DOCKETED

Docket Number:	17-IEPR-04
Project Title:	Natural Gas Outlook
TN #:	222371-4
Document Title:	Chapter 3, CCST Long-Term Viability of Underground Natural Gas Storage in California
Description:	Chapter 3, How will implementation of California's climate policies change the need for underground gas storage in the future? California Council on Science & Technology, an Independent Review of Scientific and Technical Information on the Long-Term Viability of Underground Natural Gas Storage in California.
Filer:	Lana Wong
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/26/2018 10:34:02 AM
Docketed Date:	1/26/2018

Chapter Three

How will implementation of California's climate policies change the need for underground gas storage in the future?

Jeffery B. Greenblatt
Lawrence Berkeley National Laboratory
December 1, 2017

ABSTRACT

California leads the nation in developing policies to address climate change, with a combination of economy-wide greenhouse gas (GHG) reduction *goals* policies (AB 32, SB 32, etc.) and complementary *means* policies that target specific sectors or activities, such as those that encourage energy efficiency, renewable electricity, electricity storage, etc. California also has a cap and trade program to provide an economically efficient framework for reaching emission targets. Chapter 3 is charged with examining how implementation of these policies will affect the need for underground gas storage (UGS), focusing on the years 2030 and 2050 as key policy milestones. The need for UGS derives from many different kinds of demands for natural gas, which can primarily be organized into two categories: building and industrial heat, and electricity generation. (A third category, vehicle fuel, plays an extremely minor role in today's energy system.) Depending on end use, temporal variation in gas demand can vary from subhourly to seasonal time scales, and it is the temporal variations that have the greatest influence on the demand for UGS. California's climate policies will change both the quantity of gas used for these purposes and their temporal profiles, and both of these will change the need for UGS, but not necessarily in the same direction. Understanding the net impact on UGS of changes to the energy system designed to meet climate goals requires having information not only about the time of gas use during the day (diurnal variation), but also how the demand for gas might vary on multiday to seasonal time scales.

None of California's climate policies specify the end-state energy system that would reliably meet California's energy needs as well as the emission goals, largely because maintaining the reliability required for societal well-being and the economy will become more challenging with increasingly aggressive emission goals. Natural gas currently provides the primary method for backing up renewable energy in California. If this does not or cannot

change, natural gas (or other energy-dense fuels with lower net GHG emissions, such as biomethane or hydrogen) could remain an important part of our energy system for some time. On the other hand, it may be possible to reduce or even eliminate the need for gas combustion and therefore the need for gas storage with a combination of technical advances, efficiency mandates, and regionalization. California needs to vet these alternative ideas for maintaining reliability. Until another option can be demonstrated to work, gas cannot be ruled out as part of a future energy system that has extensive intermittency.

3.0. INTRODUCTION

The purpose of this chapter is to answer the question: How will implementation of California's climate policies change the need for underground gas storage in the future? From Chapter 2, we have made it clear that alternatives to UGS exist, but they are likely to be expensive. In Chapter 3, we examine the future need for the gas reserve services currently provided by UGS. UGS can rapidly store or deliver gas to meet periods of peak gas demand during certain hours of the day in certain seasons. Although we use the term UGS, these services could theoretically be provided by the alternatives to UGS discussed in Chapter 2.

This chapter examines the impact that California's climate policies may have on the need for gas reserve services as explicitly requested by legislation. California leads the nation in developing policies to address climate change. Perhaps the most fundamental of these policies requires that California reach greenhouse gas (GHG) emission goals in 2020, 2030, and 2050. Based on AB 32, California is required to reduce GHG emissions to the 1990 level in 2020. SB 32 requires California to further reduce its GHG emissions to 40% below the 1990 level by 2030. Finally, Governor Schwarzenegger's Executive Order E-3-05 and Governor Brown's Executive Order B-30-15 both require the state to reduce GHG emissions to 80% below the 1990 level by 2050. These policies codify energy system *goals*.

California also has a number of complementary climate policies, such as those that encourage energy efficiency, renewable electricity, electricity storage, emissions limits from long-term power purchase agreements, biofuels, increases in electricity and hydrogen for transport, and decreases in short-lived greenhouse gas emissions (such as methane). California also has a cap and trade program to provide an economically efficient framework for reaching emission targets. These policies codify specific *means* to move towards the energy system goals. Appendix 3-3: Recent Federal and State Policies, lists all relevant policies, including California *goals* and *means* policies.

Since we expect that the amount of gas California will use in the future will change, because of these climate policies, it is reasonable to ask how implementation of these policies will affect the need for UGS. The need for UGS derives from many different kinds of demands for natural gas, which can primarily be organized into two categories: building and industrial heat, and electricity generation (with a third category, vehicle fuel, playing an extremely minor role in today's energy system):

- In the building and industrial heat category, different temporal profiles of gas demand are currently driven by: (1) High capacity factor or "baseload" demand (roughly constant demand at all hours and seasons); (2) Daily peak demand due to human patterns of use (morning and evening peaks); (3) Seasonal peak demand, which primarily occurs during winter mornings and evenings due to hot water and space heating; and (4) During emergencies such as cold weather events, when heating use may increase markedly.

- In the electricity category, temporal profiles of gas demand are currently driven by (1) High capacity factor or "baseload" demand (roughly constant demand at all hours and seasons); (2) Daily peak demand due to human patterns of use (morning and evening peaks); (3) Seasonal peak demand, generally occurring during summer months in the late afternoon as a result of air conditioning, with peaks occurring in September; (4) Increased balancing of intermittent renewable generation (which can occur on time scales ranging from subhourly to seasonally, and in particular for growing solar capacity, steep changes in gas use occur daily around 8 a.m. as solar generation increases, and again at 4 p.m. as it wanes); and (5) During emergencies such as wildfires, which may disable electric transmission lines.

In all these cases, there is a natural gas demand, but the demand for UGS is not necessarily the same. Strategies available for both electricity and non-electricity demand to increase flexibility in gas use, such as demand response, energy storage, regional coordination, etc., will be affected by the temporal patterns of gas use, as well as the costs, capacities, durations, and ramping speeds of the strategies.

California's climate policies will change both the quantity of gas used for these purposes and their temporal profiles, and both of these will change the need for UGS, but not necessarily in the same direction. For example, more intermittent renewable electricity will replace gas that we use for electricity generation. But more intermittent electricity means that UGS requirements will likely increase, in order to provide reliable ("firm") electricity generation when intermittent electricity output (primarily wind and solar) is low. Energy storage devices such as batteries can help with this problem, but decreased output lasting many days as a result of weather events might increase the use of gas. Meanwhile, even if we use less gas overall, the peak use of gas might not decrease, or could even increase. Understanding the net impact on UGS of changes to the energy system designed to meet climate goals requires not only having information about the time of gas use during the day (diurnal variation), but also how the demand for gas might vary on multiday to seasonal time scales. This is discussed in detail later in this chapter.

Our methodology consists of a review of available literature on future energy scenarios under different greenhouse gas emission pathways, followed by an expert synthesis of available scenarios focusing on 2030 and 2050, two key compliance years for greenhouse gas emissions. A wide variety of scenarios have been developed to explore options for meeting California's climate goals. These mirror the two types of climate policies the state currently has. Scenario studies develop alternative energy systems that meet the overall climate policy *goals*. These studies provide ranges for the amount of possible gas use in the future, constrained by having an energy system that reliably meets our needs. They do not, however, generally include information about the time of use of gas, nor factor in seasonal variation in either renewable electricity output or gas use.

A second kind of study projects the impacts of specific *means* policies designed to move California towards the climate goals. These studies do project the time of use of electricity and/or gas, but do not, in general, ensure that the energy system as a whole works to reach the overall emissions goals. For example, researchers have concluded that it will be necessary for the electricity system to reduce emissions more than its "fair share," because transportation is more difficult to de-carbonize (Williams et al., 2012). Such system-wide adjustments cannot be easily computed in a model that studies electricity or transportation alone.

Finding: We found no studies that comprehensively assess the volumes of gas needed in the future, i.e., studies that construct complete future possible energy system configurations that meet the climate goals, project the impact of the policies that provide the means to reach these goals, and project the time of use of gas and electricity on every time scale from subhourly to seasonally.

Given the studies that do exist, this chapter takes two different approaches. We looked at scenarios for different models of meeting these long-term *goals* on a system-wide basis and, where possible, inferred their impact on the need for UGS. In general, these studies tell us that the need for UGS may decrease, but it could as well increase. Secondly, we looked at projections of hourly gas demand in 2030 based on implementation of the *means* policies.

Conclusion 3.1: There are no energy assessment studies that can convincingly inform the future need for UGS in California, because greenhouse gas emissions goals and expectations for energy system reliability remain to be reconciled.

Recommendation 3.1: California should commission or otherwise obtain studies to identify future configurations of energy system technologies for the state that meet emission constraints and achieve reliability criteria on all time scales from subhourly to peak daily demand to seasonal supply variation. These studies should result in a new hybrid forecasting and resource assessment tool to inform both policy makers and regulators.

3.0.1. Assessment of Energy Technologies

Our assessment of future energy scenarios for California was informed by a detailed assessment of current and potential future energy technologies, found in Appendix 3-2: Energy Technologies. A list of technologies included in that assessment is shown in Table 1.

Table 1. Energy technologies considered in this chapter.

Wind energy	**Energy storage**
Conventional wind power	Battery storage
Floating offshore wind turbines	Thermal storage
High-altitude wind	Pumped hydroelectric storage
Solar energy	Compressed air energy storage
Solar photovoltaics	Other electromechanical technologies
Solar thermal	**Natural gas substitutes**
Geothermal energy	Biomethane
Conventional geothermal energy	Hydrogen
Enhanced geothermal systems	Synthetic natural gas
Supercritical geothermal systems	**Power-to-gas**
Hydropower	Power-to-gas hydrogen
Conventional hydropower	Power-to-gas methane
Marine and hydrokinetic power	**Vehicle fuel shifting and electrification**
Nuclear power	Electric vehicles
Conventional nuclear power	Hydrogen vehicles
Small modular reactors	Natural gas vehicles
Carbon dioxide capture and sequestration	**Building electrification**[a]

a While buildings are already partially electrified, the term "building electrification" here refers to replacing fuel combustion devices (e.g., furnaces, water heaters, clothes dryers and cooking appliances) with electric-based technologies. While all technologies can utilize resistive heating, these tend to be inefficient and less dynamic. For space heating, water heating, and clothes drying, heat pumps can be used, and have efficiencies many times higher than combustion-based technologies. For cooktops, infrared heating or magnetic induction can be used as effective substitutes for natural gas combustion. For higher-temperature applications, a variety of other technologies are also possible, including induction, radio frequency, microwave, infrared, ultraviolet, and plasma heating (Greenblatt et al., 2012)

3.0.2. Recent California and Federal Policies

In addition to reviewing the literature for GHG-compliant scenarios, we also took into consideration all recent California policies bearing on future GHG emissions. For example, policies with among the largest GHG impacts are the economy-wide GHG targets for 2020 (AB 32), 2030 (SB 32 / AB 197) and 2050 (Executive Order S-3-05 and B-30-15), renewable electricity and building efficiency targets (SB 350), as well as the recent extension of cap and trade policy to 2030 (AB 398). Since California meets or exceeds federal GHG policies in almost every area, our analysis was limited to a small number of federal policies. All relevant policies are summarized in *Appendix 3-3: Recent Federal and State Policies*.

3.0.3. Literature Review of Greenhouse Gas Scenario Studies

We examined 26 studies, with 12 covering California, 12 covering the U.S., and three with global scope. While most of the studies covered all sectors, two only examined the electricity sector, one just modeled transportation, and one only examined gas use. These latter two types of scenarios, while of less value because they did not cover all sectors that used natural gas, did provide complementary information. Studies examined are summarized in Table 2.

Note that none of these studies looked at the amount of UGS needed, or even subannual demand for natural gas—a key driver of the need for UGS. Nonetheless, the scenarios did provide additional information, e.g., the presence (or in some cases, quantities) of electricity storage, flexible loads, building and vehicle electrification, renewable electricity generation, low-carbon gas, and so on, that help provide a more complete picture of how the combined electricity-plus-natural gas system could change. This information, together with complementary data from other sources and our own expert judgment, was used to estimate the future impact on gas storage reserve capacity needs compared with today's use.

Table 2. List of studies consulted for future gas demand projections.

Reference(s)	Short title	Spatial coverage	Sectors	Years covered	Number of scenarios
Greenblatt et al., 2011; Greenblatt and Long, 2012	California's Energy Future	CA	All	2050	51 (only 17 used)
Williams et al., 2012	Pivotal Role of Electricity	CA	All	2050	5
McCollum et al., 2012	Deep GHG Reduction Scenarios	CA	All	2050	2
Wei et al., 2013a	Deep Carbon Reductions in CA	CA	All	2050	4 (+ 8 only electricity)
Wei et al., 2013b; Nelson et al., 2013	Scenarios Meeting CA 2050 Goals	CA	All	2030 (elec. only), 2050	4 (+14 only electricity)
Yang et al., 2014	Modeling Optimal Transition Pathways	CA	All	2050	12
Yang et al., 2015	Achieving 80% GHG Reduction	CA	All	2050	6
Greenblatt, 2015	Modeling CA Policy Impacts on GHG	CA	All	2030, 2050	4
E3, 2015a	PATHWAYS: Long-term GHG Reduction Scenarios	CA	All	2050 (2030 for one scenario)	8
E3, 2015b	Decarbonizing Pipeline Gas	CA	All	2050	3
CA Utilities, 2016	California Gas Report	CA	Gas only	2030 (analysis to 2035)	2
CARB, 2017a	Scoping Plan Update	CA	All	2030	3
RMI, 2011	Reinventing Fire	US	All	2050	2 (+ 4 only electricity)
Lin et al., 2013	Hydrogen Vehicles	US	Transport	2050	16
Logan et al., 2013	Natural Gas Scenarios in U.S. Power Sector	US	Electricity	2030, 2050	8
Williams et al., 2014	Deep Decarbonization	US	All	2050	5
Clarke et al., 2014	Results of EMF 24	US	All	2050	30
Fawcett et al., 2014	Overview of EMF 24	US	All	2050	7
EIA, 2014	Annual Energy Outlook 2014	US	All	2030, 2040	30

Reference(s)	Short title	Spatial coverage	Sectors	Years covered	Number of scenarios
OECD/IEA, 2015	World Energy Outlook	US, Global	All	2030, 2040	3
Risky Business Project, 2016	From Risk to Return	US	All	2050	5
White House, 2016	Mid-Century Strategy	US	All	2035, 2050	6
Cole et al., 2016	Deep Decarbonization	US	Electricity	2030, 2050	24
EIA, 2017a	Annual Energy Outlook 2017	US	All	2030, 2050	8
McJeon et al., 2014	Decadal-Scale Climate Change	Global	All	2030, 2050	10
Shell Oil, 2016	Pathways to Net-Zero Emissions	Global	All	2100	1
	TOTAL				251 (217 used)

The temporal scope of all studies extended at least until 2030. For 21 studies, the scope extended until 2050 (one study by Shell Oil extended until 2100, but contained no information about the intervening years, so was only minimally useful).

In addition, Bartos and Chester (2015) and Greenblatt et al. (2017a) did not contain quantitative data on natural gas use, but were nonetheless useful and contributed to our overall understanding by providing information on how climate change might affect the supply of, and demand for, energy in 2050.

For all the studies, we extracted any data pertaining to natural gas use. In most cases, only annual gas demand was reported. We also inferred how the use of natural gas would change on time scales shorter than annual (e.g., monthly and hourly), based on reported information such as the capacity of electricity storage, demand response/load-shifting, electric vehicle charging, etc. However, not all studies provided this information quantitatively; in many cases, we had only qualitative indications of the presence or absence of such capabilities.

Where available, we also noted the amounts of biomethane, synthetic natural gas (SNG), hydrogen, and CO_2 sequestration present in the scenarios, all of which could have an impact on required UGS in general. While biomethane, SNG, and small amounts of hydrogen can in principle be blended with conventional natural gas in the existing pipeline network, pure hydrogen (e.g., dedicated for use in vehicles) as well as CO_2 destined for underground sequestration cannot be blended with conventional natural gas and must be managed with separate pipeline networks. It was important to understand when such demands were present, as it affected how much of existing natural gas infrastructure capacity may need to be retained for these services, even if the amount of conventional natural gas used diminishes.

We divided the examined scenarios into two approximate categories: “GHG compliant” and “non-GHG compliant.” GHG compliance means meeting California’s 2030 and 2050 GHG reduction targets (of 40% and 80% below the 1990 level, respectively, via SB 32 and Executive Order S-3-05). While not all scenarios modeled California, we categorized a scenario as GHG compliant if its relative economy-wide GHG emissions fell to a level comparable to California’s GHG targets. The non-California studies were useful to examine how the same climate objectives were applied to different—but similar—energy systems. Note that, in some cases, we had to use a base year that was different from 1990 in order to estimate this GHG reduction. As a result, the categorization was somewhat qualitative given the imprecision of normalizing to different base years.

Altogether, we identified a total of 322 natural gas demand estimates across the 26 studies. Of these, 88 estimates (for 2030 and/or 2050) represented GHG-compliant scenarios. For California scenarios that included all energy sectors, there were a total of 30 demand estimates: eight for 2030 and 23 for 2050, spanning nine studies and 26 individual scenarios. Additional data were available for GHG-compliant scenarios for the entire U.S.:

30 demand estimates encompassing all energy sectors, and 25 for the electricity sector. An additional 223 demand estimates corresponded to scenarios that were not GHG compliant: 46 for California, 171 for the U.S., and six for the world.

3.1. ELEMENTS OF A FUTURE CALIFORNIA ENERGY SYSTEM

Based on our review of the literature, scenarios that meet California's 2050 climate goal all contain significant increases relative to today in several elements of the energy system:

- Increased energy efficiency in all sectors, somewhat moderating demand increases from population and economic growth, as well as the magnitude of some demand peaks
- Increased transportation electrification (portions of light- and heavy-duty vehicles)
- Increased renewable electricity generation (primarily wind and solar)
- Increased electricity storage and flexible electric loads

In addition, some scenarios employ significant implementation of:

- Fossil fuel with CO_2 capture and sequestration (CCS) in electricity generation (and to a limited extent, industrial facilities)
- Flexible, non-fossil electricity generation: nuclear, geothermal, biomass with or without CCS, marine/hydrokinetic technologies, solar thermal with storage, etc.
- Building electrification in residential, commercial, and possibly industrial sectors
- Low-carbon gas production: biomethane, SNG, and/or hydrogen blended in pipelines[1]
- Pure hydrogen production, used in vehicles and possibly other sectors
- Power-to-gas (P2G): load-balancing technology that converts excess electricity into hydrogen and/or methane, typically for direct pipeline injection

1. Here "low-carbon" refers to net GHG emissions, not just the emissions encountered when the gas is burned. Both biomethane and SNG, while chemically identical to natural gas-derived methane, have the potential to be much lower in net GHG emissions than natural gas, though for both SNG and hydrogen, the source of CO_2 can make a critical difference to net emissions. See Appendix 3-2: Energy Technologies, Natural Gas Substitutes for more information.

- Increased regional electricity transmission capacity to allow more imports of out-of-state resources (particularly renewables) to help smooth supply-demand imbalances. California policy counts the GHG emissions from out-of-state generation in its GHG inventory (CAISO, 2016a; ICAP, 2017), so high-GHG generation resources would have to be used very sparingly.

While many of these elements play prominent roles in 2050 in most scenarios, they are more subdued or not even present in 2030. As a result, the scenarios we examined did not start to diverge significantly in terms of their potential impact on UGS until after 2030.

3.1.1. Balancing Gas Demand on Multiple Time Scales

In Chapter 2, we learned that there are seven distinct functions of UGS in California:

1. Storage provides supply when, in some years, monthly winter needs exceed the pipeline capacity.

2. Storage compensates for relatively constant rates of gas production that do not match variation in gas demand.

3. Storage provides supply when winter peak day demands exceed pipeline capacity.

4. Storage provides inter-day balancing to support hourly changes in demand that the receipt point pipelines cannot accommodate. This service is essential in allowing the flexible use of gas-fired electricity generators to back up renewable generation.

5. Storage provides in-state stockpile of supply in case of upstream pipeline outage or other emergency such as wildfires.

6. Storage allows savings through seasonal price arbitrage (winter prices are usually, but not always higher than summer prices).

7. Storage grants marketers a place to hold supply and take advantage of short-term prices for liquidity and short-term arbitrage.

Of these, possible changes aimed at reducing GHG emissions in California's energy system would most strongly affect items 1, 3 and 4: meeting winter demand, daily peak demand and daily balancing. Changes to the energy system in response to California's climate policies could have a secondary effect on the need for stockpiling depending on whether the net effect results in an increase or decrease in gas demand. Short- and long-term price arbitrage represent secondary functions of underground storage to begin with and technology changes will not likely change this.

Finding: Sub second (frequency regulation) electricity storage can be provided by flywheels or fast-response batteries; response times of minutes to hours and storage capacities of several hours can be provided by thermal storage at the building or power plant, battery storage, and pumped hydroelectric or compressed air energy storage. Flexible load capacity and management of regional transmission capacity are other tools with similar response times to storage that can be called upon for multiple hours at a time.

Conclusion 3.2: Various forms of energy storage could perform intraday balancing, i.e. manage changes in gas demand over a 24-hour period.

As discussed in Chapter 2, the most cost-effective technologies for long-duration (multiple-day) electricity storage are pumped hydroelectric storage (PHES) and compressed air energy storage (CAES). However, PHES needs very specific siting characteristics and is typically problematic because of its impacts on local ecosystems (stoRE, 2013). An exception to this may be closed-loop systems that do not affect existing bodies of water (e.g., the Eagle Mountain pumped storage project near Palm Springs, CA; Eagle Crest Energy, 2016). CAES also requires specific geology to avoid high-cost aboveground storage, and is usually a hybrid system that requires fuel (typically natural gas) when air is withdrawn from storage (Akhil et al., 2013). Therefore, unless the fuel is itself very low-carbon, CAES is not a GHG-free technology. Adiabatic CAES has been proposed to avoid this limitation, but thus far only one 500 kW demonstration plant in Switzerland has been built (the Pollegio-Loderio Tunnel ALACAES Demonstration Plant) (SNL, 2016).

Battery storage is currently more expensive, but costs continue to fall rapidly as markets and technologies mature; for more information, see Electricity Storage in Chapter 2 or Energy Storage in *Appendix 3-2: Energy Technologies*. Batteries can also charge or discharge more quickly than PHES and CAES, and are therefore suitable for short-duration (intrahour) storage, but multiple day (and certainly seasonal) storage capacity would be prohibitively expensive. Flywheels and other electromechanical technologies have also been explored for very short-term (subseconds to minutes) storage, but they are still very expensive relative to incumbent natural gas turbine technology (Akhil et al., 2013).

Finding: Most forms of energy storage as currently conceived will probably be inadequate for managing daily peak demand that can occur over multiple days and seasonal demand imbalances.

With the exception of PHES technologies, storage tends to be designed with capacities of no more than 48 hours (see Energy Storage in *Appendix 3-2: Energy Technologies*). Only a handful of PHES facilities worldwide have been built with storage capacities greater than 48 hours, and only two are located in the U.S. (Grand Coulee in Washington, at 80 hours, and San Luis in California, at 298 hours) (SNL, 2016). Additional PHES capacity may be available in California and elsewhere in the U.S. (see Appendix 3-2: Energy Technologies, *Pumped Hydroelectric Storage*), but total new capacity in California is ~2.3 GW, much less than the ~30 GW of generation capacity that may occasionally be needed by 2030 to shore up intermittent renewables (see discussion in Section 3.2.4. Gas Needed to Back Up

Intermittent Renewables). Moreover, “current market structures and regulatory frameworks do not present an effective means” of expanding PHES capacity in the U.S. (NHA, 2014, p. 3). PHES also faces environmental siting barriers and a challenging regulatory approval timeline that could take up to five years to license and an additional 10 or more years to construct. The National Hydropower Association concludes that “Policy changes are needed to support the timely development of additional grid-scale energy storage” including PHES (NHA, p. 3).

As discussed in the sections that follow, both wind and solar, which could become significant or even dominant forms of electricity generation in many future scenarios in California, experience considerable seasonal variation in output, as well as shorter-term (but still multiple-day) fluctuations resulting from weather events that are sometimes correlated across large regions, affecting total statewide (and possibly out-of-state) renewable generation capacity. The economics of storage for periods of lower frequency than intraday are much more challenging at present. Moreover, the hourly variations in wind and solar outputs may not be well matched to future electricity demand, requiring other forms of generation to serve as backup.

3.1.2. Energy Storage in Chemical Fuels

Chemical energy storage of low-carbon gases presents the most likely way to address inadequate generation capacity over long (multiple days to seasonal) durations. This includes:

- Biomethane, which is chemically equivalent to the methane found in natural gas, and can be produced from biogas with very low net GHG emissions. It can be blended with ordinary pipeline natural gas, but must still be managed using UGS. Note there are also limitations to the amount of biomethane that can be produced both inside and outside of California; see Appendix 3-2: Energy Technologies, *Biomethane*.

- Synthetic natural gas (SNG) which is also identical to the methane in natural gas, but can be produced from fossil fuels, biomass, or electrolysis of CO_2 and water. If produced from fossil fuels, the CO_2 that is also produced must be captured and stored via CCS to avoid high GHG emissions. This introduces its own pipeline and storage challenges (see Appendix 3-2: Energy Technologies, Carbon Dioxide Capture and Sequestration), and net GHG emissions may still not be sufficiently low to justify its widespread use. If SNG is produced from biomass, it could be expensive to manufacture, but has the advantage that the CO_2 produced does not need to be captured and stored to achieve low net GHG emissions. If SNG is produced directly from CO_2 and water, the CO_2 must be captured from a low-GHG source, and if provided directly from the atmosphere or ocean, it could be energy-intensive and expensive to produce (see Appendix 3-2: Energy Technologies, Power-to-gas methane).

- Hydrogen, like SNG, can also be produced from fossil fuels, biomass, or water electrolysis. While CO_2 captured from fossil fuels can eliminate GHG emissions from hydrogen production, it must still be managed via a pipeline and storage system. The hydrogen itself, whether blended with natural gas or used directly, must also be stored, using either dedicated hydrogen storage or conventional UGS. For more information, see Appendix 3-2: Energy Technologies, *Hydrogen*.

One example of the use of these low-carbon fuels for managing excess electrical generation capacity is "Power to Gas" or P2G, producing either hydrogen or methane (see Appendix 3-2: Energy Technologies, Power-to-Gas). This can be invoked whenever more electricity is generated than is needed, which often arises for intermittent renewables, though there may be circumstances where dispatchable generation (fossil-CCS, nuclear, geothermal, biomass, etc.) continues to operate for economic reasons, producing excess electricity.

Finding: P2G uses electricity from low-GHG generation technologies to make a substitute chemical fuel. However, similar to natural gas, these chemical fuels require transportation and storage.

Conclusion 3.3: The only currently available means to address multiday or seasonal supply-demand imbalances without using fossil natural gas appears to be low-GHG chemical fuels. These solutions have the same storage challenges as natural gas and may introduce new constraints, such as the need for new, dedicated pipeline and storage infrastructure in the case of hydrogen or CO_2.

3.1.3. Wildfires

Another issue is that of wildfires, which have long been a concern in the western U.S. and California in particular. Every year, thousands of acres of forests in California and elsewhere burn, mainly in summer months; for instance, there were 2,900 fires burning on 106 square miles across California in July 2017, more than twice last year's average (May, 2017). When fires occur, they sometimes force electric transmission lines offline (e.g., WECC, 2002; CAISO, 2002, 2003, 2007, 2008; CPUC, 2008; FERC, 2013), which can cause sudden loss of generation capacity and may last many days, similar to the intermittency occasionally experienced by wind and solar generation. These losses hamper the State's ability to provide adequate power to load centers, particularly during the peak electricity demand season. Moreover, wildfires often occur during hot weather, when the demand for air conditioning-driven electricity is highest. This combination of factors increases the reliance on backup strategies to provide local generation and, when necessary, load curtailment. There is some evidence that wildfire extent may be increasing with climate change (e.g., U.S. EPA, 2016).

3.1.4. Climate Change

According to Greenblatt et al. (2017a), climate change in California by 2050 is projected to result in changes to energy demand, with milder winters decreasing the use of energy for heating in buildings, and hotter summers increasing the use of electricity for air conditioning. Overall electricity demand would increase 0.8-4.3%, with peak demand increases of 2.0-4.2%.

Across the western region (Bartos and Chester, 2015), generally hotter temperatures would also result in:

- Decreased efficiency of thermal power plants: 7.4-9.5% (fossil-CCS, nuclear, geothermal, biomass, even concentrating solar)
- Decreases in gas combustion turbine capacities: 1.4-3.5%
- Decreases in solar photovoltaic (PV) generation: 0.7-1.7%
- Increases in wind generation: up to ~2.2%
- A negligible impact on hydroelectric generation
- Decreases in electric transmission capacity
- Extreme heat and drought may increase under climate change, exacerbating these effects

Finding: In California (assuming a similar mix of electricity generators as today) climate change could cause a reduction in generating capacity of 2.0-5.2% in summer, with more severe reductions under ten-year drought conditions (Bartos and Chester, 2015). Considered altogether, peak demand for electricity generation could increase by 10-15% in 2050 (Greenblatt et al., 2017a).

Conclusion 3.4: Climate change would shift demand for energy from winter to summer, reducing peak gas demand from reserve capacity in winter, but increasing it in summer. Decreases in electric transmission and generation capacity would increase reliance on backup generation and hence UGS, particularly in summer. The net effect would be a stronger reliance on UGS in summer, and possibly increased gas use, than in a scenario without climate change.

3.1.5. Role of Hydrogen

Pure hydrogen might play a more central role in the future by substituting for vehicle electrification, providing an alternative low-carbon energy pathway to replace petroleum fuels. Currently, electric vehicles appear to be on a rapid growth trajectory, and the State is pursuing an aggressive policy of vehicle and charging infrastructure expansion. However, it also supports growth of hydrogen vehicles, and breakthroughs could make this technology more desirable in the future. Some of the scenarios (E3, 2015a) discussed below invoke significant amounts of hydrogen by 2050 (~20% of 2015 total gas demand). If this occurs, the role of UGS could change if hydrogen is transported and stored in pure form, rather than mixed with natural gas. Like CO_2, hydrogen would require its own pipeline and storage infrastructure to safely handle the gas. However, it is also possible that hydrogen could be produced locally from electricity or biomass, obviating the need for dedicated hydrogen infrastructure. We consider both possibilities in our analysis.

3.1.6. Scenario Elements That Informed the Evaluation of UGS

In evaluating scenarios, we paid attention to the following elements:

- Annual demand for natural gas
- Seasonal and diurnal changes in non-electricity and electricity natural gas demand
- Seasonal and diurnal changes in electricity generation from intermittent renewables
- Seasonal and annual forecast flexible electricity generation capacity
- Annual electricity generation provided by intermittent sources (solar and wind)
- Annual electricity generation provided by CCS and flexible non-fossil resources
- Amount of electricity storage and flexible demand resources
- Shares of vehicle and building electrification
- Share of natural gas vehicles
- Share of natural gas provided by low-carbon sources (biomethane, SNG, hydrogen)
- Demand for pure hydrogen

While not all of this information was available, we attempted to gather as much of it as possible from diverse sources in order to arrive at a coherent picture of how changes in California's energy system could impact UGS.

3.2. DEMAND FOR UGS IN 2030

Finding: For the scenarios available in the literature, and with some minor exceptions (see below), changes to the energy system from the current state to 2030 are modest.
The variation in total annual demand for natural gas in 2030 ranged from between 78% and 100% of current levels in the six GHG-compliant studies we reviewed.

Additional scenarios that we did not include in our analysis were Greenblatt's (2015) S3 (60% of today's natural gas demand) and CARB (2017a)'s Scoping Plan Alternative (66% of today's natural gas demand). These scenarios were eliminated because they contained multiple extensions of existing policy goals that, while perhaps reasonable in isolation, we considered to be unrealistic when implemented simultaneously by 2030.[2] Moreover, for the CALGAPS S3 scenario (Greenblatt, 2015), emission reductions exceeded the 2030 target.

3.2.1. Non-electricity Gas Demand

Finding: Among the scenarios included, we found that, by 2030, total non-electricity natural gas demand would decrease by 11-22% relative to today, mainly due to efficiency improvements in the building stock.

Efficiency improvements reduce the need for gas for heating throughout the year; see Figure 1. Building electrification does not contribute substantially to this reduction by 2030 (though it could play a larger role by 2050). However, it is the peak gas use that determines the need for storage, not the total, and this peak occurs during cold days in the winter. Currently, the pipeline capacity to meet this peak could fall short by as much as 4,300 MMcfd. None of the scenarios we reviewed addressed peak gas demand in enough detail to quantitatively assess the need for UGS. However, if we assume efficiency improvements

2. Among the measures we considered to be unrealistic in CARB's Scoping Plan Alternative were (comparisons to current policies coming from CARB, 2017a): 60% renewable electricity generation (compared with ~27% today and 50% statewide target in 2030), 2.5 times baseline building efficiency improvements (compared with SB 350 goal of twice the historical rate through 2030, which is already challenging), increased building electrification (no building electrification is required by current State policy), early retirement of HVAC equipment (likely not cost-effective), 25% reduction in fuel GHG intensity (low-carbon fuel standard currently requires 10% reduction by 2020, and 18% by 2030), 4.7 million ZEVs deployed (State policy is 1.5 million by 2025, and 4.2 million by 2030), early retirement of 1 million vehicles (likely not cost-effective), increased reductions in vehicle miles traveled (VMT) (current Mobile Source Strategy goal is 15% reduction in light-duty vehicle VMT by 2050), and industrial sector GHG emissions reductions of 25% (and 30% in the refinery sector; current State policy goal is 20% refinery sector reduction by 2030). Many of these measures were also present in the CALGAPS S3 scenario, and in addition included: relicensing of the State's two nuclear reactors, increased high-speed rail deployment, an accelerated phase-out of hydrofluorocarbons, and reconversion of pasture to forest land to increase carbon sequestration. While many of these measures may indeed be realistic to implement after 2030, we were concerned about their expected speed of implementation in the nearer term.

reduce the peak proportional to the reduction in total use, then peak non-electricity demand for natural gas in winter could decrease by ~600-1,200 MMcfd, which is not enough to eliminate the need for UGS.

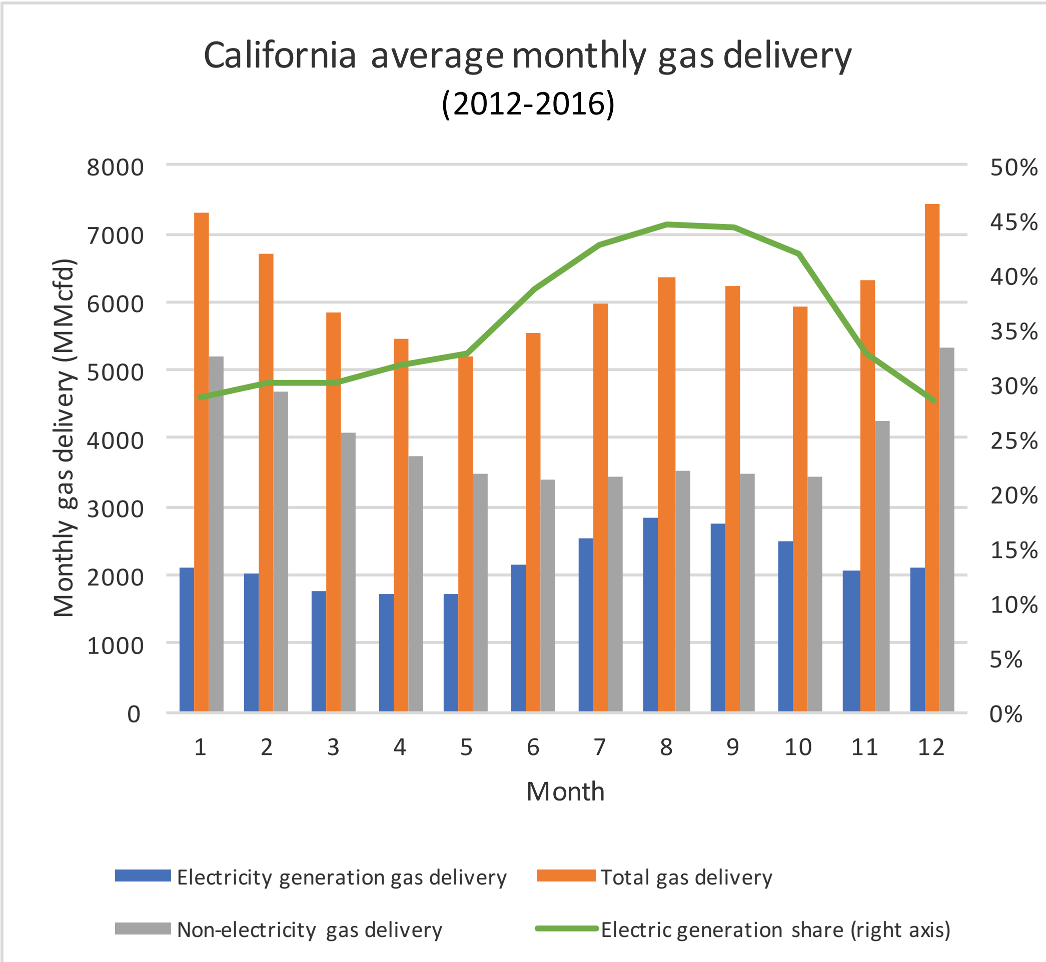


Figure 1. California average monthly gas demand, showing electricity and non-electricity breakdown. Authors' analysis based on data from EIA (2016).

Conclusion 3.5: Although we do not know what the decrease in peak natural gas demand might be, the average reduction in gas use of 600-1,200 MMcfd would not be enough to eliminate pipeline capacity deficits that are currently as much as 4,300 MMcfd.

3.2.2. Gas Demand for Electricity Generation

By comparison, we found that electricity demand for natural gas remains about the same in 2030 as today, but renewable electricity generation share increases in all scenarios, consistent with California's current policy (SB 350) goal of achieving 50% renewable electricity generation in 2030. According to E3 (2015a), the share of renewable generation increases from 27% in 2015 to ~40-50% in 2030, depending on the scenario, while the amount of natural gas used for electricity generation remains about the same or (for one scenario) increases by 14%. Electricity demand is, however, projected to increase by 8 to 14%, resulting in a change in the use of natural gas per kWh generated of between a 14% decrease and a 6% increase. UGS can act as a physical (and financial) hedge against the uncertainty in the amount of renewable generation and electricity demand that actually materializes in 2030.

Finding: The highest gas use for electricity generation occurs during summer months, roughly July-October (Figure 1). The highest output for both wind and solar also occurs in summer months, peaking in June in both cases (Figure 2). For wind, output declines steadily toward a winter low in December-January, whereas for solar, output remains high through September, after which shorter days and more cloud cover diminish statewide output toward a winter low. Gas use for electricity generation is expected to decline much more in summer than in winter by 2030.

Conclusion 3.6: If California continues to develop renewable power using the same resources the State employs today, these will be at a minimum in the winter, which could create a large demand for gas in the electric sector at the same time that gas demand for heat peaks. Consequently, the winter peak problem that exists today may remain or possibly become more acute, making UGS even more important unless California deploys complementary strategies including energy storage, demand response, flexible loads, time-of-use rates, EV charging, and an expanded or coordinated western grid.

While the contribution of wind, solar, and other renewables to electricity generation in 2030 remains uncertain, E3's projections suggest somewhat more solar output than wind, indicating less reliance on natural gas as wind output falls in late summer (E3, 2015a; CPUC, 2017).

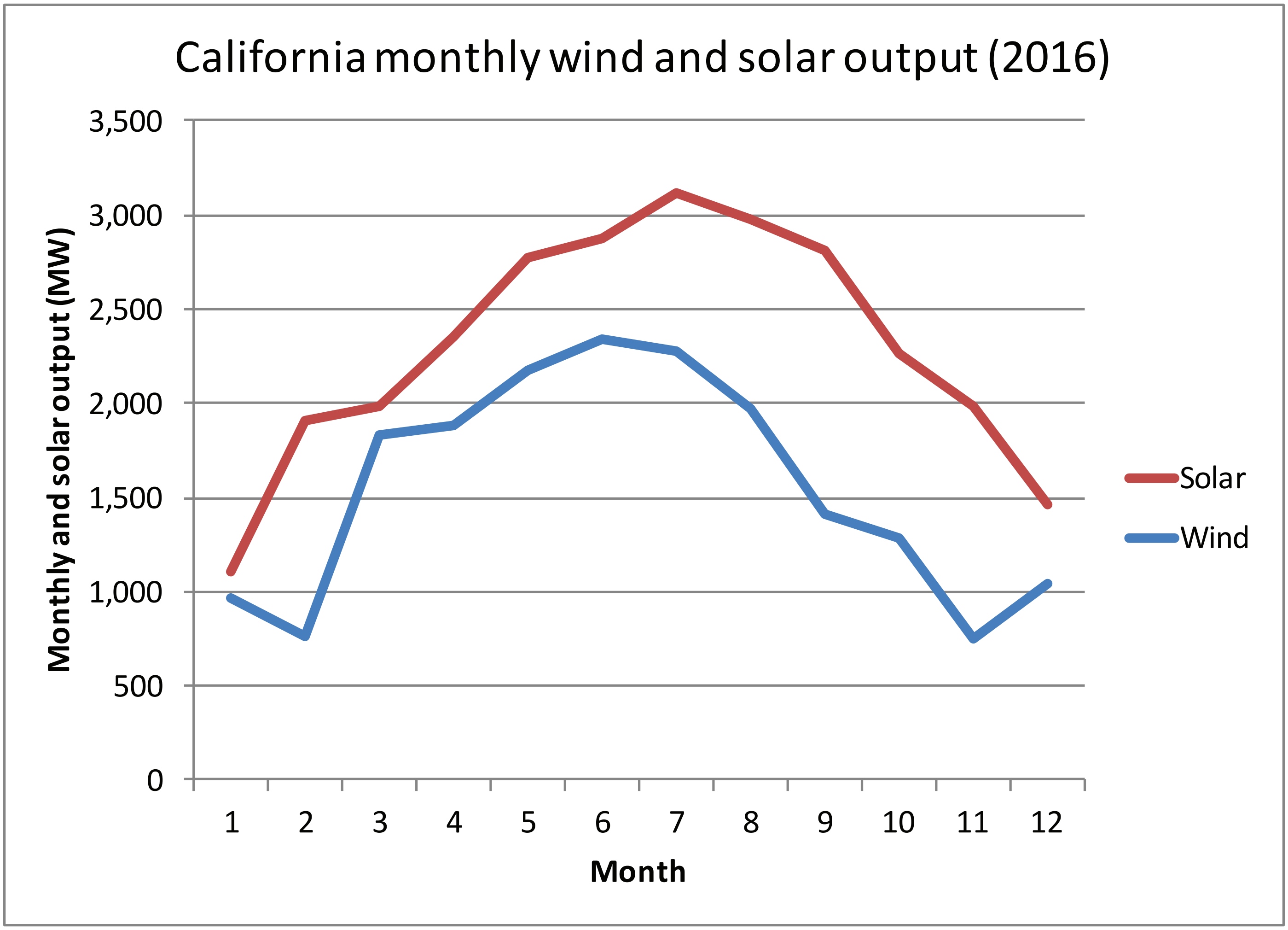


Figure 2. California monthly average wind and solar output in 2016. Reproduced from data in CAISO (2017a, Figure 1.8).

Note that whereas solar energy obviously peaks during the day, wind output in California peaks at night in summer, somewhat making up for the fall in solar output during the waning hours of the afternoon. See Figure 3.

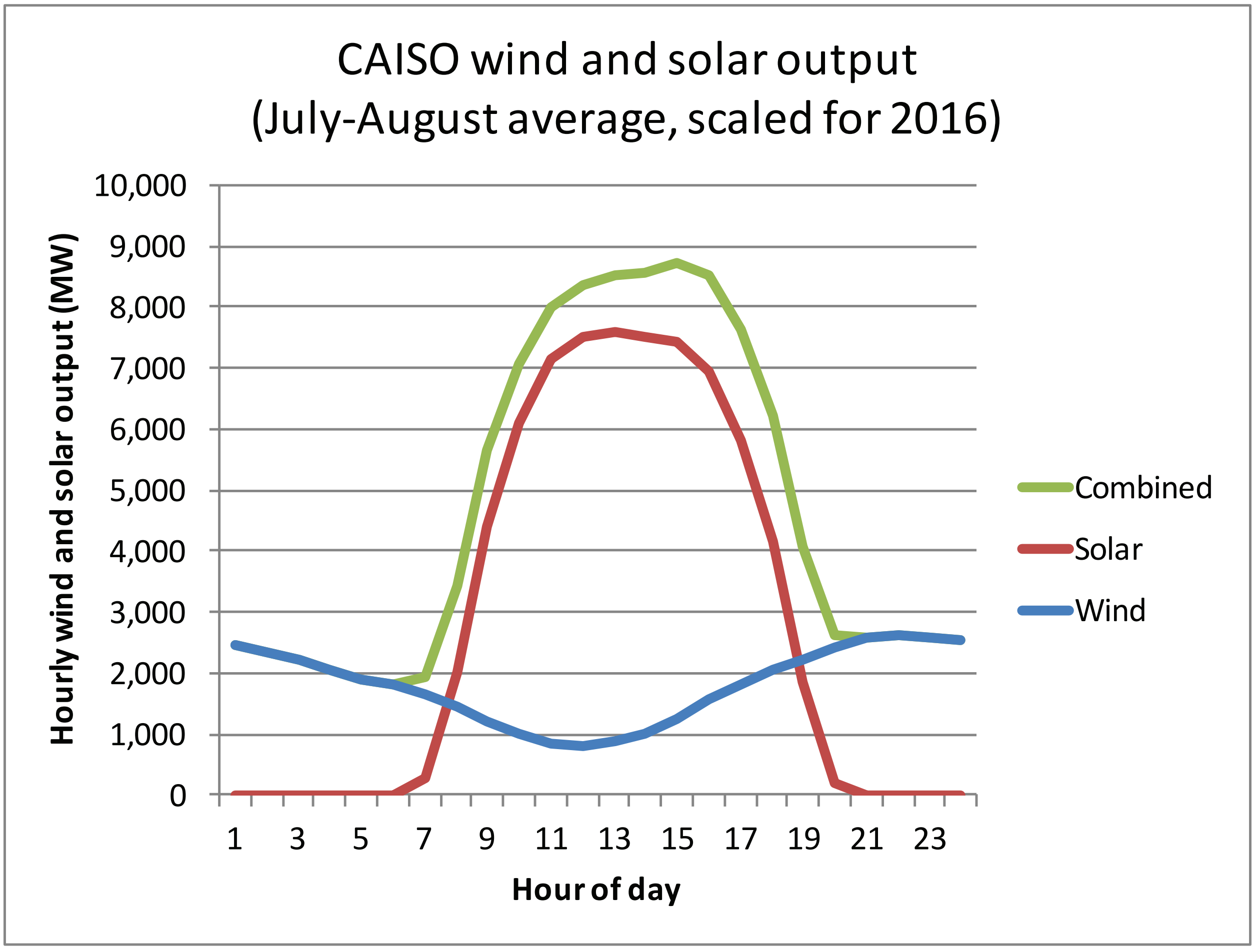


Figure 3. California average wind and solar output by hour for July-August, based on 2014 data (CAISO, 2014c) scaled approximately by 2016 solar capacity.

3.2.3. Hourly Gas Demand

The CEC developed scenarios of hourly gas demand for electricity generation from 2017 to 2030 that complies with all California policies through 2030, including a doubling of additional achievable energy efficiency, increased renewable generation, increased energy storage, and increasing numbers of electric vehicles, among other policies (A. Tanghetti, pers. commun., 2017). Projections shown in Figure 4 are simulations from the CEC "2xAAEE" case, which best represents future policy. The data represent 1-in-2 year daily gas demand for electricity generation for the State. One can observe a general decrease in natural gas use in all seasons, with the largest decreases between April and November. Whereas in 2017, natural gas use encounters a brief minimum in March, by 2030 this low period extends for three full months, from April through June. Natural gas use increases significantly in July in both 2017 and 2030, owing to the onset of higher summer temperatures.

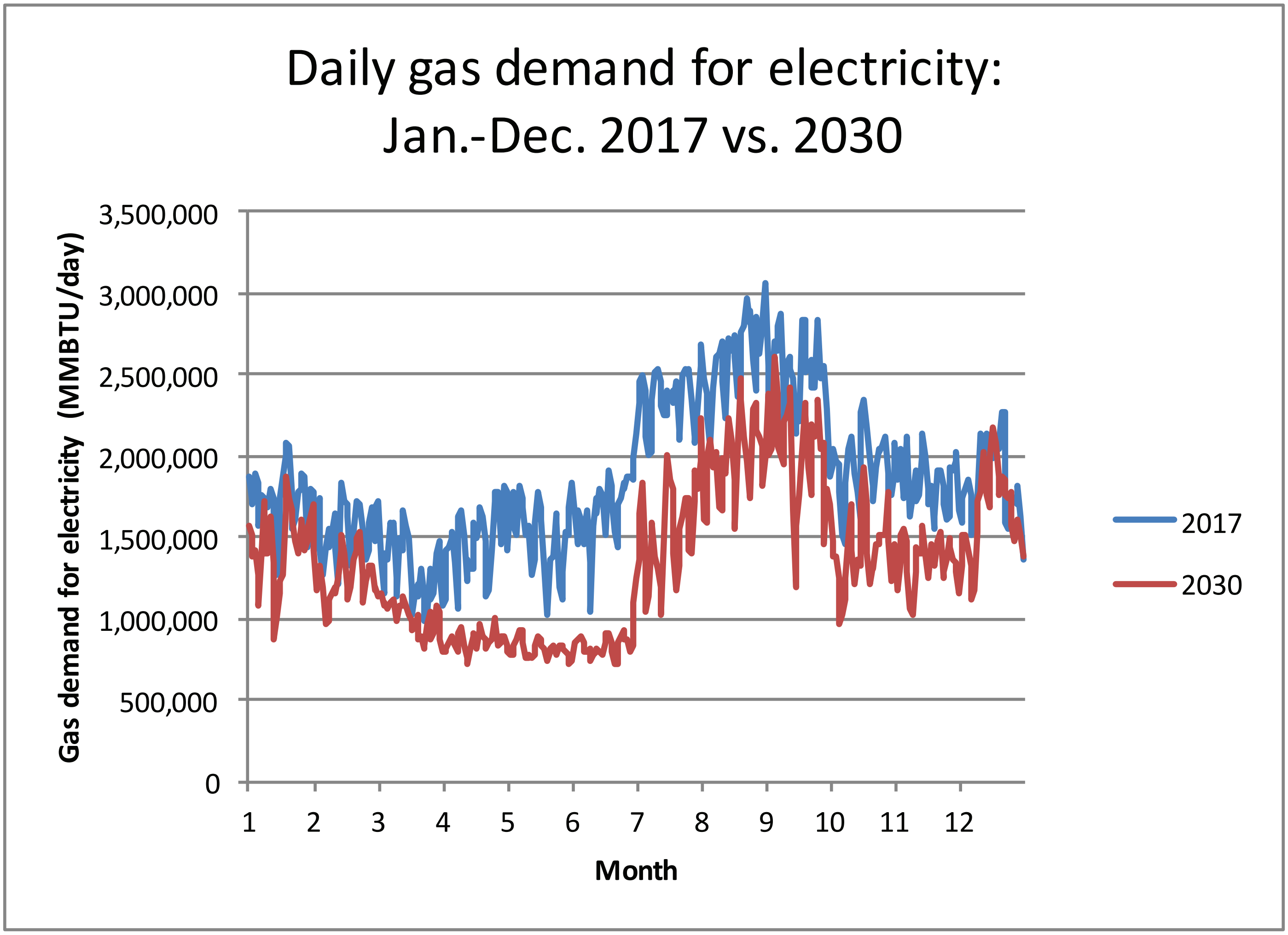


Figure 4. CEC projected 1-in-2 year daily average natural gas demand for electricity generation in California in 2017 and 2030. Projections follow the CEC "2xAAEE" scenario assumption, which is consistent with current and future policies.

Figure 4 does not, however, provide any insight into the hourly changes in natural gas demand. Monthly averages by hour in 2030 are shown for selected months in Figure 5, demonstrating the range of gas use over the year. Peak gas use as well as minimum-to-maximum gas ramps occur in September, whereas lowest gas use occurs in June. Minimum gas use occurs in the middle of the day when solar output is at a maximum (even in winter), with maximum use generally occurring in early evening (particularly in late summer). When daily gas use is high, steep ramps in natural gas use occur in early morning (~8 a.m.) when solar output is growing, and afternoon (~4 p.m.) when solar output falls off and electricity demand is growing.

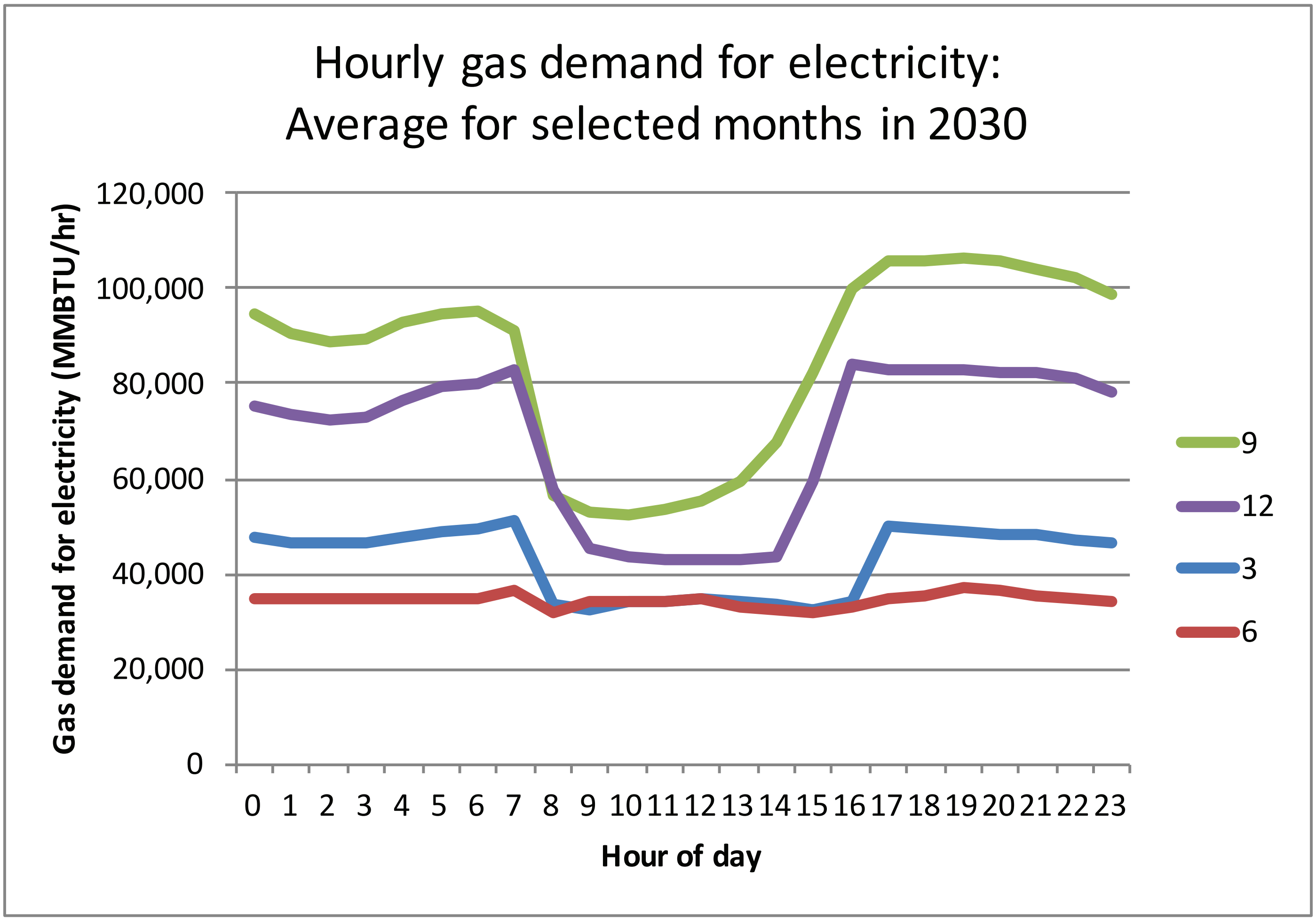


Figure 5. CEC projected diurnal 1-in-2 year average monthly natural gas demand for electricity generation in California in 2030 for selected months. Projections follow the CEC "2xAAEE" scenario assumption, which is consistent with current and future policies.

Comparing these hourly gas use profiles in 2030 to 2017 shows significant differences. Two months are shown that span the observed range in gas use for 2030: June and September. See Figure 6. For September, when electricity demand is highest because of air conditioning use, there is a large reduction in midday gas use as solar provides significant capacity during those hours, as well as reductions in early morning and evening hours, due to increased energy efficiency measures. Daily ramps are also much deeper: the average daily difference in gas use between 8 a.m. and 8 p.m. increases from 25,000 MMBTU/hr (~580 MMcfd) in 2017 to 54,000 MMBTU/hr (~1,250 MMcfd) in 2030. For June, when electricity demand is lower, gas use is more uniformly lower across the day, with a ~50% average decrease between 2017 and 2030, but peak use in morning and evening hours are also noticeably reduced. For other months (not shown), significant decreases in gas use occur during sunlit hours, along with more modest reductions in other hours.

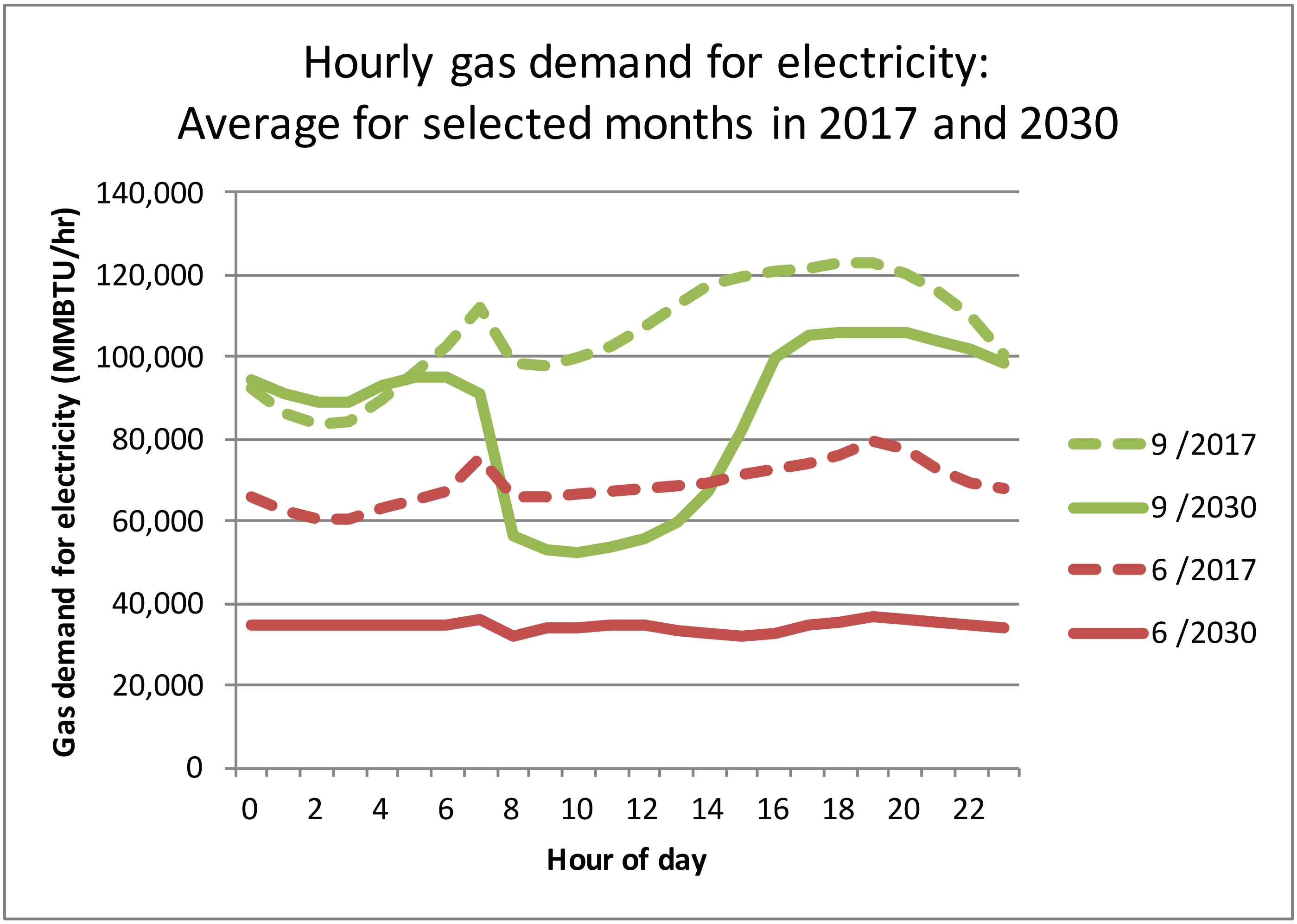


Figure 6. CEC projected diurnal 1-in-2 year average monthly natural gas demand for electricity generation in California in 2017 vs. 2030 for June and September.

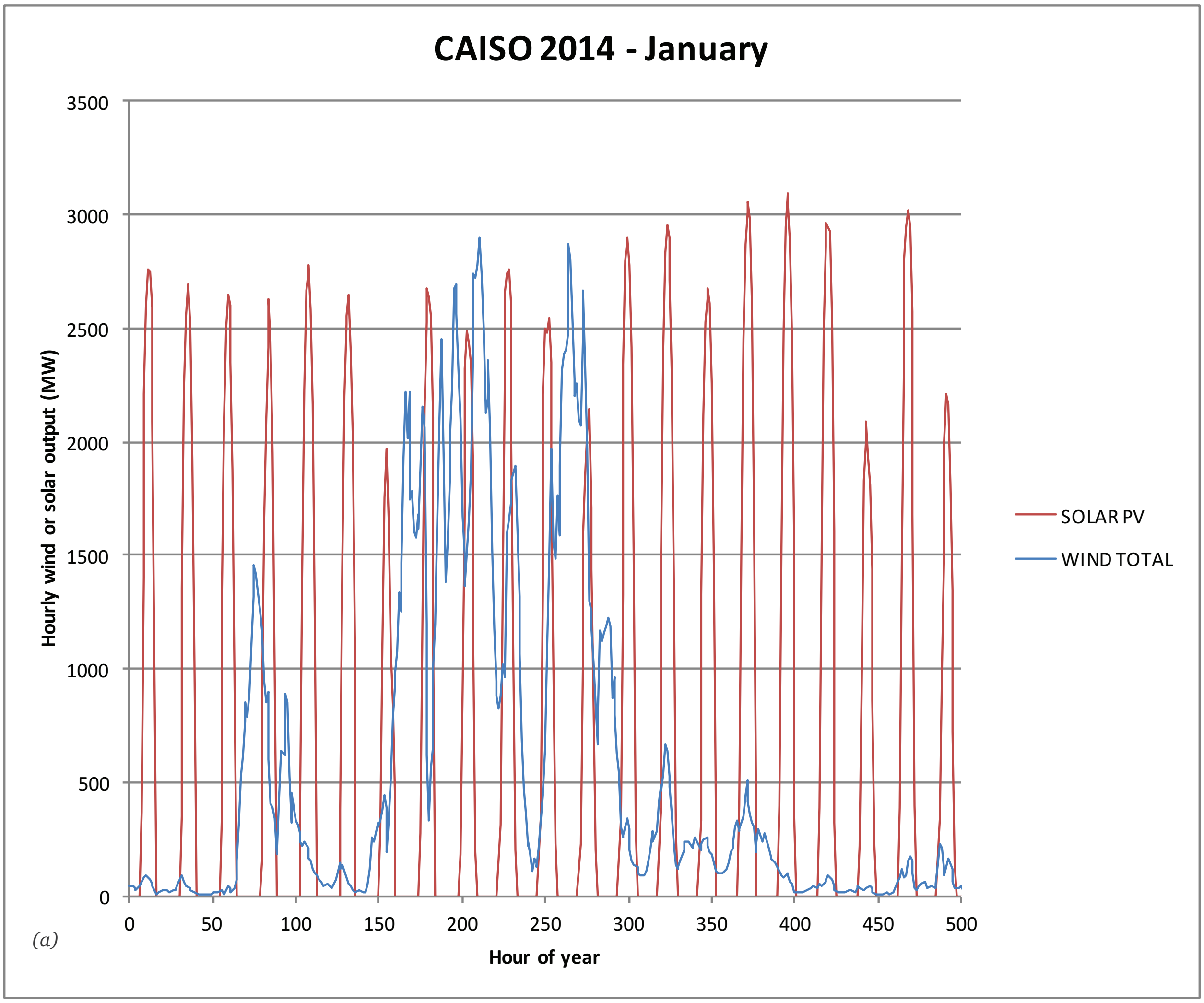
While only summer months are shown in Figure 6, winter months show behavior intermediate between that of June and September.

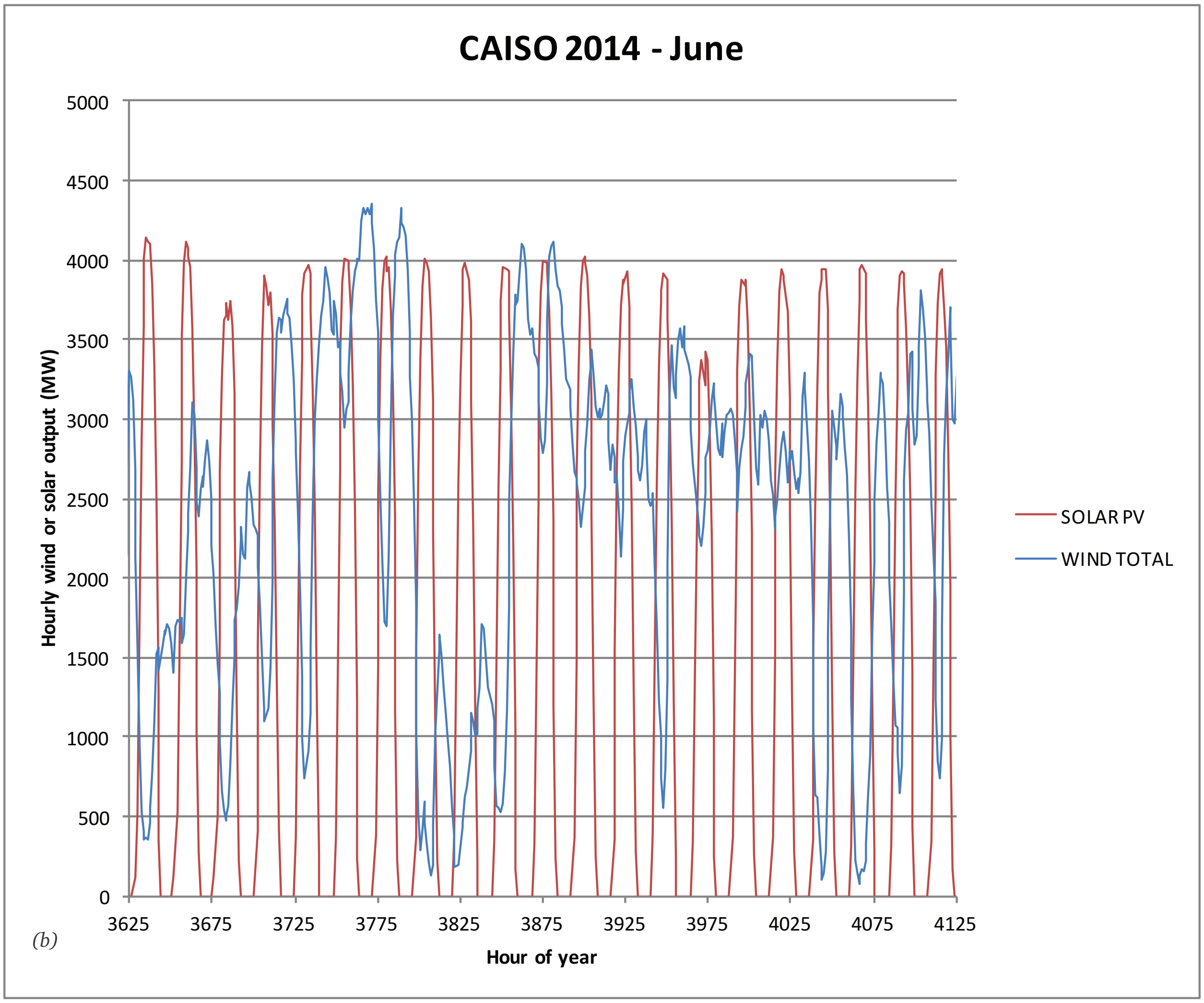
Finding: Based on State policies, CEC projections indicate that overall demand for natural gas will decrease in both summer and winter, allowing for increased flexibility for natural gas injection into storage. However, CEC projects that daily natural gas ramping capability requirements will increase in most months (July through March).

Conclusion 3.7: By 2030, an increase in the need to use gas to supply ramping capability could result in placing greater reliance on UGS.

3.2.4. Gas Needed to Back Up Intermittent Renewables

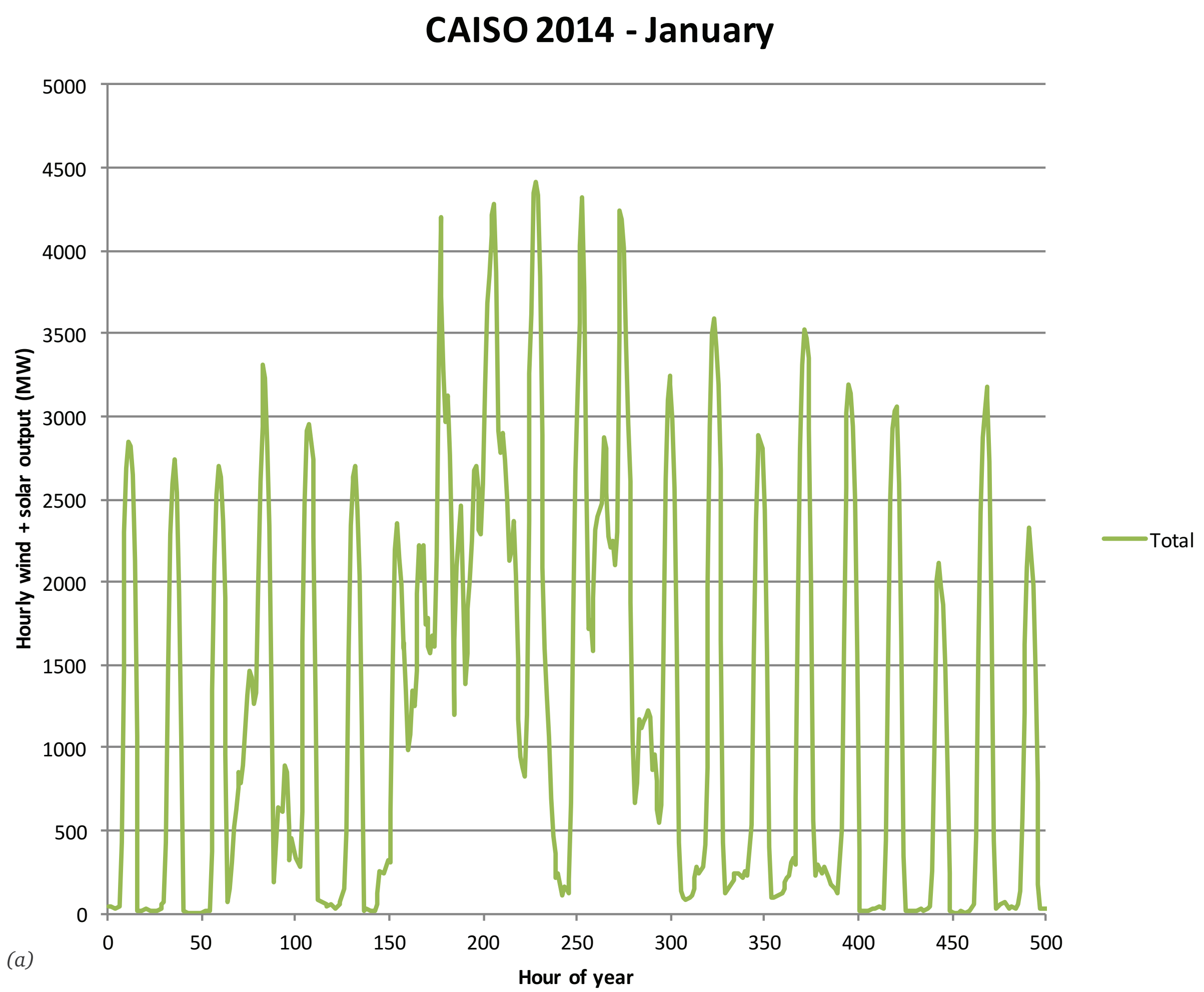
With the expected increases in both wind and solar generation, there is also increased intermittency in generation, with wind displaying large swings in output over multiple hours to days, and solar displaying a pronounced diurnal cycle with occasional drops in daytime output due to weather events. See Figure 7, which shows a snapshot of statewide hourly output during 21 days in January and June 2014. Figure 8 shows the same data but with wind and solar output combined to show total intermittent renewable output. June represents one of the highest wind and solar output periods of the year.





(b)

Figure 7. CAISO 2014 (a) January and (b) June wind and solar hourly output. Authors' analysis based on data from CAISO (2014c).


CAISO 2014 - January
Hourly wind + solar output (MW)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
0
50
100
150
200
250
300
350
400
450
500
Hour of year
Total

(a)

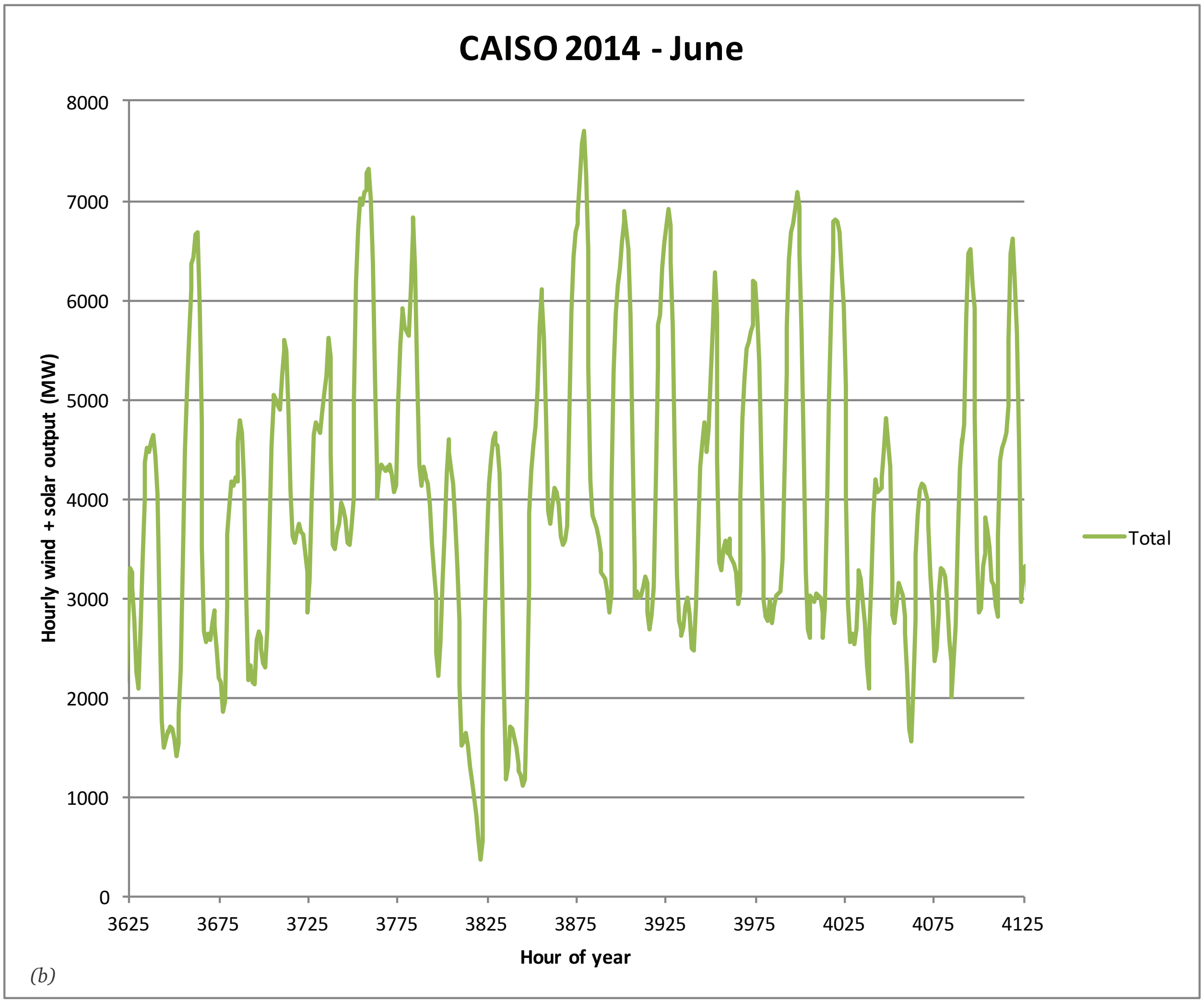


Figure 8. Same data as shown in Figure 7 but with wind and solar output combined for (a) January and (b) June 2014.

Finding: January regularly has periods when the combined output of solar and wind is nearly zero, particularly at night when solar is not operating and the wind dies down. In June, average outputs for solar and wind are much higher than January, and a strong anticorrelation between wind and solar keeps the combined output significantly higher than zero in most hours. However, there are still periods where wind output falls to almost zero, sometimes for multiple days at a time, causing dramatic (and sometimes very rapid) drops in total output. In Germany, periods of low solar and wind output are labeled "*dunkelflaute*", which literally translates as "dark doldrums" (Morris, 2016). This variability must be mitigated to ensure reliable electricity. Today the load is balanced mostly with a combination of natural gas turbine generation and hydropower.

In the future, energy storage, flexible loads, and imported (or exported) electricity could play a role in firming intermittent renewable energy. The more that other options can be used to balance variability in electricity generation, the lower the need will be for gas generation, and the lower the need to withdraw gas from storage to resolve gas imbalances caused by renewable generation.

Finding: Wind generation capacity (at ~4.9 GW) has not increased since 2014 and is expected to remain constant through 2018. Utility-scale solar PV is expected to more than double, from 4.5 GW in 2014 to 9.1 GW in 2018 (CAISO, 2015, 2016b, 2017b). The contribution from wind variability will be similar to that shown in Figure 7 and Figure 8 over the next few years, but as solar generation is always zero in the night, the solar variability will continue to grow, exacerbating the total intermittency variation.

Finding: To mitigate expected generation variability, the California Independent System Operator (CAISO) has estimated that almost as much flexible generation capacity as intermittent renewable generation capacity will be needed: for 2018, it estimates that ~16 GW will be needed to balance ~18 GW of intermittent renewables (with this capacity adding some additional intermittent renewables including a portion of behind-the-meter PV generation to the wind and solar capacities mentioned above) (CAISO, 2017b). This flexible generation capacity varies monthly, with a minimum near ~11 GW in July and a maximum in December. See Figure 9.

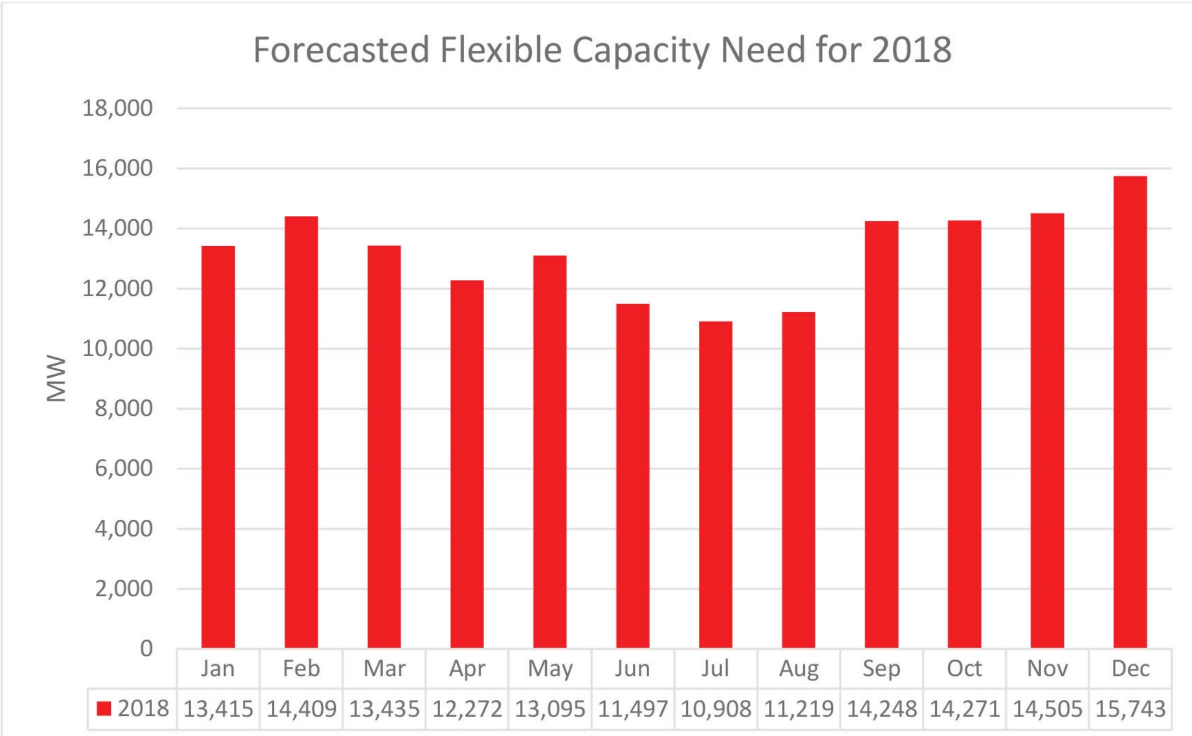


Figure 9. Forecasted flexible generation needed to balance CAISO intermittent renewables in 2018. Reproduced from Fig. 2 in CAISO (2017b). Licensed with permission from the California ISO.

The need to back up intermittent resources includes concerns about how fast the backup energy might have to be supplied, i.e., the ramping requirements. A timely example of the amount of flexible capacity needed to back up the increasing amounts of solar PV is how CAISO responded to a three-hour solar eclipse event on the morning of August 21, 2017. With ~18 GW of solar generating capacity (at both utility- and rooftop-scale) on California's grid, about 3.4 GW was estimated to be lost at the peak of the eclipse at 10:22 am (Fairley, 2017). Hydropower, gas-fired generation and regional electricity transfers were all possible options for filling the gap (CEC, 2017), but the ramping rate was very steep, up to 100 MW/min., or more than three times the normal ramp rate at that time of day (Fordney, 2017). This rate is close to the historical evening peak ramp of 13 GW over two hours (~110 MW/min.). Similarly, a 2015 total eclipse centered in Europe impacted 90 GW of solar capacity, and was considered "a true stress test" for the electricity grid, though it was handled without incident (Walton, 2017). In both cases, gas generation was a key part of the solution.

For 2030, in order to reach the 50% renewable generation targets, renewable generation will have to more than double from current levels. While the portion of generation coming from intermittent wind and solar are not knowable in advance, most studies suggest that the vast majority of it will come from these sources (e.g., E3, 2015a; Brinkman et al., 2016; Casey et al., 2016). Some of this intermittent capacity could also be imported from neighboring states.

Finding: Brinkman et al. (2016) explored a model of California's electricity system in 2030 under a 50% GHG reduction scenario, which assumed 56% renewable electricity generation that included 6% customer-sited solar PV. The study found that up to 30 GW of gas generation would be needed to backup these renewables, though half of this capacity would be utilized less than ~25% of the time, making capital investments to insure the availability of such gas generation difficult. See Figure 10.

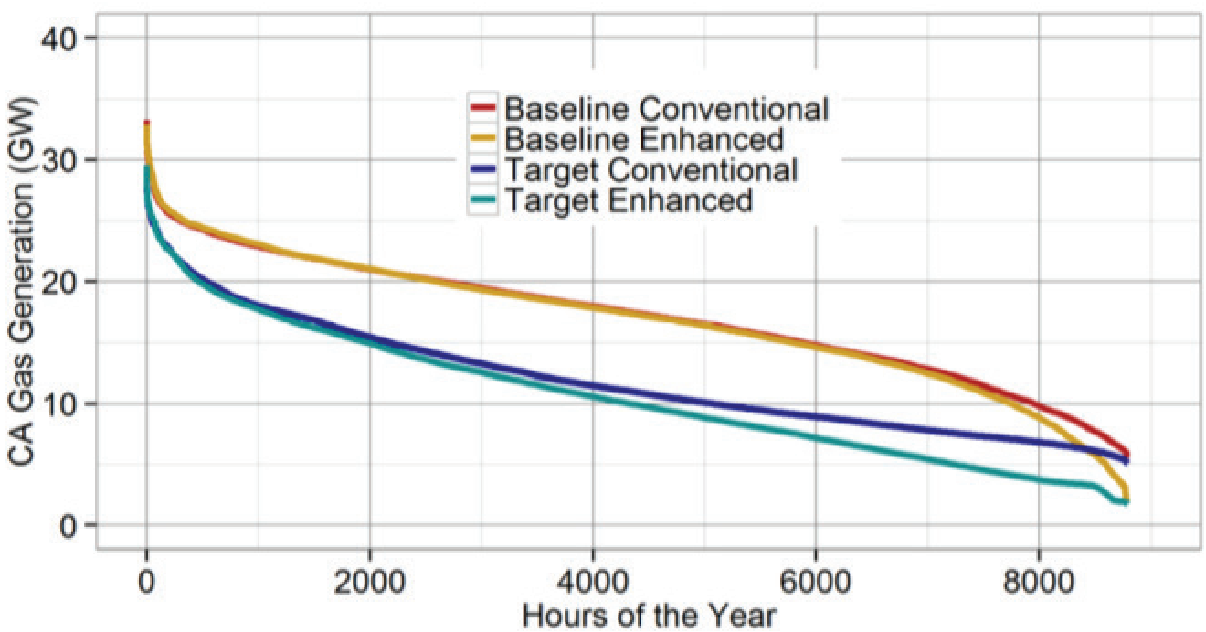


Figure 10. Duration curve of California gas generation for 2030. "Baseline" refers to a non-compliant scenario with 36% renewable generation including customer-sited solar PV. "Target" refers to a 2030-compliant scenario with 56% renewable generation including customer-sited solar PV. "Conventional" refers to a level of grid flexibility similar to today, whereas "Enhanced" provides additional import/export flexibility, grid-scale energy storage and relaxed limits on hydro and PHES capacity to provide ancillary services. Reproduced from Fig. 8 in Brinkman et al. (2016). (Note that both the Baseline and Target scenarios converge to the same gas generation capacities at 8,760 hours, reflecting baseload conditions driven by the amount of supply flexibility assumed in the model rather than the amount of renewable capacity.)

E3 (2015) also modeled several 2030 scenarios assuming 50% renewable electricity generation (a total of 53 GW of intermittent generation capacity, with 61% coming from solar resources). They found that 34 GW of dispatchable gas generation would be needed, along with ~30 GW of other flexible generation capacity to balance the electricity system. Thus, the total flexible resource capacity exceeds the intermittent renewable capacity, but some of these resources are used to mitigate other variability on the grid, such as changes in load. Broadly speaking, this result is similar to what CAISO found in its assessment of needed flexible generation capacity in 2018 (CAISO, 2017b). European studies (ENTSO-E, 2015; Verdolini et al., 2016) also found that roughly equal amounts of dispatchable fossil backup capacity were required for any additions in renewable generation in the long term, in order to handle *dunkleflaute* conditions. For instance, for 2025, ENTSO-E projected that at 7 pm, ~235-250 GW of 255 GW of wind capacity and ~110-140 GW of ~140 GW of solar capacity might be unavailable at different times of year; see Figure 11.

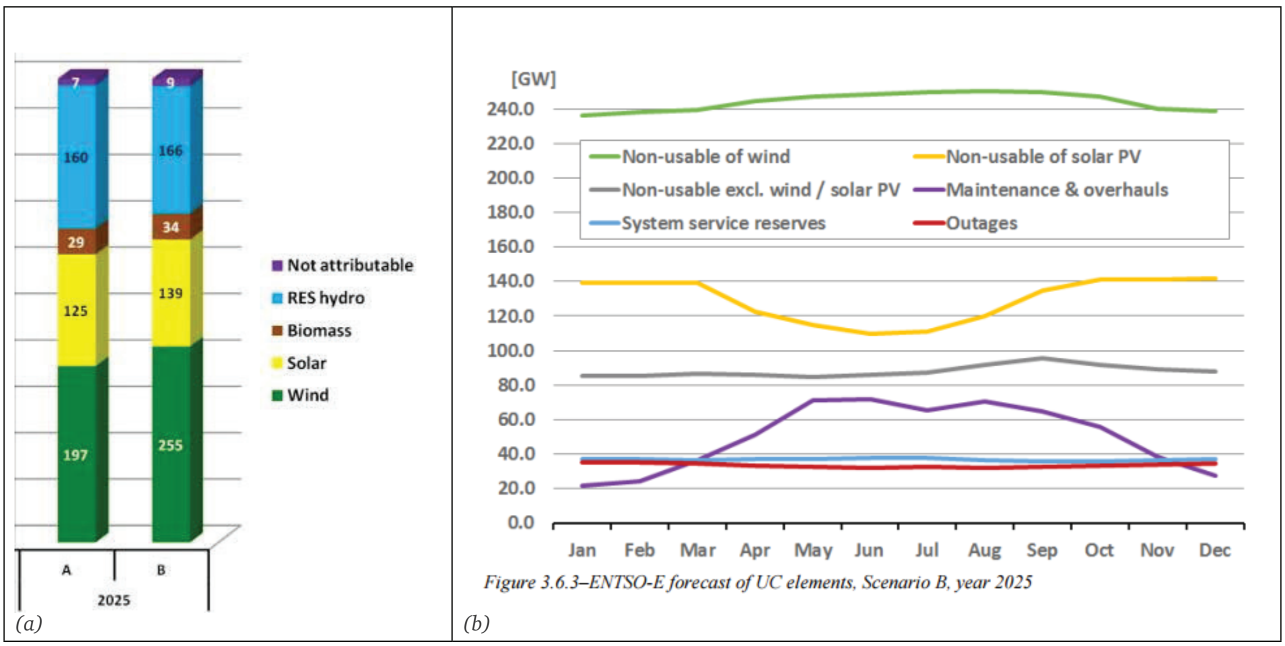


Figure 11. Western European electricity generation capacities at 7 pm in 2025: (a) available renewable capacity in January (B corresponds to a "Best Estimate" scenario), and (b) unavailable capacity across the year. Data reproduced from Figures 3.5.2 and 3.6.3, respectively, in ENTSO-E (2015).

During periods of high intermittent renewable output, renewable resources may occasionally need to be curtailed to maintain system reliability (CAISO, 2017c).[3] Such curtailment currently represents a very small fraction of total renewable generation (~0.2%), but in the first three months of 2017, it averaged 3% of total wind plus solar generation, and on March 11, 2017, more than 30% of solar output was curtailed in one hour.

As the renewable fraction on California's grid grows, curtailments may need to increase unless California deploys complementary strategies including energy storage, demand response/flexible loads, time-of-use rates, EV charging, and an expanded and/or coordinated western grid. Although this curtailment does not necessarily impact UGS, increasing the percentage of intermittent renewables will tend to increase curtailment and will help to spur thinking about how to balance load that may affect the need for gas, positively or negatively.

California has a huge, flexible natural gas fleet that exists already; adding renewables off-loads gas generation that can then be used for balancing and flexibility. However, ramps that the gas system has to meet could create large surges in gas demand for power generation and may drive a need for gas reserve capacity similar to what we have today.

Finding: The ~30 GW of backup natural gas capacity needed in 2030 translates into ~5,000 MMcfd, assuming an average heat rate of ~7,000 Btu/kWh for natural gas turbines (a reasonable assumption based on average heat rates of future California natural gas plants provided from E3, 2015a). The demand for gas to provide backup for renewable energy comes close to current pipeline import capacity of ~7,500 MMcfd
(see Chapter 2),

While statewide investor-owned utility demand response capacity has fallen from ~2,600 MW in 2012 to ~2,000 MW in 2016[4] (mainly due to increased program stringency) (Murtaugh, 2017), its potential has been estimated to provide system-wide fast-response potential capacities totaling 5,600 MW in 2020 and 7,300 MW by 2025 (Alstone et al., 2016). Assuming a linear growth in potential capacity to 9,000 MW in 2030, and converting this capacity into a natural gas flow, results in a potential reduction of ~1,500 MMcfd in 2030 due to demand response, which, while large, is insufficient to reduce the dependence on UGS to mitigate renewable intermittency.

3. Renewable curtailment is sometimes necessary if the power cannot be immediately utilized, as oversupply can threaten grid stability, especially where there are transmission bottlenecks, imbalances, or voltage or frequency instabilities.

4. Note that of the ~2,000 MW capacity in 2016, ~800 MW were price-responsive resources and ~1200 MW were reliability-based resources priced at between 95% and 100% of the bid cap of $1000/MWh. Also, demand response capacity may be subject to constraints so may have limited availability for day-to-day load balancing.

Conclusion 3.8: Although California's climate policies for 2030 are likely to reduce total gas use in California, they are also likely to require significant ramping in our natural gas generation to maintain reliability. These surges of gas demand for electric generation may require UGS.

3.2.5. Summary of 2030 Scenario Assessment

Finding: Despite an overall expected decrease in natural gas use in both summer and winter, the use of natural gas for electricity generation may become "peakier" in order to balance the increasingly intermittent output from wind and solar generation, and this potential peakiness could be nearly as large as today on an hourly or seasonal basis. However, these additional demands on UGS are likely to be small compared with the ~1,000 Bcf that is normally injected into and withdrawn from storage every year (see Figure 9 in Chapter 2).

Conclusion 3.9: The total amount of UGS needed is unlikely to change by 2030.

Recommendation 3.2: California should develop a plan for maintaining electricity reliability in the face of more variable electricity generation in the future. The plan should be consistent with both its *goals* policies and its *means* policies, notably for 2030 portfolio requirements and beyond, and should account for energy reliability requirements on all time scales. This plan can be used to estimate future gas and UGS needs.

3.3. DEMAND FOR UGS IN 2050

The ambitious GHG targets of an 80% reduction below the 1990 level by 2050 will require much more dramatic changes to California's energy system than were found for 2030. This was consistently displayed across the 23 California, 29 U.S. and two global GHG-compliant scenarios that we examined for 2050. However, the types of changes were not necessarily all in the same direction, and scenarios tended to cluster into distinct categories. As a first pass, we examined each scenario with respect to its change in total annual demand for natural gas relative to a recent reference year, and found that scenarios either significantly increased their natural gas demands (to ~150% of the current level), remained close to today's level, or significantly decreased them (to ~50% or less of today's level). All scenarios whose natural gas demand significantly increased made heavy use of CCS technology, allowing for the expansion of natural gas while dramatically reducing its GHG emissions (though many scenarios with lower amounts of CCS technology did not increase overall natural gas demand beyond today's level). Scenarios that strongly relied on low-carbon gas to reduce GHG emissions while continuing to use gaseous fuels in the energy system tended to have natural gas demand levels similar to today. And those scenarios with the lowest demand for natural gas tended to have significant building electrification, and greatly expanded the use of non-fossil electricity generation (either renewables, nuclear, or both), though these elements were also present in scenarios with higher natural gas demand levels. Some scenarios also greatly expanded their use of hydrogen. (The amount of hydrogen used was not included in our total gas demand metric.)

As discussed in Chapter 2, it is largely peak demand for gas that drives the need for UGS, as California pipeline importation capacity is insufficient to meet demand in all hours of the year. As the demands for—and uses of—gas change, it may be possible to decrease reliance on UGS, but on the other hand, it may be necessary to increase the capacity to handle greater reliance on gas in certain periods. To determine how changes in the 2050 energy system might affect peak demand for gas requires detailed information of the many factors that affect that demand on multiple time scales. Table 3 lists these elements and their expected effects on gas and UGS demand.

Table 3. Elements of a 2050 electricity system that could affect gas and UGS demand.

Element	**Total gas demand effect**		**UGS effect (driven by peak demand)**		**Comments**
	Winter	**Summer**	**Winter**	**Summer**	
Electricity sector					
Increased annual electricity demand	Increase		Neutral or increase[a]		
Increased building electrification	Increase		Neutral or increase[a]	Neutral	Heat pumps are less efficient in cold weather
Increased vehicle electrification	Increase		Neutral or increase[a]		Transport demand is roughly flat seasonally
Increased fossil-CCS generation	Increase		Increase		Also increase in CO2 transport and storage
Increased intermittent renewables	Decrease		Unclear		Renewables may decrease natural gas use overall but will increase backup requirements, particularly in winter when renewable output is lowest
Increased flexible, non-fossil generation	Decrease		Neutral or decrease[a]		Flexible generation will have a smaller effect on backup requirements
Increased energy storage, flexible loads, regional coordination, etc.	Decrease		Neutral		These approaches cannot reduce reliance on UGS for multiple-day and seasonal mismatches

a Depending on how much peak demand is affected

b Assuming hydrogen is not produced locally (from electricity or biomass) and thus requires pipeline and storage infrastructure

Element	Total gas demand effect		UGS effect (driven by peak demand)		Comments
	Winter	**Summer**	**Winter**	**Summer**	
Increased power-to-gas	Decrease		Neutral or increase[a]		Produced hydrogen or methane must be stored
Increased pure hydrogen production	Increase (if generated from electricity) or neutral		Neutral or increase[a]		
Increased wildfires causing electric transmission outages	Neutral	Neutral or increase	Neutral	Neutral or increase[a]	Primarily occurs in summer
Increased climate change effects	Neutral	Increase	Neutral	Neutral or increase[a]	Primarily affects summer generation
Non-electricity sector					
Increased annual natural gas demand	Increase		Neutral or increase[a]		
Increased building electrification	Decrease		Neutral or decrease[a]		Shift of gas demand to electricity sector
Increased low-carbon gas (in pipeline supply)	Neutral		Neutral		SNG or hydrogen use may require CO2 transport and storage
Increased pure hydrogen	Neutral for natural gas; increase in total gas demand		Neutral for UGS; increase in pure hydrogen storage[b]		Depending on hydrogen production method, may also require CO2 transport and storage
Increased natural gas vehicles	Increase		Neutral or increase[a]		Transport demand is roughly flat seasonally
Increased climate change effects	Decrease	Neutral	Neutral or decrease[a]	Neutral	Primarily affects winter gas demand

a Depending on how much peak demand is affected

b Assuming hydrogen is not produced locally (from electricity or biomass) and thus requires pipeline and storage infrastructure

3.3.1. Scenarios for 2050

In all scenarios, sufficient quantitative details of the energy system to make a robust assessment were lacking, so we relied heavily on a handful of scenarios from E3 (2015a) that had the most data available. From these data, plus our own expert judgment, we developed four representative scenarios that provided distinct combinations of energy technology elements that can achieve an 80% GHG reduction goal. Each has very different implications for natural gas demand and UGS. To simplify discussion, we invoke a logic diagram, shown in Figure 12, to illustrate how each scenario is classified, based on three basic parameters: amount of intermittent electricity generation, type of flexible generation, and amount of low-carbon gas:

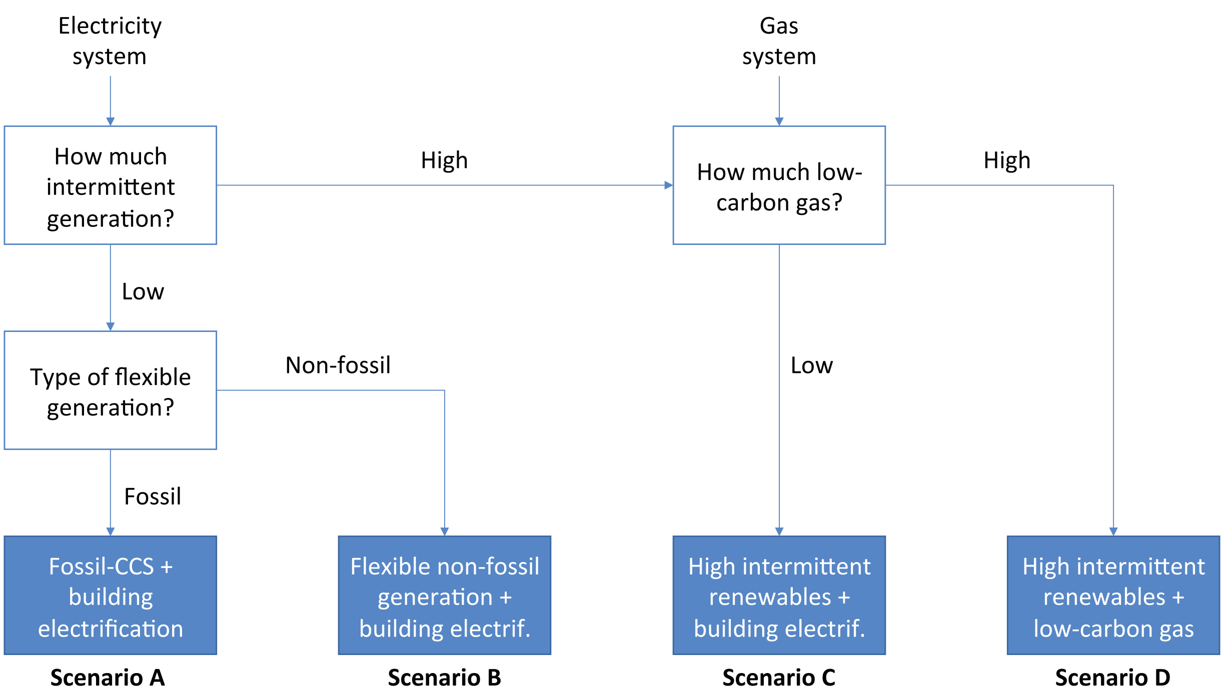


Figure 12. Logic diagram for 2050 scenario classification

Table 4 provides a qualitative summary of the main drivers of change in the four scenarios, along with example scenarios from the literature.

Table 4. Scenario table indicating main drivers of changes and example scenarios.

Scenario	Main drivers of change	Example scenarios
A: Fossil-CCS + building electrification	Increased share of electricity provided by gas, higher overall electricity demand, larger short-term peaks due to cold weather events (in winter), larger need for renewable backup	Williams et al. (2012) "High CCS," Williams et al. (2014) "High CCS," Wei et al. (2013a) "Inexpensive CCS," Yang et al. (2014) "GHG-S-CCS," E3 (2015a) "CCS," Cole et al. (2016) "Low CCS Cost + low-C target," Risky Business Project (2016) "High CCS."
B: Flexible, non-fossil generation + building electrification	Decreased share of electricity provided by gas, moderating increased use of electricity, smaller need for renewable backup	Williams et al. (2012) "High nuclear," Wei et al. (2013a) "Inexpensive NUC," Nelson et al. (2013) "New Nuclear," Williams et al. (2014) "High nuclear," Yang et al. (2014) "GHG-S-NUC," Yang et al. (2015) "GHG-S-NucCCS," Cole et al. (2016) "Low Nuclear Cost + low-C target," Risky Business Project (2016) "High Nuclear," OECD/IEA (2015) "450 Scenario"[a]
C: Intermittent renewables + building electrification	Decreased share of electricity provided by gas, higher overall electricity demand, larger need for renewable backup	Williams et al. (2012) "High RE," Logan et al. (2013) "CES," Williams et al. (2014) "High RE," several scenarios in Yang et al. (2014) including e.g., "GHG-S-HiRen," E3 (2015a) "Straight Line," Risky Business Project (2016) "Mixed" and "High Renewables" scenarios
D: Intermittent renewables + low-carbon gas	Decreased share of electricity provided by gas, larger short-term peaks due to cold weather events (in winter), larger need for renewable backup	Williams et al. (2014) "Mixed" and "High Renewables," E3 (2015a) "Low Carbon Gas," Risky Business Project (2016) "High Renewables," Yeh et al. (2016)[b]

a Note that the OECD/IEA scenario is one example of a mixed approach combining nuclear, hydro and biomass electricity generation with CCS (as well as some fossil generation with CCS). The White House (2016) "Benchmark" scenario is another example, not included in the above list, that is agnostic over whether the electricity generation not provided by natural gas (<10%) or fossil with CCS (~20%) comes from intermittent renewables, nuclear or biomass with CCS.

b Yeh et al. (2016) reviewed several California GHG-compliant scenarios developed by others, and concluded that biomethane could replace 50% of fossil natural gas in buildings and industry, though greater transport electrification would also be required to meet GHG targets.

These four scenarios are discussed in detail below, but in summary, in addition to increases in energy efficiency, renewable electricity, energy storage, and vehicle electrification:

- Scenario A provides >50% of electricity demand from fossil natural gas combustion with CCS. In order to reduce fossil fuel combustion in other sectors, aggressive building electrification is also pursued. In addition, pure hydrogen production is produced for some vehicles and possibly non-transport uses.

- Scenario B provides >50% of electricity demand from flexible, non-fossil generation such as nuclear, geothermal, hydropower, biomass or other technologies. As for Scenario A, aggressive building electrification and pure hydrogen production are also pursued.

- Scenario C provides ~80% of electricity demand from renewables, the majority of which are intermittent (solar and wind) sources. As for Scenarios A and B, aggressive building electrification and pure hydrogen production are also pursued.

- Scenario D provides most of electricity demand from intermittent renewables as in Scenario C. Unlike Scenarios A through C, however, there is less of a need for either building electrification or pure hydrogen, because low-carbon natural gas is widely available as a fuel. There is also less emphasis on energy storage because natural gas can be used for backup generation. As a result, the pattern of natural gas use is largely unchanged from today.

Note that, in addition to energy storage, flexible loads, and other non-gas-based load-balancing approaches, the E3 (2015a) study invoked significant amounts of P2G to avoid renewables curtailment. This was not present in most other studies. Table 5 summarizes the key parameter assumptions for the four scenarios. Additional quantitative data from E3 (2015a) representing three of the four scenarios (all but Scenario B) can be found in Appendix 3-4: Selected Data from E3 (2015a).

Table 5. Summary of key assumptions for the four 2050 reference scenarios. Estimates based on E3 (2015a) and authors' own analysis, unless otherwise indicated.

Scenario	Electricity					Non-electricity		Annual gas demand (relative to today's total natural gas demand)			Pure hydrogen (relative to today's natural gas demand)[a]	Demand for UGS (relative to today)
	Annual electricity demand (relative to today)	Renewable fraction: total wind+solar	Fossil-CCS fraction	Electric vehicles: lightduty heavyduty	Building electrification (relative to today)	NGVs (relative to today)	Low-carbon gas fraction	Electricity	Non-electricity	Overall		
Today (2016)	100%	27%	0%	0.3M[b]	1	1	0%	~30%	~70%	100%	0%	N/A
A: Fossil-CCS + building electrification	~160%	~40% ~35%	~50%	10M 0.7M	~15	~1.3	~6%	~120%	~30%	~150%	~20%	Increase
B: Flexible, non-fossil generation + building electrification	~220%	~80% ~40%	~0%	10M 1.0M	~15	~1.3	~10%	~10%	~30%	~40%	~20%	Decrease
C: Intermittent renewables + building electrification	~220%	~80% ~75%	~0%	10M 1.0M	~15	~1.3	~15%	~30%	~30%	~60%	~20%	Unclear
D: Intermittent renewables + low-carbon gas	~205%	~80% ~75%	~0%	33M 1.2M	~1.5	~50	~70%	~25%	~75%	~100%	~0%	Unclear

a Indicates volume of hydrogen that may need to be produced, transported and stored, if not generated on demand locally from electricity or biomass resources.

b Data from Cobb (2017).

By comparison, current California policy through 2030 strongly emphasizes renewable electricity (particularly solar PV, with some wind development) (CPUC, 2017), building and vehicle efficiency, vehicle electrification, and low-carbon transportation fuels. Fossil-CCS is not part of the State's plans, and nuclear power is being phased out. Other flexible, non-fossil generation such as geothermal, small-scale hydropower, and biomass are only present in small amounts. Moreover, while energy storage, demand response and regional electricity coordination are expanding, there is very little building electrification or movement toward producing significant amounts of pure hydrogen, though hydrogen fuel is part of the State's long-term roadmap. While there is some interest in utilizing biomethane, large amounts of low-carbon natural gas are also not being pursued. Therefore, overall, many of the elements explored in the four scenarios above are not part of current State policy, though Scenario C comes closest. It was the goal of this report to explore other technical options available to the State that could meet GHG goals with potentially significant implications for UGS.

3.3.2. Scenario A: Fossil-CCS + Building Electrification

By using natural gas with CCS as a primary means of electricity generation, this scenario would require significant increases in gas use. CCS technology would be used with natural gas combined cycle plants to capture ~90% of emitted CO_2, but reliance on natural gas for electricity generation would increase to ~50% or more of total generation, though intermittent renewables would still contribute a higher fraction of total generation than is seen today; assuming SB 350 is maintained, this fraction would need to be at least 50%. Since CCS cannot be economically applied at the scale of individual buildings or vehicles, its uses would be limited to electricity plants and large industrial facilities. Among these industrial facilities could be production of biofuels, biomethane, SNG, or hydrogen.

Aggressive building electrification would be required to keep overall GHG emissions low. This would shift the use of natural gas from being burned directly for heat to being used to generate electricity for heat, because gas used to produce electricity would use CCS to reduce its GHG emissions. As a result, natural gas would be largely phased out of buildings, but overall natural gas use would not decrease, and could increase significantly. Building electrification would result in far more electricity demand in winter, when demand for gas heating is currently highest. Moreover, electric heat pump technologies produce heat at lower efficiencies when ambient outdoor temperatures are low, requiring larger amounts of electricity to provide the needed heat.

Larger amounts (~50%) of intermittent renewables would require everyday firming, planning for unexpected drop-offs in generation capacity, as well as seasonal fill-in capacity when both wind and solar are lower in winter months—all of which would increase the need for UGS or other backup capacity.

New electric loads from transportation (required to minimize total GHG emissions) would contribute to higher overall electric loads, and thus demand for natural gas, though we expect these loads to be more even throughout the year: U.S. petroleum demand for transportation only varies by ~10% throughout the year, with peak demand in June-August, and lowest demand in January-February (EIA, 2017d).

In the E3 (2015a) "CCS" scenario that closely resembles Scenario A, 0.43 EJ/yr of pure hydrogen (21% of 2015 gas demand) is used to supply energy for transportation and possibly other end uses. This could be provided by dedicated hydrogen infrastructure, on-site generation from electricity, or possibly other sources (e.g., local biomass). Alternatively, some of this demand could be satisfied instead by additional electrification, since both hydrogen and electricity are capable of delivering low-carbon energy solutions, and to some extent can be traded off. For the fossil-CCS scenario, where the majority of electricity generation is provided by natural gas, if electrification substitutes for pure hydrogen end uses, the total gas demand could be higher, because the conversion efficiency to electricity in a natural gas-CCS power plant is ~40% (Rubin et al., 2015), whereas it can be more than 60% in a hydrogen fuel cell vehicle (DOE, 2006).

The need for UGS in winter would increase in Scenario A compared with today, due to:

- Increased reliance on gas for electricity generation, both for CCS and to back up intermittent renewables, which have their lowest output levels in winter.

- Generally higher levels of electricity needed to provide building heat, coupled with lower efficiency of heat pump technologies at lower ambient temperatures.

- Short-term electricity demand for heating during cold-weather events.

- Increased electricity and/or pure hydrogen demand for transportation.

- Given the likely inability of electricity storage, flexible electric loads and other mitigation strategies to reduce the need for extra gas electric generation for more than a few hours at a time, the need for UGS will remain and may grow significantly.

More need for UGS in summer is also likely in Scenario A, due to:

- Somewhat higher electricity use owing to electrification of end uses and a general growth in demand from the present day, but gas demand for electricity will be much higher, because of the high proportion of electricity generated by natural gas with CCS.

- Renewable electricity generation that is higher in summer, reducing the need for gas backup. However, occasional large reductions in output will still occur, requiring backup capacity to be available. This reliance on gas represents an increase from current-day uses of gas to back up renewables, with large and erratic swings in demand possible.

- If P2G is used as an energy storage strategy, it will be used more frequently in summer when intermittent renewable output is highest. This will create additional gas (hydrogen and/or methane) that must be stored.

- Non-electric uses of gas in summer would decrease, as building heating (primarily water heating in summer) shifts from gas to electricity. Because heat pump-based heating is more efficient when ambient air temperatures are high, the shift from gas to electric heating will likely result in net decreases in gas demand for these end uses during mornings and evenings, when demand for heat is highest.

- Other demands for electricity, mainly new uses such as electric vehicle charging and possible hydrogen generation, could increase slightly (~10%) in summer, driving up the overall demand for gas.

- Wildfires are more frequent in summer months, and could represent additional sources of potential generation loss that requires backup.

- Climate change would also increase the demand for electricity and hence gas, and could be amplified by extreme heat and drought events, requiring greater reliance on UGS.

- Overall, more gas use as well as higher peak gas demands will drive up the need for UGS to provide adequate gas supply in summer months.

New pipelines and storage for the management of captured CO_2 (and possibly hydrogen) would also be required in this scenario. While CO_2 management would not impact the need for UGS directly, it would increase California's reliance on storage generally, requiring approval of new storage facilities and the pipelines to carry the CO_2 to them.
The use of hydrogen (e.g., from P2G) would also possibly require new storage and pipeline facilities to manage the gas, if it is not produced from on-site resources (electricity, biomass, etc.).

3.3.3. Scenario B: Flexible, Non-fossil Generation + Building Electrification

This scenario focuses on generation technologies that can provide increased flexibility over intermittent renewables and do not consume fossil fuels. Some of these technologies are described as dispatchable, schedulable, high capacity factor, or baseload generation. While not all equivalent, examples include nuclear, geothermal, biomass, hydropower, marine and hydrokinetic, offshore or high-altitude wind, solar thermal with storage, and potentially other technologies. All of these technologies face one kind of obstacle or another to expansion, be it cost, resource limitation, regulation, or siting. Details of all technologies are discussed in Appendix 3-2: Energy Technologies.

While generation technologies such as nuclear typically operate in a nonflexible or baseload mode, it is possible to operate them flexibly (NECG, 2015): in France, where more than 75% of electricity is produced by nuclear power, many plants operate in load-following as well as frequency-regulation modes in addition to baseload. Moreover, some types of nuclear units such as CANDU reactors in Canada have the capacity to lower electrical output by up to 40% while maintaining full reactor power. The Columbia reactor in the U.S. is also able to lower output by 35% through a combination of control rod and recirculation flow adjustments.

There would likely be a decrease in annual natural gas demand in Scenario B. As for Scenario A, electricity demand would increase as a result of building electrification, electric transportation, and possibly hydrogen generation. A majority (>50%) of electricity generation would come from flexible, non-fossil electricity technologies, with most of the remaining generation coming from intermittent renewables. As a result, much less natural gas would be needed to generate electricity, and there would be a reduced need for load balancing due to the dispatchable nature of the majority electricity generation. While it is difficult to assess how much less gas would be needed for electricity generation, we estimate that significantly less than half of today's electricity gas use might be required.

Like Scenario A, there may be a significant demand for pure hydrogen. If this demand is partly satisfied instead by additional electrification, total gas demand would be lower, because natural gas would be used to provide only a small fraction of electricity in Scenario B.

Scenario B would likely reduce the need for UGS in both winter and summer in this scenario, due to the following:

- Compared with Scenario A, there would be far less reliance on UGS in both summer and winter, because of a much lower fraction of electricity generation produced from natural gas.

- While flexible, non-fossil resources would (like all generation technologies) be more economical if run at maximum output throughout the year, it is possible that such technologies could be ramped over multiple days or seasonally, in order to better balance electricity demand with supply and minimize the need for natural gas generation.

- However, there would still be a need for fast-ramping dispatchable generation, both to deal with demand spikes (in either electricity or direct use of gas) or load balancing of any intermittent renewables in the electricity system, as well as wildfires or climate change-related impacts, which could occur quickly and last over multiple days. UGS could serve this purpose.

Further study should focus on how much flexible, non-fossil resources could be ramped to further reduce reliance on natural gas generation.

3.3.4. Scenario C: Intermittent Renewables + Building Electrification

As for Scenarios A and B, electricity demand will increase due to building electrification, electric transportation, and possibly hydrogen generation. However, because renewables could increase to as much as ~80% of total generation, much less natural gas would be needed to generate electricity, though the need to balance intermittent generation would increase significantly, somewhat moderating the reduction in gas demand. While detailed modeling results for gas demand are lacking, we estimate that perhaps a similar amount of gas as used for electricity generation today would be required. For non-electricity gas demand, we estimate a decrease resulting from increased building electrification.[5] Overall, there would likely be a decrease in annual natural gas demand.

In the E3 (2015a) "Straight Line" scenario that closely resembles Scenario C, 0.47 EJ/yr of pure hydrogen (23% of 2015 gas demand) is used to supply energy for transportation and possibly other end uses. Like Scenario B, if electricity rather than pure hydrogen is used for some end uses, total gas demand would be lower, owing to the small fraction of electricity produced with natural gas.

The need for UGS in the winter could increase or decrease in Scenario C, due to the following:

- Like Scenario B, there would be less reliance on gas for electricity generation, but more reliance on gas to balance renewable intermittency, particularly in winter when renewable capacities tend to be lower. While gas demand could be lower, the reliance on UGS might actually increase.

- Depending on how much electricity storage, flexible electric loads, regional coordination, building thermal storage, and other mitigation strategies are available in this scenario, the overall need for UGS could be similar to or less than today, but as noted earlier, the multiple-day generation deficits from intermittent renewables will almost certainly drive up the need for UGS relative to the present on certain days.

The need for UGS in the summer could increase or decrease in Scenario C, due to:

- Higher electricity demand in summer resulting from increased electrification, but overall gas demand will be much lower, resulting from the lower share of electricity generated by natural gas.

---

5. An alternative approach (e.g., Mathieson et al., 2015) uses waste heat from renewable sources (mainly biomass and solar) to provide district heating in lieu of either natural gas combustion or electricity for heating. However, the infrastructure requirements of such an approach would be large. The consequences would be further lowering of gas use, making UGS requirements more comparable to those in Scenario B.

- Renewable generation will be higher in summer, but occasional large reductions in output would still occur, requiring gas backup capacity. P2G, if used, will be most heavily used in summer, providing additional gas that must be stored.

- Likely net decrease in gas use from building electrification, due to the small fraction of gas used to make electricity and the higher efficiency of heat pump-based heating in summer.

- Very small increase in demand due to vehicle electrification and possible hydrogen generation.

- Wildfires and climate change could create additional generation losses, requiring more UGS to provide backup capability.

- Overall, although some amount of UGS would still be needed, it is not possible to determine whether the need for this capacity will be higher or lower than present day in summer.

More detailed modeling of the coupled gas-electricity system at the hourly level will be needed to better help understand whether additional UGS would be needed for this scenario. Such modeling capability could be especially valuable if embedded in new planning and forecasting systems.

3.3.5. Scenario D: Intermittent Renewables + Low-carbon Gas

Annual demand for natural gas would be similar to today in this Scenario. Gas would be used much as it is today, but with much lower GHG emissions. Low-GHG substitutes for natural gas include biomethane, SNG, and hydrogen, all of which would be blended with natural gas in pipelines. While this scenario would have similar levels of electricity load balancing as in Scenario C, it would require much less building electrification, because it can burn low-carbon gas for heat. As a result, the total demand for electricity is lower, which lowers the gas demand for electricity generation. With population and economic growth, the demand for non-electricity gas increases, but with increased renewable generation and a general increase in efficiency, total gas demand remains about the same as today.

Unlike Scenarios A through C, there is less of a need for either electrification or pure hydrogen for transportation in Scenario D, because low-carbon natural gas is available as a fuel. However, if either of these alternatives are used in place of natural gas for transportation, total gas use would likely decrease, because energy conversion in natural gas turbines (MIT, 2010) or hydrogen fuel cell vehicles (DOE, 2006) is roughly twice as efficient as in conventional natural gas vehicles.

The need for UGS in the winter could increase or decrease in Scenario D, due to:

- Less reliance on gas for electricity generation, but more reliance on gas to balance renewable intermittency. The overall need for UGS is less than in Scenario C, because there is less total electricity demand.

- Slightly higher reliance on UGS to provide gas for non-electricity demand than today, particularly during cold weather events when the demand for gas-supplied heat is high.

- Slightly increased electricity demand, and hence gas, from electric vehicles, but as there is less electrification overall, this demand would be unlikely to exacerbate peaks in natural gas delivery.

The need for UGS in the summer could increase or decrease in Scenario D, due to:

- Slightly higher demand for electricity in summer, but gas demand will be much lower than today, due to the lower share of electricity generated by natural gas.

- As for Scenario C, renewable generation will be higher in summer, but occasional large reductions in output still occur, requiring gas backup capacity. P2G, if present, will be most heavily used in summer, providing additional gas that must be stored.

- Slightly higher gas demand for non-electricity heating.

- Very small increase in demand due to vehicle electrification.

- Wildfires and climate-change-driven generation losses could require more UGS for backup.

As for Scenario C, more detailed modeling of the coupled gas-electricity system at the hourly level will be needed to better help understand whether additional UGS would be needed.

3.3.6. Summary of 2050 Scenario Assessments

Table 5 summarizes our assessments for 2050.

For three of the four scenarios in Table 5 (all but Scenario B), E3 (2015a) provided cost assessments as well as build-out rates, which are summarized in Appendix 3-4: Scenario Feasibility Assessment.

While the data used for the cost assessments are likely now out of date, E3's comparison of total system costs for various scenarios, including different requirements for back-up power, transmission and construction, concluded that the CCS scenario (which closely resembles

Scenario A) was the least expensive, while the low-carbon gas scenario (which closely resembles Scenario D) was the costliest. Since then, the prices of both renewable generation and natural gas have fallen, though gas prices could increase in the future.

Finding: The maximum rate of deployment of CCS technology exhibited in any scenario is well below the maximum historical rate seen for U.S. expansion of nuclear and natural gas capacities, normalized for California, but the scale-up rates of wind and solar in scenarios which maximize these resources may be close to the historical maximum.

Appendix 3-4: Scenario Feasibility Assessment also provides an assessment of the amount of biomethane required in Scenario D, concluding that it would represent an unprecedented increase over target levels in other countries such as Europe, and while the technical resource exists within the U.S., California would have to import a significant share because the in-state resource is inadequate. Moreover, it would require significant technology development as well as expansion of portions of the national pipeline system, as very little available biomass is currently converted into biogas for biomethane production.

The decisions to pursue significant amounts of CCS and/or low-carbon gas, as represented by scenarios A and D, respectively, are important forks in the road for future California climate policy. Scenario A would greatly increase the State's reliance on natural gas as well as require significant new infrastructure to handle CO_2 destined for underground storage. By contrast, Scenario D would greatly increase the State's dependence on non-fossil sources of methane, particularly biogas. Both would require a continued reliance on UGS. On the other hand, not pursuing either of these options (e.g., scenarios B or C) might lessen California's dependence on UGS. However, Scenario C would still require grid reliability at multiday to seasonal time scales, and natural gas appears to be the only viable option; thus, in this scenario, the overall need for UGS might remain similar to today, or even increase. Only Scenario B appears poised to significantly reduce California's dependence on UGS.

Finding: Meeting seasonal demand peaks and daily balancing, including backing up intermittent renewables are important issues for reliability and these in turn will determine the future need for UGS.

Finding: Future scenarios of the energy system indicate that adding more inflexible and intermittent resources similar to those in use today will challenge reliability and require many fundamental changes to the energy system. Future energy system choices with less intermittent resources will be closer to the current energy system, but will require a wider variety of resources than are currently contemplated in California.

Conclusion 3.10: Future energy systems that include significant amounts of low-carbon, flexible generation might minimize reliability issues that are currently stabilized with natural gas generation.

Recommendation 3.3: California should commit to finding economic technologies able to deliver significantly more flexibility, higher capacity factor, and more dispatchable resources than conventional wind and solar photovoltaic generation technologies without greenhouse gas emissions. These could include biomass, concentrating solar thermal; geothermal; high-altitude wind; marine and hydrokinetic power; nuclear power; out-of-state, high capacity factor-wind; fossil with carbon capture and storage; or another technology not yet identified.

Conclusion 3.11: *Widely varying energy systems might meet the 2050 climate goals. Some of these would involve a form of gas (methane, hydrogen, CO_2) infrastructure including underground storage, and some may not require as much UGS as in use today.*

Recommendation 3.4: California should evaluate the relative feasibility of achieving climate goals with various reliable energy portfolios, and determine from this analysis the likely requirements for any type of UGS in California.

Conclusion 3.12: California has not yet targeted a future energy system that would meet California's 2050 climate goals and provide energy reliability in all sectors. California will likely rely on UGS for the next few decades as these complex issues are worked out.

Recommendation 3.5: A commitment to safe UGS should continue until or unless the State can demonstrate that future energy reliability does not require UGS.

3.4. WHAT HAS TO HAPPEN BY 2030 TO BE PREPARED FOR 2050

In order to reach any of the 2050 scenarios described above, California must begin making changes in the near term (e.g., between now and 2030) in order to facilitate the significant transition of its energy system. Some of these are already under way, such as the increase in California's renewable electricity share from 33% by 2020 to 50% in 2030 (60% if SB 100 becomes law; CALI, 2017), doubling the rate of building efficiency improvements between now and 2030 (SB 350), or installing more energy storage (AB 2514).

Generally speaking, the siting, permitting, and construction process for major infrastructure projects in California, including electric transmission lines, gas pipelines, CCS-related infrastructure, PHES, electric generating plants, and UGS, can take at least 10 years and quite possibly longer. Therefore, in most of what is discussed below, we assume a 10-year planning horizon for any new resource that must be available by a certain year.

3.4.1. Elements That Decrease Demand for UGS

3.4.1.1 Flexible, non-fossil electricity

In order to develop significant capacity of flexible, non-fossil electricity generation, a commitment to developing technologies other than conventional wind and solar photovoltaic generation technologies—whether those are biomass, concentrating solar thermal, geothermal, high-altitude wind, hydro, marine and hydrokinetic power, nuclear, or another technology not yet identified—must accelerate, beginning with a focused research effort over the next few years. This is because it will take time to analyze and develop technologies that are not yet technically mature, before pilot plants can be deployed, let alone large-scale build-out. Many of these technologies have been explored with federal research funding (see Appendix 3-2: Energy Technologies).
The CEC's Electric Program Investment Charge (EPIC) is a good example of a mechanism to direct and fund this type of research at the state level, but a roadmap for the long-term development of flexible, non-fossil resources should be completed as soon as possible, with the aim of identifying possible locations for developing these resources, as well as locations of future transmission capacity. Out-of-state resources should also be identified, and pursued if attractive. In order for these technologies to play a significant role by 2050, demonstration plants should be built in the 2020s and completed before 2030. Approvals for large-scale build-out would be needed soon thereafter, in order to ramp up beginning no later than 2040. Stimulating confidence in these technologies will be necessary to encourage the financial sector to make the needed investments.

3.4.1.2 Load balancing without using natural gas

Because of the greater challenges of balancing renewable intermittency common in all scenarios, as well as the need for some load balancing of slow-ramping dispatchable generation technologies, resources including electricity storage, flexible loads, increased transmission capacity, and regional electricity coordination will be especially important to identify early in the process. California's Energy Storage Roadmap (CAISO, 2014a) offers a useful starting point for storage technologies, and encompasses planning, procurement, rate treatment, interconnection, and market participation activities across several State agencies. The California Vehicle-Grid Integration Roadmap (CAISO, 2014b) focuses on the use of electric vehicles to perform load balancing and other grid services through determination of value and potential, development of enabling policies, regulations, and business practices, and support for technology development. CAISO's analysis of expanded renewables generation under SB 350 discussed the benefits of a regional electricity market to increase reliability and lower the cost of renewables integration (Pfeifenberger et al., 2016). SB 338, enacted in September 2017, directs California utilities to consider the GHG emissions of peak demand electricity generation (Trabish, 2017) and represents a step in the right direction.

A broad focus, encompassing all non-gas-based load-balancing technologies, and consisting of research, pilot plant construction, regulatory frameworks, financial incentives, and build-out plans, will be required to develop the necessary levels of capacity to maximally reduce GHG emissions. Because many complementary technology options may be available, an emphasis on performance metrics rather than prescriptive technologies should be pursued, to allow market forces to determine the best mix of technologies to satisfy future needs. This work must get under way today, in order for sufficient resources to be available when they begin to be needed in the 2025-2030 timeframe.

However, these technologies cannot eliminate the need for UGS (whether the stored gases are primarily fossil natural gas, biomethane, SNG, or hydrogen), because absent a technical breakthrough, they cannot cost-effectively provide multiday storage capacity. See discussion under 3.4.3. Elements That Increase Demand for UGS on development needs of those technologies.

3.4.2. Elements with Unclear Impacts on UGS

3.4.2.1 Intermittent renewable electricity

In order to grow California's renewable electricity generation share significantly beyond the 2020 goal of 33%, the State will have to identify new locations for wind, solar and other forms of renewable energy generation, including possible offshore wind generation locations, as well as transmission capacity to connect this generation to load centers. Out-of-state renewable resources must also be identified and pursued if economically attractive. This process is already under way for those renewable goals that have been established in law (e.g., 50% by 2030), but to reach the even higher targets that may be needed by 2050, the State should be establishing long-term goals as well as planning for expansion significantly beyond 50% renewables, starting in or before 2030.

The combination of intermittent renewable electricity and load-balancing technologies has unclear implications for UGS. On the one hand, increased levels of renewables tend to decrease dependence on natural gas, particularly in summer, when both electricity demand and intermittent renewable output are highest. However, the load-balancing requirements to deal with intermittent renewables on multiple time scales (intraday, multiple-day, and seasonal) are significant, and may require heavier reliance on UGS than at present, if largely supplied by gas-based technologies.

A research agenda consisting of detailed simulation of both the electric and gas systems on an hourly basis in California, with spatial granularity sufficient to resolve differences in renewable generation, transmission bottlenecks and gas propagation, will be required.

3.4.2.2. Building electrification

In order to significantly increase the fraction of buildings (and industrial facilities) using electricity rather than natural gas for heating, the State will need policy mechanisms in place soon to encourage this transition. Buildings have very long lifetimes, typically more than 50 years, so turnover rates are slow. Therefore, policies must be put in place now to have sufficient impact over several decades. Currently, the only mechanism we are aware of to increase building electrification is the zero-net energy building policy, which goes into effect for new residential construction in 2020 and commercial construction in 2030, and is being implemented through changes in Title 24, California's building code. The zero-net energy building policy is still in development, but currently plans to offer compliance for new construction through either all-electric or mixed-fuel (gas + electricity) designs. However, the vast majority of California buildings will not be affected, because annual new construction represents a small fraction (~1%) of total building stock. We recommend stronger policy mechanisms to encourage electrification of both new and existing buildings be introduced, beginning by 2020. We also recommend research on the cost-effectiveness of different electric technologies in the near term and periodically, to better guide the selection of feasible targets.

While building electrification generally results in lower utilization of gas, the combination of less efficient heat pumps during winter and short-term spikes in demand during cold-weather events could cause an increased reliance on UGS. Moreover, for an electricity system heavily dependent on gas-based generation, such as for Scenario A (fossil-CCS), gas use and hence UGS could increase relative to today.

Detailed simulations of the use of building electrification technologies in combination with electricity generation and gas delivery on an hourly basis is required, using a modeling framework similar to what is proposed above under *3.4.2.1 Intermittent renewable electricity*.

3.4.3. Elements That Increase Demand for UGS

3.4.3.1. Low-carbon gas

A commitment to low-carbon gas (through a combination of biomethane, SNG, and/or hydrogen), whether providing a small or large portion of the gas used in 2050, must start with identification of likely resources and technologies, some preliminary work for which has already been done (e.g., Murray et al., 2014; Williams et al., 2015). This work must continue over the next few years, and by 2020, goals for production over the coming decades should be established in order to begin the planning process.

For biomethane, while some resources are available in-state, it is very likely that California will have to procure out-of-state resources for the majority of its supply, so relationships with biogas-rich states will need to be developed in the next few years as well. If biomethane proves viable, there may be substantial competition for this resource as other regions adopt similar goals.

Before firm plans can be made for hydrogen, it will be important to have a thorough understanding of blending limits, the costs of system upgrades to increase those limits, as well as current and future costs of production (in collaboration with federal research programs; e.g., U.S. Department of Energy (DOE); but these should be solidified as soon after 2020 as possible in order to provide sufficient time for development and deployment.

In all cases, further technology development leading to cost reduction will be essential in order to make a low-carbon gas future economically feasible. Early investment in research and development in collaboration with other states, the federal government, private companies, international institutions, and other interested stakeholders will be essential to realize these goals. Forming a coalition, with members invited from each of these sectors, to tackle these challenges may be a useful strategy.

3.4.3.2. Power-to-Gas (P2G)

P2G technologies are still in a developmental stage, with P2G-hydrogen likely the most mature at present, with projected costs of ~$1/kg hydrogen by 2030 (Ferrero et al., 2016), equivalent to ~$7.5/MMBtu. However, P2G-methane could potentially be a more useful technology in the long run, due to the compatibility with existing pipeline networks, and the challenges of managing and blending large amounts of hydrogen in those networks. As an element of an energy storage portfolio to reduce the use of fossil natural gas, P2G could play a vital role in the future, especially when coupled with high levels of intermittent renewable electricity generation, because it has the ability to convert "excess" electricity into chemical fuels that can be stored cheaply and indefinitely in very large amounts, unlike almost all other storage technologies. P2G creates a greater need for UGS, however, by generating gases that must be stored.

In order for any P2G technology to be available for widespread use by the 2040s, research under way now must be augmented to pave the way for commercial demonstrations in the next decade. Potential synergies between P2G-methane utilizing CO_2 from low-GHG sources, and CCS technologies exist, and should be researched more thoroughly. Linkages between state energy storage, low-carbon gas and CCS roadmaps should be made, along with research objectives at both the CEC and federal agencies.

For more information on P2G, see Appendix 3-2: Energy Technologies, Power-to-Gas.

3.4.3.3 Fossil-CCS electricity

Although the federal government (and international community) has been leading CCS[6] research, development and demonstration efforts for many years, California must pursue its own agenda of technology advancement of fossil energy technology with CO_2 capture in order for CCS to play a significant role in the State's 2050 electricity system. This agenda must include further research, pilot plant construction, regulatory frameworks, financial incentives, and ultimately a roadmap for build-up of generation capacity with CCS. According to E3 (2015a), fossil-CCS capacity would need to begin coming online in 2040, which means that the planning process must be well under way by 2030 in order for this technology to be a major contributor in 2050. Pilot plants, necessary to gather early operational experience, have been built in a few locations in the U.S. and elsewhere (see Appendix 3-2: Energy Technologies, Carbon Dioxide Capture and Sequestration), but will also need to be built in California by 2025 in order for there to be sufficient time to make use of lessons learned in the planning process for full-scale deployment. Therefore, the planning process for these pilot plants, as well as the research to support them, should essentially be under way today.

Simultaneous with this effort, the State must develop a roadmap for siting and construction of CO_2 pipeline and underground CO_2 injection capacity, both in-state and in collaboration with neighboring states, since it is likely that at least some of the CO_2 storage capacity will need to be located out-of-state. This process must also be well under way by 2030, and much sooner at small scale to support pilot plants that will be needed in the 2020s. It may also create competition for underground storage sites among natural gas, hydrogen, and CO_2 uses, which could require a new type of approval process that ranks potential sites by their value in storing each of these gases.

Identification of industrial facilities other than electricity generation that would be amenable to CCS technology, such as fossil- or biomass-based fuel production plants, cement manufacturing plants, and other large-scale facilities, should be completed by 2030, along with policies to encourage the development of CCS capabilities in these sectors. Near-term opportunities to lower costs, by utilizing captured CO_2 for other purposes such as enhanced oil or gas recovery, should also be identified before 2030.

While less important than for intermittent renewable electricity, increased load-balancing resources to complement slow-ramping fossil-CCS generation that are not based on natural gas must be identified and quantified as functions of future electricity generation capacity and loads, and plans made to research and procure such resources well in advance of their actual need. See 3.4.1.2 Load balancing for more information.

6. Many researchers and advocates of CCS now refer to the technology as "CO_2 capture, utilization and sequestration" (CCUS), in order to highlight opportunities for using CO_2 and not simply storing it. While we acknowledge the potential for CO_2 utilization and consider the terms CCS and CCUS to be interchangeable, we focus on the storage challenge in this report.

3.4.3.4. Vehicle electrification

To the extent that natural gas will play a role in future electricity generation, the use of electric vehicles will increase demand for natural gas and probably UGS. Currently, electric light-duty vehicles are enjoying high growth rates and lavish media attention, with good reason: battery costs are falling rapidly, driving ranges are increasing, and costs are quickly becoming affordable to a broader range of Californians. The Governor's Zero Emission Vehicle (ZEV) Action Plan is helping drive adoption toward 1.5 million vehicles on the road by 2025 (IWG, 2016), which is an ambitious near-term target. However, electric vehicles will need additional support from the State to succeed in the market, with adequate charging infrastructure, interoperability standards, reasonable electricity rates, and the ability for vehicles to provide load-balancing services when desirable. The California Vehicle-Grid Integration Roadmap (CAISO, 2014b) is tackling many of these issues, but a long-term roadmap consistent with 2030 and 2050 GHG policy will also be needed by 2020, to continue to drive the needed infrastructure investments.

Expansion of electrification into other parts of the transportation sector, including medium- and heavy-duty vehicles, buses, rail, and marine ports, is also desirable and encouraged. While the State has developed policies to encourage this development, namely through its Mobile Source Strategy and Sustainable Freight Action Plan (see Appendix 3-3: Recent Federal and State Policies), more should be done to provide a long-term research, development, and deployment roadmap, with goals established by 2020 to support targets in 2030 and beyond.

3.4.3.5. Hydrogen vehicles

To support the long-term deployment of hydrogen vehicle technology, California's current hydrogen vehicle plans (IWG, 2016; CalEPA/CARB, 2016) must be augmented by 2020 to identify further development needed for 2030 and beyond, including plans for providing and managing the demand for low-GHG hydrogen through a possible hydrogen pipeline and underground storage network. This will need to be done in conjunction with planning for the future of UGS, since a reduction in UGS and associated pipelines for natural gas could free up resources for use with hydrogen.

3.4.3.6 Natural gas vehicles

Increases in natural gas vehicles (NGVs) will require a thorough understanding of the GHG impacts and trade-offs against other transportation options that might have lower GHG emissions. This work needs to take place now. Moreover, significant increases in NGVs on California's roads will impact natural gas demand and possibly UGS, so a research, development, and deployment roadmap that is synchronized with other transportation decarbonization plans must be developed by 2020, to avoid pursuing policies that operate at cross-purposes with other GHG goals.

3.5. ACKNOWLEDGMENTS

The authors would like to thank Mateja Pitako (University of Ljubljana, Slovenia) for invaluable research contributions to this report.

3.6. REFERENCES

Ager, J.W., M.R. Shaner, K.A. Walczak, I.D. Sharp, and S. Ardo, 2015. Experimental demonstrations of spontaneous, solar-driven photoelectrochemical water splitting. *Energy Environ. Sci*., 8, 2811–2824.

Agility, 2017. Natural Gas Fuels: CNG & LNG. http://www.agilityfuelsolutions.com/lng-vs-cng.html.

Akhil, A.A., G. Huff, A.B. Currier, B.C. Kaun, D.M. Rastler, S.B. Chen, A.L. Cotter, D.T. Bradshaw, and W.D. Gauntlett, 2013. *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*, Sandia National Laboratories, Report No. SAND2013-5131, July. https://energy.gov/sites/prod/files/2013/08/f2/ElecStorageHndbk2013.pdf.

Allis, R., T. Chidsey, W. Gwynn, C. Morgan, S. White, M. Adams, and J. Moore, 2001. Natural CO_2 Reservoirs on the Colorado Plateau and Southern Rocky Mountains: Candidates for CO_2 sequestration. DOE/NETL: 1st National Conference of Carbon Sequestration. Proceedings Volume. http://files.geology.utah.gov/emp/co2sequest/pdf/reservoirs.pdf.

Alstone, P., J. Potter, M.A. Piette, P. Schwartz, M.A. Berger, L.N. Dunn, S.J. Smith, M.D. Sohn, A. Aghajanzadeh, S. Stensson, J. Szinai, T. Walter, L. McKenzie, L. Lavin, B. Schneiderman, A. Mileva, E. Cutter, A. Olson, J. Bode, A. Ciccone, and A. Jain, 2015. *2015 California Demand Response Potential Study Charting California's Demand Response Future*, Final Report on Phase 2 Results, Lawrence Berkeley National Laboratory, 14 November. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541.

Altfeld, K., and D. Pinchbeck, 2013. Admissible hydrogen concentrations in natural gas systems. *Gas Energy*, 3.

ARPA-E, 2016. Project impact sheet. Innovative Drilling Technology. https://arpa-e.energy.gov/sites/default/files/documents/files/ForoEnergy_Open2009_ExternalImpactSheet_FINAL.pdf.

AWEA (American Wind Energy Association), 2017. U.S. Wind Energy State Facts. http://www.awea.org/state-fact-sheets.

BAC (Bioenergy Association of California), 2014. *Decarbonizing the Gas Sector: Why California Needs a Renewable Gas Standard*, November 2014. http://americanbiogascouncil.org/pdf/BAC%20Report%20on%20Renewable%20Gas%20Standard.pdf

Bachu, S., 2015. Review of CO_2 storage efficiency in deep saline aquifers. *Int. J. Greenh. Gas Control*, 40, 188–202

Baker, R.W., and K. Lokhandwala, 2008. Natural gas processing with membranes: An overview. *Ind. Eng. Chem. Res*., 47, 2109-2121.

Barbose, G., N. Darghouth, D. Millstein, S. Cates, N. DiSanti, and R. Widiss, 2016. *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States*, Lawrence Berkeley National Laboratory, Report Number LBNL-1006036. https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report_0.pdf.

Barthelemy, H., 2009. Effects of purity and pressure on the hydrogen embrittlement of steels and others metallic materials. In: *Proc. of the 3rd International Conference on Hydrogen Safety*. Ajaccio, France; September. p. 16-8.

Bartos, M.D., and M.V. Chester, 2015. Impacts of climate change on electric power supply in the Western United States. *Nature Climate Change*, 5, 748-752. DOI: 10.1038/nclimate2648.

Beiter, P., W. Musial, A. Smith, L. Kilcher, R. Damiani, M. Maness, S. Sirnivas, T. Stehly, V. Gevorgian, M. Mooney, and G. Scott, 2016. A Spatial-Economic Cost-Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015–2030 (Technical Report). *NREL/TP-6A20-66579*. National Renewable Energy Laboratory, Golden, CO (US). http://www.nrel.gov/docs/fy16osti/66579.pdf.

Benjaminsson G., J. Benjaminsson, and R.B. Rudberg, 2013. *Power to Gas–A Technical Review*, Report SGC Rapport 2013:284, Swedish Gas Technology Center (SGC). http://www.sgc.se/ckfinder/userfiles/files/SGC284_eng.pdf.

Bensmann, A., R. Hanke-Rauschenbach, R. Heyer, F. Kohrs, D. Benndorf, U. Reichl, and K. Sundmacher, 2014. Biological methanation of hydrogen within biogas plants: A model-based feasibility study, *Applied Energy*, 134, 413–425. DOI: 10.1016/j.apenergy.2014.08.047.

Bipartisan Policy Center, 2014. Natural Gas Infrastructure and Methane Emissions, 18 September. http://bipartisanpolicy.org/library/natural-gas-infrastructure-and-methane-emissions/.

Birkholzer, J.T., C.M. Oldenburg, and Q. Zhou, 2015. CO_2 migration and pressure evolution in deep saline aquifers. Int. J. Greenh. Gas Control, 40, 203–20

Blok, K., R.H. Williams, R.E. Katofsky, and C.A. Hendriks, 1997. Hydrogen production from natural gas, sequestration of recovered CO_2 in depleted gas wells and enhanced natural gas recovery. *Energy*, 22(2-3), 161-168. DOI: 10.1016/S0360-5442(96)00136-3.

Bolinger, M., and J. Seel, 2016. *Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance and Pricing Trends in the United States*, Lawrence Berkeley National Laboratory, Report number LBNL-1006037. https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf.

Boot-Handford, M.E., J.C Abanades, E.J. Anthony, M.J. Blunt, S. Brandani, et al., 2014. Carbon capture and storage update. *Energy Environ. Sci.*, 7, 130−189.

Brennan, J.W., and T.E. Barder, 2016. Battery Electric Vehicles Vs. Internal Combustion Engine Vehicles, Arthur D. Little, www.adlittle.com/BEV_ICEV

Brinkman, G., J. Jorgenson, A. Ehlen, J. H. Caldwell, 2016. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*, National Renewable Energy Laboratory Technical Report NREL/TP-6A20-64884, January.

Brown, E.G., Jr., 2016. *California Sustainable Freight Action Plan*, Office of the Governor of California, July. www.casustainablefreight.org.

Buscheck, T.A., Y. Sun, M. Chen, Y. Hao, T.J. Wolery, et al., 2012. Active CO_2 reservoir management for carbon storage: Analysis of operational strategies to relieve pressure buildup and improve injectivity. *Int. J. Greenh. Gas Control*, 6(0), 230–45.

CAISO (California Independent System Operator), 2002. Fire Burning under Major Transmission Lines Triggers Voluntary Interruptible Program in Southern California; Conservation Encouraged, Press release, 18 June.

CAISO, 2003. So-Cal Fires Force Key Transmission Line Out of Service, Press release, 27 October.

CAISO, 2007. Transmission Emergency Enters Third Day in Southern California; California ISO Encourages Conservation, Press release, 24 October.

CAISO, 2008. Northern California Wildfire Disrupts Power to Paradise, Press release, 12 June.

CAISO, 2014a. *Advancing and Maximizing the Value of Energy Storage Technology: A California Roadmap*, December. https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf.

CAISO, 2014b. *California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services*, February. http://www.caiso.com/documents/vehicle-gridintegrationroadmap.pdf.

CAISO, 2014c. *Daily Renewables Watch Output, Daily Reports and Data Files*, January 1-December 31, 2014. http://www.caiso.com/green/renewableswatch.html.

CAISO, 2015. *Final Flexible Capacity Needs Assessment for 2016*, 1 May. http://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2016.pdf.

CAISO, 2016a. *Regional Integration California Greenhouse Gas Compliance*, Issue Paper, 29 August. https://www.caiso.com/Documents/IssuePaper-RegionalIntegrationCaliforniaGreenHouseGasCompliance.pdf.

CAISO, 2016b. *Final Flexible Capacity Needs Assessment for 2017*, 29 April. http://www.caiso.com/Documents/2018FinalFlexibleCapacityNeedsAssessment.pdf.

CAISO, 2017a. *Annual Report on Market Issues & Performance*, May. http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

CAISO, 2017b. *Final Flexible Capacity Needs Assessment for 2018*, 28 April. http://www.caiso.com/Documents/2018FinalFlexibleCapacityNeedsAssessment.pdf.

CAISO, 2017c. Impacts of renewable energy on grid operations, Fast Facts, CommPR/AG/05.2017. https://www.caiso.com/Documents/CurtailmentFastFacts.pdf.

CalEPA (California Environmental Protection Agency), 2005. *California Hydrogen Blueprint Plan*, Volume 1, May. https://www.arb.ca.gov/msprog/zevprog/hydrogen/documents/historical/volume1_050505.pdf.

CalEPA/CARB (California Air Resources Board), 2016. 2016 *Annual Evaluation of Hydrogen Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development*, July. https://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_2016.pdf.

CALI, 2017. SB-100 California Renewables Portfolio Standard Program: emissions of greenhouse gases, 18 July. https://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml?bill_id=201720180SB100.

CALSTART, 2013. *I-710 Project Zero-Emission Truck Commercialization Study Final Report*, Gateway Cities Council of Governments, Los Angeles Metropolitan Transportation Authority, 20 November. http://www.calstart.org/Libraries/I-710_Project/I-710_Project_Zero-Emission_Truck_Commercialization_Study_Final_Report.sflb.ashx.

CARB (California Air Resources Board), 2016. *Mobile Source Strategy*, May. http://www.arb.ca.gov/planning/sip/sip.htm.

CARB, 2017a. *The 2017 Climate Change Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target*, https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf.

CARB, 2017b. Shore Power for Ocean-going Vessels, 15 February. https://www.arb.ca.gov/ports/shorepower/shorepower.htm.

CARB/CPUC (California Public Utilities Commission), 2017. Administrative Law Judge's Ruling Entering California Air Resources Board and California Public Utilities Commission Joint Staff Annual Report on Analysis of June 17, 2016 Utilities' Reports and Commission Staff Proposal on Best Practices into the Record and Seeking Comments, Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371, Rulemaking 15-01-008, 19 January. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K518/172518969.PDF.

Carden, P.O., and L. Patersen, 1979. Physical, chemical and energy aspects of underground hydrogen storage. *Int. J. Hydrogen Energy*, 4, 559-569, Pergamon Press Ltd.

Casey, K., M. Rothleder, D. Le Vine, S. Liu, X. Wang, Y. Zhang, J. W. Chang, J. P. Pfeifenberger, M. G. Aydin, C. O. Aydin, K. Van Horn, D. L. Oates, L. Regan, P. Cahill, C. McIntyre, A. Olson, A. Mahone, A. Mileva, G. De Moor, N. Schlag, D. Roland-Holst, S. Evans, S. Heft-Neal, D. Behnke, C. H. Springer, B. Bridsall, S. Lee, E. Capello, F. Golden, H. Blair, T. Popiel, S. Debauche, and N. Vahidi, 2016. *Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California*. Prepared for CAISO by the Brattle Group, Inc., Energy and Environmental Economics, Inc., Berkeley Economic Advising and Research, LLC, and Aspen Environmental Group, 8 July.

CA Utilities (Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Long Beach Gas & Oil Department, and Southern California Edison Company), 2010. *2010 California Gas Report*. http://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr10.pdf.

CA Utilities, 2016. *2016 California Gas Report*. https://www.socalgas.com/regulatory/documents/cgr/2016-cgr.pdf.

CEC (California Energy Commission). 2015. Geothermal Energy in California. http://www.energy.ca.gov/geothermal/background.html.

CEC, 2016. Hydroelectric Power in California. http://www.energy.ca.gov/hydroelectric/.

CEC, 2017. Facts About August 2017 Eclipse. https://ia.cpuc.ca.gov/caleclipse/eclipsefaq.html.

CGA (Canadian Gas Association), 2016. http://www.cga.ca/news_item/canadas-natural-gas-utilities-propose-target-for-renewable-natural-gas-content/.

Chandel, M., and E. Williams, 2009. Synthetic Natural Gas (SNG): Technology, Environmental Implications, and Economics. Climate Change Policy Partnership, Duke University, January. http://www.canadiancleanpowercoalition.com/pdf/SNG3%20-%20synthetic.gas.pdf.

Clarke, L.E., A.A. Fawcett, J.P. Weyant, J.McFarland, V. Chaturvedi, and Y. Zhou, 2014. Technology and U.S. emissions reductions goals: Results of the EMF 24 Modeling Exercise. *The Energy Journal*, 35, 9-38. https://web.stanford.edu/group/emf-research/docs/emf24/EMF_24.pdf.

Cobb, J., 2017. The World Just Bought Its Two-Millionth Plug-in Car, *HybridCars.com*, 16 January. http://www.hybridcars.com/the-world-just-bought-its-two-millionth-plug-in-car/.

Cole, W., R. Beppler, O. Zinaman, and J. Logan, 2016. *Considering the Role of Natural Gas in the Deep Decarbonization of the U.S. Electricity Sector Natural Gas and the Evolving U.S. Power Sector*, Monograph Series: Number 2, NREL Technical Report, February. www.nrel.gov/docs/fy16osti/64654.pdf.

Coninck, H. de, and S.M. Benson, 2014. Carbon dioxide capture and storage: Issues and prospects. *Annu. Rev. Environ. Resour*., 39(1), 243–70.

Corvini, G., J. Stiltner, and K. Clark. Mercury Removal from Natural Gas and Liquid Streams. UOP LLC, Houston, Texas, USA. https://www.uop.com/?document=mercury-removal-from-natural-gas-and-liquid-streams&download=1

CPUC (California Public Utilities Commission), 2008. Attachment 1a: Effect of Wildfires on Transmission Line Reliability, Sunrise Powerlink Project, Draft EIR/EIS, January. http://www.cpuc.ca.gov/environment/info/aspen/sunrise/deir/apps/a01/App%201%20ASR%20z_Attm%201A-Fire%20Report.pdf.

CPUC, 2017. *Proposed Reference System Plan*, 18 September. http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf.

Davies, A., 2016. A Tesla-Inspired Truck Might Actually Make Hydrogen Power Happen, *Wired*, 6 December. https://www.wired.com/2016/12/tesla-inspired-truck-might-actually-make-hydrogen-power-happen/.

Davis, S.C., S.W. Diegel, and R.G. Boundy, 2016. Alternative Fuel and Advanced Technology Vehicles and Characteristics, Chapter 6 in: *Transportation Energy Data Book: Edition 35*. Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy. http://cta.ornl.gov/data/tedb35/Edition35_Chapter06.pdf.

De Singly, B., J. Pinel, M. Garret, J. Schmit, R. Apolit, R. Bock, O. Pisani, and D. Marron, 2016. *Renewable Gas French Panorama*. http://www.grtgaz.com/fileadmin/medias/communiques/2017/EN/Renewable-gas-french-panorama-2016.pdf.

DENA (Deutsche Energie-Agentur GmbH), 2016. Biogaspartner – a joint initiative. Biogas Grid Injection and Application in Germany and Market, Technology and Players. https://shop.dena.de/sortiment/detail/produkt/broschuere-biogaspartner-a-joint-initiative-2016/?tx_zrwshop_pi1%5Bsearch_string%5D=biogaspartner&tx_zrwshop_pi1%5Bsearch_sortation%5D=relevance_desc

Derwent, R.G., P.G. Simmonds, S. O'Doherty, A. Manning, W. Collins, and D. Stevenson, 2006. Global Environmental Impacts of the Hydrogen Economy. In: *International Journal of Nuclear Hydrogen Production and Applications*, Vol. 1, No. 1.

Dixon, T., S.T. McCoy, and I. Havercroft, 2015. Legal and regulatory developments on CCS. *Int. J. Greenh. Gas Control*, 40, 431–48.

DOE (U.S. Department of Energy), 2006. *Hydrogen Fuel Cells*, DOE Hydrogen Program, October. https://www.hydrogen.energy.gov/pdfs/doe_fuelcell_factsheet.pdf.

DOE, 2016. *Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source*. http://energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source.

DOE, 2017. *Clean Cities Alternative Fuel Price Report*, Energy Efficiency & Renewable Energy, April. https://www.afdc.energy.gov/uploads/publication/alternative_fuel_price_report_april_2017.pdf.

DOE, no date, *What We Do*, Geothermal, Office of Energy Efficiency & Renewable Energy. https://energy.gov/eere/geothermal/about. Accessed December 2017.

DOE-NETL (National Energy Technology Laboratory), 2010. *2010 Carbon Sequestration Atlas of the United States and Canada*, Third edition, November. https://www.netl.doe.gov/KMD/CDs/atlasIII/2010atlasIII.pdf.

Downey, C., and J. Clinkenbeard, 2011. *Studies Impacting Geologic Carbon Sequestration Potential In California*, Final Project Report, Public Interest Energy Research Program, California Energy Commission, Publication number CEC-500-2011-044, August.

Duerr, A., 2014. DOE-Offshore Wind and Marine Hydrokinetics (MHK) Overview, BOEM Offshore Renewable Energy Workshop, https://www.boem.gov/NREL-Wind-Marine-Hydrokinetics/.

Duke Energy, no date. Edwardsport Integrated Gasification Combined Cycle (IGCC). https://www.duke-energy.com/our-company/about-us/power-plants/edwardsport Accessed December 2017.

E3 (Energy and Environmental Economics, Inc.), 2015a. *California State Agencies' PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios*, April. https://ethree.com/public_projects/energy_principals_study.php.

E3, 2015b. *Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal*. http://origin-qps.onstreammedia.com/origin/multivu_archive/ENR/1241844-Decarbonizing-Pipeline-Gas.pdf.

Eagle Crest Energy, 2016. Project Description, Eagle Mountain Pumped Storage Project. http://www.eaglecrestenergy.com/project-description.html.

EBA (European Biogas Association), 2013a. http://european-biogas.eu/2013/11/25/six-national-biomethane-registries-developing-foundation-cross-border-biomethane-trade-europe/.

EBA, 2013b. http://european-biogas.eu/2014/03/27/biomethane-bright-opportunities-towards-2030-target/.

EBA, 2013c. Proposal for a European Biomethane Roadmap. http://european-biogas.eu/wp-content/uploads/2014/02/GGG_European-Biomethane-Roadmap-final.pdf.

Edelstein, S., 2016. 2017 Toyota Mirai price stays same, fuel-cell car adds new color. *Green Car Reports*, 22 September. http://www.greencarreports.com/news/1106238_2017-toyota-mirai-price-stays-same-fuel-cell-car-adds-new-color.

EIA (Energy Information Administration), 2011. Table 8.11a: Electric net summer capacity: total (all sectors), 1949– 2011. In: *Annual Energy Review*. https://www.eia.gov/totalenergy/data/annual/xls/stb0811a.xls.

EIA, 2014. Annual Energy Outlook 2014 with Projections to 2040. https://www.eia.gov/outlooks/archive/aeo14/.

EIA, 2016. Table 15 (Consumption of Natural Gas by State, 2011-2015), Natural Gas Annual 2015. Released September 30. https://www.eia.gov/naturalgas/annual/pdf/table_015.pdf.

EIA, 2017a. Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/.

EIA (Energy Information Administration), 2017. Henry Hub Natural Gas Spot Price, last updated May 17. https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

EIA, 2017b. Underground Natural Gas Storage capacity. https://www.eia.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm.

EIA, 2017d. Table 3.7c Petroleum Consumption: Transportation and Electric Power Sectors, Monthly Energy Review, 26 July. https://www.eia.gov/totalenergy/data/monthly/#petroleum.

EIA, 2017e. Electric Power Monthly with Data for June 2017, August 2017, https://www.eia.gov/electricity/monthly/pdf/epm.pdf.

EIA, 2017f. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

EIA, 2017g. Table 8.1 Nuclear Energy Overview, In: *Monthly Energy Review*, 25 May. https://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T08.01.

EIA, 2017h. Table 7.2b Electricity Net Generation: Electric Power Sector, In: *Monthly Energy Review*, 25 May. https://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B.

Ellabban, O., H. Abu-Rub, and F. Blaabjerg, 2014. Renewable energy resources: Current status, future prospects and their enabling technology. *Renewable and Sustainable Energy Reviews*. 39: 748–764. DOI:10.1016/j.rser.2014.07.113.

ENTSO-E (European Network of Transmission System Operators for Electricity), 2015. *Scenario Outlook & Adequacy Forecast 2015*, 30 June. https://www.entsoe.eu/Documents/SDC%20documents/SOAF/150630_SOAF_2015_publication_wcover.pdf.

Fairley, P., 2017. How California Grid Operators Managed the Eclipse, *IEEE Spectrum*, 21 August. https://spectrum.ieee.org/energywise/green-tech/solar/how-california-grid-operators-managed-the-eclipse.

Fawcett, A.A., L.E. Clarke, S. Rausch, and J.P. Weyant, 2014. Overview of EMF 24 policy scenarios. *The Energy Journal*, 35, 40-67. https://web.stanford.edu/group/emf-research/docs/emf24/EMF_24.pdf.

FedEx, 2016. FedEx Introduces Zero-Emission All-Electric Nissan e-NV200 Vehicles, press release, 10 February. http://about.van.fedex.com/newsroom/asia-english/fedex-introduces-zero-emission-all-electric-nissan-e-nv200-vehicles/.

Feng, B., et al., 2016. *Annals of Nuclear Energy*, 94, 300-312.

FERC (Federal Energy Regulatory Commission), 2006. Rate Regulation of Certain Natural Gas Storage Facilities, Order No. 678, Final Rule, Code of Federal Regulations Section 18, Part 284, Docket Nos. RM05-23-000 and AD04-11-000, 19 June. https://www.ferc.gov/whats-new/comm-meet/061506/C-2.pdf.

FERC, 2013. Powerex Corp. v. California Independent System Operator Corporation: Order on Complaint, 149 FERC ¶ 61,065, Docket No. EL14-59-000, 22 October.

Ferrero, D., M. Gamba, A. Lanzini, and M. Santarelli, 2016. Power-to-gas hydrogen: Techno-economic assessment of processes toward a multi-purpose energy carrier. *Energy Procedia*, 101, 20-57.

Flett, M.A., G.J. Beacher, J. Brantjes, A.J. Burt, C. Dauth, et al., 2008. Gorgon Project: Subsurface Evaluation of Carbon Dioxide Disposal under Barrow Island. Society of Petroleum Engineers Asia Pacific Oil and Gas Conference and Exhibition, 20-22 October, Perth, Australia. DOI: 10.2118/116372-MS.

Foh, S., M. Novil, E. Rockar, and P. Randolph, 1979. *Underground Hydrogen Storage Final Report*. 1979. Brookhaven National Laboratories, Upton, NY.

Fokker, P.A., C.J. Kenter, and H.P. Rogaar, 1993. The effect of fluid pressures on the mechanical stability of (rock) salt. *SeenthSympoiunm on Sa*,,1, 75-82, Elsevier Science Publishers B.V., Amsterdam.

Fordney, J., 2017. Grid operators manage solar eclipse, *RTO Insider*, 21 August. https://www.rtoinsider.com/rtos-solar-eclipse-grid-operators-48180/.

Friðleifsson, G.Ó., W.A. Eldersb, and A. Albertsson, 2014. The concept of the Iceland deep drilling project. *Geothermics*, 49, 2–8. http://www.sciencedirect.com/science/journal/03756505/49.

Gahleitner, G., 2013. Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications. *Int. J. Hydrogen Energy*, 38, 2039–2061.

GIIGNL (Groupe Internationale Des Importateurs de Gaz Naturel Liquéfié), no date. Basic Properties of LNG, LNG Information Paper No. 1, Levallois, France. http://www.kosancrisplant.com/media/5648/1-lng_basics_82809_final_hq.pdf.

Go with Natural Gas, 2014. CNG or LNG? http://www.gowithnaturalgas.ca/operating-with-natural-gas/fuel/natural-gas-for-vehicles/cng-or-lng/.

Goodwin, A., 2016. Honda's second-gen Clarity Fuel Cell is so clean you could drink from it. *Road Show*, 29 November. https://www.cnet.com/roadshow/auto/2017-honda-clarity-fuel-cell/preview/.

Götz, M., J. Lefebvre, F. Mörs, A.M. Koch, F. Graf, et al., 2016. Renewable Power-to-Gas: A technological and economic review. *Renewable Energy*, 85, 1371-1390.

Greenblatt, J., M. Wei, C. Yang, B. Richter, B. Hannegan, H. Youngs, J.C.S. Long, and M. John, 2011. *California's Energy Future: The View to 2050*. Summary Report, California Council on Science and Technology, May. http://ccst.us/publications/2011/2011energy.php.

Greenblatt, J., and J. Long, 2012. *California's Energy Future: Portraits of Energy Systems for Meeting Greenhouse Gas Reduction Targets*, California Council on Science and Technology, September. http://ccst.us/publications/2012/2012ghg.php.

Greenblatt, J., M. Wei, and J. McMahon, 2012. *California's Energy Future: Buildings & Industrial Efficiency*, California Council on Science and Technology, November. http://ccst.us/publications/2012/2012bie.php.

Greenblatt, J.B., 2015. Modeling California policy impacts on greenhouse gas emissions, *Energy Polic.*, 78, 158–172.

Greenblatt, J.B., M. Wei, D. Kammen, and B. Tarroja, 2017a. Low Carbon Energy Scenario Insights for a Robust Electricity System: The Importance of Climate Change in Energy Planning and Scenario Analysis. *Fourth California Climate Change Assessment Symposium*, Sacramento, CA, 26 January.

Greenblatt, J.B., N.R. Brown, R. Slaybaugh, T. Wilks, E. Stewart, and S.T. McCoy, 2017b. The Future of Low-Carbon Electricity, *Annual Reviews of Environment and Resources*, Oct. 2017. DOI: 10.1146/annurev-environ-102016-061138.

Greene, D.L., and G. Duleep, 2013. Status and Prospects of the Global Automotive Fuel Cell Industry and Plans for Deployment of Fuel Cell Vehicles and Hydrogen Refueling Infrastructure. Report ORNL/TM-2013/222. Oak Ridge, TN: Oak Ridge National Laboratory.

Greenwood, MS, et al., 2016. Summary of the Workshop on Molten Salt Reactor Technologies Commemorating the 50th Anniversary of the Startup of the Molten Salt Reactor Experiment. *ICAPP 2016: Nuclear Innovation: Inventing the Future of Existing and New Nuclear Power*; April 17-20; San Francisco, CA, USA.

Grubler, A., 2010. The costs of the French nuclear scale-up: A case of negative learning by doing. *Energy Policy*, 38 (9), 5174-5188.

GTO (Geothermal Technologies Office), 2016. Geothermal Value-Added Technologies. Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, DOE/EE- 0853, February. https://energy.gov/sites/prod/files/2016/04/f30/LT-Copro%20Fact%20Sheet.pdf.

GWEC (Global Wind Energy Council), 2016. *Global Wind Report Annual Market Update 2015*. http://www.gwec.net/publications/global-wind-report-2/global-wind-report-2015-annual-market-update/.

Hahn, M., and P. Gilman, 2014. Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment, https://energy.gov/eere/downloads/2014-offshore-wind-market-and-economic-analysis.

Hall, D.G., and R.D. Lee, 2014. *Assessment of Opportunities for New United States Pumped Storage Hydroelectric Plants Using Existing Water Features as Auxiliary Reservoirs*, Idaho National Laboratory, report number INL/EXT-14-31583, March.

Homsy, G.M., 1987. Viscous fingering in porous media. *Ann. Rev. Fluid Mech.*, 19, 271-31.

Hodges, J.P., W. Geary, S. Graham, P. Hooker, and R. Goff, 2015. Injecting hydrogen into the gas network—A literature search. Research Report RR1047, Health and Safety Laboratory, Derbyshire, United Kingdom. http://www.hse.gov.uk/research/rrpdf/rr1047.pdf.

Hydro TV., 2016. HydroVision International 2016 Keynote, PennWell Corporation, Tulsa, Oklahoma, 5 December. http://www.hydroworld.com/topics/m/video/117663639/hydrovision-international-2016-keynote.htm.

IAEA (International Atomic Energy Agency), 2013. *Hydrogen Production Using Nuclear Energy*, IAEA Nuclear Energy Series No. NP-T-4.2, Vienna, Austria. http://www-pub.iaea.org/MTCD/Publications/PDF/Pub1577_web.pdf.

ICAP (International Carbon Action Partnership), 2017. USA - California Cap-and-Trade Program, 28 August. https://icapcarbonaction.com/en/?option=com_etsmap&task=export&format=pdf&layout=list&systems[]=45.

ICF International, 2012. Report on Societal Carbon Reduction Potential through Electrification, Sacramento Municipal Utility District, January.

IDDP, 2017. The drilling of the Iceland Deep Drilling Project geothermal well at Reykjanes has been successfully completed. http://iddp.is/news/.

IEAGHG, 2007. Improved Oxygen Production Technology. 2007–14, IEA Greenhouse Gas R&D Programme, Cheltenham, UK

Ippolito, M., 2010. About KiteGen. KiteGen Research, 8 May. http://www.kitegen.com/en/about-2/.

IWG (Governor's Interagency Working Group on Zero-Emission Vehicles), 2016. ZEV Action Plan: An updated roadmap toward 1.5 million zero-emission vehicles on California roadways by 2025. Office of Governor Edmund G. Brown Jr., October. https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf.

Jaffe, A.M., R. Dominguez-Faus, N. Parker, D. Scheitrum, J. Wilcock, and M. Miller, 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*, Air Resources Board Contract No. 13-307, UC Davis. https://www.arb.ca.gov/research/apr/past/13-307.pdf.

James, R., and M. Costa Ros, 2015. Floating Offshore Wind: Market and Technology Review, UK: Carbon Trust.

Jansen, D., M. Gazzani, G. Manzolini, E. van Dijk, and M. Carbo, 2015. Pre-combustion CO_2 capture. *Int. J. Greenh. Gas Control*, 40,167–87.

Jechura, J., 2015. Hydrogen from Natural Gas via Steam Methane Reforming (SMR), Colorado School of Mines, Golden, CO, 4 January. http://inside.mines.edu/~jjechura/EnergyTech/07_Hydrogen_from_SMR.pdf.

Jenne, D.S., Y.-H. Yu, and V. Neary, 2015. Levelized Cost of Energy Analysis of Marine and Hydrokinetic Reference Models. In: 3rd Marine Energy Technology Symposium, NREL Conference Paper, NREL/CP-5000-64013, https://www.nrel.gov/docs/fy15osti/64013.pdf.

Jeong, S., D. Millstein, and M.L. Fischer, 2014. Spatially explicit methane emissions from petroleum production and the natural gas system in California. *Environ. Sci. Technol*., 48(10), 5982-5990. DOI: 10.1021/es4046692.

Johnson, L., and J. Pyper, 2017. Solar Tariff Case Advances as ITC Finds 'Injury,' *Greentech Media*, 22 September. https://www.greentechmedia.com/articles/read/solar-trade-case-advances-as-itc-finds-injury.

Jones-Albertus, R., D. Feldman, R. Fu, K. Horowitz, and M. Woodhouse, 2016. Technology advances needed for photovoltaics to achieve widespread grid price parity. *Prog. Photovolt: Res. Appl*., DOI: 10.1002/pip.2755.

Kempton, W., and J. Tomić, 2005. Vehicle-to-grid power implementation: From stabilizing the grid to supporting large-scale renewable energy. *Journal of Power Sources*, 144, 280-294.

King, D., 2016. Hyundai's new fuel-cell vehicle will get dramatic price cut, more range, *Auto Blog*, 30 August. http://www.autoblog.com/2016/08/30/hyundai-plans-a-cheaper-fuel-cell-vehicle-with-more-range/.

Koornneef, J., A. Ramírez, W. Turkenburg, and A. Faaij, 2012. The environmental impact and risk assessment of CO_2 capture, transport and storage—An evaluation of the knowledge base. *Prog. Energy Combust. Sci*., 38(1), 62–86.

Kreutz, T., R. Williams, S. Consonni, and P. Chiesa, 2005. Co-production of hydrogen, electricity and CO_2 from coal with commercially ready technology. Part B: Economic analysis. *Energy*, 30(7), 769-784. DOI: 10.1016/j.ijhydene.2004.08.001.

Kuuskraa, V., and M. Wallace, 2014. CO_2-EOR set for growth as new CO_2 supplies emerge. *Oil Gas J*., 112(4), 66.

Lackner, K.S., 2013. The thermodynamics of direct air capture of carbon dioxide, *Energy*, 50, 38-46. DOI:10.1016/j.energy.2012.09.012.

Lambert, F., 2017. Electric vehicle battery cost dropped 80% in 6 years down to $227/kWh – Tesla claims to be below $190/kWh. *Electrek*, 30 January. https://electrek.co/2017/01/30/electric-vehicle-battery-cost-dropped-80-6-years-227kwh-tesla-190kwh/.

Lazard, 2016. Levelized Cost of Storage Study, Version 2.0, December. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf. Accessed July 2017.

Liang, Z., W. Rongwong, H. Liu, K. Fu, H. Gao, et al., 2015. Recent progress and new developments in post-combustion carbon-capture technology with amine based solvents. *Int. J. Greenh. Gas Control*., 40, 26–54.

Lin, Z., J. Dong, and D.L. Greene, 2013. Hydrogen vehicles: Impacts of DOE technical targets on market acceptance and societal benefits. *International Journal of Hydrogen Energy*, 38, 19, 7973–7985. http://dx.doi.org/10.1016/j.ijhydene.2013.04.120.

Linde, 2016. State-of-the-art nitrogen rejection technology. Increasing the energy density of natural gas. http://www.linde-engineering.com/en/news_and_media/press_releases/index.html.

Lockridge, D., 2016. Daimler: Electric Delivery Trucks, Vans on the Way for U.S., *Automotive Fleet*, 22 September. http://www.automotive-fleet.com/channel/green-fleet/news/story/2016/09/daimler-electric-delivery-trucks-vans-on-the-way-for-u-s.aspx.

Logan, J., A. Lopez, T. Mai, C. Davidson, M. Bazilian, and D. Arent, 2013. Natural gas scenarios in the U.S. power sector. *Energy Economics*, 40, 183–195. http://www.sciencedirect.com/science/article/pii/S0140988313001217.

Lord, A.S., 2009. Overview of Geologic Storage of Natural Gas with an Emphasis on Assessing the Feasibility of Storing Hydrogen. Sandia National Laboratories, US.

Lyman, E., 2013. Small Isn't Always Beautiful: Safety, Security, and Cost Concerns about Small Modular Reactors, Union of Concerned Scientists, September. http://www.ucsusa.org/sites/default/files/legacy/assets/documents/nuclear_power/small-isnt-always-beautiful.pdf.

Magill, B., 2014. Methane emissions may swell from behind dams. *Scientific American*, Oct. 29. https://www.scientificamerican.com/article/methane-emissions-may-swell-from-behind-dams/

Martin, R., 2016. Small, Modular Nuclear Plants Get Their First Chance in the U.S. *MIT Technology Review*, 12 May. https://www.technologyreview.com/s/601426/small-modular-nuclear-plants-get-their-first-chance-in-the-us/.

Martínez, I., M.C. Romano, J.R. Fernández, P. Chiesa, R. Murillo, and J.C. Abanades, 2014. Process design of a hydrogen production plant from natural gas with CO_2 capture based on a novel Ca/Cu chemical loop. *Applied Energy*, 114, 192-208. DOI: 10.1016/j.apenergy.2013.09.026.

May, P., 2017. Is California on fire? Seems that way this week. *The Mercury News*, 10 July. http://www.mercurynews.com/2017/07/10/wildfires-are-raging-all-over-california/.

McCollum, D., C. Yang, S. Yeh, and J. Ogden, 2012. Deep greenhouse gas reduction scenarios for California - Strategic implications from the CA-TIMES energy-economic systems model. *Energy Strategy Reviews*, 1, 19-32.

McGreevy, P., 2017. Gov. Jerry Brown marks the start of Caltrain's electrification project with rare praise for the federal government, *Los Angeles Times*, 21 July. http://www.latimes.com/politics/essential/la-pol-ca-essential-politics-updates-gov-brown-federal-leaders-mark-start-1500667890-htmlstory.html.

McJeon, H., J. Edmonds, N. Bauer, L. Clarke, B. Fisher, B.P. Flannery, J. Hilaire, V. Krey, G. Marangoni, R. Mi, K. Riahi, H. Rogner, and M. Tavoni, 2014. Limited impact on decadal-scale climate change from increased use of natural gas. *Nature*, 514, 482. DOI:10.1038/nature13837.

Mearns, E. 2016. High Altitude Wind Power Reviewed. *Energy Matters*, 4 July. http://euanmearns.com/high-altitude-wind-power-reviewed/.

Melaina, M.W., O. Antonia, and M. Penev, 2013. Blending hydrogen into natural gas pipeline networks: a review of key issues. Technical Report NREL/TP-5600-51995, National Renewable Energy Laboratory, March. http://www.nrel.gov/docs/fy13osti/51995.pdf.

Messaoudani, Z., Rigas, F., Hamid, M, and Hassan, C., Hazards, safety and knowledge gaps on hydrogen transmission via natural gas grid: A critical review, *International Journal of Hydrogen Energy*, 41: 17511-17525, 2016. DOI: 10.1016/j.ijhydene.2016.07.171.

Metz, B., O. Davidson, H. de Coninck, M. Loos, and L. Meyer, eds., 2005. *IPCC Special Report on Carbon Dioxide Capture and Storage*. Cambridge, U.K.: Cambridge University Press. 442 pp.

Mines, G., and J. Nathwani, 2013. Estimated power generation costs for EGS. *Proceedings, Thirty-Eighth Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, 11 February–13 February, 2013, SGP-TR-198 (2013).

MIT (Massachusetts Institute of Technology), 2010. *Electrification of the Transportation System: An MIT Energy Initiative Symposium*, April 8. http://energy.mit.edu/wp-content/uploads/2010/04/MITEI-RP-2010-001.pdf.

MIT, 2015. *The Future of Solar Energy*. https://energy.mit.edu/wp-content/uploads/2015/05/MITEI-The-Future-of-Solar-Energy.pdf.

Mone, C., M. Hand, M. Bolinger, J. Rand, D. Heimiller, and J. Ho, 2017. 2015 Cost of Wind Energy Review. NREL Technical Report, NREL/TP-6A20-66861, https://www.nrel.gov/docs/fy17osti/66861.pdf

Morris, C., 2016. 2015: Germany's record wind year. *Energy Transition*, 18 January. https://energytransition.org/2016/01/2015-germanys-record-wind-year/.

Muoio, D., 2016. Bill Gates is pushing a new clean energy, but it's not solar or wind, *Business Insider*, 25 April. http://www.businessinsider.com/bill-gates-talks-private-nuclear-fission-plant-terrapower-2016-4.

Murray, B.C., C.S. Galik, and T. Vegh, 2014. *Biogas in the United States: An Assessment of Market Potential in a Carbon-Constrained Future*, Nicholas Institute for Environmental Policy Solutions, Report number NI R 14-02. Durham, NC: Duke University, 2014.

Murtaugh, G., 2017. *2016 Annual Report on Market Issues & Performance*, Department of Market Monitoring, California Independent System Operator (CAISO), May. https://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Musial, W., D. Heimiller, P. Beiter, G. Scott, and C. Draxl., 2016. 2016 Offshore Wind Energy Resource Assessment for the United States (Technical Report). NREL/TP-5000-66599. National Renewable Energy Laboratory, Golden, CO (US). http://www.nrel.gov/docs/fy16osti/66599.pdf.

Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, et al., 2013. Anthropogenic and natural radiative forcing. In: *Climate Change 2013: The Physical Science Basis: Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, edited by T.F. Stocker, D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley. Cambridge, England: Cambridge University Press: 659–740. www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.

NaturalGas.org., 2013. Processing Natural Gas. http://naturalgas.org/naturalgas/processing-ng/.

NECG (Nuclear Economics Consulting Group), 2015. Flexible Nuclear Power, NECG Commentary #12, 24 September. http://nuclear-economics.com/12-nuclear-flexibility/.

Nelson, J., A. Mileva, J. Johnston, D. Kammen, M. Wei, J. Greenblatt, 2013. *Scenarios for Deep Carbon Emission Reductoins from Electricity by 2050 in Wester North America Using the SWITCH Electric Power Sector Planning Model: California's Carbon Challenge, Phase II, Volume II*, California Energy Commission Final Project Report, CEC-500-2014-109, Rebruary

NET Power, 2016. Net Power Breaks Down on Demonstration Plant for World's First Emissions-free, Low-Cost Fossil Fuel Power Technology. http://netpower.com

NGVAmerica, 2015. Vehicles. http://www.ngvamerica.org/vehicles/.

NHA (National Hydropower Association), 2014. *Challenges and Opportunities For New Pumped Storage Development*, White Paper, NHA Pumped Storage Development Council. http://www.hydro.org/wp-content/uploads/2014/01/NHA_PumpedStorage_071212b12.pdf.

NuScale, 2017. How NuScale Technology Works, NuScale Power LLC. http://www.nuscalepower.com/our-technology/technology-overview.

O'Dell, J., 2017. UPS Launching World's First Fuel Cell Electric Class 6 Delivery Truck, *Trucks.com*, 2 May. https://www.trucks.com/2017/05/02/ups-fuel-cell-electric-delivery-truck/.

OECD/IEA (Organisation for Economic Cooperation and Development/International Energy Agency), 2015. *World Energy Outlook 2015*. Report WEA-2015. http://www.worldenergyoutlook.org/weo2015/.

Oldenburg, C.M., 2003. Carbon dioxide as cushion gas for natural gas storage. *Energy & Fuels*, 17, 240-246. DOI: 10.1021/ef020162b.

Pawar, R.J., G.S. Bromhal, J.W. Carey, W. Foxall, A. Korre, et al., 2015. Recent advances in risk assessment and risk management of geologic CO_2 storage. *Int. J. Greenh. Gas Control*., 40, 292–311

Pfeifenberger, J.P., J.W. Chang, and D.L. Oates, 2016. *Senate Bill 350 Study: Volume XI: Renewable Integration and Reliability Impacts*, Brattle Group, prepared for California Independent System Operator, 8 July. http://www.caiso.com/Documents/SB350Study_AggregatedReport.pdf.

Pfeiffer, W.T. and S. Bauer, 2015. Subsurface porous media hydrogen storage—Scenario development and simulation. *Energy Procedia*, 76, 565-572.

PHMSA (Pipeline and Hazardous Materials Safety Administration), 2017. Mileage for hazardous liquid or carbon dioxide systems, Data & Statistics - Annual Report. http://www.phmsa.dot.gov/pipeline/library/data-stats/annual-report-mileage-for-hazardous-liquid-or-carbon-dioxide-systems.

Pipeline Safety Trust, 2011. Pipeline Safety New Voices Project, Briefing Paper 2 – Natural Gas Pipelines – The Basics. http://pstrust.org/trust-initiatives-programs/new-voices-project/briefing-papers/.

PluginCars.com, 2017. Compare Electric Cars and Plug-in Hybrids By Features, Price, Range, Recargo, Inc. http://www.plugincars.com/cars.

Rasberry, T., 2015. SoCalGas Comments on June 1, 2015 Workshop and Support of AB 1257 Report, Southern California Gas Company, Docket No. 15-IEPR-04. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-04/TN205034_20150615T173257_Tamara_Rasberry_Comments_SoCalGas_Comments_15IEPR04_Comments_to.pdf.

REN21 (Renewable Energy Policy Network for the 21st Century), 2016. *Renewables 2016: Global Status Report*. http://www.ren21.net/wp-content/uploads/2016/10/REN21_GSR2016_FullReport_en_11.pdf.

Raghavan, S., M. Wei, D. Kammen, 2017. Scenarios to decarbonize residential water heating in California, *Energy Policy* 109, 441-451. DOI: 10.1016/j.enpol.2017.07.002.

Risky Business Project, 2016. *From Risk to Return: Investing in a Clean Energy Economy*, Michael R. Bloomberg, Henry M. Paulson, Jr., Thomas F. Steyer, co-chairs. http://riskybusiness.org/fromrisktoreturn/.

RMI (Rocky Mountain Institute), 2011. *Reinventing Fire: Bold Business Solutions for the New Energy Era*, White River Junction, Vt.: Chelsea Green Pub. http://www.rmi.org/reinventingfire.

Rubin, E.S., J.E. Davison, and H.J. Herzog, 2015. The cost of CO2 capture and storage. *Int. J. Greenh. Gas Control*., 40, 378–400. DOI: 10.1016/j.ijggc.2015.05.018.

Rusin, A., and K. Stolecka, 2015. Reducing the risk level for pipelines transporting carbon dioxide and hydrogen by means of optimal safety valves spacing. *J Loss Prev Process Industries*, 33, 77-87.

Ruth, M.F., et al., 2014. *Energy Conversion and Management*, 78, 684-694.

SCG (Southern California Gas Company), 2014. Natural Gas Pathways to Achieve Air Quality Goals, Presentation to CEC-IEPR Workshop on Transportation, April 10. http://www.energy.ca.gov/2014_energypolicy/documents/2014-04-10_workshop/presentations/15_J_Reed_NG_Transportation_Pathways_CEC-IEPR_Transportation_Workshop_2014-04-10.pdf.

Schroeder, A., *2015. 2015 Natural Gas Vehicle Research Roadmap*. California Energy Commission, draft report. Publication number CEC-500-2015-091-D, July.

Shell Oil, 2016. *A Better Life with a Healthy Planet: Pathways to Net-Zero Emissions*, http://www.shell.com/energy-and-innovation/the-energy-future/scenarios.html.

Singhal, S.C., 2014. Solid oxide fuel cells for power generation. *WIREs Energy Environ*, 3: 179–194. doi: 10.1002/wene.96.

SNL (Sandia National Laboratories), 2016. DOE Global Energy Storage Database, Office of Electricity Delivery and Energy Reliability, 16 August. https://www.energystorageexchange.org/projects.

Snowberg D, and J. Weber, 2015. *Marine and Hydrokinetic Technology Development Risk Management Framework*. National Renewable Energy Laboratory, Report number NREL/TP-5000-63258. http://www.nrel.gov/docs/fy15osti/63258.pdf.

Socolow, R., M. Desmond, R. Aines, J. Blackstock, O. Bolland, et al., 2011. *Direct Air Capture of CO2 with Chemicals: A Technology Assessment for the APS Panel on Public Affairs*, American Physical Society, June 1. http://www.aps.org/policy/reports/assessments/upload/dac2011.pdf.

Stanger, R., T. Wall, R. Spörl, M. Paneru, S. Grathwohl, et al., 2015. Oxyfuel combustion for CO_2 capture in power plants. *Int. J. Greenh. Gas Control*., 40, 55–125.

Stewart, J., 2017a. Unlike Hyperloop, Elon Musk's Electric Big-Rig Actually Makes Sense, *Wired*, 13 April. https://www.wired.com/2017/04/tesla-electric-truck/.

Stewart, J., 2017b. Toyota's Still Serious about Hydrogen—It Built a Semi to Prove It, *Wired*, 19 April. https://www.wired.com/2017/04/toyotas-still-serious-hydrogen-built-semi-prove/.

Stone, H.B.J., I. Veldhuis, and R.N. Richardson, 2009. Underground hydrogen storage in the UK. *Geological Society, London, Special Publications*, 313, 217-226. DOI: 10.1144/SP313.13.

stoRE, 2013. What are the environmental effects of Pumped Hydro Energy Storage (PHES) and how can future development proceed? PowerPoint presentation, Intelligent Energy Europe. http://backend.store-project.eu/uploads/docs/eusew-2013-presentations/store-presentation-eusew.pdf.

Tanghetti, A., 2017. Hourly Gas Demand for Electricity in 2030, *Integrated Energy Policy Report*, revised simulations, 2xAAE and Mid demand cases, California Energy Commission, personal communication, 9 August.

Thibeau, S., S. Bachu, J. Birkholzer, S. Holloway, F. Neele, and Q. Zhou, 2014. Using pressure and volumetric approaches to estimate CO_2 storage capacity in deep saline aquifers. *Energy Procedia*, 63, 5294–5304.

Trabish, H.K., 2017. Greening the ramp: California looks to carbon-free resources to combat the "duck curve," *UtiltyDIVE*, 23 October. http://www.utilitydive.com/news/greening-the-ramp-california-looks-to-carbon-free-resources-to-combat-the/507831/.

Unitrove, 2017. Compressed Natural Gas (CNG): What is CNG? http://www.unitrove.com/engineering/gas-technology/compressed-natural-gas.

U.S. EPA (U.S. Environmental Protection Agency), 2016. Climate Change Indicators: Wildfires, 17 December. https://www.epa.gov/climate-indicators/climate-change-indicators-wildfires.

Van Ruijven, B., J.F. Lamarque, D.P. Van Vuuren, T. Kram, and H. Eerens, 2011: Emission scenarios for a global hydrogen economy and the consequences for global air pollution. *Global Environmental Change: Human and Policy Dimensions*, 21, 983-994.

Verdolini, E., F. Vona, and D. Popp, 2016. *Bridging the Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion?* National Bureau of Economic Research, Working Paper 22454, July. http://www.nber.org/papers/w22454.

Walton, R., 2017. The electric industry is prepared for next week's eclipse. But what about the one in 2024? *UtilityDIVE*, 16 August. http://www.utilitydive.com/news/the-electric-industry-is-prepared-for-next-weeks-eclipse-but-what-about-t/449409/.

WEC (World Energy Council). 2016. Energy Resources > Hydropower. https://www.worldenergy.org/data/resources/resource/hydropower/.

WECC (Western Electricity Coordinating Council), 2002. WECC Daily Report of System Status (Unreported 900 MW S. Cal Blackout), 4 September. http://www.freerepublic.com/focus/fr/745129/posts.

Wei, M., J.H Nelson, J.B. Greenblatt, A. Mileva, J. Johnston, M. Ting, C. Yang, C. Jones, J. E. McMahon, and D.M. Kammen, 2013a. Deep carbon reductions in California require electrification and integration across economic sectors. *Environ. Res. Lett*., 8, 014038.

Wei, M., J. Greenblatt, S. Donovan, J. Nelson, A. Mileva, J. Johnston, D. Kammen, 2013b. *Scenarios for Meeting California's 2050 Climate Goals: California's Carbon Challenge Phase II, Volume 1*, California Energy Commission Final Project Report, CEC-500-2014-108, September.

White House, 2016. *United States Mid-Century Strategy for Deep Decarbonization*, Washington, D.C., November. http://unfccc.int/focus/long-term_strategies/items/9971.php.

Willauer, H.D., F. DiMascio, D.R. Hardy, and F.W. Williams, 2014. Feasibility of CO_2 extraction from seawater and simultaneous hydrogen gas generation using a novel and robust electrolytic cation exchange module based on continuous electrodeionization technology. *Ind. Eng. Chem. Res*., 53, 12192–12200. http://pubs.acs.org/doi/pdf/10.1021/ie502128x.

Williams, C.F., M.J. Reed, R.H. Mariner, J. DeAngelo, and P.S. Galanis, Jr., 2008. Assessment of moderate- and high-temperature geothermal resources of the United States: U.S. Geological Survey Fact Sheet 2008-3082, 4 p.

Williams, J.H., A. DeBenedictis, R. Ghanadan, A. Mahone, J. Moore, W.R. Morrow III, S. Price, and M.S. Torn, 2012. The technology path to deep greenhouse gas emissions cuts by 2050: The pivotal role of electricity. *Science*, 335, 53-59. DOI: 10.1126/science.1208365.

Williams, J.H., B. Haley, F. Kahrl, J. Moore, A.D. Jones, M.S. Torn, H. McJeon, 2014. *Pathways to Deep Decarbonization in the United States*, Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations. https://ethree.com/publications/index_US2050.php or www.deepdecarbonization.org/.

Williams, R.B., K. Kornbluth, P.A. Erickson, B.M. Jenkins, and M.C. Gildart, 2013. Estimates of Hydrogen Production Potential and Costs from California Landfills, California Biomass Collaborative, University of California, Davis, September. http://biomass.ucdavis.edu/files/2013/09/09-20-2013-05-13-2013-2007-cbc-ca-lfg-h2-berlin-poster.pdf.

Williams, R.B., B.M. Jenkins and S.R. Kaffka, 2015. *An Assessment of Biomass Resources in California*, 2013. CEC PIER Contract 500-11-020, California Biomass Collaborative, March.

Wiser, R., et al., 2016a. *2015 Wind Technologies Market Report*, Energy Efficiency and Renewable Energy, U.S. Department of Energy.

Wiser, R., K. Jenni, J. Seel, E. Baker, M. Hand, E. Lantz, and A. Smith, 2016b. Expert elicitation survey on future wind energy costs. *Nature Energy*, 12 September. DOI: 10.1038/NENERGY.2016.135.

WNN (World Nuclear News), 2017. NRC approves safety platform for NuScale SMR, 18 July. http://www.world-nuclear-news.org/RS-NRC-approves-safety-platform-for-NuScale-SMR-1807175.html.

Yang, C., S. Yeh, K. Ramea, S. Zakerinia, D. McCollum, D. Bunch, and J. Ogden, 2014. Modeling Optimal Transition Pathways to a Low Carbon Economy in California: California TIMES (CA-TIMES) Model, UC Davis ITS Research Report – UCD-ITS-RR-14-04. https://www.arb.ca.gov/research/apr/past/09-346.pdf.

Yang, C., S. Yeh, S. Zakerinia, K. Ramea, and D. McCollum, 2015. Achieving California's 80% greenhouse gas reduction target in 2050: Technology, policy and scenario analysis using CA-TIMES energy economic systems model. *Energy Policy*, 77, 118–130.

Yang, L., and Y. Li, 2014. Biogas Cleaning and Upgrading Technologies. Fact sheet AEX-653.1-14, The Ohio State University, 26 March. https://ohioline.osu.edu/factsheet/AEX-653.1-14.

Yeh, S., C. Yang, M. Gibbs, D. Roland-Holst, J. Greenblatt, A. Mahone, D. Wei, G. Brinkman, J. Cunningham, A. Eggert, B. Haley, E. Hart, and J. Williams, 2016. A modeling comparison of deep greenhouse gas emissions reduction scenarios by 2030 in California, *Energy Strategy Reviews* 13-14: 169-180.

Yip, A.H.C., 2014. Modeling the Global Prospects and Impacts of Heavy Duty Liquefied Natural Gas Vehicles in Computable General Equilibrium, Massachusetts Institute of Technology. http://hdl.handle.net/1721.1/95587.

ZEV Program Implementation Task Force, 2014. *Multi-State ZEV Action Plan*, Northeast States for Coordinated Air Use Management, May. http://www.nescaum.org/topics/zero-emission-vehicles/multi-state-zev-action-plan.

Appendix 3-1: Scope of Key Question No. 3

Subtask 3.1

What do changes in the energy system and possible changes anticipated to meet California's 2030 and 2050 climate goals imply for future gas usage and the need for gas? How might deployment of new technology impact the need for storage? In particular, what alternatives can feasibly replace or compete with gas storage in the deployment and integration of intermittent renewable energy? What practical economic and environmental impacts might these alternatives incur?

Subtask 3.1.1: Perform a literature search on prior studies of 2050 GHG reduction pathways in California and elsewhere, and obtain the corresponding natural gas data (or qualitatively estimate it from information about the study and interaction with study authors)

- Subtask 3.1.2: Examine FERC mandates for natural gas storage, CARB long-term plans (beyond 50% RPS), other recent mandates, and major technology developments that could have an impact on storage scenarios

- Subtask 3.1.3: Categorize scenarios according to the future demand for gaseous fuels, considering both absolute amounts and temporal distributions of demand

- Subtask 3.1.4: Develop qualitative descriptions of how natural gas storage and infrastructure would change under each identified scenario, and qualitatively characterize the costs

Subtask 3.2

How could coordination of gas and electric operations reduce the need for storage? How may regional coordination of electric grid operation and planning change the role of gas/electric coordination and use of infrastructure?

- Subtask 3.2.1: Examine current and potential future coordination of gas and electric operations by CAISO

- Subtask 3.2.2: Identify how the future developments considered above could impact the scenarios identified and categorized in 3.1

Subtask 3.3

What does the assessment of storage that might be required to meet 2050 goals imply about storage in the interim time period?

- Subtask 3.3.1: For each major natural gas usage scenario identified in 3.1, consider pathways that might exist along the way to GHG compliance in 2050
- Subtask 3.3.2: Characterize interim stages of natural gas infrastructure changes, with particular attention focused on the 2030 GHG compliance year

Appendix 3-2: Energy Technologies

In this Appendix, we review the major technology components needed to achieve overall low GHG emissions for the California energy system in order to assess the need for UGS. Note: some of the materials in this section are based on content developed for Greenblatt et al. (2017b).

Wind Energy

Conventional wind power

Installed wind power capacity has more than doubled globally since 2010, reaching 433 GW by the end of 2015 (GWEC, 2016). The U.S. has the second-largest installed capacity of wind power at 74 GW, right behind China. U.S. capacity is forecast to grow to 91-107 GW in 2020, 118-218 GW in 2030, and 138-297 GW in 2040, depending on policy assumptions (OECD/IEA, 2015). In California, installed wind power was 5.66 GW as of the first quarter of 2017, ranking fourth behind Texas, Iowa, and Oklahoma. The estimated technical potential for wind power in California is 66 GW at 110 m hub height (AWEA, 2017). The average capacity factor for conventional wind power in 2016 was 35% (EIA, 2017e).

Wind turbine installed costs in the U.S. have fallen ~20-40% relative to a 2008 high of $1,500/kW in 2015, due in part to increases in hub heights and rotor diameters that have reduced project costs and wind power prices. Average 2015 installed costs were ~$1,000/kW (Wiser et al., 2016a). An extensive expert elicitation study of future wind energy costs found that relative to 2014, the levelized cost of energy[7] could fall 24-30% in 2030 for both onshore and offshore technologies (Wiser et al., 2016b).

Floating offshore wind turbines

7. We define "levelized cost of energy" as the net present total ownership cost (including capital, financing, taxes, operations and maintenance) divided by the total energy output over the life of the equipment (typically 20-40 years). It is sometimes abbreviated as LCOE. It does not usually include subsidies or other market incentives.

A 2016 NREL study showed that California's technical offshore wind resource potential is 112 GW. Unlike the Atlantic continental shelf, the Pacific shelf depth increases very quickly with distance from shore, so that conventional offshore wind turbine moorings are impractical, creating the need for floating wind turbines. This is also the case for California, where almost all offshore resources are located in waters with depths greater than 60 m (Musial et al., 2016). The number of working prototypes around the world for floating offshore turbines is rather small, but the floating offshore wind market appears to be growing. The collaboration between Statoil and Siemens has yielded the Hywind project that will begin in late 2017, constructing a 30 MW wind farm off the Scottish coast (James and Costa Ros, 2015). This will be the first floating offshore wind farm in the world, and will demonstrate if electrical, technical, and infrastructural challenges can be overcome.

Besides these challenges, which include addressing the right platform to make a turbine stable, mooring and anchor design, and high voltage dynamic cables, the main barriers for floating wind turbine installation are high capital and operating expenditures. Mone et al. (2017) estimated a 2015 levelized cost of energy of $181/MWh for fixed-bottom offshore wind turbines, and $229/MWh for floating offshore wind turbines. Beiter et al. (2016) estimated that the current levelized energy cost of floating wind turbines is ~16% higher than conventional fixed-bottom turbines, but by 2030, offshore floating wind turbines will be lower than that of fixed-bottom turbines. EIA (2017f) estimated that offshore wind turbine costs overall will fall to $157/MWh by 2022 and $129/MWh by 2040.

Capacity factors for global offshore wind plants have been slowly but steady increasing. The majority of the plants in 2014 had capacity factors between 35% and 55% (Hahn and Gilman, 2014).

High-altitude wind

High altitude wind represents a potentially game-changing technology, as wind speeds are much higher and more constant above 250 m, and available almost anywhere on Earth. However, harnessing this resource requires a fundamentally different approach than ground-based wind turbines: an airborne energy harvester, as conventional tower designs become prohibitively expensive at these altitudes. Mearns (2016) provides an excellent review on this topic. Two complementary approaches currently exist: (1) airborne energy conversion with electrical transmission to ground via conductive wire, and (2) ground-based energy conversion with mechanical transmission via tether. Two leading companies, Makani (x.company/makani/) and KiteGen (Ippolito, 2010), have designs resembling an airplane wing with multiple propellers, and a large kite, respectively; other companies with variant designs also exist (Mearns, 2016). Both approaches keep aloft utilizing some harvested energy.

Concepts are still in development, but appear technically sound due to advances in sensor, global positioning system, and computing technologies; the main challenge is safety

(Mearns, 2016). While high-altitude wind cannot provide baseload power, it delivers much higher capacity factors than conventional wind turbines. It is too soon to determine potential costs, however.

Solar Energy

Solar photovoltaics

Solar electricity today is dominated by photovoltaic (PV) technology of various types, including mono- and polycrystalline silicon (c-Si), gallium arsenide (GaAs), III-V multijunction, and thin-film designs (Bolinger and Seel, 2016; MIT, 2015). In the U.S., c-Si made up 94% of the 2014 market, with thin-film cadmium telluride (CdTe) comprising most of the remainder (Jones-Albertus et al., 2016). GaAs is inherently more efficient than c-Si but also much more expensive; it is usually reserved for high-performance applications.

Global solar PV capacity was 227 GW in 2015, having expanded nearly 10 times over the previous decade earlier, with installations spread across China, Japan, the U.S., Europe, and new markets around the world (REN21, 2016). California leads the U.S. with the most installed solar PV capacity, currently at 7.38 GW (openpv.nrel.gov/rankings). Solar PV capacity across the U.S. was 27 GW in 2015, and is projected to grow to 68-78 GW in 2020, 117-206 GW in 2030, and 169-355 GW in 2040, depending on policy assumptions (OECD/IEA, 2015).

While PV can be as small as a few kW installed on residential rooftops, it is much more affordable at larger scales. For all scales, however, solar PV has seen a tremendous decrease in installed cost since 2009, falling in the U.S. by more than 50% to between ~$\$2/W_{DC}$ (≥500 kW) and ~$\$4/W_{DC}$ (residential-scale). This drop has been mainly precipitated by the large decrease in module prices, which for residential PV fell from ~$\$4/W_{DC}$ average in 2000-2008 to ~$\$0.5/W_{DC}$ in 2015 (Barbose et al., 2016; Bolinger and Seel, 2016), though the ongoing Suniva/SolarWorld trade case may raise these floor prices in the U.S. to nearly $\$0.8/W_{DC}$ (Johnson and Pyper, 2017). EIA (2017f) projects that the levelized cost of energy of utility-scale solar PV will fall from an average of $78/MWh in 2019 to $69/MWh by 2040.

The average capacity factor for solar PV in 2016 was 27% (EIA, 2017e).

Solar thermal

Also known as concentrating solar power (CSP), this approach represents a fundamentally different way of harvesting solar energy: using concentrated solar energy as a thermal source driving a steam turbine, much like a conventional fossil-fueled power plant. CSP must inherently track the sun, and pointing stability is critical to maintain high operating temperatures. While CSP plants can store thermal energy for hours, providing dispatchable power, they are only suitable in regions with high direct insolation, and are currently costlier than PV (MIT, 2015). Largely experimental until recently, seven commercial CSP plants totaling 1.4 GW are now operating in the U.S. in Arizona, California, Florida and Nevada (Bolinger and Seel, 2016), using a mixture of single-axis (parabolic trough) and two-axis (tower) concentration designs. Global CSP capacity was 4.8 GW in 2015 (REN21, 2016). However, while prospects are not as promising now due to lower solar PV costs, they are expected to improve in the longer term (OECD/IEA, 2015).

EIA (2017f) estimated that the solar thermal levelized cost of energy will be $218/MWh in 2019, falling to $204/MWh in 2040.

The average capacity factor of solar thermal in 2016 was 22% (EIA, 2017e).

Geothermal Energy

Conventional geothermal energy

Geothermal energy is produced in high-temperature regions at shallow depths (typically >1 km), using either natural or injected water to extract heat from rock. This heat originates from residual energy of Earth's formation supplemented by natural radioactive decay (Ellabban et al., 2014). The undiscovered geothermal resource potential in the U.S. has an electrical power generation mean value of 30 GW (Williams et al., 2008), while in California, it is estimated that there is a potential for at least 4 GW of additional geothermal electricity generation in Imperial, Inyo and Mono counties using current technologies (CEC, 2015).

Conventional geothermal technologies require steam above 150°C for economic operation. However, DOE has been funding research to utilize lower temperatures and/or coproduced resources (hot, non-aqueous fluids such as oil or gas) for electricity generation. In some cases, lower-temperature fluids can improve plant economics by including a value-added secondary application (GTO, 2016).

EIA (2017f) estimated that geothermal will cost $47/MWh in 2022 and $57/MWh in 2040.

The average capacity factor for conventional geothermal power in 2016 was 74% (EIA, 2017e).

Enhanced geothermal systems

The CEC's (2015) assessment of California's geothermal energy potential increases up to 48 GW if enhanced geothermal systems (EGS) technology is introduced (Williams et al., 2008). Comparing to conventional geothermal systems, EGS is an engineered reservoir where hot, dry rock is fractured to increase its permeability and water is injected into it to carry away thermal energy. The natural permeability of rock in EGS candidate reservoirs is typically low and must be improved. Drilling through low-permeability hard rocks with current mechanical drilling technology that easily wears out is not economical, yet these formations often hide the best sources of geothermal energy.

Recent advances in laser power transmission technologies promise to expand the adoption of geothermal energy. ARPA-E funded Foro Energy (based in Colorado) to develop a laser-assisted drilling system that can cut through extremely hard rocks. This system uses advances in cheaper, more powerful lasers and more efficient fiber optic transmission of laser light to increase drill rates and thus decrease the time of drilling. According to Foro's estimates, their technology could drop the cost of geothermal plants by up to 29% (ARPA-E, 2016).

Mines and Nathwani (2013) estimated the levelized cost of energy of EGS to be between \$134/MWh and \$765/MWh; however, DOE has a goal to lower this cost to \$60/MWh by 2030 (DOE, no date).

Supercritical geothermal systems

Another project that promises to lead to a revolution in the efficiency of geothermal systems is the Iceland Deep Drilling Project (IDDP). The main purpose of the project is to determine if it is economically feasible to extract energy from a magma-enhanced geothermal system. The objective of drilling into the "heart" of a volcano is to reach fluids at supercritical conditions ($T > 374°C$, $P > 221$ bar for pure water). Extracted fluids have much more energy than fluids in conventional geothermal wells, and can therefore radically increase power output of a well. For their first well, IDDP reached magma of more than 900 °C at 2.1 km depth. The well has proven to be highly productive and became the world's hottest producing geothermal well, with wellhead temperatures of 450°C (Friðleifsson et al., 2014). At the beginning of 2017, IDDP reached a milestone with their second well, drilling to 4,659 m and reaching desired supercritical conditions (IDDP, 2017).

Hydropower

Conventional hydropower

Worldwide hydropower capacity was 1,064 GW in 2015, led by China, Canada, Brazil, and the U.S. (REN21, 2016; WEC, 2016). In developed countries such as the U.S., most significant hydropower resources are already exploited; U.S. capacity is expected to grow modestly from 80 GW today to 93 GW in 2050, with ~50% growth from repowering existing facilities (DOE, 2016). Almost all forecasts of future California hydropower generation keep generation flat at current capacities of ~14 GW. California typically also imports ~4% of its hydroelectricity from the Pacific Northwest (CEC, 2016).

Hydropower is not universally considered "green": in addition to displacing people and habitats when constructing reservoirs, dams may promote anaerobic decay of organic matter, generating the potent GHG methane; recent research suggests this effect could be even larger than previously estimated (Magill, 2014). As a result, California does not count hydropower facilities as renewable unless they are <30 MW (CEC, 2016).

EIA (2017f) estimated that the levelized cost of energy of hydropower will remain essentially flat, falling from $66/MWh in 2022 to $62/MWh in 2040.

The average capacity factor for conventional hydropower in 2016 was 38% (EIA, 2017e).

Marine and hydrokinetic power

Marine and hydrokinetic (MHK) technologies are distinct from hydropower, exploiting energy from waves, tides, and river and ocean currents, and represent a number of potentially viable technologies (www.energy.gov/eere/water/marine-and-hydrokinetic-energy-research-development). The U.S. has estimated MHK's technical potential as ≥ 50% of U.S. electricity demand (OECD/IEA, 2015; www.energy.gov/eere/water/marine-and-hydrokinetic-resource-assessment-and-characterization). However, MHK is still immature and hence expensive, and has recently suffered technological and commercial setbacks (Snowberg and Weber, 2015); while the U.S. and other countries remain supportive (Hydro TV, 2016), the future is uncertain.

The levelized cost of energy for small (10 MW) commercial-scale MHK ranges from $310/MWh to $1,470/MWh (Jenne, Yu and Neary, 2015). DOE has a goal to reduce this cost to $120-150/MWh by 2030 (Duerr, 2014).

Nuclear Power

Conventional nuclear power

While nuclear power in California is currently on a phase-out trajectory, with the 2012 permanent shutdown of San Onofre and the planned closure of Diablo Canyon in 2024, nuclear power capacity remains high elsewhere, with ~100 GW across the U.S. and ~400 GW worldwide (OECD/IEA, 2015), and significant prospects for growth (528-837 GW through 2040, depending on policy assumptions), though almost all operating nuclear reactors in the U.S. will be retired in the 2035-2055 timeframe (Feng et al., 2016) unless replaced with new reactors.

Because nuclear power can be operated at very high capacity factors (typically >90%; EIA, 2017e), it can be challenging to integrate with intermittent renewables; as a result, nuclear must sometimes sell electricity at a loss (Ruth et al., 2014). These economic realities are compounded by relatively inexpensive fossil fuels, such as natural gas, though the most significant economic challenge for nuclear energy is very high construction cost, which contrary to most other electricity generation technologies has tended to increase over time (Grubler, 2010).

There has been a recent outburst of innovation in the nuclear energy sector, with the formation of a number of start-up companies and significant interest in advanced reactors

(Greenwood et al., 2016). This interest has been summarized in a report from Thirdway, a nonpartisan think tank (www.thirdway.org/report/the-advanced-nuclear-industry).

EIA (2017f) estimated that the levelized cost of energy of "advanced" nuclear will be $99/MWh in 2022 and $90/MWh in 2040.

Small modular reactors

One example of innovative thinking in the nuclear power field is the increasing interest in small modular nuclear reactors (SMRs) (Martin, 2016), which have been championed by the U.S. Department of Energy (www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors), as well as investors such as Bill Gates (Muoio, 2016). The U.S. Nuclear Regulatory Commission has recently approved the safety platform of the NuScale SMR (WNN, 2017), the sole U.S. company currently pursuing this technology. SMRs are "theoretically safer" than conventional reactors, "reducing the need for huge containment vessels and other expensive protections" (Martin, 2016). The 50 MW NuScale design, which uses many standard off-the-shelf items, a modular design, and much shorter construction times, is being offered at ~$5,000/kW (NuScale, 2017). However, a recent study by the Union of Concerned Scientists concluded that SMRs would still be more expensive than current reactors, and raised potential safety concerns (Lyman, 2013).

Carbon Dioxide Capture and Sequestration

In carbon dioxide capture and sequestration (CCS), CO_2 that would otherwise be released to the atmosphere during fuel combustion is captured, compressed, and transported to a suitable storage site, where it is injected deep underground and retained in the subsurface through natural trapping mechanisms (Metz et al., 2005, Coninck and Benson, 2014). There are generally three different approaches to integrating CO_2 capture with power generation: pre-, post-, and oxyfuel (or oxy-) combustion:

1. In pre-combustion processes, fuels (typically coal or natural gas) are converted to a mixture of hydrogen and CO_2 via gasification, or reforming combined with the water-gas shift reaction, and the CO_2 is separated from hydrogen, the latter being used as fuel for power generation (Jansen et al., 2015). Integrated gasification combined cycle (IGCC) plants equipped with CO_2 capture, such as the Edwardsport Facility in Indiana (618 MW), are one example of this process (Duke Energy, no date).

2. In contrast, in post-combustion processes, CO_2 is separated from low-pressure flue gas—largely a mixture of nitrogen, water and CO_2—rather than from the fuel (Liang et al., 2015). Post-combustion capture can be applied to conventional pulverized coal boilers and natural gas combined cycle (NGCC) plants. The most prominent examples of post-combustion capture are the Boundary Dam Power Plant in Canada (110 MW), operating since 2014, and the W.A. Parish Power Plant in Texas (240 MW), which began operation in 2016.

3. The third approach is oxy-combustion, in which coal or gas is burned in a mixture of oxygen and CO_2 rather than air (Stanger et al., 2015). Oxy-combustion avoids the need for a CO_2 separation step, but requires separation of oxygen from air. As of 2016, there were no operating commercial-scale examples of oxy-combustion; however, oxy-combustion of coal has been successfully demonstrated at scales up to 30 MW (Stanger et al., 2015), NET Power developed a 50 MW natural gas demonstration plant that uses an oxy-fuel, supercritical CO_2 power cycle (NET Power, 2016), and cryogenic air separation is fully commercial technology, with thousands of units operating worldwide at equivalent power generation capacities up to 300 MW (IEAGHG, 2007).

The levelized energy cost for natural gas power plants with CCS is estimated to be between \$63 and \$122/MWh (Rubin et al., 2015). Such plants would capture ~90% of emitted CO_2.

CO_2 can be transported by truck, train, ship, barge, or pipeline. All these transport modes are commercially practiced today, although only pipelines are used at scales necessary for CCS from power generation (~1-10 Mt/yr CO_2 per plant). In the U.S., there were ~8,500 km of CO_2 pipelines operating at the end of 2016 (PHMSA, 2017) that, in recent years, moved ~70 MtCO_2/yr from mainly natural CO_2 sources for enhanced oil recovery (EOR) (Kuuskraa and Wallace, 2014).

The principal options for geologic CO_2 sequestration are injection into deep brine-filled aquifers, and oil or gas reservoirs (including CO_2-EOR operations) (Coninck and Benson, 2014). The technologies involved in CO_2 sequestration, such as those found in injection wells and used for monitoring, are largely borrowed from oil and gas operations and adapted for use in CO_2 sequestration. CO_2 sequestration has one critical distinction, however: large volumes of buoyant fluid (CO_2) are injected into the subsurface rather than withdrawn. This means that pressure in the receiving formation increases over a large area, and existing brines are displaced away from the injection site (Birkholzer et al., 2015). Thus, pressure build-up limits practical storage capacity in many cases (Thibeau et al., 2014; Bachu, 2015), which has spurred development of pressure management concepts generally (Buscheck et al., 2012), and brine withdrawal plans at the Australian Gorgon sequestration project specifically (Flett et al., 2008). Regulations also recognize the novel aspects of sequestration, typically requiring thorough understanding of site-specific risks (Dixon et al., 2015), which has driven much research into the potential impacts of CO_2 sequestration and risk assessment (Pawar et al., 2015; Koornneef et al., 2012).

According to GCCSI (2016), there are 17 operating large-scale CCS projects worldwide, an additional five currently under construction, and 18 in various stages of development. GCCSI defines “large-scale” as a facility “involving the capture, transport, and storage of CO_2” at a scale of at least 800,000 t/yr CO_2 for coal-based power plants, or at least 400,000 t/yr CO_2 for other industrial facilities (including natural gas-based power plants). All told, projects expected to become operational by the end of 2017 are estimated to capture ~40

Mt/yr CO_2. In addition, GCCSI lists 78 pilot-scale projects that do not meet the above criteria for large-scale.

The Scottish Carbon Capture & Storage (SCCS) research group also maintains a global database of CCS projects, and in addition to operational, pilot-scale and planned projects, includes >50 pilot projects and ~45 projects in the planning phase, as well as dormant or completed projects (www.sccs.org.uk).

Potential CO_2 storage capacity in California is 30-420 billion metric tons CO_2 across the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River Basins, according to a 2010 study (DOE-NETL, 2010). In addition, California offshore CO_2 storage capacity amounts to almost 240 Mt CO_2 (Downey and Clinkenbeard, 2011).

Energy Storage

According to SNL (2016), there are nearly 1,600 energy storage projects worldwide that are announced, contracted, under construction, operational, or offline for repairs, with a total capacity of 193 GW. Nearly all capacity is pumped hydroelectric storage (PHES), with electrochemical, electromechanical and thermal providing the majority of remaining capacity. The breakdown by technology type is shown in Table 6.

Table 6. Global energy storage projects.

	Number of projects	Rated power (GW)	Minimum storage capacity (GWh)*
Type of technology			
Pumped hydroelectric	351	183.72	1,718.30
Electrochemical	954	3.19	1.50
Lithium-based	617	2.28	0.38
Sodium-based	72	0.21	0.45
Lead-based	87	0.11	0.05
Flow	91	0.14	0.15
Other/not specified	87	0.45	0.47
Electromechanical	68	2.62	38.51
Compressed air	17	1.59	38.49
Flywheel	49	0.97	0.01
Other/not specified	2	0.05	0.01
Thermal	206	3.62	21.89
Other (mainly hydrogen)	13	0.02	0.07
Breakdown by status:			
Operational	1,323	176.03	1,725.76
Announced	164	12.45	53.43
Contracted	86	3.11	0.04
Under construction	12	1.26	0.02
Offline for repairs	7	0.33	1.01
Total	1,592	193.17	1,780.27

Note: listed are projects that are announced, contracted, under construction, operational or offline for repairs.

*Source: SNL (2016). *Not all storage capacities were available.*

For California, there are 284 projects with a total capacity of 7.55 GW. Once again, nearly all capacity is PHES. Table 7 provides a breakdown of energy storage projects by technology and status.

Table 7. California energy storage projects.

	Number of projects	**Rated power (GW)**	**Minimum storage capacity (GWh)***
Breakdown by technology:			
Pumped hydroelectric	11	6.39	148.59
Electrochemical	187	0.62	0.22
Lithium-based	157	0.43	0.05
Sodium-based	5	0.01	0.05
Lead-based	3	0.01	0.01
Flow	8	0.03	0.12
Other/not specified	10	0.15	0.00
Electromechanical	8	0.32	3.00
Compressed air	2	0.30	3.00
Flywheel	6	0.02	0.00
Thermal	78	0.22	1.31
Breakdown by status:			
Operational	201	4.32	144.00
Announced	48	1.32	9.00
Contracted	31	1.76	N/A
Under construction	1	0.01	0.01
Offline for repairs	3	0.15	0.11
Total projects	284	7.55	153.12

*Note: listed are projects that are announced, contracted, under construction, operational or offline for repairs. Source: SNL (2016). *Not all storage capacities were available.*

Battery storage

There are many types of battery storage, including lithium-based, sodium-based (mainly sodium sulfur and sodium nickel chloride), lead-based (mainly lead acid), various kinds of flow batteries (vanadium, iron chromium, zinc iron, zinc bromide, etc.) and others. Lithium-based batteries currently lead both globally and in California for the most projects and capacity of any battery technology. Battery storage durations range from less than one hour to 48 hours (SNL, 2016). Batteries can provide reasonably high power over a time period of minutes to hours, thus making them suitable for both power quality and load-shifting applications. Flow batteries have the advantage that they can be configured for larger energy capacities than other types of batteries, since stored energy is typically in the form of two chemical liquids held in tanks that are, in principle, very scalable. Batteries tend to have smaller rated power capacities than electromechanical or certainly PHES systems.

While some types of battery technologies are well-established (e.g., lead acid, lithium ion, sodium sulfur), many are still under development, and promise lower costs and/or higher performance once mature. The cost of a more mature technology such as sodium-sulfur is ~\$250 to \$300/MWh (Akhil et al., 2013), whereas immature technology can cost >\$500/MWh.

Vehicle batteries could be considered a special form of battery storage. Often connected to the electricity grid for several hours per day (typically outside of morning and evening commuting hours), these storage devices could provide inexpensive storage as they are already paid for by vehicle owners, yet could provide valuable grid services by opting to charge (or even discharge) during periods convenient to the grid operator (Kempton and Tomić, 2005). Presumably, battery owners would have to be compensated for the value of electricity supplied to the grid as well as battery degradation, and a system would have to be created to manage batteries as an aggregate resource.

Thermal storage

This type of storage technology mainly utilizes off-peak electricity to produce chilled water or ice for building air conditioning, though hot thermal storage has also been employed, usually in conjunction with solar thermal plants. Cold storage technologies do not represent two-way storage, but simply a load-shifting strategy; hot storage in conjunction with solar thermal power, by contrast, can be used to generate electricity at a later time. Storage duration ranges from less than one hour to 48 hours, with typical durations of ~6 hours (SNL, 2016).

Pumped hydroelectric storage

PHES is the dominant form of energy storage globally, having begun operation in the 1920s in the U.S. PHES currently comprises 95% of global energy storage capacity, and 85% in California (including all projects regardless of status) (SNL, 2016). PHES employs off-peak electricity to pump water from a reservoir at lower elevation to another reservoir at higher elevation. When electricity is needed, water is released from the upper reservoir to generate electricity using hydroelectric turbines. With the tremendous increase in solar PV capacity in recent years in California, off-peak electricity may be shifting from nighttime (when excess baseload coal and/or nuclear power was often available) to daytime (when solar PV exceeds demand by a considerable margin). Storage capacities range from 2.5 hours to 48 hours, with a small number of projects worldwide with greater capacities. The estimated levelized cost of energy is \$150-220/MWh (Akhil et al., 2013).

There are currently 11 PHES projects in California, including two 500 MW announced projects (Lake Elsinore and San Vicente) and one 1.3 GW contracted project (Eagle Mountain) (SNL, 2016). Expansion of existing PHES capacity is possible; Hall and Lee (2014) identified 31 existing hydroelectric plants in the U.S. meeting various inclusion criteria, with generation capacity of 10 MW or greater, that have the potential for adding PHES. In addition to three new PHES sites that have either been announced or contracted with a total capacity of 2.3 GW (SNL, 2016), six other sites are located in California, with a total generation capacity of 325 MW, and an unknown storage duration potential, and an additional five sites are located in other western states with total capacity of 240 MW. In addition, seven nonpowered dams across the U.S. were identified as PHES candidate sites, with three located in California, and 97 greenfield sites were identified with the potential to construct PHES: 24 located in California with a total potential capacity of >500 MW, and 45 elsewhere in the western U.S. with a total potential capacity of >1000 MW. Even if all of this PHES capacity were developed, it would almost certainly be insufficient to address multi-day *dunkelflaute* conditions, as we have estimated that ~30 GW of generation capacity may occasionally be needed by 2030 to shore up intermittent renewables (see 3.2.4. *Gas Needed to Back Up Intermittent* Renewables in the main text).

Compressed air energy storage

Compressed air energy storage (CAES) uses off-peak electricity to compress air and store it in a reservoir, typically an underground salt cavern or abandoned oil or gas reservoir. When electricity is needed, the compressed air is withdrawn from the reservoir, heated (typically with natural gas), and directed through an expander or conventional turbine-generator to produce electricity. Because natural gas is almost always used in the generation process, CAES is considered a hybrid technology that has non-zero GHG emissions (unless low-carbon gas such as biomethane is used). To avoid burning fuel upon air expansion, the thermal energy of compression must be stored; there is currently one 500 kW demonstration plant in Switzerland able to do this (the Pollegio-Loderio Tunnel ALACAES Demonstration Plant) (SNL, 2016).

CAES was developed in the 1980s, much more recently than PHES, but offers a similar levelized cost of energy ($120-220/MWh) for 5-8 hours of storage (Akhil et al., 2013). Currently, only a handful of plants have been built worldwide; Table 6 lists 17 CAES projects, but only 9 are operational, dominated by one project in Alabama (110 MW) and two in Germany (200 and 321 MW). However, in the U.S. there are also three other operational plants (≤2 MW) and five announced plants (up to 317 MW) including two in California (SNL, 2016). The challenges of siting a suitable underground reservoir, combined with the low cost of gas turbines, has hindered development. The levelized energy cost is estimated to be similar to PHES (Akhil et al., 2013).

Other electromechanical technologies

Besides CAES, most planned or operating electromechanical systems are flywheels, which store kinetic energy as angular momentum of a spinning mass. For safety, flywheels are housed in a containment system that is often placed under vacuum or filled with a low-friction gas like helium to enhance performance. Flywheel systems are capable of very rapid charging and discharging, making them suitable for frequency regulation and applications requiring responsiveness up to a few seconds. Unlike most batteries, flywheels exhibit little performance degradation over more than 100,000 cycles. Sizes range from 10 kW to 400 MW, and cost approximately $400/kWh for 15 min. of storage (Akhil et al., 2013).

Natural Gas Substitutes

Here we discuss the major alternatives to fossil natural gas that would allow the continued use of existing natural gas pipeline and storage infrastructure.

Biomethane

Biomethane is produced from biogas, the byproduct of biological anaerobic decay of organic matter found in municipal solid waste, landfills, manure, and wastewater. Biogas contains ~50% CO_2 and ~50% methane by volume (along with water and some trace contaminants); once the CO_2 and other contaminants are removed, biogas is known as biomethane and can be blended with fossil natural gas in pipelines. As biogas is ultimately of biological (plant) origin, its CO_2 emissions from combustion are offset by CO_2 absorbed during plant growth. Net GHG emissions include additional GHG changes associated with biological processes (changes in carbon stocks, fertilizer application, etc.), as well as fossil fuel combustion during processing and transport.

Resources

In-state biogas resources from landfills, manure, municipal solid waste, and wastewater are limited to ~250 MMcfd (Williams et al., 2015; Jaffe et al., 2016), but costs are very high: ~$10/MMBtu for 100 MMcfd, ~$30/MMBtu for 200 MMcfd and >$50/MMBtu for the full potential (Jaffe et al., 2016). By comparison, current California natural gas average demand is ~6,000 MMcfd, so these resources would provide ~4% of annual demand at most. Another study that includes the hypothetical conversion of all in-state woody biomass waste into biogas estimates that an additional ~550 MMcfd would be available from these resources (BAC, 2014), or another ~9% of current natural gas demand.

Murray et al. (2014) examined sources of biogas across the U.S., and determined that ~3,800 MMcfd could be produced at a cost of ≤$6/MMBtu in 2040, and as much as ~20,000 MMcfd at higher cost (≤$9/MMBtu). Clearly, these national resources are adequate to supply at least a majority of California natural gas demand, and potentially much more. While current natural gas pipeline prices are ~$3/MMBtu, they were well above $6/MMBtu in 2004-2008 and were above $10/MMBtu for four months each in fall/winter 2005 and spring/summer 2008 (EIA, 2017a). Although natural gas production costs may remain low for many years to come, a carbon price of $150/t$CO_2$ recently proposed for 2030 by the CPUC (2017) would increase the effective natural gas price by $8/MMBtu, potentially making biogas more competitive.

Assuming that California imported no more than its population-weighted share of this biogas (currently ~12% of the U.S. population), up to ~2,400 MMcfd would be available, or ~50% of projected 2030 California gas demand (CA Utilities, 2016). However, as a fraction of projected U.S. demand in 2030 under the most recent reference scenario (EIA, 2017b),[8] the maximum biogas potential would represent ~25% of that demand, and may be a more realistic estimate of the fraction of biogas that could be provided to California.

Leakage

According to CARB/CPUC (2017), total natural gas emissions from gas utility facilities in 2015 were 6,601 MMcf, equivalent to ~2.96 Mt/yr CO_2, or about 7.5% of statewide methane emissions in 2014. A top-down revision to California's official methane leakage estimate from California's natural gas system in 2010 is 541±144 Gg/yr (Jeong et al., 2014), or ~1.3±0.3% compared to estimated total natural gas consumption of 43.0 Tg/yr (CA Utilities, 2010). With a 100-year global warming potential of 28-34 for methane (Myhre et al., 2013), this amount of leakage is equivalent to an additional ~11-23 Mt/yr CO_2 in GHG emissions.

It is unknown whether leakage from biomethane production facilities would be higher or lower than from the fossil natural gas system, but this is a significant concern that also needs to be explored.

Treatment and processing

Raw natural gas that is extracted from the ground needs to be cleaned in order to increase its quality for pipelines. Besides methane, which typically contributes 75%-90% by volume, raw natural gas also contains impurities including water, carbon dioxide, nitrogen, hydrogen sulfide, ethane, propane, butane, and some other hydrocarbons (Baker and Lokhandwala, 2008).

To meet pipeline specifications, natural gas is processed at a processing plant to remove impurities. According to www.NaturalGas.org (2013), the process is complex but usually involves four main removal steps:

1. Oil and condensates: If these impurities do not separate on their own, they are separated with a conventional separator where gravity separates heavier oil from lighter gases. If gravity is not successful, pressure is reduced to cool the gas and separate the remaining oil and condensates. These separators use pressure differentials to cool the natural gas, which travels through a high-pressure liquid at a low temperature to separate any remaining oil and water.

8. The EIA reference scenario projects 30.36 quads/yr of natural gas consumption in 2030, or ~80,200 MMcfd.

2. Water: This substance, which would otherwise cause corrosion and other issues, is mostly removed by the above separation methods. The remaining water vapor requires dehydration of natural gas. This treatment consists of either absorption, where a dehydrating agent chemically removes water vapor from the gas, or adsorption, where water vapor is condensed and collected on a surface.

3. Natural gas liquids (e.g., ethane, propane, butane): So-called because they are often pressurized and sold as liquids, these normally gaseous hydrocarbons are removed from natural gas using techniques similar to those for dehydration. While some amounts of higher hydrocarbons in natural gas are permissible (and contribute positively to the overall heating value), at sufficient scale these liquids are often extracted from natural gas and then separated by a process called fractional distillation, an energy-intensive process resulting in high-purity hydrocarbons that can be sold at a higher price.

4. Sulfur and carbon dioxide: Sulfur compounds (particularly hydrogen sulfide) can cause corrosion and can also be lethal to breathe. Called “sweetening” because of the “sour” (acidic) nature of both hydrogen sulfide and carbon dioxide, the process uses an amine solvent to react with and remove the acids, which are then released with heating or partial vacuum, regenerating the solvent. Hydrogen sulfide is removed first, followed by CO_2.

Other impurities can occasionally be present in a raw natural gas, including mercury and nitrogen. In addition to being toxic, natural gas plant operators want to remove mercury because it amalgamates with aluminum (commonly used in heat exchangers), resulting in mechanical failure and gas leakage (Corvini et al.). Nitrogen, on the other hand, lowers the heating value of natural gas and increases transport volumes (Linde, 2016).

Like natural gas, raw biogas is also accompanied by impurities. Raw biogas consists mainly of methane, with about 50% CO_2 by volume. Impurities that are typical for raw natural gas are also common for raw biogas. In addition, biogas may contain ammonia, chlorine and siloxanes in trace amounts, all of which must be removed.

The most commonly used cleaning methods are water scrubbing, pressure swing adsorption, chemical absorption, membrane permeation and cryogenic distillation. The first method removes carbon dioxide (as well as hydrogen sulfide) by taking advantage of the much higher solubility of these gases in water compared with methane. The pressure swing adsorption method removes carbon dioxide, nitrogen, and oxygen by capturing preferred gases in a molecular sieve (or other adsorbing medium) at a high pressure, and then releasing the adsorbates at lower pressure. While impurities are adsorbed, the methane is collected. The third method uses amine solvents to absorb carbon dioxide, as described above for natural gas sweetening. The membrane permeation method uses pressurization, where highly permeable gases, such as carbon dioxide, oxygen, water, travel through a membrane, while low-permeability methane is retained and collected. The last method, cryogenic distillation, was also described above, and takes advantage of the different boiling points of gases (Yang and Li, 2014).

Because of the lower amounts of multiple-carbon containing compounds (ethane, propane, etc.) in biogas as compared with natural gas, its heating value (after removal of impurities) is typically lower than that of natural gas, which can result in a higher volume of gas needed to achieve a given heating task.

Hydrogen

Production methods and costs

There are multiple ways of producing hydrogen: from water via electricity (electrolysis), from fossil or biomass resources (gasification, with steam reforming of methane as perhaps the best-known method), biologically (via microbial conversion), high temperatures (such as found in a nuclear power plant), or even directly from solar energy (photoelectrochemical).

According to Williams et al. (2013), the cost of producing hydrogen from natural gas via steam methane reforming varies from $3.50/kg for small systems to $1.25/kg at large scale, assuming a natural gas price of $6/GJ (~$6.3/MMBtu). Jechura (2015) estimated the cost of steam methane reforming hydrogen at $0.8/kg assuming $4.4/MMBtu and electricity at $68/MWh.

While steam methane reforming is the most cost-effective way of producing hydrogen, this approach emits CO_2 and must be coupled with CCS in order to make it GHG-neutral, increasing costs. Blok et al. (1997) estimated that adding CCS to steam methane reforming incurs a modest (~7%) cost penalty, because the reforming process already produces a concentrated stream of CO_2. In addition, more recent work with chemical looping to improve hydrogen production as well as CO_2 capture efficiency has been proposed (e.g., Martínez et al., 2014). Using hydrogen from biomass would avoid the need to capture CO_2, but it is likely more expensive than using biomethane directly.

Co-production of hydrogen and electricity from coal with CCS was explored by Kreutz et al. (2005); they concluded that hydrogen could be produced for $1.0/kg along with co-produced electricity at $62/MWh with 91% CO_2 capture using an integrated gasification combined cycle/CCS configuration.

For water electrolysis, Jechura (2015) estimated the cost of water electrolysis at $6.8/kg, whereas Ferrero et al. (2016) estimated that alkaline cell technology currently offers the lowest cost of producing hydrogen for grid injection at €3.8/kg (~$4.2/kg), but by 2030, all three technologies are projected to be able to deliver hydrogen for grid injection at €1.0-1.2/kg (~$1.1-1.3/kg). By comparison, the U.S. DOE has set a goal of $2/kg hydrogen wholesale cost in 2020, so this is a very competitive cost, considering that 1 kg hydrogen has the same energy content as 1 gallon of gasoline. However, 1 kg hydrogen is also equivalent to 0.135 MMBtu of natural gas, and at the current price of ~$3/MMBtu, it will be difficult for hydrogen to compete with an equivalent price of $0.4/kg.

At elevated temperatures, e.g., 800-1000°C, there is a significant reduction in required electrical energy input, estimated at up to ~30%. Also, conversion efficiencies are significantly higher (up to ~90%). Devices capable of running at these temperatures include solid oxide cells and various hybrid designs utilizing multiple chemical cycles such as sulfur-iodine, sulfur-bromine, sulfur dioxide-sulfuric acid ("hybrid" sulfur), and various metal-halogen cycles, with thermal energy typically supplied by rejected heat from a nuclear reactor (IAEA, 2013). Direct thermochemical decomposition to hydrogen and oxygen is only feasible at temperatures of 2,500°C, which is beyond the range of most industrial processes.

Photoelectrochemical conversion, while promising, is still at an early research stage (Ager et al., 2015).

Hydrogen blending

Hydrogen can be used in various ways. It can be blended with pipeline natural gas to a limited extent; see below for estimates. It can also be used in pure form in vehicles, electricity plants, industrial facilities, and buildings, though the latter use is probably very unlikely due to the challenge of developing a parallel hydrogen pipeline infrastructure to every building, much as natural gas is distributed today.

Hydrogen may require its own pipelines and storage to manage its use, though if capacity is freed up from reduced use of natural gas and UGS, some of it could potentially be repurposed for hydrogen. Alternatively, hydrogen could also be produced on-demand locally from electricity. However, this latter solution could further exacerbate the challenges associated with peak electricity demand periods.

Literature review showed different levels of acceptable hydrogen blending into natural gas pipelines (Altfeld and Pinchbeck, 2013; Melaina et al, 2013; Hodges et al., 2015). Chapter 2 provides additional references of real-world blending experience in the German, French and Dutch gas pipeline systems. The general conclusion is that a safe level of hydrogen is below 20%, and this maximum level should be assessed on a case-by-case basis, because pipeline systems vary considerably as far as pipeline materials, operating pressures, and state of repair. Here we present some technological, environmental and economic issues to be taken into consideration before hydrogen can be implemented on a large scale.

Some elements of the gas system, including many gas turbines, are very sensitive to variations in gas composition. Turbines that can accept more than 50% hydrogen fractions are rather exceptional; the majority of gas turbines can tolerate, after modifications, a maximum hydrogen fraction of 5% to 10% by volume (Altfeld and Pinchbeck, 2013).

Hydrogen embrittlement can damage steels by changing their mechanical properties. The embrittlement depends on many factors, including the hydrogen gas pressure, purity, temperature, exposure time, stress, and strain rate (Barthelemy, 2009). About 97% of natural gas transmission pipeline miles consist of cathodically protected, coated steels (Bipartisan Policy Center, 2014) that are generally not compatible with hydrogen. On the other hand, for more than 50% of distribution pipelines, plastic has become the pipeline material of choice (Bipartisan Policy Center, 2014), which is not susceptible to hydrogen embrittlement. However, some plastics can become brittle with age (Pipeline Safety Trust, 2011), potentially compromising their use with hydrogen. In summary, hydrogen may not be compatible with the vast majority of transmission-level pipelines, and its use in distribution-level pipelines must be approached with caution.

Hydrogen is a much smaller molecule than methane, so its leakage through pipe walls and joints poses safety and environmental risks. Here are some examples:

1. Hydrogen is a flammable gas, and although it is also very buoyant and therefore dissipates quickly, its leakage could pose an ignition hazard (Rusin and Stolecka, 2014). Moreover, hydrogen produces neither visible light nor smoke (Messaoudani et al, 2016). Existing natural gas detection devices also have different detection sensitivities, so they are not necessarily able to detect hydrogen (Altfeld and Pinchbeck, 2013).

2. In the U.S., the most common UGS fields are depleted gas or oil reservoirs (EIA, 2017b). Natural gas/hydrogen mixtures in depleted reservoirs (and also aquifers) could cause bacterial growth. Bacteria that feed on hydrogen can lead to partial or total disappearance of injected hydrogen. Furthermore, there is also a possibility for hydrogen sulfide production (Altfeld and Pinchbeck, 2013).

3. Hydrogen can potentially act as an indirect greenhouse gas because its emissions may decrease ozone concentrations, and increase the lifetime of methane through hydrogen reaction with hydroxyl radicals. Hydrogen has a global warming potential (GWP) of 5.8 over a 100-year time horizon (Derwent et al., 2006), compared to ~30 for methane and 1 for CO_2 (Myhre et al., 2013).

Finally, additional leak detection devices, modified turbines, upgraded domestic appliances, and other sensitive components would likely increase costs for natural gas systems due to increased levels of hydrogen. Van Ruijven et al. (2011) estimate that changing retrofitted natural gas pipelines to hydrogen infrastructure would be 50-80% more expensive.

Hydrogen storage

The three main types of UGS in use today are depleted gas/oil reservoirs, aquifers, and salt caverns. The same type of storage facility that is used for natural gas could be used for hydrogen. However, hydrogen is a small molecule that can leak from most materials, and has a strong chemical affinity to combine with other elements, which could possibly lead to losses or other undesirable issues, summarized as follows:

1. Hydrogen can affect salt permeability if gas is stored at a higher pressure than the confining pressure (Fokker, 1993).

2. Hydrogen can interact with sulfide, sulfate, carbonate, and oxide minerals that may be present in reservoirs or excavated caverns. At certain temperatures and pressures, chemical reactions could lead to production of toxic gases and the loss of hydrogen (Foh et al., 1979). If hydrogen is intended for membrane fuel cells or solid-state hydrogen storage, sulfur-based gases are especially harmful to these devices, as sulfur can poison them and decrease their efficiencies (Stone et al., 2009).

3. Hydrogen embrittlement, whereby metals meant to contain hydrogen become weakened, could be an issue if operating pressures and storage temperatures would increase above certain levels (Foh et al., 1979). However, the use of low-strength steels as well as plastic (e.g., PVC) materials obviates this problem (Melania et al., 2013).

4. In depleted oil/gas reservoirs, residual natural gas can affect hydrogen purity (Lord, 2009).

5. The mobility and viscosity differences between hydrogen and displaced fluid could lead to increased fingering and hydrogen losses (Carden and Paterson, 1979). A fingering pattern occurs when a more viscous material is displaced by a less viscous one (Homsy, 1987).

One of the main capital expenses of underground storage facilities is cushion gas, which must be present to provide a minimum operating pressure and is usually the same as the gas being stored ("working gas"). Cushion gas can consume up to 80% of the total gas capacity of the aquifer reservoir and 50% of the depleted gas/oil reservoir (Lord, 2009). Nitrogen[9] can be used as cushion gas as it is relatively inert to chemical reactions and it is considered cheap due to its abundance (Pfeiffer and Bauer, 2015). Carbon dioxide has also been proposed as a cushion gas, with the advantage that above 74 bar, it becomes supercritical

9. In salt caverns, nitrogen is sometimes also used as a blanket gas to protect the roof, but injection/withdrawal of the working gas is performed at greater depth to prevent mixing with the blanket gas.

and vastly decreases its volume, allowing more working gas to be stored (Oldenburg, 2003). This may allow more gas to be stored in the same volume. However, the use of a cushion gas different from the working gas can present separation challenges when the gas is withdrawn.

Synthetic Natural Gas

Synthetic natural gas (SNG) can be produced from fossil or biomass resources using thermochemical (as opposed to biological) conversion processes. If SNG is produced from fossil fuels, the net GHG emissions will be at least as high as ordinary natural gas, even if any excess CO_2 produced is captured and sequestered. An alternative, potentially lower-GHG route to SNG is to use CO_2 provided by other means (ideally captured from the atmosphere, or perhaps separated from biogas) along with hydrogen to produce methane thermochemically or electrochemically.

Making SNG from non-fossil inputs is generally more costly than making hydrogen, because of the additional step required for methanation (e.g., Benjaminsson et al., 2013).

An excellent overview of approaches for producing SNG can be found in Chandel and Williams (2009). For coal gasification, they found that the cost of producing SNG without CCS ranged from \$8.4 to \$9.5/MMBtu depending on the energy content of the coal. The coal cost was assumed to be ~\$1/MMBtu. With CCS added, the cost of SNG increased by ~\$1/MMBtu and ranged from \$9.2 to \$10.6/MMBtu. For biomass-based SNG, no CCS is required to keep GHG emissions low, but the higher cost of biomass plus additional capital hardware would drive the production cost of SNG to \$12/MMBtu with a biomass price of \$2.2/MMBtu.

Power-to-Gas

P2G is considered “one-way” electricity storage in that it can reduce electricity output when there is an excess, but other technologies must be used when generation is deficient, and P2G creates chemical fuels that must be utilized immediately or stored. P2G may be well-suited to excess renewable generation over multiple days, something that other types of electricity storage cannot do (storage capacities are limited due to cost, and in some cases, physical constraints of the storage medium).

The basic idea of P2G is to utilize electricity when it is plentiful (e.g., from daytime solar PV generation in excess of electricity demand) and convert it to chemical form—hydrogen or methane—for later use, similar to a battery. However, in addition to being able to re-convert the stored energy into electricity, unlike a battery the gas can be utilized directly in other applications. For a P2G plant producing methane (P2G-methane), the methane can be injected directly into the natural gas pipeline network. For a P2G plant producing hydrogen (P2G-hydrogen), the hydrogen can either be blended with natural gas and injected into the pipeline (subject to blending limits of ~10-20%), or utilized as pure hydrogen in fuel cell vehicles or other applications.

Power-to-gas hydrogen

P2G-hydrogen produces hydrogen from the electrolysis of water, with oxygen produced as a (usually discarded) byproduct. While commercial electrolysis systems exist, the technology is still maturing, with multiple approaches competing for future market share. The most common approaches that have been explored are alkaline, proton exchange membranes (PEM), and solid oxide electrolysis cells (SOEC) (Ferrero et al., 2016). Alkaline and PEM operate at temperatures of 40-90°C, whereas SOEC, which is not yet mature, operates at much higher temperatures (650-850°C) but offers higher efficiencies. Alkaline electrolysis is the most mature technology available with very different system size outputs, from 5 kW to 6 MW. The three largest P2G facilities are the RH2 WKA (1 MW) and Demonstration (2 MW) plants operated by EON, and the Solar Fuel Beta-Plant (6 MW), the world's largest P2G facility, operated by Audi (Gahleitner, 2013). PEM electrolysis is less mature than alkaline technology, with current plant capacities ranging from 1 to 56 kW (Gahleitner, 2013). As noted above, SOEC electrolysis is still at an early stage of development. However, SOEC systems ranging from as small as 1.5 kW and up to 220 kW can be found worldwide (Singhal, 2014). Current cost of hydrogen production ranges from €27 to €104/GJ (~$32 to $123/GJ) for grid injection, but are projected to drop to as little as €7/GJ (~$8/GJ) in 2030 (Ferrero et al., 2016).

Power-to-gas methane

P2G-methane is essentially a P2G-hydrogen plant with an additional methanation step whereby CO_2 (or sometimes CO) is combined with hydrogen to produce methane and water. Whereas water is inexpensive and readily available in most locations, obtaining CO_2 may be more difficult, as it is neither widely available nor cheap. About 33 million metric tons of CO_2 from naturally occurring underground sources in the Colorado Basin are used annually for enhanced oil recovery and food and chemical applications (Allis et al., 2001), but elsewhere, the most viable sources of CO_2 are either as a component of biogas (about 50% of anaerobic manure digestion and landfill gas is CO_2 by volume) (Götz et al., 2016), or via CO_2 capture from power plant or industrial facility flue gas (Boot-Handford et al., 2013). Direct CO_2 capture from air (Socolow et al., 2011; Lackner, 2013) or seawater (Willauer et al., 2014) is also a possibility. All these approaches are immature and, for air capture, inherently less efficient due to the low concentration of CO_2 in the atmosphere. Moreover, the net greenhouse gas (GHG) emissions of the CO_2 must be considered; of the options provided above, CO_2 from natural underground sources or captured from a fossil fuel-fired power plant would result in significant net GHG emissions, whereas CO_2 captured from biogas, biomass-fired power plants, or directly from the air or seawater would have net-zero GHG emissions. SCG (2014) has embraced P2G-methane and appears to favor using CO_2 from biogas.

Both Benjaminsson et al. (2013) and Götz et al. (2016) provide excellent reviews of available approaches for P2G-methane, which divide into catalytic and biological categories. Catalytic approaches are all based on the Sabatier reaction, first discovered in the early

20th century. Temperatures of 200-550°C and pressures of 1-100 bar are typically needed, along with a metal catalyst (Ni, Ru, Rh or Co, though Ni is most often used). Because heat is produced in the reaction, it must be removed. Higher pressures are more favorable, as they allow higher conversion efficiencies as well as removal of high-grade heat that can be used for generating electricity, or heating a SOEC if used. A number of approaches, including fixed-bed, fluidized-bed, three-phase and structured reactors, have been explored.

Biological routes take place under much milder conditions, typically 20-70°C and 1-10 bar, and utilize a variety of microorganisms, including the crucial hydrogenotrophic methanogens that convert hydrogen and CO_2 into methane and water. Typically, a stirred tank is used because the organisms require an aqueous solution to grow, but hydrogen solubility is much lower than CO_2 in water. Also, optimal growth conditions for methanogens is 65°C, where solubilities of both hydrogen and CO_2 are much lower than at room temperature; as a result, pressurized reactors are preferable. Because of the much slower reaction rates of biological approaches, conversion of hydrogen into methane is limited to ~80% under best current conditions, with ~20% remaining in product gases. However, Götz et al. (2016) note that further improvements are possible. For instance, Bensmann et al. (2014) have explored injecting hydrogen directly into biogas digesters in order to convert the produced CO_2 into additional methane, without the need for initial separation.

Götz et al. (2016) conclude that P2G-methane, estimated to cost between €11 to €167/GJ (~$13 to $197/GJ), is not currently competitive with natural gas or even biomethane, but this situation could change as capital costs decline with maturing technology, higher natural gas prices, strong climate policy that effectively raises the price of natural gas, or very low off-peak electricity prices.

Vehicle Fuel Shifting and Electrification

This section discusses the main technology alternatives to fossil-fuel-based combustion in the transportation sector.

Electric vehicles

Light-duty electric vehicles are rapidly growing in California, thanks in part to the Governor's Zero Emission Vehicle (ZEV, 2014) Action Plan whose goal is 1.5 million vehicles on the road by 2025. Thus far, Californians own 230,000 ZEVs, or 47% of all ZEVs in the U.S. ZEVs include pure battery electric vehicles, plug-in hybrid electric vehicles, and hydrogen fuel cell vehicles (see *3.4.3.5 Hydrogen vehicles*); currently the majority of ZEVs are electric vehicles (IWG, 2016). California is also part of a broader multi-state effort with seven northeast states to deploy 3.3 million ZEVs by 2025 (ZEV Program Implementation Task Force, 2014).

According to PluginCars.com (2017), there are currently 15 battery electric vehicle models in the U.S. market, ranging from 62 to 315 miles per charge, and 20 plug-in hybrid electric vehicles ranging from 12 to 53 miles per charge. Costs have now fallen to general consumer levels, with 14 of the available models for $35,000 or less, including the much-anticipated Tesla Model 3 with an all-electric range of 200 miles.

Much of the expense of electric vehicles is the battery, which has fallen remarkably since 2010, when it was estimated to cost $1,000/kWh for a complete battery pack. In 2015, this cost had fallen to $270/kWh, and Tesla claims its 60 kWh Model 3 complete battery pack will cost less than $190/kWh, with reductions to $100/kWh forecast by 2020 (Lambert, 2017).

For a 2015 compact passenger vehicle, Brennan and Barder (2016) found that the average cost for an electric vehicle was $29,164 versus $17,146 for a conventional internal combustion engine vehicle. For a 2015 mid-size passenger vehicle, the electric vehicle cost was $37,865 versus $19,114 for an internal combustion engine vehicle. However, lower energy and maintenance costs, as well as current subsidies for electric vehicle purchases, make electric vehicle ownership more attractive.

Electrification of medium- and heavy-duty vehicles is also under way. In addition to prototypes or pilots by companies such as FedEx (2016), Daimler (Lockridge, 2016), Nikola Motor Company (Davies, 2016) and Tesla (Stewart, 2017a), California is providing funding assistance to expand manufacturing facilities and conduct technology demonstrations for buses, trucks, and other freight vehicles (IWG, 2016). California is also pursuing partial electrification of equipment used in marine ports (CARB, 2017b), rail electrification (e.g, McGreevy, 2017), and heavy-duty truck electrification in transportation corridors with high air pollution such as I-710 between Long Beach and Los Angeles (CALSTART, 2013).

Hydrogen vehicles

Hydrogen vehicles have long been a priority for California, starting with Executive Order S-07-04 promoting a hydrogen highway network in 2004 (CalEPA, 2005). The ZEV Action Plan (IWG, 2016) encourages the use of hydrogen fuel cell as well as electric vehicles, and California is committed to building a network of 100 hydrogen fueling stations throughout the State by 2024, through the requirements of AB 8 (CalEPA/CARB, 2016).

Fuel cells can operate at much higher efficiencies than conventional combustion engines, and after conversion of hydrogen into electricity, vehicles operate similarly to electric vehicles. The DOE is working to overcome technical barriers to fuel cell development that currently limit cost, performance, and durability. As platinum is a major cost component of fuel cells, research currently focuses on reducing the amount of platinum needed in a fuel cell, as well as finding alternative catalyst materials (www.energy.gov/eere/fuelcells/fuel-cells).

There are currently three models of light-duty fuel cell vehicles available on U.S. markets (www.fueleconomy.gov/feg/fcv_sbs.shtml), with two of the models only available in California and one also available in Hawaii. However, these vehicles currently cost around $60,000 or more (Edelstein, 2016; Goodwin, 2016; King, 2016), which is very high compared with conventional vehicles. As a result, further cost reductions will be necessary before fuel cell vehicles can become competitive with electric vehicles.

Larger fuel cell vehicles are also in development. UPS plans to launch the world's first hydrogen fuel cell delivery truck in 2018 (O'Dell, 2017), and Toyota recently unveiled a prototype hydrogen-powered heavy-duty semi-truck. While Toyota's truck has a fully loaded range of only 200 miles as opposed to 1,000 miles for a diesel-powered vehicle, it is aiming for a shorter-distance market such as the Long Beach-Los Angeles corridor (Stewart, 2017b).

According to Greene and Duleep (2013), if fuel cell vehicles were manufactured at significant scale (200,000/year), the total vehicle cost would be $37,000 in 2016 and $33,200 in 2020, without any technology breakthroughs.

Natural gas vehicles

In the transportation sector, the majority of GHGs come from diesel-fueled vehicles. This is why policymakers in California are raising costs for diesel fleet operators through some existing and forthcoming regulations. According to comments from Southern California Gas Company (Rasberry, 2015), instead of paying these higher costs, heavy-duty vehicles could be converted from diesel to natural gas or even biogas, without harming California's economy. This conversion would lower GHGs, reduce nitrogen oxide and particulate matter emissions, and also help save money to vehicle owners.

Natural gas is available as Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG). The advantage of CNG over LNG is that it is produced locally, has a lower fuel cost, and does not evaporate if not used. The LNG process is more complex, as LNG has to be stored in special tanks, requires special refueling equipment, and needs to be used within a certain time to avoid tank venting (Agility, 2017). CNG is less dense than LNG, with a density of 215 kg/m^3 at 250 bar (Unitrove, 2017), as compared to ~450 kg/m^3 for LNG (GIIGNL, no date). As a result, LNG vehicles with the same tank volume have a greater driving range than CNG vehicles (Go With Natural Gas, 2014).

There are about 165,000 NGVs in the U.S. today (NGVAmerica, 2015) and 24,600 in California (Schroeder, 2015). Most of these are heavy-duty vehicles; only ~7,000 light-duty NGVs were available in the U.S. in 2014 (Davis et al., 2016). Of these light-duty NGVs, ~7% used LNG, with the remainder using CNG. There are more than 330 CNG refueling stations in Southern California, and more than 1,500 across the U.S. (Rasberry, 2015).

Sustained low prices for natural gas coupled with higher and more volatile gasoline and diesel prices have accelerated market adoption of natural gas vehicles, particularly in heavy-duty markets (Schroeder, 2015). According to DOE (2017), the recent average national retail CNG cost was $2.43 per gallon diesel equivalent (GDE), cheaper than either diesel or gasoline. For LNG, the cost was slightly higher at $2.52/GDE, nearly the same as that of diesel ($2.55/GDE).

In the U.S., in 2013, the retail price of a Honda Civic that was designed and built to run on natural gas was $23,300, versus a gasoline-fueled Honda Civic at $18,000. The Ford F250 pickup truck that was designed to run on gasoline but converted after-market to natural gas cost $43,500, versus $34,000 for the gasoline version (Yip, 2014).

Building Electrification

While research on building electrification is more nascent, the Sacramento Municipal Utilities District (SMUD) published a ground-breaking report in 2012 concluding that a large subset of residential and commercial building end uses in California could be electrified with payback periods of 10 years or less (ICF International, 2012). In the residential sector, these technologies were heat-pump-based water heating (10 years), space heating (7 years) and pool heating (1 year), and various electric cooking technologies (1 year). In the commercial sector, the technologies were ground-source heat pump-based space heating (6-8 years), and solar water heating with electric backup (2-4 years). The report concluded that "heat pump heating and heat pump water heating should be prioritized for electrification programs because these technologies are cost effective, do not have significant technical or societal barriers, and have significant GHG emission reduction potential" (ICF International, 2012, p. ii). While these conclusions are specific to the SMUD regional climate, they may be applicable to other regions of California as well. A recent report by Raghavan et al. (2017) concluded that residential electric heat pump water heaters were feasible in California, with significant GHG benefits.

Appendix 3-3: Recent Federal and State Policies

Federal Policies Relevance to Natural Gas Use and Storage

About half of the country's 415 UGS facilities fall under FERC authority; the rest are regulated by state entities (Interagency Task Force, 2016). Therefore, both state and federal policies could be important to the future of UGS in California.

FERC Policy on Storage Development

FERC's long-held general policy, demonstrated in multiple orders, is that more storage, whether new or expansion of existing, is better. What this means for California is that if there is a new interstate storage project that might be constructed in California, or if there is new interstate storage planned in other adjacent states that could substitute for new UGS in California (connected to CA markets via pipelines), FERC would do everything in its jurisdictional authority to ensure such proposals would be considered, approved as appropriate, and placed into service.

As noted in FERC Order No. 678 (FERC, 2006), FERC clearly pointed out that there are “efforts already underway at the Commission to adopt policy reforms that would encourage the development of new natural gas storage facilities while continuing to protect consumers from the exercise of market power.” Further, in Order No. 678, FERC notes that it “is amending its regulatory policies in the Final Rule in order to facilitate the development of new natural gas storage capacity to ensure that adequate storage capacity will be available to meet anticipated market demand and to mitigate natural gas price volatility.”

In light of the CPUC’s consideration of eliminating Aliso Canyon as a UGS provider in California, FERC jurisdictional storage facilities could play a key role in providing much-needed UGS as a bridge to a future based on renewables.

PHMSA Interim Final Rule

On December 14, 2016, the U.S. Department of Transportation’s (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Interim Final Rule that revises pipeline safety regulations. The Final Rule specifically addressed safety issues related to UGS by including regulations on well integrity, wellbore tubing, and casing. More information is available about this Final Rule in Chapter 2, *How will new integrity and safety rules affect natural gas reliability?*

As a response to the Aliso Canyon incident and public concern, Section 12 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act charged PHMSA to develop a minimum federal safety standard for all UGS (PHMSA, 2016). The Final Rule incorporates two Recommended Practices from the American Petroleum Institute, API RP 1170 and 1171. The first concerns “Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage” and the second addresses “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs.” Both create safety standards for risk management and require reporting of significant incidents (PHMSA, 2016). However, PHMSA announced on June 20, 2017, that it would not be enforcing parts of their newly written regulations on natural gas storage facilities while they consider a petition to change the rules (PHMSA, 2017).

California Energy System Goals Policies Relevant to Natural Gas Use and Storage

Statewide GHG targets and cap-and-trade programs

Executive Order S-3-05: 2050 GHG target (80% below 1990 level)

On June 1st 2005, Governor Arnold Schwarzenegger released Executive Order S-3-05 which created a new target for greenhouse gas emissions. According to the document, by 2020, GHG emissions should be reduced to 1990 levels, and by 2050 they should be reduced to 80% below 1990 levels (Office of Governor Edmond G. Brown Jr., 2005). In addition, this executive order creates the Climate Action Team and appoints the Secretary of Cal/EPA to coordinate plans for meeting these targets with the help of other State agencies.

AB 32 (Pavley, 2006): 2020 GHG target (100% of 1990 level) and cap & trade policy

The Global Warming Solutions Act of 2006 (AB 32) codifies part of Executive Order S-3-05, requiring California to reduce its GHG emissions to 1990 levels by 2020. The bill gives the Air Resources Board (ARB) the authority to develop regulations that would help achieve this goal (CALI, 2006a). Apart from using a regulatory approach, ARB has also used a market approach through cap and trade. Cap and trade is a program that puts a limit on the amount of GHG emissions and enforces this limit by placing penalties on companies that exceed it. If companies opt to release more GHG, then they are able to buy and trade allowances through an auction system (CARB/CalEPA, 2014).

SB 32 (Pavley, 2016) and AB 197 (E. Garcia, 2016): 2030 GHG target (40% below 1990 level)

SB 32 set a new target for the ARB. This bill requires the board to reduce GHG emissions to 40% below the 1990 level by 2030 (CALI, 2016b). The bill was paired with AB 197, which gives the Legislature oversight over ARB when adopting regulations. This bill does not authorize the extension for ARB to utilize cap and trade, but it does provide the mechanisms that are needed to reach the goals in SB 32 (Office of Governor Edmund G. Brown Jr., 2015a).

SB 32 codified Executive Order B-30-15 issued by Governor Brown in April 2015.

AB 398 (E. Garcia, 2017): Cap and trade extension to 2030

On July 25, 2017, AB 398 was approved by Governor Brown, giving the ARB the explicit authority to establish and utilize a cap and trade program through 2030. The bill also requires ARB to update their scoping plan by January 2018. In relation to storage, AB 398 provides tax exemptions for buildings and foundations used for the generation, production, or storage of electric power. It also gives tax exemptions for those who purchase property or equipment for the use of generation, production, or storage and distribution of electric power (CALI, 2017b).

AB 617 (C. Garcia, 2017): Nonvehicular air pollution: criteria air pollutants and toxic air contaminants

As part of the cap and trade package, AB 617 was approved by the Governor on July 26, 2017. The bill addresses air quality standards as it pertains to the California cap and trade program. The purpose of the bill is to systemize a standard reporting system for air pollutants and Toxic Air Contaminants. It creates a system for implementing control technology for pollutants and increases penalties for certain types of pollutants (CALI, 2017c).

California Energy System Means Policies Relevant to Natural Gas Use and Storage

Underground gas storage

State of California RFP on Eliminating Aliso Canyon Storage Facility

On June 16, 2017, the California Public Utilities Commission (CPUC) issued notice that it is requesting public comment on the Aliso Canyon Reliability and Economic Analyses draft pre-solicitation on a plan to study the potential for eliminating the Aliso Canyon UGS facility (CPUC, 2017a). One key matter in the request for proposal (RFP) concerns estimating the impact of the reduction or elimination of the ability to use the Aliso Canyon UGS facility to store gas bought in the off-season for winter use and avoid or reduce spot market purchases on peak days. This issue is discussed in detail in Chapter 2.

Specifically, the CPUC asks “should the commission reduce or eliminate the use of the Aliso Canyon storage facility, and if so, under what conditions and parameters, and in what time frame?”

The CPUC did not receive any proposals for their original RFP. A second RFP was issued on September 11, 2017 with proposals due on October 16, 2017. (DGS, 2017).

Letter from Chair Weisenmiller

In response to the RFP, the Chair of the California Energy Commission (CEC), Robert Weisenmiller, released a letter to the President of the CPUC on July 19, 2017. Chair Weisenmiller addressed his concerns about California’s dependency on fossil fuels and what that means for California’s climate goals. Chair Weisenmiller urged the CPUC to plan for the permanent closure of Aliso Canyon. He stated that his “staff is prepared to work with the CPUC and other agencies on a plan to phase out the use of the Aliso Canyon natural gas storage facility within ten years” (CEC, 2017a).

In addition, Chair Weisenmiller specifically addresses this report in relation to the Governor’s 2016 emergency proclamation. He acknowledges that a study on the long-term viability of all natural gas storage facilities in California is being conducted by CCST, and this report “will inform how the state will rethink all natural gas storage facilities in California” (CEC, 2017a).

Electricity generation

SB X1-2 (Simitian, 2011): Prior renewable portfolio standard targets 33% by 2020

The California Energy Commission reviews the amount of renewable energy capacity being installed in California and updates the legislature on the progress being made toward the state's renewable energy goals. These goals are referred to as the State's renewable portfolio standard (RPS) targets (CEC, *Renewables Portfolio Standard*). The RPS goal was originally set in 2002 as a 20% requirement by 2017. In April 2011, Governor Brown signed Senate Bill X1-2 to approve a new target for renewables set at 33% by 2020 (CALI, 2011).

SB 350 (De Leon, 2015): 50% RPS in 2030

In October 2015, Governor Brown signed Senate Bill 350 to put into law a requirement to serve 50% of California's electricity use with renewable energy resources by 2030. This increased the RPS from 33% by 2020 to 50% by 2030 (CALI, 2015).

SB 100 (De Leon, 2017): California Renewables Portfolio Standard Program: Emissions of greenhouse gases

If passed, this bill creates a 100% zero-carbon resource electricity generation portfolio target. It would increase the current 2030 target from 50% to 60%, and increase that target to 100% by 2045 (CALI, 2017a). Note that the term "zero-carbon resource" would include generation technologies other than renewable electricity, such as nuclear power.

AB 2514 (Skinner, 2010): Energy storage systems

AB 2514 was passed and signed into law by Governor Brown in September 2010. The bill gives the CPUC the authority to set targets for load serving entities to obtain energy storage systems. The targets deemed appropriate by the CPUC would have to be adopted by 2015 and 2020. In addition, publicly owned utility companies are required to set their own energy storage targets and see that those targets are reached by 2016 and 2021 (CALI, 2010). In October 2013, in response to AB 2514, the CPUC established energy storage goals for utilities. In D. 10-03-040, the CPUC established a target of 1,325 megawatts of energy storage by 2020. This target applied to three investor-owned utility companies—PG&E, Edison, and SDG&E. Each company is required to install energy storage capacity by no later than the end of 2024 (CPUC, 2017b). However, the goal did not specify the required number of hours of storage (or, equivalently, the energy capacity in MWh), which is necessary to determine how much storage capacity is actually needed. For example, assuming eight hours of storage are required, the goal would imply 10,600 MWh of storage capacity would be built. If only one hour of storage on average is required, this capacity would be much lower (1,325 MWh).

SB 1368 (Perata, 2006): Imported coal phase-out

This bill began the process of phasing out coal production in California by establishing the emissions performance standard which applies to baseload generation owned by or under long-term contract to a utility that serves California (CALI, 2006b). As a result, 3,463 MW of coal-fired electric generation capacity was removed from California between 2006 and 2016 (CEC, 2016a). The CEC projects that coal fired generation will serve less than 3 percent of California's electricity consumption by 2024 and is expected to reach zero consumption by 2026.

Once-through cooling phase-out

In October 2010, a once-through-cooling policy was adopted by the State Water Resources Control Board (SWRCB) as a response to the Clean Water Act. This policy was created as a method of improving water quality goals while also ensuring electricity grid reliability. The SWRCB worked closely with the CEC, CPUC, and CAISO to develop a policy that specifically required 19 of California's power plants to switch to closed-cycle evaporative cooling, because it was the best available technology at the time (CEC, 2017b). Closed-cycle evaporation cooling refers to a system that transfers waste heat to the surrounding air through water evaporation instead of transferring that waste to surrounding oceans, rivers, and lakes. Each plant has the option of either reducing their intake flow rate to a level that can be attained by this technology or using operational or structural controls to reduce "impingement mortality and entrainment" for the facility as a whole to 90% of option 1. If neither option worked, the plant has the option of shutting down. Between 2010 and 2029, all California power plants are scheduled to comply. Most have plans to retire, while others have plans to repower (CEC, 2017b).

Nuclear phase-outs: San Onofre Nuclear Generating Station (SONGS) and Diablo Canyon Nuclear Power Plant

There are two nuclear power plants in California that have once-through-cooling (OTC) technologies, SONGS and Diablo Canyon. The two plants made up 55% of all OTC water use. In January 2012, SONGS was shut down because the stream generator had tube leaks (CEC, 2017b). Due to the cost of repairs, Southern California Edison announced the permanent retirement of SONGS in June 2013. In August 2016, PG&E announced to the CPUC that they would be retiring Diablo Canyon by 2025. PG&E worked with numerous groups including labor, environmental, and community advocacy organizations to develop this proposal to shut down its plant (CEC, 2017b). The phasing out of these two facilities indicates a move towards nuclear power phase-outs in California.

SB 338: Integrated resource plan: peak demand.

Currently, the California Public Utilities Commission (CPUC) must adopt a process for each load-serving entity to file an integrated resource plan and a schedule for periodic updates to the plan to ensure that the load-serving entity meets California's greenhouse gas emission reduction targets and the requirement to procure at least 50% of its electricity from eligible renewable resources by December 31, 2030. SB 338 (CALI, 2017f) requires the CPUC and the governing boards of local publicly owned electric utilities to consider, as part of the integrated resource plan process, the role of distributed energy (DE) resources and other specified energy- and energy-related tools. This will help to ensure that each load-serving entity or local publicly owned electric utility, as applicable, meets energy and reliability needs, while reducing the need for new electricity generation and new transmission in achieving the State's energy goals at the least cost to ratepayers.

Fuels

Low-carbon fuel standard (LCFS)

The LCFS was created in 2007 by Governor Schwarzenegger's Executive Order S-01-07. The Executive Order establishes a statewide goal to reduce carbon emissions from California transportation fuels by 10% by 2020 (Office of Governor Edmund G. Brown Jr., 2007). The transportation industry is responsible for 40% of GHG emissions. The authority was given to the ARB to determine whether a LCFS could be adopted as a means of reaching the emissions goals set by AB 32. The order allows ARB to use a market-based approach to regulate GHG emissions from the transportation industry. The LCFS requires producers of petroleum-based fuels to reduce the carbon emissions of their products either through technological improvements or by purchasing LCFS credits from companies that sell low carbon alternative fuels like biofuels, electricity, natural gas, or hydrogen (CEC, 2017c). The goal of the program is to reduce dependency on petroleum and reduce the emissions of other air pollutants.

Governor Brown's 2015 State of the State Address: Reduce today's petroleum use in cars and trucks by up to 50 percent

In Governor Brown's 2015 State of the State Address, he stated his commitment to reducing petroleum use in cars and trucks by up to 50% by 2030 although no legislation has been passed to accomplish this goal (Office of Governor Edmund G. Brown Jr., 2015b).

Executive Order S-06-06, Imported biofuels: 75% in-state production

In April 2006, Governor Schwarzenegger released Executive Order S-06-06 that sets California targets to increase the use of bioenergy (Office of Governor Edmund G. Brown Jr., 2006). The order requires State agencies to work together to increase the use of biofuels to 40% by 2020 and 75% by 2050. Furthermore, in a study conducted by CCST in 2013 entitled *California's Energy Future-The Potential for Biofuels*, one of the conclusions reached by the study is that in-state biomass is not sufficient to reach liquid fuel and gaseous fuel demand in 2050 and therefore would be supplied by imported biofuels. Imported biofuels from out of State or country would allow for a cheaper alternative to meet the State's GHG reduction goals (CCST, 2013).

AB 1900 (Gatto, 2012) on biomethane

AB 1900 required the CPUC to identify components of landfill gas and develop testing procedures for biomethane that is injected into common carrier pipelines. Specifically, this bill called upon the CPUC to adopt standards for biomethane that is to be injected into common carrier pipelines (CALI, 2012). This standard was put in place to ensure the gas meets pipeline safety and integrity requirements. In response to the bill, the CPUC released decision 14-01-034 in January 2014. The decision outlines the 17 compounds of concern found in biomethane and establishes concentration standards for each element before it could be injected into the utilities' gas pipeline system (CPUC, 2014).

SB 433 (Mendoza, 2017): Gas corporations: zero-carbon and low carbon hydrogen

SB 433 would give the Public Utilities Commission (PUC) the authority to allow gas corporations to obtain zero-carbon hydrogen or low-carbon hydrogen to serve consumers (CALI, 2017d). This bill would authorize gas corporations to recover in rates the reasonable cost of pipeline infrastructure developed to deliver and transport the zero-carbon or low carbon hydrogen (CALI, 2017d). Furthermore, SB 433 would give the State Air Resources Board, the CPUC, and the State Energy Resources Conservation and Development Commission the authority to approve the production of zero-carbon or low-carbon hydrogen for its intended purposes (CALI, 2017d). SB 433 did not pass through the Assembly Committee on Utilities and Energy, but may be re-introduced during the next legislative cycle.

Vehicle efficiency and electrification

AB 1493 (Pavley, 2002): standards for light-duty vehicles

AB1493 requires the ARB to develop and adopt regulations to achieve cost effective reductions in GHG emissions from passenger, light-duty, and other noncommercial vehicles (CARB/CalEPA, 2007). The bill took effect in 2006 and applied to vehicles manufactured from 2009 to 2016. ARB originally approved regulations required by the bill in 2004, however, these regulations received push back from the automaker industry (CARB/CalEPA, 2017b). An agreement was reached in May 2009 that allows for compliance flexibility from manufacturers. The original regulations added four new contaminants to the criteria for toxic air contaminant emission from vehicles- carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. The ARB estimates that the motor vehicle greenhouse gas emissions standards will reduce GHG emissions by approximately 30 million metric tons in 2020 and 50 million metric tons in 2030. This constitutes an 18% reduction in emissions from passenger cars 2020 and a 27% reduction in 2030 (CARB/CalEPA, 2007).

Zero Emission Vehicles (ZEV) Action Plan

In Governor Brown's Executive Order B-16-12, the Governor orders the State government to support and assist the accelerated commercialization of ZEVs. The Executive Order sets a target for 1.5 million ZEVs on the roads by 2025. It gives State agencies the task of building the infrastructure for these vehicles and encouraging the growth of ZEVs within the manufacturing and private sectors as well (Office of Governor Edmund G. Brown Jr., 2012). The 2016 Action Plan (IWG, 2016) highlights the progress made by agencies to implement ZEVs within the State market and also outlines the future steps agencies will take in order to achieve the goals set by the Governor's Executive Order. In the summer of 2016 there were more than 230,000 ZEVs on the road in California. Moving forward, State agencies plan on raising consumer awareness and education about ZEVs, focusing on building infrastructure to improve ZEV accessibility, broadening ZEV technology in order to reach consumers who are interested in larger vehicles, and aiding ZEV expansion beyond California (Office of Governor Edmund G. Brown Jr., 2016).

Medium and heavy-duty GHG emissions

In October 2016, the ARB collaborated with the U.S. Environmental Protection Agency (U.S. EPA) and National Highway Traffic Safety Administration (NHTSA) to develop federal Phase 2 standards for GHG emissions for medium and heavy duty vehicles. While Phase 1 focused on manufacturing improvements in engine and vehicle efficiency, Phase 2 would establish technology that could allow for the creation of standards for engines and vehicles (CARB/CalEPA, 2017c). These standards would continue to increase GHG reduction goals from Phase 1 standards. ARB plans to propose California Phase 2 implementation in late 2017 (CARB/CalEPA, 2017c).

AB 8 (Perea, 2013) and Executive Order S-07-04 promoting a hydrogen highway network

In April 2004, Governor Schwarzenegger released Executive Order S-07-04, which established the California Hydrogen Highway Network (CaH2Net). The purpose of the Executive Order was to ensure the infrastructure for hydrogen vehicles was in place to support the growing number of hydrogen vehicles on the road. The California EPA developed a Blueprint Plan outlining the steps needed in order to implement the CaH2Net (CARB/CalEPA, 2016a). The plan set the foundation for California's hydrogen achievements and allowed for both industry and government coordination for policy development. With the passage of AB 8 (CALI, 2013), California's ability to implement a hydrogen fuel station network was accelerated. AB 8 dedicates up to $20 million per year to developing the infrastructure needed for hydrogen fueling stations (CARB/CalEPA, 2016a). This initiative is funded through the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). This will enable more fuel cell electric vehicles (FCEVs) and zero emission vehicles (ZEVs) to play a larger role in meeting California's emission reduction goals.

Advanced Clean Transit initiative and Innovative Clean Transit measure

The Advanced Clean Transit initiative is a measure proposed by the California Air Resources Board that would incentivize transit fleets to switch to more fuel-efficient technologies (CARB/CalEPA, 2016b). The initiative would allow for transit companies to slowly integrate advanced technologies within their existing operations creating space for renewable fuels or advanced technologies to help reduce emissions. The types of advanced technologies available vary from zero emission battery electric and fuel cell electric buses to hybrid buses and clean combustion engines. As of June 2016, there were 88 zero-emission battery electric and fuel cell electric buses operating in California, and 162 more were on order. The Advanced Clean Transit measure has been expanded to include such things as near-term operations of zero-emission buses and renamed as the Innovative Clean Transit measure (CARB/CalEPA, 2017a).

California Sustainable Freight Action Plan

Evolving from Executive Order B-32-15, California released the *California Sustainable Freight Action Plan* in 2016. The plan was a joint effort by the California State Transportation Agency, California Environmental Protection Agency, Natural Resources Agency, California Air Resources Board, California Department of Transportation, California Energy Commission, and Governor's Office of Business and Economic Development. It provides a long-term vision of California's transition to a more efficient, more economically competitive, and less polluting freight transport system. It includes near-term strategies and targets for 2030 and 2050.

Near-term guiding principles include three pilot projects (Dairy Biomethane for Freight Vehicles, Advanced Technology for Truck Corridors, Advanced Technology Corridors at Border Ports of Entry) and steps for progress towards the Plan's vision. Targets for 2030 include: improving freight system efficiency by 25%, deploying over 100,000 freight vehicles and equipment capable of zero-emission operation, maximizing near-zero emission freight vehicles and equipment powered by renewable energy, and increasing state competitiveness and fostering future economic growth within the freight and goods movement industry.

Overall, State agencies recognize potential contributions from several measures: (1) Development and use of nonpetroleum-based transportation fuels such as diesel and gasoline substitutes, biomethane, renewable hydrogen, and renewable electricity; (2) Injection of biomethane into natural gas pipelines; (3) New technologies to increase vehicle efficiency; (4) Research, demonstration, and deployment of fuel cell electric and hybrid vehicles; (5) Continued investment in next-generation engines; (6) Integration of advanced energy storage technologies with transportation electrification; (7) Information technology management systems; (8) Enhanced traffic management technology; (9) Utilization of additional renewable electricity generation for fueling ZEVs and equipment in the freight sector; and (10) Developing a natural gas vehicle research roadmap to identify opportunities for integrating low-carbon renewable natural gas into California's medium- and heavy-duty fleets.

California Mobile Source Strategy

California's *Mobile Source Strategy* (ARB, 2016) demonstrates how the State can simultaneously meet air quality standards, achieve GHG emission reduction targets, decrease health risk from transportation emissions, and reduce petroleum consumption by 50%, all by 2030. ARB estimates that these actions would have a negligible impact on the California economy, with Gross State Product slowing by 0.051%/yr between 2023 and 2031.

The actions in the report support numerous efforts at the state level, including: (1) Modernizing and upgrading transportation infrastructure; (2) Deploying cleaner vehicle technologies; (3) Increasing engine performance standards and fuel efficiency; (4) Incentivizing funding to achieve further ZEV deployment; (5) Increasing renewable electricity generation to 50%; (6) Increasing use of renewable fuels (renewable diesel from biomass, NO_x-mitigated biodiesel, renewable natural gas from biomethane, gas to liquid diesel from biomethane, renewable hydrocarbon diesel, and/or co-processed renewable hydrocarbon diesel); (7) Reducing growth in vehicle miles traveled; and (8) Increasing worksite efficiencies. More precisely, the number of plug-in hybrid electric and noncombustion zero-emission passenger vehicles, including battery-electric and hydrogen fuel cell vehicles, would increase by over 50% compared to current programs. Internal combustion engine technology for heavy-duty vehicles would also be 90% cleaner than today's standards, with renewable fuels comprising 50% of fuels burned.

Building efficiency and electrification

IOU efficiency goals

In a 2004 decision, (D.) 04-09-060, the California Energy Commission set energy efficiency goals for investor-owned utilities (IOUs) programs (CPUC, 2004). These goals are referred to as the Energy Action Plan. There are four main objectives for the Energy Action Plan. The first is to provide guidance for the IOU programs next energy efficiency portfolios. This means that based on the outline provided for developing an energy efficiency goal, the CPUC is able to use this decision as a baseline for adopting annual and ten-year goals for electric and natural gas savings (CPUC, 2013). This also allows the utilities to create their own portfolios, which are measured and evaluated by the Energy Division. The second objective of the decision is to update the forecast for energy procurement planning by integrating the IOUs' energy efficiency goals. The third is to help inform California's future GHG reduction targets. The fourth, and last, is to have the Energy Action Plan set benchmarks for shareholder incentives (CPUC, 2013).

Title 24 standards

The California Building Standards Code, also known as Title 24, is a California Code of Regulations that sets standards for constructing buildings in California. It is comprised of twelve parts that sets regulations on all different aspects of building, including mechanics, plumbing, electric, and energy codes (DOE, 2017). The main purpose of each code is to ensure safety standards in order to safeguard building occupants. Within part 6 of the Energy Code, there are efficiency standards that newly constructed buildings, additions, alterations, and repairs are subject to. This means that there is a limit to how much energy a building can consume under the restrictions of Title 24 (DOE, 2017). In 2004, Governor Schwarzenegger signed Executive Order S-20-04, also referred to as the Green Building Initiative. This Executive Order set regulations in place that would improve energy efficiency within nonresidential buildings. The goal was to decrease the energy use of nonresidential buildings by 20% in 2015. In addition, in 2010 the California Green Building Standards Code was added to Title 24. This code requires that new buildings reduce water consumption, increase system efficiencies, divert construction waste from landfills, and install materials that would decrease the amount of pollutants emitted into the atmosphere (DGS, 2010). The purpose is for the code to help achieve GHG emission reduction goals by 2020 and possibly beyond. Title 24 standards are currently updated every three years.

California appliance efficiency standards

The Appliance Efficiency Regulations, also known as Title 20, are regulations that set standards for energy consumption for both federally and non-federally regulated appliances (DOE, *Appliance Efficiency Regulations*). Title 20 was established in 1976 in response to the Warren-Alquist Act, which charged the CEC to develop efficiency standards to reduce California's energy consumption (DOE, 2017). They are updated periodically based on new technologies and efficiency methods.

SB 350: Doubled building efficiency in 2030

SB 350 (De Leon, Chapter 547, Statutes of 2015) requires the CEC to establish statewide energy efficiency targets that will double energy efficiency savings in electricity and natural gas final end uses by 2030 (CALI, 2015). The CEC will do so to the extent that it is cost effective, feasible, and does not negatively impact public health and safety. The CEC has held multiple workshops to discuss the best approach to doubling energy efficiency targets. They held workshops in January 2017 and plan to publish a draft of their analysis in late summer of 2017 (CEC, *Doubling Energy Efficiency Savings*). As per SB 350, the CEC is scheduled to establish their targets by November 1, 2017.

Zero net energy buildings policy: residential (2020) and commercial (2030)

In SB 1389 (Bowen and Sher, Chapter 568, Statutes of 2002), the CPUC was charged with developing energy policies that promote energy reliability while also conserving resources, conserving the environment, enhancing the economy, and protecting public health and safety (CALI, 2002). In response, the CPUC established the Integrated Energy Policy Report, which is updated every two years to reflect changing energy technologies. The goal that the CPUC set is for all new residential buildings in California to produce zero net energy by 2020 (CPUC/CEC, 2015) and for all new commercial construction to produce zero net energy by 2030 (CEC, 2007). The CPUC worked closely with the State's IOUs in order to develop an Action Plan to achieve their goals. The 2019 building energy efficiency standards (Title 24) pre-rulemaking is in active discussion at the CEC and among public stakeholders as of the time of this writing (Summer 2017). Title 24 compliance can be met for both mixed-fuel (electricity and natural gas) and all-electric homes.

The current proposed approach for mixed-fuel homes is to maximize cost-effective building envelope efficiency, and to establish a minimum rating for energy efficiency in each climate zone that can only be met with efficiency measures (thus, there is no provision for increased solar PV to substitute for a lower level of efficiency) (Shirakh, M., C. Meyer, B. Pennington, 2017). The PV system will be sized prescriptively to displace the annual site electricity use (in kWh) of the mixed-fuel home. There is currently no requirement for low-carbon gas (e.g., biomethane) or a larger-sized PV system to offset the site-level natural gas fuel consumption in a mixed-fuel home.

For all-electric homes, minimum building shell energy efficiency measures would be similar to those for mixed-fuel homes, and the current proposal is for the PV system to be sized to that of a mixed-fuel home of equivalent area (Shirakh, M., C. Meyer, B. Pennington, 2017). Requiring a larger PV system is currently not preferred, because it could discourage all-electric home construction and also exacerbate issues with California's net load.

AB 758

According to Assembly Bill 758 (Skinner, Chapter 470, Statues 2009), the CEC and CPUC must work together to address the best methods to improve energy efficiency within existing residential and nonresidential buildings (CALI, 2009). In 2016, the CEC released a new Existing Building Energy Efficiency Action Plan, which incorporates the goals set by Senate Bill 350 to double energy efficiency savings. The plan includes programs that would use market mechanisms to change existing commercial, residential, and public buildings to more energy efficient buildings (CEC, 2016b).

Other policies

SB 1383 (Lara, 2016): Short-lived climate pollutants (SLCPs)

SB 1383 directs the ARB to approve and implement a plan to reduce emissions for short-lived climate pollutants (SLCPs) by 2030 (CALI, 2016c). SLCPs are different from long-lived pollutants like carbon dioxide not just because they stay in the atmosphere for a shorter period of time, but because they have the potential to heat the atmosphere in greater measures compared to long-term pollutants (CARB/CalEPA, 2017d). Short-lived pollutants include methane, hydrofluorocarbons, and black carbon. SB 1383 requires a 40% reduction in methane and hydrofluorocarbon gases by 2030 and 50% reduction in black carbon by 2030. In addition, it establishes procedures to reduce SLCP emissions from dairy and landfill sources (CALI, 2016c). ARB's SLCP Reduction Strategy was approved in March 2017.

AB 726 (Holden, 2017): Energy

AB 726 would authorize the transformation of the California ISO into a regional organization if the ISO governing board undertakes certain steps and the Commission on Regional Grid Transformation, created by the bill, makes specified findings by December 31, 2018. The bill would make inoperative other provisions of existing law relating to the ISO entering into a multistate entity or transforming into a regional organization unless the Commission on Regional Grid Transformation does not make the specified findings by that date. (CALI, 2017e). AB 726 did not pass through the Senate Rules Committee, but may be re-introduced during the next legislative cycle.

References for Appendix 3.3

CARB (California Air Resources Board)/ CalEPA (California Environmental Protection Agency), 2007. *Climate Change Emissions Standards for Vehicles*. Retrieved from https://www.arb.ca.gov/cc/ccms/factsheets/ccfaq.pdf

CARB/CalEPA, 2014. *Assembly Bill 32 Overview*, August 5. Retrieved from https://www.arb.ca.gov/cc/ab32/ab32.htm

CARB/CalEPA, 2016a. *Historical Activities, Hydrogen Vehicle Infrastructure*, July 15. Retrieved from https://www.arb.ca.gov/msprog/zevprog/hydrogen/hydrogen_cah2net.htm

CARB/CalEPA, 2016b. *Advanced Clean Transit Reducing Emissions from Transit Fleets*, July 28. Retrieved from https://arb.ca.gov/msprog/bus/faqactoverview_1.pdf

CARB/CalEPA, 2017a. *Innovative Clean Transit*, June 5. Retrieved from https://arb.ca.gov/msprog/ict/ict.htm

CARB/CalEPA, 2017b. *Clean Car Standards- Pavely, Assembly Bill 1493*, January 11. Retrieved from https://arb.ca.gov/cc/ccms/ccms.htm

CARB/CalEPA, 2017c. *CA Phase 2 GHG*, July 28. Retrieved from https://www.arb.ca.gov/msprog/onroad/caphase2ghg/caphase2ghg.htm

CARB/CalEPA, 2017d. *Reducing Short-Lived Climate Pollutants in California*, June 21. Retrieved from https://www.arb.ca.gov/cc/shortlived/shortlived.htm

CEC (California Energy Commission). *Doubling Energy Efficiency Savings*. Retrieved from http://www.energy.ca.gov/sb350/doubling_efficiency_savings/

CEC. *Renewables Portfolio Standard (RPS)*. Retrieved from http://www.energy.ca.gov/portfolio/

CEC, 2007. *2007 Integrated Energy Policy Report*. Retrieved from http://www.energy.ca.gov/2007_energypolicy/

CEC, 2016a. *Actual and Expected Energy from Coal for California- Overview*, November. Retrieved from http://www.energy.ca.gov/renewables/tracking_progress/documents/current_expected_energy_from_coal.pdf

CEC, 2016b. *Existing Building Energy Efficiency Plan Update December 2016*, December. Retrieved from http://docketpublic.energy.ca.gov/PublicDocuments/16-EBP-01/TN214801_20161214T155117_Existing_Building_Energy_Efficency_Plan_Update_Deceber_2016_Thi.pdf

CEC, 2017a. *Energy Commission Chair Releases Latter Urging the Future Closure of Aliso Canyon*, Press Release, July 19. Retrieved from http://www.energy.ca.gov/releases/2017_releases/2017-07-19-energy-commission-chair-releases-letter-ailso-canyon_nr.pdf

CEC, 2017b. *Once-Through Cooling Phase Out*, March 8. Retrieved from http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf

CEC, 2017c. *Low Carbon Fuel Standard*. Retrieved from http://www.energy.ca.gov/low_carbon_fuel_standard/

CEC, 2017d. 2016 *Appliance Efficiency Regulations*, January. Retrieved from http://www.energy.ca.gov/2017publications/CEC-400-2017-002/CEC-400-2017-002.pdf

CCST (California Council on Science and Technology), 2013. *California's Energy Future- The Potential for Biofuels*, May. Retrieved from http://ccst.us/publications/2013/2013biofuels.pdf

California Government. Office of the Governor, 2017. *Governor Brown Signs Landmark Climate Bill to Extend California's Cap-and-Trade Program*, July 25. Retrieved from https://www.gov.ca.gov/news.php?id=19891

CALI (California Legislative Information), 2002. Assembly Bill No. 1493, Pavely. Vehicular emissions: greenhouse gases, July 22. Retrieved from http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200120020AB1493

CALI, 2006a. Assembly Bill No. 32, Nunez and Pavely. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006, September 27. Retrieved from http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html

CALI, 2006b. Senate Bill No. 1368, Perata. Electricity: emissions of greenhouse gases, August. Retrieved from ftp://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1351-1400/sb_1368_bill_20060908_enrolled.html

CALI, 2009. Assembly Bill No. 758, Skinner. Energy: energy audit, October 11. Retrieved from http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB758

CALI, 2010. Assembly Bill No. 2514, Skinner. Energy storage systems, September 29. Retrieved from http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

CALI, 2011. Senate Bill No. X1-2, Simitian. Energy: renewable energy resources, April 12. Retrieved from http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_cfa_20110214_141136_sen_comm.html

CALI, 2012. Assembly Bill No. 1900, Gatto. Renewable energy resources: biomethane, September 27. Retrieved from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201120120AB1900

CALI, 2013. Assembly Bill No. 8, Perea. Alternative fuel and vehicle technologies: funding programs, September 28. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8

CALI, 2015. Senate Bill No. 350, De Leon. Clean Energy and Pollution Reduction Act of 2015, October 7. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

CALI, 2016a. Assembly Bill No. 197, E. Garcia. State Air Resourced Board: greenhouse gases: regulations, September 8. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB197

CALI, 2016b. Senate Bill No. 32, Pavely. California Global Warming Solutions Act of 2006: emissions limit, September 8. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32

CALI, 2016c. Senate Bill No. 1383, Lara. Short-lived climate pollutants: methane emissions: dairy and livestock: organic waste: landfills, September 19. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

CALI, 2017a. Senate Bill No. 100, De Leon. California Renewables Portfolio Standard Program: emissions of greenhouse gases, January 11. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

CALI, 2017b. Assembly Bill No. 398, Eduardo Garcia. California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption, July 25. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398

CALI, 2017c. Assembly Bill No. 617, Cristina Garcia. Nonvehicular air pollution: criteria air pollutants and toxic air contaminants, July 26. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB617

CALI, 2017d. Senate Bill No. 433, Tony Mendoza. Gas Corporations: zero-carbon and low-carbon hydrogen, September 12. Retrieved from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB433

CALI, 2017e. Assembly Bill No. 726, Chris Holden. Energy, September 8. Retrieved from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB726

CALI, 2017f. Senate Bill No. 338, Skinner. Integrated resource plan: peak demand, October 26. Retrieved from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB338

CPUC (California Public Utilities Commission), 2004. *Interim Opinion: Energy Savings Goals for Program Year 2006 And Beyond*, September. Retrieved from http://docs.cpuc.ca.gov/published/FINAL_DECISION/40212.htm

CPUC, 2013. *Energy Efficiency Potential and Goals Studies*. Retrieved from http://www.cpuc.ca.gov/General.aspx?id=2013

CPUC, 2014. *Decision Regarding the Biomethane Implementation Tasks in Assembly Bill 1900*, January. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF

CPUC/CEC, 2015. New Residential Zero Net Energy Action Plan 2015-2020 Executive Summary, June. http://www.CaliforniaZNEhomes.com

CPUC, 2017a. Public Comment Requested for Aliso Canyon Reliability and Economic Analyses Draft Pre-Solicitation, 16 June. http://www.cpuc.ca.gov/aliso/.

CPUC, 2017b. Energy Storage. Retrieved from http://www.cpuc.ca.gov/General.aspx?id=3462

DOE (U.S. Department of Energy). *Appliance Efficiency Regulations*. Retrieved from https://energy.gov/savings/appliance-efficiency-regulations

DOE, 2017. *Building Energy Codes Program, California*. Retrieved from https://www.energycodes.gov/adoption/states/california

DGS (California Department of General Services), 2010. *CalGreen the 2010 California Green Building Standards Code*. Retrieved from https://www.documents.dgs.ca.gov/bsc/calgreen/the-calgreen-story.pdf

DGS, 2017. *Aliso Canyon Economic Analysis RFP #17PS5004*. Retrieved from https://caleprocure.ca.gov/event/8660/0000006877

FERC (Federal Energy Regulatory Commission), 2006. Rate Regulation of Certain Natural Gas Storage Facilities, Order No. 678, Final Rule, Code of Federal Regulations Section 18, Part 284, Docket Nos. RM05-23-000 and AD04-11-000, 19 June. https://www.ferc.gov/whats-new/comm-meet/061506/C-2.pdf.

IWG (Governor's Interagency Working Group on Zero-Emission Vehicles), 2016. ZEV Action Plan: An updated roadmap toward 1.5 million zero-emission vehicles on California roadways by 2025. Office of Governor Edmund G. Brown Jr., October. https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf.

Interagency Task Force, 2016. *Ensuring Safe and Reliable Underground Natural Gas Storage: Final Report of the Interagency Task Force on Natural Gas Storage Safety*, U.S. Department of Energy, Department of Transportation, Environmental Protection Agency, Department of Health and Human Services, Department of Commerce, Department of the Interior, Federal Energy Regulatory Commission, and the Executive Office of the President, October. https://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf.

Office of Governor Edmund G. Brown Jr., 2016. Governor's Interagency Working Group on Zero-Emission Vehicles. *Zev Action Plan an updated roadmap toward 1.5 million zero-emission vehicles on California roadways by 2025*. Retrieved from https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf

Office of Governor Edmund G. Brown Jr., 2005. Executive Order S-3-05, June 1. Retrieved from https://www.gov.ca.gov/news.php?id=1861

Office of Governor Edmund G. Brown Jr., 2006. Executive Order S-06-06, April 25. Retrieved from https://www.gov.ca.gov/news.php?id=183

Office of Governor Edmund G. Brown Jr., 2007. Executive Order S-01-07, January 18. Retrieved from https://www.gov.ca.gov/news.php?id=5172

Office of Governor Edmund G. Brown Jr., 2012. Executive Order B-16-2012, March 23. Retrieved from https://www.gov.ca.gov/news.php?id=17472

Office of Governor Edmund G. Brown Jr., 2015a. *Governor Brown Establishes Mist Ambitious Greenhouse Gas Reduction Target In North America*, April 29. Retrieved from https://www.gov.ca.gov/news.php?id=18938

Office of Governor Edmund G. Brown Jr., 2015b. *Governor Brown Sworn In, Delivers Inaugural Address*, January 5. Retrieved from https://www.gov.ca.gov/news.php?id=18828

PHMSA (Pipelines and Hazardous Materials Safety Administration), 2016. *PHMSA Issues Interim Final Rule Revising the Pipeline Safety Regulations to Address Safety Issues Related to Underground Natural Gas Storage Facilities*, December 14. Retrieved from https://www.phmsa.dot.gov/pipeline/phmsa-issues-interim-final-rule-revising-the-pipeline-safety-regulations-to-address-safety-issues-related-to-underground-natural-gas-storage-facilities

PHMSA, 2017. Pipeline Safety: Safety of Underground Natural Gas Storage Facilities; Petition for Reconsideration, Docket No. PHMSA-2016-0016, *Federal Register*, 82: 28224-28225, 20 June. https://www.federalregister.gov/documents/2017/06/20/2017-12806/pipeline-safety-safety-of-underground-natural-gas-storage-facilities-petition-for-reconsideration.

Shirakh, M., C. Meyer, B. Pennington, 2017. 2019 Building Energy Efficiency Standards ZNE Strategy, workshop presentation, California Energy Commission, Docket No. 17-BSTD-01, 24 April.

Appendix 3-4: Scenario Feasibility Assessment

In this section, we review costs, scale-up rates, technical resource limits, and technological maturities of three of the four California scenarios discussed in 3.3. Demand for UGS in 2050, using data from E3 (2015a). This is important for understanding the relative viability of scenarios that the State could pursue, and therefore its impacts on UGS investment. However, it must be pointed out that the data used for the cost assessments are likely now out of date, as the cost of both renewables and natural gas have fallen, though gas prices could as well increase in the future.

Costs

In addition to the cost information contained in Appendix 3-2: Energy Technologies, E3 (2015a) provided some overall scenario implementation cost estimates relative to a baseline scenario that does not meet the GHG targets. The three scenarios presented here are "CCS," which is similar to our Scenario A (fossil-CCS + building electrification), "Straight Line," which is similar to our Scenario C (intermittent renewables + building electrification), and "Low Carbon Gas," which is similar to our Scenario D (intermittent renewables + low-carbon gas). E3 had no scenario similar to our Scenario B (flexible, non-fossil generation + building electrification), though many other studies have such scenarios.

E3 estimated annual costs relative to a reference baseline for implementing each scenario. Uncertainty analysis was included in their calculations (±50% in gasoline, diesel and natural gas prices, and reduction in key technology costs in the low fuel price case), which produced significant ranges on the estimates. E3 found that, in both 2030 and 2050, the CCS scenario was lower cost and the Low-Carbon Gas scenario, higher cost, than the Straight Line scenario, though uncertainty ranges among the three scenarios overlapped considerably. Costs are plotted on the vertical axis against GHG reduction (relative to the 1990 level) on the horizontal axis. See Figure 13 and Figure 14.

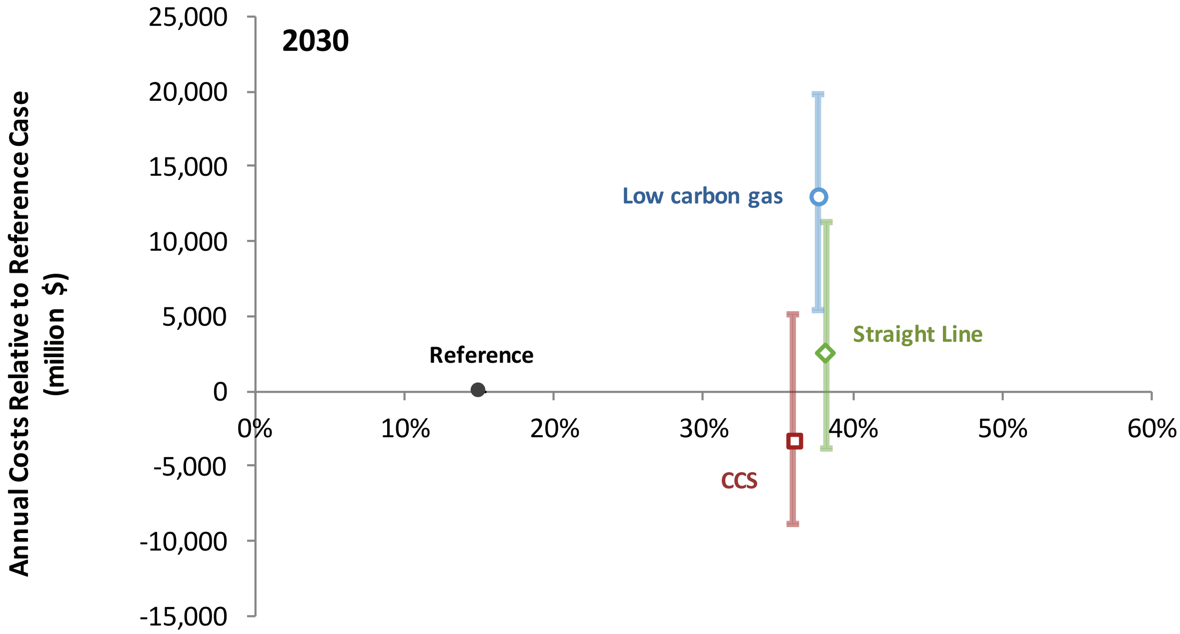


Figure 13. Scenario cost estimates for 2030. Costs are plotted on the vertical axis against GHG reduction (relative to the 1990 level) on the horizontal axis. CCS = Scenario A; Straight Line = Scenario C; Low carbon gas = Scenario D.

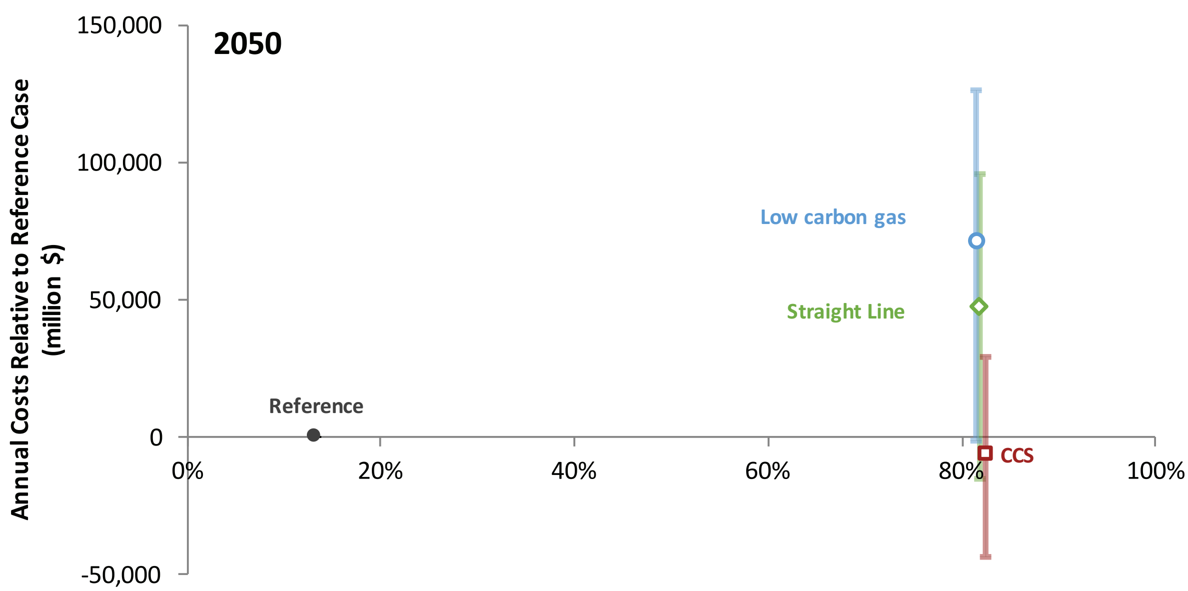


Figure 14. Scenario cost estimates for 2050. Costs are plotted on the vertical axis against GHG reduction (relative to the 1990 level) on the horizontal axis. CCS = Scenario A; Straight Line =

Scenario C; Low carbon gas = Scenario D.

In terms of annual costs, the CCS scenario trended fairly flat (i.e., close to reference case costs) between 2015 and 2050, and the base case estimate was actually slightly negative, saving an average of $5.6 billion/yr between 2030 and 2050. The uncertainty range on this cost estimate was –$26 to +41 billion/yr. See Figure 15.

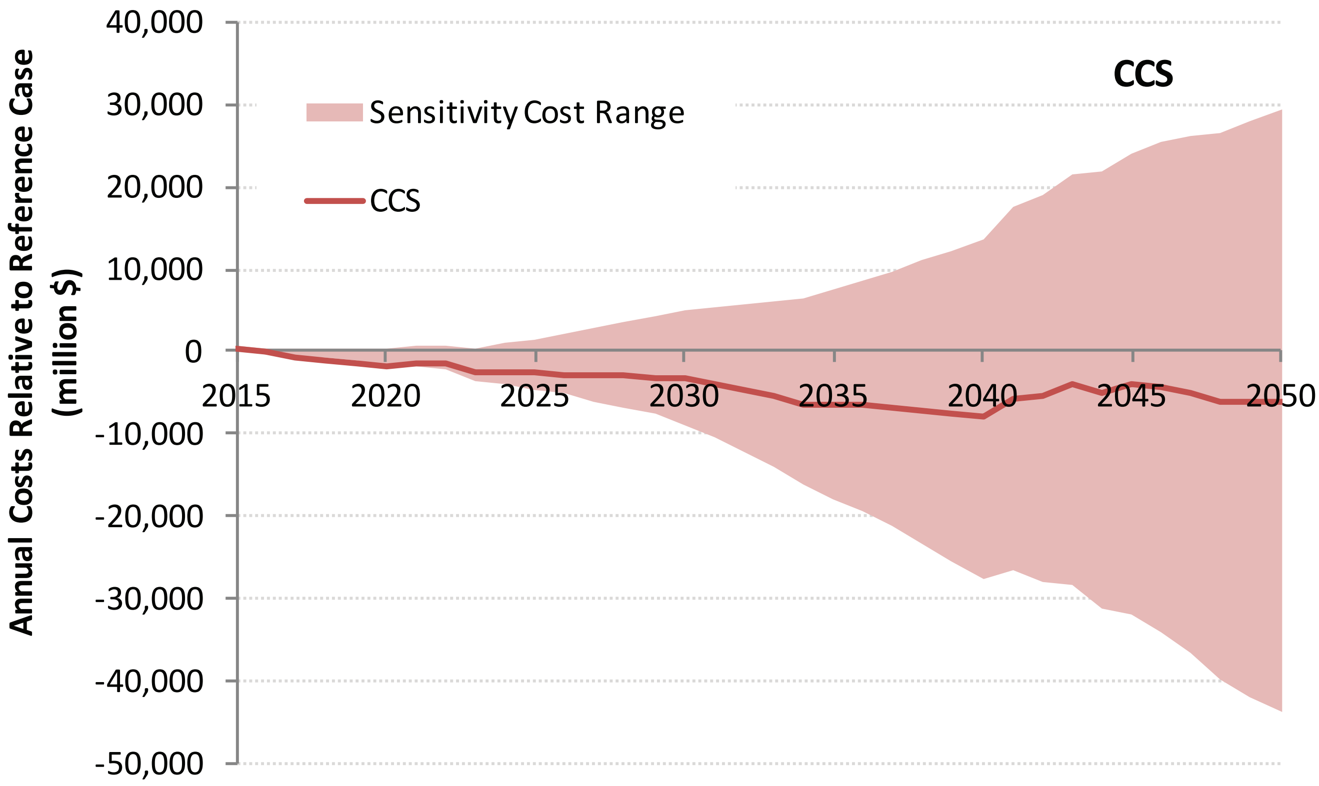


Figure 15. Annual CCS cost projections (equivalent to Scenario A)

The Straight Line scenario displayed steadily increasing costs after 2030, reaching a maximum of $49 billion in 2048. The average 2030-2050 cost was $25 billion/yr, with an uncertainty range of –$6 to +$57 billion/yr. See Figure 16.

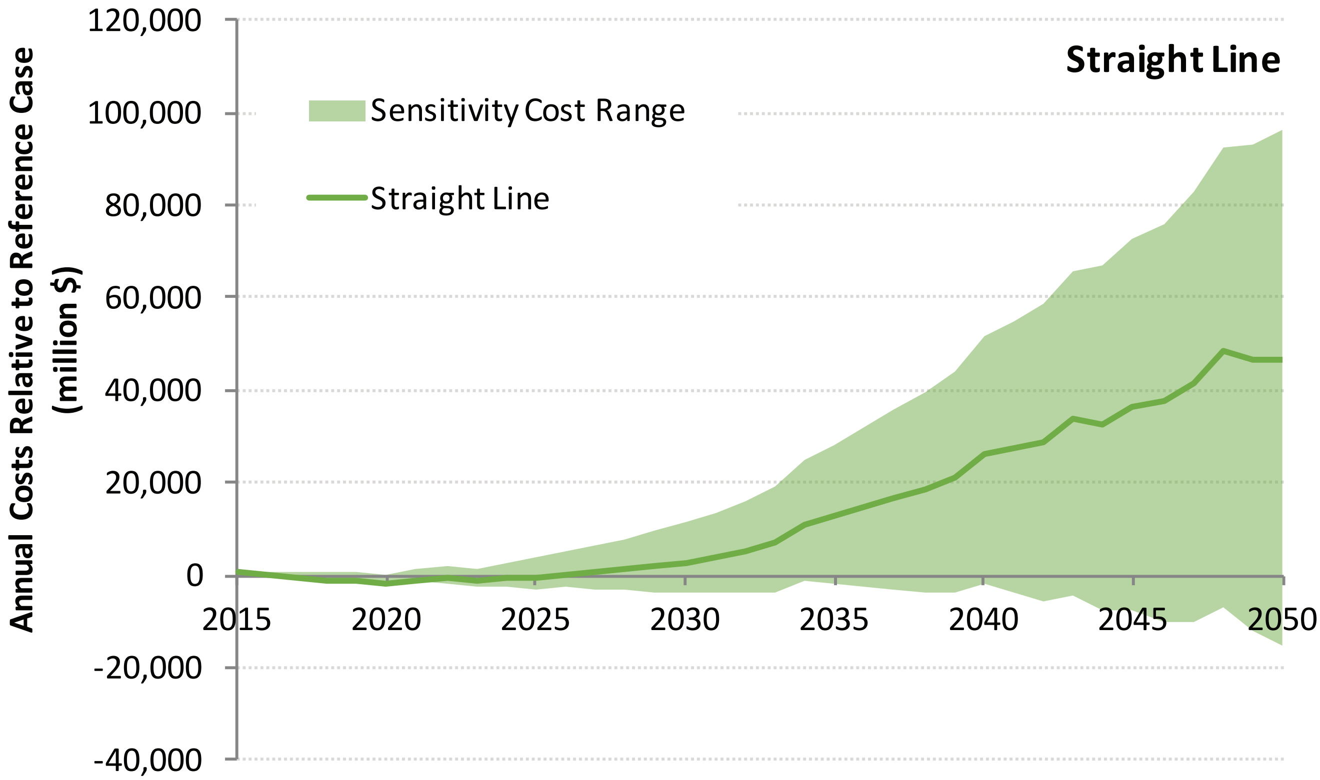


Figure 16. Annual Straight Line cost projections (equivalent to Scenario C)

The Low Carbon Gas scenario also displayed steadily increasing costs, with an earlier rise (after ~2025) and maximum cost of $71 billion in 2050. The average 2030-2050 cost was $41 billion/yr, with an uncertainty range of +$5 to +$64 billion/yr. See Figure 17.

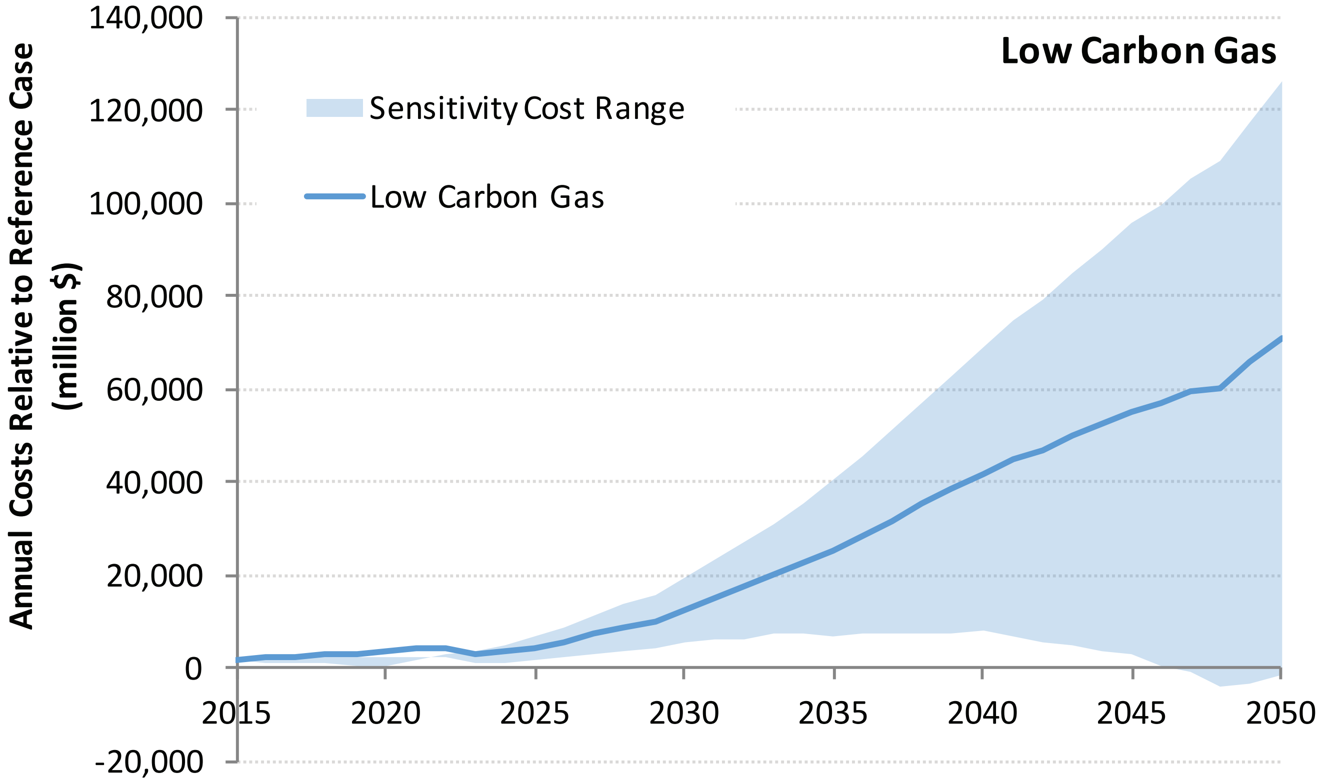


Figure 17. Annual Low Carbon Gas cost projections (equivalent to Scenario D)

Scale-up Rates

Historically, the fastest rates of growth in generation capacity in the U.S. electricity sector were seen in nuclear power and natural gas. Nuclear power grew from <1 GW to 100 GW installed capacity between 1965 and 1990, whereas natural gas grew from ~150 GW to ~400 GW between 1991 and 2009. Expressed in terms of a five-year running annual average growth rate (to smooth out noise in the data), there were two growth peaks for nuclear power, each at ~7 GW/yr: 1974 and 1985, whereas for natural gas, there was only one much larger peak (35 GW/yr) in 2001-2002. See Figure 18.

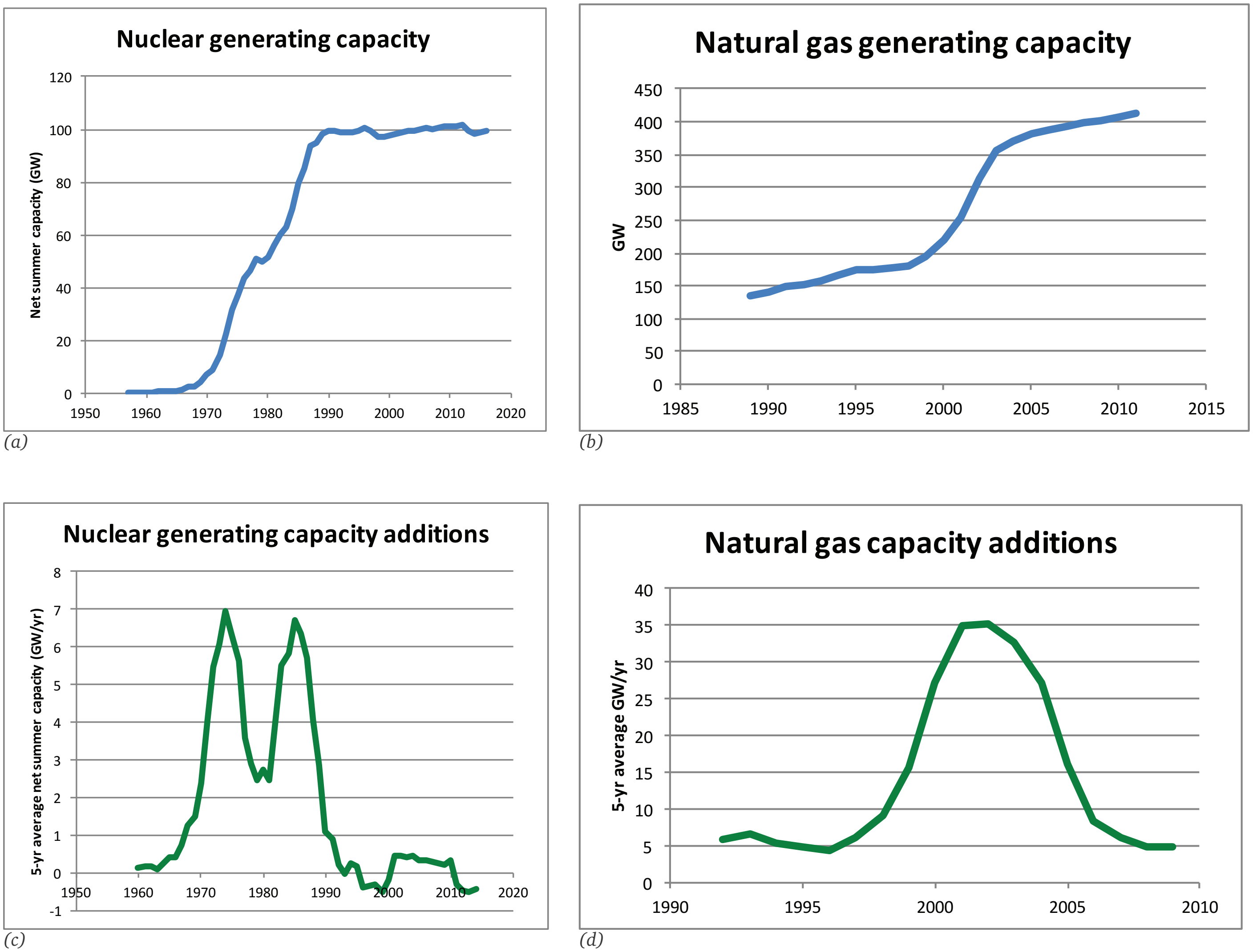
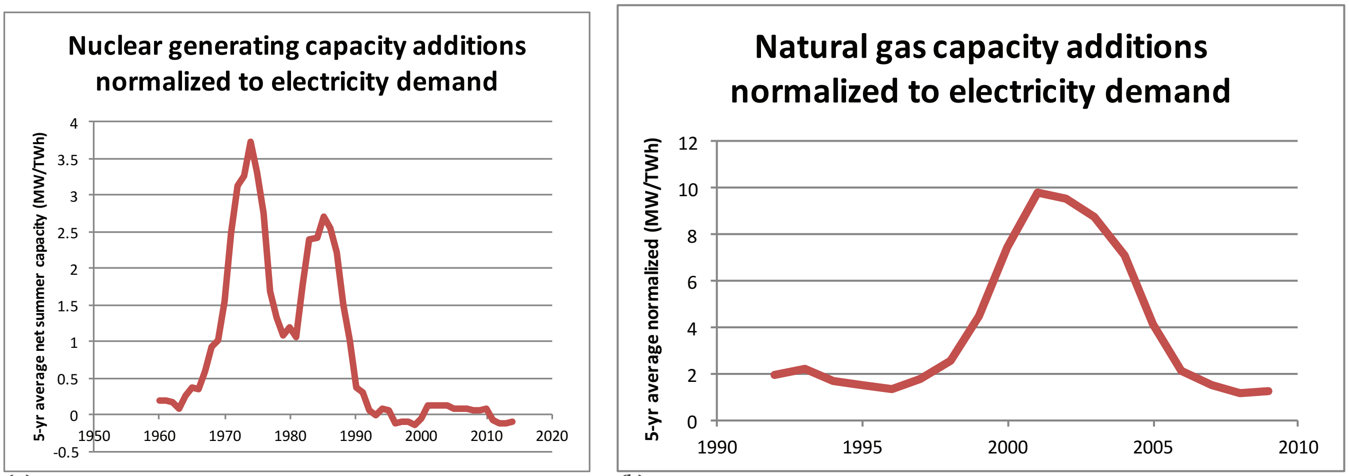


Figure 18. Historical growth of U.S. nuclear and natural gas electricity generation capacities: (a) Nuclear generating capacity (GW), (b) natural gas generating capacity (GW), (c) nuclear generating capacity average 5-yr addition rate (GW/yr), (d) natural gas generating capacity average 5-yr addition rate (GW/yr). Authors' analysis based on data from EIA (2011, 2017g).

In order to make these data more relevant to California, we have normalized them by the amount of net electricity generation (TWh) in each year, so the growth rate is expressed in terms of MW/yr per TWh/yr (or MW/TWh). Expressed this way, the maximum growth rate for nuclear power was 3.7 MW/TWh and for natural gas, 9.8 MW/TWh. These are shown in Figure 19.



(a) (b)

Figure 19. Normalized growth rates of nuclear and natural gas electricity generation capacity. Authors' analysis based on data from EIA (2011, 2017g, 2017h).

We now compare these historical growth rates to those for various types of electricity generation technologies modeled in the E3 scenarios.

Absolute growth rates

For the Straight Line (SL) and Low Carbon Gas (LCG) scenarios, while growth in most electricity generation technologies are modest, both of these scenarios have large ramp-up rates of wind and solar electricity generation after 2030, with peak five-year annual average build-out rates of ~9 GW/yr for wind and ~4.5 GW/yr for solar. Because both include increases in low-carbon gas resources, natural gas capacities also increase after 2030, reaching peaks of ~2 GW/yr. See Figure 20.

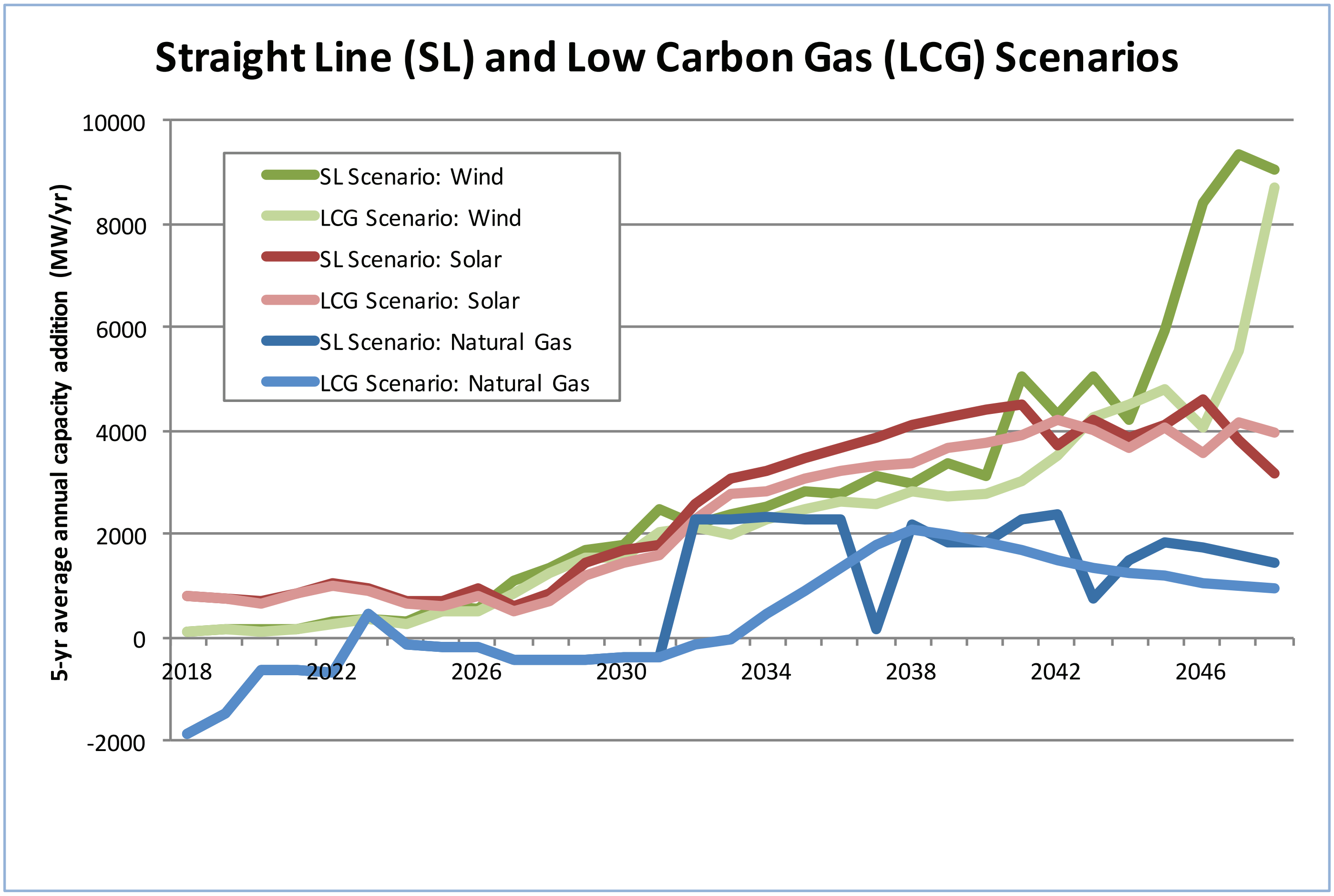


Figure 20. Required growth rates for SL and LCG scenarios

For the CCS scenario, as for the other scenarios, growth in most electricity generation technologies are modest in the CCS scenario, with the exception of natural gas with CCS, which exceeds 2.0 GW/yr after 2040, and peaks at 3.7 GW/yr in 2043-44. There is also a dramatic fall in non-CCS natural gas capacity that mirrors the growth in natural gas with CCS; its peak decline is –2.5 GW/yr in 2043-44. See Figure 21.

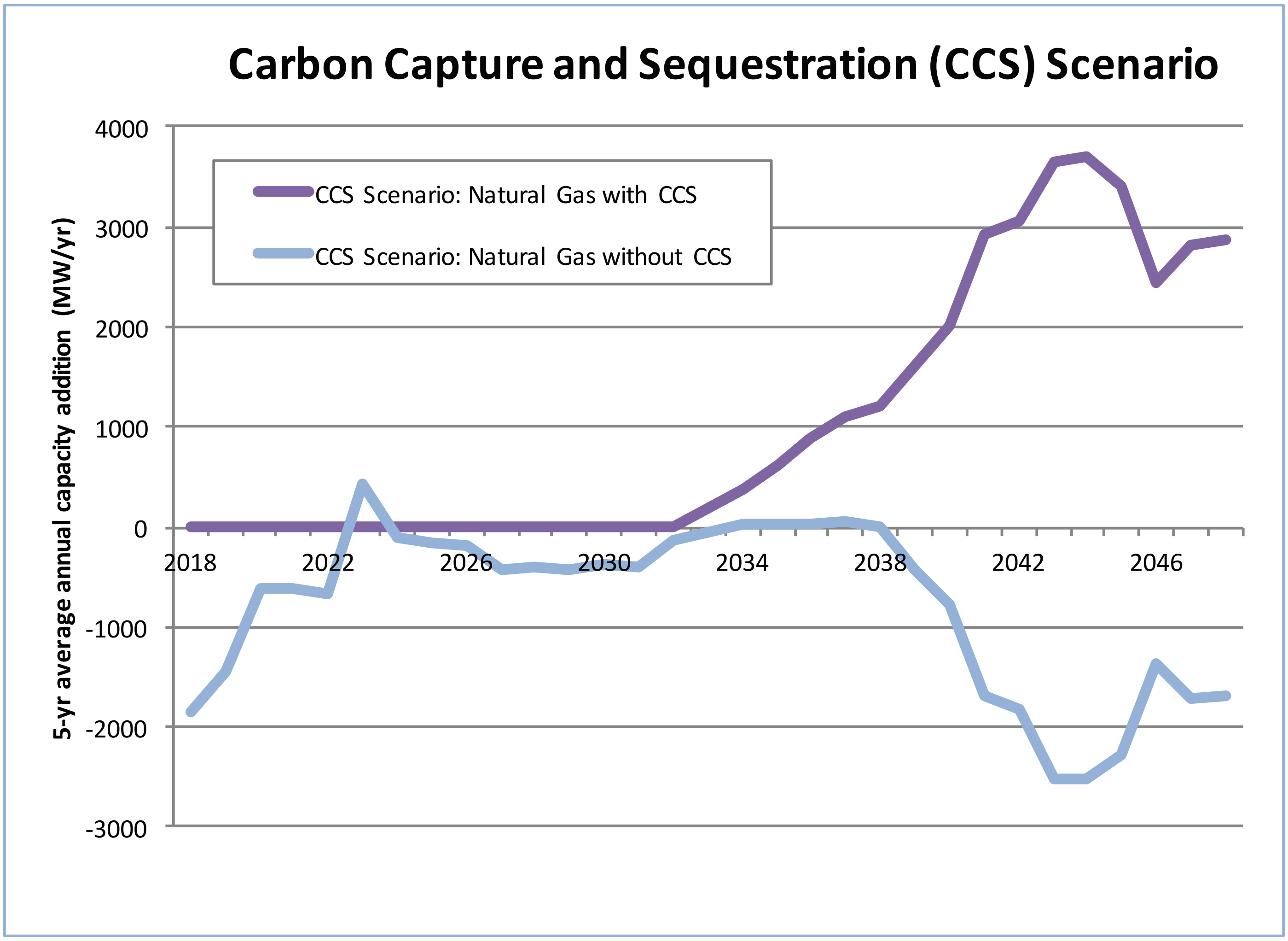


Figure 21. Required growth rates for CCS scenario

With the exception of wind, all of these growth rates are lower than peak growth in U.S. nuclear power, and all are well below the peak growth rate of U.S. natural gas. However, it may not be correct to compare California and national growth rates, so below we also examine growth rates normalized by electricity consumption.

Normalized growth rates

In Figure 22 and Figure 23, we have normalized growth rates for the three California scenarios as was done above for national growth rates for nuclear and natural gas. We have also indicated the historical peak growth rate for natural gas (9.8 MW/TWh) in the figures. Wind growth peaks at ~14.5 MW/TWh in both the SL and LCG scenarios, higher than the historical peak growth rate. However, the normalized solar rates are lower at ~8 MW/TWh.

For the CCS scenario, the normalized peak growth of natural gas with CCS is 8.3 MW/TWh. Both of these are below the historical peak growth rate for natural gas.

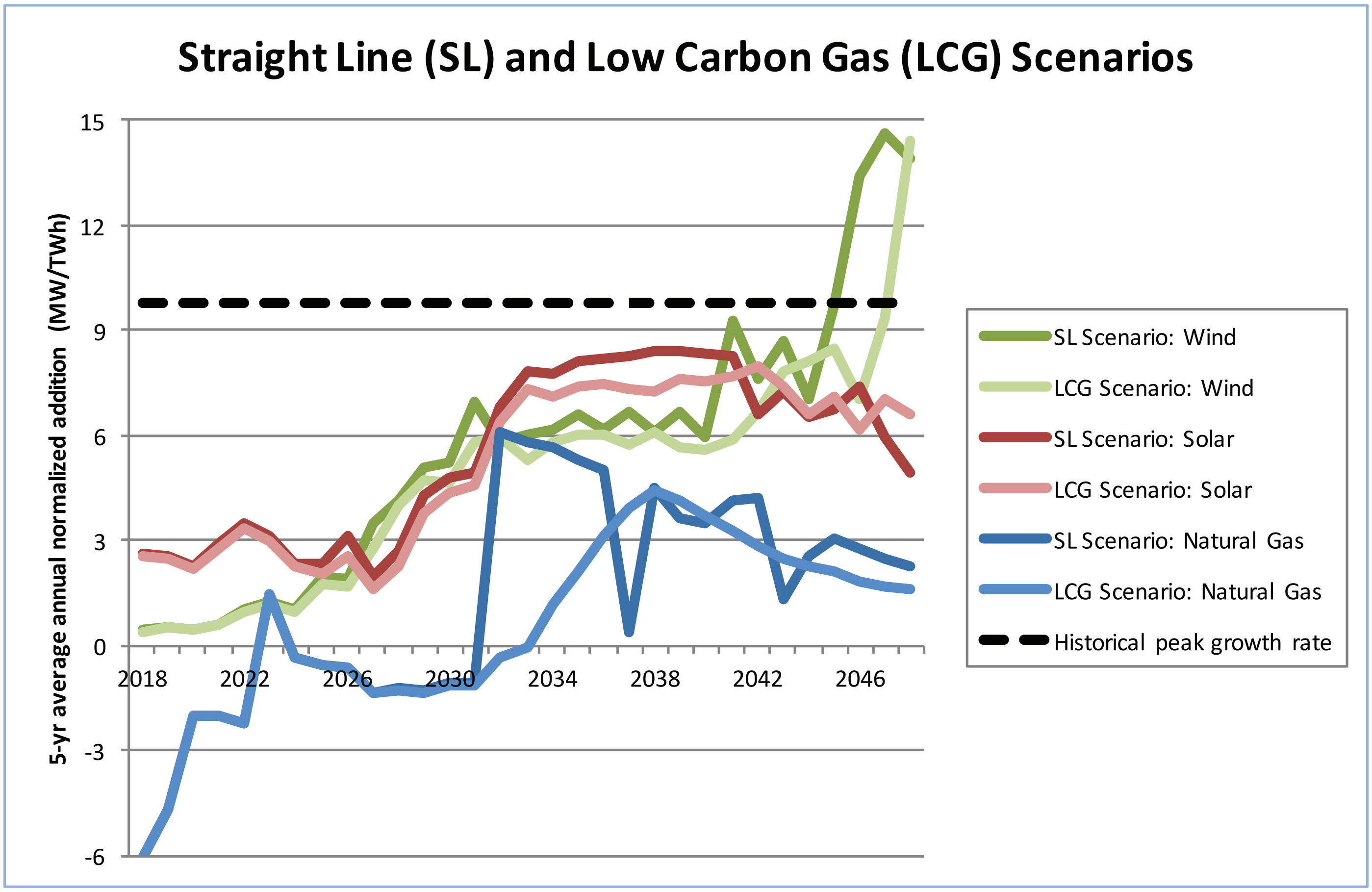


Figure 22. Normalized growth rates for Straight Line and Low Carbon Gas scenarios

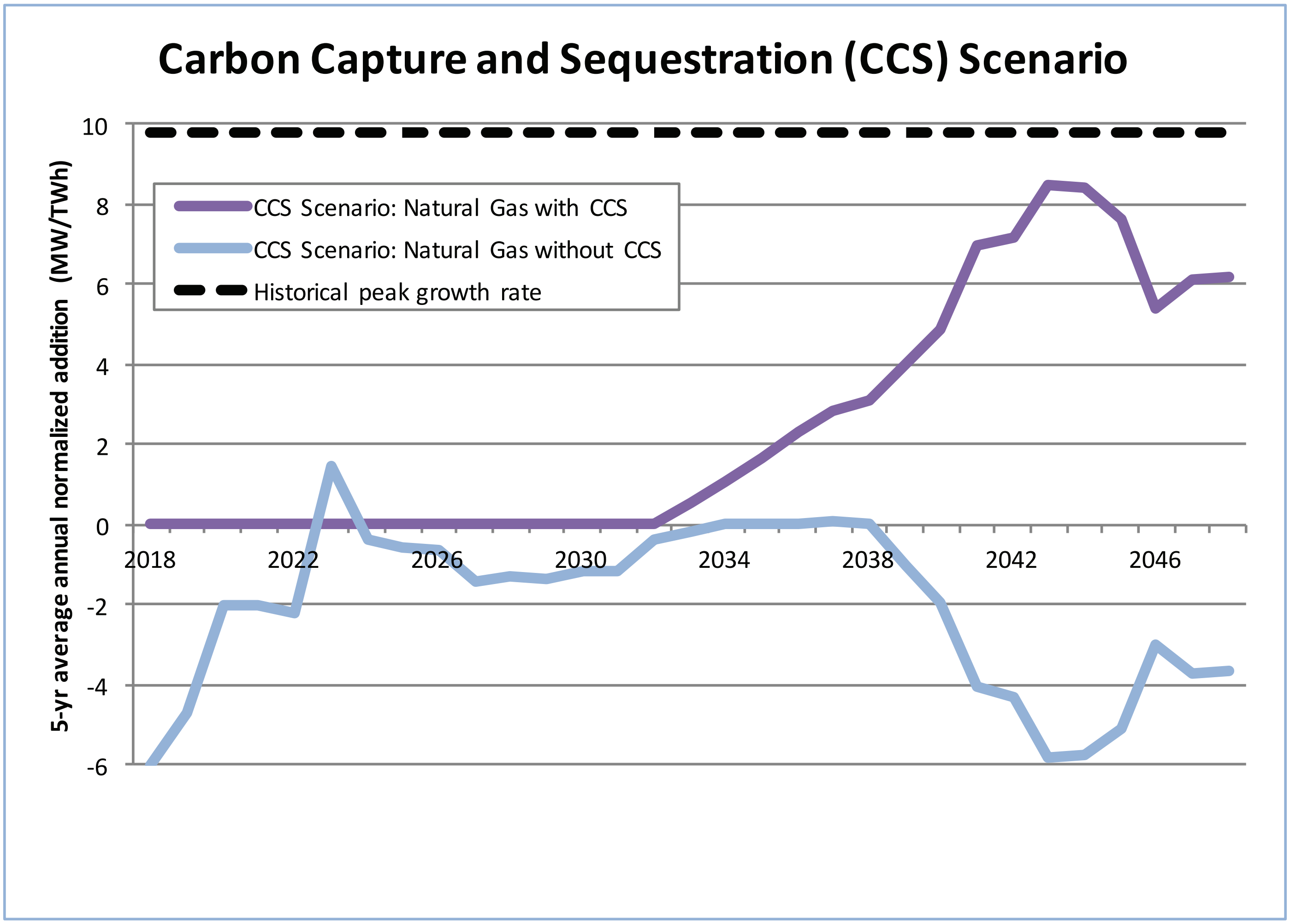


Figure 23. Normalized growth rates for CCS scenario

While it could be argued that the growth of wind in the SL and LCG scenarios exceeds the peak historical growth rate for natural gas, and therefore these scenarios should be excluded, many future scenarios for California invoke similar levels of renewable energy growth. Moreover, the balance of wind and solar capacity is dependent on future assumptions of relative costs, and it is entirely possible that the overall shares of wind and solar could be different. When we average the growth rates of these generation technologies, we find that the peak growth rates in each scenario are much closer (~10.5 MW/TWh) to the historical precedent. While still slightly exceeding the historical peak, we deemed these scenarios close enough to historical experience that we retained them in our analysis, with the caveat that build-out rates may be challenging to achieve.

Technical Resource for Biomethane

E3's (2015a) Low Carbon Gas scenario calls for ~60% biomethane in the pipeline mix by 2040, increasing from 33% biomethane in 2030 and negligible levels today. In addition, it calls for 8% SNG and 5% hydrogen in 2050, increasing from negligible levels in 2030. By comparison, the other two scenarios contain only 2% biomethane in 2030 and 5-12% in 2050, with similar levels of SNG and hydrogen.

Such an expansion would represent an unprecedented increase in the use of biomethane and other substitutes for natural gas. Biomethane is currently produced in 15 European countries in about 230 installations, and is injected into the natural gas grid in 11 countries (EBA, 2013a). Europe as a whole has set a target of 3% biomethane by 2030 (EBA, 2013b), and Germany, France, and Finland have set targets of 10% (EBA, 2013c; DENA, 2016; De Singly et al., 2016). Canada also has a target of 5% renewable natural gas blended with pipeline gas in 2025, and 10% by 2030 (CGA, 2016).

California could produce a maximum of ~250 MMcfd of biomethane from landfills, wastewater, municipal solid waste, and manure (Williams et al., 2015; Jaffe et al., 2016); an additional ~550 MMcfd would be available from woody biomass waste (BAC, 2014), but this technology is not yet mature. These resources would provide 4% and 13%, respectively, of current California natural gas demand. Clearly, these would be inadequate to meet the requirements of E3's Low Carbon Gas scenario. However, including out-of-state biomass resources could increase biomethane resources to as much as ~20,000 MMcfd (Murray et al., 2014), more than enough to satisfy ~50% of California's current natural gas demand even if California consumed no more than its population-weighted "fair share" (currently 12%) of this U.S. resource. Therefore, in principle, the target biomethane share of the Low Carbon Gas scenario could be met. For more details, see Appendix 3-2: Energy Technologies, Biomethane - Resources.

Note that these levels of biomethane generation would require significant development, as very little available biomass is currently converted into biogas for biomethane production. In particular, thermal gasification of agricultural and forest residues, which represents nearly all additional biomethane supply above $6/MMBtu in Murray et al., would have to be developed.

Appendix 3-5: Selected Data from E3 (2015a) Scenarios

In this Appendix, we provide details from three scenarios modeled by E3 (2015a) that closely resemble Scenarios A, C, and D in this chapter. E3 did not model a scenario that closely resembled Scenario B, however, so no data were available. See Table 8.

Table 8. Selected data from E3 (2015a) scenarios.

	2015	2030			2050		
E3 scenario name	**Straight Line**	**CCS**	**Straight Line**	**Low-Carbon Gas**	**CCS**	**Straight Line**	**Low-Carbon Gas**
CCST study scenario name	**N/A**	**Scenario A**	**Scenario C**	**Scenario D**	**Scenario A**	**Scenario C**	**Scenario D**
GHG reduction (% of 1990 level)	N/A	36%	38%	38%	82%	82%	81%
Pipeline gas demand							
Natural gas demand (EJ)	2.01	1.75	1.66	1.81	3.01	1.23	2.01
Fraction of 2015 gas demand	100%	87%	83%	90%	150%	61%	100%
Gas demand for electricity (EJ)	0.63	0.67	0.58	0.58	2.44	0.66	0.49
Gas demand for non-electricity (EJ)	1.38	1.08	1.08	1.23	0.58	0.58	1.52
Electricity share of pipeline gas demand	31%	38%	35%	32%	81%	53%	25%
Pipeline gas composition							
Biogas (biomethane) share	0%	2%	2%	33%	5%	12%	57%
Synthetic natural gas (SNG) share	0%	0%	0%	0.3%	0%	0%	8%
Hydrogen share	0%	0.2%	0.2%	0.2%	1%	3%	5%
Non-pipeline hydrogen demand (EJ)	0	0.06	0.06	0.06	0.43	0.47	0.04
Total gas demand (EJ)	2.01	1.81	1.72	1.87	3.44	1.70	2.05
Fraction of 2015 gas demand	100%	90%	86%	93%	171%	85%	102%
CO_2 sequestration (Mt/yr)	0	0	0	0	105	0	0
Electricity mix							
Electricity demand (TWh)	304	327	348	335	474	675	624
Renewable (excluding hydro) share of electricity generation	27%	39%	48%	47%	40%	80%	82%
Natural gas (including CHP) share of electricity generation	28%	29%	24%	25%	49%	13%	11%
Wind electricity share	10%	22%	22%	21%	24%	40%	41%
Solar electricity share	11%	11%	17%	17%	13%	36%	36%
Other (non-hydro) renewable electricity share	6%	6%	9%	9%	4%	5%	5%
New electric loads & storage							
Light-duty electric vehicles (M)	0.02	4.2	4.2	6.2	9.6	9.6	33
Heavy-duty electric vehicles (k)	0	2	45	104	682	1010	1218
Electric vehicle charging peak (GW)	0.02	2.3	2.5	4.0	3.6	3.7	15.0
Flexible load capacity (GW)	14	18	18	19	19	19	29
Electricity storage capacity (GW)	2.6	3.8	3.8	3.8	3.8	3.8	3.8

	2015	2030			2050		
E3 scenario name	**Straight Line**	**CCS**	**Straight Line**	**Low-Carbon Gas**	**CCS**	**Straight Line**	**Low-Carbon Gas**
CCST study scenario name	**N/A**	**Scenario A**	**Scenario C**	**Scenario D**	**Scenario A**	**Scenario C**	**Scenario D**
Building electric water and space heating loads (GBtu)	23	75	75	27	350	350	33
Heavy-duty natural gas vehicles (k)	33	38	38	166	43	43	1532