Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

Released January 2015

(Revised from June 2014)

Energy+Environmental Economics

Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

Released January 2015

(Revised from June 2014)

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Table of Contents

Table of Figures

Table of Tables

Executive Summary

This study examines the potential role of decarbonized pipeline gas fuels, and the existing gas pipeline infrastructure, to help meet California's long-term climate goals. The term "decarbonized gas" is used to refer to gaseous fuels with a net-zero, or very low, greenhouse gas impact on the climate. These include fuels such as biogas, hydrogen and renewable synthetic gases produced with low lifecycle GHG emission approaches. The term "pipeline gas" means any gaseous fuel that is transported and delivered through the natural gas distribution pipelines. Using a bottom-up model of California's infrastructure and energy systems between today and 2050 known as PATHWAYS (v.2.1), we examine two "technology pathway" scenarios for meeting the state's goal of reducing greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050:

+ **Electrification scenario**, where all energy end uses, to the extent feasible, are electrified and powered by renewable electricity by 2050;
+ **Mixed scenario**, where both electricity and decarbonized gas play significant roles in California's energy supply by 2050.

Both scenarios meet California's 2020 and 2050 GHG goals, to the extent feasible, accounting for constraints on energy resources, conversion efficiency, delivery systems, and end-use technology adoption. Across scenarios, we compare total GHG emissions, costs, and gas pipeline utilization over time relative to a Reference scenario, which does not meet the 2050 GHG target.

The study concludes that a technology pathway for decarbonized gas could feasibly meet the state's GHG reduction goals and may be easier to implement in some sectors than a high electrification strategy. We find that the total costs of the decarbonized gas and electrification pathways to be comparable and within the range of uncertainty. A significant program of research and development, covering a range of areas from basic materials science to regulatory standards, would be needed to make decarbonized gas a reality.

The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

+ First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) heavy duty vehicles (HDVs), and (3) certain residential and commercial end uses, such as cooking, and existing space and water heating.
+ Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed.
+ Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, eliminating

the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen pipelines or additional electric transmission and distribution capacity.

+ Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a low-carbon energy system.

1 Introduction

California has embarked on a path to dramatically reduce its GHG emissions over the next four decades. In the nearer term, Assembly Bill 32 (AB 32) requires the state to reduce GHG emissions to 1990 levels by 2020. The state appears to be on track to meet this goal. In the longer term, Executive Order S-3-05 sets a target for California to reduce GHG emissions by 80% relative to 1990 levels by 2050. Achieving this target will require significant changes in the state's energy systems over the coming decades; the state's energy supply will need to be almost entirely carbon free by mid-century.

Natural gas and other gaseous fuels face an uncertain future in California's energy supply mix. The need to reduce the carbon intensity of the state's transportation fuels and industrial output to meet near- to medium-term GHG goals opens up opportunities for natural gas as a substitute for more carbon-intensive oil and coal. However, natural gas from traditional fossil fuel sources cannot represent a significant share of energy use by 2050 if the state is to meet its long-term GHG goal. By 2050, traditional uses of oil and natural gas, including transportation fuels, water and space heating, and industrial boilers and process heating, will need to be mostly, if not fully, decarbonized.

Solutions for achieving a deep decarbonization of California's energy supply have focused on extensive electrification using renewable energy sources, with some liquid biofuel and hydrogen fuel use in the transportation sector. However, there are three principal challenges associated with this decarbonization "pathway." First, there are practical limits to electrifying some energy end uses, such as HDVs and industrial process heating. Second, there are physical limits on sustainable biomass resources, which limit the amount of biomass that can be used as a primary energy source. Third, very high levels of renewable penetration require large-scale energy storage solutions, to integrate wind and solar generation on daily and seasonal timescales. Decarbonized[1] gas fuels distributed through the state's extensive existing gas pipeline network offer a little-explored strategy for overcoming some of these challenges and meeting the state's GHG goals.

To examine the roles of gas fuels in California and utilization of the state's existing gas pipeline infrastructure from now until 2050, Southern California Gas Company (SCG) retained Energy and Environmental Economics (E3) to address four main questions:

1. Are there feasible technology pathways for achieving California's nearer- and longer-term GHG targets where gaseous fuels continue to play a significant role?
2. If yes, how do these pathways compare against a reference case and a "high electrification" strategy in terms of GHG emissions and costs?How does the use of the state's gas pipeline infrastructure differ under scenarios where more and less of the state's energy supply is electrified?
3. In what key areas would research, development, and demonstration (RD&D) be needed to produce decarbonized gas on a commercial scale?

[1] Throughout this report, the term "decarbonized gas" refers to gases that have a net-zero, or very low, impact on the climate, accounting for both fuel production and combustion.

To provide an analytical framework for addressing these questions, we develop two "technology pathway" scenarios that represent different points along a spectrum between higher and lower levels of electrification of energy end uses by 2050:

> (1) "Electrification" scenario, where most of the state's energy consumption is powered with renewable electricity by 2050;
>
> (2) "Mixed" scenario where decarbonized gas replaces existing natural gas demand and fuels HDVs, but renewable energy is used to produce electricity and to power most light-duty vehicles (LDVs).

The decarbonized gas technologies examined in this study were selected to represent a range of different options, but are not intended to be exhaustive. The focus in this study is on more generally examining the role of gas fuels over the longer term in a low-carbon energy system, not on comparing different emerging decarbonized gas options.[2] These scenarios are compared to a Reference scenario where current policies are unchanged through 2050 and the state's GHG target is unmet. Table 1 shows a high-level summary of key differences among these three scenarios.

[2] A number of emerging technology options for low-carbon gas, such as artificial photosynthesis, are thus not included in the list of technology options examined in this study. Including these technologies would likely reinforce many of the main conclusions in this study.

Table 1. High-level summary of key differences among the three scenarios examined in this analysis

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply	Source and amount of decarbonized pipeline gas[3]
Electrification	Mostly electric	Mostly electric LDVs, mostly hydrogen fuel cell HDVs	Renewable energy, some natural gas with CCS	Small amount of biogas
Mixed	Decarbonized gas for existing gas market share of end uses	Electric LDVs, Decarbonized gas in HDVs	Renewable energy, some natural gas with CCS	Large amount of biogas, smaller amounts of SNG, hydrogen, natural gas
Reference	Natural gas	Gasoline, diesel	Mostly natural gas	None

Both the Electrification and Mixed scenarios were designed to meet California's 2020 and 2050 GHG targets. For each scenario we analyzed its technical feasibility and technology costs using a bottom-up model of the California economy. This model (California PATHWAYS v2.1), which includes a detailed "stock-rollover" representation of the state's building, transportation, and energy infrastructure, allows for realistic depiction of infrastructure turnover and technology adoption; sector- and technology-based matching of energy demand and supply; and detailed energy system representation and technology coordination. The model includes hourly power system dispatch and realistic

[3] Throughout this report, the term "pipeline gas" is used to encompass different mixes of gas in the pipeline, including conventional natural gas, gasified biomass, hydrogen (initially limited to 4% of pipeline gas volume, with up to 20% allowed by 2050), and gas produced from P2G methanation.

operating constraints. An earlier version of the model was peer reviewed as part of an article published in the journal *Science*.[4]

The identification of realistic sources of decarbonized gas is a critical piece of this analysis. We considered three energy carriers for decarbonized gas, each with different potential primary energy sources:

+ **Biogas**, which includes gas produced through biomass gasification (biomass synthetic gas) and anaerobic digestion of biomass;
+ **Hydrogen**, produced through electrolysis; and
+ **Synthetic natural gas (SNG)**, produced through electrolysis with renewables (mostly wind and solar "over-generation") and further methanated into SNG in a process referred to as power-to-gas (P2G) throughout this report.[5]

By 2050, there are a limited number of primary energy sources available to supply decarbonized energy: renewable electricity, biomass, nuclear, or fossil fuels with carbon capture and sequestration (CCS). Each has different scaling constraints. For instance, wind and solar energy are intermittent and require energy storage at high penetration levels. Hydropower and geothermal energy are constrained by land and water use impacts and the availability of suitable

[4] James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

[5] P2G, though often used generically to refer to any process that converts electricity to gas, refers specifically to electrolysis and hydrogen methanation in this report. The methanation reaction requires a source of CO_2, which we assume to be air capture in this study, although carbon capture from seawater is another promising, emerging technology. This extra methanation step, and the costs of seawater carbon capture, or air capture, makes P2G relatively expensive. We examined this technology in this study primarily for its electricity storage benefits. Other potential low-carbon gas production technologies, such as synthetic photosynthesis, are not examined within the scope of this study.

sites for development. Bioenergy is limited by the amount of feedstock that can be sustainably harvested. Nuclear is limited by public acceptance and the lack of long-term storage and disposal of spent fuel. Carbon capture and sequestration is also limited by public acceptance and generates higher emissions than the other options due to partial capture rates of CO_2. Choices of primary energy sources for a decarbonized energy supply require tradeoffs in costs, reliability, externalities, and public acceptance.

Similar limits and tradeoffs exist with conversion pathways from primary energy to secondary energy carriers, often with multiple interrelated options. Biomass, for instance, can be converted into a number of different energy carriers (e.g., liquid biofuels, biogas, hydrogen, electricity) through multiple energy conversion processes. P2G is only cost-effective from an energy system perspective when there is significant renewable over-generation. Fossil fuels can be converted into partially decarbonized energy with carbon capture and sequestration (CCS). Evaluating different decarbonized gas technology options — primary energy sources, energy conversion pathways, and energy carriers — thus requires realistic scaling constraints, an integrated energy system perspective, and strategies for managing uncertainty and complexity.

Our modeling framework addresses these requirements by: consistently constraining physical resources (e.g., biomass availability), conversion efficiencies (e.g., gasification efficiency), and gas distribution (e.g., limits on hydrogen gas volumes in pipelines); allowing for interrelationships among energy sources (e.g., electricity and gas); accounting for system costs and GHG emissions across a range of technologies; and exploring different potential options under a range of inputs and avoiding over-reliance on point estimate assumptions as the driver of technology adoption. The results of this study confirm that the electricity sector will be pivotal to achieving a low-carbon future in California — in both the Electrification and Mixed scenarios the need for low-carbon electricity increases substantially. The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

+ First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) HDVs, and (3) certain residential and commercial end uses, such as cooking, existing space heating, and existing water heating.
+ Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed. At high penetrations of variable renewable generation, long-term, seasonal electricity storage may be needed to balance demand and supply, in addition to daily storage. On these longer timescales, gas "storage" may be a more realistic and cost-effective load-resource balancing strategy than flexible loads and long-duration batteries.[6]
+ Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, reducing or

[6] In this scenario, we assume that electrolysis for hydrogen production, powered by renewable electricity, can be ramped up and down on a daily basis as a dispatchable load in the medium-term. In the long-term, P2G methanation with air capture, or carbon capture from seawater to produce SNG could provide both a source of low-carbon gas and a grid balancing service.

eliminating the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen delivery pipelines or additional electric transmission and distribution lines. Increased use of decarbonized gas in the coming decades would preserve the option of continued use of existing gas pipelines as a low-carbon energy delivery system over the longer term.

+ Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a decarbonized energy system.

All of the decarbonized gas energy carriers in this study make use of proven energy conversion processes — none require fundamental breakthroughs in science. Nonetheless, these processes remain relatively inefficient and expensive, and would need significant improvements in conversion efficiency and reductions in costs to be competitive in the medium- to long-term. Additionally, existing gas pipelines and end use equipment were not designed to transport and utilize hydrogen gas, and would require operational changes as the blend of decarbonized gas shifts over time.

Developing a supply of sustainably sourced biomass presents an additional challenge. Biomass resources have competing uses — food, fodder, and fiber — which may limit the amount of sustainably-sourced biomass available for energy production. The Electrification and Mixed scenarios both assume that a limited quantity of sustainably sourced biomass would be available to California in the 2030 and 2050 timeframe. The same quantity of biomass is assumed to produce electricity in the Electrification scenario, and biogas in the Mixed scenario.

However, it remains uncertain whether it will be possible to increase the production of biomass fuels to this scale, as would be needed to significantly reduce fossil fuel use, without negatively impacting food supply or increasing GHG emissions from changes in land use.

Furthermore, current RD&D efforts and policy initiatives have prioritized the production of liquid biofuels, particularly ethanol, over the production of biogas. More generally, the state does not appear to have a comprehensive decarbonized gas strategy, in contrast to low-carbon electricity which is promoted through the state's Renewables Portfolio Standard (RPS) and the decarbonized transportation fuels are encouraged through the state's Low Carbon Fuel Standard (LCFS). Overcoming these challenges would require prompt shifts in policy priorities and significant amounts of RD&D if biofuels, and particularly biogas, are to become an important part of the state's future energy mix.

The results suggest priority areas and time frames, outlined in Table 2, for a RD&D agenda that would be needed if California is to pursue decarbonized pipeline gas as a strategy to help meet the state's GHG reduction goals.

Table 2. RD&D timescales, priorities, and challenges for decarbonized gas fuels

Timeframe of RD&D payoff	RD&D Area	Challenge
Near-term	Energy efficiency	Achieving greater customer adoption and acceptance
	Reduction in methane leakage	Cost-effectively identifying and repairing methane leaks in natural gas mining, processing, and distribution
	Use of anaerobic digestion gas in the pipeline and pilot biomass gasification	Quality control on gas produced via anaerobic digestion for pipeline delivery
Medium-term	Agronomic and supply chain innovation for biomass feedstocks	Competition with liquid fuels, food, fodder, fiber may limit amount of biomass available as a source of decarbonized gas
	Pilot decarbonized SNG technology to improve conversion efficiency and cost	Gasification, electrolysis, and methanation need efficiency improvements, reductions in cost to be competitive; safety, scale, and location challenges must be addressed
	Limits on hydrogen volumes in existing pipelines	Need pipeline and operational changes to accommodate higher volumes
Long-term	Emerging technologies (e.g., P2G, artificial photosynthesis, CO_2 capture from seawater for fuel production)	P2G must be scalable and available as a renewable resource balancing technology; in general, emerging technologies still require innovations in material science

The organization of the report is as follows: Section 2 develops the Reference case and two afore-mentioned scenarios. Section 3 describes the modeling approach and elaborates on the technology pathways for decarbonized gases. Section 4 presents the results. The final section, Section 5, distills key conclusions and discusses their policy and regulatory implications. Further details on methods and assumptions are provided in an appendix.

1.1 About this study

This study was commissioned by SCG to help the company consider their long-term business outlook under a low-carbon future, and to fill a gap in the existing literature regarding long-term GHG reduction strategies that include the use of decarbonized gas in the pipeline distribution network.

A number of studies have evaluated the options for states, countries and the world to achieve deep reductions in GHG emissions by 2050.[7] These studies each make different assumptions about plausible technology pathways to achieve GHG reductions, with varying amounts of conservation and efficiency, CCS, hydrogen fuel cells, nuclear energy, and biofuel availability, to name a few key variables. However, few studies have undertaken an in-depth investigation of the role that decarbonized pipeline gas could play in achieving a decarbonized future.[8]

In our prior work, we highlighted the pivotal role of the electricity sector in achieving a low-carbon future for California.[9] This study for SCG uses an

[7] See for example: "Reducing Greenhouse Gas Emissions by 2050: California's Energy Future," California Council on Science and Technology, September 2012; "Roadmap 2050: A practical guide to a prosperous, low-carbon Europe," European Climate Foundation, April 2010; "EU Transport GHG: Road to 2050?," funded by the European Commission, June 2010; "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft," U.S. EPA, April 2009; "Energy Technology Perspectives, 2008: Scenarios & Strategies to 2050," International Energy Agency, 2008; "The Power to Reduce CO_2 Emissions: The Full Portfolio: 2008 Economic Sensitivity Studies," EPRI, Palo Alto, CA: 2008. 1018431; "Building a Low Carbon Economy: The U.K.'s Contribution to Tackling Climate Change," The First Report of the Committee on Climate Change, December 2008; "Making the Transition to a Secure and Low-Carbon Energy System: Synthesis Report," UK Energy Research Center, 2009.

[8] For an example of a deep decarbonization study from Germany that employs both electrolysis and P2G (Sabatier), see Palzer, A. and Hans-Martin Henning, "A Future Germany Energy System with a Dominating Contribution from Renewable Energies: A Holistic Model Based on Hourly Simulation," Energy Technol. 2014, 2, 13 – 28.

[9] James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

updated version of the model (California PATHWAYS 2.1) employed in that prior work, relying on the same fundamental infrastructure-based stock roll-over modeling approach, and many of the same underlying input assumptions, such as energy efficiency potential. However, important updates to the analysis include:

+ Updated forecasts of macroeconomic drivers including population and economic growth;
+ Updated technology cost assumptions where new information has become available, including for solar photovoltaic (PV) and energy storage costs;
+ A more sophisticated treatment of electricity resource balancing, moving from a four time period model (summer/winter & high-load/low-load), to an hourly resource balancing exercise; and
+ Slightly higher biomass resource potential estimates, based on new data from the U.S. Department of Energy (DOE).[10]

The model results are driven by exogenous, scenario-defined technology adoption assumptions. Costs of technologies and fuels are exogenous, independent inputs which are tabulated to track total costs. The model does not use costs as an internal decision variable to drive the model results, rather the model is designed to evaluate technology-driven, user-defined scenarios.

[10] U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.

2 Scenarios

2.1 Low-carbon scenarios

Two distinct low-carbon scenarios are developed and compared within this study. Both of these scenarios result in lower GHG emissions than required by California's mandate of reducing emissions to 1990 levels by 2020, and are designed to meet the 2050 goal of reducing GHG emissions 80% below 1990 levels. Each scenario is further constrained to achieve an approximately linear path in GHG reductions between today's emissions and the 2050 goal. The differences between the two scenarios are not in GHG reduction achievements, but between technology pathways, implied RD&D priorities, technology risks, and costs.

The two low-carbon scenarios evaluated include:

+ **Electrification Scenario: This scenario meets the 2050 GHG reduction goal by electrifying most end-uses,** including industrial end uses, space heating, hot water heating, cooking and a high proportion of light-duty vehicles. Low-carbon electricity is produced mostly from renewable generation, primarily solar PV and wind, combined with a limited amount of natural gas with carbon capture and storage (CCS) and 20 GW of electricity storage used for renewable integration. Low-carbon electricity is also used to produce hydrogen fuel for heavy-duty vehicles. California's limited supply of biomass is used largely to generate renewable electricity in the form of biomass generation. In this scenario, the gas distribution pipeline network is effectively un-used by 2050. With very few remaining sales by 2050 and significant remaining fixed distribution costs, it seems unlikely that gas distribution companies would continue to operate under this scenario.

+ **Mixed Scenario: This scenario meets the 2050 GHG reduction goal with a blend of low-carbon electricity and decarbonized pipeline gas.** Existing uses for natural gas in California, such as industrial end uses (i.e. boilers and process heat), space heating, hot water heating and cooking are assumed to be supplied with decarbonized pipeline gas, such that the current market share for pipeline gas is maintained over time. California's limited supply of biomass is used to produce biogas which is injected into the pipeline. Over time, this scenario assumes that an increasing share of hydrogen is blended into the pipeline gas, which is assumed to be produced from renewable power (mostly solar and wind) using electrolysis. This scenario includes a significant increase in electric light-duty vehicles, while most heavy-duty vehicles are assumed to be powered with compressed or liquefied decarbonized gas and liquid hydrogen fuel. Electricity is produced mostly from renewable generation, primarily solar PV and wind, with a limited amount of natural gas with CCS and 5 GW of electricity storage used for renewable integration. Load balancing services are primarily provided by cycling the production of decarbonized gas to match the renewable generation profiles. In this way, the decarbonized pipeline gas provides both daily and seasonal energy storage. The Mixed scenario represents neither a significant expansion nor contraction of the gas pipeline distribution system. In this scenario, both the gas pipeline network and the electricity transmission and distribution system operate as conveyors of decarbonized energy.

The key parameters of these scenarios are summarized in Table 3 below.

Table 3. Summary of Low-Carbon Scenarios Based on Key Parameters in 2050

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply & resource balancing	Uses of biomass
Electrification	Mostly electric	Mostly electric light-duty vehicles, mostly hydrogen HDVs	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage and 15 GW of battery energy storage, some hydrogen production	Electricity generation, small amount of biogas
Mixed	Decarbonized gas (biogas, SNG & hydrogen) for existing gas market share of end uses	Decarbonized gas in HDVs; electric light duty vehicles (LDVs)	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage, plus P2G and hydrogen production assumed to provide resource balancing services	Biogas

Both of the low-carbon scenarios evaluated here entail different assumptions about the future feasibility and commercialization of key technologies to achieve an 80 percent reduction in GHGs relative to 1990. For the Electrification scenario to be viable, significant amounts of long-term electricity storage must be available on a daily and seasonal basis to balance intermittent renewable generation. The Electrification scenario also relies significantly on the production of low carbon liquid biofuels and hydrogen fuel cell vehicles in the transportation sector, for vehicles that are otherwise difficult to electrify. For the Mixed scenario to succeed, it must be possible to produce large quantities of biogas using sustainably-sourced biomass. Furthermore, the Mixed scenario depends on eventual adoption of P2G methanation with carbon capture from sea water or air capture to produce SNG. All of the technologies that are applied in these scenarios are technically feasible; the science exists today. The challenge is commercializing and scaling these technologies to provide a significant energy service to California before 2050. In Table 4 below, the emerging technologies applied in the low-carbon scenarios are ranked based on their "risk" to the scenario's success. Risk is determined by ranking the amount of energy that passes through each technology in 2050 for a given scenario (higher energy use implies higher reliance on the technology), combined with a measure of the technology's current commercialization stage (lower availability implies higher risk).

Table 4. Ranking of emerging technology's criticality to the Electrification and Mixed scenarios

Emerging Technologies	Overall Ranking of Technology Criticality by 2050 (maximum = 9 for most critical, minimum = 0 for least critical)	
	Electrification	Mixed
Availability of sustainably-sourced biomass	6	9
Power-to-gas methanation using carbon capture from seawater or air	0	6
Battery storage for load balancing	9	0
Carbon capture and storage	3	3
Cellulosic ethanol	6	0
Hydrogen production	4	4
Use of hydrogen in the distribution pipeline	0	4
Gasification to produce biogas	1	3
Fuel cells in transportation (HDVs)	6	3
Electrification of industrial end uses	2	0

2.2 Common strategies and assumptions across all low-carbon scenarios

Both of the low-carbon scenarios described above include a number of other carbon reduction efforts that must be implemented to achieve the state's long-term GHG reduction goal. These other assumptions do not vary between scenarios, and include low-carbon measures such as:

+ Significant levels of energy efficiency in all sectors, including transportation efficiency, industrial and building efficiency;
+ Significant reductions in non-CO_2 and non-energy GHG emissions, such as methane emissions and other high-global warming potential gases such as refrigerant gases;
+ Improvements in "smart growth" planning as per Senate Bill 375,[11] leading to reductions in vehicle miles traveled (VMT) and increased urban density leading to lower building square footage needs per person;
+ All scenarios include the use of sustainably-sourced biomass to produce decarbonized energy. The scenarios differ in how the biomass is used, to produce electricity, liquid or gas fuels.
+ All scenarios include an increase in electrification relative to today; the scenarios differ in how much additional electrification is assumed relative to other sources of low-carbon energy;
+ Flexible loads for renewable resource balancing, including limited use of controlled charging of electric vehicles and a limited share of certain residential and commercial electric thermal end uses.[12] Hydrogen and P2G production are assumed to provide fully dispatchable, perfectly flexible load-following services, helping to integrate variable renewable generation in the low-carbon scenarios.

[11] The Sustainable Communities and Climate Protection Act of 2008

[12] Up to 40 percent of electric vehicle charging load is assumed to be flexible within a 24-hour period to provide load-resource balancing services. Electric vehicles are not assumed to provide energy back to the electric grid, in a "vehicle-to-grid" configuration.

+ Imports of power over existing transmission lines are limited to a historical average and are assumed to maintain the same emissions intensity throughout the study period. New, dedicated transmission lines for out-of-state renewable resources are also tracked. Exports of electricity from California of up to 1500 MW are allowed.

2.3 Reference case

In addition to the low-carbon scenarios evaluated here, a Reference case is developed as a comparison point. The Reference case assumes a continuation of current policies and trends through the 2050 timeframe with no incremental effort beyond 2014 policies to reduce GHG emissions. This scenario is not constrained to achieve specific GHG reduction goals. As a result, this scenario misses the state's GHG reduction targets in 2050 by a wide margin, with 2050 emissions 9% above 1990 levels. In the Reference case current natural gas end uses, such as space heating and hot water heating, continue to be supplied with natural gas through 2050. With no future efforts, California achieves a 33% RPS by 2020 and maintains this share of renewable energy going forward. The transportation sector continues to be dominated by the use of fossil-fueled vehicles in the Reference case.

3 Analysis Approach

3.1 PATHWAYS model overview

This analysis employs a physical infrastructure model of California's energy economy through 2050. The model, known as PATHWAYS (v2.1), was developed by E3 to assess the GHG impacts of California's energy demand and supply choices over time. The model tracks energy service demand (i.e. VMT) to develop a projection of energy demand and the physical infrastructure stock utilized to provide that service (i.e. types and efficiency of different vehicles). End uses in the building sector, vehicles in the transportation sector, and power plants in the electricity sector are tracked by age and vintage, such that new technologies are adopted as older technologies and are replaced in a stock roll-over representation of market adoption rates.

Technology lifetimes, efficiency assumptions and cost data are generally drawn from the U.S. DOE National Energy Modeling System (NEMS), used to support development of the Annual Energy Outlook 2013. Assumptions about new technology adoption are highly uncertain, and are defined by E3 for each scenario. New technology adoption rate assumptions are selected to ensure that the low-carbon scenarios meet the state's 2050 GHG reduction goal.

The model can contextualize the impacts of different individual energy technology choices on energy supply systems (electricity grid, gas pipeline) and energy demand sectors (residential, commercial, industrial) as well as more broadly examine disparate strategies designed to achieve deep de-carbonization targets. Below, Figure 1 details the basic modeling framework utilized in PATHWAYS to project results for energy demand, statewide GHG emissions, and costs for each scenario.

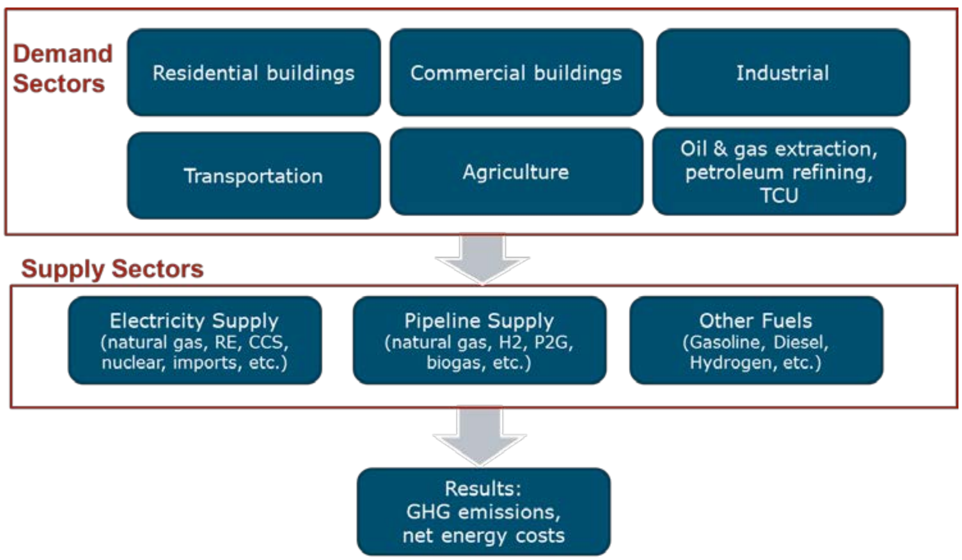

Figure 1. Basic PATHWAYS modeling framework

- **Energy Demand:** projection of energy demand for ten final energy types. Projected either through stock roll-over or regression approach.
- **Energy Supply:** informed by energy demand projections. Final energy supply can be provided by either conventional primary energy types (oil; natural gas; coal) or by decarbonized sources and processes (renewable electricity generation; biomass conversion processes; CCS). The energy supply module includes projections of costs and GHG emissions of all energy types.

- **Summary Outputs:** calculation of total GHG emissions and costs (end-use stocks as well as energy costs). These summary outputs are used to compare economic and environmental impacts of scenarios.

PATHWAYS V2.1 projects energy demand in eight sectors, and eighty sub-sectors, as shown below in Table 5.

Table 5. PATHWAYS Energy Demand Sectors and Subsectors

Sector	Subsector
Residential	Water Heating, Space Heating, Central AC, Room AC, Lighting, Clothes Washing, Dish Washing, Freezers, Refrigeration, Misc: Electricity Only, Clothes Drying, Cooking, Pool Heating, Misc: Gas Only
Commercial	Water Heating, Space Heating, Space Cooling, Lighting, Cooking, Refrigeration, Office Equipment, Ventilation
Transportation	Light Duty Vehicles (LDVs), Medium Duty Trucking, Heavy Duty Trucking, Buses, Passenger Rail, Freight Rail, Commercial Passenger Aviation, Commercial Freight Aviation, General Aviation, Ocean Going Vessels, Harborcraft
Industrial	Mining, Construction, Food & Beverage, Food Processing, Textile Mills, Textile Product Mills, Apparel & Leather, Logging & Wood, Paper, Pulp & Paperboard Mills, Printing, Petroleum and Coal, Chemical Manufacturing, Plastics and Rubber, Nonmetallic Mineral, Glass, Cement, Primary Metal, Fabricated Metal, Machinery, Computer and Electronic, Semiconductor, Electrical Equipment & Appliance, Transportation Equipment, Furniture, Miscellaneous, Publishing
Agricultural	Sector-Level Only
Utilities (TCU)	Domestic Water Pumping, Streetlight, Electric and Gas Services Steam Supply, Local Transportation, National Security and International Affairs, Pipeline, Post Office, Radio and Television, Sanitary Service, Telephone, Water Transportation, Trucking and Warehousing, Transportation Service, Air Transportation
Petroleum Refining	Sector-Level Only
Oil & Gas Extraction	Sector-Level Only

For those sectors that can be represented at the stock level – residential, commercial, and transportation – we compute stock roll-over by individual subsector (i.e. air conditioners, LDVs, etc.). For all other sectors, a forecast of energy demand out to 2050 is developed based on historical trends using regression analysis. These two approaches are utilized to project eleven distinct final energy types (Table 6).

Table 6. PATHWAYS Final Energy Types and Sources of Energy

Final Energy Type	
Electricity • many types of renewables, CCS, nuclear, fossil, large hydro.	Gasoline • ethanol & fossil gasoline
Pipeline Gas • natural gas, hydrogen, biogas, SNG	Liquefied petroleum gas (LPG)
Compressed Pipeline Gas • natural gas, hydrogen, biogas, SNG	Refinery and Process Gas
Liquefied Pipeline Gas • natural gas, hydrogen, biogas, SNG	Petroleum coke
Diesel • biodiesel & fossil diesel	Waste Heat
Kerosene-Jet Fuel	

These final energy types can be supplied by a variety of different resources. For example, pipeline gas can be supplied with combinations of natural gas, biogas, hydrogen, and SNG (produced through P2G processes). Electricity can be supplied by hydroelectric, nuclear, coal, natural gas combined cycles and combustion turbines, and a variety of renewable resources including utility-scale & distributed solar PV, wind, geothermal, biomass, etc. These supply composition choices affect the cost and emissions profile of each final energy type. Further methodology description can be found in the Technical Appendix.

3.2 Modeled energy delivery pathways

A decarbonized technology pathway can be thought of as consisting of three stages: (1) the provision of the primary energy itself, (2) the conversion of primary energy into the energy carrier, and (3) the delivery of an energy carrier for final end use. In practice, there can be many variations on this theme, including multiple conversion process steps and the use of CCS. The primary decarbonized energy sources are biomass, renewable and nuclear generated electricity, and natural gas with CCS. The main options for energy carriers in a decarbonized system are electricity, liquid biofuels such as ethanol and biodiesel, and decarbonized gases including biogas, SNG, and hydrogen and decarbonized electricity.

Figure 2 illustrates the main decarbonized technology pathways for delivering energy to end uses represented in the model. In the remainder of this section, we sketch briefly the main low-carbon pathways considered in this study and how they are modeled.

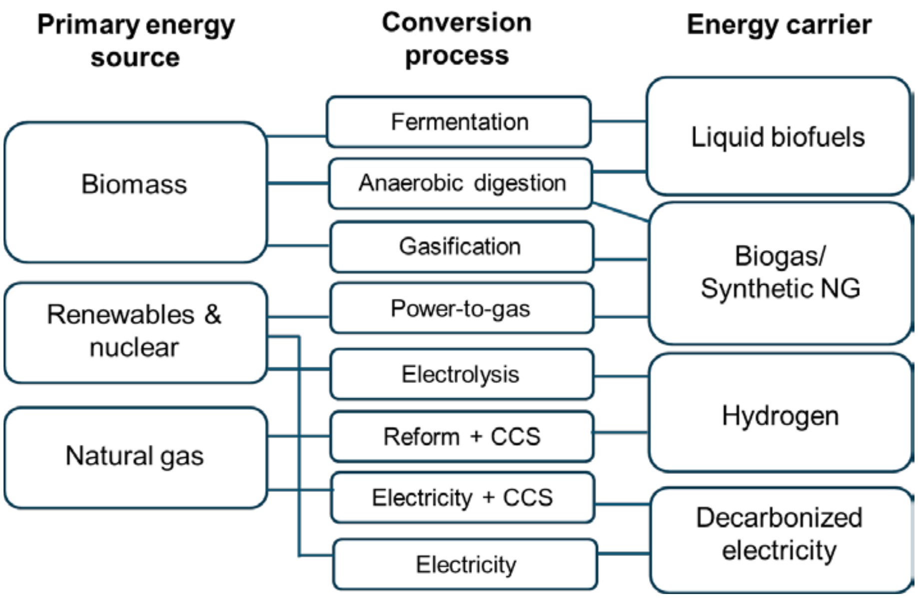

Figure 2. Major low-carbon pathways for delivered energy, from primary energy to conversion process to energy carriers

The technical opportunity for the gas distribution industry lies in providing an alternative to widespread electrification of end uses as an approach to deep decarbonization. The decarbonized gas technologies included in the Mixed scenario have been well-understood and some have been used in commercial applications for decades. For example, synthesized town gas, not natural gas, was the prevalent energy carrier for the first gas distribution companies over a century ago.

However, improvements in cost and efficiency will be required for decarbonized pipeline gas supplies to outcompete other forms of low-carbon delivered energy, such as electricity and liquid biofuels, and other issues require careful consideration and research, such as long-term biomass resource potential and carbon benefits. It is difficult at present to predict which pathways are the most likely to take root and become the dominant forms of energy delivery in a deeply decarbonized world.

3.2.1 BIOMASS RESOURCE ASSUMPTIONS

The principal data source for biofuel feedstocks in our model is the DOE's *Billion Ton Study Update: Biomass Supply for a Bioenergy and Bioproducts Industry* led by Oak Ridge National Laboratory, the most comprehensive available study of long-term biomass potential in the U.S.[13] This study, sometimes referred to as the BT2, updates the cost and potential estimates in the landmark 2005 *Billion Ton Study*, assessing dozens of potential biomass feedstocks in the U.S. out to the year 2030 at the county level (Figure 3).[14]

The estimated future supply of California produced biomass stocks is relatively small compared to the resource potential in the Eastern portion of the U.S., as shown in Figure 3. In this study, we have assumed that California can import up to its population-weighted proportional share of the U.S.-wide biomass feedstock resource potential, or 142 million tons per year by 2030. In the case of the Mixed scenario, where nearly all biomass is assumed to be gasified into biogas, this could be accomplished through production of biogas near the source of of the feedstock, which would then be distributed through the national gas pipeline network. California would not necessarily need to physically import the biomass feedstock into the state in order to utilize, or purchase credits for, the biogas fuel. Under the emissions accounting

[13] U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.
[14] U.S. Department of Energy, "Biomass as a Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply," April 2005.

framework employed in this study, California would take credit for assumed emissions reductions associated with these biofuels, regardless of where the fuel is actually produced. This assumption may not reflect California's long-term emissions accounting strategy. Furthermore, there remains significant uncertainty around the long-term GHG emissions impacts of land-use change associated with biofuels production.

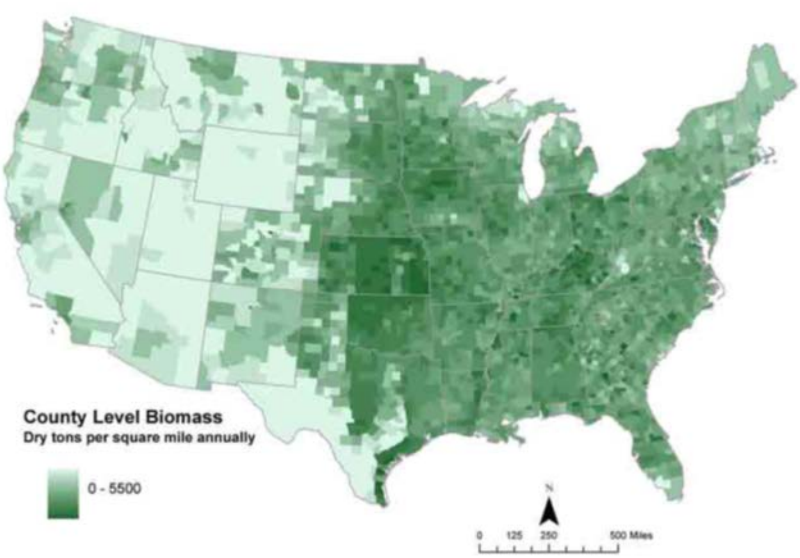

Figure 3. DOE Billions Tons Study Update Biomass Resource Potential (Source: DOE, 2011)

3.2.2 PIPELINE GAS AND LIQUID FUELS FROM BIOMASS

Biomass feedstocks ranging from purpose-grown fuel crops to a variety of agricultural, forestry, and municipal waste products can be converted into decarbonized gas. The main conversion method that is assumed in the Mixed scenario is gasification, including thermal and biochemical variants, which break down complex biomass molecules through a series of steps into a stream of SNG, consisting primarily of hydrogen and carbon monoxide. In the modeled pathway, the SNG is cleaned, shifted, and methanated to produce a pipeline-ready biogas with a high methane content. The other main method for biomass conversion represented in the model is anaerobic digestion. In anaerobic digestion bacterial digestion of biomass in a low-oxygen environment produces a methane-rich biogas which, after the removal of impurities, can be injected into the pipeline. In addition to gas fuels, biomass can be turned into liquid fuels directly through fermentation and distillation, as in the case of ethanol, or through the transesterification of fats such as waste cooking oil to produce biodiesel. Biogas from gasification can also be turned into liquid fuels, for example through the Fischer-Tropsch process.

3.2.3 PIPELINE GAS AND LIQUID FUELS FROM ELECTRICITY AND NATURAL GAS

Renewable energy, fossil generation with CCS and nuclear energy produce low-carbon electricity that can either directly power end uses or be used to produce pipeline gas or liquefied gases for transportation fuels. There are two P2G pathways in the model. One pathway uses electricity for electrolysis to split water and produce hydrogen, which can be injected into the pipeline for distribution up to a certain mixing ratio, or can be compressed or liquefied for use in hydrogen fuel cell vehicles. The other pathway modeled also begins with electrolysis, followed by methanation to produce SNG, which is injected into the pipeline. The SNG pathway requires a source of CO_2, which can come from carbon capture from sea water, air capture or biomass, or under some circumstances from CCS (e.g. situations in which the use of CCS implies no additional net carbon emissions, such as biomass power generation with CCS). The CO_2 and hydrogen are combined into methane through the Sabatier or related process.

Continued use of natural gas under a stringent carbon constraint requires that carbon be captured and stored. The low-carbon scenarios evaluated in this study assume a limited amount of natural gas with CCS is used for electricity generation in both of the low-carbon scenarios. There are two main types of CCS: (1) post-combustion capture of CO_2, and (2) pre-combustion capture of CO_2. In one pathway, CCS occurs after the natural gas has been combusted for electricity generation in a combined cycle gas turbine (CCGT), and the delivered energy remains in the form of decarbonized electricity. In the other pathway, natural gas is subjected to a reformation process to produce hydrogen and CO_2 streams. The CO_2 is captured and sequestered, and the hydrogen can be injected into the pipeline, liquefied for use in fuel cells, or combusted in a combustion turbine.

3.3 Modeling Technology and Energy Costs

3.3.1 GENERAL DESCRIPTION OF APPROACH

For long-term energy pathways scenarios, future costs are particularly uncertain. As a result, the PATHWAYS model does not use technology or energy cost estimates to drive energy demand or resource selection choices. Rather, total capital costs and variable costs of technologies are treated as input variables, which are summed up for each scenario as an indicator of the scenario's total cost. The model does not include a least-cost optimization, nor does the model include price elasticity effects or feedback to macroeconomic outcomes. As such, the model should be understood as primarily a technology and infrastructure-driven model of energy use in California.

The model includes more resolution on cost for two key types of energy delivery: pipeline gas and electricity. These approaches are described in more detail below.

3.3.2 PIPELINE GAS DELIVERY COSTS

We model the California system of delivering pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates, which can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories.

Core service traditionally provides reliable bundled services of transportation and natural gas compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September 2013 the average U.S. delivered price of gas to an industrial customer was $4.39/thousand cubic feet compared to

$15.65/thousand cubic feet for residential customers.[15] This difference is driven primarily by the difference in delivery costs and delivery charges for different customer classes at different pipeline pressures.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California investor owned utility (IOU). This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs of delivery services (to account for increasing prices of materials, labor, engineering, etc.), an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments.[16]

3.3.3 ELECTRICITY SECTOR AVERAGE RATES AND REVENUE REQUIREMENT

Electricity sector costs are built-up from estimates of the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. These costs are used to calculate an annual revenue requirement of total annualized electric utility investment in each year. These costs are then divided by total retail sales in order to estimate a statewide average electricity retail rates. These average electricity rates are applied to the annual electricity demand by subsector to allocate electricity costs between subsectors.

[15] United States Energy Information Administration, 2013.
[16] We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline approximately 1.7% per year without resulting in escalating delivery charges for remaining customers.

Transmission and distribution costs are also estimated in the model. Transmission costs are broken into three components: renewable procurement-driven transmission costs, sustaining transmission costs, and reliability upgrade costs. Distribution costs are broken into distributed renewable-driven costs and non-renewable costs. The revenue requirement also includes other electric utility costs which are escalated over time using simple growth assumptions, ("other" costs include nuclear decommissioning costs, energy efficiency program costs and customer incentives, and overhead and administration costs). These costs are approximated by calibrating to historical data. The methodology for calculating fixed generation costs in each year is described below, more details are provided in the Technical Appendix.

3.3.3.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and assumed capital cost and fixed operations and maintenance (O&M) cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the capital cost (which can vary by vintage year) times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. This methodology is also used to cost energy storage infrastructure and combined heat and power (CHP) infrastructure. Input cost assumptions for generation technologies are summarized below.[17]

[17] Cost assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012. <http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf>

In general, cost assumptions for generation technologies, as for all technology assumptions in the model, are designed to be conservative, and avoid making uncertain predictions about how the relative costs of different technologies may change over the analysis period. Generation capital cost changes are driven by assumptions about technology learning. As a result, the cost of newer, less commercialized technologies are assumed to fall in real terms, while the costs of technologies that are widely commercialized are assumed to remain constant or to increase.

Table 7. Generation capital cost assumptions

Technology	Capital Cost from present - 2026 (2012$/kW)	Assumed change in real capital cost by 2050 % change	Capital Cost from 2027 - 2050 (2012$/kW)
Nuclear	9,406	0%	9,406
CHP	1,809	0%	1,809
Coal	4,209	0%	4,209
Combined Cycle Gas (CCGT)	1,243	16%	1,441
CCGT with CCS	3,860	-3%	3,750
Steam Turbine	1,245	0%	1,245
Combustion Turbine	996	44%	1,431
Conventional Hydro	3,709	0%	3,709
Geothermal	6,726	0%	6,726
Biomass	5,219	0%	5,219
Biogas	3,189	0%	3,189
Small Hydro	4,448	0%	4,448
Wind	2,236	-9%	2,045
Centralized PV	3,210	-31%	2,230
Distributed PV	5,912	-30%	4,110
CSP	5,811	-25%	4,358
CSP with Storage	7,100	-30%	5,000

3.3.4 COST ASSUMPTIONS FOR ENERGY STORAGE, DECARBONIZED GAS AND BIOMASS DERIVED FUELS

Cost and financing assumptions for energy storage technologies are summarized below. For this analysis, these costs are assumed to remain fixed in real terms over the analysis period.

Table 8. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/kW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2,230	30	30
Batteries	4,300	15	15
Flow Batteries	4,300	15	15

The modeling assumptions for hydrogen production and SNG production are described in detail in Technical Appendix Sections 2.2.3 and 2.2.4, respectively. Below, Table 9 shows final product cost ranges, levelized capital costs, and conversion efficiencies for hydrogen and SNG pathways in the model.

Table 9. Renewable electricity-based pipeline gas final product cost, levelized capital cost, and conversion efficiencies in model

Product	Process	Levelized Capital Cost ($/kg-year for hydrogen; $/mmBTU-year for SNG)	Conversion Efficiency	Product Cost Range ($/GJ)
SNG	Electrolysis plus methanation	$7.60-$18.50	52%-63%	$30-$138
Hydrogen	Electrolysis	$0.65-$1.53	65%-77%	$24-$112

The modeling assumptions for biofuels are described in detail in Technical Appendix Section 3. Below, Table 10 shows final product cost ranges, feedstock and conversion cost ranges, and conversion efficiencies for all biomass conversion pathways in the model.

Table 10. Biomass final product cost, feedstock and conversion costs, and conversion efficiencies in model

Product	Process	Feedstock Cost Range ($/ton)	Conversion Cost ($/ton)	Conversion Efficiency (GJ/ton)	Product Cost Range ($/GJ)
Biogas Electricity	Anaerobic digestion	$40-$80	$96	6.5	$21-$27
Pipeline Biogas	Gasification	$40-$80	$155	9.5	$20-$25
Ethanol	Fermentation	$40-$80	$111	6.7	$23-$29
Diesel	Trans-Esterification	$1000	$160	36.4	$32

4 Results

4.1 Summary of results

The two low-carbon scenarios evaluated in this study present unique technology pathways to achieve California's 2050 GHG reduction goals. Each scenario represents a different technically feasible, plausible strategy to decarbonize the state's energy system, resulting in different levels of energy consumption and different mixes of fuels providing energy services. This section presents energy demand by scenario and fuel type in 2050 for the Reference case and the two low-carbon scenarios. Energy system cost projections for each scenario are provided. The cost trajectories are highly uncertain and cannot be interpreted as definitive at this point in time. Each of the low-carbon scenarios shows a similar statewide GHG reduction trajectory.

4.2 Final energy demand

Figure 4 shows final energy demand by fuel type for each scenario in the year 2050. Of note, both the low-carbon scenarios have significantly lower total energy demand than the Reference case due to the impact of energy efficiency and conservation in the low-carbon scenarios.

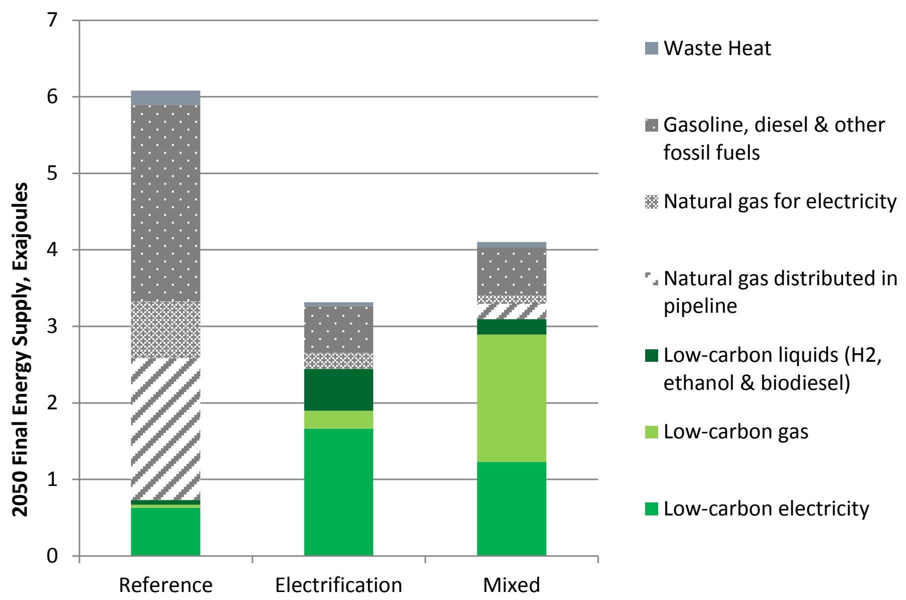

Figure 4. 2050 California economy-wide final energy demand by scenario and fuel type

Final energy consumption in 2050 is lower in the Electrification scenario than the Mixed Scenario due to the higher conversion efficiencies of electric batteries and motors compared to combustion engines and fuel cell vehicles.[18]

Low-carbon electricity is also used as an upstream energy source to produce decarbonized gas and liquid hydrogen, so it plays a larger role in meeting the state's GHG reduction goals in the Mixed scenario than indicated by final energy demand alone. To gain a more complete picture of energy supply by fuel type, the next sections discuss the composition of the pipeline gas by scenario, the sources of electricity in each scenario, and the composition of the

[18] Note that upstream efficiency losses associated with energy production: i.e. P2G methanation, hydrogen production and CCS, do not appear in the final energy supply numbers.

transportation vehicle fleet energy consumption. These results are not meant to be an exhaustive description of each assumption in each sector of the economy, but rather are selected to provide some insights into the biggest differences in energy use between the two low-carbon scenarios and the Reference case.

4.2.1 PIPELINE GAS FINAL ENERGY DEMAND

There are important differences between the two low-carbon scenarios. Pipeline infrastructure continues to be used extensively in the Mixed scenario, with decarbonized gas substituting for the natural gas that would otherwise be used in the pipeline. In the Electrification scenario, pipeline infrastructure is nearly unutilized by 2050. This corresponds to much more widespread electrification of industrial processes, vehicles, space heating, water heating, and cooking. The limited demand for pipeline gas in this scenario is assumed to be met with biogas (Figure 5).

The Mixed scenario includes a higher quantity of biogas, based on the assumption that all of the available sustainably sourced biomass are used to produce biogas. The remaining demand for decarbonized pipeline gas in this scenario is met with a mix of two technologies: 1) SNG produced using P2G methanation with air capture of CO_2[19] and 2) hydrogen produced using electrolysis with renewable electricity.

[19] Methanation using CO_2 capture from seawater is an alternative, potentially more efficient method to creating produced gases that have a net-carbon neutral climate impact.

In the Mixed Scenario, hydrogen use in the gas pipeline is limited by estimates of technical constraints. By 2050, the share of hydrogen gas in the pipeline is assumed to be limited to 20 percent of pipeline volume for reasons of safety as well as compatibility with end-use equipment.[20]

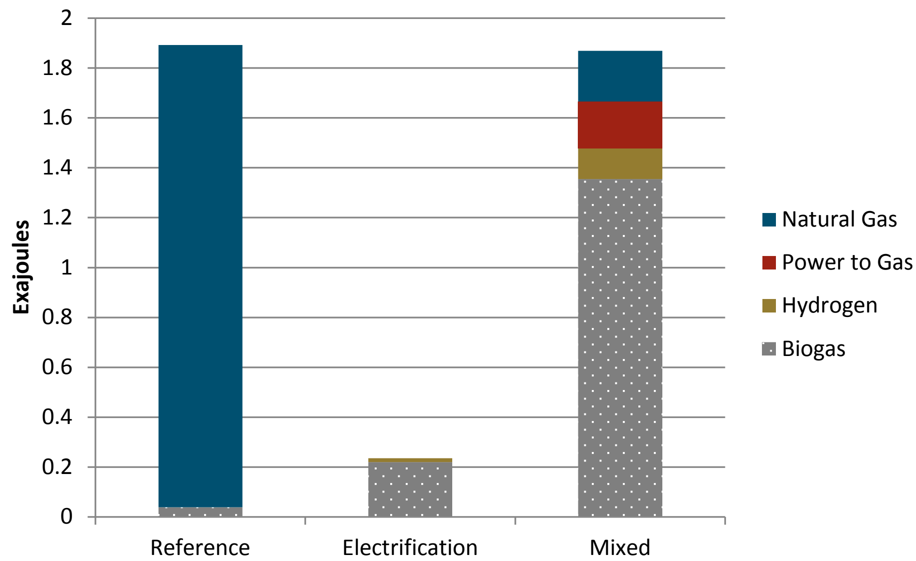

Figure 5. California pipeline gas final energy demand by fuel type by scenario, 2050

4.2.2 ELECTRICITY DEMAND

The 2050 electricity demand in each scenario tells a different part of the energy supply story. In the low-carbon scenarios, 2050 electricity demand is significantly higher in the Reference case due to the impact of electrification, particularly electric LDVs, and the electricity needs associated with P2G and

[20] Note that this limit is only a rough estimate of technical feasibility limits and the actual limit may be lower; additional research is needed to determine an appropriate limit for hydrogen gas in the pipeline.

hydrogen production. The expanding role of the electricity sector in achieving a low-carbon future is evident in each of these scenarios. Figure 6 shows the generation mix by fuel type utilized in each of the scenarios in 2050.

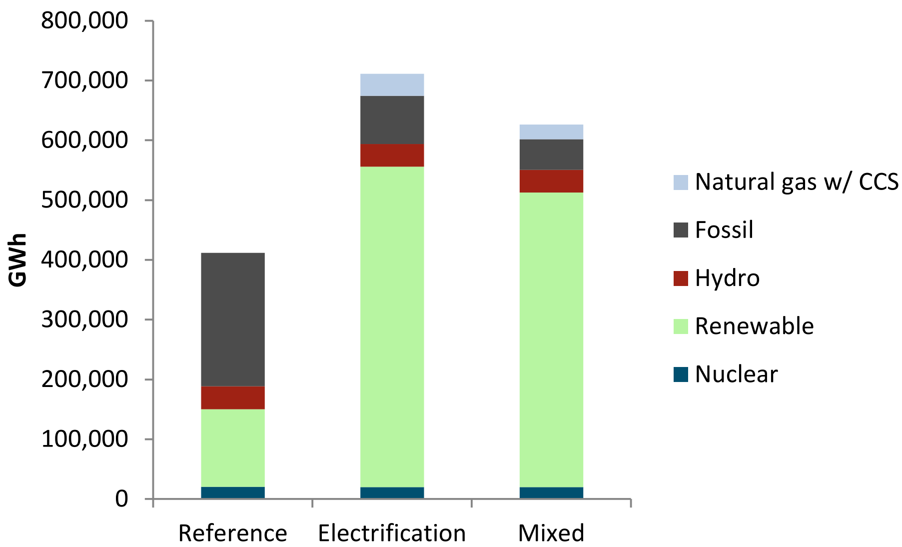

Figure 6. 2050 electricity sector energy demand by scenario and fuel type, GWh

4.2.2.1 Load resource balancing

Both of the low-carbon scenarios reflect a significant increase in intermittent wind and solar PV renewable generation by 2050 (Table 11). This results in new challenges that the grid faces to achieve load-resource balance.

Table 11. Share of 2050 California electricity generation provided by wind and solar PV

	Reference	Low-Carbon Scenarios
Intermittent renewables share of total electricity generation in 2050 (wind and solar PV)	30%	60 -70%

In the model, electricity supply and demand must be equal in each hour of each year. This load-resource balance is achieved using different strategies in each scenario, which contributes to the differences in technology costs and risks. As Table 12 indicates, the Electrification scenario relies heavily on the use of electric energy storage, in the form of flow batteries and pumped hydroelectric storage resources, while the Mixed scenario relies more heavily on P2G production as a load-following resource. Natural gas with CCS is assumed to be a load-following resource in both scenarios. Furthermore, both scenarios assume electric vehicles can provide limited load-resource balancing services through flexible charging of EVs over a 24-hour period, and that hydrogen production for fuel cell vehicles can be operated as a fully-dispatchable, flexible load.

Table 12. 2050 Load Resource Balancing Assumptions by Scenario

Load-resource balancing tool	Electrification	Mixed
Electric energy storage capacity	**20 GW** 75% 6-hour flow batteries, 25% 12-hour pumped hydro energy storage	**5 GW** 100% 12-hour pumped hydro energy storage
P2G capacity	**None**	**40 GW** P2G production cycles on during the daylight hours to utilize solar generation and cycles off at night, significant variation in production by season for load balancing
Electric vehicles & other flexible loads	**40%** of electric vehicle loads are considered "flexible" in both scenarios and can be shifted within a 24-hour period. Vehicle batteries are not assumed to provide power back onto the grid. Certain thermal electric commercial and residential end uses are also assumed to provide limited amounts of flexible loads to the grid. In both scenarios, hydrogen production is assumed to be a fully dispatchable, flexible load.	

4.2.3 ON-ROAD VEHICLE ENERGY CONSUMPTION BY FUEL TYPE

The decarbonization strategy pursed in the transportation sector differs by scenario, as illustrated in Figure 7 (LDV vehicle energy use) and Figure 8 (HDV energy use). Both of the low-carbon scenarios assume a significant reduction in VMT and vehicle efficiency improvements in the LDV fleet compared to the Reference scenario. This leads to a significant reduction in total energy demand by LDVs by 2050 in these scenarios. Among the HDV vehicle fleet, VMT reductions and vehicle efficiency improvements are assumed to be more difficult to achieve than in the LDV fleet. Furthermore, the Mixed scenario relies on a high proportion of fuel cell vehicles using hydrogen or liquefied pipeline gas, which have less efficient energy conversion processes than conventional diesel engines, leading to higher energy demand. As a result, the HDV sector does not show a significant reduction in energy consumption by 2050 relative to the Reference case, although total carbon emissions are significantly lower.

Electricity is the largest source of fuel for the transportation sector among LDVs in both the Electrification and the Mixed scenarios. The HDV fleet is harder to electrify, so the Electrification scenario assumes HDV energy demand is largely met with hydrogen fuel and fuel cells. In the Mixed scenario, the majority of HDV energy demand is assumed to be met with liquefied pipeline gas (an equivalent to decarbonized LPG), with some compressed pipeline gas (the equivalent to decarbonized compressed natural gas), electrification and hydrogen fuel cell vehicles.

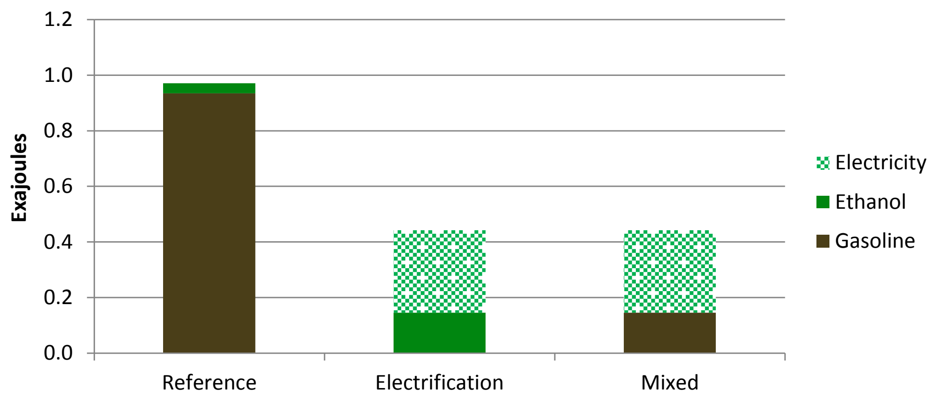

Figure 7. 2050 LDV energy share by fuel type by scenario

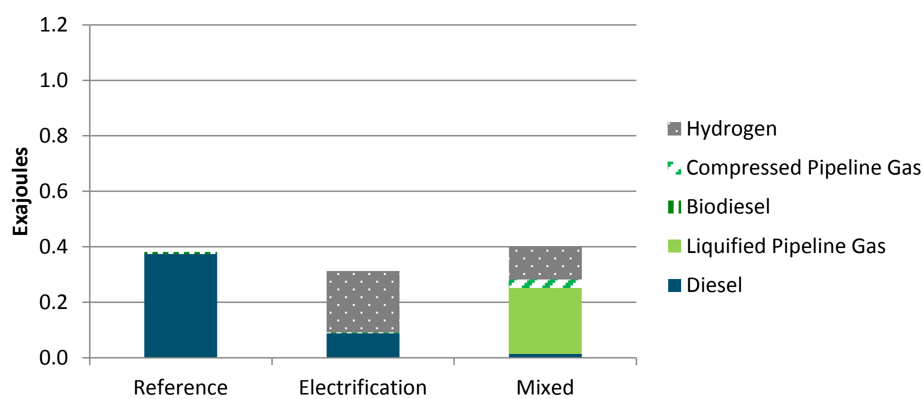

Figure 8. 2050 HDV energy share by fuel type by scenario

4.3 Greenhouse gas emissions

The Reference case shows GHG emissions that are relatively flat through 2030 before slightly increasing in the outer years through 2050. This increase occurs because population growth and increasing energy demand overwhelm the emissions savings generated by current policies. The result is a 9 percent increase in Reference case emissions relative to 1990 levels by 2050.

The GHG emissions trajectories for the two low-carbon scenarios evaluated in this report are essentially the same. Both scenarios achieve the target of 80% reduction in GHG emissions by 2050 relative to 1990 levels, and both scenarios reflect a similar, approximately straight-line trajectory of emissions reductions between current emissions levels and 2050.

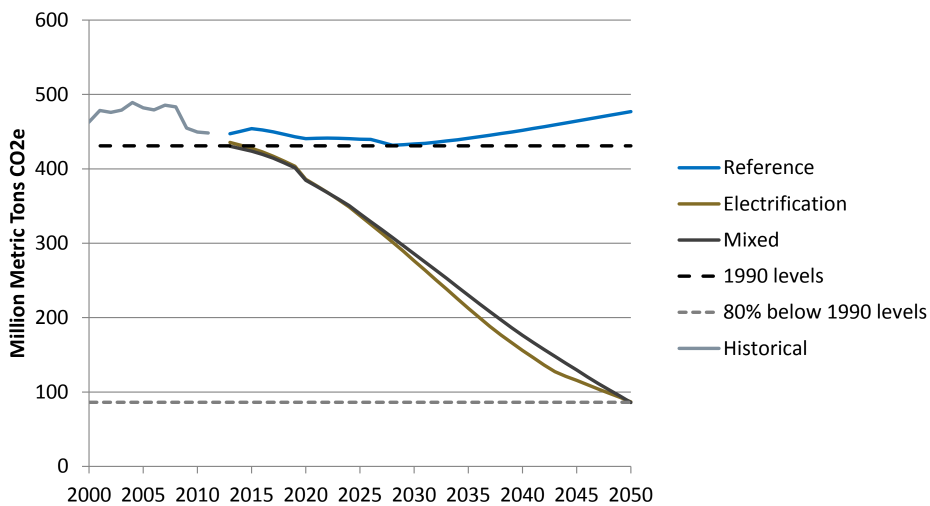

Figure 9. California GHG emissions by scenario, including historical emissions and policy targets (2000 – 2050)

4.4 Energy system cost comparison

The total energy system cost of each of the scenarios analyzed is one metric by which to evaluate different GHG scenarios. Total energy system cost is defined here as the annual statewide cost of fossil fuels and biofuels, plus the levelized cost of electricity and natural gas infrastructure, plus the cost of most energy-consuming customer products (e.g., clean vehicles in the transportation sector and energy efficiency and fuel-switching equipment in the buildings sector). The total energy system cost is calculated on a levelized basis in each analysis year, from 2015 – 2050. Further detail on cost assumptions and how costs are treated in the model is provided in the Technical Appendix.

While the Reference case is the lowest total cost scenario from an energy system perspective, it also does not succeed in meeting the state's GHG reduction goals. Of the two low-carbon scenarios, the Mixed scenario has approximately 10 percent lower cost than the Electrification scenario in 2050 using our base case assumptions. This difference is well within the range of uncertainty of projecting technology costs to 2050, and either scenario could be lower cost.

It is, however, useful to examine the differences in base case scenario costs that result from the modeling assumptions made in this analysis to identify the key drivers. Using the base case assumptions, the Mixed case results in lower total energy system costs in 2050 than the Electrification scenario for two main reasons (Figure 10). First, using the assumptions in this study, adding decarbonized gas in the Mixed case has a lower cost than adding the low-carbon electricity and end-use equipment necessary to electrify certain end-uses in the Electrification case. Therefore, the reduction of electricity-related capital costs between the Electrification and the Mixed scenario shown in Figure 10 is greater than the increase in pipeline gas capital costs and biogas fuel costs between these scenarios. Second, seasonal electricity storage needs are lower in the Mixed scenario than in the Electrification scenario. As a result, the electricity storage that is built in the Mixed scenario is utilized at a higher capacity factor than the electricity storage in the Electrification scenario. This means that the unit cost of electricity storage ($/MWh) is higher in the Electrification scenario than in the Mixed scenario.

In order to evaluate the range of uncertainty, we define high and low cost Scenarios for the key input assumptions. These do not reflect the range of all of the uncertainties in energy demands, population, or other key drivers embedded in the analysis, but serve to provide a boundary of possible high and low total costs given the same assumptions across the three cases. We then evaluate the total costs of each of the cases; Reference, Electrification Case, and Mixed Case with each cost scenario. Table 13, below, shows the range of the cost uncertainties in the analysis. Scenario 1 is purposefully designed to advantage the Mixed Case, and Scenario 2 is designed to advantage the Electrification Case.

Table 13 Cost sensitivity parameters

Cost Assumption	Scenario 1	Scenario 2
Renewable generation capital	+25%	-25%
Electrolysis capital equipment	-50%	+50%
SNG capital equipment	-50%	+50%
Fuel cell HDVs	+50%	-50%
Building electrification cost[21]	+50%	-50%
Natural Gas Costs	-50%	+50%
Other Fossil Fuel Costs	+50%	-50%
Electricity storage costs	+50%	-50%
Biomass Availability[22]	+0%	-50%

The 2050 cost results shown below indicate that there are conditions under which either case is preferable from a cost standpoint. Given that, and given the

[21] Costs of electrified water and space heating equipment
[22] Biomass is replaced with addition P2G to maintain emissions levels +- 5MMT from base case.

additional uncertainties not analyzed in terms of other technology costs, energy demand drivers, etc., the preference for pursuing one mitigation case over the other should come down to other factors than narrow cost advantages displayed over these long term forecasts.

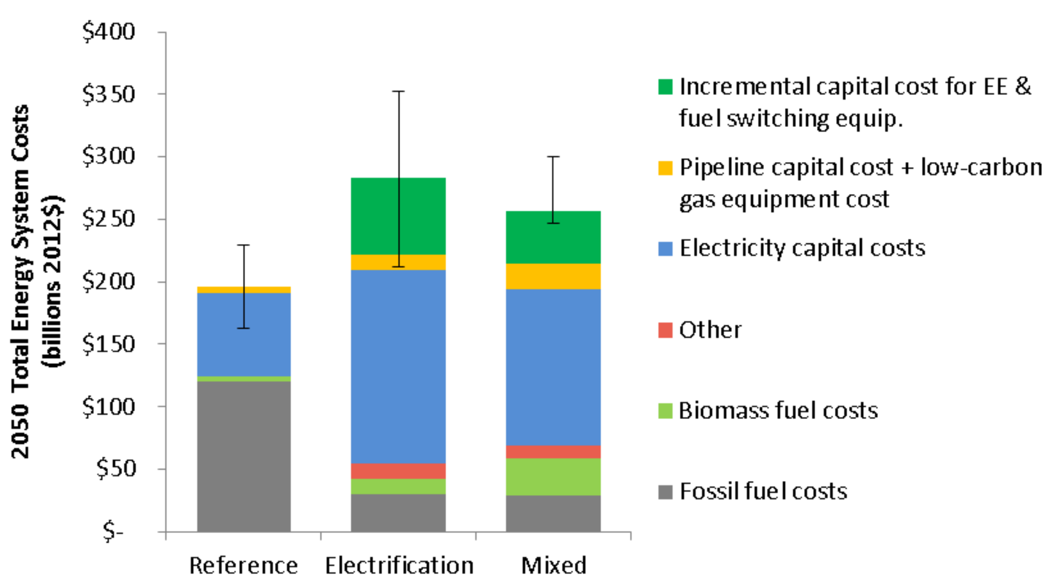

Figure 10. 2050 total energy system cost by scenario (levelized cost of fuel and levelized capital cost of energy infrastructure)

Figure 11, below, shows the base case total levelized energy system capital investment and fuel costs for each scenario along with the uncertainty range. Given the uncertainties associated with forecasting technology and commodity costs out to 2050, a difference in costs of approximately 10% ($27 billion) between the two scenarios is not definitive.

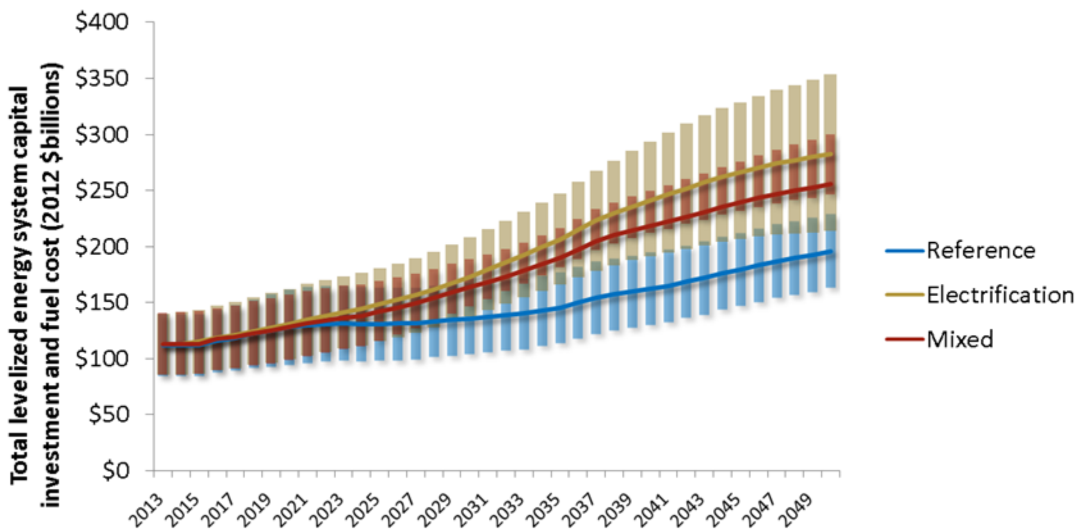

Figure 11. Total energy system cost by scenario, 2013 – 2050 (levelized cost of fuel and levelized capital cost of energy infrastructure, billions, 2012$)

Figure 12, below, shows total electricity sector costs on an annualized basis, or equivalently, the statewide electricity sector revenue requirement, in 2050. Electricity costs are higher in the Electrification scenario both because total electricity demand is higher, and because the unit cost of electricity is higher. The cost of energy storage is highest in the Electrification scenario because more storage is needed to balance intermittent renewables, and because batteries are the primary means of storage. In the Mixed scenario, less energy storage is needed because the production of decarbonized gases (hydrogen and SNG) is dispatched to balance the grid, and because gas is a more cost-effective form of seasonal energy storage, given the assumptions here, than batteries. Again, however, cost forecasts for 2050 are highly uncertain and should be interpreted with caution.

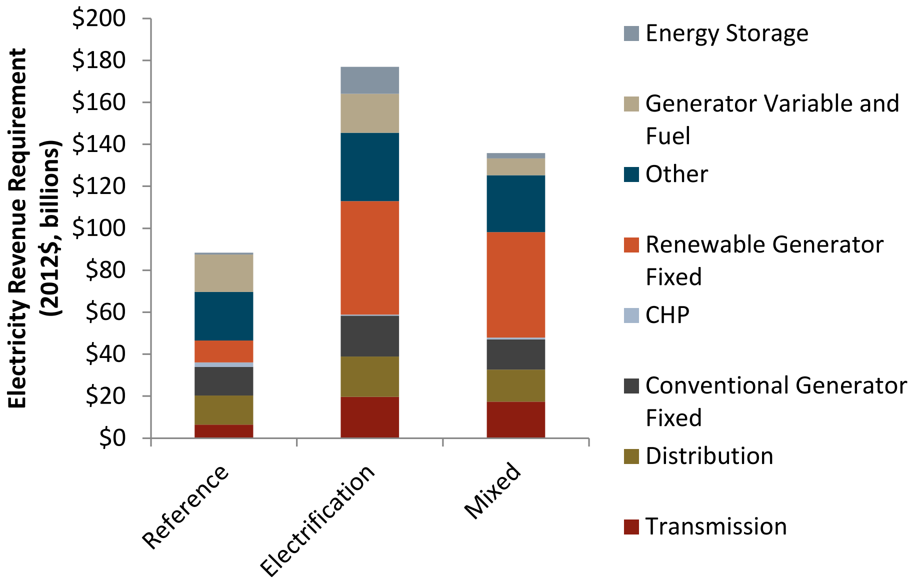

Figure 12. 2050 California total electricity sector revenue requirement by component and scenario (billions, 2012$)

5 Discussion & Conclusions

California is committed to deeply reducing CO_2 and other GHG emissions across all sectors over the next several decades, as well as to sharply reducing ground-level ozone and particulate matter to protect public health. Both of these policies imply a dramatic transition of California's economy away from fossil fuel combustion as we know it, and indeed this transition is already underway. In some places where coal is the dominant form of energy supply, natural gas is often seen as a key transition fuel to a lower carbon system. In California, however, natural gas is the main incumbent fossil fuel in electricity generation, the building sector, and many industries, and is therefore the target of transition to a lower carbon economy rather than its vehicle; the problem of methane leakage in the natural gas production and supply chain, though not modeled in this analysis, only increases the policy pressure to hasten this transition.

It is possible for SCG and other gas distribution companies to be a contributor rather than an impediment to California's transition to a low carbon economy. This path of decarbonizing pipeline gas will require a major technological transformation in the coming years. On the demand side, the transition requires reducing demand in many existing applications and improving combustion processes to increase efficiency. On the supply side, it requires developing decarbonized alternatives to conventional natural gas for delivering energy to end uses.

This study examined the role of gas fuels in California's energy supply from 2013 to 2050, using a bottom-up model of the California economy and its energy systems. We examined the feasibility andcost associated with two distinct technology pathways for achieving the state's 2050 GHG targets: (1) Electrification, and (2) Mixed (electricity and decarbonized gas).

To date, much of the literature on low-carbon strategies and policy strategies for achieving deep reductions in GHG emissions in California by 2050 has focused on extensive electrification. This study's results support our prior conclusions that the electricity sector must play an expanded and important role in achieving a low-carbon future in California. In both of the low-carbon scenarios, the need for low-carbon electricity increases significantly beyond the Reference case level: to power electric vehicles, electrification in buildings and as a fuel to produce decarbonized gases. We also demonstrate that, under reasonable assumptions, there are feasible technology pathways where gas continues to play an important role in California's energy supply.

The costs of technologies in the 2050 timeframe are highly uncertain, making it impossible to reach a definitive conclusion as to which of the low-carbon pathways evaluated here would be the lowest cost. However, we show that the Mixed scenario, where decarbonized gas meets existing natural gas market share in residential, commercial, and industrial end uses, and is used to power the heavy-duty vehicle fleet, could potentially be higher or lower cost depending on the technology and market transformation. A key driver of this result is the ability to use the existing gas pipeline distribution network to store and distribute decarbonized gas, and to use the production of decarbonized gas as a means to integrate intermittent renewable energy production. Excess renewable energy in the middle of the day is absorbed by P2G production of SNG and hydrogen production in the Mixed scenario. The Electrification scenario, which does not utilize the P2G technology to produce decarbonized gas, decreases gas pipeline use out to 2050 (shown for SCG, Figure 13) and requires more relatively high-cost, long-duration batteries for energy storage.[23]

[23] In Figure 14 the slight increase in natural gas used for electricity generation observed in 2020 is due to an existing coal generation contract being partially replaced with natural gas generation.

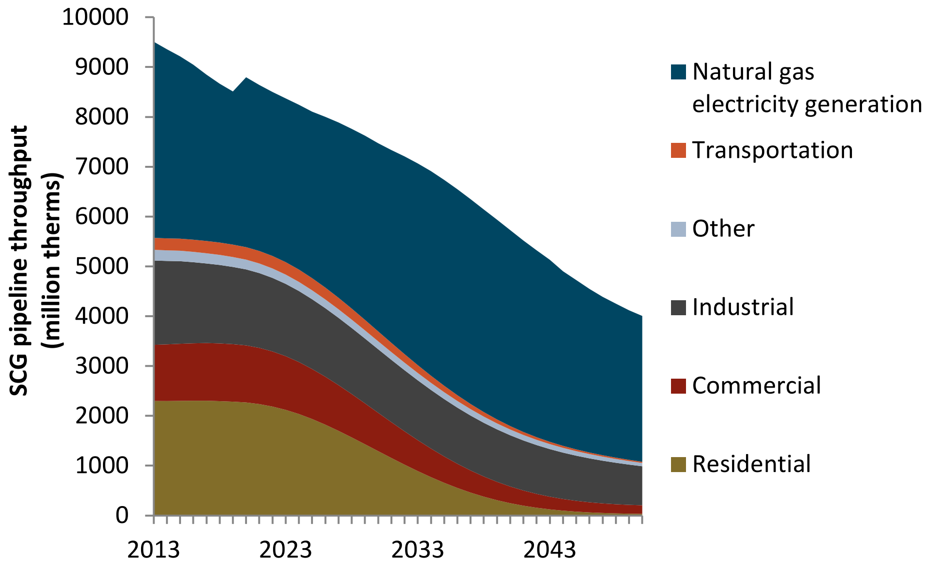

Figure 13. Electrification Scenario, SCG pipeline gas throughput (2013 – 2050)

Strategic use of decarbonized gas would additionally help to overcome four potential obstacles in California's transition to a decarbonized energy system.

First, a number of current uses of natural gas and oil are difficult to electrify. These include certain industrial processes such as process heat, HDVs and certain end uses in the residential and commercial sectors such as cooking, where customers have historically preferred gas fuels. Using decarbonized gas for these end uses could avoid the need for economically and politically costly electrification strategies.

Second, under a high renewable generation future, long-term, seasonal load balancing may be needed in addition to daily load balancing. However, meeting these seasonal balancing needs under the Electrification scenario requires uncertain technical progress in energy storage. Using the production of decarbonized gas to provide daily and seasonal load balancing services may be a more realistic and cost-effective strategy than flexible loads and long-duration batteries for electricity storage.

Third, using decarbonized gas takes advantage of the state's existing gas pipeline distribution system, and reduces the need for other low-carbon energy infrastructure such as transmission lines or a dedicated hydrogen pipeline network.

Fourth, and finally, the Mixed scenario, by employing a range of energy technologies, including electricity and decarbonized gas technologies, diversifies the risk that any one particular technology may not achieve commercial successes.

All of the decarbonized gas energy carriers examined in this analysis rely on century-old conversion processes; none require fusion-like innovations in science. However, these conversion processes — anaerobic digestion, gasification, electrolysis, and methanation — require improvements in efficiency and reductions in cost to be more competitive. Furthermore, existing pipelines were not designed to transport hydrogen, and innovations in pipeline materials and operations would be needed to accommodate a changing gas blend.

Sustainably-sourced biomass feedstock availability is another large source of uncertainty in both of the low-carbon strategies evaluated here. In the Mixed scenario, biogas plays a particularly important role in achieving the GHG emission target. In the Electrification scenario, biomass is used to produce low-carbon electricity. However, biomass feedstocks are constrained by competing uses with energy supply, including food, fodder and fiber. The amount of biomass resources available as a feedstock for fuels, or for biogas production specifically, will depend on innovations in biosciences, biomass resource management, and supply chains. None of the above three challenges — conversion technology efficiency and cost, pipeline transport limits, and biomass feedstock availability — is inherently insurmountable. For decarbonized gas to begin to play an expanded role in California's energy supply in the coming decades, however, a program of RD&D to overcome these challenges would need to begin very soon. This report identifies research priorities with near-term, medium-term and long-term payoff.

As a whole, California policy currently explicitly encourages the production of low-carbon electricity, through initiatives such as the RPS, and the production of decarbonized transportation fuels, through initiatives such as the LCFS. Biogas from landfill capture and dairy farms are encouraged, however, the state does not currently have a comprehensive policy around decarbonized gas production and distribution. This analysis has demonstrated that a technologically diverse, "mixed" strategy of electrification and decarbonized gas may be a promising route to explore on the pathway to a long-term, low-carbon future in California.

Appendix

Table of Contents

1 Demand Projections

1.1 Stock demand projections

The basic stock roll-over methodology is used both in the development of our demand unit projections as well as our supply unit stock analysis. For example, we use the stock roll-over to project square feet of indoor space and we also use a stock roll-over to estimate the stock efficiency of air conditioners used to cool that indoor space. The basic mechanics of stock roll-over are used throughout the model in estimating basic energy service demands, calculating current and future baseline stock efficiencies, and calculating the impacts of our mitigation measures. Our stock roll-over modeling approach necessitated inputs concerning the initial composition of stocks (vintage, fuel type, historical efficiencies, etc.) as well as estimates of the useful lives of each stock type.

Stock roll-overs are determined by technology useful lives, scenario-defined sales penetration rates, and the shapes of those sales penetrations (S-curves that might more closely mirror market adoption; and linear adoptions that may more accurately reflect policy instruments). Given that the model is designed to provide information on the technologies and policies necessary to reach long-term carbon goals, these are not forecasts: they are not dynamically adjusted for consumer preference, energy costs, payback, etc. that might inform actual technological uptake.

We model a stock roll-over at the technology level for a limited set of subsectors in which homogeneous supply units could be determined (i.e. residential water heating). Figure 1 shows an example stock roll-over of the residential water heating stock to 2050. This example shows the water heating stock rolling over to high efficiency devices – i.e. standard gas tank water heaters roll over to condensing and tankless gas water heaters. Stock roll-overs like these are then used to project energy demand as well as costs using the methodology described in section 1.1.5.

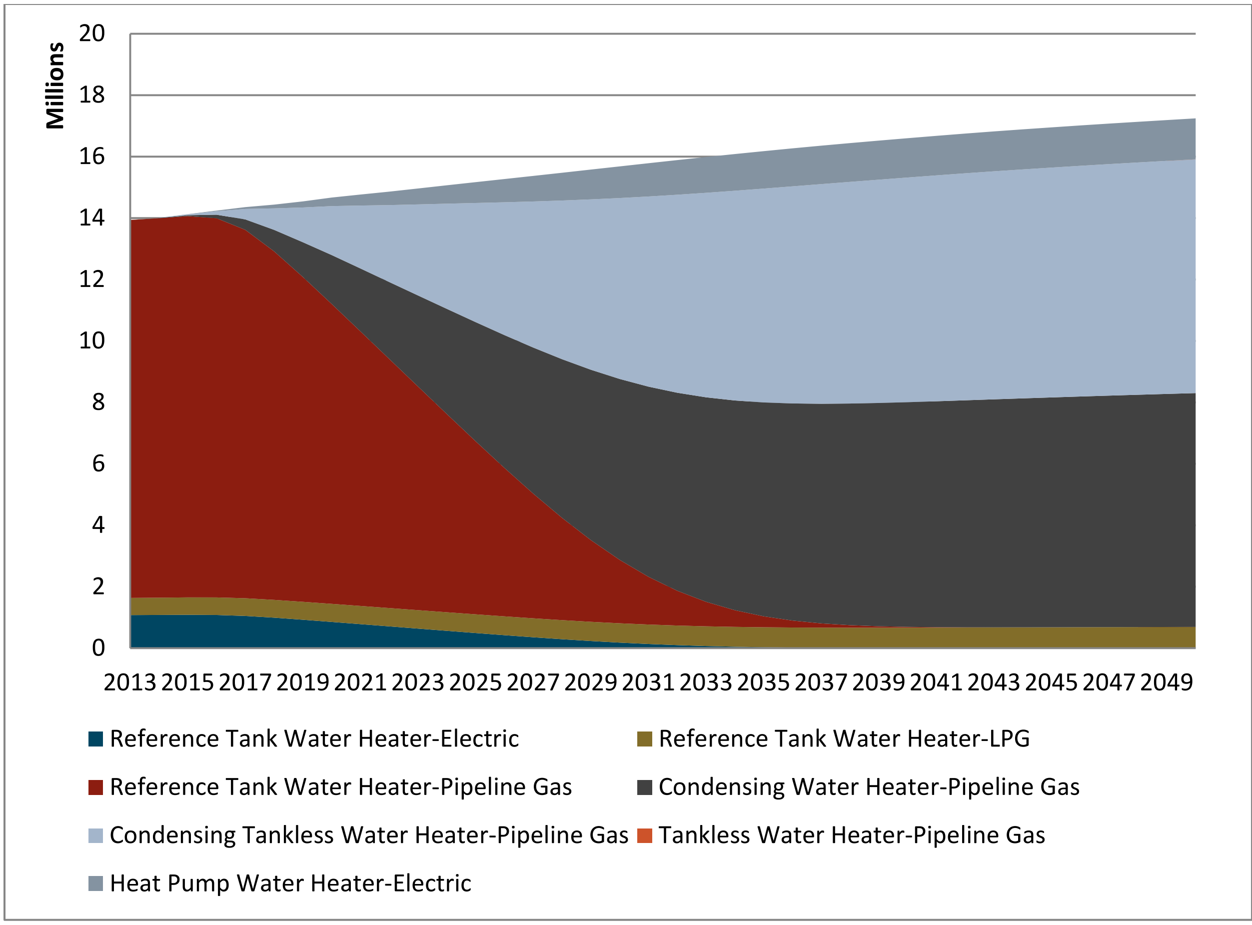

Figure 1. Residential water heater example stock roll-over

1.1.1 STOCK ROLL-OVER: TECHNOLOGIES

For those subsectors measured at the technology level, a stock roll-over is employed to model energy demand under different scenarios of policy and technological emphasis. This influences the stock composition as shown above in Figure 1. These stocks therefore influence energy demandand costs as a function of defined technology characteristics.

Technology Characteristic	Description
Primary Energy Type	Determines primary final energy type used by demand stock (i.e. gasoline, electricity, etc.)
Secondary Energy Type	Determines final energy type used by demand stock (i.e. gasoline, electricity, etc.)
Utility Factor (Transportation Only)	Allocates share of energy use between primary energy type and secondary energy type. Used for dual-fuel applications like plug-in hybrid electric vehicles.
Useful Life	Determines stock decay function of technology units
Initial Unit Costs	Starting y-coordinate (cost) on technology cost function
Initial Unit Cost Year	Starting x-coordinate (year) on cost estimation function
Forecast Unit Costs	Ending y-coordinate (cost) on technology cost function
Forecast Unit Cost Year	Ending x-coordinate (year) on cost estimation function
Efficiency	Normalized, or unitless, conversion of service demand to energy use

1.1.2 STOCK ROLL-OVER: DECAY AND REPLACEMENT

We model the decay of technology based on Poisson distributions with mean values equal to our assumed EULs. When a technology decays, it is replaced at a rate determined by scenario inputs that influence technology uptake rates and sales penetration. This determines an overall stock composition by technology and vintage. The figure below shows this for gasoline light duty vehicles (LDVs) as they are gradually phased out in an example scenario.

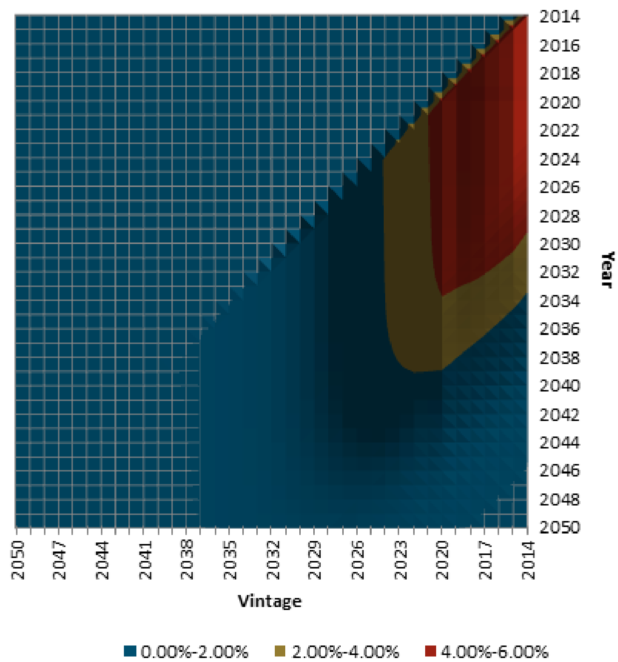

Figure 2. Example gasoline LDV stock composition

1.1.3 STOCK ROLL-OVER: ENERGY

Final energy demand by year for each subsector is determined by the technology composition of each stock. Each technology has a specified energy type and efficiency (by technology vintage). The percentage of the subsector service demand that is met by each technology and vintage combination is divided by the efficiency of the technology and summed over the applicable energy type. This converts our service demand projections into energy demand.

Equation 1.

$$\sum_t \boldsymbol{Stock}\,\% * \boldsymbol{Service\ Demand} * \boldsymbol{Efficiency}$$

1.1.4 STOCK ROLL-OVER: GHG EMISSIONS

To determine GHG emissions from the stock in each subsector, we multiply the energy demand in each subsector for each final energy type by the energy type's GHG emissions rate. The methodology for determining the emissions rate of each final energy type is described in detail in Section 2.

Equation 4.

$$\sum_t \boldsymbol{Stock}\,\% * \boldsymbol{Energy\ Demand} * \boldsymbol{GHG\ Emissions\ Rate}$$

1.1.5 STOCK ROLL-OVER: COSTS

Stock roll-over measure costs are calculated as a function of the levelized incremental cost of the replacement technology over the cost of the reference technology that would otherwise have been installed. These incremental cost trajectories are unique for each replacement year, reflecting unique cost trajectories for every technology by year.

$$\boldsymbol{Stock\ Roll-over\ Measure\ Costs} = \boldsymbol{Replacement\ Technology\ Cost}\ (\$/yr) - \boldsymbol{Replaced\ Technology\ Cost}(\$/yr) * \boldsymbol{Technology\ Units}$$

This methodology is employed for all stock roll-overs where incremental measure costs could be determined. For some stock roll-overs where it was not possible to develop technology level cost estimates, cost differences are primarily driven by the technology's energy types. An example is shown below for residential water heaters. As advanced technologies are rolled into the stock, the incremental measure costs rise; as the incremental costs of those technologies decline, we see a decrease in the total measure costs despite an increase in the technology penetration. The energy savings of these advanced technologies are not accounted for in the figure and represent the benefit of these incremental capital costs.

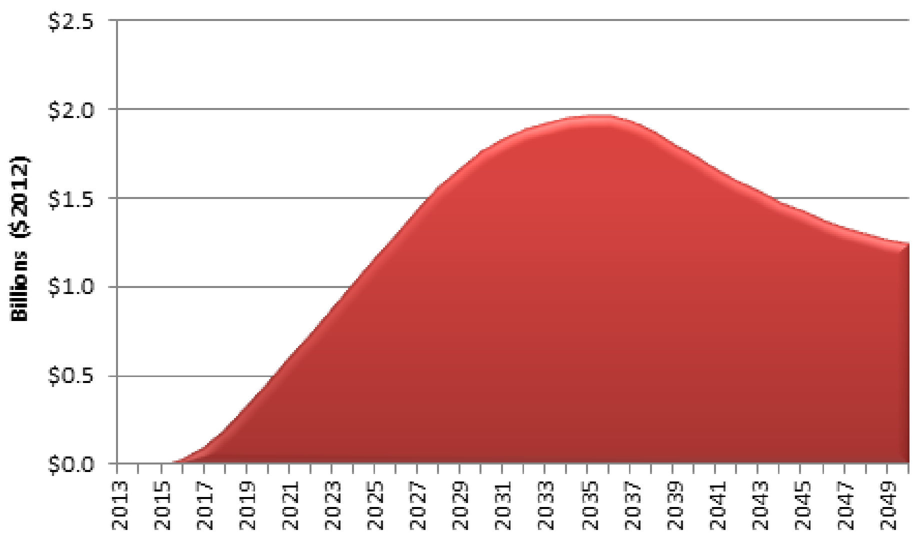

Figure 3. Residential water heater example stock roll-over measure costs

1.2 Regression demand projections

We utilize a linear regression approach to project the industrial energy demand for subsectors not able to be represented by homogenous equipment level stocks. Equation 1 shows an example regression function (GJ/year) for pipeline gas use in the chemical manufacturing subsector.

Equation 1.

Where *Year= Year-1990*

$$(374.2\ \boldsymbol{Mtherms} + (\boldsymbol{Year} * 4.5\ \boldsymbol{Mtherms})$$

1.2.1 SUBSECTOR GHG EMISSIONS

The equation below is used to calculate subsector GHG emissions as a function of final energy demand and GHG emissions factors calculated endogenously on an annual basis in the model.

Equation 2

$$\boldsymbol{GHG\ Emissions}[\boldsymbol{y},\boldsymbol{e}] = \boldsymbol{Final\ Energy\ Demand}[\boldsymbol{e}] * \boldsymbol{GHG\ Emissions\ Factor}\ [\boldsymbol{y},\boldsymbol{e}]$$

1.2.2 SUBSECTOR COSTS

Subsector costs include the costs of fuel switching measures as well as energy efficiency measures which are calculated on a levelized basis. These levelized costs represent any incremental costs of end-use equipment for fuel switching or efficiency purchases.

Equation 3

$$\boldsymbol{Fuel\ Switching\ Costs}[\boldsymbol{y}] = \boldsymbol{Levelized\ Cost} * \boldsymbol{Replacement\ Energy\ Demand}[\boldsymbol{y}]$$ [1]

Equation 4

$$\boldsymbol{Energy\ Efficiency\ Costs}[\boldsymbol{y}] = \boldsymbol{Levelized\ Cost} * \boldsymbol{Energy\ Savings}[\boldsymbol{y}]$$

[1] Replacement energy demand represents the demand for the new energy (i.e. fuel switching to electricity calculates the costs as a function of the new electricity demand).

Equation 5

$$\boldsymbol{Total\ Subsector\ Costs}[\boldsymbol{y}] = \boldsymbol{Energy\ Efficiency\ Costs}[\boldsymbol{y}] + \boldsymbol{Fuel\ Switching\ Costs}[\boldsymbol{y}]$$

2 Energy Supply Modeling

The final energy demand projections developed in the previous section are used to project energy supply stocks and final delivered energy prices and emissions. This makes our supply and demand dynamic and allows us to determine inflection points for emissions reductions and costs for each final energy type (i.e. electricity, pipeline gas, etc.) as well as potential synergies and opportunities for emissions reduction using a variety of different decarbonization strategies. We model the twelve distinct final energy types listed in Table 1 that can be broadly categorized as electricity, pipeline gas, liquid fuels, and other. For each final energy type, we model different primary energy sources and conversion processes. Additionally, we model delivery costs for some final energy types. The methodology for calculating the costs and emissions of these supply choices is modeled in this section.

Table 1. Final energy types

Energy Type	Energy Type Category
Electricity	Electricity
Pipeline Gas	Pipeline Gas
Liquefied Pipeline Gas (LNG)	
Compressed Pipeline Gas (CNG)	
Gasoline	Liquid Fuels
Diesel	
Kerosene-Jet Fuel	
Hydrogen	
Refinery and Process Gas	Other
Coke	
LPG	
Waste Heat	

2.1 Electricity

The electricity module simulates the planning, operations, cost, and emissions of electricity generation throughout the state of California. This module interacts with each of the energy demand modules so that the electricity system responds in each year to the electricity demands calculated for each subsector. Both planning and operations of the electricity system rely not only on the total electric energy demand, but also on the peak power demand experienced by the system, so the module includes functionality to approximate the load shape from the annual electric energy demand. Interactions between the load shaping, generation planning, system operations, and revenue requirement modules are summarized in Figure 4 and each module is described in this section.

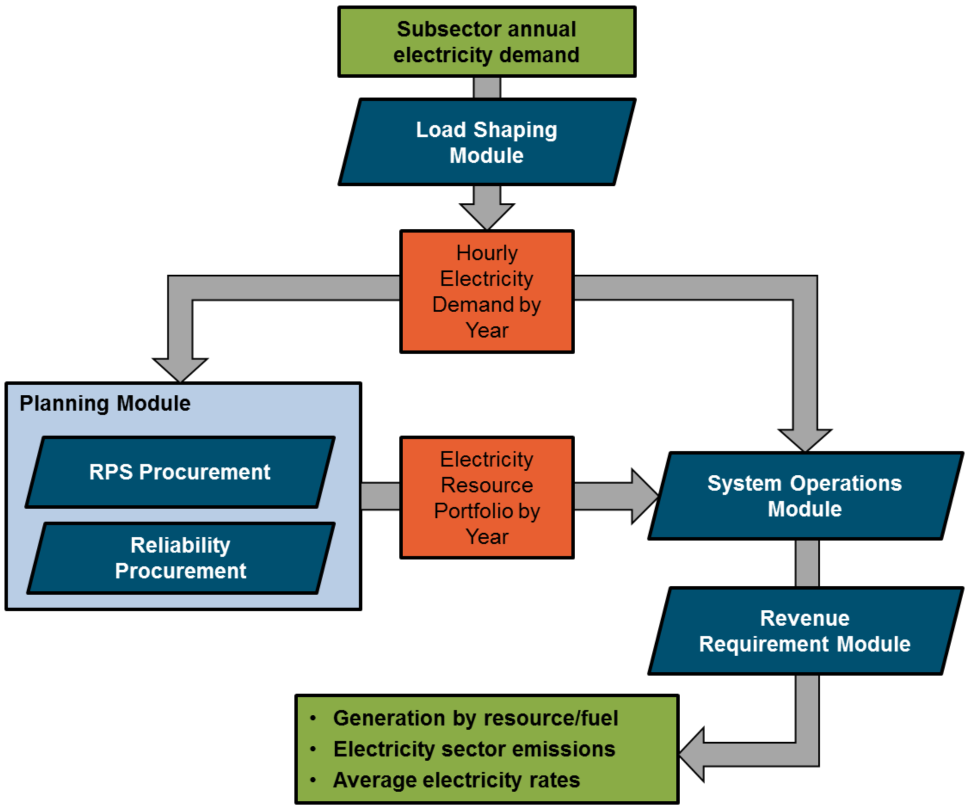

Figure 4. Summary of electricity module

2.1.1 LOAD SHAPING

Single year hourly load shapes were derived for 18 sectors/subsectors based on available hourly load and weather data. For each subsector, shapes were obtained from publicly available data sources, including DEER2008, DEER 2011, CEUS, BeOpt, and PG&E Static and Dynamic load shapes. For each temperature-sensitive subsector, corresponding temperature data was obtained from each of the 16 climate zones. The shapes obtained for this analysis and the corresponding weather year or weather data source are listed in Table 2.

Table 2. Input load shapes and sources

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
1	Residential Water Heating	DEER2008		PG&E	2008 Title 24
2	Residential Water Heating	DEER2008		SCE	2008 Title 24
3	Residential Water Heating	DEER2008		SDG&E	2008 Title 24
4	Residential Space Cooling	DEER2008		PG&E	2008 Title 24
5	Residential Space Cooling	DEER2008		SCE	2008 Title 24
6	Residential Space Cooling	DEER2008		SDG&E	2008 Title 24
7	Residential Space Cooling	DEER2011	HVAC_Eff_AC	PG&E	2008 Title 24
8	Residential Space Cooling	DEER2011	HVAC_Eff_AC	SCE	2008 Title 24
9	Residential Space Cooling	DEER2011	HVAC_Eff_AC	SDG&E	2008 Title 24
10	Residential Lighting	DEER2011	Indoor_CFL_Ltg	PG&E	2008 Title 24
11	Residential Lighting	DEER2011	Indoor_CFL_Ltg	SCE	2008 Title 24
12	Residential Lighting	DEER2011	Indoor_CFL_Ltg	SDG&E	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
13	Residential Clothes Washing	DEER2011	ClothesWasher	PG&E	2008 Title 24
14	Residential Clothes Washing	DEER2011	ClothesWasher	SCE	2008 Title 24
15	Residential Clothes Washing	DEER2011	ClothesWasher	SDG&E	2008 Title 24
16	Residential Dishwashing	DEER2011	Dishwasher	PG&E	2008 Title 24
17	Residential Dishwashing	DEER2011	Dishwasher	SCE	2008 Title 24
18	Residential Dishwashing	DEER2011	Dishwasher	SDG&E	2008 Title 24
19	Residential Refrigeration	DEER2011	RefgFrzr_HighEff	PG&E	2008 Title 24
20	Residential Refrigeration	DEER2011	RefgFrzr_HighEff	SCE	2008 Title 24
21	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	PG&E	2008 Title 24
22	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	SCE	2008 Title 24
23	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	SDG&E	2008 Title 24
24	Residential Clothes Drying	DEER2008		PG&E	2008 Title 24
25	Residential Cooking	BEopt		CZ3	BEopt

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
26	Residential Other	BEopt		CZ3	BEopt
27	Residential Space Heating	BEopt		CZ3	BEopt
28	Residential Space Heating	BEopt		CZ6	BEopt
29	Residential Space Heating	BEopt		CZ10	BEopt
30	Residential Space Heating	BEopt		CZ12	BEopt
31	Commercial Water Heating	DEER2008		PG&E	2008 Title 24
32	Commercial Water Heating	DEER2008		SCE	2008 Title 24
33	Commercial Water Heating	DEER2008		SDG&E	2008 Title 24
34	Commercial Space Heating	CEUS			Historical - 2002
35	Commercial Space Cooling	DEER2011	HVAC_Chillers	PG&E	2008 Title 24
36	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	PG&E	2008 Title 24
37	Commercial Space Cooling	DEER2011	HVAC_Chillers	SCE	2008 Title 24
38	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	SCE	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
39	Commercial Space Cooling	DEER2011	HVAC_Chillers	SDG&E	2008 Title 24
40	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	SDG&E	2008 Title 24
41	Commercial Lighting	CEUS			Historical - 2002
42	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	PG&E	2008 Title 24
43	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	PG&E	2008 Title 24
44	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	SCE	2008 Title 24
45	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	SCE	2008 Title 24
46	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	SDG&E	2008 Title 24
47	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	SDG&E	2008 Title 24
48	Commercial Cooking	CEUS			Historical - 2002
49	Streetlights	PG&E Static	LS1	PG&E	Historical - 2010
50	Agriculture	PG&E Static	AG1A	PG&E	Historical - 2010
51	Agriculture	PG&E Static	AG1B	PG&E	Historical - 2010

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
52	Agriculture	PG&E Static	AG4A	PG&E	Historical - 2010
53	Agriculture	PG&E Static	AG4B	PG&E	Historical - 2010
54	Agriculture	PG&E Static	AG5A	PG&E	Historical - 2010
55	Agriculture	PG&E Static	AG5B	PG&E	Historical - 2010
56	Agriculture	PG&E Static	AGVA	PG&E	Historical - 2010
57	Agriculture	PG&E Static	AGRA	PG&E	Historical - 2010
58	Industrial	PG&E Dynamic	A6	PG&E	Historical - 2010
59	Industrial	PG&E Dynamic	E19P	PG&E	Historical - 2010
60	Industrial	PG&E Dynamic	E19V	PG&E	Historical - 2010
61	Industrial	PG&E Dynamic	E20P	PG&E	Historical - 2010

2.1.1.1 Load shaping methodology

The load shaping module first requires normalization of each input load shape from its corresponding weather year to the simulation year. This process occurs in two steps. First, the load shape is approximated as a linear combination of the hourly temperature in each climate zone, the hourly temperature in each climate zone squared, and a constant. This regression is performed separately for weekdays and weekends/holidays to differentiate between behavioral modes on these days.

$$\boldsymbol{x_i} \approx \sum_{\boldsymbol{k \in CZ}} \left[\boldsymbol{a_{ik} w_{ik}^2} + \boldsymbol{b_{ik} w_{ik}}\right] + \boldsymbol{c_{ik}}$$

where x_i is the input load shape, w_{ik} is the hourly temperature in climate zone k in the weather year associated with the input load shape, and a_{ik}, b_{ik}, and c_{ik} are constants. Next, the hourly temperature data for the simulation year in PATHWAYS is used to transform the input load shapes into the same weather year. This process also occurs separately for weekdays and weekends/holidays.

$$\boldsymbol{y_i} \approx \sum_{\boldsymbol{k \in CZ}} \left[\boldsymbol{a_{ik} W_k^2} + \boldsymbol{b_{ik} W_k}\right] + \boldsymbol{c_{ik}}$$

where W_k is the hourly temperature in climate zone k in the PATHWAYS simulation weather year. Each set of weekday and weekend/holiday shapes are then combined into a single yearlong hourly shape to match the weekend/holiday schedule of the PATHWAYS simulation year. This results in 61 load shapes that reflect the same weather conditions and weekend/holiday schedules as the PATHWAYS simulation year.

The next step is to combine the load shapes to best reflect both the total historical hourly load and the annual electricity demand by subsector. The model achieves this by normalizing each load shape so that it sums to 1 over the year and selecting scaling factors that represent the annual electricity demand associated with each shape. These scaling factors are selected to ensure that the total electricity demand associated with the load shapes in each subsector sums to the electricity demand in that subsector in a selected historical year. An optimization routine is also used to minimize the deviation between the sum of the energy-weighted hourly load shapes and the hourly demand in the same historical year.

The optimization routine includes two additional sets of variables to allow for more accurate calibration to the historical year. The first set of variables addresses limitations in the availability of aggregate load shapes by subsector. Because some of the load shapes being used represent a single household or a single building, aggregation of these shapes may result in more variable load shapes than are seem at the system level. To account for this, the model shifts each load shape by one hour in each direction and includes these shifted load shapes in the optimization in addition to the original load shape. The model then selects scaling factors for each of the three versions of each shape to automatically smooth the shapes if this improves the fit to hourly historical data.

In addition to the load shape smoothing variables, a set of constants are also included in the model for each subsector. This allows the model to translate load shapes up and down (in addition to the scaling) to best approximate the hourly historical load. The constraints that ensure that the load shapes within each subsector sum to the annual electricity demand by subsector are adjusted to ensure that that the energy contribution of the constant term is reflected. The scaling factors and constants solved for in the optimization routine are then used to construct a single shape for each subsector. These shapes are input into PATHWAYS and are scaled in each year according to the subsector electricity demand to form the system-wide hourly load shape. Example load shapes derived using this process are shown in Figure 5. At left, the average daily load shape for weekdays in September corresponding to historical 2010 demand is shown. The load shape at right reflects the impacts of reducing all lighting demands by 50% from the 2010 historical demand.

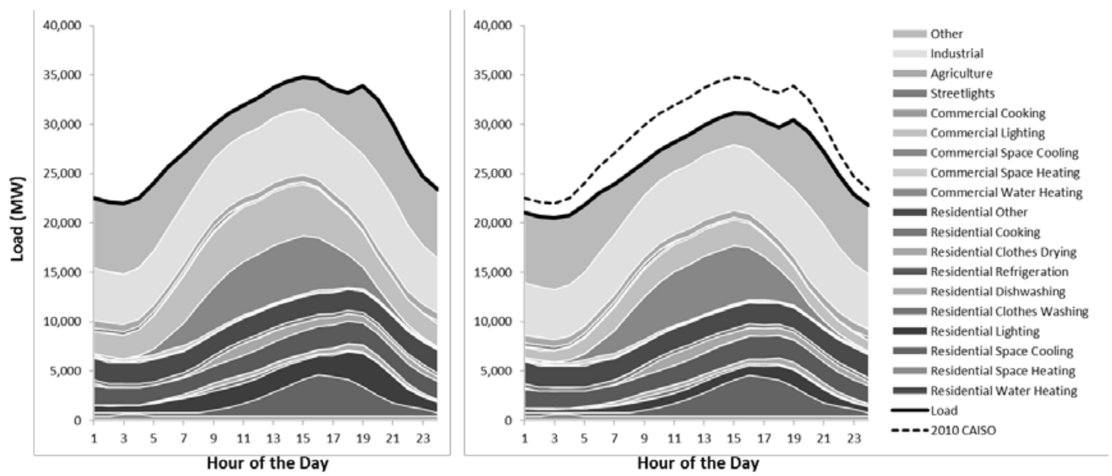

Figure 5. Example load shaping: impact of 50% reduction in lighting demand in average California load shape for weekdays in September, 2010.

Some subsectors in PATHWAYS do not have available representative load shapes. The load shaping module combines these subsectors into an "undefined" subsector and models their contribution to the demand in the optimization routine as a linear combination of all of the available load shapes and a constant. After the optimization routine has solved, the difference between the historical hourly demand and the aggregated hourly shape of all defined subsectors is normalized to sum to 1 and this shape is used to represent any subsectors in PATHWAYS with no specific load shape information.

2.1.2 GENERATION PLANNING

Generation planning occurs in three stages: user-specified resources, renewable policy compliance, and reliability requirement compliance. These are described below.

1. First, the user specifies the capacity (in MW) of or annual energy (in GWh) from each generating resource in each year. Vintages must also be supplied for this fleet of *specified resources* so that they can be retired at the end of their useful life. Early retirement can be imposed by reducing the total installed capacity of a resource type in future years. The model will retire resources of this type according to age (oldest retired first) to meet the yearly capacities specified by the user. In addition, the model will replace generators at the end of their useful life with new resources (with updated cost and performance parameters) of the same type to maintain the user specified capacity in each year. If the resource capacities are not known after a specific year then the user can specify the capacity to be "NaN" and the model will retire resources without replacement at the end of their useful lifetime.

2. In the second stage of generation planning, the model simulates renewable resource procurement to meet a user-specified renewable portfolio standard (RPS). In each year, the renewable net short is calculated as the difference between the RPS times the total retail sales and the total sum of the renewable generation available from specified resources and resources built in prior years. This renewable net short is then supplied with additional renewable build according to user-

specified resource composition rules in each year (e.g. 50% wind, 50% solar PV).

3. The final stage in generation planning is to ensure adequate reliable generating capacity to meet demand. In each year, the model performs a load-resource analysis to compare the reliable capacity to the peak electricity demand. The reliable capacity of the renewable resources is approximated by the total renewable generation level in the hour with the highest net load in the year, where the net load equals the total load minus the renewable generation. The reliable capacity of dispatchable resources is simply equal to the installed capacity. When the total reliability capacity does not exceed the peak demand times a user-specified planning reserve margin, the model builds additional dispatchable resources with a user-specified composition in each year. The default planning reserve margin is equal to 15% of peak demand.

The specified resource capacities by year and their corresponding vintage data were obtained from the Transmission Expansion Planning Policy Commission (TEPPC) 2022 Common Case. Additional input assumptions for renewable resources are listed in Table 3 and

Table 4.

Table 3. Aggregate renewable resource inputs by scenario (% renewable)

Scenario	Year 1	RPS 1	Year 2	RPS 2	Year 3	RPS 3	Year 4	RPS 4
Reference	2013	0	2020	33%				
Electrification	2010	15%	2020	33%	2030	50%	2050	90%
Mixed	2010	20%	2020	33%	2030	50%	2050	90%

Table 4. Renewable resource inputs by scenario and resource type (% of technology type that meets renewable % goal)

Scenario	Reference		Electrification		Mixed	
Year	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Geothermal		0%	5%	0%	5%	0%
Biomass		0%	0%	0%	0%	0%
Biogas		0%	0%	0%	0%	0%
Small Hydro		0%	0%	0%	0%	0%
Wind		20%	30%	30%	30%	30%
Centralized PV		80%	55%	60%	55%	60%
Distributed PV		0%	0%	0%	0%	0%
CSP		0%	0%	0%	0%	0%
CSP with Storage		0%	10%	10%	10%	10%

The final resource stack determined for each year by the electricity planning module feeds into both the system operations and the revenue requirement calculations. These calculations are described in the following sections.

2.1.3 SYSTEM OPERATIONS

System operations are modeled in PATHWAYS using a loading order of resources with similar types of operational constraints and a set of heuristic designed to approximate these constraints. The system operations loading order is summarized in Figure 6.

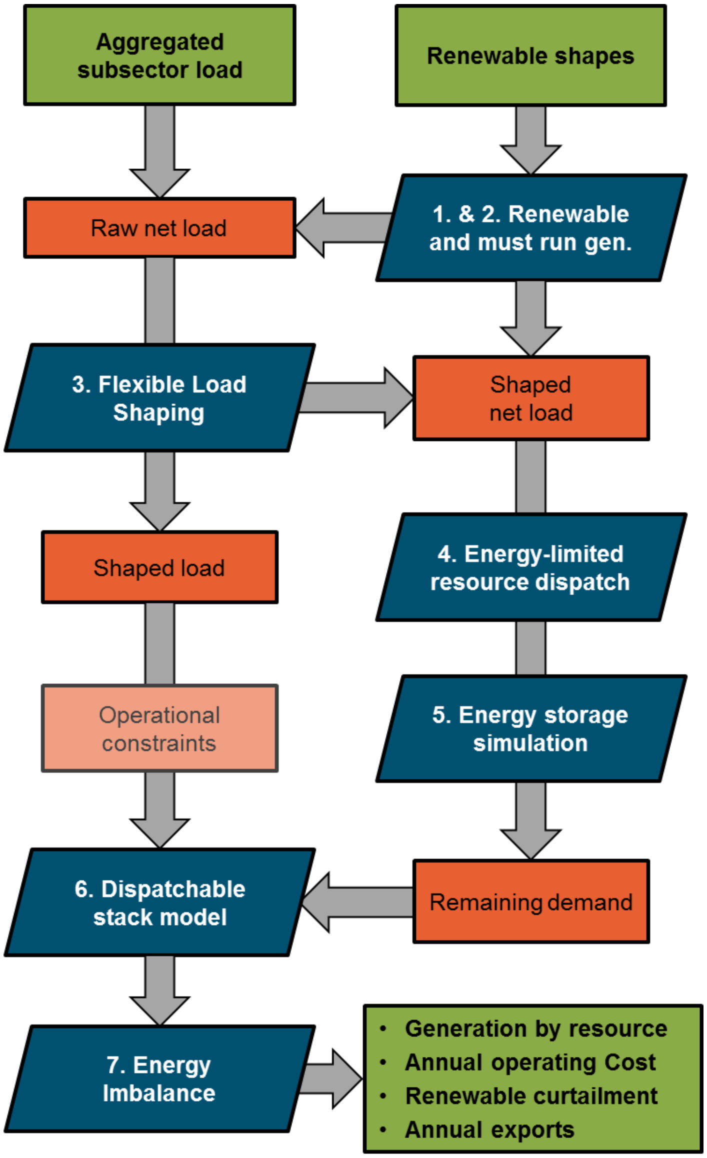

Figure 6. Summary of electricity system operations logic

Consistent with this modeling framework, generation resources must each be classified into one of the following operational modes: must-run; variable renewable; energy-limited; and dispatchable. These classifications are listed for the resource types in this analysis in Table 5.

Table 5. Operational modes by resource type

Technology	Operational Mode
Nuclear	Must-run
CHP	Must-run
Coal	Dispatchable
Combined Cycle Gas (CCGT)	Dispatchable
Steam Turbine	Dispatchable
Combustion Turbine	Dispatchable
Conventional Hydro	Energy-Limited
Geothermal	Must-run
Biomass	Must-run
Biogas	Must-run
Small Hydro	Must-run
Wind	Variable Renewable
Centralized PV	Variable Renewable
Distributed PV	Variable Renewable
CSP	Variable Renewable
CSP with Storage	Variable Renewable

2.1.3.1 Must run resources

Must run resources are modeled with constant output equal to their installed capacity in each year or with constant output that sums to the input annual energy, depending on user specifications. These resources run regardless of the conditions on the system and are therefore scheduled first.

2.1.3.2 Variable renewable resources

Variable renewable resources include any resource that has energy availability that changes over time and has no upward dispatchability. This includes all wind and solar resources. For each of these resources, a resource shape is selected, which characterizes the maximum available power output in each hour. These shapes are scaled in each year to match the total annual energy generation determined by the renewable procurement calculation. These resources can either be constrained to never generate in excess of these scaled renewable shapes (curtailable) or constrained to generate at levels that always exactly match the scaled renewable shapes (non-curtailable). The curtailment is affected by both the load and the ability of other resources on the system to balance the renewable resources. Renewable curtailment is therefore approximated as a *system imbalance* after all other resources have been modeled. The curtailability assumptions for variable renewable resources are summarized in Table 6.

Table 6. Operating assumptions for renewable resources

Technology	Able to Curtail?
Geothermal	No
Biomass	No
Biogas	No
Small Hydro	No
Wind	Yes
Centralized PV	Yes
Distributed PV	No
CSP	Yes
CSP with Storage	No[2]

2.1.3.3 Flexible loads

Flexible loads are modeled at the subsector level. For each demand subsector, the user specifies what fraction of the load is effectively perfectly flexible within the week. Note that this does not imply that the subsector contains loads that can be delayed for up to a week. The model instead approximates each flexible load shape as the weighted sum of a 100% rigid load shape component and a 100% flexible load shape component, which in most extreme case can move in direct opposition to the hourly rigid load shape. It is up to the user to select the weights that best approximate technically feasible load flexibility. Flexible loads in the model are dynamically shaped to flatten the net load (load net of must-run resources and variable renewables) on a weekly basis in each year. The

[2] CSP with Storage resources must generate according to the hourly shape in each hour, but the hourly shape utilizes the energy storage module logic to approximate the dispatchability of these resources.

flexible load dispatch therefore changes both with demand measures and renewable supply measures.

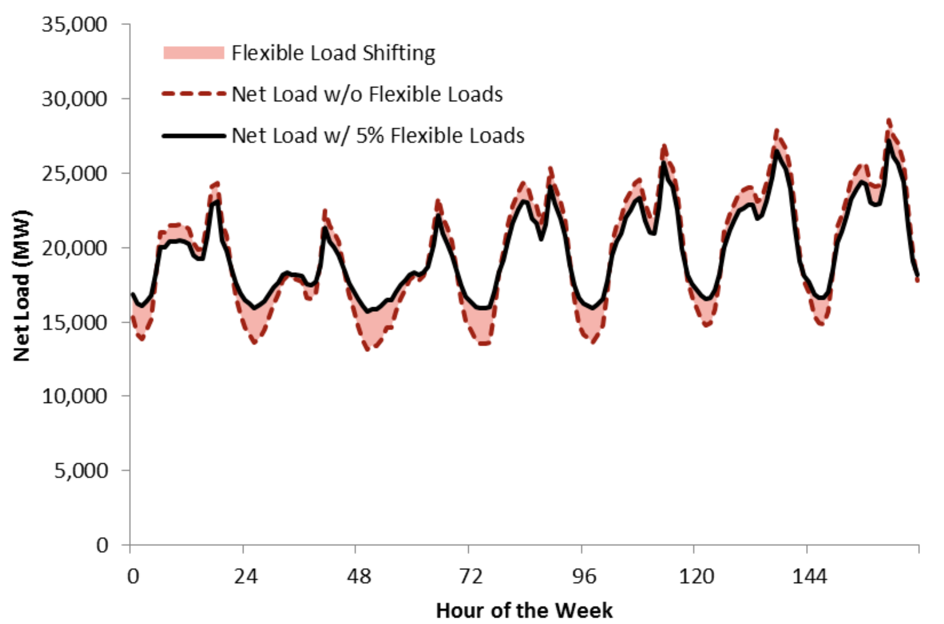

Figure 7. Example of flexible load shifting – 5% of the gross load assumed to be 100% flexible within the week.

The effects of introducing flexible loads on the total net load is shown in Figure 7 for an example week in which 5% of the gross load is approximated as 100% flexible within the week. The input flexible load assumptions are described below.

Table 7. Flexible load assumptions

Scenario			Reference	Electrification	Mixed
Subsector	**Start Year**	**Target Year**	**% Flexible**	**% Flexible**	**% Flexible**
Residential Water Heating	2010	2040	0%	20%	20%
Residential Space Heating	2010	2040	0%	20%	20%
Residential Central AC	2010	2040	0%	20%	20%
Residential Room AC	2010	2040	0%	20%	20%
Residential Clothes Washing	2010	2040	0%	20%	20%
Commercial Water Heating	2010	2040	0%	20%	20%
Commercial Space Cooling	2010	2040	0%	20%	20%
Commercial Space Heating	2010	2040	0%	20%	20%
Light Duty Vehicles	2010	2040	0%	40%	40%

2.1.3.4 Energy-limited resources

Energy-limited resources include any resource that must adhere to a specified energy budget over a weekly time horizon. Some energy-limited resources, like conventional hydropower, have energy budgets that change over time to account for seasonal fluctuations in resource availability and other constraints. Other energy-limited resources, like biomass and biogas, use a dynamic weekly energy budget that distributes resource use between weeks according to the relative electricity imbalance (between load and must-run plus renewable resources) across the weeks. For renewable energy-limited resources, the energy budget ensures that energy from the resources is being delivered for RPS compliance and the energy-limited dispatch also allows the resource to contribute to balancing the system. In addition to the weekly energy budgets, these resources are constrained by weekly minimum and maximum power output levels as well. The dispatch for these resources is approximated using the following heuristic. The method is illustrated in Figure 8 and Figure 9.

1. A normalized hourly demand shape is calculated from the load net of all must-run and variable renewable resources. This net load shape is first translated on a weekly basis so that it averages to zero.

2. The zero-averaged demand shape is then scaled so that the minimum to maximum demand over the course of each week is equal to the minimum to maximum power output of the energy-limited resource.

3. The scaled demand shape is then translated so that the total weekly demand sums to the energy budget of the energy-limited resource.

4. The transformed demand shape calculated in Step 3 will necessarily violate either the minimum or maximum power level constraints for the energy-limited resource in some hours, so two additional steps are required to meet the remaining constraint. In the first of these steps, the transformed demand shape is forced to equal the binding power constraint in hours when it would otherwise violate the constraint. This *truncation* adjustment impacts the summed weekly energy of the transformed demand shape, so a final step is required to re-impose the energy budget constraint.

5. In the weeks in which the transformed demand shape exceeds the energy budget, the model defines a downward capability signal equal to

the difference between the transformed demand shape and the minimum power level. A portion of this signal is then subtracted from the transformed demand shape so that the weekly energy is equal to the energy budget. In the weeks in which the transformed demand shape does not meet the energy budget, the model defines an upward capability signal equal to the difference between the maximum power level and the transformed demand shape. A portion of this signal is then added to the transformed demand shape so that the weekly energy is equal to the energy budget.

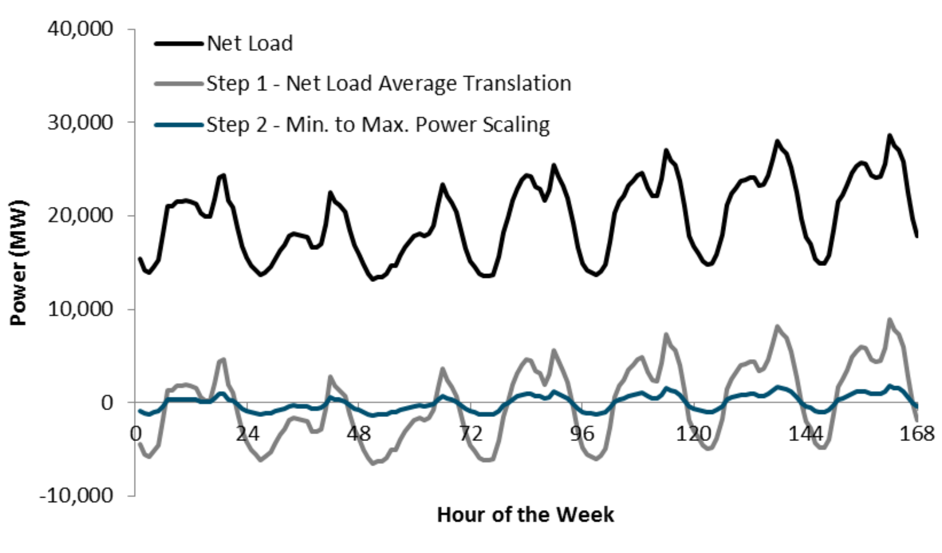

Figure 8. Energy-limited resource dispatch Steps 1 & 2 - normalization and scaling of the net load shape

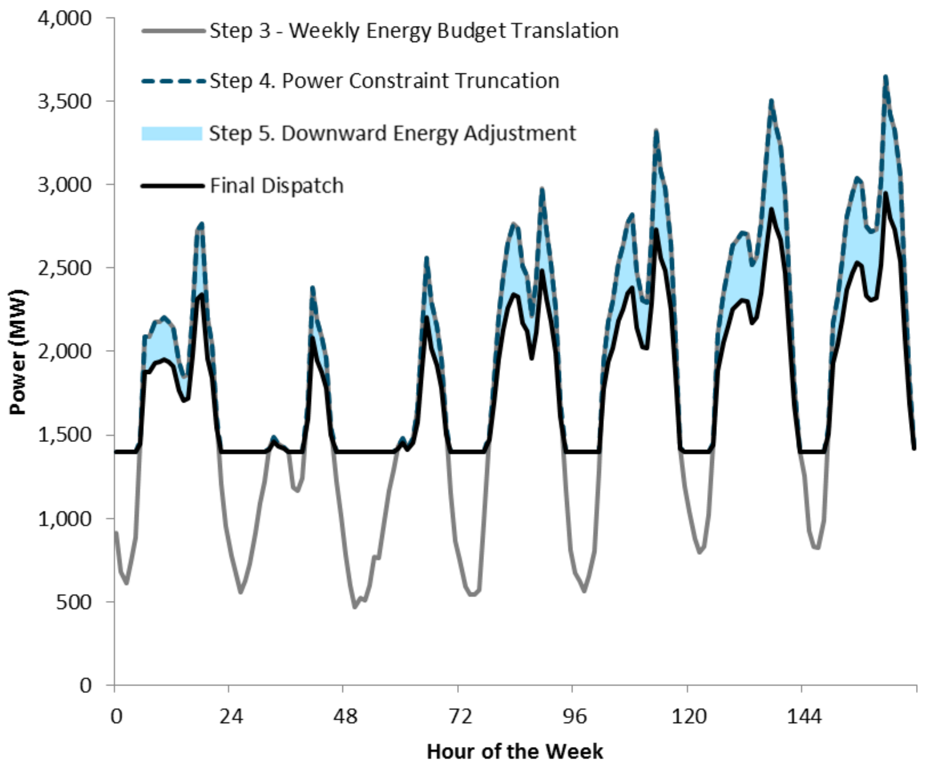

Figure 9. Energy-limited resource dispatch Steps 3 - 5 – translation, truncation, and energy budget adjustment

2.1.3.5 Energy storage

Energy storage resources in PATHWAYS are aggregated into a single equivalent system-wide energy storage device with a maximum charging capacity, maximum discharging capacity, maximum stored energy capacity, and roundtrip efficiency. The simplified energy storage device is described schematically in Figure 10.

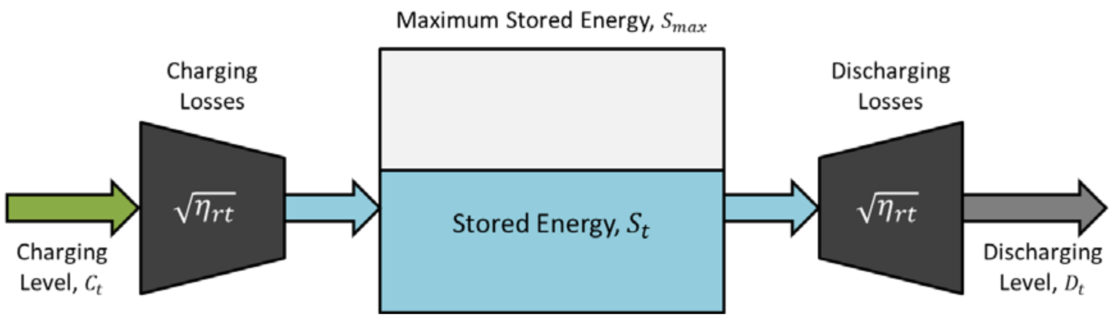

Figure 10. Energy storage model

The storage system acts by storing any renewable energy in excess of the load in each hour (subject to constraints on maximum charging and maximum stored energy) and discharging any stored energy in hours in which the load exceeds the generation from must-run, variable renewable, and energy-limited resources. In PATHWAYS, this functionality is modeled using the following equations in each time step:

$$\mathbf{C_t} = \begin{cases} \min\left(\left\{G_t - L_t, C_{max}, \dfrac{S_{max} - S_{t-1}}{\sqrt{\eta_{rt}}}\right\}\right) & \text{if } G_t > L_t \\ 0 & \text{if } G_t \le L_t \end{cases}$$

$$\mathbf{D_t} = \begin{cases} 0 & \text{if } G_t > L_t \\ \min\left(\left\{L_t - G_t, D_{max}, \dfrac{S_{t-1}}{\sqrt{\eta_{rt}}}\right\}\right) & \text{if } G_t \le L_t \end{cases}$$

$$S_t = S_{t-1} + \sqrt{\eta_{rt}}C_t - \frac{D_t}{\sqrt{\eta_{rt}}}$$

where G_t is the total generation from must-run, variable renewable, and energy-limited resources, L_t is the load, C_{max} is the maximum charging level, and D_{max} is the maximum discharging level. The hourly year-long dispatch simulation is run in an iterative mode to ensure that the stored energy level at the end of the year matched the stored energy level at the beginning of the year ($S_T = S_0$). This ensures that the storage system provides no net energy to the system. This heuristic storage dispatch algorithm is intended to alleviate short- and long-term energy imbalances, but it is not intended to represent optimal storage dispatch in an electricity market. The operating parameters for the equivalent system-wide energy storage device in each year are calculated from the operating parameters of each storage device that is online in that year. The maximum charging level, maximum discharging level, and maximum stored energy are each calculated as the sum of the respective resource-specific parameters across the full set of resources. The round-trip efficiency is calculated using the following approximation. Consider a storage system that spends half of its time discharging and discharges at its maximum discharge level. For this system, the total discharged energy over a period of length T will equal:

$$\int_0^T \boldsymbol{D_i(t)\,dt = h_i \times D_i^{max} \times \frac{T}{2h_i} = \frac{D_i^{max} \times T}{2}}$$

where h_i is the duration of discharge at maximum discharging capability, D_i^{max}. For this system, the total losses can be described by:

$$\boldsymbol{Losses_i = \int_0^T \frac{1-\eta_i}{\eta_i} D_i(t)\,dt = \frac{(1-\eta_i)D_i^{max} \times T}{2\eta_i}}$$

If the system has several storage devices operating in this way, the total losses are equal to:

$$\boldsymbol{Losses} = \frac{\boldsymbol{T}}{\boldsymbol{2}}\sum_{\boldsymbol{i}}\frac{\boldsymbol{1}-\boldsymbol{\eta_i}}{\boldsymbol{\eta_i}}\boldsymbol{D_i^{max}} = \frac{\boldsymbol{T}}{\boldsymbol{2}}\left(\sum_{\boldsymbol{i}}\frac{\boldsymbol{D_i^{max}}}{\boldsymbol{\eta_i}} - \boldsymbol{D_{max}}\right)$$

where D_{max} is the aggregated maximum discharge capacity. The total discharged energy is equal to:

$$\boldsymbol{Energy} = \sum_{\boldsymbol{i}}\frac{\boldsymbol{D_i^{max}}\times\boldsymbol{T}}{\boldsymbol{2}} = \frac{\boldsymbol{T}}{\boldsymbol{2}}\boldsymbol{D_{max}}$$

The system-wide roundtrip efficiency is therefore approximated by:

$$\frac{\boldsymbol{Energy}}{\boldsymbol{Energy}+\boldsymbol{Losses}} = \frac{\boldsymbol{D_{max}}}{\boldsymbol{D_{max}}+\sum_{\boldsymbol{i}}\frac{\boldsymbol{D_i^{max}}}{\boldsymbol{\eta_i}}-\boldsymbol{D_{max}}} = \frac{\boldsymbol{D_{max}}}{\sum_{\boldsymbol{i}}\frac{\boldsymbol{D_i^{max}}}{\boldsymbol{\eta_i}}}$$

The energy storage operational parameters used in this analysis are summarized in Table 8 and the energy storage build assumptions are listed in

Table 9.

Table 8. Energy storage technology operational parameters

Technology	Year 1	Roundtrip Efficiency in Year 1	Year 2	Roundtrip Efficiency in Year 2
Pumped Hydro	2010	70.5%	2020	80%
Batteries	2010	75%	2020	80%
Flow Batteries	2010	75%	2020	80%

Table 9. Energy storage scenario assumptions

Scenario	Technology	MW	Hours at Max. Discharge	Start Year	Target Year
Reference	Pumped Hydro	2,427	93	2010	2011
Electrification	Pumped Hydro	2,427	93	2010	2011
Electrification	Pumped Hydro	5,000	12	2020	2040
Electrification	Flow Batteries	15,000	6	2020	2050
Mixed	Pumped Hydro	2,427	93	2010	2011
Mixed	Pumped Hydro	5,000	12	2020	2040

2.1.3.6 Dispatchable resources

Dispatchable resources are used to provide the remaining electricity demand after must-run, variable renewable, energy-limited, and storage resources have been used. Dispatch of these resources, which include thermal resources and imports, is approximated using a stack model with heuristics to approximate operational constraints that maintain system reliability. In the stack model, resources are ordered by total operational cost on a $/MWh basis. The operational cost includes: fuel costs equal to the fuel price times the heat rate; carbon costs equal to the price of carbon times the fuel carbon intensity times the heat rate; and input variable operations and maintenance costs. Resources are dispatched in stack order until the remaining load is met. The default operational constraint is to require 10% of the gross electricity load to be met with dispatchable thermal resources in all hours. Imports have user-specified heat rates and capacities to best approximate historical path flows and import constraints. Dispatchable resource operational parameters are listed in Table 10 and

Table 11.

Table 10. Dispatchable technology heat rate assumptions[3]

Technology	Year 1	Heat Rate in Year 1 (MMBtu/kWh)	Year 2	Heat Rate in Year 2 (MMBtu/kWh)
Coal	2012	10,130	2027	9,000
Combined Cycle Gas (CCGT)	2012	7,000	2027	6,900
Steam Turbine	1980	14,000	2027	14,000
Combustion Turbine	2012	10,500	2027	9,200

Table 11. Dispatchable technology variable O&M assumptions[4]

Technology	Variable O&M Cost (2008$/MWh)
Coal	4.32
Combined Cycle Gas (CCGT)	4.92
Steam Turbine	5
Combustion Turbine	5

2.1.3.7 System imbalances

Once the dispatch has been calculated for each type of resource, the model calculates any remaining energy imbalances. The planning module is designed to ensure that no unserved energy is experienced in the operational simulation, but the system might encounter potential overgeneration conditions, in which the generation exceeds demand. These conditions might arise due to a combination of factors, including low load, high must run generation, high variable renewable generation, and minimum generation operating constraints.

[3] Heat rate assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012. <http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf>

[4] Derived from operating parameters in TEPPC 2022 Common Case

Overgeneration conditions are first mitigated with exports to neighboring regions, based on the user-specified maximum export level. For accounting purposes, the exported power emissions rate is approximated as the generation-weighted average emissions rate of all resources generating in each hour. If excess generation remains after accounting for exports, then overgeneration is avoided by curtailing renewable resources. Curtailment is not attributed to specific renewable resources, but does impact the total annual delivered renewable energy. Both the delivered renewable energy and the percent of renewable generation that is curtailed in each year are outputs of the model. The model does not procure additional renewable resources to meet RPS targets if renewable curtailment results in less delivered RPS energy than is required for compliance. This renewable overbuild must be decided by the user.

The system operations module outputs include:

- Total annual generation from each technology and fuel type
- Total annual electric sector emissions
- Total electric sector fuel, variable O&M, and carbon costs
- Expected annual delivered renewable energy and percent of renewable generation curtailed

2.1.4 REVENUE REQUIREMENT

The revenue requirement calculation includes the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. The methodology for calculating fixed costs in each year is described below.

2.1.4.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and the user-specified capital cost and fixed O&M cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the vintaged capital cost times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. For eligible resources, taxes are net of production tax credits and/or investment tax credits. If the plant's useful lifetime is longer than its financing lifetime, then no fixed costs are calculated for the years between the end of the financing lifetime and the retirement of the plant. This methodology is also used to cost energy storage infrastructure and combined heat and power infrastructure. Input cost assumptions for generation are summarized below.[5]

[5] Cost assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.
<http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf>

Table 12. Capital cost assumptions

Technology	Capital Cost from present - 2026 (2012$/kW)	Assumed change in real capital cost by 2050 % change	Capital Cost from 2027 - 2050 (2012$/kW)
Nuclear	9,406	0%	9,406
CHP	1,809	0%	1,809
Coal	4,209	0%	4,209
Combined Cycle Gas (CCGT)	1,243	16%	1,441
CCGT with CCS	3,860	-3%	3,750
Steam Turbine	1,245	0%	1,245
Combustion Turbine	996	44%	1,431
Conventional Hydro	3,709	0%	3,709
Geothermal	6,726	0%	6,726
Biomass	5,219	0%	5,219
Biogas	3,189	0%	3,189
Small Hydro	4,448	0%	4,448
Wind	2,236	-9%	2,045
Centralized PV	3,210	-31%	2,230
Distributed PV	5,912	-30%	4,110
CSP	5,811	-25%	4,358
CSP with Storage	7,100	-30%	5,000

Table 13. Fixed O&M cost assumptions

Technology	Year 1	Fixed O&M in Year 1 (2012$/kW-yr)	Year 2	Fixed O&M in Year 2 (2012$/kW-yr)
Nuclear	2012	72.62	2027	72.62
CHP	2012	0	2027	0
Coal	2012	35.6	2027	35.6
Combined Cycle Gas (CCGT)	2012	11.9	2027	11.9
CCGT with CCS	2012	18.4	2027	18.4
Steam Turbine	2012	11.9	2027	11.9
Combustion Turbine	2012	7.1	2027	14.2
Conventional Hydro	2012	35.6	2027	35.6
Geothermal	2012	155.6	2027	155.6
Biomass	2012	184	2027	184
Biogas	2012	154	2027	154
Small Hydro	2012	35.6	2027	35.6
Wind	2012	71.2	2027	71.2
Centralized PV	2012	59.3	2027	59.3
Distributed PV	2012	65.2	2027	65.2
CSP	2012	71.2	2027	71.2
CSP with Storage	2012	60.0	2027	60.0

Financing assumptions and other technology-specific inputs are listed below.

Table 14. Financing assumptions[6]

Technology	Financing Lifetime (yrs)	% ITC Eligible	MACRS Term (yrs)	Insurance Rate	Property Tax Rate	Useful Life (yrs)
Nuclear	20	0%	20	0.5%	1%	50
CHP	20	0%	20	0%	0%	20
Coal	20	0%	20	0.5%	1%	40
Combined Cycle Gas (CCGT)	20	0%	20	0.5%	1%	40
CCGT with CCS	20	0%	20	0.5%	1%	40
Steam Turbine	20	0%	20	0.5%	1%	60
Combustion Turbine	20	0%	20	0.5%	1%	40
Conventional Hydro	20	0%	20	0.5%	0%	80
Geothermal	20	0%	5	0%	0%	20
Biomass	20	0%	20	0%	0%	20
Biogas	20	0%	20	0%	0%	20
Small Hydro	20	0%	20	0.5%	1%	20
Wind	20	0%	5	0%	0%	20
Centralized PV	20	95%	5	0%	1%	20
Distributed PV	20	95%	5	0%	0%	20
CSP	20	95%	5	0%	0%	20
CSP with Storage	20	95%	5	0%	0%	20

Cost and financing assumptions for energy storage technologies are summarized below.

[6] Consistent with financing assumptions used in Williams et al, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science*: 335 (6064), 53-59.

Table 15. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/MW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2.23M	30	30
Batteries	4.3M	15	15
Flow Batteries	4.3M	15	15

2.1.4.2 Transmission

Transmission costs are broken into three components: RPS-driven transmission costs, sustaining transmission costs, and reliability upgrade costs. RPS-driven costs are approximated as a fixed input $/MWh times the total renewable generation in each year. Sustaining transmission costs are calculated in a reference year as the difference between the total transmission costs in that year and the RPS-driven costs calculated for that year. A user-specified portion of these costs are then escalated with the peak demand and the remaining portion is escalated according to a user-specified real cost escalation rate. Reliability upgrade costs are specified by the user in a reference year and are escalated using the same method that is used for the sustaining transmission costs. Input assumptions for transmission costs are listed below.

Distribution Table 16. Transmission cost assumptions

Cost Component	Reference Year	Total Cost Reference Year	Real Escalation Rate	Portion that Escalates with Peak Demand	Renewable Cost Multiplier
Reliability Upgrades	2012	$120M	1%	50%	
Sustaining Transmission			2%	50%	
RPS-Driven Transmission					$34/MWh
Total Transmission Cost	*2012*	*$2.6B*			

2.1.4.3

Distribution costs are broken into distributed renewable-driven costs and non-renewable costs. Renewable-driven costs are approximated as a fixed input $/MWh times the total renewable generation in each year. This calculation assumes that distributed renewable energy grows at the same rate as centralized renewable energy. The user must also use care to ensure that the $/MWh input reflects only distribution costs relative to the entire renewable portfolio, rather than just distributed resources. Non-renewable distribution costs are input by the user for a reference year and escalated with the peak demand.

Table 17. Distribution cost assumptions

Cost Component	Reference Year	Total Cost Reference Year	Real Escalation Rate	Portion that Escalates with Peak Demand	Renewable Cost Multiplier
Non-renewable			2.5%	50%	
Renewable-driven					$0/MWh
Total Distribution Cost	*2012*	*$10B*			

2.1.4.4 Calibration to reference year

The revenue requirement also includes other costs, like program costs and customer incentives. These costs are approximated with an adder that is calibrated to a historical reference year. For this calibration, the user specifies the average electricity rate in a historical year. The total revenue requirement in the historical reference year is then calculated by multiplying the average rate by the total sales calculated for the year in PATHWAYS. The cost adder in the reference year is equal to the difference between the calculated reference revenue requirement and the sum of the generation, transmission, and distribution costs. The cost adder is then scaled with the total sales in each year and added to the generation, transmission, and distribution costs calculated by the model in each year to arrive at the total revenue requirement. Average electricity rates are approximated by dividing the total revenue requirement by the total sales in each year, which reduces to:

$$\boldsymbol{Average\ Rate} = \frac{\boldsymbol{C_{gen}^{fixed} + C_{gen}^{var} + C_{gen}^{fuel} + C_{trans} + C_{dist}}}{\boldsymbol{Total\ Sales}} + \boldsymbol{Rate\ Adder}$$

where C_{gen}^{fixed} includes all generator fixed costs, C_{gen}^{var} and C_{gen}^{fuel} are determined by the system operations calculation, C_{trans} includes all transmission costs, and C_{dist} includes all distribution system costs for a given year. The *rate adder* reflects the constant revenue requirement adder in the reference year, normalized by the total sales in the reference year.

These average electricity rates are applied to the annual electricity demand by subsector to allocate electricity costs between subsectors. For a given subsector, the electricity costs in a given year are therefore:

$$\boldsymbol{Electricity\ Costs = Average\ Rate\ \times Electricity\ Demand}$$

2.1.5 EMISSIONS

The electricity module also calculates an average emissions rate for electricity generation based on the emissions rates specified for each generating technology and the energy generated by each technology in each year. The average emissions rate, E, for electricity is therefore:

$$\boldsymbol{E = \frac{\sum_{k,t} P_{k,t} \times e_k}{Total\ Sales}}$$

where $P_{k,t}$ is the power output in hour t (within the year of interest) from generating technology k, and e_k is the emissions rate of generating technology, which is equal to the carbon intensity of the fuel times the heat rate. The emissions associated with electricity demand for each subsector is therefore approximated by:

$$\boldsymbol{Emissions = E\ \times Electricity\ Demand}$$

2.2 Pipeline gas

We use the term pipeline gas here to acknowledge the potential of the pipeline to deliver products other than traditional natural gas. We model multiple decarbonization strategies for the pipeline including biomass conversion processes, hydrogen, and synthetic methane from power-to-gas processes. Below is a description of the commodity products included in the pipeline in our decarbonization scenarios as well as a discussion of our approach to modeling delivery charges for traditional as well as compressed and liquefied pipeline gas.

2.2.1 NATURAL GAS

Natural gas price forecasts are taken from the EIA's Annual Energy Outlook 2013 （EIA, 2013） for its reference case scenario and are shown below.

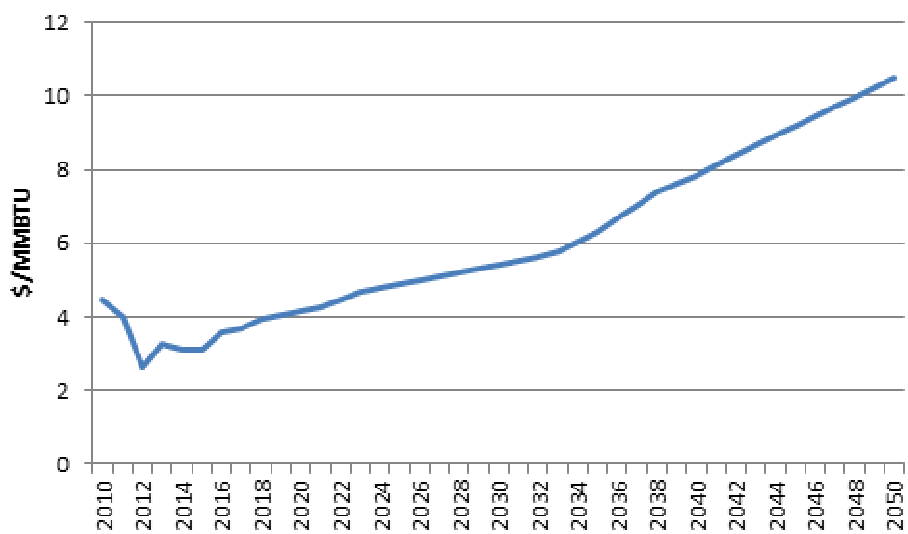

Figure 11. Natural gas commodity forecast

2.2.2 BIOMASS

A full description of the biomass methodology employed in PATHWAYS for all energy delivery types (liquid fuels, electricity, and pipeline gas) is available in section 3.

2.2.3 HYDROGEN

Hydrogen production in the model comes from both low carbon electricity generation – nuclear and renewable energy – and from natural gas with pre-combustion CCS. The data for estimating hydrogen production and delivery costs is adapted from the DOE Hydrogen Analysis Project (H2A). The production portion of the hydrogen module draws current and future assumptions from version 2.1 of the H2A production modeling, utilizing both centralized grid electrolysis and centralized natural gas reformation with CCS technology case studies. Hydrogen delivery draws current and future assumptions from version 2.3 of the H2A delivery model. The values used in the model are shown in Table 18 below.

Table 18. Hydrogen production parameter values from DOE Hydrogen Analysis Project.

Parameter	Grid Electrolysis	Natural Gas with CO_2 Sequestration
Plant Life	40	40
Initial Year	2005	2005
Initial Levelized Fixed Capacity Costs ($/kG-year)	1.53	0.14+0.45+0.09
Initial Efficiency (LHV)	0.74*0.88	0.71*0.88
Forecast Year	2030	2030
Forecast Levelized Fixed Capacity Costs ($/kG-year)	0.65	0.12+0.35+0.07
Forecast Efficiency (LHV)	0.884*0.88	0.711
Production Feedstock	Electricity	Pipeline Gas
Non-energy Variable Operating Costs ($/kG)	0.05	0.17
Capacity Factor	0.25	0.9
CO_2 Capture Ratio	0	0.9

Conversion efficiencies are the product of the efficiency of the hydrogen production process, either electrolysis of water or reformation of natural gas, times a factor of 0.88, which includes energy losses in gas cleaning and other system inefficiencies. The time trajectory of overall system efficiency for grid and natural gas CCS hydrogen production is shown in **Error! Reference source not found.**.

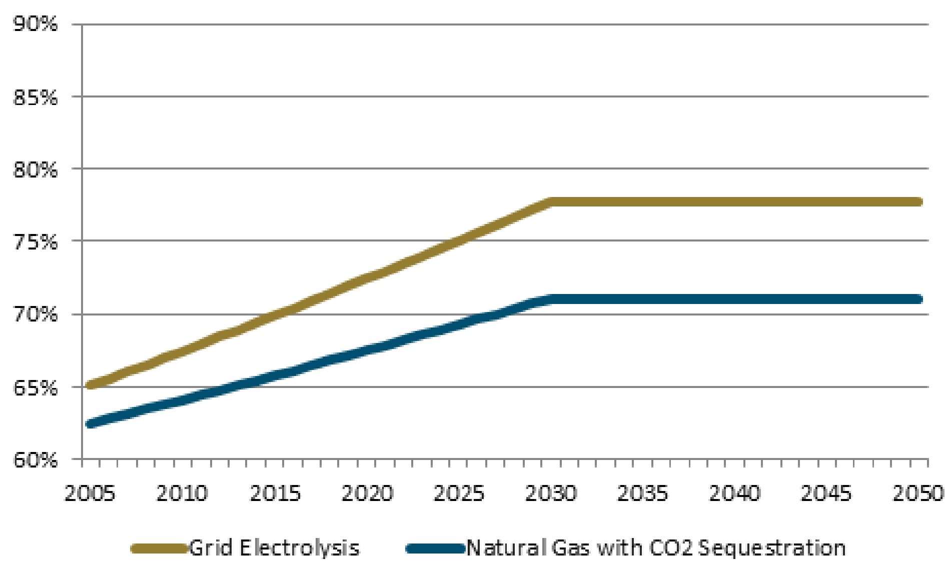

Figure 12. Conversion efficiency of hydrogen production from grid electrolysis and natural gas CCS

Levelized capital costs in the current year were calculated based on the respective H2A models for centralized grid electrolysis and centralized natural gas reformation. Capital cost reductions for 2030 were taken from H2A modeled future cases. The rate of decline to 2030 was assumed to follow the function

$$\mathbf{Cost_{Yr}} = \mathbf{Cost_i} * \mathbf{e}^{\left[\ln\left(\frac{\mathbf{Cost_f}}{\mathbf{Cost_i}}\right) * \frac{(\mathbf{Yr}-\mathbf{Cost_i})}{(\mathbf{Yr_f}-\mathbf{Yr_i})}\right]}$$

The overall levelized capital cost trajectory is shown in Figure 13.

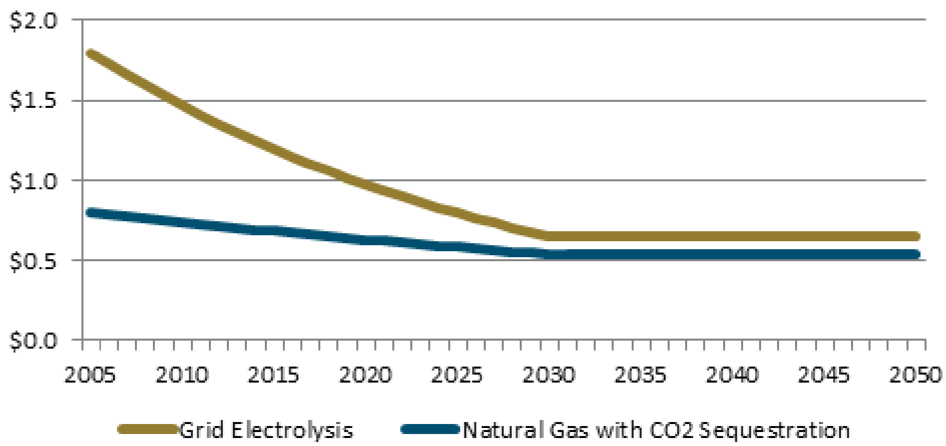

Figure 13. Levelized capital cost of hydrogen from grid hydrolysis and natural gas pre-combustion CCS.

Total annual hydrogen production is a user input. Hydrogen production capacity is built within the model to meet the user defined production level, with a stock roll-over constraint. Capacity factors are taken from the H2A models, with electrolysis running at a low capacity factor to take advantage of periods with low electricity prices. Total costs are the sum of capacity costs and variable costs, including input energy (natural gas or electricity) cost and non-fuel variable cost components. The model assumes that electrolysis-based hydrogen production pays the California average electricity rate.

2.2.4 SYNTHETIC NATURAL GAS (SNG)

SNG is produced in the model from low carbon electricity, which is used to produce hydrogen from electrolysis. In the model, the hydrogen undergoes methanation using CO_2 from air capture. The data used for estimating SNG production costs from this process is adapted from ***Power to Gas – a Technical Review*** authored by Gunnar Benjaminsson, Johan Benjaminsson, and Robert Boogh Rudberg, and published by the Swedish Gas Technology Center (SGC). These are summarized in Table 19. It should be emphasized that while SNG from power to gas is currently being demonstrated on small scale (6 MW is the largest current plant in the world), and includes air capture of CO_2, the cost estimates used here are still highly speculative due to the lack of data from large commercial operation of SNG plants.

Table 19. SNG production parameters in model based on Swedish Gas Technology Center report

Parameter	Value
Plant Life	15
Initial Year	2012
Initial Levelized Fixed Capital Costs ($/mmBtu-year)	18.5
Initial Efficiency	0.52
Forecast Year	2032
Forecast Levelized Fixed Capital Costs ($/mmBtu-year)	7.6
Forecast Efficiency	0.78*0.81
Production Feedstock	Electricity
Non-energy Variable Operating Costs ($/mmBtu)	6.5
Capacity Factor	0.25

Current year process efficiency is 52%, which is the product of an electrolysis efficiency of 65% and methanation efficiency (catalytic or biological) of 81%. Forecast efficiency in 2032 is 63%, based on the same methanation efficiency and an improved electrolysis efficiency of 78%. Process efficiency improves linearly from 2013 to 2032, and remains constant thereafter (**Error! Reference source not found.**).

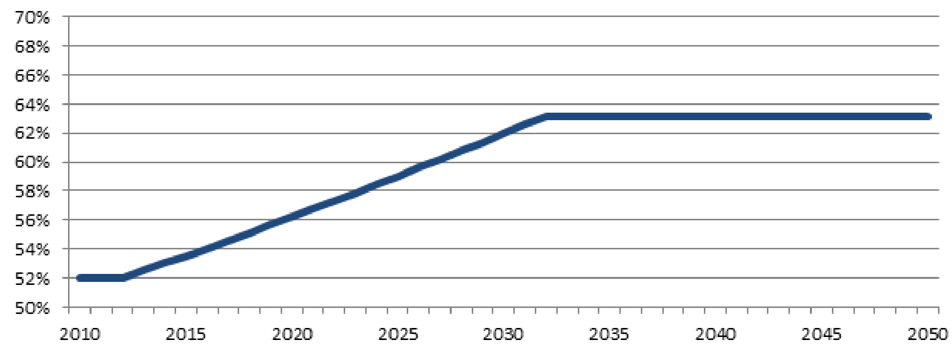

Figure 14. SNG production efficiency over time, based on SGC report

Levelized current capital cost of SNG production capacity is based on the SGC report, assuming production on the order of 25 mmBtu per hour. The capital cost assumption is probably optimistic both in terms of production volume (the throughput rate is higher than any facility currently operating) and because it leaves out plant maintenance costs, which would add approximately 10% to the levelized capital cost. Capital cost reductions to 2032 are assumed to follow the function below:

$$\boldsymbol{Cost_{Yr} = Cost_i * e^{\left[ln\left(\frac{Cost_f}{Cost_i}\right) * \frac{(Yr - Cost_i)}{(Yr_f - Yr_i)}\right]}}$$

The levelized cost trajectory is shown in Figure 15.

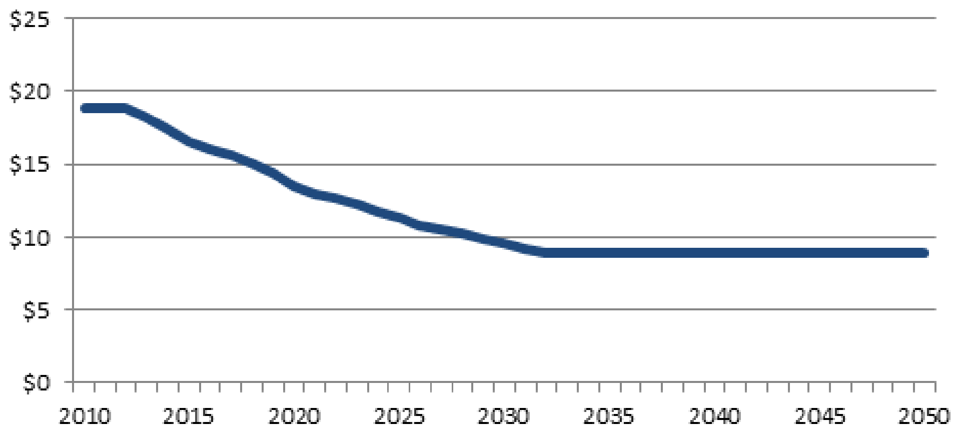

Figure 15. SNG production levelized capital cost

Annual SNG production is a model input. SNG production capacity is built by the model to meet the annual production level, based on a capacity that is assumed to be driven by the electrolysis process and is therefore identical to the assumption of electrolysis capacity factor of 25%. Total costs are a function of capacity costs and variable costs for production, including fuel/electricity costs. SNG capacity follows a stock roll-over that assumes a 15 year plant life. New capacity is added as necessary to meet the target annual production. Production energy costs are simply electricity costs, which are the average electricity rate for California. CO_2 air capture costs are assumed to be included within plant capacity costs.

2.2.5 DELIVERY COSTS

We model the California pipeline system's delivery of pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories. Core service traditionally provides reliable bundled services of transportation and sales compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September, 2013 the average U.S. delivered price of gas to an industrial customer was \$4.39/thousand cubic feet compared to \$15.65/thousand cubic feet for residential customers （United States Energy Information Administration，2013）. This difference is driven primarily by the difference in delivery charges for different customer classes.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California IOU. This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs (to account for increasing prices of commodities, labor, engineering, etc.) of delivery services, an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments. These last two model inputs influence the rate at which the rate base depreciates, which will affect the delivery rates under scenarios where there is a rapid decline in pipeline throughput that outpaces capital depreciation. We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline 1.7% per year and that any decline in throughput exceeding this rate would result in escalating delivery charges for remaining customers. This is a result of utilities being forced to recover revenue from a declining amount of throughput, increasing rates for remaining customers and potentially encouraging fuel switching, thus accelerating the process. These costs will have to be recovered and so need to continue to be represented even in scenarios where there are rapid declines in pipeline throughput.

2.2.5.1 Compressed pipeline gas

We model the costs of compression facilities at $.87/Gallons of Gasoline Equivalent (GGE) based on an average of cost ranges reported by Argonne National Laboratory （Argonne National Laboratory，2010）. Additionally, we model the electricity use of compressing facilities at 1 kWh per GGE based on the same report. These inputs affect the emissions associated with compressed pipeline gas relative to pipeline gas.

2.2.5.2 Liquefied pipeline gas

We model the non-energy costs of liquefaction facilities at $.434/Gallons of Gasoline Equivalent (GGE) based on an analysis by the Gas Technology Institute （Gas Technology Institute，2004）. Additionally, we model the electricity use of liquefaction facilities using electric drive technologies at $3.34 kWh per GGE based on the same report. These inputs affect the emissions associated with liquefied pipeline gas relative to pipeline gas.

2.3 Liquid fuels

Liquid fuels are primarily fuels used for transportation and include diesel, gasoline, jet-fuel, and hydrogen as well as LPG. We model biofuel processes for both diesel fuel as well as gasoline that are described further in section 3. Jet-fuel and LPG are only supplied as conventional fossil fuels. The sections below discuss conventional fossil price projections as well as liquid hydrogen delivery.

2.3.1 FOSSIL FUELS

Conventional fossil fuel price projections are taken from the AEO 2013 reference case scenario. They include both commodity as well as delivery costs for fuels delivered to the Pacific census division.

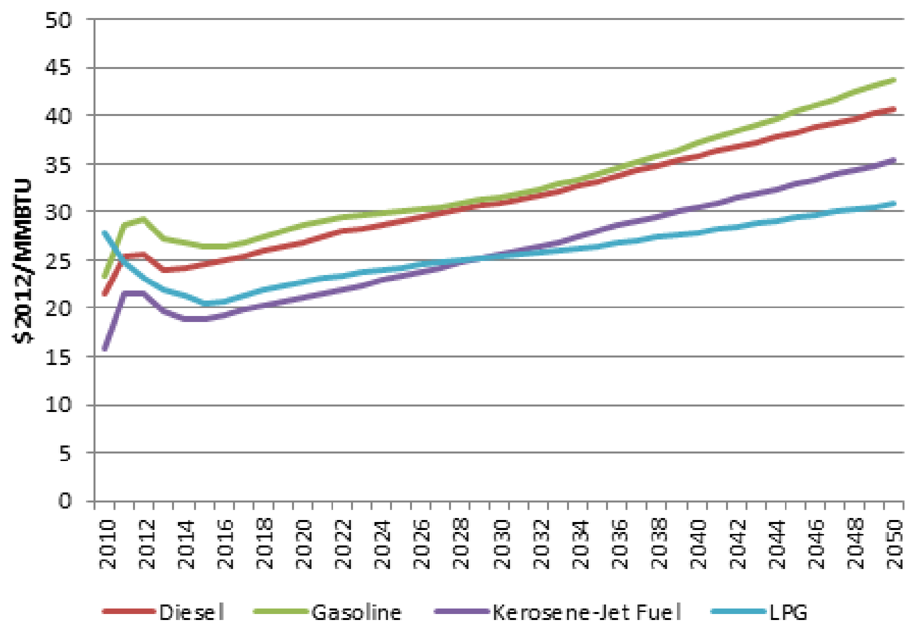

Figure 16. Fossil fuel price projections

2.3.2 LIQUID HYDROGEN

The hydrogen that is simply injected into the pipeline for distribution to end uses incurs no additional delivery costs in the model. The hydrogen that is liquefied for use in transportation, however, does incur delivery costs in addition to production costs. Delivery costs include liquefaction in a large scale plant, delivery by truck, and refueling. Parameter values for hydrogen delivery are based on H2A, as summarized in Table 20.

Table 20. Liquefied hydrogen delivery parameters.

Parameter	Value
Plant Life	30
Initial Year	2007
Initial Levelized Fixed Capacity Costs ($/kG-year)	1.01
Initial Efficiency (kWh/kg)	9.32
Forecast Levelized Fixed Capacity Costs ($/kG-year)	0.44
Forecast Year	2025
Forecast Efficiency (kWh/kg)	6.3
Production Feedstock	Electricity
Non-energy Variable Operating Costs ($/kG)	0
Capacity Factor	0.5

Levelized capital costs for the current year and 2030 were calculated based on the H2A delivery model, with the the rate of capital cost decline to 2030 assumed to follow the function

$$Cost_{Yr} = Cost_i * e^{\left[ln\left(\frac{Cost_f}{Cost_i}\right)*\frac{(Yr-Cost_i)}{(Yr_f-Yr_i)}\right]}$$

The overall levelized capital cost trajectory for liquefied hydrogen delivery is shown in **Error! Reference source not found.**.

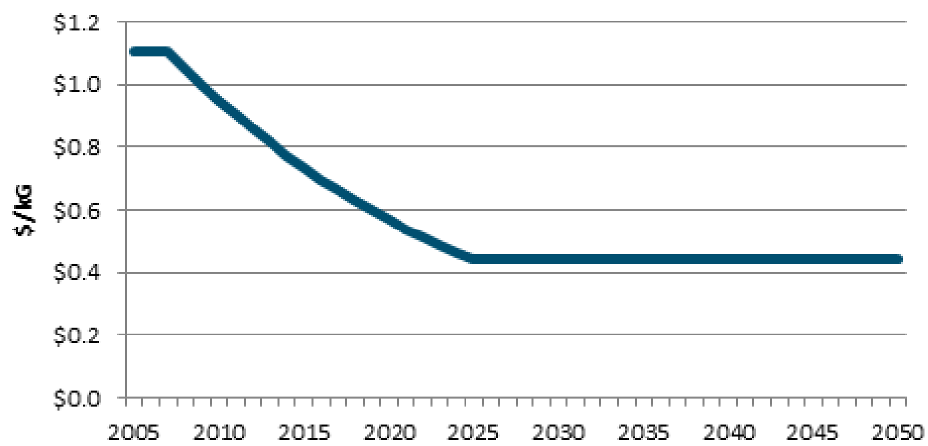

Figure 17. Levelized capital cost of liquefied hydrogen delivery, based on H2A

Forecast efficiency of delivery is taken from the H2A model and is assumed to improve over time. The improvement in process efficiency assumes a functional form identical to the cost reduction.

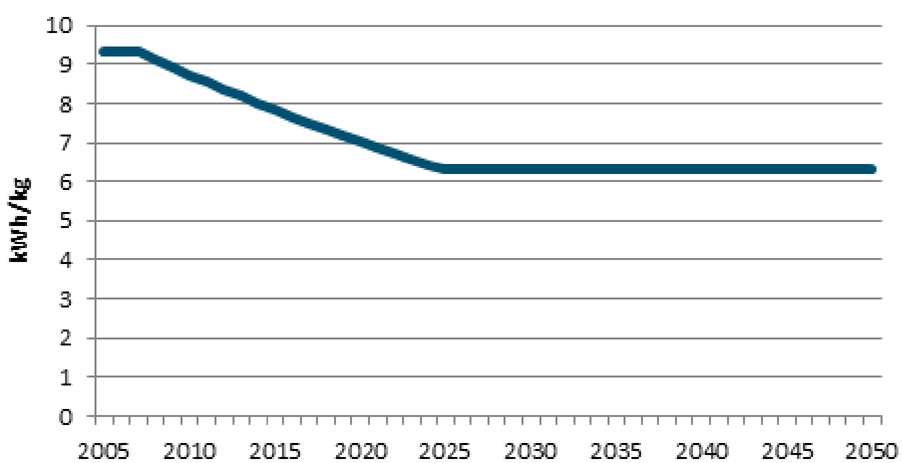

Figure 18. Liquefied hydrogen delivery efficiency, based on H2A.

As in the case of hydrogen production, the annual amount of delivered hydrogen is a user-defined input. Delivery capacity follows a basic stock roll-over model, with new capacity added as necessary to enable delivery. Delivery variable costs include electricity costs, based on the California average electricity rate.

2.3.3 REFINERY AND PROCESS GAS; COKE

We do not model any costs associated with refinery and process gas. We do model the costs of coke from the 2013 AEO Reference Case scenario （EIA, 2013）.

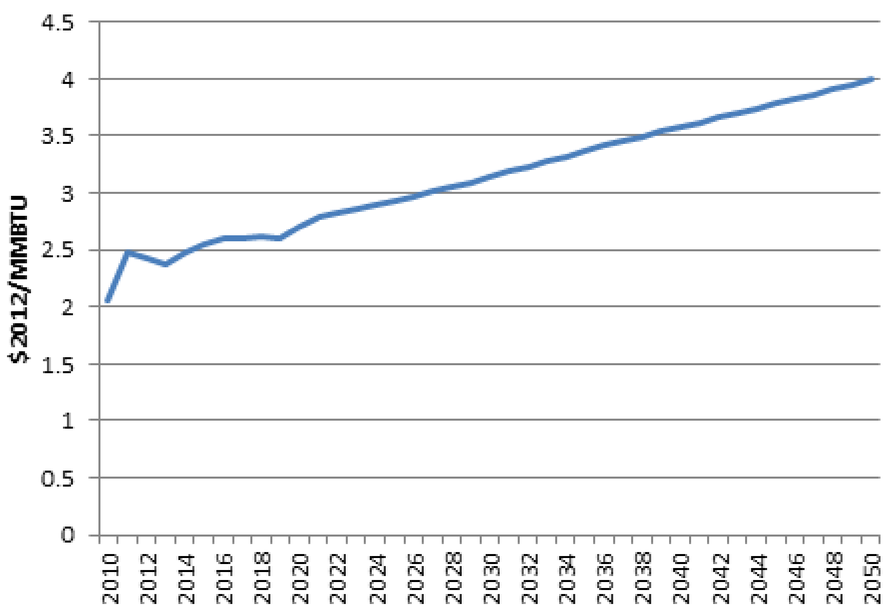

Figure 19. Petroleum coke price projection

3 Biomass

3.1 Resource assessments

The U.S. Department of Energy's 2011 Billion Ton Study Update (BT2) provides the most comprehensive analysis of biomass feedstock potential through 2030 for the United States. It provides a well-documented and publicly vetted foundation for analysis of the cost and magnitude of the US biomass resource base. However, there are a number of valid criticisms of the methods used that must be incorporated into a neutral assessment. Some of the most important critiques of the BT2 and their implications for long-term biomass supplies are described below.

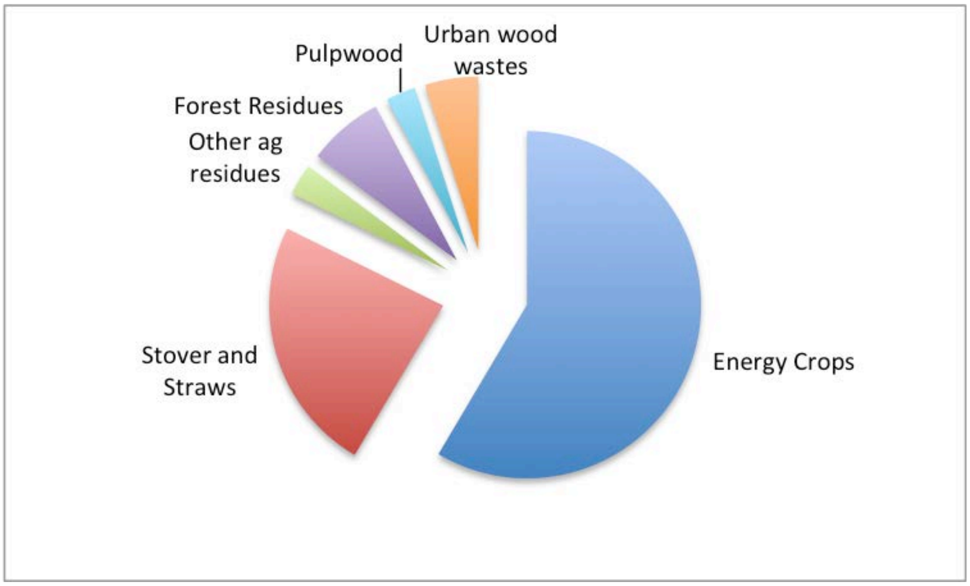

Figure 20. 2030 Billion Ton Study Update feedstock breakdown by weight at $80/ton. (Parker, 2011)

3.1.1 ENERGY CROPS

Energy crops are grown for the purpose of being used in energy production, and are chosen for high yields of biomass. They must compete with either conventional crops or pasture for land. The yield and production cost of an energy crop are therefore the two most important factors that impact its profitability and therefore whether it is competitive with incumbent land uses. The BT2 takes an optimistic view of both yields and costs in its baseline assessment and performs no sensitivity on more pessimistic parameter values.

On yield, modeled values used in BT2 are based on data from relatively small-scale trials on good agricultural lands. These yields are then used to represent the yield of an energy crop on all agricultural lands. Not surprisingly, in the modeling this leads to significant displacement of incumbent crops and pasture on marginally productive lands, but there is little evidence that the energy crop yields applied are representative of achievable yields on those marginal lands. This is a common assumption for large scale energy crop production in agricultural economic models. There is no way to systematically correct for this bias in the data.

The BT2 costs are optimistic relative to available estimates from university extension specialists who are advising farmers considering whether to grow these new crops (Duffy 1999; Wilkes 2007). Parker (2011) developed a production cost model that varied with yield based on the crop budget provided by Duffy. The costs are significantly higher especially at the high yields that are likely to induce adoption. The difference appears to be a large difference in the harvest cost and in how the harvest cost scales with yield. Based on the INL feedstock supply logistics model, the harvesting equipment is throughput limited at 2 tons per acre leading to no reductions in harvest costs as yield go over 2 tons per acre. On average, adding $17/ton of energy crop would bring the BT2 costs in line with the cost reported by extension specialists. This analysis applies to herbaceous energy crops. Further analysis would be needed to understand the quality of the woody energy crop estimate in BT2.

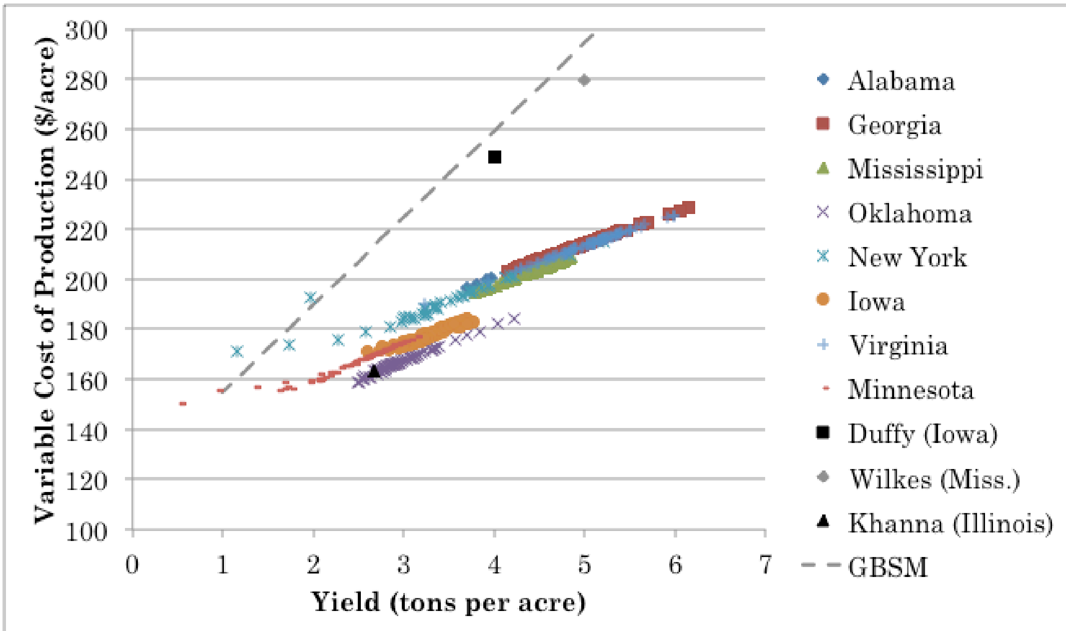

Figure 21. Variable production costs versus yield by region (Parker, 2011)

3.1.2 AGRICULTURAL RESIDUES

Agricultural residues are straws, stovers and other plant components remaining in the field after harvest of the crop. They play a role in maintaining soil health and preventing erosion (Lal, 2009; Wilhelm *et al.,* 2007). Limited removal of the residues has been proposed as a source of biomass. The scale of this resource potential depends on how much excess residues exist beyond what is required for soil maintenance, or on the existence of an economic alternative for providing the soil maintenance functions.

Muth *et al* (2012) provides the modeling basis for sustainable removal of the residues. Residues are available only if their removal will not increase soil erosion beyond the tolerable soil loss limit or cause soil organic carbon metrics to decline. This method has been questioned because its metrics for sustainability are weak, but it is a good estimate of maximum possible potential. At high prices, the BT2 estimate approaches this maximum.

3.1.3 FOREST RESIDUES

Woody biomass is available from forestry operations, and can come from three sources – integrated harvesting operations, “other forest removals,” and mill residues. Residues are also available from “other forest removals” including urban land clearing and cultural operations. Integrated harvesting operations produce residues as part of the management of the forest to produce high value timber products. Costs for this woody biomass are estimated based on the cost of road-siding and chipping, as well as a fraction of historical stumpage fees for the removal of small trees.

The BT2 forest residue assessment comes from the US Forest Service and is a fair assessment. One critique is that it requires historical logging operations in a region as a screen for whether the forests will be managed. This leads to ignoring some potentially important resources such as the beetle-kill region in Colorado and some overstocked forests in the East. On the other hand, in a resource assessment by the Union of Concerned Scientists (2012), “other forest removals” and thinnings were excluded due to concerns about the climate impact of whole-tree removal. These residue categories are an area for focused study based on a life-cycle assessment, which needs to account for the dynamics of forest growth and fire risk. Leaving out these categories from potential estimates is conservative.

3.1.4 CONVENTIONAL WOOD

Wood production for the pulp industry could be expanded or diverted to energy production if the price of biomass for energy is high enough. The BT2 estimate comes from Skog *et al* (2010). The quantity of pulpwood that would become available at higher prices from both increases in supplies and decreases in demand from pulp mills in response to the price shift were found using estimates of the elasticity of pulpwood supply. At a county level, increases in pulpwood supply are limited to not exceed annual timber growth. Displacement of current pulpwood uses is also limited to below 20% of 2007 use due to uncertainties in the elasticity estimates, especially the range over which they are valid.

3.1.5 MUNICIPAL WASTE

There is a significant resource of organic wastes that are currently disposed of in the municipal waste stream. The MSW resource is not fully counted in BT2, as only woody MSW resources are counted in BT2. Other resources that are not currently included could play a role. Of particular interest are food wastes and green wastes (yard wastes) that are already seeing some market in anaerobic digesters for energy production and waste diversion purposes. The scale of the current food waste and yard waste disposal is 30% of the wood waste stream.

Table 21. Comparison of 2030 Biomass Resource Assessments (Parker, 2014)

Feedstock	BT2 ($80/ton)	Khanna ($90/ton)	Muth (baseline)	Muth (all no till)	UCS ($60/ton)
Energy Crops	512	350-650			400
Stover and Straws	208	187-197	228.70	327.25	129
Other Ag Residues	26				26
Forest Residues	62				21
Pulpwood	24				-
Urban wood wastes	43				43

3.1.6 SUMMARY

The Billion Ton Study update is a generally good source for a reasonable estimate of long-run biomass supply in the United States, given the critiques mentioned above. Its estimates for the most part fall in line with other estimates that have been made Table 21. The principal objection is that the prices for biomass in BT2 are too low. The National Academies of Science's report on the Renewable Fuel Standard (RFS) has a significantly higher estimate of the price that biomass providers would be willing to accept. These numbers suggest that prices 10-50% higher would be required to deliver the resource potential in BT2 at $80/ton (Table 22).

Table 22. Required feedstock prices from NAS (2011) (Parker 2014)

Feedstock	Farmer's Willingness-to-Accept ($/dry ton)
Stover (CS)	$92
Stover-Alfalfa	$92
Alfalfa	$118
Switchgrass (MW)	$133
Switchgrass (MW LQ)	$126
Switchgrass (App)	$100
Switchgrass (SC)	$98
Miscanthus (MW)	$115
Miscanthus (MW LQ)	$119
Miscanthus (App)	$105
Wheat Straw	$75
SRWC	$89

3.2 Biomass transport costs

The cost of transporting biomass to biorefineries will depend on the optimal size of the biorefinery, the moisture content of the feedstock, the spatial layout of the resource, and the cost of trucking (fuel, etc). The Geospatial Bioenergy Systems Model (GBSM) optimizes the layout of the biofuels industry for a given resource base, set of conversion technologies, and fuel markets. In a case study of the 2022 RFS mandate, Parker found that the average transport cost for woody biomass was significantly higher than herbaceous biomass in an optimized system for producing biofuels. These are reasonable estimates for the average transport costs. They will be high for technologies that can operate at small scale, like anaerobic digestion, and they will be low for very large centralized production. They do match the conversion costs in terms of the assumed scale of the biorefineries.

Table 23. Biomass transport costs by feedstock type based on Parker (2012)

Feedstock Type	Avg. Transport Cost ($/dry ton)
Woody	26.71
Straws/grasses/stovers	9.89

3.3 Biomass conversion technologies

Biomass can be converted to fuels or electricity to serve all energy markets. Processes exist to convert biomass to compete in the gasoline market, the diesel market, the jet fuel market, the natural gas market and the electricity market. A few of these technologies are currently in use, but many bioenergy conversion technologies are not currently commercial. To assess the potential process efficiency and cost of these technologies, cost models are based on simulations of the biorefinery. These studies have obvious limitations but are the best available information. Table 3 shows a summary of conversion process efficiencies and costs.

Table 24. Summary of conversion technology performance and cost (Parker, 2014 based on Rhodes, 2005, and CEC cost of generation)

Pathway			Yield			Conversion Cost ($/dry ton)	
Feedstock Group	Conversion Technology	Fuel	Basis	Estimate	Range	2020 est.	2020 range
Cellulosics	AD	NG	gge/ton	77.5	32-112	$185	167-205
Cellulosics	Gasification	NG	HHV	66%	66-73	$124	118-165
Cellulosics	IGCC	Electricity	HHV	32%	30-35%	$132	
Cellulosics	Solid fuel Combustion	Electricity	HHV	25%	20-35%	$120	94-172
Cellulosics	Enzymatic Hydrolysis	Ethanol	Theoretical Ethanol	76%	67-82%	$120	83-166
Cellulosics	F-T Diesel	Diesel	HHV	42%	39-50%	$185	115-220
Cellulosics	Fast Pyrolysis	Diesel	HHV	36%	24-50%	$80	50-103
Cellulosics	Fast Pyrolysis	Jet fuel	HHV	36%	24-50%	$80	50-103
Cellulosics	Fast Pyrolysis	Gasoline	HHV	36%	24-50%	$80	50-103
Lipids (biodiesel precursors)	Hydro-treatment	Diesel	gge/ton	256	267-305 gge/ton	$314	150-
Lipids (biodiesel precursors)	Hydro-treatment	Jet fuel	gge/ton	248	267-305 gge/ton	$345	75-150
Manure	AD	NG	gge/ton	87	55-111	$40	30-40

3.3.1 RENEWABLE METHANE

The production of methane or renewable natural gas from biomass can follow two potential routes: anaerobic digestion and gasification combined with methane synthesis. The choice between the two appears to be mainly driven by moisture content, feedstock biodegradability, and cost. Anaerobic digestion is a technology that is currently in use for waste and residue feedstocks such as manures, waste water, and food wastes. In these cases, anaerobic digestion is used largely as a waste management technology that happens to produce energy.

More sophisticated anaerobic digester processes are under development to maximize the energy yield. The gasification and synthesis route is not currently commercial. Commercial projects exist for coal gasification and synthesis to methane, which is a similar process (Kopyscinski, 2010).

Anaerobic digestion is a complex biological process with four steps: hydrolysis, acidogenesis, acetogenesis, and methanation. The carbohydrates, proteins, and fats in biomass are broken down into simple sugars, amino acids, and fatty acids during hydrolysis. Through acidogensis, acetogenesis and methanation, these hydrolysis products are converted to methane and carbon dioxide following a few different paths. The effectiveness of anaerobic digestion depends on the biodegradability of the feedstock. Feedstocks with high lignin content or crystalline cellulosic structure are difficult to break down. Pretreatment of these feedstocks to make the carbohydrates available to the hydrolase enzymes can lead to good yields (Chandra, 2012). The AD technology is modeled based on Krich *et al* (2005) for manures and Shafiei *et al* (2013) for cellulosic feedstocks. The yield of methane is highly variable with reports of between 85 and 550 m^3 of CH_4 per dry ton depending on feedstock and study. The 77.5 gge/ton value suggested corresponds to approximately 265 m^3 of CH_4 per dry ton and is the reported yield for wheat straw with pretreatment.

The gasification route breaks down biomass into a syngas comprised mainly of hydrogen and carbon monoxide in a hot oxygen starved environment. The syngas is then converted to methane through a series of three synthesis reactors. The process is reported to be highly efficient, converting approximately 66% of the energy content of biomass into methane. A small amount of co-product electricity and a high quality waste heat stream can make the overall efficiency approach 80% if it can be co-located with a heat load. Only a few studies have assessed the economics of this pathway. They estimate the cost of production between \$2.55-3.65/gge at scales that seem reasonable in the next decade (Glassner, 2009; Tuna, 2014). Like most thermochemical PATHWAYS, the cost of the gasification route is heavily dependent on scale economies, with scale-up potentially leading to cost reductions of 20% or more.

3.3.2 CELLULOSIC ETHANOL

Ethanol production from cellulosic biomass is not currently a commercially viable technology. Estimates for the cost of production rely on a number of engineering studies with process-level modeling of the biorefinery. The majority of studies of cellulosic ethanol consider the biochemical pathway in which the cellulose and hemicellulose are converted to sugars through enzymatic hydrolysis and saccharification, and then fermented to make ethanol. Tao and Aden considered the thermochemical pathway via gasification and synthesis, and found the cost and performance to be similar to the biochemical pathway at a scale of 45 million gallons of ethanol per year (Tao and Aden, 2009). The biochemical route is taken to be the model cellulosic ethanol technology due to the larger base of supporting literature. The thermochemical pathway may prove to be the better technology in certain cases, but given the overall uncertainty in the technology costs and performance the performance of the thermochemical pathway is assumed to fall within the study range.

The biochemical pathway begins with feedstock pretreatment to make the cellulose available to the enzymes. There are a number of techniques under research and development for this pretreatment, including dilute acid hydrolysis, ammonia fiber explosion, liquid hot water, and steam explosion. In the process of exposing the cellulose, the hemicellulose is broken into its component sugars (xylose, arabinose, etc.). The exposed cellulose is then converted to glucose with cellulase enzymes. Glucose is fermented to ethanol and the 5-carbon sugars are fermented to ethanol either in a combined reactor using recombinant *Zymomonas mobilis* or in separate reactors using yeast for the C6 sugars and *Z. mobilis* for the C5 sugars. In the advanced designs of Laser *et al.* (2010) and Hamelinck *et al.* (2005) a consolidated bioprocessing (CBP) approach is taken where all biological conversions (enzyme production, enzymatic hydrolysis, and fermentation) occur in the same reactor. This design is attractive but the catalyst to make it possible has yet to be identified. In most designs, the lignin is separated from the beer, dried, and combusted to produce steam and electricity for the biorefinery, with some net export of electricity.

There is a large range of projected costs using “current” technology. There are three main sources of variation in the costs estimates. First is the expected yield of ethanol from cellulosic material. Estimates range from 52.4 gallons per ton to 76.4 gallons of ethanol per dry ton of switchgrass or corn stover. This variation is due to difference in the performance of the pretreatment, cellulase enzymes, and fermentation organisms each study assumes. Dutta *et al.* (2010) and Kazi *et al.* (2010) use experimentally verified performance measures and show the highest production costs. The second source of variation is the capital investment required. This is due to the variety of configurations studied, as well as yield differences. Within the same study, capital costs varied by 42% due to different configurations of pretreatment, hydrolysis, fermentation, and distillation (Kazi *et al.*, 2010). The third factor is the variable operating cost – mainly the cost of cellulase enzymes. For example, Aden (2008) projects cellulase enzymes available at $0.32/gal of ethanol where Kazi *et al.* (2010) puts the cost at $1.05/gal. Also of interest is that the estimate for year 2000 technology in Wooley *et al.* (1999) falls below the more recent estimates of current costs, demonstrating that as more is learned about these technologies, limitations are identified that lead to additional costs.

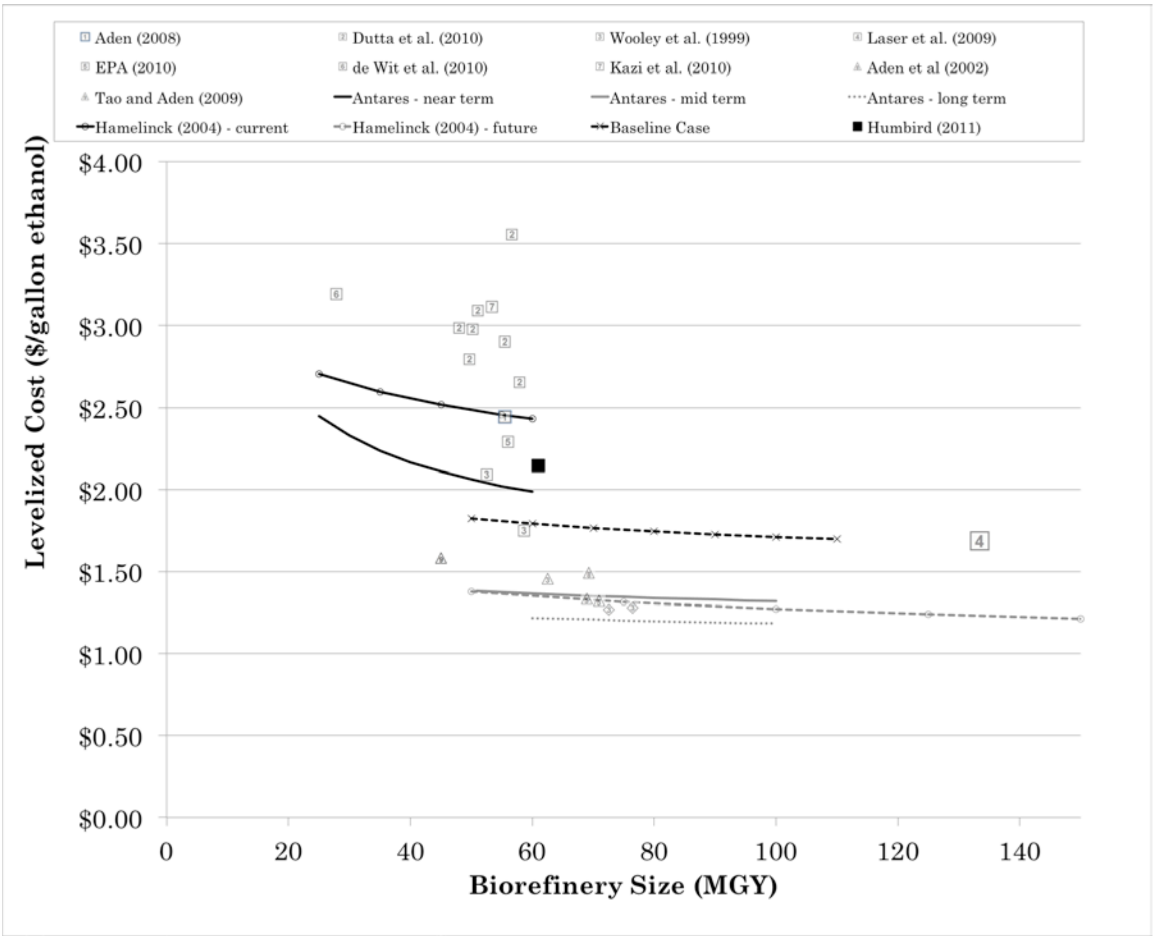

Figure 22. Comparison of estimated levelized cost of production for cellulosic ethanol. Near term technology assessments are represented by squares, mid-term technology (7-15 years ahead) are triangles; long-term projections are shown as diamonds. (Parker, 2014)

The yield for biochemical ethanol is presented as a percentage of maximum theoretical yield. The maximum theoretical yield is the production of ethanol if all the component sugars in the cellulose and hemicellulose fractions of biomass are fully converted to ethanol. The theoretical yield ranges from 73 to 122 gallons per dry ton for the feedstocks considered here. The range shrinks to 100-117 gallons per ton if considering only feedstocks with a large potential (corn stover, wheat straw, energy crops, and woody resources). Studies show a range of actual yields between 67% and 82% of the maximum theoretical yield. The equation for calculating ethanol yield for a given feedstock composition is below.

$$\boldsymbol{Yield}\left(\frac{\boldsymbol{gal}}{\boldsymbol{ton}}\right) = (\mathbf{1.11} * \boldsymbol{Cellulose\ fraction} * \%\boldsymbol{cellulose\ conversion} + \mathbf{1.136} * \boldsymbol{Hemicellulose\ fraction} * \%\ \boldsymbol{hemicellulose\ conversion}) * \mathbf{0.51} * \mathbf{2000/6.55}$$

Where: Cellulose fraction = fraction of dry matter that is cellulose

Hemicellulose fraction = fraction of dry matter that is hemicellulose

$$\%\ \text{cellulose conversion} = \frac{\boldsymbol{actual\ yield\ of\ cellulose\ to\ ethanol}}{\boldsymbol{theoretical\ yield}}$$

$$\%\ \text{hemicellulose conversion} = \frac{\boldsymbol{actual\ yield\ of\ hemicellulose\ to\ ethanol}}{\boldsymbol{theoretical\ yield}}$$

3.3.3 FISCHER-TROPSCH DISTILLATE FUELS

Thermochemical conversion of biomass to fuels can take many routes. The Fischer-Tropsch synthesis process is among the most studied and furthest developed. Commercial facilities exist or have existed in the past for production of F-T fuels from both coal and natural gas. Advances in biomass gasifiers and the optimizing of gas clean-up and the F-T synthesis process for biomass-based synthesis gas will be required for commercialization. A number of biomass gasifier configurations have been studied, the details of which can be found in Hamelinck *et al.* (2004), Larson *et al.* (2009) and Swanson *et al.* (2010).

There is a large range in the projected cost for current technology F-T diesel production. This represents disagreement on which technologies are current and which are unproven, as well as difference in design. The Swanson study states that hot gas clean up (tar cracking) is not yet commercial while all other studies employ it is if it were commercial. The Antares study uses an indirectly fired atmospheric gasifier, while most others use pressurized oxygen blown directly fired gasifiers. In projecting future technology versus current technology, Hamelinck *et al.* (2004) foresees no changes in the design but projects reductions in capital and operating costs due to incremental improvements and increases in scale. Larson *et al.* (2009) presents a case with mature technology where a once-through configuration is designed for greater electricity production than found in other studies. The EPA projection is significantly lower compared to other studies at similar scale and timeframe (EPA, 2010). Little information was provided to support this estimate.

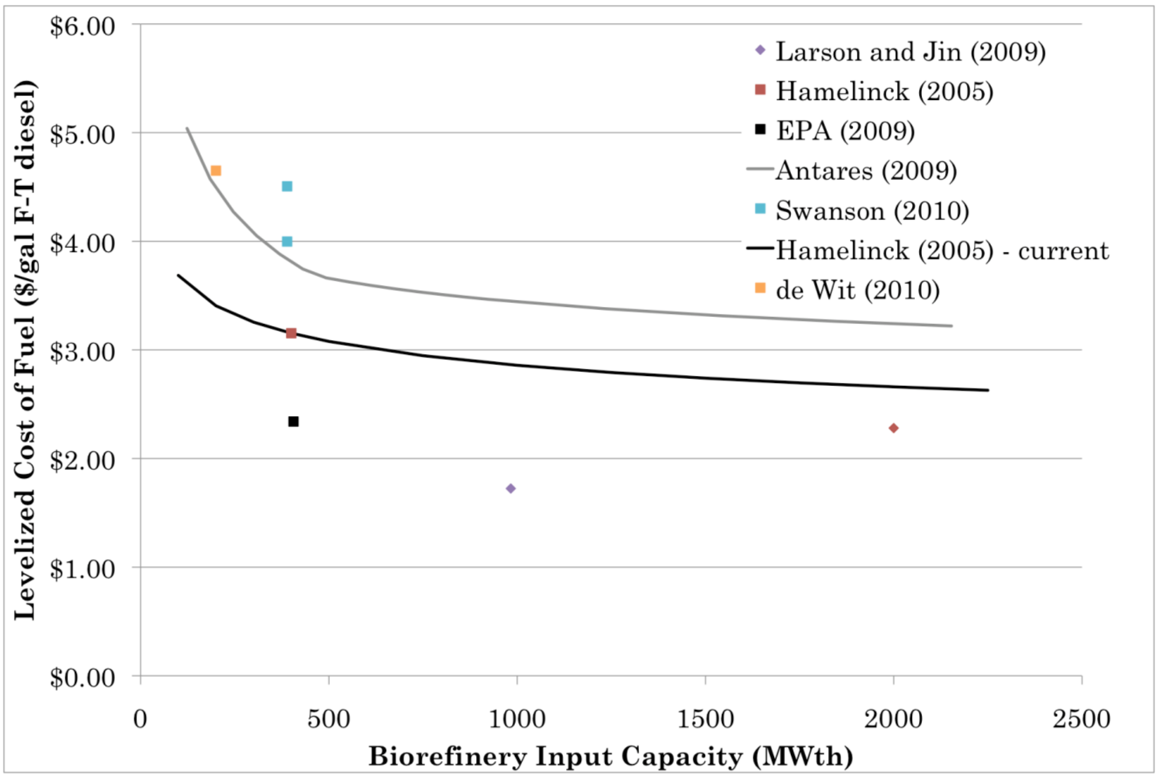

Figure 23. Comparison of estimated levelized cost of production for Fischer-Tropsch diesel technologies. Near term technology assessments are represented by squares, mid-term technology (7-15 years ahead) are triangles; long-term projections are shown as diamonds. (Parker, 2014)

3.3.3.1 Fast pyrolysis of cellulosic biomass to hydrocarbons

Fast pyrolysis of cellulosic biomass generates a crude bio-oil that then must be upgraded using petroleum refinery technologies. This technology can produce a range of hydrocarbons with some control over the fraction that goes to gasoline, diesel, and jet fuel. Upgrading this method requires hydrogen, and there have been two designs considered for fast pyrolysis; one in which he hydrogen is produced from the bio-oil itself and another in which the hydrogen is produced from natural gas. The technologies shown here all assume the hydrogen is produced from the bio-oil to simplify accounting in the model. One fast pyrolysis biorefinery at pre-commercial scale began operations in 2013. Wright *et al* (2010) found that hydrocarbon fuels could be produced via fast pyrolysis at between $2.60 and $3.75 per gallon.

3.3.3.2 Lipid (fats and oils) to diesel or jet fuels

Conversion of lipids to diesel replacement fuels is currently performed using a transesterfication process to create fatty acid methyl esters (FAME) or conventional biodiesel. Emerging technologies seek to create a hydrocarbon fuel that can be freely blended with diesel through a hydrotreatment process. These two technologies can be modeled as competitors for the lipid feedstocks, or one can be chosen as representative. The hydrotreatment technology is presented here due to its flexibility in meeting diesel and jet demands.

Techno-economic analyses of the hydrotreatment process are based on the UOP/Eni process (Holmgren *et al.*, 2007). In the process, the lipids and hydrogen pass through a hydroprocessing unit in which the oxygen is stripped from the lipids through decarboxylation and hydrodeoxygenation reactions. The resulting products are a combination of “green diesel” and lighter hydrocarbons (naphtha and/or propane) with byproducts of water and carbon oxides (CO and CO_2). The green diesel fuel is reported to have a number of desirable properties – high cetane number (70-90), energy density equivalent to ultra-low sulfur diesel, sulfur content of less than 1 ppm (USLD < 10 ppm sulfur), and good stability. Holmgren *et al* (2007) identify the potential to use green diesel as a premium blendstock allowing for the use of lower valued light-cycle oil as part of a diesel blend.

The Antares model considers two configurations for the hydrotreatment process; one as a stand-alone unit within a petroleum refinery and one as co-processing within the same hydroprocessing units as petroleum products. The stand-alone units have higher capital costs but lower hydrogen demand and higher green diesel yields. The coprocessing design has higher hydrogen requirements because the hydroprocessing units for crude oil operate in conditions that favor the hydrodeoxygenation reactions over the decarboxylation reactions, which consume 3.75 times the hydrogen per oxygen removed (Antares, 2009).

The EPA's estimate of the cost of hydrotreament-based diesel is slightly higher than the Antares model. The EPA model is based on the stand-alone design but assumes higher hydrogen consumption (0.224 lb/gal compared to 0.117 lb/gal) (EPA, 2010). The higher hydrogen cost is offset somewhat by an assumed lower capital and operating expenses besides hydrogen.

Pearlson *et al* (2013) provided an updated estimate with a distinction between diesel and jet fuel facilities. The jet fuel facilities require more hydrogen and produce less distillate fuel overall, as more fuel falls in the naphtha range. The costs are significantly higher than earlier estimates.

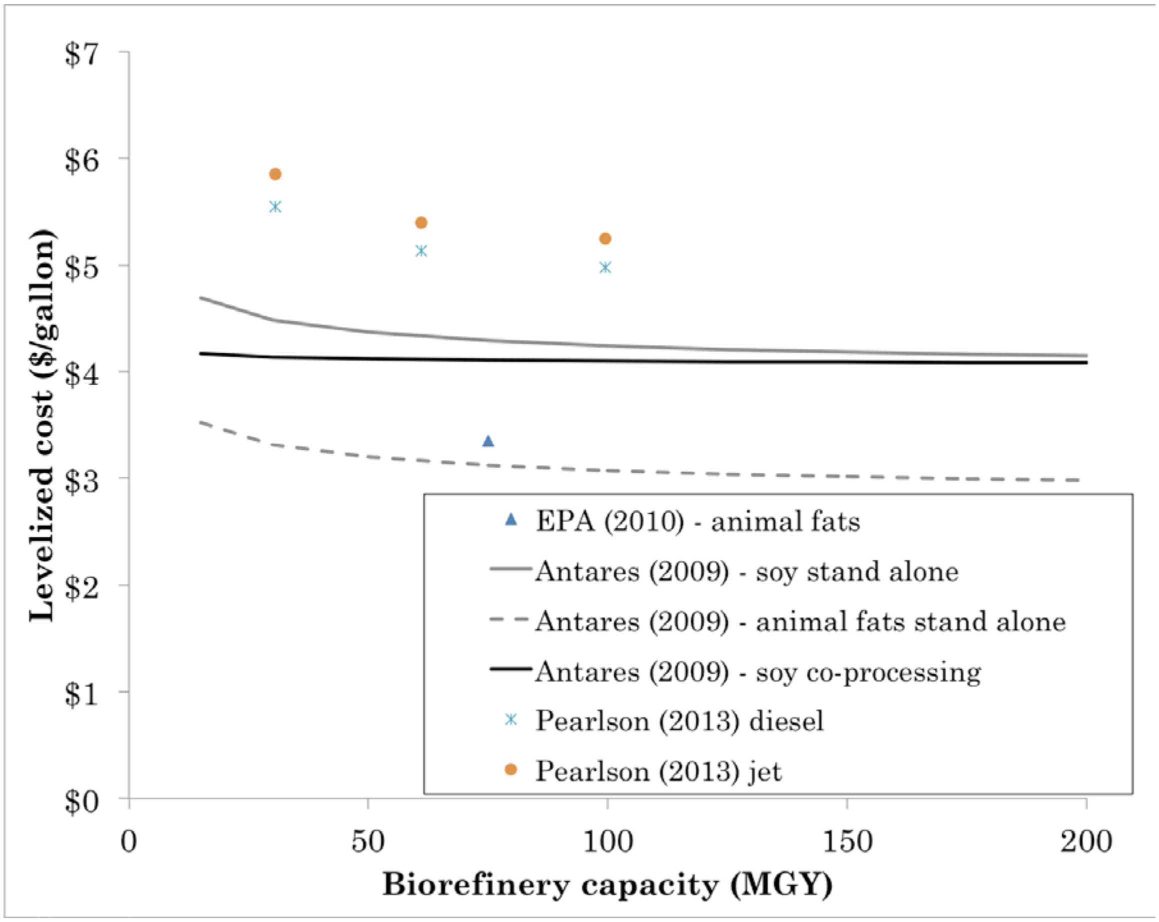

Figure 24. Comparison of estimated levelized cost of production for hydrotreatment of lipids to distillate fuels. All estimates are for mid-term technologies (7 – 15 years ahead) (Parker, 2014)

Table 25. Biomass feedstock composition and theoretical ethanol yield

Feedstock	PATHWAYS Category	HHV (GJ/tonne)	Cellulose	Hemi-cellulose	Lignin	Theoretical ethanol yield (gal/ton)	Theoretical ethanol yield (gge/ton)
Barley straw	Solids	16.1	33%	20%	17%	93	61
Corn stover	Solids	17.1	36%	23%	19%	104	68
Oat straw	Solids	17.9	38%	23%	13%	106	70
Sorghum stubble	Solids	17.6	35%	24%	25%	103	68
Wheat straw	Solids	17.9	34%	23%	14%	100	66
Annual energy crop	Solids	17.6	49%	18%	23%	117	77
Perennial grasses	Solids	18.1	32%	25%	18%	100	66
Woody crops	Solids	19.5	45%	19%	26%	110	72
Composite	Solids	19.0	45%	22%	28%	116	76
Removal residue	Solids	19.0	45%	22%	28%	116	76
Conventional wood	Solids	19.0	45%	22%	28%	116	76
Treatment thinnings	Solids	19.0	45%	22%	28%	116	76
Secondary mill residue	Solids	20.2	45%	22%	28%	116	76
Primary mill residue	Solids	20.2	45%	22%	28%	116	76
Urban wood waste other	Solids	18.4	45%	19%	26%	110	72
Urban wood MSW	Solids	18.4	45%	19%	26%	110	72
Cotton gin trash	Solids	16.0	41%	15%	29%	98	64
Cotton residue	Solids	16.0	31%	11%	28%	73	48
Manure	Biogas Precursors					-	-
Orchard and vineyard prunings	Solids	17.8	45%	19%	26%	110	72
Rice hulls	Solids	16.8	40%	19%	25%	103	68
Rice straw	Solids	15.1	39%	20%	23%	102	67
Sugarcane trash	Solids	17.8	45%	25%	18%	122	80
Wheat dust	Solids	16.8	36%	18%	16%	94	62

Fuelwood	Solids	19.0	45%	22%	28%	116	76
Mill residue	Solids	20.2	45%	22%	28%	116	76
Pulping liquors	Solids	15.0				-	-
Existing forest MSW	Solids	18.4	45%	19%	26%	110	72
Existing biodiesel precursors	Biodiesel Precursors					-	-
Existing Agricultural MSW	Solids	14.0	50%	7%	11%	99	65

4 Biomass References

Aden, A. (2008). Biochemical Production of Ethanol from Corn Stover : 2007 State of Technology Model Biochemical Production of Ethanol from Corn Stover : 2007 State of Technology Model, (May).

Aden, A., Ruth, M., Ibsen, K., Jechura, J., Neeves, K., Sheehan, J., … Lukas, J. (2002). *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehyd*.

Arbogast, S., Bellman, D., Paynter, J. D., & Wykowski, J. (2013). Advanced biofuels from pyrolysis oil…Opportunities for cost reduction. *Fuel Processing Technology*, *106*, 518–525. doi:10.1016/j.fuproc.2012.09.022

Antares. (2009). National Biorefinery Siting Model Draft Final Report – Task 2 Technologies for Biofuels Production.

Bledzki, A. K., Mamun, A. a., & Volk, J. (2010). Physical, chemical and surface properties of wheat husk, rye husk and soft wood and their polypropylene composites. *Composites Part A: Applied Science and Manufacturing*, *41*(4), 480–488. doi:10.1016/j.compositesa.2009.12.004

Brown, T. R., Thilakaratne, R., Brown, R. C., & Hu, G. (2013). Regional differences in the economic feasibility of advanced biorefineries: Fast pyrolysis and hydroprocessing. *Energy Policy*, *57*, 234–243. doi:10.1016/j.enpol.2013.01.058

Chandra, R., Takeuchi, H., & Hasegawa, T. (2012). Methane production from lignocellulosic agricultural crop wastes: A review in context to second generation of biofuel production. *Renewable and Sustainable Energy Reviews*, *16*(3), 1462–1476. doi:10.1016/j.rser.2011.11.035

Demirbas, A. (2002). Pyrolysis and steam gasification processes of black liquor, *43*, 877–884.

Duffy, M. D., & Vontalge, A. L. (1999). Estimated costs of crop production in Iowa, 1999.

Dutta, A., Dowe, N., Ibsen, K. N., Schell, D. J., & Aden, A. (2009). An economic comparison of different fermentation configurations to convert corn stover to ethanol using Z. mobilis and Saccharomyces. *Biotechnology Progress*, *26*(1), 64–72. doi:10.1002/btpr.311

Dutta, A., Talmadge, M., Hensley, J., Worley, M., Dudgeon, D., Barton, D., … Hess, J. (2011). *Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol Thermochemical Pathway by Indirect Gasification and Mixed Alcohol Synthesis*.

Dwivedi, P., Alavalapati, J. R. R., & Lal, P. (2009). Cellulosic ethanol production in the United States: Conversion technologies, current production status, economics, and emerging developments. *Energy for Sustainable Development*, *13*(3), 174–182. doi:10.1016/j.esd.2009.06.003

Foust, T. D., Aden, A., Dutta, A., & Phillips, S. (2009). An economic and environmental comparison of a biochemical and a thermochemical lignocellulosic ethanol conversion processes. *Cellulose*, *16*(4), 547–565. doi:10.1007/s10570-009-9317-x

Gassner, M., & Maréchal, F. (2009). Thermo-economic process model for thermochemical production of Synthetic Natural Gas (SNG) from lignocellulosic biomass. *Biomass and Bioenergy*, *33*(11), 1587–1604. doi:10.1016/j.biombioe.2009.08.004

Hamelinck, C., Faaij, a, Denuil, H., & Boerrigter, H. (2004). Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential. *Energy*, *29*(11), 1743–1771. doi:10.1016/j.energy.2004.01.002

Hamelinck, C. N. (2004). *OUTLOOK FOR ADVANCED BIOFUELS*.

Hamelinck, C. N., Hooijdonk, G. van, & Faaij, A. P. C. (2005). Ethanol from lignocellulosic biomass: techno-economic performance in short-, middle- and long-term. *Biomass and Bioenergy*, *28*(4), 384–410. Retrieved from http://www.sciencedirect.com/science/article/B6V22-4F320KP-1/1/6f03b6163c5c4128eafef42d9b74f8b3

Huang, H.-J., Ramaswamy, S., Al-Dajani, W., Tschirner, U., & Cairncross, R. a. (2009). Effect of biomass species and plant size on cellulosic ethanol: A comparative process and economic analysis. *Biomass and Bioenergy*, *33*(2), 234–246. doi:10.1016/j.biombioe.2008.05.007

Humbird, D., Davis, R., Tao, L., Kinchin, C., Hsu, D., Aden, A., … Dudgeon, D. (2011). *Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol*.

Jeoh, T. (1998). Steam Explosion Pretreatment of Cotton Gin Waste for Fuel Ethanol Production by.

Kazi, F. K., Fortman, J. a., Anex, R. P., Hsu, D. D., Aden, A., Dutta, A., & Kothandaraman, G. (2010). Techno-economic comparison of process technologies for biochemical ethanol production from corn stover. *Fuel*, *89*, S20–S28. doi:10.1016/j.fuel.2010.01.001

Khanna, M., Chen, X., Huang, H., & Onal, H. (2010). SUPPLY OF CELLULOSIC BIOFUEL FEEDSTOCKS AND Regional Production Patterns. In *Agricultural & Applied Economics Assiociation*.

Kopyscinski, J., Schildhauer, T. J., & Biollaz, S. M. a. (2010). Production of synthetic natural gas (SNG) from coal and dry biomass – A technology review from 1950 to 2009. *Fuel*, *89*(8), 1763–1783. doi:10.1016/j.fuel.2010.01.027

Kwiatkowski, J. R., McAloon, A. J., Taylor, F., & Johnston, D. B. (2006). Modeling the process and costs of fuel ethanol production by the corn dry-grind process. *Industrial Crops and Products*, *23*(3), 288–296. doi:10.1016/j.indcrop.2005.08.004

Liu, G., Larson, E. D., Williams, R. H., Kreutz, T. G., & Guo, X. (2011). Making Fischer−Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis. *Energy & Fuels*, *25*(1), 415–437. doi:10.1021/ef101184e

Marsh, M., Officer, C. E., Krich, K., Krich, K., Augenstein, D., Benemann, J., … Salour, D. (2005). Biomethane from Dairy Waste A Sourcebook for the Production and Use of, (July).

Muth, D. J., Bryden, K. M., & Nelson, R. G. (2013). Sustainable agricultural residue removal for bioenergy: A spatially comprehensive US national assessment. *Applied Energy*, *102*, 403–417. doi:10.1016/j.apenergy.2012.07.028

National Academies of Sciences. (2011). *Renewable Fuel Standard : Potential Economic and Environmental Effects of U . S . Biofuel Policy Committee on Economic and Environmental Impacts of Increasing Biofuels*.

Pearlson, M., Wollersheim, C., Hileman, J., & August, R. (2013). Modeling and Analysis A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production, 89–96. doi:10.1002/bbb

Piccolo, C., & Bezzo, F. (2009). A techno-economic comparison between two technologies for bioethanol production from lignocellulose. *Biomass and Bioenergy*, *33*(3), 478–491. doi:10.1016/j.biombioe.2008.08.008

Pütün, A. E., Özbay, N., Önal, E. P., & Pütün, E. (2005). Fixed-bed pyrolysis of cotton stalk for liquid and solid products. *Fuel Processing Technology*, *86*(11), 1207–1219. doi:10.1016/j.fuproc.2004.12.006

Rhodes, J. S., & Keith, D. W. (2005). Engineering economic analysis of biomass IGCC with carbon capture and storage. *Biomass and Bioenergy*, *29*(6), 440–450. doi:10.1016/j.biombioe.2005.06.007

Searle, S. Y., & Malins, C. J. (2014). Will energy crop yields meet expectations? *Biomass and Bioenergy*, 1–10. doi:10.1016/j.biombioe.2014.01.001

Shafiei, M., Kabir, M. M., Zilouei, H., Sárvári Horváth, I., & Karimi, K. (2013). Techno-economical study of biogas production improved by steam explosion pretreatment. *Bioresource Technology*, *148*, 53–60. doi:10.1016/j.biortech.2013.08.111

Silverstein, R. a, Chen, Y., Sharma-Shivappa, R. R., Boyette, M. D., & Osborne, J. (2007). A comparison of chemical pretreatment methods for improving saccharification of cotton stalks. *Bioresource Technology*, *98*(16), 3000–11. doi:10.1016/j.biortech.2006.10.022

Swanson, R. M., Platon, A., Satrio, J. a., & Brown, R. C. (2010). Techno-economic analysis of biomass-to-liquids production based on gasification. *Fuel*, *89*, S11–S19. doi:10.1016/j.fuel.2010.07.027

Tunå, P., & Hulteberg, C. (2014). Woody biomass-based transportation fuels – A comparative techno-economic study. *Fuel*, *117*, 1020–1026. doi:10.1016/j.fuel.2013.10.019

Union of Concerned Scientists (UCS). (2012). Clean Power and Fuel — If Handled Right.

Villanueva Perales, a. L., Reyes Valle, C., Ollero, P., & Gómez-Barea, a. (2011). Technoeconomic assessment of ethanol production via thermochemical conversion of biomass by entrained flow gasification. *Energy*, *36*(7), 4097–4108. doi:10.1016/j.energy.2011.04.037

Wilkes, H. L., & Jackson, M. S. Jamie L. Whitten Plant Materials Center 2007 Annual Technical Report.

Wooley, R., Ruth, M., Sheehan, J., Majdeski, H., & Galvez, A. (1999). Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current D, (July).

Wright, M., Daugaard, D., Satrio, J., & Brown, R. (2010). Techno-Economic Analysis of Biomass Fast Pyrolysis to Transportation Fuels. *Fuel*, (November). Retrieved from http://www.sciencedirect.com/science/article/pii/S0016236110003765

Wright, M. M., Daugaard, D. E., Satrio, J. A., & Brown, R. C. (2010). Techno-economic analysis of biomass fast pyrolysis to transportation fuels. *Fuel*, *89*(null), S2–S10. doi:10.1016/j.fuel.2010.07.029

Yu, J., Zhang, J., He, J., Liu, Z., & Yu, Z. (2009). Combinations of mild physical or chemical pretreatment with biological pretreatment for enzymatic hydrolysis of rice hull. *Bioresource Technology*, *100*(2), 903–8. doi:10.1016/j.biortech.2008.07.025

5 Stock Characterization and Demand Projection References

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Residential	Water Heating	2009 RASS		2009 RASS; California Appliance Standards	DOE Residential Heating Products Final Rule Technical Support Documents	DOE Residential Heating Products Final Rule Technical Support Documents	CEC Energy Demand Forecast
Residential	Space Heating	2009 RASS		2009 RASS; California Appliance Standards	DOE Life Cycle Cost Spreadsheet DHE Equipment; DOE Furnace and Central Air Conditioners and Heat Pump Life Cycle Cost and Payback Period Spreadsheets	DOE Life Cycle Cost Spreadsheet DHE Equipment; DOE Furnace and Central Air Conditioners and Heat Pump Life Cycle Cost and Payback Period Spreadsheets	CEC Energy Demand Forecast
Residential	Air Conditioning	2009 RASS		2009 RASS; California Appliance Standards; 2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	CEC Energy Demand Forecast

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Residential	Lighting	Calculated from CEC Demand Forecast and residential sq. footage projections		2013 California Building Energy Efficiency Standards: Draft Measure Information Template - Residential Lighting; 2010 Lighting Market Characterization	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	CEC Energy Demand Forecast
Residential	Misc.	Calculated from CEC Energy Demand Forecast		2009 RASS; DOE Pool Heater Life Cycle Cost Model; DOE Clothes Washer Life-Cycle Cost and Payback Period Analysis; Draft DOE Oven Life Cycle Cost Spreadsheet; DOE Dishwasher Life Cycle Cost Spreadsheet; DOE National Impact Analysis: Refrigerators and Freezers; DOE Clothes Dryer Lifecycle Cost Model	DOE Pool Heater Life Cycle Cost Model; DOE Clothes Washer Life-Cycle Cost and Payback Period Analysis; Draft DOE Oven Life Cycle Cost Spreadsheet; DOE Dishwasher Life Cycle Cost Spreadsheet; DOE National Impact Analysis: Refrigerators and Freezers; DOE Clothes Dryer Lifecycle Cost Model	DOE Pool Heater Life Cycle Cost Model; DOE Clothes Washer Life-Cycle Cost and Payback Period Analysis; Draft DOE Oven Life Cycle Cost Spreadsheet; DOE Dishwasher Life Cycle Cost Spreadsheet; DOE National Impact Analysis: Refrigerators and Freezers; DOE Clothes Dryer Lifecycle Cost Model	CEC Energy Demand Forecast
Transportation	Light Duty Vehicles	CARB EMFAC		CARB EMFAC; ARB LDV Off-Road Model	"Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013	"Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013	
Transportation	Passenger Rail	National Transit Database, Federal Transit Administration, 2011		National Transit Database, Federal Transit Administration, 2011	EIA	APTA U.S. Average New Vehicle Costs for 2010 and 2011 Vehicles by Type	

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Transportation	Bus	National Transit Database, Federal Transit Administration, 2011		National Transit Database, Federal Transit Administration, 2011; AQMD Emissions Factors; 2013 APTA Vehicle Database	Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis	Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis	
Transportation	Commercial Aviation	US DOT: Research and Innovative Technology Administration; Bureau of Transportation Statistics		US DOT: Research and Innovative Technology Administration; Bureau of Transportation Statistics	US DOT: Research and Innovative Technology Administration; Bureau of Transportation Statistics	EIA Annual Energy Outlook 2013: Air Travel Energy Use	CARB Emissions Inventory
Transportation	General Aviation	2010 General Aviation Statistical Databook and Industry Outlook		2010 General Aviation Statistical Databook and Industry Outlook			CARB Emissions Inventory
Transportation	Freight Rail	CARB Vision Off-Road Model		CARB Vision Off-Road Model	CARB Vision Off-Road Model		AQD Emissions Inventories; CARB Emissions Inventory
Transportation	Ocean Going Vessels	CARB Vision Off-Road Model		CARB Vision Off-Road Model	CARB Vision Off-Road Model		AQD Emissions Inventories; CARB Emissions Inventory
Transportation	Heavy Duty Trucking	CARB EMFAC		CARB EMFAC	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles; 2012 MODEL YEAR ALTERNATIVE FUEL VEHICLE (AFV) GUIDE	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles	AQD Emissions Inventories; CARB Emissions Inventory

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Transportation	Commercial Harbor Craft	CARB Vision Off-Road Model		CARB Vision Off-Road Model;	CARB Vision Off-Road Model		AQD Emissions Inventories; CARB Emissions Inventory
Transportation	Off-Road	2011 CARB Off-Road Diesel Emissions Inventory Model		2011 CARB Off-Road Diesel Emissions Inventory Model			EMISSIONS INVENTORY DEVELOPMENT FOR IN-USE OFF-ROAD EQUIPMENT
Agriculture	Other	CEC Demand Forecasts; EIA Diesel Farm Fuel Sales		N/A	N/A	N/A	CEC Demand Forecast (Gas and Electricity); AQD Emissions Inventories
Oil & Gas Extraction	Other	CEC Demand Forecasts; CARB Gasoline Sales Estimates		N/A	N/A	N/A	CEC Demand Forecast (Gas and Electricity); AQD Emissions Inventories
Petroleum Refining	Other	CEC Demand Forecasts		N/A	N/A	N/A	CEC Demand Forecast (Gas and Electricity); AQD Emissions Inventories
Transportation, Communication, and Utilities	Other	CEC Demand Forecasts		N/A	N/A	N/A	CEC Demand Forecast (Electricity); AQD Emissions Inventories

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Industrial	Unspecified (by industry)			N/A	N/A	N/A	CEC Demand Forecasts; AQD Emissions Inventories
Commercial	Lighting	CEC Demand Forecasts		2010 Lighting Market Characterization	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	CEC Energy Demand Forecast
Commercial	All other Sectors	CEC Demand Forecasts; California Commercial End-Use Survey;		2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	CEC Energy Demand Forecast

6 References

Argonne National Laboratory *Natual Gas Vehicles: Status, Barriers, and Opportunities*. Argonne, Illinois, s.n., 2010.

EIAAnnual Energy Outlook 2013: Natural Gas Supply Disposition and Prices. *United States Energy Information Administration*. [Online]2013. http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a.

Gas Technology Institute *Small Scale Liquefier Development*. Washington, D.C., U.S. Department of Energy: Energy Efficiency and Renewable Energy Technical Committee, 2004.

United States Energy Information Administration Washington D.C., s.n., 2013
.