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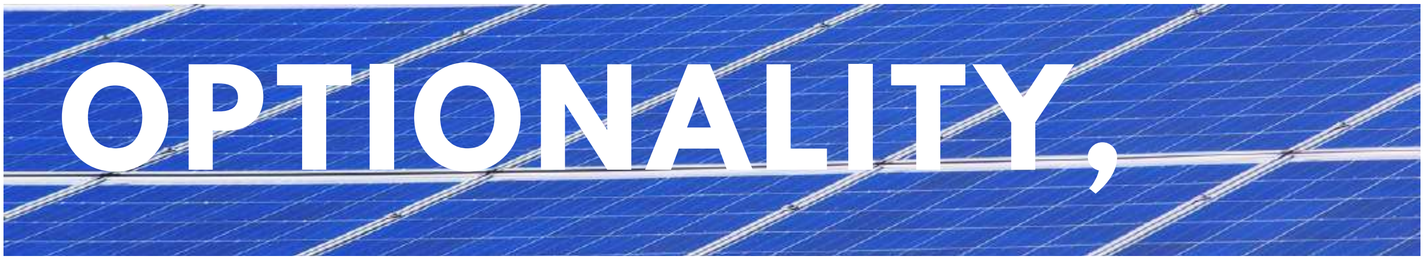

OPTIONALITY, FLEXIBILITY & INNOVATION


PATHWAYS FOR DEEP DECARBONIZATION IN CALIFORNIA

ENERGY FUTURES INITIATIVE

ABOUT EFI

The Energy Futures Initiative (EFI), established in 2017 by former Secretary of Energy Ernest J. Moniz, is dedicated to addressing the imperatives of climate change by driving innovation in energy technology, policy, and business models to accelerate the creation of clean energy jobs, grow local, regional, and national economies, and enhance energy security. We are fact-based analysts who provide our funders with unbiased, practical real-world energy solutions.

The study was produced with the support of a group of funders to define the existing California clean energy landscape and recommend steps for accelerating the move to meet the state's carbon reduction goals by midcentury.

The analysis and conclusions of this report are solely those of the Energy Futures Initiative. EFI is responsible for its contents.

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PROJECT TEAM

PRINCIPALS AND STAFF

CHAIRMAN

ERNEST J. MONIZ
CEO AND FOUNDER

PROJECT DIRECTOR

MELANIE A. KENDERDINE
PRINCIPAL

CONTRIBUTING AUTHORS

ALEX KIZER
DIRECTOR OF STRATEGIC RESEARCH

TIM BUSHMAN
SENIOR ANALYST

ANNE CANAVATI
ANALYST

SAM SAVITZ
ANALYST

ADDITIONAL CONTRIBUTORS

JOSEPH S. HEZIR
PRINCIPAL

DAVID ELLIS
DIRECTOR OF STRATEGIC COMMUNICATIONS AND POLICY

JEANETTE PABLO
GENERAL COUNSEL AND SENIOR ASSOCIATE

NATALIE VOLK
COMMUNICATIONS AND BUSINESS DEVELOPMENT ASSOCIATE

RON MINSK
EFI DISTINGUISHED ASSOCIATE

FRANK O'SULLIVAN
EFI DISTINGUISHED ASSOCIATE

ALISON SILVERSTEIN
EFI DISTINGUISHED ASSOCIATE

EMRE GENCER
CONSULTANT

MICHAEL KEARNEY
CONSULTANT

BOB SIMON
CONSULTANT

ADVISORY GROUP

The Energy Futures Initiative wishes to thank the following individuals for providing comments on this paper. The research and views in this paper are those solely of the Energy Futures Initiative.

JERRY ACOSTA
UTILITY WORKERS UNION OF AMERICA (AFL-CIO)

SHERYL CARTER
NATURAL RESOURCES DEFENSE COUNCIL

RALPH CAVANAGH
NATURAL RESOURCES DEFENSE COUNCIL

JIM CONNAUGHTON
NAUTILUS DATA TECHNOLOGIES

DIAN GRUENEICH
STANFORD UNIVERSITY

JULIO FRIEDMANN
GLOBAL CCS INSTITUTE, EFI DISTINGUISHED ASSOCIATE

DAVID FOSTER
EFI DISTINGUISHED ASSOCIATE

HAL HARVEY
ENERGY INNOVATION

DAVID JERMAIN
BOSTON UNIVERSITY, EFI DISTINGUISHED ASSOCIATE

MICHAEL LEAHY
CHEVRON

ARUN MAJUMDAR
STANFORD UNIVERSITY

GEORGE MINTER
SOUTHERN CALIFORNIA GAS COMPANY

DAN REICHER
EFI DISTINGUISHED ASSOCIATE

JEFF RISSMAN
ENERGY INNOVATION

DAVID VICTOR
UNIVERSITY OF CALIFORNIA-SAN DIEGO

PAT WOOD III
WOOD3 RESOURCES

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LIST OF ACRONYMS

A/C	air conditioning
AB	Assembly Bill (in the California Legislature)
AD	anaerobic digester
AFDC	Alternative Fuels Data Center of the U.S. Department of Energy
AFUE	Average Fuel Use Efficiency
AFV	alternative fuel vehicle
AI	artificial intelligence
ARFVTP	Alternative and Renewable Fuels and Vehicle Technology Program (California program)
AV	autonomous vehicle
B100	a diesel fuel that is 100 percent biodiesel
B20	a diesel fuel blend in which up to 20 percent is biodiesel
B5	a diesel fuel blend in which up to 5 percent is biodiesel
B99	a diesel fuel blend in which up to 99.9 percent is biodiesel
BAU	business as usual
Bcf	billion cubic feet
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
BOEM	Bureau of Ocean Energy Management of the U.S. Department of the Interior
BROs	Behavioral, Retrocommissioning, and Operational Efficiency measures
C&S	codes and standards
$CaCO_3$	calcium carbonate
CAES	compressed air energy storage
CAFE	corporate average fuel economy
CAISO	California Independent System Operator
CALGreen	California Green Building Standards Code
CaO	calcium oxide

CARB	California Air Resources Board
CCF	capital charge factor
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilization, and storage
CDFA	California Department of Food and Agriculture
CDR	carbon dioxide removal
CEC	California Energy Commission
CH_4	methane
CHP	combined heat and power
CI	carbon intensity
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide-equivalent
CPUC	California Public Utilities Commission
CSP	concentrated solar power
CT	combustion turbine
CVRP	Clean Vehicle Rebate Program (California program)
DAC	direct-air capture
DC	direct current
DGE	diesel gallon equivalent
DMV	Department of Motor Vehicles
DOE	U.S. Department of Energy
DR	demand response
DRC	Democratic Republic of the Congo
E10	a gasoline fuel blend in which no more than 10 percent is ethanol
E15	a gasoline fuel blend in which 10.5 percent to 15 percent is ethanol
E3	Energy and Environmental Economics, Inc.
E85	a gasoline fuel blend in which up to 85 percent is ethanol

HHV	higher heating value
hr	hour
Hz	hertz
ICE	internal combustion engine
IoT	Internet of Things
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
ISO	independent system operator
kg	kilogram
kt	thousand metric tons
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LCE	lithium carbonate equivalent
LCFS	Low Carbon Fuel Standard
LCOE	levelized cost of energy
LCOS	levelized cost of storage
LDV	light-duty vehicle
LEV	low emission vehicle
LFG	landfill gas
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSCM	large-scale carbon management
Mcf	thousand cubic feet
MIT	Massachusetts Institute of Technology
MMBDT	million bone-dry tons
MMBtu	million British thermal units

EE	energy efficiency
EEA Regulation	Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities Regulation
EFI	Energy Futures Initiative
EFRC	Energy Frontier Research Center (U.S. Department of Energy program)
EIA	Energy Information Administration of the U.S. Department of Energy
EO	Executive Order
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EUL	estimated useful life
EV	electric vehicle
EW	enhanced weathering
FCEV	fuel-cell electric vehicle
FFV	flexible fuel vehicle
FHWA	Federal Highway Administration
FOM	fixed operations and maintenance
g/bhp-hr	grams per brake horsepower-hour
gal	gallon
GGE	gasoline gallon equivalent
GHG	greenhouse gas
GSP	gross state product
GVW	gross vehicle weight
GW	gigawatt
GWh	gigawatt-hour
GWP	global warming potential
H_2	hydrogen
HDV	heavy-duty vehicle
HEMS	home energy management system
HERS	Home Energy Rating System
HFC	hydrofluorocarbon

MMGGE	million of gallons of gasoline-equivalent
$MMTCO_2e$	million metric tons of carbon dioxide-equivalent
mpg	miles per gallon
MSW	municipal solid waste
MW	megawatts
MWh	megawatt-hour
N_2O	nitrous oxide
NCA	nickel-cobalt-aluminum
NERC	North American Electric Reliability Council
NET	negative-emissions technology
NGCC	natural gas combined-cycle
NGV	natural gas vehicle
NHTSA	National Highway Transportation Safety Administration
NIMBY	not in my backyard
NMC	nickel-manganese-cobalt
NOx	oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
OCGT	open-cycle gas turbine
P2P	peer-to-peer
PG&E	Pacific Gas and Electric
PHEV	plug-in hybrid electric vehicle
PJM	PJM interconnection - a regional transmission organization in the eastern United States
PSH	pumped-storage hydropower
PV	photovoltaic
R&D	research and development
RD&D	research, development, and demonstration
REC	renewable energy certificate
RFS	Renewable Fuel Standard

RICE	reciprocating internal combustion engines
RIN	renewable identification number
RNG	renewable natural gas
RPS	renewable portfolio standard
RTO	regional transmission organization
SB	Senate Bill (in the California Legislature)
SCE	Southern California Edison
scf	standard cubic foot
SESAME	Sustainable Energy Systems Analysis Modeling Environment
SGIP	Self-Generation Incentive Program (California program)
SLCP	short-lived climate pollutant
SMR	steam-methane reforming
SUV	sport utility vehicle
TWh	terawatt-hour
UC	University of California
UEF	Uniform Energy Factor
UN	United Nations
USC	University of Southern California
USDA	U.S. Department of Agriculture
USREP	U.S. Regional Energy Policy (an energy model)
VMT	vehicle-miles traveled
VOC	volatile organic compounds
VOM	variable operations and maintenance
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
Wh	watt-hour
whp	water horsepower
WREGIS	Western Renewable Energy Generation Information System
ZEV	zero-emission vehicle
ZNE	zero net energy

SUMMARY FOR POLICYMAKERS

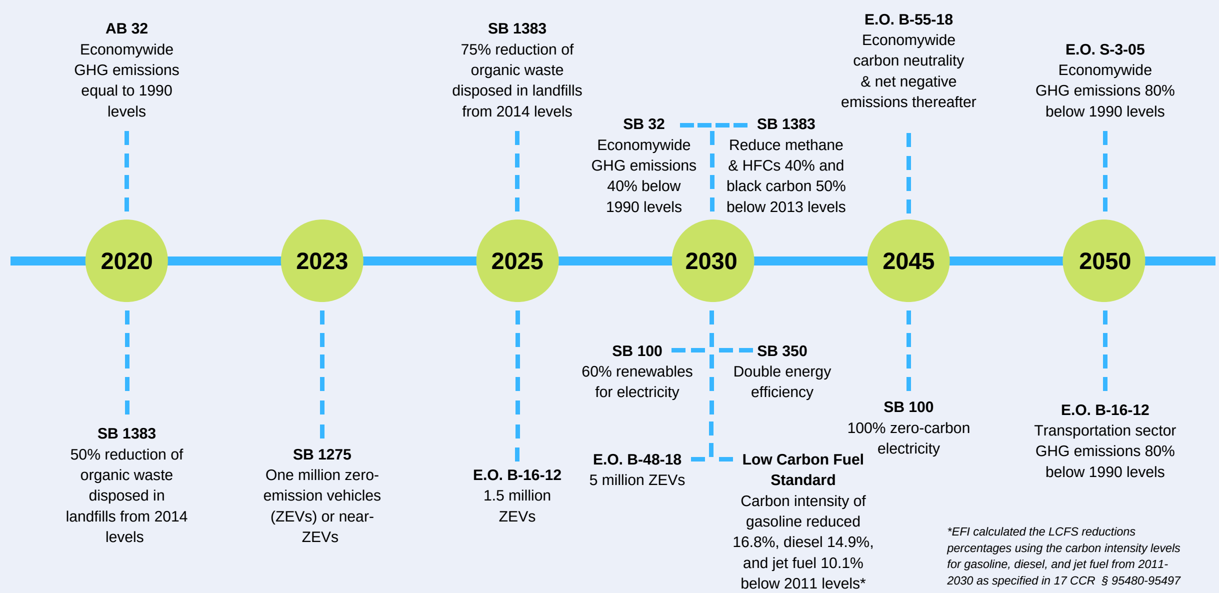
California is a global leader in climate policy. It has adopted aggressive goals to reach a low-carbon future at a scale and pace needed to meet the underlying Paris commitment of keeping temperature increases to two degrees Celsius, or even significantly lower, by the end of the century. California's commitment fundamentally translates to an 80 percent (or more) reduction in greenhouse gas emissions (GHG) relative to a 1990 baseline. If California meets its aggressive goals, it will enhance its leadership status, setting an example for the world where, unfortunately, carbon dioxide emissions continue to rise. As the world's fifth largest economy, what happens in California is critical for shaping the global response to climate change, reinforcing the importance of California's leadership.

This study analyzes the options—described as "pathways"—for meeting California's near- and long-term carbon emissions reduction goals. This analysis is designed to work within the parameters of existing state policy; it does not offer explicit policy recommendations.

California's decarbonization goals include both economywide and sector-specific policy targets (Figure S-1): Executive Order S-3-05 (2005) calls for an economywide emissions reduction of 80 percent by 2050 (from 1990 levels); Executive Order B-55-18 (2018) establishes a statewide goal of carbon neutrality by 2045; SB 100 (2018) requires 60 percent renewable electricity generation (excluding large hydro) by 2030, and net-zero-emissions electricity by 2045. Some policies are more prescriptive (e.g., five million zero emissions vehicles by 2030), while others are less so (e.g., 40 percent reduction of emissions economywide by 2030).

Figure S-1

California's GHG Emissions Reductions Policy Timeline



To meet its aggressive GHG emissions reduction goals, California has a number of policies aimed at reducing emissions from various sectors and end uses. Note that bill numbers were used as a shorthand. Source: EFI, 2019

To develop decarbonization pathways and technology options for California, this study focuses on two targets, identifying separate but overlapping tracks: aggressive decarbonization by 2030 and deep decarbonization by midcentury, both from a 2016 baseline. Each target presents its own unique challenges and opportunities. To support these different tracks, the analysis emphasizes the value of technology optionality and flexibility. Over the longer term, managing an economy that has the scale and sector diversity of California's, and is deeply decarbonized, presents dynamic challenges that have not been addressed previously. For both the near and long term, engaging a range of stakeholders is key; energy incumbents and legacy infrastructures may slow the deployment of existing clean technologies in the near term.

The top-level outcome of the analysis: California can indeed meet its 2030 and midcentury targets. Figure S-2 shows meeting the 2030 target will require success across economic sectors (Electricity, Transportation, Industry, Buildings, and Agriculture), with multiple technologies contributing in each.

Figure S-2

Identified Emissions Reduction Potential for Meeting the 2030 Targets by Sector ($MMTCO_2e$)

California can meet its 2030 target of a 40 percent emissions reduction with commercially available technologies, assuming some incremental improvements and supportive policy and regulatory environments. Emissions reduction strategies will have to accommodate and address policy interactions and business decisions. As such, technology pathways may not be additive.
Source: EFI, 2019

Achieving deep decarbonization in the midcentury timeframe will depend on innovation, including in clean energy technologies that cut across sectors. Meeting emissions reductions goals while managing their costs will require a strong focus on, and commitment to, technology optionality, flexibility, and innovation. This focus is essential for several critical reasons:

- The energy system must provide essential services (light, heat, mobility, electricity, etc.) reliably at all times;
- The current cost of many important low- and zero-carbon technologies is too high;

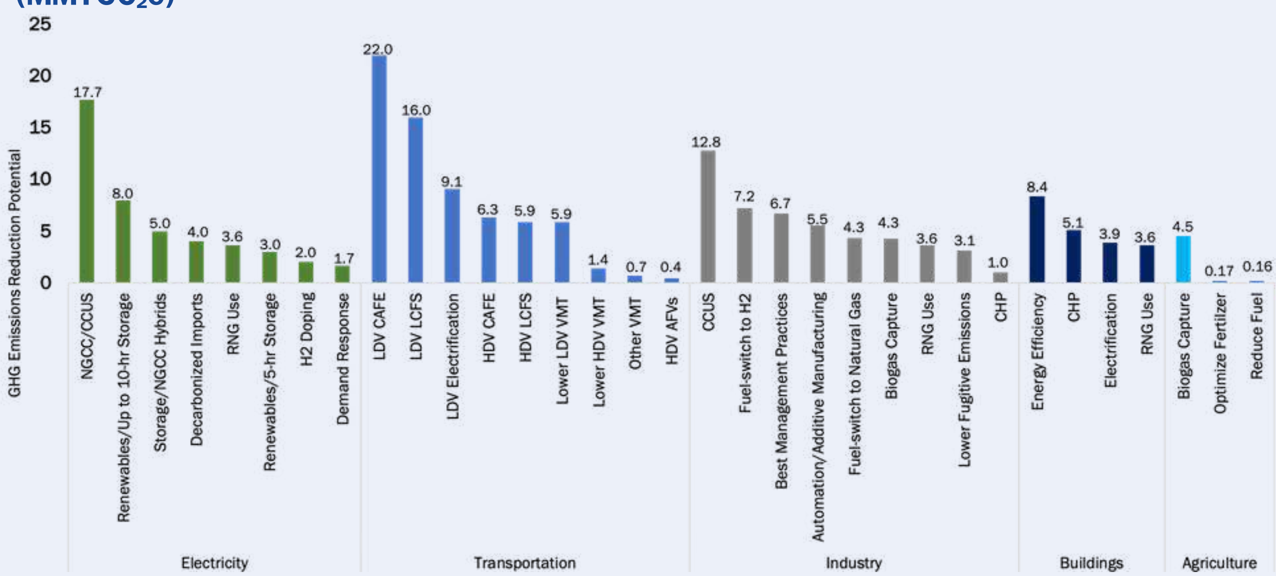
- Energy delivery infrastructure must be available, reliable, and secure as the system transforms;
- Affordable negative emissions technologies will ultimately be important at large-scale for deep decarbonization and acceptable stabilization of the earth's temperature; and
- Success will require aligning the interests and commitment of a range of key stakeholders.

Looking to 2030, this analysis provides a comprehensive, sectoral study of policies and decarbonization options for California. The analysis identifies a portfolio of 33 clean energy pathways that cover all economic sectors in California—including the most difficult-to-decarbonize (e.g., Industry and Agriculture) —and assesses the emissions reduction potential of each (Figure S-3). The portfolio prioritizes technologies with strong technical performance and economics; pathways that augment existing energy infrastructure are emphasized as they can offer significant benefits in terms of cost savings and market readiness. Detailed descriptions of each pathway are found in Part 2 of the report.

Meeting California's long-term decarbonization targets—including an 80 percent economywide reduction (or more) by 2050 and carbon-free electricity by 2045—will be extremely challenging. Managing and operating a deeply decarbonized energy system over a long duration and at the scale sufficient to meet these goals in an economy the size of California's is technically very difficult. Technology development timescales are unpredictable; technology cost curves constantly evolve; energy markets can change; public acceptance issues have been problematic in other locations and can contribute to substantial deployment and technology diffusion delays; the supporting infrastructure must be available and funded; and state and national legislative and regulatory environments can shift, constrain, or promote technology choices.

Figure S-3

Identified Emissions Reduction Potential for Meeting the 2030 Targets by Pathways ($MMTCO_2e$)



The estimated emissions reduction potential for each pathway is shown by sector. They are based on an attempt to meet California's target to reduce emissions economywide by 40 percent. This approach attempts to meet the target with an equal share from each economic sector. Source: EFI, 2019

The growing impacts of climate change on energy systems and new and changing supply chains for sustainable energy technologies must be accommodated in policies and planning. Certain clean energy pathways are more susceptible to disruption, such as hydroelectric generation or power lines exposed to wildfires. Materials and metals needed for clean energy technologies may see price spikes or supply disruptions in the future.

These factors imply that detailed, bottom-up analysis of specific pathways, while instructive for meeting 2030 goals, have little value for informing the technologies needed to operate low- to zero-carbon energy systems by midcentury. The near-term focus should be on working as hard as possible to develop many viable options, making it clear that innovation must be at the heart of a decarbonization strategy.

This report presents a “success model” for the longer term, strictly to illustrate both one of the many strategies that could meet long-term goals, as well as to demonstrate the overall difficulty of achieving midcentury goals without having a range of options for doing so. It identifies an analysis-based innovation portfolio for California, focused on technologies with long-term breakthrough potential. Technologies were screened based on California’s existing policies and programs, energy system and market needs, and other distinctive regional qualities that position California to be a technological first mover and global leader (e.g., a strong resource base, relevant workforce expertise, and robust scientific and technological capacity). Eleven breakthrough technologies were identified as major potential contributors to California’s deep decarbonization over the long term, including hydrogen produced by electrolysis, smart systems, floating offshore wind, seasonal energy storage, and clean cement, among others. The pace of research and development work on technologies with breakthrough potential must be accelerated and sustained to meet deep decarbonization goals.

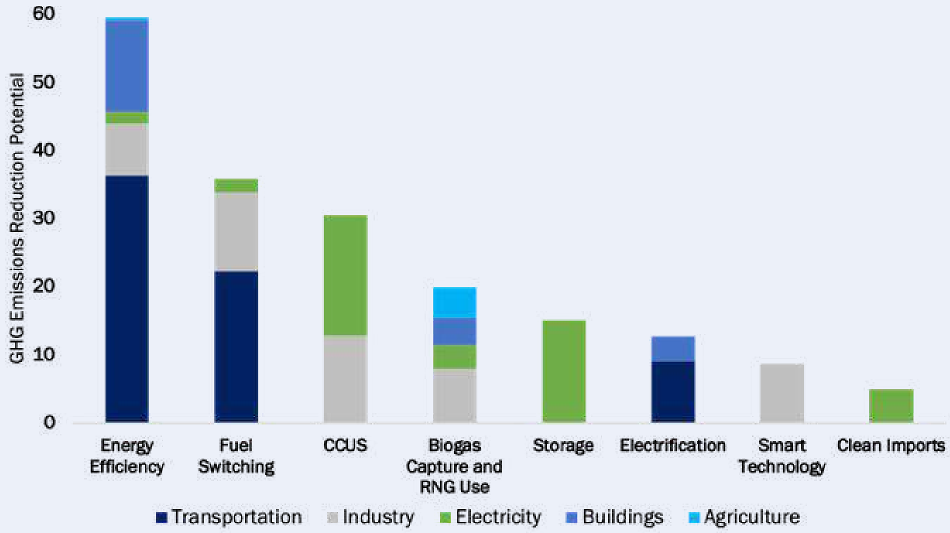
MAJOR FINDINGS FOR AGGRESSIVE DECARBONIZATION BY 2030

- Meeting California’s carbon reduction goals by 2030 will require a range of clean energy pathways across all economic sectors—Electricity, Transportation, Industry, Buildings, and Agriculture (Figure S-4). This is due to the uncertainty of each pathway and the fact that there are no “silver bullet” solutions. There are sufficient commercially available pathways to meet 2030 targets, though some technologies are less expensive and more advanced than others. To meet the 2030 target, however, it is expected that there will be incremental improvements and cost reductions in key technologies, including, for example, carbon capture, utilization, and storage (CCUS) at industrial facilities and natural gas power plants. Notably, the Industry, Transportation, and Agriculture sectors have not seen measurable emissions improvements in recent years.

- California’s ambitious policy to double economywide energy efficiency is an important step for meeting 2030 decarbonization targets. Energy efficiency, defined broadly, is likely to be the most cost-effective approach to decarbonization in the energy end-use sectors in California. This includes technologies and processes that increase fuel efficiency of vehicles (on-road and off-road, including farming equipment in Agriculture); demand-response mechanisms in the Electricity, Transportation, and Buildings sectors; highly efficient end-use technologies in all sectors, especially Buildings and Industry; and measures, such as smart systems, that reduce energy consumption in sectors with high non-combustion emissions, such as Industry and Agriculture.

Figure S-4

Identified Emissions Reduction Potential for Meeting the 2030 Targets by Cross-Cutting Technologies (MMTCO$_2$e)



Some decarbonization strategies are applicable to multiple sectors of the economy. Of these, energy efficiency/demand reduction is most significant, representing the largest emissions reduction potential and cutting across all five sectors. Source: EFI, 2019

- California's decarbonization policy focus on the Electricity sector is important. The latest policy, SB 100, signed into law in September 2018, has a requirement for 60 percent renewable electricity by 2030 and carbon-neutral electricity by 2045. Electricity plays a critical role in California's decarbonization as it is both a source of emissions (16 percent of statewide emissions in 2016), and is crucial in supporting the decarbonization of all end-use sectors. Because Electricity accounts for only 16 percent of emissions, decarbonization policy in California must extend well beyond the Electricity sector. Electrification of other subsectors, where feasible and desirable, can reduce emissions elsewhere if the Electricity sector is sufficiently decarbonized. Electricity is also relatively easier to decarbonize than other sectors: its emissions are highly concentrated, the sector is highly regulated, and there are multiple clean energy technology options, including CCUS.

- Transportation is the single largest emitting sector in California and requires transformational change to achieve aggressive decarbonization by 2030. Existing policies will have a major impact on the sector's emissions reduction by 2030. California's plans for addressing emissions from this sector rely on deploying alternative fuel vehicles, including electric vehicles; increasing vehicle fuel efficiency; decreasing the carbon intensity of fuels; and reducing vehicle-miles traveled. As there are multiple Transportation subsectors that are difficult to decarbonize—heavy-duty vehicles, aviation, marine, and rail—options for achieving deep decarbonization over the long term will go have to extend beyond energy/fuel-based technologies, and will, increasingly, depend on an ecosystem of solutions that includes new infrastructure systems, platform technologies, behavioral incentives, urban design, and advancements in materials science.

- Clean fuels (e.g., renewable natural gas [RNG], hydrogen, biofuels) are critical clean energy pathways due to the enormous value of fuels in providing flexibility and reliability for energy systems. Fuels that are durable, storable, and easily transportable play a fundamental role in ensuring that all sectors can operate at the scale, timing, frequency, and levels of reliability that are required to meet social, economic, and stakeholder needs.
    - The development of RNG in California has multiple tangible benefits: RNG is a carbon-neutral fuel; RNG diverts methane from being released into the atmosphere, enabling major emissions reductions from the difficult-to-decarbonize Industry and Agriculture sectors; and it leverages existing carbon infrastructure, potentially avoiding the costly stranding of these established systems and their associated workforces, as well as their time-consuming and costly replacement.
- California can meet its 60 percent RPS target by 2030 with continued expansion of wind (both onshore and offshore) and solar resources; some geothermal and increased imports of clean electricity will play a role as well. California will, however, have to manage the significant operational issues that arise from high penetration of intermittent renewables to ensure reliability, manage costs, and minimize system emissions. The Western Energy Imbalance Market, demand response, and increased deployment of energy storage technology including battery storage, pumped hydro, and other technologies will be critical to balancing electricity from intermittent renewables. These options are, however, currently limited in size, and by duration or geography.
- Natural gas generation will continue to play a key role in providing California's electric grid with operational flexibility and system reliability, while enabling the growth and integration of intermittent renewables. Natural gas-fired generation provides key load-following services. It has short- and long-duration applications, including the management of seasonal shifts in demand. As renewable generation has increased, natural gas units, in their balancing role, are being operated for shorter intervals and higher heat rates; this suboptimal operation is increasing their emissions intensity. Battery storage systems can be leveraged with natural gas combined cycle (NGCC) units to smooth their ramping operation, measurably reducing their emissions profile.
- Policies that affect natural gas in some sectors (e.g., building electrification) may have unintended impacts on other sectors that consume and rely on natural gas. These impacts include price volatility, reduced resource availability, and relatively higher infrastructure costs for those sectors that have limited near-term options for decarbonization.

MAJOR FINDINGS FOR DEEP DECARBONIZATION BY MIDCENTURY

- Meeting California's deep decarbonization goals by midcentury will be extremely difficult (if not impossible) without energy innovation. This is due to many challenges inherent in economywide deep decarbonization, including:

  - Predicting the mix of clean energy technologies needed by 2050. This is extremely challenging. While many studies explore technology pathways over the long term, they cannot be used to prescribe technologies or predict the future and therefore the optimal energy mix by midcentury.

  - Rising marginal costs of abatement. It is highly likely that these costs will increase over time as the lowest cost opportunities to reduce emissions are widely deployed. This study modeled the cost of reaching deep decarbonization without technology innovation (i.e. a major improvement in performance and/or cost) at $1,027 per ton of carbon dioxide in 2050, an extremely high cost. This is at or above the cost estimates for several advanced technologies, such as direct air capture.

  - Performance issues of deeply decarbonized energy systems. Managing a large, carbon-free electric grid offers challenges in terms of operation, design, size, and the growing concerns about the availability of wind and hydro due to climate change, for example. Also, scalable clean technologies are not readily available for meeting deep decarbonization goals in several key applications, including: high-temperature process heat for industry; time-flexible load-following generation; large-scale, long-duration electricity storage; and low-carbon fuels including fuels for heavy-duty vehicles, air transport, and shipping that can be stored for daily, weekly, and seasonal uses.

  - Deployment of cost-effective and efficient negative emissions technologies are needed by 2045. Technologies that could help achieve carbon neutrality are in relatively early stages of development and include carbon dioxide capture from dilute sources; massive utilization of captured carbon dioxide in commodity products; and both geological and biological sequestration at very large scale.

- There are several cross-cutting technologies or classes of technologies that can help meet the large-scale decarbonization needs for several economic sectors. These include technologies for large-scale carbon management (LSCM), hydrogen applications, leveraging carbon infrastructure and expertise, and smart systems and platforms.

  - LSCM involves CCUS from both concentrated (stationary point sources) and dilute (atmosphere and oceans) sources. Developing these technologies is a necessity because of the need to mitigate emissions from difficult-to-decarbonize sectors that may lack other suitable decarbonization options (e.g., heavy industry), as well as the need for carbon dioxide removal from the environment at the scale of 100 to 1,000 gigatons by 2100.

- Hydrogen is an energy carrier that can be produced through multiple production pathways for end uses across the Electricity, Industry, and Transportation sectors. Hydrogen that is produced in a low-carbon manner (e.g., electrolysis with a clean grid; steam methane reforming of natural gas with CCUS) has a considerable potential to assist with decarbonization. For example, it could be used for making high-temperature process heat for industry or as a seasonal storage medium for electricity.

- Decarbonization pathways are as much about infrastructure as they are about technology. The transition to a low-carbon future could potentially be improved and accelerated by seeking opportunities to leverage existing infrastructure, technological expertise, and a skilled and readied workforce. Repurposing the existing carbon infrastructure—a highly-engineered system-of-systems that spans thousands of miles across California and employs more than 100,000 people, many of whom have skillsets that could be utilized—could enable, accelerate, and improve the performance of the energy sector's transition to a deeply decarbonized economy. Repurposing existing infrastructures will also help diminish political opposition to the transition to a clean energy future.

- The rapid development of digital, data-driven, and smart systems—largely from outside the energy sector—has unlocked the potential of other "platform technologies," such as smart sensors and controls and additive manufacturing. These technologies could be scalable across the entire energy value chain. These platforms can be used to support decarbonization by optimizing performance based on emissions; advancing levels of reliability and resilience; and creating new business models that enable new services.

- As a U.S. and global leader in clean energy, California is well suited to promote the development of an advanced clean energy technology portfolio. California has robust energy innovation infrastructure including an active private sector, strong workforce, world-class research universities, four national laboratories, and major philanthropies that are aligned with the goals of decarbonization. It has multiple supportive state entities, including the California Energy Commission, the California Air Resources Board, and the California Public Utilities Commission. A clear portfolio with specific priorities can help ensure that programs pursued by multiple stakeholders in California (and beyond) are timely, durable, and mutually supportive. This approach can give innovators a framework for assessing the prospects of a particular initiative and the steps needed to sustain critical innovations over long time periods. It can also give corporate adopters, financial investors, and policymakers visibility into the evolving future of clean energy. This work must begin today.

There are technology priorities with long-term innovation breakthrough potential that California should develop (Figure S-5). These include hydrogen production with electrolysis, advanced nuclear, green cement, and seasonal storage, among others. These technology priorities were screened based on California's policies and programs, energy system and market needs, and other distinctive regional qualities that position California to be a technological first mover: a strong resource base, relevant workforce expertise, and robust scientific and technological capacity. A broader list of candidate technologies was also developed and organized by energy supply (electricity and fuels), energy application (Industry, Transportation, and Buildings), and cross-cutting technology areas (LSCM).

A REPEATABLE FRAMEWORK FOR DECARBONIZATION

This report is designed to advise California's near- and long-term decarbonization strategy. It offers insights on decarbonization pathways, timescales, technology utilization, energy system operational needs, costs, and energy innovation. It provides a comprehensive review of on-the-ground issues in California that may aid or slow the state's progress toward deep decarbonization. In addition to benefitting California, there are high-level findings that may also provide a framework for decarbonization strategies that can, and should, be repeated in other economies around the world, including:

- Energy system "boundary conditions," including considerable system inertia that works against rapid change, complex supply chains, long-duration of technology development, and commodity business models must be taken into consideration when developing decarbonization strategies.

Figure S-5
Technology Priorities with Long-term Breakthrough Potential

Technologies were identified as having longterm breakthrough potential for California based on EFI-developed screening criteria. Source: EFI, 2019

- There is no "silver bullet" technology for deep decarbonization. Technology optionality and flexibility are critical to any decarbonization strategy, especially for the difficult-to-decarbonize sectors.

- Existing carbon infrastructure and expertise must be aligned with deep decarbonization goals to prevent the creation of strong and dilatory political and business opposition to decarbonization pathways when acceleration is called for.

- Decarbonization pathways should address multiple timescales, emphasizing commercially-available technologies in the near-term and developing (and/or supporting the development of) new technologies with long-term innovation potential.

- Decarbonization pathways should support local and regional energy capacity that includes the existing workforce, the structure of economic sectors, clean technology firms, natural and scientific resources, and many other factors that shape the opportunities and challenges on the ground.

PART 1

ACHIEVING DEEP DECARBONIZATION IN CALIFORNIA

STUDY CONTEXT AND APPROACH

CHAPTER 1
ACHIEVING DEEP DECARBONIZATION IN CALIFORNIA: STUDY CONTEXT AND APPROACH

California has been a global leader on energy and climate policy for many years, and its actions on climate change have implications far beyond its borders. The state's emissions reduction goals implicitly track targets of the 2015 Paris Agreement to reduce greenhouse gas (GHG) emissions sufficient to keep global temperatures from rising more than two degrees Celsius.

Specifically, California has committed to reduce its economywide greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050, with a 40 percent reduction interim target by 2030. In addition, it has targets of 60 percent renewable power generation by 2030, and zero carbon electricity and economywide carbon neutrality by 2045. These interim targets form the "building blocks" upon which California's longer-term, deep decarbonization pathways can be established. No major economy is on a trajectory to achieve similar goals. California's policy and programmatic successes—or failures—will be widely observed, creating models for replication or avoidance, depending on their outcomes.

Deep decarbonization will require an unprecedented transformation of California's energy systems. While the state's deep decarbonization goals help address a global problem, California policymakers will also need to consider, to the extent possible, the implications of deep decarbonization for its communities, including equity issues, incentivizing economic growth, promoting public health and quality of life, and supporting consumer and societal choices.

This report provides an analysis of the pathways and technology options for meeting California's near-term (2030) and midcentury decarbonization goals, two target dates on which a range of California policies are centered. Achieving targets on these timescales is difficult. The structure of the energy sector inherently leads to slow market diffusion rates of new technologies and considerable system inertia. Because of these features, and since 2030 is only little more than a decade away, this analysis assumes limited breakthrough innovation opportunities for meeting policy targets by this date.

The analysis of 2030 pathways is much more detailed than the 2050 options because technology pathways, policies, and costs are relatively clearer for the nearer term options than those needed for meeting midcentury goals. The 2050 discussion, instead, focuses on a range of breakthrough options that should be supported to accommodate California's policies, unique characteristics, and energy needs, but also the enormous uncertainty three decades out.

Support for and successful deployment of technologies with significant breakthrough potential could position California as a technology first mover. Developing a robust technology portfolio that meets California's midcentury targets requires a shared agenda of innovation priorities to ensure that programs pursued by multiple stakeholders in California, and beyond, are timely, durable, and broadly supported.[1] This approach can give innovators a framework for assessing the prospects of a particular initiative and the steps needed to sustain critical innovations over long time periods. It can also give corporate adopters, financial investors, and policymakers visibility into the evolving future of clean energy.

The analysis utilizes an array of quantitative and qualitative approaches, including two new modeling efforts of the California economy and electricity system. These are used to help analyze the impact of key state policies on California's energy system and the costs of emissions reductions, and to understand the impacts of increased intermittent renewables on grid operations. The study also provides a detailed analysis from technology experts on the opportunities and challenges associated with developing and deploying a range of technologies at various stages of market readiness to support deep decarbonization pathways for California.

In short, ensuring California's societal and economic well-being and maximizing the state, national, and global impacts of its decarbonization approaches, will require flexible pathways that provide optionality; encourage policy, technology, and financial innovation; enable new jobs and businesses; and ensure affordable energy for all consumers. Ultimately, the policy and technology trajectory California elects to pursue will drive choices made by other subnational and national jurisdictions, through both the successful pathways identified and the impact of the state's transformation on other energy systems and infrastructures in the United States.[2]

California's Economic Base, Demographics, and Climate Affect Its Decarbonization Pathways

California has the largest economy in the United States, accounting for 14 percent of the U.S. gross domestic product. In 2017, it recorded a gross state product (GSP) of over $2.7 trillion, larger than all national economies other than those of the United States, China, Japan, and Germany.

California also has one of the largest Industry sectors in the United States. In 2016, California was the nation's top manufacturing state, with $289 billion in total manufacturing output. The sector employed over 1.2 million workers at more than 36,000 firms, accounting for 11 percent of the GSP. In 2016, California's Industry sector consumed more energy than the entire state of Colorado— and roughly the equivalent of Maryland and Delaware combined.[3] The Industry sector is a major challenge for deep decarbonization.

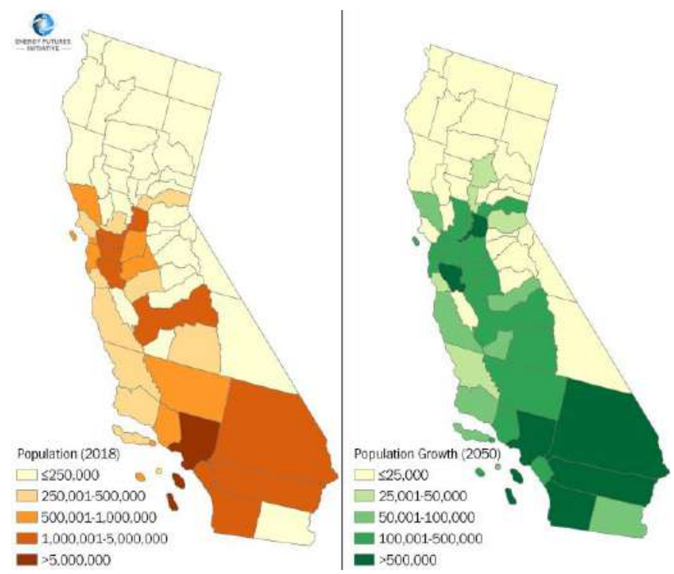
California's Transportation sector is a critical enabler of the state's economy and dominates California's overall energy consumption[4] as well as its GHG emissions. As the third largest state by land area, California has more registered motor vehicles than in any other state[5] and commute times are among the longest in the country.[6] Additionally, California is the largest consumer of jet fuel among the states, accounting for one-fifth of U.S. consumption in 2016.[7]

In 2017, California was also the top agricultural-producing state in the United States, with $50.2 billion in cash farm receipts for all agricultural commodities.[8,9] California produces more than 400 commodities, led by dairy products ($6.7 billion), grapes ($5.8 billion), and almonds ($5.6 billion). More than one-third of the nation's vegetables and two-thirds of its fruits and nuts are grown in California.[10]

Population

With nearly 40 million people, California has the largest population of any state in the country. Its population is primarily located in the central and southern portions of the state, especially in coastal counties (Figure 1-1). The state's population is projected to increase to more than 49 million by 2050, with much of the projected growth expected to occur in the same counties that currently have high population concentrations.[11] This could strain energy systems and efforts to retain their reliability, affordability, and adherence to increasingly stringent environmental performance standards.

Figure 1-1
Current Population and Projected Population Growth by 2050



At 40 million, California has the largest population in the U.S, and it is expected to increase by 22.5 percent, to 49 million by 2050. Source EFI, 2019. Compiled using data from the CA Dept. of Finance, 2018.

Climate

In general, California has a Mediterranean-style climate that is characterized by dry summers, wet winters, and mild temperatures; it also has significant mountain ranges and deserts.[12] California is considered to be one of the most vulnerable areas in North America for climate change impacts.[13] Under business as usual, the average annual maximum daily temperature is expected to increase 5.6 to 8.8 degrees Fahrenheit by the end of this century. The state is already experiencing conditions consistent with climate change including higher average temperatures, greater heat waves and dry spells, elevated wildfire risk, and more variable precipitation patterns.[14]

Fifteen of the 20 largest wildfires,[15] 15 of the 20 most destructive wildfires,[16] and 10 of the 20 deadliest wildfires[17] have all occurred in California since 2000. These negative impacts are expected to increase in frequency and magnitude.[18] In economic terms, wildfires could result in an 18 percent rise in insurance costs by 2055 (in high-risk wildfire areas). In addition to societal harm and economic impacts, there is an interactive relationship between the causes of climate change and impacts of climate change. This is illustrated by recent wildfires in the state; in 2018, GHG emissions from wildfires alone exceeded the annual emissions from the entire Electricity sector.[19]

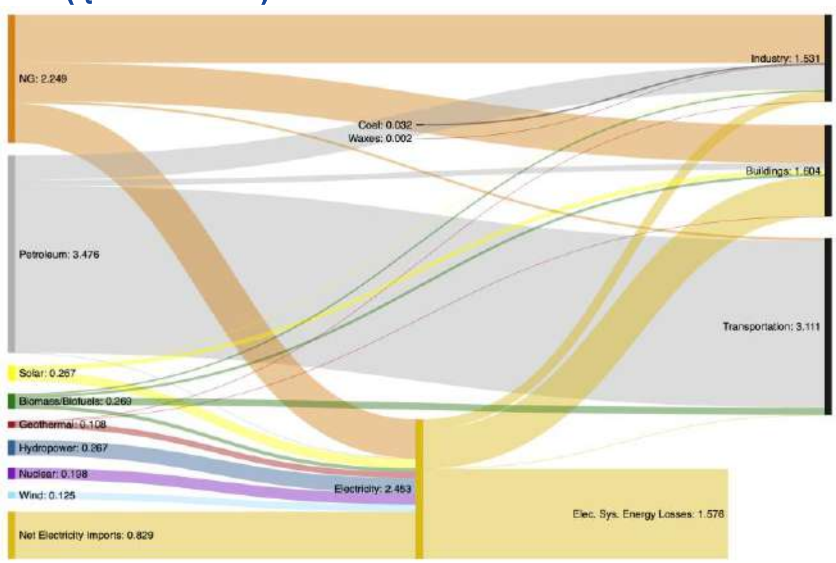
Additional climate-related challenges include higher average temperatures, sea-level rise and coastal flooding, and greater threats to public health.[20] The costs of climate damages associated with these state-level projections are estimated to be in the tens of billions of dollars by midcentury.[21] Sea-level rise could inundate 31 to 67 percent of Southern California beaches by 2100, threaten $17.9 billion worth of residential and commercial property by 2050, and triple the amount of highway infrastructure at risk of coastal flooding from 100-year storm events by 2100.[22] Water supply from snowpack is expected to decrease by two-thirds by 2100, which could pose negative consequences for agriculture and lead to water shortages of up to 16 percent in certain agricultural-producing regions by 2050.

California's Energy Profile

California is the second-largest energy-consuming state, behind Texas. In 2016, California used 7.80 quadrillion British thermal units (quads) of energy; this is more than New York (3.67 quads) and Illinois (3.91 quads) combined.[23] California's per capita energy consumption is, however, one of the lowest in the country, due to its robust energy efficiency programs and its mild climate. About 16 percent of in-state energy supply is from carbon-free energy sources, including solar, wind, nuclear, hydro and geothermal, with almost all of the energy from these sources being converted to electricity.

About 64.7 percent of energy use in the state is from fossil fuel consumption in the end-use sectors. This includes 44.4 percent from petroleum, 19.9 percent from natural gas, and 0.4 percent from coal). Electricity consumption in end-use sectors comprises 11.2 percent of the total, other fuel use (such as biofuels) makes up 2.6 percent, and direct thermal use of solar, hydro, and geothermal energy makes up 1.2 percent of consumption. The remaining 20 percent of energy consumption is lost in the production and supply of electricity and ethanol.

Figure 1-2
2016 California Energy Flows from Sources to Intermediate and End Uses (Quadrillion Btu)



California's energy flows show the source of energy, including imports (left hand side), intermediate uses, including conversion to electricity (middle), and the final end-use consumers (right hand side). Source: EFI, 2019. Compiled using data from EIA SEDS, 2016.

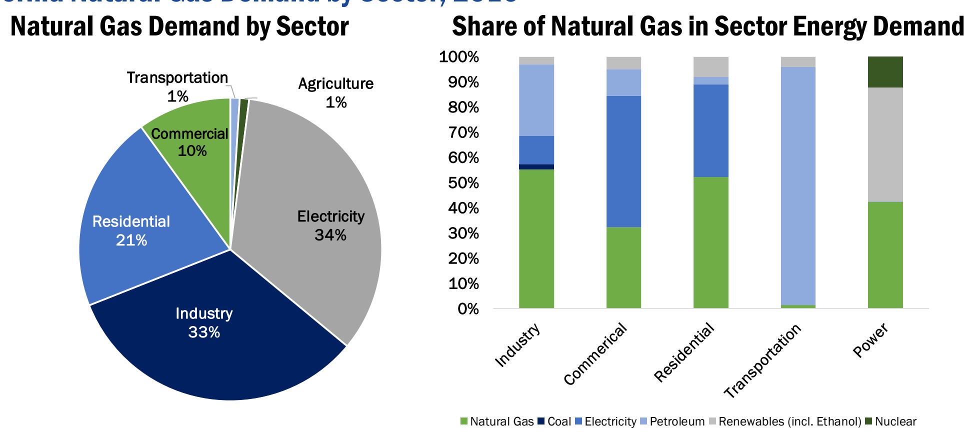
Energy Flows

The Sankey diagram (Figure 1-2) shows how primary fuels and electricity flow from various generation sources to end uses in California. This offers policymakers a picture of the relative role of each energy source and sector in the state's economy.

As noted, nearly half of all energy consumed in the state comes from petroleum products. Much of this is used by the Transportation sector, which accounts for one-third of current total energy consumption.

Natural gas is the next largest energy source consumed in the state; Figure 1-3 demonstrates its diverse uses (roughly equal amounts in Industry, Buildings, and Electricity) as well as its central role in California's economy. Two-thirds of total gas consumption was for Electricity (34 percent of consumption or 696 billion cubic feet [Bcf]) and Industry (33 percent of consumption or 661 Bcf). Residential Buildings consumed twice as much natural gas (21 percent of natural gas consumption or 418 Bcf) as Commercial Buildings (10 percent of consumption or 214 Bcf). The Transportation and Agriculture sectors consumed only marginal amounts of natural gas. California's natural gas demand has remained roughly flat over the past two decades, at around 2.3 trillion cubic feet (Tcf) annually.[24]

Figure 1-3
California Natural Gas Demand by Sector, 2016



Natural gas is the largest energy source for the Electricity, Industry, and Residential Buildings sector.
Source: EFI, 2019. Compiled using data from CARB, 2018.

Electricity, as a secondary energy source, and the Buildings and Industry end-use sectors consume roughly the same amounts of primary energy. The largest end-use energy-consuming sector is Transportation, roughly equal to the consumption of the Buildings and Industry sectors combined. Electricity system losses, which include losses from energy conversion at power plants and from electricity transmission and distribution, account for a significant amount of energy (1.6 quads)—roughly the energy consumption of Oklahoma.[25]

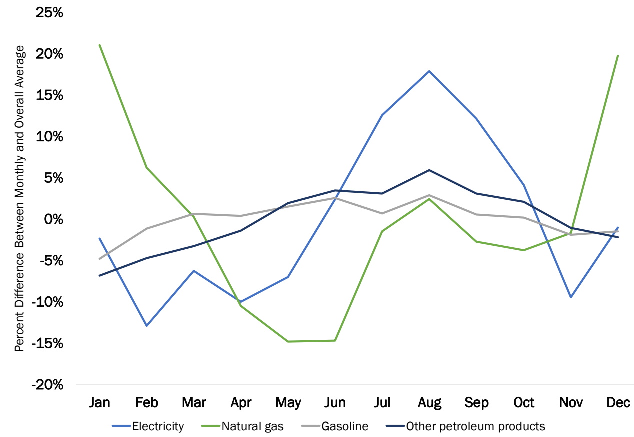
Seasonal Energy Demand Shifts

The seasonal shifts in energy demand are important factors for consideration in managing economywide decarbonization. These shifts are seen in both electricity and fuels.

California has a summer demand peak for electricity, largely due to air conditioning.[26] Throughout the year, there are major swings in demand. From 2001 to 2017, the monthly average for electricity consumption in August was 18 percent higher than the overall annual average, as shown in Figure 1-4. The monthly average for electricity consumption in February was 13 percent lower than the overall annual average. For Electricity, natural gas-fired generation balances the grid in the short-term and offers the only current in-state solution for managing these seasonal shifts in demand.

Figure 1-4

Seasonal Variability in California Energy Consumption, 2001-2017

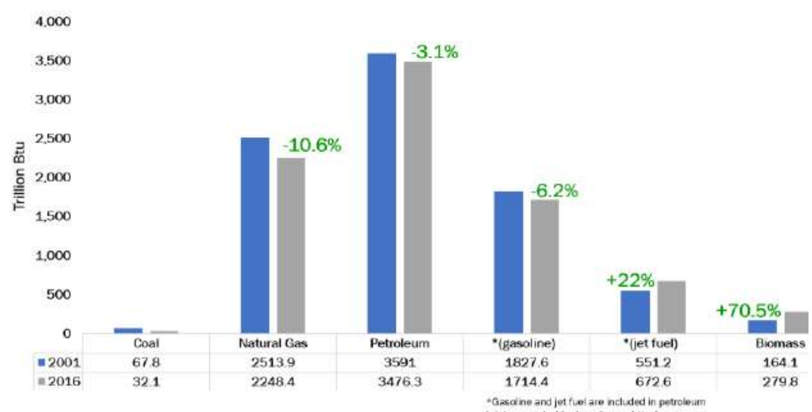


California has a summer peak for electricity demand and a winter peak for natural gas demand, while gasoline and petroleum demand stays relatively constant over the course of a year. Source: EFI, 2019. Compiled using data from EIA, 2018.

While the swings are less pronounced for other energy types, they provide important context for decarbonization. Gasoline demand has a 5 percent swing during the year, also with a summer peak. Measured in terms of gallons of gasoline, this amounts to a significant quantity of energy, due to the size of California's Transportation sector. If this demand were to be shifted from gasoline to electricity—in the form of demand for powering electric vehicles, for example—it would place even greater stresses on the electricity system. Also, the storable nature of gasoline that supports the seasonal shift is not currently replicable in electricity.

Figure 1-5

California's Fuel Consumption, 2001 & 2016 (trillion Btu)



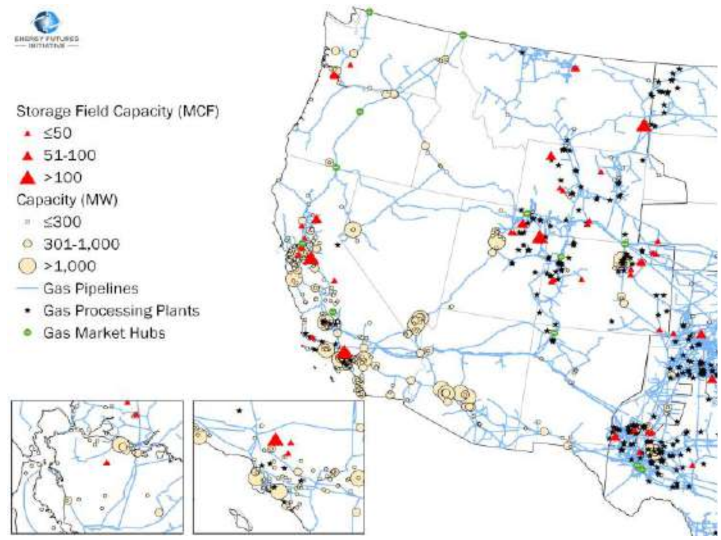
	Coal	Natural Gas	Petroleum	*(gasoline)	*(jet fuel)	Biomass
2001	67.8	2513.9	3591	1827.6	551.2	164.1
2016	32.1	2248.4	3476.3	1714.4	672.6	279.8

California's fuel mix has shifted since the turn of the century, with dramatic increases in jet fuel consumption and overall declines in natural gas and petroleum use. Source: EFI, 2019. Compiled using data from EIA SEDS, 2016.

Shifting Fuel Mix

California's fuel consumption mix (Figure 1-5), has changed over time, with less natural gas use and more jet fuel and biomass consumption. The state has been a significant fossil fuel energy producer although in-state natural gas and crude oil production have both declined precipitously. In 2016, both were less than half the levels they were in the 1980's. Around 90 percent of California's natural gas now comes from out of state.

Figure 1-6
Natural Gas Infrastructure in California and WECC Region



California has the bulk of natural gas infrastructure in the Western Electricity Coordinating Council (WECC) region. Left inset map: San Francisco Bay Area. Right inset map: Los Angeles area. Source: EFI, 2019. Compiled using data from EIA, Resource Watch, Global Energy Observatory/Google/KTH Royal Institute of Technology in Stockholm/Enipedia/World Resources Institute.

In spite of production declines, California is still a large natural gas producer and is home to significant gas infrastructure. This includes natural gas production, processing, pipeline, storage, and delivery infrastructure, with over 150,000 miles of pipeline that reach into most of California's businesses, homes, and industries (Figure 1-6).[27,28] A preliminary review of utility natural gas infrastructure assets suggests a value of more than $30 billion in 2016. These systems provide heating and cooking for many of the state's 13 million residences. Natural gas supports a large portion of California's 7.5 billion square feet of commercial space and supplies the energy for 42 GW of electric power generation. As a substitute for coal- and oil-fired generation, natural gas has been a major factor in reducing GHG emissions in California over the last two decades.

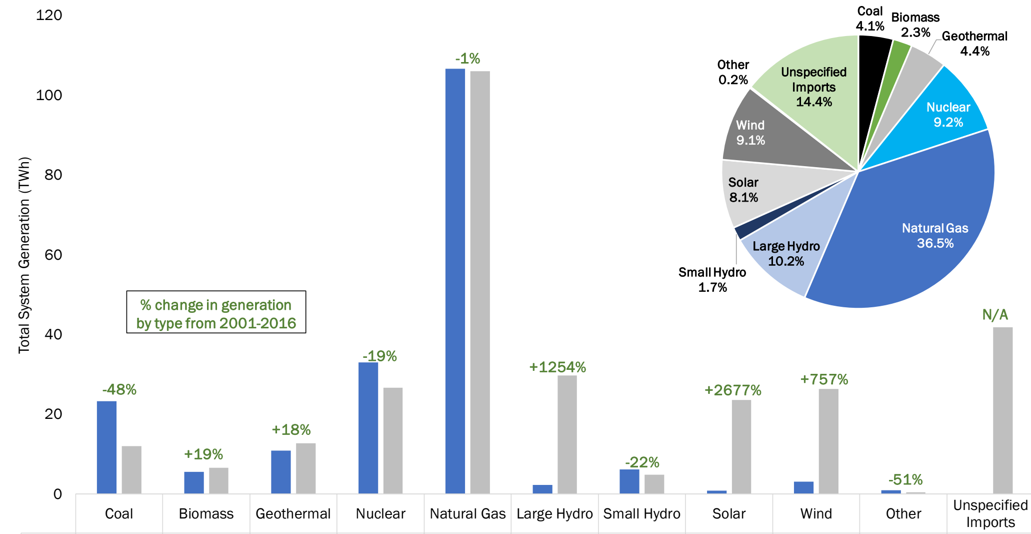
Biofuels production in California has grown rapidly, from 1.1 trillion Btu in 2004 to 30 trillion Btu in 2016 but still represents only a small fraction of the state's total fuels production. California is a net energy importer, especially of primary fuels including crude oil, but is a net exporter of finished petroleum products. California's refining industry (third-largest in the United States) imports roughly two-thirds of its crude oil from other states (mostly Alaska) and from abroad (mostly Saudi Arabia and Ecuador) to meet its own petroleum needs, and for re-export to other states.

Shifts in Electricity Generation Mix

Changes in California's electricity generation mix also have been significant (Figure 1-7). Most notable is the dramatic rise in solar and wind generation, the decline in nuclear power, the increase in large hydropower, and the near-disappearance of coal as an energy source for the Electricity sector.

Figure 1-7

Total System Generation (Including Imports) by Fuel Type, 2001 & 2016 (GWh) and Percent of Total Generation, 2016



	Coal	Biomass	Geothermal	Nuclear	Natural Gas	Large Hydro	Small Hydro	Solar	Wind	Other	Unspecified Imports
2001	23.3	5.5	10.8	33.0	106.6	2.2	6.1	0.8	3.1	0.9	0.0
2016	12.0	6.6	12.7	26.7	106.0	29.7	4.8	23.6	26.3	0.4	41.8

Renewables and other carbon-free sources have largely compensated for the declines of fossil fuel generation; however, in absolute numbers, natural gas is by far the largest source for California's electricity generation. Source: EFI, 2019. Compiled using data from CEC, 2016.

All in-state coal generation has been retired, and in-state nuclear generation has declined by over 43 percent since 2001 with the closure of the San Onofre Nuclear Generating Station in 2013. California's last nuclear power plants are expected to retire by 2025. While declining in absolute numbers, natural gas still generated over 36 percent of California's electricity in 2016.

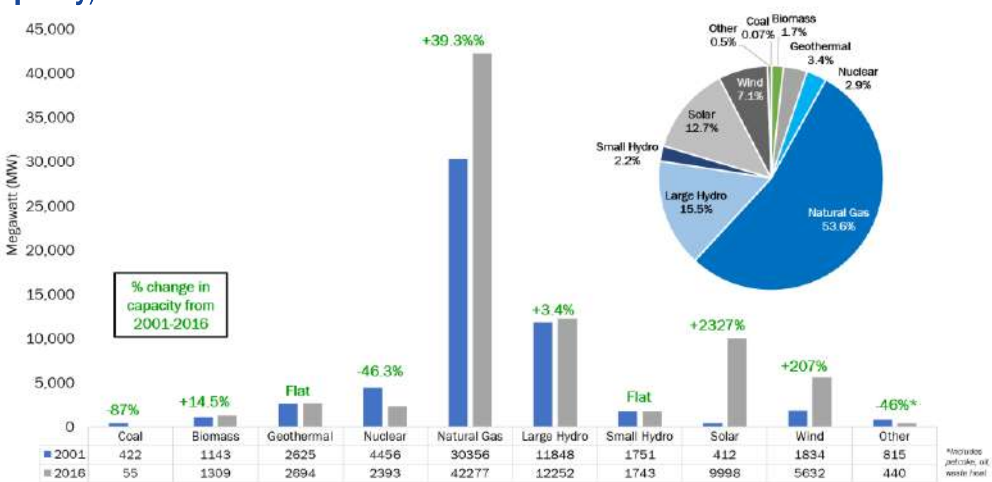
Carbon-free electricity accounted for roughly half of total electricity generation in California, led by large hydro, solar, wind, and nuclear. There has been a large shift to in-state renewable electricity generation. Renewable generation covered by the state's Renewables Portfolio Standard (RPS), encompassing solar, wind, biomass, geothermal, and small hydro, was 37.9 percent of in-state generation in 2016. Wind and solar generation combined were 16.8 percent of total in-state generation in 2016. Hydropower is an important source of electricity in California; however, weather conditions causing changes in snow and rainfall, have had negative impacts on hydro, causing its share of total in-state generation to vary up and down between seven and 21 percent during the time period from 2010 to 2017.[29]

Electricity generation *capacity* (Figure 1-8) is also important for developing and implementing decarbonization policies and supporting economic growth in California. Overall, natural gas generation capacity, like actual generation, far exceeds other generation sources, accounting for 54 percent of the state's total installed capacity. The other half of California's generation assets are carbon-free, with large hydro comprising

15.5 percent of total installed capacity. Since 2001, natural gas power capacity has increased by 39 percent (a figure that reflects capacity additions net of plant retirements), solar increased by 2,327 percent and wind by 207 percent (although the 2001 baseline for both solar and wind power was low).

Figure 1-8

In-State Generation Capacity by Fuel Type, 2001 & 2016 (MW), and Percent of Total Capacity, 2016



Both renewable and natural gas generation capacity have grown significantly since 2001, and presently natural gas capacity makes up over half of the state's total. Source: EFI, 2019. Compiled using data from CEC, 2016.

The flexibility of California's grid has largely been supplied by natural gas generation, which can quickly ramp and load-follow; these are essential functions needed to support the integration of large volumes of intermittent renewable generation. This flexibility—in addition to low capital costs and relatively rapid increases in generation—was essential for making up for the loss of San Onofre nuclear generation in 2012 (nearly 10 percent of in-state generation), which coincided with the first year of a major decline in large hydro generation because of drought conditions.[30,31] Between 2011 to 2012, California's natural gas generation was called on for an increase of 30.7 TWh, 15 percent of in-state generation.[32] This was possible because of existing fuel supply and infrastructure. The volatility of hydropower in a changing climate is likely to persist. The flexibility of the natural gas supply has significant option-value for the reliability of the overall energy system.

California remains a net importer of electricity, with 14.6 percent of its electricity coming from the Northwest and 17.2 percent from the Southwest in 2016. In the same year, 32.1 percent of electricity imports were from solar, wind, large hydro, nuclear, and coal. After renewables (at 18.6 gigawatt-hours [GWh]), coal was the second largest source of imports, with 11.7 GWh.[33] The state exports small amounts of electricity to Mexico and exports a small share of renewable generation to neighboring states, sometimes to avoid curtailment.

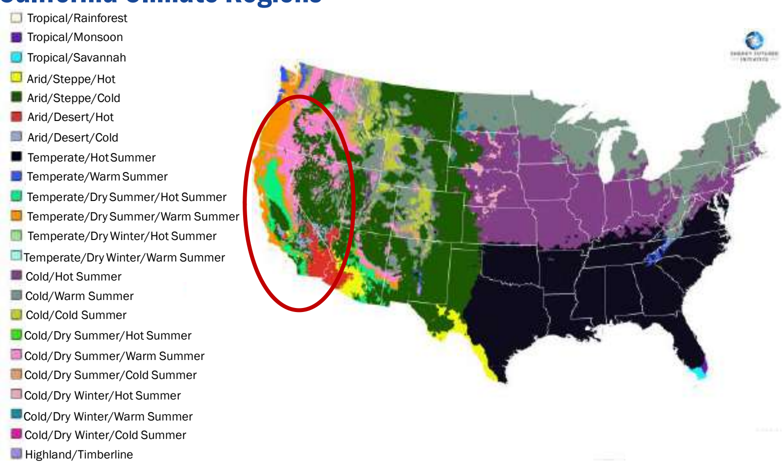
Climate Impacts on Energy Systems and Infrastructure

California has numerous climate regions and includes both arid and temperate regions throughout the state (Figure 1-9).[34] The nature of climate impacts on these microclimates is expected to vary widely and can pose unique challenges for emissions reduction pathways and for energy demand, type of fuel consumption, energy resource availability, and energy project deployment.

With respect to energy supply and the reliability of energy infrastructures, annual electricity demand is expected to increase due to hotter average temperatures and greater use of air conditioning, especially in the inland and southern portions of the state. Demand increases can be partially offset by efficiency savings (discussed in detail in the end-use sector chapters in Part 2 of this study).

Figure 1-9

California Climate Regions



California contains several different climate regions based on the Koppen Climate Index, which present unique considerations for decarbonization as localized and regional solutions are increasingly important. Source: EFI, 2019. Compiled using data from Koppen Climate Index, 2017.

The need to meet electricity peak demand will be further challenged by a temporal shift in seasonal runoff for hydropower generation. Analyses suggest that reduced snowpack in the mountains and more intense precipitation events will lead to higher real-time runoff during the winter and spring months,[35] less hydro availability in summer when electric loads are highest, and an overall reduction in hydro generation.[36] Studies of two high-elevation hydropower systems in California (the Upper America River Project and the Big Creek System) suggested hydroelectric generation will decreases by 8.2 percent and 8 percent, respectively, by midcentury. Even greater decreases are expected in the Northwest, a major source of California's electricity imports, where generation could decrease 18 to 21 percent by 2080.[37]

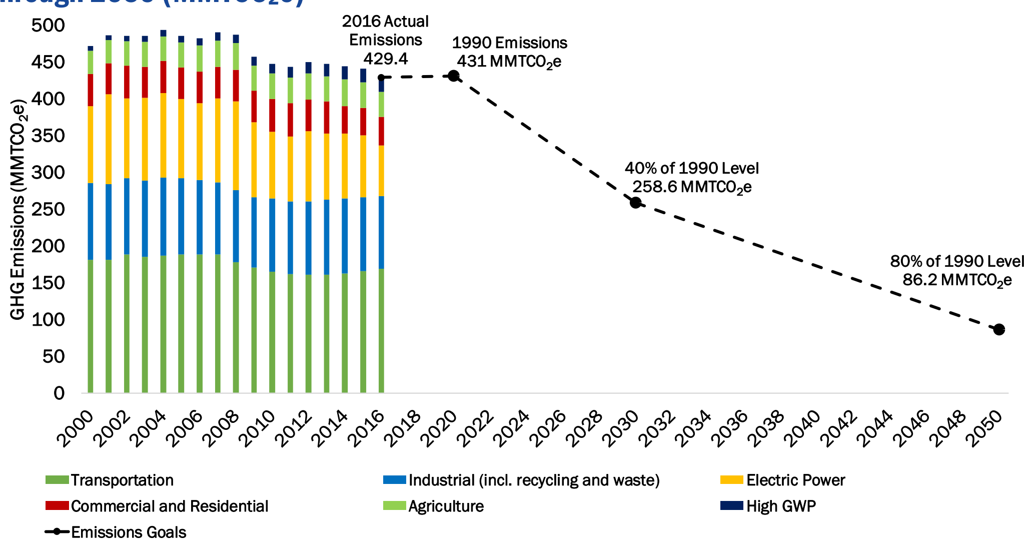
From a systems standpoint, energy infrastructure will be exposed to increasing climatic and environmental hazards in California. The combination of sea-level rise, land subsidence, and storm surges could threaten the integrity of levees and damage nearby natural gas pipelines, electric transmission infrastructure,[38] and other critical infrastructure. Oil refineries are vulnerable to sea-level rise and coastal flooding. Wildfires and flooding have already damaged the electricity infrastructure in California. Roads, railroads, and grid infrastructure are vulnerable to wildfires.[39] This not only affects transportation in general, it poses threats to the energy sector where key roads and railroads are used for the transportation of fuels.

California's Decarbonization Policies

Over the last 15 years, California has developed a series of policies aimed at deeply decarbonizing the state's economy by midcentury. These policies, which include a mix of economywide targets, sector-specific requirements, and technology-specific mandates, have already led to a reduction of GHG emissions although the deepest reduction in emissions was due to the economic downturn in 2008. Actual emissions and emissions reduction targets for 2020, 2030 and 2050 are shown in Figure 1-10.

Figure 1-10

California GHG Emissions by Sector, 2000-2016, and Emissions Reduction Targets Through 2050 ($MMTCO_2e$)



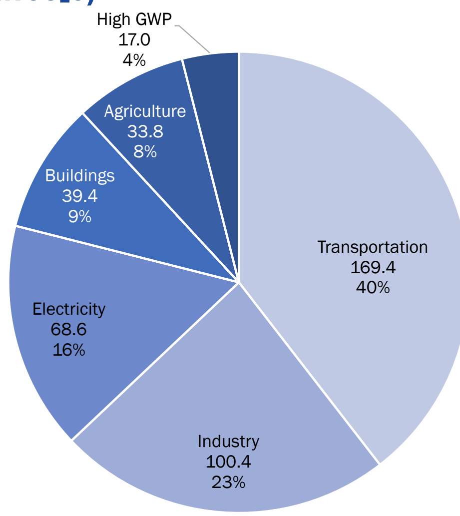
California policies have set economywide GHG emissions reduction goals of equalling 1990 emissions levels by 2020, reducing emissions 40 percent from 1990 levels by 2030, and reducing emissions 80 percent from 1990 levels by 2050. Source: EFI, 2019. Compiled using data from CARB, 2018.

In 2016, economywide emissions were 429.4 million metric tons of carbon dioxide-equivalent ($MMTCO_2e$), two $MMTCO_2e$ below 1990 levels (the state's 2020 GHG target). During the period from 1990 to 2016, California's population grew by 34 percent,[40] its GSP grew by 156 percent (in 2009 dollars),[41] and non-farm employment rose by 31 percent.[42] The Electricity sector was the primary contributor to emissions reductions, driven by energy efficiency and the substitution of coal generation by natural gas and increased renewable generation. From 1990 to 2016, annual Electricity sector emissions dropped from 111 to 69 $MMTCO_2e$ (a decrease of 38 percent), while annual emissions from the rest of the economy rose from 320 to 361 $MMTCO_2e$ (an increase of 12.8 percent).[43,44] The breakdown of emissions by sector in 2016 is shown in Figure 1-11.

The Transportation sector was the largest source of GHG emissions in the state in 2016 (39 percent), with passenger vehicles making up 28 percent of the state's total emissions and heavy-duty vehicles responsible for another 8 percent. Industry contributes the next largest share (23 percent), with the Oil and Gas and Cement subsectors as the main contributors in this sector (11 percent and 2 percent of the state total). Natural gas combustion is the source of most emissions from the Residential and Commercial Buildings and Electricity sectors, while Transportation emissions come predominantly from combustion of gasoline and other refined petroleum products.

Other sectors contribute non-combustion emissions, which are about 20 percent of the state's total. These come from Agriculture—mostly from livestock (especially cattle) manure and enteric fermentation; fertilizers; and soil management—as well as process and fugitive emissions from Industry (which includes waste subsectors in this analysis). Finally, there are significant volumes of high global warming potential (GWP) gases (CFCs, HFCs, SF_6, and other) from aerosols and foams.[45]

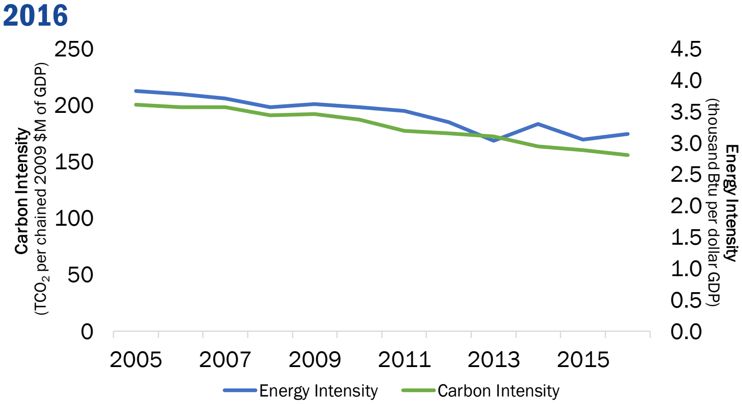
Figure 1-11
California GHG Emissions by Sector, 2016 ($MMTCO_2e$)



Transportation, Industry, and Agriculture have fewer decarbonization pathways and contribute more than 70 percent of the state's total GHG emissions. Note: figure excludes fugtitive emissions from chemicals and solvents, which contribute an additional 0.8 $MMTCO_2e$ to statewide emissions. Source: EFI, 2019. Compiled using data from CARB, 2018.

California's carbon and energy intensity trends are seen in Figure 1-12. From 2005 to 2016, the state's per capita carbon dioxide (CO_2) emissions decreased by 14.1 percent (compared to a U.S. average decrease of 20 percent);[46] the energy intensity of California's economy decreased by 18 percent (compared to a U.S. average decrease of 12.7 percent);[47] and the carbon intensity of the state's economy decreased by 22.4 percent (compared to a U.S. average of 25.4 percent).[48]

Figure 1-12
Energy and Carbon Intensity of the California Economy, 2005-2016



The energy and carbon intensity of California's economy have both decreased from 2005 to 2016. Source: EFI, 2019. Compiled using data from EIA, 2019.

California's Major Emissions Reduction Targets

Looking forward, California's policies emphasize a mix of economywide, sector-specific and technology-specific targets and mandates, with a focus on two time horizons: near-term (by 2030) and midcentury (by 2050). The principal near-term (2030) requirements include the following:

- Economywide emissions equal to 1990 level by 2020 (AB 32, enacted in 2006);[49]
- An economywide emissions reduction target of 40 percent from 1990 levels by 2030 (SB 32, enacted in 2016);[50]
- A cap-and-trade program with increasingly stringent compliance levels through 2031 (pursuant to a California Air Resources Board [CARB] regulation last updated 2018);[51]
- Reducing short-lived climate pollutants (SLCPs) 40 to 50 percent by 2030 (SB 1383, enacted in 2016);[52]
- Doubling energy efficiency of natural gas and electricity end uses by 2030 from a 2015 baseline (SB 350, enacted in 2015);[53]
- Achieving a 60 percent electricity renewable portfolio standard (RPS) by 2030 (SB 100, enacted in 2018);[54]
- Sustaining the federal CAFE standard for light duty vehicles at 54.5 miles per gallon (mpg);[55]
- Deploying one million zero emissions vehicles (ZEVs) by 2023 (SB 1275, enacted in 2014),[56] 1.5 million ZEVs by 2025 (Executive Order B-16-12, 2012),[57] and five million ZEVs by 2030 (Executive Order B-48-18, 2018).[58]

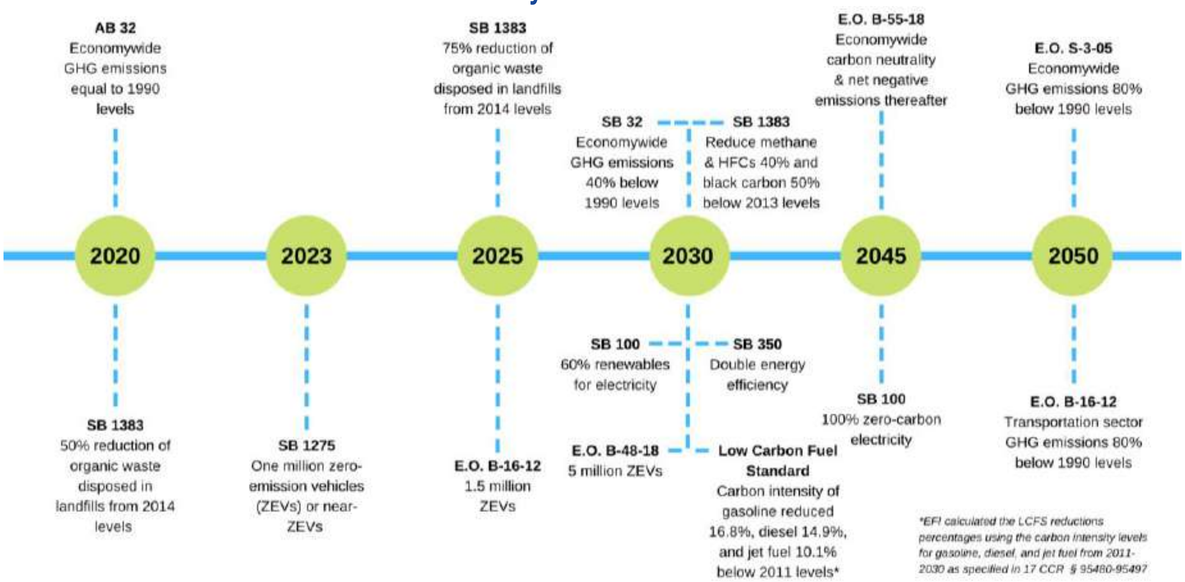
These goals and requirements become much more stringent by midcentury, and include the following:

- An economywide emissions reduction target of 80 percent from 1990 levels by 2050 (Executive Order S-3-05, 2005);[59]
- 100 percent net zero-carbon electricity by 2045 (SB 100, 2018);[60] and
- Carbon neutrality by 2045 and net-negative thereafter (Executive Order B-55-18, 2018).[61]

Figure 1-13 provides a timeline of the economywide, sector-specific, and technology-specific targets and mandates through 2050.

Figure 1-13

California's GHG Emissions Reduction Policy Timeline



To meet its aggressive GHG emissions reduction goals, California has a number of policies aimed at reducing emissions from various sectors and end uses. Note that bill numbers were used as a shorthand. Source: EFI. 2019

California's Cap-and-Trade Program

An important policy with economywide implications for decarbonization is California's cap-and-trade program. The Global Warming Solutions Act of 2006 (AB 32) gave CARB the authority to establish a "market-based compliance mechanism" as one strategy to enable California to achieve its goal of reducing GHG emissions to 1990 levels by 2020. After releasing a Climate Change Scoping Plan in 2008, CARB first required emissions reporting from entities that emit more than 10,000 metric tons of CO_2e and then launched the cap-and-trade program with the first enforceable compliance period in 2013.[62]

Entities that emit more than 25,000 metric tons CO_2e are subject to the cap-and-trade program and must also verify their emissions[a] with a third party.[63] Approximately 80 percent of economywide emissions are covered by this program, with emissions from agriculture, landfills, composting, high GWP gases, and select fugitive emissions excluded.[64] The "covered entities" of the program include:

- Operators of facilities;[b]
- First deliverers of electricity;
- Suppliers of natural gas;

[a] This includes emissions from stationary combustion, process and vented emissions, geothermal emissions, emissions associated with imported electricity, and emissions associated with final combustion of fuels reported by fuel suppliers.
[b] This includes cement, glass, hydrogen, iron and steel, lead, lime, nitric acid, and pulp and paper producers, cogeneration, stationary combustion, electricity self-generators, and petroleum and natural gas systems.

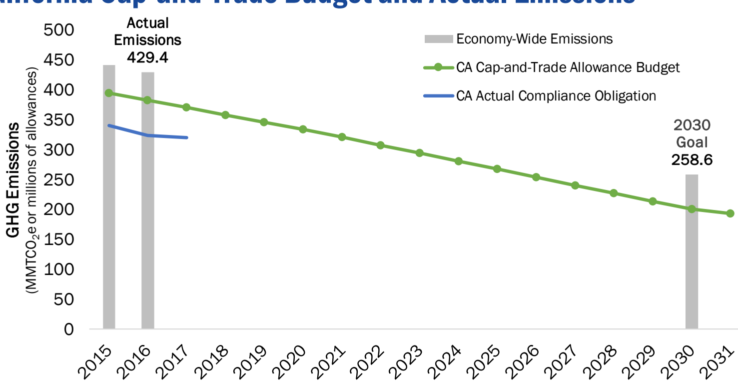
- Suppliers of reformulated blendstock for oxygenate blending and distillate fuel oil;
- Suppliers of liquefied petroleum gas;
- Suppliers of blended fuels;
- Suppliers of liquefied natural gas and compressed natural gas; and
- Carbon dioxide suppliers.[65]

The covered entities are issued a certain number of allowance permits that enable them to emit up to one metric ton of CO_2e per permit.[66] They may also buy, sell or trade additional permits in quarterly auctions that are held between the linked California and Quebec emissions trading systems.[67] California also allows up to 8 percent of an entity's compliance obligation to be met with offset credits, which are GHG removal enhancements equal to removing one metric ton of CO_2e from the atmosphere.

The cap-and-trade system has eight separate compliance periods from 2013 through 2031. Covered entities must surrender their permits at the end of each compliance period, giving them additional flexibility in how they are able to comply. Entities may also bank permits for redemption in later years of the program. For each year from now through 2031, the annual number of permits will become increasingly stringent, decreasing annually between 3 and 6 percent from the previous year. By 2031, the total budget of covered emissions will be capped at 193.8 $MMTCO_2e$.

Figure 1-14

California Cap-and-Trade Budget and Actual Emissions



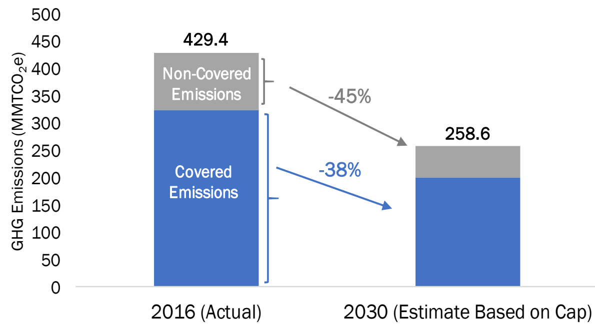
The emissions cap (green line) has exceed the actual compliance obligation (blue line) and has limited the impact that the program has had on reducing overall emissions (grey column). Source: EFI, 2019. Compiled using data from CARB, 2018.

In its initial years, the program was deemed unsuccessful because the emissions cap was too high and there were excess permits available that went unsold (Figure 1-14). This was due in part to incorrect projections of future energy demand growth following the 2008 Great Recession and slower than expected economic growth.[68] In 2017, AB 398 extended the cap-and-trade program through 2031, changed cost containment mechanisms, and directed CARB to evaluate allowance overallocation issues.

In addition, the current regulation requires the level of covered emissions to be equal to, or less than, 200.5 $MMTCO_2e$ by 2030. To meet this level, covered emissions will need to decrease at least 38 percent from the 2016 actual emissions (320.6 $MMTCO_2e$). If the cap allowance is to be met exactly, non-covered emissions will need to decrease 45 percent from 2016 levels (105.3 $MMTCO_2e$) to meet the economywide 40 percent reduction goal (Figure 1-15). This is important to consider as well since non-covered emissions are often more challenging to abate, so achieving a 45 percent reduction may be difficult.

Figure 1-15

Covered and Non-Covered Emissions Reductions Required to Meet the Cap and 2030 Goal



To meet the 2030 economywide 40 percent emissions reduction target, emissions not covered by cap-and-trade will need to be reduced by a larger proportion than covered emissions with the 2030 cap level of 200.5. Source: EFI, 2019. Compiled using data from CARB, 2018.

While it is difficult to forecast the direct impact of the cap-and-trade system on California's decarbonization trajectory, it is expected that the cap-and-trade system will continue to support emissions reductions in the covered sectors. Concerns remain, however, about the impact of the revised program on compliance obligations, the bankability of credits that may be hedged against future cap levels, and the ability of the program to directly influence final consumer behavior and emissions in non-covered sectors. An analysis of California's cap-and-trade program, released in 2017, concluded that, "GHG prices likely remain at or near the floor through 2020, increasing afterwards subject to a wide range of uncertainty. The level of complementary policies, innovation in lower-cost clean energy technologies, and natural gas prices can all have big impacts on future GHG prices."[69]

Informed by the 2017 analysis, this study assumes that California's cap-and-trade program will likely help reduce emissions in California. This study does not, however, attempt to estimate the direct contribution of the cap-and-trade program to the state's decarbonization targets. Instead, it assumes that the program could be a contributor to the motivations for developing the clean energy pathways described in the Electricity and Industry chapters of this report.

Leveraging California's Robust Innovation Capacity

In addition to California's role as a decarbonization policy leader, the state has significant innovation capacity. California is home to world-class science and research organizations and universities, active policymakers, a highly-engaged private sector, and a significant workforce in both traditional and emerging energy sectors. This robust capacity creates many opportunities for California to advance clean energy innovation to achieve both 2030 and 2050 decarbonization goals.

Strong and Supportive Private Sector

Private sector entities in California have a history of supporting policies that promote clean energy innovation. Companies and investors, for example, supported an extension of

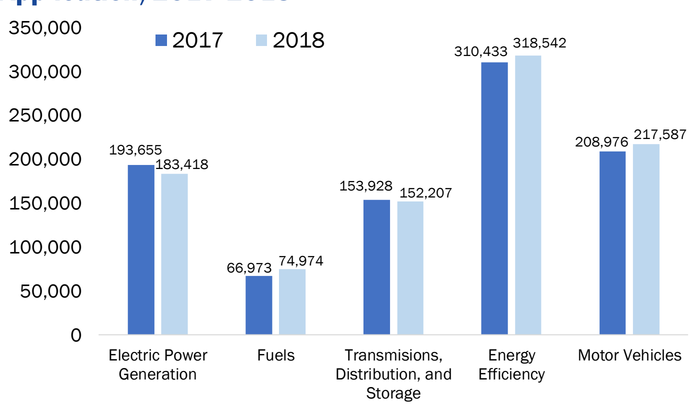
California's cap-and-trade program to beyond 2030,[70] which was passed by the state legislature and signed into law in July 2017.[71] CARB recently reported that for the compliance period from 2015 to 2017, 100 percent of businesses covered under the California cap-and-trade program met their obligations to reduce GHG emissions.[72] In the lead-up to the November 2018 gubernatorial election, a broad coalition of business groups banded together to promote a continued push toward a clean energy economy in California.[73] As of February 2019, of the 574 entities in California that were signatories to the We Are Still In pledge to uphold the goals established in the 2015 Paris Climate Agreement, three quarters were businesses in the state. Thirty-two investor groups in California also signed onto the pledge.[74]

In addition, private sector entities in California have supported research, development, demonstration, and deployment for low-carbon technologies. A direct air capture company called Global Thermostat, for example, has already tested a pilot plant in California that captures 1,000 tons of CO_2 per year.[75] A major driver of such private sector leadership in clean energy innovation in California has been the ability to raise substantial capital for early and later-stage clean energy technologies, attract a highly-skilled workforce and range of start-up companies to launch businesses in the state.[76]

Strong Energy Workforce

California has nearly 950,000 workers in the energy sector (Figure 1-16).[77] Of these jobs, 410,600 are in Traditional Energy sectors (electric power generation; fuels production; and energy transmission, distribution, and storage). California has 318,542 energy efficiency jobs (13.7 percent of U.S. total). Most of these jobs are in HVAC firms, ENERGY STAR, and efficient lighting. Finally, of the 217,587 workers in motor vehicles, approximately one-quarter are in alternative fuel vehicles or vehicle efficiency parts and products. The release of the Tesla Model 3 in 2018 contributed to an additional 34,000 jobs in 2018, for example.[78] California's motor vehicles jobs are 8.6 percent of the U.S. total.[79,80]

Figure 1-16
California Employment by Major Energy Technology Application, 2017-2018



In California from 2017 to 2018, traditional energy jobs declined 1 percent overall, while energy efficiency jobs increased 2.6 percent and motor vehicles jobs (many of which are in alternative vehicles and efficiency) increased 4.1 percent. Source: EFI, 2019.

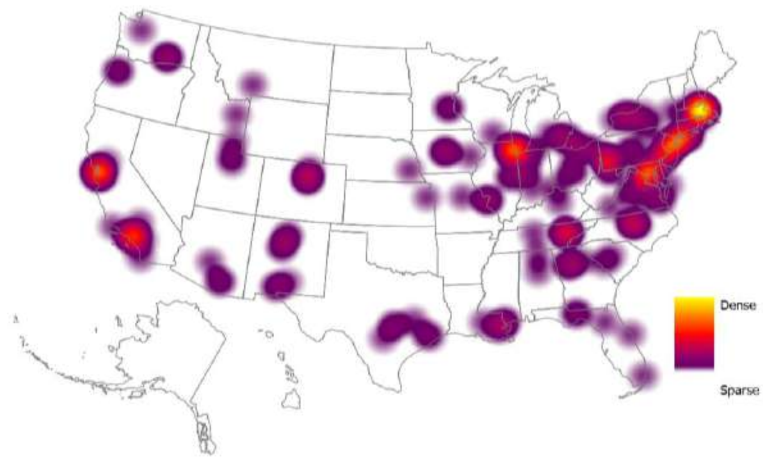
California also has the highest number of solar (126,507), natural gas for power generation (20,808), and energy storage (18,206) jobs of any state. Notably, 37.8 percent of U.S. solar jobs are in California (which includes full- and part-time positions), as well as

18.4 percent of natural gas for power generation jobs, and 22.5 percent of energy storage technologies jobs. There are an additional 7,847 natural gas jobs in fuels; however, these jobs only reflect 2.9 percent of the U.S. total in natural gas fuels. The state is also a national leader in smart grid and microgrid employment, with 43.5 percent of U.S. jobs in this category in California.

Robust Science and Technology Systems

California has a robust innovation infrastructure. Its substantial innovation capacity is driven by government, university, and private industry institutions (Figure 1-17). California is home to four Department of Energy (DOE) national laboratories, the most in any single state. The thousands of researchers at these labs explore a range of relevant topics, including climate science, supercomputing, and materials research.[81]

Figure 1-17
Clean Energy Innovation Heat Map



This map reflects concentrations of the following: DOE Labs; Federally Funded Research and Development Centers; Energy Frontier Research Centers; Top Tier research universities; Clean Tech Firms; NASA Labs and facilities; NNMIs; Energy Innovation Hubs. Source: EFI, 2019.

California also has many top-tier research universities. Along with New York State, it has the highest number of universities (11) with the Carnegie Classification of "Doctoral Universities: Very High Research Activity." [82] California has the second greatest number of Federally Funded Research and Development Centers (8), surpassed only by Virginia (11).[83] California is also home to the greatest number of DOE-funded Energy Frontier Research Centers (EFRCs) in the nation—EFRCs work to develop research tools that will deliver the greatest scientific impacts to advance DOE's energy and science missions.[84]

California's universities are also home to energy research centers across a range of technology needs including smart grids; natural gas; gas separations for clean energy technologies; energy biosciences; nanoscale electronic systems; controls on geologically sequestered CO_2; and cross-cutting needs in energy science and technology.

In addition to the energy firms described in the "Strong and Supportive Private Sector" section, California is home to Silicon Valley, where there is a significant concentration of U.S. high-technology industry, jobs, and innovation.

Finally, California has multiple supportive state entities and programs. Entities include the California Energy Commission (CEC), the California Air Resources Board (CARB), and the California Public Utilities Commission (CPUC). The CPUC runs the Electric Program Investment Charge (EPIC), a program established in 2011 that uses electricity bill surcharges to fund public-interest RDD&D in clean energy technologies. It is jointly administered by CEC and the three major investor-owned utilities (IOUs); CEC administers approximately $130 million of the program's total budget of $162 million[85]. For the 2018-2020 triennial funding cycle, EPIC has eight strategic objectives:[86]

- Advance Technology Solutions for Continuous Energy Savings in Buildings and Facilities;
- Accelerate Widespread Customer Adoption of Distributed Energy Resources;
- Increase System Flexibility and Stability from Low-Carbon Resources;
- Improve the Cost-competitiveness of Renewable Generation;
- Maximize Synergies in the Water-Energy-Food Nexus;
- Create a Statewide Ecosystem for Incubating New Energy Innovations;
- Develop Tools and Analysis to Inform State Energy Policy and Planning; and
- Catalyze Clean Energy Investment in Underrepresented and Disadvantaged Communities.

A parallel program, the Natural Gas Research and Development Program, is funded by natural gas utility surcharges.[87]

Study Approach

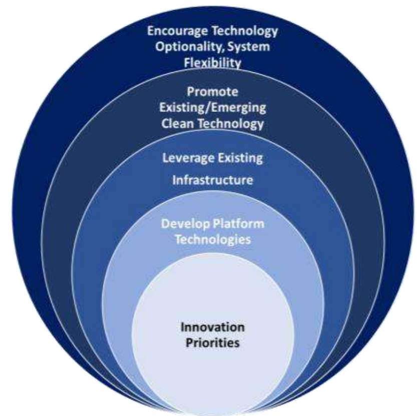
This report analyzes clean energy technology options that could enable California to meet its major decarbonization targets through 2050. It is not designed to be a critique of state policy. In cases where policy language provides guidance on how to reach the assigned emissions-related targets (e.g., five million ZEVs by 2030), this analysis assumes California will meet the goal. In cases where policy language provided relatively little guidance on how to meet the stated target (e.g., reduce economywide emissions by 80 percent, from 1990 level), this analysis has developed a range of cost-conscious pathways that could contribute to meeting the target.

To the extent possible, this analysis considers the dynamic nature of these pathways; however, it is assumed that certain identified pathways would change the need for, or value of, other pathways. For example, if a commercial facility develops on-site combined heat and power (CHP) units it may not necessarily also purchase renewable natural gas (RNG) at a price premium to conventional gas.

Four principles described below guide the review of California's potential pathways to decarbonization in the near- and long-term (Figure 1-18). These principles form the overarching framework of the study and were designed to reflect the realities of the innovation process, support a broad range of technology options (at various stages of market readiness), and consider relevant energy sector trends. They were used to shape and inform two major targets of the study: first, the clean energy pathways that could contribute to meeting California's major emissions reduction targets in the near-term

(2030), with a focus on existing technologies; and second, meeting emissions reduction targets by midcentury through a strategic innovation portfolio.

Figure 1-18
Recommended Clean Energy Innovation Priorities



The four clean energy innovation priorities used throughout this study include technology optionality and system flexibility, promoting existing and emerging technologies, leveraging existing infrastructure, and developing platform technologies. Source: EFI, 2019.

Principle 1. Clean Energy Technology Optionality and System Flexibility is Necessary

Predicting the optimal energy technology mix by 2050 is extremely challenging; no "silver bullet" technologies can be assumed. Key trends in energy, including population growth, urbanization, and climate change suggest that technology optionality and system flexibility will be critical for meeting both near- and long-term goals.

Optionality in the energy space is key and is best described as "thinking through the various scenarios that might follow a decision, *not just Plan A,* (italics added) and placing appropriate value on possibilities opened up or shut down by each path. Breaking projects into elements has value. The ability to delay a capital commitment has value. Adding assets in smaller increments has value. Reducing capital intensity has value. The ability to hedge or insure outcomes has value…Optionality allows a company to embrace new opportunities first at the margin, but eventually at the heart of operations…"[88]

Principle 2. Investment in Technologies Should be Made Based on a Set of Consistently Applied Criteria

The extended timeframes needed for energy innovation—and the unpredictability of the outcomes—creates the need for a framework for prioritizing investments. A set of technology selection criteria, developed by EFI for the report "Advancing the Landscape of Clean Energy Innovation," has been adopted to help guide the development of select existing/emerging clean energy technologies with long-term breakthrough potential.

Technology Selection Criteria

As discussed above, optionality is key to avoiding technology lock-in of suboptimal resources, and flexibility is crucial to ensuring that the energy system can meet the changing needs of the market. The analysis promotes selection criteria based on technical merit, market viability, compatibility, and consumer value.[89]

- **Technical Merit** includes energy or environmental preferences, including GHG reduction, leading to systems-level performance improvements. It also includes enabling innovations or knowledge and heuristic gains for cost, risk, and performance across a variety of technologies or systems.

- **Market Viability** includes manufacturability at scale with adequate and secure supply chains; a viable cost-benefit ratio for providers, consumers, and the greater economy; maturity to support very large scale-up; economic and environmental sustainability from a life-cycle perspective; significant market penetration; and revenue generation.
- **Compatibility** includes potential to interface with a wide variety of existing energy infrastructures (interoperability); potential to adapt to a variety of possible energy system development pathways (flexibility); potential to expand or extend applications beyond initial beachhead applications (extensibility); and the ability to minimize stranded assets.
- **Consumer Value** takes into consideration potential consumer preference issues, such as expanded consumer choice (by facilitating the introduction of new or improved products and services) and ease of use.

Principle 3. Existing Carbon Infrastructure and Expertise for Decarbonization Should be Leveraged

Decarbonization pathways are as much about infrastructure as they are about technology. Transmission and storage infrastructure, for example, will be critical to wider deployment of wind and solar. The transition to a low-carbon future could potentially be improved and accelerated by seeking opportunities to leverage existing infrastructure, technological expertise, and a skilled and readied workforce in the existing energy system. Repurposing existing carbon infrastructure—a highly-engineered system-of-systems that spans thousands of miles across California and employs more than 100,000 people with skillsets that could be utilized—could enable, accelerate, and improve the performance of the energy sector's transition to a deeply decarbonized economy.

Principle 4. Smart/Platform Technologies Have Major Breakthrough Potential

The rapid development of digital, data-driven, and smart systems—largely from outside the energy sector—has unlocked the potential of other "platform technologies" that could be scalable across the entire energy value chain. These platforms can be used to support decarbonization by optimizing performance based on emissions; advancing levels of reliability and resilience; and creating new business models that enable new services.

California has many of the tools necessary to ensure it meets its long-term deep decarbonization goals. Improving the alignment of the various players, policies, and programs will be key to developing technologies and systems that lead to long-term deep decarbonization. Building a clean energy innovation ecosystem that supports priorities set by the government is work that must begin today.

Study Methodology

The starting point for the analysis is the state's near- and long-term goals articulated in Executive Order S-3-05 issued by Governor Schwarzenegger in 2005 and Executive Order B-30-15 issued by Governor Brown in 2015. Executive Order S-3-05 set goals of emissions equal to 1990 levels by 2020 and an 80 percent reduction by 2050, and Executive Order B-30-15 calls for 40 percent economywide CO_2 emissions reduction by 2030, all from a 1990 baseline. The 2030 target was codified into law by SB 32 in 2016 and the 2050 goal is referenced in law in SB 350, passed in 2015. These emissions targets have been the foundation for other state statutes, executive orders, and regulations issued over the past decade. The 80 percent reduction may be significantly supplemented by negative emissions technologies.

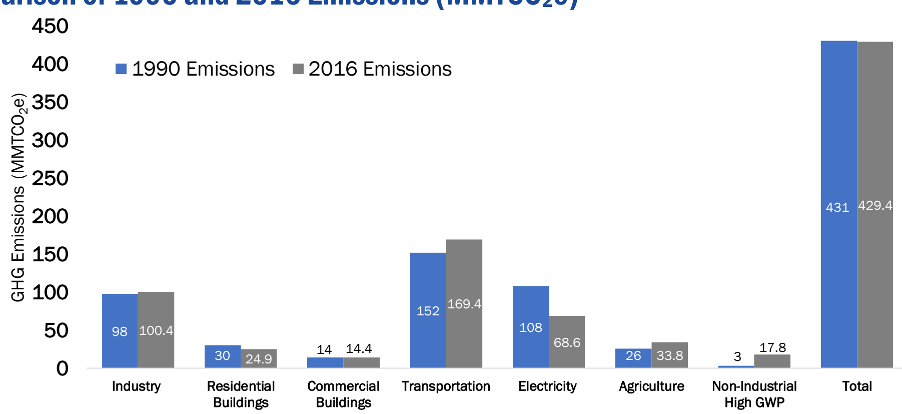
In September 2018, Governor Brown issued an executive order (Executive Order B-55-18), establishing a new economywide goal of "carbon neutrality by 2045 and net-negative emissions thereafter." This analysis offers a scenario that approximates this new goal but will be primarily guided by the emissions reduction targets of 40 percent reduction by 2030, carbon free electricity by 2045, and 80 percent reduction by 2050 emissions reduction targets.

These targets were all established against a 1990 baseline. The 1990 baseline, however, may not be sufficiently instructive to inform the range of technology and policy pathways going forward, as there have been many changes in energy systems and technologies since 1990 that are both sector-specific and cross-cutting. Also, as noted, this analysis places significant focus on the 2030 targets as technology costs and performance are less uncertain than those needed to meet 2050 goals; the 2030 emissions reduction target should be informed by more current data.

Total emissions in 1990 and 2016 are very close in absolute terms—430.9 $MMTCO_2e$ in 1990 and 429.4 $MMTCO_2e$ in 2016. The sector composition of emissions, however, changed significantly between 1990 and 2016. Emissions from transportation, for example, increased significantly between 1990 and 2016 from 152 $MMTCO_2e$ to 169.4 $MMTCO_2e$, while power generation emissions declined dramatically (Figure 1-19).

Figure 1-19

Comparison of 1990 and 2016 Emissions ($MMTCO_2e$)

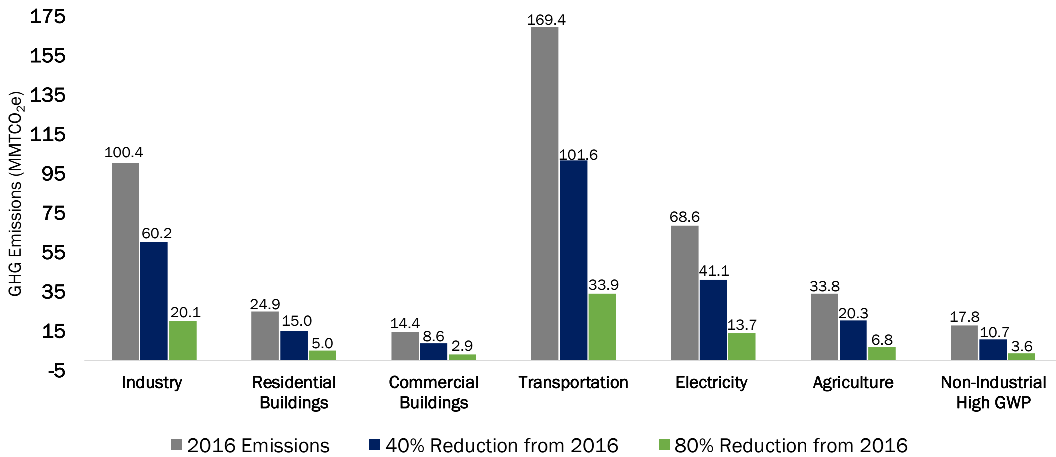


California's economywide emissions in 1990 and 2016 are very similar; however, the breakdown of emissions by sector are significantly different in transportation, electricity, and the non-industrial high global warming potential (GWP) category. Source: EFI, 2019. Compiled using data from CARB, 2018.

For purposes of this analysis, 1990 emissions will provide a benchmark for total emissions, but *sectoral* emissions from 2016 will be used to proportionally allocate 40 percent emissions reductions by 2030 (the 40 percent allocation is indicative, reductions may differ by sector). This analytical approach will provide more sector-specific and updated information about both the challenges and opportunities for meeting both the 40 percent economywide target in 2030 and 80 percent, economywide emissions reductions by 2050. These policy targets were chosen as they are aggressive, economywide and easily understood. (Figure 1-20) details emissions reductions needed to meet the economywide and sectoral targets.

Figure 1-20

Study Approach:
2030 & 2050 Emissions Reduction Targets by Sector from 2016 Baseline ($MMTCO_2e$)



This study examines emissions reductions of 40 percent by 2030 and 80 percent by 2050 for each sector from a 2016 baseline. Source: EFI, 2019. Compiled using data from CARB, 2018.

It should be noted that high global warming potential (GWP) greenhouse gas emissions are outside the scope of this study. In California, slightly under 5 percent of GHGs were from high GWP sources in 2016. Ninety seven percent of total high GWP emissions in California are from substitutes for ozone depleting substances (ODS), which were banned under the Montreal Protocol. Refrigeration and air conditioning equipment contributed 92 percent of ODS-substitutes emissions in 2016. High GWP emissions in California have been steadily increasing since 1990.[90] Sectoral emissions analyzed in this study, including baseline totals from each sector, do not include high GWP emissions, except in Industry.[c]

[c] The analysis of the Industry sector in this study uses CARB's 2018 GHG Emissions Inventory by Economic Sector Categorization in order to analyze emissions from each industrial subsector. The Economic Sector Categorization includes the high GWP emissions within the sector's total, while the CARB Inventory by 2008 Scoping Plan Categorization, which was used for Electricity, Transportation, Buildings, and Agriculture does not include the high GWP emissions within each sector; rather it groups all High GWP emissions separately.

Modeling

This study is based on an array of quantitative and qualitative efforts; it does not rely on a single model to inform its recommendations. Instead, both top-down and bottom-up modeling approaches are used to analyze and inform California's approaches to decarbonization and the opportunities and challenges they pose for current and emerging clean energy technology pathways (an econometric model was used for looking at costs of deep decarbonization by midcentury; the insights it provided are discussed below).

Top-Down Modeling

Top-down modeling is used to identify a range of possible clean energy pathways. For the top-down modeling, this report uses two models. The first is the MIT U.S. Regional Policy (USREP) model[91,92] with a representation of California's energy sector and its wider economy, including connections to other U.S. regions. The USREP model is a recursive dynamic computable general equilibrium model, used to assess how California's energy system could react to the state's policy requirements between now and 2030 and 2050. The current energy pathways include solar, wind, renewables plus backup, hydro, biomass, biofuels, and clean energy imports. The non-energy sectors include energy-intensive industries, agriculture, commercial transportation, personal transportation, services, and all other goods. Primary factors include labor, capital, and land, as well as depletable fossil fuels, biomass supply, and wind and solar resource potential. Households across income classes differ in terms of income sources and expenditure patterns.

Bottom-Up Modeling

For Electricity, this study uses the Sustainable Energy Systems Analysis Modeling Environment (SESAME) developed at MIT. This power systems model includes hourly load profiles of every generator with a capacity of more than 25 megawatts in the United States, based on U.S. EPA's historic data from 2005 to 2017. This allows assessment of power generation at hourly generator-level resolution. The model captures changes in operation profiles of various generator types and also identifies the attributes of reliable and low-carbon power systems. More detailed descriptions of the model are found in Chapter 2. Bottom-up modeling was performed for specific issues in each of California's energy end-use sectors. A detailed discussion of the scenarios evaluated is in Part 2 of this study.

In the Transportation sector, a spreadsheet model was developed to assess the emissions, cost, and timing impacts of select policies on the state's vehicle stock composition.

In the Buildings sector, a spreadsheet model was developed to assess the cost tradeoffs among different end-use technologies under different deployment scenarios, based on data from EIA's "Updated Buildings Sector Appliance and Equipment Cost and Efficiency."

In the Industry sector, a simple model was developed of the state's carbon sequestration capacity for select industrial facilities based on technical potential, proximity to storage sites, eligibility of 45Q tax credits, and (related) carbon emissions levels.

In Agriculture, a simple model was created to estimate the emissions reductions benefits of light-duty tractor electrification at the end of the useful life of existing tractors.

Other similar analysis frameworks were developed to support the conclusions in each section of the report.

Identified Pathways for Meeting the Near-Term Targets

Selecting the clean energy pathways that could contribute to meeting California's 2030 targets was based on modeling-informed analysis that included a top-down assessment of the California economy, as well as multiple bottom-up models that approximated how various technologies may impact the energy sector and reduce emissions. Combined with the modeling, technical experts helped guide the analysis to consider multiple relevant factors, including the current and expected performance of each technology in the 2030 timeframe; the relative costs, including associated infrastructure costs and the potential costs of stranded assets; the net impacts of each technology on carbon emissions in California; and potential positive and negative feedbacks of each pathway on the state's social and environmental well-being. It is assumed that incremental technology improvements are both needed and achieved in this timeframe.

A portfolio of 33 technologies was selected based on this analysis. It is important to note that these pathways are not necessarily the only options for reducing emissions from each sector. The portfolio is designed to promote optionality and flexibility, while prioritizing technologies with strong technical performance and economics. Pathways that augment existing energy infrastructure were also prioritized as they can offer significant benefits in terms of cost savings and market readiness.

In many cases, there are significant challenges involved in realizing the full emissions-saving potential of each pathway; these challenges are described in detail in other sections of the report. Each pathway relies heavily on public and private sector support. Additionally, these pathways are not orthogonal; they are discrete options that do not account for feedback among technologies or systems dynamics issues. For example, while electricity generators may leverage battery storage systems to reduce emissions during ramping (to support renewable resources), others may use carbon capture technologies. This analysis concludes that there could be a sufficient market for each technology while describing their emissions-savings potential.

Identified Pathways for Meeting the Midcentury Targets

Meeting California's long-term decarbonization targets—including an 80 percent reduction by 2050 from 1990 levels and carbon neutral electricity by 2045—is extremely challenging. It is difficult, if not impossible, to predict the right mix of clean energy technologies to meet these goals over the next three decades. Meeting deadlines is further complicated by technology development timescales; deployment and diffusion rates; public acceptance issues; land use requirements; evolving cost curves; changing energy markets; the state and national legislative and regulatory environments; and the availability of support infrastructure.

New technologies are needed and their precise roles and functions in deeply-decarbonized systems sufficient to meet the state's midcentury targets are not yet knowable; this underscores the importance of maintaining and enhancing California's already-robust innovation infrastructure, seeding a range of technology options for meeting long-term goals.

Modeling the Costs of Deep Decarbonization by Midcentury

In the last few years there has been a growing debate in the academic literature around the cost of reaching deep decarbonization, especially in the Electricity sector.[93,94,95] Many types of models have been used to simulate the available pathways, ranging from all renewable resources to the broadest set of options (e.g., clean hydrogen for power generation).

As part of the framing of the analysis of the 2050 targets, this study uses the USREP model to examine the cost of meeting the state's decarbonization policies by midcentury. The dynamic impacts to the energy system *without* technology innovation are modeled. Based on these technologies, market participants were assumed to identify the lowest cost opportunities to reduce emissions across the California economy.

As described in detail in Appendix A, costs to the economy of meeting California's low-carbon policies are relatively stable until 2035 when they dramatically accelerate; this "hockey stick" trajectory reflects the high marginal costs associated with meeting zero carbon electricity by 2045 and 80 percent economywide reduction by 2050. In this scenario, there is a shadow carbon price of $401 per t$CO_2$e in 2030 and more than $1000 by midcentury.

This scenario is used exclusively to put the compliance costs of meeting California's carbon policies by midcentury in perspective. It shows the steepness of the cost curve after 2035, emphasizes the scale of the technology needs, underscores the high value of innovation in clean energy technology, and highlights why negative emissions technologies will likely be needed. Because of highly uncertain technology winners and losers at midcentury, the work must begin today to successfully develop a range of long-term clean energy innovation pathways; the analysis in Chapter 8 discusses these options in detail.

Final Thoughts

This point cannot be overstated: there is no technology "silver bullet" to achieve economywide decarbonization in California. Given the dynamic conditions of the energy sector it is vital to avoid technology lock-in of potentially suboptimal resources and the infrastructures that support them. Any programs to promote near- and long-term decarbonization strategies must emphasize the inherent value of technology and policy pathways that offer optionality, flexibility, and consideration of both system and societal impacts.

To meet its decarbonization priorities over the long-term, California should expand its investments in its already-robust clean energy innovation ecosystem. By closely aligning the relevant energy players, policies, and programs with a broad portfolio of clean energy technologies, California could establish a clean energy innovation ecosystem that supports and leads regional, national and global decarbonization efforts.

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[1] Energy Futures Initiative [EFI] and IHS Markit, *Advancing the Landscape of Clean Energy Innovation* (Washington, DC: EFI, 2018), 40, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5c5a24864e17b6106a7bf9ce/1549411488418/BE2442_Report_013119.pdf.
[2] http://www.dof.ca.gov/Forecasting/Economics/Indicators/Gross_State_Product/
[3] Calculated from data in "Table C10. Energy Consumption Estimates by End-Use Sector, Ranked by state, 2016," in U.S. Department of Energy, Energy Information Administration [EIA], *state Energy Consumption Estimates: 1960 Through 2016* (Washington, DC: EIA, 2018), 15, https://www.eia.gov/state/seds/sep_sum/html/pdf/rank_use.pdf.
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PART 2

MEETING CALIFORNIA'S 2030 EMISSIONS TARGETS

SECTORAL ANALYSES

CHAPTER 2
REDUCING EMISSIONS FROM THE ELECTRICITY SECTOR BY 2030

FINDINGS

The Electricity sector will play a critical role in meeting California's decarbonization targets. Not only can it reduce its own emissions, it can support decarbonization pathways for end-use sectors.

In 2016, emissions from the Electricity sector (including from in-state generation and imported power) comprised 16 percent of statewide greenhouse gas (GHG) emissions. California's policies and decarbonization goals emphasize increasing the deployment of renewable and low-carbon generation, reducing energy and electricity demand, and increasing electrification of the end-use sectors. This will significantly expand electricity's share in California's economywide energy demand.

Meeting the 60 percent Renewables Portfolio Standard (RPS) established in SB 100 will require more renewable generation than is currently planned for through 2030.

According to electric utility resource plans, there are nearly 74 terawatt-hours (TWh) of additional renewable generation expected to come online in California by 2030. This is estimated to increase the state's renewable generation to 47 percent of total generation, assuming electricity demand grows by 1.27 percent, as estimated by the California Energy Commission's midrange forecast. Assuming that growth in other renewables remains flat, meeting the 2030 target will require a growth rate for wind and solar installations similar to their growth rate in the state in 2016. This scenario is discussed in the section on "Reference Frame for SB 100's 2030 Renewables Target."

Reducing emissions from power generation in the near-term will require a broad array of technology and policy options.

Electricity's emissions trajectory of the Electricity sector, including a significant build-out of renewable capacity, is estimated to reduce emissions from 68.6 million metric tons of carbon dioxide-equivalent (MMTCO$_2$e) to 60.6 MMTCO$_2$e by 2030. Additional mitigation efforts will be necessary, especially as generation from nuclear falls to zero and generation from natural gas declines. Given the magnitude of this challenge, including grid operations impacts, other opportunities to decarbonize the Electricity sector are needed and include: reducing the carbon intensity of imported power; hybridizing the gas generation fleet with energy storage to enable more carbon-efficient operation; deploying a significant amount of renewables paired with energy storage; doping natural gas with hydrogen and/or renewable natural gas; deploying carbon capture, utilization, and storage (CCUS) on gas plants; and demand response.

All pathways for decarbonization of the Electricity sector involve a significant role for intermittent renewables; this will have major impacts on grid operations.

A key challenge associated with increased intermittent generation will be maintaining the reliable operation of the electric grid. Energy storage systems that support renewables, such as lithium-ion batteries, can address certain operational issues (e.g., grid balancing) for short periods of time. There are currently no battery storage options for operational needs with longer duration (i.e., days or weeks). In the near term, grid balancing will continue to be met in large part by natural gas and hydropower, the latter utilizing both reservoir operations and pumped storage.

Energy storage can provide ancillary services, ramping capacity and capability, and short-duration reliability support for systems with high penetration of intermittent renewable resources.

As costs continue to fall, storage options can play a major role in Electricity decarbonization, including a variety of lithium-ion batteries, electrochemical (e.g., flow batteries), mechanical (e.g., compressed air energy storage), and thermal storage options (e.g., ice energy), all of which have been deployed at low levels today. For battery storage, lithium-ion chemistries are the predominant technology at grid-scale but remain costly. Other battery chemistries may be commercial by 2030 but deployment at scale and market diffusion is unlikely.

Natural gas generators play an important role in providing the electric grid with operational flexibility, enabling growth in the use of intermittent generation resources.

Natural gas-fired generation helps the electric grid address operational issues of both short and long duration, including the management of seasonal shifts in demand. As natural gas plants in California increasingly respond to daily load-following and grid-balancing needs, these plants are being operated at higher heat rates for shorter intervals. Such inefficient operation can increase plant emissions by as much as 46 percent, even as the plants generate fewer total megawatt-hours. Sustainable solutions are needed to efficiently decarbonize the electricity system, avoiding the construction of large amounts of redundant power generation or operating assets in inefficient modes.

There are supply-chain risks associated with renewable generation and storage technologies that must be considered when pursuing clean energy pathways.

Raw materials for sustainable energy technologies require serious supply-chain planning that considers demand growth and production rates; reliance on supply controlled by “too few” countries; and other supply and price risks. In addition to supply-chain planning, investments should be made in developing clean energy technologies that use earth-abundant materials.

Current market structures may not provide adequate compensation for the services that energy storage systems can provide.

In California’s current electricity market, wind and solar generation are generally dispatched first, as they have low to zero direct marginal costs. This keeps marginal electricity prices low but diminishes investment incentives for baseload or intermediate generation, as well as for grid-scale storage of longer duration and higher capacity. In addition, demand response and storage inherently reduce the magnitude and duration of energy price spikes; this further reduces the revenue, above marginal production costs, that is available to recover the capital costs for generation and grid infrastructure.

Developing CCUS technologies at existing natural gas generation facilities adds significant flexibility for meeting emissions targets while supporting grid operations.

CCUS technology is not necessary for reaching aggressive levels of decarbonization in electricity generation; this analysis assumes a limited deployment of CCUS at select facilities by 2030 due to its currently limited market diffusion. However, some CCUS can significantly improve the optionality and flexibility of both moderate and deep decarbonization, as it will both help preserve the important operational support that gas generation provides to the grid while reducing emissions. California has large sequestration capacity for carbon dioxide, providing opportunities for significant CCUS at natural gas plants. The profile of the state's NGCC fleet, as well as the availability of section 45Q tax credits for CCUS, also enhance the viability of this pathway.

While California has made significant progress in introducing lower- and zero-carbon technologies for the generation of electricity, achieving the goals set for 2030 and the deep decarbonization set for 2050 will be very challenging.

CEC estimates suggest that there could be an overall increase in electricity demand of 33 percent between 2015 and 2050. Peak electrical load in the state could almost double from 67 gigawatts (GW) in 2015 to 132 GW in 2050, because of the implementation of progressive electrification as a decarbonization pathway in the Transportation and Buildings sectors. Meeting this demand with zero-carbon generation by midcentury will be difficult and innovative technologies will be necessary.

Adding offshore wind generation capacity is an attractive option for increasing renewable energy deployment and taking advantage of the unique characteristics of offshore resources.

These resources are attractive because offshore wind generation is more consistent, can provide generation at night when solar generation decreases, has higher capacity factors than solar or onshore wind (as high as 60 percent in prime locations), and can sometimes be sited closer to load centers than onshore resources. The vast majority (95 percent) of California's offshore wind resources are located at water depths (exceeding 60 meters); this would require floating platform infrastructure. Technology commercialization of such platforms is advancing quickly, including full-size systems now deployed in Europe. While there may be some offshore wind deployed in California by 2030, it is considered a breakthrough technology by midcentury.

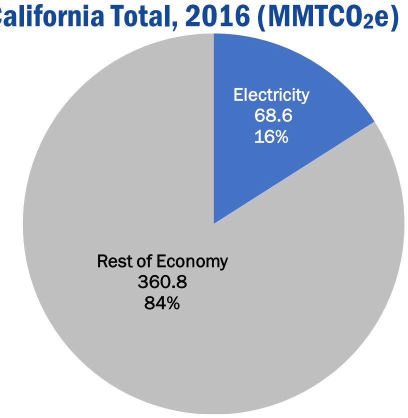
ELECTRICITY SECTOR

California's Electricity sector has been and will likely continue to be a key source of the state's greenhouse gas (GHG) emissions reductions. The state has championed the deployment of renewable generation resources and is actively pursuing other opportunities to decarbonize the sector. While there are many known low-carbon technologies available for the sector, there are still many considerations around resiliency, security, adequacy, and reliability, which must be assessed as the state looks to reduce the sector's GHG emissions. Electricity will also be central to decarbonizing other sectors, such as Buildings and Transportation. Future demand growth must be considered, as well.

By 2030, California's Electricity sector is required to meet a 60 percent Renewables Portfolio Standard (RPS); by 2045, the sector is charged with reaching carbon neutrality. This section analyzes decarbonization pathways to enable the sector to reach these goals, with a focus on the 2030 target. It reviews the major trends shaping the Electricity sector, including end-use electrification, the management of a growing share of intermittent renewable generation, and the impacts of climate change on the system. The analysis uses a baseline that includes estimates from the California Energy Commission (CEC) on the expected electricity demand growth through 2030 and considers existing and planned generation projects and retirements. This baseline is used to evaluate a range of potential clean energy pathways for the Electricity sector in California, including increased deployment of grid-scale battery storage; decarbonized imports; reduced emissions from natural gas combined-cycle (NGCC) plants through battery hybridization; use of renewable natural gas; blending of up to 10 percent hydrogen in the natural gas system; carbon capture, utilization, and storage (CCUS) at select natural gas generation facilities; and demand response.

A new bottom-up model of the electricity system in California was used to understand the reliability and emissions profile of many of these clean pathways. Together the pathways identified in this report can help California meet its 60 percent RPS target by 2030 and reduce emissions from the sector by more than 40 percent.

Figure 2-1
Electricity Emissions Compared to California Total, 2016 ($MMTCO_2e$)



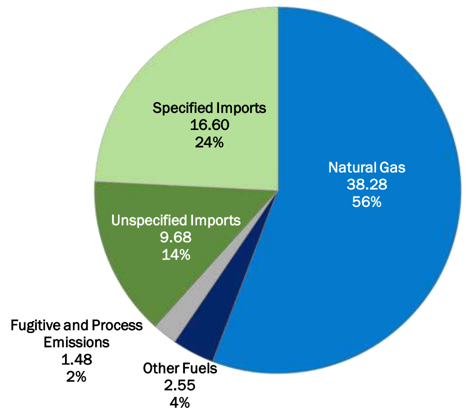
Emissions from Electricity make up 16 percent of California's total. Source: EFI, 2019. Compiled using data from CARB, 2018.

2016 Sector GHG Emissions Profile: Electricity

In 2016, emissions from the Electricity sector (including emissions from in-state generation and imported power) comprised 16 percent of statewide GHG emissions (Figure 2-1).[1] At almost 50 percent of in-state power generation, natural gas accounts for most of

Figure 2-2

Electricity Sector Emissions Profile, 2016 (MMTCO2e)



Most of the Electricity sector's emissions are from natural gas combustion from in-state power generation and imported power. Source: EFI, 2019. Compiled using data from CARB, 2018.

the GHG emissions from California's power sector. The state also imports a small amount of coal-generated electricity from the Southwest (Figure 2-2).

GHG emissions in the Electricity sector in California have declined significantly in the last ten years (Figure 2-3).[2] Peaking at 120 million metric tons of carbon dioxide-equivalent ($MMTCO_2e$) in 2008, economywide emissions fell to 68.6 $MMTCO_2e$ by 2016. These emissions reductions have occurred in part because of significant energy efficiency improvements in end-use sectors and increased zero- and low-carbon generation in the Electricity sector. In addition, large declines occurred between 2009 and 2011, due to reduced economic activity associated with the 2007-2009 Recession and its aftermath.

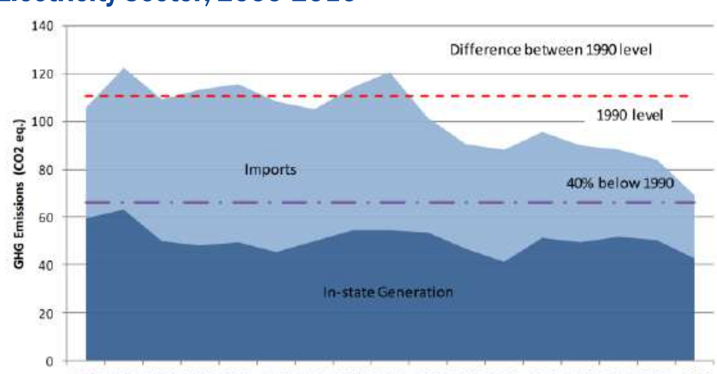
Analysis of the Electricity Sector

California's Electricity sector has been and will continue to be at the forefront of efforts to achieve deep decarbonization. As noted, many of the major pathways for deep decarbonization in other sectors will depend on a reliable, resilient (especially to the impacts of climate change), affordable, and clean electric grid.

California's policies and decarbonization goals emphasize, among other things, increasing the electrification of the state's economy. This is reflected in statutes and executive orders that have, for example, set increasingly ambitious targets for electric vehicles—with the most recent Executive Order establishing a goal of five million zero-emission vehicles (ZEVs) by 2030.[3] Policies supporting zero net energy (ZNE) buildings also promote electrification.

Figure 2-3

Historical Greenhouse Gas Emissions from California's Electricity Sector, 2000-2016



California's Electricity sector is the only sector with significant emissions reductions since 2000. Source: CEC, 2018.

California's policies and decarbonization goals have also included ambitious targets and mandates for renewable power generation. The state has had a renewable portfolio standard (RPS) since 2002.[4] The California RPS was recently modified in the 100 Percent Clean Energy Act of 2018 (SB 100), which increased the target to 44 percent renewables by 2024, 50 percent by 2026, 52 percent by 2027, and 60 percent by 2030. SB 100 also expanded the state's ambitions to 100 percent renewable and zero-carbon resources by 2045.[5] During the 2018 legislative session, California also enacted a series of statutes supporting alternative generation technologies and storage, such as biomethane procurement[6] and biomethane interconnection assessments,[7] green electrolytic hydrogen for storage,[8] and storage.[9] These policies underscore the importance the state is placing on the Electricity sector for achieving deep decarbonization.

There are additional challenges that add further complexity to decarbonization efforts. First, renewable generation in California is fundamentally changing the operating patterns required from many of California's natural gas-fired electric power generators. In the absence of adequate peaking capacity, NGCC plants are being operated at higher heat rates for shorter intervals on a daily basis, to balance intermittent and variable generation from renewable resources. This inefficient operational pattern is increasing emissions from these natural gas-fired generators even as they generate fewer total megawatt-hours (MWh) (discussed in greater detail later in this chapter). Also, market structures in California are problematic for incentivizing baseload and dispatchable generation, including storage; this is also discussed in greater detail below.

Trends Shaping the Electricity Sector

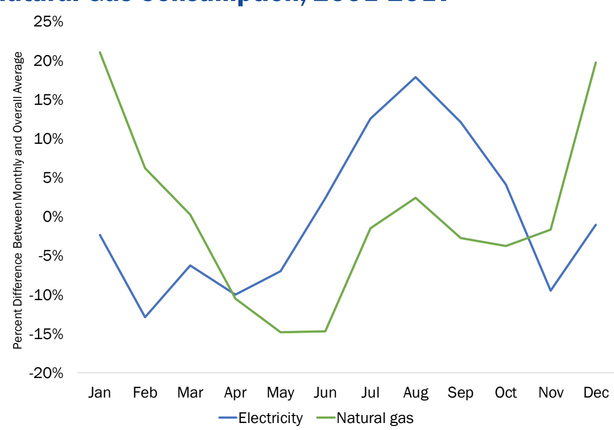
There are important trends that are shaping California's electricity system that provide context for its unique role in decarbonization. The clean energy pathways that will be needed to ensure that the power system decarbonizes must also allow that system to maintain its core mission: providing reliable electricity to its customers.

Seasonal Demand Shifts

The seasonal variability of California's electricity demand is an important trend and issue that shapes its prospects for decarbonization. As shown in Figure 2-4, California's electricity consumption peaks in the summer and is the lowest in the winter. This is due in part to demand for summer air conditioning, as described in Part 1. California's electricity

Figure 2-4

Seasonal Variability in California Electricity and Natural Gas Consumption, 2001-2017



California has a summer peak for electricity, mainly driven by the use of residential air conditioning. Source: EFI, 2019. Compiled using data from EIA, 2018.

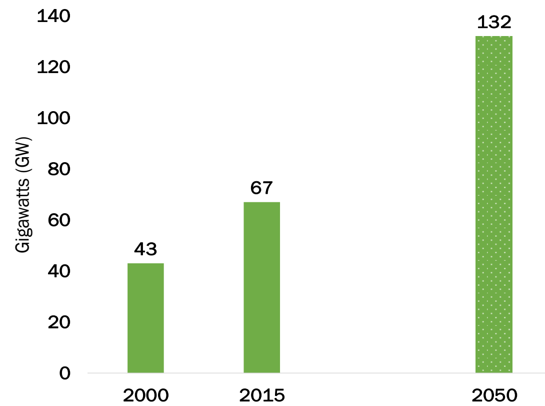
demand between 2001-2017 shows that the summer peak averaged nearly 20 percent higher than the total annual average of that same time period. Moreover, the winter low was roughly 15 percent below the overall annual average. While natural gas peaks in the winter, there is also a smaller summer peak. Natural-gas fired generation offers the only current in-state solution for managing these seasonal shifts in demand. Deep decarbonization of the electricity sector will need to account for these major swings in seasonal electricity demand.

Electrification

End-use electrification is expected to play a major role in California's decarbonization. This electrification will likely increase overall electricity consumption through 2050, moving well beyond Electricity's current share of total energy use. In its medium- and high-electrification scenarios, the CEC forecasts annual growth rates in electricity demand of 1.27 percent and 1.59 percent, respectively; annual growth in the midrange of these estimates between now and 2050 would mean an overall increase in electricity demand of 33 percent. Adding to the challenges of decarbonizing the Electricity sector in the face of carbon burden-shifting and demand growth, the National Renewable Energy Laboratory (NREL) 2016 electrification study of California projects that by 2050, in its high electrification scenario, peak electrical load in California would almost double from 67 gigawatts (GW) in 2015 to 132 GW in 2050 (Figure 2-5).[10]

Figure 2-5

California Peak Load (GW) in High Electrification Scenario



Peak load is expected to nearly double by 2050, therefore requiring decarbonization strategies that consider substantial demand growth in the long term. Source: EFI, 2019. Compiled using data from NREL, 2017.

Significant Growth in Solar and Wind Generation

As noted in Chapter 1, renewable generation—specifically from wind and solar—has grown substantially in California over the last decade. This growth been driven by both cost reductions and policy. On a nationwide basis, the levelized cost of energy (LCOE) from onshore wind dropped 41 percent between 2008 and 2015, and the LCOE of solar photovoltaic (PV) generation has dropped 54 percent for distributed PV and 64 percent for utility-scale.[11] Policies such as the RPS have also spurred the addition of more utility-scale renewables, while incentives from utilities, net metering, and other policies have improved the economics of distributed renewable systems for consumers.

From 2008 to 2017, solar PV generation in California grew from 3 gigawatt-hours (GWh) to 21.9 terawatt-hours (TWh). During the same period, solar thermal generation grew 370 percent (from 0.83 TWh to 2.5 TWh) and wind generation increased 231 percent (from

3.2 TWh to 12.9 TWh). The share for these technologies in the California generation mix has gone from 3 percent to 18 percent. Installed capacity of solar and wind grew by 13.6 GW, while the rest of the California's generation capacity shrank by 1.1 GW. Other RPS-eligible resources (geothermal, biomass, and small hydro) have experienced little change in installed capacity over this period.[12]

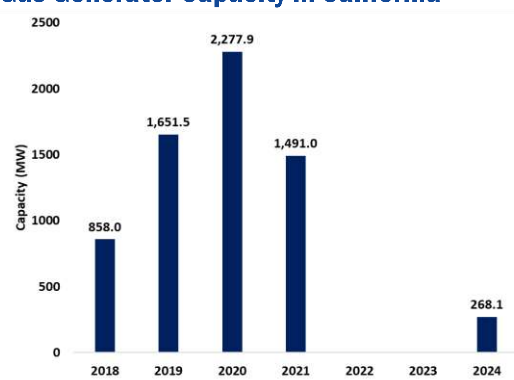
In 2016, zero-emissions generation sources—nuclear, wind, solar, large and small hydro, biomass and geothermal—were 49.8 percent of in-state generation.[13] Nuclear and (with few exceptions) large hydro are not covered by the state's RPS;[14] without this generation, zero-emissions power generation in California in 2016 was 27.9 percent of the in-state total.[15]

Stress on Natural Gas and Nuclear Generation

Part 1 of this report detailed California's fuel and electricity mixes. As noted, in 2016, natural gas was 49.8 percent of California's in-state generation and currently provides California's grid with much of its load-following and fast-ramping capacity. This important role in California's electricity system is under stress from two developments: increasing seasonal variation in both California's electricity demand and in the contribution of other generation sources to its electricity supply, and plans to retire natural gas-fired power plants.

There are 6,546 megawatts (MW) of natural gas-fired electricity generation capacity that are slated for retirement in California between 2018 and 2025 (Figure 2-6).[16] The largest concentrated phaseout is expected in the Los Angeles region, where the Los Angeles Department of Water and Power (LADWP) plans to phase out three natural gas-fired power plants in its territory over the next ten years. These plants have 1,211 MW of nameplate capacity and generated 3,770,065 MWh of electricity in 2016; they represent 38 percent of natural gas-fired electricity generation capacity in Los Angeles.[17]

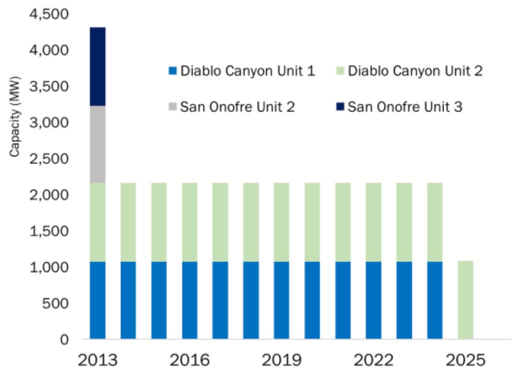
Figure 2-6
Actual and Planned Retirements of Natural Gas Generator Capacity in California



California plans to retire 6,546 MW of natural gas generation capacity from 2018 to 2025, most of which is in the Los Angeles region. Source: EFI, 2019. Compiled using data from EIA, 2019.

Nuclear power in California provided 9.5 percent of California's in-state generation in 2016 and 19 percent of its zero-emissions generation but has had a difficult history in the state. The San Onofre Nuclear Generating Station went offline in 2012 and was permanently retired in 2013,[18] leaving only the Diablo Canyon plant operating. Plans for the closure of Diablo Canyon's two reactors were announced in 2016, and its final closure and decommissioning is expected in 2025[19] (Figure 2-7). The Diablo Canyon plant provides electricity to three million people. Costs of decommissioning are estimated to be around $3.6 billion and the state will lose 2,160 MW of zero-emissions baseload power generation (see Box 2-1 for definition). This analysis assumes no new in-state nuclear generation by 2030, though imports from nuclear generation are expected to continue from other states in the U.S. Southwest.

Figure 2-7
Nuclear Power Plants and Planned Closures in California



The closures of the San Onofre Nuclear Generating Station and Diablo Canyon Power Plant from 2013-2025 will eliminate nearly 4,500 MW of zero-emissions baseload generation capacity. Source: EFI, 2019. Compiled using data from CEC, 2019.

The outsized impact of losing this zero-emissions baseload capacity is underscored by another datum: in 2016, nuclear was 3 percent of the state's generation capacity but 9 percent of its actual generation, illustrating that nuclear plants operate at very high capacity factors (since 2013, nuclear plants nationally have an average capacity factor of 92 percent[20] and Diablo Canyon has averaged 86 percent[21]). Replacing this capacity with solar, for example, would require the addition of over three times as many megawatts of capacity because of low capacity factors for solar (around 26 percent); storage, such as batteries, could increase capacity factors but is, as discussed later in this chapter, quite expensive.

Box 2-1
Defining Baseload Generation

According to the 2017 Department of Energy *Staff Report to the Secretary on Electricity Markets and Reliability*, baseload generation is defined as: "power plants that are operated in baseload patterns—that is, plants that run at high, sustained output levels and high capacity factors, with limited cycling or ramping."[22] Although this definition includes most nuclear, coal, and natural gas steam generators, it is not a requirement that all nuclear, coal, or natural gas generation be operated as baseload. Furthermore, other generation technologies, such as hydro, can serve as baseload.

Similarly, the North American Electric Reliability Corporation (NERC) differentiates baseload generation from the characteristics of generation that provide reliable baseload power. Baseload generation is that which has the lowest cost to run and is therefore dispatched first. For example, coal-fired and nuclear power generation are designed to have low operations and maintenance (O&M) costs and run continuously. These steam-driven generators are considered to be reliable, though, because they have fewer outage hours and lower exposure to fuel supply-chain issues.[23]

It is critical that some portion of the electricity power generation fleet has these high-reliability characteristics typical of "baseload generation" to ensure the reliability and resiliency of the bulk power system, even if these resources are not serving as baseload.

The Impacts of Climate Change on Electricity Infrastructure

Climate change is altering weather patterns and increasing the frequency and intensity of major storm events. Extreme weather can damage and impair infrastructure for electricity generation, transmission, and distribution--causing outages, costly repairs, and wildfires.

California has seen these impacts firsthand in spite of its efforts to understand, adapt to, and plan for future climate- and weather-related disasters.[24]

According to the *Statewide Summary Report* from California's Fourth Climate Change Assessment, released in August 2018, "peak runoff in the Sacramento River occurs nearly a month earlier now than in the first half of the last century, glaciers in the Sierra Nevada have lost an average of 70 percent of their area since the start of the 20th century," and "a relatively small number of wildfires caused much of the damage that occurred to California's electricity grid between 2001 and 2016."[25]

Extreme Temperatures. California is increasingly susceptible to extreme heat events;[26] these could impact the power sector in a number of detrimental ways. Extreme heat can exacerbate drought conditions, and hot, dry conditions increase the threat of wildfires. Extreme heat may also cause electricity equipment, such as powerlines, to sag and come into contact with the surrounding environment, causing wildfires. Wildfires, in turn, can damage and disrupt electricity infrastructure. Extreme temperatures during heat waves also reduce the output capacity and efficiency of gas-fired combustion turbines just when they are needed most to meet peak demand.[27]

Wind Pattern Changes. There are several interrelated effects between extreme temperatures and wind. Heat waves are usually accompanied by stationary high-pressure zones, which can cause lighter surface winds.[28] This could severely impact electricity output from the state's large wind generation system. On the other hand, extreme storm events can cause high winds that can damage electricity transmission infrastructure, causing outages and necessitating costly repairs.[29]

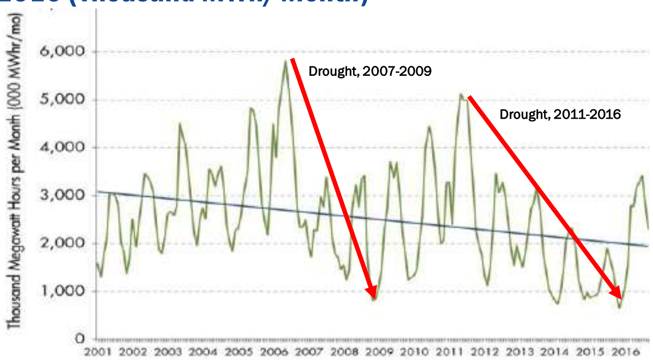
Availability of Hydro. Climate-related drought is especially important for hydroelectric power generation. California's in-state hydropower generation capacity is 12.3 GW, providing around 15 percent of state's total generation in 2016. As a benchmark, the U.S. hydropower fleet represents 7 percent of total electricity installed capacity and 6 percent of annual consumption. While large hydro is not counted as a renewable resource under California's RPS, local publicly-owned utilities that get at least 40 percent of their power from large hydro can count that power toward their RPS requirements.

Most of California's hydro capacity is along the Sierra Nevada range, with additional concentrated pockets in the Los Angeles Basin and along the Mexican border in Imperial County.[30] The hydropower subsector of the Electricity sector in California includes six pumped-storage plants, scattered throughout the state. In addition, 4.5 TWh of electricity from large hydro was imported from the Northwest, and another 1.5 TWh of electricity from (mostly) large hydro was imported from the Southwest, most of which was produced at Hoover Dam. Historically, California has imported electricity from large hydro plants in the Pacific Northwest to help meet summer peak loads and to balance wind and solar intermittency.

As noted, hydro generation is subject to weather and climate fluctuations and has historically peaked in the spring and summer months. A 2018 analysis concluded that between 2007 and 2009—a period of significant drought—hydro generation fell from a peak of 18 percent of California's total generation to about 13 percent, with monthly hydro production falling from 5,000 MWh/month to less than 1,000 MWh/month. In the most recent and more severe drought, hydro generation fell to less than 7 percent of total generation. Figure 2-8 shows the reduced levels of average monthly hydro generation in California and the substantial variability of hydro production.[31]

Figure 2-8

Total In-State Hydro Generation, Water Years 2001-2016 (Thousand MWh/Month)



Average monthly hydro generation varied by nearly 5,000 MWh/month between 2007 and 2009 and 4,000 MWh/month between 2011 and 2016 due to droughts. Source: Pacific Institute, 2017.

Current projections of climate change impacts across California and the Pacific Northwest suggest that future weather will deliver less total water and snowpack across the entire West Coast and in more concentrated weather events (whether in the form of heavy precipitation events or severe drought). This could mean that traditional hydro generation cannot be relied on as a reliable replacement for lower levels of fossil-based generation.

Technologies Covered by California's Renewables Portfolio Standard

The growth of renewable generation technologies in California has already helped reduce emissions from the Electricity sector.[32] California's RPS covers public utilities and other sellers of electricity to retail customers, requiring them to procure a share of the electricity they sell to end-use customers from renewables. The generation technologies covered by the state's RPS are discussed in this section first, followed by further analysis of some of the associated challenges, using a bottom-up model detailed below. California's RPS identifies a set of zero-emissions generation technologies,[a] the unique features of which create the potential for, and place constraints on, their contributions toward California's increasingly stringent RPS targets.

Geothermal

Geothermal is a cost-effective, non-intermittent, zero-carbon resource covered by California's RPS, and has been utilized since the 1960s. It traditionally serves as a baseload resource.[33] Geothermal generation has a capacity factor of around 75 percent nationally,[34] but around 50 percent in California.[35]

There are three types of geothermal plants in California. Direct dry steam plants use geothermal steam to directly spin a turbine. Flash plants rapidly vaporize very-high temperature fluids to turn a turbine. Binary-cycle plants use moderate-temperature fluids

[a] California's RPS includes the following zero-emissions resources: wind, solar, geothermal, biomass and small hydro.

to heat another liquid that then runs the turbine. Siting remains a significant constraint for geothermal plants (primarily because the best geothermal resources occur in a limited set of areas), and there have only been two new projects since 2000.[36] EIA estimates that the LCOE of geothermal projects coming online in 2023 is $41.0 per MWh, one of the lowest-cost resources available. Costs are expected to stay relatively level out to 2040.[37]

Between 2001 and 2016, actual geothermal generation in California declined by 14 percent, and generation capacity over that period remained flat. This decline in generation could be attributable to aging plants (the average age of active geothermal plants in California is 31 years, and several date back to the 1970s). The lack of new capacity to replace that generation is due to the difficulties in finding sites where the geothermal resources are sufficient for cost-effective new generation.[38,39] According to the Department of Energy (DOE), the challenges of building new geothermal resources in California are both technical and market-oriented.[40] Each geothermal project is tailored to the specific subsurface characteristics of its geothermal resource, which sometimes presents challenges to project development.[41]

In 2017, though, the LADWP contracted for up to 150 MW of geothermal generation in a 26-year power purchase agreement. The project, which combines three different geothermal sites, is expected to have a 95 percent capacity factor[42] and deliver power at $75.50 per MWh.[43] In addition, the 2017 California Public Utilities Commission (CPUC) capacity expansion models forecast 1,808 MW of new geothermal resources coming online.[44] Because geothermal generation can coincide with peak demand, it is likely that new geothermal generation will have higher energy and capacity value than new solar generation. This difference between the energy and capacity value of new geothermal and new solar deployment is expected to grow in the future.[45]

California is experimenting with combining geothermal power generation with mineral extraction to improve project-level economics. Specifically, the CEC is working with SRI International to extract lithium from geothermal brines of California's Salton Sea region.[46] While there are technical challenges for lithium extraction from geothermal brines, the simultaneous extraction of useful lithium for other energy applications (e.g., batteries), while utilizing the system for power generation, could make this combination cost-effective in a wide variety of locations. Already, California produces the most geothermal electric power of any state in the United States and more than 20 percent of worldwide production of geothermal electricity.[47] Improved project economics, along with advanced technologies for resource development and extraction,[48] and site availability could enable geothermal to play an expanded role in California's decarbonized future.

Small Hydro

Hydroelectric power is one of the major sources of California's electricity generation. California classifies hydro installations under 30 MW as "small hydro," and counts them as an RPS-eligible resource.[49] Total installed in-state small hydro capacity is 1.7 GW;[50] another 1.45 TWh of small hydro was imported from the Northwest in 2017.[51]

Capacity factors for hydro power vary widely as they are affected by weather, climate factors, local site characteristics, project type, and operational decisions. California's small-hydro capacity factor has varied from 16 percent to 46 percent in the last decade.[52] Overall, California's small-hydro resources had a capacity factor of 42 percent in 2017,[53] compared to the U.S. median capacity factor of 38.1 percent for all hydropower from 2005-2016.[54] Variation in capacity factors across hydroelectric generation plants is not unusual--one-fifth of hydro plants in the United States (of any size) operate at capacity factors outside the range of 25 percent to 75 percent.[55]

Hydro is one of the most inexpensive resources on an LCOE basis, at $39.1 per MWh for new generation resources expected to enter into service in 2023. Costs are expected to rise in the future, to $49.6 per MWh for generation resources entering into service in 2040,[56] in part because the most cost-effective hydro sites will have already been used.

Biomass

Biomass electricity generation uses waste products, such as wood and wood processing wastes, agricultural crops and waste, food waste, and animal manure, to generate electricity. There was 5.9 GWh of biomass generation in California in 2016 (1.9 percent of California's total in-state generation). While biomass generation is dispatchable, the plants used to date are not highly flexible and cannot ramp or cycle output levels quickly. Capacity factors for biomass generation vary by feedstock. Over the period from 2013 to 2018, capacity factors have ranged nationally from 68.0 percent to 73.3 percent for landfill gas and MSW and from 49.3 percent to 58.9 percent for other biomass sources, such as wood.[57] In 2017, the average capacity factor for all biomass generation in California was 50.6 percent.[58]

Like geothermal plants, there has not been a significant build-out of biomass plants in California; only five new plants have come online since 2003. EIA estimates that the average LCOE for biomass plants expected to enter into service in 2023 is $92.2 per MWh—more than onshore wind or solar PV. These costs are expected to decline slightly for generation resources entering into service in 2040.[59]

There are important uncertainties related to biomass pathways. These include feedstock availability, emissions benefits with and without CCUS, competing demands for feedstocks, and the cost of purpose-grown and imported feedstocks or biofuels.

Solar PV

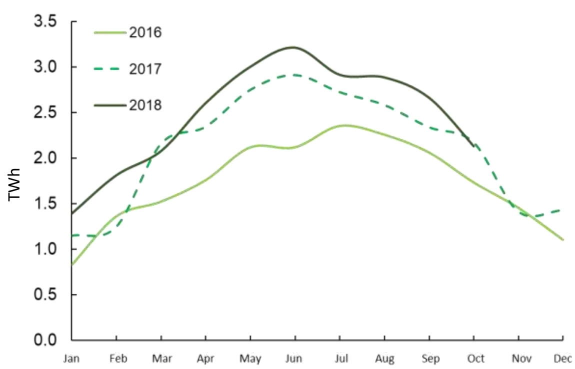
California has one of the largest solar resource potentials in the United States.[60] Most of the state has a resource potential of 6.0 kWh/m^2/day or higher. Solar generation in California comes in four forms: utility-scale PV; distributed behind-the-meter (usually rooftop) PV; commercial and industrial PV; and concentrated solar power (CSP). Statewide, 90 percent of solar deployments since 2010 have been PV systems (21.9 TWh). The remaining 10 percent of solar generation (2.5 TWh) has been from four CSP plants.

Solar also has one of the lowest capacity factors relative to other forms of renewable generation. Over the period from 2013 to 2018, solar PV capacity factors have been around 25 percent nationally, and solar thermal capacity factors have ranged between 19.8 percent and 23.6 percent.[61] In 2017, the average capacity factor in California for solar PV was 26.0 percent.[62]

Rapid deployment of solar generation over the last decade has corresponded with steep cost declines of solar PV (falling roughly 73 percent since 2010[63]), as well as with subsidies and policies that have supported the installation of distributed PV across California. Cost declines are expected to continue, reaching $52.7 per MWh (excluding any tax credits) for generation resources entering into service in 2040, a 13 percent reduction from the cost of plants in development today.[64] CSP costs have not been able to keep pace with dramatic cost declines in solar PV, raising questions about future prospects for CSP.

Stand-alone solar generation sources, though, vary as a function of insolation and do not fully match customer load patterns. High levels of PV penetration raise several operational and reliability issues, which will be discussed in detail below. The majority of California's solar PV has been built in the Central Valley, while most of the state's load centers are along the coast in the west and south.[65] Because the location of a good deal of PV resources is at some distance from the major load centers, and without access to adequate storage, these resources may have to be curtailed in the morning, when demand is off peak.

Figure 2-9
California Metered Solar Generation, January 2016-October 2018



Metered solar has grown significantly since 2016, reaching a maximum instantaneous solar generation of 10.7 GW in 2018.
Source: EFI, 2019. Compiled using data from CAISO, 2018.

Figure 2-9 shows the substantial growth in metered solar generation over the last three years (January 2016 to October 2018), with significant seasonal variation in each year. Regardless of installed capacity, California's solar generation experiences significant month-to-month variation.

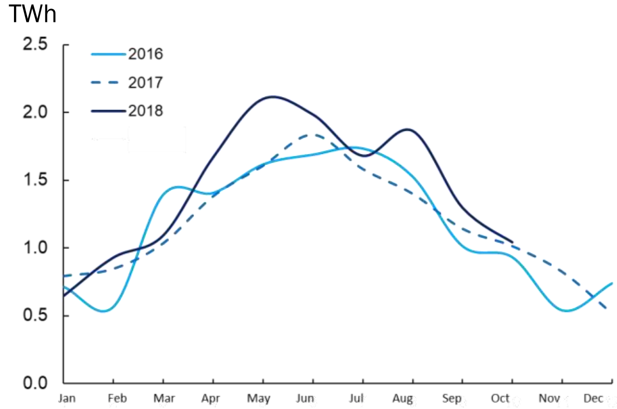
Wind

Wind has grown from 1.5 percent of California's generation in 2007 to around 7 percent in 2016. Wind generation shares many of the same challenges as solar, including intermittency and misalignment with customer loads. It also has land-use issues. Over the period from 2013 to 2018, onshore wind capacity factors in the United States have ranged from 32.2 percent to 37.4 percent, and in 2017,[66] the California average was below this range at 26.1 percent.[67]

The variation in wind generation on any given day can be substantial in both absolute scale and timing. California's onshore wind generation, like hydro and solar, peaks in the summer and hits its lowest point in the winter (Figure 2-10).

Figure 2-10

Smoothed Hourly California Wind Generation for October 2016-September 2018



Wind generation varies significantly on a seasonal basis as evidenced by the 3,500 MW difference between generation on January 1, 2017 and on June 1, 2017. Source: EFI, 2019. Compiled using data from CAISO, 2018.

The land required for a large-scale build-out of onshore wind is an important factor to consider as California taps its sizeable potential wind resources. The highest quality wind resource (greater than seven meters per second) is concentrated in California's south and northeast, with other highest quality resources in the Bay Area.[68]

The land-use requirements for wind generation vary from 30 acres per MW to 44.7 acres per MW, for small (<10 kilowatts [kW]) to large (10 MW) systems, respectively, according to NREL. This is much larger than NREL's estimates for solar PV, which range from 3.2 acres per MW to 6.1 acres per MW, depending on the size of the array.[69] If California meets its 60 percent RPS target by 2030 with a renewable generation profile similar to that in 2016 (37 percent wind, 63 percent solar), the state will need to increase its wind generation by 57 percent over 2016 levels (or 32 TWh).[b] Assuming this increase is met entirely with generation that is in-state and onshore, California's wind generation by 2030 could require between 250,000 and 400,000 additional acres of land. To put this in perspective, there are about 100 million acres of land in California, with 43 million acres in use for agriculture.[70]

As noted, California is examining offshore wind opportunities. In October 2018, the federal Bureau of Ocean Energy Management articulated a multiyear planning process for development of offshore wind, including planning and analysis, leasing, site assessment, and construction and development. Comments for this process closed at the end of January 2019.[71] Offshore wind generation is attractive because it is more consistent, provides additional supply at night when solar and onshore wind generation decrease, has higher capacity factors (an operational installation in the United Kingdom has observed a capacity factor of 65 percent),[72] and can be sited closer to load centers than onshore resources.

The EIA projects offshore wind to cost $130.4 per MWh for projects coming online in 2023, compared to only $55.9 per MWh for onshore wind projects (neither includes

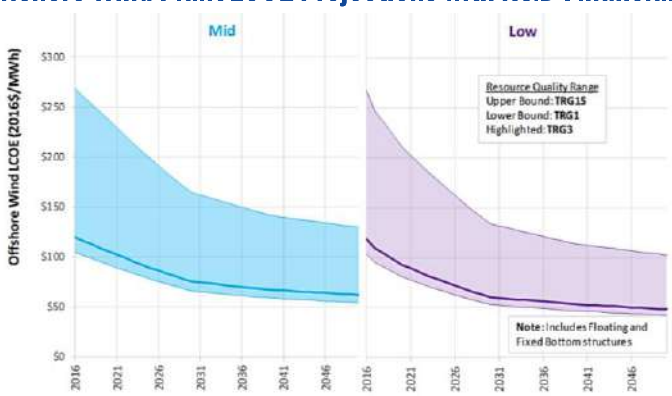
[b] Calculated using data from CAISO which provided hourly wind/solar output for Nov. 2016 to October 2017. Total wind output in this data was 13.8 TWh. To reach a 60% RPS target expanding wind and solar in the same ratio as 2016 generation, assuming an annual growth rate of 1.07% (given by CEC mid-case estimate), 31.9 TWh of wind is needed.

storage although higher capacity factors for offshore wind could limit storage needs).[73] The pricing bids for the Vineyard Wind Project off the coast of Massachusetts at $84.23 per MWh are already on the low end of that range.[74]

Figure 2-11 shows results from an NREL study that included a detailed analysis of offshore wind cost, including floating offshore wind platforms.[75] According to this analysis, 95 percent of the technical offshore wind resources in California are in water too deep for fixed bottom wind generation.[76] A follow-on NREL study concluded that "offshore wind power plant LCOE estimates continue to decrease. The fixed-bottom reference project offshore estimate is $124/MWh, and the floating substructure reference project estimate is $146/MWh. More recent European project bids or 'strike prices' suggest that costs for offshore wind could fall further in the coming years."[77] Another analysis, by the American Jobs Project, concluded that the installation of 18 GW of offshore wind by 2045 would create 17,500 jobs.[78]

Figure 2-11

Offshore Wind Plant LCOE Projections with R&D Financials



The R&D-Only LCOE sensitivity cases present the range of LCOE based on financial conditions that are held constant over time unless research and development (R&D) affects them, and they reflect different levels of technology risk. This case excludes effects of tax reform, tax credits, technology-specific tariffs, and changing interest rates over time. Source: NREL, 2018.

At the same time, siting has been a major issue in other parts of the United States where offshore wind projects have taken over 15 years to overcome local opposition to development. Floating platforms are envisaged to be 12 miles offshore in California, which could mitigate the level of public siting opposition experienced in other parts of the United States. One of the key stakeholders in California offshore energy development—the U.S. Navy—has taken the position that areas off the southern and central coasts of California that are adjacent to large demand centers, should be restricted to offshore wind development.[79]

On balance, floating offshore wind in California could make contributions to 2030 decarbonization targets and provide significant emissions reductions for meeting 2050 targets. Floating offshore wind technology is discussed in greater detail in Chapter 8.

Reference Frame for SB 100's 2030 Renewables Target

As noted, Senate Bill 100, enacted in September 2018, established major milestones for California's clean energy transformation. In 2016, the baseline year for this analysis, total electricity use in California was 291 TWh; SB 100-eligible renewables supplied roughly 25 percent of that total. Assuming an electricity demand growth rate of 1.27 percent per year, total electricity demand will be 347 TWh by 2030. Meeting SB 100 targets for renewables by 2030 would require adding 208 TWh of generation from eligible renewable resources, 2.8 times the 2016 level.

While this may seem formidable, simple arithmetic suggests that the goal is achievable. Solar generation has increased on average by 5.4 TWh per year since 2016. If this pace is sustained, solar generation would meet half of the 2030 goal. The annual addition of one GW of additional wind capacity with an average capacity factor of 40 percent (this could include some offshore wind with higher capacity factors), would meet 40 percent of the SB 100 goal. Imports of electricity from wind and solar generation in other states could also contribute to the goal, an option that underscores the value of a regional electricity grid. Generation from other eligible renewables (geothermal, small hydro, biomass), if they remain constant, would take total generation from renewables very close to the 60 percent goal. There will most certainly be opportunities for closing the small remaining gap, such as a small uptick in annual solar additions.

This estimate suggests that the 60 percent RPS goal is theoretically achievable; however, this simple analysis needs to be backed up by more fine-grained analysis that takes into account grid dynamics and reliability. That is the focus of the remainder of this chapter.

Electricity System's Operational Characteristics

Much of the electricity analysis in this section is based on the modeling work done using the Sustainable Energy Systems Analysis Modeling Environment (SESAME).[80] This tool (described in Box 2-2) informed the analysis of electricity system impacts of California policies and regulations on the Electricity sector and shaped the development of many of the clean energy technology pathways described in this chapter.

Challenges of High Penetration of Intermittent Renewables

Intermittent wind and solar provide almost 17 percent of California's current generation, driven in large part by policy choices to address climate change, energy security, and other environmental concerns (rooftop solar is responsible for an additional 5 to 6 percent).

The intermittency and variability of wind and solar raise operational concerns. The associated battery storage needs are currently difficult to value and cannot meet all the issues of reliability, cost, capacity, and security that arise from the seasonal, weekly, and daily variability of these resources. The operational situation is made more complex by the estimated 13.6 TWh[81] of behind-the-meter PV that was generated in 2018—roughly 6 percent of total in-state generation on the grid and 14 percent of all in-state renewable generation.[82] This behind-the-meter resource is non-curtailable because is it not controlled by or directly visible to grid operators.

Box 2-2

Sustainable Energy Systems Analysis Modeling Environment (SESAME)

SESAME is a software platform developed by researchers at the MIT Energy Initiative. Its purpose is to enable the comprehensive assessment of cost and sustainability for energy systems serving the Electricity, Transportation, and Industry sectors of the U.S. economy. These sectors are increasingly converging with one another and require modeling that can provide a detailed understanding of both their own technological, operational, time-dependent, and geospatial characteristics, and the corresponding characteristics of the energy systems supporting them.

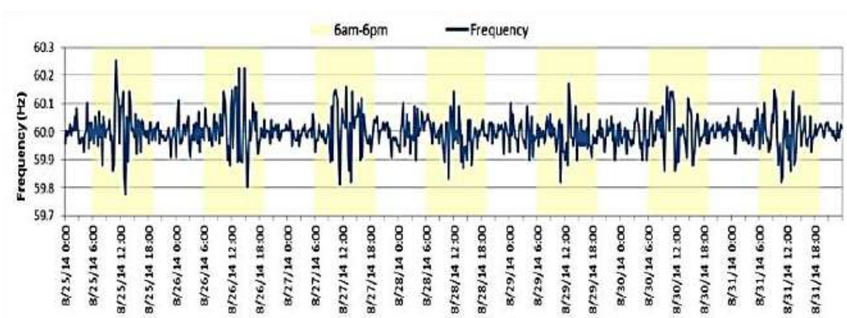
The goal of using SESAME frameworks in this report is to use a single analytical engine to develop insights that can be used by a spectrum of users with diverse needs. SESAME's ability to provide optimized solutions that achieve multiple objectives, at both the pathway level and the systems level, gives it the ability to discover non-obvious solutions to problems facing the global energy system. In doing so, SESAME is able to draw on its built-in capabilities for techno-economic assessment. SESAME can be used to simulate relevant building blocks that are crucial in the design of the U.S. energy system and to test their sensitivity to external factors that are not currently reflected as either costs or benefits in the energy system. Because it is both comprehensive in coverage and highly detailed in its focus on specific interactions, SESAME is a powerful analytical tool for guiding strategic, policy, regulatory, and commercial decision-making.

Embedded in SESAME are detailed representations of the U.S. Electricity and Transportation sectors. SESAME's power-system model includes hourly load profiles of every U.S. generator with a capacity of more than 25 MW, based on historical EPA data from 2005 to 2017. This allows for the assessment of power generation at the hourly-generator level of resolution. The SESAME power-system model captures changes in the operational profiles of various types of generator and also identifies the attributes of reliable and low-carbon power systems. The integration of high-resolution real-world data into SESAME allows it to rigorously analyze new solutions, such as the hybridization of gas turbine units with battery energy storage. For a given assumption about costs, SESAME simulates observed power generation profiles with hybrid solutions and optimizes them to minimize both the system cost and the overall environmental footprint.

Moment-to-Moment Frequency and Voltage Excursions. Depending on the size of an electric power system, frequency typically must stay within a narrow band around 60 Hertz (Hz). Data indicate that during periods of high solar output, the magnitude of frequency deviations from 60 Hz can be significant (Figure 2-12). This can affect local voltage levels and system frequency, which could damage grid infrastructure, cut customer service, and damage some customer equipment. This can be addressed with smart inverters that could automatically handle most local frequency and local voltage issues.

Figure 2-12

System Frequency Across Time in Kauai Island Utility Cooperative, August 2014



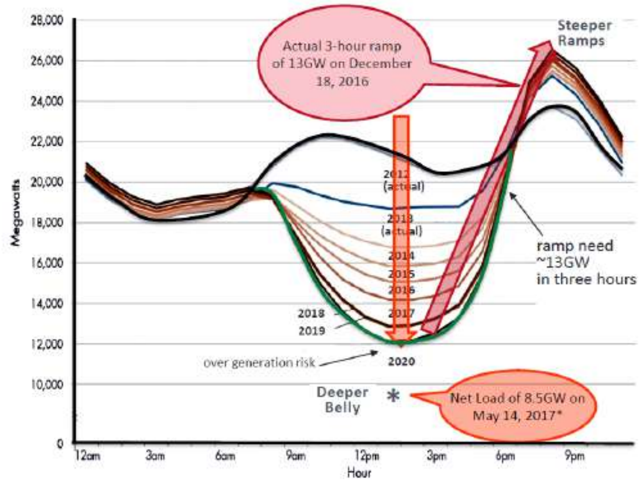
System frequency from a distribution node on the island of Kauai in Hawaii is highly variable during the period of 6am to 6pm with a high penetration of solar. Source: Hawaii State Energy Office, 2014.

Recently, the California Independent System Operator (CAISO) performed a test with NREL and First Solar, by dispatching solar-generated electricity with advanced power controls to provide automatic generation control and frequency regulation, droop response, and reactive power controls.[83] The test's conclusions noted that advances in smart inverter technologies, when paired with advanced plant controls, could support solar PV in providing regulation, voltage support, and frequency response—all services to enhance reliability. The project team's next steps will include identification of "potential barriers to providing essential reliability services to make these services operationally feasible,"[84] pointing to the need for appropriate tariff structures, and a range of systemwide analyses to enhance reliability using these technologies.

Over-Production, Under-Production, and the Duck Curve. In settings with a high penetration of non-curtailable solar generation, peak solar output to the system does not coincide with the peak demand on the system, and total available generation may exceed total customer electricity demand. This raises two operational problems.

First, solar output declines precipitously as the sun sets; this decline coincides with the time at which system demand is rising. This "Duck Curve" pattern, a well-known phenomenon, is seen in Figure 2-13.[85] The figure shows that, in 2016, California's resource mix and growing PV generation created the need for 13 GW of ramping capability over three hours to serve peak demand. Most of this ramping capability is presently served through generation rather than moderated by customer demand response (DR), although improved DR technologies may reduce the burden on generation in the future.

Figure 2-13
The California Duck Curve

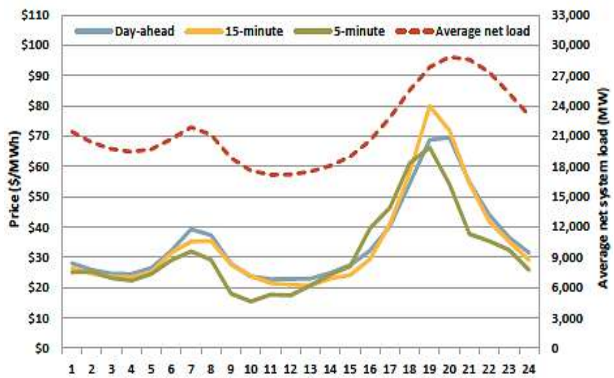


The "Duck Curve" phenomenon shows the difference between the amount of electricity demand and the amount of available solar generation over the course of a day. Source: EFI, 2019. Compiled using data from DOE Solar Energy Technologies Office, 2017.

Second, if PV and other generation (e.g., run-of-river hydro) are not curtailed, high solar output will drive energy prices down (and they may become negative) and force the grid operator to curtail whatever sources can be reduced (e.g., imports, hydro, thermal generation operating above minimum load levels, and customer DR).

Figure 2-14

California Hourly System Energy Prices, 2017



Hourly electricity prices increase with net load in the evening as solar generation decreases and demand increases. Source: CAISO, 2017.

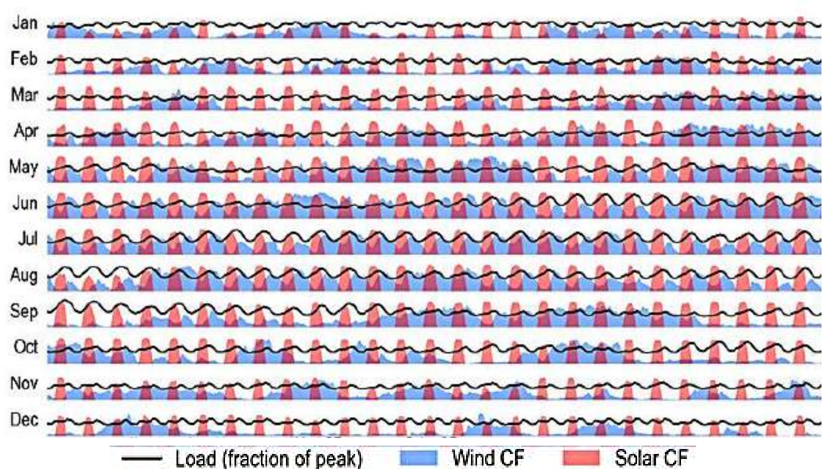
These impacts are reflected in CAISO system energy prices (Figure 2-14).[86] The peak for CAISO's net load (i.e., its customer electricity demand, net of uncurtailable wind and solar generation) has moved out to 8:00 p.m., and the system has steep ramping requirements to bring on more generation to meet that peak net load. While this is managed today using some storage and gas-fired peaking generation plants, increased penetration of intermittent renewables could exacerbate this phenomenon in the future, and policies for deep decarbonization could change both the technical options and the requirements for its management.

Seasonal Variability of Wind, Solar (and Hydro). A system with a high penetration of renewables must anticipate potential monthly or seasonal shortcomings in renewable output because wind, solar, and hydro resource availabilities are not complementary. For instance, recent California solar production was only 1.5 TWh in January 2018 but reached 3.2 TWh in June 2018. As noted earlier, wind and hydro resources demonstrate comparable seasonal variations. This factor will be dramatically exacerbated if and when solar becomes a much larger share of generation.

Figure 2-15 shows California's wind and solar generation and load for each day in 2017. It reveals the differing patterns of wind (blue) and red

Figure 2-15

California Hourly Trends in Solar and Wind Generation Normalized to Total Capacity, 2017



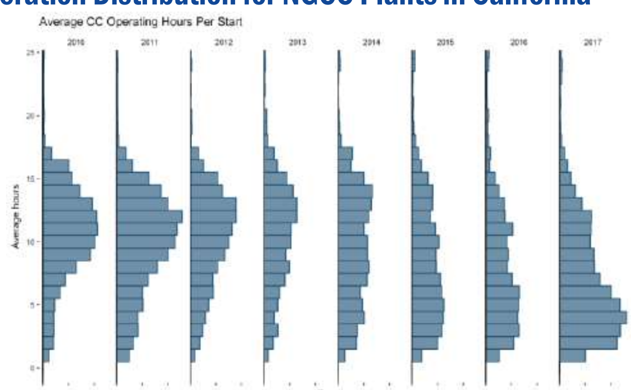
Hourly solar and wind generation in California superimposed with the peak load for every hour in 2017 shows significant renewable power generation variability; therefore, large-scale dependence on wind and solar will require very large backup options. Source: EFI, 2019. Compiled using data from CAISO, 2017.

(solar) production across the year, including 90 days with little to no wind generation. The figure shows days in January, February, November, and December on which wind and solar combined could not meet peak demand, and several periods of seven to ten days with little or no wind generation (most likely from an inadequate wind resource on those days, although wind system constraints, e.g., transmission congestion, are an alternative, if less likely, explanation for these gaps in wind generation). The length of the gaps in wind availability to the system raises a range of issues, including the adequacy of even the longest-duration storage; the placement of energy storage on the electric grid; the need for redundant, fuel-supported generation; overall system management; and the potential role for, and benefits of, a regional grid.

Changes in Operations and Use of NGCC Plants. Today, power systems are built around flexible generation, primarily natural gas generation that is able to modulate output in real-time to meet daily or weekly oscillations. Of particular value is the ability to store and transport natural gas to the locations where and when it needs to be converted to electricity. These attributes reduce systemwide costs, increase efficiency, enable greater penetration of renewable resources, and improve grid reliability. As renewable penetration increases, the role of natural gas plants begins to shift. SESAME modeling results illustrate that the operation of NGCC plants shifts in response to increasing solar penetration.

Figure 2-16

Operation Distribution for NGCC Plants in California



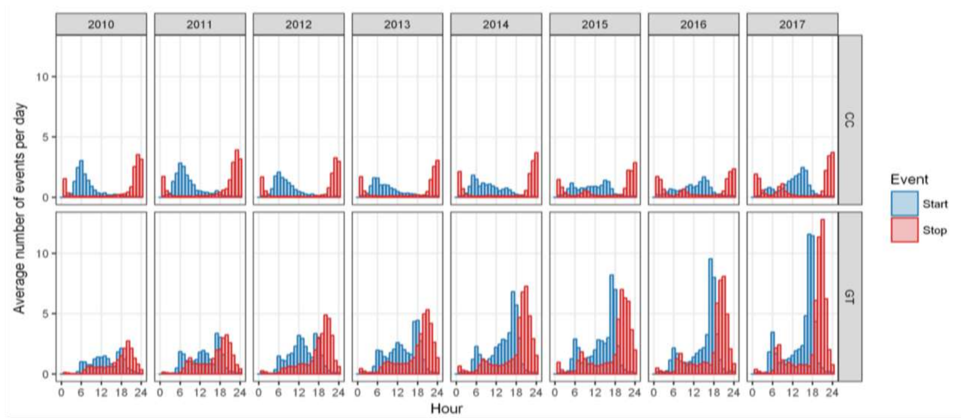
The change in natural gas combined-cycle (NGCC) operation duration distribution for instances less than 24 hours. Source: EFI, 2019. Compiled using data from EPA CEMS, 2010-2017 and EIA, 2010-2017.

In particular, when there is significant solar generation, gas plants have more start-stop cycles (Figure 2-16) and run at their optimal operation zone (i.e., with higher efficiency) for shorter periods of time in order to meet ramping requirements that emerge from the intermittent and variable system peak load and peak solar output.

These operational shifts are less efficient and result in higher GHG emissions. Under a best-case scenario, they result in a 15 percent increase in fleet emissions, relative to same power output generated at the peak efficiency of the same power generation units; total emissions from natural gas plants rise from 38.22 $MMTCO_2e$ to 44 $MMTCO_2e$. This phenomenon is illustrated in Figure 2-17, which shows changes in the distribution of NGCC operating hours over time.

Figure 2-17

Average Start and Stop Events per Day by Hour

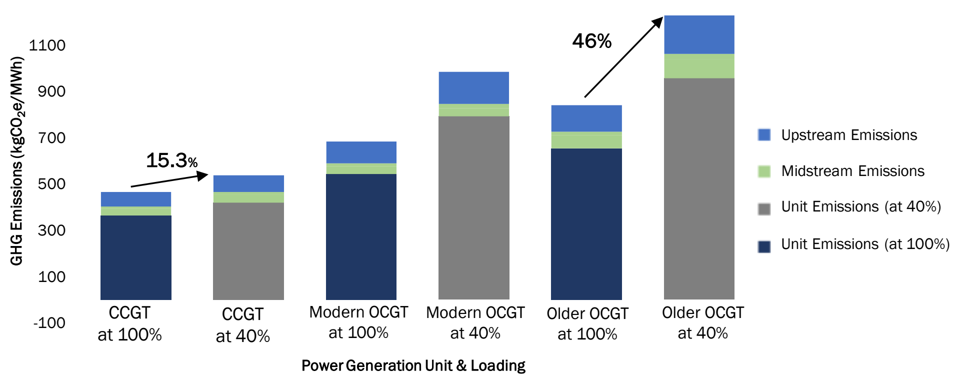


Hourly average start and stop events per day for combined-cycle (CC) and gas turbine (GT) units in CAISO showing CC unit starts shifting to afternoon hours and an increase in the total number of GT unit start-ups. Source: EFI, 2019. Compiled using data from EPA CEMS, 2010-2017 and EIA, 2010-2017.

Significant changes in plant-level operations have a range of complex performance and emissions consequences. Figure 2-18 shows increases in carbon intensity of three types of natural gas generation units as solar penetration increases.

Figure 2-18

Emissions Intensity of California Natural Gas Fleet with Increasing Levels of Solar Penetration

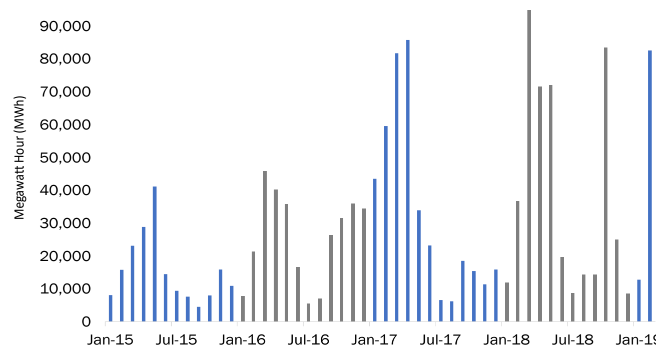


The emissions intensity of combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) units is greater at lower loading (40 percent of capacity) operation than at peak. Source: EFI using SESAME, 2019.

In addition to the emissions from the stock of power plants, lifecycle emissions include emissions associated with the extraction, separation, compression, and transportation of the natural gas. Specifically, emissions from a combined-cycle gas turbine (CCGT) increase 15.3 percent when going from peak process loading to 40 percent of peak, while an older open-cycle (OCGT) emits up to 46 percent more per megawatt-hour operating at 40 percent of peak than when operating consistently at or near capacity.

Managing Curtailments. Because intermittent renewable generation is not dispatchable, there are periods of substantial over-supply, particularly in the middle of the day. Other generation must be curtailed during these times (Figure 2-19). These curtailments can be significant—as high as 94,000 MWh in March 2018.[87] There are several options for managing curtailments and other operational issues associated with intermittent renewable generation, including participation in CAISO's Western Energy Imbalance Market, battery storage, varying hydro-generation, and demand response.

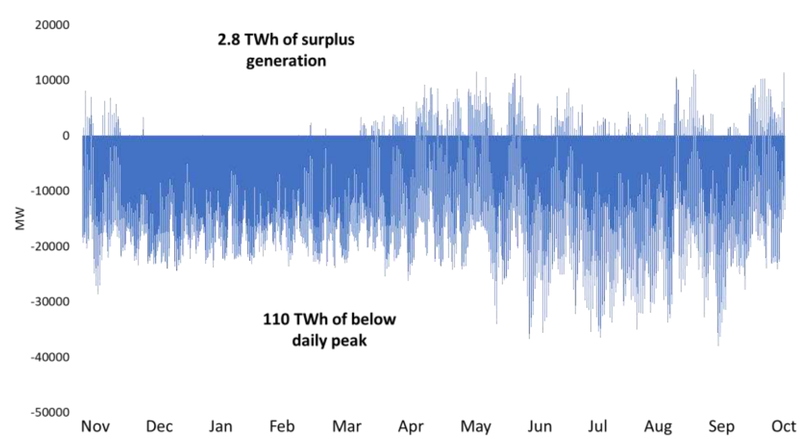
Figure 2-19
Wind and Solar Curtailments in California by Month, January 2015-February 2019



Annual curtailments of wind and solar have increased as additional renewable capacity has been added in California, with a maximum total of 94,778 MWh curtailed in March 2018. Source: EFI, 2019. Compiled using data from CAISO, 2019.

As California's share of renewables in the total electricity mix increases, there is expected to be an even larger oversupply of renewables.[88] As noted, electricity demand growth is expected to be 1.27 percent per year through 2030. Assuming California meets its 60 percent RPS by 2030 with similar load and generation profiles as today, there is significant potential for hourly mismatches between output from renewables and electricity demand (Figure 2-20). Assuming a frictionless transmission and distribution system, meeting the 60 percent RPS with wind and solar will result in 2.8 TWh of surplus generation over the course of a year. This is a conservative projection since the localized surpluses, where transmission and distribution infrastructure may be unavailable to move the power to demand centers, could be much higher.

Figure 2-20
Projected Renewables Excess Generation and Shortfall at 60% RPS

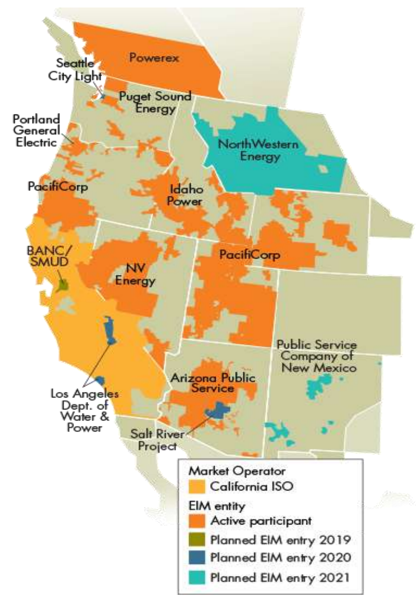


Assuming similar load and generation profiles in 2030 compared to today, there could be 2.8 TWh of surplus generation and 110 TWh of shortfall below daily peak over the course of a year. Source: EFI, 2019.

The Western Energy Imbalance Market. CAISO's Western Energy Imbalance Market (WEIM) is a real-time bulk power trading market—the first of its kind in the western United States. WEIM was designed to promote system reliability and flexibility, including helping CAISO address the challenges associated with integrating the growing penetration of intermittent renewable generation. WEIM's role has been described as a "response to the growing challenges of changing electricity markets, especially in managing the short-term dynamics of efficient operation of the grid in the presence of increasing penetration of intermittent renewable energy generation."[89]

WEIM is a real-time bulk power platform, where buyers and sellers can trade the difference between the day-ahead forecast of energy production and the actual energy produced in each hour to meet demand.[90] This enables greater grid flexibility because it allows intra-hour trading and gives producers of renewable and other generation a chance to sell their output at low real-time prices to potential buyers across the entire western interconnection, rather than having excess generation automatically curtailed. The WEIM was started in late 2014. As of the end of 2018, it had eight market participants in eight states and provinces outside of California; six more participants, including the Sacramento Municipal Utility District and LADWP in California, are expected to be added by 2021 (Figure 2-21). Its electricity trades have averaged 8.8 TWh per year, with an additional 6.2 TWh of wheel-through transfers.[91] To put this in perspective, the overall annual net generation in the territory served by the Western Electricity Coordinating Council (WECC) is over 830 TWh.[92]

Figure 2-21
WEIM Active and Planned Participants



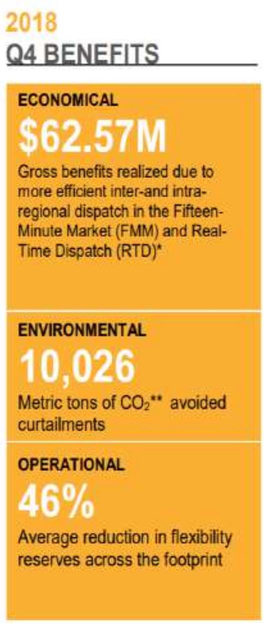
The WEIM had eight market participants in eight states and provinces outside of California as of 2018, with six others expected to be added in 2019-2021. Source: CAISO WEIM, 2018.

Because WEIM broadens member access to generation from a larger geographic area, it reduces the curtailment of low-cost renewable generation. These sales are likely replacing less clean energy sources (although it is also likely that those savings are coming at a cost to other generators and regions).

WEIM's environmental benefits to participants are calculated on the basis of avoided curtailments of renewable resources.[93] According reports from CAISO, WEIM has resulted in avoided renewable curtailments of an average of 189 GWh per year, or 758 GWh cumulatively since its inception.[94] To put this in perspective, over the same time period, total curtailments of wind and solar in California averaged 339 GWh per year, and 1358 GWh cumulatively. In its Fourth Quarter 2018 report on WEIM benefits, CAISO estimated that avoided renewable curtailments over WEIM's lifespan have reduced carbon dioxide (CO_2) emissions by over 324,000 $MMTCO_2e$, using a flat rate for emissions avoidance.[95]

As of January 2019, WEIM has delivered $564.88 million in benefits to participants (with $147.14 million for CAISO alone).[96] These benefits include cost savings from not having to run more-expensive local generators, and from competition across a larger market area where real-time, lower-priced generation is available for load balancing (Figure 2-22). The WEIM also enhances grid reliability by improving the sharing of information about electric transmission operating conditions and by better managing congestion across the Western Interconnection's 38 balancing areas.

Figure 2-22
WEIM Benefit Estimates, Fourth Quarter 2018



As of Q4 2018, WEIM participants have saved money, avoided curtailments, therefore avoiding additional emissions, and reduced flexibility reserves. Source: CAISO WEIM, 2018.

WEIM is relatively new and is still a work in progress. There are several issues WEIM is working on: concerns that its benefits disproportionately accrue to California; that there has been "resource shuffling" (defined as "…any plan, scheme, or artifice to receive credit based on emissions reductions that have no occurred, involving the delivery of electricity to the California grid");[97] and "import leakage," in which high-carbon imports are used to replace lower-carbon local resources. CAISO is in the process of finalizing a three-year strategic planning effort, the drivers of which include the need to continue improving WEIM as it expands and extending day-ahead market enhancements beyond California to bring regional benefits to the other balancing areas.[98]

Regionalization. The creation of a broader regional power market for the WECC region, a structure that exists in most other parts of the United States, has been under discussion in California and other states. A bill supported by then-Governor Brown to push California toward regionalization (AB 813)[99] was proposed in 2018, but died without being voted on.[100] Governor Brown also promoted regionalization efforts during the unveiling of his full carbon-neutrality executive order, Executive Order B-55-18,[101] arguing that it would be necessary for deep decarbonization.[102] California stakeholders are divided about the potential benefits and costs of a regional power market. Regionalization could provide an opportunity for California to access additional clean energy resources for meeting the SB 100 goals; it might also mean loss of regulatory authority by the CPUC. Many groups opposed AB 813, which would have established such a market.[103] Creation of a full western regional market is not wholly up to California, which contains 33 percent of the Western Interconnection's electric load[104,105] but only 21.1 percent of its electricity generation resources.[106,107]

Role and Value of Energy Storage Technology

Electricity storage is a catch-all term for a collection of technologies that are used to align the supply and demand of electricity. The main types of storage technologies are the following:

- Electrochemical storage, which includes different types of lithium-ion batteries, as well as other batteries of various chemistries
- Mechanical storage, which stores energy as potential energy through various means, and includes pumped hydro storage (the energy storage technology with the most currently deployed capacity), compressed air energy storage, and flywheels
- Thermal storage, which utilizes heat or cold as the medium for storage, and includes ice energy, chilled water, and molten salts
- Chemical storage, such as hydrogen, which likely will not be ready for deployment at-scale in the 2030 timeframe

These technologies will be key for transitioning to a deeply decarbonized grid, helping to meet some of the challenges of incorporating high levels of variable renewables and improving the performance of fossil-fuel generating infrastructure (Table 2-1). Storage represents one possible set of solutions for replacing carbon-rich NGCC generation as a load-following resource. However, the ability of different electricity storage technologies varies across the spectrum of charging-discharging duration and technological maturity.

Table 2-1
Uses of Energy Storage

Electricity Production	Essential Reliability Services	Transmission	Distribution	Customer
• Real-time energy production • Peaker replacement • Firming service when paired with a renewable plant • Hybrid systems with a generator to supplement peak capacity • Reduce CO_2 emissions by offsetting high-emissions generation *(including hybrid storage to smooth coal plant cycle)*	• Flexible ramping services • Primary frequency response *(synthetic inertia)* • Frequency regulation • Black-start capability • Voltage support	• Bulk transmission asset deferral • Transmission congestion relief • Decentralize reliability to put less pressure on the bulk power system to perform against all contingencies • Soak up excess PV generation to manage grid Duck Curve	• Distribution feeder peak-shaving • Increase feeder-hosting capability • Distribution capacity expansion deferral • Local reliability protection against outages • Distribution voltage support • Distribution loss reduction • Mitigation of local grid events and extreme load profiles • Manage zonal congestion	• Demand charge management • Dynamic load management for demand response, time-of-use pricing • Load-shift to absorb on-site PV generation • Power quality management • Emergency back-up power *(reliability service)*

California policy envisions a large role for electricity storage as a primary resource for frequency regulation and load-following. In accordance with AB 2514 (enacted in 2010),[108] the CPUC mandated that the state's investor-owned utilities (IOUs) procure and construct 1.3 GW of electricity storage by 2024.[109] Already, the utilities have announced over 1.5 GW of storage projects, and 332 MW are online.[110] In addition, electricity storage has been supported through the Self-Generation Incentive Program (SGIP) and accounts for two-thirds of the $567 million SGIP budget.

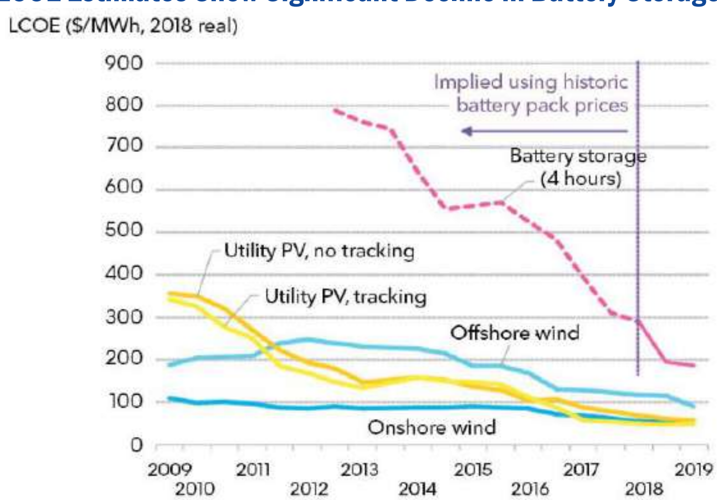
Battery Storage Technologies. The costs of various electricity storage technologies have improved over time as a result of extensive research and development and a growing demand for energy storage services[111,112] (particularly for customer reliability and resilience). As with most other technologies, as the technology matures and sales volumes increase, effective project costs fall. For example, pumped-hydro and lead-acid systems have matured, and their cost trajectories remain flat, while the costs of flow batteries are falling with maturation.

The costs of battery storage technologies can be reported in terms of their dollars per MWh stored (i.e., the full energy capacity of the system in MWh), calculated as the total project cost divided by the total energy capacity of the system. This is appropriate when energy storage is being considered on a standalone basis.[113] They can also be calculated as traditional levelized costs of energy, with additional assumptions about a battery's use throughout a year.

Figure 2-23 depicts results of a review of existing projects worldwide. The LCOE was calculated for the average 4-hour lithium-ion battery storage system, running at a daily cycle that includes charging costs at 60 percent of the wholesale base power price in each country. In 2018, the LCOE was estimated at $300 per MWh, excluding the PV system.[114] While still quite high, this is half the cost of the same system only five years ago. Their near-term forecast has the LCOE continuing to decline in the next few years.

Figure 2-23

LCOE Estimates Show Significant Decline in Battery Storage



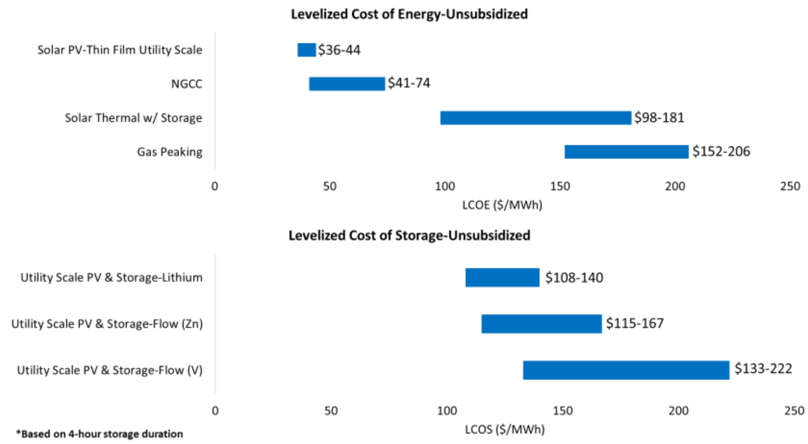
According to BNEF, the global benchmark is a country-weighted average using the latest annual capacity additions. The storage LCOE is reflective of a utility-scale lithium-ion system running at a daily cycle and includes charging assumed to be 60 percent of the wholesale base power price in each country. Source: BNEF, 2019.

Lazard developed an analysis of the levelized cost of storage (LCOS) that includes observed costs and revenue streams associated with existing energy storage projects. Select LCOE and LCOS data from Lazard are compared to NGCC costs in Figure 2-24 below.[115,116] Because wind and solar have low to zero direct marginal costs, they are generally dispatched first in today's markets. This keeps marginal electricity prices low but diminishes investment incentives for baseload or intermediate generation (this may include utility-scale storage). Intermittent renewables also impose system integration costs through ancillary or reliability services. Other storage costs are discussed later in this chapter.

In this example, there are numerous potential sources of revenue available to storage systems, depending on the market structures in which the battery systems exist. In the CAISO wholesale market,[117] where energy storage can collect revenue for providing services for arbitrage, frequency regulation, spinning/non-spinning reserves, and resource adequacy, a lithium-based energy storage system is estimated to cost between $204 and $298 per MWh.[118]

Figure 2-24

Levelized Costs of Energy and Storage (Unsubsidized)



Although the costs of solar PV have dropped below that of NGCC, when factoring in the cost of storage, solar PV & lithium or flow batteries is more expensive than NGCC, but less than gas peaking. Source: EFI, 2019. Compiled using data from Lazard, 2018a; Lazard 2018b.

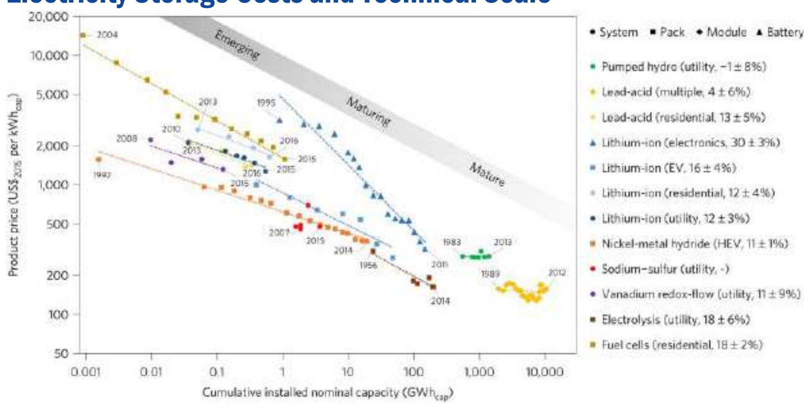
While these levelized costs remain significantly higher other electricity supply technologies, lithium-ion batteries are becoming an energy storage market leader with project announcements totaling 694.5 MW (2,403 MWh), or 47 percent of non-pumped-hydro projects. Lithium-ion technology is likely to be the primary electricity storage technology deployed through 2030. This is due in part to its cost profile, which benefits from manufacturing economies of scale, as well as the fact that battery installations can be standardized and because battery projects can be economic for both small and distributed, and large and utility-scale, applications.

Challenges of Battery Storage. Storage is essential for managing the intermittency of wind and solar generation. There are, however, a number of key battery storage challenges that grid operators, policymakers, and regulators must address.

The first is cost. While costs of the various battery storage technologies have dramatically declined, as depicted in Figure 2-24, the Lazard analyses concluded that the cost of generation from a solar-plus-storage project substantially exceeded the cost of NGCC generation. Hybrid solar-and-storage systems are not yet economic for utility-scale or residential systems even though hybrid systems are increasingly sold to residential customers for reliability benefits; prices are high and the ability to monetize behind the meter storage is limited to reducing peak demand, arbitraging real-time energy prices, and in some places, serving as a regulation resource in the wholesale market.[119] On the residential level, the value is often derived from replacing a conventional back-up generator. Figure 2-25 shows a broad selection of electricity storage system costs and levels of technical readiness.[120]

Figure 2-25

Electricity Storage Costs and Technical Scale

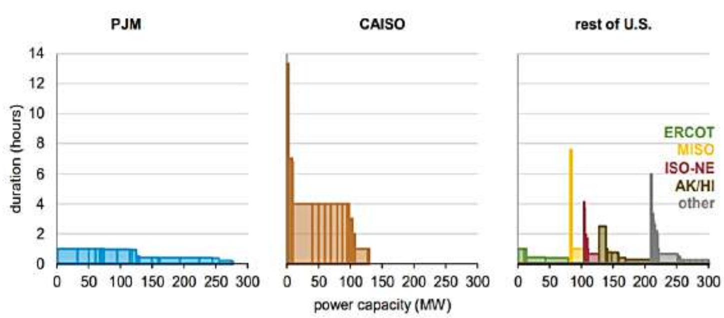


A comparison of product price for eleven electricity storage technologies shows the variable timescales required for these technologies to become economically competitive. Source: Schmidt, Hawkes, Gambhir, and Staffell, 2017.

The second challenge is the duration of existing battery systems. As seen in Figure 2-26, utility-scale battery storage in CAISO has relatively limited duration. According to EIA, "large-scale battery storage installations in CAISO have an average power capacity of five MW and an average duration of four hours."[121] While storage in CAISO is of longer duration than in PJM (where storage appears to be used for frequency regulation), it is inadequate to support the state's intermittent renewables when, as noted and shown in Figure 2-15, there are periods of seven to ten days when there was little to no wind generation.

Figure 2-26

Power Capacity and Duration of Large-Scale Battery Storage by Region, 2017



Long-duration battery storage in CAISO is typically used for reliability and has small power capacity, while PJM has shorter-duration installations with much greater capacities used for frequency regulation.

Note: Preliminary estimates; duration calculated by dividing nameplate capacity by maximum discharge rate. Source: EIA Form 860, 2018.

Lithium-ion batteries, the current technology of choice, are ill-suited for longer-duration storage applications, because they experience significant capacity fade when the batteries are deeply cycled (i.e., from full charge to empty). Unlike short-duration energy storage technologies—where lithium-ion batteries are well-established, tested, scaled, and deployed—longer-duration batteries and thermal storage opportunities are not yet proven solutions. Flow batteries currently represent 2 percent of projects in California. There is one on-going compressed-air storage project—a

300 MW (3000 MWh) system funded by the American Recovery and Reinvestment Act and the CPUC in 2009,[122] and a thermal energy storage company, Ice Energy, has received a number of project orders from Southern California Edison.[123]

Finally, the peak power output of battery systems is the monetizable asset, not the energy capacity (i.e., the peak power multiplied by the duration of the battery). However, in the context of decarbonization, it is precisely the energy capacity of the battery that is necessary to offset the energy that would otherwise be produced from natural gas-fired generation. Much of the monetizable value of energy storage comes from the nameplate power capacity of the system, whether it is utilized to defer transmission and distribution upgrades, used behind-the-meter to reduce demand charges, or utilized as a capacity resource in wholesale energy markets for frequency regulation. In these applications, storage is required to provide power to the system for short durations of times, often one to two hours to reduce peak. As a result, it is the nameplate power capacity of the storage system that is valued, not its energy capacity. In short, the potential value of five- to ten-hour energy storage is not monetizable in today’s markets.

Currently, the only way to monetize the energy portion of a grid-scale battery would be to conduct energy arbitrage in the wholesale energy market. However, as the duration of battery storage increases, the margins for its arbitrage decrease, resulting in diminishing returns for each additional hour of system duration. Ultimately, energy storage developers will be paying a premium for additional energy capacity, with limited opportunity to monetize it. Policy and regulatory mechanisms to more specifically align energy storage value with energy applications are discussed in Box 2-3.

Battery storage deployment could be inhibited by the incongruence between the value storage can provide and the value that is monetizable in California’s wholesale electricity market. DR and storage inherently reduce the magnitude and duration of energy price spikes and therefore reduce the amount of extra revenue above marginal production costs available to recover the capital costs of new energy sources. Utility-scale energy storage projects can participate in CAISO energy markets, arbitraging low and high electricity costs, but these potential revenues alone are often insufficient to warrant the capital investment required for a utility-scale energy storage system. It is probable that over the short term, many new storage projects will be uneconomical on purely energy-market terms, but offer value in non-market terms, such as transmission support or reliability protection for critical customer and critical community loads.

Box 2-3

Procuring and Valuing Storage in California Today

Delivering adequate levels of renewables and associated demand response, storage, and longer-duration, highly flexible electricity sources is difficult with California's current market structure. The marginal cost of electricity production for wind and solar (distributed or utility-scale) is near-zero, so a wholesale electricity market that clears bid-based locational marginal pricing will drive prices at zero (or below, depending on the availability of investment and production tax credits and transmission congestion patterns). This makes it difficult for generators, storage, or DR providers to earn back their capital costs. CAISO noted that the combined net revenues to a combined-cycle gas unit from energy and ancillary services in 2017 might only reach $50/kW-year, well below its fixed and operating costs. This will pose a problem for storage project cost recovery as well as natural gas units.[124]

CAISO has energy and some ancillary services markets but no clear-cut way to monetize generation capacity value, because it lacks capacity markets other than bilateral contracts between load-serving entities or end users and storage providers. As noted, the state, in AB 2514, placed requirements on IOUs for storage acquisition.[125] It does not, however, offer incentives for the utility to operate storage to realize its total potential value.

The Federal Energy Regulatory Commission (FERC) issued Order 841 in February 2018. It is designed "to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets" operated by regional transmission organizations (RTOs) and independent system operators (ISOs). It would specifically require each RTO and ISO to "revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets… [to] ensure that a resource using the participation model is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing." The Order also requires "that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer… [and] account for the physical and operational characteristics of electric storage resources through bidding parameters or other means… [and] establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW." Compliance filings for Order 841 by RTOs and ISOs were due to FERC on December 4, 2018, but it will likely take another year or two before these RTO and ISO filings are approved and implemented.[126]

The final challenge, which is not yet acute but could become an issue in the future, relates to the supply chains for battery component materials, including lithium and cobalt. These elements are used in almost all utility-scale batteries and vehicle batteries today. Box 2-4 describes some of the key issues that should be considered with the development of markets for battery storage technologies.

Going forward, adequately valuing and monetizing battery storage may require an unbundling of all market services provided by energy storage systems, to ensure that they are appropriately compensated. To ensure adequate valuation of these new technologies, it is likely that all resources that provide these or similar services would have to be clearly defined and compensated on technology-neutral, performance-based terms.

Box 2-4

Critical Materials for Battery Storage Technologies

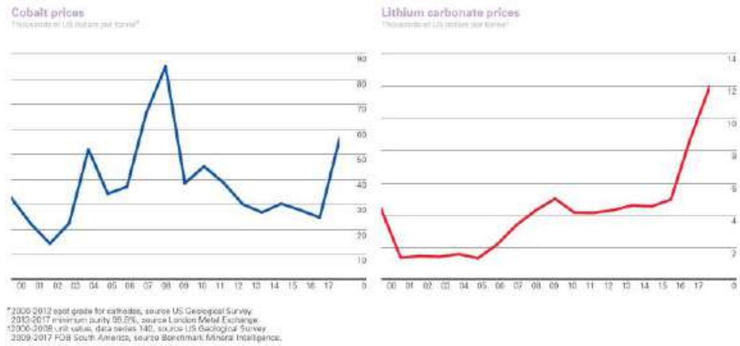
Supply Risks

Numerous battery chemistries support the technology pathways described in this chapter, but many of them are dependent on two raw materials: lithium and cobalt. Important risks that must be considered in clean energy pathways that are dependent on these raw materials.

First, global supplies of lithium and cobalt are highly concentrated in a few regions. Global lithium reserves are concentrated in South America (Argentina, Bolivia, and Chile), followed by other amounts in China and Australia. Nearly half of all global cobalt reserves—and 60 percent of production—are in the Democratic Republic of the Congo (DRC). Australia, Cuba, and Canada are the other primary sources of cobalt, but 90 percent of cobalt refining takes place in China. It is important to note that major human-rights concerns exist about the working conditions in cobalt mines in the DRC.

Figure 2-27

Prices for Cobalt and Lithium Carbonate ($1,000/metric ton)



While cobalt prices have fluctuated since the early 2000s, lithium carbonate prices gradually increased since 2001, with a sharp increase from 2015 to 2017. Source: BP, 2018.

Second, global demand growth for these materials has far outpaced production, leading to price volatility and fears that resource shortages may appear. Between 2010 and 2017, demand for lithium and cobalt grew by 74 percent and 91 percent, respectively,[127] while production growth was 70 percent[128] and 25 percent.[129] In 2017, global production of lithium carbonate equivalent (LCE)[c] and cobalt was 230,000 metric ton (230 kt) and 110 kt, respectively[130], while demand for these raw materials was 214 kt and 136 kt.[131] A tightening market for these raw materials has led to a doubling in prices from 2016 to 2017 (Figure 2-27).[132] Because nearly all lithium is produced as a primary product, it is likely to be responsive to price; however, less than 10 percent of cobalt is produced as a primary product—it is usually produced as a by-product of copper and nickel—making cobalt production inherently limited by demand for copper and nickel.

Another important risk is that global battery production capacity is becoming highly concentrated in one country: China. While batteries accounted for 41 percent of global lithium demand and 30 percent of global cobalt demand in 2017, they are likely to increase significantly due to increased interests in battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs), and grid-scale battery storage systems that help backstop variable renewable energy resources. According to one assessment, by 2025, batteries could account for 76 percent and 53 percent of global lithium and cobalt demand, respectively.[133]

Managing the Risks of Lithium and Cobalt for Clean Energy Pathways

While new battery chemistries are being pursued across all applications, the need for some lithium and cobalt for BEVs and PHEVs is likely to continue for the foreseeable future. Because cobalt faces more supply and price risks than lithium, companies have begun to try to reduce cobalt use in their batteries. Tesla batteries, produced by Panasonic, use a nickel-cobalt-aluminum (NCA) mix that uses only about 4.5 kg of cobalt per (75 kilowatt-hour [kWh]) battery.[134] Many other companies use a nickel-manganese-cobalt (NMC) mix with about 12 kg of cobalt per (55-kWh) battery.[135] NMC batteries have a lower energy density than NCAs, but are less expensive.[136] Tesla has stated an intention to fully phase out cobalt from its batteries,[137] and NMC manufacturers are attempting to develop a new mix that has half the cobalt content of current batteries.[138] Chinese manufacturer BYD uses lithium-iron-phosphate batteries. These batteries have no cobalt but also have a lower energy density, limiting the range of vehicles that use them.[139] Innovations in battery chemistry will be important to California's decarbonization goals. California plans to deploy five million ZEVs by 2030 and a large share of these are likely to be BEVs. If all five million are BEVs and use current NMC technology, they would require 37 kt of LCE and 60 kt of cobalt by 2030.[140] This amount of lithium is 0.04 percent of global reserves in 2017;[141] the cobalt required to meet this demand would account for 8.5 percent of global reserves.[142]

For grid storage lithium-ion systems, energy density is less of a concern than it is for vehicles. As a result, these systems can use battery chemistries with lower densities but greater safety and durability, as well as with lower reliance on cobalt. For example, the NCA batteries used in Tesla vehicles are relatively rare in grid storage applications. NMC batteries are the more common cobalt-based variety, as they are one of the least expensive options. Other systems that are widely deployed in the United States today include lithium iron phosphate and lithium titanate systems, which contain no cobalt.

Pumped Hydro. Pumped-storage hydropower (PSH) is an electricity load-serving and peak-shaving technology that was first used in the United States in 1929.[143] It could assist California with growing issues in grid operations, as more intermittent renewable generation is added to the grid. PSH utilizes electricity during periods of overgeneration and when prices are low to move water to an upper reservoir, where it is stored until electricity is demanded. When electricity demand is high, the stored water is released downhill through turbines, which generate electricity similar to conventional hydropower resources.[144] Although it takes more electricity to pump the water uphill than it generates flowing downhill, this process uses low or no-cost electricity (i.e., renewable generation that would otherwise be curtailed) to provide valuable energy when demand peaks and prices are high. This generates significant monetary value from otherwise unvalued resources.

Table 2-2
Existing California Pumped-Storage Hydropower Plants

Company	Plant Name	Capacity (MW)	Gross MWh	Net MWh
LADWP	Castaic	1,682	565,568	356,945
PG&E	Helms	1,212	872,197	-289,278
San Diego County Water Authority	Lake Hodges Station	40	58,192	-24,078
SCE	Eastwood	199	425,142	425,142

Source: CEC, 2017.

The efficiency of these full-cycle systems is greater than 80 percent; this is comparable to other storage technologies.[145] PSH is currently more mature than other battery technologies and its installed cost is among the lowest of all bulk energy storage technologies (starting at approximately $1,700 per KW installed).[146] Additionally, PSH can charge or discharge for longer durations than other forms of storage.

PSH is currently the main bulk storage technology utilized in California.[147] There are four operational PSH sites with a collective capacity of more than 3,100 MW (Table 2-2).[148] As of January 2018, there were five additional pumped hydro projects under development in California, which, if successful, would add an additional 3,700 MW of storage capacity (Figure 2-28). A 1,000 MW-sized PSH project would cost between $1,700/kW and $2,500/kW.[149]

Figure 2-28
Operational and Planned PSH Plants

California currently has 3,133 MW of operating PSH capacity and an additional 3,780 MW under development. Source: EFI, 2019.

[c] Note: All lithium measurements are in metric ton of lithium carbonate equivalent (LCE), the industry-standard method for measuring lithium. The conversion factor for lithium to LCE is 5.323.

Five other proposed PSH plants were either cancelled or failed to obtain a FERC license and saw their preliminary permit expire.[d] This highlights a major obstacle to PSH deployment: lengthy regulatory timelines of three to five years because PSH projects must have a FERC license, in addition to other state and federal permits. It took five years for FERC to issue the license for the Eagle Mountain Project, and the project developer, Eagle Crest Energy, expects an additional six years for engineering, planning, and construction. Also, current market structures may not recognize the full market value of PSH resources.

Looking to midcentury, there are many uncertainties regarding snowpack, melt, rain, and other weather patterns that will impact water volumes that would be available to a PSH reservoir. PSH may, however, be less impacted by climate change than traditional hydropower, because PSH systems are not integrated with rivers and are less vulnerable to changes in snowpack melt. PSH systems can also be constructed underground and tunnels can be insulated by natural features, which protect the infrastructure from weather events.[150]

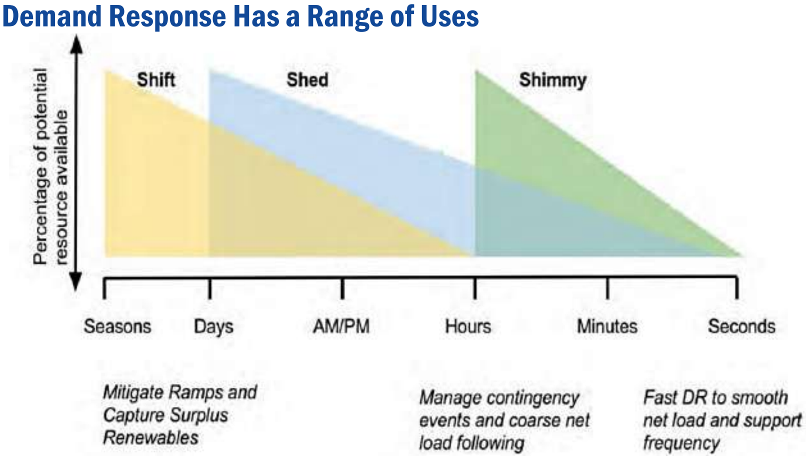
Overall, PSH is a viable technology that could assist California in reaching its climate and RPS goals, while ensuring electricity system reliability. Although regulatory and financial hurdles exist, PSH is a proven technology that has served Californians for more than 30 years and could continue to provide critical electricity services in the years to come.

Demand Response. The opportunity for DR in California spans various electricity market applications from providing fast-response ancillary services such as frequency regulation to shifting capacity from peak hours to off-peak hours or shedding capacity on peak for up to a few hours (Figure 2-29). All of these DR activities provide significant value to the electricity system through reducing peak loads or maintaining system reliability, and ultimately reducing costs for consumers. In short, the value of DR extends beyond simply the decarbonization potential of the resource.

The level of emissions-reduction potential from DR is a function of the relative elasticities of electricity demand, combined with the comparison of foregone revenue from reduced production in a commercial or industrial setting when the consumer

Figure 2-29

Demand Response Has a Range of Uses



Shift, shed, and shimmy provide a framework for valuing demand response. Source: LBNL, 2017.

[d] Data as of January 2018 from company websites. Canceled or suspended projects include: Pendleton South, Vandenberg East & West, Iowa Hill, Red Mountain Bar, and Mulqueeney Ranch.

is shedding or simply shifting demand. Importantly, the degree of emissions reduction potential of DR is acutely sensitive to the degree to which consumers are able to shed rather than shift (i.e., it is a function of what the demand curves look like).

The potential for DR in 2030 is estimated at 22 GWh of daily shift as well as 11 GW of peak shedding, based on analysis conducted by Lawrence Berkeley National Lab (LBNL).[151] These values are small in the context of California's total electricity consumption, but that comparison undervalues DR. DR's greatest value comes from being able to mitigate emissions, by tackling the times when more emissions-intensive generation is used. For example, the 22 GWh of daily shift represents 2.8 percent of the daily load in California in 2017 (800 GWh per day). That 22 GWh will likely be shifted from natural gas-fired generation to renewable resources, while also preventing some amount of the more emissions-intensive process of ramping natural gas units.

Meanwhile, the 11 GW of shedding resources represents 22 percent of the 50 GW peak that the California system reached on September 1, 2017, a day of record high temperatures and energy use in the state.[152] Eleven GW of shedding would also have brought the system well within its operational Resource Adequacy capacity of 45 GW, ensuring reliability without resorting to the large amount of imported generation in this instance.

Analysis Methodology

Table 2-3 summarizes the key assumptions and sources utilized in determining future emissions projections for the Electricity sector. Note that virtually all of the sector's emissions are from natural gas.

Table 2-3
Electricity Key Assumptions

Pathway	Subsector	Key Assumptions
Business-as-usual	All	Electricity demand growth (1.27 percent) based on CEC's medium growth rate; imported generation increases with increases in demand; all incremental imports from renewable generation. The baseline includes the 73,898 GWh of planned renewables expansion in the state, calculated from CEC utility plans.[153] In-state coal-based plants, petroleum-based plants, and nuclear power plants assumed to be zero by 2030.
NGCC-Electricity Storage Hybridization	Natural Gas	Existing cost and availability of energy storage technologies. Current electricity market design; natural gas fleet shifts toward lower capacity factors, with more start-stop cycles and less utilization between 2018 and 2030.
Decarbonized Imports	All	50 percent renewable energy targets adopted in states that export to California.
Intermittent Renewables + Short-Duration Battery Storage	Energy Storage	1,224 GWh from gas-fired plants that operate five hours per day or fewer and 5,252 GWh from open-cycle peaker gas generators (based on SESAME modeling) are replaced by 111 GW of intermittent renewables at 20 percent capacity factor and two to five-hour storage. Requires four to eleven GW of storage (depending on the distribution of storage capacities). Energy storage efficiency is 80 percent, across technology types.

Intermittent Renewables + Up to 10-Hour Storage	Energy Storage	10,360 GWh from gas-fired plants that operate six to 10-hours per day are displaced by 177 GW of intermittent renewables at 20 percent capacity factor and five to 10-hour storage. Requires three to five GW of storage (depending on the distribution of storage capacities). Energy storage efficiency is 80 percent, across technology types.
Doping Natural Gas with Clean Hydrogen (10 percent)	Natural Gas	Natural gas infrastructure can integrate 10-15 percent clean hydrogen as an additive.
Renewable Natural Gas Use	Natural Gas	Renewable natural gas (RNG) has the potential to replace 197 Bcf of conventional pipeline natural gas based RNG potential (in-state and imports) by 2030. Assumed one-third of that potential (65.6 Bcf) will be utilized in Electricity.
Natural Gas with CCUS	Natural Gas	90 percent capture rate for converted power plants. $264 per metric ton of CO_2 avoided cost, estimated based on doubling the reference price for new NGCC facilities ($117 per metric ton of CO_2 for capture; $2 per metric ton of CO_2 for transport; $13 per metric ton of CO_2 for storage), to account for uncertainty of retrofits. Capacity only includes those generating units with average capacity factor of at least 40 percent.
Demand Response	Efficiency	2030 DR estimate from Lawrence Berkeley National Labs, based on upper end of estimate: by 2030, 22 GWh of energy shifting and 11 GW of shedding. For the energy shifting, carbon intensity of off-peak generation is 40 percent of that of on-peak generation.

Emissions Trajectory Analysis for California's Electricity Sector

The business-as-usual scenario for this study examines the impact of demand growth on the Electricity sector's ability to achieve a 40 percent emissions reduction by 2030 and 80 percent by 2050 to contribute to California's economywide goal. This scenario assumes the following:

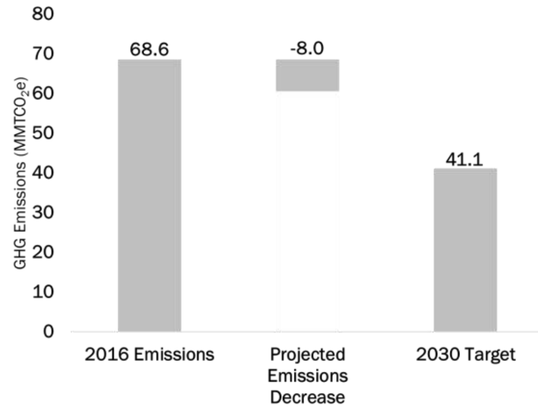
- California's emissions trajectory between 2016 and 2030 and between 2030 and 2050 reflects a 1.27 percent annual growth rate in electricity demand (the CEC's medium growth rate figure, which includes demand reductions associated with DR).
- Deployment of the 73,898 GWh of renewable resources that are currently planned through 2026 in California.[154] These additional resources are sufficient to meet the 1.27 percent annual growth in demand, while simultaneously replacing uneconomic in-state coal and petroleum-based plants, and politically nonviable nuclear, all of which are assumed to decline to negligible production in 2030.
- Imported generation increases commensurate with increases in demand, with all incremental imports sourced from new renewable generation (exclusive of large hydro).

The CEC's forecasts incorporate the state's on-going commitments to aggressive energy efficiency targets. While it is clear that the best way to reduce energy associated GHG emissions is to use less energy, in order to be conservative, this analysis neither assumes nor adds additional energy efficiency measures (beyond California's current projections) into the decarbonization solution set. Most of the energy efficiency improvements are experienced by the end-use sectors; these are not accounted for in the Electricity sector.

The business-as-usual scenario starts with California's emissions in 2016 of 68.6 $MMTCO_2e$ and has a target of 41.1 $MMTCO_2e$ by 2030—a reduction of 27.5 $MMTCO_2e$ over 14 years. In this business-as-usual case, California meets its electricity demand growth through the deployment of 73,898 GWh of renewable generation, all of which is currently in the queue for development, while simultaneously replacing coal, petroleum and nuclear, and offsetting 14,500 GWh of natural gas production. Cumulative in-state renewable generation increases to 130,000 GWh.

Figure 2-30

"Business as Usual" Electricity Emissions Reductions & 2030 Target ($MMTCO_2e$)



In the BAU scenario in which the sector's emissions are expected to decrease 8 $MMTCO_2e$, meeting a 40 percent reduction from 2016 levels by 2030 requires an additional reduction of 19.5 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

In this scenario, however, only a slight emissions reduction is achieved. Emissions fall by only 8 $MMTCO_2e$—from 68.6 $MMTCO_2e$ to 60.6 $MMTCO_2e$—because the operational changes required of the natural gas fleet, to accommodate dramatic increases in variable renewable generation, increases the carbon intensity of its generation (Figure 2-30). Under the business-as-usual pathway, California only delivers 47 percent of its electricity from renewable resources, falling short of the RPS goal, as well. These and other challenges are discussed in detail below.

Though the business-as-usual pathway falls short of meeting the 60 percent target, the target, as noted, is not out of reach. The section on "Reference Frame for SB 100's 2030 Renewables Target" shows how California's current trajectory, with slightly more aggressive additions of intermittent renewables, could reach 60 percent; this does not, however, address the associated grid operations issues. The pathways outlined below are designed in part to address these concerns while achieving deep decarbonization goals.

GHG Emissions Reduction Pathways

Optionality and flexibility of technology and policy portfolios and approaches will be needed to achieve deep decarbonization in the Electricity sector. The key to reducing carbon emissions across California's Electricity sector is finding technology pathways that decrease reliance on natural gas for load-following applications or limit natural gas plant carbon emissions by using CCUS with natural gas plants.

A range of technology options could help reduce emissions from Electricity. These options vary in their technology readiness, cost, and potential impact on emissions reduction.

- Pathway 1 reduces emissions through NGCC-electricity storage hybridization. This is a relatively near-term option to avoid increased emissions that stem from inefficient natural gas plant operation to meet the grid ramping requirements associated with high levels of renewable generation.
- Pathway 2 demonstrates the impact of decarbonizing electricity imports on California's total emissions.
- Pathways 3 and 4 replace certain natural gas peaking generators with the combination of renewables (wind and solar) and battery storage of varying durations.
- Pathways 5 and 6 reduce the carbon intensity of natural gas generation through fuel doping with hydrogen and renewable natural gas (RNG).
- Pathway 7 adds CCUS to a subset of the existing natural gas fleet.
- Pathway 8 reduces emissions through demand response from industrial and commercial consumers.

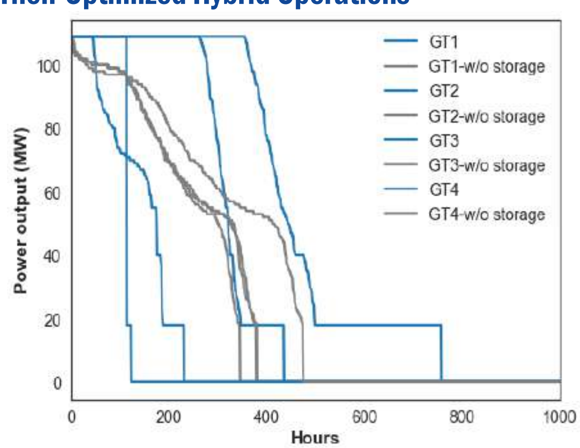
Pathway 1: NGCC-Electricity Storage Hybridization

Increasing emissions from the natural gas fleet, as described above, could be mitigated by pairing NGCC plants with electricity storage resources. In particular, adding a peak-scaled electricity storage unit next to a NGCC plant would enable the gas plant to shift some of the fast ramps onto the storage unit, enabling the host gas plant to operate at more consistent and efficient heat rates. The battery unit could be charged by low- and zero-cost off-peak electricity (as when PV generation peaks) rather than from the gas-fueled generator. With existing energy storage technologies and current market design, these projects are economic today and are being deployed.

A bottom-up hybrid gas-storage optimization model to investigate the dynamics of hybrid power plant systems was developed for this study; the results are seen in Figure 2-31. The base case assumptions use hourly load profiles of four OCGT units, each with a capacity of 109 MW, at an existing California power plant.

The hybrid system—consisting of the same OCGT units plus a 40MW-4hr lithium-ion battery—is designed to meet the same load profile while minimizing the operational cost and emissions of the power plant. The current plant load duration curves (in gray) show a wide operational range. The optimal profiles (in blue) show the hybrid storage-gas units

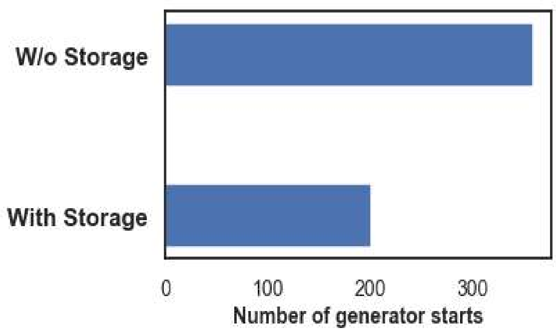
Figure 2-31
Load Duration Curves of Actual OCGT Units and Their Optimized Hybrid Operations



Observed load duration curves cover a wide range loads over the total, while the optimal profile shows a longer operation at the nameplate capacity of these units. Source: EFI using SESAME, 2019.

Figure 2-32

Number of Starts for Hybrid Versus Standalone OCGT Units



Adding storage resources to OCGT units can reduce the number of starts by nearly one-third, providing both economic and emissions reductions benefits. Source: EFI using SESAME, 2019.

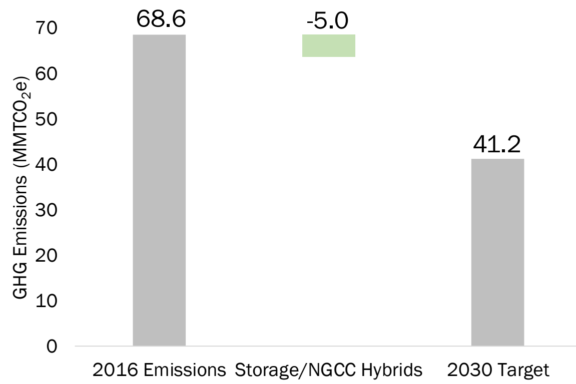
operating above the gas plant nameplate capacity, and the hybrid project is able to operate cost-competitively at the battery capacity rather than dropping to zero. The heat rate at minimum load is 70 percent higher than the heat rate at full load.

In addition to the longer operation at peak load, the hybrid gas-storage project shows a marked reduction in the number of generator starts—351 starts for the NGCC unit without storage and 206 starts for the hybrid solution with storage (Figure 2-32). Gas plants produce the highest emission intensity during start-up; hence this decrease in number of starts significantly decreases the plant's GHG emissions on average (per kWh) and in total (with more kWh generated, if the battery is charged during high renewable output periods).

This analysis concludes that hybridizing a natural gas plant with energy storage can rationalize and smooth the gas plant's cycling and ramping operational pattern and thus improve its ability and flexibility to follow net load. Ultimately, mitigating the increased carbon emissions from operational changes to the natural gas fleet through hybridization could reduce the Electricity sector's emissions by 5 $MMTCO_2e$ in 2030 (Figure 2-33).

Figure 2-33

NGCC-Electricity Storage Hybridization Pathway and 2030 Target ($MMTCO_2e$)

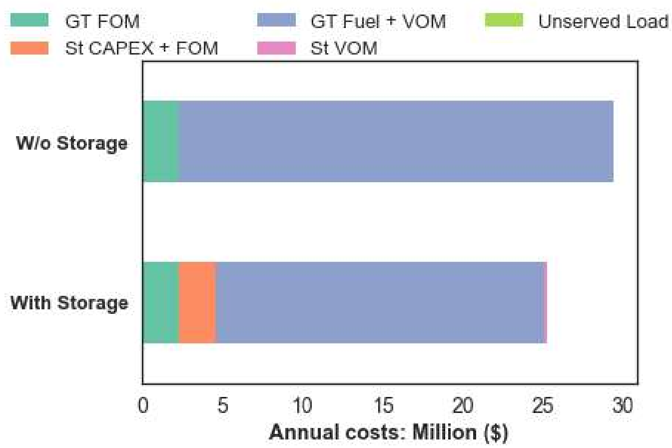


Combining NGCC plants with electricity storage resources allows the NGCC unit to operate more efficiency, therefore reducing emissions approximately 5 $MMTCO_2e$ by 2030. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

Such a hybrid project should enjoy lower overall O&M costs through shared services, reduce the plant's fuel consumption and CO_2 emissions, reduce transmission and distribution capital expenditures by shifting generation to meet peak, reduce system LCOE by improving the mix of renewables and thermal supply, and potentially provide battery storage for other uses as the system transitions. The optimal design has 20 percent lower

Figure 2-34
Annual Operating Cost of OCGT Plant and the Hybrid Plant

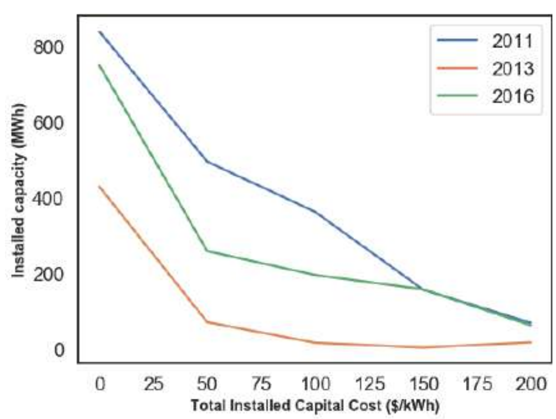


Adding storage to an OCGT plant enables it to operate more efficiently, which reduces fuel costs and provides an annual monetary savings of nearly $5 million. ***Note:*** *St: Storage, FOM and VOM: fixed and variable operating and maintenance costs.* Source: EFI using SESAME, 2019.

annual cost than the conventional OCGT plant (Figure 2-34). The cost reduction is mainly due to the lower fuel consumption as a result of the improved overall efficiency of the plant.

The optimal design of a hybrid plant, including the extent of its hybridization, changes depending on the load profile it is serving, which can be variable over time. Figure 2-35 summarizes a sensitivity analysis looking at the impact of installed capital cost of energy storage based on the load profiles of different years. The optimum energy storage deployment is higher at any price point for the 2011 load profile due to shorter duration of operation after each start event. The 2013 case displays longer runs/higher power outlets for every start; hence the benefit of energy storage is marginal. Under these circumstances, the model deploys very small capacity of energy storage, even at low capital costs. The 2016 case falls between duration levels of operation in the 2011 and 2013 cases, and so does its level of battery deployment.

Figure 2-35
Optimized Storage Installation Trends



A sensitivity analysis assessing the impact of installed capital cost on load profiles shows that installed capacity is sensitive to price variability, depending on the year. Source: EFI using SESAME, 2019.

Challenges to NGCC-Electricity Storage Hybridization Pathway

The challenges to significant expansion of NGCC-Electricity Storage Hybridization relates to the technology market fit between lithium-ion battery systems and the how these projects could be capitalized in the market. In certain geographies, these projects are viable today. Alternative market mechanisms that incentivize clean ramping technologies and/or long-duration batteries specifically will make opportunities for NGCC-Electricity Storage Hybridization more prevalent.

Pathway 2: Creating a Market for Decarbonized Imports

As noted, in 2016, California imported 92.3 TWh of electricity (accounting for 32 percent of the state's electricity use), 42.3 TWh from the Northwest and 49.9 TWh from the Southwest. In aggregate, only 20 percent of these imports (18.5 TWh) were considered renewable under California's RPS, though some of the imports came from other low-carbon sources such as large hydro and nuclear. Importing more low-carbon electricity from outside California may be an effective way for California to affordably decarbonize part of its Electricity sector. It may be cheaper, for example, for California to acquire wind from Wyoming and solar from Arizona. This would be especially important if land constraints push out the supply curve for wind and solar in California. Of course, California's ability to influence the carbon-content of its imports is limited, but potential opportunities exist through regionalization of the electric power markets. Development of an integrated Western Grid could help maximize California's imports of low-carbon electricity.

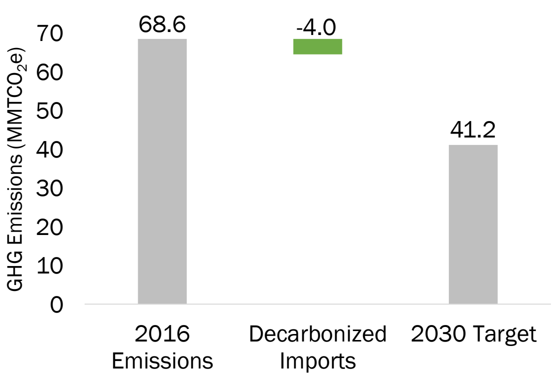
Imports into California are covered under its RPS, which regulates electricity delivered to consumers by load-serving entities in the state. California utilities already meet RPS requirements with resources from out of state: the three investor-owned utilities collectively have contracts with renewable installations in other states (plus Mexico and Canada) with 5.3 GW of capacity.[155] These projects, however, would not count under any RPS that their own states might establish.

Compliance with California's RPS is monitored through WECC's system for tracking renewable energy certificates (RECs), the Western Renewable Energy Generation Information System (WREGIS). Using a unified credit system is intended to prevent double-counting of RECs. A credit system also allows more flexibility with how renewable electricity is acquired. It need not come from generation with a transmission connection to California, but could come from replacement energy "bundled" with RECs (which can also be "firmed and shaped"—i.e., delivered to the appropriate California balancing authority in the same calendar year as the RPS generation, but not at the identical time of the RPS generation--to deal with intermittency and other issues), or from "unbundled" RECs on their own.[156] Another advantage of WREGIS is that additional renewable generation in other parts of WECC (driven by RPS's or other factors) will usually drive down the price of RECs, making it cheaper for California utilities to acquire renewable electricity.

The specifics of California's emissions accounting shape the impact that RPS's in neighboring states can have. Facility-specific emissions factors are calculated for specified imports (though specified imports of zero-carbon energy would not have any emissions at all). CARB's accounting of California's GHG emissions, though, includes 20 TWh of electricity and 9.7 $MMTCO_2e$ of emissions in 2016 that came from unspecified imports.[157] The CARB emissions factor for these imports is based on an estimate from the Western Climate Initiative[158] that has remained at 427 grams CO_2 per kWh since it was implemented in 2009 (along with similarly static factors for other GHGs).[159] Higher RPS's in other states could compel CARB to modify its emissions factor for unspecified imports, in order to more accurately reflect declining overall emissions for power generated in those states.

Currently, the RPS policies in states exporting energy to California vary. Some states do not have an RPS, and in others, the state RPS is not stringent enough to significantly affect Electricity sector emissions in California. For example, Washington State's RPS, 25 percent by 2025, is not binding on electricity exports to California, which in 2016 already comprised 37 percent renewable generation. However, more aggressive renewable policies in states in the Southwest, if applied to exports, could help California meet its 2030 targets. If California electricity imports from Southwestern states increased from 14 percent renewable (6,952 GWh of 49,963 GWh) to 50 percent renewable in 2030 (29,809 GWh of 59,618 GWh), Electricity-sector emissions in California would be reduced by an additional 4 $MMTCO_2e$ in 2030 (Figure 2-36). The size of the California market may provide sufficient incentives for renewable development in other states with the capability of exporting electricity to California. If not, California should consider other incentive options.

Figure 2-36
Decarbonized Imports Pathway and 2030 Target ($MMTCO_2e$)



If California could create a market for renewable generation in other states from which it currently imports electricity, that could lead to emissions savings of 4 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

Decarbonizing imports requires significant expansion of renewable capacity in the Southwestern states. This would likely result in a modest increase in electricity costs of imports relative to the business-as-usual scenario, where traditional generation makes up a greater percentage of imported electricity. While solar development may be marginally less expensive outside of California, either as a result of lower land costs or higher solar irradiation, there will be added costs for transmission of the power from out of state.

Challenges to Decarbonized Imports Pathway

There remains significant ambiguity around the appropriate legal, business, and policy mechanisms through which California's imports can be decarbonized. In this pathway, California has less agency to actually effect change than in other pathways. In some cases, California utilities will be able to directly contract for power with developers from out of state. Equally likely, however, is that the makeup of imported electricity will depend on the specific policies in place in a given state.

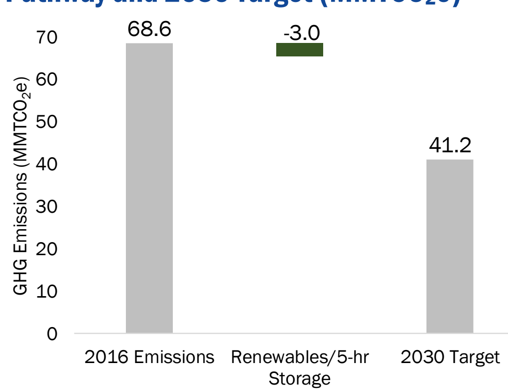
Nonetheless, the need to work with neighboring states and project developers in those states to lower the carbon intensity of those imports is important, if California is to achieve its decarbonization goals. Ultimately, economics should determine the flow of power across state lines, such that if price signals exist, whether through an organized market structure or bilateral power purchase agreements, progress can be made toward achieving a reduction in carbon intensity across imported power.

Pathway 3: Intermittent Renewables + Short-Duration Battery Storage

SESAME modeling results show that there will be a greater need for natural gas to provide late-day ramping, during the period of the day when system load increases and solar output decreases. Figure 2-16, discussed earlier, demonstrated that NGCC plant operations have already shifted from a normal distribution (with the average plant operating around 12 hours per day) to a highly skewed distribution (with a large concentration of NGCC plants operating for five hours or fewer per day). This work found that across California's combined-cycle natural gas fleet today, 1,224 GWh of natural gas generation comes from plants that only operate five hours per day or fewer. An additional 5,252 GWh of generation comes from the open-cycle gas generators that serve as peaking resources. These figures add up to 6,476 GWh of generation, which serves as a convenient barometer for the amount of natural gas generation that could be replaced with additional renewable generation combined with energy storage, to make that renewable generation as dispatchable as a natural gas-fired power plant.

Replacing this gas-fired generation with additional solar and wind generation, relative to the business-as-usual trajectory and storage projects by 2030, would require an additional 6,476 GWh of solar-powered generation paired with 7,771.2 GWh[e] of energy storage capacity. Dividing by 365 days, and 3 hours per day on average (assuming a normal distribution across the operating requirements for energy storage), this would involve a deployment of 7 GW of energy storage and would reduce sectorwide GHG emissions by about 3 $MMTCO_2e$ per year (Figure 2-37).

Figure 2-37
Renewables and Short Duration Storage Pathway and 2030 Target ($MMTCO_2e$)



Solar and short-duration storage can supplement NGCC generation for peaking, and as a carbon-free resource, lower emissions 3 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

In order to fully appreciate the costs of this pathway, the costs of different storage technologies are restated here. As noted above, the costs of solar-plus-storage opportunities depend on the size of the system and its location on the grid. Even the lowest-cost options for solar-plus-storage (i.e., power-purchase-agreement costs around $0.08-$0.13 per kWh)[160] are generally higher than the $0.04

[e] This storage calculation accounts for an estimated 20 percent efficiency loss during storage conversion.

per kWh costs of conventional natural gas generation. Table 2-4 shows current costs of various electricity storage technologies.[161,162,163]

Table 2-4
Current Costs of Various Electricity Storage Technologies

Storage Technologies	Cost ($/kWh)
Electrochemical	
Lithium-Ion	$225
Lead-Acid	$500
Flow Battery	$900
Sodium-Sulfur	$500
Thermal	
Ice Energy	$360
Molten Salts	$893
Mechanical	
Pumped Hydro	$150
Compressed Air	$150
Flywheels	$3,000

**Most flywheel projects in the DOE Energy Storage Database do not have associated CAPEX. As a result, the range of costs ($/kWh) is significant, and likely unrepresentative of where the industry is going.* Source: EFI, 2019. Compiled using data from IEA, 2014; Sandia National Lab, 2015; DOE, 2019.

Challenges to Intermittent Renewables + Short-Duration Storage Pathway

The primary challenges to this pathway relate to market design, as described in Box 2-3. Currently, project developers have little economic incentive to pair the expansion of solar with energy storage, as the additional reliability and dispatchability is not valued in the market. Only once markets integrate those incentives will the full potential of solar-plus-storage projects to displace conventional natural gas generation be realized.

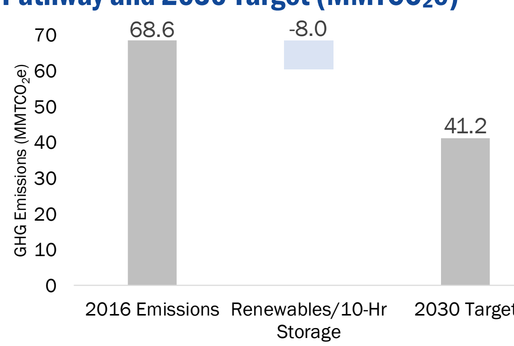
Additional challenges to this pathway relate to the scalability of lithium-ion technology as discussed in Box 2-4. As previously discussed, lithium-ion chemistries rely on cobalt and lithium, which could become supply-constrained due to political or economic reasons over the period up to 2030.

Pathway 4: Intermittent Renewables + Up to 10-Hour Storage

Similar to Pathway 3, Renewables + Short Duration Storage, this pathway replaces the natural gas plants that only operate for five to ten hours per day with additional solar generation and long-duration energy storage. SESAME modeling suggests that up to 50 percent of the natural gas fleet operates fewer than ten hours per day on average.

As a result, continued development and cost reductions associated with longer-duration electricity storage for applications of up to ten hours could result in the reduction of an additional 8.0 MMTCO$_2$e of GHG emissions per year, when paired with another 20,000 GWh of solar generation (Figure 2-38).

Figure 2-38
Renewables with Up to 10-Hour Storage Pathway and 2030 Target (MMTCO$_2$e)



Longer-duration storage with 20,000 GWh of additional solar generation can replace NGCC plants that run less than ten hours per day and reduce emissions by 8 MMTCO$_2$e. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

As discussed previously, the costs of various electricity storage technologies have decreased over time as a function of the scale of deployment. Notably, there are significant differences among storage technologies in terms of their technological maturity, which will affect whether further development and deployment will result in lower costs. For example, pumped hydro and lead-acid systems have matured and their cost trajectories remain flat, while flow batteries are projected to have lower costs moving forward as the technology matures further.

Challenges to Up to 10-Hour Storage Pathway

There are two unique challenges to long-duration storage, above and beyond those for short-duration storage. First, currently the only way to monetize the energy capacity of a long-duration battery would be to conduct energy arbitrage in the wholesale energy market. However, as the duration of battery storage increases, the margins for its arbitrage decrease, resulting in diminishing returns for each additional hour of system duration. Ultimately, energy storage developers will be paying a premium for additional energy capacity, with limited opportunity to monetize it. Box 2-3 provides more information on how energy storage markets should evolve moving forward.

The second challenge relates to the degree to which technologies are proven to be able to deliver in longer-duration applications. Partially, this stems from the reality that lithium-ion batteries are ill-suited for longer-duration storage applications. Lithium-ion batteries experience significant capacity fade when the batteries are deeply cycled (i.e., from full charge to empty). Unlike short-duration energy storage technologies—where lithium-ion-based technologies are well-established, tested, scaled, and deployed—in longer-duration batteries, these technologies are not established or validated.

Pathway 5: Doping Natural Gas with Clean Hydrogen

Interest in utilizing carbon-free hydrogen as an energy carrier has increased in recent years. While hydrogen is a common feedstock in petroleum refining and chemicals production, the use of hydrogen for power generation has been limited. In California, several fuel-cell manufacturers, including Fuel Cell Energy and Bloom Energy, are providing generation resources for distributed power applications, primarily behind the meter at commercial and industrial sites. A few utilities are using fuel cells for larger power generation applications, although these deployments are limited to date.

Hydrogen doping of natural gas could reduce the carbon content of natural gas generation if the hydrogen is produced through clean process, either through electrolysis with renewable electricity as the source of energy or through steam-methane reforming with carbon capture, utilization, and storage.

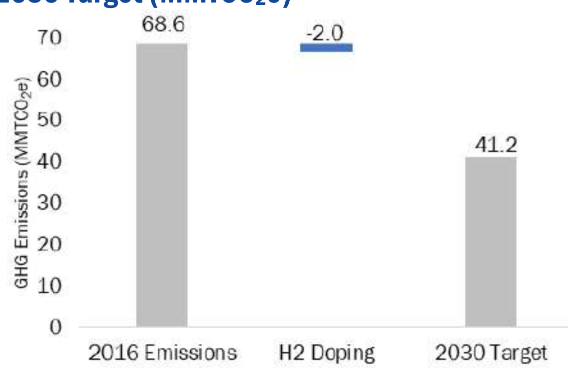
Given the high costs and magnitude of infrastructure deployment necessary for hydrogen production, transmission, and conversion into electricity at scale, it is unlikely that hydrogen, by itself, will play a major role in achieving California's 2030 goals. Tests are under way to determine whether hydrogen could be added into the natural gas system to reduce the carbon intensity of natural gas combustion with minimal retrofit requirements.

Hydrogen doping of natural gas could, however, reduce the carbon content of natural gas-fired electricity generation if the hydrogen is produced through a clean process, either electrolysis with renewable electricity as the source of energy or through steam-methane reforming (SMR) with CCUS.

Assuming that natural gas infrastructure (power plants and pipelines) can safely integrate 10 to 15 percent hydrogen as an additive, and that this hydrogen is produced using a clean process, the carbon intensity of natural gas could decline by up to 10 percent. This could reduce emissions in the Electricity sector by 2.0 $MMTCO_{2}e$ (Figure 2-39).

Figure 2-39

Doping Natural Gas with Hydrogen Pathway and 2030 Target ($MMTCO_{2}e$)



By reducing the carbon content of conventional natural gas, hydrogen doping of natural gas could lead to additional emissions savings of 2 $MMTCO_{2}e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

Electrolysis production costs of $3.9 per kilogram of hydrogen[164] are over four times the cost of hydrogen production via SMR (which costs around $0.9 per kilogram of hydrogen). Moreover, producing hydrogen from electrolysis by utilizing an oversupply of renewable power may actually have even higher production costs, because the capacity factor of electrolyzers operating intermittently would be even smaller.

Table 2-5

Hydrogen Production Cost of Replacing 10 Percent of Natural Gas Consumption for In-State Electricity Generation (2016 levels)

Metric	Amount
Natural Gas Consumption for In-state Electricity Generation	696,012 MMcf
10 Percent of Gas Consumption for In-state Electricity Generation	69,601 MMcf
Energy Equivalent Amount of Hydrogen for 10 Percent Replacement	0.594 MMT H_2
Hydrogen Production Cost from SMR with CCUS	$998 million

Source: EFI, 2019. Compiled using data from CARB, 2019 and PNNL, 2019.

Based on the amount of hydrogen needed to displace 10 percent of the state's natural gas needed for power generation, on an energy content basis, the cost of this pathway would be roughly $1 billion in production costs (Table 2-5).

Challenges to Hydrogen Doping Pathway

While there are no showstoppers, firing gas turbines with hydrogen in place of natural gas poses challenges. The first relates to heating value, since methane at a given temperature and pressure contains three times the energy of the same volume of hydrogen. This means that, for a given energy input, three times the volumetric flow of hydrogen would be required—compared to methane—to produce the same energy output. Second, the flame speed of hydrogen is four to five times faster than natural gas, so power plant combustors would have to be specially designed for hydrogen, because existing methane combustors will not work.

Furthermore, implementing this pathway would dramatically increase the scale of hydrogen demand in California, so there would need to be a quick ramp-up of clean hydrogen production. Today, electrolysis accounts for only 4 percent of total hydrogen production in the United States. Either that percentage will need to increase significantly, or CCUS projects will need to be established alongside SMR facilities; this is already being done in Texas.[165] Additionally, the distribution system for hydrogen would need to be developed to deliver it to the generation facilities. Today, most hydrogen distribution is done by vehicles, but in this setting, vehicle transport may be insufficient for the magnitude of the product shipments involved (and the resulting additional transportation could engender as many carbon emissions as this pathway is seeking to reduce by replacing natural gas combustion emissions).

Pathway 6: Renewable Natural Gas Use

Renewable natural gas (RNG), which is upgraded biogas captured from various waste streams, is a methane-rich unconventional energy resource that is commonly produced through the biochemical decomposition of organic matter (i.e., anaerobic digestion). Primary sources of biogas include landfills, livestock operations, wastewater treatment facilities, and other sites that produce organic waste. Harvesting biogas from these sources provides an opportunity to divert and monetize gaseous waste streams and provide energy services across different sectors, while delivering economic and environmental benefits. Biogas is not carbon-free in its typical form, but combustion of RNG to produce electricity would yield a net reduction in emissions.

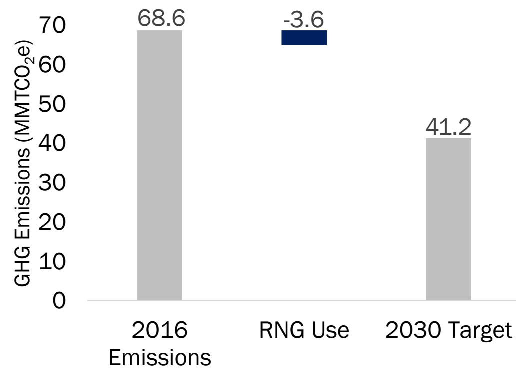
California is well-positioned to expand its deployment of biogas projects to help achieve its ambitious decarbonization goals, and previous analyses have suggested that biogas can play an important role in decreasing GHG emissions throughout the state's economy. Already, California is utilizing biogas for onsite power generation at wastewater treatment plants and farms.[166] This analysis estimates that California's in-state biogas generation potential is approximately 156.6 billion cubic feet per year (Bcf/year) that includes landfills (including candidate sites), animal manure, wastewater, and organic waste.

Additionally, California can also import RNG from the rest of the United States. By 2030, this potential is 40.4 Bcf/year based on estimated RNG production potential in the states with interstate pipeline connections to California.[167]

By 2030, California could be consuming 197 Bcf/year of RNG, delivered through existing infrastructures. Integrating this amount of RNG into the natural gas system would reduce the carbon intensity of natural gas going to the Electricity sector by 3.6 $MMTCO_2e$ (Figure 2-40).[f]

Figure 2-40

RNG Pathway and 2030 Target ($MMTCO_2e$)



Emissions reductions from RNG use in place of conventional natural gas could total 3.6 $MMTCO_2e$ by 2030.
Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

RNG is more expensive than conventional natural gas, and its price is currently shaped by the relatively high cost of its processing, upgrading, and pipeline interconnection fees.[168] As discussed thoroughly in the Biogas and Renewable Natural Gas Addendum to Chapter 6, the cost of RNG is between two to three times higher than for natural gas. It is also important to note that costs vary based on the type of feedstock, with the with the lowest costs associated with landfill gas and the highest with forestry and agricultural residues.[169]

Challenges to RNG Pathway

The largest concerns about the feasibility of the RNG pathway are the potentially limited market supply of RNG and the economic viability. Supply risk is due to the potentially limited availability of feedstock and the competing uses of feedstock (i.e., biofuels). Because RNG is more expensive than conventional natural gas there are concerns of its long-term economic viability. While additional research to improve the economics are underway, as natural gas infrastructure continues to age, costly upgrades, maintenance and repairs will be necessary. At the same time, declining natural gas throughput because of energy efficiency and electrification have contributed to gas price increases for most customer classes in the last five years.[170] With California's ambitious decarbonization efforts, it is likely that this trend will continue. These factors combined present economic risk for the RNG pathway.

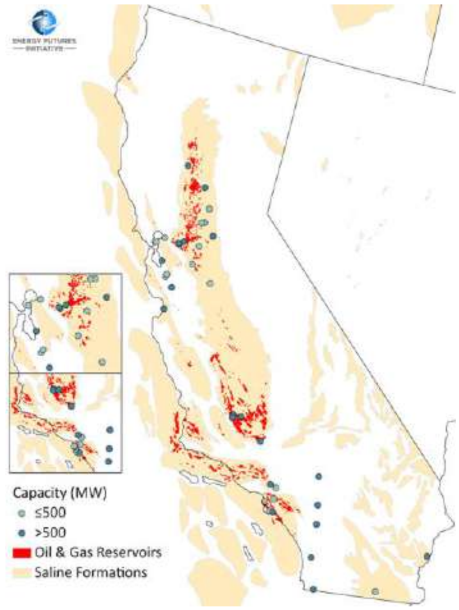
Pathway 7: Natural Gas with CCUS

California currently has an estimated 648 operable natural gas-fired generating units (combined cycle, combustion turbine, internal combustion engine, and steam turbine) with a total nameplate capacity of 43,372 MW across 34 counties.[171] Of these 34 counties, 32 have the potential for CO_2 storage in saline formations, while 24 counties have the potential for CO_2 storage in oil and gas reservoirs.[172,173]

[f] See the Biogas and Renewable Natural Gas Addendum in Chapter 6 for a full explanation of RNG allocations and emissions accounting.

Figure 2-41

Potential NGCC CCUS Candidates in California



Map shows the 37 NGCC plants in California that could be candidates for CCUS. ***Upper inset map:*** *San Francisco and surrounding area.* ***Lower inset map:*** *Los Angeles and surrounding area.* ***Note:*** *Some points lie in close proximity to one another and may appear as one point.* Source: EFI, 2019. Compiled using data from EIA and DOE National Energy Technology Laboratory, 2015.

CCUS is a technology that could help California reduce emissions from the Electricity sector (and other sectors). This analysis estimated that there are 37 natural gas-fired power plants (with a total nameplate capacity of 19,976.1 MW) that could be potential candidates for CCUS in California. Inclusionary criteria for these 37 power plants included:

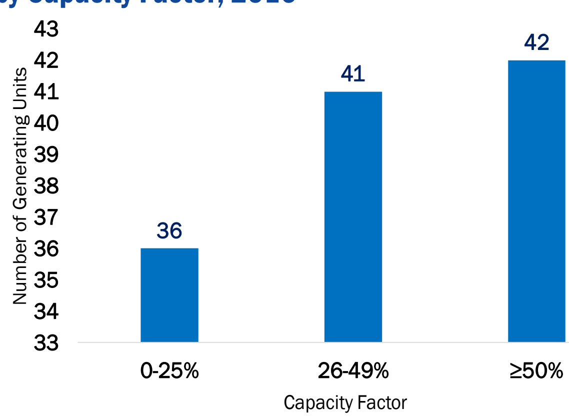
- the use of NGCC generating units that can be retrofitted with carbon capture equipment;
- an initial operating year of 1990 or later for each NGCC unit;
- no scheduled plant retirement year;
- total plant capacity of at least 100 MW (only for generating units that use NGCC technology and that went into service in 1990 or later); and
- the potential for CO_2 storage within the same county (in saline formations or oil and gas reservoirs).

Figure 2-41 shows the location of these plants relative to potential storage sites and demand centers. In 2016, these 37 plants accounted for an estimated 30.5 $MMTCO_2e$ of GHG emissions. If retrofitted with CCUS at an assumed 90 percent capture rate,[174] the emissions savings would amount to nearly 27.4 $MMTCO_2e$ (based on 2016 emissions levels).

Because capacity factors can greatly affect the performance of CCUS systems, this analysis also studied NGCC facilities that operate closer to a level of baseload service (defined in this analysis as a capacity factor of 50 percent or higher in 2016). These facilities would be optimal candidates for CCUS retrofits from a technical and economic standpoint. Figure 2-42 shows 42 generating units from

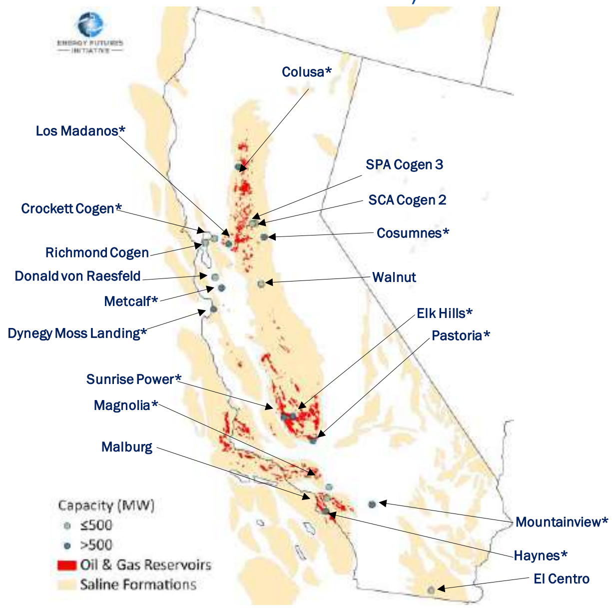
Figure 2-42

Potential NGCC CCUS Candidates in California by Capacity Factor, 2016



The 42 NGCC generating units with capacity factors greater than 50 percent operate closer to a level of baseload and are therefore optimal candidates for CCUS. Source: EFI, 2019. Compiled using data from CEC, 2016.

Figure 2-43
Baseload NGCC CCUS Candidates, 2016



*Map shows the 19 NGCC plants with capacity factors greater than 50 percent, making them optimal candidates for CCUS. *Denotes plants that would qualify under 45Q based on an assumed capture rate of 90 percent of its 2016 emissions level.* ***Note:*** *Some points lie near one another and may appear as one point.* Source: EFI, 2019. Compiled using data from EIA, 2015; NETL, 2015.

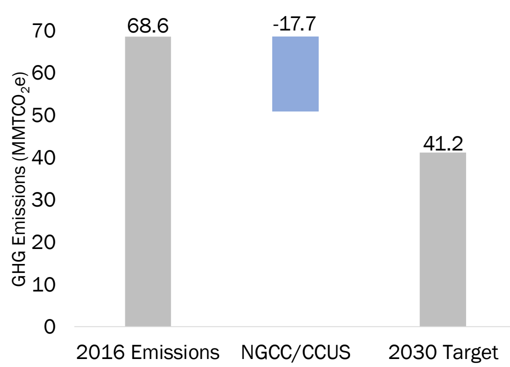
19 power plants that had a capacity factor of 50 percent or higher in 2016 and Figure 2-43 shows their locations in California relative to storage sites.

These 19 power plants, if retrofitted with CCUS, would likely be able to realize lower costs and avoid technical challenges associated with plant operability at lower capacity factors. It is estimated that the total annual emissions savings would be approximately 17.7 MMTCO$_2$e (see Figure 2-44 below).

Another recent analysis focused specifically on the impacts of tax credits under section 45Q of the federal Internal Revenue Code for the deployment of CCUS in the Electricity sector. This analysis identified potential CCUS gas plant retrofit projects in California with a total capacity of 2,276 MW (approximately 83 percent of U.S. total gas retrofit capacity).[175] This analysis also noted that importantly, this reduction in Electricity sector emissions would not interfere with those achieved from the increasing penetration of renewables on the grid.

It should be noted that, in addition to the annual floor of 500,000 million metric tons of CO_2 emissions for electricity generating facilities to qualify for section 45Q credits,[176] there are other limitations. Projects must commence construction by January 1, 2024, a timeframe that makes it difficult to exercise this option, because it would require rapid development of both CCUS projects and the regulations governing CCUS. Also, load-following plants are not currently well-suited for CCUS technologies. These limitations suggest the need for changes in section 45Q as well as additional innovation.

Figure 2-44
NGCC and CCUS Pathway and 2030 Target (MMTCO$_2$e)



Retrofitting NGCC plants with CCUS could provide significant emissions reductions to the Electricity sector. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

It is estimated that an annual cost of using CCUS for the 37 plants could be roughly $3.4-6.9 billion for the capture, transport, and geologic storage of the captured CO_2 (estimated capture rate of 27.4 million metric tons of CO_2 per year). This assumes the plants are operating at an average 40 percent capacity factor and that the NGCC fleet will continue to operate near its current capacity factor and level of emissions. The estimate also assumes no new additions or retirements of the generating units or power plants that were included in this analysis. According to the estimated emissions savings from CCUS based on the 2016 emissions level, 20 out of the 37 power plants would qualify for the section 45Q tax credit for power generation facilities, by virtue of their annual emissions rates.

Alternatively, the scenario that down selected to 19 plants had an estimated cost of $1.9 billion to $3.9 billion (based on an average capacity factor of 55 percent and $109 to $218 per metric ton of CO_2 avoided). Notably, 12 of these 19 plants would have also qualified for section 45Q tax credits, based on an assumed 90 percent capture rate of their 2016 emissions level.

Challenges to NGCC and CCUS Pathway

Despite the potential importance of using CCUS to help meet California's decarbonization goals,[177] challenges to this pathway remain and involve technical, economic, and public policy considerations. From a technical standpoint, capturing CO_2 from the flue streams of natural gas-fired power plants is more difficult than that of coal-fired generation or numerous industrial processes, such as natural gas processing.[178] This is due to the fact that the CO_2 is less concentrated in gas-fired plant flue streams, which results in greater technical (and economic) challenges for capture compared to more concentrated streams of CO_2 emitted from other types of facilities (e.g., approximately 5 percent CO_2 concentration for the flue gas from natural gas-fired power plants, compared to 15 percent for coal plants).[179] Furthermore, there is an energy penalty that occurs when utilizing carbon-capture equipment in a power plant, since the CO_2 capture process itself is energy-intensive. Its use results in the plant delivering less electricity to its customers (this aspect of plant operations is known as a parasitic load).[180] It has been estimated that using first-generation capture equipment on a coal-fired power plant (at a 90 percent capture rate) could lead to an 80 percent increase in the cost of electricity and reduce net generating capacity by 20 percent due to the parasitic load from the capture equipment.[181]

Beyond the capture process, the transport and geologic sequestration of CO_2 continues to face challenges from regulatory uncertainty, post-injection site stewardship liability, and the length of time required to demonstrate permanence.[182] The recent CCUS Protocol developed for the California LCFS program, however, does provide guidelines to help address some of these issues including a 100-year minimum requirement for post-injection site care and monitoring.[183] At present, there are an estimated 4,513 miles of dedicated CO_2 pipelines in the United States, none of which are in California.[184] The absence of signficant CO_2 pipeline infrastructure in California is another impediment to

CCUS project development. Pipelines remain the most cost-effective means of transporting large amounts of CO_2 over long distances for the purposes of utilization (e.g., enhanced oil recovery) or geologic sequestration.[185]

Although CCUS has been applied to natural gas processing facilities, there are currently no large-scale CCUS projects for natural gas-fired power generation in the United States.[186] At present, the only large-scale CCUS power generation project in the United States is the Petra Nova coal-fired power plant in Texas that captures more than one million tons of CO_2 per year and sells a portion of the captured CO_2 for EOR to help offset some of the additional costs from CCUS.[187] DOE has funded CCUS-related research development, and demonstration (RD&D) for more than 20 years. Since Fiscal Year 2010, Congress has appropriated over $5 billion for such activities.[188] However, most of the RD&D activities for CCUS to date have focused on coal-fired power generation, rather than for natural gas power plants.[189]

Pathway 8. Demand Response from Commercial and Industrial Users

Large-scale consumption of power, primarily by commercial and industrial users, creates an opportunity to use DR to reduce carbon emissions either by (1) shifting demand to non-peak hours that could align more appropriately with renewable generation portfolios or (2) shedding demand altogether. To consider the aggregate abatement potential provided by DR in California, one must simultaneously consider the abatement potential of both of these use cases.

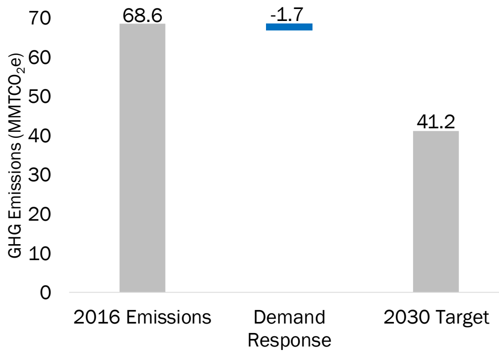
The study by LBNL referenced earlier in the section on "Demand Response" provided projections for the potential of DR in California across use cases.[190] Cumulatively, the study projected that by 2025, DR in California will provide 600 MW of fast-response resource and 12-22 GWh of daily shifting of energy, while shedding 3-11 GW of power. A reasonable projection to 2030 would include the upper end of the 2025 estimates, so there could plausibly be 22 GWh of energy shifting alongside 11 GW of shedding in 2030.

Assessing the emissions reduction of these values is complicated by the fact that the 22 GWh of daily energy shifting (8,030 GWh annually) will result in increased consumption, and thus generation, at a different, off-peak times. Assuming that the carbon intensity of generation at the off-peak time is 40 percent of the carbon intensity of on-peak generation (an assumption supported by the SESAME modeling), then DR from shifting energy can replace 8,030 GWh of carbon-intense natural gas-fired electricity production and replace it with electricity production that is 40 percent cleaner. This would result in a reduction of 1.5 $MMTCO_2e$ of GHG emissions in 2030.

Additionally, the potential emissions reductions that correspond to the 11 GW of load shedding, projected by LBNL, depend on how long the load-shedding events are, and the time of day that they occur, relative to electricity demand. In California, average DR events last for four hours and often occur when demand is on peak. LBNL estimated that, in aggregate, there would be 44 GWh of load shedding across nine load shedding events for a total of 396 GWh. This would result in the saving of an additional 0.15 $MMTCO_2e$ annually in 2030. In total, an aggressive DR pathway could save 1.7 $MMTCO_2e$ (Figure 2-45).

Figure 2-45

Demand Response Pathway and 2030 Target ($MMTCO_2e$)



Commercial and industrial demand response could reduce emissions by an additional 1.7 $MMTCO_2e$ by 2030. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs of Pathway

The benefit of DR as a pathway is that it is theoretically costless on a dollar-per-kWh basis. The true costs are a function of the opportunity cost of consumption from the units that provide the DR. Quantifying these costs is difficult. It is reasonable to assume that if consumers are participating in DR programs, the cost of their participation is less than the market value of the saved electricity. In addition, it is often the case that DR can be less expensive than alternative capacity reserves.

Challenges to Demand Response Pathway

Key challenges to utilizing and expanding DR pathways are twofold. First, DR is limited to applications where the asset response time is slower. That is, successful deployment of DR resources occurs over minutes rather than seconds. Though improvements in communications technology has enhanced this capability, the value of slow-response capacity resources may decline over time as fast-response and ramping requirements increase in value.

Second, there may be asymmetry between wholesale market needs for DR and local distribution needs, as more distributed energy resources are deployed (i.e., DR activity at one level of the system may aggravate issues at another level of the system).[191] This challenge can be remedied with additional coordination between the independent system operator and local distribution utilities.

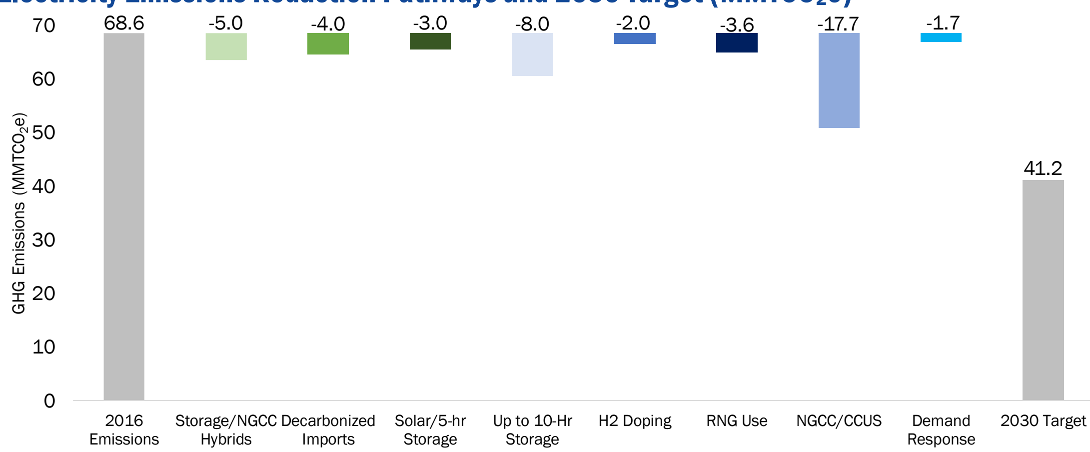
Conclusion

The business-as-usual emissions trajectory, including a significant build-out of renewable capacity, will reduce sectorwide emissions from 68.6 $MMTCO_2e$ to 60.6 $MMTCO_2e$. Pathways for significantly reducing emissions from the Electricity sector include: hybridizing the existing natural gas fleet with energy storage to enable more carbon-efficient operation of natural gas generating units; reducing the carbon intensity of imported power; significant deployment of renewables paired with energy storage; adding hydrogen and/or RNG to the natural gas feedstock for natural gas generators; deploying CCUS on gas plants and developing storage sites and regulations; and demand response.

Because the systems dynamics among pathways are not accounted for, this analysis only shows the nominal emissions-reduction potential of each pathway. These reductions are not additive but several of them could be combined—for example, renewables with 5-hour storages, NGCC plants with CCUS, gas/storage hybrids—creating significant opportunities for the Electricity sector to contribute to California's 2030 decarbonization goals (Figure 2-46).

Figure 2-46

Electricity Emissions Reduction Pathways and 2030 Target ($MMTCO_2e$)



Emissions reductions from eight decarbonization pathways could enable the Electricity sector to exceed a 40 percent reduction from 2016 levels by 2030. Source: EFI, 2019.

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CHAPTER 3
REDUCING EMISSIONS FROM THE TRANSPORTATION SECTOR BY 2030

FINDINGS

California's Transportation sector is its single largest emitting sector and will require transformational change to achieve a 40 percent reduction in emissions by 2030.

The Transportation sector is the largest energy-consuming and greenhouse gas-emitting sector in California's economy. It accounts for 39 percent of the state's greenhouse gas (GHG) emissions, and 41 percent if emissions of substitutes for ozone-depleting substances are included. Light-duty vehicles (LDVs) produce 70 percent of the sector's total emissions.

California's plans for addressing emissions from this sector rely on four basic mitigation strategies.

These strategies are deploying alternative fuel vehicles, including electric vehicles; increasing vehicle fuel efficiency; reducing vehicle-miles traveled; and decreasing the carbon intensity of fuels. Deploying electric and other alternative fuel vehicles can only make up part of the solution; fuel efficiency standards and the Low Carbon Fuel Standard have the highest mitigation potential.

Current pathways will be insufficient for reducing Transportation emissions by 40 percent.

Closing the gap will likely involve more aggressive policies along the same pathways, as the introduction of any new, viable strategies deployed at-scale by 2030 is unlikely. Additional reductions will likely be achieved in the LDV subsector, due to its size and the difficulties with decarbonizing other subsectors. This lack of optionality for meeting the 2030 target presents a potential risk if barriers to deployment of low-carbon technologies, such as infrastructure and costs are not addressed.

Technology pathways for achieving 2030 goals are likely to differ from the pathways for deeper emissions reductions by 2050, requiring a simultaneous and dual-track approach.

As in other sectors, maintaining optionality and flexibility is key. For some Transportation subsectors, such as heavy-duty vehicles, the solutions that are viable in the near term do not have the same decarbonization benefits as technologies that require additional development for market readiness. The sector should avoid locking in technologies that will be suboptimal for deep decarbonization.

There are constraints on biofuels production that may limit its supply in California by 2030.

The four main biofuel resources used in California are ethanol, biodiesel, renewable diesel, and renewable natural gas. The state's current biofuels usage requires both imported feedstocks as well as in-state biofuels. In addition to constraints on supply, the transportation sector must compete with other sectors for available biomass.

Achieving deep decarbonization in the Transportation sector will require going beyond energy/fuel-based technologies and will depend on an ecosystem of solutions that include new infrastructure systems, platform technologies, behavioral incentives, urban design, and advancements in materials science.

There are a number of effective options for reducing GHG emissions in the Transportation sector but quantifying and predicting their emissions reduction potential varies significantly. These options are particularly important to the fuel-efficiency and demand-reduction pathways. Downsizing, light-weighting, improving aerodynamics, improving tires, and increasing thermal efficiency of engines all contribute to efficiency, as do behavioral practices like avoiding idling and rapid acceleration. Demand reduction is entirely dependent on non-fuel options such as urban design (e.g., for reduced traffic congestion), infrastructure (e.g., public transit), behavior (e.g., telecommuting), and platform technologies (e.g., digital technologies that enable autonomous vehicles).

Because individual consumers are the owners and operators of emissions-generating vehicles, consumer behavior plays an important role in mitigation efforts in Transportation.

Transportation is unlike other sectors, such as Electricity or Industry, where emissions sources are more centralized and individual consumers have limited service options. Decarbonization solutions for transportation of light duty vehicles must be attractive to consumers on both a cost and general appeal levels. Success of clean pathways depends on the vehicle stock turning over. Last year, there were 2 million new vehicles sold, while the average age of on-road vehicle in California is 11.3 years.

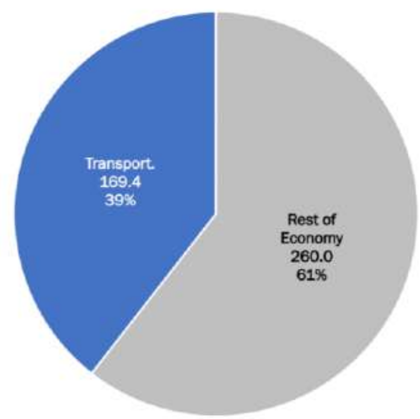
The aviation, marine, rail, and off-road subsectors are among the most difficult to decarbonize.

The most viable near-term strategy for reducing the emissions from these subsectors is energy demand reduction. Other options include electrifying rail and water-borne transportation and using heavy-duty vehicle technology for off-road transportation.

TRANSPORTATION SECTOR

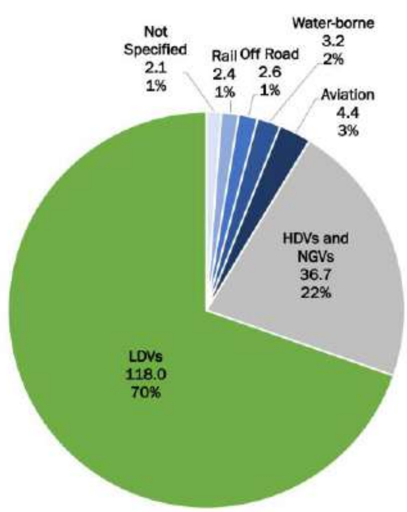
The Transportation sector is the largest energy-consuming sector in California, accounting for 3.11 quads in 2016, or nearly 39 percent of total energy demand.[1] It is also the single largest emitting sector (Figure 3-1), accounting for 39 percent of statewide greenhouse gas (GHG) emissions (169 $MMTCO_2e$).[2] Including its share of substitutes for ozone-depleting substances, it makes up 41 percent of the state's GHG emissions (174 $MMTCO_2e$).[3] Contributions from the Transportation sector include emissions from combustion of fuels sold in-state that are used by on-road and off-road (e.g., construction, mining) vehicles, aviation, rail, and water-borne transport (Figure 3-2).

Figure 3-1
Transportation's Share of Total Emissions, 2016 ($MMTCO_2e$)



The Transportation sector is the single largest emitting sector in California, comprising 39 percent of total emissions. LDVs alone create over a quarter of economy-wide emissions. Source: EFI, 2019. Compiled using data from CARB, 2018.

Figure 3-2
Breakdown of Transportation Emissions, 2016 ($MMTCO_2e$)



Light-duty vehicles (LDVs) account for a majority of combustion emissions, making it the most critical subsector to decarbonize by 2030. Source: EFI, 2019. Compiled using data from CARB, 2018.

The Transportation sector also contributes non-combustion emissions from fuels used as lubricants.

On-road transportation, especially light-duty vehicles (LDVs), will be the main source of emissions reductions in the pre-2030 timeframe. This will likely be achieved through policies and incentives that push for demand reductions, replacement of conventional vehicles with alternative fuel vehicles (AFVs), and emissions mitigation from conventional vehicles through improved fuel efficiency and low-carbon fuels.

2016 Sector GHG Emissions Profile: Transportation

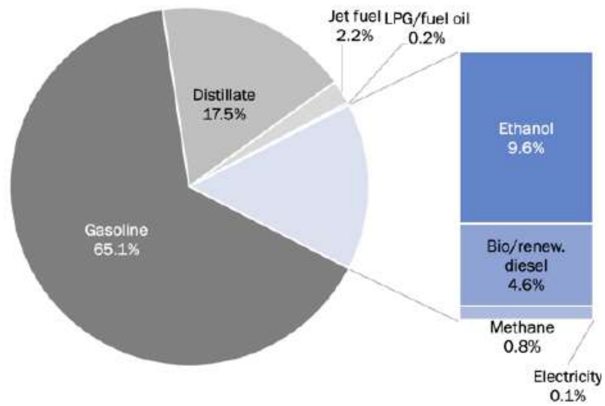
Nearly all of the combustion emissions in Transportation come from petroleum. About 65 percent of the sector's total energy consumption comes from gasoline, 18 percent from distillate (diesel), and 2 percent from jet fuel, with less than 1 percent each from liquified petroleum gas (LPG) and fuel oil (Figure 3-3).[4] The remainder of energy consumed in the sector comes from biofuels (mostly ethanol), natural gas (both fossil and renewable), and electricity.

Transportation consumes the majority of all petroleum and liquid biofuels in California, but just 3 percent of total natural gas and less than 1 percent of electricity.[5] Because of the preponderance of petroleum among transportation fuels, emissions for the sector track mainly with petroleum consumption. Overall emissions and consumption in the sector declined from their peak in 2007 but have increased since 2013 (Figure 3-4).[6,7]

Emissions in the sector are dominated by LDVs, which make up 70 percent of the total. Heavy-duty vehicles (HDVs) make up an additional 21 percent.[8] Definitions for these categories vary slightly, and often overlap. CARB's Economic Sector-based emissions inventory counts all passenger cars, motorcycles, and light-duty trucks (those with a gross vehicle weight under 8,500 lbs.)[9] as light-duty and all buses, motorhomes, and heavy-duty trucks (those over 8,500 lbs.) as heavy-duty.[10] For comparison, some federal agencies set a simple weight

Figure 3-3

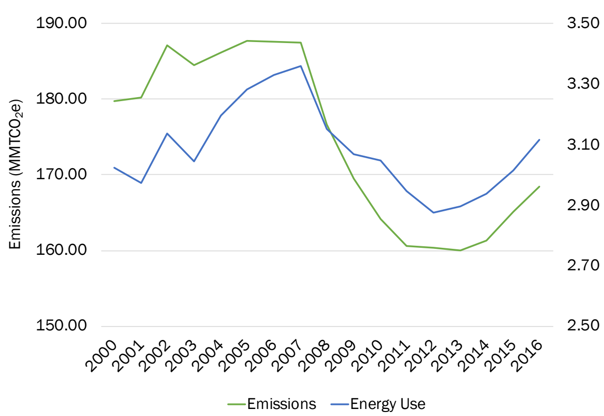
Transportation Energy Consumption from Petroleum and Non-Petroleum Sources



Transportation accounts for the majority of all petroleum and liquid biofuels consumed in California, but a small fraction of natural gas and electricity consumption. Source: EFI, 2019. Compiled using data from CARB, 2018 (fuel data); EIA, 2018 (electricity data).

Figure 3-4

Transportation Emissions and Energy Consumption, 2000-2016



Because the Transportation sector is dominated by one fuel (petroleum), emissions and energy use have a fairly strong correlation. Both dipped in the wake of the 2008 Recession, but emissions from the sector are significantly higher now than they were in 2012. Source: EFI, 2019. Compiled using data from CARB. 2018: EIA. 2019.

cutoff at either 8,500 (e.g., the Environmental Protection Agency [EPA], for emissions standards) or 10,000 lbs. (e.g., the Federal Highway Administration [FHWA]).[11] This report uses the CARB definitions, which exclude the medium-duty vehicle category (which itself has varying definitions).

The other subsectors (aviation, marine, rail, and off-road) are a limited focus of this analysis. They make up a much smaller part of the sector, have been identified as "harder-to-abate,"[12] even in the midcentury timeframe.[13] Technological solutions for decarbonizing these subsectors are, at best, much less mature than for on-road vehicles. The most viable near-term strategy for mitigating emissions from these subsectors will likely be demand reduction. Other possible options for decarbonization include electrifying rail, water-borne, and off-road transportation.[14] Some decarbonization strategies for heavy-duty vehicles may also work for off-road vehicles, which typically run on diesel.[15]

Analysis of Transportation Sector

In January 2018, the California Department of Motor Vehicles (DMV) estimated there were 30.6 million on-road vehicles in California, though estimates vary based on differing definitions of what vehicles are included. This estimate included around 3.2 million alternative fuel vehicles (AFVs).[16] The California Energy Commission (CEC) forecasts that the vehicle stock will grow to between 35.5 million and 37.7 million LDVs by 2030 (an increase of 28 to 36 percent over CEC's 2015 baseline measurement) and to between 1.24 million and 1.34 million HDVs by 2030 (an increase of 20 to 30 percent).[17] This growth in vehicle stock could result in an additional 32 $MMTCO_2e$ of GHG emissions in 2030, and possibly as much as 54 $MMTCO_2e$, if there is no change in per-vehicle emissions. It should be noted that two different data sources are used here because the California DMV provides more detailed and recent data on the current vehicle stock, and CEC provides data on projected stock.

The LDV subsector also includes the emissions from the nearly 900,000 motorcycles in the state.[18] Because many of the policies that govern LDVs do not apply to motorcycles—and emissions total just 0.52 $MMTCO_2e$—in this analysis they are grouped with non-road transportation.

California also has around 34,000 natural gas vehicles (NGVs); this includes both light- and heavy-duty vehicles. The California Air Resources Board (CARB) Emissions Inventory does not distinguish between LDVs and HDVs for NGVs, and CARB's Emissions Factor Database groups all NGVs in HDV categories. For these reasons, this analysis groups NGVs with HDVs for emissions calculation purposes.

California LDV sales dipped during the 2008 Recession but have since rebounded and have been around two million per year since 2014. In 2018, sales were 2.00 million; in 2019, they are projected to dip slightly to 1.96 million.[19] The stock growth rate in CEC's projections suggests that about three-quarters of sales are replacing older cars. The average age of a California LDV is 11.3 years, similar to the national average of 11.2 years, suggesting that the rate of vehicle turnover in California is similar to the rest of the country.[20] Sales and stock turnover information is harder to come by for HDVs, especially since lifespans vary greatly based on vehicle type and function.[21]

Table 3-1
Typology of On-Road Vehicles

Vehicle Type	Number of Vehicles, 2017 (thou.)	Alternative Fuel Vehicle (AFV)	Internal Combustion Engine (ICE) Vehicle*	Can Use Conventional Fuels	Uses Electricity**	Zero-Emissions Vehicle (ZEV)
Conventional (gasoline or diesel)	27,422 (89.67%)		X	X		
Natural gas (NGV)	34 (0.11%)	X	X			
NGV bi-fuel		X	X	X		
Propane, butane, etc.	4 (0.01%)	X	X			
Biofuel	1,739 (5.69%)	X	X*			
Biofuel flex-fuel (FFV)		X	X	X		
Traditional hybrid	1,037 (3.39%)	X	X	X	X**	
Plug-in hybrid (PHEV)	164 (0.53%)	X	X	X	X	X
Battery-electric (BEV)	178 (0.58%)	X			X	X
Fuel cell electric (FCEV)	3 (0.01%)	X			X	X
Total	**30,581**					

Analysis Methodology

California's 2007 State Alternative Fuels Plan, one of the earliest state documents on reducing Transportation emissions, presents a holistic vision of how to meet California's 2050 GHG goals in the Transportation sector, framed in terms of three broad strategies:

- Maximize the energy efficiency of vehicle/fuels systems used by Californians.
- Reduce growth in travel demand through transportation efficiency, technology changes in the delivery of goods and services, expanded transit, and more efficient land use patterns.
- Deploy an increasing mix of low GHG emission alternative and conventional fuels to satisfy the remaining transportation energy demand.[22]

Subsequent laws and regulations have refined these strategies, separating the third strategy into two focus areas—vehicle adoption, and fuel production—establishing four categories of policy actions. These categories are used as the framework for this analysis as follows:

- Deploying AFVs, including electric, biofuel, and natural gas vehicles (see Table 3-1);
- Increasing vehicle fuel efficiency;
- Reducing growth in demand through reducing vehicle-miles traveled (VMT); and
- Decreasing the carbon intensity of fuels.

These four categories of action apply to both light- and heavy-duty vehicles, though the implementation approaches differ for the two classes. Relevant actions are covered by a wide number of Transportation policies, including, for example, infrastructure incentives that enable deployment of low-carbon fuels and AFVs.

This analysis examines these four categories and identifies the most significant policies in California for the pre-2030 timeframe, then estimates the emissions mitigation potential of the identified policies. The methodology used is described in detail in the next section. The analysis estimates the number of vehicles (AFV and conventional) and the annual carbon emissions of the average vehicle in particular categories and projects how decarbonization policies will affect those numbers. Costs are also estimated for current California policies (where applicable); other technical and implementation challenges for these pathways are also identified. The conclusion: current pathways will likely be insufficient to hit the 2030 target of a 40 percent emissions reduction.

One of the key considerations for mitigation policies in the Transportation sector is that, in contrast to sectors such as Electricity and Industry, individual consumers are the owners and operators of the majority of emissions-generating assets (i.e., vehicles). Because of this, consumer behavior plays a substantial role in mitigation efforts for the sector; decarbonization solutions need to appeal to consumers at a level beyond cost.

Individual consumers are the owners and operators of the majority of emissions-generating assets…Because of this, consumer behavior plays a substantial role in mitigation efforts in the sector; decarbonization solutions need to appeal to consumers on a level beyond cost.

Technological avenues for decarbonizing Transportation must be supplemented with non-technological policies. These other solutions could include monetary incentives, urban planning/land use change, and education programs.

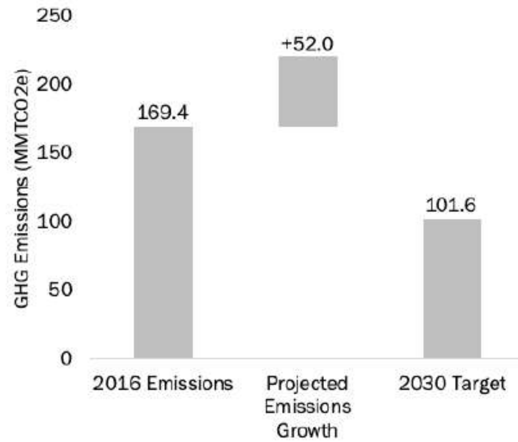
Methodology for Estimating the 2030 Pathways

To evaluate the impact of the four mitigation pathways described above, rough estimates were calculated of their effects on the California vehicle stock by 2030. These calculations are intended to estimate the interaction effects of different policies. If fuel efficiency goes up, for example, the benefits of switching a conventional vehicle for an electric vehicle goes down.

The potential for the pathways is evaluated against the projected emissions of the sector in 2030, since Transportation emissions are expected to grow significantly. Based on stock growth projections from CEC,[23] if no (existing) mitigation policies were implemented—and the characteristics of the vehicle fleet did not change for any other reason—on-road transportation emissions could grow by 40 to 53 $MMTCO_2e$ (Figure 3-5), leaving a much larger gap in meeting the 40 percent target established as the sectoral goal for this analysis.

Estimates of the pathways assume compliance with two regulations—California's Low Carbon Fuel Standard (LCFS) and the current (as of April 2019) version of the federal Corporate Average Fuel Economy (CAFE) standards. Estimates include an increase in the ZEV LDV stock to five million by 2030 (per Executive Order B-48-18), and a change in natural gas, ethanol, and electric HDVs based on a summary of CEC projections.[24]

Figure 3-5
"Business as Usual" Transportation Sector Emissions Growth and 2030 Target

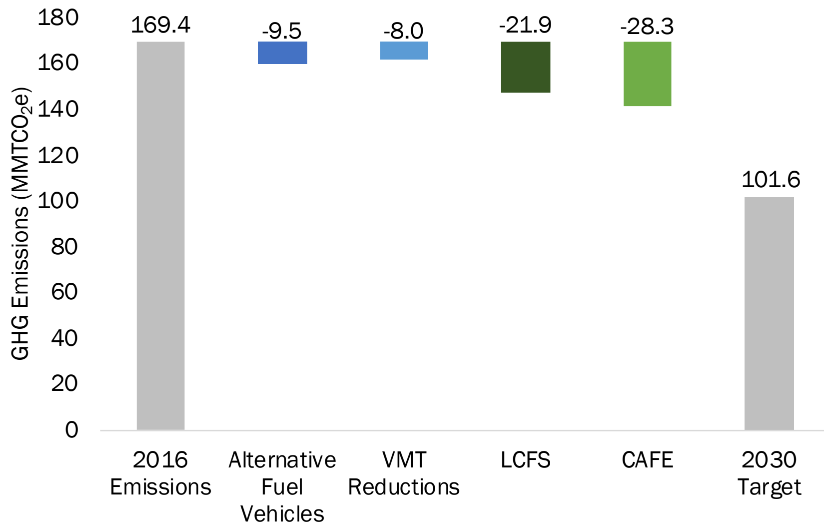


The Transportation sector's emissions are projected to grow significantly to 2030 in a business-as-usual situation. Mitigation pathways must consider this projected growth. Source: EFI, 2019. Compiled using data from CARB, 2018.

For demand reduction, where California policy is less established, assumptions are derived from a combination of CARB's assumptions for SB 375 (2008) planning;[25] the PATHWAYS High Electrification Scenario from Energy and Environmental Economics, Inc. (E3);[26] and a new assumption for this report of HDV "smart growth." LDV VMT per vehicle is assumed to decrease by 7.5 percent and all other VMT is assumed to decrease by 5 percent. Other key data sources and assumptions for these estimates can be found in Table 3-2.

The mitigation potential for each pathway is calculated by comparing the achieved mitigation of all the pathways combined with the mitigation achieved when a specific pathway is eliminated as an option. This methodology was chosen because these pathways are current California policy, and because it avoids overcounting any single pathway.

Figure 3-6
Transportation Sector Pathways and 2030 Target



Current decarbonization policies are predicted to have substantial impact, but even in an optimistic scenario they are likely to fall short of the 2030 target due to growth in the sector. Source: EFI, 2019. Compiled using data from CARB, 2018.

Current policies in these pathways are not however, likely to place the sector on trajectory to meet the 40 percent reduction target used in this analysis. Even so, the reductions could still be significant, as high as 67.7 $MMTCO_2e$ (Figure 3-6) or greater, depending on how upstream emissions reductions are counted. The largest reductions come from the CAFE standards, the LCFS, and the ZEV goal. Additional policies that could get closer to the sectoral target will likely come from more aggressive or expansive policies within the same four pathways (Box 3-1).

Box 3-1
Closing the Gap to the 2030 Target

Closing the gap to the 2030 target will likely still rely on the four pathways identified in this chapter. These pathways are not limited, however, to the policy solutions that are already being implemented in California. Ways to expand the reach of the pathways could include:

- Extending CAFE standards;
- Implementing adoption targets for new categories of AFVs, especially heavy-duty;
- Setting statewide targets or monetary incentives for demand reduction;
- Stronger policies aimed at Transportation emissions reductions from corporations;
- More funding for AFV refueling/recharging infrastructure;
- More funding for focused research and development for alternative fuels and vehicles; and
- Programs that focus on providing low-carbon transportation options for disadvantaged populations and communities.

It should be noted that there are simplifications in the estimates that could possibly underestimate the difficulty of achieving the emissions targets. First, the estimates do not account for any rebound effects or overlaps (described in detail below). Second, the estimates may overcount the emissions reductions from ZEVs by counting heavy-duty ZEVs separately from the five million vehicle goal, and by collapsing categories of AFVs—including not considering that plug-in hybrid electric vehicles (PHEVs) may be used to meet the ZEV target but are not completely carbon-free. Third, they do not consider the fact that CAFE is a federal regulation. Since the standards apply to nationwide fleets, the actual fuel economy of cars purchased in California could be either higher or lower than what the CAFE standards require.

Table 3-2
Transportation Key Assumptions

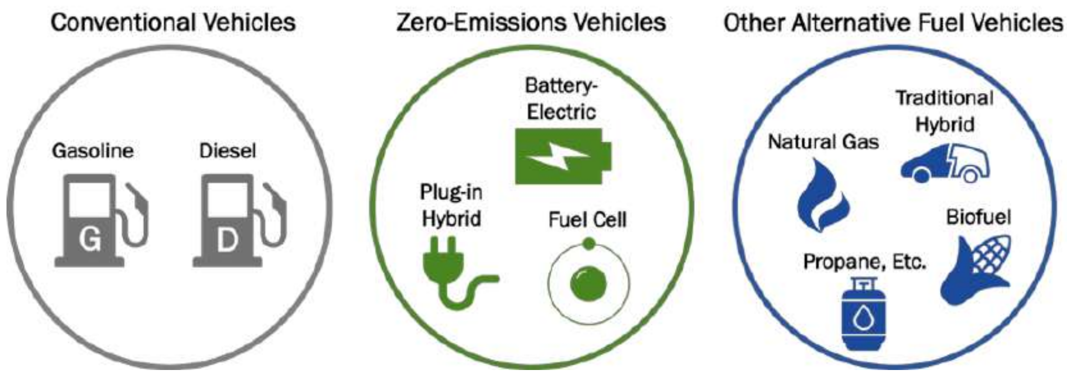
Pathway	Subsector	Key Assumptions
Baseline	All	Vehicle stock for gasoline, diesel, and natural gas vehicles are calibrated so that calculated emissions match actual emissions. Stock growth numbers come from CEC High Demand case in order to capture full mitigation potential. No reductions expected from non-combustion emissions.
Alternative Fuel Vehicles	LDV/HDV	All ZEVs are assumed to be entirely zero-carbon. ZEV baselines contain only all-electric vehicles. PHEVs, traditional hybrids, FFVs, and bi-fuel vehicles counted with gasoline/diesel vehicles.
	LDV	ZEV adoption expected to progress linearly from baseline to five million in 2030. All LDVs other than ZEVs are assumed to be gasoline-powered.
	HDV	ZEVs and NGVs are assumed to progress linearly from baseline to estimate based on CEC stock projection for 2030. E85 HDVs start from zero and progress linearly to projection starting in 2024. All other HDVs assumed to be diesel-powered. No distinction is made between LNG and CNG; RNG is not included.
Low-Carbon Fuels	LDV, HDV	Gasoline and diesel are assumed to reduce their carbon intensities by the amount prescribed in the 2018 update to the LCFS. Emissions reductions from CCUS and CHP in relevant Industry subsectors are counted towards these reductions; the rest is assumed to be met through alternative fuels. Energy intensities of fuels taken from LCFS. Tank-to-wheel carbon intensities taken from LCFS pathway documentation. Biofuels are treated as zero-carbon from tank-to-wheel; gasoline assumed to be E10, diesel assumed to be B5.
Demand Reduction and Efficiency	LDV	Baseline VMT per vehicle and fuel economy for gasoline vehicles come from CARB Emissions Factor database. New vehicles are assumed to replace average vehicles from the previous year. Fixed stock turnover rate based on sales numbers from the California New Car Dealers Association.
	HDV	Baseline VMT per vehicle and fuel economy for diesel vehicles from CARB Emissions Factor database. Natural gas vehicles assumed to be perfect substitutes for diesel vehicles. E85 vehicles assumed to share characteristics with HDV gasoline vehicles. New vehicles are assumed to replace average vehicles from the previous year. New vehicle fuel economy assumed to progress linearly from current level to Model Year 2030 fleetwide level in preferred alternative case, with an 20% adjustment for the difference between testing mpg and on-road mpg. Fixed stock turnover rates based on modification of assumption used for LDVs.
	All other subsectors	5% VMT reduction by 2030 assumed to lead to a corresponding 5% decrease in emissions below 2016 baseline.

GHG Emissions Reduction Pathways

Pathway 1: Alternative Fuel Vehicles and Zero-Emission Vehicles

Figure 3-7

What are Alternative Fuel Vehicles and Zero-Emissions Vehicles?



In this report, alternative fuel vehicles include all vehicles that are not "conventional vehicles," i.e., powered entirely by conventional gasoline or diesel. Some AFVs are zero-emission vehicles, others use hybrid engines or a variety of other fuel sources. Source: EFI, 2019. Icons from The Noun Project.

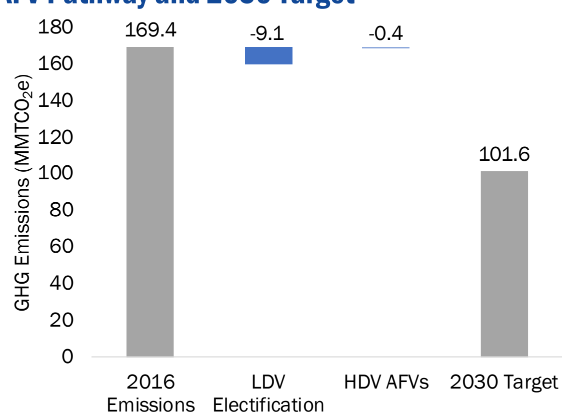
One of California's key Transportation decarbonization strategies is the substitution of AFVs for conventional, petroleum-fueled vehicles. AFVs are a broad category (Figure 3-7) that includes: vehicles fueled by electricity (battery-electric vehicles [BEVs], PHEVs, fuel cell vehicles [FCEVs], and traditional hybrids); fueled by biofuels; and fueled by less carbon-intensive fossil fuels (e.g., natural gas and propane).

Aggressive targets for adoption of zero-emissions AFVs has the potential to avoid 9.1 $MMTCO_2e$ of emissions in the LDV subsector; the impact of AFVs of various kinds in the HDV subsector will be much smaller in the near term (Figure 3-8).

AFVs purchases are increasing in California (as they are around the country). Both BEV and PHEV sales have steadily grown since 2009; in 2017, their collective sales made up 7 percent of the state total (Figure 3-9). Traditional hybrid sales are declining, as BEVs and PHEVs have apparently filled this niche.

Figure 3-8

AFV Pathway and 2030 Target

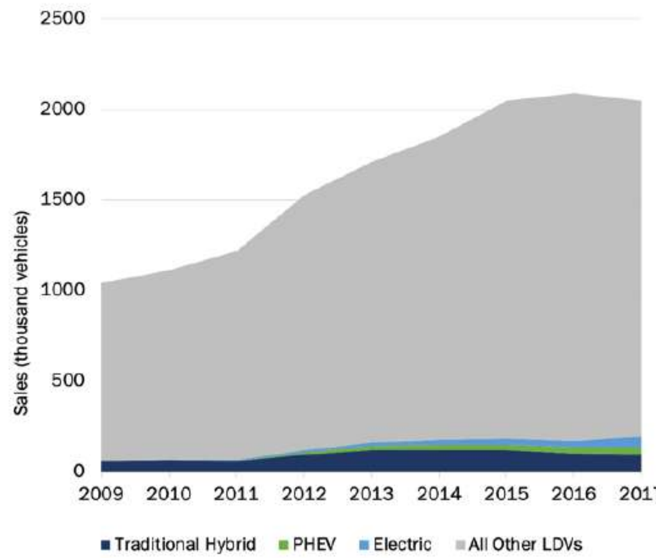


California's ZEV target will likely be met with BEV and PHEV LDVs, while the HDV subsector is projected to experience small growth in various types of AFVs. Source: EFI, 2019. Compiled using data from CARB, 2018.

California has several laws that promote AFVs. In 2005, the California Assembly passed AB 1007, which directed the CEC to prepare a State Alternative Fuels Plan.[27] This report, published in 2007, recommended a suite of policy options for adopting AFVs that have since been implemented. These include R&D funding for AFVs, encouraging utilities to invest in AFV deployment, and continuing or increasing rebates for AFV purchases and alternative fuel infrastructure construction.[28]

Figure 3-9

California Sales of Light-Duty Vehicles by Fuel Type, 2009-2017

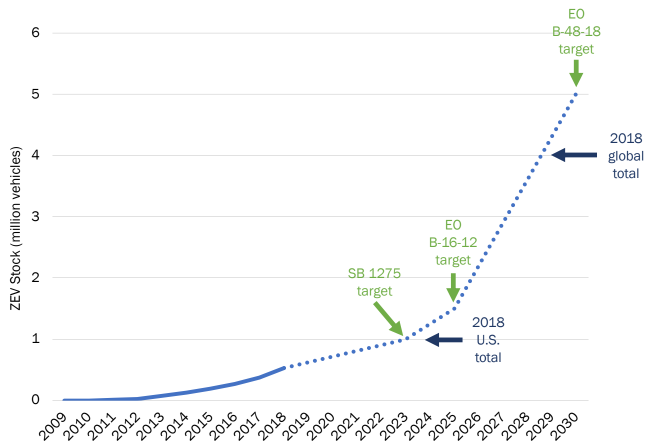


Sales of ZEVs are small, relative to the market, but climbing. The growth of ZEVs has led to decreasing sales of traditional hybrids, indicating they may fill the same niche. Source: EFI, 2019. Compiled using data from CNCDA, 2019 and CNCDA, 2014.

The 2007 report also emphasized the importance of sending clear market signals, and suggested that consistent and transparent government mandates were a key component of meeting emissions goals.[29] Subsequent actions such as SB 1275 (2014) and Executive Order B-48-18 (2018) have adhered to this direction, establishing targets for "zero-emission and near-zero-emission vehicles." SB 1275, passed in 2014, created the *Charge Ahead California Initiative*, which has a goal of placing at least one million ZEVs and near-ZEVs in service by 2023, including cars, trucks, and buses.[30] The law also expands a program that compensates low-income vehicle owners who voluntarily retire high-emitting vehicles. The ZEV category includes BEVs, PHEVs, and FCEVs; it excludes traditional hybrids, biofuel vehicles, and vehicles that run on alternative fossil fuels (e.g., natural gas and propane).

Executive Order B-48-18 increased the target of one million ZEVs and near-ZEVs to five million by 2030 (Figure 3-10). It also set goals for ZEV refueling infrastructure: it proposes a $2.5 billion investment plan over seven years (to 2025) towards constructing 250,000 charging stations (including 10,000 direct-current [DC] fast chargers) and 200 hydrogen refueling stations.[31] This funding would need to be authorized by the state legislature, but the executive order laid down an ambitious marker for investment. Since the issuance of the executive order, an Interagency Working Group on ZEVs (convened by Governor Brown) issued an action plan with over 200 items, including consumer outreach, incentives, R&D efforts, infrastructure planning, and regulatory reform.[32]

Figure 3-10
Zero-Emissions Vehicle Growth and Goals



The California ZEV stock has grown substantially and makes up around half the U.S. total. The pace of ZEV adoption will have to accelerate, however, to meet the targets set out in executive orders. Source: EFI, 2019. Compiled using data from CNCDA, 2019 and CNCDA, 2014.

The ZEV targets will most likely be met by deploying light-duty BEVs and PHEVs. These vehicles are already on the market and increasing in popularity, from less than 0.01 percent of LDV sales in 2010[37] to 7.8% in 2018.[38] Over the lifespan of these vehicles, they become cost-competitive with conventional vehicles, despite higher upfront costs. This is due to savings on fuel and maintenance costs. Advances in battery technology and more infrastructure deployment will further reduce costs. These changes will also help allay range anxiety by increasing battery life, decreasing charging time, and ensuring that charging is fast and available. Other AFVs may be a part of the LDV fleet, but BEVs and PHEVs seem likely to be the dominant vehicle type.

Box 3-2
The Grid Can Handle Five Million ZEVs

California needs approximately 4.7 million additional ZEVs to reach its target. Assuming that it reaches its target with BEVs only, with the same level of VMT as the current California average, and an energy usage rate of 30 kilowatt-hours/100 miles (the median for new BEVs in 2018),[33] the additional electricity consumption would be around 16 terawatt-hours (TWh) per year. This would represent a 6.2 percent increase in California's retail electricity consumption.[34] This number could vary with the introduction of more electric HDVs, changes in VMT trends, different energy use rates for vehicles, or the satisfaction of the ZEV requirement with other types of vehicles.

This increase of 16 TWh of electricity sounds significant but over the course of 12 years, this would represent only a 1.3 TWh annual increase on average, well within the normal year-to-year fluctuations for California's electricity system.[35] Additionally, California already possesses the latent generation potential to handle this additional load: natural gas generation ramped down by more than 18 TWh between 2015 and 2016 due to increased hydropower production. Because the electricity consumption increases of BEVs and PHEVs are cumulative over time, however, California will ultimately need to build additional generation capacity to maintain its cushion against supply decreases from sources such as hydropower.

An additional issue involves potential effects plug-in vehicles could have on the shape of daily net load, known as the Duck Curve. A study from the Lawrence Berkeley National Laboratory indicated that uncontrolled charging with 1.5 million BEVs and PHEVs would slightly exacerbate the ramp-up and ramp-down issues illustrated by the Duck Curve (see Chapter 2 for additional discussion of the Duck Curve). The study found that "managed charging" for BEVs and PHEVs could have the opposite effect.[36] During the day, BEVs and PHEVs could be used to prevent overgeneration; in the evening, they could serve as a distributed form of dispatchable storage with vehicle-to-grid integration. This type of managed charging would require incentives beyond simply charging at a particular time. There would need to be new infrastructure and regulation that facilitates a two-way interface between vehicles and the grid, which would give grid managers access to vehicles as a storage asset for grid operations. This system would necessitate significant regulatory and behavioral changes.

For HDVs, the situation is more complicated. In general, the technologies that work for LDVs—BEVs and PHEVs—do not work for most HDVs. Because of the weight of HDVs (both of the vehicle itself and the weight of cargo and additional passengers carried) and the longer average distances traveled, more battery capacity is needed. With current technologies, this additional capacity is often prohibitively expensive.

There may also be diminishing returns to adding capacity as well, since the batteries themselves add weight.[39] In addition, while LDV owners can charge vehicles when they are not in use, many HDV applications (e.g., long-haul trucking, delivery services) would require using time that would otherwise be used in transit for refueling, resulting in lost productivity and additional costs.

Tesla has announced plans to manufacture a Class 8 (GVW over 33,000 lbs.) truck, which the company says would be cost-competitive over the lifetime of the vehicle due to fuel cost savings.[40] It remains to be seen if Tesla can develop and scale up production of this vehicle at the announced cost, and if the longer refueling time compared to conventional vehicles (75 to 125 minutes for a full charge on a DC fast charger) will discourage adoption.

BEVs and PHEVs are better-suited for select HDV applications with shorter travel distances and refueling hubs (e.g., transit and school buses). Catenary hybrid trucks (which could eventually use overhead wires, or in-ground inductors or rails)[41] have also been tested in California for applications where the infrastructure can feasibly be installed, such as port transport.[42] Alternative solutions are, however, needed for other HDV types. Partial electrification in the form of traditional hybrids (gasoline or diesel) could be used for some HDVs. Hybrids offer a distinct advantage over other AFVs as they do not require new infrastructure; they do not, however, offer the same carbon savings as ZEVs.

FCEVs may be a key technology for full decarbonization of Transportation, and especially of HDVs. Hydrogen currently has select uses, such as forklifts, as well as roughly 3,300 on-road vehicles.[43] Hydrogen for Transportation is, however, likely to remain economically infeasible for deployment at scale in the pre-2030 timeframe.

The most common current price for hydrogen fuel is $5.60 per gasoline gallon equivalent (GGE). Unlike with BEVs, FCEV owners cannot make up the difference in upfront cost with fuel savings. The retail price of gasoline in California averaged $3.08 after taxes in 2017.[44] Nationwide, diesel fuel costs about the same as gasoline on a per GGE level, and even pure biodiesel costs just 60 cents more.[45] NREL's best-case scenario for the future price of hydrogen used in a FCEV puts its cost per mile traveled at 12 cents in the 2020 to 2025 period,[46]equivalent to the price per mile traveled using gasoline costing $3.20 per gallon. Hydrogen would only be cost-competitive if gasoline became more expensive or more heavily taxed. Closing the gap with gasoline in that best-case scenario, for example, would require a 25 percent increase over the current California gas tax.[47]

These cost factors may limit the growth of FCEVs in the near term; for the longer term, stakeholders should ensure that other, non-zero-carbon technologies (discussed below) do not get "locked in," curtailing FCEVs' future growth potential (Box 3-3). FCEVs themselves have zero tailpipe emissions; the emissions intensity of hydrogen production is discussed in depth in Chapter 7.

Box 3-3
Technology Lock-in and Maintaining Optionality for HDVs

Commercial HDVs generally have a shorter lifespan than other fossil fuel-consuming capital equipment (e.g., industrial equipment or power plants). This makes technology transitions—and maintaining optionality—easier for corporate entities in Transportation than in other sectors. For HDVs, non-ZEV AFVs could be used in the short term and exchanged for ZEVs later on as technological progress is made and costs come down.[48]

Infrastructure, however, remains a stumbling block for this sort of transition. Lack of refueling infrastructure will limit the growth of these short-term AFV technologies, yet investing in that infrastructure does not make economic sense if the technologies will be replaced in the slightly further future.

Another option for HDVs is natural gas, whether in the form of compressed natural gas (CNG) or liquified natural gas (LNG). Natural gas is currently cheaper than nearly any other transportation fuel. On a national level, LNG is 58 cents per GGE cheaper than diesel and CNG is 67 cents per GGE cheaper.[49] LNG is generally better for long-haul uses, but both vehicles and storage/refueling infrastructure for LNG have additional technology requirements and costs. LNG might make the most sense for point-to-point transportation (such as between major cities), to minimize infrastructure requirements. To facilitate this option, LNG refueling infrastructure could be placed along specific, heavily traveled routes.

Also, emissions from natural gas-fueled vehicles could be further lowered by use of renewable natural gas (RNG), on its own or blended with fossil gas; as noted elsewhere in this report, however, the availability of RNG supplies may be limited and there could be competition with other sectors for this resource.

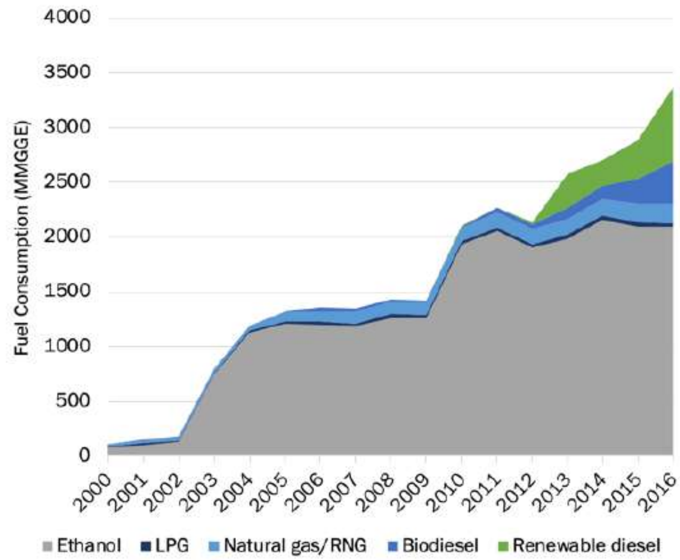
Biofuels also offer an option for HDVs. Unlike natural gas, biofuels are not a fossil fuel; however, "biofuel vehicles" often run on blends of biofuel and conventional fuels such as B99 or E85. These blends are distinguished from blends such as B20 and E10 that can function in conventional vehicle engines. Also, biofuels like E85 are currently more expensive on a per-GGE basis than conventional fuels.[50] They are, however, more competitive than hydrogen, and could become more competitive with conventional fuels if supplies expand. Innovation could also lead to lower-cost "advanced" biofuels with new uses, such as drop-in fuels that are chemically indistinguishable from fossil fuels. (For more information on biofuel technologies and supply, see the Biofuels Addendum below.)

There are HDV and LDV models that can run on both conventional fuels and natural gas (bi-fuel vehicles); or conventional fuels and biofuels (flex-fuel vehicles, or FFVs). Conventional vehicles can generally be converted to run on either of these fuels; because FFVs are widely available, however, biofuel conversions of conventional vehicles are uncommon.[51]

Both biofuels and natural gas require specialized fueling infrastructure; this makes fleet adoption more attractive as fleets generally do not have to rely on public refueling infrastructure. One advantage for biofuels is that conventional refueling infrastructure can be converted into biofuel infrastructure;[52] whereas NGVs require a completely new infrastructure for gaseous fuels. In general, it is difficult to compare how these AFVs perform in terms of emissions, both because information is harder to come by and because emissions are often dependent on usage. For example, hybrids will have a better relative performance for uses that require more city driving or idling.

It is difficult to find year-by-year statistics on the adoption of non-ZEV AFVs. Data on the use of the fuels they consume are good proxies. Consumption of every alternative fuel tracked by CARB has grown significantly since the early 2000's (Figure 3-11).[53] Much of this growth has been in biofuel blending for conventional vehicles (see the Biofuels Addendum), but AFVs have also played a role. The growth of these fuels has helped establish production pathways and infrastructure that could help facilitate further AFV adoption.

Figure 3-11
Growth in Consumption of Alternative Transportation Fuels. 2000-2016



Much of the increased alternative fuel consumption has come from requirements for blending biofuels with petroleum fuels, but some is attributable to growing numbers of AFVs. Source: EFI, 2019. Compiled using data from CARB, 2018.

Costs and Challenges of AFV Deployment

Estimating costs for this pathway is difficult, due to the variety of options included under the umbrella of AFVs, as well the fact that technology, fuel, and infrastructure all contribute to the cost. The analysis below focuses only on meeting the target of five million ZEVs, not the costs of non-ZEV AFVs. It also assumes that the mandate will be met with BEVs and PHEVs, which from this analysis, is the most likely and least-cost option. This analysis examines the costs of deployment of the most common ZEVs (BEVs and PHEVs) in order to illustrate these possible needs. California already provides subsidies for ZEV purchases and infrastructure construction, but these may be inadequate.

As noted, BEVs and PHEVs currently have a higher upfront cost than gasoline cars but generate savings over time because of lower fuel and maintenance costs. A recent comparison between four popular BEV models and similar conventional vehicles found that upfront costs for the BEVs ranged from $3,150 *less* to $11,300 more,[54] after the application of the baseline California Clean Vehicle Rebate[a] of $2,500.[55] National analysis of the 2018 Model Year indicates that the average BEV owner saves $82 on maintenance and $836 on fuel annually[56] (assuming 11,346 vehicle-miles traveled, the national LDV average).[57] In California, due to relatively higher gasoline prices, the fuel savings are over $908 annually; BEV owners in California start recouping their initial extra investment within seven to eleven years and within the average vehicle lifespan.

These cost comparisons may not show the whole picture, in part because the limited number of BEV and PHEV models currently available means direct comparison is difficult. There are currently no BEVs or PHEVs available that are comparable to some of the larger sport utility vehicles (SUVs) and light trucks, whose inclusion impacts the fuel cost comparisons. Most of the less expensive BEVs currently on the market also have a more limited range, meaning that, in general, consumers do not see them as perfect substitutes for conventional vehicles. These estimates may also underestimate the cost of the pathway because many manufacturers sell ZEVs for less than they cost to produce, possibly by $7,000 to $10,000.[58] Losing money on each of these vehicles sold makes financial sense to manufacturers when it allows them to comply with emissions and other environmental standards (such as CAFE, discussed below);[59] it also serves as a signal to investors that they are devoting resources to a technology that is increasingly important in the industry.[60]

Other factors could influence costs. Differences in VMT patterns for BEV and PHEV drivers (including a possible "rebound effect" from fuel savings) could impact the calculations. Also, how the grid responds to the rapid deployment of BEVs and PHEVs is uncertain (see Box 3-2), but costs from those impacts—such as the capital cost of new generation assets, or the additional operational costs of managing a steeper Duck Curve— could impact the price of charging these vehicles. There could also be unanticipated effects from ZEV deployment on fuels and infrastructure for conventional vehicles, but these effects are unlikely to be felt in the near term, since the number of conventional vehicles on the road in 2030 will likely be equal to or larger than today's.

An important concern for BEVs and PHEVs—the cost of replacing a vehicle battery—has been regulated by California since 1998. California has greater warranty requirements than other states, mandating that ZEV manufacturers provide 10-year/150,000-mile coverage for batteries or other energy storage devices,[61] although this falls short of the average 11.3-year lifespan for vehicles in California. As of 2017, Chevrolet said that it had yet to replace an under-warranty battery for the plug-in hybrid Volt model during its seven years on the market.

In the event that a vehicle outlasts the warranty, the out-of-warranty replacement cost for a battery varies by manufacturer and battery size; the list price for a Chevrolet Bolt is around $15,700 and the price for the smaller-capacity Nissan Leaf is $5,500.[62] This is substantially higher than the average price of a gasoline engine replacement (which

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[a] California tax credit used in lieu of federal tax credit, which is being phased out for some manufacturers; see Marielle Segara, "Tax credit for GM's electric cars starts to phase out," *Marketplace*, March 28, 2019, https://www.marketplace.org/2019/03/28/business/tax-credit-gms-electric-cars-starts-phase-out-april-1st

generally runs from $2,250 to $4,000),[63] but battery prices are expected to be significantly lower by the time current BEVs and PHEVs reach the end of their warranties.[64]

Adding large amounts of ZEVs in California will also require adding refueling infrastructure. Currently, the U.S. has a ratio of about 0.048 slow-charging ports per BEV/PHEV and 0.009 DC fast chargers per BEV/PHEV. There are also approximately 1.225 private chargers per vehicle in North America (0.9 residential chargers per vehicle and 0.325 workplace chargers per vehicle). The ratio of slow to fast charging points in California is slightly lower than the U.S. average. The state has 15,700 slow chargers and 2,600 fast chargers; this works out to 0.044 and 0.007 chargers per vehicle, respectively, for the approximately 355,000 PHEVs and BEVs on the road.

Executive Order B-48-18, which established the five million ZEVs goal, also set a goal of 250,000 charging stations by 2025, of which 10,000 would be fast chargers. These goals align well with the current ratio of chargers to vehicles, assuming the number of fast chargers is slightly above the minimum: 220,000 slow chargers and 30,000 fast chargers would align with current ratios. Assuming the ratio of residential and workplace chargers remains the same, those numbers would increase to 4.5 million and 1.6 million respectively. It should be noted, however, that charging patterns (home vs. workplace vs. public) vary by geography. There are also outstanding questions of how economies of scale play into the charging infrastructure, so the necessary ratio of chargers to vehicles may be lower.

There is also a great deal of variation in price for charging infrastructure, even within the main charging level categories. Equipment costs are driven by the number of ports in a unit, the type of mounting system (wall or pedestal), and the presence of “smart” features and network connections. Installation costs vary mainly because of issues of location (such as surface and distance from the supply panel) and load (more units and greater load require more modifications to the electrical system). There are also geographic conditions that affect installation costs, such as variability in the cost of permits and labor.

Table 3-3
Average Installation Costs for Chargers, U.S. and California

Type of charger	CA Average	Rest of U.S. Average
Single-family Residential Level 2	$1,512	$1,499
Multi-unit Residential Level 2	$3,744	–
Public Level 1 or 2	$3,533	$2,914
Workplace Level 1 or 2	$2,419	$5,330
Fleet Level 1 or 2	$2,902	$1,499
DC Fast	–	$23,662

Source: EFI, 2019. Compiled using data from EPRI, 2014.

Generally, California has higher charger installation costs than the U.S. average (Table 3-3). One study found that installation costs in major California markets were 5 to 35 percent higher for residential Level 2 units and 29 to 43 percent higher for public Level 2 units. The Los Angeles and San Francisco markets were in the top three most expensive markets nationwide for both residential and public units.

Scaling up the charging infrastructure in California will require a substantial investment. Infrastructure operators can recoup their investment over time by charging for use, but the initial capital expenditure may be an issue. Using the targets in Executive Order B-48-18 and assuming the use of lowest-cost equipment (Table 3-4), public slow chargers could cost around $865 million and public fast chargers could cost around $1.01 billion. Meeting just the 10,000-charger minimum could cost around $336 million. Assuming that the percentage of ZEV owners who are multifamily home residents stays constant (and that they install home charging at the same rate), about 630,000 residential chargers will be installed for those families, at a cost of about $3.3 billion. The cost for charging in single-family homes would probably fall between less than $1 billion and $11.7 billion, depending on how many owners opt to install Level 2 charging.

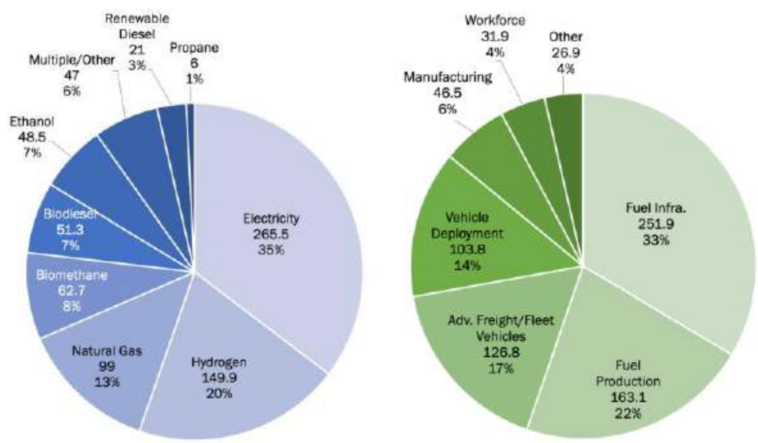
Table 3-4
U.S. Charger Installation and Equipment Costs

Type of charger	Equipment cost	Installation cost
Home Level 1	$0	$200-$2,000
Home Level 2	~$1,500	$200-$2,000
Commercial Level 1	$300-$1,500	$0-$3,000
Commercial Level 2	$400-$6,500	$600-$12,700
DC Fast	$10,000-$40,000	$4,000-$51,000

Source: EFI, 2019. Compiled using data from AFDC, 2015; CARB.

In total, the cost of installing chargers for five million ZEVs is likely to be over $5.4 billion but could be as high as $17.2 billion. Executive Order B-48-18 proposes a $2.5-billion investment plan for expanding the ZEV stock in California, covering both infrastructure investment and vehicle rebates. Additional funding—whether in the form of grants, rebates, or loans—will probably be necessary to incentivize the necessary infrastructure.

Figure 3-12
Allocation of Alternative and Renewable Fuel and Vehicle Technology Program Investments, 2007-2018 ($MM)



ARFVTP breaks down its disbursements by the type of project funded (right) and which alternative fuel the project is focused on (right). A third of ARFVTP investments since the program's start in 2007 has been devoted to fuel infrastructure, the largest project type share. On a fuel basis, the majority of funding has been devoted to electric or hydrogen vehicles. Source: EFI, 2019. Compiled using data from CEC, 2018.

California already has a mechanism in place for investments in AFV technology. The Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) is a CEC program that disburses grants for a variety of AFV-related purposes, including fuel production, vehicle deployment, and infrastructure (Figure 3-12).[65] The ARFVTP, which is funded with fees from vehicle registrations and smog abatement, has already awarded over $750 million since it was created by AB 118 in 2007. In 2013, AB 8 extended its funding through 2024.[66] In 2018, SB 1000 expanded the ARFVTP's infrastructure mandate to include programs that encourage equal access to BEV and PHEV charging infrastructure, grid integration, and managed charging.[67] In addition, SB 1000 banned ordinances that would prevent certain vehicles (especially PHEVs) from accessing public charging infrastructure.[68]

Scaling up the charging infrastructure in California will require a substantial investment…In total, the cost of installing chargers for five million ZEVs is likely to be over $5.4 billion but could be as high as $17.2 billion.

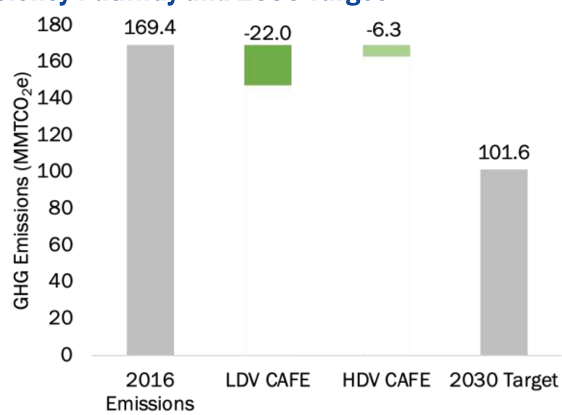
Another related challenge to this pathway is consumer behavior. While policies can lead to ZEV purchases in specific ways—such as acquisition mandates for public fleets—the vast majority of ZEV adoptions will be by individuals. Cost is motivating factor, but there are other consumer concerns as well. The majority of Americans, when surveyed, still cite range anxiety and lack of charging infrastructure as reasons that they are less likely to purchase a BEV—though these numbers are falling dramatically as BEV performance improves.[69] Other issues that may turn away consumers are the time of charging and performance degradation in cold conditions.

Finally, is the availability of critical materials could raise concerns going forward. BEVs and PHEVs depend on lithium-ion batteries that, with few exceptions, use lithium and cobalt. A key concern for the mass deployment of these vehicles is the availability of these metals. For a more in-depth exploration of these concerns, refer to Box 2-4 in Chapter 2.

Pathway 2: Increasing Fuel Efficiency and Decreasing Tailpipe Emissions

In addition to increasing the stock of AFVs, California is making progress towards decarbonizing Transportation with fuel economy and tailpipe emissions standards. The primary avenue for this is through CAFE standards, a federal regulation (created with input from CARB) that imposes both fuel economy and tailpipe emissions standards on auto manufacturers. Efficiency improvements have the highest mitigation potential in the Transportation sector, resulting in 28.3 $MMTCO_2e$ in reductions (Figure 3-13). CAFE could, in fact, have one of the largest emissions reduction impacts of any single policy in any sector.

Figure 3-13
Efficiency Pathway and 2030 Target



The tailpipe emissions part of the CAFE standards primarily targets fuel efficiency but also covers other areas of efficiency such as air conditioner improvements, which could even impact Transportation's use of substitutes for ozone-depleting substances (ODS). Source: EFI, 2019. Compiled using data from CARB, 2018.

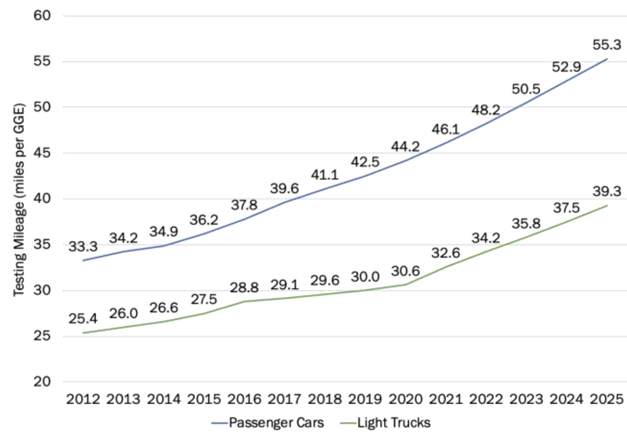
California has had its own vehicle tailpipe emissions standards in place since 1994. The Clean Air Act authorizes the EPA to grant California a waiver to establish standards that are more stringent than the federal requirements. The statute also allows other states to opt into the standards set by California.[70] California requested a waiver in 2005, but it was denied by the Bush administration.

In 2009, the EPA reversed course and allowed California to adopt the "Low Emission Vehicle (LEV) III" amendments. LEV III required more stringent GHG emissions reductions for Model Years 2015-2025 and also included criteria pollutant limits. Negotiations during the Obama administration between CARB and the federal agencies in charge of CAFE (EPA and the National Highway Transportation Safety Administration) resulted in a single standard for California and the rest of the country that applies to LDVs for Model Years 2017-2025.[71] These agencies also collaborated on a standard for 2018-2027 for HDVs.[72]

California's LEV regulations remain on the books, but manufacturers can meet them by meeting the CAFE standards; in essence, the federal regulation currently supersedes the state one. Figure 3-14[73] shows how emissions standards in California have progressed over time, with the combination of the LEV amendments and the LDV CAFE standards.

Figure 3-14

Estimated Average Required Fuel Economy, 2010 Calculation Baseline



The unified California and federal CAFE standards for LDVs will require approximately a 33 to 35 percent increase in vehicle fuel economy by 2025 over 2018 levels. Source: EFI, 2019. Compiled using data from NHTSA, 2012.

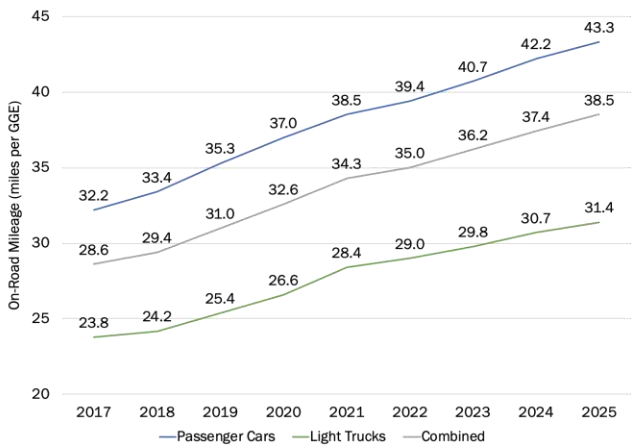
The Trump administration has attempted to both freeze the federal standards after 2020 and revoke California's Clean Air Act waiver in an effort to ease regulations on automobile manufacturers. To date these efforts have been blocked by federal courts. The administration acknowledged that freezing the standard would result in a 5 percent increase in CO_2 through 2026 and a 9 percent increase through 2035.[74] This report's estimates found that the impact could be even greater: the impact of the LDV standard alone could be 22.0 $MMTCO_2e$ (19 percent of 2016 LDV emissions); the LDV and HDV standards combined could be an increase of up to 24.6 $MMTCO_2e$ (15 percent of 2016 total Transportation emissions). California's policy is to continue with current CAFE standards, the assumption used in this analysis.

The CAFE standards for LDVs require each automobile manufacturer to achieve a certain level of fuel efficiency and emissions, calculated by taking a production-weighted average of all the models in the manufacturer's fleet.[75] Non-compliance results in a fine; over-compliance is rewarded with tradeable credits. EPA also sets minimum standards for emissions that each model must meet. CAFE specifically prescribes how manufacturers calculate their averages and the regulation acknowledges that actual emissions will typically be 25 percent higher than the values implied by the regulation.[76]

The 2017-2025 LDV regulation has different standards based on a vehicle's footprint (physical dimensions), replacing an earlier system that differentiated based on weight. The rationale for this is to avoid incentivizing manufacturers to make smaller-footprint cars to meet their compliance targets. Because this footprint-based formula is adjusted annually and for each manufacturer, the actual requirements will depend on the size of the cars a given manufacturer chooses to produce. The LDV CAFE standards do, however, include estimated averages for required and achieved averages (using compliance flexibilities) and for laboratory-testing fuel economy as well as on-road fuel economy (Figure 3-15).[77]

Figure 3-15

Estimated Average Achieved On-Road Fuel Economy, 2010 Calculation Baseline

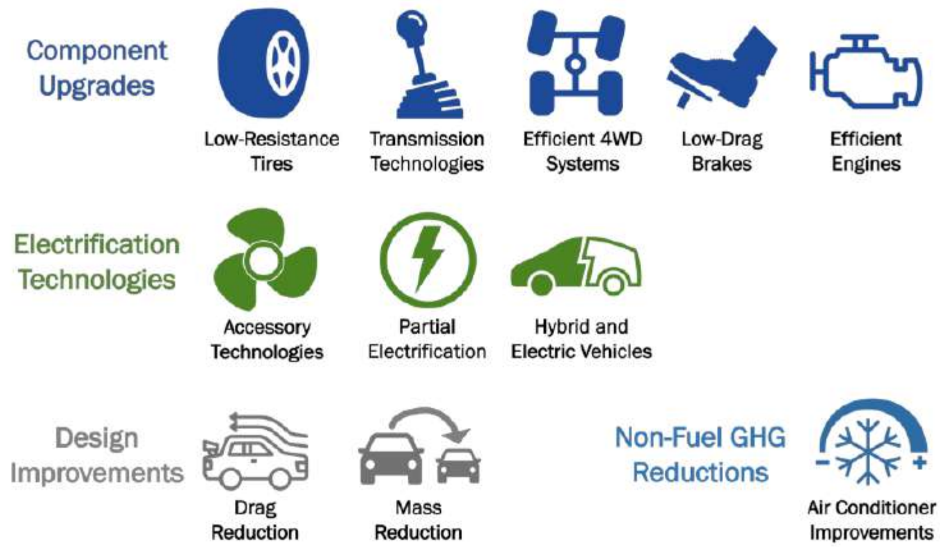


The unified California and federal CAFE standards for LDVs will achieve approximately a 30 percent increase in vehicle fuel economy by 2025 over 2018 levels. Source: EFI, 2019. Compiled using data from NHTSA, 2012.

In lieu of a footprint-based formula, the HDV standard uses "work-based" measures, such as payload and towing capacity. Because there is a greater degree of variation when using this measure, the HDV regulation does not include estimated year-by-year averages. It does, however, include an estimated industrywide required fuel economy for Model Year 2030, which ranges from 19.03 to 20.95 miles per gallon (mpg), depending on the strictness of the implementation regime.[78]

Manufacturers have two primary options for achieving compliance with the increasingly stringent standards. The first is to produce more AFVs whose mpg equivalent is generally higher than the minimum set by the standards.[79] The second is to use technology and design improvements to decrease the emissions from conventional vehicles (Figure 3-16). These improvements could include new engine and transmission technologies that improve efficiency and allow downsizing, lightweight materials, improved aerodynamics, tire resistance reductions, and improvements to decrease space conditioning energy needs.[80] Improvements to air conditioning that decrease the emissions of high-global-warming-potential gases can be used to meet tailpipe emissions requirements, but not fuel economy requirements;[81] this is one of the only Transportation regulations that directly impacts non-combustion emissions. Technological development in areas such as additive manufacturing and advanced sensors could accelerate these design improvements.

Figure 3-16
Technologies Considered by NHTSA and EPA under the LDV CAFE Standards



NHTSA and EPA considered a range of policies when determining what emissions/fuel economy standards were feasible for LDVs in the near future. Air conditioner improvements are one area where the two agencies diverge in their compliance pathways. Source: EFI, 2019. Compiled using data from NHTSA, 2012. Icons from The Noun Project.

Other existing or potential regulations that could impact fuel economy improvements include the Energy Tax Act of 1978, which includes a federal "Gas Guzzler Tax" for car models that fail to meet a minimum fuel economy standard, set at 22.5 mpg since 1991.[82] The tax only applies to "passenger cars," which excludes trucks, SUVs, and minivans;[83] this limits its effectiveness. Also, most models that incur the tax are luxury vehicles, so the tax, which starts at $1,000 and scales to $7,700,[84] may not be a deterrent to potential consumers. It is possible that manufacturers might modify cars so that they meet the threshold set by the tax, but it would be difficult to distinguish this effect from that of CAFE standards.

There are also regulations that govern the emissions of specific criteria pollutants at both the federal and state level, especially for diesel vehicles. California's Diesel Vehicle Regulation, for example, imposes limits on HDV emissions of particulate matter, nitrogen oxides, and other criteria pollutants.[85] A similar regulation also applies to off-road diesel vehicles.[86]

Other methods for improving fuel economy include tire efficiency standards and promotion of eco-driving. Tire materials and inflation levels can have a major impact on vehicle fuel economy.[87] The main policies for this include a national requirement that vehicles come equipped with tire pressure monitoring systems, and the NHTSA's tire efficiency rating system, which has been in place since 2010.[88]

Eco-driving techniques include avoiding idling, driving at efficient speeds, and avoiding rapid speed changes.[89] Policies to promote eco-driving that have been enacted outside the U.S. include mandating that it be taught in driver's education courses, or incentivizing it in corporate fleets.[90]

Costs and Challenges of Efficiency Improvements

As with ZEVs, efficiency improvements will likely generate savings for consumers in the long run due to lower spending on fuel. EPA and NHTSA each have their own cost estimates for the LDV program;[91] the regulations also provide estimates using different discount rates.[92] Using the range of costs provided in the regulations, weighted by California's share of the national vehicle stock (around 11.3 percent),[93] the following costs can be estimated:

- The standards for LDVs will likely cost \$16.8 billion to \$18.0 billion over the lifetime of the vehicles covered; benefits from fuel savings will likely be \$42.6 billion to \$60.0 billion. Most of the benefits for later Model Years will occur after 2030; the savings for Model Years through 2021 will likely be \$17.7 billion to \$22.6 billion.
- The standards for HDVs will likely cost \$2.2 billion to \$3.4 billion. Savings will likely be \$9.2 billion to \$19.7 billion, although they will not be fully felt before 2030.

The major driver for the cost estimates is the technology, although additional maintenance costs, additional congestion, and other costs due to the rebound effect (discussed below) are also factored in. The amount of additional cost passed through to consumers is reflected by the following vehicles cost changes by Model Year, as estimated by EPA and NHTSA:

- Average additional cost for LDVs in Model Year 2019 is likely \$438 to \$467 per vehicle. By Model Year 2025, it is estimated at \$1,257 to \$1,836.
- Additional cost for tractors (part of the regulation, although included under Agriculture, not Transportation, in CARB's accounting) in Model Year 2021 is estimated at over \$6,400. By Model Year 2027 it rises to over \$12,000.
- For other categories of HDV, the Model Year 2021 average additional cost will likely fall between \$500 and \$1,200, and for Model Year 2027, between \$1,000 and \$2,700.

The government's cost estimates indicate that, in most cases, vehicle owners will earn back the additional costs over the lifetime of the vehicle. The cost-benefit analyses for these regulations also include various additional positive externalities, such as the avoided social cost of carbon, increased productivity from less time spent refueling, energy security, and health benefits from reduced non-GHG pollutants. The regulations will likely be a net economic boon without factoring in these externalities, but these additional benefits increase the appeal of efficiency improvements as a mitigation strategy.

The main technical challenge for the efficiency pathway is simply whether the regulations can be as effective as they are meant to be. A key issue in the political debate over the CAFE standards is the "rebound effect," an economic principle that states that when a technology becomes more efficient, people use it more. There is substantial empirical evidence to suggest that—all else being equal—fuel economy improvements lead to increases in VMT (though experts differ on the size of that effect).[94] The rebound effect is written into the current CAFE standards as a consideration for estimating the emissions reduction potential of the regulation, but its effects could end up being larger than anticipated.[95] The rebound effect is also a concern for other Transportation pathways: for example, non-ZEV AFVs could also experience a rebound effect in terms of emissions, with the cheaper fuels leading to more usage.

The main technical challenge for the efficiency pathway is simply whether the regulations can be as effective as they are meant to be. A key issue is the "rebound effect," an economic principle that states that when a technology becomes more efficient, people use it more.

In addition, overlapping policies could diminish each other's effects. The CAFE standards, for example, can be met by producing more AFVs, in lieu of improvements to conventional vehicles. If manufacturers do this to help reach the ZEV target, it could reduce the impact of CAFE. Also, some efficiency measures that manufacturers implement could depend on consumers actually using them effectively; this is the case with tire-pressure monitoring systems described above.

Finally, there are implementation issues with the CAFE standards. As mentioned in the methodology section, federal regulations may not have the same impacts on individual states. Californians could exclusively buy relatively inefficient SUVs while Oregon buys exclusively hybrid compacts, without manufacturers falling afoul of the regulation (although consumer trends in California seem to indicate that such a scenario is unlikely). On the other hand, challenges to the current regulation imperil its status at the federal level; the effectiveness of CAFE in shaping the automobile industry would likely be diminished if it reverts to a state-level regulation.

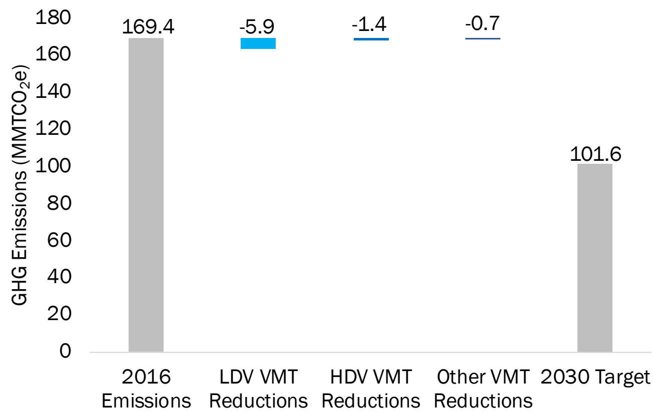
Pathway 3: Decreasing Vehicle-Miles Traveled

Demand reduction is another way to mitigate the emissions of on-road transportation, specifically through reducing VMT. It has the smallest potential of the four pathways examined here (8.0 $MMTCO_2e$), and California policy for reducing VMT is relatively underdeveloped. It is, however, the only pathway that is a viable means of emissions reduction by 2030 for all subsectors within Transportation (Figure 3-17). Unlike the other pathways in

Demand reduction can be hard to achieve, since it requires changes in consumer behavior. Tactics for changing VMT, however, are similar to those used to change demand in other sectors; providing alternatives and economic incentives to change behavior. The most effective ways to reduce VMT likely fall into the former category and involve infrastructure improvements to, for example, reduce road congestion and increase availability of mass transit.

Figure 3-17

Demand Reduction Pathway and 2030 Target



VMT reductions for on-road travel will likely require a cocktail of different transportation-related and land use policies. Reduced consumption of certain goods and supply chain efficiency can decrease demand from other subsectors. Source: EFI, 2019. Compiled using data from CARB, 2018.

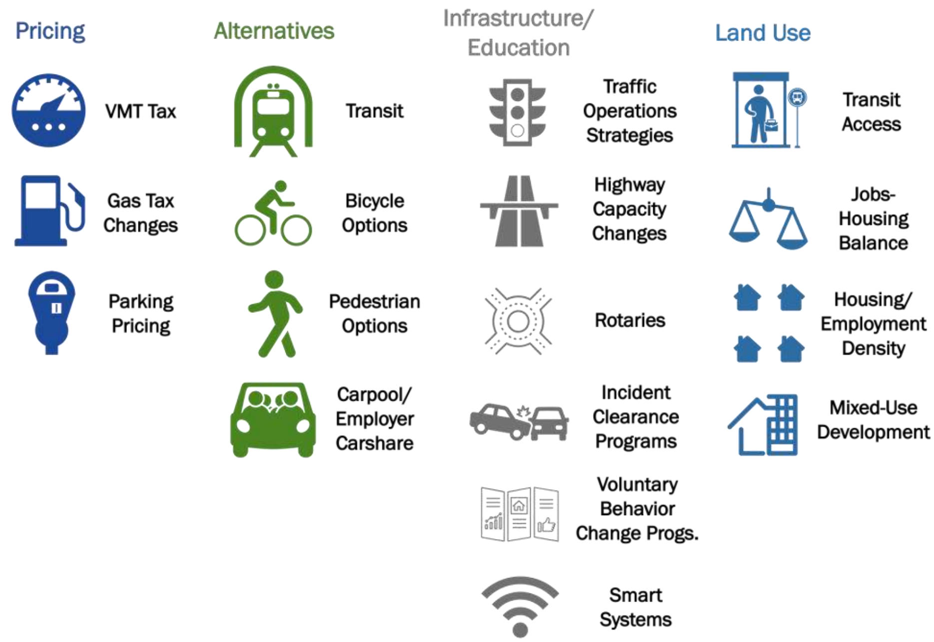
California's main policy mechanism for achieving VMT reductions is SB 375, passed in 2008.[96] SB 375 required CARB to work with regional transportation planning agencies to set regional emissions goals, and develop policies for achieving them by reducing VMT and urban sprawl.[97] The targets established in SB 375 were revised in 2018 (as part of a mandatory review every eight years); they measure per-capita carbon reductions from LDVs due to VMT-related efforts against a 2005 baseline.

Current targets for 2020 range from a 3 percent reduction to a 15 percent reduction, with a median of 8.5 percent. Reduction targets for 2035 range from 4 percent to 19 percent, with 15.5 percent being the median.[98] It is important to note that regional agencies can include some reductions from policies that fall under other pathways (such as building ZEV infrastructure) in their calculation, but not others (such as statewide or national improvements in fuel efficiency).[99] It is also worth noting that SB 375 targets do not cover the whole state; rural areas not in a Metropolitan Planning Organization are excluded.

In 2014, researchers from the University of California, Davis and the University of Southern California identified policies that could be used to achieve SB 375 targets (Figure 3-18). Their analysis included "transportation-related" policies, such as congestion reductions and public transit access noted above, as well as strategies such as promotion of telecommuting. Some of the transportation-related policies considered include pricing and taxation options—including increasing gas taxes or parking prices, or taxing VMT directly. The other policies analyzed were land use-related policies, which included influencing employment and residential density and planning transit systems around land use changes, among others.[100]

Figure 3-18

Key Transportation and Land Use Policies for SB 375 Implementation

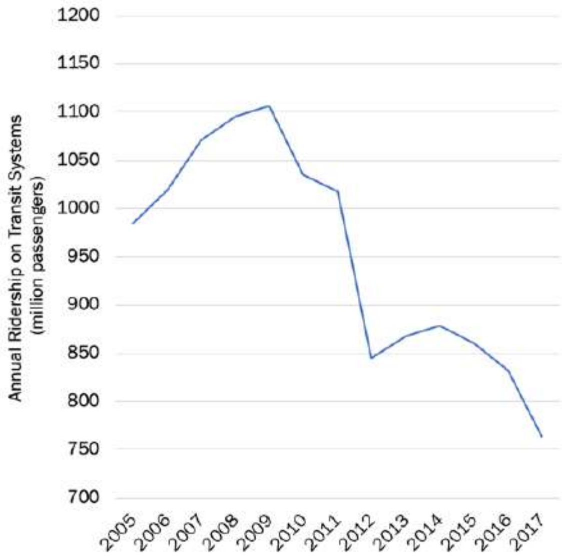


A variety of policies, across four broad categories, are available to implement SB 375. Source: EFI, 2019. Compiled using data from CARB, 2017. Icons from The Noun Project.

While SB 375 focuses on LDVs, some strategies can have an effect on non-LDV VMT as well. Pricing mechanisms will impact HDVs as much as LDVs; the introduction of alternative modes of transportation, such as the California High-Speed Rail project, could decrease dependence on aviation and trucking (though that project is facing significant issues and uncertainties). Other strategies may also work, since aviation and trucking are more heavily dominated by industrial and commercial uses. Consumers could, for example, reduce consumption of goods that require air, rail, truck, or water-borne transport, and companies can take independent action to improve the overall efficiency of their supply chains.

Despite the efforts since the passage of SB 375, VMT have been slow to change and use of alternatives to personal vehicles has decreased. Like many Transportation indicators, VMT—per capita and per vehicle—dipped during the 2008 Great Recession. Since SB 375 went into effect in 2009, however, VMT per capita has stayed essentially level (down 0.6 percent) and VMT per vehicle has risen 21.2 percent.[101] In 2017, VMT per capita was 15.5 percent lower than the national average;[102] on a per vehicle basis, California is just 5.5 percent lower.[103] These differences are largely attributed to rates of vehicle ownership, which have declined in California (hence the diverging trends since 2009); they are also are lower there than the national average. Decreasing VMT on a per capita basis is ultimately a more important goal, since California's population will likely only grow, whereas lower vehicle ownership (and corresponding higher per vehicle VMT) could actually be good for decarbonization

Figure 3-19
Bus and Rail Transit Ridership, 2005-2017



There has also been a downward trend in transit ridership in California, especially in major cities such as Los Angeles and Sacramento. Source: EFI, 2019. Compiled using data from California State Controller's Office, 2019.

There has also been a downward trend in transit ridership, with especially large reductions (by percentage) on systems in Los Angeles and Sacramento (Figure 3-19).[104] Transit systems can be a driving force for lowering VMT in urban areas, so this trend—as well as the stagnant VMT trends overall—raises questions about overall effectiveness of SB 375 and its implementation.

Innovation may be key to achieving VMT reductions in on-road transportation. One emerging option is "micro-transit"—ride-hailing (e.g., Uber and Lyft), bike-sharing, etc.—facilitated by ubiquitous smartphones. Some municipalities have embraced these systems, hoping they can act as de facto extensions of the public transit system. The emissions benefits of such services, particularly ride-hailing, are, however, mixed. Evidence suggests that, at least currently, ride-hailing services may be adding to VMT (and increasing congestion) by replacing trips that would previously have been accomplished by walking, biking, or transit, rather than trips in personal vehicles.[105]

Innovation may be key to achieving VMT reductions in on-road transportation. The emissions benefits of new services, particularly ridesharing, are, however, mixed.

Another technological opportunity for reducing VMT is the digitalization of Transportation. "Smart" systems for parking and traffic management may decrease congestion, and the arrival of autonomous vehicles (AVs) could lead to more efficient routes and driving behaviors. Whether these systems result in emissions reductions will depend, in large part, on how programs and policies that support them are implemented.

Costs and Challenges of Demand Reduction

The major challenge of this pathway is its unpredictability, which springs from the reliance on behavioral change and the fact that a combination of varied solutions will likely be necessary. Setting targets for VMT reduction can only do so much; implementing jurisdictions could fall short if proposed solutions do not end up having the expected effects. California may need more concrete, statewide directives on VMT in order to decrease the risk of failure in this pathway.

The uncertainty in this pathway extends to cost. Measuring the costs is a difficult proposition, largely because there is not a single, technological solution for reducing VMT. Infrastructure and incentive programs both create costs for administering entities, though those costs vary substantially. For example, the cost to create new bike lanes is substantially different than the cost to build a new rail line. Certain pricing mechanisms, such as taxes and tolls, can help defray these costs (as gasoline taxes already do). The policies that are most effective will be situationally dependent as well; what works for Los Angeles might not work for Merced, or San Francisco, for that matter. In tailoring solutions to specific geographic areas, policymakers should also consider the effect of policies on disadvantaged and minority groups (Box 3-4).

Another consideration are the unique co-benefits of reducing VMT, such as less congestion (i.e., less lost productivity) and fewer accidents. Some evidence has shown, for example, that replacing fuel taxes with VMT taxes that raise roughly the same amount of revenue could lead to economic gains due to these co-benefits.[106]

Box 3-4.

Social Equity Concerns and Transportation Policy

An important concern for the VMT pathway is ensuring that social equity is considered in decarbonization solutions. Policies that attempt to disincentivize greater use of personal vehicles could end up having disproportionate effects on people in lower socio-economic strata, for whom access to alternative transportation is an issue in some communities. These policies could also have an outsize effect on rural communities, where VMT tends to be higher already. So far, California's regionally focused strategy for this pathway has managed to avoid some of these pitfalls, but future policy should take these considerations into account.

Social equity should also be a consideration in other pathways. The cost of ZEVs has meant that adoption has mainly been by persons in higher socioeconomic strata. SB 1275 (2014), in order to mitigate this issue, directs CARB to create programs that promote clean transportation in disadvantaged communities.[107] Policies to this end have included rebates and financing assistance programs, ZEV car-sharing, and vehicle trade-in programs.[108] The LCFS pathway, too, has the potential to impact disadvantaged groups disproportionately; without supplementary action, the pass-through costs to consumers (see below) could end up resembling a regressive tax, in which lower-income households pay a greater proportion of their income than higher-income households.[109]

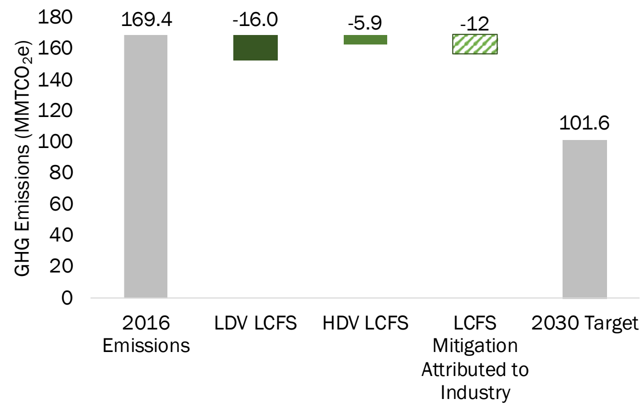
Pathway 4: Low-Carbon Fuels

Decreasing the carbon intensity (CI) of fuels is a key cross-cutting emissions reduction strategy for California. There are two key policies for decreasing the carbon intensity of fuels in California: the state LCFS and the federal Renewable Fuel Standard (RFS).

The LCFS is targeted at fuels for the Transportation sector, but also affects the Industrial sectors; discussion in this chapter will focus mainly on benefits to the Transportation sector. The LCFS, and complementary policies, could lead to 33.9 $MMTCO_2e$ in reductions across the economy (Figure 3-20).

Figure 3-20

Low-Carbon Fuels Pathway and 2030 Target



Emissions reductions from the LCFS will primarily come from the gasoline and diesel provisions. While jet fuel is also covered in the 2018 update, CI improvements will likely only come from upstream changes that would not be reflected in this sector. Source: EFI, 2019. Compiled using data from CARB, 2018.

The LCFS establishes a credit market for transportation fuels in which regulated parties—importers or refiners of gasoline, diesel, and substitutes for those fuels—earn credits for producing cleaner fuels that are below the annual carbon intensity threshold, measured in lifecycle emissions per megajoule.[110] Excess credits generated by a firm can then be bought by non-compliant petroleum providers.

Under the LCFS, regulated parties achieve compliance largely through increasing their production of biofuels (or, less commonly, other alternative fuels). This can mean blending greater volumes of ethanol or biodiesel into their fuel supply, producing more drop-in biofuels, or producing fuels for AFVs that operate entirely or partially on biofuels. There are also certain transportation energy sources—including electricity and biogas—that are presumed to be compliant, and producers of those fuels can opt into the LCFS and generate credits which can then be sold.[111] (For more information on biofuel technologies and supply, see the Biofuels Addendum.)

Regulated parties can also improve the carbon intensity of their fuels by decarbonizing their upstream supply chains. Gasoline and diesel from certain sources might meet current compliance benchmarks. There are also specific improvements to crude production or refining that can generate credits, including the following:

- Use of renewable energy or renewable hydrocarbons for energy;
- Lowering the complexity[b] or energy use of a refinery;

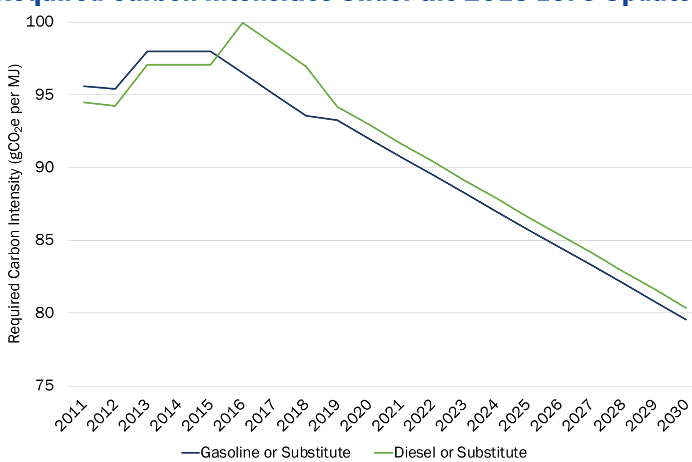
[b] Complexity is measured by a modification of the Nelson Complexity Score, a “commonly used industry measure of a refinery’s ability to convert crude oils to finished fuels, taking into consideration the complexity of the technologies

- Production of renewable hydrogen;[c]
- Use of AFVs for crude transport; and
- Use of carbon capture, utilization, and storage (CCUS).

More credits can also be generated from alternative fuels with lower upstream CIs, even when their downstream emissions are considered to be zero.

Figure 3-21

Required Carbon Intensities Under the 2018 LCFS Update



The pending 2018 update to the LCFS covers three fuels and extends the standard to 2030, with a goal of a 20 percent carbon intensity reduction by that year. Source: EFI, 2019. Compiled using data from CARB, 2018.

The LCFS was originally established by Executive Order S-01 (2007), one of the first regulations on Transportation after the establishment of the GHG targets in AB 32 in 2006.[112] It has been amended on an ad hoc basis since then; the newest version was adopted by CARB in 2018 and became effective on January 4, 2019.[113] The 2018 update extends the program to 2030 and amends the benchmarks for gasoline and diesel (Figure 3-21), loosening the near-term goals but ramping to a 20 percent decrease in CI by 2030 (below 2010 levels).[114] There are some exceptions to the standard, including lesser-used fuels (e.g., propane) and fuels for specific uses (e.g., aviation, rail, marine, and military).[115]

The 2018 update also changed what fuels fall into the opt-in category (i.e., are presumed to meet the CI standards for 2030); hydrogen and fossil natural gas were removed, and alternative jet fuel and renewable propane were added.[116] Even though jet fuel is not covered under the LCFS, the update contains CI benchmarks for jet fuel so that alternative jet fuel can be used as an opt-in fuel. The update also adds third-party verification, as well as new provisions about ZEV infrastructure, CCUS, and refinery improvements.[117]

While upstream improvements to CI will surely be a part of compliance, most of the credits generated so far have been from alternative fuels, especially biofuels (Figure 3-22).[118] One of the effects of the LCFS has been to shift production toward more innovative fuels that generate more credits, such as renewable (drop-in) diesel and RNG. This shift is

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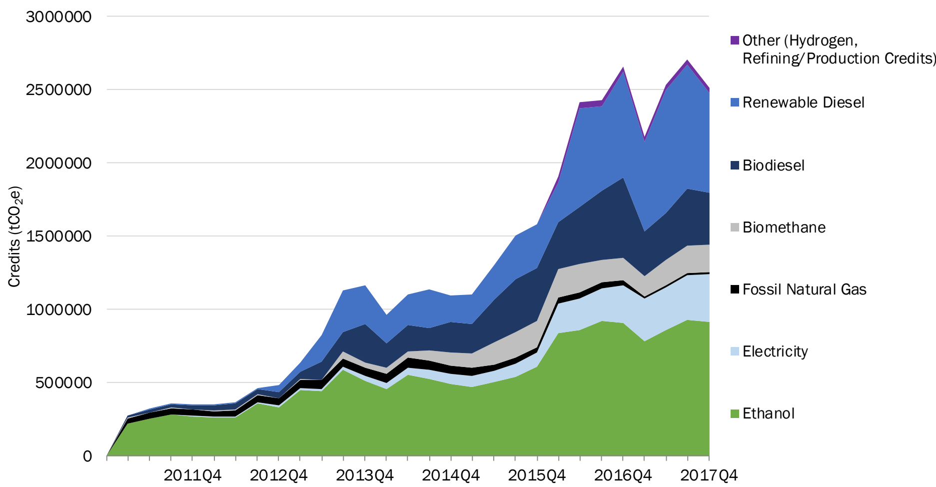
incorporated within the process and related capacities as compared to crude distillation." See Cal. Code Regs., tit. 17, § 95482(b) (2019).

[c] Renewable hydrogen is defined as hydrogen produced from electrolysis with renewable energy, SMR or catalytic cracking of renewable natural gas, or thermochemical conversion of biomass.

evidenced by the stark differences in credit sources from the start of the program in 2011 (when ethanol and fossil CNG dominated) to today.

Figure 3-22

Credits Generated Under the LCFS by Fuel Type (Quarterly)



The mix of fuels generating credits under the LCFS have changed significantly over the past seven years of the program. Source: EFI, 2019. Compiled using data from CARB, 2018.

The federal RFS (overseen by the EPA) also regulates refiners and importers of fuels and works on a credits-based system. Instead of requiring a specific carbon intensity, however, the RFS requires that a specific volume of biofuels be produced and/or blended into transportation fuels (as well as heating oil). The regulation's blending fuels are: biomass-based diesel, cellulosic biofuels, advanced biofuels (which includes the two previous categories plus others such as sugarcane ethanol), and total biofuels (which includes the above plus "traditional" biofuels such as corn ethanol).[119] The RFS currently runs until 2022 and requirements for each category except biodiesel increase each year. There have been, however, some issues with the implementation of the RFS, as nationwide production of certain categories of fuels has been insufficient to meet the standard.[120]

California refiners and importers are covered under both the LCFS and RFS; evidence suggests that the policies are mutually reinforcing, in that compliance with one makes compliance with the other more economically feasible.[121] There may be unintended consequences to layering the two policies, though, including the shifting of a disproportionate amount of biofuel resources to California, and a bias in California toward those resources that bring an RFS benefit (e.g., sugarcane ethanol).

Costs and Challenges of Low-Carbon Fuels

CARB's report on the new amendment to the LCFS indicates that the program will cost around $9.0 billion to fuel producers.[122] This does not include the costs that have come from implementing the program up to this point, or of maintaining the current carbon intensity of fuels. CARB also estimates that the regulation will actually save consumers at the pump in the short term, resulting in gasoline being 10 cents to 12 cents cheaper in 2020, and diesel being 11 cents to 14 cents cheaper. By 2025, however, the effect will start going in the other direction. By 2030, costs could be 18 cents to 36 cents higher, and diesel could be 21 cents to 44 cents cheaper. The costs of gasoline would translate to an additional $80 to $170 annually for the owner of a vehicle that gets 25 mpg (though average fuel economy would ideally be higher than 25 mpg by that point).

Other costs and benefits considered by CARB include costs for new third-party verification (which are minimal, compared to the rest of the program costs); energy security; health benefits; and tax revenue (which would be around $377 million cumulatively for the state).[123] The new version of the regulation also includes changes intended to create greater price stability for LCFS credits.[124]

Additional challenges for the LCFS involve implementation concerns. As with the CAFE standards, the LCFS overlaps with other pathways. LCFS credits can be generated by producing fuel for AFVs, as opposed to less carbon-intensive petroleum-based fuels. Ideally incentivizing production of those fuels would incentivize vehicle adoption, but that is not a guarantee.

The LCFS could also lead to recorded carbon reductions in Industry, rather than Transportation. This report has assumed that eligible pathways from Chapter 4 (combined heat and power and CCUS) will count toward the LCFS, and that the remainder of improvements would come from alternative fuels. This does not fully account for upstream changes for petroleum or alternative fuels that occur out of state—though those could be minimal, since directly regulated parties (i.e., California refiners) have more of an incentive to make upstream changes.

A significant part of the low-carbon fuel pathways is the production of biofuels, but there are technical and supply constraints that that may limit the viability of that option. These are discussed in detail in the Biofuels Addendum.

Conclusion

The challenges to Transportation sector decarbonization—including the scale of emissions from the sector, projected emissions growth, and the difficulty of decarbonizing non-LDV subsectors—will make achieving a 40 percent, sector-specific emissions reduction by 2030 extremely difficult. These challenges underscore the need for technology innovation in the sector to make deeper decarbonization possible. Nevertheless, the potential for reductions by 2030 is substantial—67.7 $MMTCO_2e$ of potential reductions represents roughly the same amount of emissions of the *entire* Electricity sector. Stakeholders must ensure that current policies are kept in place, and that more aggressive or more wide-ranging targets are adopted in order to continue moving Transportation's decarbonization forward.

BIOFUELS ADDENDUM

Biofuels are an important part of the Low-Carbon Fuels pathway and could potential figure into the AFVs pathway. According to the Department of Energy's definition, biofuels are liquid or gaseous energy carriers converted from either waste biomass or purpose-grown biomass.[125] They are distinct from biomass itself, which in its unprocessed form can also be used for energy in contexts such as direct combustion for power generation. The term "biofuels" is sometimes used colloquially to refer only to liquid biofuels that serve as substitutes for petroleum products but is used here in its more expansive sense.

The advantages of biofuels are that they come from resources that are currently abundant, relatively inexpensive, and that, to varying degrees, they can replace fossil fuels without requiring the development of new technologies. Biofuels are considered zero-carbon, either because they come from waste products and the emissions from combustion are less than the emissions from decomposition, or they come from crops that absorb more carbon while they grow than is emitted by combustion. They also provide a carbon benefit by avoiding some of the upstream and midstream emissions inherent in hydrocarbon production.

Conventional Biofuels

The most common liquid fuels are ethanol and biodiesel. Ethanol is typically used as a substitute for (and blended with) gasoline; over 98 percent of gasoline in the U.S. has ethanol in it.[126] In the U.S., it is mostly produced from corn; it can also be produced from other starch or sugar feedstocks. Biodiesel, which is a substitute and blendstock for diesel, uses lipid-based feedstocks. These include vegetable oils, animal fats, yellow grease, and used cooking oil.

One major limitation of current biofuels is that there are constraints on the amount that can be used in conventional vehicles. In general, the blends with the maximum biofuels content approved for use in conventional vehicles are E15 gasoline (10.5 to 15 percent ethanol) and B20 diesel (20 percent biodiesel). Higher volumes (such as E85 ethanol and B99/B100 diesel) require specialized infrastructure and vehicles. This is partially due to the chemical qualities of ethanol and biodiesel, and partially due to the fact that biofuels have a much lower energy content per gallon than fossil fuels.

The fact that conventional vehicles can only run on blends like E15 and B20 constrains the impact that biofuels can have on decarbonizing Transportation. However, there is potential for the expansion of biofuel-specific vehicles to aid decarbonization. There are already over 1.7 million biofuel vehicles (mostly gasoline-ethanol flex-fuel vehicles) on the road in California.[127] Deploying more of these vehicles, though, will require more specialized infrastructure. There are also some concerns about the performance of high biodiesel blends in specific conditions such as cold weather.[128]

Advanced Biofuels

There are several options for possible innovation in liquid biofuels. While some of these "advanced biofuels" are already being produced in significant volumes, most will require innovation to expand supply or become cost-competitive, but some are already being produced in significant volumes.

A major category of advanced biofuels is drop-in fuels: biomass-derived liquids that are chemically identical to the petroleum fuels they replace. Consumption in California of drop-in "renewable diesel," which is produced from the same feedstocks as conventional biodiesel, has increased substantially in the last few years, even surpassing biodiesel.[129] Renewable diesel generates more credits under the LCFS, which has made it cost-competitive with biodiesel. A future application for drop-in fuels might be jet fuel; despite the cost of renewable jet fuel, there are very few decarbonization pathways available for air travel, so it might become a promising option.

Another category of advanced biofuels is cellulosic ethanol, which is produced from waste, crop and wood residues, or purpose-grown crops like switchgrass. Cellulosic ethanol generally has lower levels of life-cycle energy use and emissions, and higher energy density.[130] Cellulosic fuels are included as a category in the federal RFS, but the EPA has repeatedly waived the RFS requirements because of production shortfalls.[131]

Additional advanced fuels include biobutanol, an alternative to ethanol with higher energy density, and dimethyl ether, a fuel that can be used in diesel engines and is produced from either biomass or natural gas. These fuels are both largely in the demonstration stage of development, though some biobutanol is available to U.S. consumers.

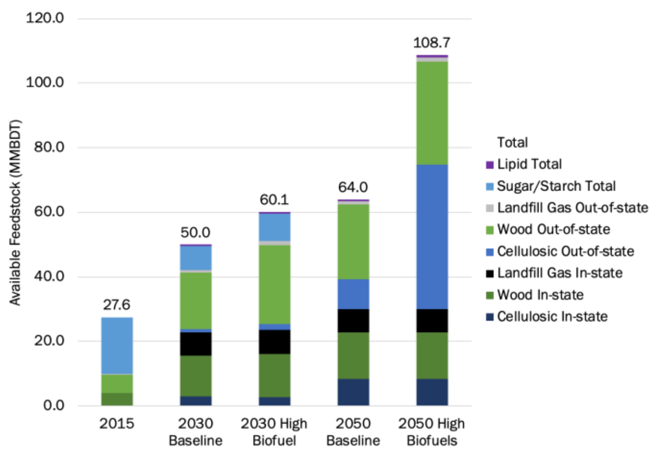
In addition to liquid biofuels, RNG is an option for Transportation. Unlike ethanol and biodiesel, RNG can substitute for fossil LNG and CNG in existing infrastructure and vehicles without modification. However, it is constrained by the same factors that constrain fossil natural gas use in Transportation. Because natural gas consumption in the sector is so minimal, this report's analysis of RNG does not allocate any to Transportation. (For the full analysis, see Chapter 6.)

Biofuels Supply and Supply Concerns

California's current technically available biomass resources total 35 million bone dry tons (MMBDT) per year, divided nearly equally among urban, agricultural, and forestry waste.[132] The state's combined production of biomass power, liquid biofuels, and biogas production currently uses only a fraction of that potential.[133] In 2018, in-state yearly production of ethanol was around 218 million gallons (148 MMGGE); biodiesel production was around 80 million gallons (85 MMGGE).[134,135] The state's current biofuels usage, however, requires both imported feedstocks as well as imports of biofuels themselves. The state's 2012 Bioenergy Action Plan estimated that potential liquid biofuels production could be over 1.6 billion GGE from in-state feedstocks alone.[136] This assumes, however, that over half of the state's biomass potential is used for these fuels, and that imports would still be needed—California already consumed roughly 1.6 billion GGE of liquid biofuels in 2017, and that number is rising. An additional 120 MMGGE of (mostly in-state) RNG use was reported under the LCFS in 2017.[137]

There is a limit, however, to the potential growth of biofuels. Recent modeling by E3 is particularly pessimistic about the growth of biofuels in Transportation. E3's baseline scenario assumes that California's biofuels potential will stay constant and that the state will continue to receive its population-weighted share of U.S. production of purpose-grown crops. However, it excludes the possibility of new purpose-grown crops because of concerns over the emissions resulting from the required land-use changes.[138] This constraint on biofuels production means that, in the model, biofuels are less competitive when compared to other decarbonization solutions (e.g., electrification). Figure 3-23 shows how this constraint affects the baseline scenario as opposed to the High Biofuels one, which includes purpose-grown crops (and a larger amount of biomass imports from other states). Biomass utilization increases much more in the latter scenario; by 2050, most of that discrepancy is from out-of-state cellulosic energy crops.

Figure 3-23
Biomass Utilization in Different PATHWAYS Modeling Scenarios



The biggest advantage of biofuels is that they can replace fossil fuels without requiring new technologies. Source: EFI, 2019. Compiled using data from E3, 2018.

In addition to these constraints on supply, another issue is competition for biomass resources between the Transportation sector and other sectors. Direct combustion of biomass can be used for power generation; RNG can be used in nearly every economic sector as a replacement for natural gas. Other sectors' decarbonization efforts may crowd out Transportation, further limiting the potential future supply of cost-effective biofuels.

Biofuels Policy

The main policies promoting biofuels include the RFS and LCFS, regulations that apply to refiners and importers of fuel. Both of these use credit systems that incentivize or require the production of biofuels. In addition to these regulations, there are tax and other incentives for biofuel-specific vehicles, as they are considered AFVs, though not ZEVs. Another policy promoting biofuels use is the CARB requirements for gasoline and diesel that require the blending of biofuels. As in other states, gasoline is required to be at least 10 percent ethanol; the biomass-based diesel proportion of California diesel is now up to 15.6 percent.[139]

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CHAPTER 4
REDUCING EMISSIONS FROM THE INDUSTRY SECTOR BY 2030

FINDINGS

Industry is the second-largest contributor of GHG emissions in California and one of the most difficult sectors to decarbonize.

Since 2000, annual Industry sector emissions in California have accounted for approximately one-fifth of the state's economywide greenhouse gas (GHG) emissions, second only to the Transportation sector. There are very limited options for reducing emissions from several industrial processes, due in part to their requirements for high-temperature process heat. These include coking, metal smelting and melting, calcining, and non-metal melting for such things as glass and ceramics.

There is a large technical potential for GHG emissions reductions from a range of mitigation options that can help decarbonize the Industry sector. Given the complexity and heterogeneous nature of many industrial processes, however, an effective decarbonization strategy will require tailored solutions that take into account the unique challenges and opportunities in each subsector.

The portfolio of decarbonization strategies needed for the Industry sector includes a range of options whose selection depends on factors such as the source of emissions (e.g., fuel combustion versus non-combustion) and the unique characteristics that define each subsector (e.g., process heat requirements; electrification potential). Emissions reduction pathways encompass a range of mitigation opportunities across the Industry sector as a whole and within specific subsectors including: Cement; Chemicals and Allied Products; Food Products; Industrial Combined Heat and Power (CHP); Landfills; Oil & Gas Production and Processing; Petroleum Refining and Hydrogen Production; and Transmission and Distribution (of natural gas).

California's Industry sector has both combustion and non-combustion emissions. The sector can achieve a 40 percent reduction in GHG emissions from 2016 levels by 2030 by focusing only on the mitigation of fuel combustion-related emissions, which represent two-thirds of the sector's emissions.

While the Industry sector in California could meet its 2030 goal by only reducing emissions from fuel combustion, the state could maximize industrial emissions reductions by focusing on the mitigation of both fuel combustion and non-combustion emissions. This can be addressed through a combination of technologies and practices including carbon capture, utilization, and storage (CCUS); fuel-switching; facility best management practices; new technology adoption; biogas collection; reducing fugitive emissions; renewable natural gas (RNG); industrial CHP; and energy efficiency. Fuel-switching (to hydrogen or electricity) and CCUS have a large technical potential to help meet the sector's 2030 goal.

The dominance of natural gas use in the Industry sector represents an opportunity for emissions reductions using RNG, but there would be significant associated costs, including for infrastructure.

The majority of California's industrial energy consumption in 2016 was supplied by natural gas (54 percent), which constituted 33 percent (661 Bcf) of the total in-state gas usage.

Electrification of industrial processes that require lower-temperature process heat could reduce the sector's emissions.

The subsectors with the greatest potential for industrial electrification include those that have lower energy costs; exhibit less process complexity and a lower level of systems integration; require lower-temperature process heat; are able to use induction-heating technology, and have end uses that do not currently employ CHP. Possible challenges and risks to industrial electrification include large capital costs for equipment turnover; higher costs of electricity as a fuel, relative to other energy resources; low natural gas prices (particularly for California industrial consumers relative to other sectors in the state); technical hurdles to providing high-temperature process heat; aversion to process disruption; and a current lack of industry momentum for electrification.

CCUS, RNG, and hydrogen offer options for decarbonization of industrial processes with requirements for higher-temperature process heat.

At present, CCUS is likely the only option available for decarbonizing several industrial processes, including cement production, oil refining, and natural gas processing. CCUS also provides further opportunities across California's large industrial base to meet the sector's 2030 goal. CCUS could take advantage of California's estimated geologic storage potential of 34 to 424 billion metric tons of CO_2, making it a viable option for industrial decarbonization. The use of RNG for decarbonizing pipeline gas is particularly well-suited to helping reduce GHG emissions from the Industry sector, since natural gas plays a prominent role in numerous industrial applications--as a resource for process heat, as a fuel for CHP systems, and as a feedstock for commercial products such as chemicals. A further opportunity to achieve a comparatively smaller reduction in emissions could include fuel-switching to natural gas from coal and petroleum.

Deployment of CHP technology can provide emissions reductions from a number of Industry subsectors by reducing energy consumption.

According to the Department of Energy (DOE), California has the second-highest total potential for new CHP projects in the United States, behind only Texas. In total, the Industry subsectors with the highest technical CHP potential in California were Petroleum Refining (1,427 MW); Chemicals (1,111 MW); Food (776 MW); Stone, Clay, and Glass (204 MW); and Transportation Equipment (147 MW).

Opportunities for reducing emissions in the Industry sector include energy efficiency measures and the adoption of facility best management practices. There are, however, a range of institutional and personnel challenges to pursuing energy efficiency in the Industry sector.

These challenges include lack of awareness of energy efficiency opportunities; challenges accessing technical assistance and qualified personnel; business strategies that are focused on profit margins and not energy management; risk aversion to new technology adoption and process disruption; and limited organizational resources (e.g., time, capital) to devote toward energy efficiency assessments and projects.

As with other sectors, smart systems offer opportunities for decarbonization of the Industry sector.

Smart systems for process automation in the Manufacturing subsector could achieve a reduction in energy intensity of 20 percent. For example, smart sensors could engender behavioral changes, use less energy for the same output (energy efficiency), and reduce overall energy use (conservation).

INDUSTRY SECTOR

California's Industry sector is the second-highest emitting sector in the state's economy and is one of the most technically and economically difficult to decarbonize. The California Air Resources Board (CARB) divides this sector into 11 subsectors, one of which—the Manufacturing subsector—is further divided by CARB into a second set of subsectors (Table 4-1). These primary and secondary subsectors provide the framework for the analysis in this chapter.

Each of these subsectors has its own energy requirements, emissions sources, and process needs. Many subsectors have large-scale, energy-intensive operations with complex supply chains and a low tolerance for operational downtime. In many cases, a new clean energy pathway could have impacts that would reverberate throughout the entire subsector, affecting requirements for workforce expertise, necessary suppliers and vendors, and production timetables, among others.

The portfolio of decarbonization strategies for the Industry sector includes a range of options whose selection depends on factors including the source of emissions (e.g., coal, petroleum, or natural gas); the nature of the emissions (e.g., fuel combustion versus non-combustion emissions); and the unique characteristics that define each subsector (e.g., process heat requirements; electrification potential).

There is a large technical potential for greenhouse gas (GHG) emissions reductions across a range of technologies that can help decarbonize the Industry sector in California. These include carbon capture, utilization, and storage (CCUS); fuel-switching; facility best management practices; new technology adoption; biogas collection; renewable natural gas (RNG); reducing fugitive emissions; industrial combined heat and power (CHP); and energy efficiency. Given the heterogeneous nature of many industrial processes, an effective decarbonization strategy will require tailored solutions that accommodate the unique challenges and opportunities in each subsector.

Table 4-1
Industry Emissions by Subsector, 2016

Subsector	2016 Emissions Level ($MMTCO_2e$)
Industrial CHP	8.0
Landfills	8.5
Manufacturing, Total	24.2
Chemicals and Allied Products	6.2
Construction	0.2
Electric and Electronic Equipment	0.2
Food Products	3.3
Metal Durables	0.7
Plastics and Rubber	0.1
Primary Metals	0.5
Printing and Publishing	<0.1
Pulp and Paper	0.4
Stone, Clay, Glass, and Cement	8.4
Storage Tanks	<0.1
Textiles	0.2
Tobacco	<0.1
Transportation Equipment	0.3
Wastewater Treatment	<0.1
Wood and Furniture	<0.1
Manufacturing: Not Specified	3.5
Mining	0.2
Oil & Gas Production and Processing	17.9
Petroleum Marketing	<0.1
Petroleum Refining and Hydrogen Production	29.5
Solid Waste Treatment	0.3
Transmission and Distribution (Pipelines and Storage)	5.1
Wastewater Treatment	1.9
Not Specified	4.7
Total	100.4

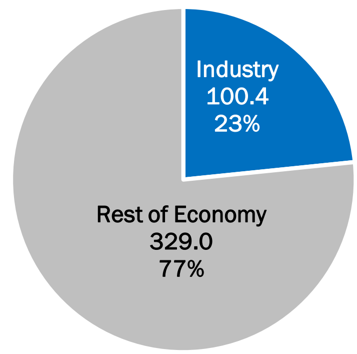
According to the CARB GHG inventory used for this analysis, there are 11 subsectors in the Industry sector. One of those, the Manufacturing subsector, consists of 17 secondary subsectors. For the purposes of this analysis, all the subsectors are termed "subsector" in this chapter. Source: EFI, 2019. Compiled using data from CARB, 2018.

2016 Sector GHG Emissions Profile: Industry

In 2016, the Industry sector was responsible for 100.4 MMTCO_2e of GHG emissions (Figure 4-1),[1] 66 percent of which stemmed from fuel combustion, with the remaining 34 percent from non-combustion sources.[2] In 2016, roughly 54 percent of the Industry sector's fuel combustion emissions were from natural gas.[3] Of the 33.9 MMTCO_2e of non-combustion emissions, 80 percent was from four sources: landfill gas (25 percent); fuel consumption (21 percent); fugitive emissions (19 percent); and clinker production (15 percent).[4] Since 2000, annual Industry sector emissions in California have accounted for approximately one-fifth of the state's economywide GHG emissions, at an average emissions level of 102.1 MMTCO_2e per year.[5]

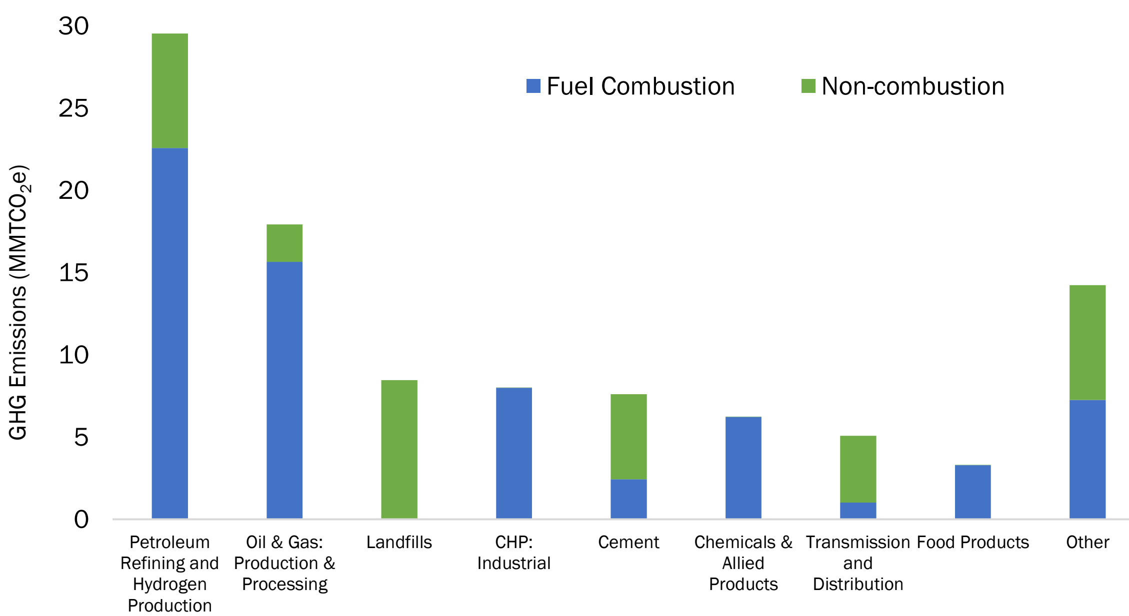
As seen in Table 4-1, several secondary subsectors within the Manufacturing subsector have emissions levels that are sufficiently large and are comparable to that of the

Figure 4-1
Industry Emissions Compared to California Total, 2016 (MMTCO_2e)



Emissions from Industry make up approximately 23 percent of California's total emissions. Source: EFI, 2019. Compiled using data from CARB, 2018.

Figure 4-2
Industry Sector Emissions Profile, 2016 (MMTCO_2e)



The majority (66 percent) of Industry sector emissions in 2016 stemmed from fuel combustion, while one-third was the result of non-combustion emissions. Source: EFI, 2019. Compiled using data from CARB, 2018. See Appendix B-4 for description of subsectors included in the "Other" stacked bar.

other primary subsectors. These secondary subsectors are a focus of specific analyses in this chapter and include Cement (within Stone, Clay, Glass, and Cement), Chemicals and Allied Products, and Food Products. A depiction of the combustion and non-combustion emissions for these three subsectors, the top five primary subsectors other than Manufacturing, and all other Industrial subsectors combined is shown in Figure 4-2; these correspond to the nine pathways identified and analyzed in this chapter.

Analysis of Industry Sector

Industry is a difficult sector to decarbonize. Challenges include the level of systems integration, high-temperature process heat requirements, and the heterogenous nature of industrial processes. There are, however, several opportunities for reducing GHG emissions that may avoid massive system retooling, protracted operational downtime, or a complete overhaul in technical expertise. These opportunities include energy efficiency improvements and facility best management practices, new technology adoption and fuel-switching, CHP, and CCUS. These pathways, especially fuel-switching and CCUS, can lead to measurable emissions reductions across the major Industry subsectors in California.

Trends and Issues Shaping the Industry Sector

There are important trends and issues that shape the Industry sector in California and provide the context for developing decarbonization pathways. These factors include the sources and nature of emissions in the various Industry subsectors, energy consumption profiles and projections, and the policies that support sustained emissions reductions.

Table 4-2
Profile of Industry Energy Resource Consumption in California, 2016

Combustion as Fuel		Consumption as Feedstock
Associated gas	Liquefied petroleum gas	Lubricants
Biomass	Municipal solid waste	Natural gas
Biomass waste fuel	Natural gas	Petroleum feedstocks
Biomethane	Other petroleum products	Refinery gas
Catalyst coke	Petroleum coke	
Coal	Process gas	
Crude oil	Propane	
Digester gas	Refinery gas	
Distillate	Residual fuel oil	
Ethanol	Tires	
Gasoline	Waste oil	
Kerosene	Wood (wet)	
Landfill gas		

A diversity of resources provide energy services throughout the Industry sector. Source: EFI, 2019. Compiled using data from CARB, 2018.

Industrial Processes and Energy Consumption

A defining characteristic of the Industry sector is the diversity of energy resources that are consumed, the means in which they are consumed, and the multitude of different end uses and processes that are enabled through that consumption. In 2016, the Industry sector in California combusted 25 different types of fuel; in addition, it consumed four energy-related resources as feedstocks (Table 4-2).[6] Some key industrial processes that use energy resources as a feedstock are involved in hydrogen production in the Petroleum Refining and Hydrogen Production subsector. Here, natural gas and refinery gas are consumed by steam-methane reforming (SMR) pathways to hydrogen and petroleum feedstocks are consumed by partial-oxidation pathways to hydrogen.[7]

Energy resources are consumed in the Industry sector for a variety of end uses and processes; the resources that are utilized are dependent on the needs and characteristics of each subsector. These end uses and processes can be categorized as onsite generation, process energy, and non-process energy.[8]

Onsite Generation. Onsite generation involves the production of electricity or steam within the industrial facility. For example, CHP and on-site generators (including renewables) can be used to produce electricity, while conventional boilers and CHP can be used to produce steam.[9]

Process Energy. Process energy involves the provision of energy resources for process-specific activities within numerous Industry subsectors. For example, process heating is used to provide thermal energy for various end uses such as heating a cement kiln or melting scrap for steel production. Process energy can also involve electrochemical activities to induce chemical transformations.[10]

The provision of process heat is a vital energy service for manufacturing most consumer and industrial products, such as those made from metal or glass.[11] Process heat is used in a variety of Industry subsectors in California, in processes including refining, chemical manufacturing, and metal fabrication. Each subsector has its own process heat requirements that include specific temperatures, applications, and scales. Heating requirements, combined with associated energy needs, make process heating emissions-intensive. In some cases, there are relatively cleaner alternatives for the same end-product, such as a shift from thermal combustion to electric process heating.

Process heating technologies can be grouped into the following four general categories, based on the type of fuel consumed: fuel, steam, electric, and hybrid systems.[12]

- Fuel-based process heating systems transfer heat from combusted fuels to the material (through direct or indirect means). Examples include kilns and furnaces. Sixty-four percent of process heating in U.S. manufacturing comes from fuels.
- Steam-based process heating systems transfer heat from steam production to an industrial process that typically has a temperature requirement of less than 400°F and easy access to low-cost steam. Examples include boilers and fluid heating systems. Thirty-two percent of process heating in U.S. manufacturing comes from steam.
- Electricity-based process heating systems (also called electro-technologies) transform materials through direct resistance heating or indirect inductive heating. Examples include electric arc furnaces and laser heating. Only five percent of process heating in U.S. manufacturing comes from electricity.
- Hybrid process heating systems include a combination of fuel-, steam-, and electric-based methods for heat production. For example, hybrid process heating systems can combine fuel- and electric-based boilers to help reduce system costs when electricity prices are relatively low.

Non-process Energy. Examples of non-process energy include end uses such as facility lighting and heating, ventilation, and air conditioning. Non-process energy is not used for specific industrial or manufacturing purposes, and therefore does not tend to be subsector-specific.[13]

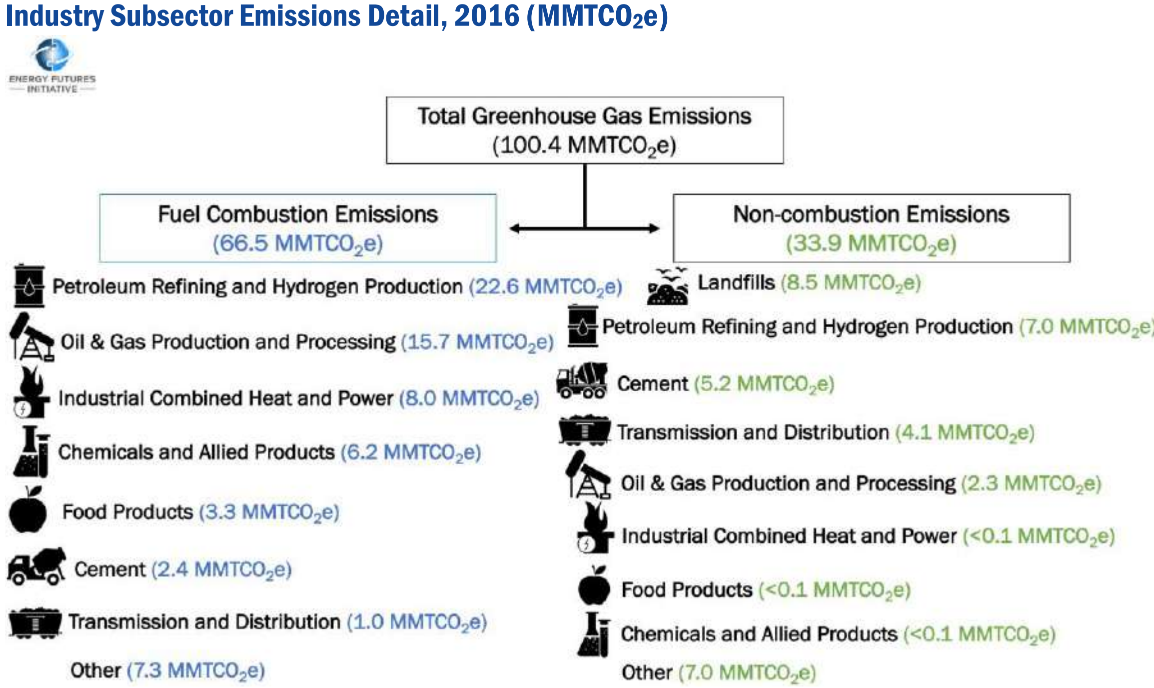
Fuel Combustion Versus Non-Combustion Emissions

Mapping Industry subsectors by the nature of their emissions (e.g., combustion versus non-combustion) provides an organizational framework for understanding potential decarbonization pathways. In many cases, fuel-switching to cleaner sources offers a substantial decarbonization opportunity in subsectors with a large amount of fuel combustion emissions. For non-combustion emissions, biogas collection and reducing or eliminating fugitive emissions could offer strategies for significant emissions reductions.

There are also several cross-cutting decarbonization strategies that could address both fuel combustion and non-combustion emissions. Opportunities such as improving process efficiency, including the use of sensors and adoption of best available technologies, can help reduce fuel consumption (and subsequent fuel combustion emissions) and also lower non-combustion emissions (e.g., less need for coal fuel storage or natural gas throughput in pipelines). Figure 4-3 highlights California's 2016 Industry sector emissions at the subsector level, further delineated in terms of fuel combustion emissions and non-combustion emissions.[14]

Figure 4-3

Industry Subsector Emissions Detail, 2016 ($MMTCO_2e$)



In 2016, the California Industry sector was responsible for 100.4 $MMTCO_2e$, of which two-thirds came from fuel combustion and one-third from non-combustion emissions. Source: EFI, 2019. Compiled using data from CARB, 2018.

Energy Consumption

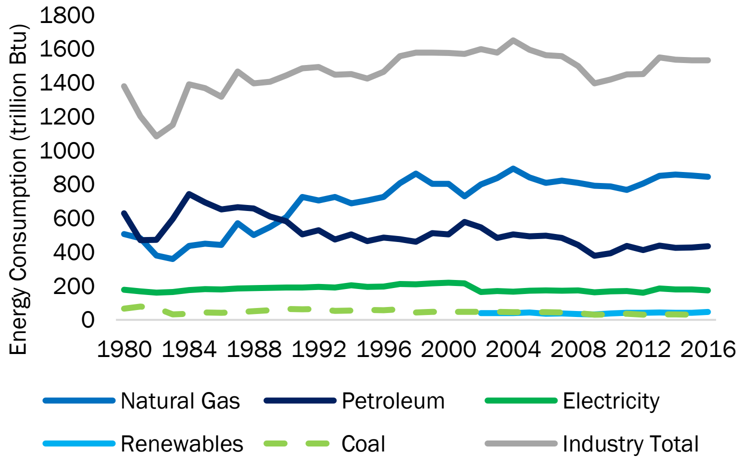
In 2016, California had the third-highest total industrial energy consumption in the United States, behind Texas and Louisiana. California's industrial energy consumption was a large percentage of the U.S. Industry total: 8.8 percent of natural gas, 5.2 percent of petroleum; 5.2 percent of electricity; 2.7 percent of coal; and 1.7 percent of biomass.[15]

California's total industrial energy consumption peaked in 2004 (from a 1980 baseline) and declined to 1,532.7 trillion Btu in 2016. Since 1980, natural gas consumption has increased, coal and petroleum use has declined, and electricity consumption has been relatively flat. A consistent data set on renewable energy use goes back to 2002; in the period since then, renewable energy use in industry has grown slightly.[16] These trends are shown in Figure 4-4.

The majority of California's industrial net energy consumption in 2016 was supplied by natural gas, followed by petroleum, electricity, renewables, and coal (Figure 4-5).[17] For petroleum products, a similar amount of distillate fuel oil, petroleum coke, and asphalt and road oil were consumed, followed by lesser

Figure 4-4

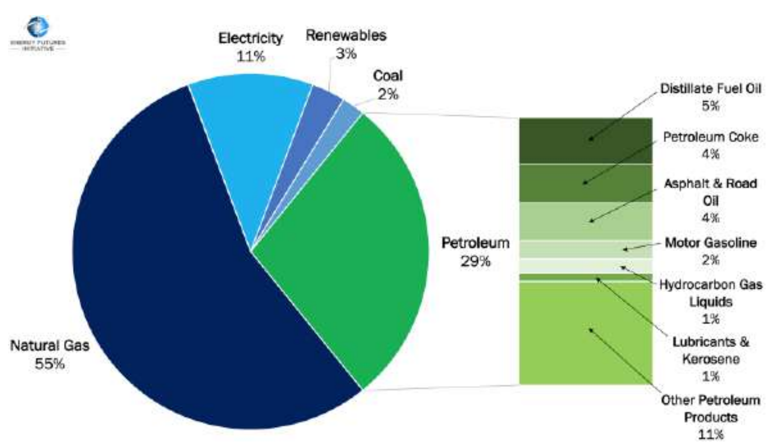
Industry Sector Energy Consumption, 1980-2016 (trillion Btu)



Between 1980 and 2016, California's industrial energy consumption increased by 88.6 trillion Btu. Source: EFI, 2019. Compiled using data from EIA, 2018.

Figure 4-5

Industry Sector Energy Consumption by Fuel Type, 2016



The majority of industrial energy consumption in 2016 came from natural gas. Note: The 55 percent natural gas consumption estimate from EIA was slightly higher than that reported by CARB (54 percent). Source: EFI, 2019. Compiled using data from EIA, 2018.

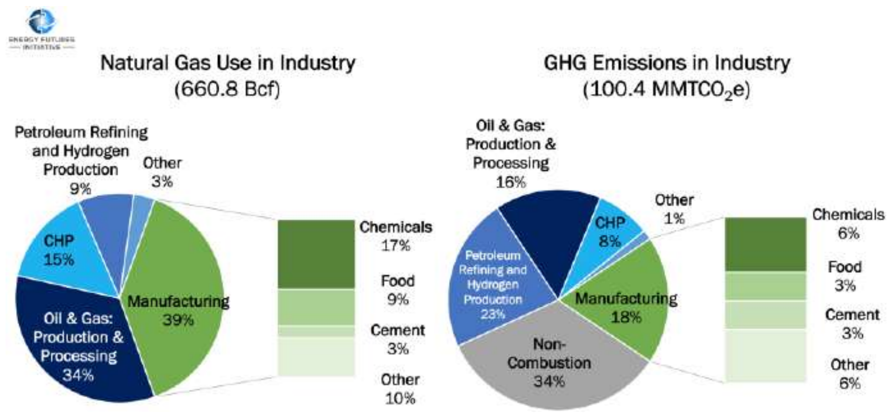
consumption from motor gasoline, hydrocarbon gas liquids, lubricants and kerosene, and other petroleum products.

Natural Gas Consumption

In 2016, approximately 39 percent of industrial natural gas consumption in California was used in the Manufacturing subsector, 34 percent was consumed by the Oil & Gas Production and Processing subsector, 15 percent was consumed for Industrial CHP, 9 percent was consumed by the Petroleum Refining and Hydrogen Production subsector, and 3 percent was consumed for other uses (Transmission and Distribution and Mining subsectors) (Figure 4-6).[18]

Figure 4-6

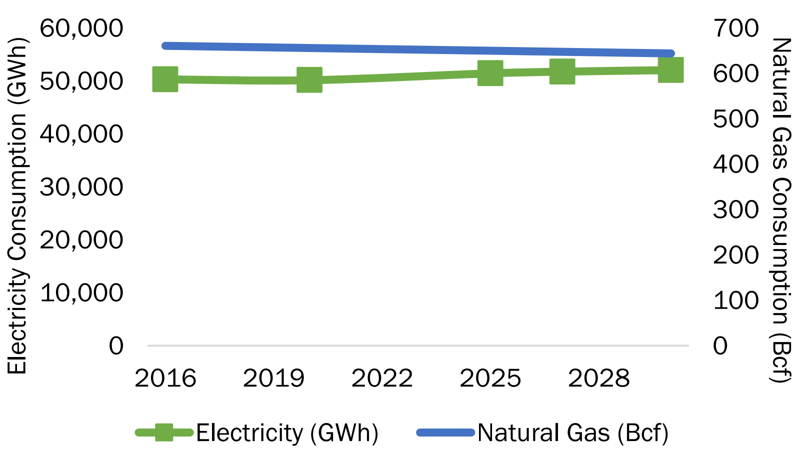
Natural Gas Use and GHG Emissions in Industry, 2016



Most of the industrial natural gas consumption in California occurs in the Manufacturing subsector, followed by the Oil & Gas Production and Processing subsector. Source: EFI, 2019. Compiled using data from CARB, 2018. See Appendix B-4 for description of the subsectors included in "Other" in both stacked bars.

Figure 4-7

Industrial Electricity and Natural Gas Demand Forecast, 2016-2030



Industrial electricity consumption in California is projected to rise to 2030, while natural gas consumption is expected to experience a slight decline. Source: EFI, 2019. Compiled using data from CEC, 2017. See Appendix B-4 for notes on projections.

For petroleum refineries in general, the Department of Energy (DOE) estimates that two-thirds of natural gas consumption is for process heat and one-third for onsite electricity generation.[19] In manufacturing, the majority of natural gas consumption is used for process heat (43 percent) and indirect boiler fuel to produce steam and hot water (42 percent).[20] (See Appendix B-1 for a visual depiction of industrial natural gas consumption in California.)

Electricity and Gas Demand Projections

According to the California Energy Commission (CEC), industrial electricity consumption is projected to increase around 3.5 percent by 2030 (from 50,308 GWh in 2016 to 52,050 GWh). This is less than the average annual growth rate projected for the Residential and Commercial Buildings subsectors. Electricity consumption estimates for the 2017 business-as-usual forecast are higher than the 2016 forecast, due to a projected increase in manufacturing output.[21] The CEC also projects a slight decrease in industrial natural gas demand by 2030 (Figure 4-7).[22]

Public Policy Support

Public policies play a pivotal role in supporting decarbonization of the Industry sector. Three policy tools that could help California achieve a reduction in industrial emissions are AB 262, section 45Q of the federal Internal Revenue Code, and the Low Carbon Fuel Standard (LCFS) program.

Buy Clean California Act (AB 262). The Buy Clean California Act (AB 262, enacted in 2018), established procurement standards for low-carbon construction materials used for state infrastructure projects. The construction materials covered include carbon steel rebar, flat glass, mineral wool board insulation, and structural steel.[23] AB 262 could provide an incentive for California's Manufacturing subsector to reduce the carbon intensity of its construction materials to make them more attractive for in-state infrastructure projects, of which the state of California spends an estimated $10 billion per year.[24] For example, California imported approximately $2 billion in iron and steel in 2017 (a 6 percent increase over 2016).[25] Under the new procurement standards, the state will ultimately seek to import steel, along with other commonly-used construction materials, that adheres to the higher environmental performance standards set forth in AB 262.

Enhanced 45Q Incentives. In February 2018, the federal Furthering Carbon Capture, Utilization, Technology, Underground Storage, and Reduced Emissions Act (FUTURE Act) was enacted as part of the Bipartisan Budget Act of 2018. The FUTURE Act provides for an expansion of the Internal Revenue Code section 45Q tax credit for CCUS projects. It includes a higher credit value for qualifying projects ($35 per ton of carbon dioxide [CO_2] for utilization including enhanced recovery and $50 per ton of CO_2 for geologic sequestration), longer time horizon for project developers to claim the credit (12 years), and a broader definition of qualifying projects (e.g., direct air capture). In order to qualify for the 45Q tax credit, industrial facilities must capture at least 100,000 tons of CO_2 per year. EFI estimates that the FUTURE Act could lead to 50 to 100 million tons of CO_2

...to qualify for the 45Q tax credit, industrial facilities must capture at least 100,000 metric tons of CO_2 per year...the FUTURE Act could lead to 50 to 100 million tons of CO_2 captured per year in the United States, especially from production of ethanol, ammonia, and hydrogen in the Industry sector.

captured per year in the United States, especially from production of ethanol, ammonia, and hydrogen in the Industry sector.[26] Projects must start by January 1, 2024 to be eligible for the tax credit, an extremely tight deadline for large projects.

Low Carbon Fuel Standard Program (LCFS). An evolving use case for industrial CCUS in California is to support the Transportation sector through its LCFS program, which mandates a reduction in carbon intensity of transportation fuels used in the state.[27] The LCFS program, which began in 2011, was recently extended to 2030 and expanded in scope to allow a greater number of qualifying entities to participate. Low-carbon transportation fuels produced using CCUS are now eligible to generate credits under the LCFS program if certain requirements are met. Entities that are eligible for credits include those who capture CO_2 on-site and store it in geologic formations (e.g., oil and gas producers, refineries, alternative fuel producers) and those who use direct air capture with geologic sequestration.[28]

Multisector Opportunities for Decarbonizing Industry in California

The following mitigation opportunities are not specific to any individual subsector and thus offer the potential to reduce GHG emissions across numerous subsectors. Given the complexities stemming from the heterogeneous nature of industrial processes and facilities, however, mitigation opportunities should be assessed on a subsector-specific basis to maximize the decarbonization opportunity.

Energy Efficiency and Facility Best Management Practices

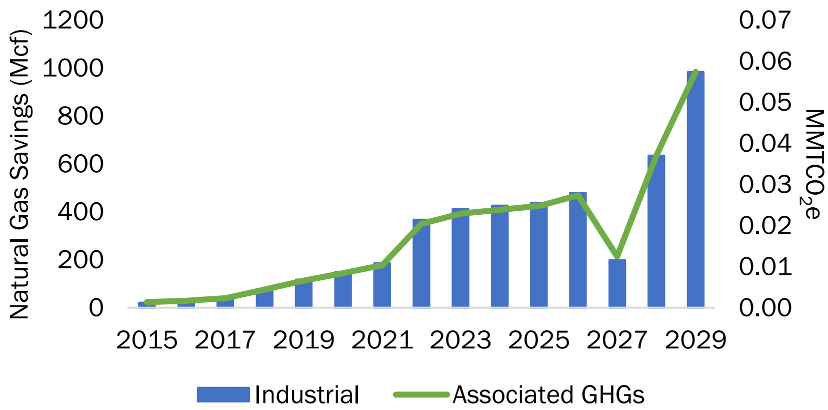
Energy efficiency improvements offer major near-term opportunities for reducing Industry sector emissions. Since July 2011, large-scale industrial facilities in California[29] have been required to undergo a one-time energy efficiency assessment through the state's Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities Regulation (EEA Regulation).[30]

An analysis of additional achievable energy savings potential in the Industry sector between 2015 and 2029, to help meet SB 350's requirements for doubling energy efficiency savings by 2030, concluded that California could realize a reduction in natural gas consumption of around 1.0 Bcf in 2029, corresponding to a modest emissions reduction of 0.06 $MMTCO_2e$ (Figure 4-8).[31]

Using best available technologies and promoting energy efficiency are key strategies for reducing emissions from the Industry sector in the near term.[32] This could be facilitated in part by the ISO 50001 energy management standard, which provides a framework for industrial and manufacturing facilities to better manage energy use. Entities implementing ISO 50001 have seen measurable benefits in terms of energy cost savings and reduced GHG emissions. For example, industrial facilities that have achieved ISO 50001 certification (along with DOE's Superior Energy Performance Program) have realized energy cost savings of up to 10 percent within the first 18 months.[33] Estimates suggest that over 23,000 sites around the world have achieved ISO 50001

Figure 4-8

Natural Gas Savings Potential from Energy Efficiency & Associated GHG Emissions Reductions



California could realize an emissions reduction benefit of nearly 0.06 $MMTCO_2e$ through a decrease in industrial natural gas consumption associated with energy efficiency measures. Source: EFI, 2019. Compiled using data from Noresco, TRC, CSE, and EPA.

certification.[34,35] As of December 2017, 77 companies had achieved the ISO 50001 certification in the United States,[36] including California-based companies such as Google.[37]

The DOE Advanced Manufacturing Office also promotes ongoing collaborations to bolster the efficiency and competitiveness of the domestic Manufacturing sector. As of 2016, California had 117 state entities participating in 32 different partnerships and projects.[38] In addition, DOE's energy efficiency standards cover 30 percent of industrial energy use (e.g., pumps and motors). These standards have made a considerable difference in reducing industrial energy and carbon emissions but are currently being rolled back or delayed at the federal level.

Costs and Challenges to Energy Efficiency and Facility Best Management Practices. SB 350 directs the CEC to establish energy efficiency targets that achieve statewide energy efficiency savings in electricity and natural gas final end uses by 2030. SB 350 also directs these targets to be cost-effective, to be feasible, and to avoid adversely impacting public health and safety.[39] The energy efficiency pathways were deemed to be cost-neutral. This assumption is also supported by the CEC's Final Commission Report that identified opportunities for reaching the statewide targets and describes the emissions-reduction potential, which shaped the emissions-reduction potential pathway.[40]

The challenges of energy efficiency for the Industry subsectors range from facility retooling to component replacement to process changes. The California Public Utilities Commission (CPUC) noted several major barriers to achieving energy efficiency in the Industry sector including the following:[41]

- Lack of awareness of energy efficiency opportunities;
- Challenges accessing technical assistance and qualified personnel;
- Business strategies focused on margins, not energy management;
- Risk aversion to new technology adoption and process disruption; and
- Limited organizational resources (e.g., time, capital) to devote toward energy efficiency assessments and projects.

Fuel-switching

There are several opportunities for reducing GHG emissions in the Industry sector through fuel-switching. These include fuel-switching from fossil fuels to electrification or hydrogen, substituting gas (or RNG) for coal, and substituting gas (or RNG) for petroleum.

Electrification. Electrification could play a role in decarbonizing certain subsectors of California's Industry sector (Table 4-3).[42] In general, the subsectors with the greatest potential for industrial electrification include those that have lower energy costs; exhibit less process complexity and a lower level of systems integration; require lower-temperature process heat; are able to use induction heating technology; and have end uses that do not currently employ CHP.[43]

Table 4-3
GHG Emissions, Process Heat Temperatures, and Electrification Potential by Industry Subsector

Subsector	California GHG Emissions, 2016 (Metric Tons CO_2e)	Process Heat Temperatures	Electrification Potential
Chemical and Allied Products	6,234,353	High	Medium
Food Products	3,290,383	Medium/High	Medium
Metal Durables: Fabricated Metal Products	454,567	High	High*
Metal Durables: Machinery	86,346	High	High*
Petroleum Refining and Hydrogen Production	29,534,155	High	Low
Plastics and Rubber	114,083	Low/Medium	High
Primary Metals	495,933	High	High*
Pulp and Paper	404,256	High	Low
Stone, Clay, Glass, and Cement	8,446,176	High	Low
Transportation Equipment	282,930	Medium/High	High
Wood and Furniture	43,387	Medium	High

*Numerous Industry subsectors have a high electrification potential. *Some subsectors that require high-temperature process heat also have a high electrification potential due to available technologies such as induction heating and electric arc furnaces.* Source: EFI, 2019. Compiled using data from LBNL, 2018; CARB, 2018.

Process heat currently accounts for one-half of the energy consumed in the Manufacturing subsector; however, only 5 percent of process heat applications are electrified.[44] Although there are some commercial electric technologies today to supply industrial process heat, they are not widely deployed. Fossil fuels still account for the majority of energy used in conventional boilers and for direct-combustion process heat.[45]

Industrial process heat requirements can vary widely depending on the Industry subsector, ranging from 150 to 3,000 degrees Fahrenheit across a number of applications (Table 4-4).[46] Although very little process heat currently comes from electricity,[47] electrification can be a viable near-term option for helping to decarbonize industrial processes that require low- or medium-temperature process heat (less than 400 degrees Celsius), while also potentially being sufficient for certain high-temperature process heat requirements such as electricity-based steel production.[48]

Table 4-4
Industrial Process Heat Requirements

Industrial Process	Examples	Temperature Requirements (°F)
Fluid heating, boiling, and distillation	Distillation; reforming; cracking; chemicals production and food preparation	150 - 1,000°
Drying	Removal of water and organic compounds	200 - 700°
Metal heat treating and reheating	Hardening; annealing; tempering	200 - 2,500°
Other	Preheating; catalysis; thermal oxidation; incineration; softening; warming	200 - 3,000°
Curing and forming	Polymer production; molding; extrusion	300 - 2,500°
Coking	Coke production for iron and steel manufacturing	700 - 2,000°
Metal smelting and melting	Ore smelting; steelmaking	800 - 3,000°
Calcining	Lime calcining	1,500 - 2,000°
Non-metal melting	Glass; ceramics	1,500 - 3,000°

Industry process heat requirements can range from 150 to 3,000 degrees Fahrenheit. Source: DOE, 2015.

Many of the potential industrial electrification opportunities involve electrifying the provision of process heat for applications across a variety of subsectors. Process heat can be provided through: resistance heating; industrial heat pumps; electric boilers; direct resistance melting; direct arc melting; electrolytic reduction; infrared processing; induction furnaces; and ultraviolet curing. In addition, the Manufacturing subsector could employ industrial heat pumps and electric machine drives for building HVAC and machine drives, respectively (Table 4-5).[49,50] Some of the electrification technologies with the highest potential for adoption include electric boilers, electric arc furnaces, heat pumps, and induction melting.[51]

Table 4-5
Opportunities for Industry Electrification by Technology Type

End Use	Subsector	Electrification Technology
Process Heat	Chemicals and Allied Products	Resistance heating; industrial heat pump; electric boiler
	Food Products	Industrial heat pump; electric boiler
	Plastic and Rubber Products	Resistance heating; infrared processing
	Primary Metals	Induction furnace
	Primary Metals: Iron & Steel	Direct arc melting
	Primary Metals: Non-ferrous Metals (Excluding Aluminum)	Electrolytic reduction
	Pulp and Paper	Industrial heat pump
	Stone, Clay, Glass, and Cement: Glass and Glass Products	Direct resistance melting (electric glass melt furnace)
	Transportation Equipment	Induction furnace; electric boiler
	Other Manufacturing subsectors	Resistance heating; electric boiler
Process Heat: Curing	Printing and Publishing; Wood and Furniture	Ultraviolet curing
Building HVAC	All Manufacturing subsectors	Industrial heat pump
Machine Drive	All Manufacturing subsectors	Electric machine drive

There are several technologies that could be used to promote Industry electrification. Source: NREL, 2017a; NREL, 2017b.

Costs and Challenges to Electrification. Challenges for subsectors with electrification potential include large capital costs for equipment turnover; higher costs of electricity as a fuel, relative to other energy resources; and technical hurdles to achieving high-temperature process heat.[52]

As indicated by Table 4-3, industrial segments in subsectors with high-temperature process heat requirements--such as Cement production within the Stone, Clay, Glass, and Cement subsector—have low potential for electrification with existing commercial technology and have fewer options for decarbonization; the options that remain include CCUS and the use of RNG or hydrogen as fuels.

Oil refineries also present major challenges to electrification. The high degree of process integration that is characteristic of the Petroleum Refining and Hydrogen Production subsector means that any technological disruption (e.g., electrification) could require considerable systems re-engineering. It is also common practice for oil refineries to self-consume energy resources that are generated as byproducts of the refining process; electrification would eliminate this option, which could result in increased energy costs for oil refineries.[53] CCUS may be one of the readily available options for decarbonizing California's 17 oil refineries, which have a combined capacity of more than 1.9 million barrels per day.[54]

Additional challenges to the electrification of the Industry sector include low natural gas prices (particularly for California industrial consumers relative to other sectors in the state), aversion to the major redesign of processes, and little current industry momentum for electrification.[55] In California, industrial consumers enjoy relatively low natural gas prices, compared to end users in other sectors of the state's economy; in 2016, their natural gas prices were the second-lowest of all end-use sectors—only utilities in the electric power sector paid less.[56] These relatively low natural gas prices, coupled with the high equipment costs of switching, could discourage industrial facilities from electrification of certain end uses.

Industrial facilities can have useful lifespans of 50 years or longer, and any process changes through retrofits or systems re-engineering can be relatively costly. This has the potential to make some commodities (e.g., steel) more expensive if it comes from an industrial facility that pursues emissions reduction strategies compared to a facility that does not employ low-carbon strategies.[57] For example, fuel-switching in the Industry sector typically requires a change in manufacturing processes, which can lead to substantial new equipment costs.[58]

Another barrier to Industry sector electrification is the lack of empirical data and information (e.g., cost data), which limits the ability of analysts, modelers, and policymakers to determine the efficacy of industrial electrification.[59] Although there is a strong technical potential for industrial electrification in some subsectors, detailed techno-economic studies of issues such as process designs and efficiency are not readily available.[60] A 2017 report on industrial electrification opportunities yielded limited available data, especially for the costs of different electrification technologies; much of the available data was reportedly anecdotal.[61] However, while technology options for electrification in the 2030 timeframe are limited, evidence suggests that, with innovation and infrastructure turnover, nearly all Industry subsectors could see a high technical potential for the electrification of high-temperature process heat applications by 2050.[62]

Another current barrier to industrial electrification involves the potentially higher cost of energy from fuel-switching to electricity.[63] One cost comparison of electric and natural gas-fired boilers indicated that although electric boilers had a lower capital cost and were more energy-efficient, the electricity price was approximately three times more expensive than natural gas on an energy-equivalent basis, making the electric boiler roughly twice as expensive as a natural gas boiler for first-year costs (Table 4-6).[64]

Table 4-6

Cost Comparison of Electric Steam and Natural Gas Boilers in the West U.S. Census Bureau Region (100-Boiler Horsepower)

Metric	Electric Boiler	Natural Gas Boiler
Purchase price	$53,860	$87,540
Fuel price ($/MMBtu)	$24.09	$6.20
Hourly fuel cost	$81.39	$25.94
First-year cost	$483,615	$224,501

On an energy-equivalent basis, electric boilers can have a higher first-year cost than natural gas boilers. The first-year cost equates to the purchase price of the equipment plus fuel costs in the first year (calculated at 5,280 annual operating hours). Source: NREL, 2017b.

Hydrogen. In cases where electrification and energy efficiency cannot lead to measurable emissions reductions, hydrogen can offer a clean-burning substitute. Certain processes require combustion-based heat because the fuel both meets a specific heating need and provides components important to the chemistry of the process. A blast furnace for making iron is one example. Where industrial end-use systems permit, hydrogen may be blended with natural gas to reduce the emissions intensity of methane. Alternatively, certain equipment can be retrofitted to run on hydrogen. For example, ethylene crackers have seen retrofits to support hydrogen use (and hydrogen is already a by-product in refineries); and in cement production, hydrogen can be combined with waste-derived fuels. Clean hydrogen could replace natural gas or coal in both refining and ironmaking as a substitute for fossil-based feedstocks and/or reducing agents.[65]

Costs of Hydrogen. The two most common methods to produce hydrogen include SMR of natural gas and electrolysis.[66] SMR is currently the cheapest method for producing hydrogen,[67] and has a high-volume production cost of less than \$2 per gallon of gasoline equivalent.[68] Large-scale SMRs (central station reformers) are a mature technology that have an initial investment cost of \$400 to \$600 per kilowatt (kW).[69] Hydrogen can also be produced using smaller, distributed SMR units that can be scaled according to the desired production level.[70] Aside from the cost per kilogram of hydrogen produced, other production cost estimates include a total plant capital cost of approximately \$190 to \$350 million depending on use and type of carbon-capture equipment;[71] hydrogen pipeline infrastructure (\$1 million per mile for dedicated hydrogen pipelines);[72] hydrogen compression, storage, and dispensing costs (\$2 per kilogram of hydrogen);[73] and CO_2 transport and sequestration (roughly \$2 per metric ton of CO_2 for transport and \$13 per metric ton of CO_2 for storage).[74] Electrolysis is currently expensive and is considered a longer-term option; it is discussed in detail in Chapter 8.

Pipeline-Quality Renewable Natural Gas (RNG). Fuel-switching from coal and petroleum to natural gas blended with RNG could also provide emissions reductions. RNG is biogas that has been upgraded to pipeline quality and is chemically equivalent to fossil natural gas. RNG also diverts gaseous waste streams that would otherwise emit methane. For this reason, RNG is considered a lower carbon source, because the methane emissions it prevents have a higher global warming potential than the CO_2 that results from RNG combustion.[75]

The use of RNG for decarbonizing pipeline gas is particularly well-suited to helping the Industry sector reduce its GHG emissions, since natural gas plays a prominent role in numerous industrial applications--as a resource for process heat, as a fuel for CHP systems, and as a feedstock for products such as chemicals and fertilizers.[76] These industrial needs—currently met by conventional natural gas—could also be met by RNG. In addition, fuel-switching to RNG could require little-to-no infrastructure turnover; and therefore lower infrastructure-associated costs relative to other fuel-switching options.

Costs and Challenges of RNG. RNG is considerably more expensive to produce than natural gas (between 2-3 times the cost). It is important to note, however, that these costs vary based on the type of feedstock. RNG qualifies as an advanced biofuel under the federal Renewable Fuel Standard (RFS) and is eligible to generate offsets under California’s LCFS and cap-and-trade programs. An in-depth analysis of the cost-competitiveness of RNG is included in Chapter 6.

Biogas Capture. Biogas is waste methane that is passively emitted in many sectors. Within the Industry sector, biogas sources are found in the Landfills, Wastewater Treatment, and Solid Waste Treatment subsectors. In 2016, these subsectors emitted 8.83 $MMTCO_2e$ in biogas. By capturing and diverting these sources of methane for upgrading to RNG, the Industry sector could receive a double benefit in terms of methane emissions savings plus displacement of fossil natural gas.

Costs and Challenges of Biogas Capture. The typical capital cost for a 40-acre landfill gas (LFG) collection system (designed for 600 cubic feet per minute) is approximately $1.1 million with additional annual operation and maintenance costs of $191,000. Biogas collection systems generally include the processing infrastructure needed to purify the LFG for different end uses, which occurs through primary treatment (e.g., removal of water, moisture, and particulates) and, if necessary, more involved stages of processing including secondary treatment (e.g., removal of sulfur compounds) for power generation or medium-Btu applications and advanced treatment (e.g., removal of impurities such as CO_2) for high-Btu applications such as vehicle fuels or pipeline-quality gas.[77,78]

Two of the key factors that make RNG more expensive than conventional natural gas are the special requirements for processing and upgrading RNG and pipeline interconnection fees.[79] Prior to injection into a local distribution network through an interconnection, RNG must undergo testing and verification to ensure that it meets pipeline-quality standards.[80] The infrastructure required to upgrade and inject RNG into a local distribution pipeline system typically makes up two-thirds of capital equipment costs for an RNG project, with the remaining one-third of the cost attributed to the actual biogas collection system (for anaerobic digestion).[81] These capital costs also vary by project site,[82] with the lowest costs associated with landfill gas, and then progressively higher costs for RNG from wastewater treatment, municipal solid waste, dairy manure, and forestry and agricultural residues, respectively.[83]

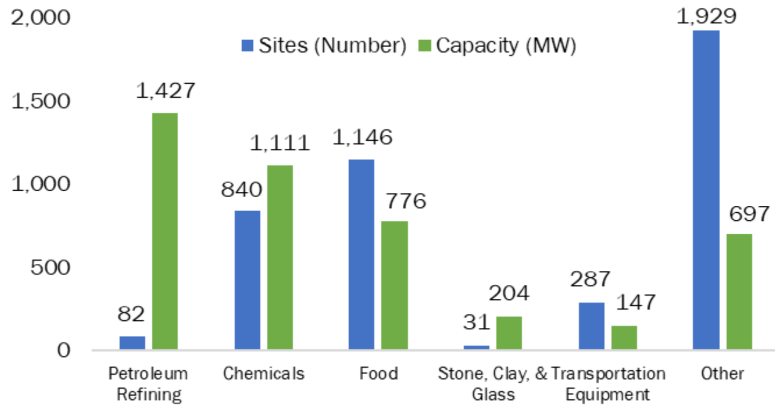
Combined Heat and Power

CHP can be used in industrial facilities to generate electrical and thermal energy from a single fuel source and lead to reduced energy consumption, lower fuel costs, and decreased GHG emissions. According to an analysis by the DOE CHP Deployment Program, California had the second-highest total technical potential for new CHP projects in the United States, behind only Texas.[84]

In 2016, California had a total CHP installed capacity of 8,590 megawatts (MW) across 1,220 installations, of which 4,097 MW (48 percent) are located in the Industry sector with just 189 installations (15 percent).[85] Estimates suggest that California has 3,633 MW of new topping-cycle CHP technical potential across 4,253 sites. It also has 729 MW of new technical potential available through bottoming-cycle CHP across 62 sites.[86] In total, the Industry subsectors with the highest technical CHP potential in California (in terms of capacity) were Petroleum Refining and Hydrogen Production (1,427 MW); Chemicals and Allied Products (1,111 MW); Food Products (776 MW); Stone, Clay, Glass, and Cement (204 MW); and Transportation Equipment (147 MW) (Figure 4-9). [87]

Figure 4-9

Total CHP Technical Potential by Industry Subsector in California

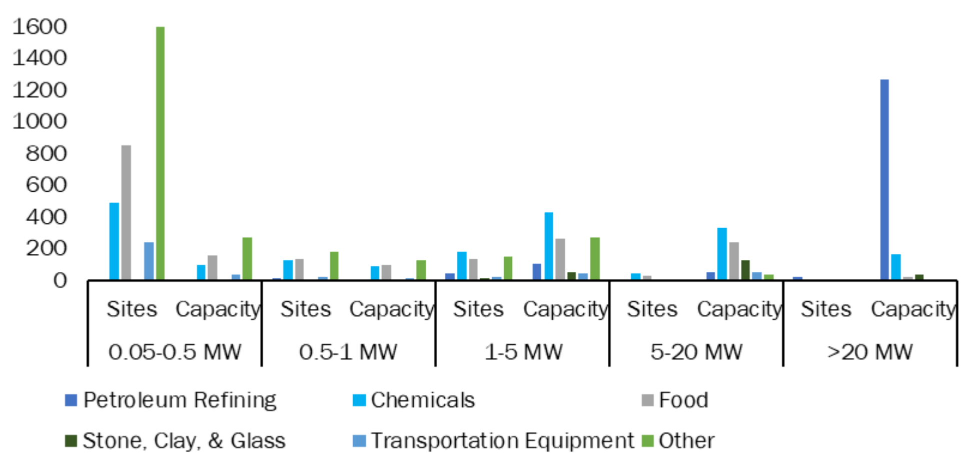


California has a large CHP technical potential across numerous Industry subsectors. Source: EFI, 2019. Compiled using data from DOE, 2017. See Appendix B-4 for additional explanatory notes.

The Chemicals and Allied Products subsector has the highest technical potential for topping-cycle CHP, while the Petroleum Refining and Hydrogen Production subsector has the highest technical potential for bottoming-cycle CHP. Petroleum Refining and Hydrogen Production was also identified as the subsector with the highest technical potential for large (i.e., greater than 20 MW) CHP projects (Figure 4-10).[88]

Figure 4-10

Total CHP Technical Potential by Project Size and Industry Subsector in California



The Chemicals and Petroleum Refining subsectors have the highest technical potential for CHP. Source: EFI, 2019. Compiled using data from DOE, 2016.

California has had a series of policies to encourage CHP projects. They include the following:

- In 2001, the state initiated a Self-Generation Incentive Program that provided electricity customers with incentives to produce electricity through a variety of distributed energy resources; the program has included financial incentives for conventional and renewables-based CHP projects.[89]

- In 2007, California's AB 1613 established policies to promote the deployment and compensation of CHP systems of less than 20 MW.[90]
- The state set a target for an additional 4,000 MW of CHP, which included an emissions target of 6.7 $MMTCO_2e$ by 2020, in the state's 2008 Scoping Plan for AB 32.[91]
- In 2010, the CPUC entered into a settlement agreement with three major California utilities requiring that they procure a minimum of 3,000 MW of CHP capacity from 2010 to 2015 and reduce GHG emissions by 4.8 $MMTCO_2e$.[92]
- A goal of 6,500 MW of additional CHP capacity by 2030 as part of then-Attorney General Brown's Clean Energy Jobs Plan, set in 2010.[93]
- A 2015 CPUC ruling that allowed the Southern California Gas Company to design, implement, and maintain CHP projects at locations adjacent to customer property to help circumvent barriers to CHP project adoption for interested parties that do not have the capital or experience to manage such projects (available to customers on a voluntary basis).[94]

Additional policies could enable California to capitalize on its large technical potential for new industrial CHP projects across the state to reduce GHG emissions. CHP is also discussed in detail in Chapter 5, in connection with decarbonizing the Buildings sector.

Costs and Challenges of CHP. CHP is a mature technology that is currently used in both the Buildings and Industry sectors. The project economics for CHP are generally based on the net benefit of displacing purchased electricity and boiler fuel with self-generated power and thermal energy.

CHP systems face several challenges involving different subnational laws and regulations, grid interconnection issues, and accessing different fuel sources. Challenges at the state level can have a major impact on CHP project deployment.[95]

Table 4-7
Industrial CHP Costs by Size and Technology Type

Technology	System Size and Type	Average Installed Cost ($/kW)
Reciprocating Engine	100 kW, rich burn	$2,475
	800 kW, lean burn	$1,710
	3,000 kW, lean burn	$1,378
	5,000 kW, lean burn	$1,378
Gas Turbine	3,000 kW GT	$2,328
	10 MW GT	$1,444
	40 MW GT	$1,141
Microturbine	65 kW	$2,790
	185 kW	$2,700
	925 kW	$2,610
Fuel Cell	300 kW MCFC	$4,760
	200/400 kW PAFC	$4,250
	1,200 kW MCFC	$4,097

Source: ICF, 2012.

Industrial CHP systems can range in cost depending on factors such as technology type and size of the system (Table 4-7).[96] An analysis of CHP opportunities in California identified reciprocating engines as the most economic CHP technology for smaller projects less than 5 MW, while gas turbines were more economic for larger projects above 5 MW.[97]

Carbon Capture, Utilization, and Storage

CCUS is expected to play an important role in sectors and processes that are difficult to decarbonize. At present, CCUS is likely the only option available for decarbonizing several industrial processes such as cement production, oil refining, and natural gas processing, in addition to further mitigation opportunities across California's large industrial base (Table 4-8).[98]

Table 4-8
Profile of Select California Industry Subsectors

Type	Characteristics	Ref.
Industrial CHP: Current Installations	189 installations; 4,097 MW of installed capacity	99
Industrial CHP: New Technical Potential	4,315 sites; 4,362 MW of potential capacity	100
Landfills	298 landfills (176 closed; 116 open; 6 unknown)	101
Manufacturing, Total	36,117 firms; Manufacturing output: $300.35 billion; Share of total GSP: 10.9 percent	102
Chemical and Allied Products: Fuel ethanol plants	5 plants; Production capacity: 200 million gallons/year or 13,000 barrels/day	103
Primary Metals: Iron and steel jobs	8,710 structural iron and steel workers	104
Primary Metals: Raw steel facilities	Steel industry supports 38,700 jobs in California	105
Pulp and Paper: Mills	46 pulp, pulp and paper, and paper mills	106
Stone, Clay, Glass, and Cement: Cement plants	11 plants; Clinker capacity: 12.1 MMT; Cement production: 9.6 MMT Cement consumption: 9.3 MMT	107 108
Wastewater Treatment	900 plants	109
Mining	395 active mines and plants in 2003 (latest year available from USGS)	110
Oil & Gas Production and Processing: Natural gas processing plants	10 plants; 100,780 million cubic feet/year	111 112
Petroleum Refining and Hydrogen Production: Oil refineries	17 refineries; 1,901,971 barrels/day	113
Petroleum Refining and Hydrogen Production: Hydrogen production	1,065 million cubic feet/day	114

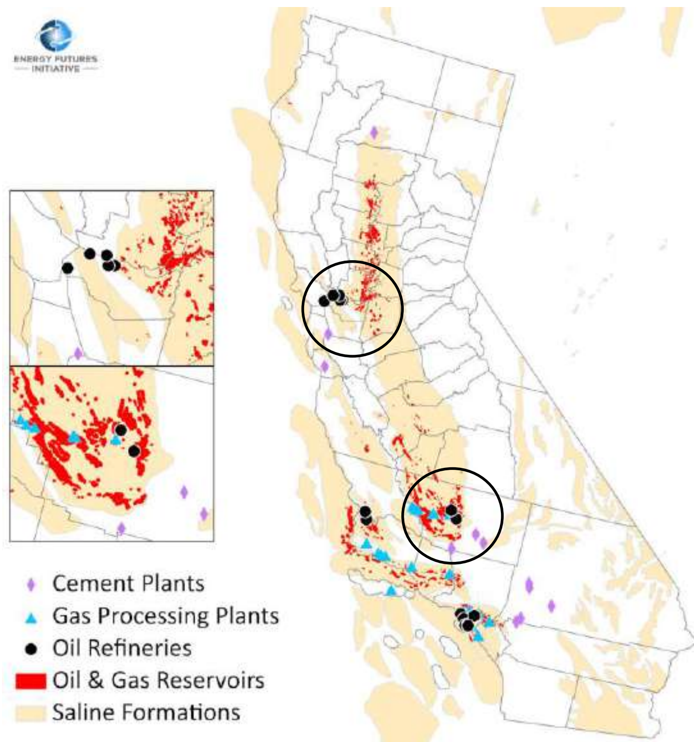
California has a large industrial base across numerous subsectors that are complex and difficult to decarbonize. Source: EFI, 2019.

California is also well-positioned to take advantage of its estimated geologic storage potential of 34 to 424 billion metric tons of CO_2,[115] making CCUS a viable option for industrial decarbonization. There are a large number of industrial facilities clustered near San Francisco and the surrounding area, Los Angeles and the surrounding area, and along the Central Valley (Figure 4-11).[116,117,118,119,120] The proximity of these industrial facilities to potential CO_2 sequestration sites could offer an opportunity to build new infrastructure that would support the transport and storage of captured CO_2 from numerous facilities.

Costs and Challenges of CCUS in Industry. CCUS presents technical, economic, and public policy challenges that must be addressed to ensure viability of this option. From a technical standpoint, capturing CO_2 can be a challenging and energy-intensive process; however, numerous industrial processes tend to have higher concentrations of CO_2 in their effluent streams, which can result in fewer technical (and economic) challenges for capture compared to less concentrated streams of CO_2 such as those found in the power sector (e.g., approximately 5 percent CO_2 concentration for natural gas plants and 15 percent for coal plants).[121]

Figure 4-11

Industrial Facilities and Potential Sequestration Opportunities



A large portion of the industrial base in California is located near potential CO_2 sequestration sites. Upper inset map: San Francisco and surrounding area. Lower inset map: Lower Central Valley and surrounding area. The circled regions denote regional clusters that could provide opportunities for shared infrastructure related to CCUS (e.g., CO_2 pipelines). Source: EFI, 2019. Compiled using data from USGS, EIA, CEC, and NETL.

The transport and geologic sequestration of CO_2 also presents challenges that include regulatory uncertainty, post-injection site stewardship and liability, and the length of time required to demonstrate permanence.[122] However, the recent CCS Protocol developed for the California LCFS program does provide guidelines to help address some of these issues including a 100-year minimum period for post-injection site care and monitoring, prior to site closure.[123] The absence of sufficient CO_2 pipeline infrastructure in California is another impediment to CCUS project development. Pipelines remain the most cost-effective means of transporting large amounts of CO_2 over long distances for the purposes of utilization (e.g., EOR) or geologic sequestration.[124] At present, there are an estimated 4,513 miles of dedicated CO_2 pipelines in the United States, none of which are in California.[125]

Cost estimates for industrial CCUS are more uncertain than those in the power sector and can vary based on the type of industrial facility and capture technology (Table 4-9).[126] The costs (and technical difficulties) of industrial CCUS are also affected by the number of emissions sources present at each type of facility. For example, emissions from cement plants stem from the precalciner and kiln, whereas emissions from petroleum refineries come from a much larger number of individual sources. Despite the uncertainty and variability in CCUS costs, industrial facilities tend to form regional clusters; this characteristic can be leveraged for shared CO_2 transportation networks and geologic storage opportunities.[127]

Table 4-9
Overview of Carbon Capture Costs by Industry Activity

Activity	Capture Cost ($/t$CO_2$)
Ammonia production	$3.90-45.30
Hydrogen production	$6.00-74.00
Liquid natural gas production	$8.70
Iron and steel	$9.80-119.20
Natural gas processing	$10.25-39.00
Ethanol production	$12.30
Ethylene oxide production	$15.40
Cement plants	$17.00-164.60
Petroleum refineries	$28.70-250.00
Pulp and paper mills	$56.40-59.00

Source: EFI, 2019. Compiled using data from Leeson et al., 2017.

Analysis Methodology

Analysis of emissions reduction potential in the Industry sector is based on the "Economic Sector Categorization" version of CARB's GHG inventory, which provides a more granular data structure of emissions at sector and activity levels. Potential GHG savings to 2030 assume that total Industry sector emissions will remain near the 2016 level of 100.4 MMTCO_2e (Table 4-10). The reasonableness of this assumption is supported by the finding that the average annual Industry sector emissions level in California was 102.1 MMTCO_2e between 2000 and 2016.[128]

Due to the heterogeneous nature of the Industry sector, mitigation opportunities were assessed at the subsector level. A detailed profile of each of the nine Industry subsectors analyzed in this chapter was created to help inform which mitigation opportunities could be the most appropriate to pursue with respect to the unique challenges and opportunities afforded by the individual subsector. The subsector profiles (Appendix B-2) include a breakdown of fuel combustion versus non-combustion emissions (including specific emissions sources and their corresponding 2016 emissions level), process heat requirements, near-term electrification potential, and a comprehensive list of mitigation opportunities across different technologies. Based on these profiles, one or more mitigation opportunities were selected to address the emissions sources in each subsector while considering process heat requirements and near-term electrification potential, where applicable.

Table 4-10
Industry Key Assumptions

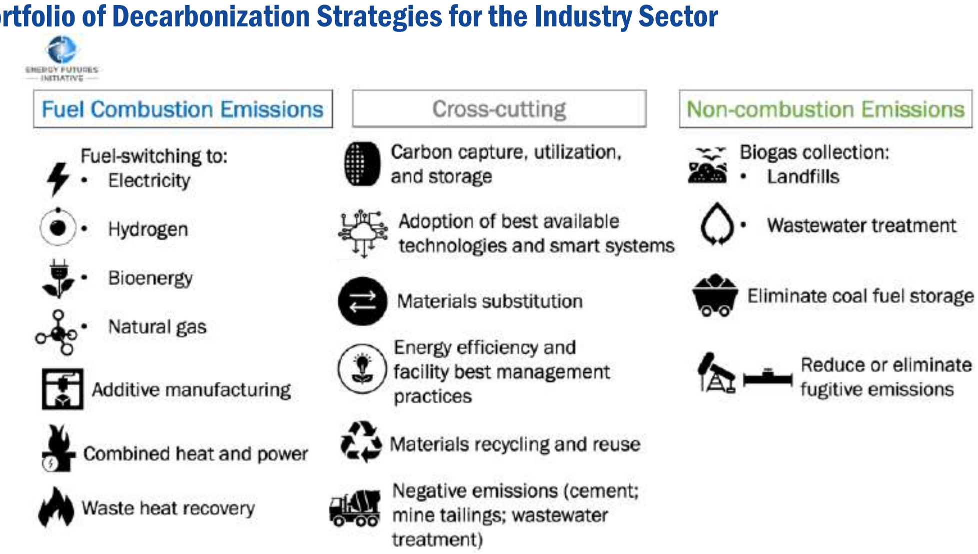
Technology Pathway	Subsector	Key Assumptions
Baseline	All	Energy demand growth remains flat, based on historical energy demand (2000-2016).
Carbon Capture, Utilization, and Storage (CCUS)	Cement (60 percent capture rate); Oil & Gas Production and Processing (50 percent capture rate); Petroleum Refining and Hydrogen Production (65 percent capture rate)	CCUS capture rates were specific to subsectors where historical data were available, otherwise a 50 percent capture rate was assumed. CCUS applied to fuel combustion emissions except for Cement which also included the capture of non-combustion emissions. Two regional clusters of industrial facilities located nearby potential sequestration sites were identified as candidates for CCUS and included four cement plants, one large cluster of natural gas processing facilities, and seven oil refineries. These clusters include the large oil refining capacity in the Bay Area and the large gas production and processing operations near Bakersfield.
Fuel-switch: H_2 or Electrification; Fuel-switch: Natural Gas	Industrial CHP; Manufacturing (Construction; Electric & Electronic Equipment; Metal Durables; Plastics & Rubber; Primary Metals; Printing and Publishing; Pulp and Paper; Stone, Clay, Glass and Cement; Textiles; Tobacco; Transportation Equipment; Wood and Furniture, Manufacturing--Not Specified); Mining; Oil & Gas Production and Processing; Petroleum Refining and Hydrogen Production	Fuel-switching opportunities were based on a qualitative assessment of electrification potential by Lawrence Berkeley National Laboratory. Fuel-switching to hydrogen or electrification was assumed to result in zero emissions, while fuel-switching to natural gas from coal and petroleum was calculated based on the difference in emissions factors. Subsectors with a "Low" and "Medium" electrification potential were assumed to not be ready for electrification; "High" electrification potential subsectors were assumed to be ready for electrification.
Facility Best Management Practices (MGMT)	All	Facility best management practices were benchmarked to the U.S. Environmental Protection Agency (EPA) ENERGY STAR Challenge for Industry, which seeks to reduce the energy intensity of industrial sites by 10 percent in five years.
New Technology Adoption	Manufacturing (Cement; Construction; Electric and Electronic Equipment; Food Products; Textiles; Transportation Equipment; Wood and Furniture)	This included the combined emissions savings from three technologies: higher-efficiency kilns in the Cement subsector (30 percent lower thermal fuel use), smart systems for manufacturing automation to reduce energy intensity by 20 percent, and a 25 percent reduction in energy use through additive manufacturing in select Manufacturing subsectors.
Biogas Collection	Landfills (50 percent capture); Wastewater Treatment (50 percent capture); Solid Waste Treatment (50 percent capture)	Biogas collection was based on a capture rate of 50 percent (only methane emissions in CO_2e) from Landfills, Wastewater Treatment, and Solid Waste Treatment (from composting).
Reduce Fugitive Emissions	Oil & Gas Production and Processing (50 percent capture); Transmission and Distribution (50 percent capture)	Reducing or eliminating fugitive emissions was based on a capture rate of 50 percent.
Renewable Natural Gas Use	All	RNG has the potential to replace 197 Bcf of conventional pipeline natural gas based on RNG potential (in-state and imports) by 2030. Assumed one-third of this potential is used in Industry. See Biogas and Renewable Natural Gas Addendum in Chapter 6 for full explanation of accounting and estimation.
Combined Heat and Power (CHP)	Manufacturing (Chemicals and Allied Products); Petroleum Refining and Hydrogen Production	Based on maximizing new installed capacity and minimizing the number of new project sites, which were in the Chemicals and Allied Products subsector for smaller projects (39 sites at

		5 MW capacity each using reciprocating engines at 9,190 metric tons of CO_2e savings per unit relative to coal use) and the Petroleum Refining and Hydrogen Production subsector for large projects (21 sites at 20 MW capacity each using natural gas combustion turbines at 30,508 metric tons of CO_2e savings per unit relative to coal use). The actual emissions savings from industrial CHP was calculated using online calculators provided by the EPA that included assumptions for CHP size and operations.
Energy Efficiency (EE)	All	The emissions savings potential through reduced natural gas consumption for industrial energy efficiency was considered to be industrywide and was taken from CEC.

GHG Emissions Reduction Pathways

There is a large technical potential for GHG emissions reductions across a range of technologies that can help decarbonize the Industry sector in California (Figure 4-12). Fuel-switching (to hydrogen or electricity) and CCUS have a considerable individual technical potential to help meet the Industry sector's 2030 goal.

Figure 4-12
Portfolio of Decarbonization Strategies for the Industry Sector



There are a host of decarbonization strategies that can be employed to address both fuel combustion and non-combustion emissions in the Industry sector. Source: EFI, 2019. Graphics from the Noun Project.

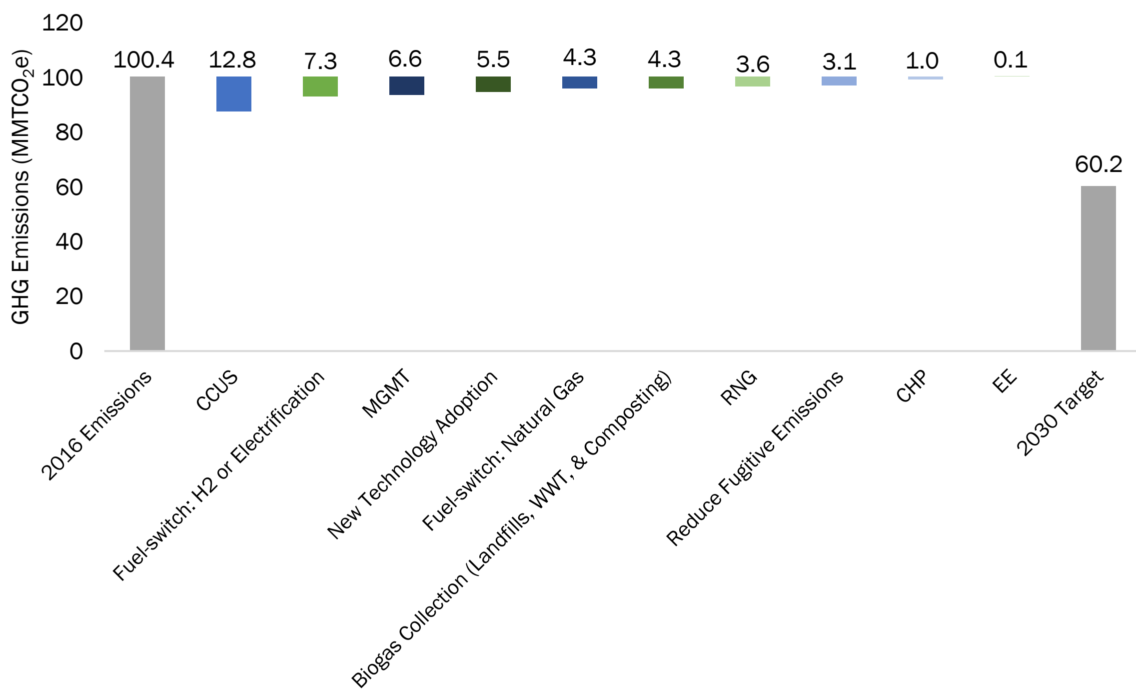
Illustrative High-level Mitigation Portfolio Pathway

In order to meet California's economywide GHG emissions reduction targets of 40 percent by 2030 and 80 percent by 2050, all sectors will likely need to implement tailored strategies to decrease emissions. Consistent with the methodology of this analysis (each sector is assumed to reduce its emissions by 40 percent from a 2016 baseline to achieve the overall target), the Industry sector would need to reduce its GHG emissions 40.1 $MMTCO_2e$ by 2030, relative to the 2016 emissions level of 100.4 $MMTCO_2e$.

The following illustrative mitigation portfolio pathway (Figure 4-13)[129] was created from a selection of the mitigation opportunities described in Appendix B-2.

Figure 4-13

Illustrative Mitigation Portfolio Pathways by Industry Subsector



It is estimated that an emissions reduction of 48.6 $MMTCO_2e$ could be possible by 2030 through a combination of CCUS, fuel-switching, facility best management practices, new technology adoption, biogas collection, RNG, reducing fugitive emissions, CHP, and energy efficiency. Source: EFI, 2019. Compiled using data from CARB, 2018.

An additional target of achieving statewide carbon neutrality no later than 2045, and maintaining net negative emissions thereafter, would require breakthrough innovations in the Industry sector and across California's economy. Given the difficult-to-decarbonize nature of the Industry sector, California will likely need to consider a host of potential decarbonization strategies to achieve deep and sustained reductions in GHG emissions.

The following analysis summarizes a range of mitigation opportunities to meet 2030 targets across the Industry sector and within subsectors using data from CARB.[130] Unlike in the other sectors (Electricity, Transportation, Buildings, and Agriculture), the industrial pathways take a subsectoral approach rather than a technological one. This is due to the highly diverse nature of the various subsectors, which require tailored solutions for decarbonization.

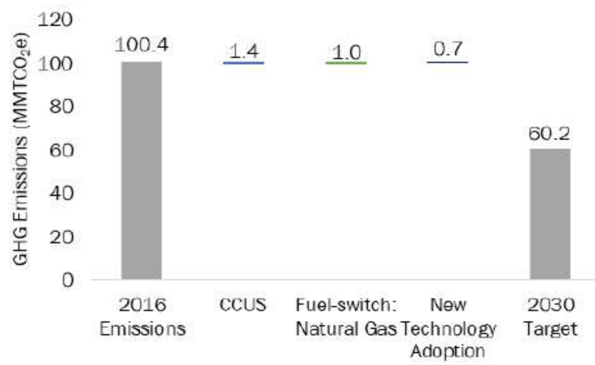
Pathway 1: Reducing Emissions from Cement Production

The Cement component of the Stone, Clay, Glass, and Cement subsector was responsible for approximately 7.6 $MMTCO_2e$ of GHG emissions in 2016, of which 32 percent was from fuel combustion and 68 percent from non-combustion sources (mostly process emissions).[131] Cement production has a high-temperature process heat requirement and a low near-term electrification potential. Previous estimates of California's cement plant fuel consumption found that nearly two-thirds (62 percent) of fuel demand was met by coal, followed by petroleum coke (14 percent), electricity (12 percent), scrap rubber tires (7 percent), and natural gas (4 percent).[132] In 2016, coal was responsible for 56 percent of the total fuel combustion emissions from cement production in California.[133] Fuel combustion emissions are mostly from coal, while non-combustion emissions are from clinker production.

Several strategies to reduce emissions in cement production include emissions savings through materials substitution (e.g., reduce clinker-to-cement ratio);[134] new technology adoption (higher-efficiency kiln);[135] fuel-switching; CCUS; and various utilization and sequestration opportunities.[136,137]

For this analysis, CCUS was applied as a cross-cutting mitigation opportunity to four cement plants identified in two regional clusters that are located near potential geologic sequestration sites (Figure 4-11). Electrification was not pursued due to the low near-term electrification potential and high-temperature process heat requirements of cement production. However, fuel-switching from coal and petroleum products to natural gas was examined, to reduce the emissions intensity of fuel consumption while maintaining the ability to provide high-temperature process heat. New technology adoption of higher-efficiency kilns were used across the industrial base of cement plants to help reduce emissions through less fuel consumption. Based on the illustrative mitigation portfolio, the Cement subsector could achieve an emissions reduction of 3.1 $MMTCO_2e$ by 2030 through a combination of CCUS, fuel-switching to natural gas, and new technology adoption (Figure 4-14).[138]

Figure 4-14
Emissions Reduction Pathways in the Cement Subsector



According to the illustrative mitigation portfolio, emissions reductions in the Cement subsector could total 3.1 $MMTCO_2e$.
Source: EFI, 2019. Compiled using data from CARB, 2018.

Pathway 1A: Energy Efficiency, New Technology Adoption, and Materials Substitution

As of 2013, eight cement plants in California had undergone or were considering 79 different energy efficiency improvement projects under the EEA Regulation. These energy efficiency projects were expected to lead to a reduction in GHG emissions of 0.68 $MMTCO_2e$ per year, a one-time cost of $690 million, annual costs of $8.4 million, and annual savings of $16.4 million.[139]

The adoption of best available technologies such as higher-efficiency dry kilns that have a lower thermal energy intensity is another efficiency measure that could help reduce GHG emissions from cement production.[140] For non-combustion process emissions, the materials substitution of coal fly ash or blast furnace slag for clinker in the production of cement (and/or the adoption of CCUS) could help mitigate CO_2 emissions that are otherwise unavoidable during the heating of limestone.[141,142]

Pathway 1B: Fuel-switching for Cement Production

Using lower-carbon fuels to heat kilns is another strategy to decrease GHG emissions from cement production. Fuel switching from coal to natural gas and/or RNG could present an immediate opportunity to reduce cement production emissions. Alternatively, clean hydrogen could be used to decarbonize the thermal energy supply needs for cement production using hydrogen produced either through SMR of natural gas with CCUS (due to the better near-term economics for hydrogen production) or through electrolysis.

Pathway 1C: CCUS

Although materials substitution could provide an alternative method for reducing CO_2 emissions from cement manufacturing, this subsector tends to be more averse to making major process changes. This might mean that CCUS is one of the few viable options for reducing GHG emissions. It is estimated that cement manufacturing produces 0.65 to 0.95 metric tons of CO_2 per metric ton of cement.[143]

Sixty percent of CO_2 emissions during cement manufacturing are process emissions from the calcination of calcium carbonate (e.g., limestone), while the remaining emissions stem from fossil fuel combustion.[144] CCUS can be a promising technology to help reduce GHG emissions associated with cement production, as the CO_2 concentrations in the flue gas streams of cement plants are approximately 30 percent (around two times more concentrated than the flue gas of coal power plants),[145] which can improve the economics of such carbon capture projects.

Pathway 1D: Utilization Opportunities from Cement Production

The curing of concrete using captured anthropogenic CO_2 presents an immediate opportunity for CO_2 utilization, which has demonstrated greater performance benefits than traditional methods of curing. Estimates suggest that the market for curing concrete with CO_2 could grow by 6.5 to 16.5 billion metric tons by 2030. However, challenges to the use of CO_2 for concrete curing include an uncertain availability of CO_2 and lack of incentive to modify the existing concrete manufacturing process.[146] Carbonate aggregates also offer a longer-term opportunity to fix CO_2 in concrete, asphalt, or construction fill—a market opportunity that could grow by 1.0 to 10.5 billion metric tons of CO_2 by 2030.[147] One study that used CO_2 as an admixture to concrete found that the optimal dose of CO_2 increased the one-day compressive strength by 14 percent and three-day compressive strength by 10 percent.[148] A further incentive to capitalize on these opportunities involves the prospect of minimal disruption to operations, as retrofitting cement plants with certain enabling technologies might only require a system downtime of one or several days.[149]

Pathway 1E: Cement and Sequestration Opportunities

The natural uptake of CO_2 by cement-based materials can lead to additional GHG emissions reductions, with the potential to induce net-negative emissions. Cement-based materials constitute a natural carbon sink through the carbonation process. Several startup companies, some in California, are focused on reducing the emissions footprint of cement.[150] Chapter 8 includes a further discussion on this process.

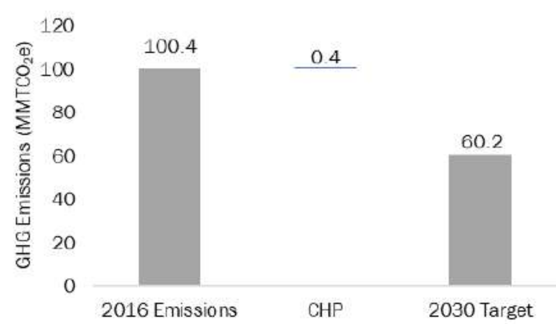
A large portion of the process emissions from cement production are sequestered through the carbonation of cement materials within 50 years, which creates the possibility of inducing net-negative emissions if CCUS is used during the manufacturing process.[151] Within the first two years after production, cement can absorb approximately one-third of its process emissions.[152] From 1930 to 2013, global estimates suggest that 4.5 gigatons of carbon were sequestered through the carbonation of cement materials, which led to a 43 percent reduction in process CO_2 emissions that were emitted through cement production over that time period (excluding emissions stemming from fossil fuel combustion).[153] It has been estimated that capturing 80 percent of process emissions from cement production could make cement carbon-neutral with the additional sequestration achieved through carbonation.[154]

Pathway 2: Reducing Emissions from Chemicals and Allied Products

The Chemicals and Allied Products subsector was responsible for approximately 6.2 $MMTCO_2e$ of California's GHG emissions in 2016, and more than 99 percent of emissions was from fuel combustion (all from natural gas).[155] This subsector has a high-temperature process heat requirement and a medium near-term electrification potential. The two main strategies for reducing emissions in this subsector include fuel-switching from natural gas to hydrogen (since electrification of this subsector does not have a high near-term potential) and CCUS.

For this analysis, CHP was pursued as a mitigation opportunity since Chemicals and Allied Products was identified as one of the two subsectors with the highest technical potential for new projects. CCUS was not pursued since this subsector was not identified as one of the three highest-value opportunities for that technology. Electrification was not pursued due to the medium near-term electrification potential and high-temperature process heat requirement. Based on the illustrative mitigation portfolio, the Chemicals and Allied Products subsector could achieve an emissions reduction of 0.4 $MMTCO_2e$ by 2030 through the deployment of CHP (Figure 4-15).[156]

Figure 4-15
Emissions Reduction Pathway in the Chemicals and Allied Products Subsector



According to the illustrative mitigation portfolio, emissions reductions in the Chemicals and Allied Products subsector could total 0.4 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Pathway 3: Reducing Emissions from Food Products

The Food Products subsector was responsible for approximately 3.3 $MMTCO_2e$ of California's GHG emissions in 2016, of which more than 99 percent was from fuel combustion (all from natural gas) along with a marginal amount from non-combustion emissions.[157] This subsector has a medium- to high-temperature process heat requirement and a medium near-term electrification potential. The two main strategies to reduce emissions in this subsector include fuel-switching from natural gas to hydrogen (since electrification of this subsector does not have a high near-term potential) and CCUS.

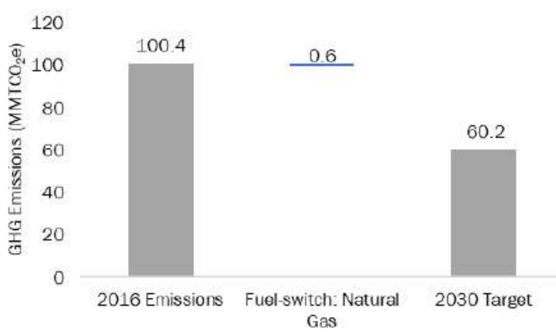
Given that the Food Products subsector has a medium-to-high temperature process heat requirement, medium near-term electrification potential, and was not one of the three highest-value subsectors for CCUS deployment identified in this analysis, no mitigation opportunities were specifically assigned to this subsector.

Pathway 4: Reducing Emissions from Industrial CHP

The Industrial CHP subsector was responsible for approximately 8.0 $MMTCO_2e$ in 2016, of which more than 99 percent was from fuel combustion along with a marginal amount from non-combustion sources. Most of the fuel combustion emissions are from natural gas, followed by coal, refinery gas, associated gas, petroleum products, and other energy sources.

One possible option for mitigation is fuel-switching to natural gas from coal and petroleum products to decarbonize a portion of the thermal energy supply needed for industrial CHP (with the additional option of CCUS). Another possible mitigation option would be to fuel-switch from fossil energy to hydrogen, with the hydrogen produced through SMR of natural gas with CCUS or electrolysis.

Figure 4-16
Emissions Reduction Pathway in the Industrial CHP Subsector



According to the illustrative mitigation portfolio, emissions reductions in the Industrial CHP subsector could total 0.6 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Beyond mitigation from the existing installed capacity, California could pursue new natural gas-based industrial CHP projects to capitalize on the technical potential available throughout the Industry sector. The highest-value opportunities for new CHP projects (defined as maximizing new installed capacity and minimizing the number of new project sites) are in the Chemicals and Allied Products subsector for smaller projects (39 sites at 5 MW capacity each using reciprocating engines at 9,190 metric tons of CO_2e savings per unit) and the Petroleum Refining and Hydrogen Production subsector for large projects (21 sites at 20 MW capacity each using natural gas combustion turbines at 30,508 metric tons of CO_2e savings per unit).

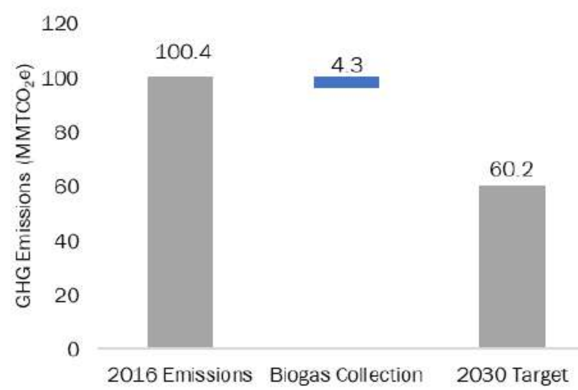
Based on the illustrative mitigation portfolio, the Industrial CHP subsector could achieve an emissions reduction of 0.6 $MMTCO_2e$ by 2030 through fuel-switching to natural gas for existing projects (Figure 4-16).[158]

Pathway 5: Reducing Emissions from Landfills, Solid Waste Treatment, and Wastewater Treatment

Biogas collection is a mitigation opportunity for several Industry subsectors including Landfills (8.5 $MMTCO_2e$), Solid Waste Treatment (0.3 $MMTCO_2e$), and Wastewater Treatment (less than 0.1 $MMTCO_2e$).[159] The main mitigation opportunity in these subsectors is through the deployment of biogas collection systems to divert these gaseous waste streams and allow them to provide useful energy services including: on-site power generation with minimal processing; upgrading to RNG for medium- or heavy-duty transportation fuels in the form of compressed natural gas or liquefied natural gas; and upgrading to RNG to decarbonize the pipeline gas network for the Industry and Buildings sectors.

For this analysis, biogas collection was pursued as a mitigation opportunity. Based on the illustrative mitigation portfolio, these three subsectors could achieve an emissions reduction of 4.3 $MMTCO_2e$ by 2030 through the deployment of biogas collection systems (Figure 4-17).[160]

Figure 4-17
Emissions Reduction Pathway from Biogas Collection in Select Subsectors



According to the illustrative mitigation portfolio, emissions reductions in the Landfills, Solid Waste Treatment, and Wastewater Treatment subsectors could total 4.3 $MMTCO_2e$.
Source: EFI, 2019. Compiled using data from CARB, 2018.

Pathway 6: Reducing Emissions from Oil & Gas Production and Processing

The Oil & Gas Production and Processing subsector was responsible for approximately 18.0 $MMTCO_2e$ of California's GHG emissions in 2016, of which 87 percent was from fuel combustion emissions, with the remainder from non-combustion emissions.[161] Fuel combustion emissions are driven by emissions from natural gas and associated gas, with the remainder coming from fugitive emissions; most of these are from production, followed by processing, storage, and wastewater treatment. This subsector has a high-temperature process heat requirement and a low near-term electrification potential.

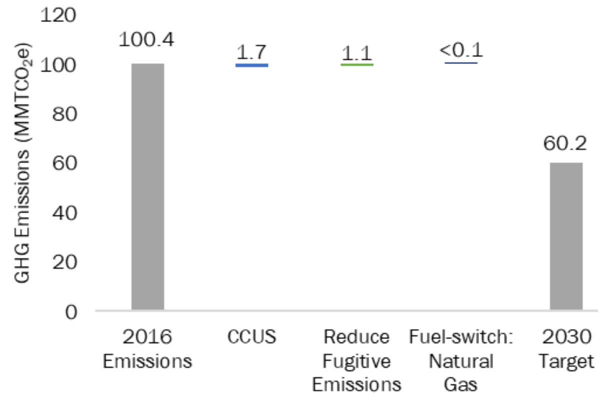
Strategies to reduce emissions in this subsector include fuel-switching from natural gas to hydrogen (since electrification of this subsector does not have a high near-term potential); CCUS; and the reduction or elimination of fugitive emissions.

For this analysis, CCUS was applied as a mitigation opportunity to one regional cluster of natural gas processing plants that are located near potential geologic sequestration sites (Figure 4-11). Reducing or eliminating fugitive emissions from processing, production, fuel storage, and wastewater treatment was pursued in this subsector at a 50 percent capture rate. Electrification was not pursued due to the high-temperature process heat requirements.

Fuel-switching from petroleum products to natural gas was an option that was pursued to reduce the emissions intensity of fuel consumption while maintaining the ability to provide high-temperature process heat. Based on the illustrative mitigation portfolio, the Oil & Gas Production and Processing subsector could achieve an emissions reduction of 2.8 $MMTCO_2e$ by 2030 through a combination of CCUS (natural gas processing plants), reducing fugitive emissions, and fuel-switching to natural gas (Figure 4-18).[162]

Figure 4-18

Emissions Reduction Pathways in the Oil & Gas Production and Processing Subsector



According to the illustrative mitigation portfolio, emissions reductions in the Oil & Gas Production and Processing subsector could total 2.8 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Pathway 7: Reducing Emissions from Petroleum Refining and Hydrogen Production

The Petroleum Refining and Hydrogen Production subsector was responsible for approximately 29.6 $MMTCO_2e$ of California's GHG emissions in 2016, of which 76 percent was from fuel combustion with the remainder from non-combustion.[163] This subsector has a high-temperature process heat requirement and a low near-term electrification potential. Emissions from fuel combustion are mostly from refinery gas, followed by petroleum products and natural gas. Non-combustion emissions mostly stem from fuel consumption of refinery gas and natural gas.

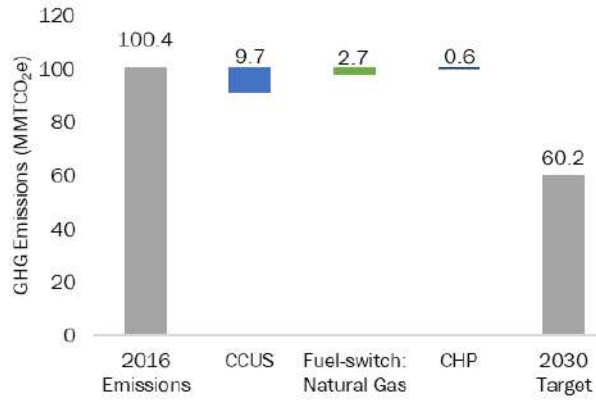
Strategies to reduce emissions in this subsector include fuel-switching from petroleum to natural gas; fossil energy to hydrogen (since electrification of this subsector does not have a high near-term potential); CCUS; and the reduction or elimination of fugitive emissions.

For this analysis, CCUS was applied as a mitigation opportunity to seven oil refineries identified in two regional clusters that are located near potential geologic sequestration sites (Figure 4-11). As noted, electrification was not pursued due to the low near-term electrification potential and high-temperature process heat requirement. However, fuel-switching from coal and petroleum products to natural gas was pursued to reduce the emissions intensity of fuel consumption while maintaining the ability to provide high-temperature process heat. CHP was pursued as a mitigation opportunity since it was identified as one of the two subsectors with the highest technical potential for new projects.

Based on the illustrative mitigation portfolio, the Petroleum Refining and Hydrogen Production subsector could achieve an emissions reduction of 13.0 $MMTCO_2e$ by 2030 through a combination of CCUS (oil refineries), fuel-switching to natural gas, and CHP (Figure 4-19).[164] More detailed information on oil refineries are in Appendix B-3.

Figure 4-19

Emissions Reduction Pathways in the Petroleum Refining and Hydrogen Production Subsector



According to the illustrative mitigation portfolio, emissions reductions in the Petroleum Refining and Hydrogen Production subsector could total 13.0 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Pathway 8: Reducing Emissions from Transmission and Distribution Pipelines

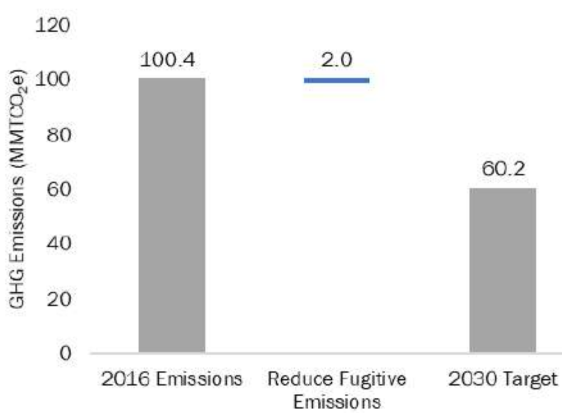
The Transmission and Distribution subsector was responsible for approximately 5.1 $MMTCO_2e$ of California's GHG emissions in 2016, of which 80 percent was from non-combustion sources.[165] Non-combustion emissions are largely fugitive emissions from natural gas pipelines, with a marginal amount of fugitive emissions from natural gas storage. Fuel combustion emissions are all from natural gas.

One possible mitigation opportunity is to reduce or eliminate fugitive emissions from gas pipeline infrastructure. A second mitigation opportunity that could address fuel combustion-related emissions from natural gas is by fuel-switching to hydrogen or electrification (with subsequent elimination of natural gas storage).

For this analysis, reducing or eliminating fugitive emissions from gas storage and pipelines was pursued in this subsector at a 50 percent capture rate. Based on the illustrative mitigation portfolio, the Transmission and Distribution subsector could achieve an emissions reduction of 2.0 $MMTCO_2e$ by 2030 through reducing fugitive emissions (Figure 4-20).[166]

Figure 4-20

Emissions Reduction Pathway in the Transmission and Distribution Subsector



According to the illustrative mitigation portfolio, emissions reductions in the Transmission and Distribution subsector could total 2.0 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Pathway 9: Other Opportunities for Reducing Industry Sector Emissions

There were numerous smaller Industry subsectors that were collectively responsible for a similar amount of fuel combustion (52 percent) and non-combustion (48 percent) GHG emissions in 2016 (13.9 $MMTCO_2e$ in total). These smaller subsectors included: Manufacturing (Construction; Electric and Electronic Equipment; Metal Durables; Plastics and Rubber; Primary Metals; Printing and Publishing; Pulp and Paper; Stone, Clay, and Glass; Storage Tanks; Textiles; Tobacco; Transportation Equipment; Wood and Furniture; and Manufacturing: Not Specified), Mining; Petroleum Marketing; and overall emissions in the Industry sector that were “Not Specified” in CARB’s database.

The majority of fuel combustion emissions were from natural gas, followed by petroleum. Non-combustion emissions stemmed from the use of hydrofluorocarbons—high-global-warming-potential substitutes for ozone-depleting substances used in refrigeration and air conditioning—followed by wastewater and consumption (e.g., soda ash), and other sources.

Five of the secondary subsectors within the Manufacturing subsector had a high near-term electrification potential (Metal Durables; Plastics and Rubber; Primary Metals; Transportation Equipment; Wood and Furniture) and were considered eligible for electrification. These five subsectors were collectively responsible for 1.7 $MMTCO_2e$ of emissions, which was 23 percent of the total fuel combustion emissions in this group of subsectors (7.3 $MMTCO_2e$). The remaining fuel combustion emissions were assumed to be eliminated by fuel-switching to clean hydrogen, which is an energy resource that is well-positioned to play a prominent role in decarbonization of the Industry sector (and across the economy).

For energy efficiency, the CEC has estimated that compliance with SB 350 could help the Industry sector realize a potential GHG savings of 0.06 $MMTCO_2e$.[167] Similarly, the EPA ENERGY STAR Challenge for Industry aims to improve energy efficiency at any industrial site by reducing its energy intensity by 10 percent within five years.[168] Achieving this target across California’s Industry sector could potentially reduce fuel combustion emissions by 6.6 $MMTCO_2e$.

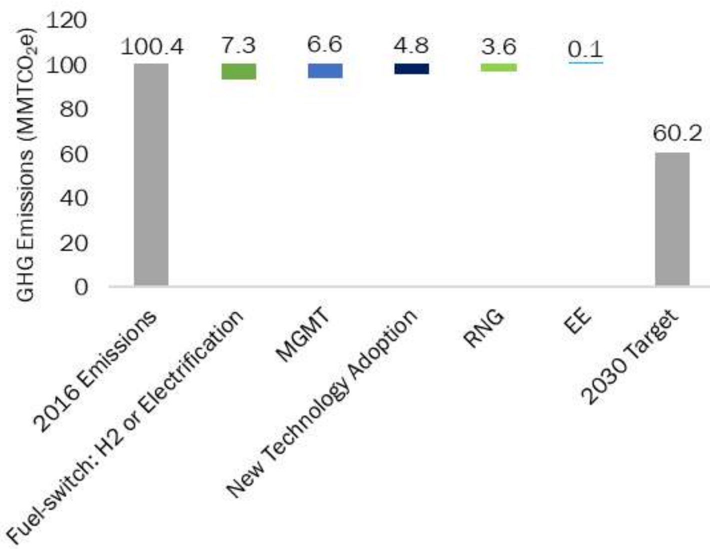
New technology adoption is possible within the Manufacturing subsector and includes additive manufacturing and smart systems. Estimates suggest that additive manufacturing could reduce energy use in manufacturing operations by 25 percent.[169,170] It may be most relevant in the following Manufacturing subsectors: Construction, Electric and Electronic Equipment, Food Products, Textiles, Transportation Equipment, and Wood and Furniture. Implementing additive manufacturing in these subsectors could potentially reduce emissions by 1.0 $MMTCO_2e$. Smart systems could assist process automation in the Manufacturing subsector, with the potential to achieve a reduction in energy intensity of 20 percent.[171] For California’s Manufacturing subsector, a 20 percent reduction in energy consumption could potentially result in an emissions savings of nearly 3.8 $MMTCO_2e$.

RNG could also provide an opportunity to decarbonize pipeline natural gas through harvesting in-state biogas resources and potentially importing RNG from other states.

Based on the analysis for decarbonizing the pipeline gas supply with RNG, the estimated 2030 emissions reduction potential could be 3.6 $MMTCO_2e$.[172]

Based on the above illustrative mitigation portfolio, this collection of other Industry subsectors could achieve an emissions reduction of 22.4 $MMTCO_2e$ by 2030 through electrification and fuel-switching to hydrogen, facility best management practices, new technology adoption (additive manufacturing and smart systems), RNG to help decarbonize pipeline gas, and energy efficiency (Figure 4-21).[173] Note that further emissions reductions could be pursued in several of these sectors through negative emissions (e.g., wastewater treatment),[174] but were not factored into this analysis.

Figure 4-21
Other Emissions Reduction Pathways in the Industry Sector



According to the illustrative mitigation portfolio, emissions reductions in other Industry subsectors could total 22.4 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

Conclusion

Although California could achieve a decarbonization target of 40 percent by 2030 in the Industry sector by only focusing on the mitigation of fuel combustion-related GHG emissions, it will not be able to achieve an 80 percent reduction by 2050 (based on the 2016 emissions level)—with further ambition for carbon-neutrality by 2045--without addressing non-combustion emissions. Based on this analysis, California could achieve a potential GHG emissions savings of 48.6 $MMTCO_2e$ by pursuing a portfolio of mitigation opportunities that addresses both fuel combustion and non-combustion emissions in the Industry sector.

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CHAPTER 5
REDUCING EMISSIONS FROM THE BUILDINGS SECTOR BY 2030

FINDINGS

The Buildings sector, which includes both commercial and residential buildings, is responsible for 9.2 percent of the state's GHG emissions. Energy efficiency and fuel switching are major pathways for both subsectors.

The Residential Buildings subsector contributes approximately two-thirds (63 percent) of the Buildings sector's greenhouse gas (GHG) emissions, while the Commercial Buildings subsector contributes the remaining one-third (37 percent). Energy efficiency has contributed to declining emissions in buildings, even as the overall stock in California has grown. The majority of emissions from buildings come from natural gas use in space and water heating, and for cooking.

Clean energy pathways for the Buildings sector require overcoming barriers such as the sector's highly distributed nature, consumer choice dynamics, existing policies, cost, and the historic rate of stock turnover of end-use systems.

Four emissions reduction pathways were identified that promote optionality and flexibility: energy efficiency of building end-use technologies, increased use of renewable natural gas (RNG), expanded deployment of combined heat and power (CHP) units in large commercial facilities, and increased electrification of certain end uses.

Energy efficiency for commercial and residential buildings, and the appliances used in buildings, represent significant emissions reductions potential.

Energy efficiency has contributed to a decrease in the sector's emissions since 2000, despite the sector's growth since then. According to the California Energy Commission (CEC), mandatory codes and standards, plus programs that incentivize emissions reductions through behavioral and financial mechanisms, can save 152 Bcf of natural gas by 2029, which equates to a reduction of 8.4 $MMTCO_2e$.

Combined heat and power offers a flexible, cost-effective option to reduce emissions in commercial buildings.

California has the second highest CHP potential in the United States. CHP is a mature technology that generates electrical and thermal energy from a single fuel source to reduce energy consumption, lowering fuel costs and associated GHG emissions. California policy promotes CHP deployment by allowing CHP owners to sell excess generation to the grid, providing both a revenue stream and a pathway for emissions reduction.

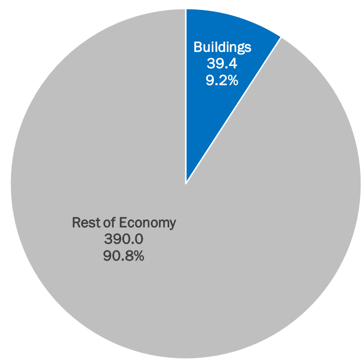
California's Zero Net Energy (ZNE) Buildings initiative aligns with increased building electrification, especially for new buildings.

California's Residential subsector is expected to grow by 1.5 million new homes by 2030. All new residential construction is slated to be ZNE starting in 2020. While on-site renewables will play a significant role, increased end use electrification can contribute to measurably lowering residential emissions by 2030.

BUILDINGS SECTOR

In 2016, Residential and Commercial Buildings combined contributed 9.2 percent to statewide greenhouse gas (GHG) emissions, mainly due to natural gas consumption for space heating, water heating, and cooking. The Buildings sector in California—which excludes industrial buildings—is a growing sector that has experienced an overall decrease in emissions since 2000. This is due largely to California's successful energy efficiency (EE) efforts, which have kept its per-capita energy use flat—while U.S. per-capita energy consumption has grown by 33 percent.[1] As a large energy consumer, the Buildings sector could decarbonize by implementing EE measures, utilizing renewable natural gas (RNG), installing combined heat and power (CHP) units in commercial buildings, and electrifying various natural gas end uses.[a]

Figure 5-1
Commercial and Residential Buildings Emissions Compared to California Total, 2016 ($MMTCO_2e$)



Emissions from commercial and residential buildings make up 9.2 percent of California's total. Source: EFI, 2019. Compiled using data from CARB, 2018.

2016 Sector GHG Emissions Profile: Buildings

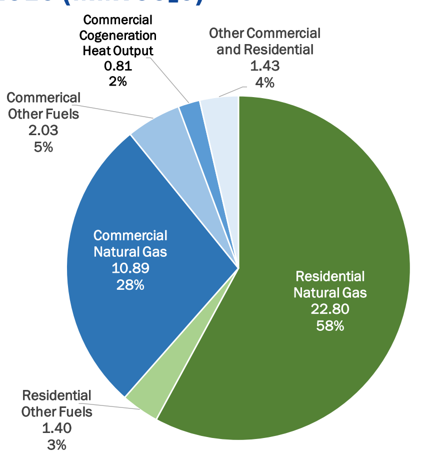
Between 2012 and 2016, California's Gross State Product (GSP) grew by an average of 3.6 percent per year, excluding inflation.[2] Along with the growth in its economy, California's housing market also grew steadily over this period,[b] from 12.7 to 12.9 million households.[3] During this period, commercial floor space increased by around 4 percent per year, on a square footage basis.[4]

At the same time, direct GHG emissions from residential and commercial buildings fell by an average of 2.2 percent per year,[5] these GHG emissions from California Buildings amounted to 39.4 million metric tons of carbon dioxide-equivalent ($MMTCO_2e$) in 2016 (Figure 5-1).[6] This figure excludes indirect emissions from power generation, which are analyzed separately (see Chapter 2).

[a] In CARB's sector-based breakdown of GHG emissions, there are also 12.03 $MMTCO_2e$ of GHG emissions from high-global-warming-potential (GWP) gases. As noted in Chapter 1, those emissions are excluded from this chapter's analysis of the sector.

[b] The total number of housing units, including vacant units, also grew from 13.7 million in 2012 to 14.0 million in 2016. See "E5CountyState2012" and "E5CountyState2016" worksheets in "E5 Population and Housing Estimates for Cities, Counties, and the State, January 1, 2011-2018, with 2010 Benchmark," http://dof.ca.gov/Forecasting/Demographics/Estimates/E-5/.

Figure 5-2
Building Sector Emissions Profile, 2016 ($MMTCO_2e$)



Natural gas is the largest contributor to emissions in California's commercial and residential buildings. Source: EFI, 2019. Compiled using data from CARB, 2018.

As seen in Figure 5-2, emissions from natural gas combustion account for approximately 90 percent of the Buildings sector's emissions. For this reason, any strategy to reduce emissions from Buildings must address natural gas consumption.

It is important to note that pathways for reducing emissions from the Buildings sector must address growing energy demand for space heating and water heating (the primary emissions sources in buildings); slow stock turnover rate for both buildings and their energy end-use systems; and consumer preferences that may prioritize other choices than those that reduce emissions with electric end-use systems, especially in the Residential Buildings subsector.

Analysis of Buildings Sector

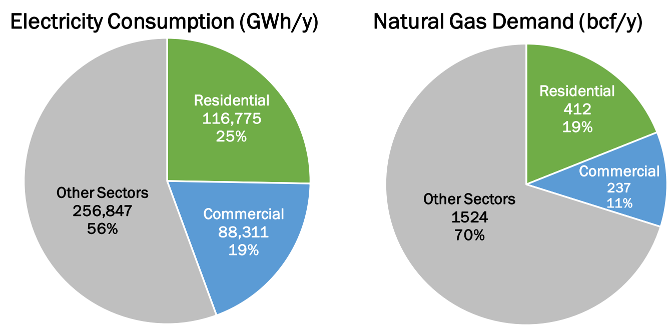
Natural gas and electricity are by far the largest energy sources for buildings in California. Figure 5-3 shows the relative share of electricity and gas consumption in the Buildings sector compared to other energy sectors in California.

Residential Buildings Subsector

The 13 million residential buildings in California in 2016[7] were primarily centered in the north, around the Bay Area, and in the south, near Los Angeles, with other clusters along the Central Valley. In 2016, these residences accounted for 17.7 percent[8] of the state's total energy demand and resulted in roughly 25.0 $MMTCO_2e$ of direct GHG emissions[9]—5.8 percent of all statewide emissions and 64 percent of emissions from the Buildings sector.[10]

Nearly all residential energy use is for lighting, plug loads, space heating and cooling, water heating,

Figure 5-3
Select Energy Data for California Buildings, 2016

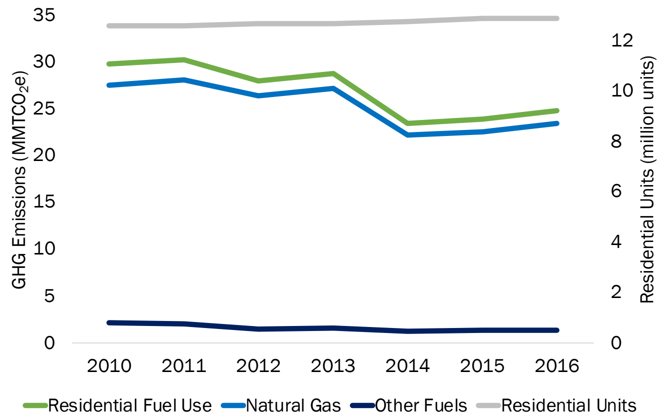


California's residential and commercial buildings consume nearly half of the state's electricity and account for more than a quarter of natural gas demand. Source: EFI, 2019. Compiled using data from EIA SEDS, 2016.

and cooking. Electricity and natural gas are the major energy sources for homes in California, with other small shares from propane (3 percent of homes)[11] and fuel oil.[c] While the number of residential housing units has grown steadily since 2010,[12] emissions and fuel consumption per housing unit have generally declined (Figure 5-4).[13] Space heating, water heating, and cooking account for the majority of natural gas use and combustion emissions.[14]

Figure 5-4

California Residential Emissions by Fuel Source and Stock Growth, 2010-2016



While the number of residential housing units has gradually increased, fuel use has declined since 2010. Source: EFI, 2019. Compiled using data from EIA, 2016.

According to the Energy Information Administration, Residential Energy Consumption Survey,[15] 88 percent of homes in California consumed some amount of natural gas; roughly two-thirds of homes in California used natural gas as their primary source for space heating; the remaining one-third used electricity. Natural gas also fuels more than 84 percent of residential water heating, with electricity providing the remainder. In addition, 64 percent of California's residences have gas cooking, including ovens and stovetop burners.[d] These gas-consuming end uses contribute the majority of the Residential Buildings subsector's emissions and are detailed in Table 5-1.

Table 5-1

Estimated Primary Emissions Source by Residential Energy End Uses in California

Select Residential End Uses	Energy End Use & Unit Efficiency	Natural Gas Use[16] (Bcf)	Number of Units, 2016 (Millions)	Direct End-Use Emissions[17] (MMTCO2e)	Share of Residential Emissions[18]	Share of Buildings Emissions
Space Heating	Gas-Fired Furnace (80% AFUE)[19]	172	8	9.52	38 percent	24 percent
	Electric Heating	–	4	–	–	–
	None	–	*1*	–	–	–

[c] The exact number of California homes using fuel oil is unknown, since the proportion is too small to be captured in the Residential Energy Consumption Survey.

[d] To analyze California-specific energy consumption for residential end uses this study used data from the 2009 EIA Residential Energy Consumption Survey (RECS) and the CEC State Energy Demand (SED) Forecast for 2005-2016. More recent state-level data was unavailable. The 2015 EIA RECS did not include state-level data; however, the information from the Pacific region was also cross-referenced to compare percentages. Additionally, the 2009 CEC Residential Appliance Saturation Study (RASS) [https://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-V2.PDF] was cross-referenced, but its results did not provide comprehensive information to determine appliance end-use percentages.

Water Heating	Gas Water Heater (0.58 UEF)[20]	163	12	9.03	36 percent	23 percent
	Electric Water Heater	–	1	–	–	–
Cooking	Gas Cooking (Oven 40% CE, Stovetop 6.5% CE)[21]	23	7.8	1.30	5 percent	3 percent
	Electric Cooking	–	4.8	–	–	–
Other NG End Uses	Pools & Spas, Dryers, etc.	54		2.96	12 percent	8 percent
NG Totals		**412 Bcf**	**27.8**	**22.80 $MMTCO_2e$**	**91 percent**	**58 percent**
Other Fuels		–		**1.40 $MMTCO_2e$**	**6 percent**	**4 percent**
Total Fuel Use		–		**24.20 $MMTCO_2e$**	**97 percent**	**61 percent**

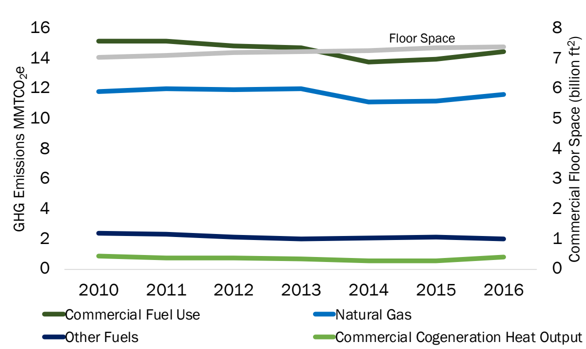
Columns may not sum because of rounding. Space and water heating are the largest users of natural gas within buildings. Source: EFI, 2019. Compiled using data from EIA, 2017; EIA, 2018; CEC, 2014; CARB, 2018; E3 Pathways Model.

Commercial Buildings Subsector

In 2016, there were roughly 7.4 billion square feet of commercial floor space in California.[22] Offices, warehouses, and retail account for about half of the state's commercial space.[23] In 2016, the Commercial Buildings subsector consumed 18.9 percent of the state's total energy[24] but was responsible for only 3.3 percent of statewide emissions.[25] This is due in part to the large use of electricity in this subsector. Emissions from electricity are not allocated across sectors; instead they are exclusively attributed to the Electricity sector (see Chapter 2).

Both Commercial Buildings subsector emissions and floor space grew by roughly 5 percent between 2010 and 2016, while total subsector emissions declined slightly (see Figure 5-5).[26] In 2016, the Commercial Buildings subsector in California consumed roughly 237 billion cubic feet (Bcf) of natural gas, the majority of which was for space heating, water heating, and cooking (Table 5-2).

Figure 5-5
California Commercial Buildings Emissions and Floor Space Growth, 2010-2016



Commercial floor space has gradually increased since 2010, while fuel consumption decreased slightly overall; however, gas consumption has trended positively between 2014-2016. Source: EFI, 2019. Compiled using data from CARB, 2018

Table 5-2
Estimated Primary Emissions Source by Commercial Energy End Uses in California

Commercial End Uses	Primary End Uses	Natural Gas EI[27](scf/ft²-year)	Natural Gas Use[28] (Bcf)	Direct End-Use Emissions[29] (MMTCO$_2$e)	Share of Commercial Emissions[30]	Share of Buildings Emissions
Restaurants	Cooking	203	58	2.87	20 percent	7 percent
Large Offices (>39,000 ft²)	Space Heating; Water Heating	21	27	1.32	9 percent	3 percent
Health	Space Heating; Water Heating	73	32	1.60	11 percent	4 percent
Lodging	Space Heating; Water Heating	41	21	1.05	7 percent	3 percent
Schools and Universities	Space Heating; Water Heating; Cooking	21	26	1.30	9 percent	3 percent
Other Major Categories (Food Stores, Small Offices, Retail, Warehouses)	Space Heating; Water Heating; Cooking	7	24	1.21	8 percent	3 percent
Miscellaneous	Space Heating; Water Heating; Cooking	22	48	2.35	16 percent	6 percent
NG Total			**237**	**11.70**	**82 percent**	**30 percent**
Other Fuels (including petroleum)			–	**2.03**	**14 percent**	**5 percent**
Total Fuel Use			–	**13.73**	**96 percent**	**35 percent**

Columns may not sum because of rounding. No single class of facilities in the Commercial Buildings subsector consumes gas or emits vastly more than the others, although restaurants and healthcare facilities combined comprise an estimated 31 percent of Commercial Buildings subsector emissions and 11 percent of sectorwide emissions.
Source: EFI, 2019. Compiled using CEC Commercial End Use Survey, 2006; EIA, 2017; CARB, 2018.

As in the Residential Buildings subsector, natural gas accounts for the predominant fraction of the emissions in the Commercial Buildings subsector, with a small share from other fuels, including distillate and liquefied petroleum gas (LPG). Restaurants, schools and universities, healthcare facilities, large offices, and lodging are the largest natural gas-consuming segments of the Commercial Buildings subsector.[31]

Analysis Methodology

Meeting the 2030 emissions reduction target requires abatement pathways that consider future increases in emissions. California's overall energy demand is expected to grow steadily through 2030, based on interdependent factors including in-state economic and population growth, energy efficiency improvements, and trends in the larger U.S. economy. The California Energy Commission (CEC) forecasts that California's natural gas demand will increase to 673 Bcf by 2030 (446 Bcf in the Residential Buildings subsector and 227 Bcf in the Commercial Buildings sector).[32]

Using the standard emissions factor provided by the CEC[33] demand grows by 24 Bcf from EIA's 2016 estimate (649 Bcf).[34] This would result in an additional 1.3 MMTCO$_2$e of emissions by 2030. Demand growth from other fuels in the Buildings sector would also lead to increased emissions.[e] In this scenario, California's Buildings sector would account for a total of 40.7 $MMTCO_2e$ of emissions in 2030.

After identifying the emissions sources in the Buildings sector, relevant California policies, decarbonization strategies, and other governmental publications were reviewed and assessed to inform the development of decarbonization pathways. The key assumptions and sources used in determining decarbonization pathways for the Buildings sector are listed in Table 5-3.

Table 5-3
Buildings Key Assumptions

Pathway	Subsector	Key Assumptions
Baseline	All	Emissions from the Buildings sector excludes emissions from the Electricity sector. Buildings stock and growth data from Caltrans *California County-Level Economic Forecast 2017-2050*. 2016 natural gas use data from EIA State Energy Data System, EIA Residential Energy Consumption Survey, and CEC Commercial End Use Survey. 2030 natural gas use data from CEC *California Energy Demand 2018-2030 Revised Baseline Forecast*, Mid Demand Case projection. Standard emissions factor for natural gas from CEC. Standard conversion factor of 10.37 between Bcf and millions of therms of natural gas.
Energy Efficiency	All	Based on SB 350 (2015) targets for doubling energy efficiency of electricity and natural gas end uses by 2030. CEC's Mid-Case Demand forecast projections for sources of efficiency were used to estimate economywide savings. Feasibility of reaching these targets was not modeled.
Renewable Natural Gas	All	RNG has the potential to replace 197 Bcf of conventional pipeline natural gas (in-state and imports) by 2030.
Combined Heat and Power	Commercial	Based on DOE reporting on California's total CHP technical potential in the Commercial Buildings subsector: 7,400 MW across 24,000 sites. Only half of that potential is assumed to be deployed by 2030 based on the largest eligible facilities. Costs of CHP include the value of selling some electricity back to the grid (per AB 1613) and the projected "spark spread" in California. The full emissions-savings benefit of CHP (including savings in power generation) are counted in the Commercial Buildings subsector. This is because new CHP units act like distributed generation from commercial owners. The actual emissions savings was calculated using online calculators provided by the U.S. EPA that included assumptions for CHP size, operations, efficiency, fuel use, fuel cost, and the electric grid in California.
Electrification	Residential	Electrification potential (beyond that defined in SB 350, which is counted in the EE pathway) in Scenario 1 is based on the assumption that California's Zero Net Energy buildings initiative will be met by end-use electrification by 2030. Scenario 2, which includes electrifying 22 percent of residential buildings by 2030, is based on the Navigant report "Analysis of the Role of Gas for a Low-Carbon California Future", July 24, 2018. Costs and performance of electric end-use technologies are from EIA's 2018 *Updated Buildings Sector Appliance and Equipment Costs and Efficiency* report.

GHG Emissions Reduction Pathways

Based on the methodology outlined above, the 2030 business-as-usual (BAU) GHG emissions projection for buildings is 40.7 $MMTCO_2e$. A 40 percent reduction from 2016 Buildings sector emissions (39.4 $MMTCO_2e$) is equal to 23.6 $MMTCO_2e$. The gap between

[e] The CARB inventory includes relatively small shares for wood, kerosene, LPG, and distillate.

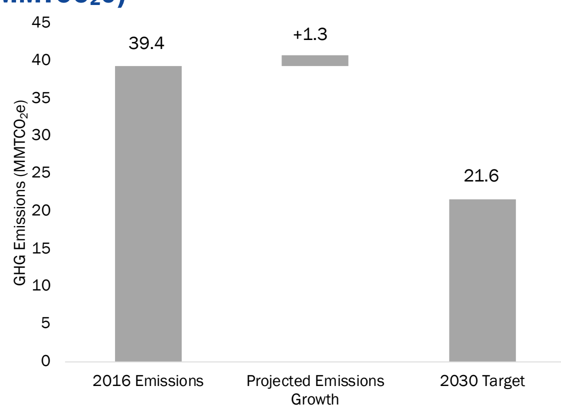
the 2030 BAU projection and the emissions reduction target is 17.1 $MMTCO_2e$ as shown in Figure 5-6.

The major pathways for reducing emissions from California's Buildings sector are:

- energy efficiency programs aimed at reducing natural gas use in buildings;
- increased throughput of use of net-zero-carbon RNG the California natural gas system;
- CHP systems installed in many commercial facilities; and
- the switch from natural gas to electric end-use technologies ("electrification") where, as noted, the net emissions benefits are dependent on the emissions intensity of the electric grid.

Figure 5-6

Building Emissions Trajectory and 2030 Target ($MMTCO_2e$)



To reduce emissions in buildings 40 percent from 2016 levels by 2030, 17.1 $MMTCO_2e$ GHG emissions must be abated if growth is considered. Source: EFI, 2019. Compiled using data from CARB, 2018; CEC, 2017

Pathway 1: Energy Efficiency

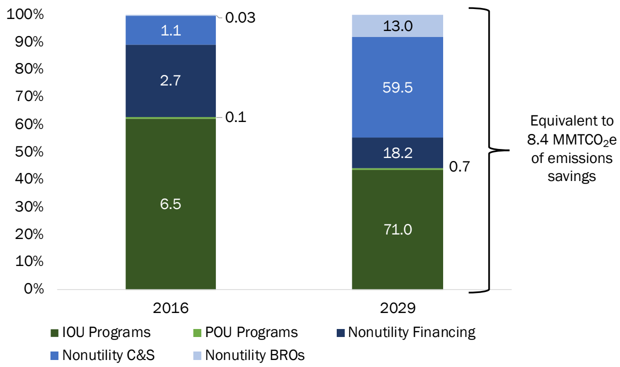
Ambitious EE policies and programs are already in place in California, aimed at reducing the use of electricity and natural gas for all residential and commercial buildings. SB 350 (enacted in 2015) requires that the CEC set annual targets to achieve a statewide cumulative doubling of energy efficiency savings (based on 2014 CEC projections[f]) in electricity and natural gas end uses by January 1, 2030.[35] According to the CEC, "much of the untapped energy efficiency potential to meet the doubling targets can be achieved by improving the energy efficiency of existing buildings, as well as the appliances, and other devices used in them."[36]

Efforts aimed at doubling EE statewide focus on both utility- and nonutility-funded programs. According to the CEC, for the nonutility programs, mandatory codes and standards (C&S) for facilities, such as building envelope design and home appliances will contribute the greatest share to reducing GHG emissions from the sector.[37] In addition, emissions reductions would be achieved through programs that incentivize efficiency measures through behavioral strategies (e.g., Behavior, Retro-commissioning, and Operational Efficiency measures [BROs]) or financial mechanisms.

[f] SB 350 requires the Commission to base the targets on a doubling of the mid-case estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the Commission in 2014, extended to 2030 using an average annual growth rate.

Figure 5-7

Change in Sources of EE Savings Under SB 350 Between 2016 and 2029



Values in columns represent Bcf of savings against a 2014 baseline. In the CEC's Energy Demand Mid-Case Forecast, two-thirds of EE savings in 2016 were attributed to the utility-funded programs; however, by 2029, the CEC estimates that state programs will contribute more than half of the natural gas end use savings from EE. Source: EFI, 2019. Compiled using data from CEC, 2017.

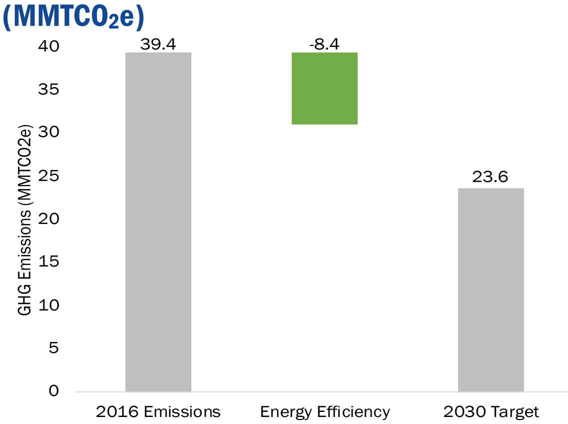
Forecasts from the CEC show that incentives within the utility programs are expected to result in 44 percent of the emissions savings by 2030, down from 63 percent in 2016 (Figure 5-7).[38] In 2030, codes and standards are expected to contribute to 37 percent of efficiency savings, financing 11 percent, and incentives 8 percent. Incentive programs are designed to reduce energy consumption through more efficient services (e.g., pipeline retrofits) and/or customer engagement programs (e.g., rebates for new heat pumps). The relative share of savings from utility and nonutility programs changes over time due to the requirements of the associated state and federal policies.

In total, data from the CEC shows a decrease of gas demand for the Buildings sector by 152 Bcf per year in 2030 (compared to 2016) as a result of the state's energy efficiency programs.[39] To put this in context, 152 Bcf per year is approximately 7 percent[40] of the state's 2016 gas demand. Using a standard emissions factor used by the CEC,[41] this reduction of gas demand would lead to an 8.4 $MMTCO_2e$ overall emissions reduction by 2030 (Figure 5-8).

Leveraging the full potential of the state's existing EE programs could help the Buildings sector meet roughly half of its 40 percent emissions reduction goal by 2040. This means a further reduction of 8.7 $MMTCO_2e$ would be needed from other decarbonization pathways to meet the 2030 goal for the buildings.

Figure 5-8

Energy Efficiency Pathway and 2030 Target ($MMTCO_2e$)



Savings from energy efficiency programs could total 8.4 $MMTCO_2e$, which is roughly half of the emissions reductions needed to meet a 40 percent reduction from 2016 levels by 2030. Source: EFI, 2019. Compiled using data from CEC, 2017 and CARB, 2018.

Box 5-1

Utility and Nonutility Energy Efficiency Programs in California

Behavior-Based Incentives:

- Utility-funded programs provide marketing, education, and outreach on voluntary energy efficiency measures.[42]
- Nonutility programs include the CEC's Home Energy Rating System (HERS) program[g] that maintains a rating system that provides California homeowners and prospective homebuyers with information about the energy efficiency of the homes they live in or are considering for purchase,[43] Building Energy Information Management Systems that provide energy data to building owners to then make EE improvements, and efforts to promote fuel substitution or electrification.[44]

Codes & Standards:

- Utility programs advocate for strengthening the codes and standards, improve compliance with existing codes and standards, and assist local governments in establishing ordinances for efficiency.
- Nonutility programs include the CEC's Title 24 Building Energy Efficiency Standards,[45] the California Green Building Standards Code (CALGreen),[46] CEC's Title 20 Appliance Efficiency Regulations,[47] and federal appliance standards.

State Financing:

- Utility programs provide a portfolio of financing options to encourage customers to invest in EE projects and leverage ratepayer funds by bringing in private capital.[48]
- Nonutility programs provide grants and loans to residential customers for EE projects, retrofits, new construction, appliance replacement, and other efficiency upgrades.

Costs of the EE Pathway

SB 350 directs the CEC to establish EE targets that achieve a statewide, cumulative doubling of EE savings in electricity and natural gas final end uses by 2030.[49] SB 350 also directs that these targets be cost effective, feasible, and avoid adversely impacting public health and safety.[50] SB 350 sets guidelines to determine the cost-effectiveness of these programs. For the utility programs, for example, the California Public Utilities Commission (CPUC) uses the total resource cost and program administrator cost tests. SB 350 directs building standards to be cost-effective when taken in entirety and when amortized over the economic life of the structure, compared with historical practice. Similar guidelines exist for all EE programs.

Challenges to the EE Pathway

Energy efficiency is a robust option for deep decarbonization. Important challenges, however, will need to be addressed to ensure that the state's ambitious EE targets are met. First, the EE pathway largely depends on the timing and turnover rate of building stock and end-use equipment. Even with more efficient end-use equipment available for purchase, the net impact on emissions will depend on the final deployment of these systems.

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[g] CEC's HERS program is distinct from national-level HERS indices, such as the one developed by the Residential Energy Services Network.

These, in turn, depend on manufacturer timetables and consumer uptake. These factors are more significant if EE programs require voluntary replacement of appliances and/or consumers to replace existing systems before the end of their estimated useful life (EUL). An additional risk comes from manufacturers. Most sell goods nationally, if not globally; stricter standards in California could affect entire product lines and may be vigorously opposed.

Finally, preemption by federal standards may impact California's ability to set efficiency standards for appliances. States can set their own standards for products not covered by federal regulation, but in order to preempt a federal regulation on a product that is covered, the state must be granted a waiver. California has been granted a waiver for metal halide lamp fixtures, for example.[51] California's ability to use new appliance standards to meet some of its energy efficiency targets will require federal approval; this may prove difficult in the current environment in Washington and in cases where manufacturers of nationally-distributed appliances raise supply-chain issues.

Pathway 2: Renewable Natural Gas

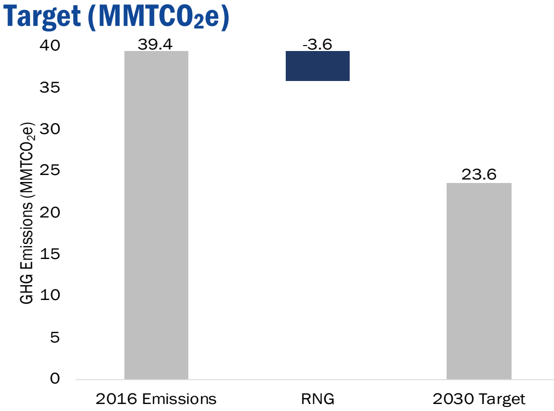
Another technology pathway that could lead to a measurable reduction in emissions in the Buildings sector is the use of RNG. RNG is methane produced from renewable sources of biomass that create a net-zero-carbon methane supply. RNG is a clean substitute for natural gas that, at the same time, addresses emissions reductions in the difficult-to-decarbonize sectors such as Agriculture and Industry.

Based on a review of multiple studies, by 2030 California could be consuming 197 Bcf per year of renewable gas, delivered through existing gas distribution infrastructures (although processing and gathering systems are separate and necessary infrastructure needs). This includes 156.6 Bcf per year of RNG from in-state production and 40.4 Bcf per year from imports.

This analysis assumes that carbon-neutral RNG would be added to California's natural gas supply, leading to an emissions reduction in the gas consuming sectors that is proportional to their gas demand (see Biogas and Renewable Natural Gas Addendum in Chapter 6 for additional information). Based on the expected 2030 supply of natural gas to the Buildings Sector (673 Bcf) and supply of RNG available to the sector (65.7 Bcf), RNG would make up nearly 10 percent of the Buildings sector's gas demand in 2030. The resulting emissions reduction would be approximately 3.6 $MMTCO_2e$ (Figure 5-9).

Figure 5-9

Renewable Natural Gas Pathway and 2030 Target ($MMTCO_2e$)



Replacing 66 Bcf of conventional natural gas with RNG reduces an additional 3.6 $MMTCO_2e$ from the Buildings sector. Source: EFI, 2019. Compiled using data from CEC, 2017; CARB, 2018; ICF, 2017.

Costs of the RNG Pathway

RNG is more expensive than conventional natural gas, and its price is currently shaped by the relatively high cost of its processing, upgrading, and pipeline interconnection fees.[52] As discussed thoroughly in the Biogas and Renewable Natural Gas Addendum, the cost of RNG is between two to three times higher than for natural gas.[53] It is also important to note that costs vary based on the type of feedstock, with the with the lowest costs associated with landfill gas and the highest costs associated with gas from with forestry and agricultural residues.[54]

Challenges to the RNG Pathway

The principal concerns about the feasibility of the RNG pathway relate to a potentially limited market supply of RNG and to economic viability. The potentially limited availability of feedstock is a supply risk. As discussed above, the potential availability of RNG in 2030 (per this report's analysis) can only replace 10 percent of the natural gas use in the sector. It is unclear if there are any ways to increase the supply of available RNG (without greater imports).

Because RNG is more expensive than conventional natural gas there are concerns regarding its long-term economic viability. Incentives and additional research, development, and demonstration could potentially ameliorate these cost issues. An additional economic issue is that RNG use is contingent on the existing natural gas infrastructure. As that infrastructure continues to age, costly upgrades, maintenance, and repairs will become necessary. At the same time, declining natural gas throughput because of energy efficiency and electrification have contributed to gas price increases for most customer classes in the last five years.[55] With California's ambitious decarbonization efforts, it is likely that this trend will continue. The combination of these factors creates economic risk for the RNG pathway.

Pathway 3: Combined Heat and Power

Meeting the Buildings sector's 2030 target will require reducing emissions by another 5.1 $MMTCO_2e$, assuming 8.4 $MMTCO_2e$ reductions from efficiency and 3.6 $MMTCO_2e$ from RNG. An important pathway for reducing emissions from the Commercial Buildings subsector is increased use of CHP systems to generate electrical and thermal energy from a single fuel source. CHP can reduce energy consumption, lower fuel costs, and reduce associated GHG emissions. CHP is a relatively mature technology and can simultaneously reduce fuel requirements for on-site generators and provide decentralized electricity generation.[56] Even if CHP units are not part of a deeply decarbonized economy over the long-term, these systems can immediately provide higher efficiency in electricity generation and eliminate transmission and distribution losses associated with centralized generation, thereby contributing to lowering greenhouse gas emissions in a transition to decarbonization.[57]

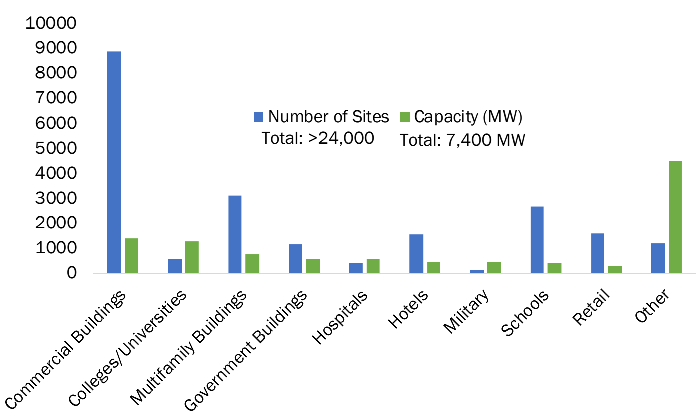
Following the passage of AB 32 in 2006, CARB prepared a Climate Change Scoping Plan that included a GHG emissions reduction goal of 6.7 $MMTCO_2e$ from CHP resources.[58] In 2015, California's AB 1613 established policies that promote the deployment and compensation of CHP systems.[59] This set the stage for compensating CHP system owners who sell excess electricity to the grid and outlined incentive programs, including ways for utilities to finance new CHP systems.

CARB set a target for an additional 4,000 megawatts (MW) of CHP, which included an emissions target of 6.7 $MMTCO_2e$ by 2020 in the state's 6.7 $MMTCO_2e$ by 2020, in the state's 2008 Scoping Plan.[60] In 2010, the CPUC entered into a settlement agreement with three major California utilities requiring that they procure a minimum of 3,000 MW of CHP capacity from 2010 to 2015 and reduce greenhouse gas emissions by 4.8 MMTCO2e.[61] As a candidate for governor in 2010, then-Attorney General Brown set a goal of 6,500 MW of additional CHP capacity by 2030 as part of his Clean Energy Jobs Plan.[62] The CPUC 2010 settlement agreement was not strictly comparable to the CARB Scoping Plan baseline,[63] and as of late 2016, the path forward for an increased target for CHP as part of the Scoping Plan was unclear.[64]

While estimates vary by system type, size, and age, CHP systems generally convert as much as 90 percent of a fuel's chemical energy into useable energy, resulting in cost savings and GHG reductions.[65] In 2016, the Commercial Buildings subsector in California already had 674 CHP installations, totaling 1,700 MW of capacity. Combustion turbines are often used for larger sites (greater than 20 MW) and they account for the largest installed capacity of CHP in California.[66] For the smaller sites, reciprocating internal combustion engines (RICE) are the most widely used systems.

Figure 5-10

California Technical Potential for CHP Applications in Commercial Sector



Commercial buildings have the greatest number of potential CHP sites, while the majority of the capacity (MW) is in the "other" category.
Source: EFI, 2019. Compiled using data from DOE, 2017.

According to the Department of Energy (DOE), California has the second-highest total CHP technical potential in the United States.[67] The Commercial Buildings subsector represents a significant share of the state's untapped CHP potential, where large buildings, colleges and universities, hospitals, and military bases provide some of the state's largest untapped potential for CHP. Based on the DOE study, California could leverage an additional 7,400 MW of new CHP across more than 24,000 sites (Figure 5-10).[68] More than 19.800 of these sites are smaller facilities, with potential for 0.5 MW (or smaller) CHP systems, while 14 sites are capable of leveraging systems larger than 20 MW. About 4,800 additional facilities are capable of systems between 0.5 MW and 20 MW.[69]

Leveraging the state's untapped CHP potential in the Commercial Buildings subsector could significantly contribute to emissions reductions. One simplified pathway for doing this would involve replacing the on-site natural gas boilers with natural gas-fired RICE and combustion turbine (CT) systems at eligible facilities in California (see Table 5-4). This assumes that one CHP unit is used for each site and that the vast majority of sites need 500 kW RICE systems—an assumption derived from DOE's analysis.[70] The avoided emissions factor is based on an EPA calculator for the per-unit avoided emissions of various sizes and types of CHP systems. The calculator also assumes natural gas and electricity prices based on EIA data for California.[71]

Table 5-4
Total Potential of California Commercial CHP and Avoided Emissions

CHP Units Size Class (Capacity Assumption)	Number of Sites	Annual Emissions Savings Per Unit (tons of CO_2e)	Avoided Emissions ($MMTCO_2e$)
Small RICE (0.5 MW)	19,814	418	8.28
Mid-size RICE (0.7 MW)	4,825	379	1.83
CT (20 MW)	14	7,500	0.15
Totals	**24,653**	**8,297**	**10.26**

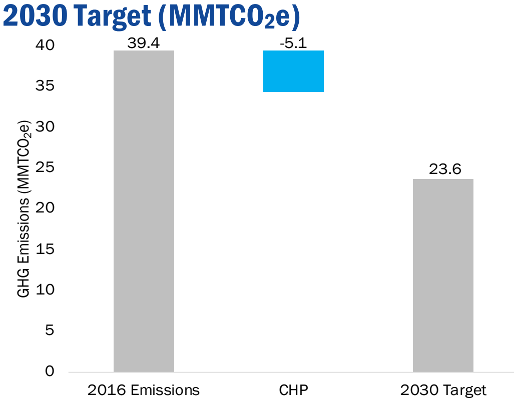
CHP in California's Commercial Buildings subsector could provide emissions savings of up to 10.26 $MMTCO_2e$ if it utilized all of its technical potential. These calculations assume that all installations in the smallest size class have 0.5 MW of capacity (due to the limitations of the calculator used), which may inflate the avoided emissions potential. Source: EFI, 2019. Compiled using data from DOE, 2017 and EPA, 2015.

According to EPA accounting, if California met its full CHP potential in the Commercial Buildings subsector with this share of CHP systems, the total emissions reduction potential would be 10.26 $MMTCO_2e$. These savings are achieved because CHP fuel use (and resulting emissions) is measurably outweighed by the emissions avoided by displacing electric grid generation and fuel use for on-site boilers.

Capturing the full emissions reduction potential from 7,400 MW at over 24,600 sites is an ambitious target by 2030, especially considering that capacity in 2016 was 1,700 MW at 674 sites. Assuming half of the number of sites switch to CHP across each CHP size class, the Commercial Buildings subsector could meet the remaining target of 5.1 $MMTCO_2e$ by 2030 (Figure 5-11).

The carbon accounting for CHP is unique among emissions reduction pathways. According to CARB, CHP systems can result in energy savings that affect "power

Figure 5-11
Combined Heat and Power Pathway and 2030 Target ($MMTCO_2e$)



Utilizing roughly half of California's full CHP potential in commercial buildings would result in 5.1 $MMTCO_2e$ emissions reductions from the Buildings sector. Source: EFI, 2019. Compiled using data from DOE, 2017; EPA, 2015; CARB, 2018.

generation, service, and transmission providers, load serving entities, irrigation districts, and other electricity service providers."[72] Because CHP systems can act as both on-site heating and generation systems, their net emissions savings are often counted in the Electricity sector. For purposes of this study, the emissions savings of CHP are counted in the Commercial Buildings subsector because facility owners who switch to CHP systems are the primary drivers of the emissions savings. This approach is also used for analyzing pathways for the Industry sector (see Chapter 4).

An in-depth study in 2011 of the potential market penetration of CHP in the Commercial Buildings subsector and Industrial sector in California offered a more conservative view. The study suggested that the total emissions savings from CHP in these sectors by 2030 will be between 1.7 $MMTCO_2e$ and 5.6 $MMTCO_2e$.[73] The study estimated there were fewer eligible facilities with a smaller total potential—between 1,888 MW and 6,108 MW in the Commercial Buildings subsector and Industrial sector,[74] roughly half of the potential estimated by DOE. It provided insight into the economics of CHP in each utility territory based on the fixed and variable costs of the systems, as well as on the electricity and heating demand of candidate facilities.[75]

Costs of the CHP Pathway

The total cost of CHP includes the installation cost and the long-term operations and maintenance (O&M) costs of the system. The economics of CHP systems for uses in the Commercial Buildings subsector in California (according to one assessment) are described in Table 5-5. Net power cost is equal to the unit cost of power from the CHP system, after the value of the thermal energy is subtracted.[76]

Table 5-5
Cost Analysis of California Commercial CHP

CHP Units (MW)	Installed Unit Cost ($/kWh)	Estimated Annual Hours of Operation per Unit	O&M per Unit ($/kWh)	CHP Gas Cost ($/MMBtu)	Boiler Fuel Gas Cost ($/MMBtu)	Net Power Cost ($/kWh)
0.5 RICE	1,710	5840	0.02	5.75	7.71	0.087
0.7 RICE	1,000	5840	0.014	5.66	7.28	0.078
20 CT	1,378	5840	0.006	5.44	6.24	0.0549
Average	**1363**	**5840**	**0.013**	**5.62**	**7.08**	**0.0733**

In October 2018, the average price of electricity for commercial customers in California was $0.1728/kWh, which is considerably higher than net power costs from CHP. Source: EIA, 2018; ICF, 2012

The total marginal cost of CHP compared to conventional approaches for heat generated and electricity is based on the "spark spread," defined as the difference between the price received by a generator for electricity produced and the cost of natural gas needed to produce the electricity.[77] This means that determining the cost and payback of CHP systems depends on the market prices for electricity and natural gas. One analysis of CHP systems found that a typical mid-size CHP installation (1.5 MW, for a facility with 1.8 MW of average electricity demand) could have O&M cost savings that pay for the unit in around

6.3 years; the payback period could be as short as 3.6 years or as long as 10.4, depending on the prices of electricity and natural gas.[78] CHP systems can also generate revenue by selling excess electricity back to the grid, as outlined in AB 1613.[79]

Challenges to the CHP Pathway

The project economics for CHP are based on the net benefit of displacing purchased electricity and boiler fuel with self-generated power and thermal energy. As such, the savings in power and fuel costs need to be compared to the increased capital, fuel, and O&M costs associated with a CHP system.[80] For some projects, especially small ones, the marginal benefits of switching to CHP may not outweigh the costs. There is also a concern that larger CHP facilities could have trouble selling their excess electricity to the grid, which would decrease the potential benefits of CHP conversion.

Another challenge is that CHP systems can result in increased emissions of criteria pollutants, including oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compounds (VOC). These increase emissions create environmental concerns with reciprocating engines that operate on natural gas, as many do in California.[81] Exhaust treatment systems can be used to significantly reduce on-site emissions. NOx, CO, and VOC emissions from an average 633-kilowatt lean-burn RICE can have an average upper limit between 1.0-1.5 grams per brake horsepower-hour (g/bhp-hr) without an exhaust treatment and attain an average between 0.05-0.08 g/bhp-hr with the added controls.[82]

Pathway 4: Electrification

The pathways discussed so far for decarbonizing the Buildings sector describe options for reaching a 40 percent emissions reduction. A relatively mature technology pathway to further reduce emissions from the Buildings sector is electrification—more specifically, substituting electrically powered end-use equipment and appliances for existing natural gas ones.

There is a significant amount of academic literature on electrification pathways that generally calls for high rates of electrification in the Buildings sector.[83] As noted, California's EE programs already include some fuel substitution (i.e., electrification) in its behavioral incentive programs. According to CEC projections, these programs will account for 8 percent of the total natural gas reduction in the Buildings sector from EE in 2030.[84] The total opportunity for additional fuel substitution likely exceeds the CEC's estimates due to the fact that electric heat pumps, water heaters, and cooking systems are already widely used throughout the state and the nation.[85]

The state's Zero Net Energy (ZNE) Buildings initiative[86] is a potential driver of building electrification. ZNE describes a building in which the annual delivered energy is less than, or equal to, the on-site renewable exported energy. For example, a ZNE buildings project might emphasize electrified end uses, smart controls, and efficient materials, combined with rooftop solar photovoltaic (PV) arrays.[87] This pathway suggests that new ZNE buildings (per California policy) will choose electric end-use equipment and appliances over natural gas-powered ones. As spelled out in the California Energy Efficiency Strategic

Plan, the state has ambitious goals for the development of ZNE buildings, including the following:

- All new residential construction will be ZNE by 2020.
- All new commercial construction will be ZNE by 2030.
- 50 percent of commercial buildings will be retrofit to ZNE by 2030.
- 50 percent of new major renovations of state buildings will be ZNE by 2025.[88]

The CEC and CPUC have laid out efforts to achieve the ZNE goals for residential buildings through updates to the California Code of Regulations Title 20 appliance efficiency standards and Title 24 building EE standards, which will come into effect in 2020.[89]

To determine the extent to which electrification of building energy end uses could support the state's 2030 carbon reduction goals, EFI analyzed the following questions:

- How many residential buildings need to substitute electric end uses for gas end uses to meet the state's ZNE targets (considering the emissions savings from energy efficiency)?
- Which natural gas end uses, if switched to electricity, would offer the greatest benefit—at the lowest cost to households and the economy—in terms of meeting the emissions target?
- What risks are involved to either the household or the wider economy from a shift away from natural gas for certain energy end uses in Buildings in California?

Residential Electrification Pathway

In 2016, an estimated 412 billion cubic feet (Bcf) of natural gas was consumed by around 13 million homes. Based on the breakdown from residential energy use data collected in 2009, the majority of homes in California consumed some natural gas; roughly 64 percent of homes used natural gas for cooking, 84 percent used gas for water heating, and 61 percent used gas for space heating.[90]

To assess the emissions-reduction potential of electrification in the Residential Buildings subsector, this analysis uses two scenarios, described below.

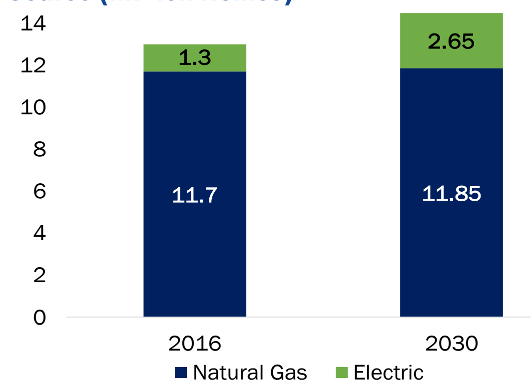
Scenario 1—Electrifying New Residential Buildings After 2020*.* Based on estimates from the California government,[91] the state's residential building stock is forecasted to grow by 1.6 million new homes from 2016 to 2030. A viable electrification pathway would be to fully electrify 100 percent of new homes starting in 2020, as this would support the state's ZNE policy requirement and impact the fewest number of homes.

The emissions savings from this pathway would come from the avoided emissions from new electric homes that would otherwise have been natural gas. Assuming that in a BAU scenario the share of new homes that would have been natural gas remains roughly the same as the proportion of homes that currently consume natural gas (88 percent), this electrification pathway would result in avoided emissions from 1.4 million additional homes by 2030.

Based on the gas consumption from the Residential Buildings subsector in 2016 (412 Bcf) and the number of gas-consuming households (11.4 million), the average gas consumption per household was 36,000 cubic feet. Given this average use, and the standard CEC emissions factor, the emissions impact of electrifying 1.4 million additional buildings by 2030 would be This pathway would result in avoided emissions of 2.8 $MMTCO_2e$ by 2030—a 7 percent reduction from 2016 levels.

Even if approximately 1.4 million new homes chose electricity over natural gas, the overall proportion of all-electric homes in the state's building stock would remain relatively low (Figure 5-12).

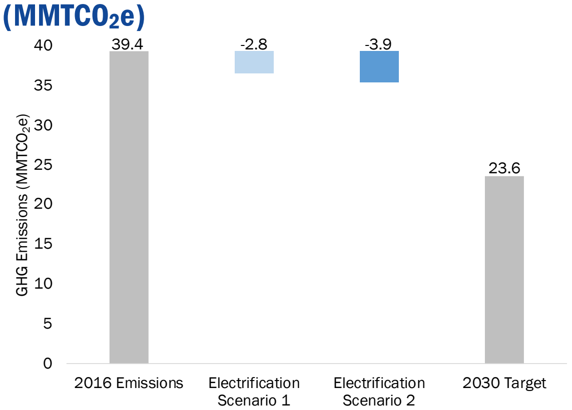
Figure 5-12
Residential Buildings Stock by Primary Fuel Source (Million Homes)



Roughly 90 percent of California homes consume natural gas as a primary fuel source, and while gas is predicted to be the dominant fuel source, electricity's share will increase from 10 percent to 18 percent by 2030. Source: EFI, 2019. Compiled using data from Table 5-1 for 2016 estimate and CA DOT, 2017 for 2030 forecast for building stock growth.

Scenario 2—Electrifying 22 Percent of Residential Buildings by 2030. A second scenario to consider is one in which 22 percent of California's residential buildings are all-electric by 2030, a scenario adopted from a recent study, *Analysis of the Role of Natural Gas for a Low Carbon California Future*.[92] This scenario sees a larger share of natural gas end-use equipment and appliances, at their EUL, replaced with electric equipment and appliances. A review of EIA's 2018 *Updated Buildings Sector Appliance and Equipment Costs and Efficiencies* report[93] shows there are sufficient electric-powered technology options for cooking, water heating, and space heating for California to meet its 22 percent target by 2030.

Figure 5-13
Electrification Pathways and 2030 Target ($MMTCO_2e$)



Electrification could reduce the sector's emissions by an additional 2.8 or 3.9 $MMTCO_2e$ depending on the electrification scenario chosen. Source: EFI, 2019. Compiled using data from Navigant, 2018, CARB, 2018.

Similar to Scenario 1, the emissions savings from this pathway would come from the avoided emissions from electric homes that would otherwise have used natural gas. If 22 percent of California's residential buildings stock is all-electric by 2030, this translates to 3.19 million all-electric and 11.31 million natural gas-consuming homes. This would lead to an additional 0.54 million electric homes than in Scenario 1 and avoided emissions of nearly 3.9 $MMTCO_2e$ by 2030 (Figure 5-13), estimated using the methodology described in Scenario 1.

With a minimum lifespan of 6 to 20 years for natural gas end-use technologies for space heating, water heating, and cooking, many of these units will need to be replaced by 2030.[94] Homes that opt for electric end-use equipment and appliances for these replacements can contribute toward meeting the 22 percent goal without necessitating extensive retrofits.

This electrification pathway assumes that all-electric residential buildings resulted in a 100 percent emissions reduction from this subsector within the Buildings sector. As mentioned above, emissions from electricity generation are only counted in the Electricity sector. This calculation method makes this pathway inherently optimistic, given that the electric grid is projected to continue to lower its emissions by 40 percent[95] by 2030 and become net-zero-carbon by 2045.[96] As such, the emissions benefits of electrifying end uses will increase proportionately to grid decarbonization. Based on the emissions intensity of the grid in 2016, one study describes the carbon reduction from fuel substitution in the Residential Buildings subsector in California as 50-70 percent for water heating and 45-54 percent for space heating.[97] Furthermore, there is also evidence that the average daily load profile of home water heaters loosely matches the daily load profile of solar PV generation in California. This could mean added benefits with respect to grid balancing over time. Finally, as new end-use technologies leverage smart and connected systems, there may be additional benefits to the grid in terms of load management.

Costs of the Residential Electrification Pathway

According to the analysis assumptions, home units that are built with electric equipment and appliances would pay the full upfront cost of electric end-use units, plus installation costs, based on EIA estimates.[98] Costs for home electrical wiring upgrades are not included, though according to some estimates these costs could be considerable.[99]

Choosing electric heating is the only option where there are near- and long-term cost savings. This is because homeowners who switch to electric heat pumps can avoid the $3,650 typical installed cost of an air-conditioning unit, as air-source heat pumps provide both heating and cooling services.[100] The O&M costs include estimated maintenance costs, provided by EIA,[101] as well as the difference in annual fuel costs between the natural gas and electric units. Price projections for each fuel were provided by EIA and multiplied by the estimated energy requirements per unit.[102,h] This does not include the corresponding electricity price increases that are the likely result of major electrification programs in California.

Based on these estimates, the estimated cumulative marginal cost to build all electric homes that would otherwise have been natural gas would be $1.5 billion by 2030. The specific costs for each end-use technology are shown in Table 5-6.

[h] Fuel costs do not include the proposed rate increases from the “Test Year 2019 General Rate Case Application of Southern California Gas Company (U 904 G),” Application 17-10-008, Filed October 6, 2017, https://socalgas.com/regulatory/A17-10-008.shtml, as the proposal was pending a decision by the CPUC at the time of this study.

Table 5-6

Select Costs of Electrification Scenario 1 (2017 Minimum Estimates)

	Gas Water Heater[103]	Electric Heat Pump Water Heater[104]	Gas Furnace[105]	Air Source Heat Pump[106]	Gas Cooking[107]	Electric Cooking[108]
Unit + Installation Cost ($)	1,350	1,600	5,700 (Gas furnace plus A/C unit)	4,850	980 (Oven plus cooktop)	980
Annual O&M Cost ($)	242 (16.7 MMBtu/y)	485 (1500 kWh/y)	465 (Includes 29 MMBtu/y & 30 kWh/y, A/C)[109]	295 (1000 kWh/y)	58 (4 MMBtu/y)	135 (900 kWh/y)
Average Cost (2020-2030) ($)	**4,012**	**6,935**	**10,815**	**8,095**	**1,618**	**2,465**
Marginal Cost Per Home (2020-2030)		2,923		(2,720)		847
Total Marginal Costs for 1.35 M new homes ($billions)		**4.1**		**(3.8)**		**1.2**

The total net marginal cost of the electrification pathway totals $1.5 billion through 2030. Source: EFI, 2019. Compiled using data from EIA, 2017; Best Buy, 2019.

Challenges to the Residential Electrification Pathway

There are multiple factors that must be considered by any policy that promotes a switch to electric end-use technologies. Many of these challenges involve the fully burdened impacts of fuel substitution. For example, the switch described above would lead to a growth of demand of more than 6,700 gigawatt-hours per year on the grid in California—roughly 5 percent of the Residential Buildings subsector's load in 2016. This is based on the average electricity use of the electric equipment and appliances substituting for the use of natural gas.[i] End-use efficiency programs may reduce this level of electricity use over time. The cost of adding this amount of new generation depends largely on the type of generation. In any case, a measurable increase in load could translate to increased electricity prices for residential customers, which were not modeled as part of this analysis. Electrification could also require more significant upgrades to electric distribution systems, which would incur additional costs.

Widespread electrification of buildings could also increase the risk of exposure to the increasing climatic and environmental hazards in California. Sea-level rise, land subsidence, and storm surge, for example, all pose severe threats to the electric power grid, which has proven especially susceptible to damage from heavy winds and flooding. For example, during Hurricane Sandy in 2013, the Northeast region experienced widespread electricity outages, while the natural gas system remained mostly operational. This does not mean that natural gas is more resistant to storms, nor does it mean that significant redundancy cannot be built-in to California's Electricity sector. The key point is that there are inherent challenges to address when reducing energy resource diversification.

[i] See Table 5-1. "Estimated Primary Emissions Source by Residential Energy End Uses in California"

Other risks include negative impacts to the natural gas system where some customers—industry in particular—have few pre-2030 options and for whom relative costs of maintaining the needed gas infrastructure may rise. In short, policies across sectors to promote reductions in natural gas use will lead to increased prices for remaining natural gas customers. If, for example, residential gas customers switch to electric appliances and equipment, gas-fired electric generators (49 percent of total CA generation in 2016) might have to pay higher prices for natural gas; they would then pass those costs back onto the same residential customers through higher electricity bills. A rapid loss of large customer classes could have serious impacts on the ability of the natural gas industry to continue to serve existing customers in other sectors.

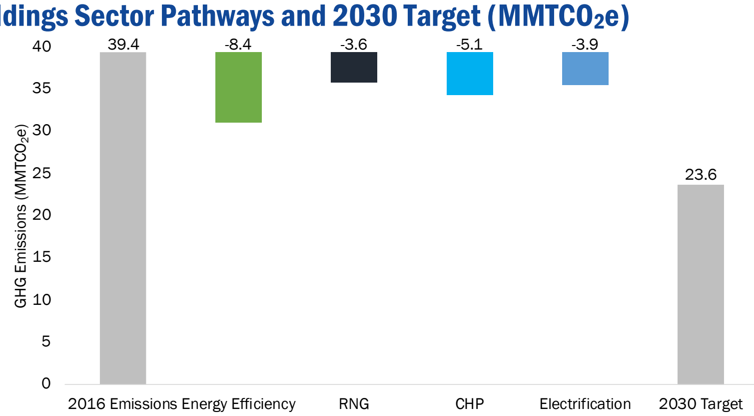
Consumer preference may also pose an obstacle to widespread residential electrification; the extent of this, however, is not well understood. While one survey of California consumers found that 90 percent of homebuyers would not choose solely electrical appliances for their home,[110] another poll found that 61 percent of Californians stated that they would support the state creating incentives to replace natural gas with electricity for heating.[111] For commercial customers, eliminating natural gas for cooking presents an additional barrier.[112]

Conclusion

The Residential and Commercial Buildings subsectors have the potential to meet a 40 percent reduction from 2016 emissions levels by 2030 through a combination of energy efficiency, RNG use, CHP, and electrification (Figure 5-14). While there is strong technical potential for each of these pathways to play a role in reducing emissions from buildings 40 percent by 2030, it is important to consider the impacts to buildings and homeowners, involving costs, consumer preferences, and disruption, in addition to the emissions reduction potential.

Figure 5-14

Buildings Sector Pathways and 2030 Target (MMTCO$_2$e)



The Buildings sector could meet a 40 percent reduction in emissions by 2030 by pursuing energy efficiency measures and utilizing RNG, CHP, and electrification for various commercial and residential end uses. Source: EFI, 2019.

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[8] "California: State Profile and Energy Estimates," Energy Information Administration, U.S. Department of Energy [EIA], Overview: Consumption by Sector tab, last updated November 15, 2018, https://www.eia.gov/state/?sid=CA#tabs-2.
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[10] Calculated as a percentage of the total statewide emissions and emissions for Commercial and Residential in "California Greenhouse Gas Inventory for 2000-2016 — by Category as Defined in the 2008 Scoping Plan," 2, CARB.
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[13] CARB, *California Greenhouse Gas Emissions for 2000 to 2016*, 12.
[14] Calculated using data from California Energy Commission [CEC], *Attachment 12: References for Energy End-Use, Electricity Demand and GHG Emissions Reference and Calculations* (Sacramento, CEC, 2014), 2, https://www.energy.ca.gov/contracts/PON-13-302/Attachment_12-References_for_Energy_End-Use_Electricity_Demand_and_GHG_Emissions_Calculations.pdf; "California Greenhouse Gas Inventory for 2000-2016 — by Category as Defined in the 2008 Scoping Plan," CARB.
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[23] CEC, *Attachment 12*, 2.
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[30] Total subsector emissions include subsector's non-combustion emissions from fertilizer use. See CARB, "California's Greenhouse Gas Inventory by Scoping Plan Category," Included emissions worksheet.
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[32] EFI calculation from 2030 projected natural gas consumption in residential and commercial sectors in "STATE Form 1.1" worksheet in "CEC 2017 Revised Baseline Natural Gas Planning Area and Sector Mid Demand Case TN-222319," January 22, 2018, prepared for the discussion of the CA Mid Case Revised Demand Forecast, California Energy Commission Business Meeting, Sacramento, CA, February 21, 2018, https://www.energy.ca.gov/2017_energypolicy/documents/2018-02-21_business_meeting/2018-02-21_middemandcase_forecst.php. A value of 1.035 Therm/ccf, the average heat content of natural gas in California in 2016 according to EIA, was used in the calculation.
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CHAPTER 6
REDUCING EMISSIONS FROM THE AGRICULTURE SECTOR BY 2030

FINDINGS

Agriculture is one of the most difficult sectors in California to decarbonize. More than 80 percent of the sector's emissions are from widespread, non-combustion sources, principally livestock and fertilizer use.

California's Agriculture sector's unique emissions profile is largely from the livestock subsector, which contributed 68 percent of the sector's emissions in 2016. Livestock emissions in 2016 were nearly 15 percent higher than 2000 levels, even though the cattle population increased only 1 percent. Fertilizers, which includes manure-based and synthetic fertilizers, contribute another 16 percent of the sector's total.

One-third of the sector's emissions are due to enteric fermentation from ruminant livestock for which no substantial abatement pathways exist.

Enteric fermentation is a natural process among ruminant animals (mainly cattle), in which microbes in the digestive tract decompose and ferment food, producing methane. Reducing emissions from livestock is particularly challenging due to California's large cattle population, which was 5.15 million in 2016.

Due to the sector's unique emissions profile, a combination of biogas capture, fertilizer application optimization, and electrification, could be pathways to reduce emissions.

The Agriculture sector emits 8 percent of California's total greenhouse gas (GHG) emissions. Three decarbonization pathways were identified in the 2030 timeframe: capturing methane (biogas) from livestock manure for renewable natural gas (RNG) production, optimizing fertilizer application rates to reduce non-combustion emissions, and reducing fuel-use emissions by gradually electrifying the light-duty tractor fleet.

The Agriculture sector's greatest contribution to statewide emissions reductions is its biogas production potential for use as RNG.

Utilizing agricultural residues and manure as biogas feedstocks for RNG could provide up to 46.6 Bcf per year of carbon-neutral gas by 2030, providing emissions benefits to end-use sectors. Biogas capture also could provide emissions reductions and economic benefits to the Agriculture sector since methane that is released into the atmosphere has a global warming potential (GWP) that is 8.5 times higher than methane combusted to CO_2. Diverting methane into a useable product in the form of RNG could have a significant net impact on GHG levels—potentially reducing the Agriculture sector's emissions 13 percent by 2030.

Policies and strategies for the Agriculture sector must consider the unique nature of local factors, such as soil composition and weather patterns, making standardized approaches difficult.

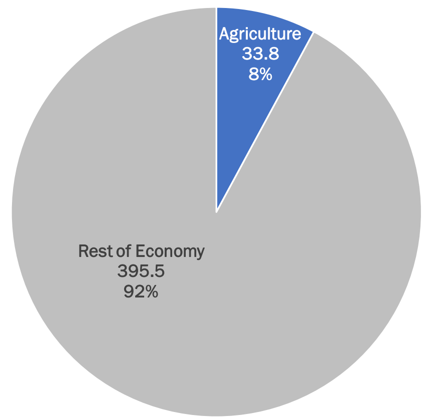
Decarbonization pathways, if improperly planned or implemented, could adversely impact farmers, local communities, consumers, and the sector as a whole. This underscores the importance of localized farm management strategies, as the agronomic and environmental factors that impact emissions are different on each farm. Additionally, agricultural areas may have limited access to infrastructure and the internet, which must be considered when assessing various technological solutions.

AGRICULTURE SECTOR

California is the top agricultural state in the country. Valued at $46 billion, the sector produces more than 400 different commodities and employs an estimated 420,000 people.[1,2,3] Overall, the Agriculture sector contributes 33.8 million metric tons of carbon dioxide-equivalent ($MMTCO_2e$) or 8 percent of California's total emissions (Figure 6-1).[4] Unlike the other sectors in California's economy, the majority of Agriculture's emissions are from non-combustion sources.

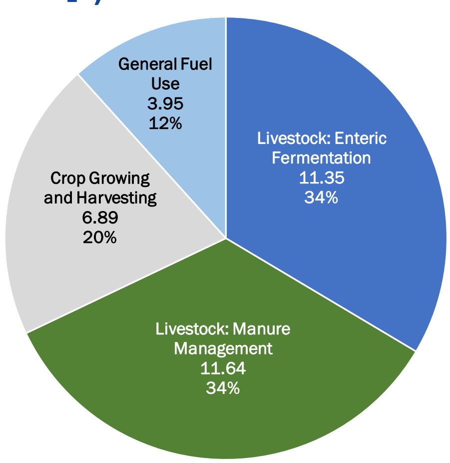
Agricultural emissions have fluctuated between 31.6 $MMTCO_2e$ in 2000 and 36.1 $MMTCO_2e$ in 2012. These fluctuations have a number of causes, including drought and weather conditions as well as market factors, such as price and demand for certain crops and products.

Figure 6-1
Agriculture Emissions Compared to California Total, 2016 ($MMTCO_2e$)



Emissions from Agriculture contribute approximately 8 percent of California's total emissions. Source: EFI, 2019. Compiled using data from CARB, 2018.

Figure 6-2
Agriculture Sector Emissions Profile, 2016 ($MMTCO_2e$)



The three largest emissions sources in agriculture—enteric fermentation, manure management, and crop growing and harvesting—are non-combustion sources, while fuel combustion contributes the remaining 12 percent. Source: EFI, 2019. Compiled using data from CARB, 2018.

Decarbonizing Agriculture requires different approaches than the other sectors, since the majority of the sector's emissions are from non-combustion sources. The decarbonization pathways include the collection of biogas from livestock manure for conversion into renewable natural gas (RNG), modifying fertilizer application to optimize output while minimizing emissions, and reducing combustion emissions through electrification as well as through the use of biodiesel, smart devices, and energy efficiency measures.

2016 Sector GHG Emissions Profile: Agriculture

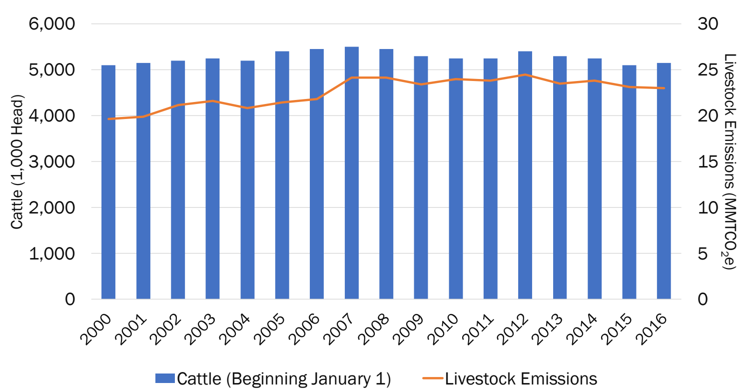
Most agricultural GHG emissions are methane from livestock and fertilizer (Figure 6-2). Methane is a potent GHG that is classified as a short-lived climate pollutant (SLCP), and California has mandated an emissions reduction for methane of 40 percent by 2030.[5] Agricultural emissions make up 36 percent of California's total SLCPs. Additionally, agricultural emissions contribute more than 70 percent of statewide ammonia and over 60 percent of nitrous oxide emissions, negatively impacting air quality.[6] Approximately one-third of agricultural emissions are from enteric fermentation (i.e., burping and flatulating) from California's 5.15 million dairy and beef cattle.[7,8] Manure from livestock, including cattle, swine, poultry, and sheep, contributes another third of the emissions. The remaining emissions are from crop growing and harvesting activities (20 percent), and fuel use (12 percent).[9]

Non-combustion Emissions

As stated above, the majority of emissions in the Agriculture sector are from non-combustion sources, with the largest shares coming from livestock followed by emissions from fertilizer use. This presents unique challenges for emissions reductions in the sector.

Enteric fermentation is difficult to manage since it is a natural process among ruminant animals, mainly cattle. Dairy farms are a major source of GHG emissions in California, accounting for roughly 60 percent of agricultural emissions. Overall, in 2016, livestock emissions were almost 15 percent higher than 2000 levels, although the cattle population increased only 1 percent from 5.1 million in 2000 to 5.15 million in 2016.[10,11,12] As seen in Figure 6-3, GHG emissions from livestock (which includes manure management and enteric fermentation) increased from 2000 to 2007 as the industry grew and cattle population increased from 5.1 to 5.5 million. From 2007 to 2016, however, overall cattle population decreased 7 percent from 5.5 million to 5.15 million cows, and livestock emissions decreased almost 5 percent.

Figure 6-3
Cattle Inventory and Livestock Emissions



Cattle population and livestock emissions have trended similarly since 2000, and although the cattle population only rose 1 percent, associated emissions from livestock activities have increased 14.7 percent. Source: EFI, 2019. Compiled using data from CARB, 2018; CDFA 2013; CFDA 2017.

Crop growing and harvesting activities produced 6.89 $MMTCO_2e$ of GHG emissions in 2016, which was 20 percent of the sector's total. Over 75 percent of these emissions were from manure-based and synthetic fertilizer use (5.25 $MMTCO_2e$). Synthetic fertilizers increase soil denitrification, a process in which nitrous oxide, a potent GHG, is emitted from soil more rapidly than under natural conditions.[13] Soil management, including irrigation, tillage, and land fallowing, contributed an additional 1.56 $MMTCO_2e$.

Emissions from the growing and harvesting of crops have been declining since 2000 but leveled off from 2015 to 2016. This is due in part to reductions in crop acreage and associated fertilizer use, which resulted from prolonged drought events. Additionally, the severe drought events led to widespread adoption of drip irrigation in place of flood irrigation.[14] Overall, emissions in this category experienced an overall decline of 15.6 percent from 8.16 $MMTCO_2e$ in 2000 to 6.89 $MMTCO_2e$ in 2016.[15]

Combustion Emissions

Combustion emissions in the Agriculture sector have increased 3.6 percent from 3.81 $MMTCO_2e$ in 2000 to 3.95 $MMTCO_2e$ in 2016. Combustion emissions from fuel use account for 3.95 $MMTCO_2e$, or 11.7 percent, of agricultural emissions. Of this total, 3.19 $MMTCO_2e$ are from diesel consumption in tractors and other farming equipment.[16,17] The remaining 0.72 $MMTCO_2e$ and 0.04 $MMTCO_2e$ are from natural gas and gasoline use, respectively. Emissions from fuel use have fluctuated between 2.61 $MMTCO_2e$ in 2009 (in the depths of the Great Recession) and 4.66 $MMTCO_2e$ in 2014 (when global growth and demand had recovered).

Analysis of Agriculture Sector

California has several policies in place to reduce emissions from the Agriculture sector. One of the main policies is SB 1383 (enacted in 2016), which calls for a 40 to 50 percent reduction in SLCPs (methane, hydrofluorocarbons, and black carbon) by 2030. This law requires the California Air Resources Board (CARB), in consultation with the California Department of Food and Agriculture (CFDA), to implement regulations after January 1, 2024 to reduce methane emissions from livestock and take actions to increase the production of biogas and use of RNG. It would reduce methane emissions from livestock and dairy manure management operations by up to 40 percent of 2013 levels by 2030,[18] a reduction target of 4.2 $MMTCO_2e$.[19]

AB 1900 (enacted in 2012) requires the California Public Utilities Commission (CPUC) to create standards and requirements for RNG[a] and to adopt policies and programs to promote in-state production and distribution.[20] AB 2313 (enacted to 2016) requires the CPUC to increase the amount of money that the state can reimburse RNG project developers to partially cover interconnection costs to local natural gas distribution networks. RNG project developers can be reimbursed for up to 50 percent of project costs (up to $3 million for standalone RNG projects and up to $5 million for dairy RNG projects that are clustered together). The program, which began in 2015 and is scheduled to run until December 31, 2021, is capped at $40 million in total reimbursements.[21] Most recently, AB 3187[22] and SB 1440[23] (both enacted in 2018) require the CPUC to consider additional investment incentives and procurement targets, respectively, to further promote in-state RNG production and distribution.

The state's cap-and-trade program has established protocols that allow biogas control systems that reduce emissions from manure on dairy and swine farms to qualify as an

[a] California law refers to RNG as biomethane. These terms are used interchangeably in this analysis.

offset.[24] As of February 2019, nearly 5.6 million offset credits—each of which represent one metric ton carbon dioxide-equivalent (CO_2e)—have been issued for livestock emissions offset projects.[25]

There are also other state funding efforts, such as the CDFA 2017 Dairy Digester Research and Development (R&D) Program and the Bioenergy Market Adjusting Tariff (BioMAT) program. The latter program supports small in-state bioenergy generators that provide electricity to the state's major utilities[26] and creates financial incentives and market certainty for livestock operations to implement biogas capture projects. The Dairy Digester R&D Program has awarded more than $100 million to 63 projects, which were matched with an additional $197.6 million provided by the grantees. In 2015, six initial projects were funded to generate electricity from biogas. In 2017 and 2018, 16 and 41 additional projects, respectively, were funded to generate RNG from biogas.[27] The program estimates that 12.5 $MMTCO_2e$ of methane emissions will be reduced over ten years from the existing 63 projects.[28]

California's multi-agency approach to reducing the sector's emissions is important and critical to ensuring that a range of mitigation options can be applied at the farm level.

Decarbonizing the Agriculture sector is a difficult task and it involves many stakeholders. California's multi-agency approach to reducing the sector's emissions is important and critical to ensuring that a range of options can be applied at the farm level. This will help ensure that decarbonization pathways do not disproportionately or adversely impact farmers, local communities, consumers, and the sector as a whole.

Analysis Methodology

For several reasons, demand projections for California's Agriculture sector and the associated impact on emissions are highly uncertain. To assess decarbonization pathways, this analysis first examined future demand (and therefore emissions) growth of the sector through 2030 for livestock and crops.

Livestock Emissions Projection

Although the U.S. Department of Agriculture (USDA)[29] and Food and Agricultural Organization of the United Nations (FAO)[30,31] both project that demand for beef in the United States and globally will increase through 2030, [32] it is unclear if and how this will impact California. The state has decreased its supply of cattle by 6 percent between 2007 and 2016, despite increases in demand for beef products in the United States and abroad since that time.[33]

Currently, California's share of U.S. cattle and calf production is 4 percent.[34] The state is, however, a major exporter of beef to growing Asian markets, which purchased 94 percent of California's beef product exports in 2015 and 93 percent in 2016.[35] The dairy industry has also seen increased output per cow, which means that fewer cows are needed to produce the same quantity of milk. At the same time, in 2016, milk supply in California and globally outpaced demand, leading to depressed prices for milk. This development caused many California dairy farmers to begin diversifying their agricultural production by adding plots of almonds and other nuts, which command higher prices and are increasing in demand in many markets.[36]

Based on these uncertainties, this analysis estimated California's future emissions from livestock activities (which includes enteric fermentation and manure management), by assuming that emissions will continue at the same rate as the average rate over the period from 2000 to 2016. The resulting estimate for 2030 is 22.6 $MMTCO_2e$, which is slightly lower than 2016 emissions from livestock (23.0 $MMTCO_2e$).

Crop Activities and Fuel-Use Emissions Projection

Changing demand for—and the changing value of—field crops, fruits, and nuts are impacting agricultural land uses. From 2013 to 2017, the average value per acre of cropland in California increased 14.5 percent, while the value per acre of pastureland increased by only 1.9 percent.[37] Because land crops have a significantly smaller carbon footprint than livestock operations, a shift to supplying more non-livestock commodities could lead to emissions reductions.

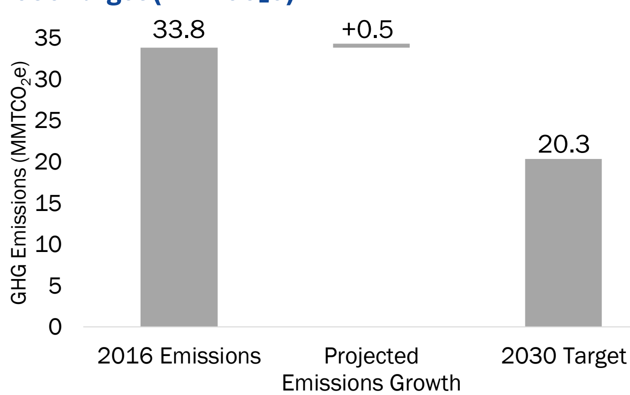
This analysis again used average emissions from 2000 to 2016 to estimate 2030 emissions from crop growing activities at 7.7 $MMTCO_2e$ in 2030, which is slightly higher than 2016 levels (6.9 $MMTCO_2e$). Since fuel use is closely related to agricultural output, as described above, the same methodology was used to forecast fuel-use emissions in 2030. The result was 4.0 $MMTCO_2e$, which is slightly higher than 2016 emissions from fuel use (3.95 $MMTCO_2e$).

Emissions Trajectory Analysis for California's Agriculture Sector

Based on the methodology described above, emissions in the Agriculture sector are expected to increase 0.5 $MMTCO_2e$ by 2030, bringing the business-as-usual (BAU) 2030 projection for the sector to 34.3 $MMTCO_2e$. A 40 percent reduction from 2016 agricultural emissions (33.8 $MMTCO_2e$) is equal to 20.3 $MMTCO_2e$ (Figure 6-4).[b]

Figure 6-4

Agriculture Emissions Reductions Needed to Meet 2030 Target ($MMTCO_2e$)



To reduce emissions in Agriculture 40 percent from 2016 levels by 2030, 13.5 $MMTCO_2e$ GHG emissions must be abated; however, if projected emissions growth is considered, the gap increases to 14 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018.

[b] Note: The CARB Scoping Plan estimates Agriculture sector emissions in 2030 to be 24-25 $MMTCO_2e$, indicating that a 40 reduction in agricultural emissions is not expected.

Table 6-1 summarizes the key assumptions and sources utilized in determining future emissions projections and decarbonization pathways for the Agriculture sector.

Table 6-1
Agriculture Key Assumptions

Pathway	Subsector	Key Assumptions
Baseline	All	Cattle population and agricultural output statistics are from the *California Agricultural Statistics Review, 2016-2017* published by the CDFA. Emissions projections from agriculture were based on the 16-year average emissions calculated from the CARB California Greenhouse Gas Inventory for 2000-2016—by Category as Defined in the 2008 Scoping Plan. The projection resulted in a slight increase in emissions from 33.8 MMTCO$_2$e in 2016 to 34.3 MMTCO$_2$e in 2030.
Biogas Capture	Livestock	Biogas capture only applies to emissions from manure management *(enteric fermentation emissions are not reduced by this or any other pathway)*. A 50 percent capture rate was applied based on a review of other studies and estimates. Per the GHG emissions accounting methodology in this analysis, 88.7 percent of the emissions reductions from biogas capture are attributed to the Agriculture sector (the remaining 11.3 percent are counted as savings in the RNG consuming sector).
Optimizing Fertilizer Use	Crop Growing/ Harvesting	Crop area, nitrogen application rates by crop, and percent of total nitrogen use from 1973 and 2005 are from *Nitrogen fertilizer use in California: Assessing the data, trends and a way forward* published by UC-Davis in 2013; the average fertilizer rate was calculated from the minimum and maximum nitrogen fertilizer rate guidelines as listed in Table 2 of the study.
Reducing Fuel-Use Emissions	Livestock; Crop Growing/ Harvesting	Information on machinery and equipment in operation in California for 2017 is from USDA *2017 Census of Agriculture–State Data*. Data on the year of manufacture for tractors less than 40 horsepower (PTO) from USDA Agricultural Censuses for years 2012, 2007, 2002, and 1997 were used to estimate stock turnover by 2030. Emissions reduction potential from displacing diesel-consuming tractors with electric tractors was estimated using the “Individual Calculation Tool” in CARB’s Off-road Emissions Factors spreadsheet.[38] Inputs for tool included the following: horsepower–40; model year–2000, 2005, 2010; Calendar year–2017, 2030 *(note: changing calendar year and model year did not change CO$_2$ emission output)*; activity (annual hours)–500, 600, 700 and 800 *(for range)* and 650 *(for midpoint)*; accumulated hours on equipment–6000; load factor–0.48 *(given by CARB for agricultural tractors)*.

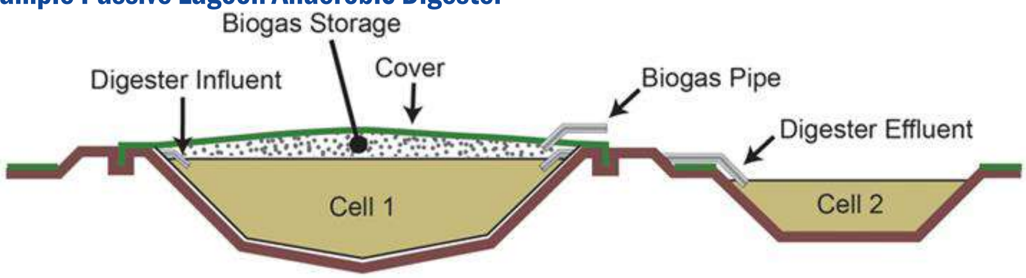
GHG Emissions Reduction Pathways

This analysis identified three decarbonization pathways that could be used to reduce agricultural emissions by 2030. These pathways include collecting biogas from livestock manure, optimizing fertilizer use, and electrifying part of the small tractor fleet in California. Other farming practices that could reduce emissions as well as opportunities to reduce fuel combustion emissions include the use of biodiesel, smart devices, and energy efficiency are also discussed. Collectively, these pathways could reduce emissions by approximately 4.8 MMTCO$_2$e; however, there are technical, financial, and public acceptance uncertainties and challenges that could limit success.

Pathway 1: Capturing Biogas from Manure for RNG Production

Biogas is a methane-rich unconventional energy resource that is produced through the biochemical decomposition of organic matter through a process known as anaerobic digestion. In this process, anaerobic digesters (ADs) capture passive methane emissions and convert the methane into a useable energy resource.[39] One of the simplest AD types is the passive lagoon-style AD (Figure 6-5).[40]

Figure 6-5
Example Passive Lagoon Anaerobic Digester



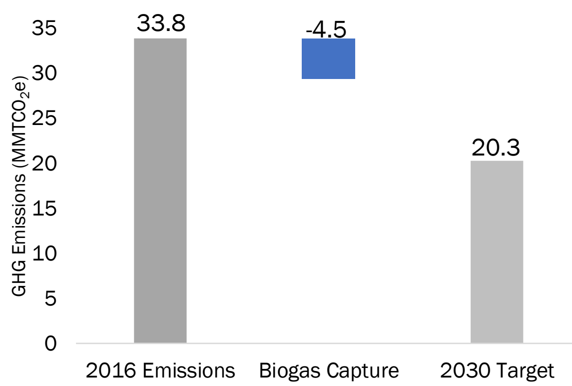
Lagoon-style ADs are a low-maintenance and relatively low-cost manure management strategy that prevent methane emissions, control odors, and enable the capture of biogas for conversion to useable energy. Source: University of Wisconsin-Madison.

In the covered-lagoon AD, the lack of oxygen in the digester causes the manure and other organics to decompose anaerobically, which produces biogas over the course of several weeks.[41] The covered-lagoon type of digester does not require additional heat; however, it is only cost-effective in warm climates, such as in Southern California, since anaerobic digestion times are significantly longer in colder temperatures.[42]

There are also several types of more complex AD systems that can be installed on site at farms or centrally clustered for larger-scale biogas collection. For example, in California there is a centralized facility with multiple AD tanks that process manure from 14 dairy farms; this centralized AD facility reduced emissions by 58 percent.

This analysis calculated that widespread deployment of ADs as a manure management strategy could reduce emissions by 4.5 $MMTCO_2e$ by 2030 (Figure 6-6).[c,43,44]

Figure 6-6
Biogas Capture Pathway and 2030 Target ($MMTCO_2e$)



Biogas capture from livestock manure could reduce 4.5 $MMTCO_2e$ from the Agriculture sector. Source: EFI, 2019. Compiled using data from CARB, 2018; ICF, 2017.

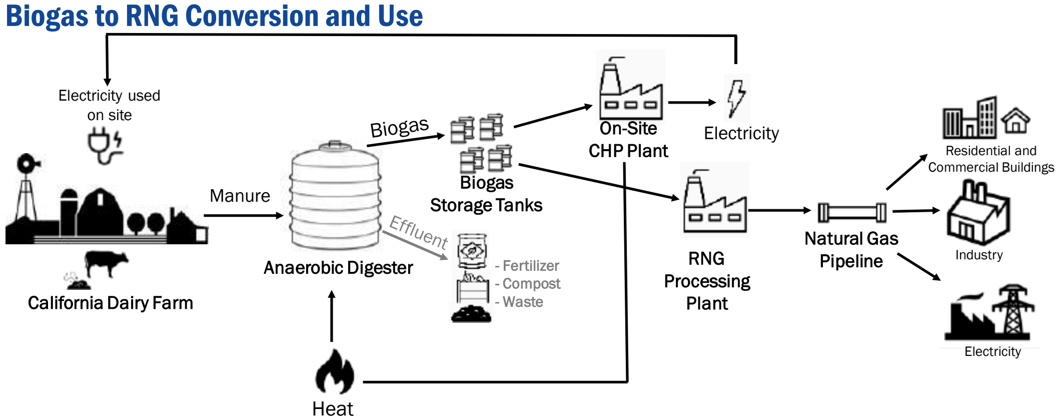
[c] Assumptions and methodology detailed in the Biogas and RNG Addendum at the end of this chapter.

Benefits of Biogas Capture

Harvesting biogas from livestock operations provides an opportunity to divert and monetize gaseous waste streams as well as provide energy services to different sectors. The intended use of biogas determines the extent to which it will need to be processed to remove impurities and carbon dioxide prior to final consumption. Biogas for end uses such as power generation typically requires minimal processing, whereas vehicle fuels and pipeline-quality gas need to undergo a more extensive upgrading process.

Renewable Natural Gas. RNG or biomethane, refers to vehicle- or pipeline-quality gas that is captured from biogas sources and upgraded to meet certain purity standards. After upgrading, the RNG has a higher methane content than raw biogas and can be used for transportation fuels (as compressed natural gas [CNG] or liquefied natural [LNG]) or injected into pipelines and co-blended with conventional natural gas. Using estimates from ICF International,[45] this analysis calculated that biogas capture from manure could yield an estimated 15.5 billion cubic feet (Bcf) per year in California. Figure 6-7 depicts potential uses of biogas captured from manure—used on-site for heat and power generation or converted into RNG for use in Buildings, Industry, and Electricity.

Figure 6-7
Biogas to RNG Conversion and Use



Biogas capture provides several opportunities for use, including on-site thermal energy and electricity use or off-site upgrading to RNG for use in place of conventional natural gas in Buildings, Industry, or Electricity. Source: EFI, 2019. Graphics from the Noun Project.

In addition to biogas from manure, agricultural residues (such as unusable crops, stalks, stems, leaves, branches, and seed pods) are also biogas feedstocks that have an RNG production potential of 31.05 Bcf per year in California (mean estimate).[d] Agricultural residues are converted to biogas through a process called thermal gasification, in which solid biomass decomposes into non-condensable gases.[46] After gasification, the biogas can be used on-site for electricity and heat or upgraded into RNG. At present, agricultural residues are typically burned or left as waste. Utilizing them as biogas feedstocks provides an economic benefit for a waste product that otherwise may not have monetary value.

[d] See the Biogas and RNG Addendum at the end of this chapter for additional information on RNG potential estimates.

Agricultural residues are currently not included in the CARB emissions database. While utilizing agricultural residues as a biogas feedstock for processing into RNG would not directly provide an emissions reduction benefit to the Agriculture sector, it would provide emissions benefits to the end-use sectors using RNG. Utilizing agricultural residues thus provides an economic benefit to the Agriculture sector and emissions benefits to the Buildings, Industrial, or Electricity sectors.[e]

Environmental Benefits. In addition to the financial benefits of harvesting biogas for RNG, biogas capture also provides environmental benefits including the following:[47]

- Greater odor control than conventional manure storage
- Reduced GHG emissions
- Water quality protection
- Creation of valuable byproducts (e.g., fertilizers from the effluent)
- Collection of tipping fees by accepting organic wastes from other entities
- Eligibility for renewable energy certificates (RECs) and renewable identification numbers (RINs)

Infrastructure Compatibility. A final benefit of RNG is its compatibility and interchangeability with existing natural gas infrastructure.[48] A previous analysis by the University of California, Davis (UC-Davis) found that there are many synergies between natural gas and RNG infrastructure, including the same midstream pipeline infrastructure for transport and the same vehicle stock. Given these synergies, traditional natural gas companies can benefit from carbon credits generated through RNG use, while RNG project developers can take advantage of existing infrastructure to move their product to market. This could minimize the risk of infrastructure turnover and stranded assets given a greater shift from traditional natural gas to RNG. However, to fully maximize the biogas opportunity in California, the state will likely need to build new facilities to process and upgrade biogas from its sizeable resource base.[49]

Biogas Capture Projects in California

As of April 2018, California had 23 operational AD projects and three AD projects under construction. At least 18 of these projects are lagoon-style ADs (see Figure 6-5 above) located at dairy farms, which use the biogas on-site for electricity. According to the Integrated Energy Policy Report prepared by the California Energy Commission (CEC), these projects collectively capture and destroy less than 2 percent of the state's lagoon methane, so widespread efforts for methane management in livestock operations are important for the state to meet its SB 1383 methane reduction goal. The CDFA 2017 Dairy Digester R&D Program has already committed $35 million to fund dairy digesters, with an additional $65 to $80 million from the Greenhouse Gas Reduction Fund expected to be utilized for livestock biogas projects.[50] Figure 6-8 shows the RNG generation potential by California county.

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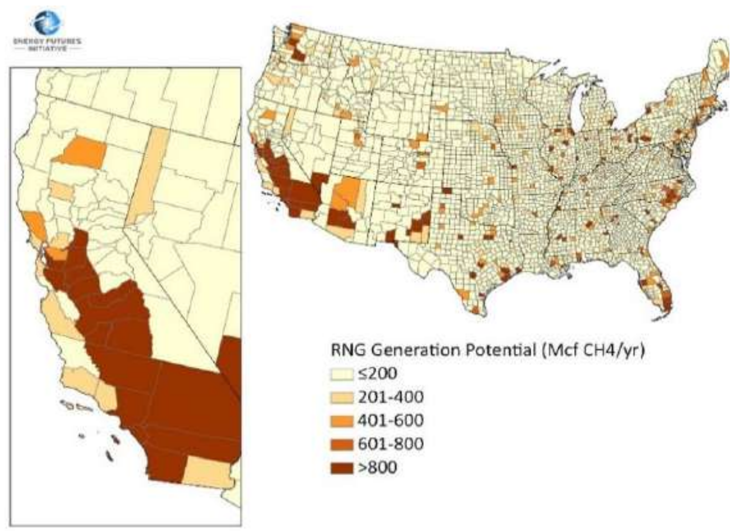
[e] See the Biogas and RNG Addendum for additional information on emissions accounting methodology.

Challenges to Biogas Capture Pathway

The challenges for wider deployment of biogas in California include high capital costs; insufficient processing infrastructure; the need for further policy support for project deployment; complex permitting issues, regulatory inconsistency associated with the standards for pipeline-quality gas; and a lack of public awareness about the benefits of biogas.

Figure 6-8

RNG Generation Potential in California (Mcf methane/year)



California has one of the largest RNG generation potentials in the United States. Source: EFI, 2019. Compiled using data from NREL, 2014.

Costs of Pathway

The collection of biogas and its processing into RNG is typically more expensive than collection and processing for conventional natural gas, largely due to the requirements for processing and upgrading the gas, along with the pipeline interconnection fees.[51] Biogas derived from manure is one of the most costly feedstocks[f] according to a study by UC-Davis. This study concluded that RNG derived from dairy manure biogas needs a minimum price support of $26 per million Btus (MMBtu) for the RNG to be competitive in conventional gas markets.[52] This highlights the prohibitive costs of biogas development on dairy farms in California.

The capital costs of dairy manure AD systems for electricity generation vary depending on the generation capacity and the number of cows. The AgSTAR program of the U.S. Environmental Protection Agency (EPA) estimates capital costs ranging from $1,000 per cow to $2,000 per cow with additional maintenance costs ranging from $0.015 per kilowatt-hour (kWh) to $0.02 per kWh of electricity generated;[53] however, there are a number of variables that impact these costs.

A study by Duke University indicated that a complete-mix ADs using manure from 1,000 to 1,999 dairy cows (the average number of mature cows at a candidate farm for a digester in California[54]), has capital costs of around $1.2 million and annual operations and maintenance (O&M) costs of around $438,000. If the costs of upgrading biogas into RNG are included, capital costs increase to approximately $2.0 million and O&M is $475,000 annually.[55]

[f] Costs of RNG derived from other feedstocks are discussed in the Biogas and RNG Addendum at the end of this chapter.

Without policy support, high costs could significantly hinder further development of biogas AD projects, because present market conditions make these projects unattractive for private capital investment.[56] This has been a barrier to biogas and RNG project development in California, despite the incentive programs and policies in place.[57]

A major challenge for project developers of biogas collection systems on livestock operations involves the relatively large distances between the project sites and offtake locations for the gas (e.g., existing pipeline systems and natural gas refueling infrastructure).[58,59] Analysis suggests that the most cost-effective project sites in California are near natural gas fueling infrastructure in the Los Angeles area.[60] Opportunities to reduce anticipated project costs include co-locating biogas processing and upgrading sites and clustering projects on livestock operations.[61] At the same time, some natural gas customers have indicated a willingness to pay a premium for RNG as a substitute for conventional natural gas through their utility,[62] and some gas companies are now looking to begin pilot programs that offer customers the opportunity to purchase RNG to satisfy a portion of their consumption.[63]

Pathway 2: Optimizing Farming Practices

Farming practices, which include fertilizer use, soil management, and livestock feeding, can have a substantial impact on agricultural emissions. Emissions from the over-application of fertilizer combined with other soil management practices accounted for 6.9 $MMTCO_2e$ of the emissions in California's Agriculture sector in 2016. Enteric fermentation contributed another 11.4 $MMTCO_2e$ to the sector's emissions. While there are few options for eliminating these emissions entirely (e.g. livestock will always be a source of emissions and fertilizer application is necessary for optimizing agricultural output), there are farming efficiency practices that could reduce some of these emissions.

Optimize Synthetic Fertilizer Use Pathway

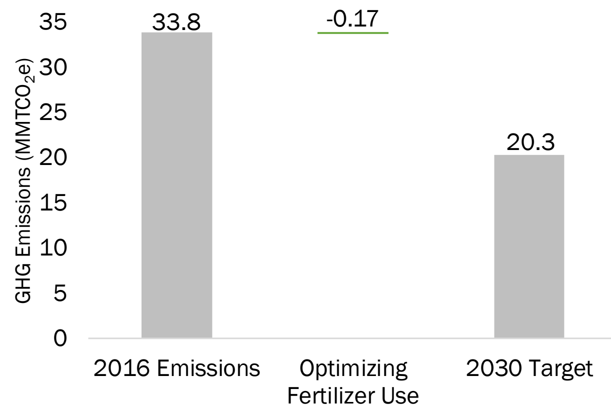
Inorganic compounds can be added to fertilizer to increase productivity. The use of synthetic nitrogen fertilizer in California has grown rapidly in the last few decades, according to a 2013 assessment by UC-Davis. Between 1973 and 2005, for example, the nitrogen application rate for almonds increased 41 percent.[64]

The UC-Davis assessment also included a review of the nitrogen rate guidelines for select crops grown in California. The guidelines provide a maximum and minimum amount of fertilizer, measured in pounds nitrogen per acre, for a range of crops.[65] These guidelines are made based on identifying the minimum amount of nitrogen needed to optimize productivity. If the six most fertilizer-consuming crops (cotton, almonds, rice, wheat, processing tomatoes, and lettuce) all used the minimum level of nitrogen, there could be a direct decrease in emissions of 0.53 $MMTCO_2e$.[66] Note that this excludes any potential emissions benefit upstream of the fertilizer use.

The minimum nitrogen rate would not be appropriate for every farm due to differences in soil composition, climate, and other agronomic factors, therefore this analysis used the mid-point between the maximum and minimum nitrogen rate guidelines for the six highest fertilizer-consuming crops. This would translate to an emissions reduction of 0.17 $MMTCO_2e$ by 2030 (Figure 6-9).

Figure 6-9

Reducing Fertilizer Use Pathway and 2030 Target ($MMTCO_2e$)



Using the midpoint of the nitrogen fertilizer rate guidelines for the six most fertilizer-consuming crops in 2005 results in emissions reductions of 0.17 $MMTCO_2e$. Source: EFI, 2019. Compiled using data from CARB, 2018; UC-Davis, 2013.

Other Strategies for Optimizing Farming Practices

Other farming practices that could lead to GHG emissions reductions include optimizing livestock feeding and implementing soil management practices that minimize emissions. Because research and literature on the emissions benefits of optimizing livestock feeding and soil management practices is sparse and inconsistent, the analysis did not attempt to quantify a potential emissions reduction estimate for these two strategies.

Optimize Livestock Feeding. To reduce GHG emissions from enteric fermentation, feed composition and feeding rates can be modified to meet the specific needs of ruminant livestock. Diets that include ionophores, fats, high-quality forages, and more grains have been shown to reduce methane emissions from ruminant animals.[67] There also may be genetic factors that affect methane production, so selective breeding of lower-emitting cows could be used.[68] Because there are so many factors that impact enteric fermentation emissions, it is difficult to estimate the reduction potential.[69]

Optimize Soil Management Practices. In addition to optimizing fertilizer use, there are many soil management practices that could be made at the farm level to reduce emissions. Again, it is difficult to quantify or predict the potential emissions savings because of the multitude of variables that impact emissions from soil and crop management.

Irrigation practices impact the effectiveness of fertilizer use and could be updated to maximize the effectiveness of fertilizer application. For example, in addition to using less energy and water, drip irrigation systems (which are slow-release) can reduce fertilizer and herbicide use,[70] as individual plants absorb water and fertilizer more slowly.

Soil management practices such as reduced tillage and no-till farming can minimize disturbances to the soil, which can enable carbon to stay sequestered in the soil instead of being emitted into the air; however, studies of California's Agriculture sector have found that the relative mitigation potential of conservation tillage or no tillage is low.[71] A meta-study of 49 papers with 196 comparisons found that the impacts of tilling practices on emissions are highly variable and depend on many other agronomic practices, such as fertilizer use, crop type, soil condition, temperature, and moisture.[72] This highlights the importance of localized farm management strategies, since the agronomic and environmental factors that impact emissions are different on each farm.

Challenges to Optimizing Farming Practices Pathways

The durability of this pathway depends on farmers changing their fertilizer use. Many external factors impact the appropriate amount of fertilizer used on each farm, including climate, soil type, and crop rotation practices. Moreover, data on these elements are rarely reported in consistent ways. The UC-Davis study, for example, relied on studies published between 1999 and 2009 to compile sufficient evidence and even stated that the available data on California fertilizer sales and use is insufficient to precisely quantify fertilizer use by crop and geography.[73] Improving the accuracy of fertilizer application data is critical for designing and/or implementing a program to optimize fertilizer use. The CDFA relies on self-reporting by distributors of bulk fertilizers and manufacturers of packaged products for its annual *Fertilizer Tonnage* report;[74] however, there is a lack of farm-level information about where and how much fertilizer is used.

Another challenge is any potential adverse impact to farm performance from reducing fertilizer use. While the UC-Davis study provided a minimum and maximum amount of nitrogen fertilizer that is appropriate for each crop, there are soil- and crop-specific differences that must be considered at the farm-level. Insufficient fertilization presents a risk of diminished crop yields, which is important to avoid.

This highlights the importance of localized farm management strategies since the agronomic and environmental factors that impact emissions are different on each farm.

Finally, forecasting emissions from this pathway is difficult because behavioral, environmental, and agronomic factors impact emissions from synthetic fertilizer use.[75] Soil can be a source or a sink for CO_2, a sink for methane, and a source of nitrous oxide.[76] The quantity and concentration of fertilizer, as well as the frequency of application, impacts the resulting emissions. In addition, soil composition, weather patterns, and crop type greatly impact how much of the fertilizer is absorbed versus how much nitrous oxide is emitted.[77] For these reasons, the farming practices employed by each farmer directly affects the GHG emissions reduction potential.

Similarly, the other farming practices described require tailored solutions for local conditions. Soil management practices, such as irrigation and tilling have varying emissions impacts.[78] Any approach taken must consider the implications on crop and livestock performance, applicability to the environment, and impacts on and costs to the farmer, since there are many factors to consider (e.g., soil, climate, and crop type). There is not a one-size-fits-all solution, and efforts to encourage inappropriate technologies or behaviors could result in negative crop yields and excessive costs.

Costs of Pathway

Farm management practices that optimize fertilizer use, animal feed, and soil management practices could lead to a reduction of costs, since using less fertilizer, feed and tilling less would save money and time. For fertilizer, this could alleviate some of the financial hardship from fertilizer price volatility that affects farming costs. Between March 2010 and March 2014, for example, the U.S. average farm price of anhydrous ammonia, a commonly used nitrogen fertilizer, increased from $400 to $851 per ton.[79]

Pathway 3: Reducing Fuel-Use Emissions

Fuel use contributed 12 percent of agricultural emissions in 2016. This includes diesel, natural gas, and gasoline combustion; nearly all of this fuel is used in farming equipment. Diesel is the primary fuel used in California's Agriculture sector and contributes to 3.19 $MMTCO_2e$ of the 3.95 $MMTCO_2e$ fuel-use emissions. According to the 2017 Census of Agriculture conducted by the U.S. Department of Agriculture (USDA), tractors make up 94% of farming equipment in California, with grain and bean combines, cotton pickers and strippers, forage harvesters, and hay balers making up the remainder.[80]

Electrifying light-duty tractors at the end of their useful life is one pathway to reduce emissions from fuel use. Additionally, using biodiesel blends in place of conventional diesel, smart devices, and energy-efficient farming equipment could provide opportunities to reduce fuel-use emissions in Agriculture.

Electrifying Light Tractors Pathway

According to the 2017 USDA Census of Agriculture, tractors with less than 40 horsepower-power-take-off (HP-PTO)[g] are 28 percent of the operational machinery and equipment in California. These light-duty tractors have high electrification potential due to the fact that they require less power and have fewer technical challenges associated with electrification compared to larger tractor classes (100 HP-PTO or more). This pathway determined a share of the light-duty tractors that would be eligible for replacement with an electric alternative by 2030 based on their age, performance, and use.

By 2030, an estimated 20,142 tractors in the less than 40 HP-PTO category will reach the end of their estimated useful life in California. This is nearly half of the 41,919 light-duty tractors currently operational in California.[81] If all 20,142 light-duty tractors were replaced with electric substitutes at the end of their useful life, that would result in emissions reductions of approximately 0.12 $MMTCO_2e$ to 0.20 $MMTCO_2e$ by 2030.[82] The emissions savings depend on the annual hours of activity, which were assumed to range from 500 to 800 for the calculations in this pathway. Using the midpoint of 650 annual hours of use for a 40 HP tractor[h] with a load factor of 0.48 (the load factor for tractors according to

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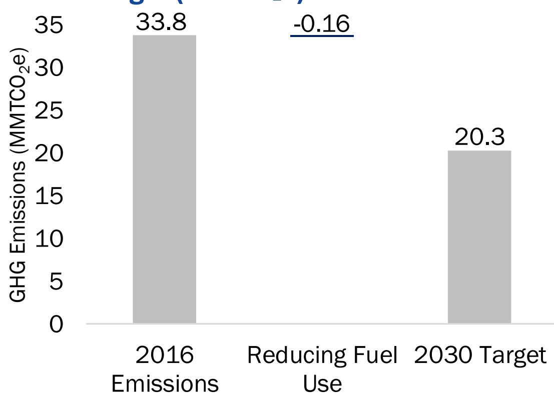
[g] The USDA uses Horsepower Power Take Off (HP-PTO) to classify three sizes of tractors: less than 40 HP-PTO, 40 to 99 HP-PTO, and 100 HP-PTO or more. HP-PTO differs from horsepower because it includes the amount of horsepower available to power attachments to the tractor in addition to just the engine. For this reason, it is commonly used to measure the power output of farming tractors, which often have implements, such as bush hogs, balers, mowers, or plows.

[h] CARB's 2017 Off-road Diesel Emission Factors spreadsheet Individual Calculation Tool utilizes HP rather than HP-PTO. Since HP-PTO is lower than HP, this analysis used 40 HP as the input for the calculations. See Table 6-1 for assumption on inputs.

CARB), this pathway results in 0.16 MMTCO$_2$e of GHG emissions reductions by 2030 (Figure 6-10).

Figure 6-10
Reducing Fuel Use Through Electrification Pathway and 2030 Target (MMTCO$_2$e)



If small, diesel-powered agricultural tractors are replaced with electric alternatives at the end of their useful life, around 0.16 MMTCO$_2$e of GHG emissions could be reduced from Agriculture by 2030. Source: EFI, 2019. Compiled using data from CARB, 2018; USDA, 2017.

Electric light-duty tractors have become commercially viable in part due to improvements in battery technology, charging times, and vehicle performance for off-road vehicles. The largest classes of tractors have greater power demand, and therefore would need larger batteries, more frequent charges, or another method of providing sufficient power over long durations of use (e.g., corded models, such as one prototyped by John Deere[83]). Smaller, cost-competitive tractors are commercially available by companies, such as California-based Solectrac[84] and the German manufacturer Fendt,[85] which provide the same utility as diesel tractors in the 40 HP-PTO category. Farming equipment manufacturers, such as John Deere,[86] have made prototypes of large tractors that are all-electric; however, they are unlikely to reach commercial availability and penetration for significant emissions reductions in the 2030 timeframe.

Other Strategies for Reducing Fuel-Use Emissions

Switching from conventional diesel to biodiesel or biodiesel blends, utilizing smart devices to reduce fuel use, and increasing the efficiency of farming equipment could also provide emissions reductions in the sector. This analysis did not determine a quantitative estimate for the potential emissions savings from these technologies due to the number of variables and uncertainties associated with their use in the sector.

Biodiesel. Biodiesel can lower the carbon intensity of fuels depending on the blend's concentration. The most common blend—B20 biodiesel—is 20 percent diesel from biomass and 80 percent conventional diesel, which results in 20 percent fewer emissions. Many major agricultural equipment manufacturers, such as AGCO, Cummins, and John Deere, have engines that can run on biodiesel blends.[87,88] These engines are used to power a variety of agricultural machinery including tractors, combine harvesters, and irrigation systems. Utilizing biodiesel widely could have a major impact on the largest source of combustion emissions in Agriculture.

Smart Devices. Agricultural technologies are also evolving to include sensors, automation, and other "smart devices" that enable farmers to manage their crops and livestock in more efficient ways. Some of these devices are embedded into modern tractors, which have cameras and computing capabilities that provide real-time information to the vehicle operator.[89] There is also ongoing research and development into self-driving tractors,[90] which, if programmed and operated optimally, could reduce vehicle miles traveled, save fuel, and lower GHG emissions.[91]

There are many options for increasing the efficiency of combustion sources in agriculture that can provide benefits for farmers while reducing emissions.

Efficiency. There are many options for increasing the efficiency of combustion sources in agriculture that can provide benefits for farmers while reducing emissions. The USDA offers guaranteed loans and grants each year through its Rural Energy for America Program, which provides funding for any project that saves energy.[92] California also offers financing and support for farmers wishing to implement energy efficiency measures. Increasing access to financing for machinery upgrades could support the deployment of energy-efficient farming equipment on California's farms, in turn reducing emissions from combustion sources.

Challenges to Reducing Fuel-Use Emissions Pathway

There are limits to the applicability of advanced technologies, which may also limit the extent to which they can be applied. For example, many smart devices require an internet connection, which may not be reliable (or available) in rural areas. Similarly, rural electricity supply may sometimes be insufficient to power electric motor systems that require more than 30 horsepower,[93] limiting electrification. An additional challenge is the competing demand for biodiesel, which may limit its availability and use.

Public acceptance is another potential risk. Upfront engagement to determine localized solutions will be critical to determine appropriate farming practice improvements and to gain buy-in from farmers. In addition, competing interests in the Agriculture sector could be problematic. For example, the livestock subsector is vulnerable to policies that shift crop resources from animal feed production to energy feedstock,[94] so proposed shifts from diesel to biodiesel could be met with resistance. It is important for policymakers to engage with farmers on a farm-to-farm basis to select best practices for each farm as well as for macro-level policies, programs, and incentives.

Costs of Pathway

The technologies to reduce fuel combustion emissions vary in cost and commercial readiness. Biodiesel and biodiesel blends are generally available at many fuel distributors. B20 biodiesel can be interchanged with fossil diesel fuel for use in most conventional diesel-consuming equipment, making it a low-cost decarbonization option since technical upgrades are not required.[95] As of July 2018, the U.S. average fuel price for B20 biodiesel was less than that of fossil diesel—at $3.12 per diesel gallon equivalent (DGE), compared to $3.24 per DGE for fossil diesel. Unblended biodiesel (B100) was $3.91 per DGE.[96]

Smart devices for agriculture are beginning to enter the commercial realm but lack comprehensive cost information that is available to the public. Studies have shown that the capital costs of smart devices and sensors are small, compared to the savings from reduced energy and water costs and increased farm yield. For example, a study of "smart farms" in Vietnam found the total cost of a "Smart Farm IoT Kit," which includes nine devices (e.g., sensors, thermometers, communication devices, relay modules, circuits, and gateways) totaled $103 USD.[97] A larger up-front cost, which may be an obstacle to utilizing certain smart device applications, is the cost of installing wireless access points or infrastructure to ensure internet connectivity on rural farmland.

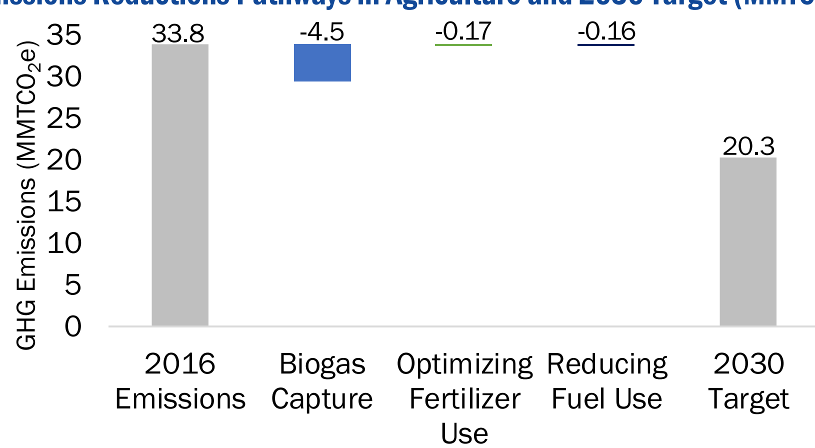
Finally, the costs of electric and energy-efficient farming equipment vary depending on the function the equipment serves. While upfront costs remain a challenge for the deployment of energy-efficient technologies, replacing conventional agricultural machinery and equipment with energy-efficient alternatives at the end of its useful life provides future savings on fuel costs that generally make up for any additional capital costs.

Conclusion

While reducing emissions in the Agriculture sector is possible and important, achieving a 40 percent reduction from current levels will be challenging due to the unique emissions profile of the sector (i.e., mainly non-combustion emissions). Figure 6-11 shows the emissions reduction potential from the three pathways assessed in this study, which total 4.8 $MMTCO_2e$. A prudent overall strategy for California may be to focus on achieving greater than 40 percent reductions in other sectors to compensate for the difficulties in achieving significant emissions reductions in Agriculture.

Figure 6-11

Emissions Reductions Pathways in Agriculture and 2030 Target ($MMTCO_2e$)



While there are pathways for addressing emissions in Agriculture, it is unlikely that the sector will reduce its emissions 40 percent by 2030; therefore, overcompensation in other sectors with more feasible pathways is necessary. Source: EFI, 2019.

BIOGAS AND RENEWABLE NATURAL GAS ADDENDUM

Biogas is a methane-rich unconventional energy resource that commonly occurs through anaerobic digestion (biochemical decomposition of organic matter) or thermal gasification (breakdown of biomass into non-condensable gases).[98] Primary sources of biogas include the following:[99]

- Landfills
- Livestock manure
- Wastewater treatment facilities
- Crop residues
- Forestry products and residues
- Other municipal solid waste ([MSW]; e.g., food waste from manufacturing facilities, grocery stores, and restaurants; leaves; and grass clippings)

Capturing biogas from these feedstocks prevents passive methane emissions and can provide several energy services, as biogas can be used for power generation or processed into RNG. RNG, also known as biomethane, is biogas that has been processed to meet certain purity standards. The intended use of biogas determines the extent to which it will need to be processed to remove impurities (e.g., CO_2) or upgraded (e.g., improve methane content) prior to final consumption.

Once biogas has been processed into RNG it can enter conventional natural gas pipelines. For this reason, converting biogas to RNG enables gaseous waste streams to be monetized and provide energy services across different sectors for any natural gas end use. Generally speaking, RNG has the same properties as natural gas. For this reason, it can be consumed by the Buildings, Transportation, Industry, and Electricity sectors in place of conventional natural gas.

Currently, many biogas producers burn the captured biogas at the site of production, either to produce thermal energy, electricity, or a combination for onsite use. Electricity may also be produced and then sold to a utility, for whom it counts as a low-carbon, renewable resource in California.[100] Any of these options avoids the need to upgrade the biogas to RNG, and the need for transmission (whether by pipeline or some other means). RNG provides more flexibility of use and may be more useful to decarbonization efforts in sectors with high natural gas use and limited abatement opportunities.

Emissions Accounting and RNG Estimation Methodology

As the state with the largest biogas potential,[101] California is well positioned to further expand its deployment of biogas projects to achieve its ambitious decarbonization goals.

Biogas capture reduces emissions in the sectors producing methane (Agriculture and, within the Industry sector, the Wastewater Treatment, Landfills, and Solid Waste Treatment subsectors) and RNG use can reduce emissions in the consuming sectors (Industry, Buildings, Electricity, and Transportation). To determine the emissions benefits of biogas capture and RNG use, this analysis developed an emissions accounting framework utilizing previous RNG studies to (1) determine an estimate for the potential for RNG production and import into California and (2) allocate emissions savings between the producers of biogas and consumers of RNG.

Emissions Accounting Framework

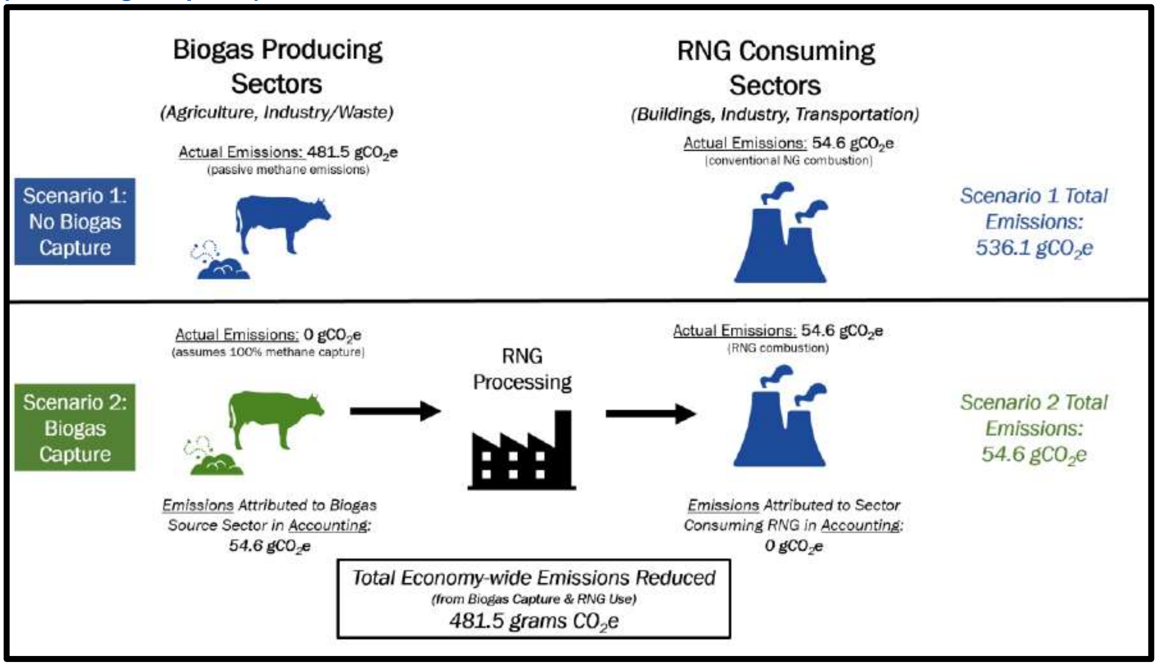
To create a coherent emissions accounting framework, the analysis first compared the emissions intensity of methane and CO_2. When natural gas is combusted, it produces CO_2, which on a CO_2e basis has a global warming potential (GWP) that is 8.5 times lower than passive methane emissions. For example, if a landfill emitted one standard cubic foot (scf) of methane, it would emit 481.5 grams CO_2e; [102] however, if that methane was captured, converted to RNG, and combusted, the resulting emissions would be about 54.6 grams CO_2e. [103]

Because of the differences in GWP, capturing, upgrading, and combusting one scf of biogas (to replace one scf of conventional natural gas) saves approximately 481.5 grams CO_2e in the passive methane-producing sector (Agriculture and the Industrial subsectors listed above) and none from the methane-consuming sector (Industrial, Buildings, Transportation, and Electricity). However, in order to incentivize the consuming sectors to utilize RNG (instead of conventional natural gas), the analysis attributed 11.3 percent of the savings (equivalent to the amount of emissions produced by combusting one scf of natural gas) to the consuming sector. This accounting enables RNG to be considered a zero-carbon fuel and allows the consuming sectors to consider RNG consumption as a decarbonization pathway.

The remaining 88.7 percent of savings is attributed to the producing sectors (i.e., Agriculture, and within Industry, the Wastewater Treatment, Landfills, and Solid Waste Treatment subsectors). The savings to the producing sector only apply to certain feedstocks--those that would otherwise have passive methane emissions.[i] Figure 6-12 shows the GHG accounting approach for the economywide emissions reduction potential of biogas and RNG pathways.

[i] See "Exceptions to Double-Counting Emissions Benefits" section below.

Figure 6-12
Sample In-State Biogas Emissions Accounting Scenario
(1 scf of biogas captured)



The emissions accounting methodology in this study distributes the emissions reductions benefits between the biogas producing sectors and the RNG consuming sectors to incentivize RNG consumption. Source: EFI 2019. Graphics from the Noun Project.

The accounting method in this analysis differs from two methods used by CARB to measure the emissions impact of biogas. In CARB's emissions inventory, sources of methane with capture-in-place have lower GHG emissions, *and* combusting biogas is considered carbon-neutral. This method potentially overstates the savings from biogas by treating the entire process as if it produced no emissions. On the other hand, CARB's methodology for calculating carbon intensities for RNG under the California Low Carbon Fuel Standard (LCFS) *does* take into account the GHG emissions from combustion into account. The final carbon intensity number involves subtracting the savings from RNG production from the combustion emissions (resulting in a negative carbon intensity, i.e., carbon savings). The LCFS methodology is not usable here because it factors in the lifecycle emissions of the fuel (e.g., energy use in biogas production, RNG transportation), and does so on a case-by-case basis for different RNG producers.

Biogas Capture Rates

Biogas capture rates range widely from 20 percent to 78 percent and vary by the type of biogas capture project type.[104] For example, landfill biogas projects sometimes have lower emissions savings because they do not constantly capture the methane, so there are periods during the day when methane is emitted into the air. A California dairy-manure biogas project collected manure from 14 dairy farms and brought the feedstock to a centralized anaerobic digestion facility. The net-emissions savings from this project was 58 percent.[105] Based on the range of capture rates, this analysis estimates 50 percent capture of passive methane emissions to calculate potential emissions savings attributable to biogas capture in the producing sector.

Exceptions to Double-Counting Emissions Benefits

There are exceptions to double-counting emissions benefits, which include out-of-state biogas, biogas produced that would not naturally be emitted as methane, biogas from feedstocks not currently included in CARB's GHG emissions inventory, and biogas from feedstocks that are currently combusted as CO_2.

The emissions accounting methodology used in this study provides an incentive to import out-of-state RNG, as this gas would not otherwise provide emissions benefits to California. For in-state biogas, 100 percent of the emissions savings are attributable to California, but for out-of-state biogas, California would only get 11.3 percent of the savings.

Since anaerobic digestion and thermal gasification can cause feedstocks to emit more methane than would be emitted under natural conditions, not every cubic foot of biogas produced would have been emitted as waste methane.[106] For the extra volume of biogas produced because of this, there is a benefit to the consuming sector but *not* the producing sector.

The additional benefit to the producing sector is also not generated in cases where biogas production happens in lieu of either the feedstock or gas being combusted (e.g., crop residues that are burned or landfills that capture and flare gas). Nor is it generated when forestry wastes are used, since the gaseous waste streams diverted in those cases are non-anthropogenic and therefore are not part of California's emissions inventory. In all these cases, however, biogas still decreases emissions in the consuming sector by enabling conventional natural gas to be replaced with RNG.

RNG Potential in California

To estimate California's RNG production potential, this analysis used the average of the high and low estimates determined in a 2017 analysis from ICF (Box 6-1).[107] Taking the average of ICF's range of RNG production potential, this analysis estimated California's in-state RNG production potential to be approximately 156.6 Bcf per year. To determine out-of-state RNG potential that could be used in California, the analysis used 2014 estimates from the National Renewable Energy Laboratory (NREL)[108,j] of the biogas feedstock potential in 11 states (Arizona, Colorado, Idaho, Nevada, New Mexico, Oklahoma, Oregon, Texas, Utah, Washington, and Wyoming) with interstate pipeline connections to California.[109] The total potential for these 11 states adds up to 80.9 Bcf. The analysis assumed that half that potential—40.4 Bcf—could feasibly be used by California in 2030.

[j] NREL's estimates were used because ICF's report, which was used for in-state calculations, did not include state-by-state data for states other than California.

The availability of RNG from other states will be dependent on a number of factors. New decarbonization policies at the federal level or in neighboring states may make it more advantageous for those states to use their RNG in-state. New programs could also facilitate California's use of RNG from states without physical transmission infrastructure, namely by using credits to convey the carbon benefit of biogas capture and RNG use. Credit systems could include extant systems like the federal Renewable Fuels Standard (RFS) or California's LCFS, or some other system designed more specifically for biogas or RNG. In the near-term, California is likely to have access to biogas from other states because it is at the forefront of decarbonization efforts. For example, RNG from 15 other states and provinces (nine of them east of the Mississippi River) has been certified under the LCFS and nominally transported to California via pipeline or truck.[110]

Combined with the calculated in-state potential, the total RNG potential available to California would be 197.0 Bcf per year. Table 6-2 details the RNG potential, both in-state and imported, for each biogas feedstock. In 2016, natural gas consumption in California was 2.17 Tcf,[111] meaning this amount of RNG could replace approximately 9 percent of supply. Projections vary for natural gas consumption in 2030; however, this analysis in other chapters includes pathways that would lead to use increases from some sectors (e.g., Transportation, Industry) and decreases from others (e.g., Electricity).

Table 6-2
Technical Potential for Primary Sources of RNG

Sector	Biogas Source	In-State RNG Potential (Bcf/year)	Out-of-State RNG Potential Available to CA (Bcf/year)
Industry	Wastewater Treatment	5.65	12.2
	Landfills	38.4	13.3
	Solid Waste Treatment	36.3	6.1
Agriculture	Livestock Manure	15.5	8.8
	Agricultural Residue	31.05	*No data*
Other	Forestry and Forest Product Residue	29.7	*No data*
Total		*156.6*	*40.4*
Grand Total (In-State and Out-of-State)		***197.0***	

Source: EFI, 2019. Using data from ICF, 2017; NREL, 2014.

Box 6-1

Comparing Navigant, ICF, and EFI RNG Estimates for Decarbonization of the Buildings Sector

A 2018 study by Navigant Consulting[112] determined the amount of RNG needed to achieve the same GHG emissions reductions in Buildings as in its appliance electrification scenario.[113] Navigant assumed that "sufficient R[N]G is available to meet the requirements in the California building market" in the service territory of the Southern California Gas Company and referenced ICF's data[114] regarding RNG supply availability and constraints.[115] ICF determined that 104.9 to 208.3 Bcf per year was the in-state RNG production potential for California.[116] ICF did not determine an out-of-state potential estimate; however, it cited other studies, which estimated 932 to 9,230 Bcf per year throughout the entire United States.

This is different than EFI's approach to estimating RNG potential. As mentioned previously, EFI took the average of ICF's high and low estimates to determine the potential RNG available to California, which was 156.6 Bcf per year from in-state sources and 40.4 Bcf per year from out-of-state sources. To determine the potential RNG available for import, EFI assumed the availability of half of NREL's estimate of the biogas potential in 11 states with gas pipeline infrastructure that connects to California. EFI used this estimate, rather than the amounts ICF listed for the entire United States, due to demands for RNG elsewhere in the United States and uncertainties with transportation and costs. This results in 197.0 Bcf per year of RNG available to California.

According to Navigant, in 2030, RNG will comprise 12 percent, 23 percent, 46 percent, or 63 percent of gas use in Buildings in their scenarios for Normal Replacement (25 percent), Normal Replacement (50 percent), Normal Replacement (75 percent), and Overnight (by 2020) Conversion of gas appliances to electricity, respectively. Based on CEC natural gas demand growth projections to 2030, gas demand in buildings will be 673 Bcf.[117,118] Using Navigant's percentages above, EFI determined the amount of RNG necessary to meet Navigant's projections for Buildings throughout California (not just in the service territory of Southern California Gas).

Table 6-3
RNG Requirement Calculation Using Navigant's Estimated Proportions for Buildings and CEC Gas Demand Forecasts

Scenario	Percent of Buildings Gas Use	RNG (Bcf/yr)
Normal Replacement (25%)	12%	80.8
Normal Replacement (50%)	23%	154.8
Normal Replacement (75%)	46%	309.7
Overnight Replacement	63%	424.1

Source: EFI, 2019. Using data from Navigant, 2018.

Table 6-3 shows that Navigant's projected RNG proportions in the Normal Replacement (75 percent) and Overnight Replacement Scenarios results in a greater amount of RNG than EFI calculated is available to California. This amount is also greater than the amount of RNG that ICF calculated is available in California. The Normal Replacement (50 percent) Scenario, however, is in line with EFI's estimates.

Navigant also calculated the percentage of RNG in total gas throughput in 2030: 4 percent, 8 percent, 16 percent, and 22 percent in its scenarios for Normal Replacement (25 percent), Normal Replacement (50 percent), Normal Replacement (75 percent), and Overnight Conversion, respectively.[119] Again, using Navigant's proportions, EFI determined the RNG (in Bcf per year) that each scenario would need in Table 6-4.

Again, the Normal Replacement (75 percent) and Overnight Replacement scenarios require more RNG in the system than EFI estimates will be available; however, the Normal Replacement (50 percent) scenario is in line with EFI's estimates of RNG availability.

Table 6-4
RNG Requirement Calculation Using Navigant's Estimated Proportions for Total Gas Throughput and CEC Gas Demand Forecasts

Scenario	Percent of Total Gas Throughput	RNG (Bcf/yr)
Normal Replacement (25%)	4%	51.6
Normal Replacement (50%)	8%	103.2
Normal Replacement (75%)	16%	206.4
Overnight Replacement	22%	283.8

Source: EFI, 2019. Using data from Navigant, 2018.

Emissions Savings from Reduced Fossil Natural Gas Use

Using the RNG potential estimated above and the emissions accounting framework in this analysis, emissions savings from replacing 197.0 Bcf of conventional natural gas would be about 10.8 $MMTCO_2e$ (using a value of 54.6 grams CO_2e per scf of natural gas; CARB provides different values for different natural gas uses, so the actual number could vary).[120]

Emissions Savings from Reduced Methane Emissions

Savings from the subsectors where waste methane could be diverted through biogas capture—Manure, Wastewater, Landfills, and Solid Waste Treatment—add up to 8.8 $MMTCO_2e$, which was 23 percent of California's economywide methane emissions in 2016 (38.93 $MMTCO_2e$). This does not include emissions savings from sources mentioned above where the "double benefit" is not available (e.g., crop residues, forestry wastes), which are not included in or currently count as sources of methane in the CARB inventory.

Table 6-5
California Methane Emissions by Sector, 2016

Sector	Emissions Source(s)	Methane Emissions ($MMTCO_2e$)	% of Total Methane Emissions	Biogas Source?
Electricity	All Sources	0.20	0.51%	No
Transportation	All Sources	0.24	0.61%	No
Buildings	All Sources	0.05	0.13%	No
Agriculture	Energy Use	0.00	0.01%	No
	Residue Burning	**0.03**	**0.07%**	**Yes***
	Rice Cultivation	0.83	2.13%	No
	Enteric Fermentation	11.35	29.16%	No
	Manure Management	**10.17**	**26.13%**	**Yes**
Industrial	Fuel Combustion and Storage	0.10	0.26%	No
	O&G Production, Refining, Marketing	1.94	4.99%	No
	Wastewater Treatment	**1.07**	**2.75%**	**Yes**
	Landfills	**8.47**	**21.75%**	**Yes**
	Solid Waste Treatment	**0.23**	**0.60%**	**Yes**
	Transmission and Distribution (Pipelines)	4.06	10.43%	No
	Other Industrial	0.18	0.47%	No
Total methane emissions: 38.93 $MMTCO_2e$				
Total from potential biogas sources: 19.97 $MMTCO_2e$				

**Note: Agricultural residue is a source of biogas, but most of its emissions currently are in the form of CO_2, and therefore are not represented here and not included in the emissions savings calculation.* Source: EFI, 2019. Compiled using data from CARB, 2018.

The estimate for avoided emissions uses the assumption of a 50 percent capture rate for all methane in these subsectors, as well as the accounting procedure (described above in Figure 6-12) that this analysis used to distribute biogas savings among sectors. Specifically, this analysis divided the 2016 emissions in the biogas producing sectors (in boldface in Table 6-5) by two (representing 50 percent capture rates) and multiplied that number by 88.7 percent, consistent with the emissions accounting procedure described above.[k] The analysis projects that maximized biogas capture and RNG usage in California could add up to emissions reductions of 19.6 $MMTCO_2e$ economywide (10.8 $MMTCO_2e$ in the RNG consuming sectors and 8.8 $MMTCO_2e$ in the biogas producing sectors). This number does not count the savings from diverted waste streams in the biogas exporting states.

Because this study uses a sector-by-sector approach for its analysis through 2030, it is necessary to allocate those savings among the various sectors. The savings from diverting gaseous waste streams are 4.5 $MMTCO_2e$ for the Agriculture sector and 4.3 $MMTCO_2e$ for the Industry sector (mainly from the Landfills and Wastewater Treatment subsectors). These savings are derived from the 2016 levels of usable emissions; they are likely independent from any sectoral policies, as biogas capture itself is the main policy for methane emissions mitigation in these subsectors.

The method for estimating the carbon mitigation potential of RNG is agnostic to which sector the RNG is used in. The key estimate is the economywide savings from the use of 10.8 $MMTCO_2e$ worth of biogas emissions. By adding carbon-neutral RNG to the state's natural gas supply, each gas-consuming sector will reduce its emissions proportional to the amount of natural gas (fossil and renewable) it consumes. For example, if the state's natural gas supply is 10 percent RNG, then the Buildings sector, which produced 33.7 $MMTCO_2e$ of emissions from natural gas combustion in 2016,[121] would reduce its emissions by 3.37 $MMTCO_2e$ (10 percent).

Table 6-6
2030 Emissions Savings from Biogas and RNG by Sector

Sector	Savings from Biogas Capture ($MMTCO_2e$)	Savings from RNG Use ($MMTCO_2e$)	Total Savings ($MMTCO_2e$)
Agriculture	4.5	-	4.5
Industry	4.3	3.6	7.9
Buildings	-	3.6	3.6
Electricity	-	3.6	3.6
Transportation	-	n/a	0
Economywide Total	***8.8***	***10.8***	***19.6***

Source: EFI, 2019

Carbon benefits could be reallocated to sectors that "need" them more through an accounting or credit system that transfers ownership of the RNG's mitigation benefits, but the overall savings to the economy would be the same. The analysis has assumed no such system; if it did exist, it would have no effect on the economywide savings. Instead, the analysis has allocated these savings equally across the three primary gas-consuming sectors: Buildings, Industry, and Electricity. In 2016, these three sectors consumed approximately equal volumes of natural gas (with much smaller percentages consumed by the Transportation and Agriculture sectors).[122] Thus, each of these sectors would reduce emissions by approximately 3.6 $MMTCO_2e$. The breakdown of emissions savings by sector is found in Table 6-6.

[k] Values in table may not sum to 8.8 MMTCO2e due to rounding

Benefits of Biogas Capture and RNG Use in California

Biogas capture reduces passive methane emissions from the Agriculture and Industry sectors and can provide monetary benefits to the producers. At the same time, RNG use in the consuming sectors can provide a zero-carbon resource that can be used in place of conventional natural gas.

Reduced Emissions

Capturing biogas is a unique option for reducing economywide emissions in California. Most biogas sources have historically had limited options for decarbonization. Diverting gaseous waste streams and converting them into a useful fuel source provides a double benefit by limiting passive methane emissions from these sub-sectors and then utilizing RNG over conventional natural gas. A net emissions benefit to the economy is generated because, on a CO_2e basis, combusting methane in the form of biogas is 8.5 times better than allowing an equivalent volume of methane to be released into the atmosphere (due mostly to the higher GWP of methane compared to CO_2).

Opportunities for the use of RNG as a zero-carbon fuel in California include on-site power generation using the captured biogas, decarbonized pipeline gas through fuel switching to RNG from conventional natural gas (in the Industry, Electricity, and Buildings sectors), and the displacement of higher-emitting conventional fuels through non-pipeline fuel switching (in the Transportation sector). In all cases, RNG is a net-zero fuel to the consuming sector. While emissions generated at the point of consumption are no different between RNG and natural gas, the consumption of RNG does lead to an equivalent reduction in emissions (at least) from somewhere else. Replacing fossil natural gas with biogas or RNG also has the potential to avoid the upstream emissions generated by the production, transmission, and distribution of conventional gas.

The development of biogas collection projects and competitive RNG markets can be instrumental for California to meet its goal of reducing methane emissions 40 percent by 2030 as required by SB 1383 (enacted in 2016). This bill also requires CARB, in consultation with the CDFA, to implement regulations after January 1, 2024, to reduce methane emissions from livestock and dairy manure operations. Additionally, the bill requires the CEC and the CPUC to consider and adopt policies and incentives to support the production and use of RNG.[123] Additionally, in 2018, California passed SB 1440, which directs the CPUC, in consultation with CARB, to consider specific RNG procurement targets for each gas corporation in the state.[124]

Revenue Generation

In many cases, biogas capture creates a new revenue source for the producer. The energy produced, whether in the form of RNG or electricity generated onsite, can be used by the producer to save costs or can be sold. Other mitigation strategies, such as policies that create financial incentives for parties obligated to comply with California's decarbonization policies, could increase the potential revenue producers receive from captured biogas and/or RNG. For example, electricity generated from biogas counts as a renewable, zero-carbon resource in California, enhancing its value; it also qualifies for

RECs. RNG qualifies as an advanced biofuel under the federal RFS[125] and is eligible to generate offset credits under California's Low Carbon Fuel Standard (LCFS). Biogas capture is also a qualifying offset protocol for California's cap-and-trade program. Table 6-7 highlights the value of dairy manure-derived RNG in a variety of markets.

Table 6-7
Value of Dairy Manure-Dervied RNG from Biogas Under the RFS

Attribute	Value
RNG (D3) RIN Value (February 2017)	$2.60/RIN
RNG (D3) RIN Value (May 2018)	$0.20/RIN
Commodity Natural Gas Value	$2.80/MMBtu
Conversion of MMBtu to RIN	11.7 RINs/MMBtu
Total RNG Value (February 2017)	$2.80 + ($2.60 * 11.7) = $33.42/mmBtu
Total RNG Value (May 2018)	$2.80 + ($0.20 * 11.7) = $5.14/mmBtu

RNG qualifies as an advanced biofuel (as either a D3 or D5 RIN), which obligated parties can use to meet their compliance obligation under the federal Renewable Fuel Standard.[126] Source: Dairy Business.[127]

In addition to revenue from energy production, ADs also produce valuable byproducts such as fertilizers. Some of the fertilizers produced are considered organic (depending on the feedstock), which makes them more highly valued. Digesters that utilize waste from other entities can also collect tipping fees for managing that waste. Furthermore, the AD process in particular produces benefits beyond revenue and emissions mitigation, including greater odor control and water quality protection.[128]

Costs and Challenges for Biogas and RNG in California

While there are several benefits to biogas capture and RNG use in many sectors, there are numerous challenges, including high production costs. Without significant policy support, there will be limits to the extent to which California can realize the full benefits of these pathways.

Cost Considerations and Analysis

There are a number of factors that affect the cost of biogas and RNG production. Factors that impact capital and operational costs include:

- **Feedstock Type:** Analysis by ICF found that, for California, landfill gas is cheaper than digester gas; among biogas feedstocks, wastewater treatment is cheapest, followed by MSW, manure, and forestry or agricultural residue. The latter category is most expensive because it usually requires gasification of the feedstock.[129]
- **Feedstock Quantity and Quality:** Biogas operations are typically only viable when feedstocks are a certain size. Digesters can collect feedstock from multiple sources,[130] but that brings its own costs. Quality of the feedstock also matters, such as the proportion of organic material in a landfill (higher is better) or the type of manure used in a digester (dairy cow manure is most viable).
- **Existing Infrastructure:** Some facilities already collect biogas and flare it; converting such operations to use the gas is cheaper than constructing entirely new facilities.

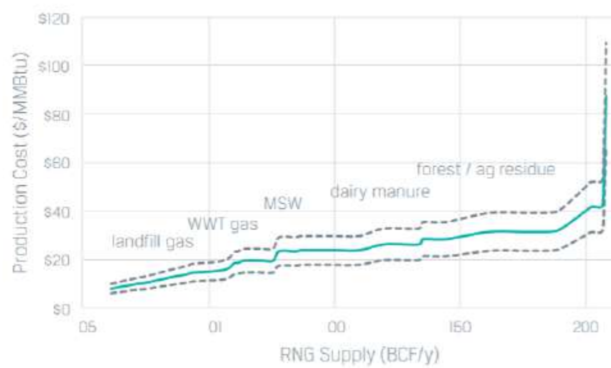
For livestock operations, certain existing manure collection techniques are viable for biogas collection, others are not.

- **Climate:** Warmer climates are typically better for biogas collection, as those conditions accelerate the process of anaerobic digestion.[131,132]
- **Use:** Using biogas onsite for thermal energy or electricity generation (for use or sale) is less expensive than upgrading to RNG. [133] This depends on methane content of the biogas produced; offtake agreements (for electricity or gas); and compression, pipeline, and interconnection costs.

The supply-cost curve for RNG resources in the United States (Figure 6-13) was developed by ICF, and includes national supply estimates of 932 to 9,230 Bcf per year taken from the range provided by three other RNG potential studies conducted by the National Petroleum Council,[134] the American Gas Foundation,[135] and the U.S. Department of Energy.[136] ICF calculates the LCOE for each feedstock and includes the capital costs of the equipment, O&M costs, and financing. ICF applied a discount rate of 5% over a 20-year financing period. The costs pictured below do not include the capital costs or O&M costs of pipeline interconnection.[137]

Figure 6-13

ICF's RNG Supply-Cost Curve for the United States



ICF's estimates for RNG supply and production costs vary significantly based on the feedstock, with landfill gas as the least expensive and forest and agricultural residues as the most expensive. Source: ICF, 2017.

These factors make it difficult to estimate a "typical" cost for a biogas processing facility, though an analysis from Duke University provides some indication of the scale of investment, depending on gas production capacity (Table 6-8).

Table 6-8

Average Costs for Biogas Collection and RNG Processing by Size Category

	Conditioning Unit		Compressor Unit		Collection Equipment		
Size category (scf/hr.)	Capital cost	O&M	Capital cost	O&M	Capital cost	O&M	Electricity cost
6,000	$845,000	$36,535	$132,500	$9,465	$165,180	$375	$7,416
21,000	$2,270,000	$86,600	$200,000	$16,400	$578,130	$1,313	$25,956
42,000	$3,000,000	$132,000	$225,000	$45,500	$1,156,260	$2,625	$51,912
72,000	$3,800,000	$315,100	$325,000	$119,900	$1,982,160	$4,500	$88,992
120,000	$5,200,000	$526,200	$450,000	$193,800	$3,303,600	$7,500	$148,320
300,000	$8,600,000	$1,276,000	$600,000	$474,000	$8,259,000	$18,750	$370,800

Source: EFI, 2019. Compiled using data from Duke University, 2014.[138]

The Duke study also indicated that for a dairy facility between 1,000 head of cows and 1,999 head of cows (the average number of mature cows at a candidate farm for a digester in California[139]) and a complete-mix digester, the capital costs without upgrading to RNG would be around $1.2 million and operations and maintenance (O&M) costs would be around $438,000 annually. With upgrading to RNG, those numbers would be around $2.0 million in capital costs and $475,000 in annual O&M costs. A much larger landfill gas project would have similar or lower costs—about $1.1 million in capital costs and $191,000 in annual O&M costs for a 40-acre collection system.[140]

On the other hand, the Heartland Digester project in Colorado, which until 2017 was selling RNG to the Sacramento Municipal Utility District, had capital costs of $102 million for a much larger project.[141] Larger projects such as Heartland, that collect feedstock from a variety of sources, may become more common.

RNG is not cost-competitive with conventional gas without some form of price support. The 2017 citygate price for natural gas in California was $3.45 per MMBtu;[143] the national analysis from Duke found that the breakeven price for the majority of the technically available RNG supply was $8 per MMBtu, and that 99 percent would be available at $9 per MMBtu. A study from UC-Davis found that California supply might need even greater price support, requiring between $3.75 per MMBtu and $26 per MMBtu, depending on the feedstock (Table 6-9).

Table 6-9
Minimum Required Price Support for RNG in Conventional Gas Markets

Source	Price Support ($/MMBtu)
Municipal Solid Waste	11.50
Landfill	3.75
Wastewater Treatment Facility	5.90
Dairy	26.00

This table shows the price support needed to make RNG derived from various feedstocks competitive in the conventional natural gas market. Source: EFI, 2019. Compiled using data from UC-Davis, 2017.[142]

A particular concern is the cost associated with getting RNG into the pipeline. Injecting RNG into a pipeline system may be more useful than on-site power generation from a mitigation perspective, but it is also expensive and requires specific policy attention. Proximity to a pipeline makes a huge difference in terms of capital costs: pipeline extension can cost up to $1 million per mile.[144] Upgrading RNG to pipeline-quality gas alone can add substantial costs. Without subsidies, processing landfill gas typically costs $4 to $6 per MMTBtu, which on its own is greater than the price of conventional gas;[145] costs for other feedstocks could be even higher.[146]

A variety of policies provide some subsidies for biogas production. As mentioned above, cross-cutting programs, such as the LCFS and RFS provide price support. There are also policies designed to reimburse distributed energy producers for the energy they generate, such as SB 1122 (enacted in 2012)[147] which created California's Bioenergy Feed-in Tariff Program and AB 970 (enacted in 2000),[148] which created the Self-Generation Incentive Program. There are also cost-sharing mechanisms for particular parts of the RNG production process, such as AB 2313 (enacted in 2016),[149] which expanded a program through the CPUC that allows RNG project developers to be reimbursed for interconnection costs into a local natural gas distribution network. The reimbursement amount was increased from $1.5 million to up to $3 million (or up to $5 million for dairy RNG projects that are clustered together). In September 2018, the state passed AB 3187, which requires the CPUC to open a proceeding to consider a cost recovery incentive program for investments in RNG projects by July 1, 2019.[150] Additionally, some biogas production facilities can take advantage of subsidies for agricultural operations or rural infrastructure from a variety of government entities such as EPA and USDA.

Other Challenges

The largest concern about the feasibility of the RNG pathway is the availability of feedstock. While the estimates of the full resource potential vary, they tend to be in the 100-200 Bcf per year range for California[151] and another 932 to 9,230 Bcf per year for the rest of the country.[152] California has the nation's largest resource potential.[153] However, even if California leveraged its full in-state biogas potential, as well as a large share of potential out-of-state imports, it still would account for a relatively small share of total gas demand (approximately 9 percent). Without the necessary feedstock, California will not be able to leverage the full extent of the RNG pathway.

Regulatory uncertainty is another challenge to the development of an RNG market. In 2005, regulatory programs for AD projects were established but compliance was found to be challenging, including delays in the design approval process.[154] The permitting process for biogas projects is still considered difficult to navigate, due in part to different processes throughout the state.[155] To help ameliorate some of these concerns, California now offers a permitting process known as Consolidated Permitting that allows applicants for ADs to have their permitting needs coordinated through a single agency.[156]

Finally, there is relatively little public awareness of biogas and the benefits it can provide.[157] A federal interagency road-mapping exercise on the opportunities for biogas in the United States, identified a lack of public awareness of the benefits of biogas as one of the six major barriers to the establishment of a robust national biogas industry.[158]

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PART 3

MEETING CALIFORNIA'S DEEP DECARBONIZATION TARGETS BY MIDCENTURY

CROSS-CUTTING TECHNOLOGIES AND A BREAKTHROUGH INNOVATION PORTFOLIO

CHAPTER 7
CROSS-CUTTING PATHWAYS FOR DECARBONIZATION IN CALIFORNIA

FINDINGS

There are four clean-energy pathways that cut across multiple sectors of California's economy that offer significant decarbonization potential due to their reach and scalability.

In addition to sector-specific opportunities for emissions reductions, four cross-cutting technological pathways can further reduce greenhouse gas emissions across multiple sectors of California's economy. These four technology pathways enable and use large-scale carbon management systems; hydrogen applications; leveraging of California's existing carbon infrastructure; and smart systems and platform technologies. Achieving the potential of these technology pathways will require substantial public and private sector investment, new business models and markets, supportive regulatory frameworks, and—in a number of cases—coordination and collaboration among traditional and non-traditional energy stakeholders. While there are specific cross-cutting technologies within these pathways that are commercially available today, the development and adoption of these pathways—at the scale required to transform California's energy systems—will require long lead times.

Large-scale carbon management is essential for achieving long-term deep decarbonization.

There are no realistic clean-energy pathways that eliminate carbon dioxide (CO_2) from California's economy without large-scale carbon management (LSCM). LSCM is a broad pathway that generally involves a multistep process in which CO_2 is removed from dilute sources (e.g., the atmosphere and oceans) or concentrated sources (e.g., emissions from power plants and industrial facilities) and is then either used for commercial products or stored in geologic formations. It includes carbon capture, utilization, and storage and direct-air capture. LCSM technologies are especially important for reducing emissions from difficult-to-decarbonize sectors that may lack other suitable decarbonization options.

Hydrogen's use as a storable clean fuel across multiple sectors, including in the most difficult-to-decarbonize applications, makes it a valuable clean energy pathway that promotes optionality and system flexibility.

Hydrogen has many possible uses, but four key applications with significant potential are replacing natural gas turbines with hydrogen turbines; energy storage for the electric grid; heavy-duty vehicles; and industrial energy and feedstock uses.

Leveraging California's existing carbon-based energy infrastructure, technological expertise, and skilled workforce could smooth the transition to a deeply decarbonized economy by accelerating implementation, lowering costs, decreasing stranded asset risk, and preserving or improving skilled employment.

Repurposing California's existing carbon infrastructure—a highly-engineered system-of-systems that spans thousands of miles and employs more than 100,000 people—could be utilized to enable, accelerate, and improve the performance of the energy sector's transition to a deeply decarbonized economy.

Smart technologies that use data, connectivity, and analytics to improve the performance of new and legacy systems offer a pathway to deep decarbonization and can unlock new economic and social value.

Economywide trends suggest that widespread digitalization and the rapid expansion of smart technologies could lead to technology breakthroughs with long-lasting impacts on society, energy, and the environment. These platform technologies can be used to support decarbonization by optimizing performance based on emissions; advancing levels of efficiency, reliability, and resilience; and creating new business models that enable a range of new technologies and services. Realizing the full benefits of smart technologies will require leveraging both existing and emerging platform technologies. The result will be more granular, coordinated, and holistic views of the energy sector that will improve the decision-making of system operators, investors, planners, and emergency responders.

Current pilot projects for direct-air capture and hydrogen technologies demonstrate the potential of these options.

Three companies—Carbon Engineering, Climeworks, and Global Thermostat—are operating pilot plants with direct-air capture technology. The first fuel cell-powered trains, by Alstom, began running a 62-mile route in Germany in 2018, and Alstom plans to deliver another 14 trains by 2021. Easy Jet is developing a hybrid engine system that would use fuel cells during taxiing. Home Depot has deployed 28 MW of fuel cells at its stores in the United States. These projects will be important to shaping the future direction of the clean energy transition.

The investment capacity of large oil and gas companies is supporting clean energy technologies—with significant long-term potential benefit to the clean energy transition.

In 2018, select global oil and gas companies invested around 1 percent of their capital expenditures in clean energy technologies. Based on a review of the annual reports and financial documents of a group of oil and gas firms, 17 firms that cover the entire oil and gas supply chain invested over $9.5 billion on clean energy firms and technologies in 2018. These firms have arguably the world's greatest technical potential to create the clean energy system of the future; in general, the scale of future energy services will require companies of significant capacity.

EMISSIONS REDUCTION POTENTIAL OF CROSS-CUTTING TECHNOLOGIES

Deep decarbonization will require tailored solutions that draw from a portfolio of mitigation strategies for each economic sector in California. There are also several cross-cutting pathways that can assist with decarbonization across multiple sectors of California's economy. These include large-scale carbon management, hydrogen applications, leveraging existing carbon infrastructure and expertise, and smart systems and platform technologies (Figure 7-1). Individual technologies within these pathways may be commercially available today; however, these cross-cutting pathways have special scalability and decarbonization potential that could lead to substantial and lasting emissions reduction across California's economy.

Pathway 1. Large-Scale Carbon Management. Large-scale carbon management (LSCM) involves carbon capture, utilization, and storage (CCUS) from both concentrated sources (e.g., stationary-point emitters) and dilute sources (e.g., the atmosphere and oceans). LSCM could, through wide-scale innovation, help reduce emissions from difficult-to-decarbonize sectors that currently lack suitable decarbonization options (e.g., heavy

Figure 7-1

Cross-Cutting Pathways for Decarbonization

Major Technology Cross Cuts	Electricity	Transportation	Industry	Buildings	Agriculture
Large-Scale Carbon Management	Creates emissions reduction buffer for extremely hard to decarbonize processes		Reduces carbon from atmosphere and oceans, from diffuse and concentrated sources	Creates potential market for carbon-based products in Buildings (materials), Transportation (fuels), and Agriculture (greenhouses)	
Hydrogen	Can be used for grid balancing, or as end use for excess renewables	Can provide clean fuel for all vehicle classes	Can meet requirements for process heat, or be used as clean feedstock	Can be blended with natural gas for all end use needs	Can provide fuel for farming systems
Leveraging Carbon Infrastructure/ Expertise	Cleaner fuels (RNG, H_2) can be co-fired with natural gas	Existing networks can carry and store clean fuel alternatives	Refineries and terminals can blend, store, and consume clean alternatives	Existing distribution pipes can carry natural gas doped with H_2, RNG	Can access markets with biomass-based products
Smart/Platform Technologies	Smart sensors and controls improve efficiency and resilience	Autonomous vehicles, on-road and in-vehicle sensors improve safety and lower fuel use	Automation and additive manufacturing decrease fuel use and other costs	Improved building management can cut cost and connectivity improves livability	Data analytics can improve yields, lower costs

There are overlaps in the cross-cutting technology areas with breakthrough potential. The overlaps described here are illustrative, not inclusive. Source: EFI, 2019.

industry). LSCM could also meet the need for carbon dioxide (CO_2) removal from the environment, a need that the UN Intergovernmental Panel on Climate Change (IPCC) projects at the scale of 100 billion to 1 trillion metric tons of CO_2 over the 21st century, to limit global warming to 1.5 degrees Celsius.[1]

Pathway 2. Hydrogen Applications. Hydrogen is an energy carrier that can be produced in multiple ways for end uses across the Electricity, Industry, and Transportation sectors. Low-carbon hydrogen (e.g., electrolysis with a clean grid; steam-methane reforming (SMR) of natural gas with CCUS) has a considerable potential to help decarbonize high-temperature process heat in Industry; as a seasonal storage medium for Electricity; or as a fuel for Transportation, including heavy-duty vehicles (HDVs).

Pathway 3. Leveraging Existing Carbon Infrastructure and Expertise. Decarbonization pathways are as much about infrastructure as they are about technology. The transition to a low-carbon future could be accelerated by seeking opportunities to leverage existing infrastructure, technological expertise, and a skilled and readied workforce. Repurposing existing carbon infrastructure—highly engineered systems-of-systems that span thousands of miles across California and employ more than 100,000 people with high-value skillsets—could enable, accelerate, and improve the energy sector's transition to a deeply decarbonized economy.

Pathway 4. Smart Systems and Platform Technologies. The rapid development of digital, data-driven, and smart systems—largely from outside the energy sector—has unlocked the potential of other "platform technologies" that could be scalable across the entire energy value chain. These platforms can be used to support decarbonization by optimizing performance based on emissions, advancing levels of reliability and resilience, and creating new business models that enable new services.

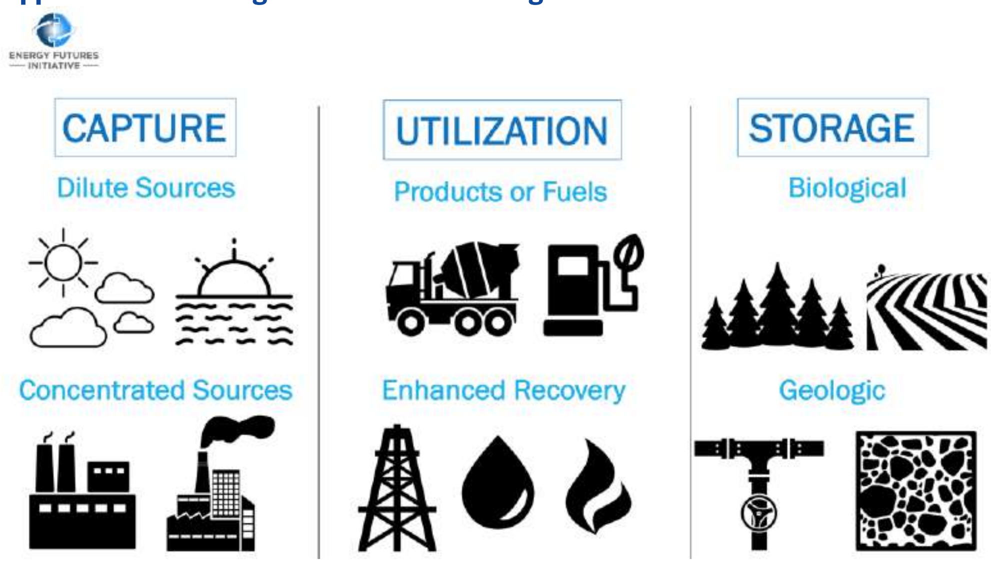
Large-Scale Carbon Management

In 2018, Governor Brown signed Executive Order B-55-18, which established the goal of reaching economywide carbon neutrality by 2045, and then net-negative emissions thereafter. For California to reach carbon neutrality and beyond, the state will depend heavily on CCUS and negative-emissions technologies (NETs) to either directly prevent emissions (e.g., point-source capture of CO_2) or remove carbon directly from the environment (e.g., direct-air capture, or DAC).

As noted, certain sectors of California's economy have limited options for decarbonization in the 2030 timeframe, including (but not limited to) Industry, Agriculture, and HDVs in Transportation. These difficult-to-decarbonize sectors and subsectors accounted for more than 23 percent of statewide emissions in 2016; this makes achieving economywide carbon neutrality by midcentury especially challenging.

LSCM is a broad technology area that generally involves a multistep process in which CO_2 is removed from dilute sources (e.g., the atmosphere and oceans) or concentrated sources (e.g., emissions from power plants and industrial facilities) sources and is then either used for commercial products or stored in geologic formations (Figure 7-2). For utilization, captured CO_2 can be compressed and transported to merchant markets (e.g., the beverage industry), converted into products or fuels (e.g., cement), or used for the enhanced recovery of hydrocarbons (e.g., enhanced oil recovery [EOR]).

Figure 7-2
Opportunities for Large-Scale Carbon Management



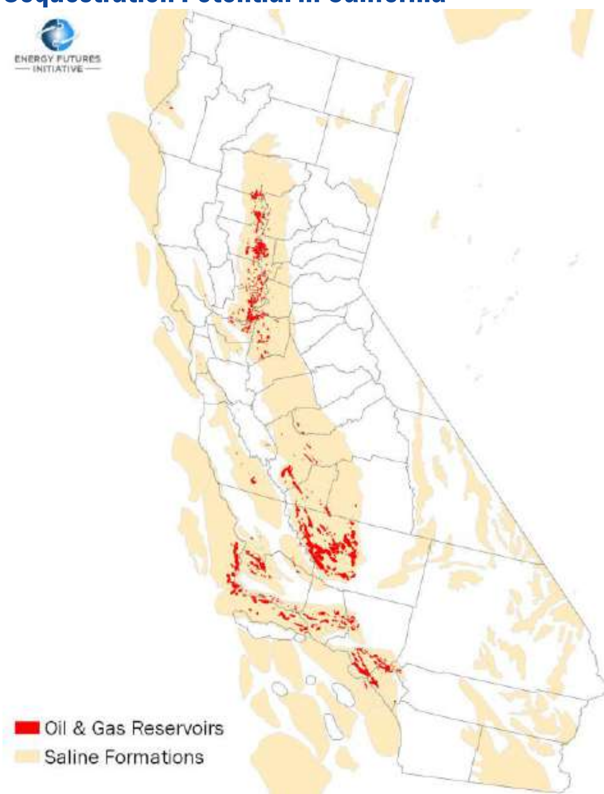
Large-scale carbon management includes CO_2 capture from dilute and concentrated sources; utilization of captured CO_2 in products, fuels, or for enhanced oil and gas recovery; biological storage of CO_2 through photosynthesis or geologic sequestration in locations such as saline formations and oil and gas reservoirs. Source: EFI, 2019. Graphics from the Noun Project.

Alternatively, carbon may be injected underground for long-term or permanent storage in various geologic formations such as saline aquifers and oil and gas reservoirs. There are 18 operational large-scale CCUS facilities worldwide, with another 26 in various stages of development.[2] California has some of the largest geologic storage potential for CO_2 in the nation (Figure 7-3), ranking in the top five states for storage potential in oil and natural gas reservoirs, and in the top ten states for storage potential in saline formations. Recent estimates suggest that California has up to 424 billion metric tons of geologic storage capacity for CO_2, enough to permanently sequester its annual economywide emissions at current levels for around 1,000 years.[3]

The IPCC has identified CCUS as one of the pathways to limit global warming to the levels adopted under the Paris Agreement.[4,5] The Global CCS Institute concluded that 14 percent of global greenhouse gas (GHG) emissions reductions will need to be met through CCUS, the equivalent of nearly 2,500 CCUS facilities in operation by 2040.[6]

CCUS was previously excluded from California's Low Carbon Fuel Standard (LCFS) and cap-and-trade programs, because there was no established quantification methodology nor regulatory requirements that described permanent sequestration.[7] CARB has recently developed a protocol that meets the requirements of California's AB 32 and describes a methodology for determining whether a CCUS project leads to permanent CO_2 storage and the corresponding GHG emissions reduction benefits. This protocol has been adopted to allow LCFS credits to be generated by refineries and fuel producers using point-source capture, as well as by producers of low-carbon transportation fuels made using DAC with sequestration. The new CARB protocol is inclusive of both existing and new projects, but does not apply to projects that seek to sequester CO_2 offshore.[8] The inclusion of CCUS in the LCFS program could help to spur investment and overcome historic barriers to deployment which included a lack of policy support relative to other mitigation options, in addition to permitting and regulatory uncertainty.[9]

Figure 7-3
Sequestration Potential in California



California has an estimated sequestration potential of 34 to 424 billion metric tons of CO_2 within saline formations and oil and gas reservoirs. Source: EFI, 2019. Compiled using data from NETL, 2014.

Negative-Emissions Technologies

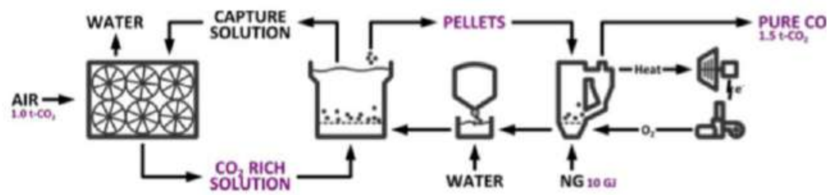
NETs (also known as carbon dioxide removal, or CDR) are a category of technological systems, biological approaches, and technologically enhanced natural processes that directly remove carbon from the ocean or atmosphere. Unlike CCUS technologies, which are designed to be deployed at a power plant or industrial facility, NETs may be disconnected from a specific system. Common NETs include DAC with sequestration, bioenergy with carbon capture and storage (BECCS), enhanced weathering (EW), and terrestrial or coastal CDR.

Direct-Air Capture

DAC involves the chemical separation of ambient air to capture CO_2 for the purposes of utilization or sequestration. Current DAC techniques use large fans that move ambient air through a filter, using a chemical adsorbent to produce a pure CO_2 stream that can then be stored.[10] DACs have inherent placement flexibility; they may be positioned near geologic storage sites, which could reduce infrastructure costs. They may also be used to produce CO_2 products at a market-desired purity.[11] DAC technology is in early stages of development, with only a few demonstration projects worldwide. A company called Global Thermostat has tested a pilot plant in California that captures 1,000 metric tons of CO_2 per year.[12] Another company, Carbon Engineering, has DAC technology that it claims can scale up to one million metric tons of CO_2 per year.[13] A third company, Climeworks, announced its second-generation DAC plant in Italy last year.[14]

Figure 7-4

Carbon Engineering's Direct-Air Capture Process



The major unit operations of Carbon Engineering's DAC system include the air contactor, pellet reactor, slaker, and calciner--which collectively capture, purify, and compress atmospheric CO_2. Source: Carbon Engineering, 2019.

The CO_2 in air is around 300 times more dilute than the flue gas from a coal-fired power plant,[15] which makes the separation of ambient gas mixtures very expensive. While first-of-a-kind DAC plants are estimated to cost anywhere from $600 to $1,000 per metric ton of CO_2, advances through learning-by-doing could decrease costs to around $100 to $300 per metric ton of CO_2.[16] Lower DAC costs of $94 to $232 per metric ton of CO_2 could be realized by using the captured CO_2 to make carbon-neutral synthetic hydrocarbon fuels or other commercial products.[17]

Bioenergy with CCUS

BECCS involves harvesting dedicated bioenergy crops or agriculture and forestry residues (wastes) and combusting them for the purposes of power generation or fuel production. If point-source carbon capture is applied to the biomass power plant or refinery, the post-combustion CO_2 could then be either utilized or sequestered to potentially induce negative emissions (since the carbon in this CO_2 was originally removed from the atmosphere through the photosynthetic process that created the biomass).

Biomass feedstock for BECCS could come from forest management (e.g., tree stems), agriculture (e.g., purpose-grown feedstock), algae cultivation, or collection of municipal organic solid waste. California has a total of 93 operating biomass power plants (total installed capacity of 1,305 megawatts [MW]), some of which could be eligible for retrofits with carbon-capture systems. According to one estimate, California also has more than 150 million bone dry tons of potential biomass feedstock resources that can be sustainably harvested, with minimal impacts on erosion, riparian zones, soil organic matter, and other agronomic factors.[18]

Although estimated costs have ranged from $30 to $400 per metric ton of CO_2,[19] BECCS has recently been identified as one of four NETs that could be deployed today in the United States at a cost of less than $100 per metric ton of CO_2.[20]

One potential use case for deploying CCUS in California is through biomass-fired power plants in the Electricity sector. There are currently 93 biomass-fired power plants in California with a total installed capacity of 1,305 MW. In 2017, the state generated 5,767 GWh of electricity (2.8 percent of state total) from biomass.[21] Many of these plants are in close proximity to potential geologic storage sites,[22] of which the state has an estimated storage potential of 34 to 424 billion metric tons of CO_2.[23]

As of January 2018, California had five in-state fuel ethanol plants with a nameplate capacity of 200 million gallons per year (13 million barrels per day).[24] A recent analysis estimated the near-term deployment potential of CCUS for biorefineries in the United States. It found that 1.5 billion gallons of ethanol per year could be supplied to the California market through 2030, resulting in the capture of 7 million to 8 million metric tons of CO_2 per year, on a lifecycle basis. At this rate of ethanol production and subsequent carbon capture, California could meet approximately 4-5 percent of its 2030 LCFS carbon-intensity reduction target.[25,26]

Enhanced Weathering and Carbon Mineralization

Enhanced weathering (EW) is the process of artificially accelerating the decomposition of rocks or mine waste material to sequester CO_2 on a much shorter timescale than would otherwise occur through natural means. This process is facilitated by crushing or grinding rock into a powder form. This promotes greater reactivity with atmospheric CO_2, since the powder can then be spread over larger surface areas to maximize contact with ambient air.[27] EW may also provide the co-benefit of serving as a soil amendment and nutrient source for degraded soils.[28,29]

Waste material from mining operations could serve as a potential option for sequestering CO_2 through EW.[30,31] Certain mining wastes (also referred to as tailings), such as those derived from ultramafic rocks, have the ability to react with and mineralize atmospheric CO_2. This process could be amenable to acceleration. Magnesium silicate mine tailings, such as those from talc production could promote EW of mining waste rock and accelerate CO_2 sequestration at an estimated cost of $10 to $20 per ton of CO_2.[32] Talc mines could contribute to this option,[33] and there are five active talc mines in California (Table 7-1). Natural rocks such as basalt and dunite are also suitable options for EW at a cost of $200 per metric ton of CO_2 and $60 per metric ton of CO_2, respectively.[34]

A major advantage of using mine tailings for EW is that the waste rock is typically already finely ground, which can help avoid the energy requirements and associated costs for crushing large quantities of rock.[35,36]

Mantle peridotite is a type of rock that is particularly reactive with CO_2 and has the potential to achieve CDR through carbon mineralization.[37] Northern California has been identified as a region with peridotite formations (e.g., the Coast Ranges, Klamath Mountains, Western Sierra Nevada Mountains), which could be used for field experiments and pilot projects related to carbon mineralization.[38,39]

Table 7-1
Active Mines and Plants in California

Commodity	Frequency
Sand and Gravel	199
Crushed Stone	78
Sulfur	14
Cement	11
Gemstones	10
Common Clay and Shale	9
Dimension Stone	8
Gypsum	7
Perlite	6
Boron; Salt; Talc	5
Bentonite; Gold; Pumice; Silver	4
Feldspar; Lime; Zeolites	3
Diatomite; Fullers Earth; Kaolin; Pyrophyllite	2
Barite; Magnesium Compounds; Soda Ash; Sodium Sulfate; Trona	1

California currently has an estimated 395 mines and plants that operate across many commodities. Note: In instances where rows contain multiples, each commodity is represented by the given frequency of mines and plants. Source: EFI, 2019. Compiled using data from USGS, 2018.

Terrestrial and Coastal CO_2 Removal

Biological CDR can be accomplished through a range of forestry and land management practices that include afforestation, reforestation, forest management, and soil management.[40] These practices seek to increase organic carbon stocks through the assimilation of CO_2, and also decrease the amount of CO_2 that is lost to the atmosphere from biological disturbances.[41] Importantly, these approaches have been identified as NETs that could be deployed today in the United States at a cost of less than $100 per metric ton of CO_2.[42] These CDR approaches tend to be more vulnerable to reversal (e.g., forest fires; soil disruption),[43] and may therefore require risk management. They generally have lower capacity for carbon removal than other approaches (e.g., DAC). Opportunities for biological CDR through forestry and land management could be explored throughout California's 1.6 million forest acres[44] and 24.3 million acres of farmland.[45]

One promising type of terrestrial CDR involves the use of organic waste on agricultural soil. A 2018 study by the California Natural Resources Agency assessed the ability to use compost to facilitate carbon sequestration. It found that California has a large potential for sequestration through the use of organic waste streams (e.g., food and yard waste; animal manure) as a soil amendment. Specifically, adding a quarter inch of compost would lead to an increase in soil carbon storage of 2.1 megagrams of carbon per hectare.[46]

Blue carbon is a CDR approach that involves carbon storage in tidal wetlands and coastal ecosystems including salt marshes, mangroves, and seagrass beds. Like terrestrial CDR, coastal blue carbon approaches have the advantage of being relatively low-cost, but also have a lower capacity for carbon removal.[47] California's 3,427 miles of coastline could provide opportunities for this NET.[48]

Key Considerations for Policymakers for LSCM

Unlike other decarbonization strategies, CCUS and NETs not only require innovation and cost reduction, but also need entirely new business models, infrastructures, markets, and regulations. Key concerns for NETs and CCUS as they develop include lowering costs and improving efficiency, finding effective ways to monetize these technologies, and addressing risks and uncertainty.

Lowering Costs and Improving Efficiency

NETs and CCUS technologies can meet their potential through innovation. The current costs of DAC—around $600 to $1,000 per metric ton of CO_2—are too high to deploy the technology at scale.[49] In addition to ameliorating the cost of the technology itself, innovation could reduce the energy intensity of DAC, another major barrier to its deployment. Issues for point-source carbon capture are similar to those for DAC, though current prices are much lower. Costs reductions are needed, however, to make these technologies competitive with other mitigation options; innovation could also increase the percentage of emissions from these sources that are captured and sequestered.

Some NETs have costs under $100 per metric ton of CO_2 and are considered ready to deploy. They include biological sequestration strategies such as afforestation, forest management, and BECCS. Absent innovation, however, these technologies have limited potential, as they compete for limited land resources with other economic and ecological activity. Innovation—such as bioengineering for BECCS or new forest management techniques—could decrease the land required to sequester the same amount of carbon.

The other component of cost for NETs and CCUS is sequestration infrastructure, especially for geologic sequestration. While DAC and CCUS can sometimes be co-located with sequestration sites (such as saline formations), widespread deployment of these technologies will require transportation infrastructure including compressors and pipelines. Infrastructure for transportation and injection will carry further costs, risks, and needs (e.g., land, materials, human capital), and could be an additional focus of technological innovation.

Monetizing NETs and CCUS

In addition to technology innovation in capture technologies, market monetization strategies are needed for NETs and CCUS, including creating markets for captured and sequestered carbon. The closest parallels might be RECs and RINs, but these markets are tied to valued commodities. The successful monetization of NETs and CCUS sufficient to create similar markets will likely require a more expansive carbon-pricing system.

Another option for monetization is improving CO_2 utilization options. As part of a comprehensive analysis of sequestration potential in California, the Lawrence Berkeley National Laboratory and the California Institute for Energy and Environment analyzed and ranked opportunities for CO_2 utilization to help California meet its emissions reduction goals, based on potential impact.[50] The utilization cases that ranked the highest included EOR, enhanced gas recovery, and biological conversion (i.e., biofuels), three technologies that are already in widespread use in the United States. Biofuels could expand its contribution to CO_2 utilization with additional innovation, especially if progress is made on developing new types of energy crops. Other options in the report include building materials (e.g., cement); working fluids for energy storage, generation, and geothermal power; chemical conversion; and treatment of displaced aquifer fluids. All of these use cases require some degree of technological development and demonstration to be viable.

Addressing Risks and Uncertainty

NETs and CCUS technologies carry varying levels of risk and uncertainty. Addressing these issues will be key to expanding their deployment. One of the risks relates to the permanence of sequestration. Geologic storage and CO_2 transmission may be susceptible to leaks that could be either gradual or sudden, due to human error (e.g., improper well installation) or natural events like earthquakes. There is some evidence that geologic storage could also induce seismicity, though this is extremely limited. Biologic sequestration methods also carry their own risks that could undermine permanence, such as wildfires. Wildfire emissions in 2018 were on par with total Electricity sector emissions in California, demonstrating the vulnerabilities of biological sequestration options, especially in a changing climate.[51]

In addition, there are potential social concerns (e.g., not-in-my-backyard or NIMBY issues) that could make siting CO_2 transportation and sequestration difficult. There could also be resistance to using land for afforestation or BECCS, if that could limit other economic activities, such as residential or commercial development, growing of food crops, or renewable power generation.

These risks can be mitigated through technology development, policy, and regulations that govern liability for NETs and CCUS, especially for transportation and storage infrastructure. However, establishing clear liability responsibilities, lines of authority for governmental jurisdiction and oversight, and monitoring and verification regimes has the potential to be contentious and time-consuming.

Hydrogen Applications

Hydrogen is a robust and clean energy carrier, capable of storing and delivering energy on demand. Hydrogen offers a clean energy pathway for nearly every sector of the economy, including for some of California's most difficult-to-decarbonize applications: providing energy and feedstock for Industry, providing fuel for HDVs in Transportation, and providing long-term energy storage for Electricity. The long-term decarbonization potential of a hydrogen economy is immense.

Periodically over the last half-century, public- and private-sector leaders have considered the potential of hydrogen as an energy carrier, particularly for applications in the Transportation and Electricity sectors. During the expansion of the nuclear power industry in the 1970s, for example, hydrogen was expected to serve as a load-following resource to complement baseload nuclear power. Interest in hydrogen has been revived, driven by deep-decarbonization mandates and policies. Hydrogen's use as a storable clean fuel across multiple sectors, including the most difficult to decarbonize, makes it a viable clean energy pathway that promotes optionality and system flexibility.

Hydrogen for Electric Power

Natural gas turbines are the primary resource for grid balancing and load-following generation in California. For a deeply decarbonized electricity system, however, hydrogen can also play this role, alongside other technologies such as gas turbines with CCUS.

In the near term, as described in Chapter 2, hydrogen can be co-fired with natural gas in existing gas turbines with minimal retrofitting requirements. In the longer term, other applications could bring significantly greater decarbonization potential, such as using modified gas turbines or specially designed turbines that burn pure hydrogen, or the use of fuel cells in place of gas turbines. This would provide a flexible, low-carbon fuel for the power system; improving systemwide cost and enhancing reliability. The efficacy and cost of generation from hydrogen could vary depending on items like how the turbines get dispatched (i.e., capacity factors and ramping requirements) and how much hydrogen storage is required.

The other use of hydrogen in Electricity is for storage (discussed in greater detail in Chapter 8), an attractive option to address issues associated with wind and solar generation, that include avoiding curtailment, limiting overbuild, and solving issues of seasonal variation in production. Renewable electricity can be used to produce hydrogen when renewable production peaks (such as in the summer months) and can then be stored until a period of lower production. The hydrogen can then be called on by grid operators for use in turbines to balance the grid. A case study in Chapter 8 shows the modeled value of leveraging excess renewable generation for the production of hydrogen in California by 2030.

Hydrogen for Transportation

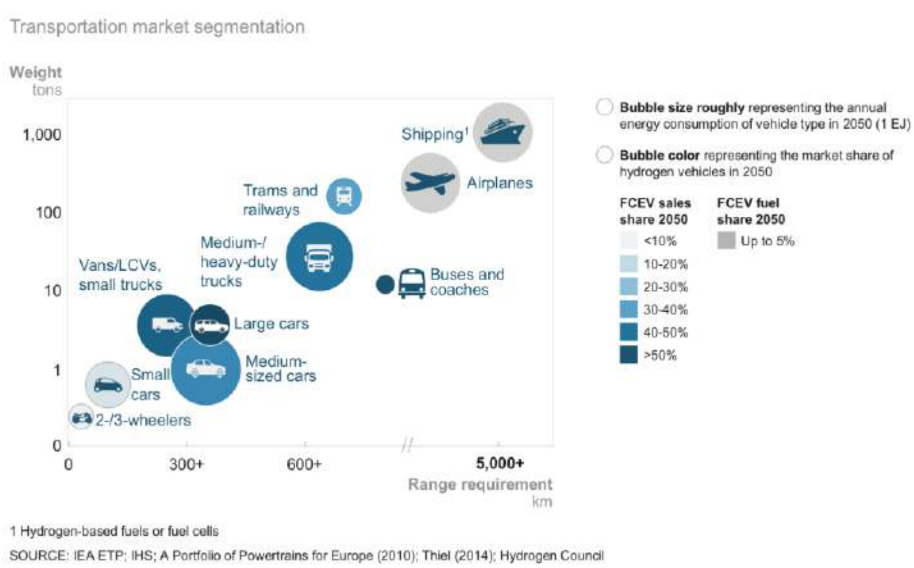
The Transportation sector holds large market potential for hydrogen. The Department of Energy (DOE) estimated in 2004 that the demand for hydrogen from the Transportation sector could surge to 150 million tons per year in 2040.[52] U.S. production of hydrogen in 2014 across all sectors (including captive, by-product, and merchant hydrogen production) was 15.36 million metric tons.[53] It is estimated that 10 million metric tons of hydrogen per year could satisfy the fuel requirements for 50 million light-duty fuel cell electric vehicles (FCEVs).[54]

Costs of the key component in FCEVs, the fuel-cell system, have dropped considerably in recent years. The cost of the fuel-cell system in the 2015 Toyota Mirai, a leading FCEV, was one-twentieth the cost of the fuel-cell system in Toyota's 2008 FCHV-adv.[55] Despite this progress in lowering costs, FCEVs have been slow to gain commercial traction. In general, FCEVs still compare unfavorably to battery-electric vehicles (BEVs) in terms of overall vehicle price and access to refueling infrastructure. There are also concerns about their CO_2 mitigation potential: FCEVs would not be fully zero-carbon except through the utilization of hydrogen produced from SMR with perfect carbon capture or produced by electrolysis from a fully decarbonized Electricity sector (though BEVs also have the latter problem).

There are specific characteristics of HDVs that align more appropriately with hydrogen-based technologies than alternatives, such as battery-electric technologies. First, power trains for HDVs require much larger bursts of power than light-duty vehicles; BEVs struggle to compete on a power density basis. In order to achieve such high-power outputs, BEV batteries must be larger; increasing the battery size, however, increases the weight of the vehicle and the power necessary to move that weight. Ultimately, short of dramatic improvements in battery power density, BEVs will be an inefficient method for decarbonizing the HDV fleet.

Figure 7-5

FCEVs Can Help Decarbonize a Range of Transport Applications



Understanding potential hydrogen applications in the near and long term could help drive a market that supports increased production. Source: Hydrogen Council, 2017.

FCEVs, on the other hand, can combine high power and low emissions. On a specific energy (watt-hour per kilogram) basis, FCEVs provide nearly four times as much power per unit of mass.[56] Simultaneously, in-vehicle hydrogen storage takes up one-half the space as a lithium-ion battery for a given range. This means that the energy density of a 10,000-psi hydrogen storage system combined with a fuel cell (about 400 watt-hours [Wh] per liter) is about twice that of lithium-ion battery packs (about 200 Wh per liter).[57]

In commercial rail applications, the first fuel cell-powered trains, built by Alstom, began running a 62-mile route in northern Germany in 2018. Alstom has said it plans to deliver another 14 trains by 2021. The trains can run for about 600 miles on a single tank of hydrogen.[58] A British airliner, Easy Jet, is developing a hybrid engine system for aircraft where the plane would operate on fuel cells during taxiing.[59] Hydrogen-powered flight, however, remains a major innovation focus.[60,61]

Fuel-cell maritime vessels are also in the testing phase. A recent analysis by Sandia National Laboratories found that hydrogen-powered vessels and passenger ferries were both technically feasible, may be commercially attractive, and fit within existing regulatory requirements for maritime vessels.[62] Similarly, Royal Caribbean Cruises plans to use a Ballard fuel cell onboard its new class of luxury cruise ship, where it will power the vessel's electrical load during port calls, with the longer-term goal of using fuel cells for propulsion.[63]

California Initiatives for Hydrogen Deployment in Electricity and Transportation

So far, policy and incentives promoting hydrogen use in California have focused on the Electricity and Transportation sectors. In Electricity, the California Public Utility Commission's (CPUC) Self Generation Incentive Program initially sought to support the deployment of fuel cells—among other technologies—for behind-the-meter applications. In recent years, however, the majority of deployment capital has gone toward non-hydrogen energy storage technology,[64] which accounts for two-thirds of the program's $567 million budget.[65]

In addition, the CPUC administers the Fuel Cell Net Energy Metering Program, which was extended in 2017 and allows behind-the-meter fuel cell deployments (no greater than 5 MW) to receive a bill credit for any power generated by the fuel cell that provided back to the grid.[66] The program is capped at 500 MW of cumulative deployments and runs through 2021.[67]

These fuel cells are being deployed for backup power at commercial and industrial locations and in some cases for renewable energy integration. As of the end of 2016, Home Depot had deployed fuel cell systems at 140 of its locations in the United States; including the installation of 200-kW systems at stores in California.[68] IKEA and Walmart have followed suit, along with a variety of grocers, food and logistics companies, industrial and consumer product companies, and retailers.[69] A 50 kW solid-oxide fuel cell was deployed at Port Hueneme, California to demonstrate the combined production, compression, storage and conversion of hydrogen at a single site.[70] Partially driven by state incentives, fuel cell deployments topped 97 MW in 2017, with a growth rate of 8 MW per year.[71]

In Transportation, there were 3,300 FCEVs on the road in California at the end of 2017.[72] The California Air Resources Board expects rapid growth in this market as well, with over 13,400 FCEVs on the road in 2020 and 37,400 in 2023, though these figures are sensitive to assumptions related to the deployment of refueling infrastructure.[73] Three automakers are active in the FCEV market: Honda, Hyundai, and Toyota. In July 2018, Toyota announced plans to scale up investment in its FCEV, the Mirai, specifically with the goal of reducing fuel-cell costs.[74] California's Clean Vehicle Rebate Project (CVRP) enables residents to receive up to $5,000 rebates for the purchase of fuel-cell vehicles. The credit is expanded by an additional $2,000 for low-income residents.[75] However, as of January 2017, only 775 fuel-cell vehicle purchasers have claimed the rebate.[76]

As of June 30, 2018, California had opened 36 retail hydrogen fueling stations in 15 different counties[77] The CEC has also funded the deployment of 16 new hydrogen refueling stations through grant opportunity GFO 15-605.[78] These stations are projected to open in 2019 and will expand the hydrogen refueling network by over 40 percent.

The Alternative and Renewable Fuels and Vehicle Technology Program (ARFVTP) and the LCFS are two important programs that support the use of hydrogen in Transportation. The ARFVTP provides grants for hydrogen vehicle and refueling infrastructure deployment.[79] LCFS credits can be generated for production of hydrogen for transportation use, installation of hydrogen refueling infrastructure, and production of "renewable hydrogen"[80] by refineries.[81] For more on these programs, see Chapter 3.

To date, most hydrogen used for energy applications in the state is produced out-of-state and imported to the point of consumption. This reduces the environmental benefit of hydrogen technologies, as it is often transported overland by trucks, rather than by pipeline.

Hydrogen for Industrial Processes

The Industry sector is currently the largest user of hydrogen in California. Most of this hydrogen is used as a chemical feedstock in various processes, such as ammonia production and petroleum refining.

The Industry sector produces heat and power from boilers, turbines, and furnaces, primarily fired by fossil fuels. Projections suggest there could be expanded uses of hydrogen in these areas, especially if industrial facilities are subject to emissions restrictions. Each energy-intensive Industry subsector, however, presents different opportunities and challenges and must be analyzed individually.

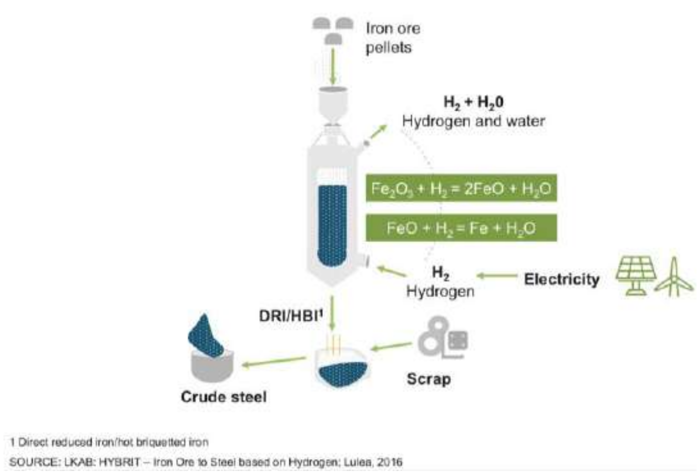
Cement

As mentioned in Chapter 4, the heart of the cement process is the calcination of limestone, which converts limestone (calcium carbonate, or $CaCO_3$) into calcium oxide (CaO) and CO_2. The reaction takes place in a kiln, which is directly fired by a fuel, usually coal or natural gas. The combustion gases mix with the CO_2 produced from calcination. About 60 percent of the CO_2 emissions from the cement process comes from the calcination reaction, with the remaining 40 percent from combustion. Even if hydrogen fires the kiln, there will be significant CO_2 in the effluent. Today, the leading candidate for mitigation of CO_2 emissions in the cement industry is CCUS.

Iron and Steel

There are several processes used in the iron and steel industry, but most production processes use carbon (e.g., coke) as a reducing agent for the iron ore. As with cement, there are significant process emissions from coking, in addition to the combustion emissions from generating the thermal energy necessary for iron and steel production. Steel production emits 1.6 to 3.1 tons of process CO_2 per ton of crude steel.[82] As in cement production, this CO_2 emitted from the process in a blast furnace mixes with the additional CO_2 emitted from combustion to provide heat. CCUS offers an option for emissions mitigation. There are also additional heating and reheating furnaces in which hydrogen would be a good replacement fuel. In the long term, it is theoretically possible to develop new processes where hydrogen serves as a reducing agent in place of coke (Figure 7-6).[83] This is technically very challenging as carbon provides strength and other desirable properties to steel.[84]

Figure 7-6
Hydrogen-Based Ironmaking Process



The ironmaking process can be highly energy and carbon intensive. Using hydrogen as a reductant is an exciting potential pathway to industrial decarbonization. Source: Hydrogen Council, 2017.

Refining

Petroleum refineries are complex plants and no two refineries are the same. Refineries already use significant amounts of hydrogen for hydrotreating and desulfurization. CO_2 is emitted from many process units; the potential for using hydrogen to mitigate these emissions will vary.

Refineries use gas turbines to provide heat and power, along with furnaces and heaters. These units provide the greatest opportunities for hydrogen use. The fluidized catalytic cracker unit is a major CO_2 emitter but most of its emissions are process-related and not amenable to hydrogen use.

Hydrogen Production

There are three primary pathways for hydrogen production: reforming of hydrocarbon gases or liquids; gasification of hydrocarbons, primarily solids, but also liquids or gases; or electrolysis of water. Hydrogen is also produced as a byproduct of industrial processes like petroleum refining or coking for iron and steel production. Today, hydrogen is produced globally almost exclusively from fossil fuels, as follows:[85]

- 48 percent from natural gas via SMR
- 30 percent from petroleum as a result of the refining process
- 18 percent from coal via gasification or as a byproduct of coking for iron and steel production
- 4 percent from water via electrolysis

Electrolysis is an electrochemical process that uses electricity to decompose water into hydrogen and oxygen. This process can be zero-carbon—if the electricity is generated from clean resources. The challenge is managing the operational efficiencies of electrolyzers and procuring sufficient and steady supplies of clean electricity.

Furthermore, running electrolyzers only when renewable electricity is available could be cost-prohibitive due to the high capital costs per unit of hydrogen produced. Additionally, alkaline electrolyzers, the primary electrolyzer used today, have limited flexibility to follow changing electrical demand on the grid, a needed requirement to take advantage of excess intermittent electricity.[86] SMR is currently the predominant production pathway for hydrogen at commercial scales. Compared to electrolysis, SMR requires less capital investment per unit of hydrogen production and the equipment has a longer lifetime. In addition, the energy costs are much lower for SMR.

As California's electric grid becomes increasing clean, the opportunities for producing clean hydrogen at scale will also increase. The emissions factor of electrolytic hydrogen is proportional to electric grid emissions. Based on the average carbon content of California's electric grid (0.28 kilograms [kg] of CO_2 per kilowatt-hour [kWh]),[87] and the typical electricity requirements for an electrolyzer (54-57 kWh per kg hydrogen) the carbon content of electrolytic hydrogen is still higher than the carbon footprint of hydrogen made by natural gas reforming. As California's Renewables Portfolio Standard increases to 60 percent by 2030, this will measurably lower the GHG emissions of producing hydrogen from electrolysis. However, a wide gap will remain to reaching 100-percent clean hydrogen.

Cleaner hydrogen from natural gas reforming is also possible if production is paired with CCUS. This hydrogen is unlikely to be fully zero-carbon, though, even with technological progress; achieving CCUS for hydrogen production with a 100-percent capture rate is technologically difficult.

Table 7-2
Comparison of SMR and Water Electrolysis Technologies for Hydrogen Production

Application	Power or Capacity	Efficiency	Initial Investment Cost ($/kW)*	Lifetime	Maturity
SMR, large-scale	150-300 MW	70-85 percent (LHV)	400-600	30 years	Mature
SMR, small-scale	0.15-15 MW	~51 percent (LHV)	3,000-5,000	15 years	Demonstration
Alkaline electrolyzer	<150 MW	65-82 percent (HHV)	850-1,500	60,000-90,000 hours	Mature
PEM electrolyzer	<150 kW (stacks)	65-78 percent (HHV)	1,500-3,800	20,000-60,000 hours	Early market
Solid oxide electrolyzer	Lab-scale	85-90 percent (HHV)	-	~1,000 hours	R&D

The key attributes that drive hydrogen production technologies.
Note: kW refers to energy output. LHV=lower heating value. HHV=higher heating value. Source: EFI, 2019.

Looking to the future, the emphasis will be on producing hydrogen with a small carbon footprint. It seems highly unlikely that the cost of low-carbon electricity will be less than today's electricity costs. Even in a very pessimistic scenario of a doubling of costs for SMR with CCUS, SMR is a much lower-cost option than electrolysis. Despite SMR's advantages today, though, the future could look different. Natural gas prices may rise significantly. Technological change can make electrolyzers more competitive. Heterogeneous markets may make room for multiple technologies.

Key Considerations for Policymakers for Hydrogen

Ongoing innovation is one key requirement for progress that policymakers need to support. In addition, policymakers need to encourage public-private collaboration in pursuing opportunities for cross-cutting uses of hydrogen. Such collaboration is needed to overcome two primary hurdles to the wider use of hydrogen: infrastructure deployment and the development of scale-appropriate safety regimes.

Infrastructure Deployment

The market for hydrogen will not significantly expand without a robust supply network—and a robust network to supply hydrogen will not emerge without a set of applications for its use. This classic chicken-and-egg problem is not unique to hydrogen; electrification of the transportation fleet is confronting similar issues. Because hydrogen has so many uses across energy and end-use sectors, the scale of its problem is much larger.

Public policy should continue to support the deployment of hydrogen refueling stations. Local and state governments should work together to identify prudent locations for an effective distribution of these refueling stations. They should, however, also consider direct grants to private firms with vehicle fleets for the installation of refueling infrastructure on their sites. At the same time, state and federal governments need to collaborate with private industry to subsidize the development of an expanded hydrogen distribution system. Notably, the expansion should connect states with significant refining capacity (where hydrogen may be produced) to states with heavy industry (where hydrogen can be used).

Much more analysis is necessary to better understand the intricate relationships between infrastructure and applications. Ultimately, the network configuration will vary by locale and be a function of the geographic distribution of hydrogen production, the availability of distribution infrastructure and conversion equipment, and the hydrogen demand by different applications in that geography. Trade-offs among these factors make the challenge of efficiently deploying infrastructure—while encouraging the growth of hydrogen applications—particularly challenging.

Safety

Hydrogen gas is the smallest known molecule; this makes it more susceptible to leaks than any other material. If hydrogen leaks, the chances of fire can be extremely high. Once ignited, the flame is almost invisible during daylight hours, making it a potential safety hazard.[88] It has been suggested that an odorant be added to hydrogen, as is done with natural gas. However, this is not a realistic option. In some uses, such as fuel cells, the odorant could act as a poison. Second, there is a high probability that the odorant will not leak in tandem with the hydrogen. Certain types of sensors can detect a hydrogen leak or flame but may require a large number of sensors to be effective.

Hydrogen embrittlement of metals is also a problem. This can lead to leaks and ruptures of pipes and tanks. Researchers are examining ways to detect embrittlement and testing metals and coatings to address this safety and infrastructure concern.

On the positive side, hydrogen is non-toxic. Also, unlike gasoline, hydrogen does not pool, but quickly diffuses in the atmosphere. Moreover, hydrogen has a good safety record in industrial applications, where it is subject to strict codes and regulations. Having experienced professionals interfacing with hydrogen technology in a workplace environment is, however, decidedly different than having the wider population interfacing with hydrogen technology on a daily basis. The safety standards that should be transferred from industrial settings to consumer settings have yet to be defined or adapted.

Leveraging Existing Carbon Infrastructure and Expertise for Decarbonization

Decarbonization pathways are as much about infrastructure as they are about technology. The transition to a low-carbon future could potentially be improved and accelerated by seeking opportunities to leverage California's existing physical infrastructure, technological expertise, and its skilled and readied workforce.

Developing programs and policies for repurposing existing infrastructure could expand California's role as a leader in climate change. California's existing energy infrastructure is one of the largest in the United States. This includes nearly 100 oil and gas terminals that receive products by tanker, barge, rail, truck, or pipeline;[89] 17 oil refineries, processing 1.9 million barrels per day of products;[90] more than 150,000 miles of natural gas pipeline; and 14 underground natural gas storage facilities with a working storage capacity totaling 600 billion cubic feet.[91] Experience gained in California on transitioning its carbon-related infrastructure could serve as a model both domestically and around the world.

Decarbonization pathways are as much about infrastructure as they are about technology. The transition to a low-carbon future could potentially be improved by seeking opportunities to leverage California's existing physical and intellectual infrastructure, technological expertise, and its skilled and ready workforce.

The long lifespans of infrastructure assets (and the large established base of such infrastructure) could pose barriers to the rapid adoption of low-carbon technologies, due to factors such as the capital cost recovery of existing assets. Stranding valuable assets will be strongly resisted, and jobs could be lost, and workers displaced.

A Framework for Greening Carbon Infrastructure

Substantial investment in energy infrastructure is expected in the United States, with the potential to add 1.5 million new energy-sector jobs by 2030. This investment could help facilitate the adoption of low-carbon technologies across the economy and promote decarbonization (e.g., charging stations for EVs; battery storage for intermittent renewables). Any opportunity to leverage existing energy infrastructure using adaptation, retrofits, and new system design strategies could help reduce the cost of deep decarbonization. Utilizing expertise within the energy workforce can both facilitate a more rapid transition and mitigate the economic pitfalls of stranded workers and lost jobs.

Table 7-3 provides examples of the range of opportunities for using existing infrastructure to aid in the transition to a clean energy future.

Table 7-3
Opportunities for Using Existing Carbon Infrastructure for Decarbonization

	Oil Refineries & Gas Processing	Natural Gas Generation	Oil & Gas Pipelines	Waterborne Transportation & Ports	Storage
Biofuels	• Conversion of oil refineries to biorefineries • Upstream blending of oils with drop-in biofuels • Applying industry expertise	• See Renewable Natural Gas examples below	• Transporting biofuels in petroleum product pipelines • Leveraging pipeline rights-of-way	• Using fuel storage and transportation hubs	• Using underground storage tanks for biofuels and petroleum-biofuel blends
Hydrogen Fuel or Feedstock	• Leveraging industry expertise using hydrogen safely • Producing hydrogen • Redirecting hydrogen currently produced for refining petroleum to perform other energy services	• Co-firing hydrogen (up to 50 percent) with NG • Gas turbine combined-cycle plants with expected efficiency of ≥60 percent	• Doping in NG pipelines (≤15 percent with minor pipeline upgrades needed) • Leveraging pipeline right-of-way	• Using fuel storage and transportation hubs	• Using salt caverns and other geologic formations • Capitalizing on industry expertise with NG storage
Negative Emissions Technologies/Carbon Capture, Utilization, and Storage (CCUS)	• Applying industry expertise to CCUS technologies for direct-air capture (DAC) and bioenergy with carbon capture and storage (BECCS)	• Applying industry expertise: CCUS technologies for DAC and BECCS	• Using compression technologies similar to those in NG infrastructure for CO_2 • Rail and roadway = existing infrastructure • Leveraging pipeline rights-of-way	• Using industry expertise in liquefaction and transport of LPG/LNG for liquid CO_2 • Marine vessels for CO_2 using the same technology as existing LPG or LNG tankers • Port infrastructure for loading • Offshore facilities for subsea injection	• Using saline formations, depleted O&G reservoirs, unmineable coal seams, basalt formations • Using industry expertise in large-scale CO_2 separation and sequestration • Applying technologies for drilling and injection, subsurface characterization, and site monitoring, same as in the O&G sector • Leveraging similarities with NG storage, acid gas disposal, and CO_2-EOR
Renewable Natural Gas (RNG)	• Processing technologies are similar to NG processing	• Minimal processing for using RNG for power generation in gas turbines	• Doping in NG pipelines • Leveraging pipeline rights-of-way	• Utilizing existing fuel storage and transportation hubs	• Leveraging industry expertise with NG storage
Smart Systems/ Platforms	• Applying process automation for improved refinery performance	• Creating smart generation solutions: NG-battery and NG-solar hybrids	• SCADA expertise • Improving the efficiency of transport of RNG, H_2, CO_2 • Enhanced leak detection • Leverage pipeline right-of-way	• Using transport management systems and other IoT applications • Data tracking of supply chains	• Optimizing revenues from grid-scale storage systems

There are numerous opportunities to leverage existing carbon infrastructure to enable decarbonization.
NG = natural gas; LPG = liquefied petroleum gas; LNG = liquefied natural gas; SCADA = supervisory control and data acquisition; IoT = internet of things
Source: EFI, 2019.

Petroleum Infrastructure

Oil refineries are complex industrial facilities with significant engineering support systems. In California, refineries process 1.9 million barrels of oil each day, which provide California with a slate of refined products.[92] These facilities are also connected to the region's extensive pipeline, storage, and terminal system that stores products until they are moved by ship, pipeline, rail, or truck. In California, there are more than 100 terminals with capacities that range between a few thousand and a few million barrels, and some terminals with as many as 70 tanks.[93]

In the transition to a low-carbon future, this massive system could support a range of clean energy pathways. Extensive CCUS systems, for example will be needed to transport and store CO_2. California's existing refined products system—already the largest handler of CO_2 in the state—could be repurposed to carry even more CO_2. Pipeline transport of CO_2, which began in the early 1970s, is a mature technology and is the most common transport method for large volumes of CO_2.[94,95] Dedicated CO_2 pipelines made from carbon-manganese steel do not require corrosion-resistant material, as dry CO_2 is non-corrosive and moisture can be removed from wet CO_2 prior to transport.[96]

Another pathway for leveraging the existing petroleum infrastructure would support clean fuel production and transport options. While it would require upgrades, biofuels, for example, could be produced by refineries and then stored and distributed in the petroleum supply chain. In 2006, the biodiesel company World Energy Alternatives LLC reportedly transported 75,000 barrels of B5 through a common-carrier pipeline that was typically reserved for the transport of petroleum products such as jet fuel.[97] France's Total is planning to convert its La Mede crude oil refinery to a biorefinery to produce renewable diesel with used cooking oil, in part, serving as a feedstock.[98]

Repurposing refineries to produce clean hydrogen at scale for various sectors of the economy provides another repurposing option. Oil refineries are already the largest hydrogen producers in California—with over one million cubic feet per day of production capacity.[99] While it could involve a significant investment to shift from producing refined products to making hydrogen—with either electrolysis or SMR—oil refineries have existing systems, processes, and expertise in hydrogen production and use that could be employed to support a hydrogen-based economy.

Natural Gas Pipeline and Storage Infrastructure

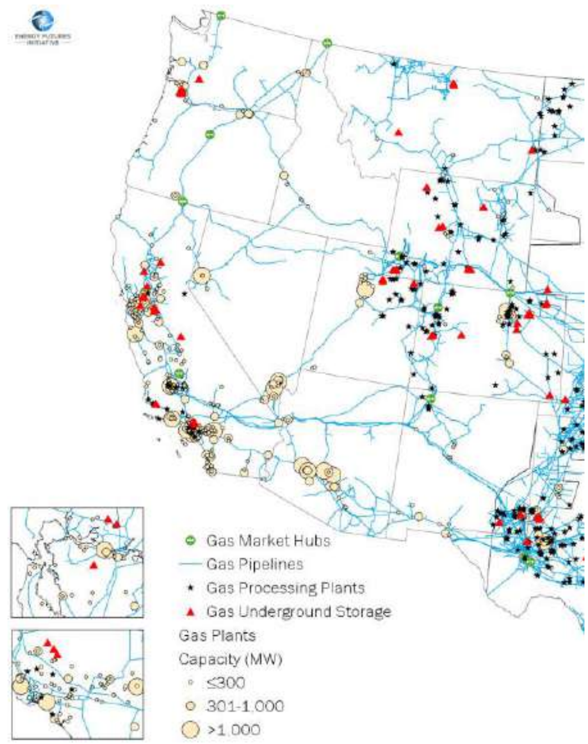
California's natural gas infrastructure supports millions of customers that range from individual homes to large industries, including manufacturing and power generation. Its pipeline and storage system connects to a regional network that spans more than 13 states, as well as to Mexico and Canada (Figure 7-7).[100]

As with petroleum infrastructure, California's natural gas infrastructure could be repurposed to process and transport hydrogen and CO_2. It is estimated that California has over 150,000 miles of utility-owned natural gas pipelines,[101] and 28,080 miles of interstate natural gas pipelines.[102] The technologies used to compress CO_2 in preparation for transport are similar to those used in natural gas pipeline infrastructure. (For large-volume processing, centrifugal compressors are the preferred technology).[103] Industry knowledge of the liquefaction and transport of liquefied petroleum gas (LPG) and liquefied natural gas (LNG) could also assist with efforts for liquid CO_2 transport.[104]

Existing natural gas pipeline infrastructure could also be used to transport hydrogen, using a blend of natural gas and hydrogen (possibly up to 15 percent) with relatively minor infrastructure upgrades.[105,106] This blend could also be combusted in existing natural gas turbines (Box 7-1). Regional clusters of power plants and/or industrial facilities could provide an opportunity to leverage existing natural gas infrastructure for the transport of hydrogen in order to reduce infrastructure costs.

Figure 7-7

Natural Gas Infrastructure in California and WECC Region



California has the bulk of natural gas infrastructure in the Western Electricity Coordinating Council (WECC) region. Left inset map: San Francisco Bay area. Right inset map: Los Angeles area. Source: EFI, 2019. Compiled using data from EIA, Resource Watch, Global Energy Observatory/Google/KTH Royal Institute of Technology in Stockholm/Enipedia/World Resources Institute.

Box 7-1

Repurposing Today's Natural Gas Turbines to Run on Hydrogen

As discussed in Chapter 2, hydrogen can be used in gas turbine combined-cycle plants with an expected efficiency of 60 percent or more.[107] California currently has 43.4 GW of natural gas generating capacity, about one-half of which is from natural gas combined-cycle (NGCC) plants.[108] Clean hydrogen produced through SMR with CCUS (or electrolysis) could be co-fired in gas turbines as a substitute for natural gas in these NGCC plants.[109] An additional opportunity to leverage existing NGCC units could be to co-fire biofuels in gas turbines[110] or gasified biofuel (up to 40 percent) in an NGCC combined heat and power plant to reduce GHG emissions.[111]

Hydrogen, CO_2, and other renewable fuels can make use of the knowledge base that has developed around natural gas storage infrastructure in California. California currently has 14 underground natural gas storage sites with a total capacity of more than 600 Bcf.[112] Much of the knowledge that has been gained from natural gas storage is directly applicable to underground hydrogen,[113] which can be stored at large-scale in salt caverns and other geologic formations.[114] In addition, many of the technologies that are required for the geologic sequestration of CO_2 (onshore and offshore) are similar to those used in the oil and gas industry. Such technologies may include those used for drilling and injection, subsurface characterization, and site monitoring. Finally, biofuels and petroleum-biofuel blends can be stored in underground storage tanks, which are an important component of fueling infrastructure.[115,116] Such underground storage could draw lessons learned from storage in the oil and gas industry.

Surface Transportation Infrastructure

In addition to pipelines, there are important surface transportation modes that could be repurposed to support decarbonization including ships, trucks, and rail.[117] Maritime transport of CO_2 is already a common industry practice in small volumes. CO_2 is currently transported via ship at lower pressures, and transport of CO_2 at higher pressures would be possible in LPG tankers.[118] Marine vessels to transport liquefied CO_2 can also be constructed using the same technology as existing LPG or LNG vessels.[119] Maritime transport of CO_2 may be the most economical option at smaller volumes (i.e., less than several million metric tons of CO_2 per year) for distances greater than 1,000 kilometers (approximately 620 miles).[120]

CO_2 transport by truck or rail is feasible and is currently done in small volumes. For transport by truck, vessels range from 2 to 30 metric tons of CO_2. CO_2 transport by truck or rail is, however, less economic than pipelines and maritime transport, and is unlikely to play a significant role in large-scale CCUS systems.[121]

Energy Workforce

California has nearly 950,000 workers in the energy sector.[122] Many of these workers work in conventional, carbon-intensive energy systems such as natural gas transmission and distribution, electricity generation, petroleum production and refining, and conventional motor vehicles (see Chapter 1 for a more specific breakdown of energy jobs). Facilitating economic growth while decarbonizing these systems will require transitioning workers to other jobs in energy. In addition to ensuring that these workers are not left stranded by decarbonization, transitioning these workers to newly decarbonized systems provides an opportunity to utilize their expertise and experience. For example, the expertise of workers from the offshore drilling industry could be key to the development of offshore wind energy. As the alternative fuel vehicle industry grows, it will likely draw its workforce from conventional vehicle manufacturing. Of course, transitioning workers to these decarbonized systems is easier said than done. Government, labor, and industry stakeholders should make enabling these transitions a priority.

Oil and Gas Firms are Investing in the Clean Energy Future

In addition to leveraging the existing carbon infrastructure and expertise, oil and gas companies can also contribute to the clean energy transition through their own investment in time, resources, and capital. In 2018, major global oil and gas companies invested an estimated 1 percent of their capital expenditures on clean energy technologies.[123]

A review of the annual reports and financial documents of a select group of oil and gas firms found that 17 major firms spent over $9.5 billion in annual clean energy investments (Table 7-4). These firms span the O&G value chain—upstream, midstream, and downstream. The largest firms, including ExxonMobil, Shell, and Chevron, spent the most. Their investments included renewable generation, energy storage, and negative emissions technologies, such as DAC.

Table 7-4

Estimated Investments from Select Oil and Gas Firms in Clean Energy Technologies

Company	Est. Investment	Renewable Generation	Electric Vehicles	Bio- & Alternative Fuels	Advanced Nuclear	Energy Storage	NETs
Marathon Oil	$21M[124]			✓			✓
	$992M[125]	✓	✓	✓		✓	✓
Chevron	$1.3B[126]	✓		✓			✓
TOTAL	$353M[127]	✓		✓		✓	✓
bp	$500M[128]	✓	✓	✓			✓
eni	€1.2B[129]	✓		✓	✓		✓
ExxonMobil	$1B[130]	✓		✓			
ConocoPhillips	$10M[131]	✓		✓			✓
Schlumberger	$387M[132]	✓	✓			✓	
HALLIBURTON	$360M[133]	✓					✓
KOCH INDUSTRIES INC	$600M[134]		✓				
OXY	$195M[135]	✓		✓			✓
equinor	$1B[136]	✓		✓			✓
Sempra Energy	$497M[137]	✓		✓			
Denbury	$241M[138]						✓
REPSOL	€833M[139]	✓	✓	✓			✓

The above estimated investments in clean energy technologies total $9.5 billion. Source: EFI, 2019.

Oil and gas companies have taken different paths to add low-carbon technologies to their portfolio. Royal Dutch Shell, whose total 2018 capital expenditure was $24.8 billion,[140] has been prolific about investing in new areas, often through the acquisition of smaller companies.

Other oil and gas majors have taken a different approach, opting to invest in existing cleantech companies without acquiring them outright. One example is the Canadian DAC technology company Carbon Engineering. In early 2019, it received equity investments from BHP[141] (2018 capital expenditure: $6.8 billion),[142] and from the venture-capital subsidiaries of two global energy companies,[143] Chevron (2018 capital expenditure: $18.3 billion),[144] and Occidental Petroleum (2017 capital expenditure: $3.6 billion).[145] Both venture capital subsidiaries have been investing in low-carbon technologies. Their decision to invest in Carbon Engineering was cited as the first "significant collaboration" between the energy industry and a developer of DAC technology.[146]

Equinor is attempting to expand its operations in offshore wind generation. The Norwegian-based oil and gas company, which had a 2017 capital expenditure of $9.4 billion,[147] has grown its offshore wind business through a combination of acquisition and internal development, and currently has multiple operational projects in the United Kingdom, as well as planned projects in Germany and Long Island, New York.[148] Equinor has invested in the development of floating offshore wind, starting with the acquisition of a pilot project in Norway and continuing with an operational floating wind farm in Scotland, the first of its kind globally. Equinor already has expertise in offshore engineering from its oil and gas operations, which it claims has been put to use for its offshore wind projects.[149] Ideally, other energy companies would be able to similarly leverage their existing resources and infrastructure toward the development of low-carbon technologies.

Smart Systems and Platform Technologies

The number of smart devices deployed across the global economy continues to grow. According to one report, the number of connected devices (often referred to as the "Internet of Things," or IoT) is expected to increase from nearly 27 billion in 2017 to 125 billion in 2030.[150] This could lead to a doubling in the annual rate of growth of global data transmissions, from annual increases of 20-25 percent per year now to annual increases of 50 percent per year by 2032.[151] Internet traffic has already tripled between 2011 and 2016.[152] Many of the economywide trends suggest that widespread digitalization and the rapid expansion of smart technologies that use data, connectivity, and analytics could lead to technology breakthroughs that have long-lasting impacts on society, energy, and the environment. Smart technologies that use data, connectivity, and analytics to improve the performance of new and legacy systems offer a unique long-term pathway to help California meet the challenges and risks of deep decarbonization; at the same time, they unlock new economic and social value for the state.

Realizing the full benefits of smart technologies will, however, require more than just the widespread deployment of digital equipment. It will also require leveraging existing and emerging platform technologies[153] that offer more granular, coordinated, and holistic views of the energy sector to improve the decision-making of system operators, investors, planners, and emergency responders. California's energy sector is a system of systems: separate infrastructures operated and managed independently. Platform technologies can help these systems to work together as a coordinated network, integrated through sensors, smart controls, data analytics, and eventually artificial intelligence (AI).

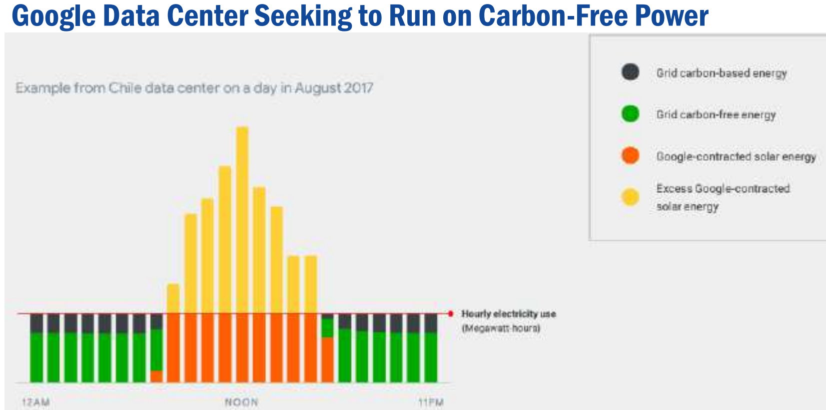
New Players in the Energy Sector

Data is now arguably the most valuable commodity in the world. Its leaders—Alphabet (Google's parent company), Amazon, Apple, Facebook and Microsoft—have used data and analytics to establish the five most valuable listed firms in the world.[154] These technology-centric firms have emerged as new players in the energy sector, becoming major consumers *and* producers of energy.

A significant focus for these new players has been developing energy portfolios for their global operations that are 100 percent renewable. Major milestones have been reached in the last few years. Amazon Web Services, for example, reached 50 percent renewable energy usage in January 2018, with renewable energy projects delivering more than two million MWh annually.[155] This is enough electricity to power the city of Nashville, Tennessee.

In 2017, Google surpassed its goal of purchasing more renewable energy than the total electricity consumption at its data centers, reaching 2.6 GW of renewable purchases. Going forward, Google has targeted 24/7 carbon-free electricity for its global data center operations, up from around two-thirds today.[156] To maintain its operational uptime, when intermittent renewables are unavailable, Google buys electricity generated from non-renewable resources on the grid. Figure 7-8 shows Google's actual daily energy use at one of its data centers, depicting the challenge of shifting from 100 percent clean energy procurement to 24/7 carbon-free electricity.

Figure 7-8
Google Data Center Seeking to Run on Carbon-Free Power



Despite access to sufficient renewable electricity to cover the data center's daily demand, the variability issues of the wind and solar, combined with Google's zero tolerance for electricity disruption, result in dependence on carbon-based electricity in Chile. Source: Google, 2018.

Technology-centric players in the energy sector could unlock significant innovation opportunities across the value chain. In addition to building capacity for clean energy supply, these firms can add tremendous benefit to cross-cutting issues like data analytics for each end-use sector, cybersecurity for the energy system, and the evolution of smart grids and smart cities.

Platform Technologies: Key Enablers of Smart Cities

Cities are home to more than one-half of the world's population and face significant environmental challenges and infrastructure requirements. Major progress has been made in improving the sensor, communications, and open data systems of dozens of major cities around the world.[157] There will be numerous benefits for energy systems associated with the continued investment of cities in smart technologies.

As cities leverage smart technologies to manage their growing populations, complex activities, and scope of services, they will be generating significant amounts of data.[158] This data, if coordinated across a Smart Energy System, could greatly improve the performance, and lower the cost, of energy services—resulting in positive feedback to the city.

Many cities are actively developing planning documents to guide smart city development. A common approach to address smart city design and implementation, including shared definitions and guiding principles for decision-making, could be useful in this rapidly changing environment. Concise, unified smart city frameworks could inform policymakers and investors on how to translate and distill the imperatives, requirements, opportunities and challenges of making cities smarter. These frameworks should actively coordinate with owners and operators of energy systems and guide parallel development of highly compatible, smarter energy systems.

Technology Platforms that Could Enable Long-Term Deep Decarbonization

Smart technologies provide the foundation for the long-term transition to Smart Energy Systems. Without strong coordination between firms and sectors, however, the widespread deployment of smart technologies may only reinforce the silos among energy infrastructures, duplicating effort and leaving value on the table. If, for example, each electric utility builds its own independent smart grid, there may be little financial incentive to share data across utilities.

Technology platforms that coordinate data and controls across systems and sectors should be encouraged, in order to ensure that data and analytics are distributed to relevant stakeholders. Examples of platform technologies that could play major roles in a deeply decarbonized economy include smart grid technology, 5G networks, additive manufacturing, AI, blockchain, and home energy management systems. Figure 7-9 illustrates the potential scale of interactions throughout a Smart Energy System that could be integrated to unlock new value through technology platforms.

Figure 7-9
Scoping the Interactions on a Smart Energy System

This network map helps to define the relationships between stakeholders in a smart energy system. Source: EFI, 2019.

Smart Grid Technology

The "smart grid" is a broad term that defines the digital technology that enables two-way communication between electric utilities and their customers. Smart grid technologies include controls, computers, automation, and other technologies that work together seamlessly. According to SmartGrid.Gov, the benefits of smart grid technologies include the following:

- More efficient electricity transmission
- Faster system restoration times
- Reduced operations and management costs for utilities and lower power costs for consumers
- Reduced peak demand
- Increased integration of large-scale clean energy systems
- Improved integration of customer-side energy supply, including distributed renewable energy
- Improved security[159]

5G Networks

5G networks, which could be highly integrated with a Smart Energy System, promise to enable new levels of productivity across the economy. A few specific expected benefits of 5G include: faster connections (1000 times more bandwidth per unit area) that carry more data (1 to 20 gigabits per second) to more connections (10 to 100 times more connected devices) with extremely low latency (less than one millisecond), and that require relatively low amounts of energy to operate.[160] In addition, 5G offers major opportunities to increase cybersecurity protections of IT-enabled systems, as many 5G networks are building cybersecurity features into their frameworks. According to CISCO, 5G services help operators and consumers address cyber risks by enabling more visibility into internet traffic, with automated protections and advanced analytics.[161]

Additive Manufacturing

Additive manufacturing (including 3D printing) leverages computer modeling and advanced raw materials to construct a wide range of customizable products. According to DOE, additive manufacturing reduces energy use by 25 percent and material costs by up to 90 percent. It also allows for greater flexibility and reduces production time.[162] Additive manufacturing can also produce customizable products and lightweight materials for other sectors—such as Transportation—that can create greater efficiency in those sectors.

Artificial Intelligence

Advances in computing power and efficiency have enabled more powerful systems for analyzing data, including automation and AI.[163] These include visual perception, understanding and communicating with natural language, and adapting to changing situations—tasks that normally require human intelligence.[164] Increasing complexity of energy markets and networks, as well as increasing risks from both human-made and natural events, can be better managed through AI. According to one study, AI can cut 10 percent of national electricity usage, increase energy production by 20 percent, and save customers $10 to $30 on their monthly energy bills.[165] Transportation is another sector that is well suited to leveraging AI to enable remote control; improve system operations, safety, efficiency, and service; lower costs; and create and deploy autonomous vehicles.[166]

Blockchain

Blockchain technology is an example of a platform technology that could enable many aspects of a Smart Energy System. Blockchain, an electronic ledger managed without a central authority, creates a highly-scalable network for managing large volumes of transactions, settled quickly, securely, and at relatively low cost.[167] Blockchain is being tested throughout energy systems in Europe, Asia, and North America to improve operator visibility, control, and security in a range of energy and end-use applications, including Distributed Energy Resources, EVs, supply chains, cybersecurity, and others.[168] Advances have also made new blockchain systems far less energy intensive than the first generation of blockchains (e.g., Bitcoin).

Home Energy Management Systems

Home Energy Management Systems (HEMS) are another example of a platform technology that could be leveraged at scale to benefit a Smart Energy System. HEMS provide users with data and/or control of household energy use. Applications exist for specific end uses, such as lighting, heating, cooling, and appliances, as well as for home energy loads.[169] Building loads can be turned on or off using active control systems that collect, process, and adapt to real-time conditions. According to one assessment, improving the operational efficiency of buildings by using real-time data could lower total energy consumption between 2017 and 2040 by as much as 10 percent.[170] The decarbonization potential of HEMS is further discussed in Chapter 8.

Growth of Smart Technologies in California

California is already a leader in deploying smart technology throughout the energy and end-use sectors. For example, the state's electric grid had more than 12 million smart meters in 2016,[171] covering 80 percent of the state's residential customers.[172] These systems collect and transmit customer data to utilities—establishing "touch points" at which utilities and customer interact. According to the CPUC, these smart devices have helped utilities improve electric reliability through enhanced reporting.[173]

California's Buildings sector is also experiencing major growth in connectivity. There are now more than a dozen state-approved home energy management systems on the market,[174] and there are financial rebates and demand response (DR) programs for the three investor-owned electric utilities.[175] California's Title 24 Building Codes set standards in 2016 that promote—and in some cases require—that new construction and retrofits for residential and non-residential buildings use two-way, connected end-use systems.[176]

The Industry sector in California also has a long history of using digital technologies to improve safety, increase productivity, and lower operating costs.[177] In the last decade, major developments in additive manufacturing projects, for example, have emerged that promise to lower emissions by accelerating production schedules and lowering energy intensity. One firm based in California, called Carbon, produces a wide range of products including athletic footwear, fiber optic cables for ships, lightweight auto parts, and highly customizable medical devices.[178] Large aerospace and defense companies have also quickly ramped up the scale of their additive manufacturing operations in the last decade—scaling up to large and critical components, such as rocket parts. Lockheed Martin, for example, now produces military, commercial, and civil space technology at its additive manufacturing center in Sunnyvale, California.[179]

In addition, California is seeing rapid developments in autonomous vehicles. In April 2018, the CPUC first permitted on-road testing of autonomous vehicles. Then in May 2018, the CPUC announced pilot programs that allow completely autonomous, as well as driver-monitored, vehicles to transport passengers that can find the vehicles through a smartphone app.[180]

Scoping the Benefits of Platform Technologies

Platform technologies promote a long-term vision for how today's individual energy infrastructures and end-use sectors could become seamlessly connected. This vision is intended to provide guidance to policymakers on the potential long-term value of fully leveraging smart, intelligent, and connected systems. Key areas where platform technologies can unlock value include optimized performance based on GHG emissions; advanced levels of reliability and resilience; and distributed, consumer-centric services.

Optimized Performance to Reduce Emissions

Platform technologies offer tremendous opportunities to measurably reduce emissions from California's energy and end-use sectors. Smart technologies and data analytics tools can help to optimize energy supply and demand to reduce waste, increase energy conservation, and create a market for energy efficiency and DR programs. These technologies could also increase the value of clean, renewable, and negative-emissions technologies in the energy sector.[181]

Applications for optimization exist across the economy, but Electricity provides a useful case study. One report[182] determined that fully deploying available smart grid technology could reduce GHG emissions from the Electricity sector by 18 percent. In the California context, that would amount to a reduction of 12.3 $MMTCO_2e$. One emerging market opportunity, a digital gas plant, uses digital technology to improve the performance of legacy electricity systems.[183] The application uses sensors, controls, and software optimization that enable increased efficiency, lower emissions, and faster responsiveness by adding real-time operational decision-making capability.

Advanced Levels of Reliability and Resilience

Platform technologies can integrate data from multiple infrastructures to improve reliability and resilience. These technologies can help infrastructures face natural and manmade threats of increasing in frequency and severity.

As noted, California is already experiencing devastating wildfires, variable precipitation patterns, and more heat waves and dry spells. These negative impacts are expected to increase in frequency and magnitude for the foreseeable future.[184] Energy systems will have to adapt to these changing conditions; they may also become key to detecting high-risk situations. Data analytics tools can analyze data on weather and climate, electric equipment health, road blockages, behind-the-meter resource availability, distribution line status, and DR programs to guide more informed operator decision-making.

Smarter electric grids are already having a measurable impact on grid reliability and resilience. According to DOE, smart technologies accelerate service restoration following major storm events, reduce the number of customers affected by outages, and improve overall service reliability to reduce customer losses from power disruptions.[185] One assessment found that state-of-the-art smart tools could help reduce systemwide power outages by 45 percent.[186] The value of these smart systems could grow significantly if paired with data analytics platforms that span the energy and end-use sectors. These systems and platforms could help advise a range of stakeholders in the Electricity and Transportation sectors, dealing with topics such as natural gas service, and emergency response.

Another major threat to California's energy system (especially the electric grid) is the potential for cyberattacks. As more internet-connected devices have been deployed throughout the system, cyber adversaries have discovered additional ways to exploit their weaknesses and attack system vulnerabilities. California's government is taking this issue seriously—imposing the nation's first cybersecurity standards for IoT devices.[187] By building cybersecurity into the entire energy value chain, a Smart Energy System could provide grid operators and planners with the monitoring and control tools needed to deter, isolate, and increase the barriers to entry for cyber adversaries.

Lawrence Berkeley National Lab's Data Science and Technology Department is one cyber research and development program that focuses on developing tools for monitoring and protecting power grid control system devices.[188] This work specializes in smart technologies, such as state-of-the-art sensors, that help automate electric grid protections and responses against cyberattacks. This research shows there are significant potential benefits of leveraging smart technologies in the fight against cyber adversaries.

Distributed, Consumer-centric Services

A major trend throughout the economy has been a shift to more distributed economic services. Platform technologies could enable energy consumers of all types (e.g., individuals, households, businesses, communities, and municipalities) to engage with the energy system in new—and highly distributed—ways.

Consumer-centric services have already emerged in the Transportation sector, including ride-hailing firms such as Uber and Lyft. According to one survey published in March 2018, between 5.6 and 17.5 percent of respondents in California used Uber or Lyft more than once a month, with especially high use among younger, highly educated, urban-dwelling populations.[189] Additionally, Uber drivers throughout California reportedly earned nearly $3 billion in revenue in 2017.[190]

In Electricity, recent trends show increased interest in using automation technology and intelligent controls to enable peer-to-peer (P2P) transactions at the distribution level.[191] A project in Brooklyn, New York, for example, leverages blockchain technology to manage and automate transactions over a microgrid between around 60 energy producers and 500 consumers.[192] This is reflective of the overall trend in P2P transactions. An estimated 82.5 million Americans were expected to make at least one P2P transaction in 2018, up from 63.5 million in 2017. By 2021, the total transaction volume is expected to generate more than $300 billion.[193]

A Smart Energy System would also allow for an expanded role for other resources, such as DR. Digital tools can help utilities signal to residential and commercial customers, industrial facilities, and even drivers of EVs to either add supply or reduce demand.[194] One project in the Netherlands is testing the use of EVs to balance the transmission grid through cellphone applications and blockchain.[195] This entire process is being automated based on preset conditions from all parties.

This could have significant impact on DR in the United States. In 2016, there was around 36 GW of peak demand savings response capacity across the United States and Canada.[196] However, the total potential is likely much greater. According to another assessment, in 2019, the total DR potential could be closer to 188 GW.[197] That could cover one-half of the total electricity supply resources in the Western Electricity Coordinating Council region or all of the resources in the Electric Reliability Council of Texas region.[198]

Key Considerations for Policymakers for Smart Systems and Platform Technologies

This vision aims to provide policymakers with guidance on the potential long-term benefits of smart and platform technology. While there are many challenges to realizing a Smart Energy system, there are some that will be especially important to overcome.

The first is the need for close coordination among sectors and stakeholders in California that have traditionally not worked together, and that—in some instances—are commercial competitors. Building a smart electricity system, for example, will involve the coordination and control of hundreds of thousands of energy assets and data from across the end-use sectors. California's Emerging Technology Coordinating Council claims that a major barrier to HEMS deployment has been limited interoperability of various in-home smart technologies.[199] Technology platforms that can integrate and analyze information from new and legacy smart technologies is key to fully leveraging the energy savings potential.

New business models are needed to monetize the cross-sectoral linkages of a Smart Energy System.[200] This could lead to a fundamental shift from energy-only, asset-intensive business models to platforms that enable the exchange of services. As described above, HEMS can package together services to allow consumers to optimize their in-home consumption, electric-vehicle charging, and possible P2P transactions.

Another key challenge that will have to be addressed is data privacy and system security. Ultimately, data related to individuals or other stakeholders must be available for analysis in order to make subsequent control decisions for a Smart Energy System. In today's world of ubiquitous mobile internet connectivity, technology companies already have enormous insights into individuals' behavior. In many respects, customers have become comfortable—or at least accepting—of this reality. By contrast, many utilities have faced very significant pushback from customers and regulatory agencies for even relatively modest efforts to integrate smarter metering into their systems. In the push towards a Smart Energy System, these tensions will have to be satisfactorily addressed in a manner that balances data resolution (and the associated value that creates) with personal privacy.

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CHAPTER 8
BEYOND 2030: MIDCENTURY DECARBONIZATION

FINDINGS

Meeting California's deep decarbonization goals by midcentury is possible but will be extremely difficult without breakthrough energy innovation.

The marginal cost of carbon abatement will rise as California continues to decarbonize its economy. This is partly because there are no "silver bullet" solutions to decarbonization and there are no examples of successful deep decarbonization of an economy the size of California's. Predicting the mix of clean energy technologies needed by 2050 is also very challenging.

California is well suited to develop a clean energy innovation portfolio that can provide innovators, investors, adopters, and other policymakers better visibility into the evolving future of clean energy.

California has a robust energy innovation infrastructure, including an active private sector, a strong workforce, world-class research universities, national laboratories, and major philanthropies that are aligned with the goals of decarbonization. Decarbonization pathways should support local and regional energy capacity to reflect on-the-ground issues.

Eleven high-priority clean energy technologies were identified as having long-term breakthrough potential in California. Now is the time to start working to develop them, building on and accelerating the pace of foundational work to date.

A broad list of candidate technologies was developed that considered a range of economic sectors, specific applications, and development timeframes. From this list, a shortlist of technologies was chosen, based on California's policies and programs, energy system and market needs, and other distinctive regional qualities that position California to be a first mover. The list of high-priority technologies includes negative-emissions technologies that will likely be needed for midcentury deep decarbonization.

A model framework was created of a clean economy that relies on electricity and electrolytically produced hydrogen in order to demonstrate the scale, system operational needs, and potential infrastructure characteristics of a deeply decarbonized economy.

In this trial framework, the Electricity, Transportation, Buildings, and Industrial sectors receive two-thirds of their energy from direct electricity use and one-third from hydrogen. The electricity requirements in this framework are four to five times higher than current levels in California. This model helps to frame the scale of the system requirements and emphasizes the value of optionality and innovation.

AN INNOVATION PORTFOLIO: MEETING CALIFORNIA'S MIDCENTURY EMISSIONS REDUCTION TARGETS

This chapter describes the essential role of clean energy technology innovation in supporting California's midcentury carbon emissions reduction targets. It explains how innovation can contribute significantly to the reduction of costs associated with deep decarbonization and the high value of investing in technologies with breakthrough potential. Technology selection criteria are used to identify a portfolio of emerging clean energy technologies that could support California's goals. These technologies were further screened based on California's existing policies and programs, energy system and market needs, and other distinctive regional qualities that support the state as a first mover in addressing climate change: a strong resource base, relevant workforce expertise, and robust scientific and technological capacity including an extensive university system, some of the world's greatest software technology companies in Silicon Valley, and four Department of Energy (DOE) national labs (Lawrence Berkeley National Lab, Lawrence Livermore National Lab, Sandia National Labs, and SLAC National Accelerator Lab).

The Challenge of Economywide Deep Decarbonization by Midcentury

California's state government has enacted legislation and issued executive orders to increase clean energy deployment and to reduce greenhouse gas (GHG) emissions by 2030 and midcentury. As described in previous chapters, the 2030 targets can, by and large, be achieved with commercially available technologies and their incremental improvements.

In contrast, meeting the long-term decarbonization targets—including carbon-neutral electricity by 2045, economywide carbon neutrality, and an 80 percent reduction by 2050 from a 1990 baseline—will require clean energy technology innovation. Many challenges must be addressed to meet these goals, including the following:

- The rising marginal costs of GHG abatement. As the lowest-cost opportunities to reduce GHG emissions (e.g., solar, wind, hydro, biofuels) become widely deployed, additional technologies will be needed to meet the remaining required reductions.
- The need for new infrastructure as California deploys a dramatically different portfolio of clean resources (e.g., economywide hydrogen and advanced electrification). Building a new infrastructure raises the question of the fate of costly and substantial legacy assets. There may be resistance to stranding these assets.
- The extreme difficulty of predicting and prescribing the mix of clean energy technologies needed by 2050. Enormous uncertainties surround not only the question of the technology breakthroughs that may occur over the next 30 years, but also issues such as the dynamics of public acceptance of new technologies (e.g., questions concerning land use, siting new infrastructure, large-scale

sequestration); evolving costs; changing energy markets; the state and national legislative and regulatory environment; international progress on GHG emission reductions; and the availability of supporting infrastructure.

- The uncertainties surrounding how deeply decarbonized systems will operate at large scale and for long durations. Studies show that for electric grids to perform reliably in scenarios with high penetration of intermittent renewables, the total installed generation capacity would need to be between 3.0 and 5.5 times peak demand.[1] In California, this could mean an installed capacity of up to 275 gigawatts (GW) of renewables—roughly the equivalent of the combined current U.S. installed capacity of nuclear, wind, and large hydro electricity generation.[2] There are a number of factors that could limit this level of renewable deployment. They include the costs to construct large amounts of renewable generating capacity, including storage; land-use consequences; and uncertainties that could affect renewable resources, such as long-range changes in weather associated with climate change (e.g., precipitation patterns, extreme temperatures, fog) and the related increased potential for natural disasters (e.g., drought, wildfires, and sea-level rise).
- The current lack of scalable and affordable technologies and systems for meeting deep decarbonization goals in several key applications. These include high temperature process heat for Industry; time-flexible load-following electricity generation; large-scale, long-duration electricity storage; and low-carbon fuels, including fuels for heavy-duty vehicles, air transport, and shipping, that can be stored for daily, weekly, and seasonal uses.
- The strong likelihood that cost-effective and efficient negative-emissions technologies (NETs) will be needed for California to meet carbon-neutral economywide and zero-emissions electricity goals by midcentury. The technologies that could help achieve carbon neutrality are in relatively early stages of development and include: CO_2 capture from dilute sources; massive utilization of captured CO_2 in commodity products; and both geological and biological sequestration at very large scale.

The impact of breakthrough innovation "surprises" cannot be underestimated in shaping the midcentury low-carbon system. For example, if large-scale carbon dioxide utilization becomes economic, the demands on sequestration are commensurately less. If large-scale carbon direct removal is employed, physically and/or biologically, net-zero emissions become a more practical goal. Low-carbon hydrogen, and an associated infrastructure, could address many sectoral challenges and long-term storage issues. All of these options need to be the subject of a greatly enhanced research, development, and demonstration (RD&D) effort starting now.

All of these issues raise a final concern: the availability of large amounts of capital to finance the fundamental transformation of the California energy system. Many of the technologies discussed in this report are not economically viable at present. For this reason, capital formation is challenging and traditional investors in the development and deployment of energy technologies cannot be relied on. Venture capital investments in clean energy technology have dramatically declined. Most institutional investors—the source of much of the capital for U.S. energy project finance—typically see too much risk in advanced technology development and deployment. DOE has limited energy technology and project investment dollars, as does the government of California. Corporate energy investment is available but tends to look for later-stage, lower-risk opportunities. The Chinese have demonstrated an appetite for this sort of investment, but their capital often comes with a host of challenges. This overarching challenge of capital formation must be addressed in parallel with the technology and policy work discussed in this report.

Modeling the Cost of Deep Decarbonization by Midcentury

Over the last several years, there has been a growing debate in the academic literature around the cost of reaching deep decarbonization, especially in the Electricity sector.[3] Many types of models have been used to simulate the available pathways, ranging from using only renewable resources to employing the broadest set of options (e.g., clean hydrogen for power generation).

This study provides a cross-sectoral analysis of the potential pathways for California's decarbonization. It uses an economywide model of California—the U.S. Regional Energy Policy (USREP) model—to examine the cost of meeting the state's decarbonization policies by midcentury *without technology innovation*, while considering the dynamic impacts to the energy system. The USREP model,[4] developed at the Massachusetts Institute of Technology (MIT), is a recursive dynamic computable general equilibrium model that considers the state's policies as constraints and then solves for these constraints sector-by-sector. Details of the model are found in Appendix A, including the list of California policies that informed the model and its results.

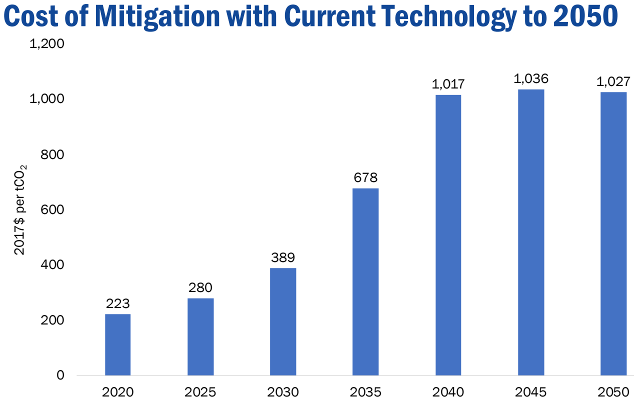
A highly instructive result of the modeling is the costs to California of meeting its policies without fundamental changes in commercially available clean energy technology. In the scenario shown in Figure 8-1, all existing policies are removed and replaced with a carbon charge. The price is determined over time as that needed for a linear reduction of CO_2 emissions to meet the midcentury goal.

As shown in Figure 8-1, costs to the economy of meeting California's low-carbon policies remain relatively stable until 2035 when they dramatically accelerate; this "hockey stick" trajectory reflects the high marginal costs associated with meeting zero-carbon electricity by 2045.

In this scenario, there is a mitigation cost of \$389 per metric ton of CO_2e in 2030, \$1,036 in 2045, and \$1,027 in 2050. To put this in perspective, the

Figure 8-1

Cost of Mitigation with Current Technology to 2050



In a scenario in which California's decarbonization policies are replaced by a carbon charge, without innovation that charge would have to be \$1,027 in 2050 in order to achieve the 80 percent carbon reduction target. Source: MIT, 2019.

2018 estimated costs of direct air capture (DAC) technology is between $30 and $1,000 per metric ton of CO_2.[5]

The results of the MIT USREP modeling of the "no technology innovation" scenario strongly underscores the essential role and value of clean energy technology innovation for California—and the rest of the world—to affordably meet midcentury emissions reductions goals. A factor of two reduction in DAC costs alone, for example, would have a profound effect in the USREP scenario.

The results of any energy sector model that makes long-term projections should not be over-interpreted. This model does not solve for hourly electricity dispatch, for example, nor does it have a robust module for simulating emerging technologies, such as grid-scale battery storage, renewable natural gas, or clean hydrogen.

The model is, however, instructive concerning cost trajectories associated with meeting California's emissions reduction goals, absent major improvements in technology performance and cost. The modeling results reinforce the need for ongoing support from the state for a robust portfolio of clean energy technology options. It also reinforces the intuition that there is a very steep cost curve for getting the last percentage of CO_2 emissions out of the system.

Reference Frame for Meeting the Midcentury Targets

Before discussing possible building blocks for a deeply decarbonized midcentury energy economy, an "existence proof" is offered to help establish greater context for the need for innovation. This proof considers the macro-supply issues for an economy built on carbon-free electricity (principally solar and wind), plus carbon-free hydrogen produced by electrolysis of water using carbon-free electricity. In short, it is a scenario in which California has a carbon-free, electricity-driven economy.

In a more detailed model of energy in California's economy, additional dynamics would need to be incorporated, such as the use of storage technologies and/or natural gas for meeting the challenges of large amounts of intermittent generation and the uncertainty of the availability of renewables in the days-to-weeks timeframe. The focus here is on the seasonal characteristics of a very-low-carbon economy driven principally by solar and wind.

As shown in Chapter 2, solar and wind in California produce more energy, by greater than a factor of two, at their summer peak compared to their winter minimum. This implies there will be considerable excess generation in the summer. This generation could be used to produce hydrogen (on a carbon-free basis) that can be stored and used year-round to serve the needs for fuel and/or heat in hard-to-decarbonize sectors, especially in heavy-duty vehicles and in subsectors that rely on high-temperature process heat.

Direct electricity use in California is nearly 300 TWh per year. Low-end projections of increased electricity demand increase this use to over 400 TWh per year by 2050, reflecting—among other things—population growth. A comparable amount of electricity would be needed to electrify the light-duty vehicle fleet, and roughly 200 TWh for replacing natural gas heating of residential and commercial buildings. This scenario assumes that hydrogen (produced from wind and solar) replaces diesel in heavy-duty vehicles and natural gas in Industry, with a small amount used in the Buildings sector (i.e., mainly for fuel cells).

Qualitatively, the top line of this "toy model" of a clean electricity- and hydrogen-based economy is that overall electricity use increases by a factor of four to five by midcentury compared to today. The bulk of the generation comes from wind and solar—especially solar. The resulting estimate of two-thirds/one-third split of direct electricity use (roughly 930 TWh/y) and hydrogen production (370 TWh/y) is a very good match to California's sectoral needs: the large summer electricity peak can be used to produce enough hydrogen to cover the major seasonal swings in generation. A scenario of this type could be used as the basis of a deeply decarbonized economy at midcentury.

Of course, it is also important to emphasize that this "toy model" is neither a prediction nor a solution that would stand on its own. For example, the grid dynamics of such a strong dependence on intermittent generation would have to be addressed. Also, such an energy economy would be very expensive because of the very high cost of electrolytically-produced hydrogen.

This is where innovation comes in to play. Can electrolyzer capital costs be reduced significantly? Even more importantly, will the very large amount of carbon-free electricity be available at very low cost? Will large-scale CCUS make steam reforming of natural gas a less expensive future option for hydrogen production? Will there be long-duration storage to manage the grid reliably and affordably? The bottom line is that optionality will be central to devising an optimal low- to no-carbon midcentury energy economy tailored to California's objectives, opportunities, and challenges. The focus of this chapter is on some of the key pathways that could contribute considerable flexibility—and presumably add to reliability and resilience and reduce costs—to a deeply decarbonized California energy system.

Pathways to Deep Decarbonization by Midcentury

As a U.S. and global leader in clean energy, California is well suited to promote the development of an advanced clean energy technology portfolio. This work must begin today. A portfolio with specific priorities can help ensure that programs pursued by multiple stakeholders in California (and beyond) are timely, stable over time, and mutually supportive.[6] This approach can give innovators a framework for assessing the prospects of a particular initiative and the steps needed to sustain critical innovations over long time periods. It can also give corporate adopters, financial investors, and policymakers visibility into the evolving future of clean energy.

Technology Selection Criteria

To develop a clean energy innovation portfolio, this analysis promotes a set of selection criteria based on technical merit, market viability, compatibility, and consumer value. The selection criteria were adopted from the Energy Futures Initiative (EFI) and IHS Markit report *Advancing the Landscape of Clean Energy Innovation*, released in February 2019.[7]

- **Technical Merit** includes energy or environmental performance, including GHG reduction, that lead to systems-level performance improvements. It includes the development of new knowledge, enabling innovations, and gains from learning-by-doing that favorably affect cost, risk, and performance across a variety of technologies or systems.
- **Market Viability** includes manufacturability at scale with adequate and secure supply chains; a viable cost-benefit ratio for providers, consumers, and the greater economy; maturity to support very large scale-up; economic and environmental sustainability from a life-cycle perspective; significant market penetration; and revenue generation.
- **Compatibility** includes the potential to interface with a wide variety of existing energy infrastructures (interoperability); the potential to adapt to a variety of possible energy system development pathways (flexibility); the potential to expand or extend applications beyond initial beachhead applications (extensibility); and the ability to minimize stranded assets.
- **Consumer Value** takes into consideration potential consumer preference issues, such as expanded consumer choice (by facilitating the introduction of new or improved products and services) and ease of use.

Figure 8-2

Technology Priorities with Long-Term Breakthrough Potential

Technologies were identified as having long-term breakthrough potential for California based on EFI-determined screening criteria. Source: EFI, 2019. Graphics from Noun Project.

A broad list of candidate technologies was developed and organized by energy supply (electricity and fuels), energy application (industrial, transportation, and buildings), and cross-cutting technology areas (large-scale carbon management, advanced materials, and high-performance computing). Table 8-14, listing these technologies along with their estimated timeframe for development, is found in the Addendum at the end of this chapter.

Technology Priorities for California's Innovation Portfolio

Using the selection criteria described above, a shortlist was created of technologies are likely to have long-term breakthrough potential (Figure 8-2). The technologies in this shortlist were further screened based on California's policies and programs, energy system and market needs, and other distinctive regional qualities that would position California to be a technological first mover: a strong resource base, relevant workforce expertise, and robust scientific and technological capacity.

Technology development occurs on a continuum. Depending on the level of investment, policy support, and market readiness, it is highly likely that incremental improvements in many of the key breakthrough technologies identified in this analysis would facilitate their deployment before midcentury.

Others may reach the critical tipping point and disrupt the state's energy systems much earlier than current data and analyses suggest. As noted above, however, there is significant uncertainty associated with research outcomes and technology uptake. The following discussion of this suite of technologies—which have the potential for breakthroughs that could dramatically bend the cost curve of their application and help meet midcentury emissions goals—reflects both this continuum and the lack of a neat division of technologies by timescales. Many of these technologies also relate to and enable large-scale carbon management, which is likely to be essential for meeting midcentury emissions goals, especially carbon neutrality, as discussed in Chapter 7.

Technologies to Support Smart Cities

California's population is expected to grow to 49 million people by 2050, up from 40 million in 2016. The last census in 2010 showed that 95 percent of the state's population lived in urban areas.[8] Expected urban population growth could strain energy systems, as operators and policymakers work to ensure that these systems remain reliable, affordable, and resilient. Technologies that support "Smart Cities," such as sensors, communications, and open data systems, are being deployed in dozens of major cities around the world.[9] Expanding the use of these technologies to accelerate Smart City systems in California could provide the state with a range of options for lowering its emissions profile while improving its resilience to the impacts of climate change. Table 8-1 maps the technology innovation selection criteria with opportunities of smart city technologies.

Table 8-1
Smart Cities

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
 Smart Cities	Revolutionizes the interoperability of energy and city systems Scalable approach to reducing GHG emissions, increasing resilience to climate change impacts, and creating economic value	Provides foundation for innovation of multiple infrastructures: energy, urban, commercial, transport, industrial, and residential[10]	California is already a leader in smart end-use systems and development of smart technology California's population growth and concerns over impacts of climate change will require innovative solutions	Unlocks new economic value Links customer needs to wider economic activity May reduce customer costs Improves resource efficiency
Challenges				
Cross-sectoral jurisdictional issues; upfront costs; cyber and physical vulnerabilities, especially at large-scale; standards issues				
Source: EFI, 2019.				

The evolution of a Smart City is a dynamic process—policies and programs to make cities smarter must be thoughtfully and carefully developed and implemented to provide continuous and economical essential services. At the same time, success in developing the 21st century infrastructure backbone for Smart Cities will provide competitive advantage in attracting talent and businesses. Embracing emerging technologies such as artificial intelligence will be critical for differentiating the many varieties of Smart Cities that are emerging. The key is to commit to advanced integrated information, communication, and electricity infrastructures with deep data collection. This will be the platform for entrepreneurial opportunity to supply services tailored to different cities.

California is already a leader in deploying smart technology in its energy and end-use sectors. This puts California at a competitive advantage in transitioning these individual technologies into a coordinated Smart City system. Creating frameworks for leveraging this existing infrastructure, while creating a platform for new growth, will be critical to the energy transition. Existing smart end-use systems are already being deployed across the Electricity, Buildings, Industry, and Transportation sectors.

- In Electricity, for example, these systems collect and transmit customer data to utilities, establishing "touch points" at which utilities and customers can interact. According to the California Public Utilities Commission (CPUC), these smart devices have helped utilities improve electric reliability through enhanced reporting.[11]
- In Buildings, there are now more than a dozen state-approved home energy management systems on the market,[12] and financial rebates and demand response programs exist for each of the three major electric utilities.[13] According to market research cited by Southern California Edison (SCE), by 2020, 25 percent of SCE customers are expected to own a smart thermostat.[14]
- In Industry, major developments in the last decade in additive manufacturing (also known as 3D printing), have emerged that promise to lower emissions by accelerating production schedules and lowering energy-intensity. Additive manufacturing leverages computer modeling and advanced raw materials to construct a wide range of customizable products.
- In Transportation, California is a leader in the development and deployment of autonomous vehicles. In May 2018, for example, the CPUC announced pilot programs that allow completely autonomous, as well as driver-monitored, vehicles to transport passengers that can find the vehicles through a smartphone app.[15]

Many cities are actively developing planning documents to guide Smart City development. A common approach to address Smart City design and implementation, including shared definitions and guiding principles for decision-making, could be useful in this rapidly changing environment. A concise, unified framework to inform policymakers and investors on how to translate and distill the imperatives, requirements, opportunities, and challenges for informed decision-making would be valuable (see Figure 8-3). Such frameworks should be actively coordinated with energy system owners and operators and guide parallel development of highly compatible, smarter energy systems.

Figure 8-3

End-to-End Flow of Data and Information in a Smart City Design: Start of a Framework

Inbound Flows → Channels and Platforms → Operations → Outcomes

Inbound Flows

- Energy
- Water
- Information
- Mobility (people flows)
- Food
- Materials / Equipment
- Land development
- Health
- Security & Safety

Channels and Platforms

- Pipelines
- Ports -- air and sea
- Data via wires and airwaves
- Streets, roads, highways
- Sidewalks, promenades, etc.
- Platforms—integrated hardware, software, knowledge, and processes that orchestrate and direct various inbound flows into one or more frameworks for operations and control.
- Capacity building of a variety of institutional actors in cities to participate in designing or adapting new technologies to achieve desired social outcomes.

Operations

- Street lighting
- Police and fire
- Security cameras and monitoring
- Ambulances
- Utility systems and services
- Communications infrastructure
- Waste management
- Traffic flow and congestion management
- Taxis and other mobility services
- Entertainment and shopping venues

Outcomes

The *benefits* realized from inbound flows through channels and platforms to operational apps, such as:

- Sustainable, reliable clean energy
- Low crime, safe neighborhoods
- Effective and reliable connectivity
- Improved traffic flows, with low to zero emissions impacts
- Better public places and land uses
- A wide array of enhanced values captured through smart applications and deployments (further discussion in Part III)
- Healthy land uses, urban developments and redevelopments

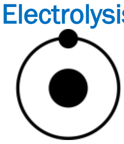
Cities function by taking in resources, then processing and leveraging them through channels and platforms as well as transforming them into operational tools (or apps) to achieve desired outcomes, i.e., benefits that enhance the quality of life of city residents. These flows remain the same whether achieved through analog or digital means, but digitalization enables faster and more precise realization, while creating a spatial environment that partially overlaps the natural environment. Source: EFI, 2019.

Hydrogen from Electrolysis

As noted in Chapter 7, hydrogen is a clean energy carrier, capable of storing and delivering energy on demand. Hydrogen offers a clean-energy pathway in nearly every sector of the economy, including some of California's most difficult-to-decarbonize sectors: high-temperature process heat for Industry, fuel for heavy-duty vehicles in Transportation, and long-term energy storage for Electricity.

Today, most hydrogen is produced using natural gas; its near-term decarbonization benefits are limited unless production is integrated with carbon capture, utilization, and storage (CCUS). Hydrogen can also be produced via electrolysis where electricity and water are the only inputs to the process. Using renewable generation in this process would eliminate GHG emissions from hydrogen production, making hydrogen an emissions-free fuel. Finally, using excess generation from renewables that would otherwise be curtailed would add value and provide a large-scale storage option. Table 8-2 maps the opportunities of electrolytic hydrogen with the technology innovation selection criteria.

Table 8-2
Hydrogen from Electrolysis

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Hydrogen from Electrolysis 	Wide applicability: Electricity, Industry, Transportation, Buildings. Energy storage for renewables, reductant and heat for Manufacturing (Chemicals and Steel), and Petroleum Refining Portable, storable, durable energy-dense fuel	Supports large-scale renewables grid, as a long-term storage and load-following resource	Large industrial sector experience Significant workforce and science and technology expertise Interfaces with numerous other infrastructures: natural gas, chemicals, refining	At-scale could significantly drive down cost of clean alternatives in Industry, Electricity, and Transportation
Challenges				
Technical, cost, and infrastructure requirements to develop clean hydrogen at-scale				

Source: EFI, 2019.

Hydrogen from electrolysis could offer a viable option for deep decarbonization in the midcentury timeframe. A brief techno-economic case study—on a hypothetical electrolyzer facility that generates hydrogen, using excess solar photovoltaic (PV) electricity generation in California in 2020 and 2030—is presented in Box 8-1.

California is well suited to support economically viable pathways to producing clean, electrolytic hydrogen at scale. California already has supportive policies and programs for exploring the long-term benefits of clean hydrogen. This support spans a number of programs that target multiple sectors, including Transportation and Electricity. California has, for example, established several Low Carbon Fuel Standard (LCFS) compliance credits across the hydrogen value chain—from fuel retailers to hydrogen producers and refiners—intended to support hydrogen's entry into the state's fuel market.[16]

California also possesses a significant workforce and science and technology capacity to support the development of clean hydrogen pathways. Lawrence Berkeley National Lab (LBNL) is a leader in exploring economically viable, clean hydrogen in support of DOE's H2@Scale initiative.[17] Its researchers are looking to develop intermittent electrolyzers that could operate more efficiently with variable renewable resources.[18] In addition, many of California's research universities have robust hydrogen research efforts underway. Scientists at Stanford are developing an anode that directly converts alkaline seawater to hydrogen.[19] This technology could help address the water requirements of at-scale hydrogen electrolysis. The University of California at Irvine supports the National Fuel Cell Research Center with the goal of accelerating the development and deployment of fuel cell technology and systems. The program supports beta-testing of prototype systems, which is critical to helping hydrogen end-use systems enter the marketplace.[20]

Box 8-1

Case Study of Using Excess Renewables in California to Produce Hydrogen

The cost of producing hydrogen at a steady rate using solar PV and low-temperature electrolysis technologies was estimated, with an explicit accounting for the variability in PV resource availability and the role for energy storage to mitigate this variability. The integrated design and operation of the PV-electrolysis process is modeled to identify the process configuration that minimizes the sum of the annualized capital costs and operating costs while adhering to various system constraints (Figure 8-4). These include: (1) inter-temporal constraints on the available capacity of energy storage in each hour of the year (hydrogen and battery storage); (2) limits on hourly PV resource availability for the region of interest; (3) AC power requirements for hydrogen compression; and (4) power and energy capacity limits of various components (e.g., PV, electrolysis, battery).

Table 8-3

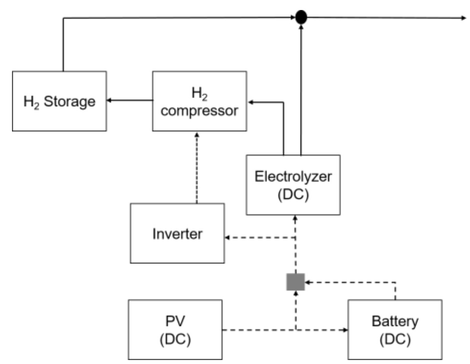
Costs of Hydrogen Production

Parameters	2020 Scenario	2030 Scenario
Capital Costs		
PV ($/kW DC)	850	608
Electrolyzer ($/kW)	800	300
Hydrogen storage ($/kg)	800	400
Compressor ($/kW)	1200	1200
4hr -battery storage costs ($/kWh)	350	180
Inverter ($/kW)	60	60
Capital charge factor (CCF)	7.8 percent	7.8 percent
Fixed Operations and Maintenance Costs		
Storage ($/kW/yr.)	7.8	5.3
PV ($/kW/yr.)	13	13
Electrolyzer ($/kW/yr.)	42	42
Hydrogen storage ($/kg/yr.)	0	0
Variable Operations and Maintenance Costs		
PV ($/MWh)	0	0
Electrolyzer ($/MWh)	0	0
Storage charge/discharge ($/MWh)	2.7	2.7
Hydrogen storage ($/kg)	0	0
Performance Parameters		
Electrolyzer efficiency, LHV (percent)	70	
Design hydrogen flow rate (kg/hr.)	500	
Minimum hourly utilization factor	90 percent	

Technology cost and performance assumptions.

Figure 8-4

Hydrogen System Constraints



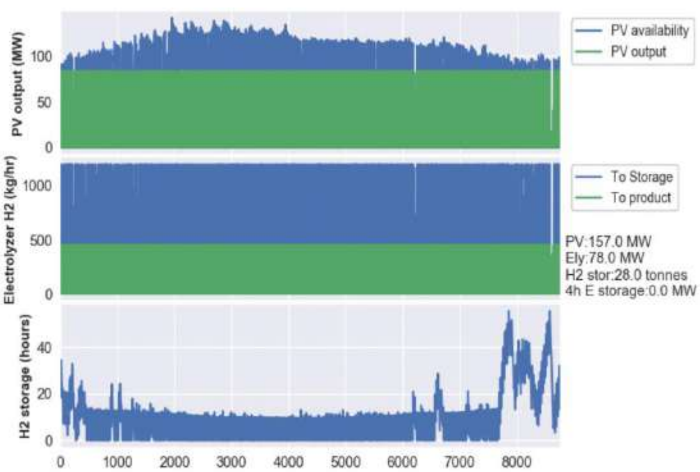
Hydrogen production from integrated PV-electrolysis systems. Dotted lines and solid lines indicate electrical energy flows and hydrogen (H_2) flows, respectively. EFI, 2019

Major Design and Operational Trends

Table 8-3 summarizes the optimal design and annual operating profile for a hypothetical hydrogen production facility located in California for assumptions following the "2020 Scenario" in Table 8-3. For this scenario, the optimal electrolyzer capacity for the process is estimated to be about 50 percent of the peak PV capacity rating, which results in about 58 percent of the PV resource being utilized. This underutilization of PV generation is prevalent throughout the year, as highlighted by the difference in the height of the blue and green lines in the top panel of Figure 8-5. For the purposes of the modeling, no four-hour battery storage is deployed as part of the optimal system design for the assumed capital cost of $350 per kilowatt-hour (kWh). Consequently, the electrolyzer operates only when the PV array is producing power) and in general, a majority of the hydrogen produced is sent to storage (about 60 percent), while the remaining hydrogen is used to meet hourly production requirements (450-500 kg per hour).

The capacity of hydrogen storage required to meet hourly production requirements is set by the storage requirements during the winter months when solar resource availability tends to be the lowest across the year.

Figure 8-5
Summary of Annual Operating Profiles for Hydrogen Storage



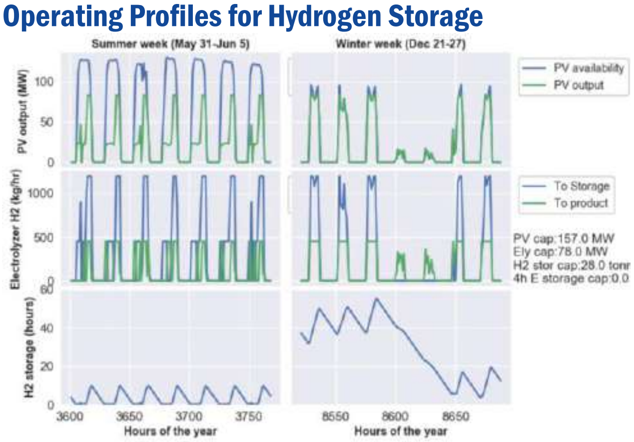
This figure shows PV and electrolyzer for a facility located at Albuquerque, NM, and cost assumptions as per the "2020" scenario. Hours of hydrogen storage are calculated by dividing the inventory of stored hydrogen with the design flow rate of 500 kg H_2/hr. Source: EFI, 2019

The difference in storage levels across seasons is illustrated by a comparison of weekly operating profiles for summer and winter seasons, shown in Figure 8-6. During the summer, the amount of hydrogen stored is much less than 20 hours of storage and is reflective of the need to manage the diurnal variability in solar availability. In winter, however, there may be instances when hourly PV output during the day may be insufficient to even supply the instantaneous hourly production requirements. At such times, hydrogen storage needs to be discharged over much longer durations (as much as about 60 hours) without having the opportunity to be recharged. Figure 8-6 illustrates such an event in a week in December where hydrogen storage discharges continuously over two days in order to make up the deficit in daytime hydrogen production from the electrolyzer.

Solar availability has a major impact on the cost of hydrogen produced. Figure 8-7 shows the cost of hydrogen at different locations with varying solar capacity factors and profiles. It also demonstrates the cost reduction from 2020 to 2030. Table 8-3 shows the basis for the changes in cost between the two timeframes.

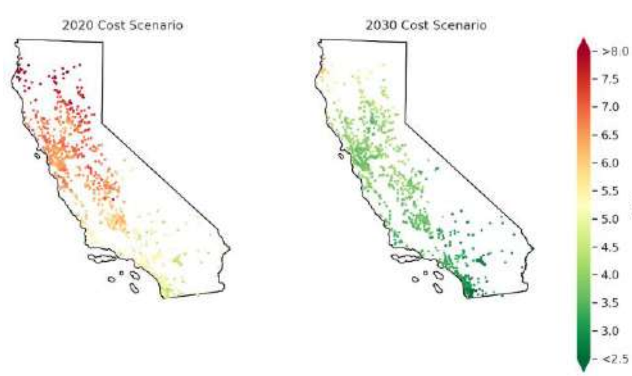
The expected build-out of California's wind and solar resource aligns with a clean energy pathway to produce hydrogen using excess renewable electricity. This clean hydrogen, as an energy carrier, can serve as a critical energy storage medium at different scales for the stability of California's electric grid.

Figure 8-6
Operating Profiles for Hydrogen Storage



This figure shows PV and electrolyzer for a facility located at Albuquerque, NM across a summer week (1st column) a winter week (2nd column). Cost and performance assumptions are defined in Table 8-3. Source: EFI, 2019

Figure 8-7
Hydrogen Cost Variation Due to Solar Availability Throughout California



Hydrogen variation due to solar availability throughout California. Source: EFI, 2019

Seasonal Energy Storage

The growth of zero-emissions renewable energy in California is essential for achieving its midcentury decarbonization goals. The increased penetration of intermittent renewable generation, however, creates significant challenges for grid operations. Today's short-duration energy storage offers a limited alternative to natural gas for managing intermittency, but longer-duration storage is needed to operate a reliable grid without natural gas-fired generation as a backup. Currently, there is no clear technology pathway to address long-duration (i.e., days to weeks to seasonal) needs. Table 8-4 maps the opportunities for seasonal storage with the technology innovation selection criteria.

Table 8-4
Seasonal Storage

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Seasonal Storage	Allows the transition to a high-renewables grid with less overbuild or use of natural gas-fired generation	Monetizes excess renewable generation that might otherwise be curtailed Allows for a less expensive high-renewables grid	Existing projects in California with compatible technologies RD&D from California utilities and universities Synergy with other hydrogen development	Could bring down the levelized of energy from resources like solar and hydro

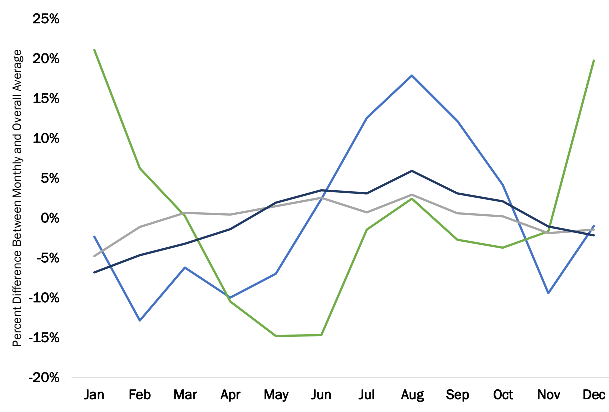
Challenges

Technical and cost challenges of storage technologies; market to properly value seasonal storage

Source: EFI, 2019.

The need for seasonal storage is driven by both demand-side and supply-side seasonal differences. On the demand side, there is significant fluctuation in electricity consumption, largely driven by air conditioning needs. Between 2001 and 2017, the average electricity consumption in August was 18 percent higher than the overall annual average, while consumption in February was 13 percent below the annual average, a swing of around 6.6 TWh (Figure 8-8).[21] Seasonal consumption trends may be also be impacted by widespread electrification of end uses, such as transportation or home heating. Electrification could exacerbate the

Figure 8-8
Seasonal Variability in California Energy Consumption, 2001-2017



Electricity consumption undergoes an average swing of 6.6 TWh between February and August. End-use electrification could shift some of the seasonal loads of natural gas and petroleum to the electricity system. Source: EFI, 2019. Compiled using data from EIA, 2017.

seasonal peak, or it could create a second peak (e.g., in December or January, when natural gas use in California currently peaks).[22]

On the supply side, California solar, wind, and hydropower generation have concurrent seasonal peaks in the summer. This creates mismatches where periods of overgeneration (i.e., summer) result in curtailment, selling of excess electricity, or even paying other states for offtake. In periods of under-generation (i.e., winter), natural gas generation fills the gap. In the absence of seasonal storage, these mismatches will become more severe as California shifts away from baseload resources, such as nuclear, and brings more solar and wind generation online.

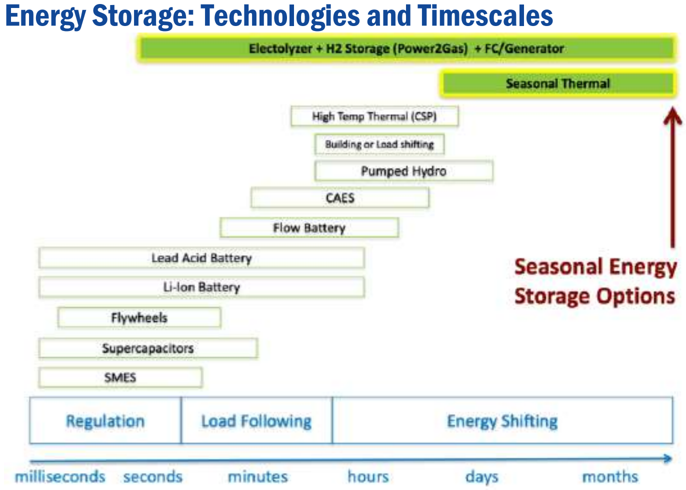
Short-duration storage has been dominated by electrochemical technologies, especially lithium-ion batteries. In general, however, electrochemical options are unsuited to seasonal storage (Figure 8-9). There has been research on flow batteries that could be used for seasonal applications, but to date there have been no breakthroughs.[23]

There are two mechanical storage technologies that may be more viable for longer-duration storage: pumped storage hydropower (PSH) and compressed air energy storage (CAES).[24] PSH is a relatively mature technology, but it is geographically constrained, has little room to grow in California (as described in Chapter 2). CAES involves compressing air into tanks or caverns and storing it under pressure. When the unit is called to dispatch, the pressure is released, spinning a turbine and generating electricity. While these technologies have been utilized for longer-duration storage (i.e., greater than five hours), their capability for seasonal storage is questionable.

California already has around 4.0 GW of PSH capacity, with an additional 2.4 GW of announced projects from closed-loop PSH (i.e., not connected to a flowing water source).[25] Pacific Gas and Electric (PG&E) has announced plans for a 300-megawatt (MW) underground CAES system in San Joaquin County.[26] There is more than 30 MW of installed thermal storage capacity in California,[27] divided among ice thermal, heat thermal, and chilled water storage; SCE and Riverside Public Utilities have announced or contracted additional ice thermal systems totaling 35.6 MW.[28] These systems are not designed for seasonal storage.

Their deployment lays the groundwork for further development of these technologies in California. All of the technologies in the load-following and longer-duration columns in Figure 8-9 require

Figure 8-9
Energy Storage: Technologies and Timescales



Mechanical solutions have dominated the development of short-duration storage, but different options – especially thermal technologies and hydrogen for storage. Source: NREL, 2016.

innovation to adapt them for seasonal storage purposes and to reduce costs. Fuels-based systems, however, avoid the dependence on breakthrough innovation in seasonal storage. Market innovation will also be required, as there is currently no market for seasonal storage.

Building Performance Technologies

Residential and commercial buildings accounted for 9.2 percent of statewide emissions in 2016, mainly driven by natural gas use for space conditioning, water heating, and cooking. California's Zero Net Energy (ZNE) Buildings initiative sets the course for long-term energy improvements from buildings by calling for new residential and commercial buildings to be ZNE by 2020 and 2030, respectively, for 50 percent of new major renovations of state buildings to be ZNE by 2025, and for 50 percent of commercial buildings to be retrofitted to ZNE by 2030.[29] This goal has been accompanied by updates to the state's energy efficiency codes and standards for buildings and appliances that have already lead to significant reductions in electricity consumption from the Buildings sector.[30]

Through 2030, California has options for achieving modest levels of emissions reduction from the Buildings sector: energy efficiency, combined heat and power (Commercial Buildings subsector only), renewable natural gas use, and end-use electrification, among others. Each of these pathways will likely play an increasing role through 2050. To support statewide emissions reductions by midcentury, however, technology breakthroughs will likely be needed in building design, operations, materials, and end-use systems. Table 8-5 maps the opportunities of select building performance technologies with the established innovation selection criteria.

Table 8-5
Building Performance Technologies

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Building Performance Technologies 	Multiple pathways for reducing total energy needs for buildings Emerging "smart" technologies can be harnessed for energy savings	California already has ambitious EE policies that will depend on breakthroughs in building technologies Smart building designs can support advances in other sectors (i.e., Electricity)	Significant R&D support for energy efficiency in California Robust smart systems capacity in California Wide range of technologies with substantial upside	Pathways should lead to measurable cost savings to commercial and residential buildings
Challenges				
Large building stock with slow turnover; consumer preferences can pose issues; most emerging technologies only provide incremental improvements; additional R&D is necessary				

Source: EFI, 2019.

Improving the energy efficiency of building envelopes can significantly contribute to reducing overall building energy use, 35 percent of which is for maintaining a comfortable and safe interior environment. According to DOE, currently available technology can only incrementally improve the energy efficiency of building envelopes.[31] The next generation of designs for buildings will include technologies for highly insulating windows, walls, and rooftops; methodologies and analysis tools for measurement and validation of building envelope performance; and market-enabling efforts such as the creation of an organization responsible for rating, certifying, and labeling materials and products.[32]

Improved building operation is another area that could measurably improve the energy needs of California's building stock. Platform technologies, such as Home Energy Management Systems (HEMS), could provide homeowners with data and control of household energy use. Applications exist for specific end uses, such as lighting, heating, cooling, and appliances, as well as for home energy loads.[33,34] Building loads can be turned on or off using active control systems that collect, process, and adapt to real-time conditions. Based on a modeled use of a HEMS at a household in New York by the New York State Energy Research and Development Authority, the cost savings per household was estimated to be $268 for the year from a reduction in the use of electricity (savings of 1,241 kWh per year) and natural gas (savings of 52 therms per year).[35]

Due to the long lifetime of the buildings stock in California—the majority of residential buildings are more than 35 years old[36]—there should be a focus on developing building performance technologies for retrofits. Key research opportunities[37] include the following:

Building Envelopes/Lighting

- High-efficiency lighting, including improved green light-emitting diodes, phosphors, and quantum dots;
- High-efficiency heat pumps that reduce or eliminate the use of refrigerants with high GWP;
- Thin insulating materials;
- Windows and building surfaces with tunable optical properties;
- "Smart windows" enabled by electrochromism, a reversible process that blocks both visible light and heat from light;
- Dynamic facades;

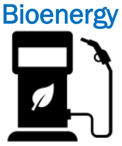
Smart Controls

- Improved software for optimizing building design and operation (e.g., Home Energy Management Systems);
- Low-cost, energy harvesting sensors and controls;
- Interoperable building communication systems and optimized control strategies; and
- Decision science related to issues affecting purchasing and operating choices.

Bioenergy

Bioenergy is a broad term for renewable energy resources derived from organic material (biomass) that can serve as an energy substitute in many end uses, including heating, power, and transportation. Biomass feedstocks include wet organic wastes (sewage sludge, animal wastes and organic liquid effluents, and the organic fraction of municipal solid waste), cellulosic feedstocks (crop and forest residues and non-food energy crops), food crops (corn, wheat, sugar and vegetable oils produced from palm, rapeseed and other raw materials);[38] and nonfood crops such as perennial lignocellulosic plants (grasses and trees).[39] Table 8-6 shows the opportunities of bioenergy with the technology innovation selection criteria.

Table 8-6
Bioenergy

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Bioenergy 	Renewable hydrocarbon biofuels have identical chemical composition to fossil fuels Provide options for hard to decarbonize sectors	Biofuels are currently economically supported through California's Low Carbon Fuel Standard (LCFS) and the federal Renewable Fuels Standard (RFS)	Advanced biofuels are interchangeable with their fossil fuel counterparts and are compatible with existing vehicles, machinery, and petroleum pipeline infrastructure	Biomass fuel costs have a higher degree of stability compared to fossil heating fuels[40]
Challenges				
Biomass feedstock availability and supply chain limitations; land-use implications (deforestation, CO_2 emissions from land-use change, nitrogen losses, unsustainable water withdrawals and food prices);[41] costs of production; existence of credits or other policy support				
Source: EFI, 2019.				

In 2017, biomass provided 2.35 percent of California's total power generation[42] and as of January 2018, biofuel blends replaced conventional fuels in the more than 1.7 million biofuel vehicles on the road in California.[43] Biomass can be directly combusted for power or heat, or it can be converted to fuels through processes such as pyrolysis (decomposition through heating in the absence of oxygen),[44] or thermochemical or biochemical conversion.[45] Biomass can also be gasified to produce hydrogen.[46]

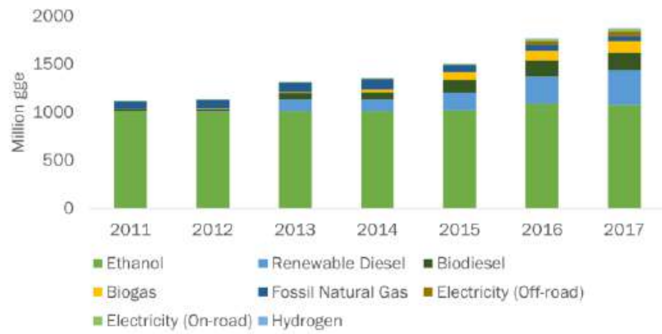
Innovation in bioenergy technologies could provide new decarbonization pathways for many Industry subsectors—such as Cement, which requires high process heat and is very carbon-intensive—as well as applications in the Buildings and Agriculture sectors. Three major focus areas of bioenergy basic research are: creating new energy crops; developing new methods for deconstructing lignocellulosic material; and inserting new metabolic pathways into microbial hosts to increase the production of ethanol and other advanced hydrocarbon fuels that can displace petroleum-based fuels with biomass-based fuels.[47]

While there already is policy support for bioenergy in California, as evidenced by its successful LCFS and other policies supporting alternative fuels, technical and economic challenges remain to midcentury (Figure 8-10). Biomass feedstock availability is a critical constraint. Globally, biomass feedstock will need to increase fivefold for bioenergy to play a major role in decarbonization.[48] Costs and uncertainties of feedstock availability could limit the success of this long-term solution.

Advanced biofuels, according to the International Energy Agency, are "sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant lifecycle GHG emissions savings compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts."[49] At present, production of advanced biofuels is low, due to high investment requirements, production costs, limited policy support, and additional cost uncertainties related to feedstock availability and conventional fuel costs. Yet, expanded production of bioenergy for transportation, heating, and electricity has significant potential to reduce GHG emissions across several end-use sectors to meet midcentury decarbonization targets.

Figure 8-10

California LCFS Alternative Fuel Use by Type, 2011-2017



The LCFS has already promoted greater production and use of biofuels in California, including advanced fuels such as drop-in renewable diesel. Source: EFI, 2019. Compiled using data from Witcover and CARB, 2018.

In the Transportation sector, medium-duty and heavy-duty vehicles as well as the marine and aviation subsectors are currently difficult to decarbonize. Renewable hydrocarbon biofuels, or "drop-in biofuels," are chemically identical to today's petroleum fuels (unlike current biofuel blends, which must be mixed with petroleum fuels to function in conventional vehicles). For this reason, renewable hydrocarbon biofuels can be used interchangeably with fossil fuels in vehicles, marine vessels, and airplanes. These fuels can also use existing petroleum pipelines and are considered infrastructure-compatible fuels. Renewable gasoline, renewable diesel, and renewable jet fuel can be produced from multiple different biomass sources, including lipids and cellulosic materials. Current production technologies include hydrotreating at petroleum refineries, biological sugar upgrading, catalytic conversion of sugars, gasification, pyrolysis, or hydrothermal processing.[50]

Industry could also benefit from expanded bioenergy deployment, namely for heating and power applications. Biomass can be combusted directly for electricity, decomposed through anaerobic digestion to produce biogas methane which can be used to generate electricity, gasified to syngas (mostly carbon monoxide and hydrogen) for use in conventional boilers or in combined-cycle gas turbines, or pyrolyzed into a crude bio-oil for use in place of fuel oil in furnace, turbines, or engines.[51] Large-scale (>50 MW) biomass power plants are a highly efficient way to produce low-carbon electricity and could be important renewable power sources in the future. Small-scale (<10 MW) plants are less efficient and have higher generation costs; however, they are well suited for combined heat and power (CHP) applications or district heating when there is a consistent heat demand, making them appropriate solutions for some industrial processes with high heating demands.

Floating Offshore Wind

Floating offshore wind is a nascent but growing renewable energy technology that can capitalize on favorable offshore wind resources. While there may be some floating offshore wind projects deployed in California in the near term (around 2030), this analysis finds more breakthrough potential by midcentury. The high costs of the technology (as well as siting concerns) will prohibit more widespread deployment in the near term.

Early projects are seeing relatively high capacity factors: an estimated 65 percent off the coast of the United Kingdom.[52] The levelized cost of electricity for offshore wind projects in Europe, according to Bloomberg NEF, has dropped below 10 cents per kWh for new projects, but in more favorable conditions than will be the case in California.[53] California has an estimated 112 GW of offshore wind resource potential, 95 percent of which is located at water depths that would require floating platforms. If California begins to deploy floating offshore wind in the next decade, there is an opportunity for a sizeable deployment by midcentury to contribute to meeting the state's carbon-free electricity goals. Table 8-7 shows the opportunities of deep offshore wind mapped to the technology innovation selection criteria.

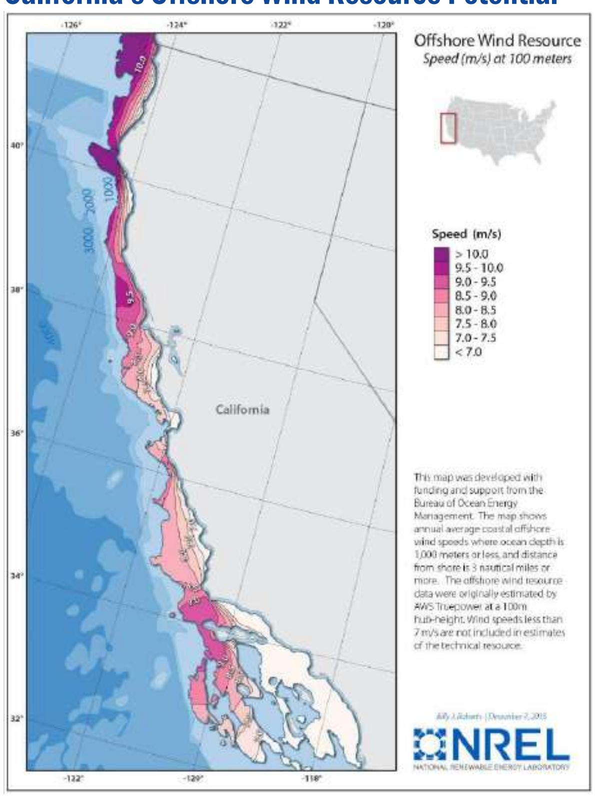
Table 8-7
Floating Offshore Wind

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Floating Offshore Wind 	High-capacity factor renewable resource with no land-use issues High-quality coastal resources near California's population centers	Technology at demonstration stage, companies have expressed interest in offshore wind development in California	Significant science and technology expertise in California Robust wind sector and offshore oil operations that could be leveraged	Option for consumers in parts of California with few other renewable resources
Challenges				
Water depths in California require floating facilities; high capital costs; early stage technology development				
Source: EFI, 2019.				

Estimates suggest that 237 MW of floating offshore wind projects were already in progress worldwide and could come online by 2020.[54] To date, the 30-MW Hywind project off the coast of Scotland is the world's only large-scale floating wind project.[55] The project, which is operated by Equinor (formerly Statoil), provides electricity for roughly 20,000 households in the United Kingdom and reported a 65 percent capacity factor during its first three months of operation (from November 2017 to January 2018). (Note that the annual fleetwide average capacity factor for onshore wind was 37 percent in the United States in 2017.)[56,57] By 2030, Equinor anticipates a global floating offshore wind market of more than 12 GW.[58]

DOE estimates that the United States has more than 2,000 GW of offshore wind technical potential in state and federal waters, which amounts to nearly twice the total installed generating capacity across all technology types. However, the majority of this resource potential (58 percent) lies in deep offshore waters that are not amenable to conventional (fixed-bottom) offshore turbines.[59] Therefore, there is a major market potential for floating offshore wind deployment in the United States, especially on the West Coast. As a whole, the United States could see an installed capacity of two GW of floating offshore wind by 2030.[60]

Figure 8-11
California's Offshore Wind Resource Potential



Wind speed map of California offshore technical potential calculated at 100 m above water. Source: NREL, 2016.

California maintains a significant offshore wind resource potential (Figure 8-11), especially in strategic locations near some of the state's major population centers. Estimates suggest that California has an offshore wind potential of 112 GW (equivalent to 392 TWh per year of generation potential), although only 5.1 GW (4.5 percent) is located in areas with a water depth of less than 60 meters (roughly 200 feet).[61]

There are three different technologies under development for floating offshore wind including spar-buoy, semisubmersible, and tension leg platforms. Despite advantages and disadvantages for each technology, all three could be suitable for floating offshore wind project deployment in California.[62] However, high costs remain the largest barrier to floating offshore wind technology deployment, which are currently more expensive than fixed-bottom offshore wind turbines.[63]

Based on the semisubmersible floating offshore wind technology type and anticipated improvements in performance variables over time (e.g., turbine-rated power), NREL reported that costs could improve from an LCOE (unsubsidized) of $188 per megawatt-hour (MWh) in 2015 to $100 per MWh by 2030 for one specific location off the California coast (Humboldt Bay), with similar costs for a second site near the Channel Islands.[64] Note that conventional offshore wind is still one of the most expensive generation options available (second only to solar thermal) at $117.9 per MWh,[65] with a 45 percent capacity factor, entering into service in 2023.[66] NREL has also assumed that operating and maintenance costs for floating offshore wind could decline by 7-16 percent by 2050.[67] Commercialization of floating offshore wind technology could reportedly occur between 2020 and 2025,[68] while continuing to take advantage of cost reductions that have already been realized through technological innovation and learning-by-doing for onshore and (traditional) offshore wind projects.[69] DOE's Wind Energy Technologies Office has funded research and development (R&D) for offshore wind, supporting 85 projects from Fiscal Year 2009 to Fiscal Year 2019, with combined funding of over $225 million during that period.[70]

Given the relatively high capacity factors compared to onshore wind, avoidance of land-use issues, and limited seabed disruption (which can occur when traditional offshore wind turbines are anchored into the sea floor),[71] floating offshore wind could be an important clean resource for California over the long term.

However, challenges to deployment remain including permitting and regulatory issues. For example, offshore wind project developers in California will need to account for exclusionary zones that have been proposed by the U.S. Navy, which affects large sections of the southern and central coasts, along with other site-specific stipulations along the northern coast. According to the Navy, deployment of offshore wind in these areas could impede Department of Defense operations and mission readiness.[72] Deployment of offshore wind will also require cooperation between state and federal agencies, as waters up to three nautical miles from shore are under state jurisdiction, while federal waters span from three to 200 nautical miles offshore.[73,74]

The process for implementing offshore wind has already started in California, showing that there is a demand for the technology, especially if costs come down and other concerns are addressed. Since 2016, the U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM) and the California Energy Commission (CEC) have operated a joint taskforce on offshore renewables.[75] BOEM has received expressions of interest in offshore leases from multiple parties, including Redwood Coast Energy Authority (a Humboldt County intergovernmental agency); Norwegian oil major Equinor; and Castle Wind LLC (a collaboration between Seattle-based Trident Winds and German energy company and offshore wind owner EnBW).[76,77] BOEM is currently embarking on a competitive leasing process and has put out a Call for Information and Nominations.[78] Three potential lease areas have been identified: Humboldt Bay in Humboldt County, and Morro Bay and Diablo Canyon in San Luis Obispo County.[79] Enabling infrastructure for offshore wind project development, including grid connections and ports, are more readily available in the southern portion of the state.[80]

California has the potential to leverage existing expertise and workforce towards innovation in offshore wind. Oil and gas companies have already been using technologies that come from offshore drilling for floating wind development. Domestic California offshore producers could be future drivers of innovation in this space, and workers from that sector would be a good resource for the specialized needs of offshore wind construction.[81] Expertise could come from California universities and governmental agencies as well, which often have the best data on the state's coastline and could provide valuable information (e.g., wave conditions at candidate offshore wind sites) for technology modeling, siting, and safety analyses.[82] Offshore wind also provides an opportunity for interstate collaboration, as research on marine renewables is also occurring in the other Pacific Coast states, which face similar challenges to California in deploying offshore wind.[83] However, protracted siting negotiations, the possible need for new transmission lines to move power from unrestricted offshore spaces to demand centers, and cost issues make it unlikely that floating offshore wind will be deployed at scale until after 2030.

Advanced Nuclear

Nuclear reactor designs that address concerns about waste management, safety, cost, and scalability could offer significant long-term benefits to California as it moves toward zero-carbon electricity by 2045. Nuclear energy provides high capacity factors and non-intermittent, carbon-free electricity from a storable fuel, services that may be both desirable and necessary for meeting California's midcentury goals.

While there is a moratorium on new nuclear plants in California, nuclear could rejoin the California generation mix in the midcentury timeframe, if technological solutions are found that address concerns about cost and waste management. Some advanced nuclear reactors could offer solutions to both concerns. Even though current limitations exist (e.g. opportunity cost of providing alternative services) they could also provide an additional benefit: decarbonizing intermediate-temperature process heat for industrial applications, which is one of the most difficult sectors to decarbonize. Table 8-8 maps the opportunities of advanced nuclear to the technology innovation selection criteria.

Table 8-8
Advanced Nuclear

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Advanced Nuclear 	Provides firm low-carbon electricity resources for the grid and high-grade heat for industrial use; next-generation designs employ advanced safety features	Electricity markets may move to improve valuation of energy resources; California needs reliable carbon-free electricity resources, especially with climate change	California has a long history with nuclear generation, including technical expertise and operation of facilities	May offer long-term benefit to managing cost of electricity and heat to Industry, which could benefit consumers
Challenges				
Public acceptance issues; costs of new designs; electricity market issues				

Source: EFI, 2019.

The category of “advanced nuclear reactors” covers a broad range of technologies (Table 8-9).[84] Options for cooling in lieu of light water or heavy water include molten fluoride salt, liquid metal (especially sodium or lead), and gas (usually helium).[85]

Table 8-9
Advanced Nuclear Technologies and Potential Benefits

Technology	Less Cost	Managing Waste	Improving Safety	Decreasing Proliferation Risk	Distributed Designs	Scalability	Industrial Applications
Molten Salt Reactors	X	X	X				
Sodium-Cooled Reactors	X			X			X
Lead-Cooled Reactors	X						X
Gas-Cooled Reactors		X		X			
Very High Temperature Reactors				X	X		X
Small Modular Reactors	X		X			X	
Micro-Reactors	X		X		X		
Fusion Reactors		X	X	X			

Source: Third Way, 2015.[86]

Small modular reactors—which include light-water reactors as well as advanced reactor types—are produced in factories, with the potential that the quality assurance advantages of a production line environment (in contrast to on-site construction) can lead to significant cost advantages. Some advanced reactor designs with a fast neutron spectrum may address nuclear waste concerns by eliminating long-lived transuranic elements, thereby reducing the nuclear waste challenge to a century timescale. Small modular reactor designs also incorporate passive safety features. Other benefits include decreased proliferation risks and the ability to site in remote locations.

California has a history as a nuclear innovator, dating back to the University of California (UC), Berkeley’s work on the discovery of transuranic elements and on the Manhattan Project. Nuclear R&D has continued in the state at places like UC Berkeley and General Electric’s Vallecitos Nuclear Center, the first commercially owned nuclear plant to provide electricity to the public.[87] Despite the moratorium on new nuclear construction, nuclear innovation has continued in California.

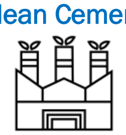
Projects include established players like UC Berkeley (molten salt) and General Atomics (high temperature, gas-cooled small modular reactor), as well as start-ups such as Brillouin Energy (molten salt) and OKLO (liquid metal). There is also an ecosystem of companies, universities, and other institutions working on other advanced nuclear technologies, such as fusion.[88] Another resource for innovation in California could be workers and experts from reactors that have shut down or are in the process of doing so, both from research reactors (e.g., the Vallecitos Center) and commercial ones (e.g., Diablo Canyon, San Onofre Nuclear Generating Station).

Clean Cement

Cement production is a valuable industry in California that requires high-temperature heat for certain core processes. This is an energy- and emissions-intensive process for which there are no commercially available clean alternatives. Developing pathways that reduce emissions from cement production without major infrastructure overhauls, that avoid long periods of operational downtime for retooling, and that do not compromise the final cement products could be gamechangers to California's long-term carbon reduction ambitions. Table 8-10 maps the opportunities of cleaner cement production to the technology innovation selection criteria.

Cement is a vital component of concrete—the second most-used substance globally after water[89]—and other building materials, California is the nation's second-largest producer of cement (after Texas),[90] producing around 10 percent of the supply of Portland cement, the most common variety.[91] Portland cement in California is a $2.4 billion industry, with five companies producing cement at nine plants, as well as two corporate headquarters.[92]

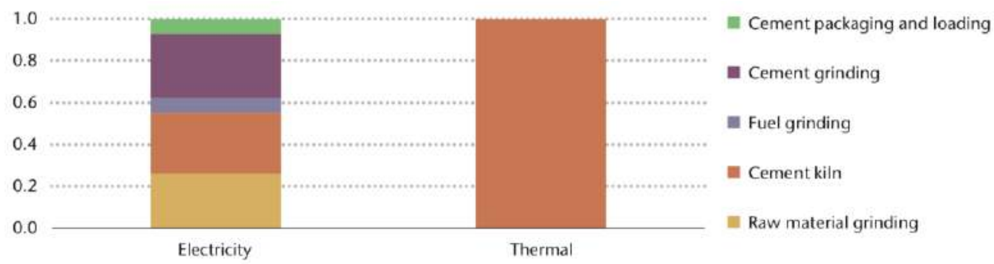
Table 8-10
Clean Cement

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Clean Cement 	Alternative cement mixes; carbon capture; and process innovation that reduce emissions from clinker production can have profound impact on industrial emissions (8 percent of sector total in California)	California is the second largest U.S. cement producer (after Texas); major consumer of cement	California has significant carbon sequestration capacity; multiple firms already experimenting with "green cement"	California policy already directed at emissions from buildings; early movers may see value of using clean raw materials
Challenges				
Additional R&D is needed for alternative cement mixes; difficult for facilities to go offline for retooling; capital-intensive industries				

Source: EFI, 2019.

The use of high-temperature heat and the emissions created by heating limestone make cement production a very carbon-intensive process. Its GHG emissions in California are one of the largest among industrial subsectors, representing 8 percent of all emissions from California's Industry sector.[93] As noted, the process of making cement is very energy intensive. Electricity is used to run system processes (i.e., to grind and load equipment), while fuels such as natural gas and petroleum are used to provide the thermal energy for the kiln (Figure 8-12).[94] This step generates direct CO_2 emissions due to fuel combustion and the carbon released from raw materials.

Figure 8-12
Energy Demand by Step of Cement Making Process



Electricity and thermal energy are used throughout the cement making process. Source: IEA, 2018.

The major pathways to decarbonizing the cement-making process—efficiency (e.g., higher-efficiency kilns), fuel-switching, and lowering the clinker-to-cement ratio—can have meaningful impacts on the sector's emissions. Larger investments in applying carbon capture or using new chemistries and processes that create "clean cement" will be necessary to deeply decarbonize the sector.[95]

There are a variety of pathways under development for less carbon-intensive cement production. Some companies and researchers are using new materials to replace limestone, such as waste products from other industrial processes (e.g., fly ash from coal combustion[96] or slag from steel production[97]) or synthetic materials. As noted in Chapter 4, some processes are examining the utilization of CO_2 to make cement by curing concrete with CO_2 or replacing some of the limestone with other proprietary formulations that can combine with CO_2 during the curing process.[98] Innovation for CO_2 uses in cement production is needed, however, to make utilization technology options affordable and scalable. This "green cement" option could be a substitute for cement as the calcium carbonate cement made in the Calera process can be used without any other cement or binder system.[99]

California's Cement subsector is a major resource for the development of green cement. The industry's technical knowledge, workforce, and infrastructure can support innovation pathways. There have already been some attempts to bring green cement production to California. Monterrey County-based Calera produces cement with captured CO_2. Calera previously demonstrated its technology in concrete sidewalks but has since switched its focus away from concrete to other cement-based products. Calera is still in the process of scaling up its operations for these products.[100] A manufacturer of slag-based cement, Orcem, is working on building a production facility in a former flour mill in Vallejo.[101] The project has been delayed by citizen concerns and governmental objections over the adequacy of the environmental analyses of the project.[102]

Lithium-ion Battery Recycling

Battery technologies, especially those with lithium-ion chemistries, are starting to play an integral role in the global economy. Everything from laptops to smartphones to data servers rely on battery technologies to operate. Clean energy technology, including battery-electric vehicles (BEVs) and grid-scale battery storage, are also increasingly dependent on these battery chemistries, especially lithium-ion. Effective recycling of lithium-ion batteries—both small and large—can have significant impacts on lowering their environmental footprint and increasing the useful life of these critical systems and chemicals. Table 8-11 maps the opportunities of lithium-ion battery recycling to the technology innovation selection criteria.

All current models of BEVs and plug-in hybrid vehicles (PHEVs) contain lithium-ion batteries that depend on critical materials such as lithium and cobalt. There are serious concerns about the future availability of supply for these materials, their lifecycle emissions, and human rights issues associated with cobalt's mining and refining supply chains. These concerns will be felt acutely in California, which leads the nation in adoption of BEVs and PHEVs (roughly one out of every two BEVs and PHEVs sold in the United States in 2018 were sold in California).[103,104] California's goal of scaling up to five million zero-emissions vehicles by 2030 would dramatically increase demand for lithium and cobalt. One of the solutions that has been proposed is battery recycling. California has a clear opportunity to reap significant benefits if innovation makes this technology commercially viable. Benefits could come from the recycling of batteries for other purposes as well, such as grid-scale storage.

Table 8-11
Lithium-ion Battery Recycling

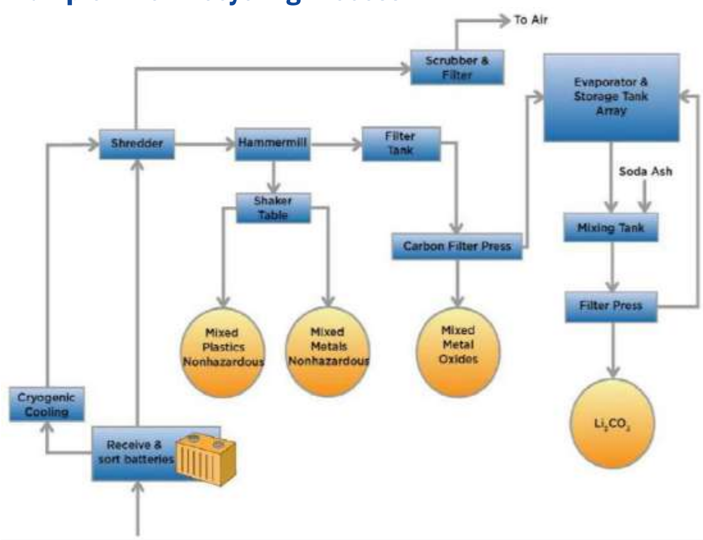
Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Lithium-ion Battery Recycling	Wide applicability in most sectors: Electricity, Transportation, Buildings, Manufacturing, Improving the lifecycle performance and economics of energy storage is critical	Supports smart growth across every aspect of the economy California will continue to be a major user of Li-ion-based technologies	Large tech-sector experience Significant workforce and science and technology expertise	At-scale systems could significantly improve the lifecycle emissions of battery-based technologies and drive down cost of clean alternatives
Challenges				
Technical improvements in recycling process needed to improve economics				
Source: EFI, 2019.				

Scalable, economically viable reuse of recoverable materials from recycled batteries would provide several benefits (Figure 8-13).[105] For producers, it would decrease demand for newly mined critical materials and thereby decrease production costs. For battery consumers, it could decrease costs because there would be some monetary value in a spent battery, as opposed to today when those benefits are nil. This is particularly important from a consumer preference perspective, since potential BEV adopters are concerned about costs to repair or replace a battery.[106]

The main barrier to battery recycling currently is cost. Material recovery costs are more expensive than the value of materials recovered. As a result, only 5 percent of lithium-ion batteries are recycled in Europe.[107] Incremental improvements to current recycling techniques could reduce some costs but making the process economically viable will require major breakthroughs. These could come from early-stage innovation, such as new metallurgical techniques that allow more of the material to be recovered. Change could also come from later stages of the innovation process, including systems for using spent batteries for new applications rather than recycling them.[108]

Battery recycling and reuse has been ramping up, with regulations in China and the European Union forcing carmakers to take responsibility for their spent batteries.[109] California could be a locus for innovation in this space, as much of the impetus and technical knowledge for innovation will come from manufacturers. California is home to many electric vehicle (EV) manufacturers, including Tesla and the U.S. headquarters of BYD (the world's largest producer of EVs), both of which maintain manufacturing facilities as well as corporate headquarters in the state.[110,111] There are many smaller EV start-ups also located in California such as Coda, Karma, and Lucid.

Figure 8-13
Example Li-ion Recycling Process



Process diagram of a Toxco lithium-ion battery recycling process.
Source: CM Solutions, 2015.

In addition, California is home to some of the companies that are already working on lithium-ion recycling, such as Retriev Technologies[112] and Redwood Materials, a start-up created by current and former Tesla employees.[113] EVgo, a Los Angeles-based EV charging company, has a pilot project using spent vehicle batteries to store electricity for its charging stations.[114] There is potential for innovation outside the corporate space as well. UC San Diego has been a pioneer in battery recycling research, and is one of three university collaborators for DOE's newly created Advanced Battery Recycling Center.[115] Furthermore, California already has a model for public-private partnerships in this space. The California Air Resources Board and the CEC work alongside vehicle manufacturers, utilities, and other corporations in the EV-promotion initiative Veloz.[116]

Advanced Photovoltaics

Solar energy is one of the world's fastest-growing, zero-emissions resource for power generation. Enormous progress has been made in reducing the costs and price of utility-scale solar PV,[117] with more cost declines expected in the future.[118] Table 8-12 maps the opportunities in advanced photovoltaics to the technology innovation selection criteria.

Table 8-12
Advanced Photovoltaics

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
Advanced Photovoltaics 	Improving the efficiency of solar PV supports major renewables deployment Reducing costs of solar PV supports long-term growth if financial incentives are reduced	California's large solar resource base and policy support will continue to increase role for solar PV	Significant solar workforce and science and technology expertise Large electricity market support Potential manufacturing capacity of advanced PV	Higher-performing PV technologies could drive down the cost of deep decarbonization
Challenges				
Lifecycle performance and costs issues; new materials need further testing for durability				
Source: EFI, 2019.				

California has one of the largest solar energy resource bases in the nation[119] and is a leader in solar technology development, making it an ideal leader for supporting the next generation of solar technologies. It is first in the nation in utility-scale deployment of solar generation, in residential deployment, in solar jobs, in solar investment (by an order of magnitude), and in projected growth over the next five years.[120] This solar growth has been enabled by the state's abundant resource potential, supported by policies, rebate programs, and other initiatives at the local level.[121]

Research is underway to lower the costs of solar electricity, improve the reliability and durability of solar systems, lower the material and process costs, and increase efficiency.[122] This research addresses the technical, cost, and operational challenges of large-scale PV buildout. More efficient systems could, for example, decrease land-use concerns; use of new cell types could allay concerns about critical materials and lifecycle emissions; and efficiency and deployment innovation could increase the capacity factor of solar and mitigate concerns about periods of time with no generation.

There are several avenues that researchers are taking in developing advanced photovoltaics, including the following:[123]

- New materials for PV cells, including thin films, cells from organic materials, and cells from earth-abundant materials (e.g., perovskites);
- Improved materials, such as higher-efficiency crystalline PV cells;
- Improved manufacturing techniques, including device and process modeling, silicon/thin film deposition, nanomaterial synthesis; and
- Deployment and configuration strategies, including integration with storage, solar tracking, and innovative deployment techniques such as spray-on PV.

California's significant solar resource potential, its sizeable solar workforce, large private-sector investment, and robust community of research universities and national laboratories focusing on solar technology development and deployment make California well suited to be a leader in advanced photovoltaics, as well. Examples of programs that have funded PV research include the following:

- LBNL's Advanced Light Source, Molecular Foundry, and Cyclotron Road programs
- SLAC National Accelerator Laboratory and Stanford University's Institute for Materials and Energy Sciences;
- The University of California Advanced Solar Technologies Institute, a cross-system research institute headquartered at UC Merced;
- UC Riverside's Southern California Research Initiative for Solar Energy, which has partnerships with the city government and the local public utility; and
- The California Institute of Technology, which previously hosted the Light-Material Interactions in Energy Conversion Energy Frontier Research Center and currently is the headquarters for the Joint Center for Artificial Photosynthesis Energy Innovation Hub, which is exploring research frontiers similar to those for advanced PV.

Other innovation resources could come from CEC's Electric Program Investment Charge Program, which allocates public funds for advanced clean energy research,[124] and the California Storage and Solar Association, an industry group that pushes for statewide policy support for solar.

Direct Air Capture

Carbon dioxide removal (CDR) at the gigaton-scale will be a necessary complement to mitigation efforts in order to avoid the worst impacts of climate change.[125] Pursuing CDR through the deployment of a range of NETs can also help offset residual emissions across the economy that may be too technically difficult and/or expensive to abate. Given the considerably large size of the California economy, the difficult-to-abate nature of certain economic sectors (e.g., heavy industry; aviation), and the state's ambitions to reach carbon neutrality by 2045 (with further efforts to maintain net-negative emissions thereafter), CDR will likely need to play a role in mitigation efforts by midcentury.[126] Direct air capture is a NET that has the potential to play a large role in achieving negative emissions, but substantial challenges remain to its market readiness and widespread deployment. Table 8-13 maps the opportunities for DAC to the technology innovation selection criteria.

Table 8-13
Direct Air Capture

Technology	Technical Merit	Market Viability	Compatibility	Consumer Value
 Direct Air Capture	High capture capacity with low risk of reversal depending on CO_2 conversion and disposition Innovations in DAC could provide co-benefits for point-source carbon capture technologies on power plants and industrial facilities	Captured CO_2 can be used to produce synthetic, carbon-neutral liquid fuels for sectors such as aviation Rapid scale-up would require significant manufacturing which could create many jobs in California	Flexible siting options including for locations with cheap and abundant clean energy; waste heat availability; CO_2 offtake markets Can be sited on non-arable lands to avoid competition with food production	Can offset emissions in difficult-to-abate sectors that may be too technical and/or costly to eliminate, which could help lower the cost of deep decarbonization for certain sectors and processes
Challenges				
High current costs and cost uncertainty; basic R&D needs; large electrical and thermal energy requirements from clean sources; regulatory and permitting issues; need for more knowledge and innovation in CO_2 utilization and sequestration opportunities (including geologic site characterizations)				

Source: EFI, 2019.

One benefit of DAC includes the potential for a high capture capacity and production of high-purity CO_2, which can then be utilized for multiple uses (e.g., food and beverage industry; cement production) or disposed of in various geologic formations. California is well-suited to provide potential offtake markets and disposal options for CO_2. For example, the state has a relatively large number of cement plants that could utilize the anthropogenic CO_2 for cement and concrete production, which is already being pursued by at least one concrete plant in California.[127] Captured CO_2 could also be used to make synthetic liquid fuels, which could offer lower-carbon options for difficult-to-abate sectors in California's economy such as aviation.

Geologic sequestration is another viable option for captured CO_2 in California, which has an estimated storage potential of 34 to 424 billion metric tons of CO_2.[128] While this analysis assumes some geologic sequestration by 2030, deployment at-scale will be important by midcentury. Another benefit of DAC is that it offers flexible siting options for project deployment, which can help ensure that the plants are not located in areas with other competing land-use interests (e.g., food production). Furthermore, the plants could be sited in areas with abundant, clean energy to reduce the carbon intensity of the DAC process.

Major challenges confronting DAC include the high current costs relative to other NETs, ongoing R&D needs, and large energy requirements from clean sources. The costs for a first-of-a-kind DAC plant have been estimated at $30 per metric ton of CO_2 to $1,000 per metric ton of CO_2, while other estimates have reported the costs to be as low as $94 per metric ton of CO_2 to $232 per metric ton of CO_2.[129,130] Given the innovation capabilities of the companies, national laboratories, and manufacturing facilities located within the state, California could play an outsized role in helping to advance this technology and prepare it for commercial deployment, where it could help the state achieve its clean energy ambitions.

CANDIDATE TECHNOLOGIES ADDENDUM

A broad list of technologies with innovation potential was developed and organized by applications and estimated timeframe for development (Table 8-14). This list was the basis for the screening of technologies assessed in this chapter. It is important to note that the operational feasibility of realizing the benefits of each candidate technology is subject to local infrastructure, resource availability, energy mix, strategy, regulations, and market structures.

Technologies described in this chapter are in boldface in the table.

Table 8-14
List of Breakthrough Candidate Technologies

Application Area	Near Term (2025)	Intermediate Term (2035)	Longer Term (2050)
Electricity Supply & Distribution			
Heat Sources for Electricity Generation			
Concentrated Solar Power (CSP)	Capital cost reduction	Hybrid systems	
Geothermal	Modeling, simulation, & technology validation; gas cleanup; advanced materials	EGS with application of hydraulic fracturing; mineral recovery and hybrid systems; membrane processes	
Natural Gas Combined Cycle (NGCC)		Natural gas combined cycle with carbon capture	
Nuclear Fission	LWR advanced fuels for safety; LWR cost reduction; LWR life extension; SMRs design and licensing	Advanced non-LWR, small-scale reactor technologies (e.g., high-temperature and fast reactors); advanced materials/fuels; modeling and simulation; used fuel degradation; alternative repositories; actinide burn-up; hybrid systems	Very high temperature reactors (power and process heat), especially SMRs
Nuclear Fusion			**Science development and cost reduction for tokomak technology; development of non-deuterium-tritium fusion concepts**
Biopower	**Biogas processes**	**Utility scale bio-power with CCS**	
Heat-to-Electricity Conversion	Ultra-supercritical steam turbines; thermionics; Allam cycle	Supercritical CO_2 turbines; high-temperature-enabling materials for gas turbines	
Direct Electricity Generation			
Solar PV	**Low cost manufacturing techniques; soft cost reduction**	**Perovskites and other non-silicon materials; systems integration with storage and energy management systems**	

Onshore Wind	HPC model development to improve wind farm design and operation; high-resolution short-term resource modeling	Materials and manufacturing technologies for large and segmented wind turbine blades	
Offshore Wind	**Demonstration Projects to test alternative concepts (e.g., tethering), applications (icing conditions), and cost reduction opportunities**	**Deepwater offshore wind platforms**	
Advanced Nuclear Power	**Small modular reactor (SMR) design and licensing**	**Advanced reactors, large and small, for heat and power; waterless designs**	**Generation IV reactors**
Water Power (Hydro and Marine Hydrokinetic)	Marine hydrokinetic component technology; supporting research, monitoring and modeling of hydro systems	Materials and turbine designs; modularization	
Fuel Cells	Improved membranes processes and materials		
Seasonal Storage	**Full system designs to address cost**	**Non-lithium battery chemistry; flow batteries; solid state control systems; physical and cybersecurity**	
Transmission and Distribution Systems	Interoperability standards; software and models; solid state components; cybersecurity	Grid architecture development; innovative control approaches; material innovations including wide bandgap semiconductors	Technologies and tools to interpret and visualize data and enable faster controls;
Distributed Energy Resources	Advanced "smart" technologies	Controllers for integrated systems, such as smart buildings and microgrids	
Smart Grid Technologies	**Internet of Things (IOT); high fidelity models, tools and simulators; common modeling framework; nontraditional contingency planning; technologies to assess system trust**	**Resilient and adaptive control systems; integration of artificial intelligence, automated and distributed decision-making**	**Systems-of-systems integration that creates holistic view of the energy system by leveraging data and operations across energy networks, including electricity.**
Fuel Supply & Distribution			
Oil and Gas Production	Water quality management; water recycling; oil spill mitigation technology	Understanding induced seismicity; CO_2 fracking fluid	Methane hydrates
Oil and Gas Transmission and Distribution	Methane leakage controls		
Alternative Fuels (Feedstocks and Conversion Technologies)	**Feedstock cost reduction; improved cellulosic conversion technology**	**Improved biochemical and thermochemical conversion pathways; high-value bioproducts and bio-based inputs to chemicals**	**Affordable low-carbon drop-in fuels; sunlight-to-fuels**
Hydrogen Production	**End-to-end fuels infrastructure cost reduction**	**Improved cost/performance of low- or zero-carbon H_2 production pathways; improved materials**	**Utilization approaches for high energy intensity manufacturing**
Hydrogen Fueling Infrastructure	H_2 fueling demonstrations, including point-to-point, to test storage and safety systems	System design for H_2 distribution infrastructure for integrated transportation and industry applications	
Renewable Natural Gas (RNG)	Process efficiency for collection and production	More efficient conversion technologies	
Manufacturing & Industry			

Advanced Manufacturing Technology	Smart manufacturing (sensors, controls, automation); new-paradigm materials manufacturing techniques (e.g., electrolytic metals processing); advanced additive manufacturing	New production methods, including replacement and recycling of critical materials (includes Green Cement)	
Process Heat	Lower-energy processing (e.g., microwave heat); waste heat recovery;	CSP for energy intensive industry process heat (including hybrid systems)	Hydrogen as a chemical reductant and as fuel for process heat for energy-intensive industries
Industrial Energy Efficiency	Expanded CHP applications; process intensification; roll-to-roll processing	Industrial CCUS applications	
Transportation & Mobility			
Light Duty ICE Vehicles			
Engines & Fuels	Flex-fuel engines; simulation, sensors, controls, materials, and engine waste heat recovery; co-optimization of fuels and engines	Low-carbon drop-in fuels	
Vehicle Technology	Light-weighting		
Heavy Duty ICE Vehicles			
Electric Drive Vehicles			
Batteries	Lithium-ion cost, performance, and weight improvements; alternative lithium sourcing (e.g., brines)	Advanced, non-lithium battery technology	
Electric Drive Systems	Improved power electronics and controls; motors, system controls	Continued cost reduction	
Fuel Cell vehicles	Improved efficiency (75 percent) and durability; storage for 300-mile range	Reduced cost and increased durability; improved on-board hydrogen storage	
Transportation System Management	Pathways to enhanced vehicle connectivity and automation; traffic management improvements; autonomous vehicles		
Built Environment			
Space Conditioning Technology		High efficiency electric heating systems (e.g., heat pumps that use refrigerants with low or zero Global Warming Potential)	
Lighting	Long-term durability testing; more efficient, high power density LEDs	Efficient, durable, low-cost OLEDs; efficient quantum dot materials	
Cooling Cycle Technologies	HFC replacements	Alternative thermodynamic cooling cycles (e.g., solid state)	
Building shells	Thin insulating materials for deep retrofit; improved metrics for energy performance of building shells	Tunable PV systems (e.g., PV windows)	
Systems and Controls; Integrated Systems	More flexible power management systems; communications	Wide-band-gap semiconductors; wireless sensors and controls; control algorithms	

	protocols; more efficient circuitry; improved sensors and controls;		
Systems Integration	**Interoperable building communications systems and optimized control strategies; decision science affecting consumer choice**	**Smart Cities systems integration of buildings, transportation and industry**	
Large-Scale Carbon Management			
Terrestrial Sequestration	Large-scale integrated demonstrations of sequestration in alternative geologic media	Subsurface CO_2 management at gigaton scale; mineralization	
Biological Sequestration	Research and field testing of alternative approaches for innovative large-scale biological sequestration approaches	Large-scale demonstrations of most promising biological sequestration approaches with potential gigaton-scale application	
CO_2 Utilization		CO_2 fracking fluid	Large-scale CO_2 utilization alternatives (including conversion to fuels or products such as polymers and carbon fibers)
Carbon Capture Cross-cut (Recap from Above)	Second generation coal/CCUS pilot plants; CCUS retrofit demonstration; international partnerships	Natural gas CCUS; industrial CCUS; chemical looping, oxy-combustion; fuel cell carbon capture	Carbon Direct Removal, including Direct Air Capture
Cross-Cutting & Enabling Technology			
Enabling Science and Technology	Structural analysis of materials using X-ray light and neutron sources; novel nanoscale synthesis and fabrication techniques; advances in genomic and biological analytical and observational tools; modeling, simulation, and data analysis using high performance computing; advanced sensors and monitoring systems (e.g., drones)		
Smart Cities	**Increase deployment of smart end-use devices and systems (e.g. blockchain); increase deployment of advanced networking, such as 5G**	**Develop cross-sectoral command and control systems**	**Integrated city and energy infrastructure with comprehensive views and controls**
Battery Recycling	Lower cost of material recovery	Increase scalability of recycling facilities	
Energy/Water Nexus	Desalination		
Advanced Materials	Composite materials; earth-abundant substitutes; materials by design; materials in harsh Environments	Advanced materials and materials interaction to enable additive manufacturing	
High Performance Computing	Development of exascale computing capability including software		Large-scale quantum computing

Source: EFI, 2019.

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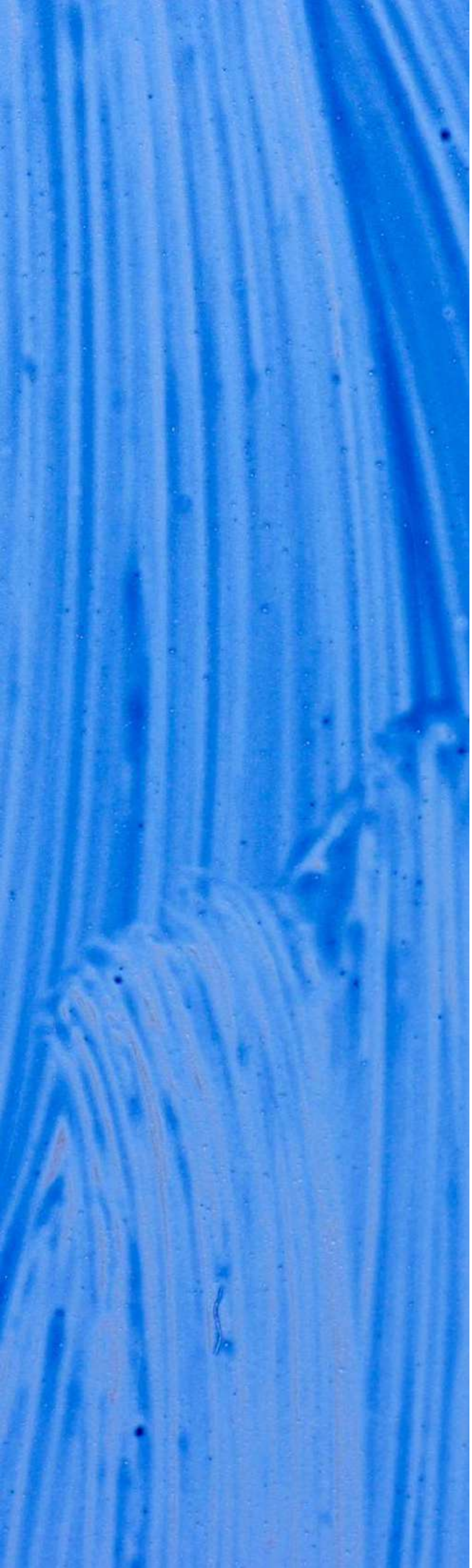


APPENDICES

APPENDIX A: ECONOMYWIDE MODELING OF CALIFORNIA'S ENERGY POLICIES: SCENARIOS THROUGH 2050

California can meet its 2030 emissions reduction goals using existing technologies. Because of the time required to deploy new energy technologies at scale, it is unlikely that transformative technologies could be deployed in a manner to meaningfully reduce emissions in that short of a timeframe. But just as such technologies are unavailable for the 2030 timeframe, they are indispensable for 2050. While there are opportunities to reduce emissions using existing technologies, they can only go so far; innovation will be necessary.

California has developed a portfolio of policies aimed at deeply decarbonizing its economy by midcentury. These policies include a mix of economywide targets, sector-specific requirements, and technology-specific mandates, with a focus on two time horizons: near-term (2030) and midcentury (2050). This study evaluates a range of clean energy technology options that could help California meet its 2030 and 2050 policy targets in terms of their performance, emissions reduction potential, cost to the economy, and impact on the electric grid. As many of the clean energy technology pathways could affect the electric grid, either directly (e.g., changed generation mix) or indirectly (e.g., increased load from electric vehicles), it is critical to evaluate each in the context of electric grid capacity and resource adequacy.

To help do this, this study has developed an analysis based on the U.S. Regional Energy Policy (USREP) model,[1] a recursive dynamic computable general equilibrium (CGE) model developed at the Massachusetts Institute of Technology (MIT). This model and its results have been used to examine the dynamic impacts of different clean energy technology options on the composition of California's energy supply and emissions profile; results are focused on cost minimization. As discussed in this appendix, multiple scenarios were developed to evaluate these pathways in the 2030 and 2050 timeframes. While this analysis focuses on the key assumptions and findings of the modeling scenarios, a detailed description of each scenario will be included in a subsequent publication by the authors of the USREP model.

Eight technologies used in this analysis are assumed to be perfect substitutes for electricity. Five technologies are assumed to be perfect substitutes for conventional fossil fuels. Electric vehicles provide a substitute in personal vehicle transportation. These are highlighted in Table A-1.[a] It is important to note that battery storage is not included as a technology option. It should be considered an option for lowering costs in subsequent analysis as appropriate.

[a] Throughout the USREP inputs and outputs, "biogas" refers to renewable natural gas and "EVs" refers to battery-electric vehicles.

Scenarios Evaluated

Four scenarios were evaluated in the modeling of California's potential technology pathways for meeting 2030 and 2050 emissions reduction goals. These are designed to examine both policy and technology pathways in the state and are described below.

Table A-1:
The Range of USREP Technology Options

	Technology	Description
Electricity	Biomass generation	Converts biomass into electricity
	Wind/solar	Intermittent wind/solar resources
	Wind/gas backup	Wind with natural gas backup
	Wind/biomass backup	Wind with biomass backup
	Advanced nuclear	Next generation nuclear power
	Advanced gas	Natural gas combined cycle
	Advanced gas with CCS	Natural gas combined cycle with carbon capture and storage
	Advanced coal with CCS	Advanced coal with carbon capture and storage
Fuels	Coal gasification	Converts coal to natural gas
	Shale oil	Converts shale oil into a crude oil
	Carbon-free biofuel	Converts biomass into a substitute for refined oil
	Carbon-free biogas	Converts biogas into a substitute for natural gas
	Hydrogen	Converts hydrogen into a substitute for refined oil
Personal Transport	EV	Electric Vehicles

Reference Scenario: Limited Policies (RSLP)

The reference case reflects California's greenhouse gas (GHG) emissions trajectory based on a limited set of policies established prior to 2015. This scenario is based on the Reference Scenario from the California PATHWAYS model from Energy and Environmental Economics (E3).[2] The RSLP provides an important reference point for comparing other policies. Key policies considered by the RSLP include:

- As described in the California Energy Commission's (CEC) 2017 Integrated Energy Policy Report (IEPR),[3] a sales-weighted average LDV fuel economy of 35 miles per gallon by 2020, 40 by 2025, 43 by 2030, and 46 by 2050;
- SB 2 (1X) (2011), Renewables Portfolio Standard (RPS):[4] 35 percent RPS by 2020, declining to 33 percent with retirements post-2030;
- SB 1275 (2014), Charge Ahead California Initiative: requires one million zero-emissions or near-zero-emissions vehicles (ZEVs) in service by 2023;[5]
- Executive Order B-48-18: a target of five million ZEVs in service by 2030;[6] and
- The Low Carbon Fuel Standard (LCFS), as adopted in 2015: a ten percent reduction in carbon intensity of fuels by 2030 (from a 2010 baseline), with 1.9 billion gallons of gasoline equivalent (GGE) biofuels.[7]

At-Scale Deployment of Current Technology by 2030 Scenario (DCT2030)

This scenario evaluates how the mix of commercially available energy technologies may be used to meet many of the state's current low carbon policies. This scenario was shaped by the assumption that for California to reach many of its carbon reduction targets in 2030 (e.g., 40 percent economywide reduction from 1990 levels) it will rely heavily on *existing* clean energy technologies deployed at-scale. With 2030 just over a decade away, it would be unwise for California to rely too heavily on technology breakthroughs to reach commercialization and then deployment in such a relatively short timeframe. Key policies in the DCT2030 Scenario include:

- AB 32, the Global Warming Solutions Act of 2006: requires GHG emissions reductions 20 percent below 1990 levels by 2020;[8]
- SB 350, the Clean Energy and Pollution Act of 2015: requires a 40 percent reduction of GHG emissions from grid by 2030;[9]
- SB 100, the 100 Percent Clean Energy Act of 2018: raises the state's RPS to 50 percent by 2026, 60 percent by 2030, and has established a clean energy standard of 100 percent by 2045;[10] and
- SB 1275 and the LCFS, described above.

Accelerated Technology Innovation by 2050 Scenario (ATI2050)

This scenario builds on the policy assumptions in the DCT2030 Scenario and evaluates the value of technology innovation on meeting California's long-term economywide emissions targets, and the state's 2045 target for carbon-free electricity.[b] Multiple technologies that are not commercially available today, as well as conventional technologies deployed at-scale, will be analyzed in terms of their potential cost and benefit in helping California meet its midcentury emissions reduction goal. The ATI2050 Scenario is motivated by recent plans for deep reductions in carbon emissions in California, including:

- Executive Order B-55-18: sets a target of economywide carbon neutrality by 2045, and net negative emissions thereafter;[11] and
- Executive Order S-3-05[12] (later reaffirmed by SB 350): reduce GHG emissions by 80 percent by 2050 (from 1990 levels).

Our modeling approach explicitly evaluates Executive Order S-3-05's 80 percent reduction. A side analysis considers the potential scale of negative emissions technology.

Carbon Charge Scenario (CC)

There is a broad consensus among economists that a carbon charge is the most efficient means of reducing carbon emissions, because it allows the economy to naturally find the lowest cost opportunities to reduce emissions. This scenario was examined to offer a point of reference that can project the incremental cost of alternative policies relative to an efficient and transparent carbon charge.

This analysis employs an economywide carbon charge that replaces all existing regulations and policies from the previous scenarios, including the 2017 extension of the State's cap and trade program through 2030.[13] In the CC Scenario, the charge begins in 2020 and is set at a level needed to achieve the 80 percent emissions reduction by 2050, a linear modeling exercise that can inform decisions. The carbon charge revenue is returned back to households in lump-sum payments.

[b] See Text Box A-1 for description of technology required to achieve carbon neutrality.

Modeling Results for Four Scenarios: RSLP, DCT2030, ATI2050, and CC

The key results from each scenario are described below, with the results framed by the key model assumptions. A detailed review of the modeling will be found in an upcoming publication from the MIT Joint Program on the Science and Policy of Climate Change.

What Does the Reference Scenario: Limited Policies (RSLP) Tell Us?

This scenario evaluates the likely emissions reduction trajectory of California based on a limited set of policies established prior to 2015, based on the Reference Scenario from the E3 California PATHWAYS model.[14] This scenario shows the expected economywide emissions of California between 2016 and 2050.

Assumptions in RSLP

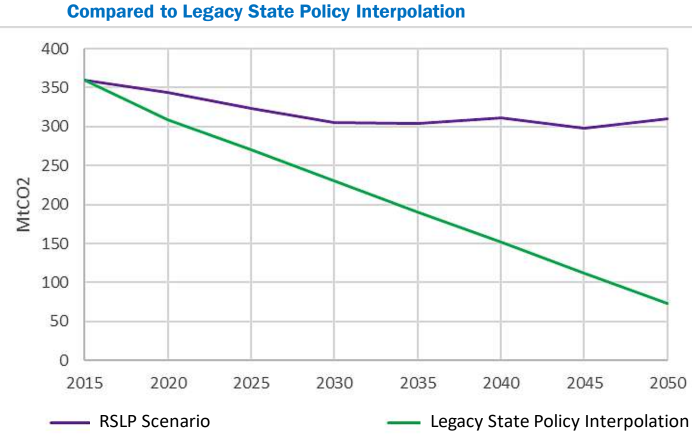
To build the RSLP, the USREP assumes that:

- California's economic growth rate will average 2.7 percent per year through 2030 and 2050. This is based on personal income projection of CEC's *2018-2030 Revised Baseline Forecast*, Mid Demand Case.[15] The forecast is extended from 2030 out to 2050 holding a constant growth rate equivalent to the rate of growth between 2025 and 2030.
- Statewide electricity demand will be about 340 terawatt-hours (TWh) in 2030 and about 390 TWh in 2050. These projections are highly influenced by the assumption that 100 percent of the state's ZEV targets of one million by 2023 and five million by 2030 will be met by battery-electric vehicles (BEVs).
- There is limited end-use electrification in other sectors.
- The California RPS is assumed to rise from 25 percent in 2016 to 33 percent in 2020,[16] based on SB 2 (X1), signed in 2011. The 2011 RPS applied to all electricity retailers, including publicly owned utilities, investor-owned utilities, electricity service providers, and community choice aggregators. This approach is based on assumptions made by E3.[17]

Results from Modeling the RSLP

California's statewide carbon emissions would result in about 10 percent emissions reduction from 2020 to 2030, with emissions decreasing by additional 10 percent by 2050 (compared to 2020) (see Figure A-1). Reductions are mostly driven by the RPS and increased fuel efficiency in Transportation. Many of these policies stabilize after 2030. As the economy and electricity demand grow through 2050, the net emissions benefits from the policies declines.

Figure A-1: California's CO_2 Emissions in RSLP Scenario Compared to Legacy State Policy Interpolation



What Does the At-Scale Deployment of Current Technology by 2030 Scenario (DCT2030) Tell Us?

This scenario evaluates whether California can meet its primary near-term (2030) emissions reduction goals using a mix of commercially available energy technologies. In this scenario, the USREP model analyzes a portfolio of clean energy technologies considered to be commercially available between 2020 and 2030, and then performed an optimization analysis to determine the lowest-cost portfolio that also allowed for adequate generation resources for the electric grid. The clean energy technologies included in the USREP model deemed to be commercially available by 2030 are identified in Table A-1 at the start of this chapter.

Exclusions, Assumptions and Constraints in DCT2030 Scenario

The USREP model does not represent transmission lines explicitly; the changes in electricity trade are driven by relative electricity prices. Also, the model does not represent battery storage backup capacity.

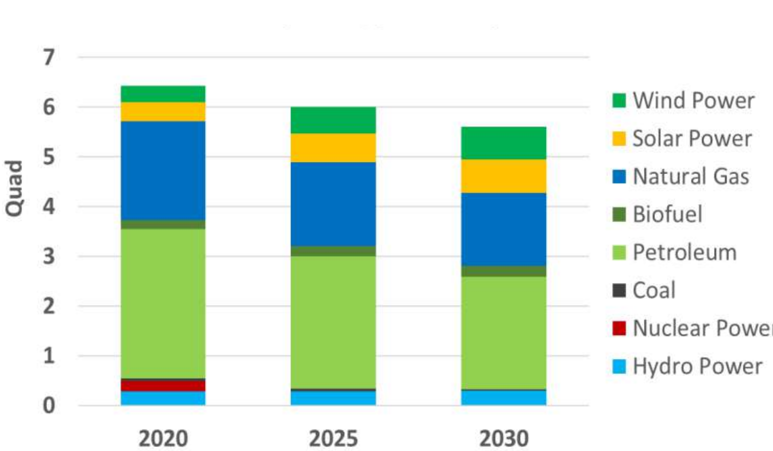
In this scenario, the model does not impose a 2030 target on ZEVs but assumes these major policy goals:

- The economywide 40 percent emissions reduction target; and
- SB 100's 50 percent RPS by 2026 and 60 percent by 2030.

Exogenous constraints are applied to the following resources, based on analysis from technology experts:

- Using estimates from the U.S. Department of Energy,[18] it was assumed that 30 gigawatts (GW) of solar and 20 GW of wind were available to California by 2030;
- No nuclear generation will be available after all current capacity is retired by 2030; and
- Electricity imports are based on historic transmission capacity.

Figure A-2: California's Primary Energy Consumption, 2020, 2025, 2030 Under the DCT2030 Scenario

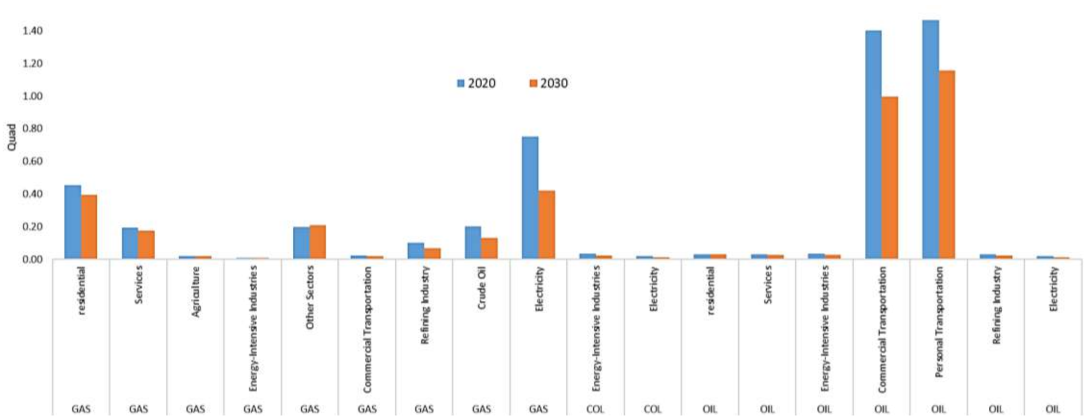


Results from Modeling of DCT2030

The USREP modeling found that sufficient energy resources were available to meet the economywide emissions goals and the state RPS targets by 2030. As shown in Figure A-2, the emissions reductions are primarily due to a decline in statewide primary energy consumption, including lower demand for petroleum and natural gas.

Primary energy consumption falls by 13 percent between 2020 and 2030. The reductions come mostly from the Transportation sector due to improved vehicle efficiency, greater deployment of electric vehicles, and the use of biofuels. Using these assumptions, however, there are only 3.5 million BEVs on the road by 2030, up from around 700,000 in 2015;[c] California does not meet its five million ZEV target by 2030.

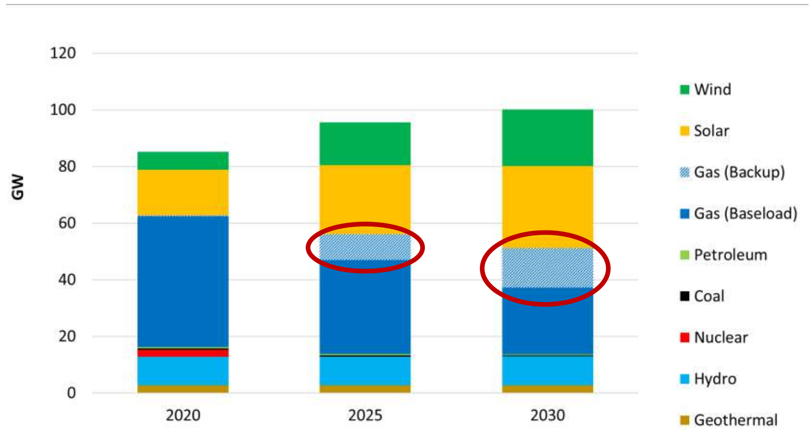
Figure A-3. Energy Consumption by Sector and Fuel, 2020 & 2030 in CT2030 Scenario



California's overall fossil fuel consumption falls significantly between 2020 and 2030. Economywide demand for petroleum and natural gas fell by 25 percent and 27 percent, respectively. Most of the reduction in petroleum comes from the Transportation sector, followed by Industry (especially from refineries), with additional reductions from the Residential Buildings and Commercial Buildings subsectors. The greatest overall reduction in natural gas comes from its use in power generation, where the share of gas-fired power generation declines from 43 percent in 2020 to 25 percent in 2030 (Figure A-3). There are minor declines in natural gas use in the Buildings sector.

While total natural gas generation falls from 46.1 GW in 2020 to 37.7 GW in 2030, the existing natural gas fleet assumes an essential role in supporting grid operations. As shown in Figure A-4, 37 percent of gas capacity in 2030 is used to

Figure A-4: California's Electricity Generation Capacity , 2020/2030 Under DCT2030 Scenario (GW)



[c] If *all* emission-related policies were replaced by a carbon charge, the number of electric-drive vehicles on the road would be close to one million in 2030, because the existing vehicle-focused policies will require more electric-drive vehicles, than a carbon charge, that will find more low-cost emission reductions in the power sector, especially in the early years.

provide backup to intermittent renewable energy resources (i.e. wind and solar). This includes providing load-following and peaking services that are required in order to balance the electric grid. In the DCT2030 scenario, only natural gas could provide these grid-balancing services (in part because battery storage is not modeled).

It is crucial that California's mix of clean energy technologies meets the needs of the electric grid. Thus, it is important to note that hydro generation plays a key role in ensuring electric grid reliability across all scenarios. To ensure the grid is balanced between supply and demand, the electricity module assumed that hydro generation will remain flat through 2030. While the future is unknown, this assumption may involve measurable risk. As described in Chapter 2, the variability of hydro in California has been significant from year-to-year. Between 2010 and 2017, hydro represented between 7 percent and 18 percent of the state's total electricity supply. Since 2012, after the retirement of the San Onofre Nuclear Generating Station, which had a capacity of 2 GW, the state's reliance on hydro and natural gas has increased. With the uncertainty of hydro, this places even greater importance on the remaining gas fleet to ensure grid reliability.

What Does the Advanced Technology Innovation by 2050 Scenario (ATI2050) Tell Us?

This scenario evaluates how the introduction of transformative clean energy technologies could help California meet its economywide emissions reduction target (80 percent below 1990 levels by 2050) and its carbon neutrality goal by midcentury (Executive Order B-55-18).

Assumptions and Limitations of ATI2050 Scenario

It is important to note that the USREP model used in this study does not employ negative emission technologies and does not lead to a carbon-neutral economy without additional emissions sinks. To approximate a carbon-neutrality policy, however, the USREP model set a target of 80 percent emissions reduction economywide with an 80 percent RPS by midcentury. Box A-1 highlights the magnitude of additional technology deployments that would be needed for carbon neutrality.

The USREP model assumes there is significant energy innovation by 2050, largely reflected in cost reductions of key technologies, and analyzes a portfolio of advanced clean energy technologies that could be commercially available by that date. Similar to the previous scenarios, the model performs an optimization analysis to determine the lowest-cost technology portfolio. In addition to the technologies used in previous scenarios, the innovative clean energy technologies available by 2050 are:

- Advanced biofuels (e.g., drop-in fuels);
- Renewable natural gas (RNG); and
- Clean hydrogen (e.g., produced by SMR with carbon capture or by electrolysis).

Box A-1

Carbon Neutrality

The USREP model does not include negative-emissions technologies (NETs) and reduces emissions in California to about 70 $MMTCO_2e$ in 2050. To achieve carbon neutrality, other technological options must be employed. The following calculation illustrates the magnitude of the remaining effort beyond the 80 percent supported by the USREP model. One 2018 analysis estimates that power generation with bioenergy plus carbon capture and storage (BECCS) technology can result in 1.29 $kgCO_2$ of negative emissions per kilowatt-hour (kWh) produced.[19] A hypothetical BECCS plant with 0.5 GW of capacity running at 80 percent capacity factor will result in 4.5 $MMTCO_2$ of negative emissions per year. To make California carbon-neutral in the scenarios considered here, at least 15 such BECCS plants would be required.

If one assumes *more* deployment of technologies with negative emissions, then the reduction from other sources can be correspondingly smaller. At the extreme end of this assumption lies a hypothetical scenario in which, with enough deployment of NETs, no additional emissions reductions would be required anywhere else in California. This analysis does not consider this scenario to be realistic (or desirable), however, due to the costs and other uncertainties associated with NETs. An approach that employs all available technologies is preferred for ensuring optionality and flexibility. For more analysis of the NETs in California, see Chapter 7.

Scenario results are highly sensitive to assumptions of cost, availability, and substitutability for each advanced clean energy technology. Small changes in any of these variables for advanced biofuels, for example, could have a significant impact on the market. To manage the uncertainty, sensitivity analyses were performed to further evaluate each clean energy pathway. The following is a full list of these sensitivities, referred to as "cases":

- **Clean Electricity**: California's RPS is ramped up to 80 percent by 2050.
- **Clean Economy**: California's RPS is ramped up to 80 percent by 2050 and California's economy reaches carbon neutrality by midcentury through means other than advanced biofuels, renewable gas and hydrogen.
- **Unlimited Biofuels**: California reaches the requirement of the Clean Economy case with an unlimited supply of advanced biofuels that are near-zero-carbon (e.g., lignocellulosic fuel). It assumes the cost of the biofuels is 2.2 times higher than the cost of refined oil. Other scenarios also assume cost is 2.2 times higher but limit supply to 0.25 quads. This scenario assumes biofuel supply is unlimited by 2050 with graduated increases from 2030.
- **Competitive RNG**: California reaches the requirement of the Clean Economy case, and the cost of RNG is competitive with natural gas in 2040 (compared to 2.2 times higher in the RSLP). RNG is somewhat supply-constrained due to the availability of feedstock; this is reflected in the model.[20] This enables the exploration of the use of RNG as a zero-carbon substitute for natural gas. In this pathway, the power sector and other gas consuming sectors continue to operate with minimal adjustments to their infrastructure.

- **Competitive Hydrogen**: California reaches the requirement of the Clean Economy case and the cost of hydrogen is 20 percent higher in 2050 than hydrogen from SMR (compared to 3.5 times higher in 2015). This pathway explores the use of hydrogen as a zero-carbon substitute fuel in Transportation, the state's largest emitting sector.

Results from Modeling of ATI2050

Figure A-5: California's Primary Energy Consumption in 2050 under the ATI2050 Scenario

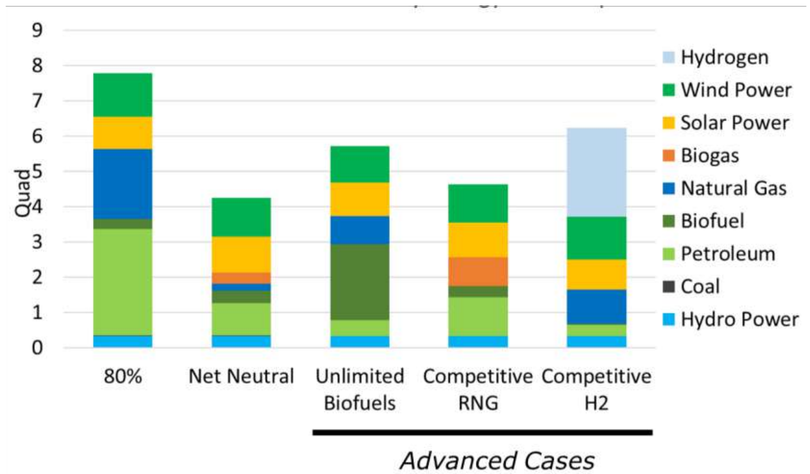
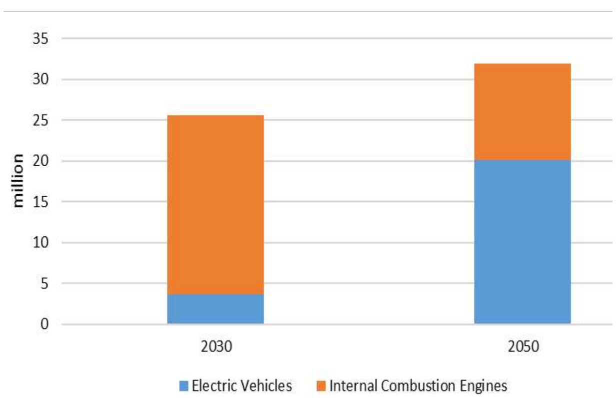


Figure A-5 shows the results of the modeling that includes the cases described above. The demand for primary energy varies sharply across all cases, with most of the variance in the Transportation sector. This is mainly driven by cases that will encourage electrification in Buildings, Industry, and Transportation.

In the Competitive Hydrogen case, hydrogen becomes the predominant fuel in the Transportation sector. However, to meet the requirements of the Clean Economy case, lacking the benefits of advanced biofuels or clean hydrogen, California would also need to have 20 million BEVs by 2050. In the Competitive RNG case, while there is a large growth of RNG use in Buildings, Industry, and Electricity, BEVs still remain the primary method for decarbonizing transport, because gas does not penetrate the Transportation sector.

Figure A-6. Private Vehicles in California in 2030 and in the ATI2050 Scenario + Net Neutral Assumptions

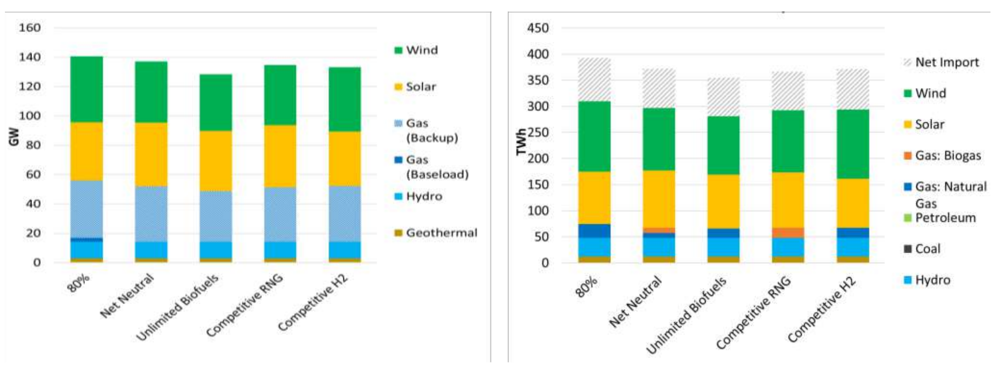


While primary energy consumption varies significantly across cases, the demand for electricity in 2050 remains relatively stable (Figure A-6). The total power consumed does not vary by more than about 5 percent from the average across all cases. This is mainly driven by the fact that the power sector modeling requires a certain amount of dispatchable power to firm up the system, as all cases have relatively high renewables deployment. Across all cases, the electric grid requires 11 percent of generation to come from hydro to cover baseload and some load-following requirements, and roughly 6 percent to come from natural gas, for load-following and peaking services. These services are required by the model to ensure grid resource adequacy and reliability.

The USREP model highlights the importance of natural gas in a carbon-constrained system, as the few remaining gas resources in the system provide needed flexibility to system operations. In 2050, to cover the intermittency issues of wind and solar, for example, the power sector requires similar gas capacity as in 2030 (35 to 40 GW), though the assumption is that gas generation will be called on less frequently, thus reducing supply from 64 TWh in 2030 to between 18 and 26 TWh in 2050, depending on the scenario.

While the modeling shows the value of natural gas, it also describes how achieving this level of decarbonization will require massive deployments of wind and solar to cover for retired gas capacity (Figure A-7). In 2016, in-state wind and solar resources provided roughly 13.5 TWh and 20 TWh, respectively. In the DCT2030 Scenario, these resources increased by 440 percent to 73 TWh and 255 percent to 71 TWh over the course of just a decade. In the ATI2050 Scenario, wind and solar generation would almost double from the base 2030 levels in the DCT2030 Scenario to around 135 TWh and 110 TWh, respectively.

Figure A-7: California's Generation Capacity and Electricity Consumption in 2050 Under ATI2050 Scenario



The model shows that this is technically feasible based on the land-use change, economic, and grid-operations impacts. There may be inherent risk, however, to long-term decarbonization that relies on such large-scale deployment of wind and solar, such as problems raised by hourly and seasonal variations in the volume of power generated, the difficulty in integrating large volumes of non-dispatchable power into the grid, and extremely high costs. Because the USREP model does not include battery storage, natural gas—and a lesser extent, hydro—helps balance the grid and can be considered proxies for storage (although significant storage challenges are discussed in Chapter 2).

Another risk factor is the long-term dependability of hydro resources. As described in the RSLP, there is significant variability in California's hydro generation and climate change impacts are likely to further reduce the region's hydropower. The modeling, however, does not forecast annual weather patterns that affect available hydropower resources, and instead applies a historic utilization rate to available capacity. These assumptions leave generation from hydro mostly unchanged, providing both a share of baseload and backup resources.

Figure A-8: California's Energy Consumption in 2030 and 2050 in the ATI2050 Scenario

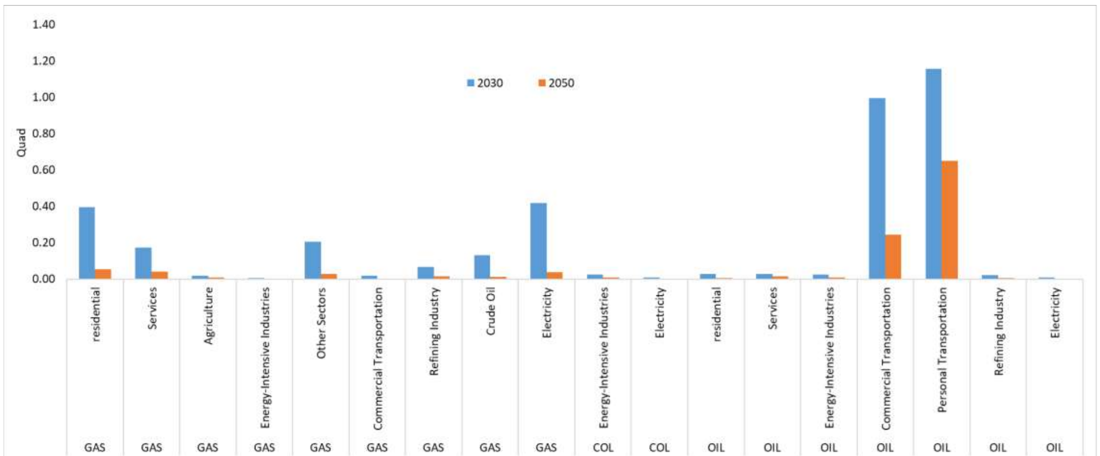


Figure A-8 shows the extent to which energy consumption must fall across most sectors of the economy in the ATI2050 Scenario.

Without major breakthroughs in clean technologies that provide grid-balancing support (e.g., RNG), decarbonize the Transportation sector (e.g., hydrogen, advanced biofuels), or lower the emissions from the energy-intensive Industry subsectors (e.g., RNG), there will be significant barriers for California to meet its long-term emissions reduction targets. This further emphasizes the importance of reducing emissions significantly across all sectors, including harder-to-abate subsectors such as heavy-duty transportation and petroleum refining. There are no clear practical pathways to reaching deep levels of decarbonization in these sectors based on commercially available technologies; these challenges will require innovation.

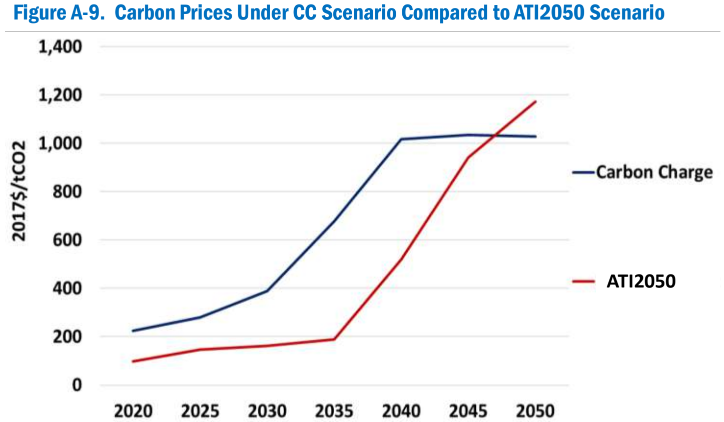
What Does the Carbon Charge Scenario (CC) Tell Us?

The CC Scenario is designed to test the assumption that a carbon charge is a highly efficient means of reducing carbon emissions.

Assumptions of CC Scenario

In this scenario, a carbon charge replaces all other emissions policies described in the RCLP and DCT2030 Scenarios. The scenario then compares the cost effectiveness of an economywide carbon charge beginning in 2020 to the Clean Economy case in terms of helping California meet its 80 percent emissions reduction and carbon neutrality goals by midcentury (Figure A-9).

Figure A-9. Carbon Prices Under CC Scenario Compared to ATI2050 Scenario

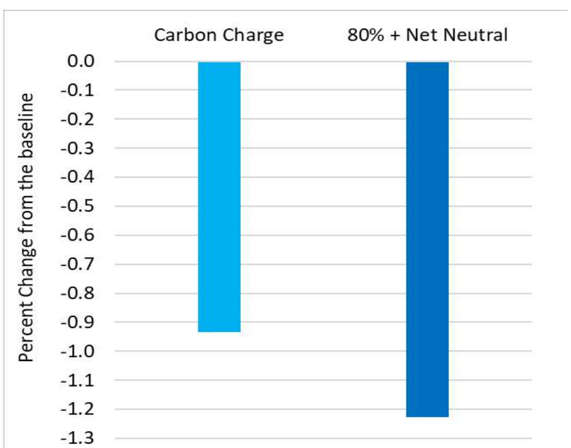


Results from Modeling CC Scenario

In this scenario, a carbon charge was modeled to demonstrate the incremental cost of alternative policies relative to an efficient carbon charge. A carbon charge is generally thought to be more efficient than a portfolio of regulations that include narrow mandates or requirements, because a well-designed charge would encourage market participants to identify the lowest cost opportunities to reduce emissions across the entire economy, as doing so will reduce their compliance cost. A carbon charge that is transparent and applied uniformly across the economy could potentially result in economic efficiencies that alternative policies are unable to achieve. This efficiency in the USREP results that show that the price of emissions abatement is higher than under an approach that meets the same emissions target by using a broad portfolio of alternative policies (Figure A-10).

Using the same technology cost assumptions, a market-based charge allows for substantial cost savings in comparison to regulatory approaches (such as CAFE, LCFS, RPS, etc.). This mechanism essentially identifies the lowest cost emission reductions across the economy and achieves them first. Also, because a carbon charge yields more cost-effective emissions reduction across the economy, it can replace narrower policies effectively achieving an equal of greater level of emissions reductions at the same or lower costs.

Figure A-10. Discounted Present Value of California's Gross State Product with a Carbon Charge vs. the Net Neutral +80% Case



Finally, and critically, committing at the outset to increase the charge over time sends signals to both innovators and those sectors of the economy where emission reductions are more difficult and expensive that there is time to develop new decarbonization pathways to lower their costs. The charge can be adjusted over time to yield the level of emission reductions that policymakers seek to achieve. Ultimately, USREP show that an economywide carbon charge is a more cost-effective approach to achieving emissions reductions, such as those in the Clean Economy case. This is reflected in Figure A-10, which shows that California can meet its goal of 80 percent emissions reduction and carbon neutrality goals by midcentury more cost-effectively with a carbon charge than with a broad portfolio of alternative policies. Nevertheless, it may be that a more effective policy approach could be to combine a carbon charge with sectoral policies to limit emissions.

The modeling results allow an analysis of cost trajectories (in addition to overall costs) under the different scenarios (Figure A-9). In the ATI2050 Scenario, for example, costs are relatively stable until 2035 then they dramatically accelerate; this "hockey stick" trajectory reflects the high marginal costs associated with meeting carbon neutrality goals by 2050. In contrast, the cost per ton of CO_2 abated under the CC Scenario starts at a higher value but increases more gradually.

Conclusions from Economywide Modeling

California can meet its 2030 emissions reduction goals using existing technologies. Because of the time required to deploy new energy technologies at scale, it is unlikely that transformative technologies could be deployed in a manner to meaningfully reduce emissions in that short of a timeframe. But just as such technologies are unavailable for the 2030 timeframe, they are indispensable for 2050. While there are opportunities to reduce emissions using existing technologies, they can only go so far; innovation will be necessary.

This modeling exercise examined several potential pathways to sharply reduce emissions. It concluded that wind and solar will play a critical role in generating clean energy, and that more than 20 million BEVs will be required to reduce emissions from Transportation (barring the substantial penetration of very low-emission advanced biofuels or hydrogen into the market). No matter what the path, a transition toward vehicle electrification appears to be a prerequisite to sharp emissions reductions unless other fuels make substantial and rapid progress.

Finally, the modeling demonstrated the economic efficiency of a carbon charge where revenues are returned to households. While there are substantial political obstacles to a carbon charge, the modeling shows that the flexibility it offers in terms of identifying the lowest-cost opportunities to reduce emissions across the economy could lead to more cost-effective outcomes than a portfolio of regulations and policies.

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[9] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350
[10] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100
[11] https://www.gov.ca.gov/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf
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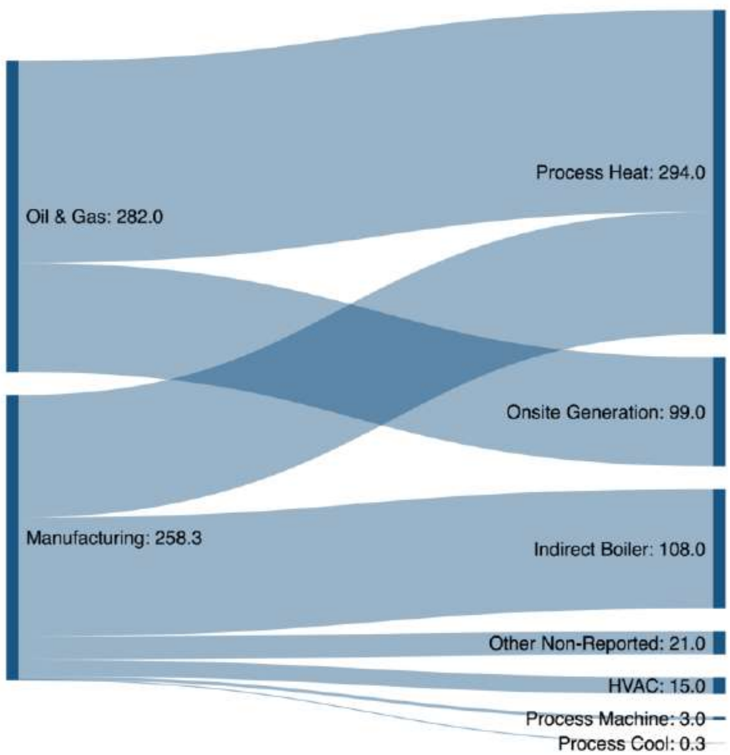
APPENDIX B: SUPPORTING INFORMATION FOR INDUSTRY DECARBONIZATION PATHWAYS

Appendix B-1

Figure B-1

Industry Sector Emissions Profile, 2016 ($MMTCO_2e$)



It is estimated that the majority of natural gas consumption in California is used for process heat in the Oil and Gas subsector, while the majority of natural gas in the Manufacturing subsector is used for process heat and steam production (indirect boiler). Sectors not shown: CHP (15.1 percent or 99.5 Bcf); Transmission & Distribution (3.3 percent or 18.6 Bcf); Mining (0.5 percent or 3.0 Bcf). Data was based on Industry sector natural gas fuel consumption in California in 2016 (660.8 Bcf) from the California Air Resources Board (CARB). The sectoral breakdown of gas consumption was based on data from CARB. Oil & Gas includes the CARB inventory categories of Oil & Gas: Production and Processing (224.3 Bcf) and Petroleum Refining and Hydrogen Production (57.4 Bcf). Other includes Transmission and Distribution (18.6 Bcf) and Mining (3.0 Bcf). The Production and Refining subsector was calculated based on natural gas demand for petroleum refining, of which 65 percent was for process heat and 35 percent was for onsite generation based on data from the Department of Energy (DOE). The Manufacturing subsectors were based on data from CARB. Other includes "Not Specified" (19.5 Bcf), Textiles (3.7 Bcf), Construction (2.0 Bcf), Plastics and Rubber (1.8 Bcf), Printing and Publishing (0.9 Bcf), Wood and Furniture (0.8 Bcf), Electric and Electronic Equipment (0.5 Bcf), and Tobacco (0.0006 Bcf). Gas consumption by end use was based on data from the California Measurement Advisory Council. Source: EFI, 2019.

Figure B-1 was created using data from CARB,[1] DOE,[2] and the California Measurement Advisory Council.[3]

Appendix B-2

The following analysis profiles a range of mitigation opportunities across the Industry sector as a whole and within Industry subsectors using data from the California Greenhouse Gas Inventory (2018 Edition).[4] (Note that the subsector profiles and mitigation opportunities are calculated from 2016 emissions levels.)

Table B-1
GHG Reduction Opportunities for Industry in California

Subsector Profile and Mitigation Opportunities	Potential GHG Savings (Metric Tons CO_2e)
Cement **Fuel combustion emissions: 2.4 MMTCO_2e (32 percent)** • Coal: 1.4 MMTCO_2e • Natural gas: 0.2 MMTCO_2e • Petroleum: 0.7 MMTCO_2e • Other: 0.2 MMTCO_2e **Non-combustion emissions: 5.2 MMTCO_2e (68 percent)** • Clinker production: 5.2 MMTCO_2e • Fuel storage (coal): <0.1 MMTCO_2e **General characteristics:** • Process heat requirement: High • Near-term electrification potential: Low	n/a
Mitigation Opportunity 1. Materials substitution: Reduce average clinker-to-cement ratio from 66 percent to 64 percent	Unknown
Mitigation Opportunity 2. Technology adoption: Higher-efficiency kiln for clinker production	731,616*
Mitigation Opportunity 3. Fuel-switching: All natural gas fuel switching from coal and petroleum, keep existing natural gas, eliminate coal fuel storage	983,194*
Mitigation Opportunity 4. CCUS at 60 percent capture (indexed to four cement plants identified in two regional clusters that are located near potential geologic sequestration sites)	1,431,636*
Mitigation Opportunity 5. CCUS at 60 percent capture (fuel combustion): No fuel switching	1,463,233
Mitigation Opportunity 6. Negative emissions: Cement carbonation of one-third of process emissions (clinker production) after two years	1,700,218
Mitigation Opportunity 7. Fuel-switching pre-CCUS at 60 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum	1,861,132
Mitigation Opportunity 8. Fuel-switching: All H_2 or electrification fuel switching, keep existing natural gas, eliminate coal fuel storage	2,211,792
Mitigation Opportunity 9. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas, eliminate coal fuel storage	2,443,458
Mitigation Opportunity 10. CCUS at 60 percent capture (fuel combustion and clinker production): No fuel switching	4,554,538

Mitigation Opportunity 11. Fuel-switching pre-CCUS at 60 percent capture (fuel combustion) and CCUS at 60 percent capture (clinker production): All natural gas fuel switching from coal and petroleum	4,952,437
Mitigation Opportunity 12. Negative emissions with CCUS at 80 percent capture (clinker production): Capture 80 percent of process emissions from clinker production, no capture of thermal emissions, carbon-neutral cement by 2050 (greater capture rates could induce net negative emissions)	7,598,599
Mitigation Opportunity 13. Negative emissions with CCUS at 53 percent capture (clinker production): Capture 53 percent of process emissions from clinker production, fully decarbonized thermal supply, carbon-neutral cement by 2050 (greater capture rates could induce net negative emissions)	7,598,599
Chemicals & Allied Products **Fuel combustion emissions: 6.2 $MMTCO_2e$ (99 percent)** • Coal: 0 $MMTCO_2e$ • Natural gas: 6.2 $MMTCO_2e$ • Petroleum: 0 $MMTCO_2e$ • Other: 0 $MMTCO_2e$ **Non-combustion emissions: <0.1 $MMTCO_2e$ (<1 percent)** • Fugitive emissions: <0.1 $MMTCO_2e$ • Other (nitric acid production): <0.1 $MMTCO_2e$ **General characteristics:** • Process heat requirement: High • Near-term electrification potential: Medium	n/a
Mitigation Opportunity 1. Industrial CHP: Add new CHP technical potential at select project sites (39 sites at 5 MW capacity each using reciprocating engines at 9,190 metric tons CO_2e savings per unit relative to coal use)	358,410*
Mitigation Opportunity 2. CCUS at 50 percent capture (fuel combustion): No fuel switching	3,115,749
Mitigation Opportunity 3. CCUS at 50 percent capture (fuel combustion and fugitive emissions): No fuel switching	3,117,130
Mitigation Opportunity 4. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas	6,231,499
Food Products **Fuel combustion emissions: 3.3 $MMTCO_2e$ (99 percent)** • Coal: 0 $MMTCO_2e$ • Natural gas: 3.3 $MMTCO_2e$ • Petroleum: 0 $MMTCO_2e$ • Other: 0 $MMTCO_2e$ **Non-combustion emissions: <0.1 $MMTCO_2e$ (<1 percent)** • Fugitive emissions: <0.1 $MMTCO_2e$	n/a

General characteristics: • Process heat requirement: Medium/High • Near-term electrification potential: Medium	
Mitigation Opportunity 1. CCUS at 50 percent capture (fuel combustion): No fuel switching	1,644,101
Mitigation Opportunity 2. CCUS at 50 percent capture (fuel combustion and fugitive emissions): No fuel switching	1,645,191
Mitigation Opportunity 3. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas	3,288,201
Industrial Combined Heat and Power **Fuel combustion emissions: 8.0 $MMTCO_2e$ (99 percent)** • Coal: 1.3 $MMTCO_2e$ • Natural gas: 5.5 $MMTCO_2e$ • Petroleum: <0.1 $MMTCO_2e$ • Other: 1.2 $MMTCO_2e$ **Non-combustion emissions: <0.1 $MMTCO_2e$ (<1 percent)** • Fuel storage (coal): <0.1 $MMTCO_2e$ **General characteristics:** • Process heat requirement: n/a • Near-term electrification potential: n/a	n/a
Mitigation Opportunity 1. Fuel-switching: All natural gas fuel switching from coal and petroleum, keep existing natural gas, eliminate coal fuel storage	567,176*
Mitigation Opportunity 2. Industrial CHP: Add new CHP technical potential at select project sites (39 sites at 5 MW capacity each using reciprocating engines at 9,190 metric tons CO_2e savings per unit in the Chemicals and Allied Products sub-sector; 21 sites at 20 MW capacity each using natural gas combustion turbines at 30,508 metric tons CO_2e savings per unit in the Petroleum Refining sub-sector)	999,078
Mitigation Opportunity 3. Fuel-switching: All H_2 or electrification fuel switching, keep existing natural gas, eliminate coal fuel storage	1,318,465
Mitigation Opportunity 4. CCUS at 50 percent capture (fuel combustion): No fuel switching	3,996,299
Mitigation Opportunity 5. Fuel-switching pre-CCUS at 50 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum	4,283,075
Mitigation Opportunity 6. Fuel-switching pre-CCUS at 50 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum, add new CHP technical potential at select project sites (39 sites at 5 MW capacity each using reciprocating engines at 9,190 metric tons CO_2e savings per unit in the Chemicals and Allied Products sub-sector; 21 sites at 20 MW capacity each using natural gas combustion turbines at 30,508 metric tons CO_2e savings per unit in the Petroleum Refining sub-sector)	5,282,153
Mitigation Opportunity 7. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas, eliminate coal fuel storage	7,998,975
Mitigation Opportunity 8. Industrial CHP: Add new CHP technical potential	7,551,835

Mitigation Opportunity 9. Fuel-switching: All natural gas fuel switching from coal and petroleum, keep existing natural gas, eliminate coal fuel storage, add new CHP technical potential	8,119,011
Mitigation Opportunity 10. Fuel-switching: All H_2 or electrification fuel switching, keep existing natural gas, eliminate coal fuel storage, add new CHP technical potential	8,870,300
Mitigation Opportunity 11. CCUS at 50 percent capture (fuel combustion): No fuel switching, add new CHP technical potential	11,548,135
Mitigation Opportunity 12. Fuel-switching pre-CCUS at 50 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum, add new CHP technical potential	11,834,911
Mitigation Opportunity 13. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas, eliminate coal fuel storage, add new CHP technical potential	14,320,668
Landfills, Solid Waste Treatment, and Wastewater Treatment **Fuel combustion emissions: 0 $MMTCO_2e$ (n/a)** **Non-combustion emissions: 8.8 $MMTCO_2e$ (100 percent)** • Landfill gas generation: 8.5 $MMTCO_2e$ • Composting: 0.3 $MMTCO_2e$ • Wastewater treatment (biogas production): <0.1 $MMTCO_2e$ **General characteristics:** • Process heat requirement: n/a • Near-term electrification potential: n/a	n/a
Mitigation Opportunity 1. Biogas collection at 50 percent capture†	4.3 (50 percent)*
Oil & Gas Production and Processing **Fuel combustion emissions: 15.7 $MMTCO_2e$ (87 percent)** • Coal: 0 $MMTCO_2e$ • Natural gas: 12.2 $MMTCO_2e$ • Petroleum: <0.1 $MMTCO_2e$ • Other: 3.3 $MMTCO_2e$ **Non-combustion emissions: 2.3 $MMTCO_2e$ (13 percent)** • Fugitive emissions (production, processing, storage, wastewater treatment): 2.3 $MMTCO_2e$ **General characteristics:** • Process heat requirement: High • Near-term electrification potential: Low	n/a
Mitigation Opportunity 1. Fuel-switching: All natural gas fuel switching from coal and petroleum, keep existing natural gas	18,109*
Mitigation Opportunity 2. Fuel-switching: All H_2 or electrification fuel switching, keep existing natural gas	65,945

Mitigation Opportunity 3. Reduce or eliminate fugitive emissions at 25 percent, 50 percent, 75 percent, and 100 percent capture	568,370 (25 percent) 1,136,741 (50 percent)* 1,705,111 (75 percent) 2,273,348 (100 percent)
Mitigation Opportunity 4. CCUS at 50 percent capture (applied to one regional cluster of natural gas processing plants that are located near potential geologic sequestration sites)	1,655,557*
Mitigation Opportunity 5. CCUS at 50 percent capture (fuel combustion): No fuel switching	7,827,811
Mitigation Opportunity 6. Fuel-switching pre-CCUS at 50 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum	7,836,865
Mitigation Opportunity 7. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas (not including associated gas)	12,306,598
Petroleum Refining and Hydrogen Production **Fuel combustion emissions: 22.6 MMTCO$_2$e (76 percent)** • Coal: 0 MMTCO$_2$e • Natural gas: 2.8 MMTCO$_2$e • Petroleum: 5.7 MMTCO$_2$e • Other: 14 MMTCO$_2$e **Non-combustion emissions: 7.0 MMTCO$_2$e (24 percent)** • Fugitive emissions (process losses, storage tanks): <0.1MMTCO$_2$e • Process emissions: 0.2 MMTCO$_2$e • Other (acid gas control, flaring, fuel consumption): 6.8 MMTCO$_2$e **General characteristics:** • Process heat requirement: High • Near-term electrification potential: Low	n/a
Mitigation Opportunity 1. Reduce or eliminate fugitive emissions at 25 percent, 50 percent, 75 percent, and 100 percent capture	8,178 (25 percent) 16,357 (50 percent) 24,535 (75 percent) 32,713 (100 percent)
Mitigation Opportunity 2. Industrial CHP: Add new CHP technical potential at select project sites (21 sites at 20 MW capacity each using natural gas combustion turbines at 30,508 metric tons CO$_2$e savings per unit in the Petroleum Refining sub-sector)	640,668*
Mitigation Opportunity 3. Fuel-switching: All natural gas fuel switching from coal and petroleum, keep existing natural gas	2,748,792*
Mitigation Opportunity 4. CCUS at 65 percent capture (fuel consumption)	4,241,158
Mitigation Opportunity 5. Fuel-switching: All H_2 or electrification fuel switching, keep existing natural gas	5,729,079
Mitigation Opportunity 6. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas (not including refinery gas)	8,575,804
Mitigation Opportunity 7. CCUS at 65 percent capture (indexed to seven oil refineries identified in two regional clusters that are located near potential geologic sequestration sites)	9,695,595*
Mitigation Opportunity 8. CCUS at 65 percent capture (fuel combustion): No fuel switching	14,670,571

Mitigation Opportunity 9 CCUS at 65 percent capture (fuel combustion and process emissions): No fuel switching	14,769,216
Mitigation Opportunity 10. Fuel-switching pre-CCUS at 65 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum	15,632,648
Mitigation Opportunity 11. Fuel-switching pre-CCUS at 65 percent capture (fuel combustion and process emissions): All natural gas fuel switching from coal and petroleum	15,731,293
Transmission and Distribution **Fuel combustion emissions: 1.0 MMTCO$_2$e (20 percent)** • Coal: 0 MMTCO$_2$e • Natural gas: 1.0 MMTCO$_2$e • Petroleum: 0 MMTCO$_2$e • Other: 0 MMTCO$_2$e **Non-combustion emissions: 4.1 MMTCO$_2$e (80 percent)** • Fugitive emissions (gas storage): <0.1 MMTCO$_2$e • Fugitive emissions (gas pipelines): 4.0 MMTCO$_2$e **General characteristics:** • Process heat requirement: n/a • Near-term electrification potential: n/a	n/a
Mitigation Opportunity 1. Reduce or eliminate fugitive emissions (gas pipelines) at 25 percent, 50 percent, 75 percent, and 100 percent capture	998,363 (25 percent) 1,996,727 (50 percent)* 2,995,090 (75 percent) 3,993,453 (100 percent)
Mitigation Opportunity 2. Fuel-switching: All H_2 or electrification fuel switching	1,014,050
Mitigation Opportunity 3. Fuel-switching: All H_2 or electrification fuel switching, eliminate natural gas storage	1,084,226
Other Subsectors Manufacturing [Construction; Electric and Electronic Equipment; Metal Durables; “Not Specified”; Plastics and Rubber; Primary Metals; Printing and Publishing; Pulp and Paper; Stone, Clay, and Glass; Storage Tanks; Textiles; Tobacco; Transportation Equipment; Wood and Furniture]), Mining; “Not Specified”; Petroleum Marketing **Fuel combustion emissions: 7.3 MMTCO$_2$e (52 percent)** • Coal: 0 MMTCO$_2$e • Natural gas: 4.5 MMTCO$_2$e • Petroleum: 2.8 MMTCO$_2$e • Other: <0.1 MMTCO$_2$e **Non-combustion emissions: 6.6 MMTCO$_2$e (48 percent)** • Fugitive emissions (process losses, storage tanks, wastewater treatment)	n/a

• Consumption (CO_2, lubricants, limestone, dolomite, soda ash) • Substitutes for ozone-depleting substances • Production (lime) • Other (semiconductor manufacture) **General characteristics:** • Process heat requirement: Varies • Near-term electrification potential: Varies	
Mitigation Opportunity 1. Negative emissions: Mine tailings	Unknown
Mitigation Opportunity 2. Negative emissions: Wastewater treatment	Unknown
Mitigation Opportunity 3. Reduce or eliminate fugitive emissions at 25 percent, 50 percent, 75 percent, and 100 percent capture	45,518 (25 percent) 91,035 (50 percent) 136,553 (75 percent) 182,071 (100 percent)
Mitigation Opportunity 4. Fuel-switching: All natural gas fuel switching from coal and petroleum, keep existing natural gas (Construction and "Not Specified")	414,565*
Mitigation Opportunity 5. CCUS at 50 percent capture (fuel consumption, lubricants)	869,416
Mitigation Opportunity 6. Fuel-switching pre-CCUS at 50 percent capture (fuel combustion): All natural gas fuel switching from coal and petroleum	1,500,303
Mitigation Opportunity 7. CCUS at 50 percent capture (fuel combustion): No fuel switching (Mining; Construction; Electric & Electronic Equipment; Metal Durables; Plastics & Rubber; Primary Metals; Printing and Publishing; Pulp and Paper; Stone, Clay, and Glass; Textiles; Tobacco; Transportation; Wood and Furniture)	3,626,094
Mitigation Opportunity 8. Fuel-switching: All H_2 or electrification fuel switching, eliminate existing natural gas (Mining; Construction; Electric & Electronic Equipment; Metal Durables; "Not Specified"; Plastics & Rubber; Primary Metals; Printing and Publishing; Pulp and Paper; Stone, Clay, and Glass; Textiles; Tobacco; Transportation; Wood and Furniture)	7,300,000*
Other Opportunities for Reducing Industry Sector Emissions	n/a
Mitigation Opportunity 1. Energy efficiency: Compliance with SB 350	60,000*
Mitigation Opportunity 2. Additive manufacturing at 25 percent reduction in energy use (Construction; Electric & Electronic Equipment; Food Products; Textiles; Transportation Equipment; Wood & Furniture)	1,053,003
Mitigation Opportunity 3. Fuel-switching: Decarbonize pipeline natural gas supply with RNG	3,600,000*
Mitigation Opportunity 4. Smart systems at 20 percent reduction in energy intensity (fuel combustion) through manufacturing automation	3,757,753
Mitigation Opportunity 5. Facility best management practices	6,644,299*
**Denotes values that were selected for the illustrative mitigation portfolio pathway.* *†Denotes a 50 percent capture rate for biogas sources (only methane emissions in CO_2e) according to EFI biogas calculations.* Source: EFI, 2019. Compiled using data from CARB, 2018.	

Appendix B-3

California currently has 17 oil refineries with a total production capacity of more than 1.9 million barrels per day (Table B-2). Previous refinery production capacity was 20 percent higher than current levels; reflecting the fact that 10 refineries closed during the period of 1985 to 1995. Further refinery closures are expected in the future, particularly for those with a production capacity of less than 50,000 barrels per day.[5]

The current fleet of operating refineries is located in and around the Central Valley, Los Angeles, and San Francisco.[6] In 2018, California refineries consumed 641,989,000 barrels of crude oil, the majority of which came from foreign countries (58 percent) followed by California (31 percent) and Alaska (11 percent).[7] Fifty-one percent of the foreign sources of crude oil imports to California in 2018 came from Saudi Arabia (37 percent) and Ecuador (14 percent).[8] Although California previously supplied 61 percent of the crude oil consumed by its refineries in the early 1980s, the proportion of in-state supply to its refineries decreased by one-half from 1982 to 2017.[9] As a result, the demand for crude oil imports has been on the rise in order to meet the state's petroleum demand.[10] Refinery locations outside of California that can produce gasoline for the California market include Washington state, the U.S. Gulf Coast, Eastern Canada, Finland, Germany, U.S. Virgin Islands, Middle East, and Asia.[11]

Table B-2
California Oil Refineries

Name	Barrels Per Day	CARB Diesel Production	CARB Gasoline Production
Chevron U.S.A. Inc., El Segundo Refinery	269,000	Yes	Yes
Chevron U.S.A. Inc., Richmond Refinery	245,271	Yes	Yes
Andeavor, Carson Refinery	243,800	Yes	Yes
Andeavor, Golden Eagle Martinez Refinery	166,000	Yes	Yes
PBF Energy, Torrance Refinery	160,000	Yes	Yes
Shell Oil Products US, Martinez Refinery	156,400	Yes	Yes
Valero Energy, Benicia Refinery	145,000	Yes	Yes
Phillips 66, Wilmington Refinery	139,000	Yes	Yes
Phillips 66, Rodeo San Francisco Refinery	120,200	Yes	Yes
Andeavor, Wilmington Refinery	97,500	Yes	Yes
Valero Energy, Wilmington Refinery	85,000	Yes	Yes
Kern Oil & Refining Company, Bakersfield Refinery	26,000	Yes	Yes
San Joaquin Refining Company Inc., Bakersfield Refinery	15,000	Yes	No
Greka Energy, Santa Maria Refinery	9,500	No	No
Santa Maria Refinery Company	9,500	No	No
Lunday Thagard, South Gate Refinery	8,500	No	No
Valero Wilmington Asphalt Refinery	6,300	No	No

California oil refineries have a total capacity of approximately 1,901,971 barrels per day.[12] Source: CEC, 2018.[13]

Appendix B-4

Figure 4-2. Industry Sector Emissions Profile, 2016 ($MMTCO_2e$). "Other" includes the major subsectors of Mining; Petroleum Marketing; Solid Waste Treatment; Wastewater Treatment; and "Not Specified," and the subsectors within Manufacturing of Construction; Electric & Electronic Equipment; Metal Durables; Plastics and Rubber; Primary Metals; Printing & Publishing; Pulp and Paper; Stone, Clay, and Glass (minus Cement); Storage Tanks; Textiles; Tobacco; Transportation Equipment; Wood and Furniture; and Manufacturing: Not Specified.

Figure 4-6. Natural Gas Use and GHG Emissions in Industry, 2016. For natural gas use in industry, "Other" includes Mining and Transmission and Distribution. For greenhouse gas (GHG) emissions in Industry, "Other" includes combustion-related emissions from: Mining, Transmission and Distribution and "Not Specified." For Manufacturing sub-sectors: Chemicals represents Chemicals and Allied Products; Food represents Food Products; Cement represents Stone, Clay, Glass, & Cement; and Other represents Construction, Electric and Electronic Equipment, Plastics and Rubber, Printing and Publishing, Textiles, Tobacco, Wood and Furniture, and "Not Specified."

Figure 4-7. Industrial Electricity and Natural Gas Demand Forecast, 2016-2030. Note: Electricity consumption projections are based on data from the California Energy Commission (CEC). Natural gas projections are based on data from CEC using an estimated annual decrease of 0.183 percent. The 2016 industrial natural gas consumption level reflects actual consumption (660.8 billion cubic feet or Bcf) as reported by the California Air Resources Board.

Figure 4-9. Total CHP Technical Potential by Industry Subsector in California. Data includes traditional topping-cycle CHP (4,253 sites; 3,633 MW) and bottoming-cycle waste heat-to-power CHP (62 sites; 729 MW). Traditional topping-cycle CHP involves fuel combustion for the initial purpose of generating electricity and subsequent conversion of leftover heat into useful thermal energy. Bottoming-cycle CHP, or waste heat-to-power, involves fuel combustion for the initial purpose of heat production, and the leftover waste heat is captured and subsequently used for power generation. Traditional topping-cycle CHP had 98.6 percent of the total sites and 83.3 percent of the total capacity. Opportunities by subsector include Petroleum Refining (1.9 percent of total sites, 32.7 percent of total capacity); Chemicals and Allied Products (19.5 percent of total sites, 25.5 percent of total capacity); Food Products (26.6 percent of total sites, 17.8 percent of total capacity); Stone, Clay, and Glass (0.7 percent of total sites, 4.7 percent of total capacity); Transportation Equipment (6.7 percent of total sites, 3.4 percent of total capacity); and Other (44.7 percent of total sites, 16.0 percent of total capacity).

[1] "Fuel Activity for California's Greenhouse Gas Inventory by Sector & Activity," California Air Resources Board [CARB], last updated June 22, 2018, https://www.arb.ca.gov/cc/inventory/data/tables/fuel_activity_inventory_by_sector_all_00-16.xlsx .

[2] Sabine Brueske et al., *U.S. Manufacturing Energy Use and Greenhouse Gas Emissions Analysis* (Columbia, MD: Energetics, Inc., 2012), https://www.energy.gov/sites/prod/files/2013/11/f4/energy_use_and_loss_and_emissions_petroleum.pdf.

[3] XENERGY, Inc., *California Industrial Energy Efficiency Market Characterization Study* (Oakland: XENERGY, 2001), http://www.calmac.org/publications/California%20Ind%20EE%20Mkt%20Characterization.pdf.

[4] "Fuel Activity for California's Greenhouse Gas Inventory by Sector & Activity," CARB.

[5] "California's Oil Refineries," Petroleum Data, Almanac, California Energy Commission [CEC], accessed April 17, 2019, https://www.energy.ca.gov/almanac/petroleum_data/refineries.html.

[6] "California's Oil Refineries," Petroleum Data, Almanac, California Energy Commission [CEC], accessed April 17, 2019, https://www.energy.ca.gov/almanac/petroleum_data/refineries.html.

[7] "2018 Monthly Receipts of Crude Oil by Source," Petroleum Data, Almanac, CEC, accessed April 17, 2019, https://www.energy.ca.gov/almanac/petroleum_data/statistics/2018_monthly_oil_sources.html.

[8] "Foreign Sources of Crude Oil Imports to California 2017," Petroleum Data, Almanac, CEC, March 1, 2018, https://www.energy.ca.gov/almanac/petroleum_data/statistics/2017_foreign_crude_sources.html.

[9] "Oil Supply Sources to California Refineries," CEC, accessed April 17, 2019, https://www.energy.ca.gov/almanac/petroleum_data/statistics/crude_oil_receipts.html

[10] Petroleum section in "Profile Analysis," California State Profile and Energy Estimates, Energy Information Administration [EIA], Department of Energy, last modified November 15, 2018, https://www.eia.gov/state/analysis.php?sid=CA.

[11] "California's Oil Refineries," CEC.

[12] "California's Oil Refineries," CEC.

[13] "California's Oil Refineries," CEC.

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