cement plant described in Table 5 [31] [30] .

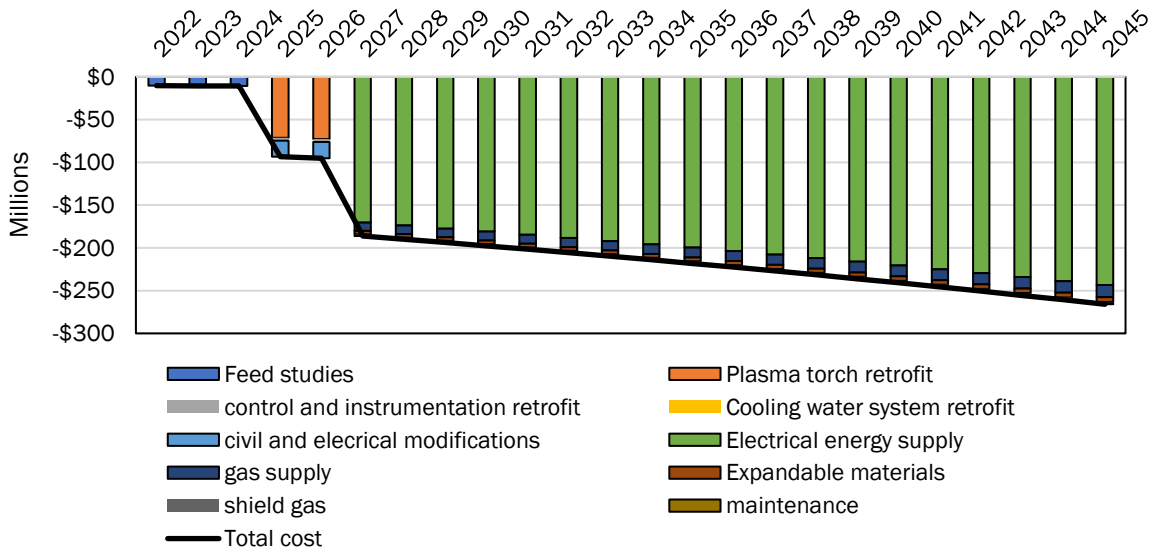


Figure 22: Modeled cash flow for cement plant with 1.5 Mt of cement production per year electrified with plasma generators [30] [31].

Hydrogen Fuel Switch

A fuel switch to hydrogen at a cement plant requires numerous modifications including new burners, hydrogen storage tanks, and renovation or installation of pipelines (for H_2 transport). Additional costs in addition to the general assumptions shown in Table 1 and Table 5 are shown below in Table 8. This technology option is very sensitive to hydrogen fuel price, which for this analysis was assumed to be $3.50/kg. With current assumptions, a cement plant that switches to hydrogen for fuel would likely add $108.13 to the cost per ton of cement and yields a negative cash flow as seen in Figure 23.

Hydrogen Fuel Switch Assumptions	
Hydrogen fuel usage (kg)	61,749,571
Hydrogen burner ($)	831,312
Hydrogen storage tank($)	415,656
Pipeline Renovation ($)	207,828
OPEX without fuel cost ($)	101,835
Fuel cost total ($)	216,123,499
burner efficiency %	53
Incentives	None
Model Results	
Volume of CO_2 abated (t/yr)	370,000
Levelized Cost of Abated CO_2 ($/t CO2e)	438.36
Levelized Cost per Ton of Cement ($/t)	108.13
% Of Abated Emissions	37

Table 8: Technoeconomic model assumptions and model results for hydrogen fuel switch at the cement plant described in Table 5 [31] .

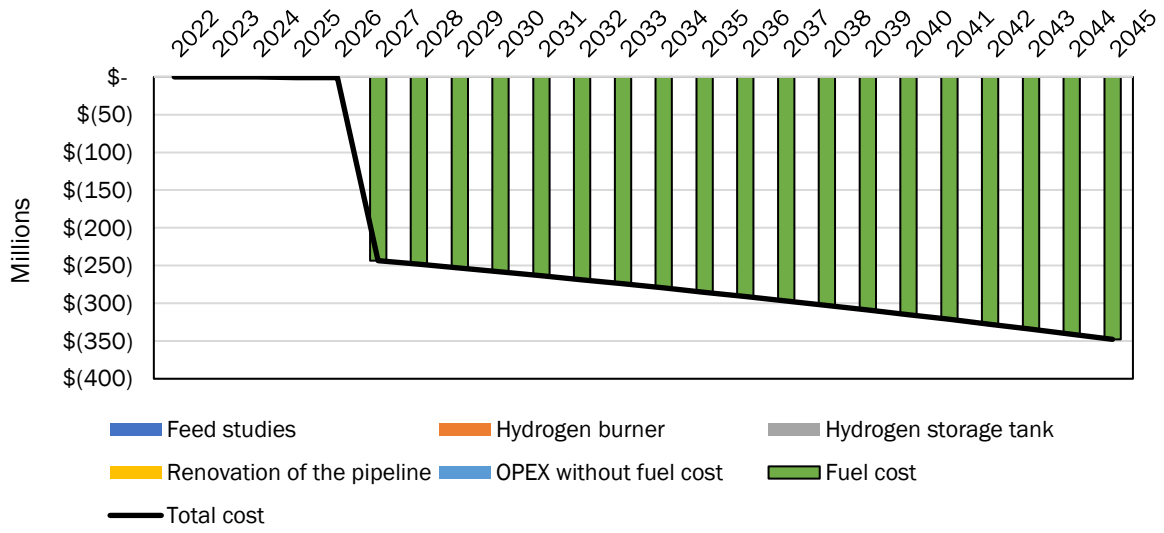


Figure 23: Modeled cash flow for cement plant with 1.5 Mt of cement production per year fueled by hydrogen [31].

Technoeconomic Comparison

All three decarbonization options are cash flow negative, with CCS the least so as shown below in Table 9. The CCS retrofit technology option is eligible for the US 45Q tax credit, while the other technology options are not. The hydrogen fuel switch option is burdened by current assumptions on hydrogen costs. Both electrification and a fuel switch to hydrogen will only abate 37% of the cement emissions, while a CCS retrofit could abate 85%. At this point in time, CCS retrofits on cement plants appear to be the best options for decarbonizing the cement industry in California.

	CCS retrofit	Electrification	Hydrogen Fuel Switch
Volume of CO_2 abated (t/yr)	900,000	370,000	370,000
Levelized Cost of Abated CO_2 ($/t CO_2e)	38.93	380.22	438.36
Levelized Cost per Ton of Cement ($/t)	25.96	93.79	108.13
% Of Abated Emissions	90%	37%	37%
Incentives	45Q	None	None

Table 9: Comparison of technoeconomic model results.

Manufacturing & Mining Subsectors

Excluding cement, the Manufacturing and Mining subsectors accounted for 18% of industrial sector emissions (18 Mt CO_2e) in 2019 [1]. The Manufacturing and Mining subsectors include thousands of different products fabricated by hundreds of facilities in California. The Manufacturing and Mining subsectors have been combined for this analysis because it is difficult to determine whether the reported emissions from certain facilities (e.g., a gypsum, lime, or borax manufacturing companies) are classified by CARB as Manufacturing or Mining. The majority of these facilities utilize natural gas for process heat as shown in Figure 24 below.

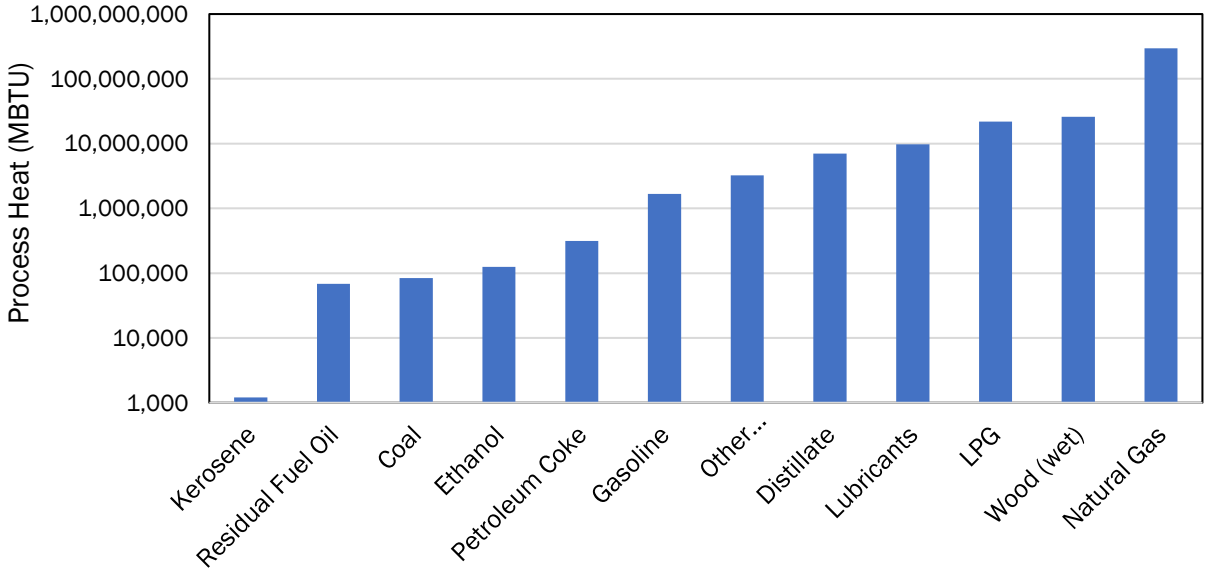


Figure 24: 2019 fuel mix (excluding electricity) utilized by the Manufacturing and Mining subsectors in California [1]. Note logarithmic scale on left axis.

Out of 18 Mt of reported CO_2e emissions, 10.2 Mt were identified, categorized, and aggregated from over 225 separate entities reporting emissions in California in 2019 [4] [5] [6]. Figure 25 compares the emissions reported by CARB by various industries to the detailed bottom-up analysis used in this study.

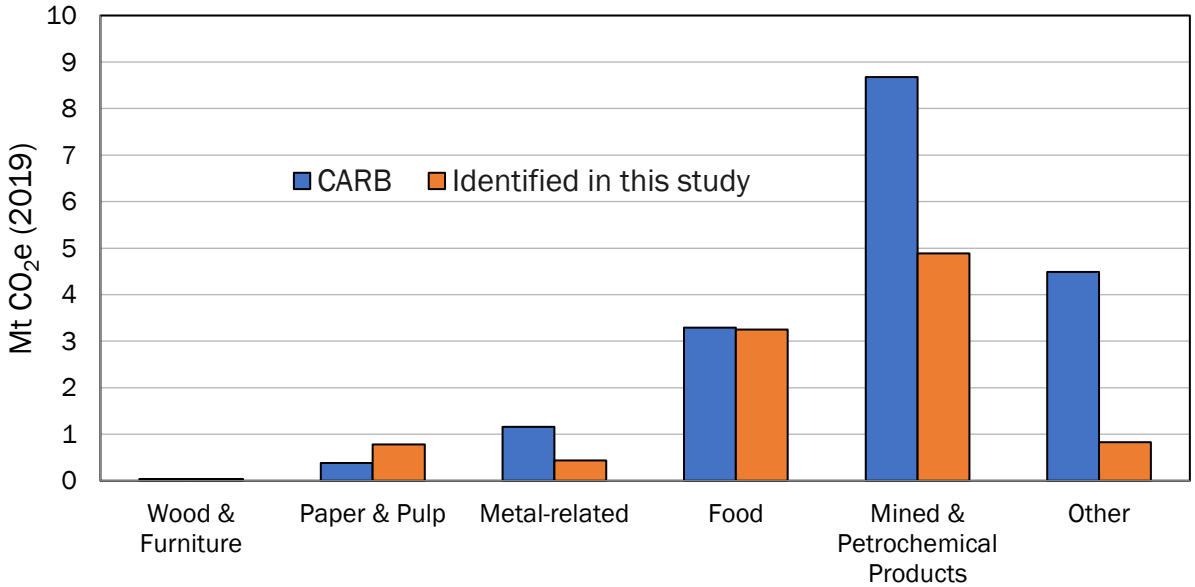


Figure 25: Industries associated with individual facility emissions identified in this study [4], [5], [6] compared to CARB GHG Inventory [1].

The top two emitting sub-categories in Manufacturing and Mining are: (1) mined and petrochemical products and (2) food products as shown in Figure 26, accounting for around 66% of reported CARB emissions in the subsector.

Emissions from Manufacturing and Mining

The diversity of manufacturing in California makes decarbonizing this sector uniquely challenging. However, most reported emissions involve the use of process heat, with particular temperature regimes and end-uses. For food processing, lower temperatures are required in the range of 60-250 °C [32]. The heat transfer medium is often pressurized steam in these applications while required food process temperatures are often below 150 °C. For processing mined material and petrochemicals into products, processing temperatures can reach over 1000 °C for inorganic products, where direct heating with natural gas is often employed [33]. In this analysis, alternative technologies to reduce CO_2 emissions for two temperature ranges: (1) <250 °C, and (2) >250 °C were explored. Some industries span both temperature regimes, such as Paper and Pulp. Dehydration of pulp into paper requires temperatures below 250 °C, whereas the calcination to create slaked lime (CaO) from limestone ($CaCO_3$) for pulp processing requires temperatures up to 900 °C [34], [35]. The 250 °C value is the approximate upper temperature for pressurized steam boilers employed widely in industry for indirect process heat transfer [36].

Given the large number of facilities in the manufacturing sector, targeting and decarbonizing the top emitting facilities can have a significant impact on the overall CO_2e emissions. For example, in 2019, the 12 facilities that would have potentially qualified for the 45Q federal tax incentive (emitting over 100,000 t CO_2e/yr) accounted for 48% of the total identified emissions in this subsector (5.1 Mt.). These 12 facilities represent 5% of the total identified facilities in the manufacturing sector as depicted in Figure 26 below. Importantly, by focusing on a small number of large emitters, decarbonization efforts could potentially be maximized with the fewest resources and logistical hurdles.

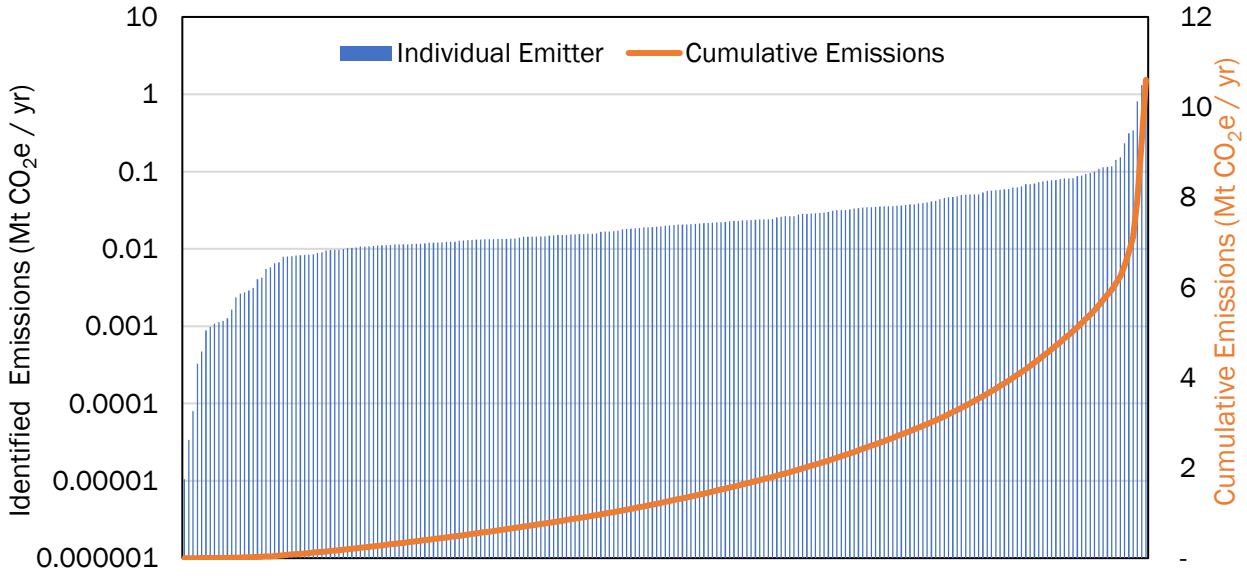


Figure 26: 2019 CO_2e emissions from 225 individual reporting facilities in the Manufacturing and Mining subsector [4] [5] [6].

Given the significant variety and number of facilities in the manufacturing sector, technoeconomic analysis was carried out for two subsectors. This was accomplished by aggregating the process heat requirements with corresponding CO_2e emissions and then calculating the required capital equipment and operational costs between 2025-2045 for different commercialized decarbonization technology options: (1) heat pumps, (2) electric steam boilers, (3) H_2 steam boilers, (4) direct resistive heating, (5) direct H_2 heating, (6) and CCS. General modeling assumptions and inputs are laid out in Table 1. Selected mature and commercially viable technologies were explored which can provide the heat and temperature range necessary for manufacturing processes in each subsector. Promising nascent thermal storage technologies, such as those from Rondo[1] or Antora Energy[2], are not included in this analysis. Such technologies store electric energy as high-temperature heat (>1000 °C) in an insulated thermal environment for extraction at a range of temperatures and powers. Additional manufacturing efficiency gains that could reduce energy usage can be made by improving manufacturing processes with applied data analytics. Companies such as Arch Systems or Guidewheel provide such services that are not considered here.

In this analysis, only the top two emitting subsectors are discussed: Mined and Petrochemical Products and Food Products. A special discussion on Timber and Wood Products is also included. CARB's Emissions Inventory separates biogenic (e.g., originating from biological sources) and non-biogenic (e.g., originating from sources like fossil fuels) emissions sources. This study focuses on non-biogenic emissions. However, the emissions in this subsector originate primarily from the combustion of wood residue, a biogenic source. Abating these biogenic CO_2e emissions from high-emitting point sources would be beneficial and could serve as a carbon sink in certain carbon-counting frameworks. Finally, in each section, a levelized cost of carbon (LCOC) is provided for each proposed decarbonization technology.

Mined and Petrochemical Products

There are many inorganic and organic materials manufactured in California, from glass and gypsum for construction to ethanol and asphalt for automotive purposes (Figure 27). Mined and petrochemical products were combined into one category for this analysis as separation was not possible given CARB's categorization. Chief among this sector's top emitters are facilities that process mined inorganic material such as soda ash and borates. Just like cement, soda ash production requires the calcination of limestone into slaked lime at temperatures up to 900 °C [35]. For petrochemical products, "cracking" is sometimes employed to transform alkanes at temperatures above 800 °C if needed beyond standard refining or at lower temperatures if needed for separation and melting material for product formation.

[1] https://www.rondo.energy/
[2] https://antoraenergy.com/

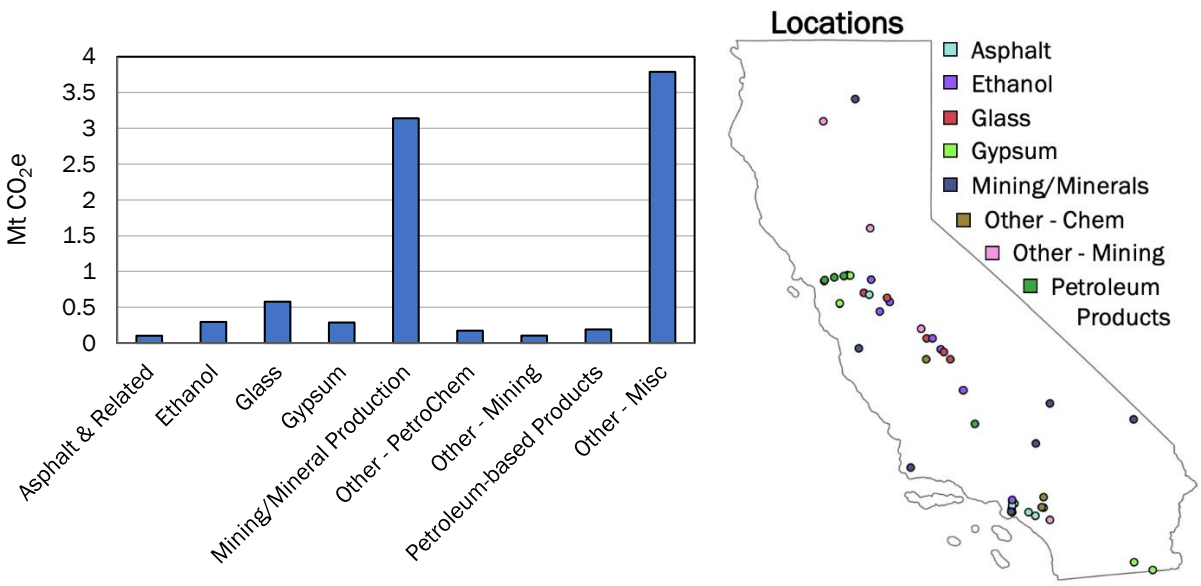


Figure 27: Contributions by manufacturing activity in mined and petrochemical products, which emitted 4.9 Mt of CO_2e in the manufacturing sector from identified facilities in 2019.

The subsector breakdown by emissions and a map of all the identified reporting emitters is shown in Figure 28. The top 5 emitters (10% of total identified facilities) in this subsector accounted for 67% (3.2 Mt) of all identified CO_2e emissions in 2019 (Figure 28). Again, targeting a small number of high-volume emitters can have a significant effect on sectoral emission reductions.

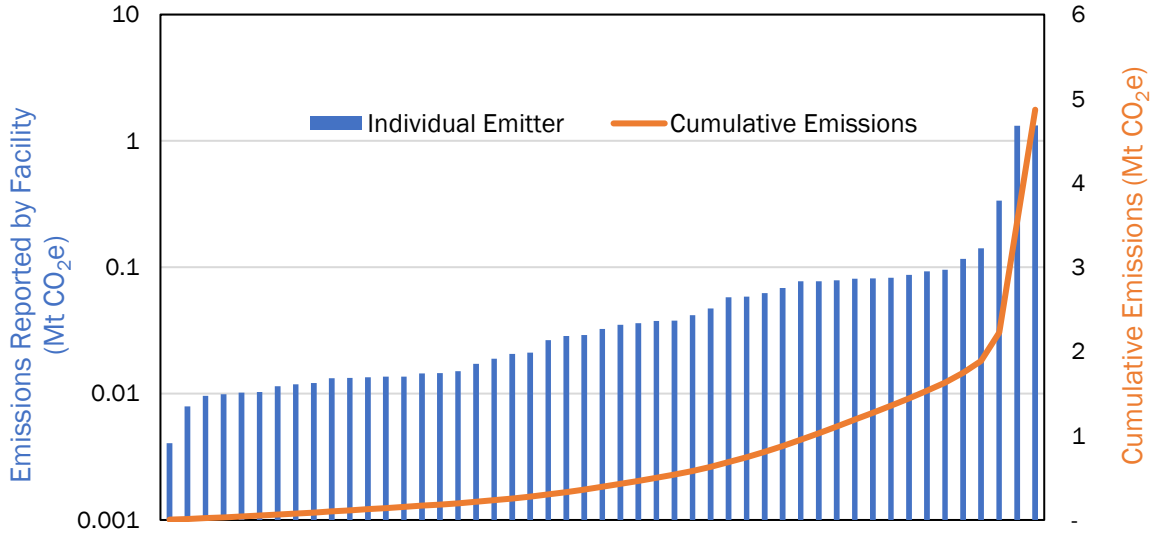


Figure 28: 2019 emissions from 49 identified mining and petrochemical processing facilities.

Decarbonization Options and Technoeconomics

Most process heat emissions in the mined and petrochemical processing facilities originate from the direct combustion of natural gas. Leading technology alternatives to replace this heat source include direct resistive heating and switching from natural gas to H_2. As shown

in Figure 20, traditional direct resistive heating has an upper temperature range of 1800 °C and H_2 firing of 2100 °C. The required capital equipment and operational costs were used and adapted from the Danish Energy Agency's "Technology Data: Process Heat and CC" [36]. To reach high temperatures, resistive heating technology often employs $MoSi_2$ heating coils. In molten metal, graphite rods are used. For an H_2 fuel switch, the capital cost of an H_2 burner was considered equivalent to natural gas burners, per announcements from leading industrial manufacturers that H_2 boilers would be similar in cost to natural gas boilers [37]. For both technologies, the lifetime of the equipment is less than the 20-year decarbonization timeline starting in 2025, meaning that the capital equipment must be purchased twice.

CCS is another option for abating CO_2 emissions from use of natural gas combustion. The technoeconomics of the three aforementioned decarbonization strategies: electric heating, H_2 heating, and CCS are summarized below in Table 10. The values summarized for electric heating and hydrogen fuel switch consider the entire subsector instead of specific facilities identified for CCS. Notably, employing CCS with a 45Q tax incentive (for qualifying facilities emitting 100,000+ t CO_2/yr year), 2.9 Mt CO_2/yr could be abated. The LCOC is lower than the proposed alternatives at \$60.7/t CO_2. When comparing the two alternative heating technologies to natural gas, both the capital and operational costs of an H_2-fuel switch are lower than the electric alternative with an LCOC of \$953/t CO_2e. While electrification has the highest cost, it could be reduced significantly depending on the cost of grid electricity (modeled at \$144/MWh), which represents nearly all the levelized operating costs. Alternative electricity sources, such as distributed solar and storage could potentially reduce electricity costs. Sensitivity of the LCOC based on electricity cost will be explored in future studies. Additionally, thermal storage technologies could smooth out intermittent renewable energy generation curves and utilize renewables that would otherwise be curtailed.

	Direct Resistive Heating (Electric)	H_2 Fuel Switch - Direct Fire	CCS 45Q, (100,000 t/yr)	CCS 45Q Hybrid (25,000 t/yr)
Model Assumptions				
CapEx (\$M)	517	127	104	178
OpEx Energy (M\$/yr)	8,460	5,999	60.7	151
OpEx Other (M\$/yr)	N/A	815		
Unit output (MW)	5	2.5	N/A	N/A
Incentives	none	none	45Q (\$50/t CO_2)	45Q for facilities with > 100,000 t/yr emissions
Limitations	Temp <1800 °C	Temp <2100 °C		
No. Facilities	All	All	5	28
Model Results				
LCOC (\$/t CO_2)	1,146.00	953.00	51.50	72.30
Abated CO_2 (Mt/yr)	8.65	8.65	2.91	4.13

*Assumes 90% capture efficiency

Table 10: Technoeconomic costs and additional metrics comparing leading decarbonization technologies for mined and petrochemical products. "CCS 45Q" scenario considers only emitters above 100,000 t CO_2, "CCS 45Q Hybrid" includes facilities between 25,000-100,000 t CO_2 without a 45Q tax incentive.

Food Products

Among the three top emitting industries in the Manufacturing and Mining subsector, the public is most familiar with and dependent on food every day. California is the most diverse and productive agricultural supplier in the US. Over 70 food processing plants are co-located within its borders, concentrated around the Central Valley. The agriculture sector provides $50 billion in yearly revenue from direct farm products for California [38]. Food and beverage processing adds $25 billion in direct value along with 198,000 full- or part-time jobs [39]. The top identified food product areas are shown in Figure 29 and consist of sugar (0.90 Mt CO_2e, 28%), tomatoes (0.63 Mt CO_2e, 20%), dairy (0.57 Mt CO_2e, 18%), and dried/roasted food (0.47 Mt CO_2e, 15%).

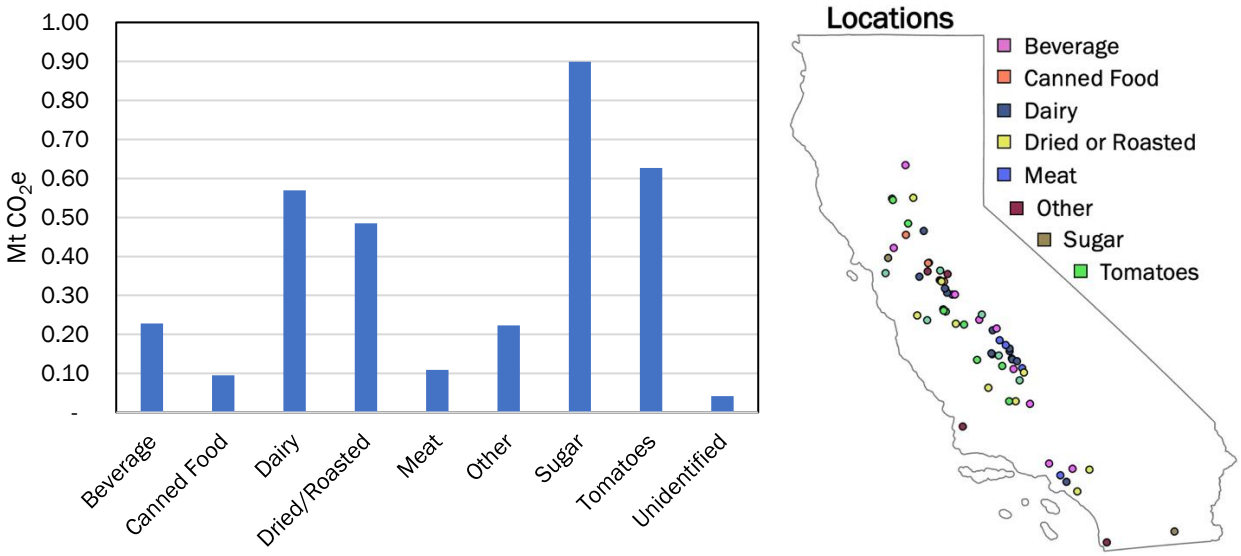


Figure 29: 2019 emissions from food processing activities and identified facilities.

Unlike in the Mined and Petrochemical Products area, the distribution of emitters in the food product area skews heavily towards emitters below 50,000 t CO_2e/yr as shown in Figure 30.

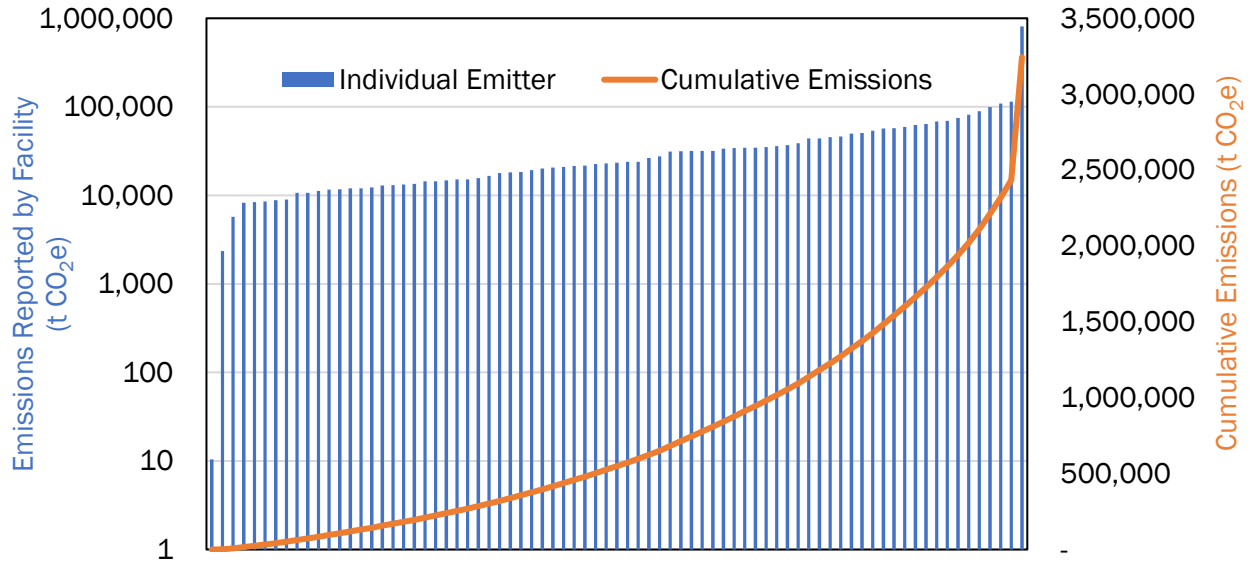


Figure 30: 2019 emissions from 79 identified food products facilities.

Many food processing facilities rely on pressurized steam boilers and heat transfer pipes to provide process heat. For perspective on the energy requirements of different common food processes, Figure 31 shows requirements for cooling, heating, freezing, and drying, which are based off the thermodynamic values of pure water. Hot air drying is by far the most energy intensive at ~30 times more energy intensive than cooling [40].

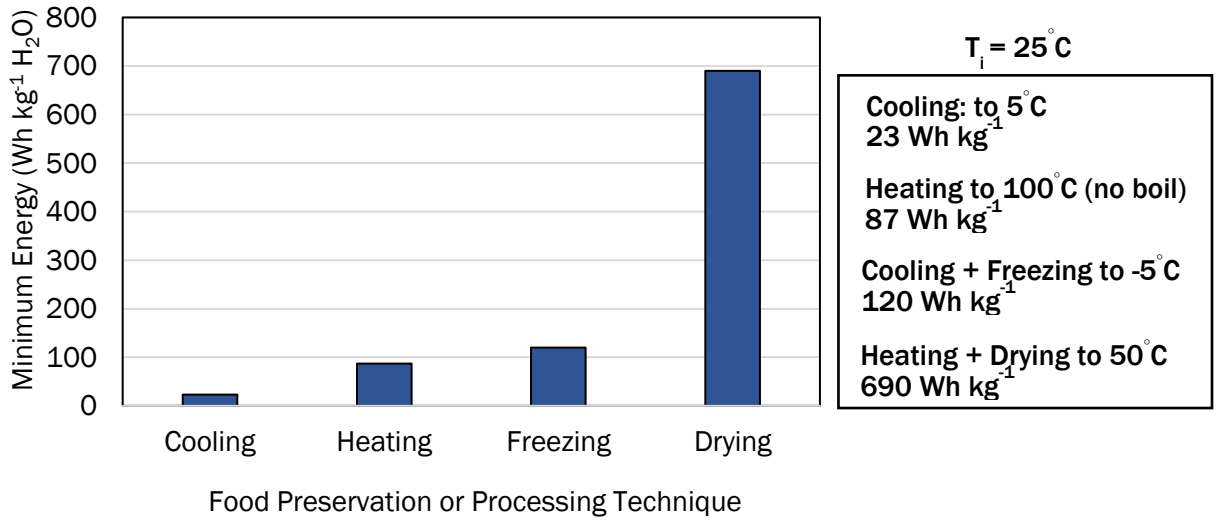


Figure 31: Relative energy requirements for different food preservation and processing methods using the physical properties of pure water [40].

In sugar production, the primary heat uses are for water evaporation and crystallization with upper temperature limits of 133 °C [41]. As the biggest tomato processor in the US, most tomato processing involves sterilization and evaporation with common "cold break" or "hot break" of the tomato skin removal processes that require temperatures of 60-105 °C [42]. Dairy pasteurization requires brief high temperatures of 70 °C, but the highest processing

temperatures for dairy are used in the production of dried milk powder at 135 °C [43]. A range of temperatures is required for dried (~55 °C), roasted (<155 °C) and fried foods (180 °C) [44].

Decarbonization Options and Technoeconomics

Considering the required temperature ranges up to 155 °C for most processes, alternative steam heating technologies include high-temperature boosted heat pumps, electric boilers, and H_2-fired boilers. As shown in Table 11, the highest LCOC are associated with switching from natural gas steam boilers to electric or H_2 boilers with values around $1000/t CO_2e. These values are dominated by the cost of the energy carrier or fuel.

CCS with 45Q tax incentives covers fewer sector emissions at 29% of those identified in this study (only 3 facilities) compared to the previous discussion involving mined and petrochemical products. LCOC with CCS is nearly 20 times lower than electric resistive and H_2 alternatives. Even without 45Q, the LCOC for CCS is over an order of magnitude less than alternatives and covers 73% of identified emissions. The large number of small emitters can make coordinating CCS and transport to sequestration challenging. However, coordination of logistics given the concentration of facilities in the Central Valley could make this viable, particularly because the facilities are located over suitable geological storage [22].

Outside of CCS, the use of high temperature booster heat pumps could be a retrofit option for steam production is many cases. However, temperatures cannot be achieved above 150 °C, which eliminates some processes, especially in the dried, roasted, and fried food subsector.

	Booster Heat Pump**	Electric Boiler	H_2-Switch Boiler	CCS 45Q, (100,000 t/ yr)	CCS 45Q Hybrid (25,000 t/ yr)
Model Assumptions					
CapEx (M$)	5,230	222	112	37.4	129
OpEx Energy (M$/yr)	1,482	2,964	2,160	21.4	131
OpEx Other (M$/yr)	50	14	240		
Unit Power Output (MW)	4	15	20	N/A	N/A
No. Facilities	All	All	All	3	36
Incentives	none	none	None	45Q ($50/t)	45Q ($50/t CO_2) for facilities with > 100,000 t/yr emissions only
Limitations	<150 °C, excl. added F-gases	retrofit	Similar Equip. to Natural Gas		
Model Results					
LCOC ($/t CO_2e)	735	1,110	889	57.50	99
Abated CO_2e (t/yr)	3.29	3.29	3.29	0.93	2.38

*90% CO_2 emissions capture (% of identified facilities) **Coefficient of Performance: 2.0 for steam heat pump

Table 11: Technoeconomic costs and additional metrics comparing leading decarbonization technologies for food products [36]. "CCS 45Q" scenario considers only emitters above 100,000 t CO_2, "CCS 45Q Hybrid" includes facilities between 25,000-100,000 t CO_2 without a 45Q tax incentive.

Wood and Furniture Products

According to CARB's *Annual Summary of 2019 Greenhouse Gas Emissions Inventory Data* [1] emissions accounting from non-biogenic sources, manufacturing of wood and furniture products is responsible for only 37,300 t CO_2e of manufacturing subsector emissions. These reported emissions are mostly due to the combustion of natural gas for initiating drying processes [45]. However, there is a major difference in accounting between non-biogenic and biogenic sources in this category. In general, biogenic sources fall within the IPCC fast domain carbon cycle (e.g., soils, biomass, ocean) for carbon turnover of 1-500 years, where non-biogenic energy sources fall under the slow domain carbon cycle with turnovers of >10,000 years [46]. Fossil fuels release carbon and transfer it from the slow to the fast domain carbon cycle. For wood and furniture, however, reporting only non-biogenic emissions can be misleading as the subsector requires a significant amount of process heat. Much of this heat is generated from the combustion of wood-based residue left over from the wood manufacturing process. These combustion emissions are not included in the non-biogenic CARB inventory that is the focus of California's decarbonization strategy. If these biogenic emissions are included, timber and wood production would account for 1.8 Mt CO_2 additional emissions in the Manufacturing and Mining subsector. As relatively large CO_2e emitters from point sources (see Figure 32), abating these emissions could have additional benefits and serve as a carbon sink depending on the emission accounting framework.

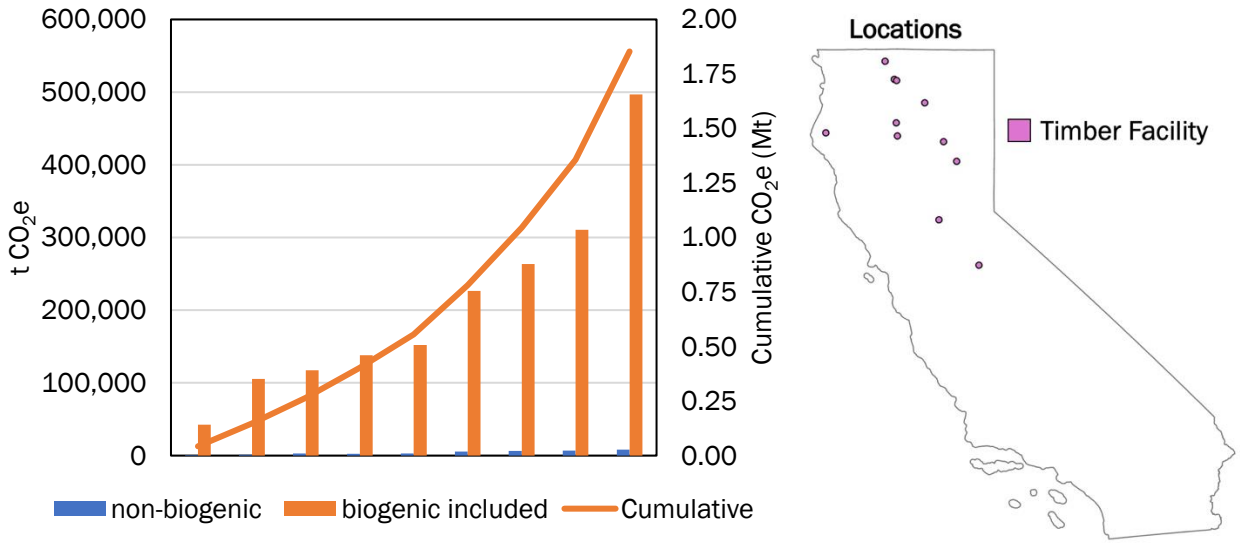


Figure 32. Comparative percentage of Timber or Wood Product production emissions from non-biogenic sources (left) and emissions if biogenic combustion of wood-based residues is included (right).

Manufactured wood products include multiple kinds of wood products (e.g., planks, doors, wood chips). Because of the significant heat of vaporization of water required for drying, only around 1% of energy consumed at a sawmill is electrical, while the rest is process heat [45]. Eight timber processing facilities in California account for 99.8% of the subsector emissions and each emit over 100,000 t CO_2e/yr (if biogenic emissions are included).

Interestingly, 43% of the final disposition of wood products in 2016 for California was for bioenergy generation of electricity and heat through combustion, which may not all be included in the manufacturing subsector. Of total harvested wood, 23% was used directly for bioenergy, where an additional 11% from manufacturing wood residues were added for bioenergy generation such as heating for kiln drying. To this end, lumber constituted only 33% of the final disposition of wood with veneer, mulch, reconstituted board, exports, and material losses making up 24% [47]. This suggests a potentially severe undercounting of CO_2e emissions by overlooking biogenic combustion of wood products.

Decarbonization Options and Technoeconomics

Electrifying the heating process or using a H_2 fuel switch would have similar costs as those estimated in the Food Products subsector discussion. Additionally, it would likely be difficult to convince an industry that uses a waste product from their manufacturing processes for energy to replace it with a source that costs money. Further, lumber companies play a critical role in thinning tree stands for forest fire management control. Excess electricity from biomass fueled power plants are also sold back to the grid. As such, in this study only CCS is considered for reduction in emissions.

Given the small number of large emitters, CCS is proposed for emissions reductions as shown in Table 12 below, which can reduce emissions by 1.66 Mt CO_2 per year or 90% of all emissions primarily produced through biomass combustion.

	CCS w/45Q, 100,000/yr
Model Assumptions	
CapEx (M$)	76.2
OpEx (M$/yr)	42.6
No. of Facilities	8 (73%)
Incentives	45Q
Incentive Limitations	>100,000 ($50/t CO_2)
Model Results	
LCOC ($/t CO_2)	64.9
Abated CO_2 (Mt/y)*	1.66 (90%)*

*90% CO_2 emissions capture (% of identified facilities)

Table 12: Technoeconomic modeling assumptions and results associated with CCS retrofits to decarbonize biogenic combustion in the timber and wood industry.

Transmission and Distribution Subsector

Reported emissions in the Transmission and Distribution subsector were 5.3 Mt in 2019 as shown in Figure 1 [1]. CARB reports Transmission and Distribution subsector emissions based on natural gas conveyance only. Among emissions sources in this sector, fugitive methane (CH_4) emissions from natural gas conveyance comprised the majority, (78% or 4.1 Mt CO_2e) and the remainder of emissions (1.3 Mt CO_2e) are from the combustion of natural gas at compressor stations [1] as shown in Figure 33. This analysis focuses on direct fugitive CH_4 emissions from natural gas and converts CH_4 emissions into their CO_2 global warming equivalence as needed for discussion.

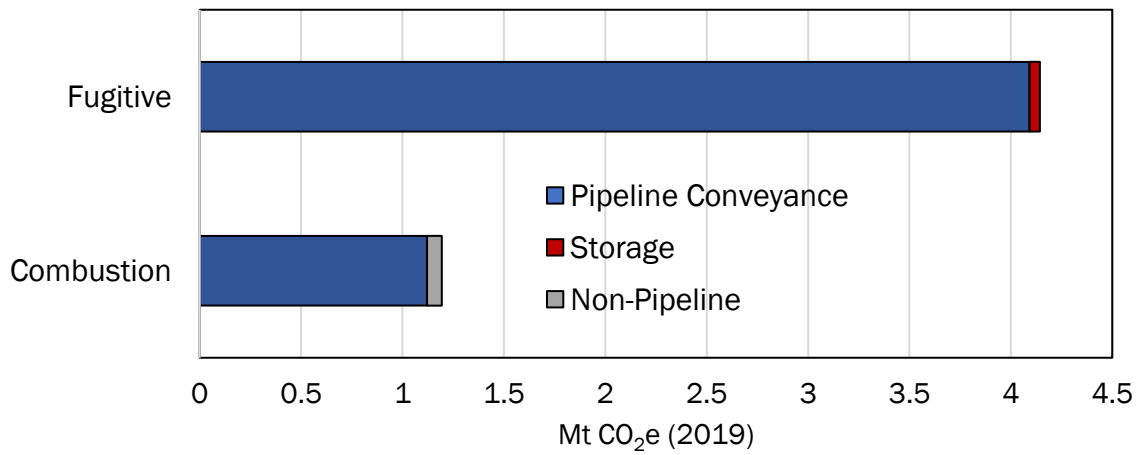
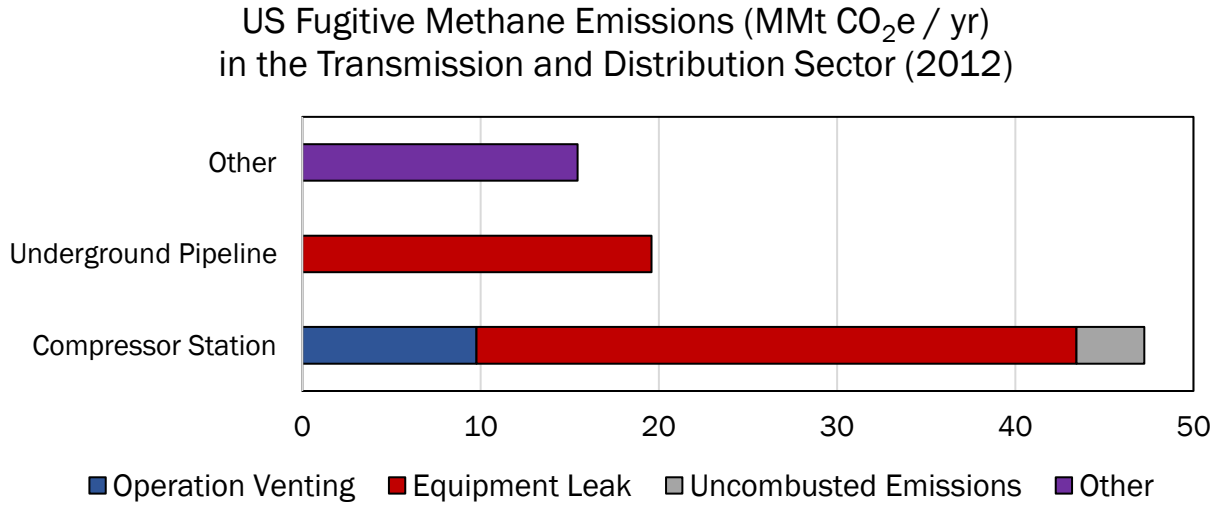


Figure 33: 2019 sources of CO_2e (22% CO_2 & 78% CH_4) emissions from the Transmission and Distribution subsector in California [1].

Sources of Fugitive Emissions

The three primary sources of fugitive emissions from pipeline conveyance of natural gas are compressor stations, metering and regulating stations, and natural gas pipelines. The relative volume of emissions from these three different sources is not known for California but estimates for the entirety of the US suggest that most fugitive emissions are generated at compressor stations, as shown in Figure 34 [48]. The distribution of emissions by source for the US were applied to California for local estimation. Of the total fugitive emissions shown in Figure 33, this study estimates that compressors accounted for 57% of emissions (2.4 Mt CO_2e) due to venting, equipment leakage, and combustion exhaust. Leakage through underground pipelines is estimated to account for 24 % of emissions (0.98 Mt CO_2e), mostly due to spot leaks. Specific causes of these emissions are discussed in the subsequent sections.



Reciprocating Compressor

Natural Gas Pipelines

Figure 34: Distribution of fugitive emissions by source [48] and photos of a reciprocating compressor [49] and installation of an underground natural gas pipeline [50].

Compressor Stations

As their name suggests, compressor stations pressurize natural gas for conveyance down pipelines. There are two main types of compressor designs: reciprocating and centrifugal. Reciprocating compressors use pistons to compress the natural gas and resemble a traditional internal combustion engine. Centrifugal compressors use turbines to increase the velocity of the gas, increasing the kinetic energy, which when passing through a diffuser is converted into potential energy in the form of pressure. The three largest natural gas emitting processes at compressor stations are **venting, equipment leakage** and **uncombusted exhaust** emissions.

Figure 35 compares the relative emissions during operation and standby for these different compressor types at case study sites [51]. Notably, reciprocating compressors emit in the **exhaust** stream due to incomplete combustion but these emissions from centrifugal compressors are much lower. In fact, exhaust emissions (un-combusted CH_4) are ~40 times higher for reciprocating compressors than centrifugal due to the lower efficiency of the compressors [52].

However, **venting** emissions are significant for both centrifugal and reciprocating compressors. Venting is the process of releasing the gas used as a starter and is typically released into the atmosphere. Venting is also required if the system must be “blown down” for safe maintenance of the equipment (e.g., it is unsafe to work on equipment full of compressed flammable gas). This means venting only happens when restarting/starting a compressor and typically occurs during maintenance when the compressor needs to be shut off. Improved maintenance and operation can decrease these types of emissions.

Because they have moving and connecting parts, methane **equipment leakage** is present in both types of compressor systems, but reciprocating compressors, unfortunately, leak under normal operating conditions no matter how well-designed their piston-compression components. It is estimated that small to medium-sized reciprocating compressors that are

properly aligned and fitted lose approximately 11 to 12 scf per hour, while large compressors can emit between 24 and 150 scf per hour [53].

Within California, there are over 100 compressor stations, but the ratio of compressor types is not available. However, nationwide approximately two-thirds of installed compressor power originates from reciprocating compressors [52].

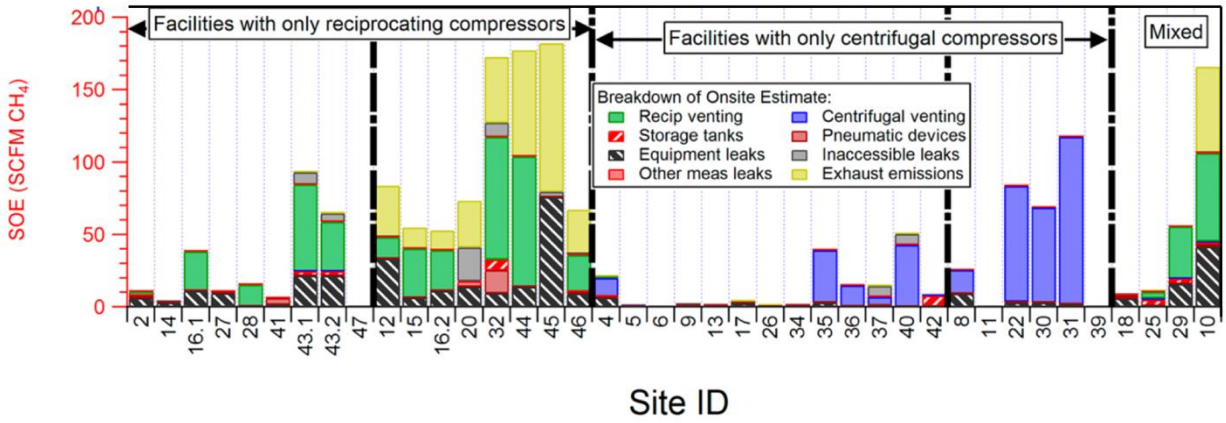


Figure 35: A case study of emissions sources for centrifugal and reciprocating natural gas compressors. Source: Subramanian et. al., (2015) [51].

Underground Pipelines

There are approximately 215,000 miles of transmission, distribution, and service lines in California as shown in Figure 36 [54]. Transmission lines convey natural gas to distribution lines which feed into customer service regions with decreasing pipe diameter, much like the root system of tree. In total there are 82,635 miles of steel pipeline, 55 miles of cast iron pipeline, and 120,748 miles of plastic pipeline. Based on material type and installation requirements, these pipelines leak CH_4 at different rates as shown in Table 13 below.

Pipeline Material	Value	Units
Cast Iron Pipeline	4,570	kg CH_4/mile-yr
Unprotected Steel Pipeline	125	kg CH_4/mile-yr
Protected Steel Pipeline	6.8	kg CH_4/mile-yr
Plastic Pipeline	10	kg CH_4/mile-yr

Table 13: Average leakage rate reported for natural gas pipelines by pipeline material [55].

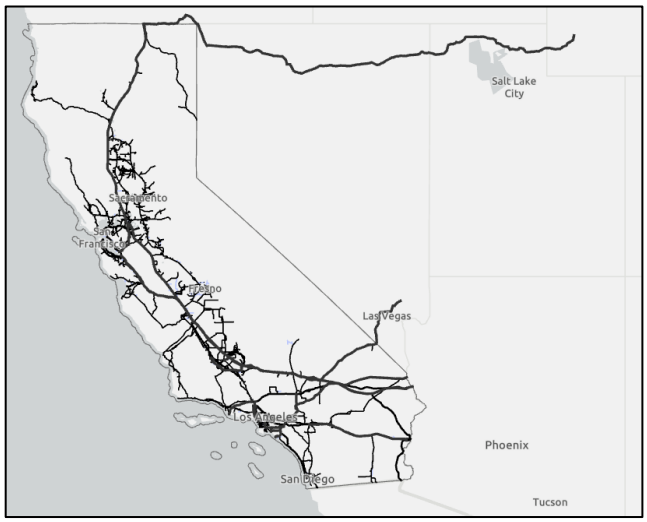


Figure 36: Map of natural gas Transmission and Distribution Pipelines (not including service pipelines to customers) [56].

Options for Reducing Emissions

Compressor Emissions and CO_2e Abatement Technoeconomics

As compressors are the largest source of fugitive methane emissions and methane is a valuable product to recapture and use, a number of cost-effective abatement opportunities have been proposed by the Joint Institute for Strategic Energy Analysis for the natural gas supply chain [57]. Figure 37 shows the sector-specific marginal costs of fugitive methane abatement opportunities considering a "full-revenue" scenario. A full-revenue scenario includes the economic value of abated fugitive methane emissions which are sold for consumption. A partial-revenue scenario is also presented, where all sectors excluding transmission and distribution sector can utilize the economic value of abated methane emissions to payback implementation costs. This difference stems from market and policy behavior where producers of natural gas are incentivized to reduce fugitive emissions so that they can sell more natural gas. However, transmission operators are not necessarily financially incentivized to reduce fugitive emissions, meaning they may not get paid for abated methane emissions. "Owners of natural gas transmission, as a result of how transmission owners recover costs and earn revenue, may not be able to recoup the value of saved gas resulting from transmission infrastructure improvements." A practical change from partial to full revenue scenarios could require policy or market changes.

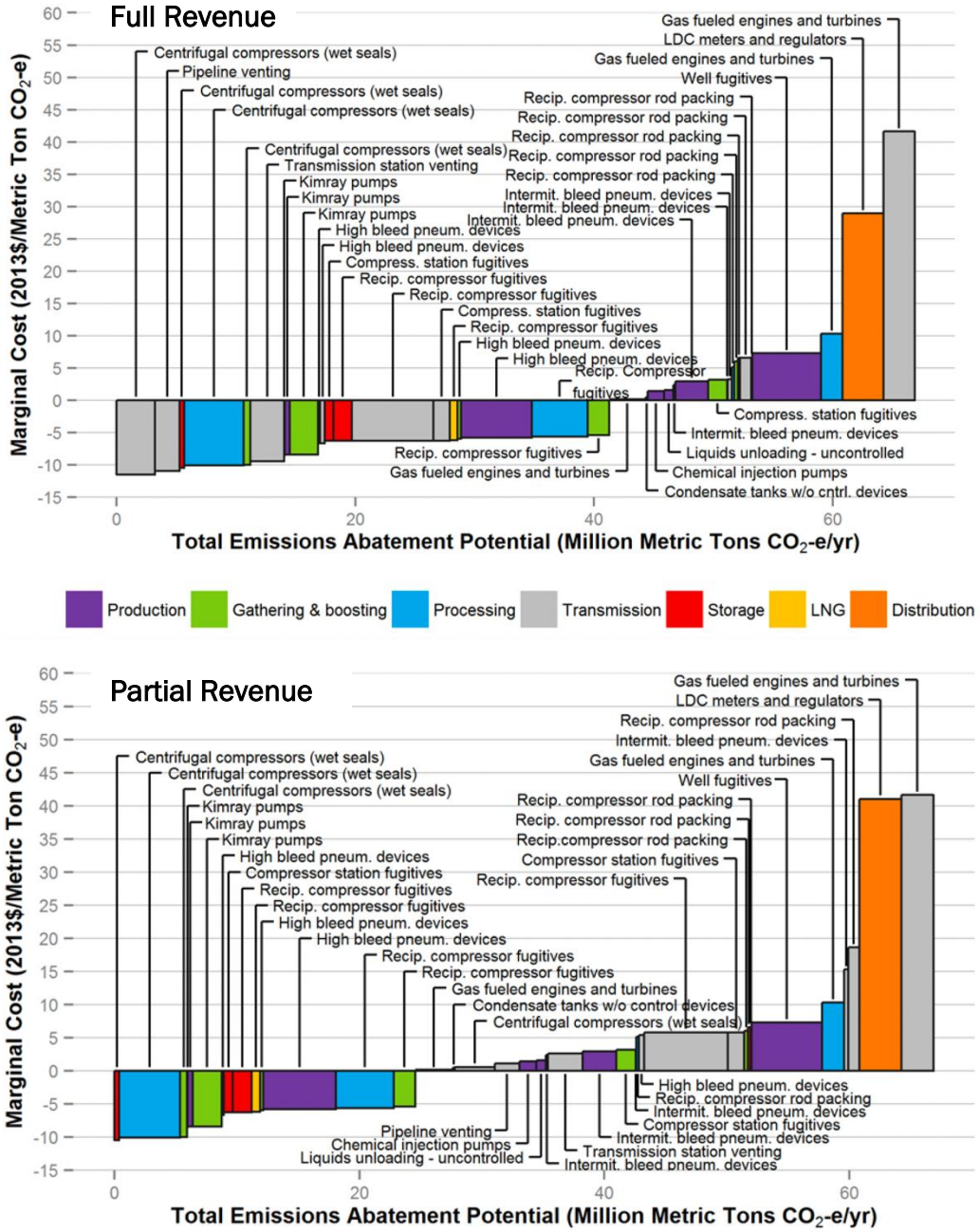


Figure 37: Full and partial emissions abatement potential. Source: Warner et. al.(2015) [57].

Considering a full-revenue scenario and only zero-to-negative marginal costs of potential abatement measures, the methane abatement potential was estimated for California at a reduction or 1.0 Mt CO_2e/yr. When considering full-abatement potential, a 36% fugitive emissions reduction (1.5 Mt CO_2e) could be achieved. Notably, the most expensive abatement measures when adjusted for inflation to 2025 yield an LCOC of $53/t CO_2e,

which is considerably lower than other LCOC abatement values presented in this study. A list of the most cost-effective abatement measures is provided by Warner et. al.(2015) [57].

Pipeline Emissions and CO_2e Abatement Technoeconomics

The 200,000+ mile natural gas pipeline system in California can leak gas through diffusion and at pipe defects or seams in pipes. Cast iron and unprotected steel are more leakage prone compared to alternatives.

Although these two materials comprise only 0.03% and 1.7% of total pipeline miles in California, respectively, based on data from the EPA in Table 14, they potentially account for 10% and 18% of total average fugitive pipeline emissions [58].

Table 16 shows the calculated emissions rates based on EPA estimates for existing pipelines in California. Much of the older cast iron and unprotected steel pipe in California has already been replaced with protected steel and plastic pipe. To reduce emissions and costs of replacement, remaining cast iron and unprotected steel pipelines can also be retrofit with plastic liners [59]. The cost of replacing an underground pipeline with a different pipe material is estimated to be between $1-5 million per mile due to excavation and replacement. Alternatively, an existing pipe can be coated with a plastic liner at ~$10,000 per mile [59].

The retrofit costs of a plastic liner are considered in Table 15. Assuming the leakage rate of plastic pipe for the plastic liner, retrofitting cast iron and unprotected steel yields a relatively small reduction in emissions of 16,000 t CO_2e/yr. Compared to retrofitting unprotected steel pipe, cast iron retrofit yielded a profitable LCOC due to recovered and sold CH_4.

Pipeline Material	Length in CA (mi), PHMSA	CH_4 emitted (t/yr), EPA	CO_2e (t/yr), calculated	Percent of Abatable Emissions, calculated	Capital Cost ($M), 2025 EPA	LCOC ($/t) calculated
Cast Iron Pipeline	54.9	251	6,272	95%	0.66	-2.67
Unprotected Steel Pipeline	3464	433	10,823	92%	4.60	348
Protected Steel Pipeline	79,172	538	13,459	N/A	N/A	N/A
Plastic Pipeline	120,748	1207	30,187	N/A	N/A	N/A
TOTAL	203,438	2,430	60,742	27%	35.1	0.23
Abated CO_2e Emissions (t CO_2e/yr)					16,200	

Table 15: Costs and results for plastic liners to abate CO_2e emissions from pipelines. Note that in this table negative costs make revenue (from sale of methane that is no longer leaked).

Acute Leakage Points

Statistical analysis of average pipe leakage rates accounted for only 60,000 t CO_2e/yr which does not account for the relatively high fugitive emissions extrapolated from Figure 34 that result in an estimated 980,000 t CO_2e/yr. Some recent reports suggest leakage rates of natural gas may be an order of magnitude higher in some areas than previously thought [60]. Until recently, gas leaks were reported by service visits or passersby calls near gas line locations by smell or by sight, or by catastrophic occurrences such as the pipeline explosion in San Bruno, California in 2010 (Figure 38).

Figure 38: 2010 Natural gas leakage and explosion from underground natural gas pipeline in San Bruno, California. Source: Pipeline and Hazardous Materials Safety Administration.

Prevention of gas leaks from pipelines is the first line of defense but active searching is also required and exists at different scales and costs. When analyzing different methods of leak detection there are increasing spatial scales: Individual, Facility-to-Site, Regional, and Global [61]. It is likely that all resolutions of detection will be needed to combat fugitive emissions in California and beyond. Techniques that could be employed include acoustic monitoring, soil monitoring, flow monitoring, and flame ionization detection.

- *Acoustic monitoring* utilizes acoustic emission sensors to detect leaks based on changes with background noise patterns are used within pipes. The advantage of this method is the ability to pinpoint the exact location of the leak. Disadvantages include a large number of sensors needed to monitor an extended range of pipelines as well as the inability of the technology to pick up small leaks.

- *Soil monitoring* is another method of leakage monitoring, where the pipeline is inoculated with a tracer chemical that is then tested for within the surrounding soil to see if there is leakage. A drawback to soil monitoring is that is relatively expensive to continuously pump tracer chemicals into the pipeline.

- *Flow monitoring* devices are also used within pipes to measure the rate of change of pressure or mass flow, which can be used to identify leakage. The main advantage of

this method is the low cost of the system. There are two drawbacks, however, the main one being the inability to pinpoint the actual leak location as well a high rate of false alarms. These flow monitoring devices can also be integrated into a software-based dynamic modeling system that continuously tracks flow parameters to identify if there are leaks. This large-scale software modeling system is expensive especially with a large array of pipelines.

- *Flame ionization* detector, which is typically housed in a handheld or mounted device. One key benefit of using a flame ionization detector is that it is very sensitive to small concentrations of gas and has no false alarms. The negatives include slow detection rate and limited spatial sampling, only accounting for the local area where the gas is drawn [62].

Facility-to-Site Measurement typically encompass a larger spatial scale than individual source measurements. The primary example of Facility-to-Site measurement is the measurement of gas downwind of a facility or a compressor station to see if methane can be detected. This is primarily conducted with flame ionization detectors that are mounted on vehicles downwind of the facility. The Environmental Defense Fund and Google Earth recently to develop a pilot project where Google streetcars are equipped with high-precision methane analyzers and drive around cities identifying zones where there is significant leakage. The precise methane detector is a Picarro high precision CH_4 analyzer, which when coupled with GPS and a 2-D anemometer could identify areas where there is probable leakage [63].

Regional measurements typically focus on the use of aircraft and towers. A case study within the Barnett Shale, Texas shows the benefits of utilizing aircraft and how those estimates compare to typical measurements where super emitters are not typically looked at separately but are instead aggregated. When using aircraft or towers the measurements include the total atmosphere GHG enhancements downwind or above the plants and give a bigger picture of what is being emitted. Airplanes are more accurate than towers as they can move back and forth above the plants continuously measuring methane emissions. The drawback of these two methods is that it is not easy to attribute emissions which may lead to emission overestimation due to methane from a different source that the tower or plane was not trying to measure [64].

The largest Spatial Scale captures continental to global measurements of methane emissions using satellites, Currently MethaneSAT, the “most advanced methane-tracking satellite in space…” is being produced and will enable high-precision tracking of emissions. The data turnaround will be in days and be available to the public. The MethaneSAT works by covering a 200-kilometer view path, passing over target regions every few days. Using an imaging spectrometer, the satellite will separate the narrow band within the shortwave infrared spectrum that detects methane. With a resolution of 100 meters, MethaneSAT’s biggest advantage over other satellites is a much smaller spatial resolution that will help

identify leakage areas faster [65]. Because of the relatively higher detection limit of satellites, they will be more useful for finding large leaks from, for example, compressor stations or large diameter pipe failures.

Conclusions

Industrial sector emissions are some of the most difficult to abate due to the sector's diversity, capital intensive operations, and the need for process heat which is typically provided from the combustion of fossil fuels. This study contains a bottom-up accounting of over 400 emitting facilities in the industrial sector in California. While electrification and fuel switching are technically feasible methods for decarbonizing many of these facilities, currently CCS is the most cost-effective technology, especially for the larger emitting facilities that are eligible for the federal 45Q tax incentive. Additional emerging technologies that support industrial process efficiencies can further reduce the decarbonization burden.

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