CALIFORNIA ENERGY COMMISSION

Energy Research and Development Division

FINAL PROJECT REPORT

The Challenge of Retail Gas in California's Low-Carbon Future

Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use

Gavin Newsom, Governor

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division manages the Natural Gas Research and Development program, which supports energy-related research, development, and demonstration not adequately provided by competitive and regulated markets. These natural gas research investments spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

The Energy Research and Development Division conducts this public interest natural gas-related energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public and private research institutions. This program promotes greater natural gas reliability, lowers costs, increases safety for Californians, and is focused in:

- Buildings End-Use Energy Efficiency.
- Industrial, Agriculture, and Water Efficiency.
- Renewable Energy and Advanced Generation.
- Natural Gas Infrastructure Safety and Integrity.
- Energy-Related Environmental Research.
- Natural Gas-Related Transportation.

The Challenge of Retail Gas in California's Low-Carbon Future is the final report for the future of natural gas project (PIR-16-011) conducted by Energy and Environmental Economics and the University of California, Irvine. The information from this project contributes to the Energy Research and Development Division's Natural Gas Research and Development Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at 916-327-1551.

ABSTRACT

This study evaluates scenarios that achieve an 80 percent reduction in California's greenhouse gas emissions by 2050 from 1990 levels, focusing on the implications of achieving these climate goals for gas customers and the gas system. Achieving these goals is not guaranteed and will require large-scale transformations of the state's energy economy in any scenario.

These scenarios suggest that building electrification is likely to be a lower-cost, lower-risk long-term strategy compared to renewable natural gas (RNG, defined as biomethane, hydrogen and synthetic natural gas, methane produced by combining hydrogen and carbon). Furthermore, electrification across all sectors, including in buildings, leads to significant improvements in outdoor air quality and public health. A key uncertainty is whether consumers will adopt electrification technologies at scale, regardless of their cost effectiveness.

In any low-carbon future, gas demand in buildings is likely to fall because of building electrification or the cost of RNG. In the High Building Electrification scenario, gas demand in buildings falls 90 percent by 2050 relative to today. In the No Building Electrification scenario, a higher quantity of RNG is needed to meet the state's climate goals, leading to higher gas commodity costs, which, in turn, improve the cost-effectiveness of building electrification.

The potential for large reductions in gas demand creates a new planning imperative for the state. Without a gas transition strategy, unsustainable increases in gas rates and customer energy bills could be seen after 2030, negatively affecting customers who are least able to switch away from gas, including renters and low-income residents.

Even in the High Building Electrification scenario, millions of gas customers remain on the gas system through 2050. Thus, this research evaluates potential gas transition strategies that aim to maintain reasonable gas rates, as well as the financial viability of gas utilities, through the study period.

Keywords: Natural gas, greenhouse gas emissions, climate change, renewable natural gas, electrification, equity, air quality and public health

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TABLE OF CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

Page

EXECUTIVE SUMMARY

Introduction

This research evaluates scenarios that achieve an economywide reduction in greenhouse gas (GHG) emissions of 40 percent by 2030 and 80 percent by 2050 from 1990 levels. California has also set a carbon-neutral target for 2045, which is not directly evaluated as part of this research.

Natural gas is an integral part of California's energy system, including in buildings, industry, and electric generation. Nearly 80 percent of all homes in California are connected to the natural gas system. Californians spend nearly $14 billion per year on gas, both to use the gas itself in buildings, industry, and electric generation and to maintain and operate the gas system.

To meet California's climate goals, use of fossil fuels like natural gas will need to decrease by 80 percent or more by 2050. Zero-carbon electricity requirements under Senate Bill 100 (de León, Chapter 312, Statutes of 2018) will lead to a substantial reduction in annual demands for natural gas in electric generation. Efforts to reduce built environment emissions, particularly strategies to reduce GHG emissions from natural gas use in buildings via efficiency or electrification, could also lead to reductions in natural gas demand over time. However, no Energy and Environmental Economics, Inc. (E3) study has yet identified a strategy that eliminates the use of pipeline gas altogether, since zero carbon gas alternatives can replace natural gas in the pipeline. Every scenario leaves residual gas demands in industry, while others allow gas usage in the buildings or transportation sector.

The implication is that any scenario that meets California's climate policy goals uses some amount of renewable natural gas (RNG). The research team defines RNG as climate-neutral gaseous fuels and uses it as an umbrella term to encompass four fuels, including 1) biomethane produced from anaerobic digestion of biomass wastes, 2) biomethane produced from gasification of biomass wastes and residues, 3) climate-neutral sources of hydrogen gas, and 4) methane produced synthetically from a climate-neutral source of carbon and hydrogen. (*Gasification* is a technology that converts carbon-containing materials, including biomass, into synthetic gas.) This study finds that, at scale, the costs of these fuels far exceeds that of natural gas. Relatively inexpensive portions of biomethane RNG are limited in quantity, so it may be preferable to reserve the use of these supplies for more energy-intensive, trade-exposed sectors of the California economy that do not have efficient, electrified substitutes readily available.

The question of the future of retail gas – defined here primarily as gas usage in the buildings sector – hinges on cost and consumer acceptance. Electrification, the use of electricity in place of other fuels, appears to be a cost-effective strategy for some consumers today. The addition of relatively high cost RNG into the gas pipeline would improve the economics of electrification in buildings. If demand for natural gas in California falls dramatically because of some combination of policy and economically driven electrification, the fixed costs to maintain and operate the gas system will be spread over a smaller number of gas sales and, ultimately, will increase costs for remaining gas customers. This outcome raises the possibility of a feedback effect where rising gas rates caused by electrification spur additional electrification. Such a feedback effect would threaten the financial viability of the gas system, as well as raise substantial equity concerns over the costs that remaining gas system customers would face. Given these risks, building electrification could serve as a risk-reduction strategy to protect low-income and vulnerable communities from future gas rate increases. However, achieving meaningful levels of building electrification will require changes to both new construction practices as well as retrofits of the existing building stock. Consumer adoption of building electrification technologies is one the largest barriers to achieving the emissions reductions from the building sector described in the High Building Electrification scenario.

If building electrification is delayed, missing the lower-cost opportunities for all-electric new construction and replacement of equipment upon failure, there is a greater risk that expensive early retirement of equipment may be needed, or that the climate goals could be missed. Furthermore, there are significant technology and cost risks of commercializing large quantities of renewable natural gas compared to electrifying buildings, which relies on technologies that are commercialized today.

This analysis, and work by others, suggests that achieving the state's ambitious climate goals is possible, but is far from assured, requiring rapid and near-term transformation in all sectors of the economy, as well as widespread consumer adoption of low-carbon technologies, fuels and practices.

Project Purpose

The future of natural gas, in the context of meeting the state's climate goals, is an important question for natural gas and electric ratepayers, as well as for policymakers interested in enabling California's clean energy transition. The research team takes a forward-looking view of future gas use in California, focusing on implications for, and strategies to protect, ratepayers.

To do that, this research evaluates the potential cost, energy infrastructure, and air quality implications of achieving the state's economywide climate goals, with an emphasis on:

1) Technology options to decarbonize the natural gas system. Specifically, what are the costs, and resource potential, for renewable natural gas technologies, including biomethane, hydrogen gas and climate-neutral synthetic natural gas?
2) Implications for natural gas customers. What are the potential changes in natural gas demand, rates, and bills associated with meeting California's climate goals? What are potential strategies to address the equity implications of changes in natural gas rates and utility bills while maintaining the safety and financial viability of the gas system?
3) Outdoor air quality and public health. What are the outdoor air quality and health benefits of meeting California's climate goals, and what are the air quality implications of reducing GHG emissions from natural gas?

The purpose of this research is not to define or recommend policies nor provide a definitive set of conclusions about California's energy future. Instead, the research team strives to use the best information available today to provide insights about how the decisions made today could affect the state's future choices. Those insights will inform researchers and policy makers on potential next steps toward achieving the state's clean energy transition.

Project Approach

E3 and the Advanced Power and Energy Program at the University of California, Irvine, (UCI) comprise the research team.

E3 led the development of economywide GHG scenarios using the California PATHWAYS model, as well as a detailed evaluation of the long-term natural gas rate and bill impacts of those scenarios. The California PATHWAYS model is a technoeconomic model of the state's energy consumption and GHG emissions that has been used and updated by California energy agencies since 2014.

The GHG mitigation scenarios evaluated in the PATHWAYS model do not represent forecasts of what is likely to happen, but rather represent "back-casts" of what kinds of changes, on what timeframe, may be necessary to meet a long-term climate goal.

E3's natural gas utility revenue requirement tool estimates how changes in natural gas demand throughput and changes in gas commodity costs could affect natural gas rates, both over time and by customer class. The revenue requirement tool was developed specifically for this project and benefited from insights and detailed feedback provided by the Southern California Gas Company (SoCalGas) and Pacific Gas and Electric (PG&E) and relied exclusively on publicly available data. Neither SoCal Gas nor PG&E was asked to endorse the revenue requirement tool or the study findings, which remain entirely the responsibility of the study team.

The UCI Advanced Power and Energy Program team worked with E3 to develop bottom-up estimates of RNG technology production costs using conservative and optimistic assumptions about technology learning curves, as well as other key input parameters.

The UCI team also led the analysis of outdoor air quality and health impacts of achieving the state's climate goals. The UCI team used the California PATHWAYS scenarios as the basis for assumptions about future changes in energy demand by fuel type and equipment type over time. The UCI team employed a sophisticated set of air quality modeling tools, including Sparse Matrix Operator Kerner Emissions (SMOKE) to resolve the emissions spatially by geography, the Community Multiscale Air Quality Modeling System (CMAQ) to simulate air quality, and the Environmental Benefits Mapping and Analysis Program (BenMAP) to estimate the health savings effects.

The project team benefited from in-kind labor contributions from the Sacramento Municipal Utilities District (SMUD) and SoCalGas, who both participated on the Technical Advisory Committee (TAC) and provided other data and feedback to the research team. SoCalGas also cofunded a portion of UCI's research. Other members of the TAC included representatives from PG&E; the California Air Resources Board; University of California at Riverside; University of California at Davis; the Natural Resources Defense Council; the Environmental Defense Council; Mitsui and Co.; and the Greenlining Institute. For a complete list of TAC members, see Appendix B.

Key areas of discussion and debate among TAC members and the research team included the following:

1. How to reflect the costs and uncertainties around wildfire risk in California?

2. How to assess the future resource potential for biomass and biofuels available to California?
3. How to reflect current state programs that encourage through incentives the use of biofuels, electricity, and hydrogen in the transportation sector, particularly the Low Carbon Fuel Standard?
4. How to characterize the most likely future trajectory for hydrogen gas and synthetic natural gas production costs?

Each one of these topics was evaluated in the course of this research as described in this report and in the Appendices. For a more detailed discussion of some of the "frequently asked questions" and comments about this report, see Appendix A.

Participation on the TAC was voluntary and in no way indicates that TAC members endorse the study conclusions. In addition to participating in the TAC meetings, the TAC members, as well as many other organizations and members of the public, submitted formal comments on the draft study findings, and again on the draft report. While all the comments provided by the TAC members and other stakeholders were considered, this research remains an independent research project, and the study authors are solely responsible for the contents of the report.

Project Results

This study evaluates the cost and resource potential for biomethane, hydrogen and synthetic natural gas, collectively, renewable natural gas. Of these three gases, biomethane is the most commercialized and is lowest cost, but is limited in availability based on sustainable sources of biomass feedstock. Hydrogen and synthetic natural gas could be produced with low-cost electricity that might otherwise be considered "over-supply" and curtailed, but the quantity of this low-cost electricity is far lower than the amounts of electricity that would be needed to produce large enough quantities of hydrogen and renewable natural gas to replace natural gas use in California. Hydrogen use in the natural gas pipeline is limited to 7 percent by energy, before costly pipeline upgrade costs would be incurred to transport higher concentrations of the gas. Even under optimistic cost assumptions, the blended cost of hydrogen and synthetic natural gas is 8 to 17 times more expensive than the expected price trajectory of natural gas.

Renewable natural gas is found to be a valuable, but relatively expensive from of carbon reduction. Relatively low-cost biomass feedstocks are limited in quantity, so lower-cost PATHWAYS scenarios allocate these limited feedstocks to sectors that are difficult to electrify, like aviation, industry, and trucking. The limited supply of and competing uses for biofuels mean that scenarios that maintain high volumes of gas throughput in buildings require hydrogen and synthetic natural gas to reduce emissions.

In all the long-term GHG reduction scenarios evaluated here, electrification of buildings, and particularly the use of electric heat pumps for space and water heating, leads to lower energy bills for customers over the long term than the use of renewable natural gas. Likewise, building electrification lowers the total societal cost of meeting California's long-term climate goals. The High Building Electrification scenario is lower cost than the No Building Electrification scenario in 2050 by $5 billion to $20 billion per year (in 2018 dollars). The primary reason for this cost difference is the cost of decarbonizing natural gas with renewable natural gas, relative to electrification buildings. Furthermore, in the No Building Electrification scenario, a larger amount of fossil fuel emissions remain in buildings, which means that more expensive GHG mitigation measures, such as additional zero-emission trucks, are needed elsewhere to meet the economywide climate goal.

This strategy, of leaving more fossil fuel emissions in the building sector in order to minimize the reliance on expensive RNG, may not be possible in a scenario that achieves the state's 2045 carbon-neutrality goal. Achieving carbon neutrality in buildings would likely increase the relative costs of high RNG scenarios, such as the no building electrification scenario, compared to scenarios relying on building electrification.

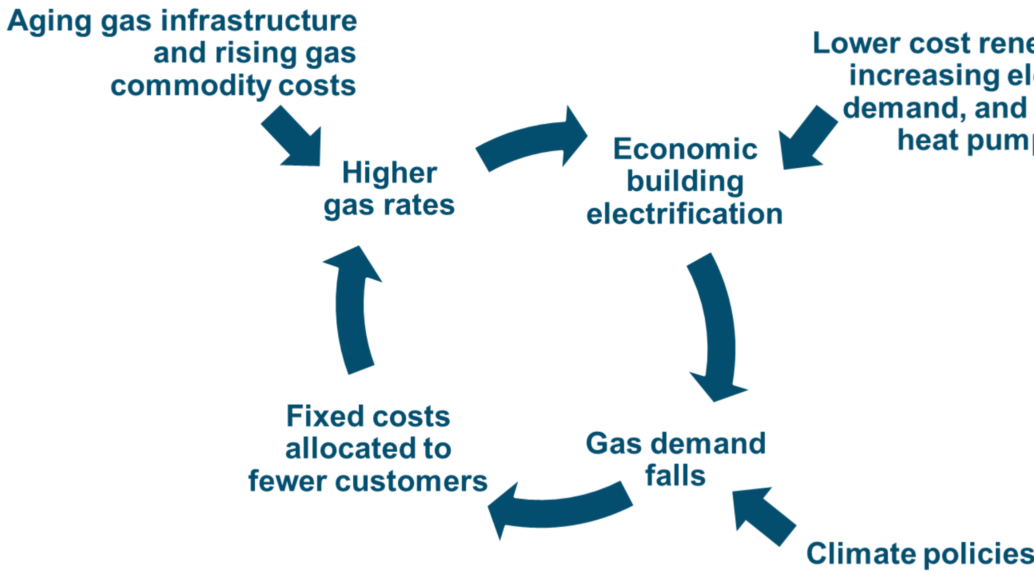
Building electrification is found to improve outdoor air quality and public health outcomes, particularly in the winter, when nitrogen oxide emissions create secondary fine particulate matter (PM 2.5) pollution in the Central Valley. Electrification in other sectors, including transportation and industry, also shows dramatic improvements in outdoor air quality.

In all scenarios, the cost of maintaining the electric grid, including the costs of wildfires and upgrades to the electric grid to prevent future wildfires, are expected to increase, even those scenarios with low building electrification. While is it uncertain what the magnitude of these electricity sector costs will be, wildfire adaptation costs are not expected to vary by scenario, so would not impact the net scenario costs, which are reported relative to the reference scenario. This study finds that the addition of new electric loads, in the form of electric vehicles and building electrification, helps mute these cost impacts on electric rates. Furthermore, these new electric loads offer the possibility to provide flexibility to the grid, which could help to reduce the cost of decarbonized electricity. Higher electricity costs will affect the relative customer economics of electricity versus RNG, so a wide range of potential electricity and gas system costs are explicitly evaluated. The economic results are found to be robust across a wide range of electricity and RNG costs.

In all of the scenarios evaluated here, some gas consumers will find it in their economic self-interest to electrify. Electrification is likely cost effective for large subsets of Californians today, so higher gas commodity costs only expand the set of end-uses and customer types that would find electrification advantageous. In any future where California meets its long-term climate goals, natural gas demand is likely to decline, putting upward pressure on gas rates and bills. That pressure may cause more customers to exit the gas system, as a feedback loop takes effect (Figure ES-1). The prospect of such a feedback loop makes it prudent for the state to begin considering strategies for managing the costs of the natural gas distribution system in California.

The decline in gas demand in all scenarios meeting the state's climate goals, and especially in the High Building Electrification scenario, poses significant challenges to maintaining equitable cost allocation. Residential customers pay most of the costs of the gas distribution system. The gas distribution system constitutes the majority of the book value of both California's major natural gas utilities. As residential customers exit the gas system, those costs are spread over a smaller quantity of throughput and number of customers, leading to increased rates for remaining customers. Absent a policy intervention, low-income customers who are less able to electrify may face a disproportionate share of gas system costs.

Figure ES-1: Outside Forces in the Natural Gas Delivery Sector Could Lead to Lower Gas Demand and Higher Rates in Future Greenhouse Gas Reduction Scenarios



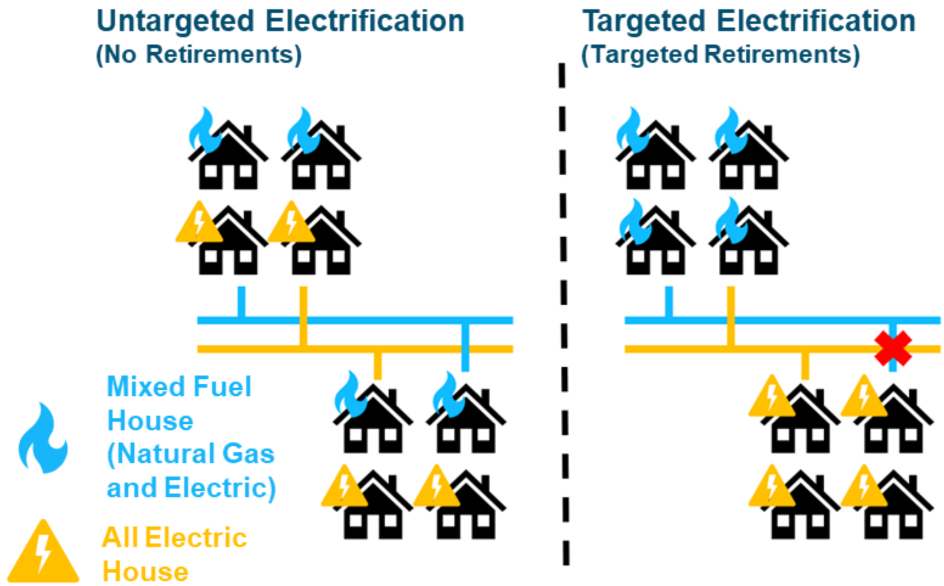
Source: E3

It is important for the state to consider a gas transition strategy to ensure that, even as gas demand falls, the system remains safe and reliable for the remaining gas customers while helping reduce future customer cost and utility bill impacts, as well as addressing equity challenges. Even in the High Building Electrification Scenario, which assumes a rapid transition to 100 percent of sales of all new water heaters and HVAC systems to electric heat pump equipment by 2040, there are still millions of gas customers remaining in California by 2050. Early retirement of gas equipment could speed the pace of this gas transition but would come with real economic costs that are difficult to estimate at this time. In addition, early retirement of gas equipment would likely face other challenges, including customer adoption barriers.

Given the long lifetimes of buildings and building equipment, a complete gas transition is likely to require decades in any scenario. For these reasons, this research evaluates potential gas transition strategies that aim to maintain reasonable gas rates, as well as the financial viability of gas utilities through the study period. Legal and legislative options, including strategies for a more rapid transition away from gas, are not evaluated.

A well-managed gas transition could enable cost reductions of gas infrastructure investments, as well as some reductions in gas system operations and maintenance costs that would be incurred in the absence of a gas transition strategy. Such a managed gas transition would likely require some amount of targeted or zonal electrification, to enable a reduction in the gas distribution infrastructure (illustrated on the right side of Figure ES-2). Without a managed gas transition and without any effort to target electrification, it would be difficult to reduce the size or scale of gas system investments and costs (illustrated on the left side of Figure ES-2). Additional research is needed to better understand the geographic scope, scale, pace, and limitations to reducing gas distribution system costs.

Figure ES-2: Two Gas System Futures With and Without Targeted Electrification



Source: E3

A further reason a structured gas transition is needed is that high-pressure gas transmission and underground gas storage systems may continue to serve important roles, even in a scenario with an 80 percent or higher reduction in GHG emissions. Those roles might include serving either natural gas or decarbonized gaseous fuels to remaining electric generation, industrial customers, compressed natural gas (CNG) trucks and other CNG transportation options, as well as potentially providing   benefits via distributed hydrogen fuel cells. A comprehensive analysis of the role of distributed fuel cells or the uses for the bulk gas system in a carbon-neutral future is beyond the scope of this analysis and is an area that deserves further investigation. However, each of these uses would need to rely on an increasing share of RNG to meet the state's climate goals, rather than continued reliance on fossil natural gas.

A structured gas transition could help ensure the continued viability of gas infrastructure assets that the state needs to maintain reliable energy service, while phasing down investments in gas distribution assets that become too costly to maintain as demand for retail gas declines. If the results of this research are correct in concluding that retail gas in a low-carbon future is likely to be more expensive than building electrification, it raises a number of challenging questions and areas recommended for additional research. Key policy questions include the following:

- If demand for retail gas declines, how should the benefits and costs of a gas transition strategy be allocated among stakeholders?
- If demand for retail gas declines, how can California protect low-income residents and gas workers during a gas transition?

Key engineering questions around gas pipeline safety and costs remain as well. These questions include the following:

- To what degree can targeted electrification efforts safely reduce gas distribution expenditures?

- What is the cost of targeted electrification, considering the potential for early retirements of consumer equipment? A better understanding is needed of the real-world technical and economic options to reduce gas system expenditures. Pilots and real-world research could help identify the costs and options to launch targeted electrification in communities in such a way that would enable targeted retirements of the gas distribution system and consider the impacts on the electric distribution system of targeted electrification, along with the potential for cost savings on the gas distribution system.

Finally, more research is needed to identify the legal and regulatory barriers to implementing a gas transition strategy, along with targeted electrification programs. For example:

- Should natural gas companies be able to collect the entire value of their gas system assets through 2050 or beyond? Should shareholder return be affected in a gas transition strategy? How does the timing of a gas transition strategy affect the answer to these questions?
- Should California gas utilities' obligation to serve be redefined?

This research paper does not seek to make policy recommendations, but rather highlight key issues for further policy discussion. The paper also seeks to illuminate some of the implications of meeting the state's climate goals, with the goal that California's future is as equitable and well planned as possible.

Knowledge Transfer

The CEC has taken steps to ensure that a broad audience has the opportunity to comment on the draft results of this research. The Commission held a public staff workshop June 6, 2019. More than 30 unique public comments were filed to the docket. Additional public comment was solicited by the CEC on the draft report.

Some stakeholders have argued that California should move faster on meeting its climate goals compared to the scenarios evaluated in this study, phasing out the use of all natural gas as quickly as possible due to concerns over combustion emissions, indoor and outdoor air quality concerns, and the prospect of methane leakage—a high global warming potential gas. Other stakeholders have highlighted the uncertain mix of climate change impacts on the future costs of electricity in California. Wildfires, flooding, and extreme heat mean that the provision of reliable and low-cost energy services in the state is becoming more complex and challenging.

The research team envisions this project as a contribution to the continued conversation that stakeholders and policy makers will have over the next several years, as the state considers what steps will be needed to meet the goal of economywide carbon neutrality by 2045, and how to expedite a gas transition strategy that ensures an equitable transition to a low-carbon future for all California residents.

Benefits to California

This project highlights the need for long-term planning for the natural gas system in the context of meeting the state's climate goals. This project provides a long-term, scenario-based view to investigate how the natural gas system can help California meet its long-term GHG reduction goals. Specifically, this project benefits California by providing:

- Information to help lower the costs of meeting California’s climate goals and to inform technology research and investment. By taking a long-term view of the state’s climate goals and evaluating the role of the natural gas infrastructure in that future, this research allows the state to potentially avoid stranded assets in the gas system. Stranded assets are investments which are not used and useful, and for which the full investment cost cannot be recovered from ratepayers, triggering a premature write-down or devaluation. This project provides information about the potential for changes in natural gas demand and implications for future investments in the gas sector, the gas system rate base, natural gas prices (wholesale and retail), customers’ home energy bills, costs of GHG reduction, and capital and fuel costs by sector.
- Energy metrics to make better planning easier. Long-term scenarios provide information on economywide energy use by sector and industry, including energy demand for electricity and natural gas.
- Environmental and public health metrics. This project evaluates long-term, detailed criteria air emissions and pollutant levels statewide at a 4x4 kilometer grid within the context of meeting the state’s climate goals. By identifying scenarios that can provide cleaner air and improve public health, policy makers can develop policies to enable a future with cleaner air for Californians and particularly for environmental justice communities with a greater pollution burden.

CHAPTER 1: Introduction

California has a long-standing commitment to reducing greenhouse gases (GHGs) and combating climate change. The state's original climate change mitigation goals, set during Governor Arnold Schwarzenegger's tenure in 2005, aimed to reduce emissions to 1990 levels by 2020 and reduce GHGs by 80 percent below 1990 levels by 2050 (EO S-03-05). The 2020 goal was codified into law in 2006 in Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), while the 2050 goal remains an executive order.

A decade later, Governor Edmund G. Brown Jr. set a 2030 climate target for the state when he signed Senate Bill (SB) 32 (Pavley, Chapter 249) in 2016, requiring the state to reduce GHGs 40 percent below 1990 levels. In 2018, Governor Brown called for the state to achieve carbon neutrality by no later than 2045 (EO B-55-18). The carbon neutrality goal is in addition to the state's 80 percent reduction goal for GHG emissions.

This research project was defined before Governor Brown issued the 2018 carbon neutrality executive order, so the scenarios evaluated here focus on investigating futures that achieve a 40 percent reduction in GHGs by 2030 ("40 x 30") and an 80 percent reduction in GHG emissions by 2050 ("80 x 50"). To meet the state's carbon-neutrality target by 2045, it is safe to assume that most of the mitigation measures modeled here will be needed, as well as additional measures like negative emissions technologies that are not considered in this analysis. While more research is needed to understand the full scope and scale of actions needed to achieve carbon neutrality in California, the research findings presented here serve as a useful guidepost.

California's energy and climate policies extend beyond emissions targets. California law requires the state to achieve a 60 percent Renewables Portfolio Standard (RPS) by 2030 and meet 100 percent of retail sales from zero-carbon electricity by 2045 (SB 100, de León, Chapter 312, Statutes of 2018). Complementary to electric sector decarbonization goals are mandates and targets aimed at increasing the share of zero-emission vehicles on California roads. The state's energy transition also extends to the built environment. Recent legislation (AB 3232, Friedman, Chapter 373, Statutes of 2018) requires the California Energy Commission to examine strategies to reduce emissions from buildings 40 percent below 1990 levels by 2030. These and other policy mechanisms are moving California toward achievement of the state's long-term decarbonization requirements and targets.

This study evaluates and synthesizes the potential impacts of technology innovation, along with California's many long-term energy and climate policies, that are acting on the natural gas sector in California through 2030 and 2050. This research focuses particularly on impacts to retail gas delivered through the natural gas distribution system, the low-pressure system of pipelines that serve most homes and businesses in California. Other research (for example, Long, 2018; Ming, 2019) has evaluated the role of gas on the higher-pressure, bulk gas distribution system.

This project builds on recent studies pertinent to the future of the natural gas industry in California. These studies include recently completed California Energy Commission (CEC)

Electric Program Investment Charge - (EPIC) funded research into the impacts of climate change on temperature and hydroelectric availability in California, as well as the development of long-term scenarios of California's energy sector through 2050.

This study leverages Energy and Environmental Economics' (E3's) expertise in modeling long-term, low-carbon scenarios for the State of California using the California PATHWAYS model. In 2015, the CEC, California Public Utilities Commission (CPUC), California Air Resources Board (CARB) and California Independent System Operator (California ISO) engaged E3 in a joint effort to use the PATHWAYS model to develop statewide greenhouse reduction scenarios through 2050. E3 evaluated several low-carbon scenarios, including a "low-carbon gas" scenario that included the use of biomethane, hydrogen, and synthetic methane in buildings and industry, as well as the use of renewable compressed natural gas (CNG) in trucks. The PATHWAYS model has been further developed for use in CARB's Scoping Plan Update[1] and through support from the CEC's EPIC research program. However, none of those past studies have fully addressed the question of "what is the future of retail natural gas in California?"

The present study also builds on past work by synthesizing technical, economic, and achievable resource assessments of advanced biofuels and low-carbon technologies. Some of these studies had a high-level focus on the potential for synergies between natural gas and renewable electricity (Pless, 2015) without in-depth research on the potential advanced alternatives or the technical and economic aspects. Other studies had deep analysis of particular technologies (Melaina, 2013) or the potential feedstocks and conversion technologies without a focus on the potential for decarbonization of the natural gas system (DOE, 2016; McKendry, 2002).

This project builds on E3's 2018 report to the CEC titled *Deep Decarbonization in a High Renewables Future* (Mahone et al, 2018). That report modeled ten scenarios that all meet California's 2030 targets of a 40 percent reduction in GHGs below 1990 levels and an 80 percent reduction in GHGs below 1990 levels by 2050. A key finding of that study is that electrification is among the lower-cost, lower-risk strategies to decarbonize the buildings sector, given the cost and resource supply limitations associated with low-carbon gas. Informed by this approach, deep decarbonization in the buildings sector was recommended to avoid more expensive or speculative mitigation options elsewhere in the economy.

However, the 2018 study focused on economywide metrics[2] and did not evaluate in-depth what the implications of building electrification, or technology innovation in low-carbon gas technologies, would mean for the natural gas sector or natural gas customers in the state. This study takes a closer look at the distributional implications of building decarbonization in the context of the same 2030 and 2050 California GHG reduction targets. Of particular interest

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1 California Air Resources Board. November 2017. *California's 2017 Climate Change Scoping Plan*, https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

2 A total resource cost perspective captures the net costs of California's energy system relative to a reference scenario. This metric includes expenditures on infrastructure (for example, power plants, trucks, heating, ventilation, and air-conditioning [HVAC] equipment) and fuels (for example, jet fuel, biodiesel, renewable natural gas). This perspective does not, however, capture potential distributional implications of different GHG mitigation options on customers.

are the impacts of building decarbonization strategies on households' energy bills and the gas utilities themselves.

This project examines several aspects of strategies to decarbonize buildings in an economywide context. This examination included working with UC Irvine to look into a range of costs for renewable natural gas; a detailed analysis of the gas utility financials and rate impacts of low-carbon scenarios (for example, using a gas utility revenue requirement model); an examination of the consumer bill effects that follow; and an examination of potential gas system transition strategies.

This project asks three main research questions:

1) What are the technology options and potential costs to reduce GHG emissions from natural gas consumption in California?
2) What are the natural gas rate and utility bill implications of different strategies to reduce GHG emissions from natural gas use in California?
3) What are the air quality benefits and human health implications of different electrification and decarbonization strategies?

Technical Advisory Committee and Public Comments

The preparation of this report benefited from a wide range of inputs and perspectives throughout the study development and presentation of draft findings. The Technical Advisory Committee (TAC) members for this project listed in Appendix B represent a wide and diverse range of viewpoints on the topics covered by this research. More than 30 unique comments were filed as part of the public comment period on the draft study results, including comments from more than 200 Sierra Club members. In addition to written comments, many public comments were provided verbally in the staff workshop on June 6, 2019, and filed with the CEC in response to the draft report. Overall, the key areas of discussion and disagreement include:

- The pace and urgency of electrifying buildings as a decarbonization strategy.
- The availability and cost of biomass resources to produce biofuels as an alternative to rapid electrification in buildings.
- The availability and cost of hydrogen as an alternative to rapid electrification in buildings.
- The impact of wildfires and wildfire liability on the future cost and reliability of electricity.

This report does not represent a consensus document on these issues, and many areas of disagreement remain. However, the researchers have seriously considered all the comments provided by stakeholders and have responded to some of these comments directly in this report and to other comments in a "frequently asked questions" document in Appendix A.

Methods

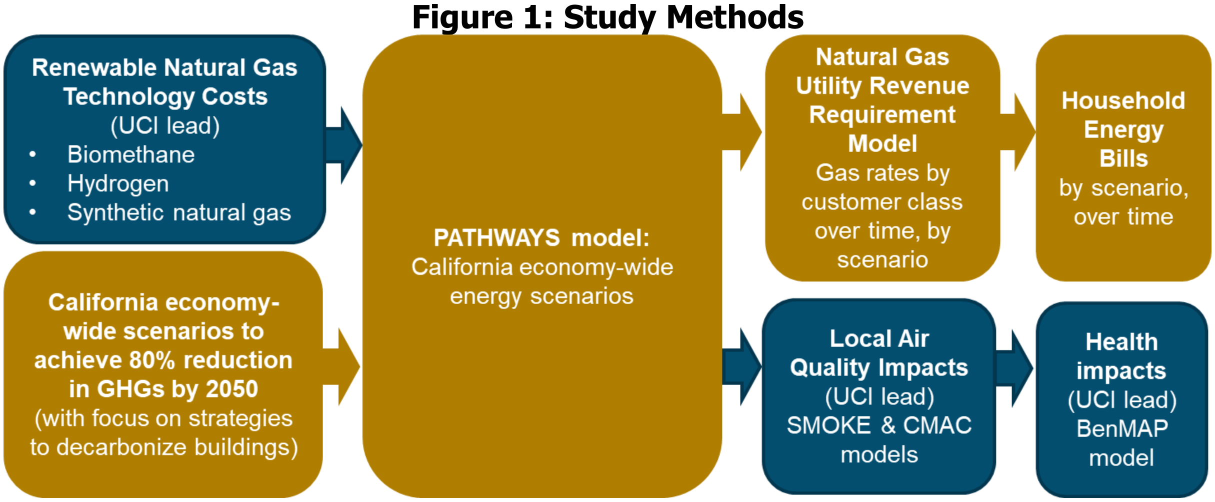
This research involved several phases of analysis steps, as illustrated in the figure below.

First, E3 worked with the University of California, Irvine (UCI) APEP (Advanced Power and Energy Program) (together, the research team) to develop assumptions for future costs and efficiencies of different biofuel conversion processes. APEP also conducted a technoeconomic assessment of power-to-gas pathways to produce renewable natural gas. That analysis examines a variety of different processes to produce hydrogen and synthetic natural gas. The result of that analysis is a conservative case and an optimistic case for the cost of electrolytic fuels ("power to gas").

The research team used these gas technology cost assumptions as inputs to the E3 California PATHWAYS Model. The authors' PATHWAYS model is used to develop economywide mitigation strategies that meet the state's climate policy targets using different combinations of mitigation measures. PATHWAYS is an energy infrastructure, energy and emissions counting model. A key source of variation in the PATHWAYS scenarios evaluated in this study is the blend of pipeline gas and the quantity of gas that is decarbonized.

Using the energy demand outputs from the PATHWAYS model, E3 evaluated how changes in natural gas demand by sector could affect natural gas utility revenues, gas rates, and customer energy bills. To perform this analysis, E3 developed the Natural Gas Revenue Requirement Tool (RR Tool). The RR Tool tracks utility capital expenditures, depreciation, and operational costs given user-defined scenario inputs, including changes in natural gas consumption by sector (from PATHWAYS scenarios), gas equipment reinvestment and depreciation schedules, cost allocation assumptions and the utility cost of capital, among other financial criteria. The tool is benchmarked to general rate case (GRC) filings from Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E),[3] the state's two largest gas distribution utilities. The tool returns gas rates by customer class through 2050. It also includes the ability to model potential gas transition scenarios to reduce the customer bill impacts, as an illustration of some of the strategies that might be considered in more detail going forward.

Figure 1: Study Methods



Source: E3

E3 also developed a bill impacts calculator. The residential customer utility bill calculations in this analysis combine estimates of future electricity rates and gas commodity costs from the

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3 The research team relied on the following regulatory filings to build and benchmark the revenue requirement models: PG&E GCAP 2018, PG&E GRC 2020, PG&E GTS 2019, SCG TCAP 2020, SCG GRC 2019, SCG 2017 PSEP Forecast Application, SCG PSEP Forecast application.

PATHWAYS model with gas delivery rates from the RR Tool. The result is a comparison of future utility bills for an "all-electric" and "mixed-fuel" customer in each scenario.

Finally, the UCI APEP team used the PATHWAYS scenario results to inform a detailed air quality and health impacts analysis. The energy demands from the PATHWAYS scenarios were geographically distributed using a tool called Sparse Matrix Operator Kerner Emissions (SMOKE). Then, the air quality impacts of these scenarios were simulated using the Community Multiscale Air Quality Modeling System (CMAQ) tool, accounting for atmospheric chemistry and transport effects to establish distributions of ground-level ozone and $PM_{2.5}$ at a local level. The air quality results were then translated into human health and health benefits metrics using the Environmental Benefits Mapping and Analysis Program (BenMAP) tool. The air quality analysis is discussed in Appendix F.

Building Electrification in California Versus Other Regions

This study finds that electrification in buildings is likely to be the lowest-cost means of dramatically reducing GHG emissions from California's buildings. However, this finding is influenced, in part, by California's relatively mild winter climate.

Electric heat pumps are an efficient means to deliver heating and cooling, but the associated efficiency decreases as the outdoor air temperature drops. Electric resistance heating is commonly used as a supplemental heat source in cold climates, but this use can also lead to substantial new electric-peak demands and the needs for new electric infrastructure in colder climates. Cold climate heat pumps are making important technology strides, but "peak-heat" challenges have been identified as legitimate concerns in colder climates, including parts of northern Europe (Strbac, 2018) and the northern United States (Aas, 2018). Peak heat needs occur during the coldest periods of the year when demand for heating in buildings in highest. These cold periods become particularly challenging when they correspond to periods of low renewable electricity availability. Research in those colder jurisdictions tends to find a plausible ongoing role for low-carbon gas as a "peak-heat" capacity resource.

In studies from colder regions of the world, electrification is also identified as an important strategy to decarbonize buildings, however with a greater reliance on supplemental heat sources. For example, a recent report commissioned by a coalition of European gas utilities finds that widespread electrification of buildings is necessary to achieve the continent's climate goals, and it can be achieved at reasonable cost (Navigant 2019). In that study, gas is used in buildings solely as a capacity resource to avoid large electric sector upgrades. In contrast, in California, with its relatively mild winters and warm summers, electrification of buildings is not expected to cause the state's electricity system to shift from summer peaking to winter peaking (Mahone, 2019). However, more research into local distribution upgrades associated with electrification, as well as changes in electricity demand under future weather conditions influenced by climate change, are both warranted.

This research also did not consider scenarios with greater than 7 percent (by energy) hydrogen blended into the gas pipeline, due to the projected costs of upgrading the gas distribution system and end-use appliances to handle higher blends of hydrogen gas. In European studies, hydrogen in the gas pipeline has been suggested as an option for back-up heating needs in cold climates but, to the author's knowledge, has not been suggested as a cost-effective alternative to building electrification for meeting the majority of annual energy demands in buildings.

CHAPTER 2: Technology Options to Decarbonize the Natural Gas System

Overview

Renewable natural gas (RNG) is an umbrella term that can encompass several low-GHG substitute fuels for fossil natural gas (primarily methane). This report evaluated four categories of RNG: biomethane derived from waste biogas resources via anaerobic digestion, biomethane derived from waste or residues via gasification of biomass (a biofuel production process), hydrogen derived from electrolysis, and synthetic natural gas derived from hydrogen and a renewable CO_2 source (Figure 2). These fuels allow the continued use of natural gas distribution infrastructure, but each has limitations.

Biomethane, purified from biogas sources such as landfills, organic waste digesters, and manure digesters, represents the form of RNG commonly available today, but supplies are limited. Thermochemical processing of agricultural and forest residues and some urban wastes via gasification extends the potential supply of biomethane. However, these residues can also be processed for competing uses, such as liquid biofuels to substitute for petroleum-derived fuels.

Hydrogen can be produced relatively efficiently from zero-carbon electricity via electrolysis, but an upper limit for how much hydrogen can be blended in the existing pipeline system with only modest upgrades is 7 percent by energy (20 percent by volume).[4]

Synthetic natural gas (SNG) also uses electricity as an input and can be directly substituted for fossil natural gas, but it requires a renewable, climate-neutral CO_2 source in addition to hydrogen. Waste bio-CO_2, the waste CO_2 byproduct of ethanol production, is available to produce SNG, however, this low-cost source of climate-neutral CO_2 is relatively limited. Once waste bio-CO_2 sources of CO_2 have been used up, other more expensive sources of climate-neutral CO_2 are needed produce SNG using not-yet commercial technologies such as direct air capture. Collectively, hydrogen and SNG are referred to here as examples of electrolytic fuels, or more specifically as power to gas (P2G) because electricity (power) is used to produce the gas.

For each of these fuel categories, the research team modeled the costs (including costs of energy, capital, and feedstock, where applicable) and the resource potential. The biggest drivers of costs and potential for biomethane are the underlying feedstock supply curves, the conversion efficiencies, and the competing demands for other fuels and sectors. For electrolytic fuels, the costs of input electricity and the assumed effects of innovation on capital costs over time are important drivers.

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4 See Appendix C. Some literature supports a maximum of only 5 percent blending, by energy, without pipeline system upgrades. It was assumed here that up to 7 percent could occur with about $1 per million British thermal units (MMBtu) levelized cost of upgrades, based on Haines et al. (2005). Because 5 to 7 percent represents a small fraction of pipeline throughput, the results are not very sensitive to this assumption.

Figure 2: Four Categories of Renewable Natural Gas That Could Be Used Within Existing Distribution Infrastructure

Waste biogas	Gasification of biomass	Hydrogen	Synthetic Natural Gas
Sources: Municipal waste, manure	**Sources:** Agriculture and forest residues	**Sources:** Electrolysis + zero-carbon electricity, or steam methane reformation with carbon capture and sequestration*	**Sources:** Renewable hydrogen + CO2 from biowaste (bi-product of biofuel production) or direct air capture
Constraints: Very limited supply	**Constraints:** Limited supply and competing uses for biofuels	**Constraints:** Limited pipeline blends (7% by energy, 20% by volume) without costly infrastructure upgrades**	**Constraints:** Limited commercialization, low round-trip efficiency

***This analysis did not model SMR + CCS for hydrogen production.**
****This analysis did not evaluate conversion of the gas system to 100 percent hydrogen, which would require replacement of end-use devices and gas pipeline upgrades.**

Source: E3

Biomethane

Biomethane analysis is integrated with analysis of liquid biofuels, including renewable gasoline, diesel, and jet fuel, and is conducted using the E3 biofuels module described in Mahone et al (2018). This module allows selection of an ideal economywide biofuels portfolio given scenario demands, allocating scarce biomass to competing final fuels. All biofuels are derived from the limited supply of sustainable biomass assumed to be available to California, and most or all of this biomass is used in the mitigation scenarios described in Chapter 3.

Biomass Potential

As in Mahone, 2018, sustainable biomass is defined as consisting of California municipal solid waste (MSW), manure, agricultural residues, and forest residues, in addition to imports of similar feedstocks from other states up to a total equaling California's population share of the United States supply, estimated at 43 million dry tons per year by 2040. Raw biomass supply curves are developed from the United States Department of Energy (DOE, 2016), and these are supplemented by adding resources from Jaffe (2016), which has greater resolution on in-state MSW and manure than DOE (2016). As in E3's prior work, purpose-grown crops and forests primarily for bioenergy production are excluded from all scenarios due to ongoing sustainability concerns, including emissions from indirect land-use change, as well as uncertainty around the plausibility and cost of developing the supply chains necessary to grow, deliver, and process new types of purpose-grown crops for biofuels.[5]

The estimate of 43 million dry tons, including imports of biofuels to California from other states, is comparable to the ranges of California biomass estimates by other studies including the 2017 CEC Integrated Energy Policy Report (IEPR). The author's estimates are higher than all previous assessments of in-state biomass (without including imports), with the exception of the "high biomass scenario" in Youngs and Somerville (2013). These studies are reviewed in Appendix D and include assessments by the California Biomass Collaborative (Williams et al. 2015), reviewed in the 2017 CEC IEPR, as well as more recent assessments by Breunig et al (2018).[6]

Conversion Efficiency and Costs

Anaerobic digestion is a series of biological processes through which microorganisms decompose moist biomass in the absence of oxygen. The products are digestate and biogas, which is typically around 60 percent methane. In order to blend biogas into the gas distribution pipeline, it must be upgraded to remove impurities and increase the share of methane in the gas. Pipeline quality biogas is referred to as biomethane.

Anaerobic digesters are a mature and commercialized technology and are being used at facilities like wastewater treatment plants and agriculture and livestock farms. Because some of the bioenergy content is consumed by microorganisms and left in the digestate, the methane yield is relatively low, for instance, about 38 percent higher heating value (HHV) energy efficiency for dairy manure today. This analysis assumes that industry learning increases the assumed yield over time, reaching 47 percent HHV energy efficiency for dairy manure by 2050. Additional cost is associated with upgrading and injecting the methane into the pipeline. Landfill gas is a special case where the digestion is already inherent to the landfill and most gas is already collected in California, so only the upgrading and injection incur costs.

Gasification reacts fuels with air in a high-temperature, limited oxygen environment to turn dry biomass such as cellulosic or woody feedstocks into syngas, a gaseous mixture composed primarily of hydrogen and carbon monoxide, that is then converted to methane. (Wet feedstocks such as food waste can be gasified as well, with some energy penalty for predrying.) Gasification is a mature technology but not as commercially common as anaerobic digestion for this purpose, and is more expensive, with larger facilities typically required. However, yields are relatively high, and this analysis assumes that they reach 75 percent lower heating value (LHV) energy efficiency for dry woody feedstocks by 2050 compared with 67 percent today. As with anaerobic digestion, upgrading the gas and injection into the gas pipeline also incur costs. Full conversion efficiency and costs for obtaining pipeline-quality biomethane from raw feedstocks are found in Appendix D.

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5 In addition to the references in Mahone, 2018, also note newer work highlighting the concerns about large-scale use of purpose-grown bioenergy resources such as Norton et al. (2019) and IPCC (2019).

6 Breunig et al (2018) estimate up to 71 million dry metric tonnes of gross biomass potential in 2050, but the technical potential of recoverable biomass for fuel was estimated at 40 million dry metric tonnes (44 million dry short tons; obtained via personal communication with H. Breunig in 2018).

Biomethane Potential

With these conversion assumptions and biomass resources, the research team projects the technical potential for biomethane availability for California in 2050, assuming that all available 43 million dry tons of biomass is used exclusively for biomethane. This potential is 635 trillion Btu, which is near the high end of the range estimated in the literature for other studies that estimate the RNG potential for California. A detailed comparison with these studies and explanations for differences is presented in Appendix D.

Biofuel Portfolios

Along with biomethane conversion assumptions, liquid fuel conversion assumptions are used in determining the optimal biofuel portfolios. Commensurate with the cost reductions assumed from industrial production "learning by doing" for biomethane pathways, this analysis incorporated industry learning for advanced liquid fuel pathways that included thermochemical pyrolysis and Fischer Tropsch to convert cellulosic and woody feedstocks to drop-in renewable gasoline, diesel, and jet fuel. Biochemical hydrolysis of cellulosic feedstocks to advanced renewable ethanol was also considered, and conventional corn ethanol was assumed to be phased out consistent with the exclusion of purpose-grown bioenergy resources. Overall, the energy efficiency of thermochemical conversion to liquid fuels reaches about 60 percent by 2050 for conversion of woody feedstock to renewable diesel compared with 54 percent today, somewhat less than assumed for gasification. Complete conversion assumptions are found in Appendix D.

In the PATHWAYS scenarios described in Chapter 3, remaining liquid and gaseous fossil fuel demands are calculated after scenario-driven efficiency and electrification mitigation measures are applied. Given remaining liquid and gaseous fuel demands in those scenarios, and a set of feedstock and conversion cost assumptions, PATHWAYS identifies an optimal biofuels portfolio that maximizes cost-effective CO_2 emissions reduction.

All or nearly all the biomass is used in both mitigation scenarios. In the optimal portfolios, much of the biomass is converted to liquid fuels because of the higher emissions intensity and cost of petroleum fuels compared to natural gas. Some biomethane is also produced for use in CNG trucks, as these attain an assumed market share of at least 24 percent of heavy-duty trucks by 2040, displacing additional petroleum. After accounting for the limited biomethane potential and the competing uses of the feedstock for liquid fuels, biomethane is blended in the range of 15 and 25 percent of natural gas throughput in 2050 in the economywide PATHWAYS scenarios.

As in Mahone, 2018, biofuels costs are based on a single market-clearing price, with economic rents flowing to lower-cost biomass suppliers. Here, the market-clearing price assumes a single implicit carbon price for biofuels across sectors and fuels. Due to the increase in conversion efficiency assumed to occur over time in this study, final biofuels prices are lower than in E3's prior work.

Market-based policies such as the Low Carbon Fuel Standard (LCFS) and cap and trade are not modeled. This analysis uses a societal cost framework that excludes transfers among customers within California. Furthermore, it is unclear what the 2050 carbon prices for LCFS credits or the cap-and-trade market would look like in a future that achieves an 80 percent reduction in GHG emissions economywide.

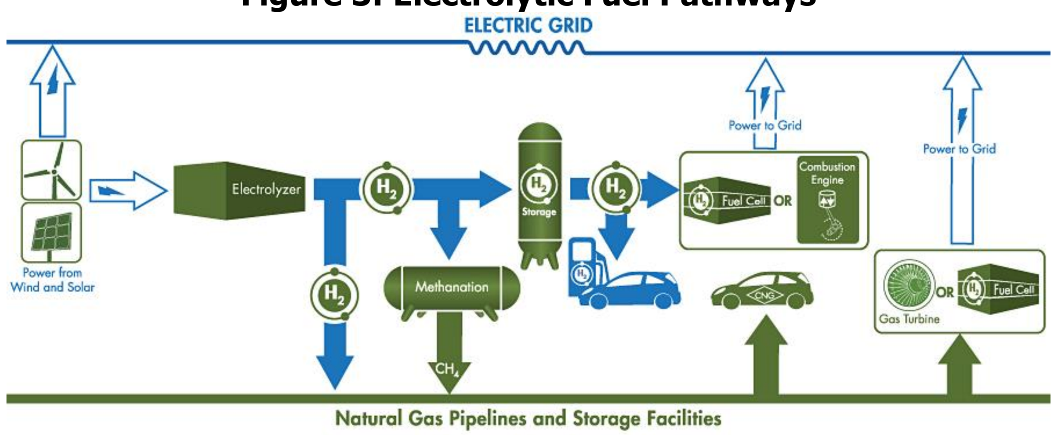
Electrolytic Fuels: Hydrogen and Synthetic Natural Gas

Overview

Power to gas (P2G) is a subset of electrolytic fuels that are considered here as options to be blended into or replace natural gas in the gas transmission, distribution, and storage infrastructure (the "gas system"). P2G consists of transforming electricity to energy in the form of either hydrogen or methane, which can be considered zero-carbon if the electricity source is zero carbon and associated emissions such as fugitive methane or hydrogen are reduced or otherwise accounted for. Because P2G connects the electric grid and the natural gas system (Figure 3), it allows complementary characteristics of these two energy distribution systems to be used, such as the seasonal storage capabilities of the gas system.

Electrolytic fuels have also been modeled, in prior studies, to be a cost-effective use of variable renewables such as wind and solar, which may need to be overbuilt to serve demands at high levels of renewable penetration (Shaffer, Tarroja, & Samuelsen, 2015; Eichman, Mueller, Tarroja, Schell, & Samuelsen, 2013; Baranes, Jacqmin, & Poudou, 2017). However, in the scenarios defined in Chapter 3, the significant quantities of P2G used as a fuel would very likely require additional dedicated renewable capacity to produce the fuel, far more renewables than would be available as oversupply of renewable generation that was developed to satisfy other electricity demands. This requirement is because the energy demands associated with producing hydrogen and synthetic natural gas at the scales envisioned in deep decarbonization scenarios far exceed the amount of electric curtailment that would occur in an electric system that balances curtailment, storage deployment, and use of firm generating resources for reliability (Chapter 3).

Figure 3: Electrolytic Fuel Pathways



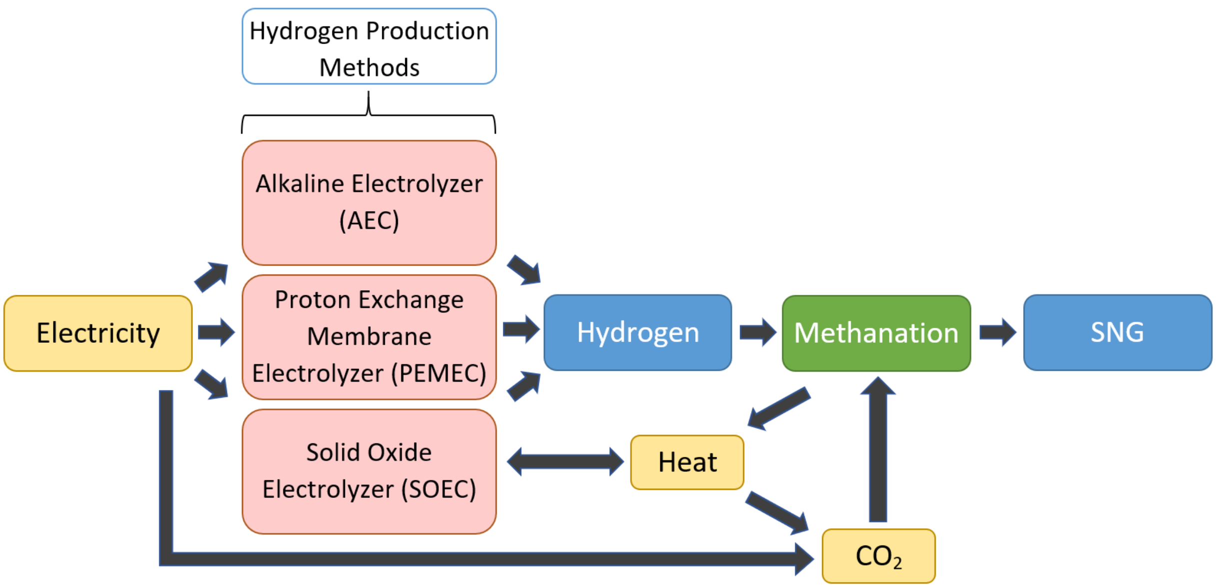
This is an illustrative schematic; not all pathways shown here are considered in this study. The hydrogen- and CNG-fueled cars represent broader use in the transportation sector including in trucks.

Source: UCI APEP

An assortment of P2G technologies are being considered in the academic literature as well as in small commercial pilots, and these are reviewed in more detail in Appendix C. The research team selected technologies based on the related environmental characteristics and a technology readiness level (TRL) of 6 or higher.[7] Only pathways that could be considered zero carbon in a decarbonized energy system were included. For instance, sourcing CO_2 from post-fossil-fuel-combustion capture was excluded, and this analysis did not assume that excess zero-carbon waste heat from industry or combined heat and power (CHP) would be available as an input (Figure 4).

Two key technology choices are the type of electrolyzer and the CO_2 source; other technology considerations are discussed in Appendix C. Electrolyzer technologies included in this study are alkaline electrolytic cells (AECs), proton exchange membrane electrolytic cells (PEMECs), and solid oxide electrolytic cells (SOECs). AECs and PEMECs are common today, while SOECs have the highest efficiency and the greatest potential for price reduction with increased scale, even though they are more expensive today.

Figure 4: Flowchart of Analyzed Power to Gas Pathways



Source:

Source: UCI APEP

The CO_2 source technologies considered include post-combustion capture (PCC), direct air capture (DAC), and electrolytic cation exchange modules (E-CEM). PCC is considered only in the case of co-locating P2G plants with a biorefinery to source carbon dioxide from them. Biorefineries such as those producing biofuels from anaerobic digestion, pyrolysis, hydrolysis, and gasification have streams with relatively high concentrations of CO_2 (Jones et al., 2013; Kabir Kazi, Fortman, & Anex, 2010; Humbird et al., 2011; Davis et al., 2014; N. C. Parker,

7 The *technology readiness level* is a metric used by the United States Department of Energy (U.S. DOE, 2011) and other sources to assess the maturity of technologies and readiness for commercial-scale deployment. It ranges from 1 for basic research to 9 for fully mature: operation of the actual system over the full range of operating conditions.

Ogden, & Fan, 2008; Liu, Norbeck, Raju, Kim, & Park, 2016), which can be separated from the streams relatively efficiently.[8]

DAC involves a liquid solvent or solid sorbent to capture CO_2 from the ambient air. These approaches are being tested in pilots by Carbon Engineering (based in North America) and Climeworks (based in Switzerland), respectively. Because of the lower concentration in ambient air, DAC is more expensive and is highly energy-intensive. A recent review (NAS, 2018) found it required 0.15 to 0.47 megawatt-hour (MWh) electricity input and 3.2 to 10.1 MMBtu of heat input per tonne of CO_2 captured, which is assumed here to be provided by electric resistance heating.[9]

The United States Navy is pursuing E-CEM technology, which is promising due to the ability of the technology to capture carbon dioxide and hydrogen from seawater (Parry, 2016). However, it has a lower TRL than DAC and is projected to be higher cost, so it is not included in the PATHWAYS scenarios in Chapter 3.

Projections of Efficiency and Cost for P2G Pathways

For hydrogen and SNG, the research team determined the efficiency and cost metrics over time as a function of five major inputs. The resulting efficiency and cost metrics included the levelized per-unit capital costs, variable operations and maintenance (VOM) costs, and the overall energy efficiency in units of MMBtu of fuel produced per MMBtu of electricity input.

1. Industry learning rate and global installed capacity: The industry learning rate is used along with Wright's Law (Nagy, Farmer, Bui, & Trancik, 2012) to project future cost declines as cumulative global installed production capacity increases. Higher learning rates and greater global industry scale-up lead to greater cost decreases.
2. Electrolysis technology: This technology is discussed above.
3. CO2 source (for SNG): CO2 is a waste product of biofuel production and may be used as a climate-neutral CO2 source for SNG production. This product is referred to as a biorefining CO2 coproduct and is used to produce SNG when possible, as a cost saving measure. However, the availability of this biorefining CO2 coproduct depends on SNG production colocated with biorefining, which is assumed to be limited in each scenario. After this supply is exhausted, DAC is used as the CO2 source for SNG production.
4. Energy supply: This analysis assumes the energy is provided by utility-scale solar PV or wind generation, harmonized with the PATHWAYS scenario cost assumptions. The electricity could be provided on-grid. If operated flexibly, hydrogen and SNG production could help to integrate renewable generation on the grid, for example, by turning on during periods of renewable overgeneration, and turning off during peak demand

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8 Technically, no combustion need occur in some of these biorefining processes, but this study uses the term "post-combustion capture" to be consistent with the commonly used term in the literature.

9 A tonne is a metric ton. Metric units are used throughout this report. As discussed, large quantities of waste heat input may not be available in a low-carbon future. The temperature required varies depending on the DAC process, ranging from 100 to 900 ° Celsius. Other sources for this waste heat, not evaluated here, include natural gas with CCS, collocating electrolytic fuel production with nuclear power, additional biomass, concentrating solar thermal, or a heat pump at the lowest end of the temperature range.

periods. Off-grid fuel production avoids new transmission costs. The research team determined the latter option was more cost-effective in the scenarios modeled here. In particular, researchers assumed enough flexibility in other loads that the renewable integration benefits of on-grid fuel production were outweighed by the cost of new transmission.

5. Capacity (that is, load) factor: The capacity factor is implied by the source of energy supply. Greater capacity factors mean better capital utilization for P2G equipment and, thus, lower levelized capital costs; however, especially if the energy input is restricted to be zero-carbon, this improved utilization may mean higher energy costs. In these scenarios, researchers did not consider baseload zero-carbon feedstocks like nuclear power or fossil fuel with CCS, so the capacity factor is aligned with the renewable generation resources determined to be used.[10]

For many of these inputs, the research team developed assumptions for conservative and optimistic P2G cost scenarios. These assumptions are summarized in Table 1, with full details in Appendix C. The conservative cost scenario aligns more closely with the costing approach used elsewhere in the PATHWAYS modeling (Chapter 3).

Table 1: Summary of Power to Gas Assumptions

Assumption	**Conservative Scenario**	**Optimistic Scenario**
Industry Learning	Moderate learning and scale-up*	Rapid learning and scale-up*
Electrolysis Technology	Even proportions of AEC and PEM through 2030, transitioning to SOEC by 2040	Even proportions of AEC and PEM in 2020, transitioning to SOEC by 2030
CO_2 Source	Limited California bio-CO_2 coproduct, with most provided by DAC	Entirely bio-CO_2 coproduct from co-located Midwest biofuel production[11]
Energy Source	Off-grid California solar ($26/MWh and 25% cap factor in 2050)	Off-grid Midwest wind ($40/MWh and 40% cap factor in 2050)

***Moderate scale-up implied 0.3 terawatt (TW, a trillion watts) of global electrolysis capacity by 2050, while rapid scale-up implied 2.7 TW. (Today's capacity is estimated at 0.013 TW). See Appendix C for full details.**

Source: E3

In these two scenarios, this analysis projects the efficiency of hydrogen electrolysis with SOECs to reach 80 percent by 2050. The overall energy efficiency of SNG production is lower,

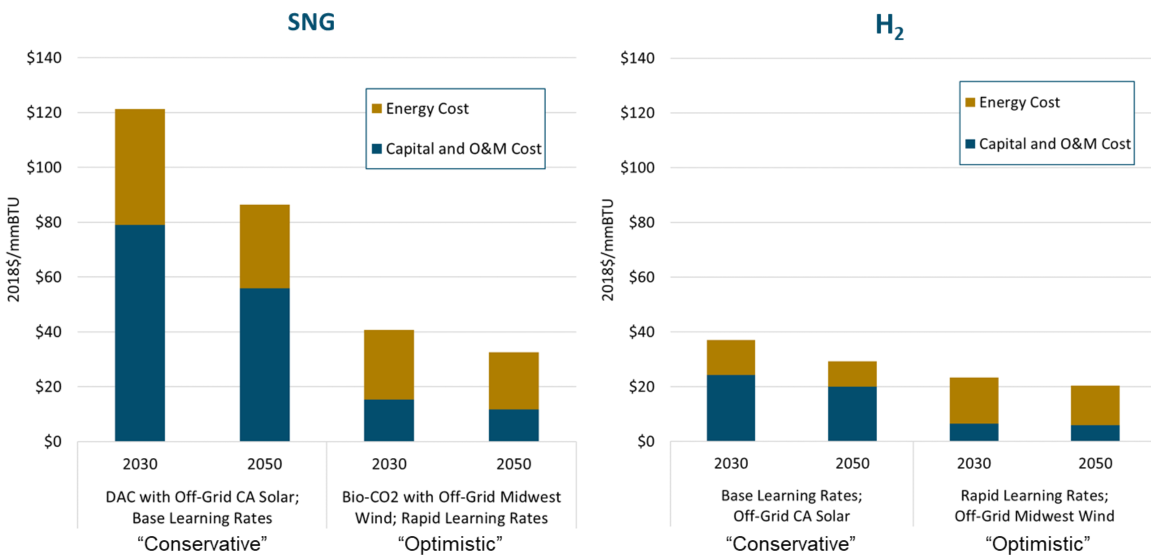
10 Higher capacity factor could be assumed if additional renewable integration solutions, such as batteries, were used to maximize P2G capital utilization, with uncertain impacts on total cost. This option was not evaluated here.

11 This requires coordination of biofuel production with SNG production outside California, the colocation of this production with off-grid wind farms, and California GHG credit for injection of this SNG into the gas pipeline system at the point of production.

as methanation and CO_2 supply are associated with additional conversion losses. The efficiency reaches 56 percent with bio-CO_2 and 45 percent with DAC in 2050.

The resulting all-in commodity costs are illustrated in Figure 5. The costs of SNG are very high when DAC is required. Even with modest cost declines due to industry learning, SNG produced from a new plant is projected to be $86/MMBtu by 2050 in the conservative P2G scenario, compared with a natural gas price forecast of $5/MMBtu. Commensurate with the optimistic case with full use of bio-CO_2 and rapid industry learning, costs from a new plant decline to just greater than $30/MMBtu in 2050, consistent with other studies (Navigant 2019). Commodity costs of hydrogen are projected to be much lower than those of SNG, reaching as low as $20/MMBtu for a new plant in 2050 in the low-cost scenario; however, the upper limit of 7 percent in the existing distribution pipeline system limits the benefit of this lower-cost P2G option.

Figure 5: Power to Gas Commodity Costs for Production From a New Plant in 2030 or 2050



These are costs for production from a new plant in 2030 or 2050 with either 100 percent DAC or 100 percent bio-CO_2 and a single electrolysis technology. The conservative and optimistic labels roughly correspond with the PATHWAYS scenarios shown in Chapter 3. In PATHWAYS, however, the capital costs are vintage over an assumed 20-year life, the CO_2 source blend varies over time in the base cost scenario, and the electrolysis technology blend also varies over time.

Source: E3

Renewable Natural Gas Supply Curve

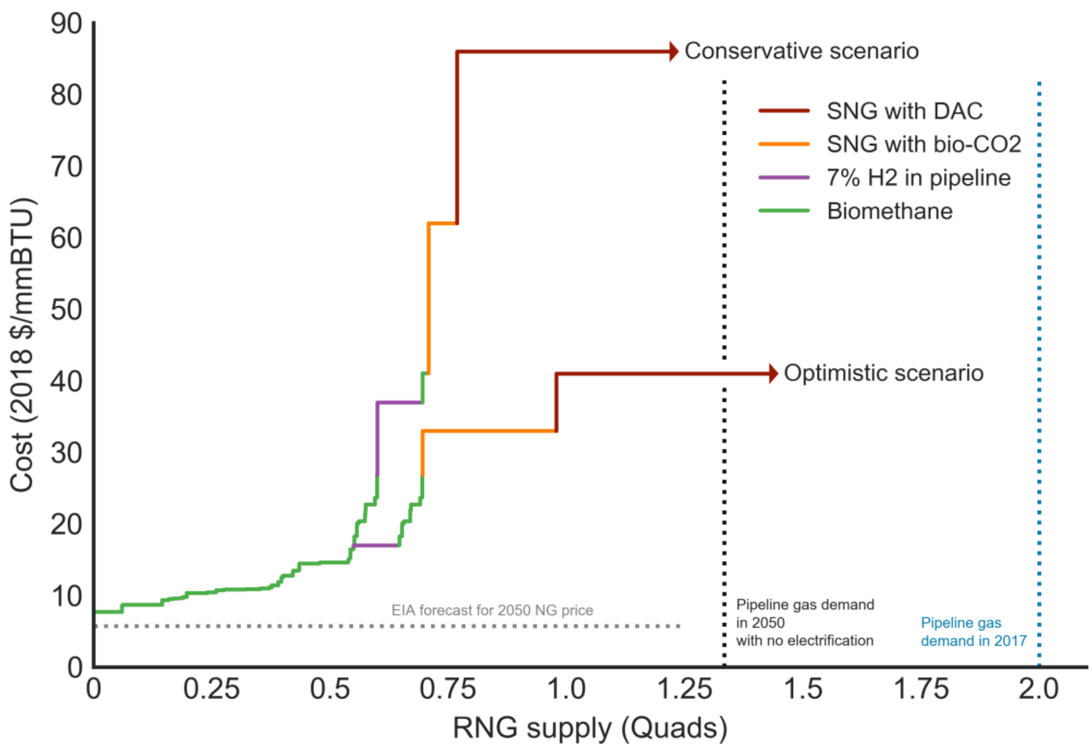
Figure 6 below summarizes the results of this section in a supply curve representing the technical potential for RNG available to California using the four categories of RNG assessed: biomethane from waste biogas via anaerobic digestion; biomethane from gasification of wastes and residues; electrolytic hydrogen up to a 7 percent pipeline blend; and electrolytic SNG, with a portion, representing the available bio-CO_2 followed by SNG with DAC as the marginal, potential-unlimited resource.

As was found in Mahone et al (2018), Figure 6 implies that there is insufficient low-cost, sustainable RNG supply to decarbonize the pipeline fully without electrification. Pipeline gas demand in 2017 was 2 quadrillion Btu (quads), including electricity generation. This demand could decline to 1.3 quads in a scenario with high energy efficiency and renewable electricity generation by 2050 (Chapter 3). However, the relatively low-cost RNG (from California's population share of United States biomass, excluding purpose-grown crops), provides only a maximum of 0.6 quads in the absence of any competing demands for this resource. Consequently, expensive portions of the RNG supply curve available would very likely be needed to decarbonize gas demand without electrification.

In the optimistic scenario, SNG with DAC at $41/MMBtu would be the marginal resource required to fully decarbonize the gas system in 2050.

With economywide decarbonization (Chapter 3), competing uses for the limited biomass resource available further reduce the economic potential of RNG. Much of the biomass may be used to displace relatively expensive and high-GHG-intensity petroleum fuels, such as diesel and jet fuel. Indeed, current state policy directs nearly all biofuel production toward transportation, most of this as liquid biofuels.

Figure 6: California Renewable Natural Gas Technical Potential Supply Curve in 2050, Assuming All Biomass Is Directed to Renewable Natural Gas



The biomethane supply curve segments (green) are based on allocating California's population-weighted share of United States waste and residue biomass entirely to biomethane. In the PATHWAYS scenarios, much of the biomass is used for liquid fuels to displace petroleum consumption in transportation and industry.

Source: E3

CHAPTER 3: California Economywide Decarbonization Scenarios

Methods

PATHWAYS Model

The California PATHWAYS model uses user-defined scenarios to test how mitigation measures interact across sectors and add up to meet deep economywide emissions targets. The California PATHWAYS model has been used in several California studies, including research that informed setting the state's 2030 GHG goal (E3, 2015), studies to model the California Air Resources Board (CARB) Scoping Plan Update (CARB, 2017), and CEC research exploring a range of scenarios to achieve an 80 x 50 goal for 2050 (Mahone et al, 2018). Because the model represents the stocks and turnover of building appliances and on-road vehicles, it represents the infrastructure inertia of the energy system. Modeling a deep decarbonization scenario requires making tradeoffs about how to allocate scarce fossil and bioenergy budgets across sectors to meet an economywide GHG constraint. For example, different scenarios may leave more fossil emissions in the transportation sector versus the industrial or buildings sector.

The model used in this study includes minor updates to that used in Mahone et al (2018) beyond the improved representation of RNG and biofuels discussed in Chapter 2 and described in Appendix E. Costs of renewable electricity generation and battery storage resources have been updated, resulting in lower cost renewable electricity post-2030.

In addition, retrofit costs for installing heat pumps in existing buildings were added, with a range of $0 to $8,000 of incremental capital cost assumed upon first fuel-switching to heat pump space heating for homes, depending on vintage and the presence of existing air conditioning (AC).[12] Retrofit costs were added in commercial buildings upon first fuel-switching, with a range of 0% to 100% of the capital cost of heat pump HVAC. Together, these retrofit costs add nearly $3 billion of annualized capital costs to high electrification scenarios in 2050 based on building retrofits over the preceding decades. This cost increment peaks in 2048 and would decline over time if the scenario were continued beyond 2050, as a smaller share of buildings incur retrofit costs over time. While incremental building electrification retrofit costs are uncertain, they were not found to significantly impact the study results.

12 See (Mahone et al., 2019) for a more detailed analysis of costs to retrofit existing buildings for electric appliances. The range here is based loosely on TRC (2016) and accounts for electrical panel upgrade costs, as well as first-time costs in the absence of existing air conditioning like compressor siting. See Appendix E for more details.

Scenario Design

In (Mahone et al., 2018), researchers developed 10 scenarios that met the climate goal of 80 percent GHG reductions below 1990 levels by 2050 ("80 x 50"). These scenarios tested the impact of greater or lesser reliance on key decarbonization strategies, like building electrification, biofuels, and hydrogen trucks. That study found that building electrification resulted in substantially lower economywide mitigation costs, relative to a scenario that excluded building electrification but had comparable other assumptions, such as biofuel availability.

In this study, the research team adapts several of the scenarios presented in 2018 to incorporate the biofuels and P2G analysis in Chapter 2, as well as other minor updates to cost and scenario assumptions. These scenarios (Table 2) were designed to investigate whether updated RNG cost information changes any of the previous findings, as well as to explore the distributional and air quality impacts of building decarbonization strategies (subsequent chapters). This report highlights two bookend scenarios, a "high building electrification" scenario (HBE) and a "no building electrification" scenario (NBE). Those scenarios are compared against a common baseline, the "current policy reference scenario" (shortened to Reference). Full scenario assumptions, such as key input measures by sector, are in Appendix E. Several additional scenarios were developed with intermediate levels of building electrification, but these were found to show predictable intermediate results on key scenario metrics, so they are included only in the appendix.

- Current Policy Reference: This scenario does not meet California's 2030 and 2050 GHG goals. It reflects the energy efficiency goals of Senate Bill (SB) 350, the CARB Short-Lived Climate Pollutant Strategy (SLCP—De León, Chapter 547, Statutes of 2015), the CARB Mobile Source Strategy, and other known policy commitments included in the 2017 Scoping Plan Update (CARB, 2017),[13] as well as a "zero-carbon retail sales" interpretation of SB 100.[14] Besides SB 100, additional updates since the 2018 published "Current Policy Scenario," based on recent trends and legal challenges, include assuming reduced progress in fuel economy standards of new vehicles and higher vehicle miles traveled (VMT). Only very high efficiency natural gas furnaces and water heaters are installed by 2025, and no building electrification is assumed.
- High Building Electrification: This scenario (based on the 2018 "no hydrogen" scenario) achieves a 40 percent reduction of GHGs below 1990 levels by 2030 and 80 percent by 2050. It includes high electrification of buildings. The scenario also includes high electrification of light-duty vehicles and moderate electrification of medium- and heavy-duty vehicles, with fuel-switching of most non-electrified diesel trucks to compressed natural gas (CNG) for air quality. The limited biofuel and fossil energy emissions

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13 As in previous PATHWAYS studies, the CARB Cap-and-Trade Program is not explicitly modeled, but it would be expected to contribute to further emission reductions beyond those associated with these known policy commitments.

14 Interpretation of SB 100, a 2018 law to decarbonize electricity, is still ongoing. This study assumes that it requires utilities to procure zero-carbon generation equal to their retail sales by 2045, with a small amount of remaining in-state or imported natural gas generation commensurate with losses, exports, and other exemptions. In 2030, SB 100 is represented as a 60 percent RPS.

budgets are allocated largely to transportation (particularly heavy-duty and off-road) and industry, including pipeline biomethane. Buildings are nearly completely decarbonized by 2050. Most but not all the available biomass is used for advanced biofuels, as the maximum portfolio is not needed to meet the economywide GHG target.

Table 2: PATHWAYS Scenario Summary of Key Metrics for 2050

Category	Reference	High Building Electrification	No Building Electrification
GHG Emissions	Does not meet state climate goals	Meets 40 x 30 and 80 x 50 goals	Meets 40 x 30 and 80 x 50 goals
Building Electrification	None	100% equipment sales by 2040	None
Industrial Electrification	None	None	None
Pipeline Biomethane (% energy)	0%	25%	16%
Pipeline H_2 (% energy)	0%	0%	7%
Pipeline SNG (% energy)	0%	0%	21%
Electric and Fuel Cell Trucks	Low	Medium	High
Advanced Biofuels	71 TBTU	478 TBTU	533 TBTU
Energy Efficiency	Meets SB 350	Exceeds SB 350	Exceeds SB 350
Light-Duty Vehicle Electrification	Medium	High: 100% Sales by 2035	High: 100% Sales by 2035
Short-Lived Climate Pollutants	Meets CARB SLCP Strategy	Exceeds CARB SLCP Strategy	Exceeds CARB SLCP Strategy
CNG Trucks	Displace some diesel trucks	Displace most non-electrified diesel trucks	Displace most non-electrified diesel trucks
% Zero-Carbon Generation	89%	95%	95%

Notes: The "40 x 30" goal is a 40% reduction of GHG emissions below 1990 levels by 2030, and the "80 x 50" goal is an 80% reduction of GHG emissions below 1990 levels by 2050. Although the blend proportion of biomethane is smaller in the no building electrification scenario, the total quantity is similar due to the greater pipeline throughput. Advanced biofuels exclude corn ethanol. SB 100 compliance is based on a zero-carbon retail sales interpretation, meaning that less than 100% of total generation is served by zero-carbon resources. The reference and no building electrification scenarios do not include any fuel substitution of natural gas end uses in buildings for electricity, instead maintaining a constant market share of natural gas end uses; however, some propane and fuel oil end uses are electrified. A more detailed listing of scenario measures is in Appendix E.

Source: E3

- No Building Electrification: In this scenario, fuel-switching in buildings is not assumed. Natural gas and electric appliance shares remain constant from 2015. This scenario represents a hypothetical bookend, as some economic or local policy-driven electrification is underway. Only high-efficiency natural gas furnaces and water heaters are installed by 2025. The same high level of light-duty vehicle electrification is assumed as in high building electrification, and most non-electrified diesel trucks shift to CNG. To make up for the emissions mitigation shortfall from not electrifying buildings, hydrogen and SNG are blended into the pipeline as well as biomethane; in addition, more battery-electric and hydrogen fuel cell trucks are included. Much of the limited biofuel and fossil energy emissions budgets are allocated to buildings. The pipeline gas blend remains 56 percent fossil natural gas by 2050 to avoid increasing scenario costs by blending additional expensive SNG. In addition to a similar amount of biomethane and renewable diesel as in the high building electrification scenario, the remainder of the biomass supply is used to make renewable gasoline and jet fuel to displace additional GHGs. For cost results, this analysis presents both using the conservative and optimistic P2G cost scenarios (Chapter 2).

Greenhouse Gas Accounting and Methane Leaks

PATHWAYS uses a direct GHG emissions accounting metric benchmarked to the CARB inventory for 2015 emissions. The CARB inventory is used to monitor California's progress against its emissions reduction targets. This inventory accounts for in-state emissions as well as emissions from imported electricity. It uses the 100-year global warming potentials (GWP) calculated based on the 2007 IPCC (the fourth assessment report) (Forster et al., 2007).[15] Because the inventory focuses on in-state emissions, upstream or life-cycle emissions from imported fossil fuels and biofuels are excluded,[16] as are embedded emissions from imported goods and raw materials. The 20-year GWP is sometimes used to emphasize the role of short-lived climate pollutants (SLCPs), such as methane, black carbon or fluorinated gases, which have a shorter residence period in the atmosphere than carbon dioxide in near-term warming. However, the research team cautions that neither GWP metric is universally appropriate.

15 The United States EPA explains 100-year global warming potential in the following way, "The Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO2). The larger the GWP, the more that a given gas warms the Earth compared to CO2 over that time period. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases." Quoted from United States Environmental Protection Agency (https://www.epa.gov/ghgemissions/understanding-global-warming-potentials).

16 To avoid GHG emissions from indirect land-use change, additional fertilizer use, and so forth, biofuels are limited to those derived from waste and residue resource (Chapter 2). Depending on the future biofuels industry development, fossil emissions associated with collecting, transporting, and processing the biomass may occur. Fossil natural gas extraction incurs significant upstream emissions from fugitive methane, but petroleum extraction and transport are also associated with large upstream emissions, varying widely depending on the petroleum source.

The CARB inventory includes fugitive methane emissions from in-state natural gas production and the pipeline system. The most recent inventory update (2019) also includes behind-the-meter methane leakage from homes, which is equivalent to roughly 0.5 percent of residential consumption, based on CEC research (Fischer et al., 2017). That increase represents a 4 percent increase in CO_2-equivalent (CO_2e) emissions associated with residential natural gas consumption, using the 100-year GWP (0.9 MMT CO_2e). The total fugitive methane emissions in the CARB inventory are equivalent to about 0.7 percent of statewide natural gas consumption. Recent studies support higher leakage proportions in the Greater Los Angeles Area and eastern United States metropolitan areas (He et al., 2019; Plant et al., 2015), but it is not yet clear whether these would generalize to all of California or the United States, respectively.

This study includes only fugitive emissions quantified in the 2015 CARB inventory and assumes that methane leak mitigation will proceed according to the CARB SLCP Strategy in all scenarios, achieving a 40 percent reduction by 2030. As a simplifying assumption and because of the absence of available data,[17] this analysis does not assume that reduction in gas consumption avoids any fugitive emissions, nor does it assume any increased fugitive emissions from gasification or SNG production. These assumptions collectively could lead to underestimating the magnitude of GHG emissions from continued use of methane in buildings. In particular, higher levels of behind-the-meter methane leakage would suggest that electrification of buildings could reduce more GHGs than estimated in this study.

Cost Accounting and Scenario Philosophy

PATHWAYS scenario economywide costs are based on a total resource cost (TRC) metric. This metric includes all direct energy system costs within the California economy resulting from fuel consumption and from capital costs from energy infrastructure associated with purchase of building appliances or vehicles, as well as incremental energy efficiency or fuel-switching capital costs. It does not represent transfers within the California economy such as Low Carbon Fuel Standard (LCFS) credits, the Cap-and-Trade Program, or other new policy incentives; distributional impacts will be discussed in Chapter 4 and Chapter 5. The metric also excludes societal costs from air pollution, both from local health impacts and GHG emissions. For a quantification of air quality benefits from electrification see the air quality results section of this report and Appendix F.

Technology costs for climate mitigation measures in PATHWAYS are generally conservative, representing expected, incremental innovation relative to commercially available technologies. No major cost reductions or market transformation are assumed *except* for biofuels and electrolytic fuels (Chapter 2). For instance, modeled heat pump space heater efficiencies in PATHWAYS improve only modestly from an achieved coefficient of performance (COP) of 3.2

17 It is unclear how much methane leakage could be avoided in a scenario with reduced throughput or partial shutdown of gas distribution infrastructure but without complete shutdown. Likewise, E3 is not aware of estimates of methane leakage associated with gasification and SNG production. Elimination of most natural gas appliances in buildings would save up to 0.9 MMT CO2e from behind-the-meter leakage not accounted for here.

to 4.3 for new installations between 2015 and 2030. No improvements are assumed between 2030 and 2050.[18]

This report focused on the potential innovation in RNG technologies specifically to test whether these would change the results from E3's 2018 Deep Decarbonization study, which showed that building electrification was a more cost-effective option to decarbonize buildings. In addition, this analysis does not assume any increase in air conditioning adoption relative to the adoption share found in existing buildings, even though recent trends that could be enhanced by climate change show greater levels of AC adoption.[19] This assumption is a modeling limitation that the research team intends to address in future studies. Previous work (Mahone et al, 2019) finds that heat pump space heaters have zero or negative incremental capital cost when central AC is present or planned. If there were more AC in the current policy reference scenario, the incremental cost of the high building electrification scenario would be lower than that calculated here.

Scenario Results

Energy Consumption

Both mitigation scenarios show a large increase in electricity demand and decrease in fossil energy demand relative to today's fuels, with especially large reductions in transportation fossil energy demand (Figure 7 and Figure 8). However, several differences between the high building electrification and the no building electrification scenarios emerge. The high building electrification scenario has lower energy demand overall because of the efficiency associated with building electrification. Both scenarios include substantial quantities of remaining fossil natural gas and relatively similar quantities of biofuels by 2050, but these are allocated to different sectors. The high building electrification scenario allocates more natural gas and biomethane to transportation, industry, and agriculture, while in the no building electrification scenario, about half of these fuels are consumed in buildings.[20] The no building electrification scenario also includes 53 trillion British thermal units (TBtu) of liquid hydrogen for trucks and 82 TBtu of hydrogen in the pipeline, plus 248 TBtu of SNG. Hydrogen, which is the less expensive electrolytic fuel, remains a small proportion of economywide fuel consumption in the no building electrification scenario because of the 7 percent pipeline blending limit and a substantial reliance on battery-electric trucks rather than hydrogen fuel cell trucks.

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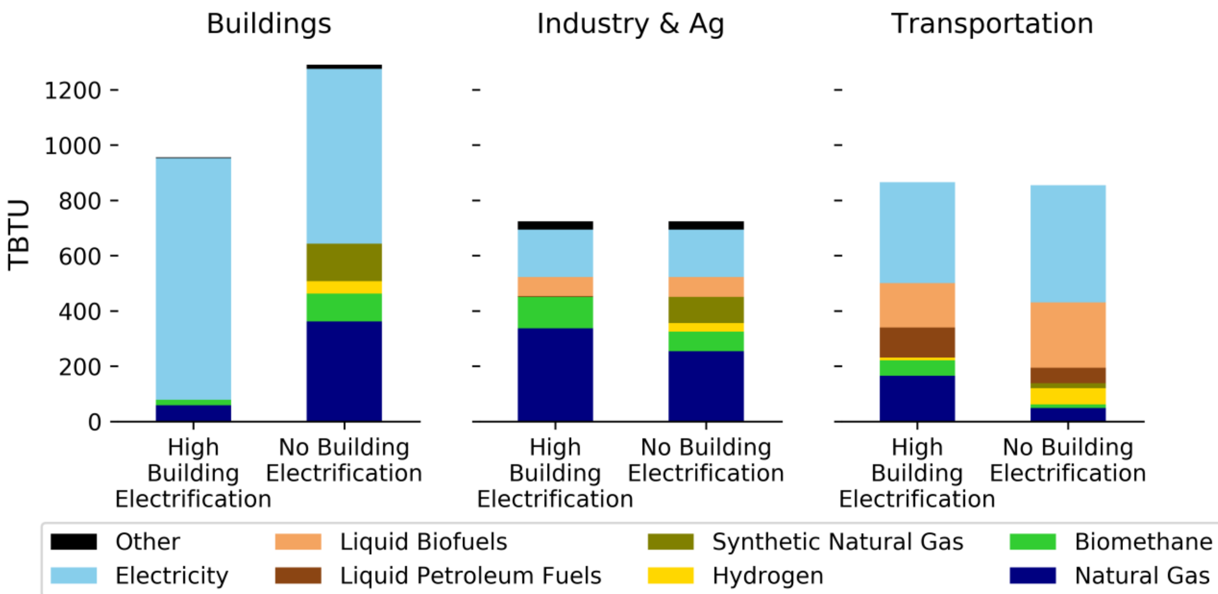
18 The *COP* is a measurement of the efficiency of the equipment. In California, where temperatures are relatively mild compared to other parts of the country, the achieved efficiency of heat pumps can exceed the rated efficiency. The COP assumptions applied in this study are conservative, as the COP of 3.2 is close to the code minimum requirement, and most models on the market would exceed it if properly installed.

19 The Residential Appliance Saturation Survey shows a trend of increasing central air-conditioning penetration in newer building vintages.

20 Both scenarios also allocate biomethane to electricity generation based on the pipeline blend assigned to other sectors. In the current PATHWAYS implementation, hydrogen and SNG are not allocated to electricity generation and are instead assumed to be used by other sectors (such as transportation, buildings, and industry).

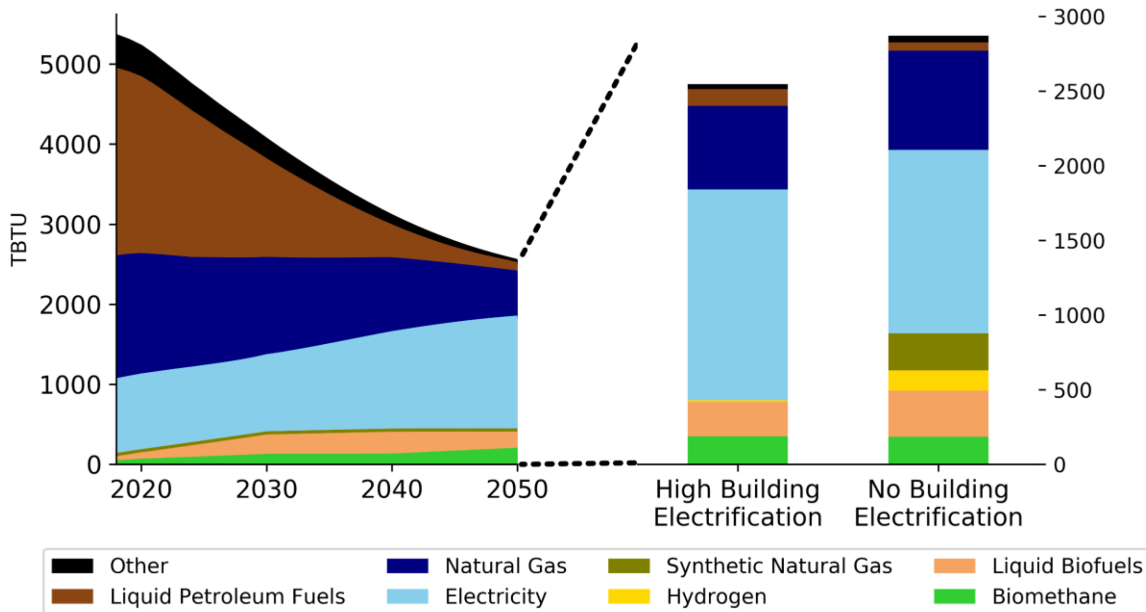
Figure 7: Final Fuel Consumption by Sector in PATHWAYS Scenarios in 2050



Final fuel consumption is final energy demand broken out by fuel constituent (that is, fossil fuel, biofuel, or electrolytic fuel). "Other" fuels include solid fossil fuels, wood, refinery gas, liquefied petroleum gas (that is, propane), and waste heat.

Source: E3

Figure 8: Economywide Final Fuel Consumption in PATHWAYS Scenarios

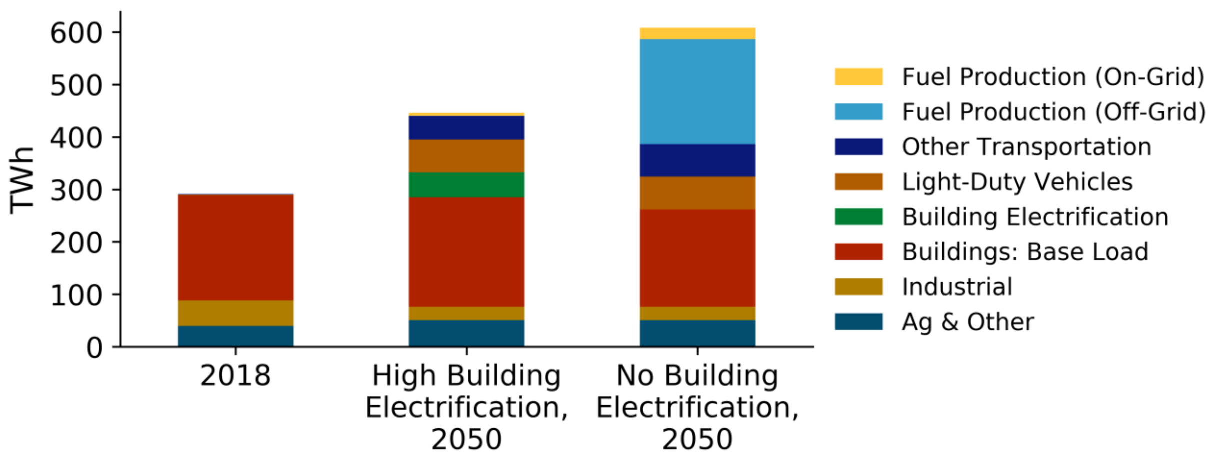


Final fuel consumption is final energy demand broken out by fuel constituent (in other words, fossil fuel, biofuel, or electrolytic fuel). "Other" fuels include solid fossil fuels, wood, refinery gas, liquefied petroleum gas (that is, propane), and waste heat. The bar charts on the right are for 2050.

Source: E3

Both scenarios show large increases in electricity loads relative to today's loads, but loads are greater in the no building electrification scenario, when the fuel production loads are accounted for. Fuel production loads total 195 to 222 TWh in 2050, depending on the P2G cost scenario, compared with today's loads of about 293 TWh. Most of these fuel production loads are assumed to be served by off-grid wind and solar, so they may avoid buildout of new transmission and distribution infrastructure. Off-grid renewables are cheaper than on-grid renewables once accounting for the fact that renewable curtailment or "over-generation" of renewables will not lead to zero, or negative, cost electricity for any significant quantity of hydrogen production. New nuclear or CCS technologies are not considered as a fuel production pathway in this study. In these scenarios, fuel production still represents a larger expansion of the electricity system and renewable generation capacity requirement than in the high building electrification scenario. In the high building electrification scenario, nearly complete electrification of buildings induces 47 terawatt-hours (TWh) of new load, which is less than half that associated with transportation electrification.

Figure 9: Electricity Loads by Sector in PATHWAYS Scenarios



Electricity loads consist of final demand for electricity, except for fuel production loads; production of hydrogen and SNG are assumed served by off-grid renewables, except for liquid hydrogen for delivery to fuel cell trucks, which are assumed to be produced on-grid so they can be relatively close to consumption. The no building electrification scenario loads shown here correspond to the conservative cost P2G scenario. These loads would be slightly lower in the optimistic cost P2G scenario due to greater use of bio-CO_2 rather than DAC.

Source: E3

A common claim is that electrolytic fuel production can use low-cost wind and solar energy that would otherwise be curtailed. This study finds that the loads required to produce sufficient quantities of hydrogen and SNG far exceed the amount of curtailment that can be expected in a future electricity system that uses renewable integration solutions. Those solutions include flexible loads, storage, and gas combustion turbine electric generators that use a small amount of biomethane or natural gas. Using those solutions, 16 percent of renewable generation, or 63 TWh, is curtailed in the no building electrification scenario.[21] This curtailment means that up to 159 TWh of additional electricity generation is needed for fuel-production alone in this scenario, or just greater than half of California's annual electric loads today (Figure 10).

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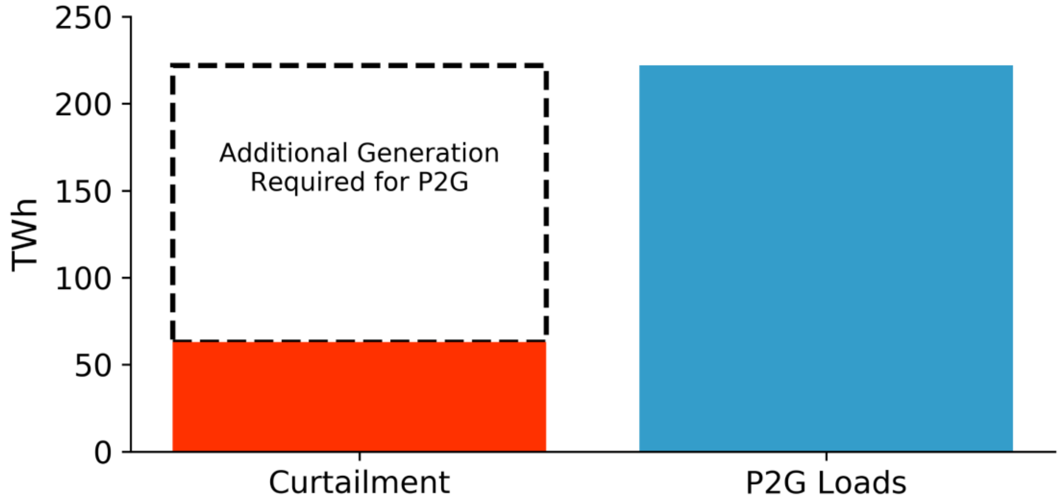
21 This amount is based on PATHWAYS modeling, which does not optimize the portfolio of renewables and storage to strictly minimize electricity generation costs. RESOLVE modeling for an 80 x 50 scenario in (Mahone 2018) showed 15 percent curtailment. Newer simulations with lower-cost storage yield lower optimal curtailment levels.

Figure 10: 2050 Curtailment Compared to Power to Gas Loads in the No Building Electrification Scenario



Source: E3

Natural Gas Throughput and Commodity Composition

Natural gas throughput declines in all scenarios. In the reference scenario, natural gas electricity generation declines markedly as renewables displace natural gas because of modeled implementation of SB 100 (Figure 11). In the no building electrification scenario, high energy efficiency and reduced petroleum industry energy demand (included in both mitigation scenarios) further reduce natural gas demand. However, natural gas demand in buildings remains relatively flat in this scenario (and in the reference), with efficiency offsetting population and economic growth. In the high building electrification scenario, in contrast, natural gas demand in buildings falls precipitously post-2030, reaching an 89 percent reduction by 2050, and is on pace to decline further beyond 2050.

The throughput declines in each scenario follow from the respective decarbonization strategies. In the high building electrification scenario, decrease in gas throughput is a key source of emissions reduction as electricity is used to displace gas use in buildings. A blend of 25 percent biomethane plays an important role in reducing the GHG emissions intensity of remaining pipeline gas demands. In the no building electrification scenario, hydrogen and SNG are blended in addition to biomethane to reduce GHGs from natural gas consumption. These RNG blends increase the aggregate, or combined, pipeline blend commodity cost, especially in the no building electrification scenario, where the commodity cost reaches $1.8/therm in the optimistic P2G cost scenario and $2.9/therm in the conservative P2G cost scenario.[22] The authors emphasize that this blended commodity cost assumes that 56 percent of the pipeline gas is natural gas. The commodity cost in a completely decarbonized gas pipeline would be between $5.5 per therm and $9.0 per therm if SNG were used to displace all remaining fossil fuel.

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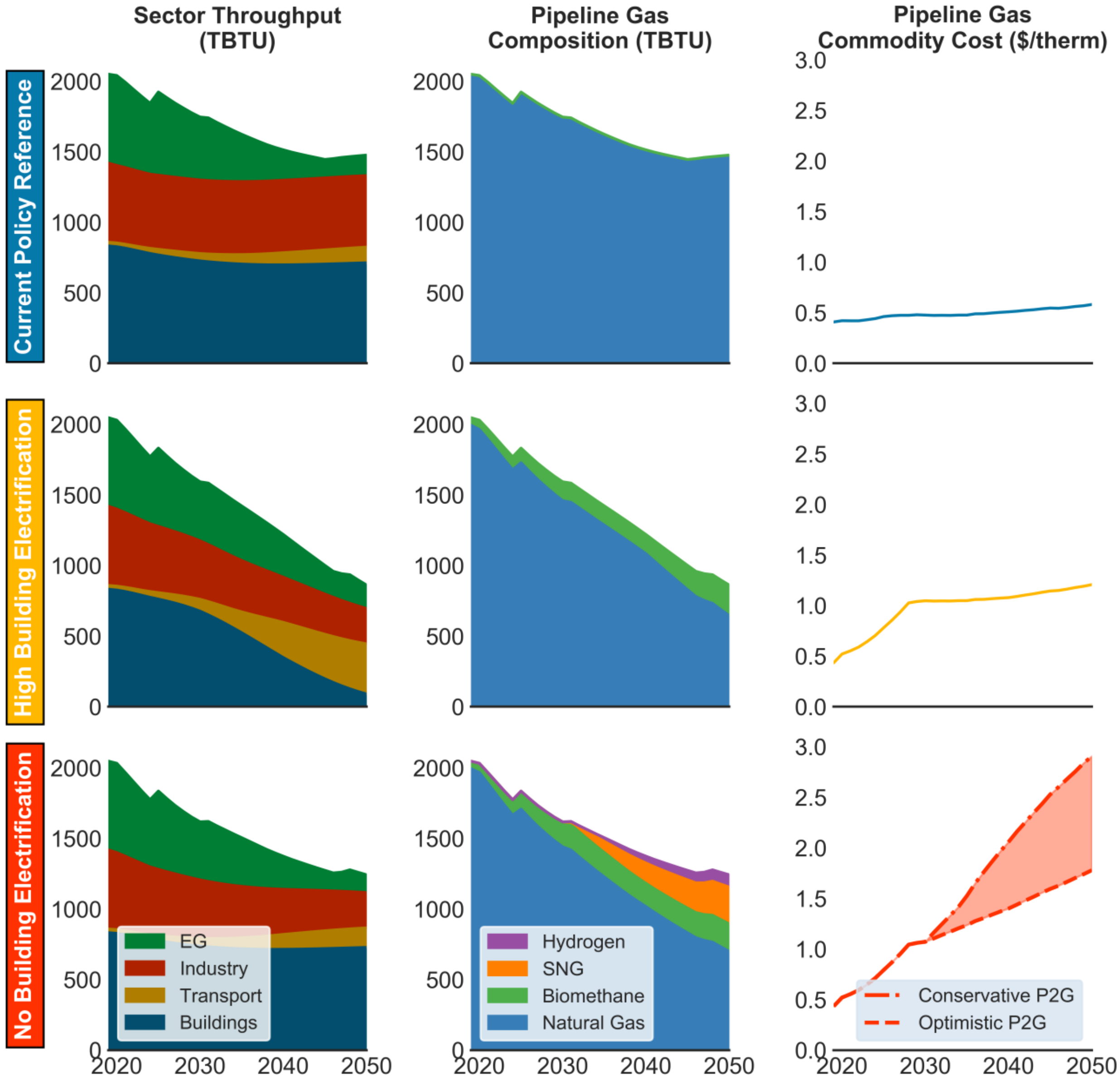
22 In the reference scenario, commodity costs of fossil natural gas increase only modestly to $0.59/therm based on the Energy Information Agency (EIA) Annual Energy Outlook (AEO) forecast for the Pacific region.

Figure 11: Gas Throughput, Pipeline Gas Composition, and Pipeline Gas Blend Commodity Cost in PATHWAYS Scenarios



Pipeline commodity costs do not include gas transmission, storage, or distribution costs. Biomethane shown in the reference scenario corresponds to biogas used in CNG trucks. Throughput figures in these charts are based on gas utility loads and do not include use of nonutility gas for enhanced oil recovery steaming or cogeneration.

Source: E3

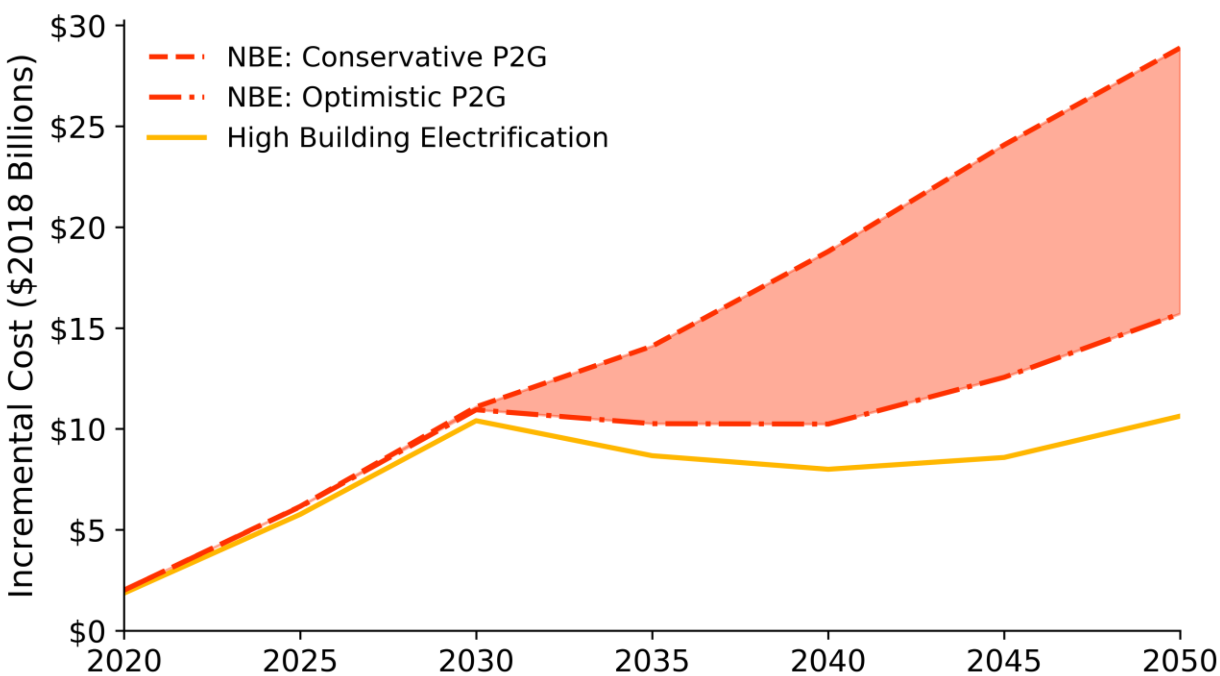
Economywide Costs

Similar to the results in Mahone et al. (2018), high reliance on building electrification is projected to lower economywide costs relative to a scenario in which building electrification is excluded (Figure 12). The costs of the high building electrification and no building electrification scenarios are similar through 2030 because both scenarios include a similar set of GHG mitigation measures through this time frame to meet the state's 2030 GHG reduction goal. The costs of the scenarios diverge after 2030 as increasing quantities of expensive hydrogen and SNG are blended into the pipeline in the no building electrification scenario. The conservative and optimistic P2G cost scenarios bracket a wide range of economywide costs in the no building electrification scenario. However, even in the optimistic P2G cost scenario, the scenario cost is greater than in the high building electrification scenario and on an upward trend, as increasing quantities of RNG are required over time.

Importantly, the high building electrification scenario costs shown in Figure 12 assume no retirement of natural gas distribution infrastructure. Put another way, this scenario assumes all the gas infrastructure continues to be paid for, despite declining throughput. The total cost for this scenario could be lower if gas distribution system costs were reduced. However, the high building electrification scenario also does not assume any early retirement of gas equipment, which would tend to increase the cost of this scenario. See Chapter 5 for a discussion of the challenges associated with reducing gas system capital expenditures.

Overall, the cost difference between the high building electrification and the reference scenario is smaller than the difference between "high electrification" and "current policy reference" in Mahone et al. (2018), particularly after 2030, owing primarily to assumed lower costs for wind and solar generation, battery storage, and biofuels. In addition, the reference scenario now includes a nearly decarbonized electricity system, reducing the net electricity system costs of the 80 x 50 scenarios. Similar quantities of biofuels are used in the high building electrification and no building electrification scenarios so the biofuels costs have little effect on the relative costs of those two scenarios.

Figure 12: Economywide Annual Net Costs, Relative to Current Policy Reference Scenario



NBE is short for "no building electrification" scenario. The high building electrification scenario does not assume any retirements of natural gas distribution infrastructure. Transfer payments such as cap-and-trade and LCFS policies do not affect the total costs to the California economy shown here.

Source: E3

In addition to being lower cost, the high building electrification scenario is likely lower risk than the no building electrification scenario. The high building electrification scenario relies on the implementation of commercialized technologies in buildings, while the no building electrification scenario relies on the commercialization of electrolytic fuels, as well as deeper, and potentially more speculative, GHG mitigation strategies in other sectors, including the heavy-duty transportation and industrial sectors.

In addition, building electrification could serve as a risk reduction strategy to protect low-income and vulnerable communities from future gas rate increases. Conversely, if building electrification is delayed, missing the lower-cost opportunities for all-electric new construction and replacement of equipment upon failure, there is a greater risk that expensive early retirement of equipment may be needed, or that the climate goals could be missed.

Remaining Emissions in 2050 and Implications for Carbon Neutrality

The no building electrification scenario allocates nearly half of the 2050 fossil energy emissions budget to buildings (Figure 13). In contrast, the high building electrification scenario has eliminated most emissions from buildings and is on track to reduce them further as remaining natural gas appliances reach the end of useful life.

This study focused on modeling scenarios reaching the 80 x 50 goal, but Executive Order B-55-18 of 2018 set a more stringent goal of a carbon-neutral California by 2045. While it is not known exactly what combination of measures might be employed to meet the carbon neutrality goal, additional direct reductions in GHG emissions are likely needed relative to an 80 x 50 scenario, in addition to direct air capture and other carbon removal strategies. In short, both 80 x 50 scenarios modeled here would likely require additional GHG mitigation measures throughout the economy to achieve net-zero GHG emissions. However, the high building electrification scenario may be better placed to reach that goal because it has more remaining low-cost options to decarbonize transportation and industry, whereas these are already used in the no building electrification scenario to make up for continued emissions in buildings. Bringing down the building sector emissions in the no building electrification scenario to match those in the high building electrification scenario by 2050 would require using SNG with DAC, as other less expensive RNG options are already fully used. This option would cost $4.1 to $8.6 per therm in commodity cost, assuming the optimistic and conservative P2G cost scenarios, respectively, relative to $0.59/therm fossil natural gas. This would result in an additional economywide cost of $11 billion to $24 billion per year in 2050.

Scenario Discussion

Understanding the Economywide Cost Results

Based on the finding that there is likely to be insufficient biomethane available to fully decarbonize the natural gas system, decarbonized electrolytic fuels are likely to be required. These fuels require zero-carbon electricity generation.[23] The electricity generation requirement can be compared with using the electricity directly in a heat pump to serve the same heating demand.

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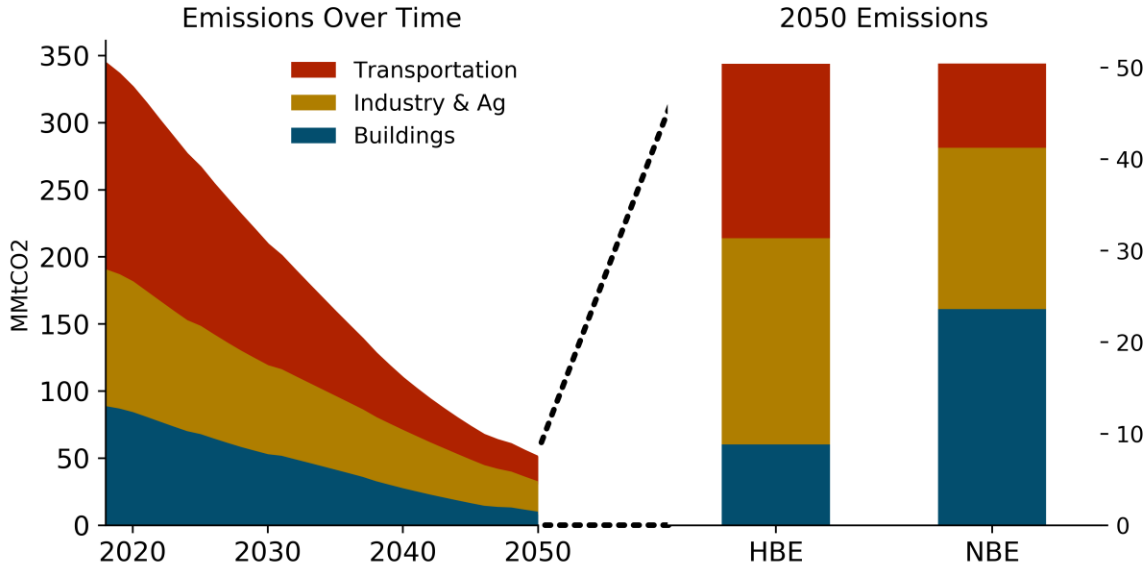
23 An alternative would be using hydrogen produced from fossil NG with steam methane reformation coupled with CCS or nuclear and upgrading the pipeline infrastructure and appliances to use greater blends of hydrogen. This alternative was not modeled in this study but may be worth further study, particularly if higher hydrogen blends in the pipeline system are possible without major system upgrade costs.

Figure 13: Energy Emissions by Sector



Energy emissions by sector include upstream emissions in electricity in this chart.

Source: E3

The life-cycle primary energy efficiency[24] of using zero-carbon electricity to provide building space heating ranges from about 300 to 500 percent, accounting for heat pump efficiency and 7 percent electricity transmission and distribution losses. This amount equates to about 0.1 kilowatt-hour (kWh) of electricity generation input for 1 kBtu of heat delivered. In contrast, producing SNG from DAC or bio-CO_2 and then burning this in a natural gas furnace provides about 35 to 53 percent primary energy efficiency accounting for conversion losses, or about 1 kWh of input electricity for each 1 kBtu of heat delivered, given 45 to 56 percent production efficiency (Chapter 2) and a combined 77 to 95 percent efficiency for delivery and furnace operation.[25]

More broadly, this is an example of a principle emerging from a consensus in the deep decarbonization literature (for example, Committee on Climate Change 2019) of reserving biofuels and synthetic fuels for the sectors that are the most challenging to electrify, where required energy density or lack of efficiency benefit from electrification makes electrification most challenging. With known technologies, low-cost, sustainable liquid and gaseous fuels are likely to be scarce in any low-carbon future; so they are likely best targeted to uses like aviation, freight, industrial high-temperature heating, and backup thermal electricity

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24 This is defined as the ratio of the delivered useful energy (that is, heating service) to the energy in the form of renewable electricity generation to serve this use. Conversion losses in fuel production, losses in transmission and distribution, and wasted energy in heating systems reduce this ratio.

25 The Energy Information Administration estimates about 3 percent consumption of natural gas within the pipeline system itself, which is not modeled here (EIA 2017).

generation. Because buildings can be electrified at high efficiency with existing technology, this sector is a less ideal candidate to absorb a large proportion of RNG supply.

Monthly Operating Costs for Completely Decarbonizing Space Heating Using Electricity or RNG

The order of magnitude difference in primary energy efficiency drives large differences in the projected costs of decarbonizing space heating using these two approaches (Figure 14). Assuming that space heating is fully decarbonized[26] by either a heat pump powered by decarbonized electricity or 100 percent RNG, this analysis finds that the heat pump would cost from \$34 to \$53 per month to operate, while RNG in a gas furnace would cost from \$160 to \$263 per month to operate.

For this calculation, the research team assumed that space heating service demand averaged 29 therms per month, based on the PATHWAYS assumption for a single-family home in the PG&E service territory. Then, the team calculated the energy demand as the service demand divided by the efficiency. To make a direct comparison, researchers express units of energy consumed in therms (1 therm = 29.3 kWh). In California's mild climate, heat pumps can deliver an equivalent amount of heat with less than one-fifth the site energy of a gas furnace.[27] In 2020, the statewide residential electricity rate is projected to be \$5.30/therm, several times the gas rate of \$1.60/therm, and could be higher if wildfire-related costs and liabilities are passed on (Chapter 4). This rate partially offsets the higher efficiency of the heat pump in 2020, yielding a monthly cost estimate of \$34 to \$53 to run the heat pump vs. \$38 to \$57 to run the gas furnace.

However, the difference is greater in 2050 with decarbonized electricity and gas. PATHWAYS projects an electricity rate of \$5.90/therm in 2050 in the high electrification scenario, but given uncertainties in electric sector costs, this study shows a range of results up to \$7.70/therm, resulting in a monthly cost range from \$34 to \$44 for a heat pump. The gas rate in the no building electrification scenario if the RNG blend were increased to 100 percent would range from \$5.50 to \$9.00, according to the optimistic and conservative P2G cost scenarios, respectively. Even assuming a 98 percent condensing gas furnace, this scenario yields a monthly cost of \$160 to \$263 to operate a gas furnace. The 2050 Reference scenario result is included as a conservative comparison, in which electricity is decarbonized because of SB 100, but the natural gas blend remains 100 percent fossil. Even in this case, operating costs of a heat pump space heater would be expected to be lower than those of the gas furnace.

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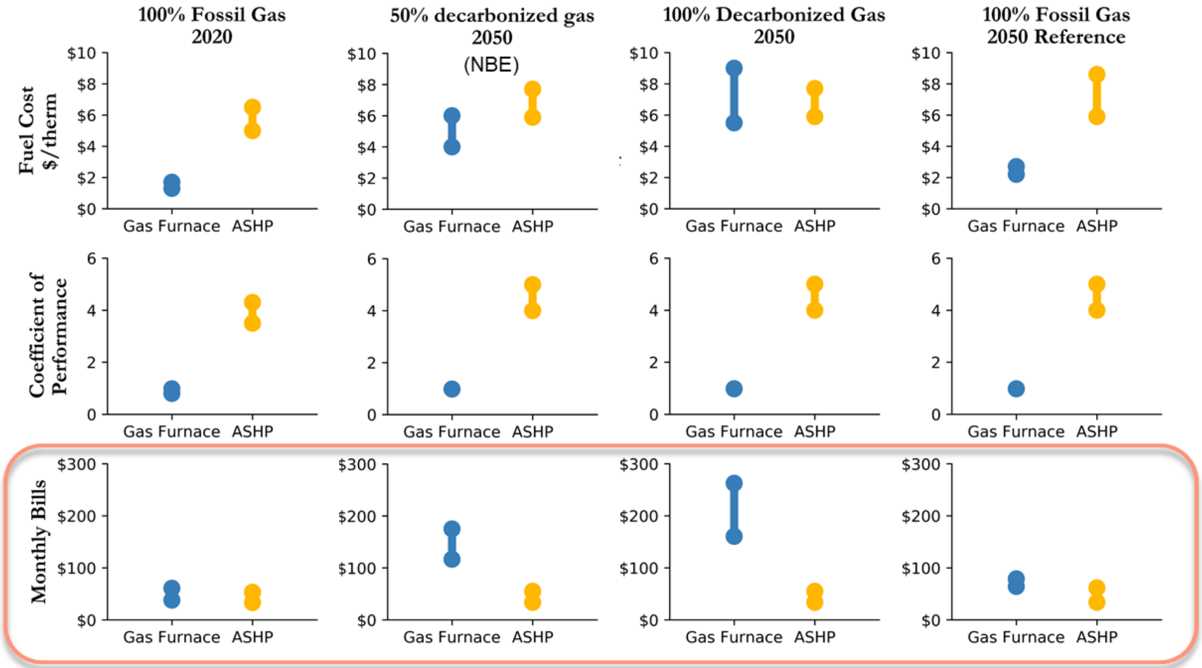
26 A small amount of emissions would remain in both cases because of 5 percent natural gas generation in electricity and any unmitigated fugitive methane emissions from the pipeline system and end uses.

27 In today's electricity system, site energy, a measure of direct energy consumption on-site (rather than "source energy", which includes upstream energy consumption associated with electricity generation), is a somewhat incomplete metric given thermal losses that occur in generating electricity in combustion-based power plants. However, these scenarios assume that California's electricity shifts to a largely noncombustion-based system, at which point the site-energy versus source-energy distinction is less meaningful.

Figure 14: The Cost of Residential Space Heating Using Electricity, Natural Gas, and 100 Percent Renewable Natural Gas



Notes: Statewide average residential electricity and natural gas rates in 2020 and 2050 from PATHWAYS scenarios are shown. The electricity rate range encompasses the wildfire cost sensitivity (Chapter 4), while the gas rate range encompasses the conservative and optimistic P2G cost scenarios and, in 2020, the range between PG&E and SCG rates. To estimate the gas rate with 100 percent RNG, SNG with DAC is used as the marginal resource to displace the remaining fossil NG from the no building electrification scenario. The appliance efficiencies (that is, coefficients of performance, the ratio of output heat to input fuel energy) are chosen to reflect moderately high-efficiency options on the market for 2020, up to the highest efficiency available shown as the high end of the range in 2050. Heat pump performance is based on the Sacramento-area climate. In the reference, the electricity is assumed to be largely decarbonized in 2050 because of SB 100, while the natural gas blend would still be 100 percent fossil.

Source: E3

Because the costs of operating a heat pump space heater are expected to be lower than the costs of operating a gas furnace even with 100% fossil natural gas in 2050, some economic electrification is likely to occur in any case, which will lead to upwards pressure on gas rates that could create a self-reinforcing feedback loop (Chapter 4). For this reason, the economic challenges of decarbonizing the gas system largely with RNG are likely robust to even faster cost declines in RNG than modeled here. These challenges are exacerbated by 7% (by energy) blend limit for hydrogen in the distribution system without infrastructure and appliance upgrades. Combined with the limited supplies of biomethane, this means that the marginal RNG resource in the absence of electrification is likely to be SNG. Projected costs of this commodity, which is not commercially available today, would have to decline far faster than modeled here in the optimistic P2G cost scenario to be competitive with fossil natural gas or with operating a heat pump.

Air Quality Results

The UCI team assessed regional, outdoor air quality impacts in 2050 under the three PATHWAYS scenarios and a fourth scenario where the high electric and fuel cell trucks measure from no building electrification is incorporated into high building electrification. The research team did not assess the effects of gas combustion on indoor air quality in this study.

Researchers took emissions outputs from PATHWAYS and ran them through an emissions processing system, the Sparse Matrix Operator Kernel Emissions tool (SMOKE), to determine the composition of criteria air pollutant emissions and allocate them by geographic location and time. The Community Multi-Scale Air Quality Model Version 5.2 (CMAQv5.2) tool then established fully developed distributions of concentrations for two criteria air pollutants: $PM_{2.5}$ and tropospheric ozone. $PM_{2.5}$ and tropospheric ozone are used to assess air quality because of their association with human health impacts because many regions in California experience ambient levels in excess of state and federal standards. The team calculated average and peak ground-level concentrations of $PM_{2.5}$ and tropospheric ozone for a summer episode (July 8-21) and winter episode (January 1-14) to capture the effect of seasonal variation in meteorology and emissions concentrations. The Benefits Mapping and Analysis Program-Community Edition (BenMAP-CE) tool then estimated the avoided incidence and economic value of health impacts from short-term exposure to ozone and $PM_{2.5}$ during these periods.

Overall, the no building electrification scenario had a larger and more widespread impact on ozone than the high building electrification scenario because of the larger reduction of HDV emissions. However, the high building electrification scenario had larger reductions in $PM_{2.5}$, especially during the winter episode. This impact on $PM_{2.5}$ follows from secondary effects from building NOx emissions. The scenarios are not directly comparable in that emission reductions from buildings and HDV are not equivalent in scope, that is, a larger penetration of electrification is assumed in buildings relative to alternative measures assumed for HDV.

Health savings for the three alternative scenarios as a result of air quality improvements relative to the reference scenario are shown in Table 3 below. While health savings are similar between the high building electrification and no building electrification scenarios for the summer episode, there are larger health savings in the high building electrification scenario for the winter episode because of the larger impact on $PM_{2.5}$ during the winter. While both building electrification and truck measures lead to air quality improvements and health savings, the highest benefits are achieved when the measures are combined.

Table 3: Mean Health Savings for Air Quality Improvements Estimated for Summer and Winter Episodes in 2050

Episode	High Building Electrification	No Building Electrification	High Building Electrification With Trucks
Summer	$202	$202	$261
Winter	$190	$166	$249

Mean health savings in million $/episode.

Source: UCI APEP

While annual health savings cannot be estimated from the episodic modeling method used in this study, the use of long-term exposure $PM_{2.5}$ health impact functions like those used in a recent analysis of air quality impacts in California[28] would lead to substantially higher health benefits for all scenarios. The full draft air quality impacts assessment by UCI can be found in Appendix F.

Other studies have investigated the impacts of natural gas cooking on indoor air quality (Logue et al., 2013) and the impact of gas appliances more generally on indoor air quality (Mullen, 2012). Logue et al. (2013) conclude that using natural gas cook stoves without venting range hoods can expose a substantial proportion of residents to pollutant concentrations that exceed health-based standards and guidelines for outdoor air quality. Logue uses simulated results to evaluate only emissions from natural gas combustion, not emissions from cooking food. While Logue concludes that indoor air pollution from natural gas cooking burners can be reduced, but not eliminated, through the use of current venting range hoods, Mullen's empirical results showed no statistical association between the use of a kitchen exhaust fan and pollutant concentrations in California homes.

28 Alexander et al. 2019. *Air Quality Implications of an Energy Scenario for California Using High Levels of Electrification*. California Energy Commission. Publication Number: CEC-500-2019-049.

CHAPTER 4: Implications for Natural Gas Customers

This chapter explores the customer energy rate and bill impacts of the PATHWAYS scenarios described in Chapter 3. It examines the effects of those scenarios on customers who electrify their homes and businesses and those who do not. This distinction is particularly important from an energy equity and environmental justice perspective. While some customers may prefer to continue to use gas even if it becomes more expensive than electricity over time, other customers may not be *able* to electrify, regardless of potential energy bill savings. For instance, low-income customers have more limited access to capital and may not be able to afford the upfront costs associated with a building retrofit (Scavo et al 2016). Renters do not own their buildings, so they typically have little to no say about what types of equipment are installed in their homes and businesses.

To assess the energy equity and energy bill effects of different low-carbon scenarios, the research team developed a representation of the revenue requirements of California's natural gas distribution utilities. That analysis, paired with scenarios of gas throughput and pipeline composition from PATHWAYS, allowed the research team to develop estimates of gas rates and bills for each scenario through 2050.

California's Energy Cost Challenge

California's electric and natural gas systems face daunting cost challenges. A common driver of increasing costs among electric and natural gas utilities are recent safety-related incidents. Incidents like the San Bruno gas pipeline explosion and Aliso Canyon gas storage field leak have spurred renewed investment in the state's gas infrastructure. The state's electric system also faces increasing costs following a series of catastrophic wildfires attributed to ignitions from electric infrastructure. These fires are expected to put upward pressure on electric utility rates because of expected damages owed to victims of the fires, a portion of which will be passed onto ratepayers, and utility costs associated with reducing future wildfire risks.

The cost impacts of safety-related investments are already being felt. Gas utilities in California are in the midst of large safety-related investments, and those investments are expected to increase gas rates over the next three years. PG&E has requested an increase of 15 percent for its gas revenue requirement, and a recent decision in SCG's rate case will increase that utility's revenue requirement by 25 percent ($2018 real) from 2018 to 2022. (PG&E 2018, CPUC 2019). As of this writing, these applications have not yet been decided upon at the CPUC.

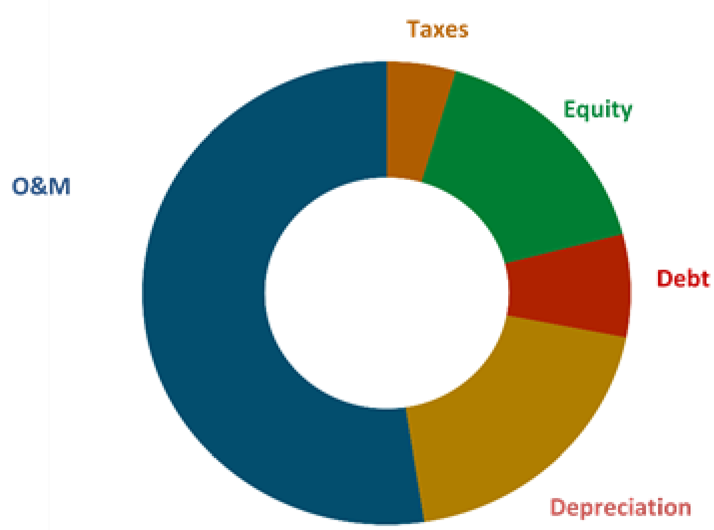
The extent and duration of wildfire-related electric system cost increases are not yet known. However, California's investor-owned electric utilities have proposed substantial increases in their cost of capital in response to the large liabilities wildfires present to their systems under the state's current liability standards (PG&E 2019, SCE 2019). Utilities have also begun to implement the set of operational expenditures and investments required to reduce the risk of wildfires associated with their systems. These expenditures will increase the cost of serving the state's electric loads, although the extent and duration of those cost increases, and how they will be allocated among electric customers, are not yet known.

The Financial Structure of the California Gas System Today

The California Public Utilities Commission regulates natural gas utilities in California. Gas utilities file their planned revenue requirement and rates on three-year intervals and are allowed the opportunity to earn a fair return on their investment in return for safe, reliable gas service to their customers. The gas utility revenue requirement covers the infrastructure and operational costs associated with delivering gas to homes and businesses in California, not the commodity cost of natural gas itself.

To evaluate the financial implications of decreased throughput on California gas utilities, the research team developed a gas revenue requirement model for PG&E and SoCalGas. The revenue requirement model captures the set of operational and investment expenses associated with delivering gas through those utilities' systems. The revenue requirement model developed by the research team is benchmarked to each utility's most recent general rate case (GRC) filed with the CPUC.[29] PG&E and SoCal Gas comprise roughly 94 percent of gas utility throughput in California. After combining those two utilities' revenue requirements and scaling by their proportion of total statewide gas utility load, this analysis estimates that the gas utility revenue requirement in California is $7 billion in 2019. Operational costs are just over half the statewide gas revenue requirement, while costs related to capital expenditures are responsible for most of the remainder. Those costs include annual depreciation expenses, payments to holders of debt, equity returns and taxes (Figure 15).

Figure 15: Composition of California's Gas Revenue Requirement



Source: E3

Importantly, the utility financial data obtained from these regulatory filings do not readily distinguish between costs to provide and maintain gas service to new gas interconnections and

29 The research team relied on the following regulatory filings to build and benchmark the revenue requirement models: PG&E GCAP 2018, PG&E GRC 2020, PG&E GTS 2019, SCG TCAP 2020, SCG GRC 2019, SCG 2017 PSEP Forecast Application, SCG PSEP Forecast application.

costs to maintain and operate the existing gas system. As such, the E3 gas revenue requirement model is not designed to explicitly estimate the gas system cost savings from, for example, all-electric new construction. Rather, the tool is designed to test broad scenarios around what the effect on gas revenue requirements and rates would look if a reduction in total gas system expenditures were achieved.

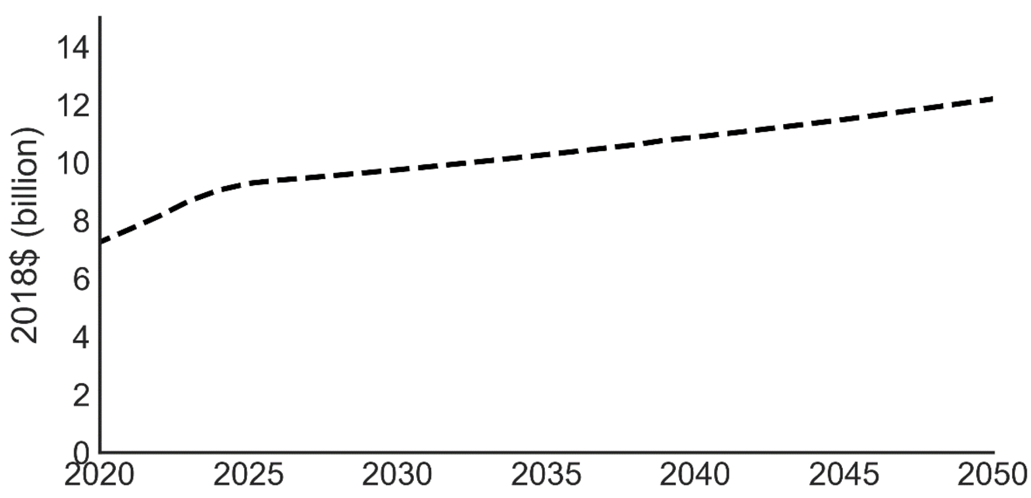
Investor-owned utilities (IOU) provide delivery service to most gas customers in California but sell only commodity gas to a subset of customers in the state, called "core" customers. Core customers include all residential customers, some commercial customers, and a small number of larger users like industrial facilities or electric generators. "Noncore" customers contract for commodity gas with non-IOUs but pay for delivery service via the regulated utility. These customers tend to be larger users and are often connected to higher-pressure segments of the gas system.

Gas Revenue Requirement — Reference Scenario

The reference scenario gas system revenue requirement is meant to represent a future where California continues to use and invest in its gas infrastructure. This near-term forecast of the state's revenue requirement is based on 2018 – 2019 general rate case requests from PG&E and SoCalGas, and the September 2019 CPUC decision on the SoCalGas GRC. In those rate cases and related regulatory documents, both utilities outline a series of ongoing safety-related investments that lead to a sharp increase in their respective revenue requirements in the near term (SCG 2017). This analysis assumes that those large, incremental safety-related investments continue through 2025, at which point the state's revenue requirement has reached $9 billion annually, compared to about $7 billion today, a 28% increase in real terms over a 7-year period.

Costs further out in time are more speculative. This study assumes costs continue to increase as gas utilities reinvest in their systems. Historical experience suggests that the costs of system reinvestments increase over time, in real terms, because of escalation of both operations and investment costs (WRA 2018, CPUC 2019). The result is that by 2050, the state's gas revenue requirement is estimated at $12.2 billion in the current policy reference scenario, 80 percent higher than today's value.

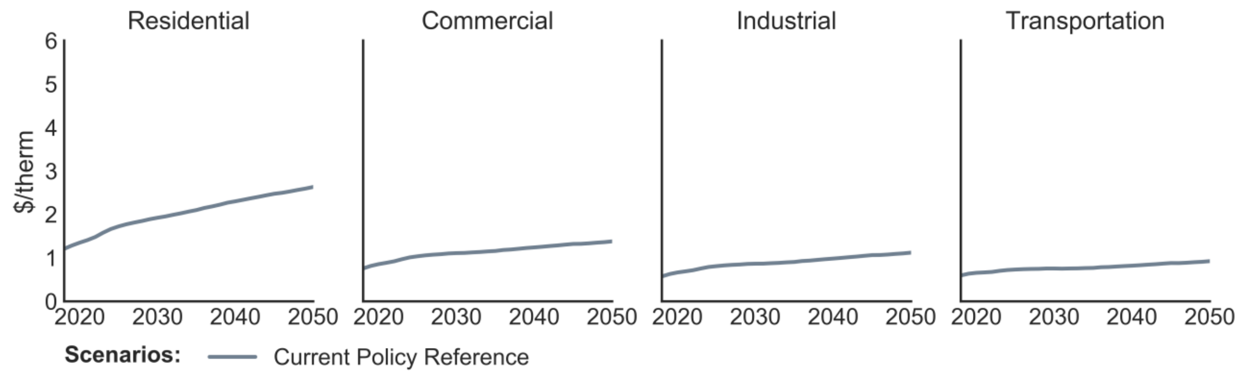
Figure 16: Reference Gas Revenue Requirement



Source: E3

The state's gas revenue requirement is expected to increase, but gas throughput is expected to decrease. Gas rates are, at a high level, based on the average cost of service. If costs increase but gas demand does not, rates will rise. That phenomenon is borne out in the PATHWAYS current policy reference scenario, where rates increase for all customer classes.

Figure 17: Reference Gas Rates by Sector



Source: E3

Costs of the Gas System in Mitigation Scenarios

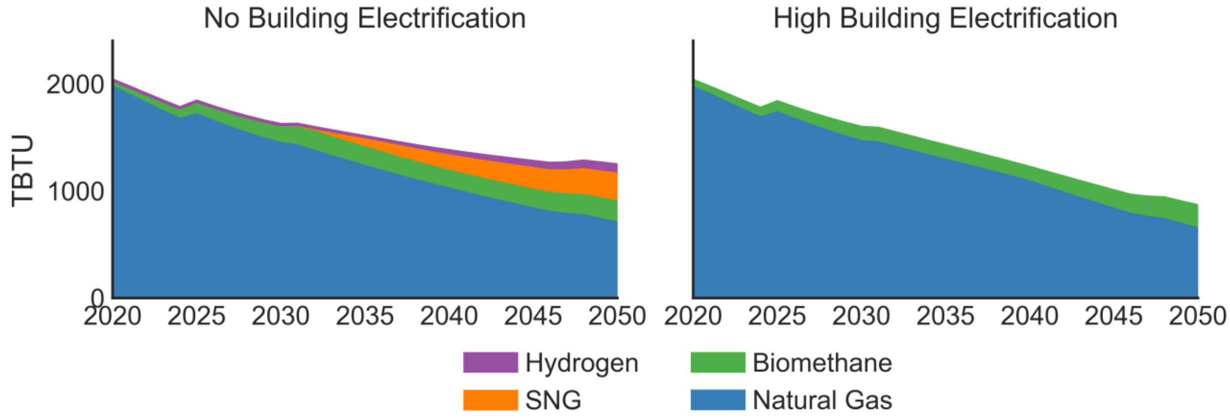
California's gas system faces transformations in all scenarios that achieve an 80 percent reduction of GHGs from 1990 levels by 2050. Those changes include decreased throughput and a shift in the composition of commodity gas flowing through the system.

Gas Commodity Costs

The composition of gas changes in California as a share of natural gas in each scenario is replaced with either climate-neutral methane or renewable hydrogen. Those fuels carry incremental costs above natural gas, so the blended cost of the commodity flowing through the gas system will increase over time as well. As discussed in Chapter 3, the rank order of climate-neutral pipeline gases from least to most costly is biomethane, hydrogen, and SNG. All mitigation scenarios blend biomethane into the pipeline. Where the mitigation scenarios differ is in the associated use of the more expensive hydrogen and SNG commodities. The high building electrification scenario does not require these electrolytic fuels to meet the state's 80 percent reduction by 2050 (80 x 50) climate target. In contrast, the no building electrification scenario has higher gas system throughput. As a result, SNG and hydrogen are used in this scenario to reduce emissions from gas use enough to meet the state's 80 x 50 climate target.

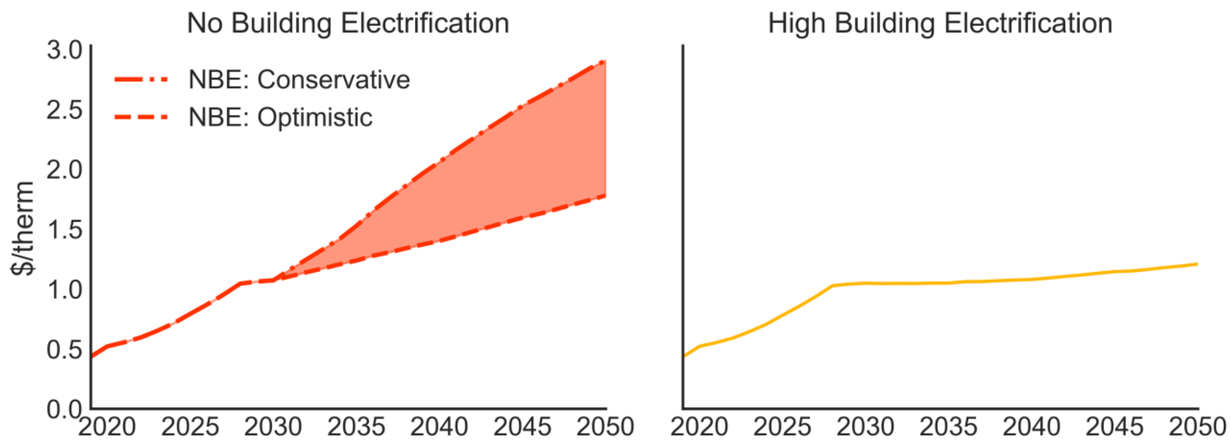
The use of hydrogen and SNG in the no building electrification scenario leads to a pipeline gas commodity cost that is four to seven times higher than today in 2050. Whereas commodity natural gas costs less than $0.4 per therm today, by 2050, the blended pipeline commodity cost is between $1.4 and $2.4 per therm in the no building electrification scenario. The high building electrification scenario sees a more moderate gas commodity cost increase ending with a 2050 cost of $0.75 per therm.

Figure 18: Pipeline Gas Demand and Fuel Blend (Million Therms)



Source: E3

Figure 19: Blended Commodity Cost by Scenario



Notes: "Conservative" and "Optimistic" refer to the respective P2G cost scenarios.

Source: E3

Gas System Revenue Requirement and Cost Recovery

As long as California's gas system is being used, that system will require continued reinvestment to ensure safe and reliable service. California's gas system has many components, ranging from interstate pipelines to the distribution laterals that connect homes and businesses to gas supply. For the gas revenue requirement analysis, the research team separated the gas system into two segments:

1. Transmission and underground storage: The gas transmission system is used to transport gas from each utility's citygate (that is, the connection to the interstate gas pipeline system[30]) to load centers. Underground storage is used to ensure a sufficient

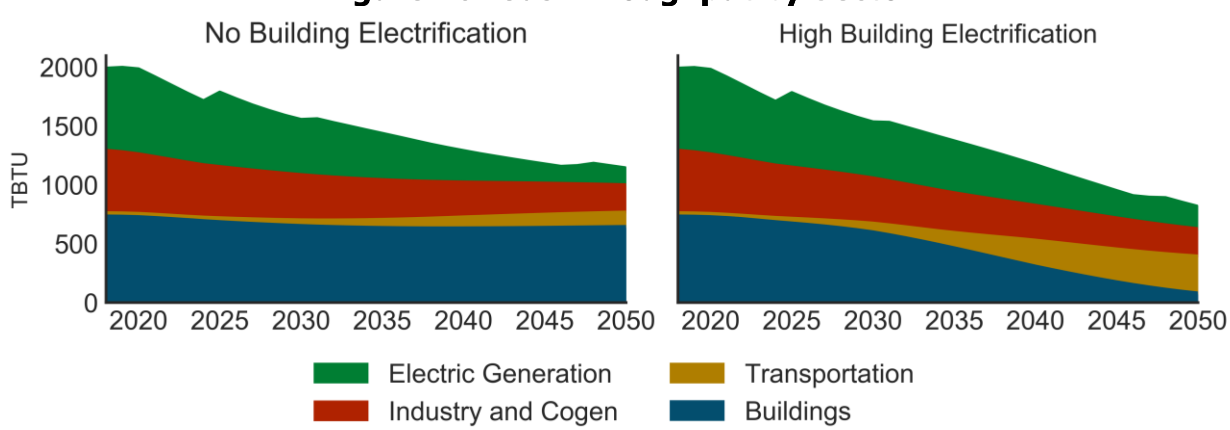
30 This study assumes that costs associated with the interstate pipeline system are captured in the basis differential (the gas price difference between regions) incorporated in EIA natural gas commodity cost forecasts. An examination of how that basis differential could change under lower levels of gas throughput nationally is beyond the scope of this analysis.

quantity of natural gas is available in the state during periods of high load. The gas storage system also plays an important role in hedging commodity gas costs.

2. Distribution: The distribution system delivers gas from the transmission and underground storage systems to end users. It has the largest footprint of any portion of the system. For instance, PG&E has more than 42,000 miles of distribution pipeline compared to 6,400 miles of transmission pipeline (PG&E 2019b). In Sempra Energy's 2019 10-k filing, they report over 114,00 miles of distribution pipeline, compared to just over 3,000 miles of transmission pipeline for both San Diego Gas and Electric and Southern California Gas Company combined.

Both segments see a decline in utilization over the study period. The steepest declines modeled in these scenarios occur in the gas distribution system in the high building electrification scenario. The gas distribution system was largely sized to serve building heat loads. The high building electrification scenario switches those loads from the gas system to the electric system. Gas throughput also declines in the gas transmission system, largely because of the role of renewable generation displacing gas generation on the grid, but that decline is somewhat muted by sustained industrial sector usage and an increased role for CNG in heavy-duty transportation. Importantly, the gas transmission and storage system also may have a role to play in ensuring electric system reliability in any deep decarbonization scenario. Recent studies by E3 and others point to the importance of maintaining rarely used firm generation capacity to balance a future electricity system powered almost entirely by intermittent renewables (Sepulveda, 2018; Ming, 2019).

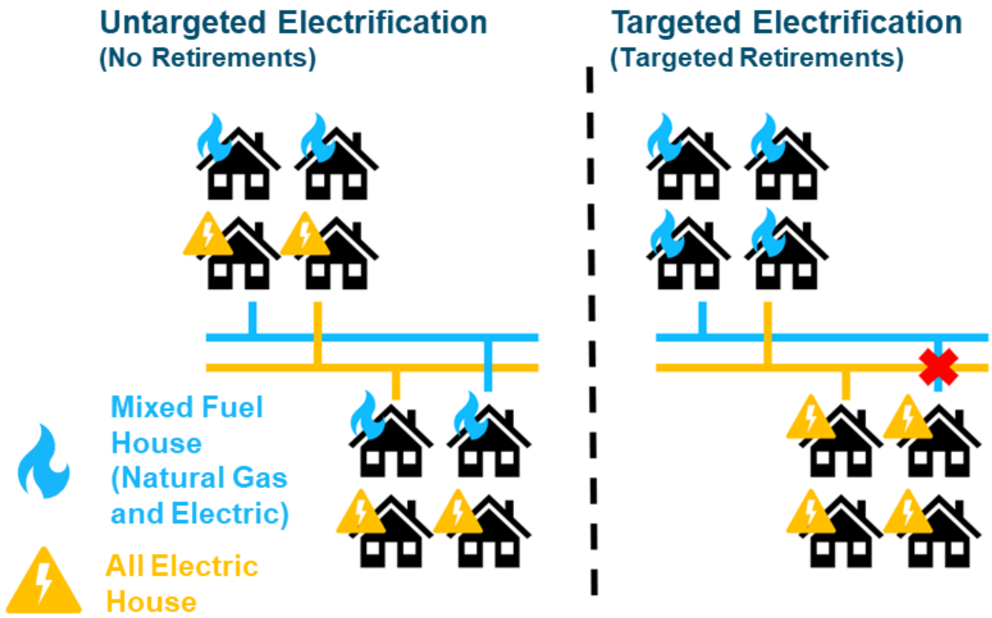
Figure 20: Gas Throughput by Sector



Source: E3

An open question is to what degree these changes in gas utilization will be accompanied by changes in gas system infrastructure and operations and maintenance costs. If a future gas system looks largely the same in terms of today's footprint and operations, it is likely that gas system costs will not change materially, despite lower throughput. On the other hand, decreased throughput could allow the expansion of the gas system to be halted, retirement of existing gas infrastructure, and cost savings on operations and maintenance expenses. These different worldviews implicate the expected future revenue requirement of utilities, the costs borne by customers that continue to receive gas service, and the consumer economics of building electrification.

Figure 21: Two Gas System Futures With and Without Targeted Electrification

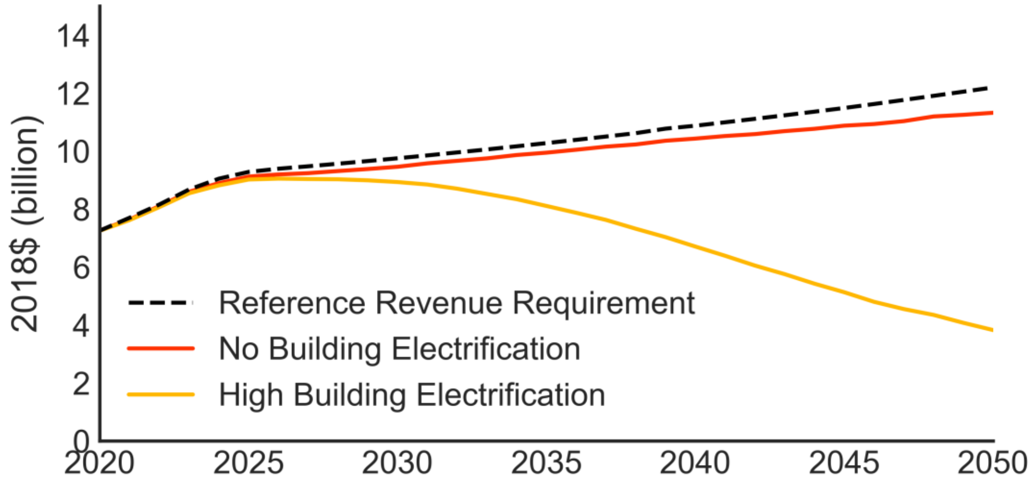


Source: E3

The base assumption of this study is that the gas system revenue requirement in both mitigation scenarios is equal to that of the reference case. This assumption is consistent with a future with scattershot electrification (that is, the left half of Figure 21, with "untargeted electrification"), where the costs of safely and reliably operating California's gas system would not change even as throughput decreased. To illustrate the magnitude of the cost recovery challenge in each scenario, this study compares the Reference revenue requirement against the revenues utilities would receive in those scenarios. The difference between the revenue requirement and revenues at reference rates in each scenario can be thought of as a cost recovery "gap." The gap for the no building electrification and high building electrification scenarios is shown in Figure 22.

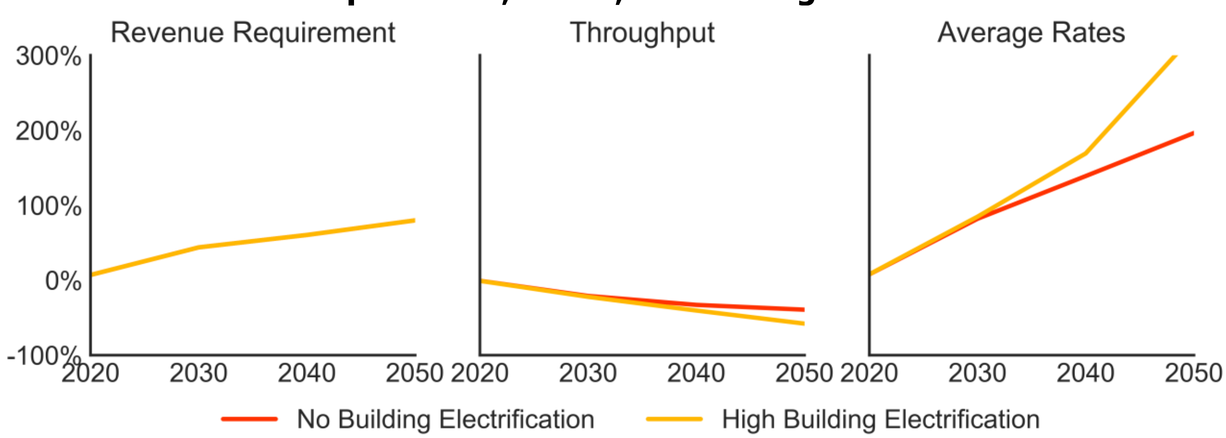
The default approach to close a gap between a utility's revenue requirement and its expected revenues is to increase customer rates. Gas delivery rates increase in both mitigation scenarios for all end users. Gas delivery rates increase above the reference scenario in the no building electrification and high building electrification mitigation scenarios. These rate increases stem from a combination of increasing costs and decreasing utilization. The largest decrease in gas system utilization occurs in the high building electrification scenario. In that case, increasing gas system costs are paid for by a rapidly shrinking set of customers. The results are rates that increase by 80 percent by 2030 and 480 percent by 2050).

Figure 22: Gas System Revenues in Mitigation Scenarios Assuming Reference Rates



Source: E3

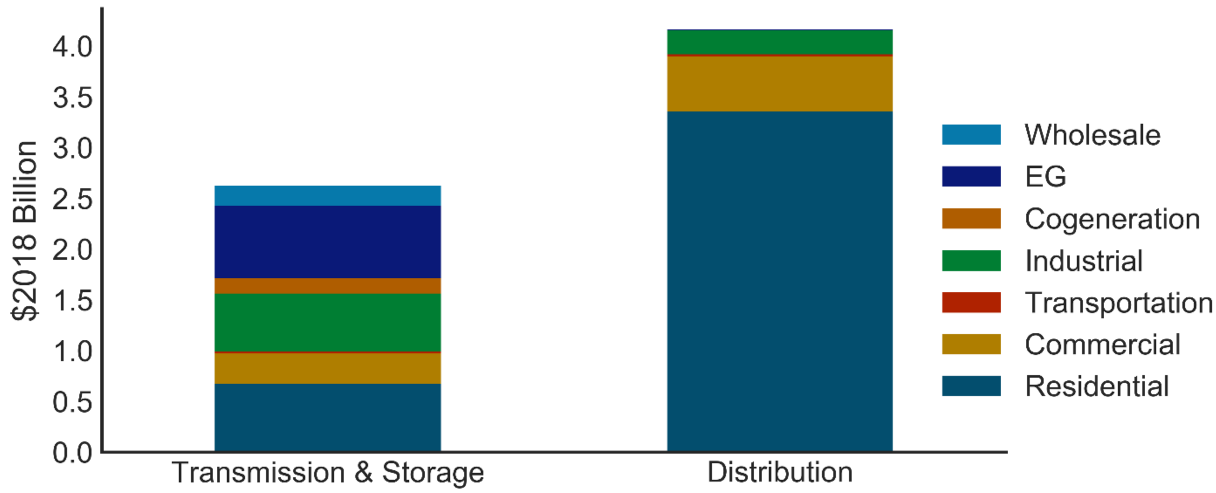
Figure 23: Percentage Increase Relative to 2019 in Gas Sector Revenue Requirement, Loads, and Average Rates



Source: E3

Rate increases are most marked for residential customers in the high building electrification scenario. This outcome follows from how gas system costs are allocated to customers. Recall that California's gas distribution system was largely sized to serve building heating loads. Large users—like those in the industrial sector—typically do not receive distribution-level service. As a result, residential and (to a lesser extent) commercial customers pay for the bulk of the distribution system, and the distribution system is the most expensive segment of California's gas infrastructure (Figure 24).

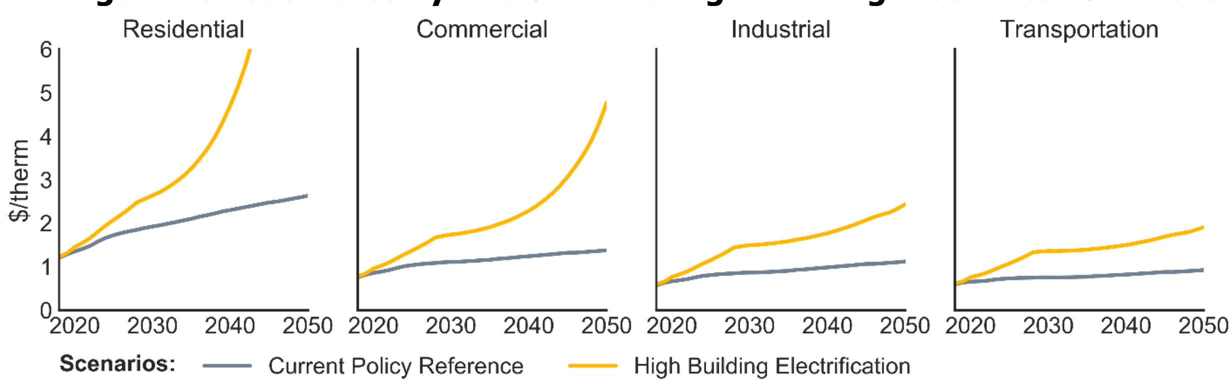
Figure 24: Estimated 2019 Gas System Revenues by Customer Type and System Segment



Source: E3

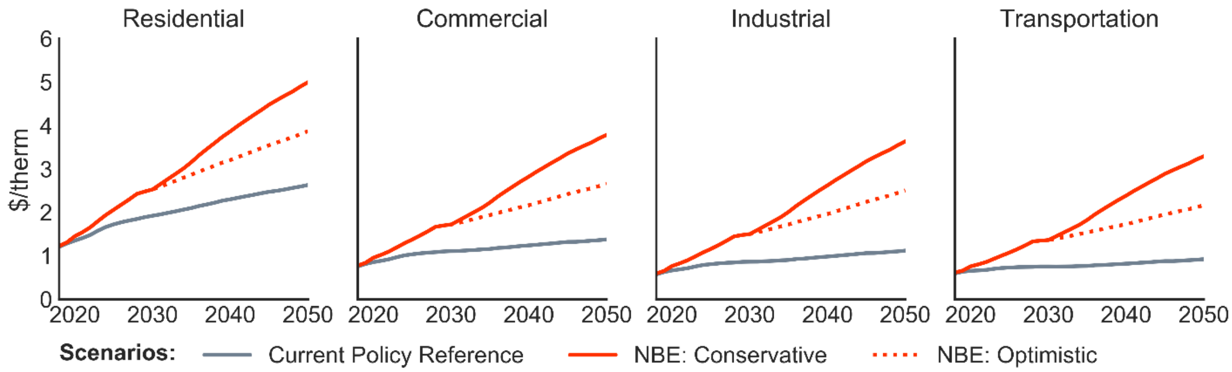
The average retail rate each customer class will pay includes commodity and delivery charges. Both elements of gas rates increase in both mitigation scenarios. The no building electrification scenario sees larger increases in the commodity cost of gas due to a higher blend of RNG. The high building electrification scenario sees a larger increase in the delivery charge because of decreasing utilization. The result is that the scenarios have different rates by customer class. The sectoral rate impacts of these scenarios are a function of the composition of the rates of those sectors. Delivery charges are a large portion of residential rates, while commodity charges are a large portion of industrial customers' rates. The result is that residential gas rates increase more in the high building electrification scenario, and industrial rates increase more in the no building electrification scenario.

Figure 25: Gas Rates by Sector in the High Building Electrification Scenario



Source: E3

Figure 26: Gas Rates by Sector in the No Building Electrification Scenario



Notes: "Conservative" and "Optimistic" refer to the respective P2G cost scenarios.

Source: E3

Electric Sector Rates

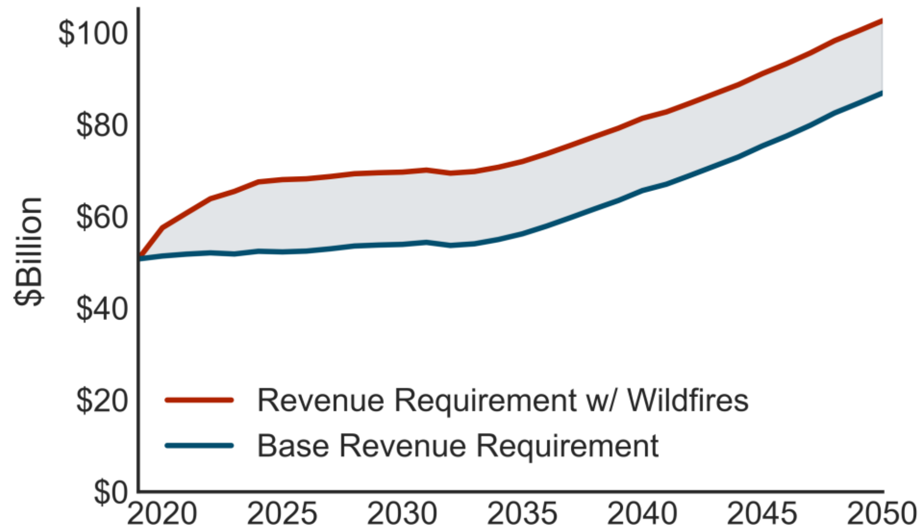
The electric sector is pivotal to enabling economywide decarbonization in all mitigation scenarios. Electrification-driven load growth increases annual on-grid electric loads by 24 percent in the no building electrification scenario and 43 percent in the high building electrification scenario. Furthermore, these new electric loads offer the possibility of providing flexibility to the grid, which could help reduce the cost of decarbonized electricity.

Like the California gas system, the state's electric system can also be expected to incur substantial new costs through 2050. These costs are driven by four main factors: 1) electrification-driven load growth, 2) large additions of new zero-emission electric supply resources and the storage necessary to integrate them, 3) business-as-usual costs such as the replacement of aging infrastructure and other cost escalations, and 4) wildfire-related, and other climate adaptation costs. The first two cost drivers are direct outputs of the PATHWAYS model. In PATHWAYS, load growth and electric power supply decarbonization lead to between a 52 to a 71 percent increase in the state's revenue requirement, depending on scenario. Business-as-usual cost increases are included in the Reference scenario forecast and are included in all other scenarios.

However, the exact magnitude and duration of wildfire-related costs, or other climate change adaptation costs, are less certain. To account for those increases, the research team developed a "wildfire cost" sensitivity case. To do so, researchers used PG&E's filing to collect wildfire-related costs over its next general rate case cycle (A. 18-12-009). If approved, those additional costs would increase PG&E's electricity rates 22 percent by 2022, though it is possible additional cost increases will be incurred beyond that period.

To develop a wildfire sensitivity, the study team assumed that this same percentage increase applies to the revenue requirement of all electric utilities, both public and private, in California. Like the gas system cost assumptions, increases in wildfire safety-related investments are assumed to attenuate by 2025, at which point they remain steady through 2050. An important caveat of this approach is that using PG&E costs may bias upward the near-term rate increases that can be expected statewide because PG&E has a larger share of its service territory in "high-risk exposure" areas of California than other utilities in the state (Wildfire Strike Force 2019). Furthermore, the assumption that all costs related to wildfires will be borne by ratepayers, and that those costs will be assessed on a purely volumetric basis, may not hold in practice. The cumulative effect of these incremental wildfire costs is a $20 billion per year increase in the revenue requirements of the state's electric utilities, as illustrated in Figure 29.

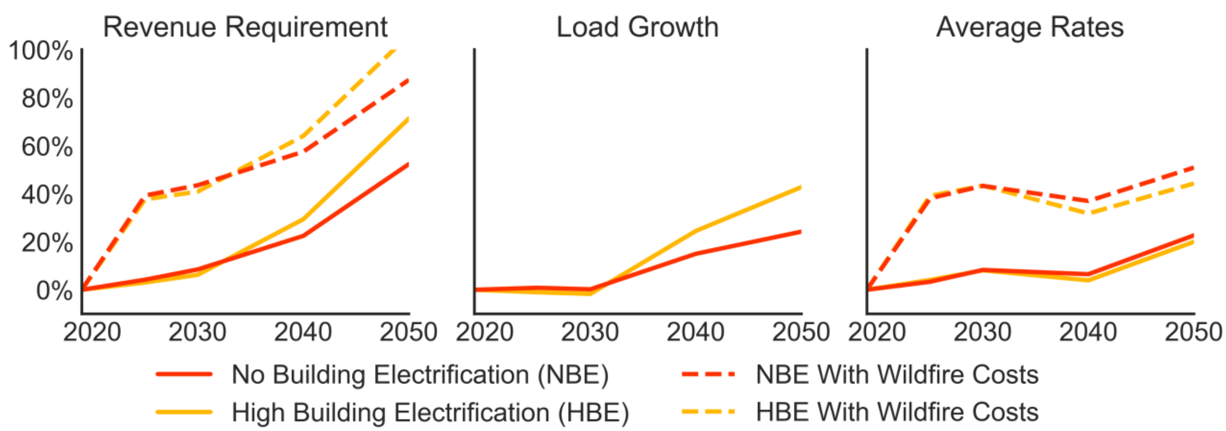
Figure 27: State Electric Revenue Requirement, High Wildfire Sensitivity



Source: E3

Despite those incremental costs, electric rate increases are relatively muted compared to those seen in the gas system. Absent wildfire costs, electric rates remain almost flat in near term and increase to 20 percent above today's rates by 2050. In the wildfire cost sensitivity, electric rates exhibit a marked near-term increase to 40 percent above today's rates but stabilize post-2030. In both cases, electric rates exhibit long-run stability because the state's rising electric revenue requirement is partially paid for by new electrification loads. This result differs from the Mahone 2018 results largely due to lower projected costs for renewable energy and energy storage technologies.

Figure 28: Percentage Increase in Electric Sector Revenue Requirement, On-Grid Loads and Average Rates



Source: E3

Residential Bills

To identify those potential utility bill impacts of these long-term, low-carbon scenarios, the research team developed an indicative residential bill impact analysis based on average rates. This analysis is intended to show directional changes over time between electric and gas customers, recognizing that there is wide variation among homes reflecting home type, home vintage, climate, utility, and rate design (as illustrated in Mahone 2019).

The residential customer bill impact analysis compares "mixed-fuel" IOU customers (buildings that use both gas and electricity) against "all-electric" IOU customers that have electrified their appliances. Specifically, mixed-fuel customers are defined as homes that have gas furnaces, water heaters, stoves, and clothes dryers and use electricity for all other uses in the home. All-electric customers are defined as those with homes that have electrified those four appliances.

This study finds that all-electric low-rise residential customers are likely to see lower total utility bills, on average, post-2030. In the near term, mixed-fuel customers are likely to see slightly lower utility bills than all-electric customers on average. This cost advantage erodes over time in both mitigation scenarios as an increasing share of more expensive biomethane is blended into the pipeline and gas delivery charges increase for the reasons discussed above. Between 2025 and 2030, depending on wildfire mitigation costs, the monthly utility bills of mixed-fuel customers increase above those of all-electric customers in both mitigation scenarios. Of course, energy consumption and utility bills vary widely by building and climate zone, so there is a wide range of potential utility bill outcomes across the building stock in the state.

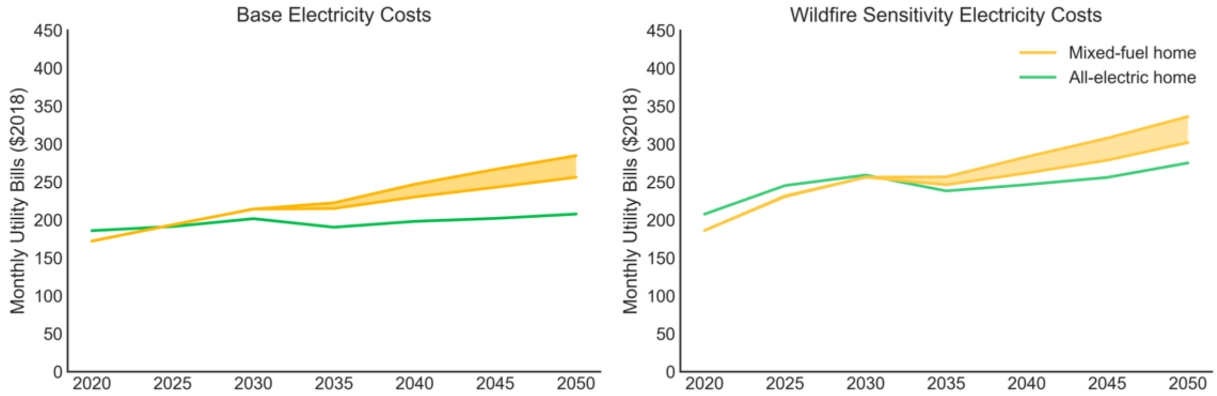
No Building Electrification

Utility bills in the no building electrification scenario increase over time because of a combination of decreased gas system throughput and an increasing share of costly electrolytic fuels that are blended into the pipeline (Figure 29). As a result, by 2040, a typical mixed-fuel customer could pay between $35 to $50 more per month than a typical all-electric customer in this scenario.

The largest impact of the wildfire cost sensitivity is to push out in time the point at which a typical all-electric home sees bill savings relative to a mixed-fuel home. In the base electricity cost case that crossover occurs in 2025, while in the wildfire sensitivity electricity costs case, that point is 2030.

Residential customers may still find cost savings from electrifying a subset of their appliances before cost savings would occur from electrifying their entire homes or businesses. For instance, this analysis finds that typical single-family residential IOU customers save from $6 to $12 per month on their utility bills in 2025 when adopting a heat pump HVAC system. Given the bill savings available, economic electrification of HVAC systems could become a particularly advantageous strategy for customers with air conditioning. Customers with air conditioning may already have the wiring, ducting, and electrical panel capacity required to install an electric heat pump with low to no retrofit costs. Heat pumps provide heating and air conditioning, allowing a single piece of equipment to replace a traditional furnace and air-conditioning unit. In fact, the cost of installing a heat pump may be less than the combined cost of the two separate pieces of HVAC equipment it replaces. That hypothesis has been supported by recent studies by E3 and others that find HVAC electrification to be economical at today's gas rates for a sizeable number of residential customers in California (Mahone et al 2018, Bilimoria et al 2019 2018, Hopkins et al 2018).

Figure 29: Consumer Bills in the No Building Electrification Scenario



Notes: The range for the mixed-fuel home depicts a range of bill impacts between the optimistic and conservative P2G commodity cost ranges. The no building electrification scenario assumes no economic electrification and reaches a pipeline blend of 44 percent RNG and 56 percent fossil NG by 2050; economic or policy-driven electrification or higher blends of RNG would increase mixed-fuel bills.

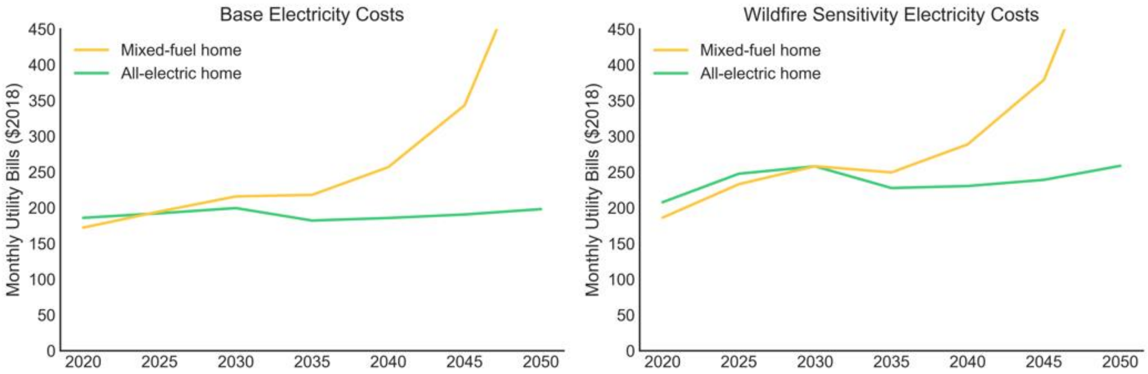
Source: E3

Each customer that electrifies some or all their heating equipment decreases the use of the gas system and increases the cost of service for remaining gas customers. As gas rates increase, the economics of electrification will improve for additional segments of residential and commercial customers. The dynamics of such a feedback loop are hard to predict because they will depend on the relative cost of pipeline gas and electricity, the relative cost of gas and electric end-use equipment and other factors ranging from consumer preferences to builder practices. For this reason, the research team did not attempt to model the potential for customer feedback effects in this analysis.

High Building Electrification

The high building electrification scenario presents gas customer challenges and points out the potential for step-changes in customer preferences and behavior based on the increasing cost of gas relative to electricity. The customer rate and bill impacts seen in that scenario would represent a cost imposition on households that continue to use gas. Those cost impacts are particularly concerning for low-income consumers who are less likely to be able to afford the upfront investments required to adopt electric technologies and are more likely to be renters.

Figure 30: Consumer Bills in the High Building Electrification Scenario



Notes: The high building electrification scenario assumes no cost savings from retirement of gas infrastructure and maintains the reference level of gas revenue requirement (excluding commodity costs) through 2050.

Source: E3

Absent policy intervention, the rate increases seen in the high building electrification scenario are unlikely to be consistent with financially stable gas utilities. Utilities raise capital from debt and equity markets on the expectation of future revenues from a customer base that is, at minimum, stable. In the high building electrification scenario, the number of gas customers in the state decreases. Those customer exits accelerate over time, leading to the rapid rate increases seen above. Those rate increases follow from the assumption that all gas system costs continue to be recovered from gas ratepayers. If that assumption does not hold, then some or all of the gap between expected customer revenues and gas utility revenue requirements will need to be filled to maintain safe operation of the remaining gas system.

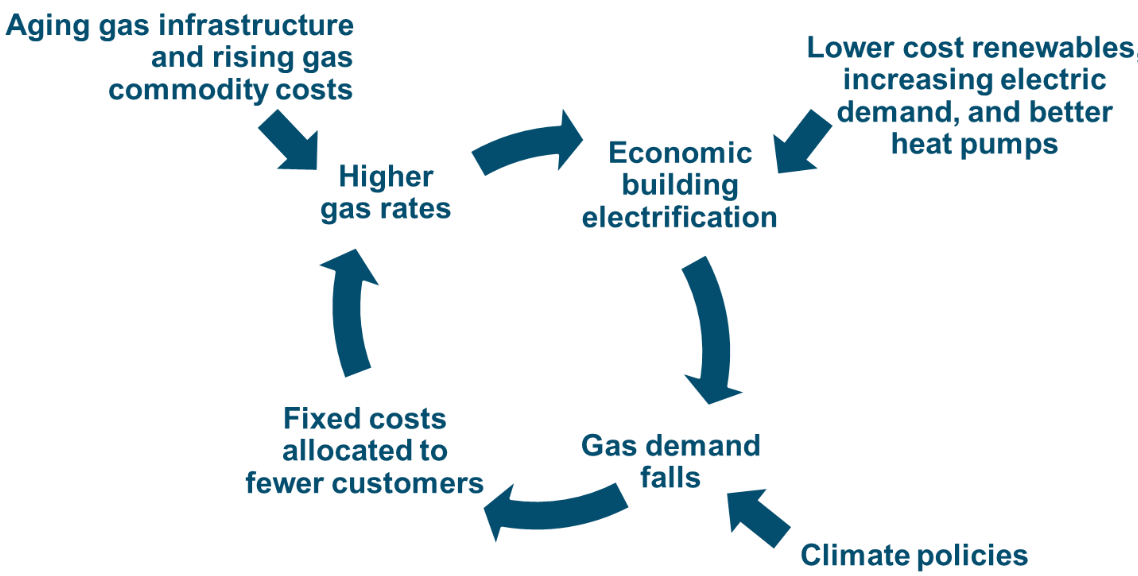
Bill Impacts Comparison and Conclusions

With those bill savings and the recent work on the economics of building electrification in mind, the research team concludes that the no building electrification scenario is unlikely to represent a stable, internally consistent future. A world in which increasing quantities of RNG are blended into the pipeline will lead to steady improvements in the economics of building electrification. So long as the state is on track to meet its climate targets, and RNG costs remain high (as estimated in this study), then building electrification appears to be the least-cost outcome from both an economy-wide perspective and from a customer-cost perspective. However, a number of potential barriers, including very high upfront capital costs for building electrification could represent a barrier to achieving this outcome. The remainder of this report will focus on the retail gas system challenges, and potential solutions, of moving toward a largely electrified building stock in California.

CHAPTER 5: Envisioning a Natural Gas Transition Strategy

California's gas system is under near- and long-term cost pressure. The costs of maintaining gas infrastructure are increasing while throughput is expected to decrease. Gas commodity costs will also increase in successful economywide mitigation scenarios, putting further upward pressure on the cost of pipeline gas. Absent intervention, these trends could drive a feedback effect that results in an unsustainable future for the gas system (Figure 31). As discussed previously, electricity costs are also expected to increase, but since electricity demand is also expected to increase, the impact on electric rates may be more muted.

Figure 31: Outside Forces Driving Change in the Natural Gas Delivery Sector Could Lead to Lower Gas Demand and Higher Gas Rates in Any Number of Future Scenarios



Source: E3

The goal of this chapter is to explore the contours of a potential gas system transition strategy for California. The potential gas transition strategies evaluated in this chapter aim to maintain reasonable gas rates for remaining gas customers, as well as the financial viability of the gas utilities, even as gas use declines in the state over the coming decades. A gas transition strategy could be designed to reduce rate impacts to all customer classes or particularly protect customers who are least able to switch away from gas, including renters and low-income residents. These scenarios were developed in recognition of the fact that, even in the high building electrification scenario, millions of gas customers remain on the gas distribution system through the entire study, albeit with reduced gas demand volumes.

In that context, maintaining reasonable gas rates becomes imperative because of the substantial equity concerns that could follow from a world in which the wealthy are more likely to be able to electrify, or to afford paying higher gas costs if they do not, but low- and middle-income households are less able to do so.

Furthermore, the operation of a safe gas system will require continued reinvestment and maintenance, even in scenarios with lower throughout. These scenarios evaluate a future in which maintaining the financial viability of gas utilities is used to ensure that these entities can continue to finance the ongoing operations and maintenance of this system. Alternative operation and maintenance structures for the gas system are conceivable, such as the creation of a state-owned enterprise. That and other legal and legislative options for a more rapid transition are outside the scope of this study.

A comprehensive gas transition strategy, informed by a myriad of interested parties, is needed. Such a strategy might include:

- Efforts to reduce barriers to electrification. It is not a straightforward process for even relatively motivated and well-resourced homeowners to install technologies like electric heat pumps. Those interested run into issues like difficulty receiving permits and contractors without heat pump installation experience. Market transformation initiatives will be needed to lower the costs and barriers to retrofits and make electrification an easy decision for homeowners.[31] There will also need to be initiatives in place to enable adoption of electric equipment for low-income homeowners and renters, particularly given the relative vulnerability of these groups to the bill impacts identified in Chapter 4.
- Avoid gas system expansion. Gas system investments come with long lifetimes. Making such investments in the context of declining throughput—an outcome that occurs in all mitigation scenarios—will increase the average cost of gas service. Unlike gas system retirements, a speculative measure at this point, building communities without gas is a common practice in large portions of the United States and world (Vivid Economics, 2017).
- Reduce costs of the existing gas system. California's gas system requires ongoing reinvestment to ensure safe, reliable service. In recent years, the magnitude of these reinvestments has increased as utilities have responded to high-profile safety incidents. A key challenge in any gas transition will be to reduce the costs of the existing gas system while still ensuring exacting standards of safety and reliability are maintained. The research team hypothesized that geographically targeted electrification and retirement of the gas system could be one potential strategy to achieve these reductions, though other measures (for example, derating of pipes to lower pressures) may also be available.
- Accelerated depreciation. Accelerated depreciation recovers investments over a shorter period than the traditional useful lifetime. When paired with reduced gas system expenditures, accelerated depreciation can further reduce the remaining costs of the gas system toward midcentury. However, accelerated depreciation will increase near-term gas rates and gas utility revenue collection. If it is not combined with a reduction in gas system expenditures and a long-term gas transition plan, accelerated depreciation may be counterproductive.

31 Senate Bill 1477 (Stern, Chapter 378) adopted in 2018 instructs state agencies to develop market transformation programs for building decarbonization, and the CPUC has instituted rulemaking R.19-01-011 on this topic, but rules were not finalized as of this writing.

- Changes to cost allocation. The gas distribution system was built to serve building heating loads. As these loads decline, there could be justification to shift a larger share of costs to customers that continue to use the gas system. Such an approach would need to be balanced against competitiveness concerns that follow from higher rates for remaining customer classes that use the gas system (for example, industry).
- Recover gas system costs on the bills of electric ratepayers. The gas distribution system was built to serve demand from California homes and businesses. Utilities raised funds to finance that system with the expectation of a fair opportunity to recover their investments from a stable customer base. The plausibility of recovering system costs for gas customers decreases as those customers exit the gas system. It could be justifiable to collect some share of the gas system costs from customers that exit the gas system and go all-electric. The potential equity benefits of such an exit fee would need to be balanced against the potential for such a fee to discourage beneficial electrification. An alternative approach could be a competitive transition charge that is applied to the bills of all electricity customers. This approach would allow costs to be spread out more evenly over time but is less directly tied to the decision of a customer to exit and the amount of gas system costs that were incurred on his or her behalf.
- Additional funds from outside the gas system. Regulatory mechanisms to reduce and reallocate gas system costs can reduce the rate and bill impacts of a gas transition strategy. However, even under relatively aggressive assumptions about the success of those mechanisms, a substantial cost challenge remains. One option evaluated in this chapter examines the implications of infusing "additional funds" to manage remaining costs. These funds could be derived from a variety of sources (such as cap-and-trade revenues or the state general fund), though this report does not try to specify a source for such additional funds.
- Shut down uneconomic gas infrastructure built to serve building loads. In 2050, there are still 2 million residential gas customers in the high building electrification scenario. California's gas system was built to serve more than 13 million residential customers. That imbalance only worsens beyond the 2050 time horizon of this study. The high building electrification scenario assumes that the last gas appliance is sold in 2040. Given the typical lifetimes of gas equipment, this assumption means that, in a world with no early retirement of equipment, the number of gas customers in California would approach zero toward the late 2050s. The PATHWAYS model assumes relatively smooth transitions between gas and electric end uses, in part because it is so difficult to predict the timing for more abrupt changes in customer behavior or energy system choices. That said, there is likely a point between 2 million (or perhaps before) and 0 residential gas customers where customers would abruptly leave the gas system for economic reasons, even if meant early retirement of their gas equipment, and there is a point when it would no longer be viable to operate much of the state's gas distribution system. In advance of that point, without knowing exactly when that time will arrive, policy makers will need to consider what set of measures are needed to shut down unused infrastructure.

The next section evaluates each of these gas system strategies in more detail.

Gas Transition Mechanisms

Defining a complete gas transition strategy for California is beyond the scope of this or any study. Instead, this analysis is meant to examine plausible impacts of a subset of the policy and regulatory mechanisms that could fall within a broader transition plan. The mechanisms examined target two key goals:

1. Reduce the cost of the gas system while ensuring reinvestment to ensure safety and reliability
2. Equitably allocate the fixed costs of the gas system

Reduce the Costs of the Gas System

A fundamental challenge facing California's gas system is that costs are expected to increase, and throughput is expected to decrease. Chapter 4 outlined the adverse consumer effects of this phenomenon assuming gas-system costs were equal to the reference scenario and were collected entirely through rates. Those results are meant to highlight the scale of the cost challenge facing the California gas system and associated customers. Given those challenges, California's energy policy and business community will need to consider strategies to reduce the cost of the gas system.

A key premise of this analysis is that California's gas system requires reinvestment to ensure safety. Any strategy to reduce costs will need to be implemented with that imperative in mind. Such reductions might be possible via a variety of mechanisms, including:

- Halting expansion of the gas system. Gas infrastructure is long-lived, with a typical distribution main having a book life of between 50 and 65 years (PG&E 2018, SCG 2019). Adding new infrastructure increases the size of the gas system financial obligation California will face in the future. Insofar as throughput declines and customer exits can be expected, these additional obligations will increase the cost of gas service for remaining gas customers, with all the potential negative consumer equity implications outlined in Chapter 4. Avoiding new infrastructure could help slow the growth of future financial obligations without incurring any risk of declines in system safety or reliability.
- Targeted retirement of the gas distribution system. California's gas utilities spend nearly $3.5 billion per year in operations and maintenance to ensure safe and reliable gas service. That ongoing O&M expense is in addition to capital reinvestments to replace aging infrastructure. A potential response to these expenditures could be to reduce the overall footprint of the state's gas distribution system. Doing so would reduce the need to reinvest in, and potentially reduce the O&M costs associated with, aging infrastructure. However, this strategy is somewhat speculative, hinging on successful identification of geographies that are ripe for retirement and successful targeting of electrification efforts. That overlay is particularly important because early retirements of utility infrastructure and consumer end-use equipment carries real economic costs.
- Derating of infrastructure to reduce reinvestment and O&M costs. It may be possible to reduce the cost of maintaining existing gas infrastructure if, for instance, certain segments of the gas system could be operated at lower pressures.

There are not sufficient data available at this time to allow precise modeling of each of these mechanisms. Instead, this study models scenarios that stipulate a decrease in gas system capital reinvestment and annual O&M. These scenarios are defined by two key parameters.

1. Percentage reduction in annual capital expenditures. This analysis models the amount of capital that needs to be reinvested as the previous year's depreciation, grossed-up by a real capital escalation factor of 1 percent per year. The exact percentage chosen can be thought of as capturing either how sensitive capital expenditures are to system utilization or how successfully a targeted gas distribution program has been implemented.
2. The year in capital reinvestments that can start being reduced: This figure represents how quickly a targeted electrification/targeted retirement program can be ramped up. This study assumes that such a program would need to achieve enough gas disconnections to avoid substantial early equipment retirement costs.

Using those parameters, the research team defined three gas system cost reduction scenarios (Table 4). These scenarios are meant to illustrate the effects of reduced gas system expenditures. These cases are compared against a "no action" scenario where the state's gas revenue requirement is equal to the Reference scenario forecast.

Table 4: Gas Cost Reduction Scenarios

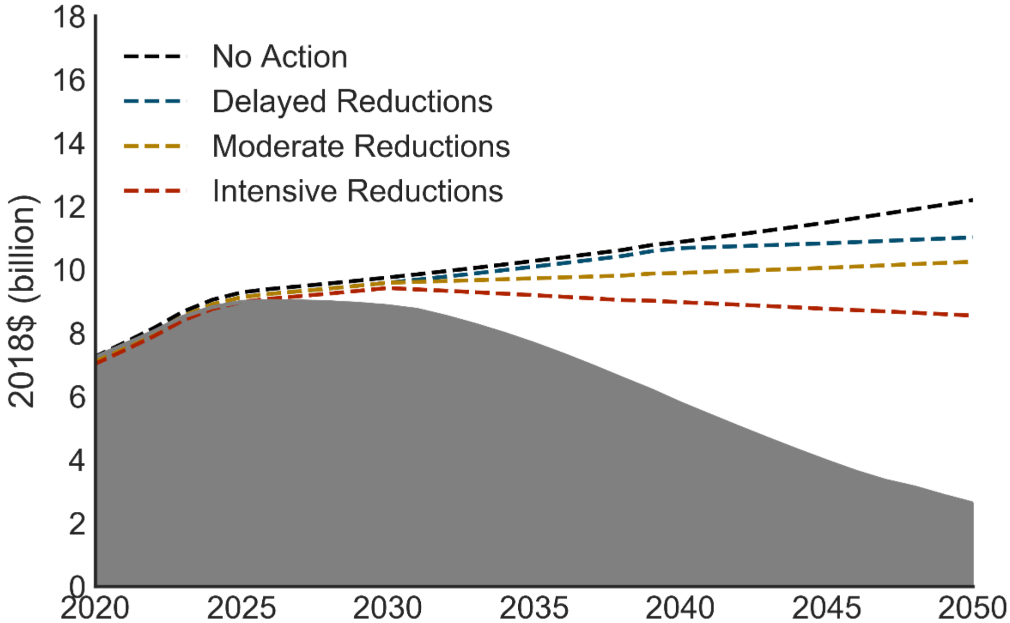
Retirement Scenario Name	Year Reinvestments Are Decreased	% Reinvestment Avoided
Intensive Reductions	2030	50%
Moderate Reductions	2030	25%
Delayed Reductions	2040	50%

Source: E3

Figure 32 shows California's gas revenue requirement in each of these scenarios.

Strikingly, even the most ambitious revenue requirement reduction scenario modeled, the "intensive retirements" scenario, does not reduce the state's gas system revenue requirement below that of the current value. This result occurs for two reasons. First, as discussed in Chapter 4, the state's gas system revenue requirement is expected see a marked near-term increase as utilities continue their safety-related upgrades to the state's gas system. By 2025, these investments increase the state's revenue requirement by more than one-third. The second reason is real escalation of gas capital costs. This study assumes, based on historical indices of gas capital costs, 1 percent real escalation of capital and operations and maintenance costs. The compounding effect of this real cost escalation puts upward pressure on the reinvestment costs of the gas system. Some of the growth assumed within that escalation rate could be offset by avoiding expansion of the gas system.

Figure 32: Gas Cost Reduction Scenarios



Source: E3

The cost reduction scenarios modeled in this analysis are meant to represent a set of plausible futures where the gas system revenue requirement can be reduced below the no action baseline. Exactly what magnitude of cost decreases are achievable in practice is not yet known. However, what this analysis does indicate is that even a very aggressive set of cost-reduction measures can probably only mute—and certainly cannot eliminate—the cost and equity challenges facing the state's gas system. Further measures are needed to ensure energy affordability and equity.

Equitably Allocate the Costs of the Gas System

The cost challenges facing the gas system result from declining throughput and customer exits. The customer rates and residential bill impacts results presented above reflect a world where gas system costs are allocated similarly to today. That means residential customers continue to pay for the bulk of the gas distribution system, depreciation schedules follow current assessments of the useful life of assets, and the gas revenue requirement is recovered entirely via rates. However, current methods of allocating gas system costs were designed for a world in which gas demand was expanding in California. Current cost allocation methods may not be appropriate in a world with rapidly decreasing gas demand.

Cost allocation changes could take different forms. Within the gas regulatory context, costs could be shifted from customers that no longer use that system (that is, residential) to customers that continue to use the system (that is, industrial). It could also be advisable to shift costs within customer classes over time. For instance, accelerated depreciation could allow long-term obligations to be paid for when a larger share of customers continue to receive gas service. Finally, costs could be shifted outside the gas system. Such a shift could be based on achieving procedural fairness and equitable outcomes. This section examines several mechanisms to reallocate remaining gas system costs.

Shift Cost Allocation Between Customer Classes

Today, gas delivery in California is allocated to customers based on their utilization of the system. "Utilization" can be defined in a variety of ways but typically includes total annual consumption and peak demands.[32] For this analysis, researchers assumed that transmission costs are allocated to customers based on their share of annual throughput, while distribution costs are allocated based on the existing share of revenue each customer class pays to that part of the system. In practice, distribution costs are allocated based on peak demands, using either a peak-day or peak-month method.

A key challenge with cost recovery in a future with high building electrification is that throughput falls most rapidly in the gas distribution system. Further, those throughput reductions occur in roughly equal proportion between the two primary users of the distribution system, residential and commercial buildings. These reductions lead to rapidly increasing costs for remaining gas distribution customers. A potential solution could be to allocate distribution costs to a broader set of gas system customers. This analysis models changes in gas cost allocation as a percentage shift from current allocations of distribution costs toward a system throughput-based allocation. To illustrate the effect of this cost reduction, it further models a scenario where the percentage of distribution costs that are allocated based on throughput increase from 0 to 40 percent in 2050. Such a shift could reflect a different allocation of peak-day or peak-month loads by customer classes.

Accelerated Depreciation

Accelerated depreciation shortens the period over which capital investments are recovered. For instance, a utility asset with a baseline depreciation schedule of 20 years could instead be collected over 10 years. In practice, this collection schedule would effectively double the annual depreciation charge for that asset. This approach could be justified for two key reasons. The first is that, as a matter of principle, depreciation schedules are meant to reflect the useful life of an asset (Bilich et al 2018). In current practice, the useful lives of assets are typically assessed based on a likely survivor curve derived from historical experience. In the future, an empirical survivor curve is a less accurate predictor of useful life than expected utilization over time. If utilization is expected to decrease such that the asset is no longer used, then the associated useful life could plausibly be considered shortened. A second reason to consider accelerated deprecation is that it would effectively allow the fixed costs of the gas system to be collected over a larger group of ratepayers. Accelerated depreciation would shift fixed-cost recovery to periods before large-scale electrification and customer exits from the gas system occur (Figure 33).

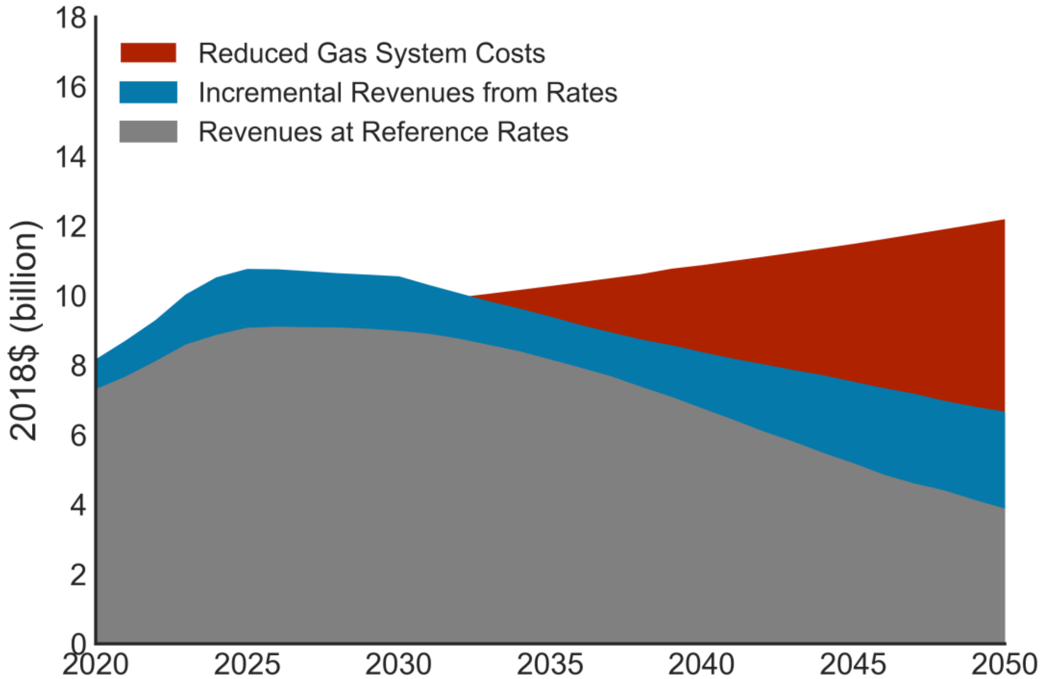
Exit Fees

The gas system was built with the expectation of a stable long-term customer base. Customers that leave the gas system no longer contribute toward the fixed costs of infrastructure that was built on their behalf. As shown above, this situation shifts those fixed costs to remaining gas customers, with the associated rate bill effects and equity concerns. A potential measure to address this issue could be to charge customers that leave the gas

32 Peak demands are assessed based on daily and monthly consumption in the distribution system (SCG TCAP 2019).

system an exit fee. Such an exit fee could be collected either as a lump sum or amortized over a longer time frame. This study assumes the latter approach because it avoids adding a substantial upfront incremental cost that could slow otherwise beneficial electrification. This approach is modeled as a $5-per-month exit fee applied over a 15-year period, collecting a total of $900 per exiting customer (Figure 34).

Figure 33: Revenue Requirement With Intensive Reductions and Accelerated Depreciation



Notes: The red wedge shows the cost savings associated with gas system cost reductions and accelerated depreciation. The blue wedge shows incremental revenue collected through gas rates. The blue wedge increases revenues substantially in the near term, but doing so enables deeper cost savings in the future than can be achieved by reduced reinvestment alone.

Source: E3

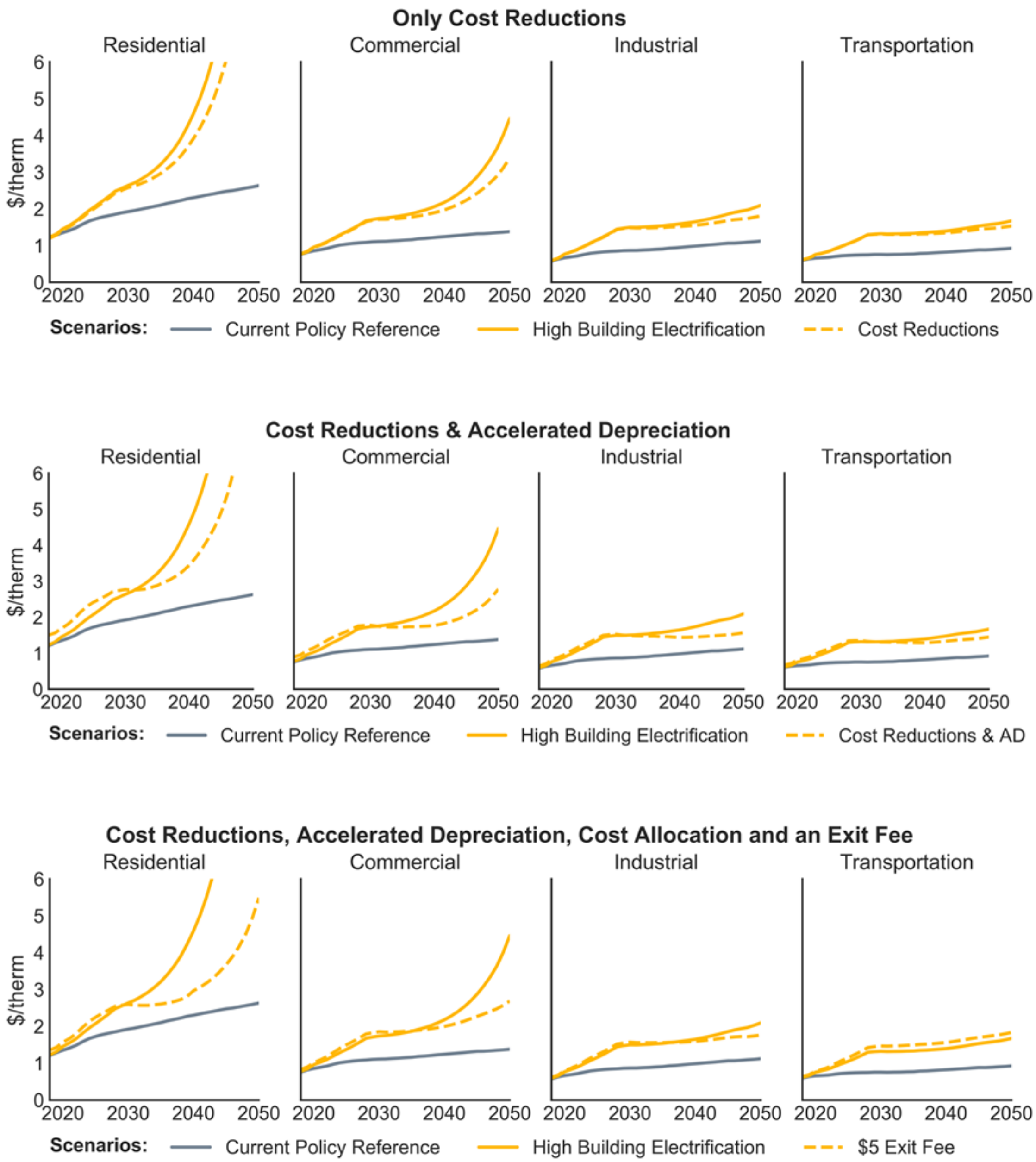
Other Funds

Given the magnitude of gas system cost recovery challenges, there may be good reason to commit funds from elsewhere in the economy to reduce the cost stresses on the gas system and related customers. Potential sources of these funds include the state's general fund cap-and-trade revenues, a transition charge on the bills of all electric ratepayers, or decreased returns for utility shareholders. This analysis treats these types of measures as a source of "additional funds" without attempting to attribute a specific source. Instead, the research team aims to explore what magnitude of additional funds are required after other strategies are exhausted.

Effect of Gas Transition Mechanisms on Rates

Figure 34 shows the effects of gas transition mechanisms on the rates paid by residential, commercial, industrial, and transportation customer rates. The first row shows the rates that would follow from the "Intensive Cost Reductions" scenario described above. Reducing gas system costs does reduce rates somewhat, but rates continue to escalate rapidly for residential and commercial customers. The next row layers accelerated deprecation onto retirements. This layering leads to increased customer costs in the near term but lower rates in later periods. The final row adds a shift in cost allocation and a $5-per-month exit fee. This scenario markedly reduces residential and commercial customer rates but still leaves costs that are likely untenable for low- and middle-income Californians.

Figure 34: Natural Gas Rates With Gas Transition Mechanisms



Source: E3

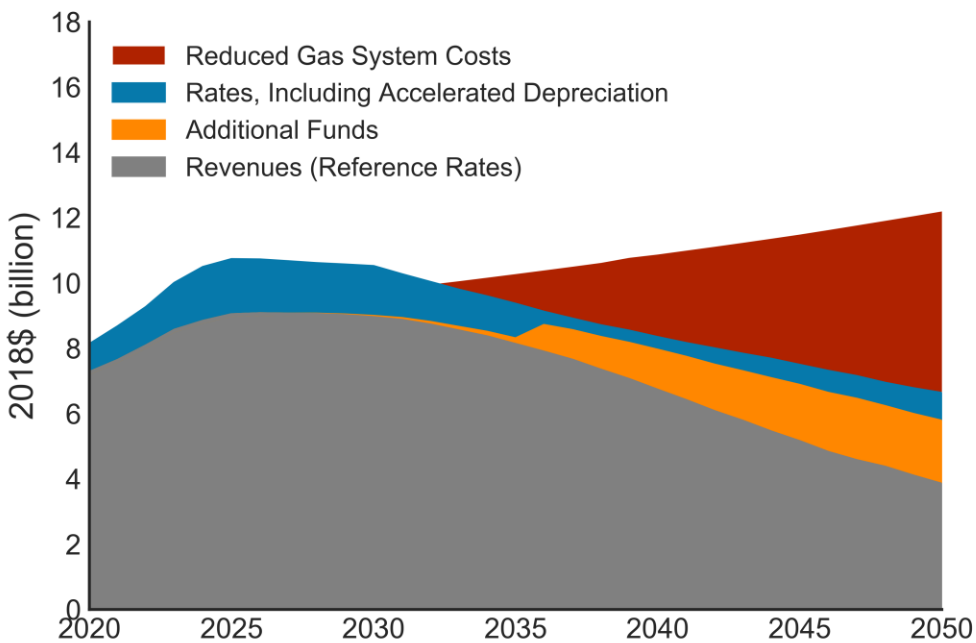
Example Gas Transition Strategy

This section offers an example gas transition strategy that uses a combination of the mechanisms described above. The strategy aims to manage the rate effects of decreasing gas throughput for all customer classes, with an aim of reducing the financial impacts of the transition on the most vulnerable Californians. The research team is not recommending any strategies here but rather illustrating what a systematic treatment of this issue could entail. The example gas transition strategy includes the following assumptions:

- Gas system cost reductions: Following the intensive cost reductions case, this strategy assumes a 50 percent reduction in capital reinvestment and associated operations and maintenance expenses.
- Accelerated depreciation of gas system capital: This strategy shortens the depreciation schedule of all existing and new capital to half that used today.
- Shift gas customer cost allocation: This strategy assumes that by 2050, 40 percent of distribution costs are allocated based on total system throughput.
- Gas customer exit fee: A $5-per-month would be collected for 15 months on exiting customers' electric bills.
- Additional funds: Starting in 2035, additional nonratepayer funds are used to cover a share of the gas system revenue requirement. The amount of additional funds rises to $2 billion per year in 2050.

Figure 35 shows the effect of the gas transition strategy on California's gas system revenue requirement.

Figure 35: Revenue Requirement With Gas Transition Strategy



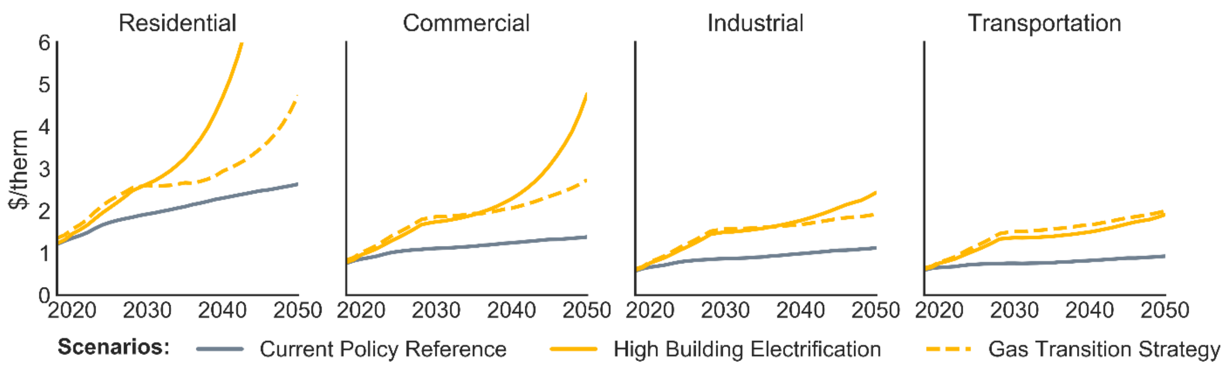
The orange wedge represents additional unspecified "additional funds" that are used to reduce bill impacts on remaining gas customers

Source: E3

The state sees a more rapid near-term increase in its gas revenue requirement due to accelerated depreciation (depicted in blue). However, the additional near-term expense allows deeper gas system cost reductions in later years (depicted in red). While incurring more near-term costs may not be preferable from a time value of money perspective, the cost reduction achieved in later years eases the challenge of achieving an equitable gas system transition. This example still requires a substantial infusion of "additional funds" of $11 billion in net-present value terms (depicted in orange).

Compared to the base high building electrification scenario, the example gas transition strategy in Figure 37 reduces rates for all customers except those in the transportation sector, whose gas rates are little affected by these changes. Residential customers see the largest decreases in rates relative to the base case because of reduced distribution system costs and a shift toward throughput-based cost allocation.

Figure 36: Customer Rates After a Gas Transition Strategy in the HBE Scenario



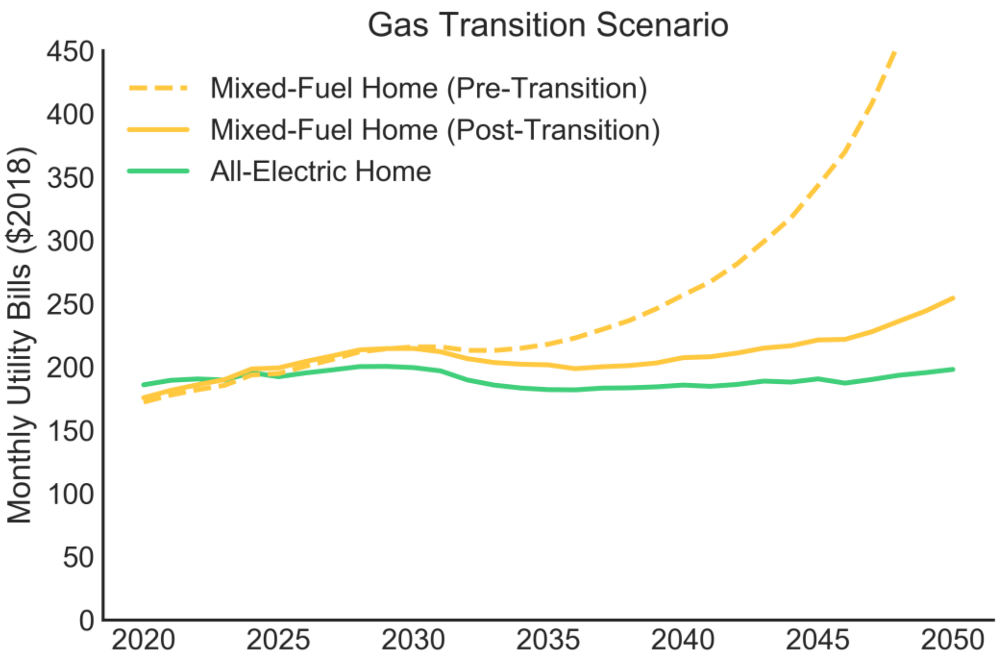
Source: E3

Residential customers also see large bill savings as a result of the example gas transition strategy. In the base case, those customers' bills increase to more than $600 per month, an amount that is cut by more than half after the example gas transition strategy (Figure 37). Mixed-fuel customer bills are slightly higher in the near term due to the additional accelerated depreciation expense, but those costs are relatively small on a per-capita basis compared to the savings achieved further out in the study period.

Sensitivity of Results to Early Retirements

The example gas transition strategy reduces the cost of the gas system by $4 billion annually in 2050 and $25 billion cumulatively in net-present value terms. However, gas system infrastructure retirements may not be achievable without early replacement of consumer end-use equipment. There are two real economic costs that stem from replacement of equipment. The first is that the equipment has remaining useful life. The second is the opportunity cost of purchasing a new appliance earlier than a consumer would have otherwise. All else being equal, these costs are tied to the average lifetimes of equipment that are retired. Post-2040, no new gas equipment is sold in California in the high building electrification scenario, so the age of remaining equipment increases after that year, and the cost of early retirement decreases.[33] Though not modelled in this analysis, it would be the case that by the mid- to late-2050s early retirement costs in the high building electrification scenario would approach zero.

Figure 37: Residential Bills Before and After the Example Gas Transition Scenario



Source: E3

This study tests two early retirement sensitivities: one where 20 percent of building equipment is retired early over the study period and one where 10 percent of building equipment is retired early. The sensitivities assume that the oldest equipment is retired first and economic costs include the two categories mentioned above. These percentages are meant to reflect a successful, though not perfect, targeted electrification program that replaces most appliances on burnout. Table 5 summarizes the NPV costs of each sensitivity.

Table 5: Cost of Early Retirement Sensitivities

Early Retirement Sensitivity	Incremental NPV Cost
10% Early Retirement	$4 billion to $6 billion
20% Early Retirement	$8 billion to $12 billion

Source: E3

These sensitivities illustrate the potential trade-offs between reducing gas system expenditures and the costs associated with achieving those retirements. If gas system cost reductions require large-scale early retirements of gas equipment, then those cost savings may be somewhat eroded.

33 Assuming an average equipment lifetime of roughly 15 years for gas furnaces, the early retirement costs in the high building electrification scenario approach $0 in the mid-2050s.

CHAPTER 6: Conclusions

Achieving California's climate policy goals requires transformational changes across all sectors of the state's energy economy. This study focuses on the role of the state's gas infrastructure, particularly the low-pressure, retail gas distribution system, examining different scenarios for how gas use will change in California. A key finding is that gas use decreases in all scenarios that meet an 80 percent reduction below 1990 emissions by 2050 target. Common drivers of that throughput decline across scenarios are steep reductions in gas use in electric generation and energy efficiency in industry and buildings. The key source of throughput variation in scenarios developed in this study is the amount of electrification in buildings. Scenarios with more building electrification lead to lower overall retail gas demand, with especially sharp declines in buildings. The level of gas demand, in turn, has profound implications for the overall amount and distribution of costs related to achieving California's climate policy objectives.

Scenarios with more gas demand require a combination of more mitigation elsewhere in the economy and higher levels of RNG. Relying on mitigation elsewhere in the economy means that more energy-intensive sectors of the California economy, like heavy-duty trucking and industry, would need to carry a greater share of the GHG reduction load. If those challenging mitigation measures do not prove workable, then the remaining strategy to achieve the 80 percent by 2050 reduction is to increase the share of RNG in the pipeline.

Another key finding of this study is that relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough to achieve 80 percent reduction. Once the biomethane portion of the RNG supply curve is exhausted, then the state must turn to more expensive hydrogen and yet more expensive SNG. The result is that by 2050, the commodity cost of blended pipeline gas is more than four to seven times that of natural gas today. This premium leads to large increases in rates and total costs for all customers that use pipeline gas today. Importantly, the no building electrification scenario leaves 56 percent of the pipeline as natural gas. If more pipeline decarbonization were needed—as may be the case in a carbon-neutral scenario—the cost of the marginal RNG resource, SNG with DAC, would be between 10 and 22 times that of natural gas today. Indeed, the level of costs seen in the no building electrification scenario suggest that there will be some level of economic electrification based on price alone.

A conclusion of this analysis is that scenarios with more building electrification have lower total societal costs. However, these scenarios raise challenging issues related to the cost of maintaining the state's retail gas distribution infrastructure in the context of lower utilization. If throughput declines and gas system costs do not, then large financial obligations will be left to be paid by a smaller number of customers. In the later years of the study period, this situation leads to rapidly increasing gas customer bills and rates. These rates and bills are unlikely to be consistent with an economically sustainable gas system. Particularly concerning is the prospect that low- and moderate-income Californians or renters, who may be unable to electrify due to upfront costs or lack of home ownership, could bear the impact of these cost increases.

Another consideration around building electrification pertains to risk and uncertainty. The choices facing California regarding building decarbonization present asymmetric risks, particularly because of the time required to transform building infrastructure and the urgency of addressing climate change. The main barriers to building electrification are upfront capital cost and consumer acceptance. However, once these costs are paid and consumers gain familiarity with electric appliances, even if inexpensive sources of RNG become available later, the state's climate goals will still be met, and residents will be able to heat their homes relatively affordably. In contrast, should building electrification be delayed in the hope that RNG technology will progress more rapidly than considered in the optimistic P2G cost scenario here, and these RNG cost reductions do not materialize, then it will be difficult to recover from delays in building electrification and it may prove difficult to reduce emissions at reasonable cost. Further, customers who do not electrify face the risks associated with high cost of gas, while customers who electrify, do not face the same level of rate impact risk.

The results of the two bookend scenarios indicate that California should begin investigating a natural gas system transition strategy. A gas transition strategy could have several goals, ranging from cost reductions to protection of gas utility workers. This study focuses on components of a gas transition strategy that relate to reducing total system costs and the bill impacts for remaining gas customers. Results from this analysis suggest that there is no silver bullet strategy to manage these challenges. Instead, a suite of measures will need to be considered, including reductions in gas system costs, accelerated depreciation, changes to cost allocation, and infusion of electric- or non-ratepayer funds. The gas distribution system continues to be used throughout the study period in these scenarios, so such a strategy will need to be developed without compromising the safety and reliability of the remaining system.

This study also sets out the contours of an ongoing research agenda for California. A clear finding of this study is that RNG, particularly biomethane, is used in all mitigation scenarios that achieve an 80 percent reduction by 2050. Electrolytic fuels appear to have more limited roles in an 80 percent reduction policy regime but may have larger roles in achieving the state's 2045 carbon-neutrality target, particularly in sectors of the economy that are otherwise difficult to decarbonize. Research by UCI suggests that there is a wide range of potential cost trajectories for those technologies, so further consideration of how to achieve costs consistent with the "optimistic" P2G scenario of this study is warranted. Identifying the role of these zero-GHG gaseous fuels—both on their own merits and in comparison to alternatives—in providing resiliency benefits to the state of California was beyond the scope of this study and is a topic that may warrant further investigation, as are questions around the possibility of exceeding the 7% hydrogen blend limit in the gas system.

Another area deserving of further research relates to the development of the gas transition strategy itself. Many important next steps are recommended for additional research in the arenas of policy questions, engineering questions, and legal and regulatory questions. Key policy questions include the following:

- How should the benefits and costs of a gas transition strategy be allocated among stakeholders?
- How can California protect low-income residents, and gas workers, during a gas transition?

Key engineering questions around gas pipeline safety and costs include:

- To what degree can targeted electrification efforts safely reduce gas distribution expenditures? To answer this question, more data are needed to understand the geographic details of the gas system in California, as well as the replacement schedules for the existing gas system.
- What is the cost of targeted electrification, considering the potential for early retirements of consumer equipment? A better understanding is needed of the real-world technical and economic options to reduce gas system expenditures. Pilots and real-world research could help understand the costs and options to launch targeted electrification in communities in such a way that would enable targeted retirements of the gas distribution system and would consider the impacts on the electric distribution system of targeted electrification, along with the potential for cost savings on the gas distribution system.

More research is needed to identify the legal and regulatory barriers to implementing a gas transition strategy, along with targeted electrification programs. For example:

- Should natural gas companies be able to collect the entire book value of their assets? Should shareholder return be affected in a gas transition strategy? How does the timing of a gas transition strategy affect the answer to these questions?
- Should California gas utilities' obligation to serve be redefined?

Finally, this study does not include an in-depth investigation of the role of the high-pressure gas system to deliver decarbonized fuels in the context of achieving California's 2045 carbon neutrality goal. This study, done in the context of an 80 by 50 target, assumes that unabated natural gas continues to serve industrial and electric generator loads. In a carbon neutral future, zero-GHG gaseous fuels may play a larger role in those sectors.

This research paper does not seek to make policy recommendations, but rather highlight key issues for further policy debate and illuminate some implications of meeting the state's climate goals. With foresight and coordination, Californians can plan for an equitable, low-carbon future.

LIST OF ACRONYMS

Term	Definition
AAEE	Additional achievable energy efficiency
AEC	Alkaline electrolytic cells
APEP	Advanced Power and Energy Program
CARB	California Air Resources Board
BEV	Battery-electric vehicle
CCS	Carbon capture and storage
CEC	California Energy Commission
CFC	Chlorofluorocarbons
CNG	Compressed natural gas
CPUC	California Public Utilities Commission
CO_2	Carbon dioxide
DAC	Direct air capture
E3	Energy and Environmental Economics, Inc.
EE	Energy efficiency
EJ	Exajoule, a unit of energy equal to one quintillion (10^{18}) joules
EPIC	Electric Program Investment Charge
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
F-gas	Fluorinated gas
GGE	Gallons of gasoline equivalent
GHG	Greenhouse gas
GRC	General rate case
GWh	Gigawatt-hour, a unit of energy in electricity
GWP	Global Warming Potential
H_2	Hydrogen
HBE	High building electrification scenario
HDV	Heavy-duty vehicles
HFC	Hydrofluorocarbons

Term	Definition
HHV	Higher heating value
HVAC	Heating, ventilation, and air conditioning
IOU	Investor-owned utility
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicles
LHV	Lower heating value
MDV	Medium-duty vehicles
MW	Megawatt, a million watts, a unit of capacity in electricity
NBE	No building electrification scenario
PCC	Postcombustion capture
PEMECs	Proton exchange membrane electrolytic cells
P2G	Power to gas
PHEV	Plug-in hybrid electric vehicle
PJ	Petajoule, a unit of energy equal to one quadrillion (10^{15}) joules
PM	Particulate matter
NOx	Oxides of nitrogen
RNG	Renewable natural gas
RR	Revenue requirement
RPS	Renewables Portfolio Standard
SB	Senate Bill
SLCP	Short-lived climate pollutant
SOEC	Solid oxide electrolytic cells
SNG	Synthetic natural gas
TRC	Total resource cost
TRL	Technology readiness level
TW	Terawatt is a trillion watts (10^{12}), or a million megawatts
TWh	Terawatt is a trillion watt-hours (10^{12}), or a million megawatt-hours
UCI	University of California, Irvine
VMT	Vehicle miles traveled
ZEV	Zero-emission vehicle

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