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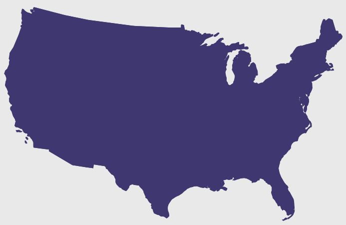
Technical Report

pathways to deep decarbonization *in the United States*



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Pathways to Deep Decarbonization in the United States

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US 2050 REPORT

Pathways to Deep Decarbonization in the United States

Energy and Environmental Economics, Inc. (E3)
Lawrence Berkeley National Laboratory
Pacific Northwest National Laboratory

November 2015

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The authors take full responsibility for the contents of this report.

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Preface

Deep Decarbonization Pathways Project

The Deep Decarbonization Pathways Project (DDPP) is a collaborative global initiative to explore how individual countries can reduce greenhouse gas (GHG) emissions to levels consistent with limiting the anthropogenic increase in global mean surface temperature to less than 2 degrees Celsius (°C). Limiting warming to 2°C or less, an objective agreed upon by the international community, will require that global net GHG emissions approach zero by the second half of the 21st century.[1] This, in turn, will require steep reductions in energy-related CO_2 emissions through a transformation of energy systems, a transition referred to by the DDPP as "deep decarbonization."

The DDPP is led by the Sustainable Development Solutions Network (SDSN) and the Institute for Sustainable Development and International Relations (IDDRI). Currently, the DDPP includes 15 research teams from countries representing more than 70% of global GHG emissions: Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Japan, Mexico, Russia, South Africa, South Korea, the United Kingdom, and the United States. The research teams are independent and do not necessarily reflect the positions of their national governments. Starting in the fall of 2013, the research teams have been developing potential high-level roadmaps, or "pathways," for deep decarbonization in their respective countries.

The initial results of this effort were published in September 2014 and officially presented as part of the *Economic Case for Action* session at the Climate Summit convened by UN Secretary General Ban Ki Moon in New York. That study, "Pathways to Deep Decarbonization: 2014 Report," included a chapter on deep decarbonization pathways in the U.S.[2] The present report represents a continuation of the analysis in the DDPP Report, providing expanded results and greater detail on methods and data sources.

Research Team

The research for this report was conducted by Energy and Environmental Economics, Inc. (E3), a San Francisco-based consulting firm, in collaboration with Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest National Laboratory (PNNL). The overall project director was Dr. Jim Williams (E3), with Dr. Andrew Jones (LBNL) and Dr. Haewon McJeon (PNNL) responsible for GCAM modeling. PATHWAYS analysis and report writing were conducted primarily by Ben Haley, Jack Moore, and Dr. Fredrich Kahrl of E3. Senior supervisors included Dr. Margaret Torn (LBNL) and Snuller Price (E3).

Advisory Committee

This report was reviewed by a distinguished advisory committee consisting of Prof. John Weyant of Stanford University and Director of the Energy Modeling Forum, and Dr. Jae Edmonds, a Laboratory Fellow at PNNL's Joint Global Change Research Institute.

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[1] Intergovernmental Panel on Climate Change, *5th Assessment Report*, http://www.ipcc.ch/report/ar5/

[2] SDSN and IDDRI, *Pathways to Deep Decarbonization: 2014 Report*, www.deepdecarbonization.org/

Addendum to November 2015 Revision

This report includes a new technical supplement contained in Appendix D. It was prepared in order to show additional detail from the PATHWAYS analysis by case, sector, and geographic region for cost, GHG emissions, final energy demand, primary energy flows, and investment. The analysis was performed by Ben Haley and directed by Dr. Jim Williams.

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Abstract

Limiting the anthropogenic increase in global mean surface temperature to less than 2 degrees Celsius (°C), an objective agreed upon by the international community, will require that global net GHG emissions approach zero by the second half of the 21st century. The principal finding of this study, conducted using the PATHWAYS and GCAM models, is that it is technically feasible to achieve an 80% greenhouse gas reduction below 1990 levels by 2050 in the United States (U.S.), and that multiple alternative pathways exist to achieve these reductions using existing commercial or near-commercial technologies. Reductions are achieved through high levels of energy efficiency, decarbonization of electric generation, electrification of most end uses, and switching the remaining end uses to lower carbon fuels. The cost of achieving these reductions does not appear prohibitive, with an incremental cost to the energy system equivalent to less than 1% of gross domestic product (GDP) in the base case. These incremental energy system costs did not include potential non-energy benefits, for example, avoided human and infrastructure costs of climate change and air pollution. The changes required to deeply decarbonize the economy over the next 35 years would constitute an ambitious transformation of the energy system. However, this study indicates that these changes would not necessarily entail major changes in lifestyle, since the low carbon pathways were designed to support the same level of energy services and economic growth as the reference case based on the U.S. Department of Energy's *Annual Energy Outlook*. Starting now on the deep decarbonization path would allow infrastructure replacement to follow natural replacement rates, which reduces costs, eases demand on manufacturing, and allows gradual consumer adoption.

Executive Summary

Decision makers in government and business increasingly need to understand the practical implications of deep reductions in global greenhouse gas (GHG) emissions. This report examines the technical and economic feasibility of such a transition in the United States, evaluating the infrastructure and technology changes required to reduce U.S. GHG emissions in the year 2050 by 80% below 1990 levels, consistent with a global emissions trajectory that limits the anthropogenic increase in earth's mean surface temperature to less than 2°C.

The analysis was conducted using PATHWAYS, a detailed, bottom-up energy model that draws on the architecture and inputs of the U.S. National Energy Modeling System (NEMS). For each year out to 2050, PATHWAYS evaluates annual changes in infrastructure stocks by sector and region in each of the nine U.S. census divisions, and includes an hourly electricity system simulation in each of the three major electric grid interconnections. Scenarios using different portfolios of measures were developed to represent a range of decarbonization strategies across energy supply and demand sectors including electricity, fuels, residential and commercial buildings, passenger and freight transportation, and industry. The resulting incremental energy system emissions and costs were calculated in comparison to a reference case based on the U.S. Department of Energy's *Annual Energy Outlook (AEO)*. Uncertainty was addressed through sensitivity analysis. Complementary analyses were performed using GCAM, a global integrated assessment model, to examine land-use emissions associated with bioenergy production and the mitigation potential of non-CO_2 GHGs. The study addresses four main research questions:

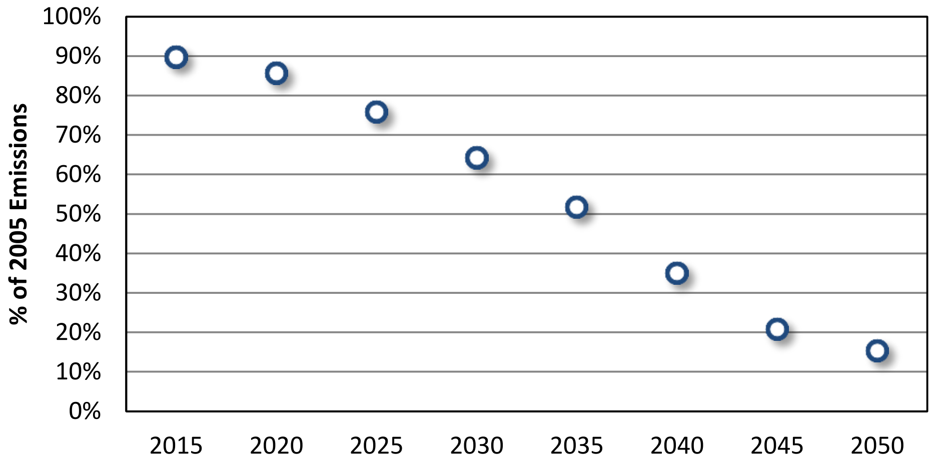
1. Is it technically feasible to reduce U.S. GHG emissions to 80% below 1990 levels by 2050, subject to realistic constraints?

This study finds that it is technically feasible for the U.S. to reduce GHG emissions 80% below 1990 levels by 2050 with overall net GHG emissions of no more than 1,080 MtCO$_2$e, and fossil fuel combustion emissions of no more than 750 MtCO$_2$. Meeting a 750 MtCO$_2$ target requires a transformation of the U.S. energy system, which was analyzed using PATHWAYS. The analysis employed conservative assumptions regarding technology availability and performance, infrastructure turnover, and resource limits. Four distinct scenarios employing substantially different decarbonization strategies —High Renewable, High Nuclear, High CCS, and Mixed Cases, which were named according to the different principal form of primary energy used in electricity generation, and also differed in other aspects of energy supply and demand—all met the target, demonstrating robustness by showing that redundant technology pathways to deep decarbonization exist.

Analysis using the GCAM model supports the technical feasibility of reducing net non-energy and non-CO_2 GHG emissions to no more than 330 Mt CO$_2$e by 2050, including land use carbon cycle impacts from biomass use and potential changes in the forest carbon sink.

The U.S. total emissions trajectory for the Mixed Case, assuming a constant terrestrial CO_2 sink, is shown in Figure ES-1.

Figure ES-1. U.S. Total GHG Emissions for the Years 2015-2050, as a Percentage of 2005 Emissions



2. What is the expected cost of achieving this level of reductions in GHG emissions?

Achieving this level of emissions reductions is expected to have an incremental cost to the energy system on the order of 1% of GDP, with a wide uncertainty range. This study uses incremental energy system costs—the cost of producing, distributing, and consuming energy in a decarbonized energy system relative to that of a reference case system based on the *AEO*—as a metric to assess the cost of deep reductions in energy-related CO_2 emissions. Based on an uncertainty analysis of key cost parameters in the four analyzed cases, the interquartile (25^{th} to 75^{th} percentile) range of these costs extends from negative \$90 billion to \$730 billion (2012 \$) in 2050, with a median value of just over \$300 billion. To put these estimates in context, levels of energy service demand in this analysis are consistent with a U.S. GDP of \$40 trillion in 2050. By this metric, the median estimate of net energy system costs is 0.8% of GDP in 2050, with 50% probability of falling between -0.2% to +1.8%. GCAM analysis indicates that the complementary reductions in non-energy and non-CO_2 GHGs needed to meet the 80% target are achievable at low additional cost.

These cost estimates are uncertain because they depend on assumptions about consumption levels, technology costs, and fossil fuel prices nearly 40 years into the future. To be conservative, energy service demands in this analysis were based on an economy and lifestyles that resemble the present day and on technology cost assumptions that reflect near-term expectations, with relatively flat cost trajectories for many technologies out to 2050. Even at the higher end of the probability distribution (the 75^{th} percentile estimate of \$730 billion), which assumes little to no technology innovation over the next four decades, the incremental energy system cost of a transition needed to meet the 750 $MtCO_2$ target is small relative to national income.

These incremental energy system costs did not include non-energy benefits, for example, the avoided human health and infrastructure costs of climate change and air pollution. Additionally, the majority of energy system costs in this analysis were incurred after 2030, as deployment of new low-carbon infrastructure expands. Technology improvements and market transformation over the next decade could significantly reduce expected costs in subsequent years.

3. What changes in energy system infrastructure and technology are required to meet this level of GHG reduction?

Deep decarbonization requires three fundamental changes in the U.S. energy system: (1) highly efficient end use of energy in buildings, transportation, and industry; (2) decarbonization of electricity and other fuels; and (3) fuel switching of end uses to electricity and other low-carbon supplies. All of these changes are needed, across all sectors of the economy, to meet the target of an 80% GHG reduction below 1990 levels by 2050.

The transformation of the U.S. energy system, while gradual, entails major changes in energy supply and end use technology and infrastructure. With commercial or near-commercial technologies and limits on biomass availability and carbon capture and storage (CCS) deployment, it is difficult to decarbonize both gas and liquid fuel supplies. For this reason, meeting the 2050 target requires almost fully decarbonizing electricity supply and switching a large share of end uses from direct combustion of fossil fuels to electricity (e.g., electric vehicles), or fuels produced from electricity (e.g., hydrogen from electrolysis). In our four decarbonization cases, the use of electricity and fuels produced from electricity increases from around 20% at present to more than 50% by 2050.

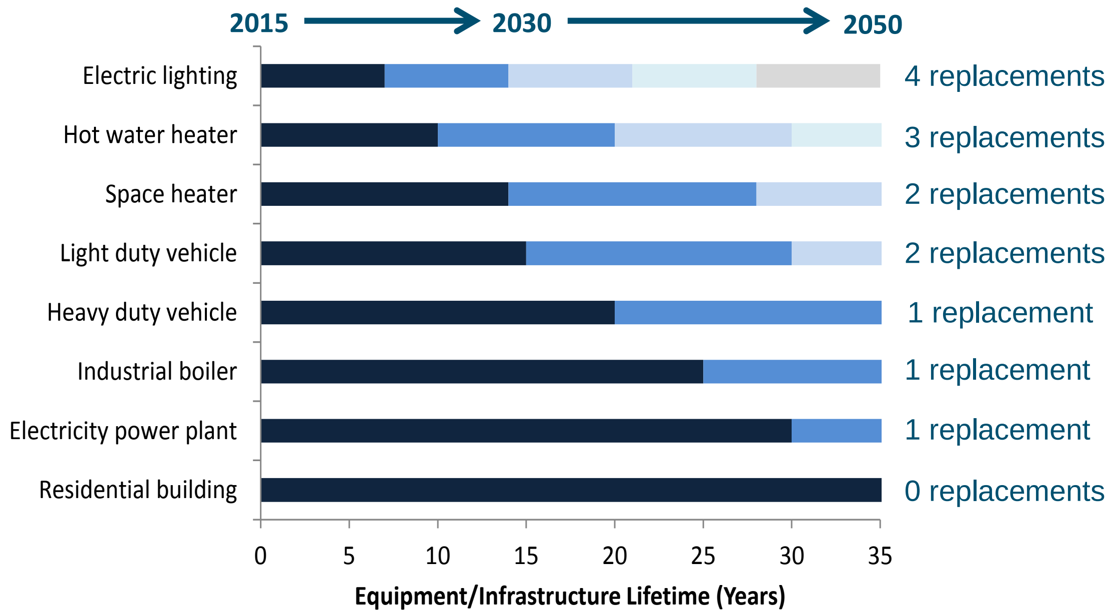
As a result, electricity generation would need to approximately double (an increase of 60-110% across scenarios) by 2050 while its carbon intensity is reduced to 3-10% of its current level. Concretely, this would require the deployment of roughly 2,500 gigawatts (GW) of wind and solar generation (30 times present capacity) in a high renewables scenario, 700 GW of fossil generation with CCS (nearly the present capacity of non-CCS fossil generation) in a high CCS scenario, or more than 400 GW of nuclear (4 times present capacity) in a high nuclear scenario.

Similar levels of transformation would be required in other sectors. For example, light duty vehicles (LDVs) would need to become more efficient and switch to low carbon fuels. The average fleet fuel economy of LDVs would need to exceed 100 miles per gallon gasoline equivalent in 2050, while shifting 80-95% of miles driven from gasoline to alternative fuels such as electricity and hydrogen. This would require the deployment of roughly 300 million alternative fuel vehicles by 2050.

4. What are the implications of these technology and infrastructure changes for the energy economy and policy?

There is still sufficient time for the U.S. to achieve 80% GHG reductions by 2050 relying on natural infrastructure turnover. However, to achieve emissions goals and avoid the costs of early retirement, it is critical to account for economic and operating lifetimes in investment decisions. The figure below illustrates the limited number of opportunities between now and 2050 for replacement or addition of infrastructure based on natural stock rollover for different types of equipment.

Figure ES 2. Stock Lifetimes and Replacement Opportunities



For some important kinds of long-lived infrastructure—for instance, power plants—there is likely to be only one opportunity for replacement in this time period. Adding new high carbon generation (e.g., coal plants) creates infrastructure inertia that either makes the 2050 target more difficult to reach, requires expensive retrofits, or puts investments at risk. Reflecting full lifecycle carbon costs up-front in investment decisions for long-lived infrastructure would reduce these risks. Transitions that involve shorter-lived equipment—for example, LDVs—raise other considerations. This analysis shows that adoption rates for alternative LDVs can initially ramp up slowly, constituting only a small share of the LDV fleet by 2030, but that they must comprise the bulk of new sales shortly thereafter in order to ensure that only a small share of conventional gasoline vehicles remain in the stock by 2050. This suggests that current barriers to adoption of low carbon LDV technologies need to be addressed well before 2030. One key barrier is upfront costs, which can be reduced by timely R&D, market transformation programs, and financial innovation. Anticipating and addressing such barriers in advance is essential to meeting emissions targets at low overall cost.

A deeply decarbonized energy economy would be dominated by fixed cost investments in power generation and in efficient and low-carbon end-use equipment and infrastructure, while fossil fuel prices would play a smaller role. Petroleum consumption is reduced by 76–91% by 2050 across all scenarios in this study, declining both in absolute terms and as a share of final energy. Meanwhile, incremental investment requirements in electricity generation alone rise to $30–70 billion per year above the reference case by the 2040s. The overall cost of deeply decarbonizing the energy system is dominated by the incremental capital cost of low carbon technologies in power generation, light and heavy duty vehicles, building energy systems, and industrial equipment. This change in the energy economy places a premium on reducing capital and financing costs through R&D, market transformation, and creative financing mechanisms. The new cost structure of the energy system reduces the exposure to volatile energy commodity prices set on global markets, while also suggesting a critical role for investment in domestic energy infrastructure.

The recent U.S. government commitment to reduce U.S. total GHG emissions by 26–28% below 2005 levels by 2025 is consistent with the results of this report. Figure ES-1 shows the reduction in total GHG emissions over time relative to 2005 for the Mixed Case in this study, assuming a constant terrestrial carbon sink. In this scenario, U.S. total GHG emissions (net CO_2e) were reduced by 25% in 2025 relative to 2005.

In its announcement, the U.S. government also reaffirmed the goal of "economy-wide reductions on the order of 80% by 2050." Since the U.S. commitment level for 2025 lies on the same trajectory as the deep decarbonization pathways in this analysis, this suggests that successfully achieving the 2025 target would put the U.S. on the road to 80% reductions by 2050. From the perspective of this study, there are different ways that the U.S. can achieve the 2025 target, some of which would lay the necessary groundwork for deeper reductions to follow, and others that might meet the target but tend to produce flat, rather than declining, emissions in the long term. This indicates the importance of evaluating near-term approaches in the light of deep decarbonization analysis. For example, proposals to prevent the construction of new coal power generation unless it is equipped with CCS are consistent with this report's finding that long-lived infrastructure additions must be low-carbon if the 2050 target is to be met while avoiding stranded assets. Other measures, such as increasing the stringency of vehicle fuel economy and appliance efficiency standards, are effective low-cost measures for reaching the 2025 goal, but to continue along the deep decarbonization trajectory after 2025 will require complementary efforts in policy, technology development, and market transformation to enable deeper decarbonization measures (e.g. deeper generation decarbonization, extensive switching of end uses to electricity and low carbon fuels) later on.

This study did not find any major technical or economic barriers to maintaining the U.S. long-term commitment to reducing GHG emissions consistent with limiting global warming to less than 2°C. In terms of technical feasibility and cost, this study finds no evidence to suggest that relaxing the 80% by 2050 emissions target or abandoning the 2°C limit is justified. In addition, the 2°C goal plays a critical role as a guide for near-term mitigation efforts, providing a benchmark for the necessary scale and speed of infrastructure change, technical innovation, and coordination across sectors that must be achieved in order to stay on an efficient path to climate stabilization.

Energy system changes on the scale described in this analysis imply significant opportunities for technology innovation and investment in all areas of the U.S. energy economy. Establishing regulatory and market institutions that can support this innovation and investment is critical. Both areas—technology innovation and institutional development—are U.S. strengths, and place the U.S. in a strong leadership and competitive position in a low carbon world.

1. Introduction

1.1. Background

The Deep Decarbonization Pathways Project (DDPP) is a collaborative global initiative to explore how individual countries can reduce greenhouse gas (GHG) emissions to levels consistent with limiting the anthropogenic increase in global mean surface temperature to less than 2 degrees Celsius (°C). Limiting warming to 2°C or less, an objective agreed upon by the international community, will require that global net GHG emissions approach zero by the second half of the 21st century. This, in turn, will require steep reductions in energy-related CO_2 emissions through a transformation of energy systems, a transition referred to by the DDPP as "deep decarbonization."

The DDPP is led by the Sustainable Development Solutions Network (SDSN) and the Institute for Sustainable Development and International Relations (IDDRI). Currently, the DDPP includes 15 research teams from countries representing more than 70% of global GHG emissions: Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Japan, Mexico, Russia, South Africa, South Korea, the United Kingdom, and the United States. The research teams are independent and do not necessarily reflect the positions of their national governments. Starting in the fall of 2013, the research teams have been developing potential high-level roadmaps, or "pathways," for deep decarbonization in their respective countries.

The initial results of this effort were published in September 2014 and officially presented as part of the *Economic Case for Action* session at the Climate Summit convened by UN Secretary General Ban Ki Moon in New York. That study, "Pathways to Deep Decarbonization: 2014 Report," included a chapter on deep decarbonization pathways in the U.S. The present report represents a continuation of the analysis in the DDPP Report, providing expanded results and greater detail on methods and data sources.

1.2. Objectives

Decision makers in government and business need to understand the practical implications of deep reductions in greenhouse gas (GHG) emissions consistent with limiting the anthropogenic increase in global mean surface temperatures to 2°C or less. To that end, this report has four principal objectives:

1. To assess the technical and economic feasibility of reducing U.S. GHG emissions 80% below 1990 levels by 2050, a level consistent with the 2°C limit
2. To understand what this goal implies for the magnitude, scope, and timing of required changes in the U.S. energy system, at a relatively concrete and granular level
3. To provide a benchmark for evaluating the consistency of current and proposed climate policies with what is required to meet the 2050 target
4. To demonstrate the need for granular, long-term deep decarbonization analysis in both domestic and international climate policy processes

1.3. Research Questions

This study addresses four main research questions. First, is it technically feasible to reduce U.S. GHG emissions to 80% below 1990 levels by 2050, subject to realistic constraints? Second, what is the expected cost of achieving this level of reductions in GHG emissions? Third, what changes in energy system infrastructure and technology are required to meet this level of GHG reduction? Fourth, what are the implications of these technology and infrastructure changes for the energy economy and policy? The study focuses primarily on energy-related CO_2 emissions. Reductions in non-energy and non-CO_2 GHGs required to meet the 80% net CO_2e target are also considered, but in less detail.

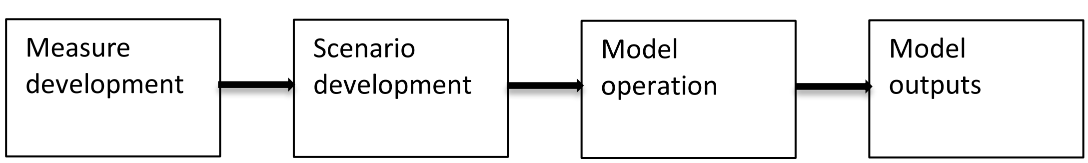
Technical feasibility is defined here as a robust analytical demonstration that multiple technology pathways exist for achieving the 2050 emissions target that satisfy a broad set of reasonableness criteria, including reliance on commercial or near-commercial technologies, natural infrastructure turnover, power system operability, and sustainability limits on natural resources. The cost of achieving the target is assessed in terms of incremental energy system costs—that is, the net cost of producing, distributing, and consuming energy in a decarbonized energy system relative to a reference case—using sensitivity analysis to address the high uncertainty in technology costs and fuel prices over a multi-decade time frame.

1.4. Research Approach

The research in this study was conducted using two models, PATHWAYS and GCAM. These models and their roles in the study are described in Chapter 2, along with other details on methods and data sources. The approach used in this study involves four main steps (see Figure 1):

1. Measure development. Model inputs used to represent energy supply and end use infrastructure and equipment, including current and projected cost and performance for incumbent technologies and a wide range of low carbon measures, were developed from a broad survey of the literature and expert opinion. The GCAM model was used to develop measures for non-energy and non-CO_2 GHG mitigation.
2. Scenario development. Cases were developed to represent a reference (current policy) scenario and four low carbon scenarios. To generate the latter, reference case infrastructure and equipment were replaced by the low carbon measures developed in step 1 at the scale and rate necessary as to meet the 2050 target while obeying a set of reasonableness constraints.
3. Model operation. The PATHWAYS model developed for this analysis produces changes in the annual stock of energy infrastructure and equipment based on the scenarios developed. It balances energy supply and demand by fuel type and end use, and employs an hourly dispatch to ensure that sufficient energy and capacity is available in a given scenario for the reliable operation of the electricity system. Complementary analyses were performed with GCAM to examine land-use emissions associated with bioenergy production and the mitigation potential of non-CO_2 GHGs.
4. Model outputs. Based on the scenarios and input values developed, the PATHWAYS model outputs annual results for primary and final energy, CO_2 emissions, the net cost of low carbon scenarios relative to the reference case, and stocks of specific infrastructure and equipment.

Figure 1. Research Approach



1.5. Current GHG Emissions and the 2050 Target

1.5.1. Current U.S. GHG Emissions

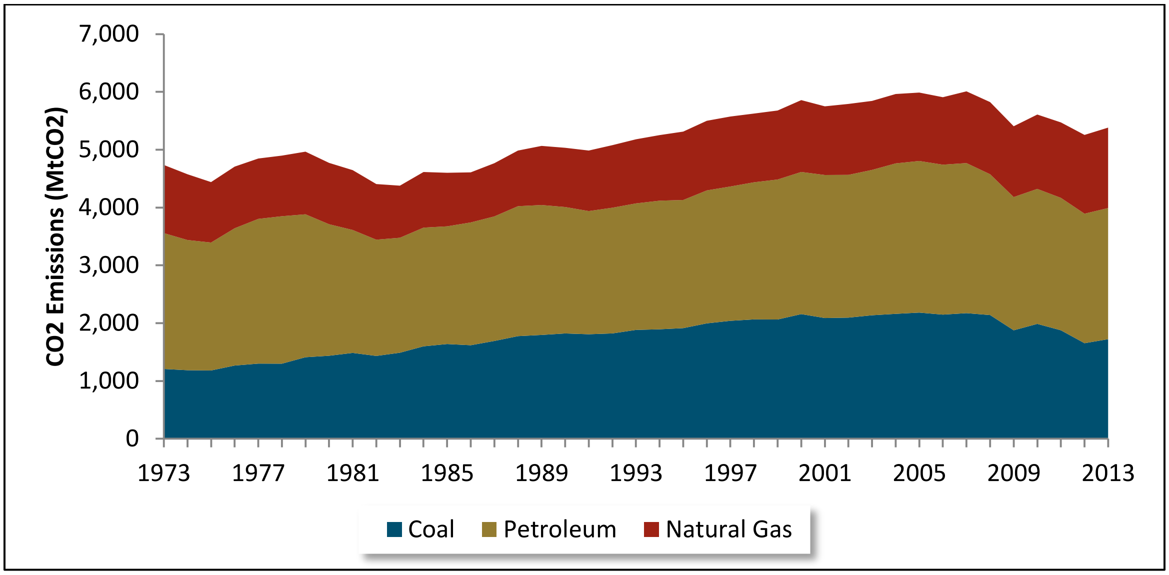
U.S. GHG emissions are dominated by CO_2 emissions from fossil fuel combustion. These have accounted for more than three-quarters of total gross GHG emissions over the last two decades (Table 1). Methane (CH_4) and nitrous oxide (N_2O) are also important GHGs in the U.S., accounting for around 15% of gross emissions. The U.S. has a net CO_2 sink (negative CO_2 flux) from land use, land-use change, and forestry (LULUCF), which the EPA estimates has grown since the 1990s. This sink represents CO_2 that is removed from the atmosphere each year and stored in terrestrial ecosystems, primarily forests. Net GHG emissions, which are the ultimate concern for climate policy, are calculated as gross GHG emissions minus the CO_2 sink.

Table 1. U.S. Gross and Net GHG Emissions, 1990, 2005, and 2012 (Source: U.S. EPA 2014)

	1990		2005		2012	
	$MtCO_2e$	% Gross	$MtCO_2e$	% Gross	$MtCO_2e$	% Gross
Fossil fuel combustion CO_2	4,745	76%	5,753	79%	5,066	78%
Total CO_2	5,109	82%	6,112	84%	5,377	83%
CH_4	632	10%	586	8%	564	9%
N_2O	399	6%	416	6%	410	6%
Hydrofluorocarbons (HFCs)	37	1%	120	2%	137	2%
Perfluorocarbons (PFCs)	21	0%	6	0%	5	0%
Sulfur hexafluoride (SF_6)	33	1%	15	0%	8	0%
Gross GHG emissions	**6,230**	**100%**	**7,254**	**100%**	**6,502**	**100%**
Net CO_2 flux from LULUCF	**-831**		**-1,031**		**-979**	
Net GHG emissions	**5,399**		**6,223**		**5,522**	

Figure 2 shows the contributions of the three fossil fuels—coal, natural gas, petroleum—to CO_2 emissions in the U.S. over the last four decades. Owing to a number of different factors—the global financial crisis, natural gas displacement of coal, and the accumulated effects of energy efficiency policies—emissions from fossil fuel combustion declined sharply beginning in 2008, and were only 14% above 1973 levels in 2013 (Figure 2).

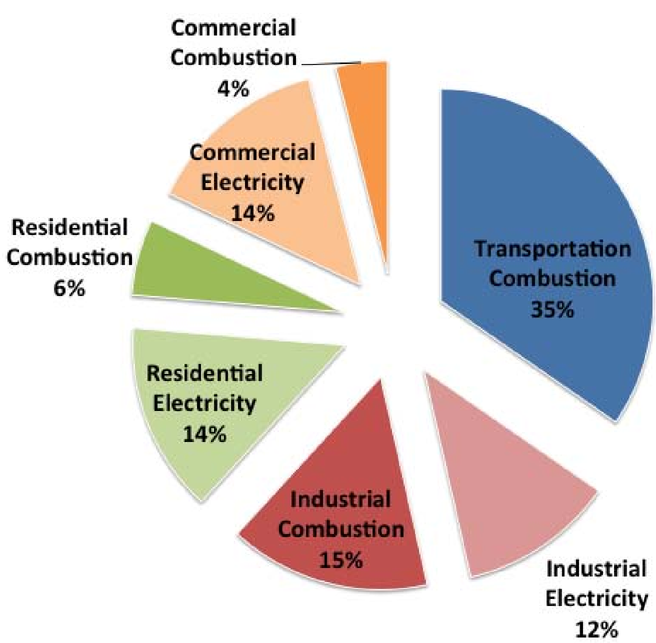
Figure 2. U.S. CO_2 Emissions from Fossil Fuel Combustion by Fuel Source, 1973–2013



Source: EIA , March, 2014 Monthly Energy Review

Fossil fuel combustion CO_2 emissions are spread across all major sectors, with the transportation and industrial sectors accounting for a higher share of emissions (62%) than the residential and commercial sectors (38%). Transportation sector CO_2 emissions arise largely from direct fuel combustion, whereas industrial sector CO_2 emissions are split between direct fuel combustion and electricity consumption, and residential and commercial emissions are primarily from electricity consumption (Figure 3).

Figure 3. U.S. CO_2 Emissions from Fossil Fuel Combustion, with Electricity Emissions Allocated to End Use, 2012



Source: U.S. EPA 2014

1.5.2. 2050 GHG Target

The target for CO_2 emissions from fossil fuel combustion used in this analysis is consistent with the DDPP *Pathways to Deep Decarbonization* report principle of convergence in global per capita energy-related CO_2 emissions to 1.7 tonnes CO_2 per person in 2050.[3] For the U.S., the target derived through this process is 750 $MtCO_2$ based on a population forecast of 440 million in 2050. This study also evaluates what additional non-energy and non-CO_2 reduction measures are required in order to meet the overall GHG emissions target for all emission sources and fuel types of 80% below 1990 by 2050, a level the scientific community has judged consistent with limiting anthropogenic warming to 2°C. Chapter 9 shows how the two targets—energy-CO_2 only and net CO_2e—are reconciled in this report using GCAM.

EPA's estimate for net GHG emissions in 1990 is 5,399 $MtCO_2e$ (Table 1). An 80% reduction below this level yields an upper limit of 1,080 $MtCO_2e$ for the 2050 target. If fossil fuel combustion results in emissions of 750 $MtCO_2e$, this implies that the total budget for all other emissions net of the LULUCF sink would be 330 $MtCO_2e$ in 2050 (Table 2). If EPA's estimated net terrestrial carbon sink for 2012 (979 $MtCO_2$ per year) were maintained out to 2050, the budget for gross emissions of all types other than fossil fuel CO_2 would be 1,309 $MtCO_2e$. Meeting this would require a 9% reduction below 2012 levels (1,436 $MtCO_2e$), or 12% below 1990 levels (1,485 $MtCO_2e$), of these non-energy and non CO_2 emissions. If the sink were to reduce sufficiently in size by 2050, deeper reductions would be required, either from energy CO_2 emissions or from these other emissions. We explore this sensitivity in Chapter 9.

Table 2. Budget for Allowable 2050 GHG Emissions Other than Fossil Fuel Combustion CO_2

Net GHG emissions target in 2050 (80% below 1990)	1,080 $MtCO_2e$	–
Budget for CO_2 emissions from fossil fuel combustion in 2050	750 $MtCO_2e$	=
Allowable other GHG emissions net of LULUCF sink in 2050	**330 $MtCO_2e$**	

At the 2009 Climate Change Summit in Copenhagen, the U.S. announced a target of reducing GHG emissions by 83% below 2005 levels by 2050. This target is consistent with legislation passed by the House of Representatives earlier in 2009, but never approved by the U.S. Senate. It is, nevertheless, an important reference point. At the EPA's current estimate of 6,223 $MtCO_2e$ of net GHG emissions in 2005, this target equates to an upper limit of 1,056 $MtCO_2e$ in net GHG emissions in 2050. In this case, assuming a constant sink at 2012 levels, allowable non-fossil fuel combustion GHGs in 2050 would be 306 $MtCO_2e$, and the required reduction in these gases below 2012 levels would be 11%.

1.6. Report Overview

The remainder of this report is organized as follows. Chapter 2 describes the methods used, including an overview of the PATHWAYS and GCAM models. Chapter 3 describes the scenarios developed and the principles underlying their design. Chapters 4-10 present detailed results for emissions, energy, and costs. Chapter 11 provides a synoptic view of the low carbon transition in the U.S. energy system. Chapter 12 provides summary observations and conclusions.

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[3] SDSN and IDDRI, *Pathways to Deep Decarbonization: 2014 Report*, www.deepdecarbonization.org/

2. Methods

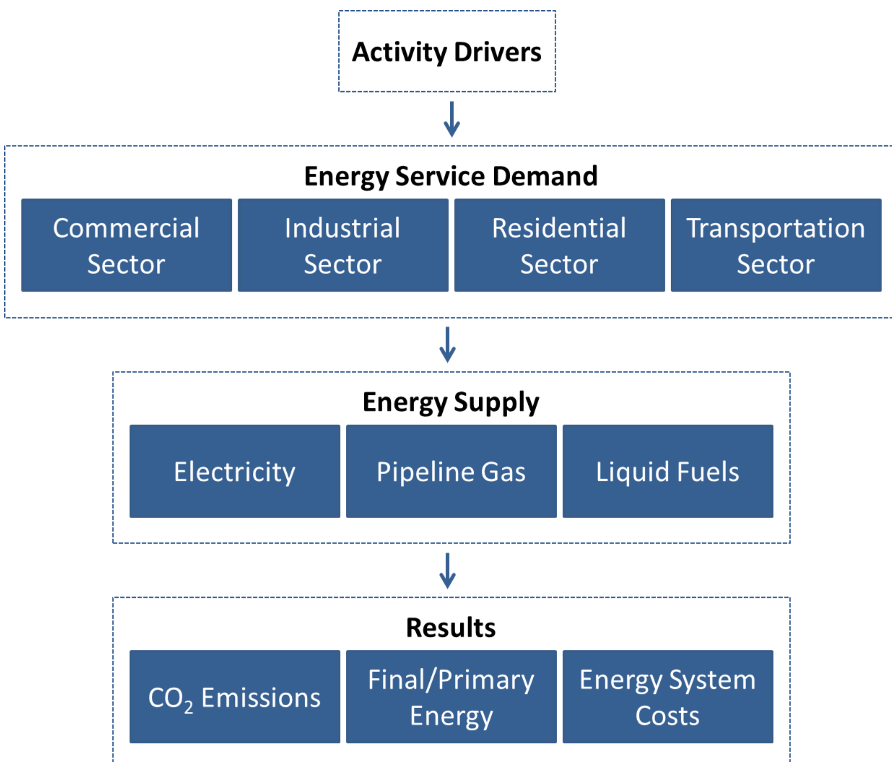
2.1. PATHWAYS Model

PATHWAYS is a bottom-up, stock rollover model of the U.S. energy system. It shares a common architecture with and uses many of the same inputs as NEMS,[4] but includes a more detailed representation of the electricity sector and is more flexible and transparent. PATHWAYS's combination of bottom-up detail and flexibility allows for examination of a broad range of technology pathways to deep decarbonization at different levels of resolution—from energy system-wide trends to, for instance, changes in the stock of light duty vehicles in the South Atlantic census region.

PATHWAYS tracks final and primary energy use, CO_2 emissions, and energy system costs across four end use sector modules: commercial, industrial, residential, and transportation (Figure 4). Energy demand in these four sectors is provided through electricity, pipeline gas, and liquid fuel modules. The electricity module includes an hourly dispatch of regional power systems for each model year, to ensure that electricity reliability requirements are met and that the costs of balancing wind, solar, and nuclear output with demand are accurately accounted for.

Energy service demand in each PATHWAYS end use sector module is driven by exogenously-specified activities. In the commercial and residential sectors, these include building floorspace, population, households, and residential square footage. In the transportation sector, activities are based primarily

Figure 4. PATHWAYS Model Architecture



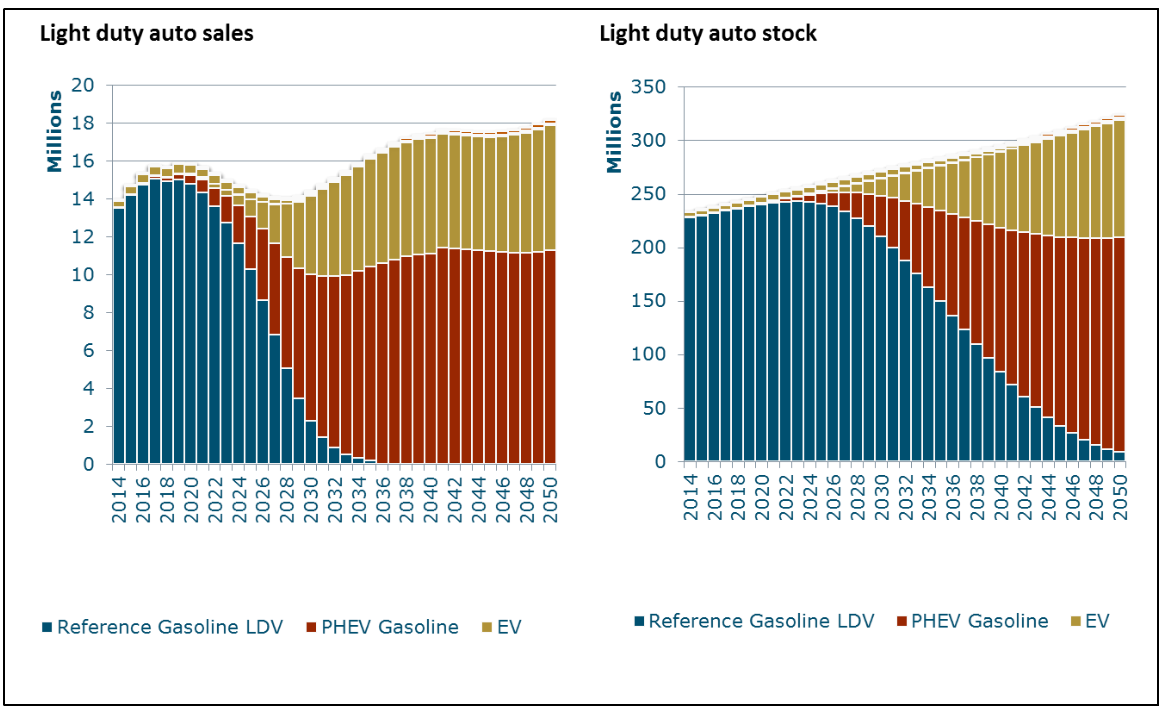
[4] EIA, National Energy Modeling System

on travel distance (VMT). In the industrial sector, they are based on sector output (value of shipments). All activity drivers are drawn from NEMS and the 2013 *Annual Energy Outlook's* (AEO's) Reference Case, which is effectively a linear extrapolation of the current U.S. economy. This approach is intended to reduce the uncertainty inherent in forecasting changes in relative prices over such a long timeframe and focus attention on the dynamics of energy system transformation. It is also intended to be conservative, to illustrate the scope and magnitude of energy system changes needed to reach 750 $MtCO_2$ of emissions in a world that resembles one very much like the current.

The Reference Case in PATHWAYS follows an emissions trajectory very similar to that in the 2013 AEO Reference Case, with total CO_2 emissions from fossil fuel combustion remaining over 5,000 $MtCO_2$ by 2050. To reach the 750 $MtCO_2$ target by 2050, users incorporate CO_2 emission reductions through three kinds of measures: (1) energy efficiency, including improved equipment and building envelopes; (2) fuel switching, including electrification and a shift to lower net CO_2 gas and liquid fuels in end use sectors (3) decarbonization of energy supplies.

Measures are incorporated in PATHWAYS through a stock rollover process. At the end of each year, some amount of energy supply and distribution equipment, buildings, and end use equipment ("energy infrastructure") is retired, based on a survival function. New energy infrastructure is needed to replace this retiring infrastructure and meet growth in energy service demand. Users implement measures by changing the composition of new energy infrastructure, by parameterizing an adoption curve for each measure. The use of adoption curves for new infrastructure moderates changes in the stock of infrastructure over time, as shown in Figure 5 for light-duty autos. Although users can retire infrastructure early, before the end of its useful life, this imposes a cost in the model. In all of the cases in this report infrastructure is allowed to retire naturally.

Figure 5. Stock-rollover Example in PATHWAYS: Light Duty Auto Sales and Stock by Model Year



PATHWAYS is a scenario model. Portfolios of measures that constitute a case are chosen manually by the user—the model does not choose measures based on price or other characteristics. The resulting technology pathways represent technically feasible and reasonable, but not optimized, strategies for deeply decarbonizing the U.S. energy system. This approach assumes a change in relative prices consistent with an explicit or implicit carbon price, which shifts adoption of energy technologies toward less CO_2-intensive alternatives. PATHWAYS makes no assumptions about the mechanisms, be they mandate or market, through which this change in relative prices is achieved.

The granularity in PATHWAYS's energy supply and end use modules is similar to that in NEMS. In the residential and commercial sectors, PATHWAYS tracks infrastructure stocks and energy demand by census region, building type, end use, and equipment. For passenger and freight transport, it tracks stock and demand by mode and vehicle type; in the industrial sector, by economic sector and end use. Granularity in the gas and liquid fuel supply in PATHWAYS is limited to the fuel mix. In the electricity sector, energy accounting is done regionally, to allow for differences in renewable resource endowments and the physical and political feasibility of nuclear power.

PATHWAYS incorporates three main, high-level constraints: energy resource constraints, energy distribution constraints, and power system operating constraints. Resource constraints apply to renewable resources, but in particular the availability of hydroelectricity and zero-net-CO_2 biomass. Distribution constraints limit the amount of electricity that can be exchanged across regions, and the amount of hydrogen that can be safely distributed in the existing gas pipelines. For the power system, PATHWAYS builds new generation, transmission, and distribution infrastructure to meet reliability needs in each census region, and dispatches generation resources to balance supply and demand in each of the three main interconnection regions in the U.S. When electricity supply exceeds demand, for instance in situations when nuclear, solar, or wind output exceeds demand and storage capacity, supply is curtailed, raising costs. The extent of load flexibility and energy storage are user determined, in the latter case via a consideration of cost-effective levels of curtailment.

Economic accounting in PATHWAYS is limited to energy system costs, which include the incremental capital and operating costs of energy supply and end use infrastructure. Incremental costs are measured relative to reference technologies in the 2013 *AEO* Reference Case. Incremental capital costs are annualized and tracked by vintage, which means that the total incremental capital cost in each year reflects the total additional, annual expenditure on infrastructure stock in a given year. In other words, annual stock costs are the annualized cost of the entire infrastructure stock, and not just new stock. Most capital cost estimates and fossil fuel prices are drawn from NEMS and the 2013 *AEO* Reference Case, extrapolated to 2050. Where appropriate, these estimates were supplemented with others, primarily U.S. government reports. PATHWAYS uses a static forecast of activity levels based on the *AEO*, and thus does not include pricing or macroeconomic feedbacks. Costs are not optimized in the model.

Technology cost and fossil fuel price projections 40 years into the future are very uncertain. To address this, uncertainty analysis was conducted by assigning distributions around base case estimates of petroleum costs, natural gas costs, and alternative fuel costs. These distributions were applied as a trajectory to 2050, so the maximum uncertainty (as a % of base case estimates) in all parameters occurs in 2050. The cost results in this report are presented with the results of this uncertainty analysis rather than only as point estimates. Base case technology cost assumptions are likely conservative, as they are based on current understanding of the potential for cost reductions in energy technologies.

2.2. GCAM

The version of PATHWAYS used in this study does not track non-CO_2 emissions or emissions from agriculture, land use, and land cover change. As a complementary analysis, GCAM was used to identify a feasible balance of CO_2 and non-CO_2 mitigation strategies consistent with an 80% reduction in 1990 GHG emissions by 2050. GCAM was also used to identify a level of domestic purpose-grown bioenergy crop production that would not add to global land use change emissions if implemented in conjunction with a retirement of the current Renewable Fuel Standard (RFS) requirements for corn ethanol. This amount of purpose-grown bioenergy (371 MMT of biomass) was used as the upper limit for domestic energy crop production in all PATHWAYS cases.

GCAM is a global integrated assessment model.[5] The model includes detailed representations of the global economy, global energy systems, and global land use, and a simplified representation of the earth's climate. Supply and demand for energy and other goods and services, and consequently land use patterns, are determined through a partial equilibrium economic simulation. The energy and land use market equilibrium is established in each period by solving for a set of market-clearing prices for all energy and agricultural good markets. This equilibrium is dynamic-recursively solved for every five years over 2005–2100. GHG mitigation in GCAM is achieved through a carbon pricing mechanism that alters the market equilibrium, thereby inducing both technological changes and demand responses according to the cost structures assumed for each technology. Activities emitting CO_2 are taxed directly, while non-CO_2 GHGs respond to carbon pricing through technology and GHG-specific marginal abatement cost curves (MACs) (EPA, 2013).

GCAM tracks 16 different GHGs, aerosols, and short-lived species. Aggregate gas emissions data are first disaggregated by sector and then converted into technology-based emission factors, which can be adjusted by changing the level of that technology. Table 3 provides the list of the gases and the data sources for calculating emission coefficients for each sector in GCAM.

Given large uncertainties in the total terrestrial carbon sink—which is poorly constrained in general and depends on both past and future land cover changes as well as land management practices, climate, and atmospheric CO_2 concentrations—the U.S. sink was held constant in the GCAM analysis at 1990 levels in most cases. The 1990 sink value is the lower than the 2012 value and so represents a conservative estimate based on recent historic values. The importance of changes in the sink for achieving the target emissions level was evaluated through a sensitivity analysis discussed in Chapter 9.

[5] The standard release of GCAM 3.2 was used in this analysis. The full documentation of the model is available at GCAM wiki: wiki.umd.edu/gcam/

Table 3. GCAM Greenhouse Gas Emission Modeling and Source Data[1]

Name	Treatment	Aggregate Emissions data	Sectoral disaggregation data
CO_2	Endogenous	CDIAC	IEA
CH_4	Endogenous	RCP	EDGAR
N_2O	Endogenous	RCP	EDGAR
F-Gases	Endogenous	EMF21	EMF21
Aerosols	Endogenous	RCP	EDGAR

CDIAC: Carbon Dioxide Information Analysis Center; IEA: International Energy Agency; RCP: Representative Concentration Pathway data; EDGAR: Emission Database for Global Atmospheric Research; EMF-21: Energy Modeling Forum Study 21.
Data sources are listed in the Bibliography section.

2.3. Biomass Budget

The primary basis for our estimate of biomass availability and costs is the DOE *Billion Ton Study Update* (BTS2), which includes resource potential estimates to 2030 for purpose-grown energy crops, agricultural and forest residues, and waste products. Table 4 shows the adjustments made in order to align biomass estimates for BTS2 with the PATHWAYS modeling framework. First, currently used resources in the *AEO* reference case were removed from the BTS2 estimates. These include fuel wood, mill residues, pulping liquors, and forest waste resources. These resources are primarily used by industry in combined heat and power (CHP), power generation, and direct fuel applications. PATHWAYS continues to satisfy this current demand and does not make these biomass resources available for other applications in the future. Second, the quantity of purpose-grown energy crops is constrained to a level (371 MMT) that does not result in indirect land use change (ILUC) GHG emissions based on GCAM analysis, described in greater detail Chapter 9. The composition of purpose-grown energy crops nationally is intentionally altered over time in the GCAM analysis, transitioning land currently used for corn ethanol production to second-generation energy crops (perennial grasses and woody purpose-grown feedstocks). With the remaining BTS2 biomass resources included, the upper limit on dry biomass supply in this report is 1,081 million metric tons, with a total primary energy value of 18.5 EJ.

Table 4. Biomass Supply in PATHWAYS Scenarios

Biomass Category	Data Source	Million Metric Tons
Purpose-grown energy crops	GCAM	371
Currently-used biomass resources	AEO Reference Case Demand	250
Other	DOE Billion Ton Study Update	460
Total		**1,081**

2.4. Key References and Data Sources

Many journal articles and technical reports were referred to in the development of the PATHWAYS model and as general points of reference for the assumptions and results in this study. Key sources include the Intergovernmental Panel on Climate Change, the International Energy Agency, the Energy Modeling Forum, U.S. federal government agencies, the National Research Council, national laboratories, university research organizations, state government agencies, and industry. Selected references are included in the Bibliography to this report.

The main data sources used for PATHWAYS model inputs and scenarios in this study are described in the Appendix. The most important single data source used was input files from the DOE National Energy Modeling System (NEMS) used to develop the Energy Information Administration's *Annual Energy Outlook 2013.* NEMS input files covered all major supply and demand sectors in PATHWAYS. These were supplemented by other data sources most of which were federal government reports, models, and databases from the U.S. Environmental Protection Agency, Department of Energy, Federal Highway Administration, and Federal Energy Regulatory Commission, along with similar types of materials from the National Research Council, national laboratories, and state governments.

3. Scenarios

3.1. Design Principles

Four deep decarbonization scenarios were developed in PATHWAYS for this analysis, in order to demonstrate a range of alternative pathways for reaching the 2050 emissions target. A set of twelve design principles was used to constrain these scenarios to be consistent with a conservative approach to engineering and economic feasibility. These principles cover a broad range of concerns—from technology readiness, to resource constraints, to infrastructure inertia, to power system reliability (Table 5). The deep decarbonization scenarios employ the same level of economic activity and demand for energy services as the *AEO* Reference Case, which assumes an economy and lifestyle similar to that of today. Emission reductions are achieved within the U.S., not through international offsets, and with no assumption of growth in the U.S. terrestrial CO_2 sink to offset energy emissions.

Technologies were limited to those that are currently commercial or are near-commercial now and can be reasonably expected to be commercial by the time of their application in the model (Table 5). For instance, electrification of the freight transport and industrial sectors is limited to plausible levels, taking into account foreseeable battery range and industrial process constraints. In the electricity sector, supply-demand balancing constraints are enforced for regional power systems, necessitating storage or curtailment and increasing costs in cases with high penetrations of non-dispatchable resources. For pipeline gas, an upper bound (7%) is enforced on the volumetric share of hydrogen based on safety constraints, requiring that any hydrogen gas produced beyond that from electricity is converted into synthetic natural gas (SNG), incurring additional energy penalties. The total supply of biomass available for energy use was limited based on analysis described elsewhere in this report. The development of new hydropower resources is also limited for sustainability reasons.

Table 5. Scenario Design Principles and Corresponding Modeling Approach

	Design Principle	Modeling Approach
1	Consistent, conservative activity levels	Assume same level of energy service demand in all cases, based on an AEO Reference Case vision of the future economy
2	Technological conservatism	Use commercially demonstrated or near-commercial technologies and conservative cost and performance assumptions
3	Robust emissions strategy	Develop and explore multiple cases with alternative emission reduction pathways and technologies
4	Robust input assumptions	Test sensitivity of results to assumptions about future demand drivers, fuel and technology costs
5	Infrastructure inertia	Enforce natural retirement of infrastructure in stock rollover model
6	Infrastructure conservatism	Minimize application of major new types of distribution infrastructure (e.g., hydrogen pipeline) when alternatives exist

7	Electric reliability	Use hourly dispatch model to ensure adequate capacity and flexibility for all generation mixes
8	Realistic sectoral approaches	Make all decarbonization measures granular and explicit, including challenging sectors (e.g. freight, industry)
9	Environmental sustainability	Apply reasonable sustainability limits to biomass use and hydropower
10	Domestic emissions focus	Do not assume international offsets will be available to reduce U.S. emissions
11	Energy system focus	Focus on reducing energy system CO_2 as the pivotal transition task, do not assume large forestry sink will be available
12	Regional flexibility	Employ decarbonization strategies consistent with regional infrastructure, resources, and policy preferences

3.2. Decarbonization Strategies

The scenarios were developed around portfolios of measures used to implement three main decarbonization strategies:

1. **Energy Efficiency**—making final energy consumption more efficient;
2. **Energy Supply Decarbonization**—reducing net CO_2 emissions from energy conversion;
3. **Fuel Switching**—switching to energy carriers that have lower net CO_2 emission factors.

The menu of key measures used to implement these strategies in different energy supply and demand sectors are shown in Table 6.

Table 6. Key Decarbonization Measures by Sector and Decarbonization Strategy

Strategy and Sector	Measures
Energy Efficiency Strategies	
Residential and commercial energy efficiency	• Highly efficient building shell required for all new buildings • New buildings require electric heat pump HVAC and water heating • Existing buildings retrofitted to electric HVAC and water heating • Near universal LED lighting in new and existing buildings
Industrial energy efficiency	• Improved process design and material efficiency • Improved motor efficiency • Improved capture and re-use of waste heat • Industry specific measures, such as direct reduction in iron and steel
Transportation energy efficiency	• Improved internal combustion engine efficiency • Electric drive trains for both battery and fuel cell vehicles (LDVs) • Materials improvement and weight reduction in both LDVs and freight

Energy Supply Decarbonization Strategies	
Electricity supply decarbonization	• Different low-carbon generation mixes with carbon intensity <50 gCO_2 /kWh that include renewable, nuclear, and CCS generation
Electricity balancing	• Flexible demand assumed for EV charging and thermal building loads • Flexible intermediate energy production for hydrogen and power-to-gas processes to take advantage of renewable overgeneration • Hourly/daily storage and regulation from pumped hydro • Natural gas w/CCS
Pipeline gas supply decarbonization	• Synthetic natural gas from gasified biomass and anaerobic digestion • Hydrogen and SNG produced with wind/solar over-generation provides smaller but potentially important additional source of pipeline gas
Liquid fuels decarbonization	• Diesel and jet-fuel replacement biofuels • Centralized hydrogen production through electrolysis • Centralized hydrogen production through natural gas reformation w/CCS
Fuel Switching Strategies	
Petroleum	• LDVs to hydrogen or electricity • HDVs to LNG, CNG, or hydrogen • Industrial sector petroleum uses electrified where possible, with the remainder switched to pipeline gas
Coal	• No coal without CCS used in power generation or industry by 2050 • Industrial sector coal uses switched to pipeline gas and electricity
Natural gas	• Low carbon energy sources replace most natural gas for power generation; non-CCS gas retained for balancing in some cases • Switch from gas to electricity in most residential and commercial energy use, including majority of space and water heating and cooking

3.3. Pathway Determinants

This study finds five critical elements that strongly determine pathways, the ensemble of technologies and measures deployed over time to decarbonize energy supply and demand. These elements, once determined by explicit policy choices, market realities, resource endowments, or institutional inertia, can significantly constrain or enable other resource and technology options and shape the overall features of the resulting energy system:

- **CCS availability and application.** The question of the commercial viability of CCS in different applications, its availability in different geographic locations, its capture rates and associated energy requirements, and its storage capacity and throughput fundamentally determine how much fossil fuel combustion can remain in the energy system. In this study, CCS is used in two of the four cases: for power generation only in the mixed case, and for power, industry, and bio-refining in the high CCS case.
- **Biomass supply and allocation.** Because biomass is a versatile energy feedstock that can displace different kinds of fossil fuel, the amount available with zero or low net lifecycle CO_2 emissions, and

its allocation to different forms of final energy supply, has a strong impact on other aspects of the energy system. In this study, biomass supply is used primarily for production of renewable gas and liquid fuels. Negative emissions bioenergy-CCS is applied only to bio-refining in the high CCS case.

- **Primary energy for electricity generation.** Electricity generation, including that used for production of intermediate energy carriers, becomes the dominant form of delivered energy in all deep decarbonization cases. The forms of primary energy used for electricity generation thus have a strong impact on cost, balancing requirements, system design, siting, and secondary environmental impacts. In this study, the effects of generation mix are explored using "corner cases" with high renewables, high nuclear, and high CCS generation portfolios, plus a mixed case includes roughly equivalent generation from all three decarbonized options.
- **Electricity balancing resources.** The choice of primary energy for generation strongly affects electricity balancing requirements. For systems with high levels of inflexible generation (e.g., variable wind and solar, conventional baseload nuclear), a variety of balancing strategies are needed to maintain reliable system operation, including regional coordination, natural gas generation, curtailment, energy storage, and flexible loads. In this study, power-to-gas hydrogen and synthetic natural gas production are also used as balancing resources, providing low carbon fuels in the process.
- **Fuel switching.** Energy efficiency is widely considered the first option to pursue in a low carbon portfolio, with value independent of other pathway determinants. In deep decarbonization cases, coordinating end use choices with the other design choices (e.g., whether CCS exists, how biomass is allocated) is required to make optimal tradeoffs between fuel type and efficiency level from the standpoint of cost and emissions. In this study, significant efficiency improvements come from thermodynamic advantages inherent in certain kinds of fuel switching (e.g., from internal combustion to electric drive train vehicles, from natural gas heat to ground-source heat pumps).

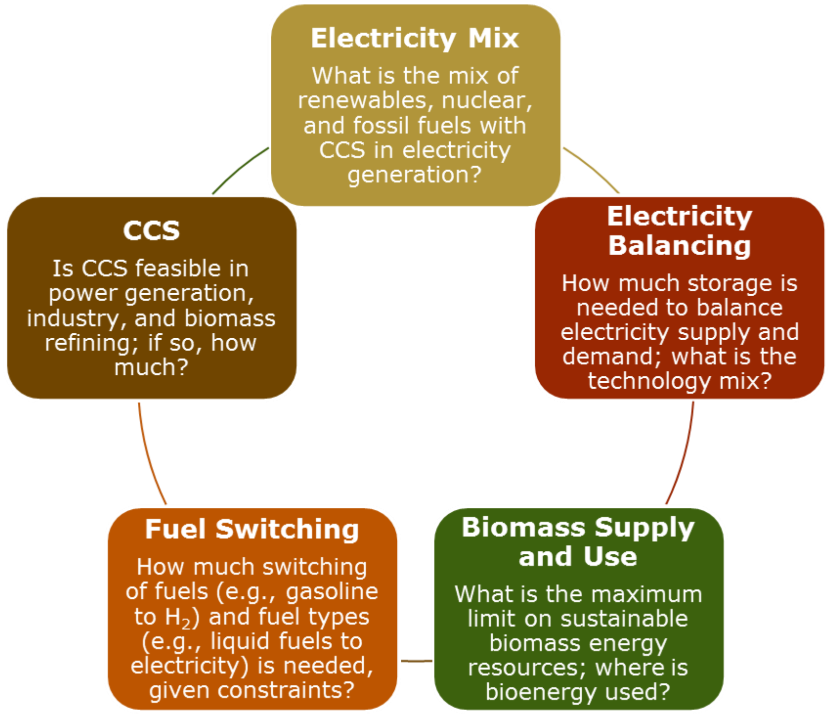
An example illustrates how these critical elements interact to shape a low carbon pathway. If CCS is not an option in power generation, the choices for low carbon electricity are narrowed to renewable energy and nuclear power. The amount of electricity storage required to balance either of these resources depends on the mix of generation resources (e.g., wind, solar, hydropower, nuclear), their location, and load flexibility (e.g., EV stock and charging schedules). Electricity can be stored in different carriers—electricity (pumped hydro, batteries), gas (electrolysis, electrolysis-methanation), or liquids (electrolysis-liquefaction). The energy storage technology mix, limits on biomass supply and how it is used, and CCS feasibility influence fuel switching decisions, both within a given fuel type (e.g., gasoline to liquid hydrogen) and across fuel types (e.g., liquid fuels to electricity).

The interactions between these critical elements affect the balance of electricity, gas, and liquid fuels across end use sectors and the extent of fuel decarbonization required.[6] Decarbonizing pipeline gas with gasified biomass and power-to-gas (hydrogen or synthetic methane) limits the need for fuel switching (e.g., pipeline gas to electricity) in industry, but it also enables liquid-to-pipeline gas fuel switching for freight transport. Decarbonizing liquid fuels with biofuels and electric fuels (hydrogen) limits the need

[6] Throughout this report, gas and liquid fuels are distinguished by how they are distributed. Liquefied pipeline gas, for instance, is considered a gas, whereas liquefied hydrogen, which is distributed in liquid form, is considered a liquid.

for switching fuel types (e.g., liquids to electricity or gas) in transport, but can require greater switching of fuel types in buildings and industry, depending on how decarbonized the liquid fuel mix is.

Figure 6. Pathways Determinants: Critical Elements that Determine the Features of a Low Carbon Energy System



3.4. Four Deep Decarbonization Scenarios

The four deep decarbonization cases created for this analysis represent a range of pathways that result from significantly different technology choices among the critical elements in Figure 6, organized around the three primary energy choices for electricity—renewable energy (High Renewables Case), nuclear (High Nuclear Case), and fossil fuels with CCS (High CCS Case). The Mixed Case includes a balanced mix of all three primary energy resources. All cases have similar strategies for and levels of energy efficiency. The four cases are intended to illustrate a broad suite of consistent, interrelated technology choices, while still remaining tractable for purposes of presentation. They are not intended to be exhaustive.

Figure 7 characterizes each scenario as a function of the pathway determinants in Figure 6. The figure shows a column for each determinant and a row for each scenario, with a colored "donut" showing the mix of options following the legend at the top, and the full scale value of a complete "donut" shown at the bottom of the figure. For example, the fifth column from the left shows generation mix, with the "donut" for each scenario showing the percentage of each type of primary energy used in generation, in each case adding up to 100%. As another example, the second column from the left shows CCS. For each scenario, the "donut" shows how much of the total reduction in fossil fuel CO_2 across all scenarios, 4890 Mt CO_2 (the difference between the 750 Mt target and the 2050 Reference Case emissions of 5640 Mt) results from non-CCS measures and CCS measures of different kinds, which are used only in the Mixed and High CCS cases.

The Mixed Case has no deployment of CCS outside the electricity sector, and a balanced mix of renewable energy, nuclear power, and natural gas with CCS in electricity generation. Non-dispatchable renewables and nuclear power are balanced with electricity storage (pumped hydro), flexible end-use electric loads (electric vehicles and thermal loads like water heating), and electric fuel loads. Hydrogen and synthetic natural gas (SNG) produced from electricity (referred to here as power-to-gas (P2G)) and biomass are used to decarbonize pipeline gas, which is used in freight transport and industry.

In the High Renewables Case, high penetrations of wind and solar energy require higher levels of electricity balancing, still in the form of P2G, than in the Mixed Case. Due to safety limits on hydrogen in the gas pipeline, SNG production (methanation of hydrogen from electrolysis) is used to balance the renewable portfolio on a seasonal (weeks to months) basis, which takes advantage of existing gas distribution system storage capacity to produce only when there are over-generation conditions on the electricity grid. Most available biomass resources are gasified and used in the pipeline, which, combined with high volumes of P2G, leads to a low net CO_2 pipeline gas mix. Pipeline gas becomes the dominant non-electric fuel, primarily used in industry and freight transportation.

Liquid fuels are the dominant non-electric fuel in the High Nuclear Case. Electricity imbalances in this case are on shorter timescales (days to weeks), and do not require longer-term fuel storage as in the High Renewables Case. Electricity balancing is done primarily through liquid hydrogen production. Hydrogen and biofuels are used in tandem to decarbonize the transportation (liquid) fuel supply. This allows higher levels of natural gas to remain in the gas pipeline, with pipeline gas primarily used in industry.

The High CCS Case seeks to preserve a status quo energy mix, both on the supply and consumption sides. Coal remains a significant share of the electricity generation mix, requiring large volumes of CCS and creating a large CO_2 residual (i.e., capture is not 100% effective) that must be balanced by reductions elsewhere. This is accomplished by significant use of CCS in industry and the use of CCS to capture CO_2 emissions in biomass refining, which creates a source of negative net CO_2 emissions. End-use fuel switching is limited to building and passenger vehicle electrification. The primary energy sources of fuels do change, however, with the major transition occurring in freight transport, where there is a shift to "renewable diesel"—a Fischer-Tropsch biofuel. The use of biomass energy CCS (BECCS) gives the transportation sector net negative CO_2 emissions,[7] allowing higher CO_2 emissions in industry.

The Mixed Case serves as the main case in this report. This is not the result of a judgment that the Mixed Case is inherently more plausible than the three "High" cases, but is rather intended to incorporate a greater mix of technologies for illustrative purposes. The analysis does not seek to evaluate or rank these cases.

[7] For new energy sources, we allocate CO_2 emissions for upstream refining to end use sectors, rather than to the industrial sector.

Figure 7. Pathway Determinants by Scenario in 2050

Table 7 shows key metrics for all of the scenarios referred to in this report.

Table 7. Scenario Summary for 2014, 2050 Reference Case, and Four 2050 Deep Decarbonization Scenarios

Indicator	Units	2014	Reference	Mixed	High Renewables	High Nuclear	High CCS
Emissions							
Residential	MMT	1,053	1,128	28	35	54	119
Commercial	MMT	942	1,080	48	57	73	141
Transportation	MMT	1,797	1,928	450	385	247	-73
Industry	MMT	1,361	1,503	220	263	374	555
Total all sectors	MMT	5,153	5,639	746	740	747	741
Final Energy Demand							
Residential	EJ	11	13	7	7	7	7
Commercial	EJ	9	11	8	8	8	8
Transportation	EJ	27	29	15	15	14	15
Industry	EJ	22	27	24	24	23	26
Total all sectors	EJ	68	80	54	55	53	56
Electricity Share (Final Energy)							
Buildings - Residential	%	46.0%	51.9%	94.2%	94.2%	94.2%	94.2%
Buildings - Commercial	%	57.8%	61.2%	89.9%	89.9%	89.9%	89.9%
Transport - Passenger (primarily LDV)	%	0.1%	0.2%	28.2%	45.8%	20.2%	46.1%
Transport - Freight (primarily HDV)	%	0.0%	0.0%	3.7%	2.5%	3.4%	2.6%
Industry	%	22.7%	18.9%	27.1%	24.9%	28.2%	20.4%
Total all sectors	%	20.8%	24.1%	42.9%	42.9%	43.0%	40.5%
Electric Fuel (Hydrogen and SNG) Share (Final Energy)							
Buildings - Residential	%	0.0%	0.0%	0.4%	0.8%	0.2%	0.0%
Buildings - Commercial	%	0.0%	0.0%	0.9%	1.7%	0.5%	0.0%
Transport - Passenger (primarily LDV)	%	0.0%	0.0%	29.3%	1.7%	55.4%	1.5%
Transport - Freight (primarily HDV)	%	0.0%	0.0%	21.5%	31.4%	39.3%	5.7%
Industry	%	0.0%	0.0%	4.9%	8.3%	2.8%	0.0%
Total all sectors	%	0.0%	0.0%	8.5%	8.8%	12.3%	0.9%
Electric generation							
Total net generation	EJ	15	20	30	32	32	24
Delivered electricity (final energy)	EJ	14	19	23	23	23	23
Share wind	%	5.4%	7.2%	39.2%	62.4%	34.1%	14.2%

Indicator	Units	2014	Reference	Mixed	High Renewables	High Nuclear	High CCS
Share solar	%	0.4%	4.0%	10.8%	15.5%	11.3%	5.3%
Share biomass	%	1.1%	0.9%	0.6%	0.6%	0.6%	0.8%
Electric generation (continued)							
Share geothermal	%	0.5%	1.0%	0.7%	0.6%	0.6%	0.8%
Share hydro	%	6.2%	7.0%	5.6%	5.3%	5.4%	7.0%
Share nuclear	%	19.2%	15.2%	27.2%	9.6%	40.3%	12.7%
Share gas (CCS)	%	0.0%	0.0%	12.2%	0.0%	0.0%	26.3%
Share coal (CCS)	%	0.0%	0.0%	0.0%	0.0%	0.0%	28.6%
Share gas (non-CCS)	%	21.9%	31.4%	0.5%	2.8%	4.6%	0.1%
Share coal (non-CCS)	%	41.5%	28.1%	0.0%	0.0%	0.0%	0.0%
Share other (fossil)	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Share CHP	%	3.3%	5.2%	3.3%	3.1%	3.2%	4.2%
Gas							
Final energy	EJ	16.2	17.1	11.8	16.0	8.2	10.6
Fossil Share of Final Energy	%	100.0%	100.0%	6.4%	17.1%	58.1%	81.2%
Biomass share of final energy	%	0.0%	0.0%	81.9%	60.2%	35.3%	6.1%
H2 share of final energy	%	0.0%	0.0%	6.7%	6.7%	6.6%	0.0%
SNG share of final energy	%	0.0%	0.0%	5.0%	16.0%	0.0%	0.0%
Fossil w/CCS Share of Final Energy		0.0%	0.0%	0.0%	0.0%	0.0%	12.7%
Liquids and Solids							
Final energy	EJ	34	37	15	12	18	19
Share biomass	%	2.0%	2.3%	0.8%	1.0%	24.0%	28.8%
Share liquid H2	%	0.0%	0.0%	20.7%	10.3%	32.6%	2.6%
Share petroleum	%	80.6%	78.7%	43.4%	41.8%	13.9%	32.5%
Share coal and coke	%	4.6%	4.0%	1.1%	1.3%	0.8%	6.7%
Share feedstocks	%	12.8%	15.1%	34.1%	45.5%	28.7%	29.3%
Intensity metrics							
US population	Million	323	438	438	438	438	438
Per capita energy use rate	GJ/person	211	183	123	125	121	128
Per capita emissions	t CO_2/person	16.0	12.9	1.7	1.7	1.7	1.7
US GDP	B 2012$	16,378	40,032	40,032	40,032	40,032	40,032
Economic energy intensity	MJ/$	4.17	2.00	1.35	1.37	1.32	1.40
Economic emission intensity	kG CO_2/$	0.31	0.14	0.02	0.02	0.02	0.02
Electric emission intensity	g CO_2/kwh	510.9	413.5	13.5	16.0	23.4	54.7

4. Results: High Level Summary

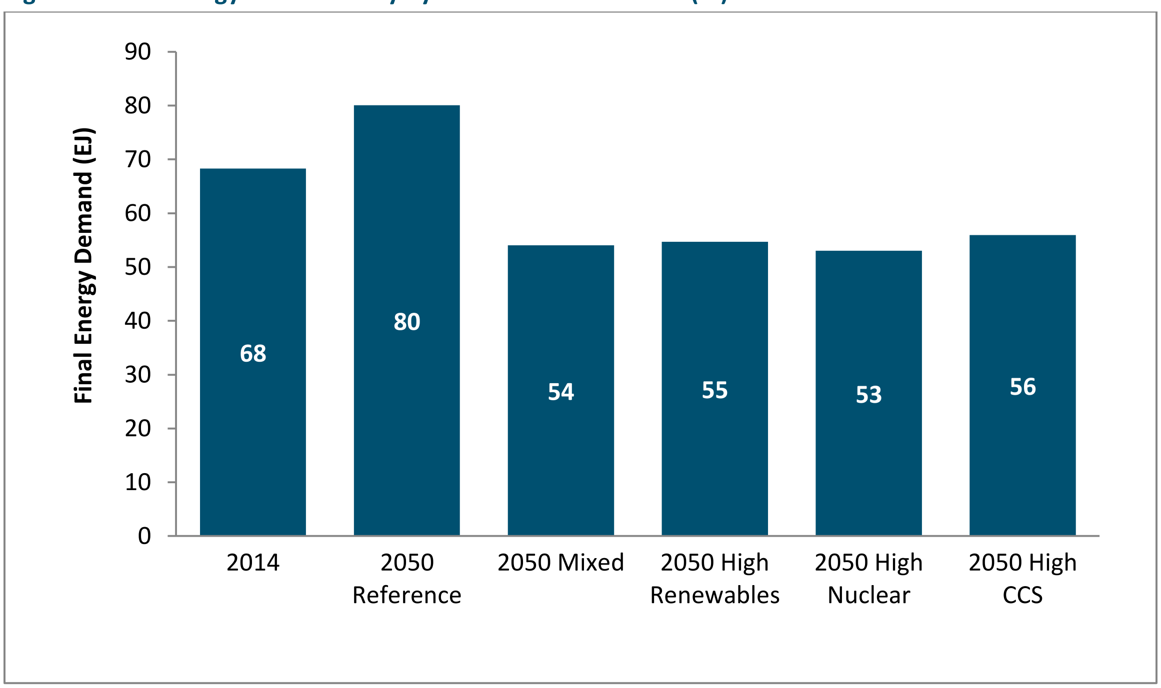
This section summarizes the high level results of this analysis across the four deep decarbonization scenarios and the Reference Case. Subsequent sections contain the following results:

- **Energy Demand—**results for end use efficiency and fuel switching in the residential, commercial, transportation, and industrial sectors;
- **Energy Supply—**results for electricity, gas, and liquid fuel mixes, and illustrative results for regional power system dispatch;
- **CO_2 Emissions—**CO_2 emissions results for end use, sectors, and regions;
- **Costs—**incremental costs results by sector and cost component, household and electricity costs; comparison to cost results from EMF-24.
- **GCAM Results—** results for technical feasibility and cost of non-energy and non-CO_2 emissions mitigation

4.1. Final Energy

By 2050, the Reference Case shows a modest 17% increase in total final energy use relative to 2014 levels, from 68 to 80 EJ (Figure 8). The underlying drivers of energy use—population (+35%), building floor area (+44%), industrial output (+81%)—all grow significantly over this time period, but their impact on energy use is partially offset by increases in the efficiency of energy use, which are a continuation of current policy and technology trends. Final energy use in the deep decarbonization cases ranges from 53 to 56 EJ, a reduction of 30-34% below the Reference Case in 2050, and 18-22% below 2014 levels.

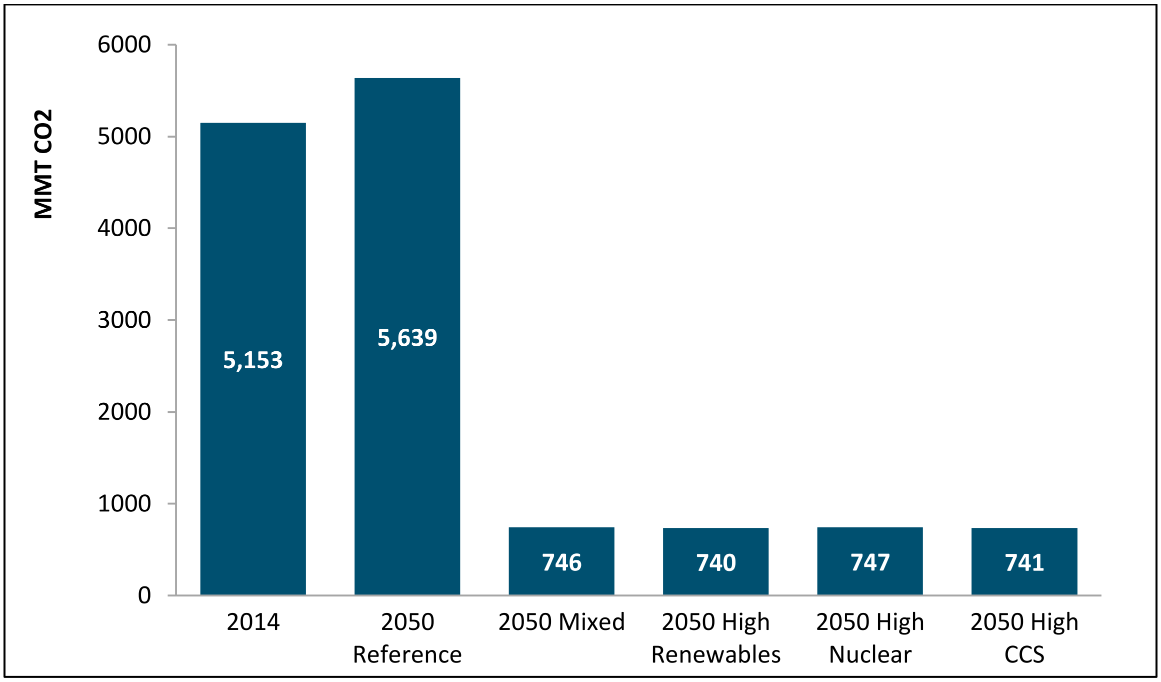
Figure 8. Final Energy Use Summary by Case in 2014 and 2050 (EJ)



4.2. Emissions

Energy-related CO_2 emissions levels experience more dramatic change (Figure 9). Reference Case CO_2 emissions reach 5,639 $MtCO_2$ by 2050, a 9% increase from total 2014 emissions and a 19% reduction in emissions per capita—from 16.0 to 12.9 tCO_2 per person. All four deep decarbonization cases reach emissions below 750 $MtCO_2$, or 1.7 tCO_2 per person, an 85% reduction in total emissions and an 89% reduction in emissions per capita relative to 2014 levels.

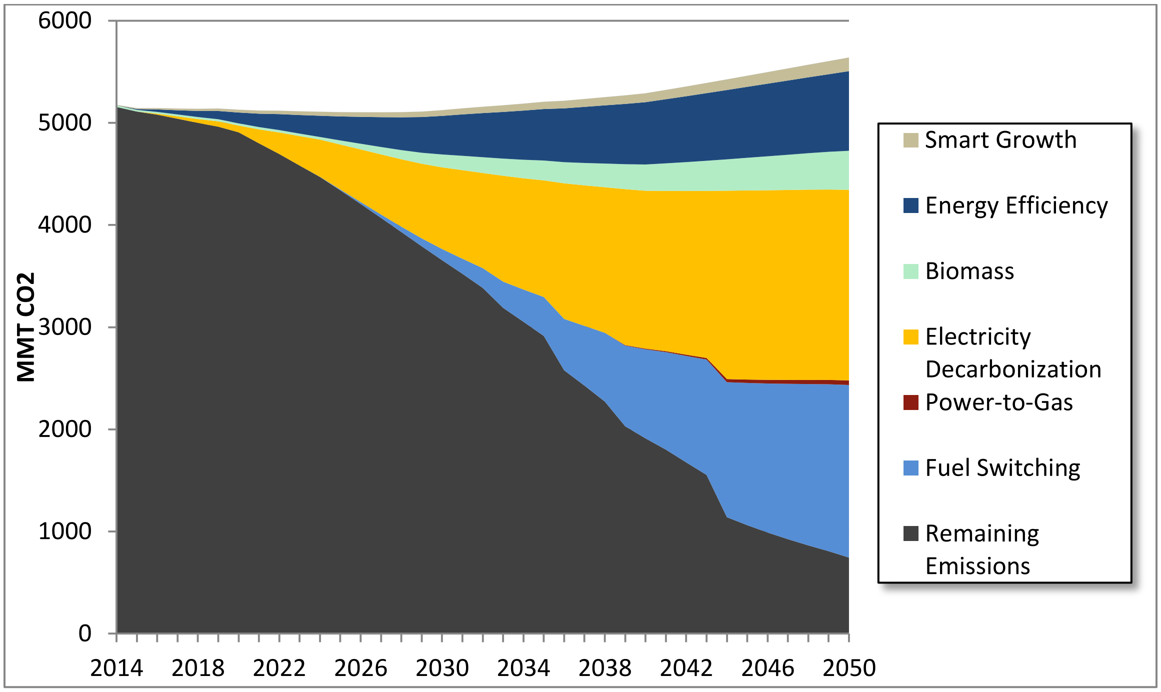
Figure 9. CO_2 Emissions by Case in 2014 and 2050



4.3. Emission Reductions

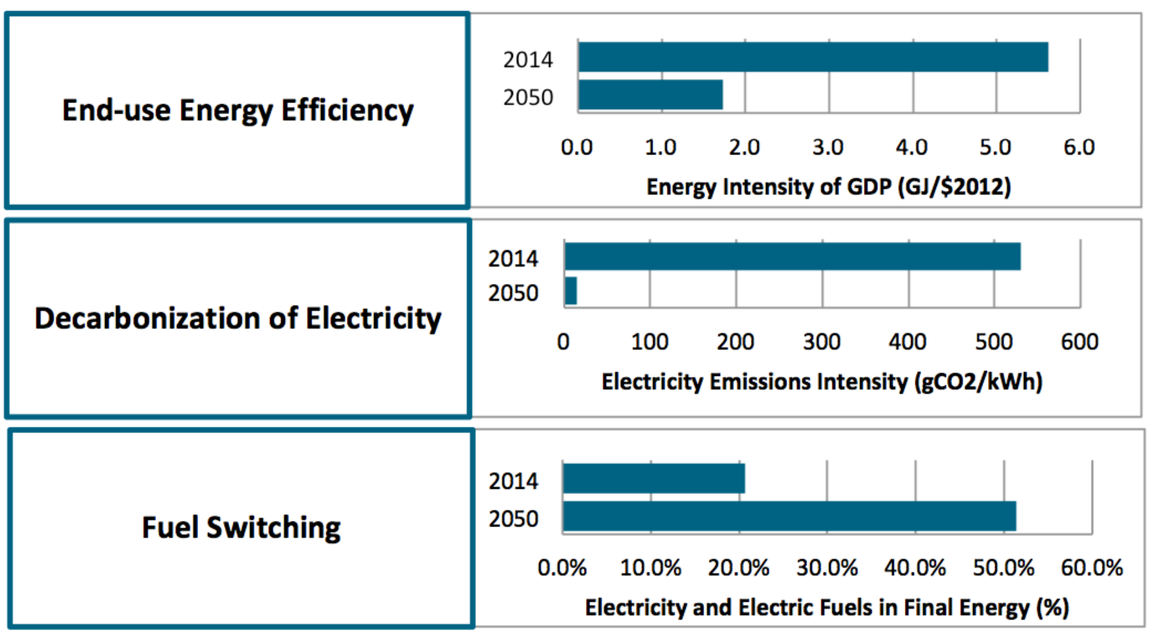
The transition to a low-carbon energy system entails three main strategies: (1) highly *efficient end use* of energy in buildings, transportation, and industry; (2) *decarbonization* of electricity and other fuels; and (3) *fuel switching* of end uses from high-carbon to low-carbon supplies, primarily electric. All three of these strategies must be applied to achieve the 2050 decarbonization goal. For the case shown in Figure 10, these measures together account for 90% of the reduction from Reference Case emissions of about 5500 Mt in 2050 to the target level of 750 Mt, with energy efficiency accounting for 20%, fuel switching for 31%, and electricity decarbonization for 39%. (Note that the allocation of emission reductions to different decarbonization wedges is subjective due to interactive effects between the measures. For example, the replacement of an inefficient internal combustion engine automobile with an efficient electric vehicle that charges on a low carbon electricity grid simultaneously employs all three main strategies.)

Figure 10. Decarbonization Wedges for the U.S., Mixed Case



Indicators for the three main decarbonization strategies are shown for the Mixed Case in Figure 11. The share of end-use electricity or electrically-produced fuels increases from 20% in 2010 to over 50% in 2050. The carbon intensity of electricity is reduced from more than 500 g CO_2/kWh in 2014 to less than 15 g CO_2/kWh in 2050. Energy intensity of GDP decreases by 70% over this period as final energy use declines from 68 to 54 EJ while GDP nearly doubles.

Figure 11. Indicative Metrics for the Three Main Decarbonization Strategies, Mixed Case Compared to 2014

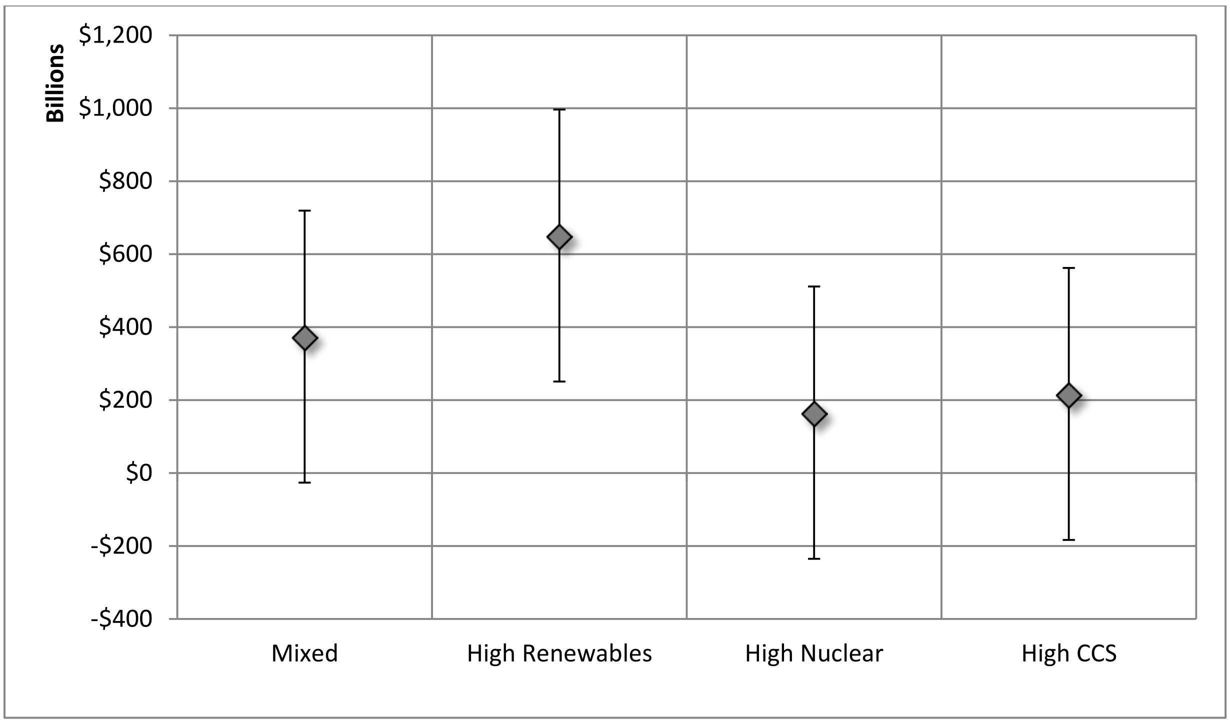


4.4. Cost

Incremental energy system costs—incremental capital costs plus net energy costs—exhibit a broad range in 2050, reflecting the significant uncertainty in technology costs and fossil fuel prices over such a long timeframe. Under base assumptions of technology costs and fossil fuel prices, the median value of incremental costs ranges from $160 billion (2012 $) to $650 billion across scenarios, with the difference driven primarily by the relative quantities and prices of residual natural gas and petroleum fuels remaining in the energy system in 2050.[8] The average median value across cases is just over $300 billion.

Based on an uncertainty analysis of key cost parameters, the interquartile range of incremental energy system costs extends from negative $250 billion to $1 trillion across all cases (Figure 12). To put these numbers in context, the activity drivers in PATHWAYS that drive energy service demand in all of the cases are consistent with a U.S. GDP that grows by a real annual average rate of just over 2% per year over the next four decades, to around $40 trillion in 2050. The average 75th percentile estimate of net incremental energy system costs ($730 billion) across cases is equivalent to 1.8% of this GDP level. The average 25th percentile value is negative $90 billion.

Figure 12. Incremental Energy System Costs in 2050



Note: The error bars in the figure show the 25th and 75th percentile values.

[8] Petroleum fuel prices are significantly more expensive than natural gas by 2050 in the AEO 2013 Reference Case. Thus, scenarios in which more petroleum fuels are displaced are lower net cost.

5. Results: Energy Demand

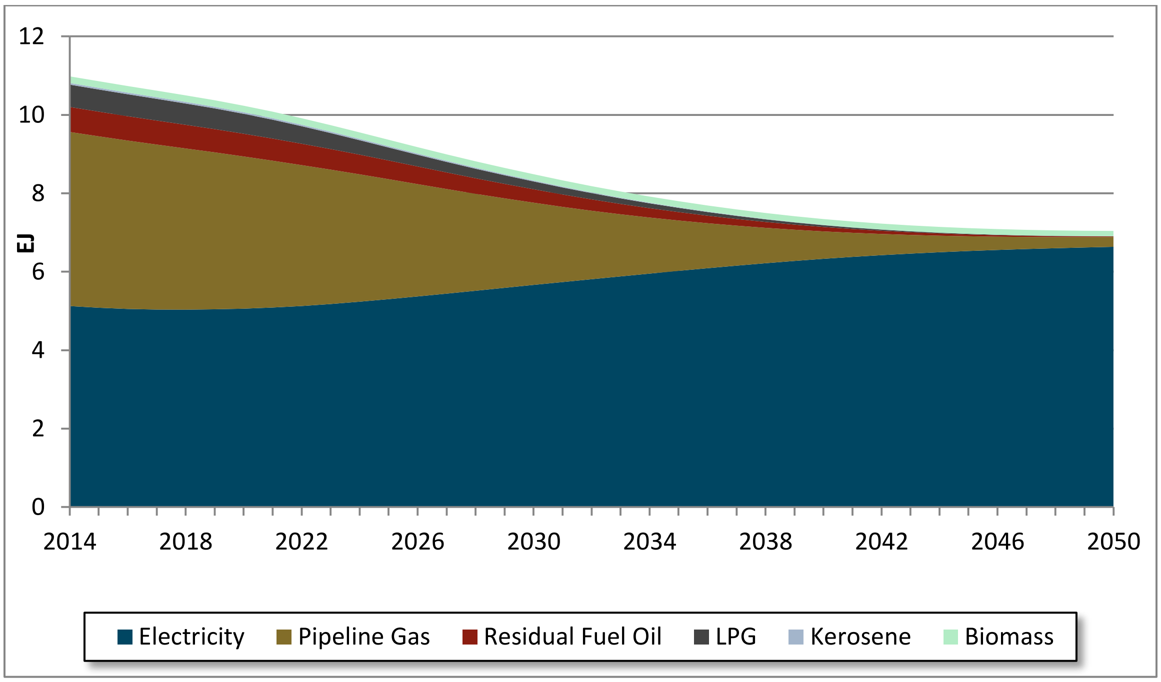
5.1. Residential

In all four decarbonization cases, significant gains in end use energy efficiency offset a 36% increase in population from 2014 to 2050. Improvements in efficiency result from three primary strategies:

1. Electrification of space and water heating, the two primary residential energy end uses;
2. Aggressive efficiency improvements in electric end uses, such as clothes washers, dishwashers, and lighting;
3. Improving residential building envelopes (e.g., windows, roofs, insulation) to reduce the demand for space heating and cooling.

As a result of the electrification of space and water heating, electricity accounts for the vast majority of final energy demand by 2050 in all decarbonization cases (Figure 13).

Figure 13. Residential Energy Demand, All Decarbonization Cases

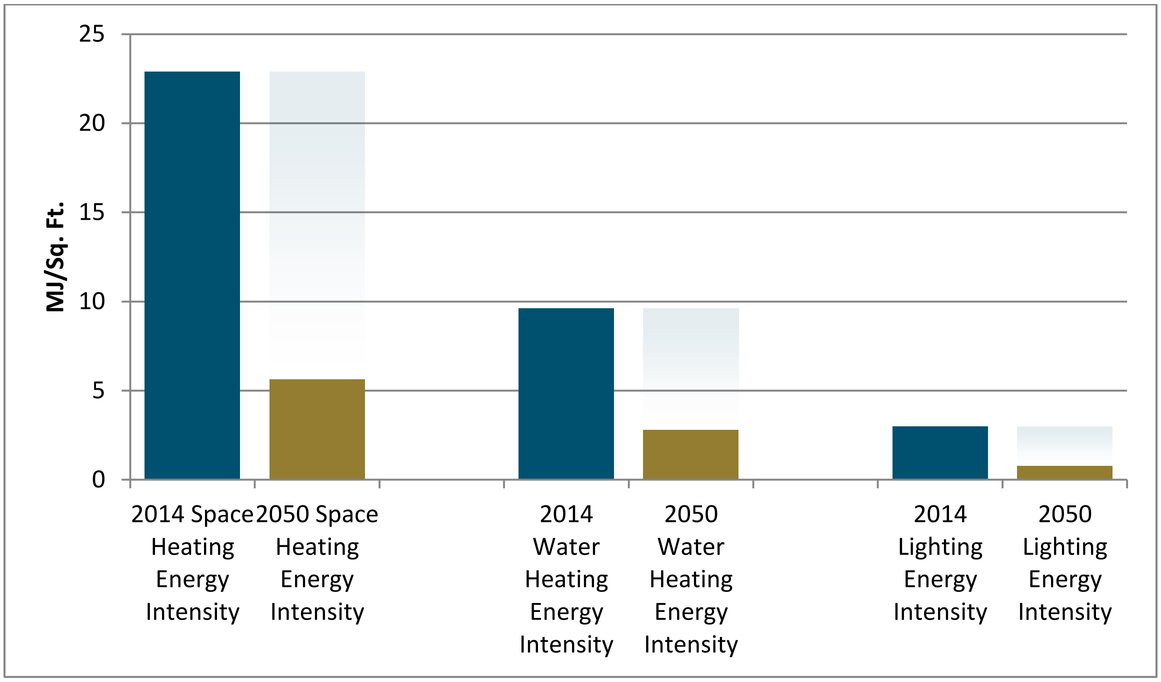


The largest declines in residential energy intensity are seen in three end uses:

1. Space heating, due to the higher efficiency of heat pumps and the effect of building envelope measures that reduce heating demand;
2. Water heating, due to the higher efficiency of heat pumps and hot water savings from high-efficiency dishwashers and clothes washers;
3. Lighting, due to the high penetration of very efficient LEDs.

Figure 14 shows the magnitude of these efficiency improvements by 2050 relative to 2014, normalized by floor space.

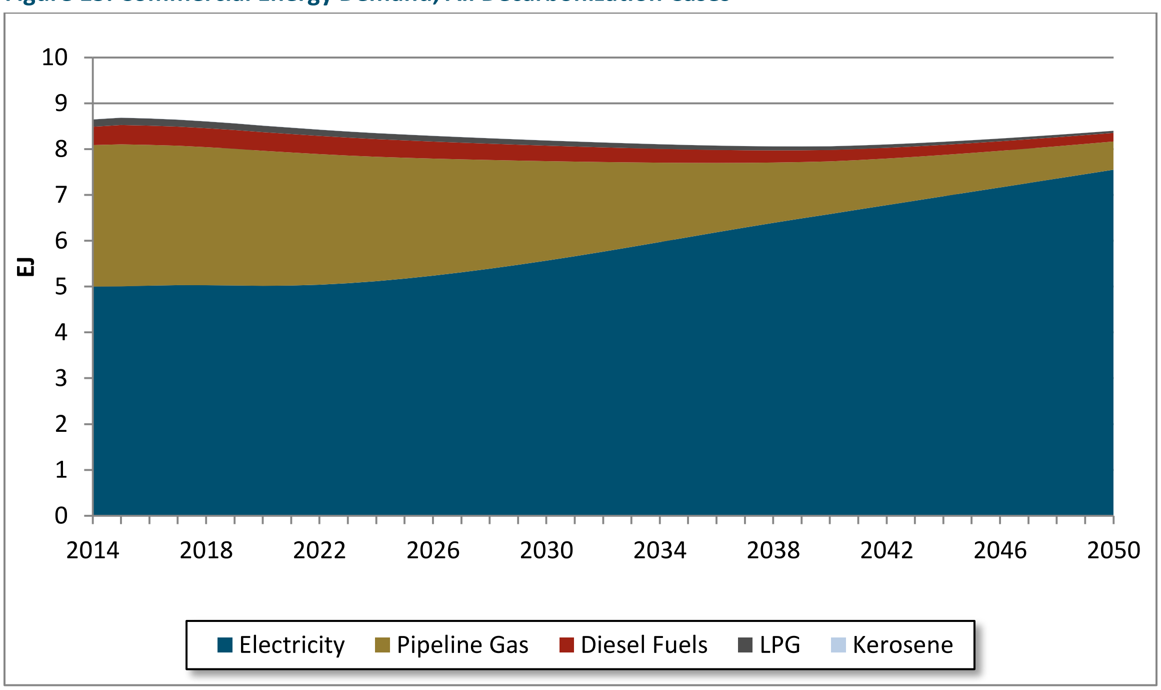
Figure 14. Residential Energy Intensity Comparison: 2014 and 2050 Decarbonization Case Results



5.2. Commercial

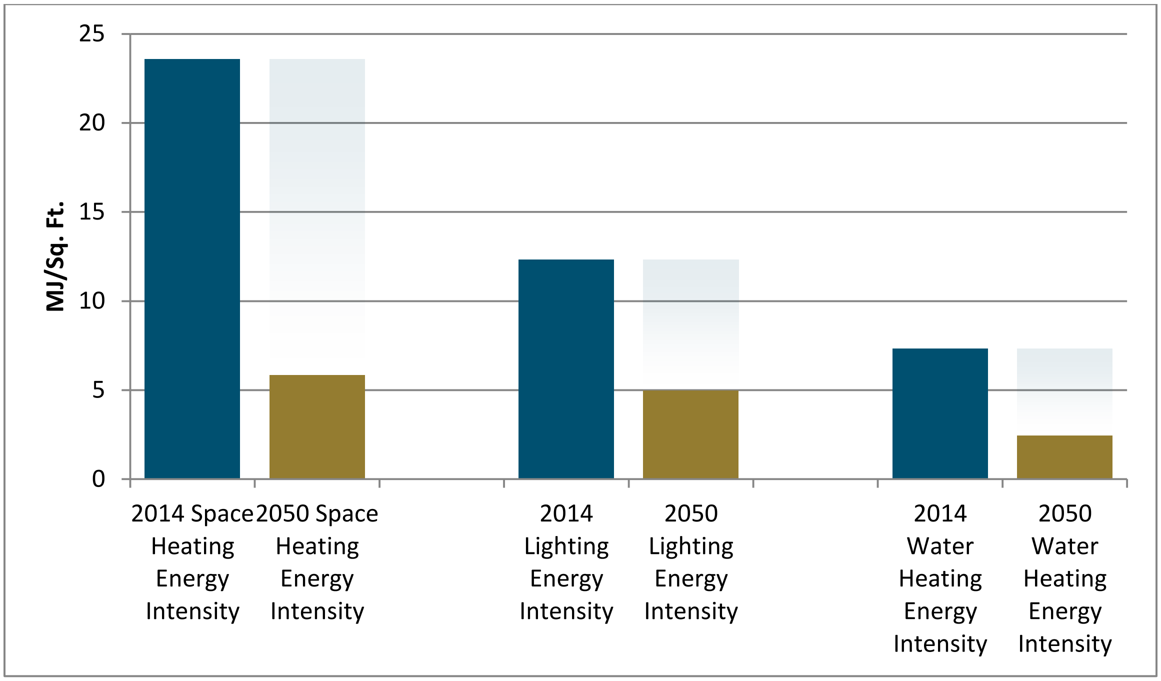
Like the residential sector, most commercial sector end uses are electrified, and electricity becomes the dominant energy carrier across all four decarbonization cases (Figure 15). Through improvements in efficiency, commercial final energy use remains relatively flat over 2014-2050, despite a more than 40% increase in commercial floor area.

Figure 15. Commercial Energy Demand, All Decarbonization Cases



Similar to the residential sector, the largest gains in commercial sector end use efficiency are in space heating, lighting, and water heating, with improvements in space and water heating due to the use of high efficiency electric heat pumps and improvements in lighting efficiency to the prevalence of LEDs. The magnitude of improvements in these three areas by 2050, relative to 2014, is shown in Figure 16.

Figure 16. Commercial Energy Intensity Comparison: 2014 and 2050 Decarbonization Case Results



5.3. Transportation

5.3.1. Light-Duty Vehicles

LDV stocks evolve from the fossil fuel-powered internal combustion engines (ICEs) prevalent today to a mix of electric vehicles (EVs), plug-in hybrid electric vehicles (PHEVs), and hydrogen fuel cell vehicles (HFCVs). None of the technology options modeled here achieves significant stock penetration until the 2030 timeframe, as shown in Figure 17 for the Mixed Case. Electricity is the dominant energy carrier for passenger vehicle transport in all cases except for the High Nuclear Case, where hydrogen produced from electrolysis is the primary energy carrier. Gasoline is used as the residual fuel for PHEVs traveling beyond their electric range, and thus gasoline continues to be a non-trivial portion of LDV energy use in the High Renewables and High CCS Cases, which have large PHEV stocks (Figure 19).

By 2050, however, no significant numbers of ICE LDVs remain in any of the cases (Figure 18), as a result of high penetrations of non-ICE vehicles in new car sales by 2035. In the High Renewables and High CCS Case, EVs and PHEVs dominate the vehicle fleet. In the High Nuclear Case, HFCVs and EVs dominate. The Mixed Case has a roughly equal blend of EVs, PHEVs, and HFCVs by 2050.

Figure 17. Annual LDV Stock

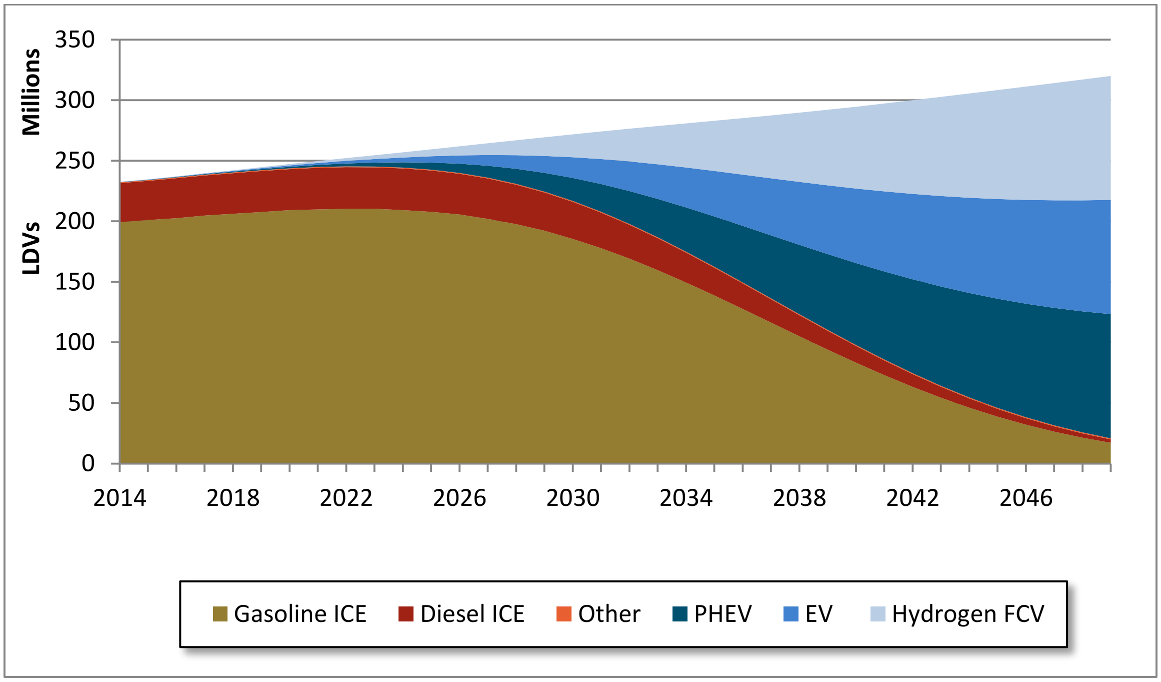


Figure 18. 2050 LDV Stock

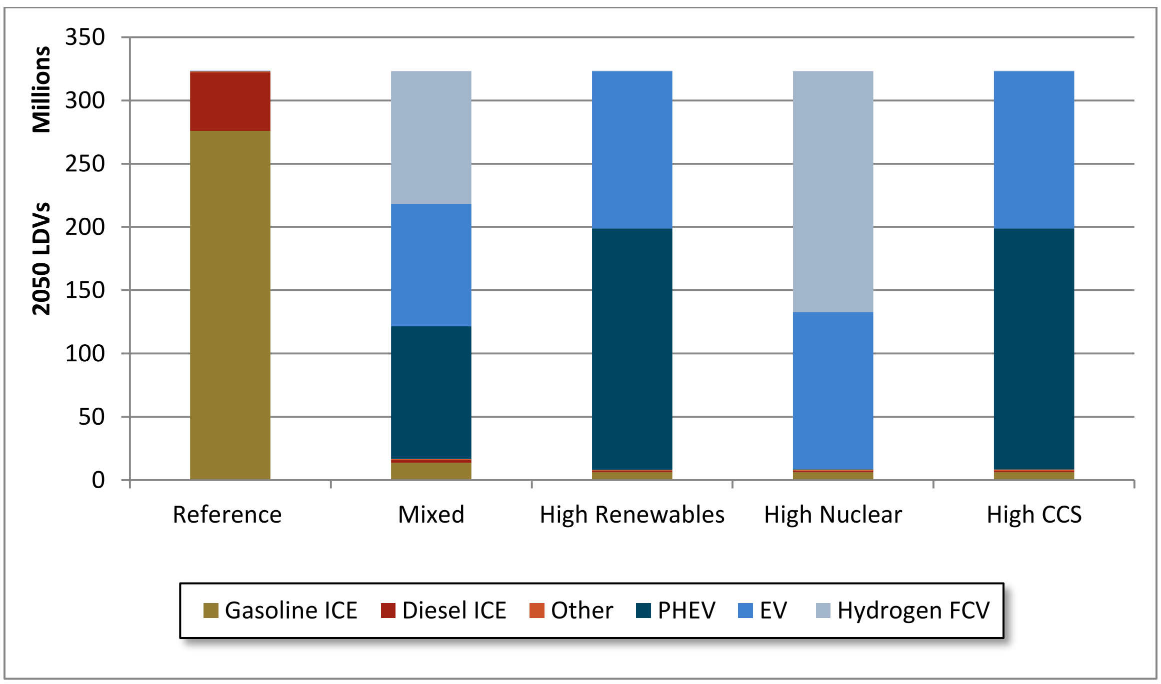
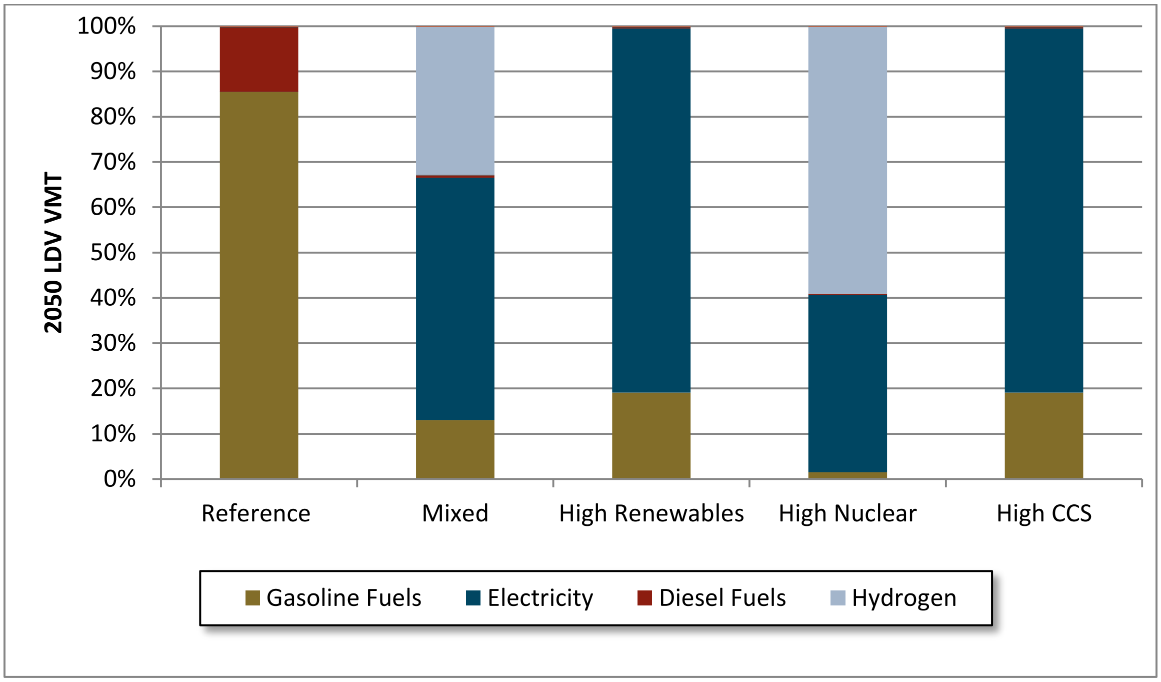
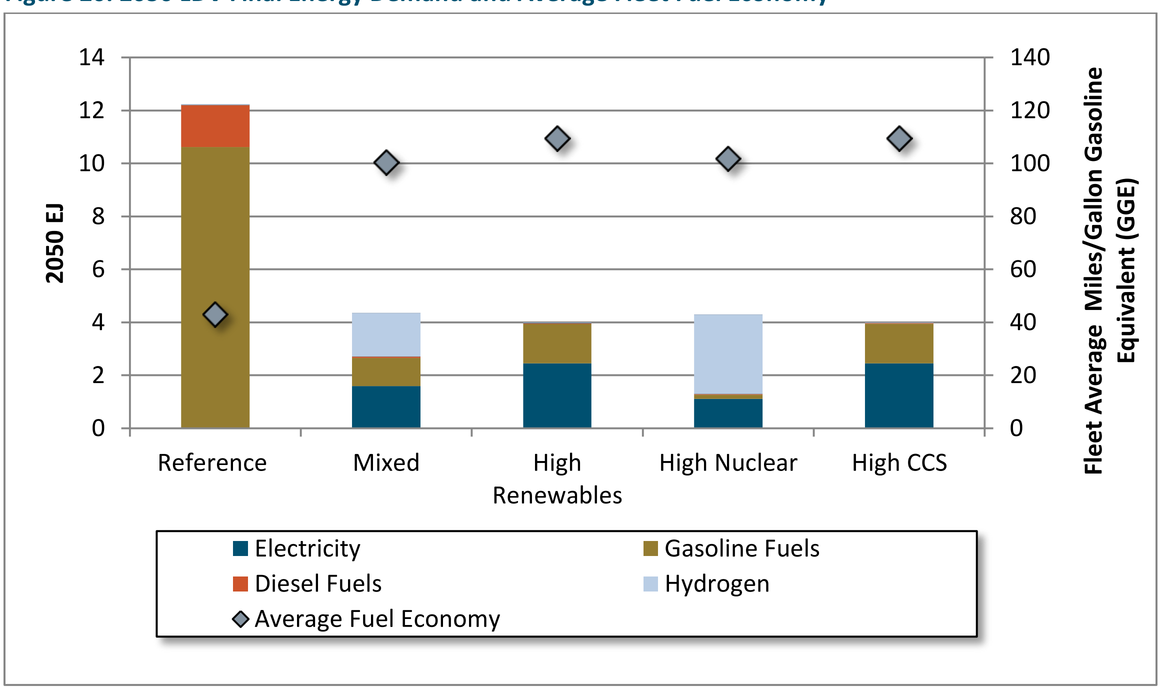


Figure 19. 2050 LDV VMT by Fuel



Across all cases, LDV final energy demand declines by nearly 70% from the Reference Case by 2050. This decline results primarily from a more than doubling of the LDV fleet's fuel economy, with the average fleet fuel economy of exceeding 100 miles per gallon gasoline equivalent (GGE) in all four decarbonization cases (Figure 20).

Figure 20. 2050 LDV Final Energy Demand and Average Fleet Fuel Economy



5.3.2. Heavy Duty Vehicles

The heavy duty vehicle (HDV) fuel mix in 2050 is primarily determined by whether biomass is used to make a diesel "drop-in" fuel or to make synthetic natural gas that is blended into the pipeline gas mix. In cases where the former dominates (High Nuclear, High CCS), ICE diesel vehicles remain the main form of heavy duty transport. If biomass is used to make gas, this necessitates a transition to liquefied pipeline gas or hydrogen HDVs. We do not model a complete conversion of the HDV fleet due to hydrogen in

Figure 21. HDV VMT by Fuel

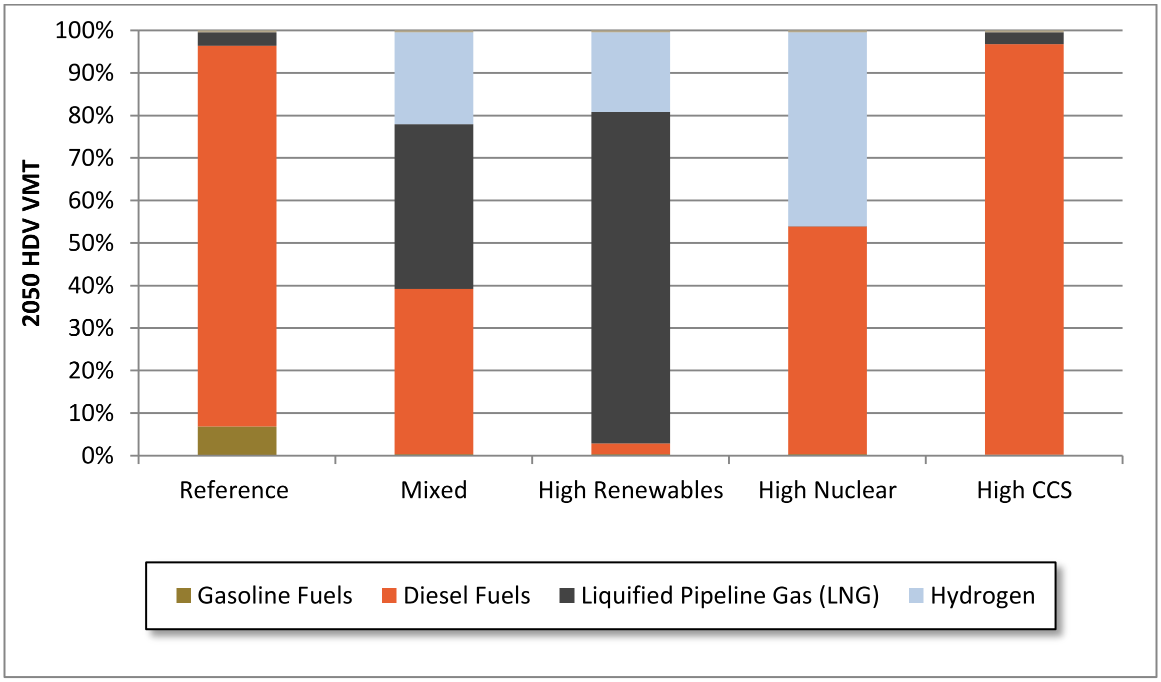
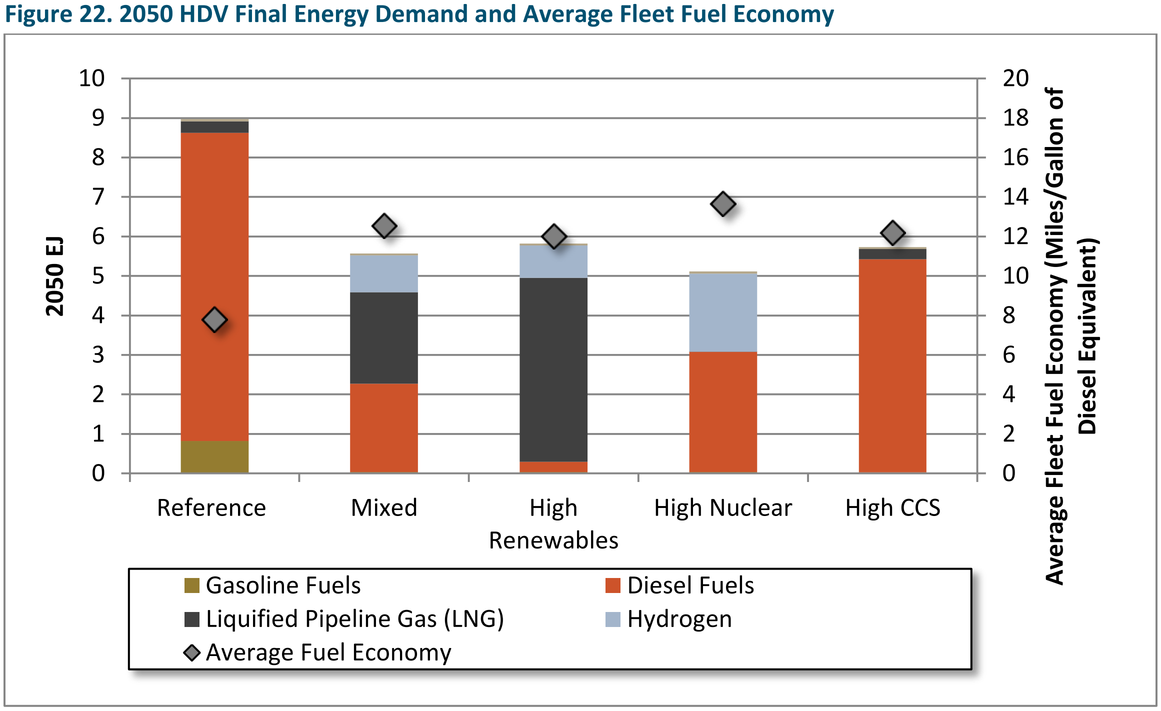


Figure 22. 2050 HDV Final Energy Demand and Average Fleet Fuel Economy



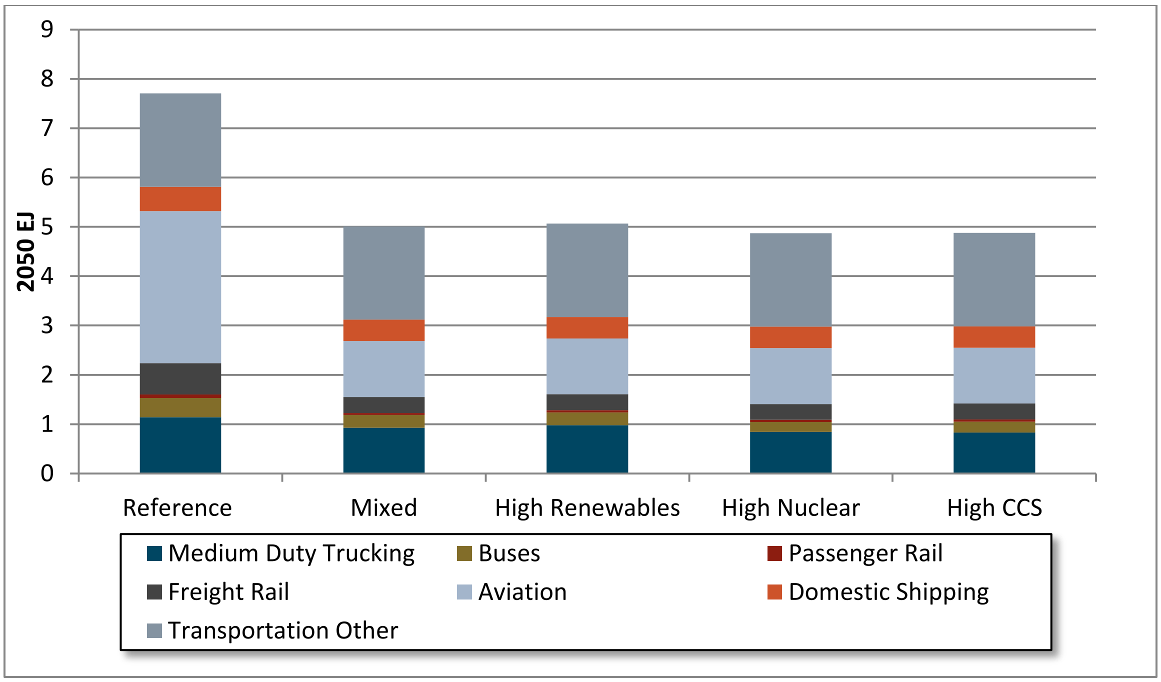
any of the four cases, due to questions about commercialization timelines and energy density limitations. The High Nuclear Case, which also has HFCVs in its LDV fleet, has the highest penetration of HDV HFCVs (50%) (Figure 21).

In addition to decarbonizing the HDV fuel supply, alternative fuel HDVs improve the average fleet fuel economy in the four decarbonization cases to greater than 12 miles per gallon diesel equivalent (GDE). The highest average HDV fleet efficiency is found in the High Nuclear Case, due to the prominence of HFCVs (Figure 22).

5.3.3. Other Transportation

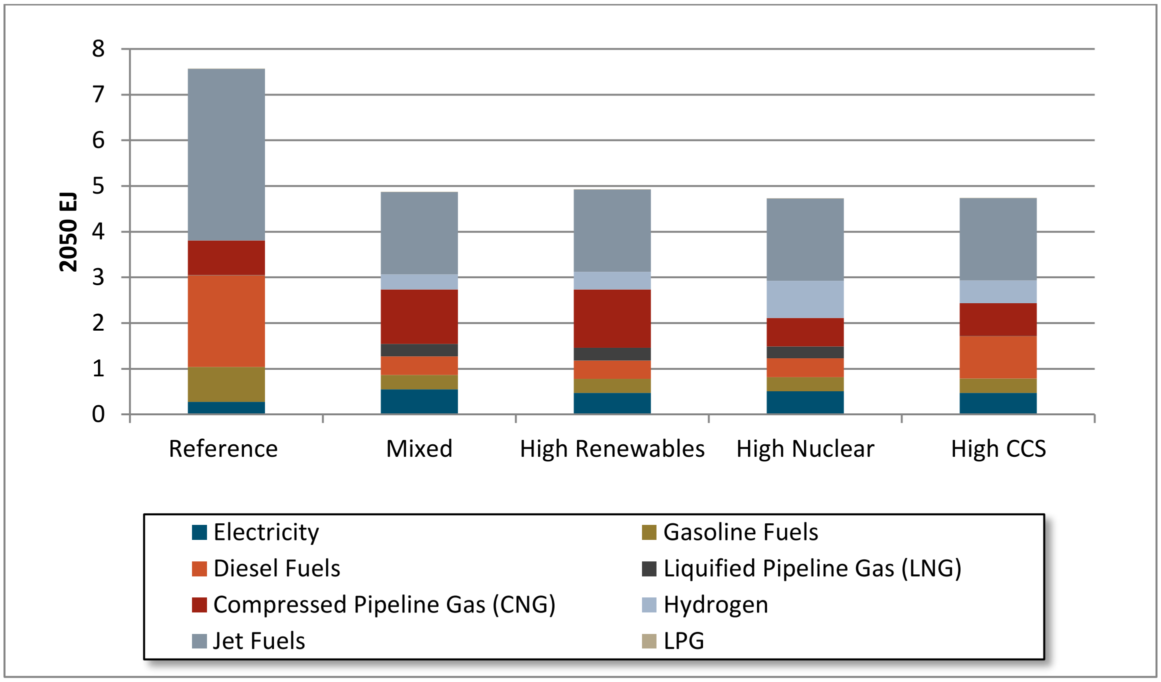
HDVs and LDVs account for roughly two-thirds of transportation sector energy demand in all cases. The remaining one-third includes aviation, freight rail, passenger rail, medium-duty trucking, buses, and military use. For these modes, a combination of biofuels (aviation), electrification, hybridization, and fuel cells (freight rail, passenger rail, medium-duty trucking, buses) were employed to reduce emissions. These changes in technology are accompanied by energy efficiency improvements, resulting in around 35% reductions in final energy demand relative to the Reference Case (Figure 23).

Figure 23. Other 2050 Transportation Subsector Energy Demand



In the High Renewables and Mixed Cases, fleet vehicles like medium-duty trucks and buses are fueled by compressed pipeline gas and the majority of freight rail and some shipping switches to liquefied pipeline gas, using decarbonized pipeline gas. In the High Nuclear Case, fleet vehicles are powered by hydrogen fuel cells. In the High CCS Case, fleet vehicles are powered by renewable diesel—a drop-in synthetic diesel fuel produced from biomass. Aggressive aviation efficiency reduces the relative importance of jet fuel demand by 2050 in all four cases (Figure 24).

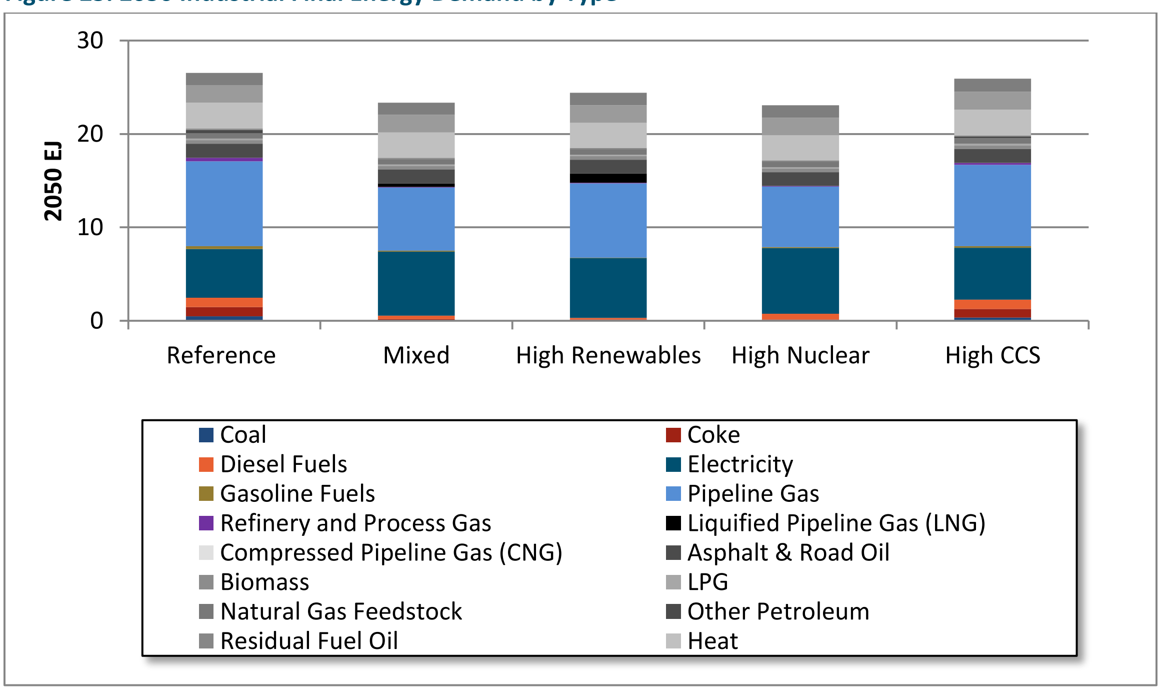
Figure 24. 2050 Other Transportation Subsector Energy Demand by Energy Type



5.4. Industrial

In the four decarbonization cases, industrial final energy demand does not significantly change from Reference Case levels (Figure 25). All four cases achieve efficiency gains from some electrification of heating (heat pumps) and, except for in the High CCS Case, some steam production (boilers). Additionally, there is fuel switching from diesel in areas like agricultural pumping and construction

Figure 25. 2050 Industrial Final Energy Demand by Type

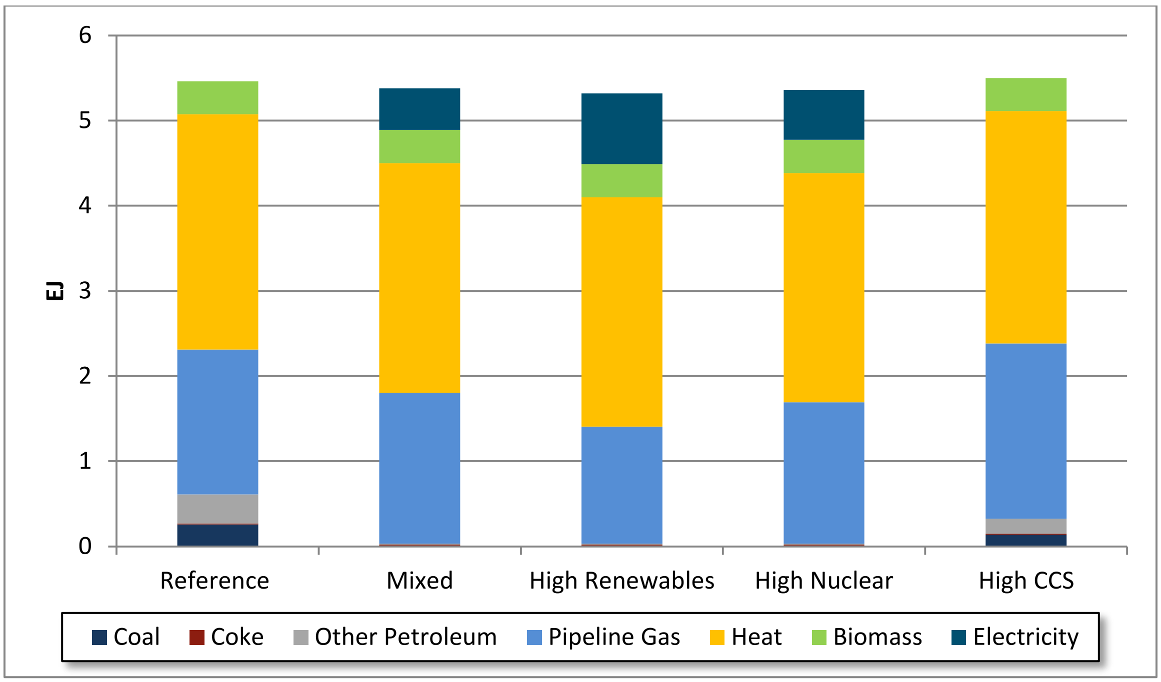


vehicles, as well as process change-related fuel switching in iron and steel, in all cases except for the High CCS Case. A lack of fuel switching-related efficiency, in addition to CCS energy penalties, makes industrial final energy demand in the High CCS Case higher than in other scenarios.

5.4.1. Steam Production

While the level of steam produced for industrial processes (all sectors) is roughly the same across the Reference Case and the four decarbonization cases, the mix of energy sources for steam production varies across cases. In all decarbonization cases, coal, coke, and petroleum fuels are replaced by electricity (Mixed, High Renewables, High Nuclear Cases) and pipeline gas (High CCS Case). Levels of steam generated by combined heat and power (CHP) facilities ("Heat" in Figure 26) and with biomass-fueled boilers are kept at Reference Case levels across all cases. The largest share of boiler output is electrified in the High Renewables Case, while no boilers are electrified in the High CCS Case, which instead relies on CCS in large-scale applications to reduce the net CO_2 intensity of fuels.

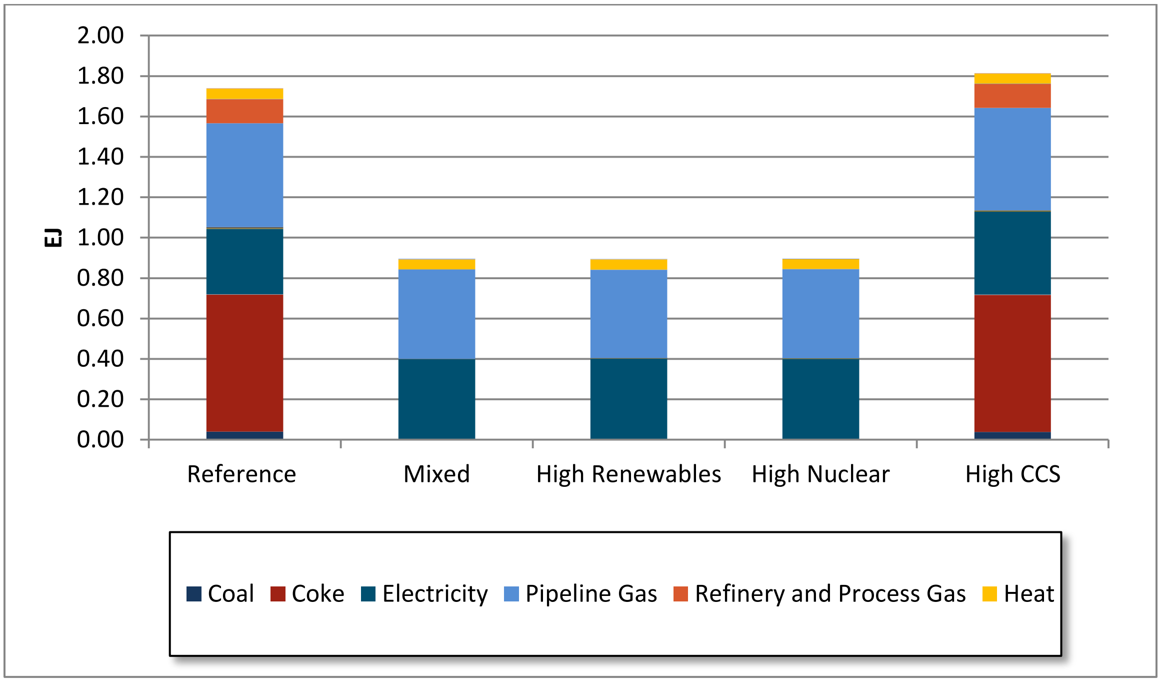
Figure 26. 2050 Steam Production Final Energy Demand by Type



5.4.2. Iron and Steel

The most significant fuel switching in the industrial sector is in iron and steel, with an acceleration of the Reference Case trend of converting basic oxygen furnaces (BOF) utilizing pig iron as a feedstock to electric arc furnaces (EAF), which use scrap steel or direct reduced iron (DRI). This strategy is used in all cases except the High CCS Case, which instead utilizes CCS to capture combustion-related emissions. These alternative strategies result in significant final energy demand differences among the cases (Figure 27). The CCS Case increases final energy demand relative to the Reference Case, because of the energy penalties associated with CCS. In the Mixed, High Renewables, and High Nuclear Cases, there is an increase in final electricity demand from EAF/DRI relative to the Reference Case, but total final energy demand falls significantly with reductions in coal, coke, and process gas use.

Figure 27. 2050 Iron and Steel Industry Final Energy Demand by Type

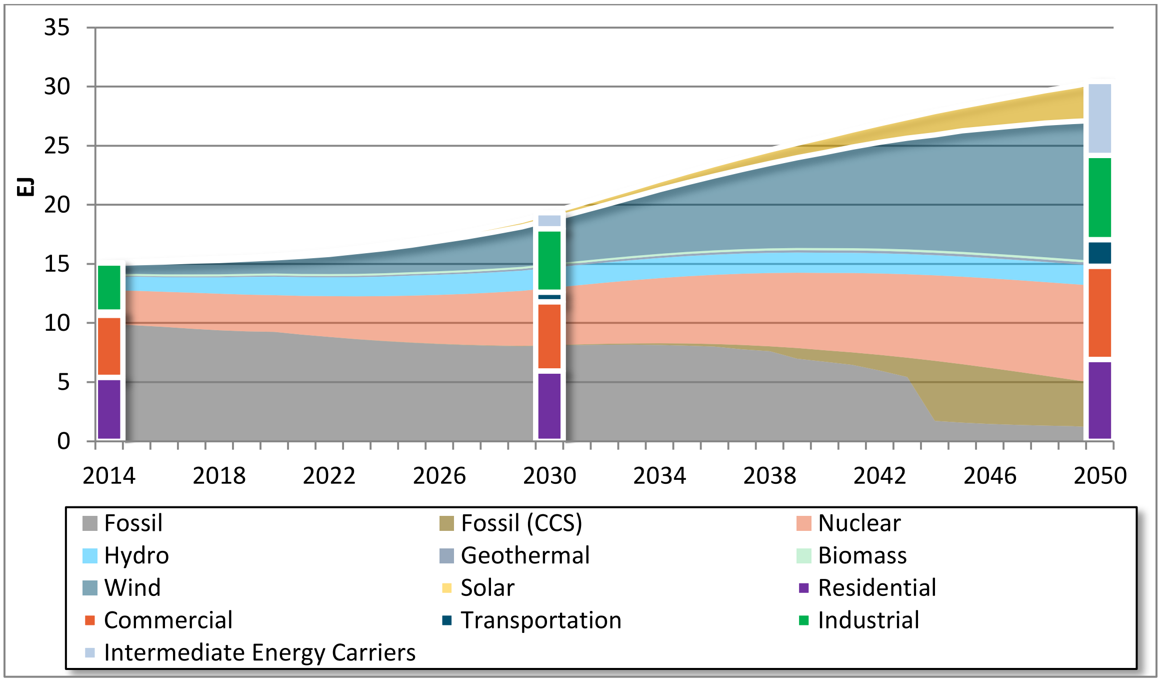


6. Results: Energy Supply

6.1. Electricity

The Mixed Case illustrates the interaction between supply decarbonization and end use electrification that occurs, to different extents, in all of the decarbonization cases (Figure 28). In the Mixed Case, end use electrification doubles demand for electricity by 2050, with particularly rapid growth after 2030.

Figure 28. Mixed Case Electric Sector Supply and Demand



Some of this growth occurs as a result of the electrification of end uses, such as electric water heating or vehicles, but a large portion results from the electrification of fuels ("Intermediate Energy Carriers" in Figure 28), such as hydrogen produced through electrolysis. Fossil fuel generation declines gradually over 2014-2050, and beginning in the late 2030s remaining coal-fired generation is retired and replaced with gas-fired generation equipped with CCS. The only remaining uncontrolled fossil fuel generation in 2050 is a small amount of gas generation that operates as a peaking resource. Much of the increase in demand for electricity after 2030 is met by significant increases in wind, nuclear, and solar power output.

Case names are indicative of final 2050 generation mixes, shown in Figure 29. The High Nuclear, High CCS, and High Renewables Cases have the highest amount of each respective type of generation, though they do not exclusively rely on this type of generation. For instance, the High Renewables Case has roughly the same amount of nuclear power as in the Reference Case. The High CCS Case relies primarily on fossil fuel generation, but includes an expansion of wind and solar generation.

Figure 29. 2050 Electric Generation by Resource Type

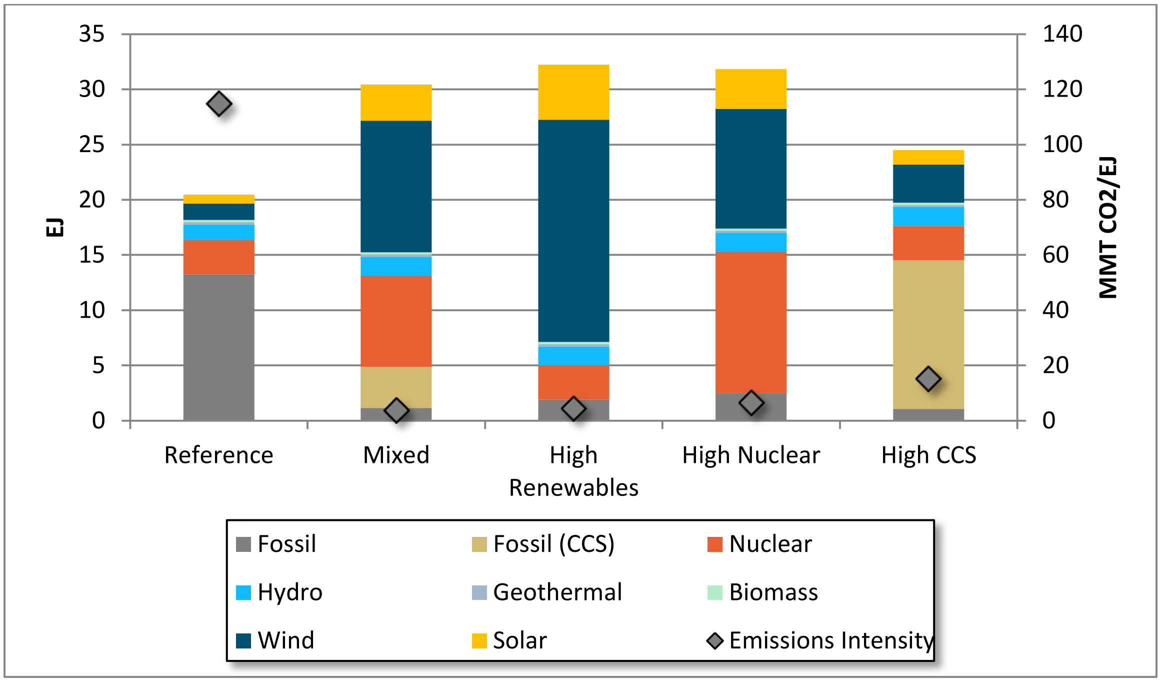
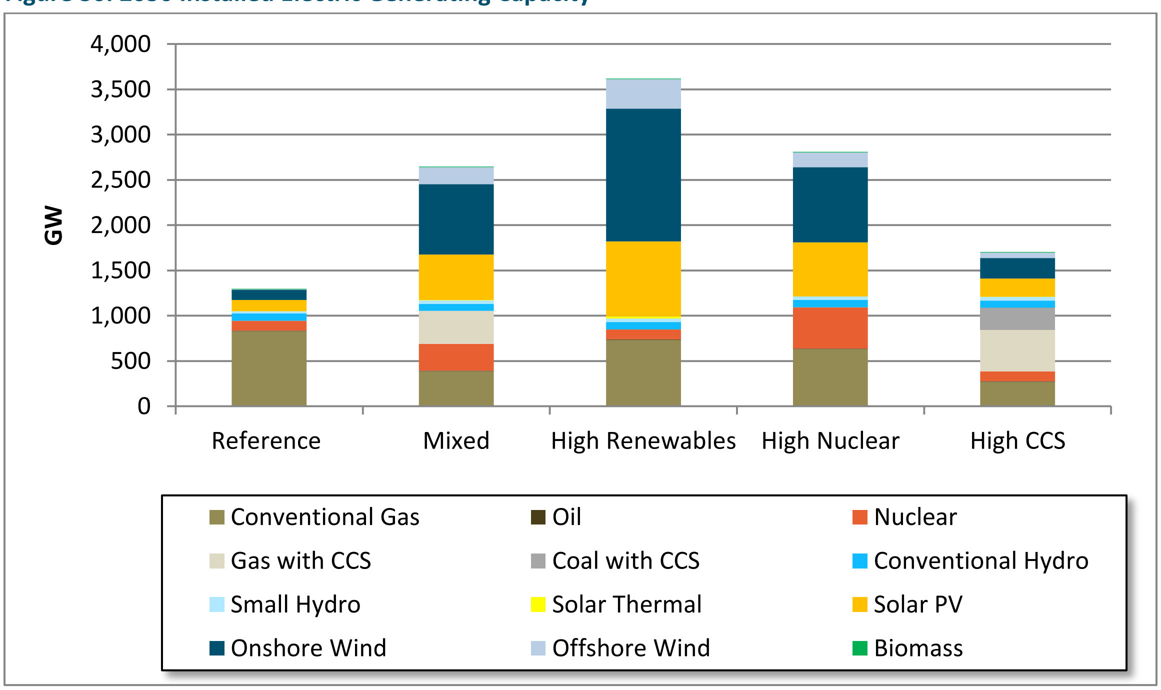


Figure 30. 2050 Installed Electric Generating Capacity



The Mixed Case includes a more balanced expansion of renewable, nuclear, and fossil fuel CCS generation. CO_2 emission factors fall precipitously in all decarbonization cases, from 329 gCO_2/kWh in the Reference Case to at most 54 gCO_2/kWh (High CCS) and at least 14 gCO_2/kWh (Mixed).

Figure 30 shows the installed capacity implications of the generation mixes in Figure 29. The Mixed, High Renewables, and High Nuclear Cases have significantly higher capacity requirements than the Reference or High CCS Cases, as a result of their higher electricity demand and lower capacity factors for wind and solar generation relative to fossil fuel generation.

6.1.1. Electricity Balancing

Large penetrations of non-dispatchable decarbonized resources (wind, solar, nuclear) present challenges for balancing electricity supply and demand (load). Due to the lack of coincidence between these generation sources and conventional loads, high penetrations require supporting dispatchable generation or greater flexibility in load. By 2050, this dispatchable generation must be primarily low carbon—either generation from electricity storage facilities or gas power plants with carbon capture—in order to meet a 2050 GHG target. For dispatchable loads, flexibility in newly electrified loads like water heating, space heating, and electric vehicles was incorporated in the model.

Much of the balancing on the load side comes in the form of electric fuel production—hydrogen and synthetic natural gas (SNG)—in which facilities were oversized in production capacity in order to allow them to operate flexibly and absorb excess generation. While these electric fuels may be inefficient from a primary energy perspective, their ability to operate flexibly reduces curtailment, which represents a system-wide inefficiency caused by large amounts of non-dispatchable generation. When this flexible load reduces curtailment, it can provide significant value as a component of an integrated energy system, despite its potentially high cost when viewed in isolation.

Figure 31. 2050 Mixed Case Eastern Interconnection Electricity Dispatch

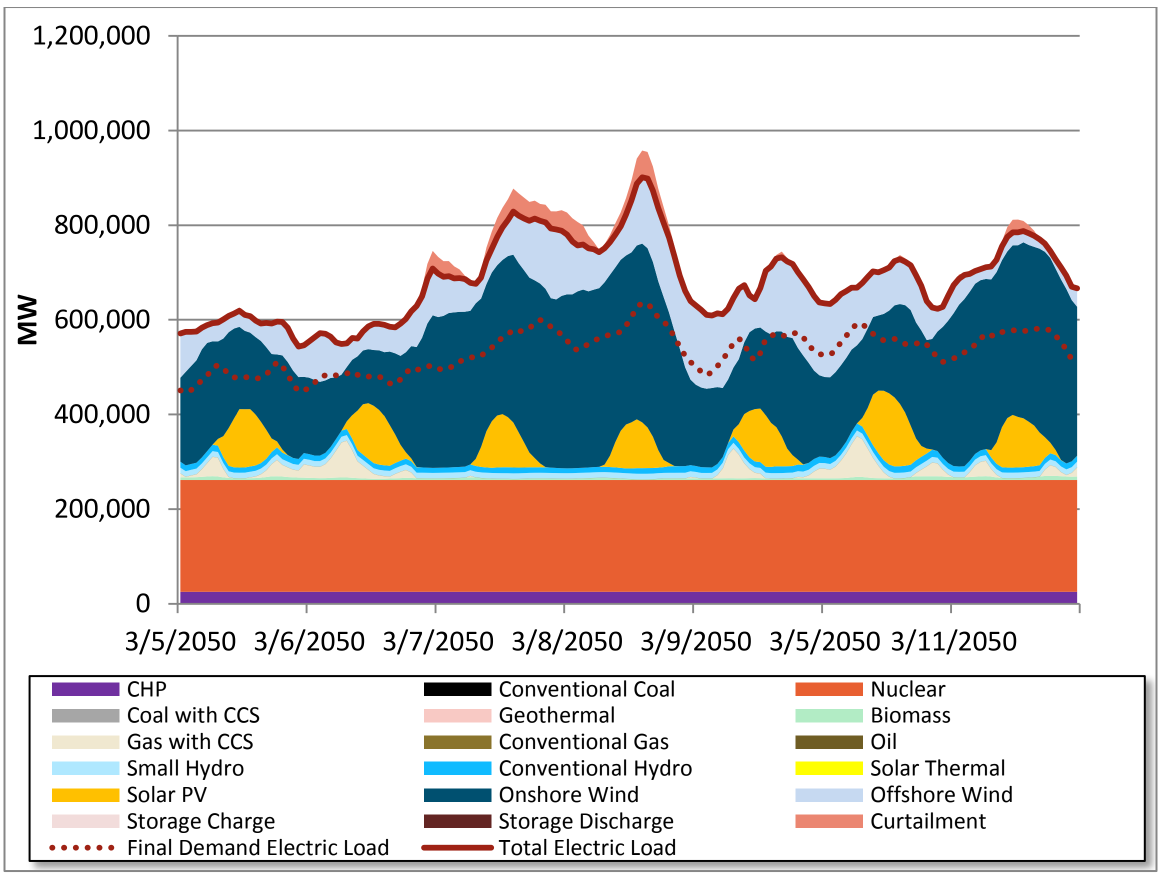
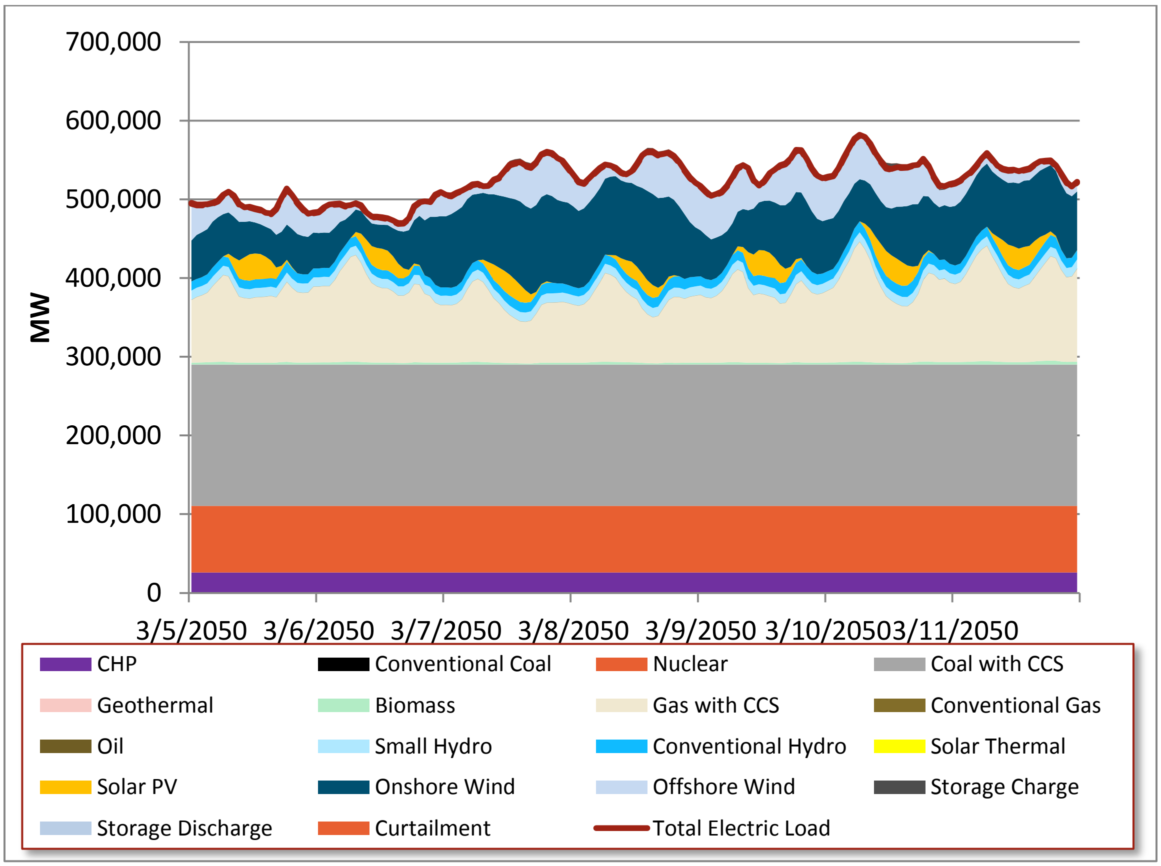


Figure 31 illustrates these challenges, showing dispatch in the Mixed Case for a week in March 2050 in the Eastern Interconnect. The coincidence of significant nuclear generation online and large wind power output means that total electric load (the solid red line) exceeds final demand for electricity (the dotted red line). The majority of the difference is absorbed by facilities producing electric fuels, and a small amount of wind output is curtailed. The use of flexible loads for balancing, as in this case, would represent a new paradigm in power system operations, as system operators have traditionally relied on the flexibility of supply, rather than the flexibility of demand, to address load-resource imbalances.

The High CCS Case, which has lower penetrations of non-dispatchable resources, has a more traditional generation dispatch, shown in Figure 32 for the Eastern Interconnection in the same week of March 2050. Here, nuclear and coal with CCS operate as baseload resources and gas CCS operates as a load-following resource to balance modest penetrations of wind and solar.

Figure 32. 2050 CCS Case Eastern Interconnection Electricity Dispatch



6.2. Gas

Pipeline gas blends vary by case as a function of three factors:

1. Whether biomass has been used primarily to produce gas or liquid fuels;
2. Need for intermediate energy production loads (P2G hydrogen and SNG) to provide grid balancing services;
3. Assumed availability of CCS.

Due to its higher balancing needs, for instance, the High Renewables Case has the highest gas energy demand and the largest amount of electric fuels, in addition to a significant biogas blend (mainly bio-SNG) (Figure 34, also present in the Mixed Case in Figure 33). The High CCS Case uses only a limited amount of biomass (wet biomass for anaerobic digestion) in the pipeline, instead using CCS in industry to reduce the CO_2 intensity of pipeline gas. The High Nuclear Case has residual biomass to use in the pipeline because demand for liquid biofuels is reduced by using HFCVs in heavy duty trucking.

Figure 33. Mixed Case Pipeline Gas Supplies and Sector Demand

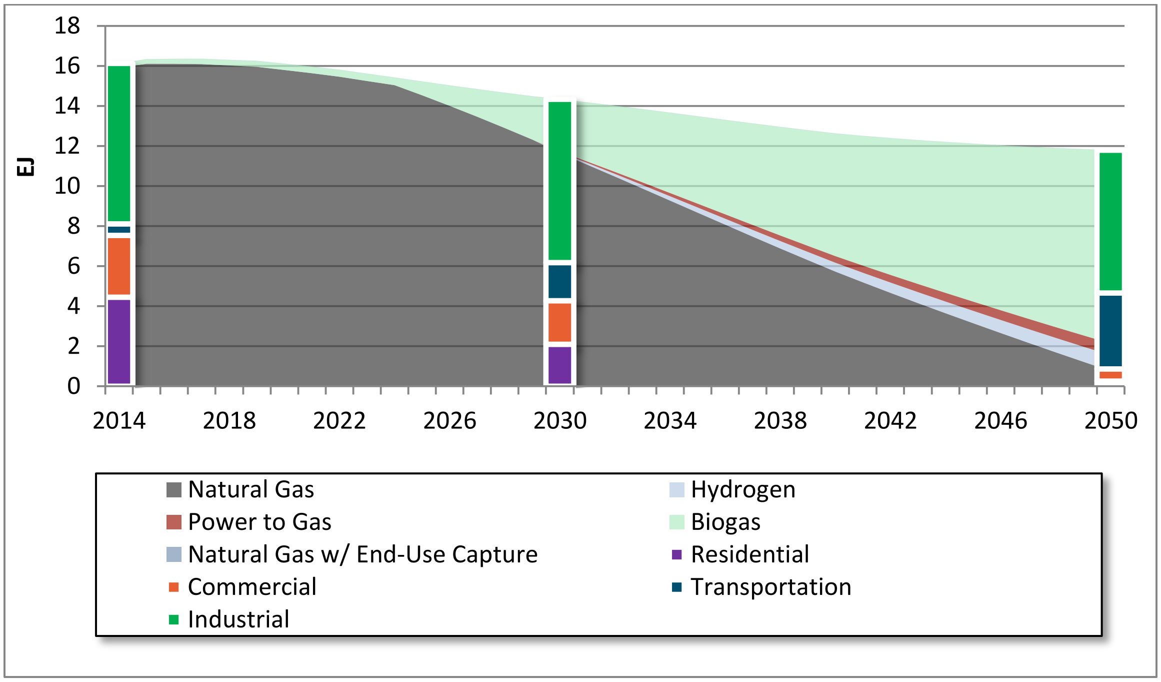


Figure 34. 2050 Pipeline Gas Portfolios

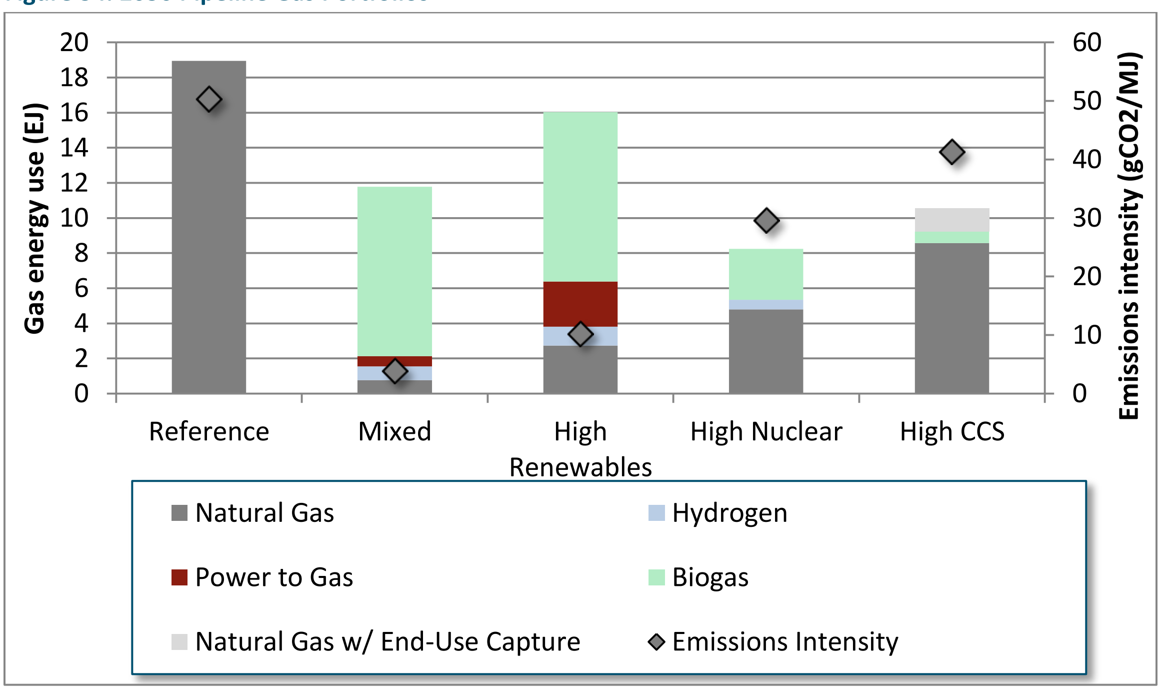


Figure 33 illustrates the dynamics of gas supply and demand from 2014 to 2050, using the Mixed Case. In this case, demand for gas remains relatively high because the gas supply is decarbonized using biomass (mainly gasification to bio-SNG) and, to a lesser extent, P2G hydrogen and SNG. Most of this gas is used in the heavy duty transportation and industrial sectors, where electrification is less practical.

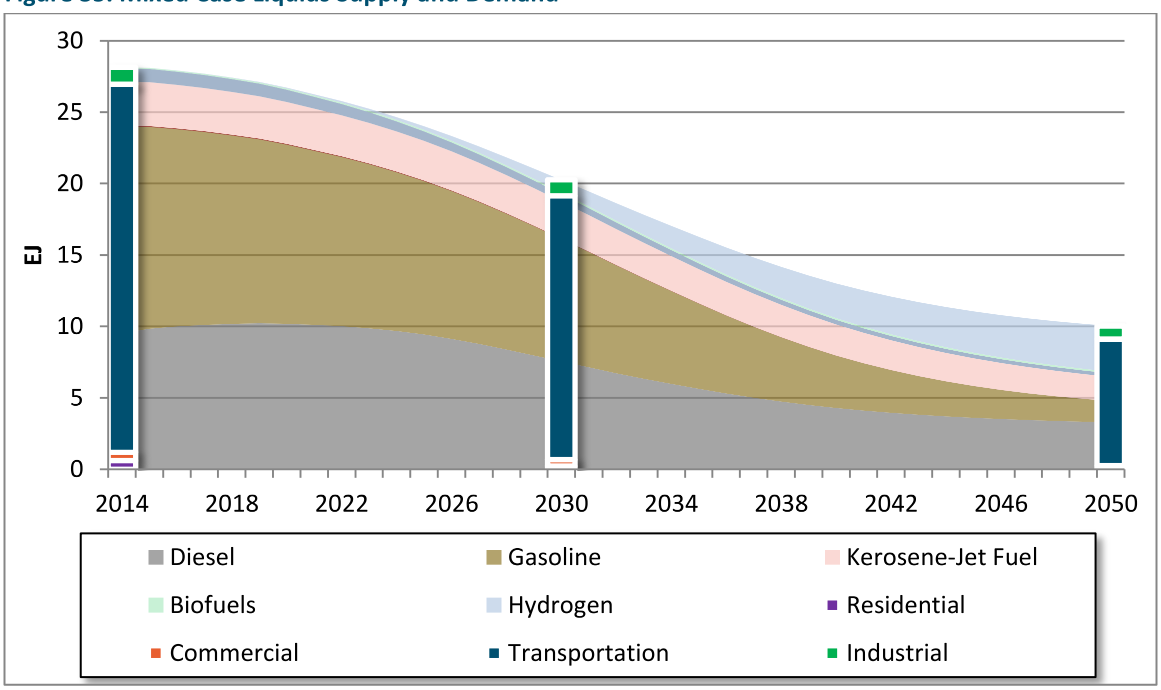
Pipeline gas blends vary by case as a function of three factors: (1) whether biomass has been used primarily to produce gas or liquid fuels, (2) the need for intermediate energy production loads (P2G hydrogen and SNG) to provide grid balancing services, and (3) the assumed availability of CCS. Due to its higher balancing needs, for instance, the High Renewables Case has the highest gas energy demand and the largest amount of electric fuels, in addition to a significant biogas blend (mainly bio-SNG) (Figure 34). The High CCS Case uses only a limited amount of biomass (wet biomass for anaerobic digestion) in the pipeline, instead using CCS in industry to reduce the CO_2 intensity of pipeline gas. The High Nuclear Case has residual biomass to use in the pipeline because demand for liquid biofuels is reduced by using HFCVs in heavy duty trucking.

Average CO_2 emission intensities for gas fuels vary across cases, depending on the final demand for gas and the share of natural gas remaining in the gas mix. In the Mixed and High Renewables Cases, gas use is higher, very little natural gas remains and gas emissions intensities are less than 11 gCO_2/MJ. In the High Nuclear and High CCS Cases, gas use is lower and emissions intensities are higher because larger emission reductions are occurring for liquid fuels.

6.3. Liquids

Figure 35 shows the supply portfolio evolution for liquid fuels. In the Mixed Case, and in all four decarbonization cases, demand for liquid fuels falls dramatically as a result of efficiency improvements

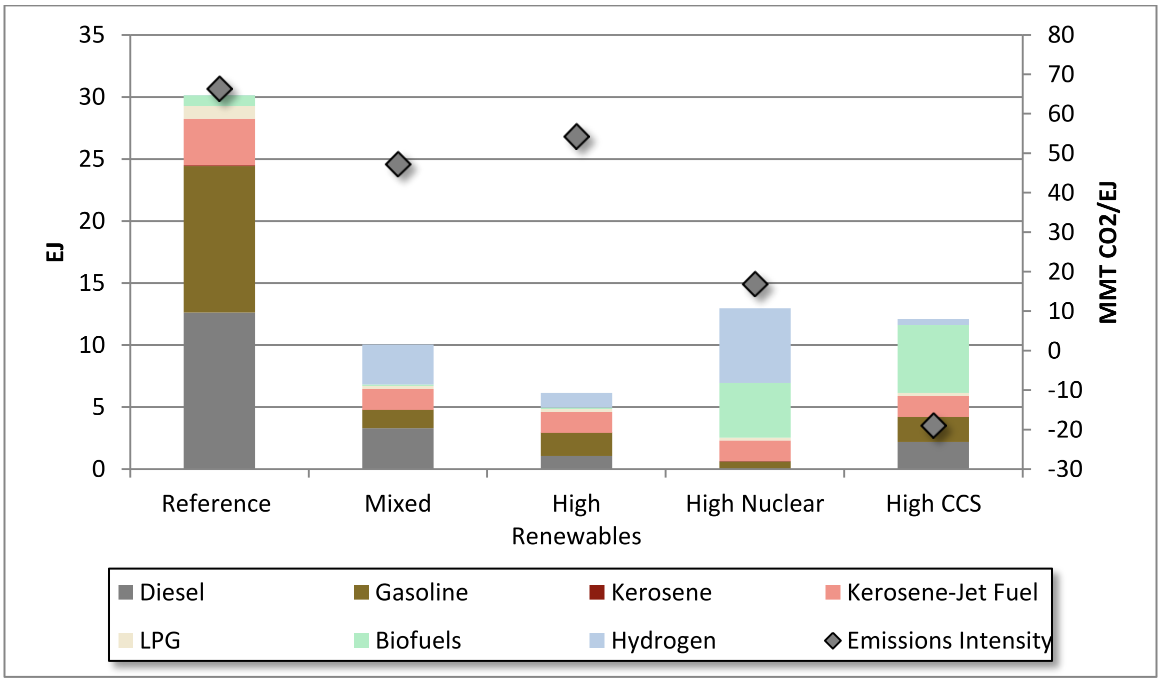
Figure 35. Mixed Case Liquids Supply and Demand



and fuel switching. Biomass in the Mixed Case is largely used in the gas pipeline, which limits the use of liquid biofuels in transportation. Instead, on-road transportation transitions primarily to electricity (LDVs) and pipeline gas (HDVs), with some hydrogen use in LDVs, jet fuel used in aviation, gasoline used in PHEVs, and diesel used in HDV and "other" transportation modes.

The same factors that shape the 2050 gas blend also shape the 2050 liquid fuel mix. The highest liquid fuels demand occurs in the High Nuclear and High CCS Cases, where HDVs use a combination of biofuels (renewable diesel) and hydrogen rather than pipeline gas (Figure 36). The lowest demand for liquid fuels is in the High Renewables Case, where the transportation sector shifts from liquid fuels to electricity and gas. In cases where liquid fuel use remains high, their average CO_2 emissions factors are much lower. The negative CO_2 emission factor for liquid fuels in the High CCS Case results from the use of BECCS in this case.[9]

Figure 36. 2050 Liquid Fuel Supply Mix



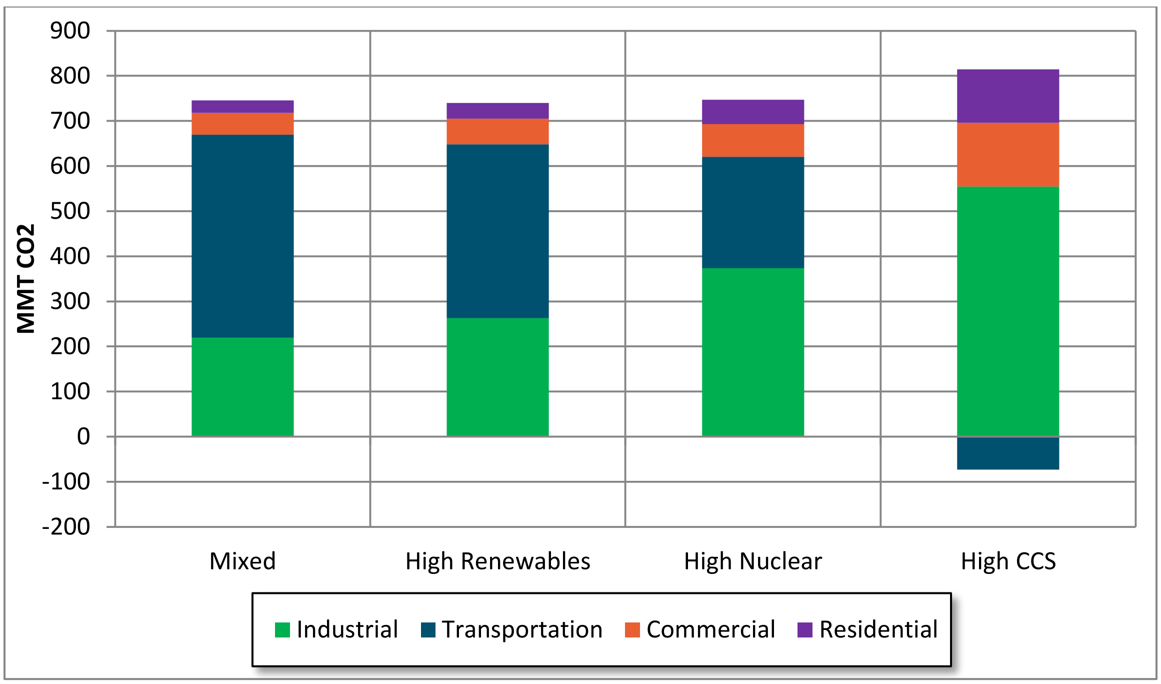
[9] Sustainably harvested biomass is generally given a net CO_2 emission factor of zero, because the CO_2 released to the atmosphere through combustion is offset by subsequent sequestration of CO_2 in plant biomass. By capturing and storing CO_2 from the bioenergy refining process, BECCS can lead to negative emissions. We only use BECCS in the High CCS Case, consistent with our case development criteria.

7. Results: CO_2 Emissions

7.1. CO_2 Emissions by End Use Sector

In all decarbonization cases, the transportation and industrial sectors have the largest remaining CO_2 emissions by 2050 (Figure 37). These remaining emissions are mainly from direct combustion of fossil fuels rather than upstream CO_2 emissions associated with electricity consumption. The ratio of transportation to industrial sector emissions across cases is determined primarily by the allocation of biomass between gas and liquid fuels. Biomass conversion to liquid fuels reduces the transportation sector's emissions relative to industry (High Nuclear, High CCS), whereas conversion to gas and greater use of gas in transportation increases them. Differences between residential and commercial sector emissions among cases are driven primarily by the emissions intensity of electricity; the CCS Case, which has the highest electricity emissions intensity, has twice the residual emissions in these sectors as any other case.

Figure 37. 2050 CO_2 Emissions by Sector



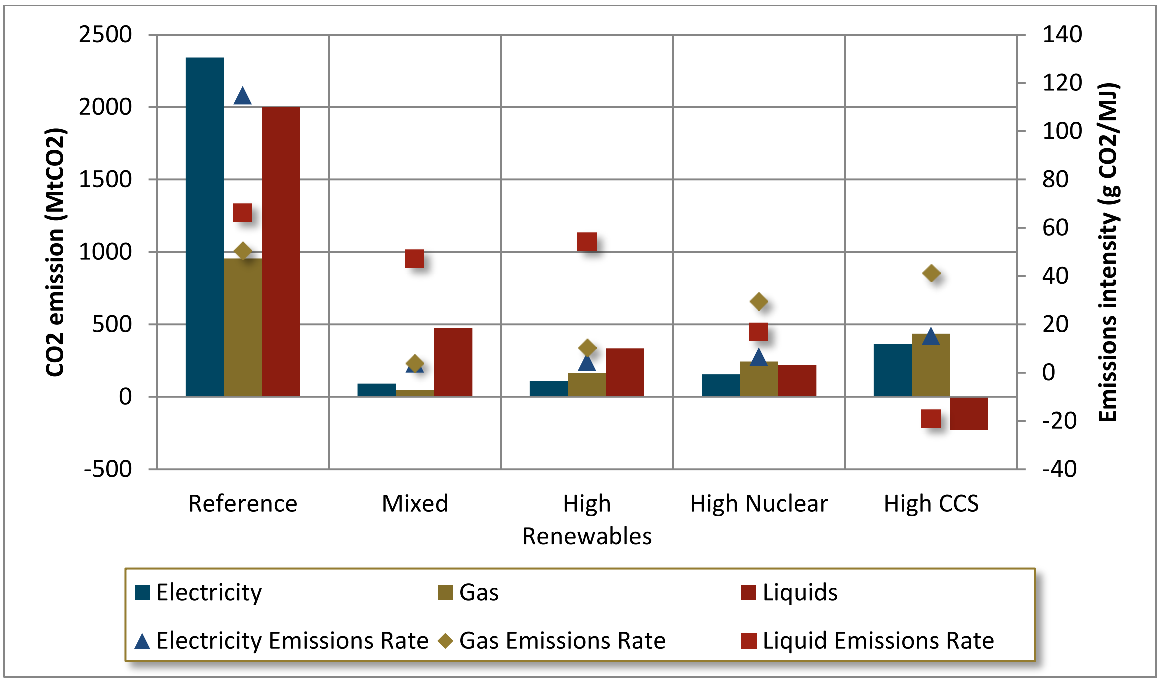
The starkest allocation of CO_2 emissions among cases is in the High CCS Case, which has limited fuel switching in industry and no decarbonization of pipeline gas, leaving over two-thirds of residual emissions in the industrial sector. Such a high level of residual emissions is feasible because of the use of BECCS and renewable diesel in the High CCS Case, which creates a diesel fuel with net negative emissions that are allocated to the transportation sector.

7.2. CO_2 Emissions by Energy Type

End use sector CO_2 emissions are consistent with the emissions intensities of their main energy sources—electricity, gas, or liquids. Buildings, which are largely electrified using very low CO_2 electricity by 2050 in all cases, are small contributors to overall emissions. Industry, where gas dominates final energy demand, has the lowest emissions in cases where the pipeline has been significantly decarbonized. Transportation sector emissions depend on the relative balance and CO_2 emissions intensities of liquid and gas fuels.

Figure 38 illustrates this balancing act among electricity, gas, and liquid fuel CO_2 emissions. The Mixed and High Renewables Cases emphasize electricity and gas decarbonization, and most residual CO_2 is in liquid fuels, which have an emissions intensity only slightly less than the Reference Case. The High Nuclear Case has significant reductions in both gas and liquid fuels emissions intensity, and roughly equivalent CO_2 emissions from each. The use of BECCS in the High CCS Case allows for a net negative CO_2 emissions intensity in liquid fuels, a much higher gas emissions intensity, and a slightly higher electric emissions intensity. Across decarbonization cases, electric emissions intensities fall dramatically relative to the Reference Case.

Figure 38. CO_2 Emissions and Emissions Intensities by Energy Type in 2050

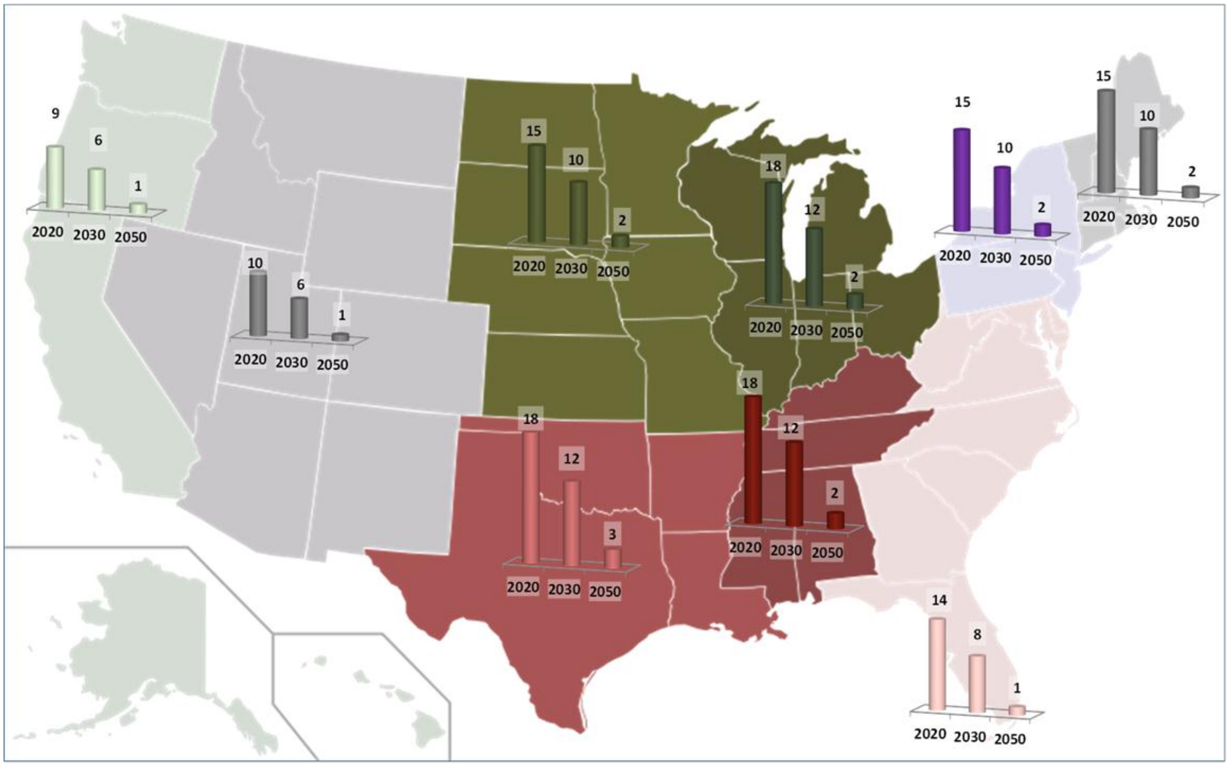


The total average CO_2 emissions intensity in all four decarbonization cases ranges from 13 to 14 gCO_2 per MJ of final energy consumed, which is a useful reference point. Electricity, gas, and liquid fuel emissions intensities, weighted by their respective shares of final energy demand, must add up to this total average. In cases without very high end use electrification where liquid fuels have a higher emissions intensity, gas intensities will need to be lower and gas use be higher than liquids (Mixed and High Renewables Cases). In cases where the combined average gas and liquid fuel intensities are high, electricity intensity must be very low and a greater share of end uses must be electrified, a scenario that we do not model in this study.

7.3. CO_2 Emissions Intensity by Region

Figure 39 illustrates the change in regional emissions intensities for the years 2020, 2030, and 2050 for the nine U.S. census divisions represented in PATHWAYS. These differences are a result of different initial infrastructure, energy supply and demand characteristics, and regional electricity sector

Figure 39. Mixed Case Regional Per Capita CO_2 Emissions Intensity (Tonnes CO_2 Per Person)



generation mixes. They show relatively steeper emission intensity reductions trajectories in the Midwest and Eastern regions of the U.S. in comparison to the Mountain West and Pacific regions, a function of the higher initial per capita emissions intensity.

8. Results: Costs

8.1. Incremental Costs by End Use Sector and Cost Component

Across end use sectors, the timing of energy system costs varies according to investment needs and changes in technology costs. Figure 40 shows energy system costs, net of Reference Case costs, by sector for the Mixed Case. Annual costs are shown with uncertainty distributions. Residential, commercial, and industrial costs grow slowly to 2050. Transportation costs are higher in the mid-term and then decline by 2050, a result of declining costs of alternative fuel vehicles and higher avoided costs of conventional fossil fuels.

Figure 40. Mixed Case Incremental Energy System Costs to 2050

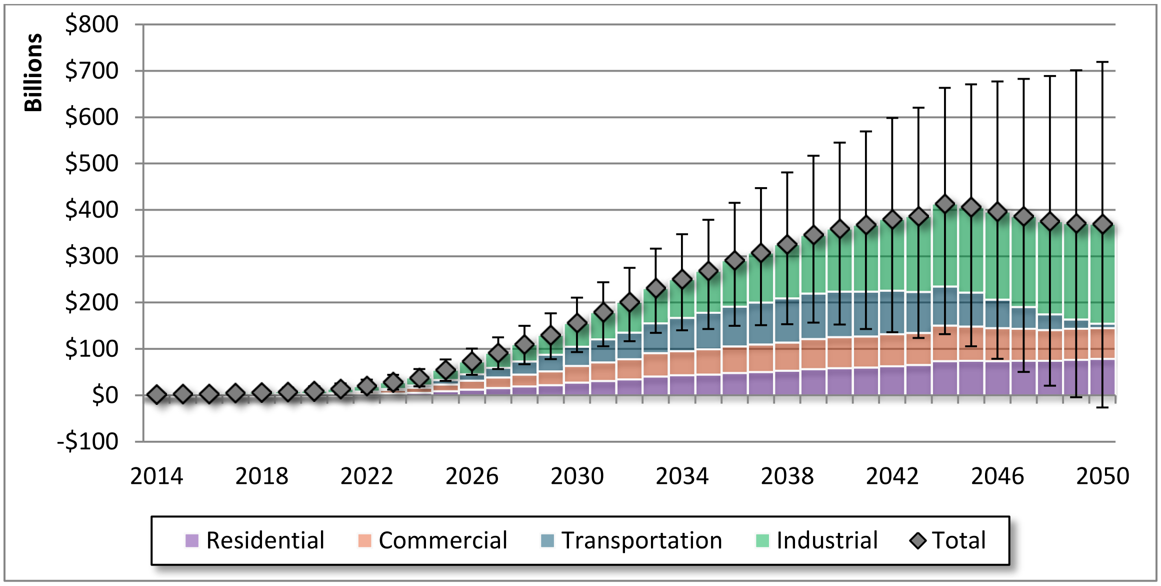


Figure 41. 2050 Mixed Case Incremental Costs by Component

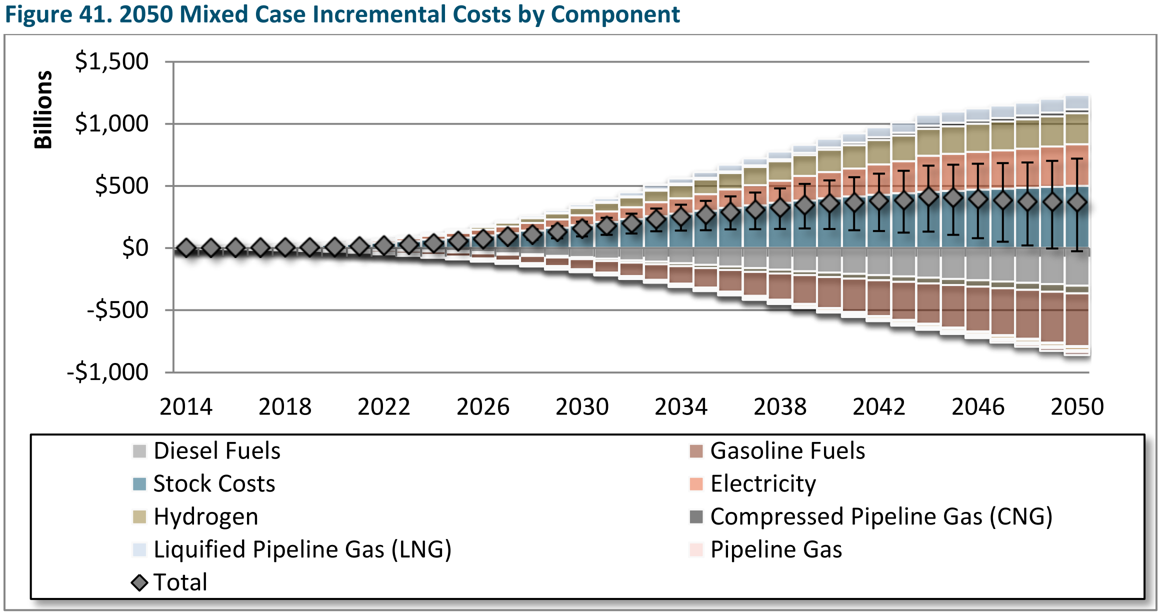
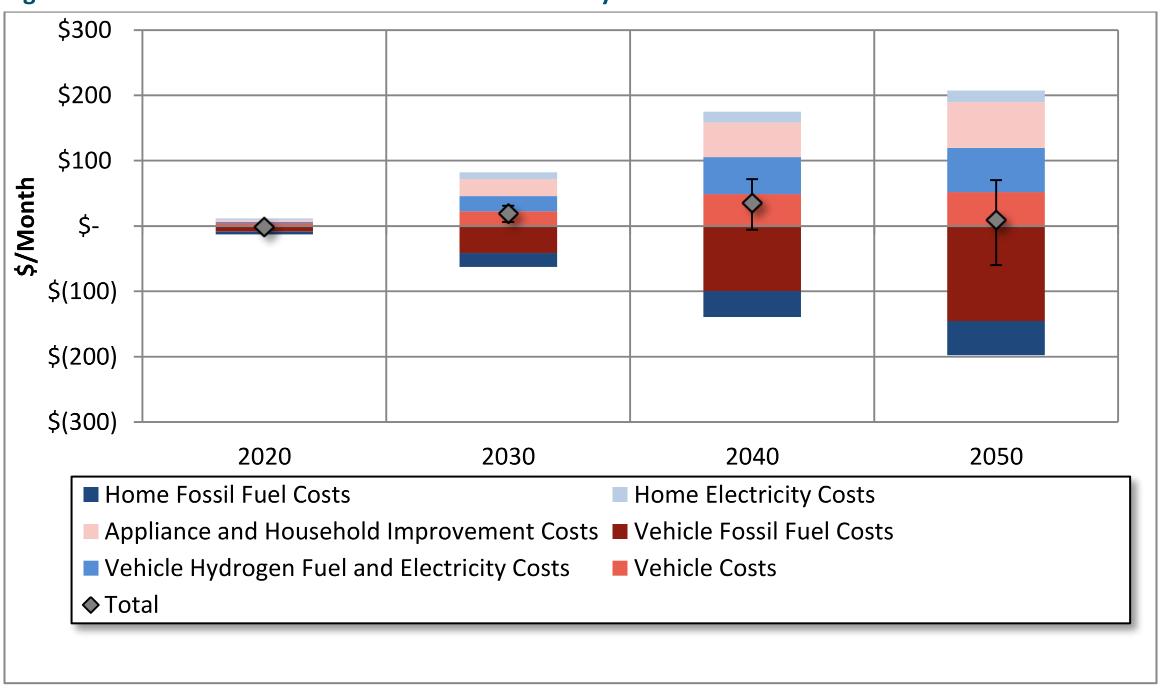


Figure 41 shows incremental costs by component for the Mixed Case, with fossil fuel savings shown as a negative value. In this case, savings are primarily from avoided liquid fossil fuels (gasoline and diesel). Increased costs are from stock costs (end-use capital equipment like vehicles and appliances), electricity (due to slight rate increases and higher electricity demand from electrification), hydrogen, and compressed and liquefied pipeline gas (due to higher demand as well as higher delivered costs from the low-carbon blend in the pipeline). In broad terms, Figure 41 illustrates a shift from fossil fuel expenditures to investments in electric generating capacity and equipment that uses electricity.

8.2. Household Costs

Figure 42 shows the progression in incremental household energy costs from 2020 to 2050 in the Mixed Case. Initial decarbonization costs peak in the 2030 timeframe, as fossil fuel prices are not yet high enough to offset incremental costs of appliances and alternative fuel vehicles. Costs decline by 2040 as the costs of alternative fuel vehicles converge with those of gasoline ICE vehicles, and by 2050 households save money over the Reference Case due to the avoidance of gasoline, natural gas, and some diesel costs.

Figure 42. Mixed Case Incremental Household Monthly Costs



8.3. Electricity Costs

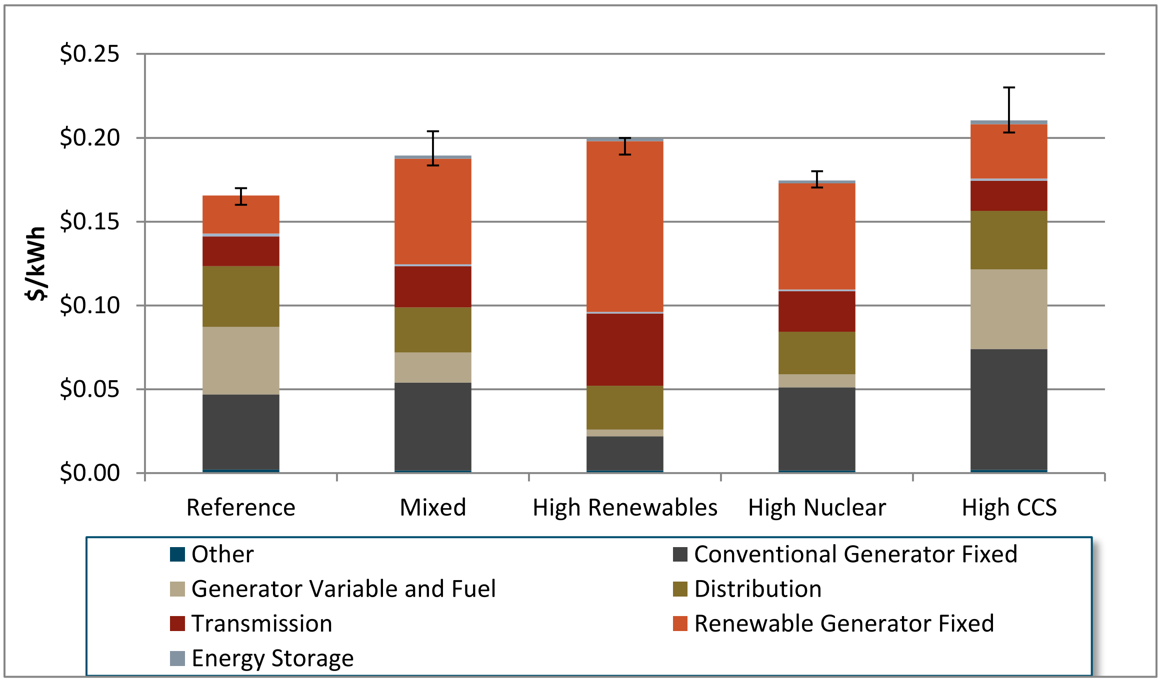
One of the main incremental cost drivers in the four decarbonization cases is the cost of electricity generation and delivery, measured in electricity rates. Differences from Reference Case rates result primarily from four factors:

1. Penetration of renewables, which adds renewable generator fixed costs and associated transmission costs while reducing conventional generation fixed, variable, and fuel costs;
2. Assumed nuclear capacity expansion, which adds conventional generation fixed costs but reduces variable and fuel costs;

3. Assumed CCS capacity expansion, which adds conventional fixed (CCS costs) and variable costs (heat rate penalties);
4. Amount of electricity used in the production of intermediate energy carriers, which reduces the share of electricity that needs to be delivered on the distribution system and thus lowers average distribution costs.

Despite significant differences in rate components, average rates in all cases are similar to Reference Case levels (Figure 43), with the High CCS Case representing the only significant rate increase (27% over Reference Case rates) and the High Nuclear Case showing only a slight rate increase (5%) under base technology cost assumptions.

Figure 43. 2050 Average Electricity Rate



8.4. Electricity Investment

In addition to showing average rates, we also calculate the incremental investment in electricity generation facilities, relative to the Reference Case. This is a way of conceptualizing the necessary capital that needs to be directed towards the electricity system, as well as identifying specific technology sectors that would experience rapid growth under mitigation cases. In the Mixed Case, increases in annual electricity generation investments would increase $15 billion per year from 2021-2030 (Figure 44). From 2031 to 2040, incremental investments would need to more than double to over $30 billion per year. By 2050, the electricity sector would need more than $50 billion per year of incremental investment from Reference Case projections.

The High Renewables case would require increased annual investment in renewable generation of over $70 billion per year by 2050 (Figure 45). The High Nuclear Case would need investment in nuclear facilities, both new and repowered existing, of $20 billion per year along with $30 billion in renewable investment increases. The High CCS Case would require nominal increases in renewable generation, with most of the increased investment needed in fossil power plants with CCS. The Mixed Case would require increased investment in all decarbonized generation sources. All cases would see a decline in traditional fossil power plant investment of up to $10 billion.

Figure 44. Mixed Case Incremental Annual Electricity Generation Investment by Decade

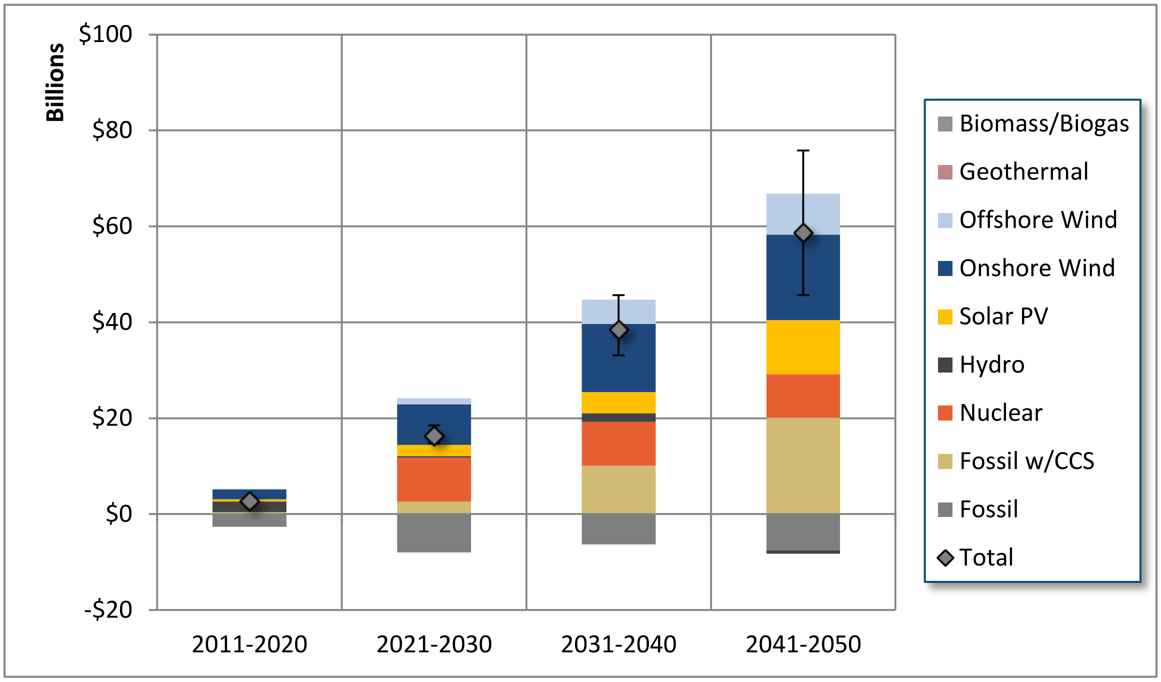
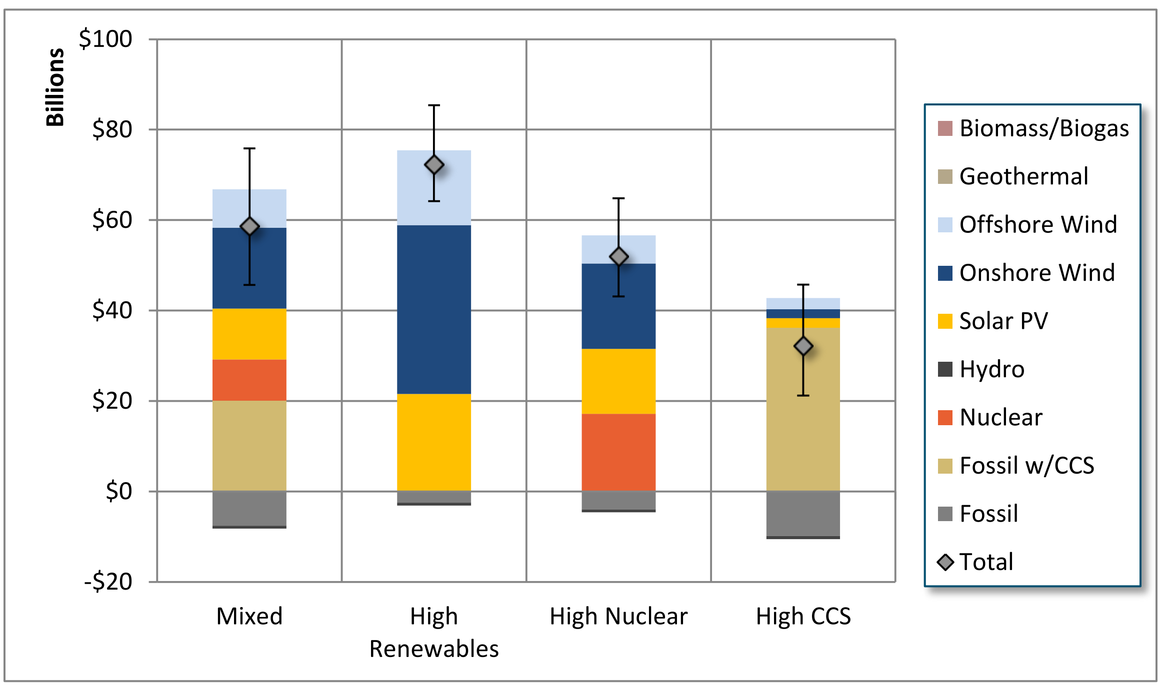


Figure 45. Annual Incremental Investments from 2041-2050



9. Results: GCAM Analysis

This section describes the results of the non-CO_2 emissions analysis conducted in GCAM, organized into three sections:

- **Non-CO_2 mitigation—**describes key results from the GCAM analysis of non-CO_2 mitigation
- **Sensitivity to terrestrial carbon sink assumptions**—explores sensitivity of results to levels of the terrestrial carbon sink
- **Biomass production and indirect land-use change emissions**—describes net zero GHG emission levels of purpose-grown biomass production

9.1. Non-CO_2 Mitigation

Using GCAM, we examined several cases of CO_2 and non-CO_2 mitigation in 2050, with the aim of identifying a reasonable set of low-cost non-CO_2 GHG mitigation measures that would complement the CO_2 emission reductions modeled in PATHWAYS, achieving an overall net GHG reduction of at least 80% below 1990 levels.[10]

Emissions of CH_4, N_2O, and fluorinated gases (f-gases)[11] represented nearly 20% of U.S. total gross GHG emissions in 1990, and are approximately 20% of GCAM reference emissions (without mitigation) in 2050. Some non-CO_2 emissions are associated with fossil energy production, such as CH_4 leakage from coal and natural gas extraction and processing. CO_2 mitigation strategies that reduce fossil fuel production therefore also result in non-CO_2 emissions reductions. We refer to this phenomenon as 'co-mitigation.' Deeper reductions in non-CO_2 emissions require active measures, such as CH_4 flaring, catalytic reduction of N_2O from industrial processes, and switching to low-global warming potential (GWP) refrigerants.

In order to maintain consistency with most of the PATHWAYS cases, we eliminated CCS on biofuel facilities as a technology option in GCAM, and limited purpose-grown bioenergy production to a level consistent with the cap identified in the *Biomass and Indirect Land-use Change* section below, while removing the current Renewable Fuel Standard (RFS) requirements for corn ethanol. We also assume that the rest of the world is participating in GHG mitigation efforts consistent with a 2°C warming target. However, we do examine a Reference Case in which no mitigation takes place globally. For these cases, we made the assumption that in 2050 the U.S. terrestrial carbon sink is at its 1990 level of 831 $MtCO_2$, although we explore sensitivity to this assumption in the next section.

Active mitigation of non-CO_2 emissions in GCAM is driven by the same carbon price that induces CO_2 mitigation, based on marginal abatement supply curves (MACs) for each technology and each non-CO_2 gas represented by the model. The MACs, which are based on EPA estimates, specify percent reductions feasible at various carbon price levels.[12] Many non-CO_2 mitigation measures are available at low or even

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[10] Achieving the U.S. government's Copenhagen target of 83% below 2005 levels requires an additional reduction of 2% (24 $MtCO_2e$) beyond what is required to meet the 80% below 1990 target.

[11] These include HFC125, HFC134a, HFC245fa, CF_4, and SF_6.

[12] United States EPA (2006), Global Mitigation of Non-CO2 Greenhouse Gases, report 430-R-06-05.

negative carbon prices. However, even with high carbon prices (greater than \$150 per tCO_2), technological limitations prevent complete non-CO_2 mitigation.

The GCAM results, shown below in Table 8, achieve non-CO2 emissions (992 $MtCO_2e$) that are consistent with the PATHWAYS goal (750 $MtCO_2$ + 46 $MtCO_2$ in additional non-energy industrial CO_2) and an overall net GHG target of less than 1,080 $MtCO_2e$, given an assumed terrestrial carbon sink of 831 $MtCO_2$.

Table 8. GCAM 2050 Case Results, Relative to U.S. 1990 and 2005 GHG Emissions ($MtCO_2e$)[13]

Emissions Category	1990	2005	2012	2050 case	% below 1990	% below 2005
Fossil fuel and industrial CO_2 emissions	5,108	6,112	5,383	796	84%	87%
Non-CO_2 emissions (all)	1,125	1,141	1,143	992	12%	13%
Gross CO_2e emissions	6,233	7,253	6,526	1,788	71%	75%
Terrestrial CO_2 sink	831	1,031	979	831	0%	19%
Net CO_2e (including sink)	5,402	6,222	5,547	957	82%	85%

The GCAM scenario was constructed to match the PATHWAYS energy CO_2 target of 750 $MtCO_2$ in 2050, which corresponds to an 84% reduction from 1990 levels. Since GCAM accounts for some industrial CO_2 emissions not accounted for by PATHWAYS, the GCAM fossil fuel and industrial emissions target was adjusted up to 796 $MtCO_2$, preserving the 84% decline for this class of emissions. The carbon price required to achieve this level of fossil fuel and industrial emissions leads to a 12% decline in non-CO_2 GHG emissions (detailed below by sector and gas), which together with a terrestrial sink held at the low range of recent values (831 MtCO2), is sufficient to surpass the 80% below 1990 target for all emissions.

As discussed below, the sink would need to decline to 15% below its 1990 value or 27% below its 2012 value before more aggressive mitigation measures would be required to meet the 80% target for all emissions. Furthermore, technological limits on additional non-CO_2 reductions mean that additional GHG mitigation on the deep reduction frontier must come primarily from CO_2 mitigation and associated co-mitigation of non-CO_2 emissions rather than active non-CO_2 mitigation.

The figures below show each non-CO_2 gas category (CH_4, N_2O, and f-gases) by sector in 2050 for our central case, compared to historical values, a 2050 reference with no mitigation, and a 2050 reference with CO_2 mitigation but no active non-CO_2 mitigation. The CO_2-only mitigation case is included to provide insight into the degree of non-CO_2 co-mitigation present in each sector. We decompose the sectors differently for each gas category to reflect the diversity of primary sources among them.

As the figures show, co-mitigation of non-CO_2 emissions is greatest for CH_4, which is a by-product of fossil fuel extraction and processing. The greatest co-mitigation reductions are in the coal and natural gas sectors, and would presumably be greater if CCS were less widely deployed as a CO_2 mitigation

[13] Fossil fuel and industrial CO_2 emissions were chosen to match the 84% reduction found in the PATHWAYS cases. Note that the GCAM case includes some industrial CO_2 emissions not accounted for in PATHWAYS. Data for 1990, 2005, and 2012 are from the EPA 2014 GHG inventory.

technology, which would require even deeper reductions in fossil fuel use. Active mitigation measures further reduce coal-related CH_4 emissions, as well as CH_4 emissions from landfills, industrial emissions of N_2O and f-gases, and f-gases associated with air conditioning in both commercial and residential buildings.

Figure 46. CH_4 Emissions

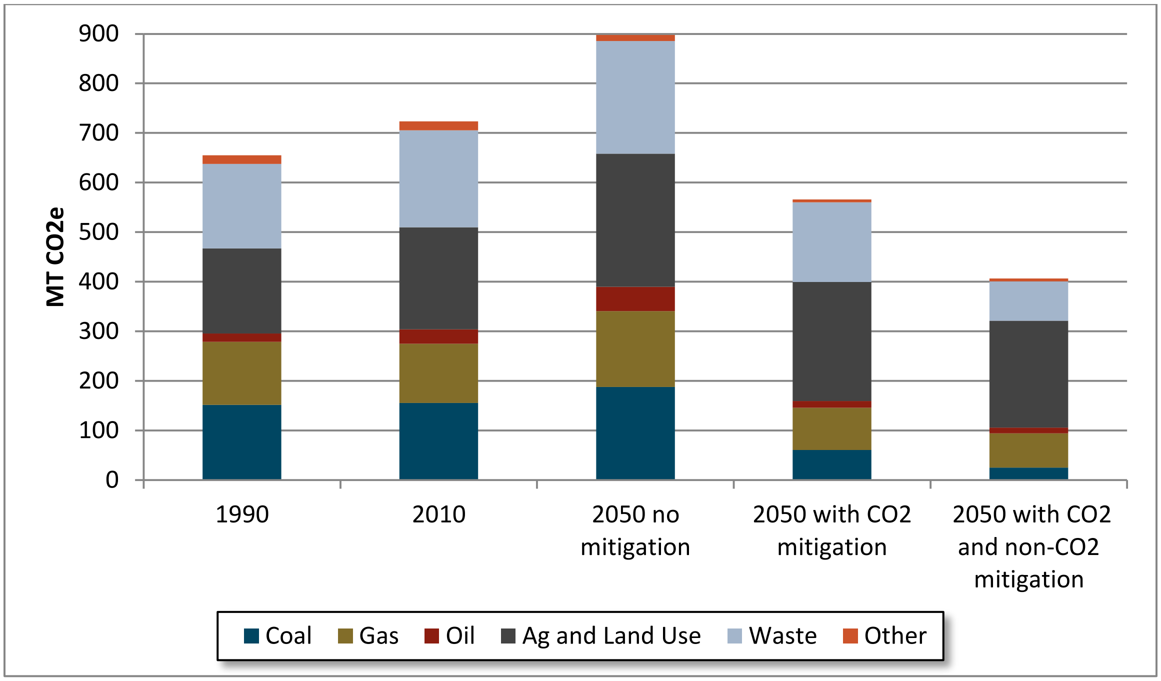


Figure 47. N_20 Emissions

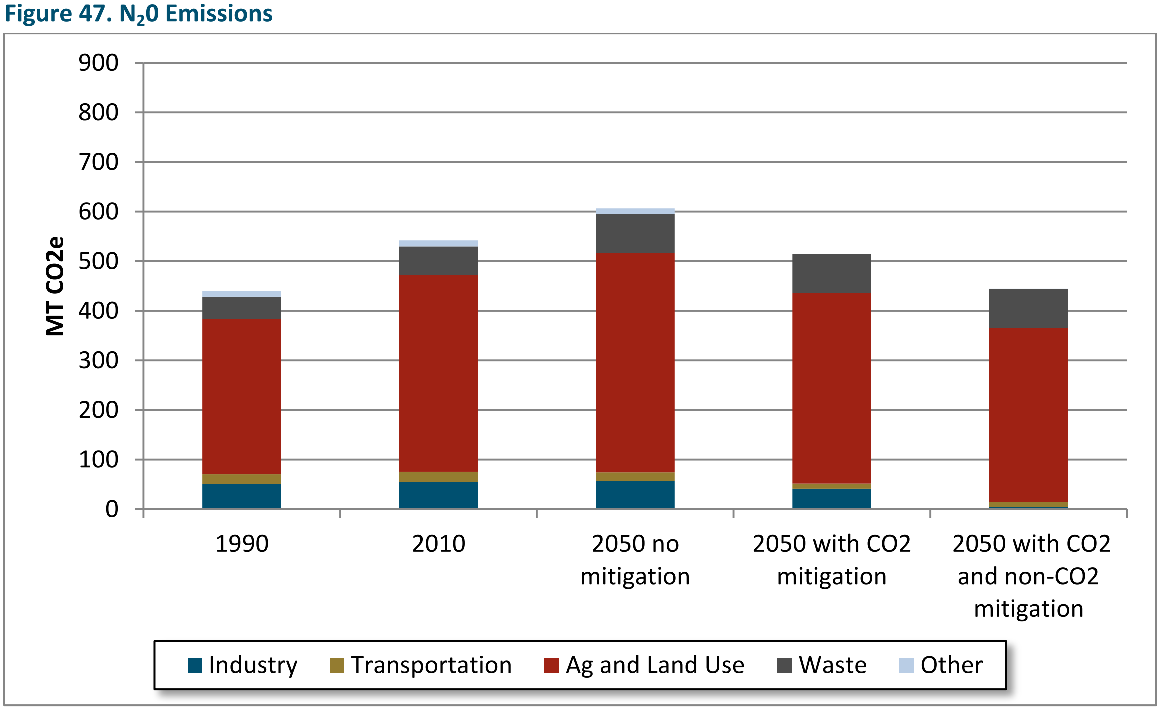


Figure 48. Fluorinated Gas Emissions[14]

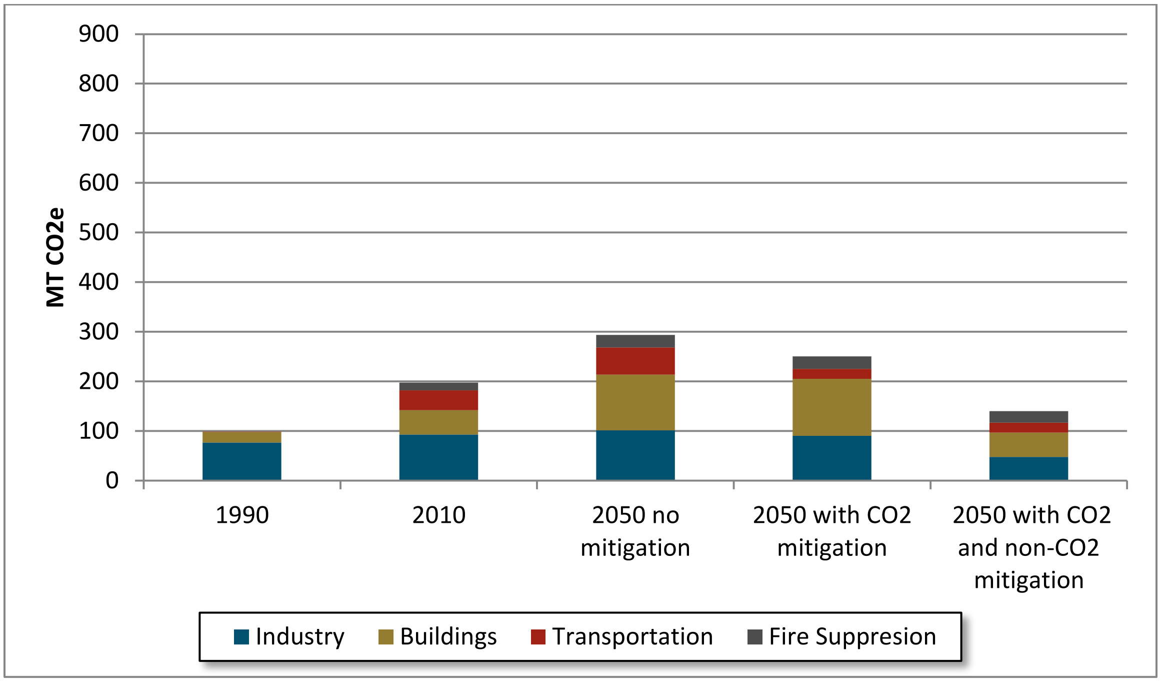


Table 9 shows the largest active mitigation measures by subsector required to reduce non-CO_2 emissions to 992 $MtCO_2e$ in 2050. The largest three measure areas are CH_4 reductions from landfills, N_2O

Table 9. Principal Non-CO_2 Mitigation by Gas and Subsector[15]

Subsector	Absolute Reduction ($MtCO_2e$)	Percent Reduction
	CH_4	
Landfills	82	73%
Coal	35	58%
Enteric Fermentation	16	9%
Natural Gas	16	19%
	N_2O	
Agricultural Soils	33	9%
Adipic Acid Production	27	96%
Nitric Acid Production	10	89%
	Fluorinated Gases	
Air Conditioning	64	63%
Solvents	32	82%

[14] Note that fire suppression and transportation data are not available for 1990.

[15] Absolute and percent reduction in 2050 versus an alternative 2050 case with CO_2 mitigation only.

reductions in industrial processes, and f-gas reductions. Without these active mitigation measures, we would only reach a 76% reduction in total net GHG emissions by 2050.

9.2. Sensitivity to Terrestrial Carbon Sink Assumptions

Terrestrial carbon sinks play an important role in the global carbon cycle, removing approximately 25% of anthropogenic emissions from the atmosphere annually [*Canadell et al.,* 2007]. Yet, the magnitude, mechanisms, and geographic location of terrestrial sinks are poorly understood. The EPA estimates the US sink to be 831 MtCO_2 in 1990, increasing to 1,031 in 2005 and 979 in 2012 [*EPA*, 2014]. The largest term in the EPA inventory results from carbon sequestration on existing forestland, which is regaining carbon as a result of past clearing. Net terrestrial carbon dynamics are also sensitive to forest harvest and the growth of product pools, agricultural management that affects soil carbon, and the uncertain role of climate change and CO_2 fertilization.

Given these uncertainties, we have opted to perform a simple sensitivity analysis to demonstrate the impact of sink strength on our results. Table 10 shows the required emissions reductions in 2050 to meet GHG reduction target for various levels of sink strength. The central GCAM case was chosen to match the 84% reduction in energy-related CO_2 emissions relative to 1990 levels present in the PATHWAYS cases, which results in a slight overshoot of the 80% total GHG target. Given this overshoot, the sink would need to decrease to 710 MtCO_2 (15% below the 1990 sink level, or 27% below the 2012 sink level) in order to require more aggressive reductions in non-CO_2 emissions than the case already outlined.

Table 10. Terrestrial Carbon Sink Sensitivity Analysis (MtCO_2e)

Sink sensitivity	1990 sink +50%	1990 sink +25%	Central Case	1990 sink -25%	1990 sink -50%
2050 terrestrial CO_2 sink	1,247	1,039	831	623	416
Allowable 2050 gross CO_2e	2,327	2,119	1,911	1,704	1,496
Fossil fuel + industrial CO_2	1,312	1,109	796	711	513
Non-CO_2 emissions (all)	1,017	1,009	992	991	983
% Reduction in fossil fuel + industrial CO_2	74%	78%	84%	86%	90%
% Reduction in non-CO_2	10%	10%	12%	12%	13%
% Reduction in net CO_2e	80%	80%	82%	80%	80%

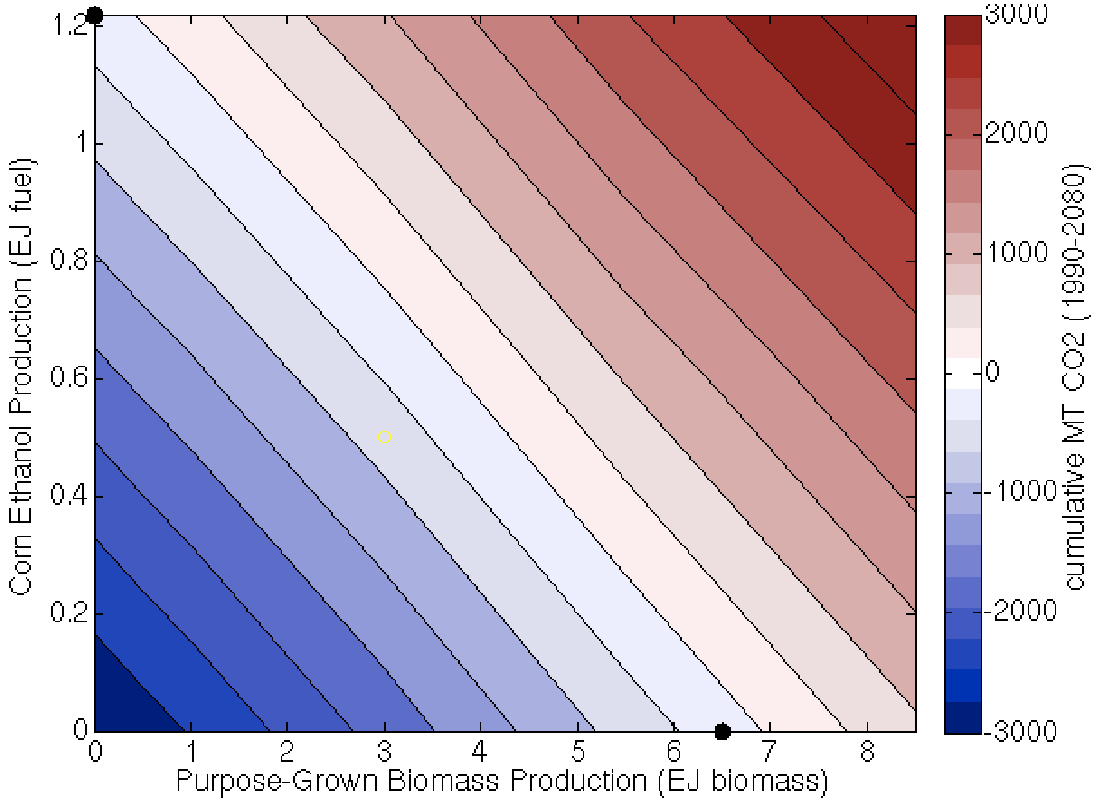
Due to the difficulty of mitigating non-CO_2 emissions beyond a certain point, most of the additional reductions required in the event of a lower than expected sink would need to come via additional reductions in fossil fuel use. For instance, with a sink that is 50% below 1990 levels, fossil fuel and industrial CO_2 emissions decrease by 90% versus 84% in the central case, whereas non-CO_2 emissions decrease by 13% compared to 12% in the central case.

9.3. Biomass Production and Indirect Land-Use Change Emissions

Domestic bioenergy production induces changes in agricultural markets that result in land-use emissions worldwide [*Searchinger et al.,* 2008; *Plevin et al.*, 2010]. To address this issue in PATHWAYS, we performed a series of simulations in GCAM designed to identify a level of purpose-grown biomass that would not increase GHG emissions from global land use change if the increase in bioenergy production were implemented in conjunction with a contraction in corn ethanol production currently required by the RFS. In these cases, we eliminated international trade in bioenergy in order to isolate the effect of domestic production and consumption of purpose-grown bioenergy crops and/or corn ethanol. We systematically varied the level of these two bioenergy sources while imposing an 80% reduction in fossil fuel and industrial CO2 emissions both in the U.S. and globally. To account for co-products of corn ethanol that are not included in GCAM, we assume that one-third of the corn land used for ethanol production would need to remain in production to meet animal feed demands currently met by co-products. This effectively reduces the carbon benefit of retiring corn ethanol production by one-third.

As a baseline, we choose a world in which the RFS corn ethanol requirements of 1.22 EJ (15 billion gallons) of fuel production are maintained until 2050. Figure 49 shows the change in cumulative global land use emissions from 2005 to 2080 that would result from various levels of either corn ethanol or purpose-grown bioenergy production. We focus on cumulative emissions because the effect of land-use change on terrestrial carbon can take several decades to be realized. Reducing corn ethanol to zero and increasing purpose-grown production to 6.5 EJ (371 MMT) of biomass yields a net zero change in global emissions (i.e., moving from the black circle on the y axis of Figure 49 to the black circle on the x axis).

Figure 49. Change in Cumulative GHG Emissions from Global Land Use Change from Purpose-Grown Biomass Production



10. Comparison of PATHWAYS Results with EMF-24

The existence of multiple technologically feasible pathways to an 80% emissions cut in the US by 2050 is supported by the energy-economic model literature, most notably the 24th Energy Modeling Forum intercomparison effort (EMF-24; [*Fawcett et al.*, 2014a]), which examined both 80% and 50% emissions reduction scenarios in 2050 across nine energy-economic models of varying degrees of sectoral and process resolution. These models included integrated assessment models, computable general equilibrium models, and optimization models, in which some concept of economic optimality (e.g., cost minimization, supply-demand equilibrium) drives the future evolution of the energy system subject to technology and emission constraints.

The PATHWAYS model differs from most of these energy-economic models in several important ways. It features a relatively high level of sectoral granularity tied to stock rollover constraints, and an electricity dispatch sub-model requiring that regional load curves be satisfied on an hourly basis. Perhaps most distinctively, PATHWAYS outcomes are not arrived at through economic optimization (although it tracks costs), but rather by calculating the energy system and emissions consequences of detailed user-specified technology investment and deployment constraints. Given these differences between PATHWAYS and the models that have been used to examine deep emissions cuts in the US so far, it is worthwhile to identify common outcomes and unique insights offered by the different approaches. Pathway's highly granular approach provides the opportunity to flesh out in unprecedented detail what deep decarbonization scenarios look like for the US, while the combination of user flexibility and detailed constraints offers the possibility of discovering unique technology solutions that simply would not emerge from a model that doesn't represent, for example, hourly electrical dispatch.

Consistent with PATHWAYS, one common feature of deep emissions reduction scenarios in the EMF-24 effort is significant decarbonization of the electricity sector, reflecting the relatively low cost of mitigation in this sector. The EMF-24 effort paid particular attention to the role of energy technology assumptions (e.g. cost, availability, and performance) in shaping future scenarios. For example, within the context of 80% emissions reduction scenarios, the effort examined a "pessimistic renewables" scenario that tended to favor nuclear and fossil fuel generation with CCS, as well as a "pessimistic nuclear/CCS" scenario that tended to favor renewables. From a cost and feasibility perspective, no one technological strategy emerged from these scenarios as dominant. That is, effectively eliminating individual technologies did not consistently increase costs across model, indicating (1) that there is a "flat optimum" with respect to different energy system configurations, and (2) that factors other than technological characteristics (e.g. social acceptability of nuclear energy or bioenergy) may play a relatively important role in the future trajectory of the energy system [*Clarke et al.*, 2014].

Energy efficiency also played an important role in the EMF-24 scenarios. Both of the 80% emissions cut scenarios assumed that a 20% reduction in primary energy consumption was possible as a reference level of energy efficiency improvement. Some models (5 of 9) found reductions in electricity supply above and beyond this level, reflecting additional end-use efficiency and service demand reductions in response to emission policies and associated prices [*Clarke et al.*, 2014].

The remaining EMF-24 models showed an increase in electricity supply in the 80% reduction scenarios relative to their 2050 reference scenarios [*Clarke et al.*, 2014]. In these models, end-use electrification outweighed additional energy efficiency improvements in its influence on total electricity supply. With the data currently available from the EMF-24 effort, it is not possible to disaggregate the relative contributions of end-use energy efficiency and fuel switching on electricity supply, nor can one identify which end-use sectors undergo the largest degree of electrification. This is one area that the PATHWAYS model identifies some compelling solutions, particularly in the high renewables scenario, in which electrical load-matching constraints are met by absorbing excess renewable generation with intermediate energy carrier (e.g. H_2 and synthetic natural gas) production. PATHWAYS is able to quantify the degree of end-use fuel switching required to balance this excess generation.

From a cost standpoint, the PATHWAYS results ($1 to $2 trillion) are consistent with those found in the EMF 24 studies, which ranged from $1 to $4 trillion[16] for most of the 80% emission reduction scenarios, although one outlying model found costs as high as $6 trillion [*Clarke et al.*, 2014]. Not all models were able to report the same cost metrics due to structural differences, so the costs reported for each model reflect different ways of handling, for example, the value of leisure time and costs associated with reduced service demands. The above values reflect either total consumption loss, the area under the marginal abatement cost curve, or equivalent variation. A thorough description of the differences among these metrics can be found in Fawcett et al. [2014b]. PATHWAYS calculates the total energy system costs, and does not model changes in service demands in response to higher prices. Finally, there was no consistent trend among models in the EMF 24 studies in terms of the relative costs of the pessimistic renewables vs. the pessimistic nuclear and CCS scenarios.

[16] Net present value of cumulative costs through 2050 in 2005 dollars using a 5% discount rate.

11. Energy System Transitions

11.1. Introduction

This section presents several different kinds of graphical representations of the low carbon transition in energy supply and demand sectors as a different way of considering the results in the previous chapters. PATHWAYS was developed in part to allow broad aggregate trends in energy mix and CO_2 emissions to be seen side by side with the underlying details of stock composition, timing of stock turnover, and rates of uptake of new low carbon infrastructure and equipment. This kind of granular visualization of the low carbon transition can help policy makers, researchers, business, investors, and the public understand what kinds of concrete changes are required, at what scale, with what timing, over the next three to four decades.

11.2. System-Wide Transition

One potential low-carbon transition of the U.S. energy system is illustrated in the Sankey diagrams below. Sankey diagrams use arrows to represent the major flows of energy from supply to end use, with the width of the arrows being proportional to the magnitude of the flows. Figure 50 represents the current U.S. system, and Figure 51 represents the system in the 2050 Mixed Case. In both figures, primary energy supplies are shown on the left.[17] The middle of the figure shows conversion processes, with conversion losses implied but not explicitly shown. The right side of the figures shows final energy consumption, with all end uses allocated to the three aggregate categories of buildings, transportation, and industry.

The main results are illustrated by comparing the two figures. Overall, both primary and final energy use are reduced in the 2050 Mixed Case through improvements in energy efficiency. On the primary energy side, fossil fuels are greatly reduced, including the complete elimination of coal and a dramatic reduction of petroleum use. A substantial amount of natural gas remains in the system due to the availability of CCS for power generation in this scenario. Renewable and nuclear primary energy for generation are dramatically increased, and biomass-derived pipeline gas and liquids become the dominant combustion fuels. Conversion processes that are small or negligible at present—biomass refining and the production of hydrogen and synthetic natural gas from electricity—play an important role in the 2050 energy system. End uses show dramatic fuel switching away from fossil fuels toward electricity, electricity-derived fuels, and biomass-derived fuels.

[17] Primary energy here is calculated using the "captured energy" approach in which renewable and nuclear electricity are converted to primary energy on a 1:1 basis.

Figure 50. Sankey Diagram for U.S. Energy System in 2014

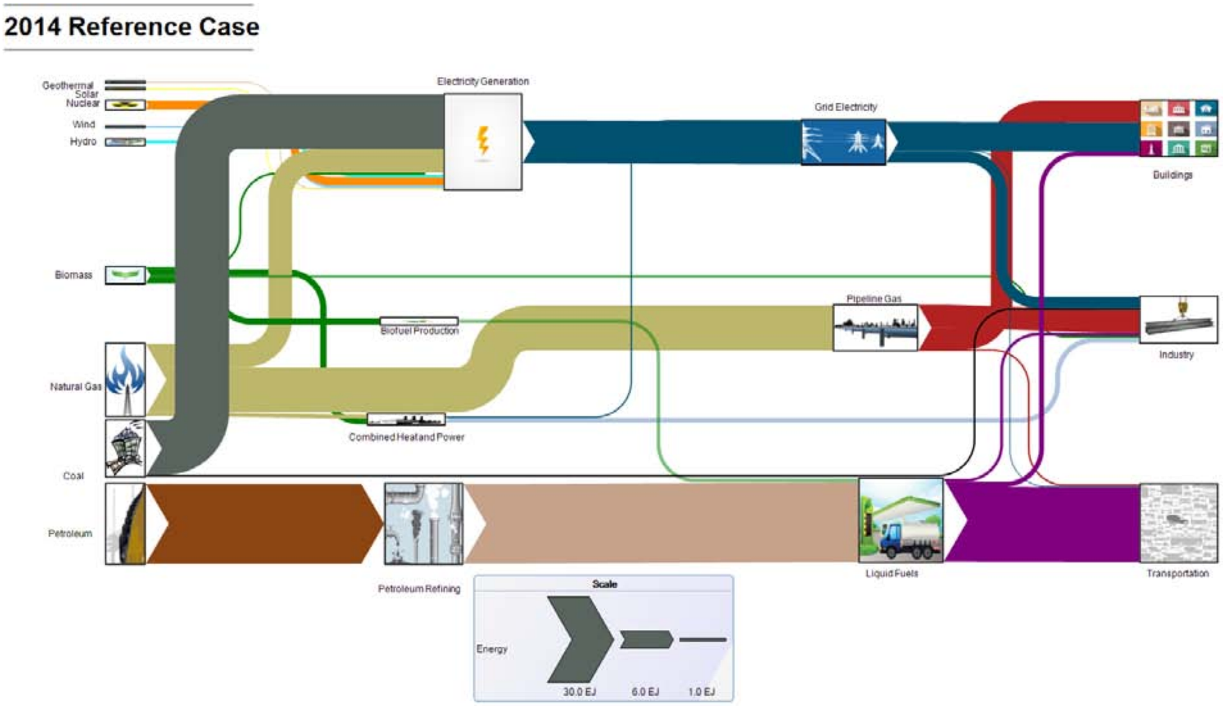
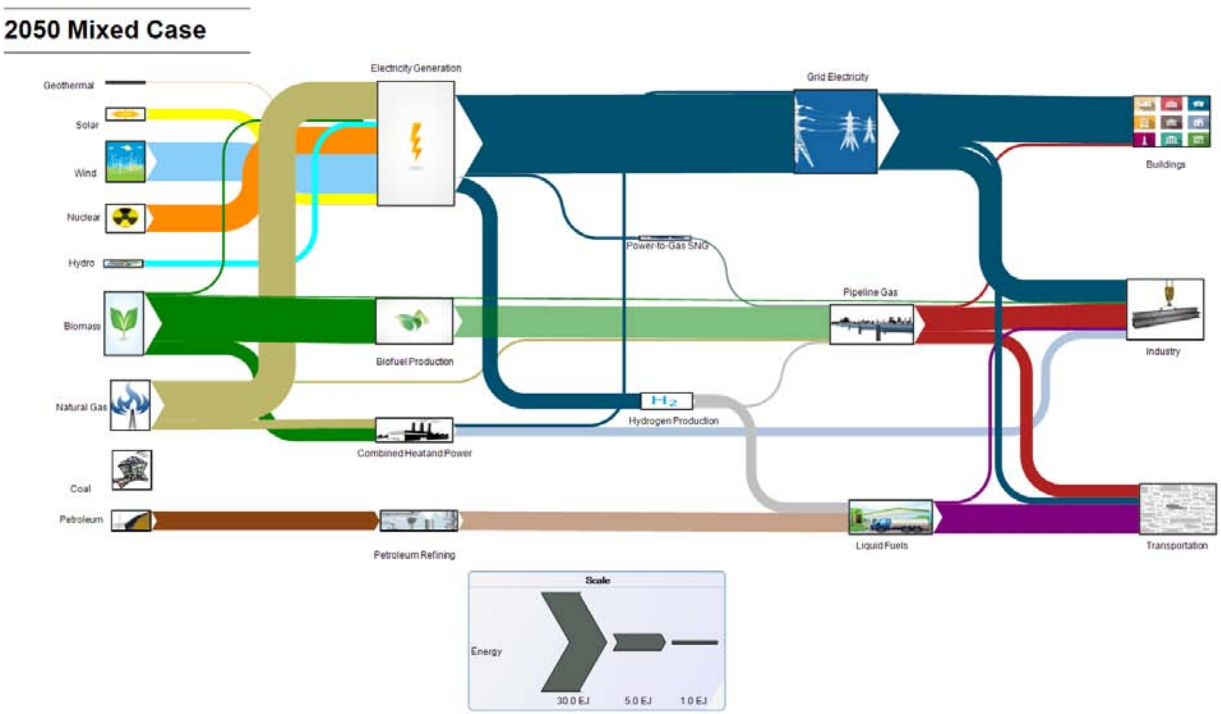


Figure 51. Sankey Diagram for 2050 Mixed Case U.S. Energy System



11.3. Supply Sector Transition

The figures below show the transition in energy supplies for each of the four low carbon scenarios in this study, illustrating how the strategies differ by case. In each figure there are three columns representing three main types of final energy supply—electricity, pipeline gas, and liquid fuels. The middle row of each figure shows how the composition of the supply mix within each supply type changes over time, from present to 2050. The bottom row shows the resulting change in carbon intensity of the delivered energy. The top row shows the demand composition of supply—the amount and relative share that each final demand type consumes of each supply type—at present and in 2050. Demand includes the use of electricity to produce hydrogen and SNG.

Figure 52 shows the low carbon transition for the Mixed Case. The carbon intensity of electricity is reduced by a factor of more than 30 over time despite a near doubling of generation as new electric loads are brought on in buildings, transportation, and industry, plus production of hydrogen and SNG as fuels for load balancing. The steady carbon intensity decline is the result of phasing out uncontrolled fossil fuel generation at it retires while increasing the shares of renewable, nuclear, and CCS generation, a process that is accelerated after 2030. Pipeline gas is decarbonized by an order of magnitude over time, with almost all biomass resources turned into bio-SNG and added to the pipeline, in combination with SNG and hydrogen produced from electricity. Overall pipeline gas demand decreases slightly over time, as most building gas and a portion of industrial gas use are eliminated by electrification, and the primary new gas loads are in heavy duty transportation (in the from of CNG and LNG). In liquid fuels petroleum use declines by about three-quarters as a consequence of vehicle efficiency improvements in combination with fuel switching to electricity for light duty vehicles and pipeline gas for heavy duty vehicles. Some transportation fuel demand is met by hydrogen, which is trucked in liquid form from supply to fueling stations, and therefore included in the liquid fuels category. The overall energy intensity of liquid fuels decreases modestly over time, as the hydrogen share grows, but petroleum remains the principal liquid fuel.

Figure 53 the low carbon transition in the High Renewables Case. It resembles the pattern of the Mixed Case in many regards, with the exception of no CCS in generation, which is replaced by a higher share of renewable generation, with a steep ramp in wind generation beginning around 2030. Generation carbon intensity is again reduced more than 30 fold. The production of hydrogen and SNG from electricity is higher than in the Mixed Case, as a result of higher balancing requirements from variable generation, and the resulting share of these fuels in the pipeline gas mix is higher. The overall quantity of pipeline gas remains constant over time, with reduced building gas use offset by higher transportation gas use than in the mixed case. The proportion of natural gas remains somewhat higher within the pipeline mix, and consequently the carbon intensity decrease is somewhat less over time. Petroleum, on the other hand, decreases more rapidly, with an especially steep decline in the 2030s, as electricity replaces more gasoline in light duty transportation and CNG/LNG replaces more diesel in heavy duty transportation. Hydrogen plays a smaller role in transportation for a similar reason, and again the carbon intensity of liquid fuels overall is only modestly reduced as petroleum remains the dominant residual liquid fuel, albeit in much reduced quantity.

Figure 52. Energy Supply Sector Low Carbon Transition in Mixed Case

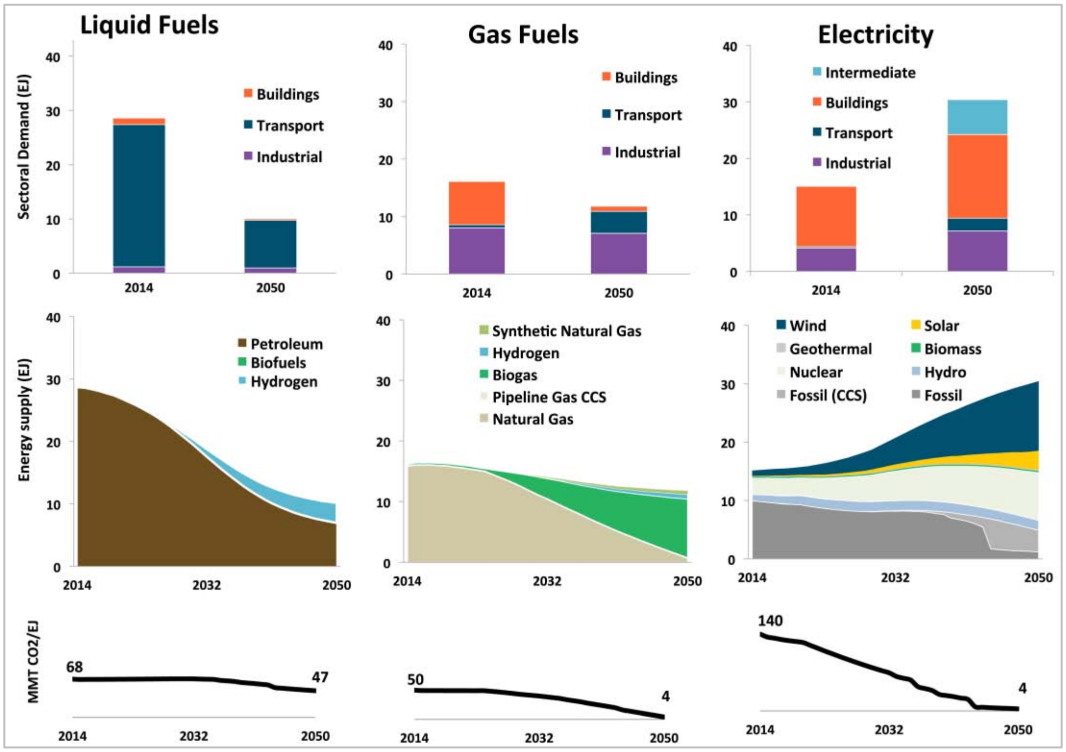


Figure 53. Energy Supply Sector Low Carbon Transition in High Renewables Case

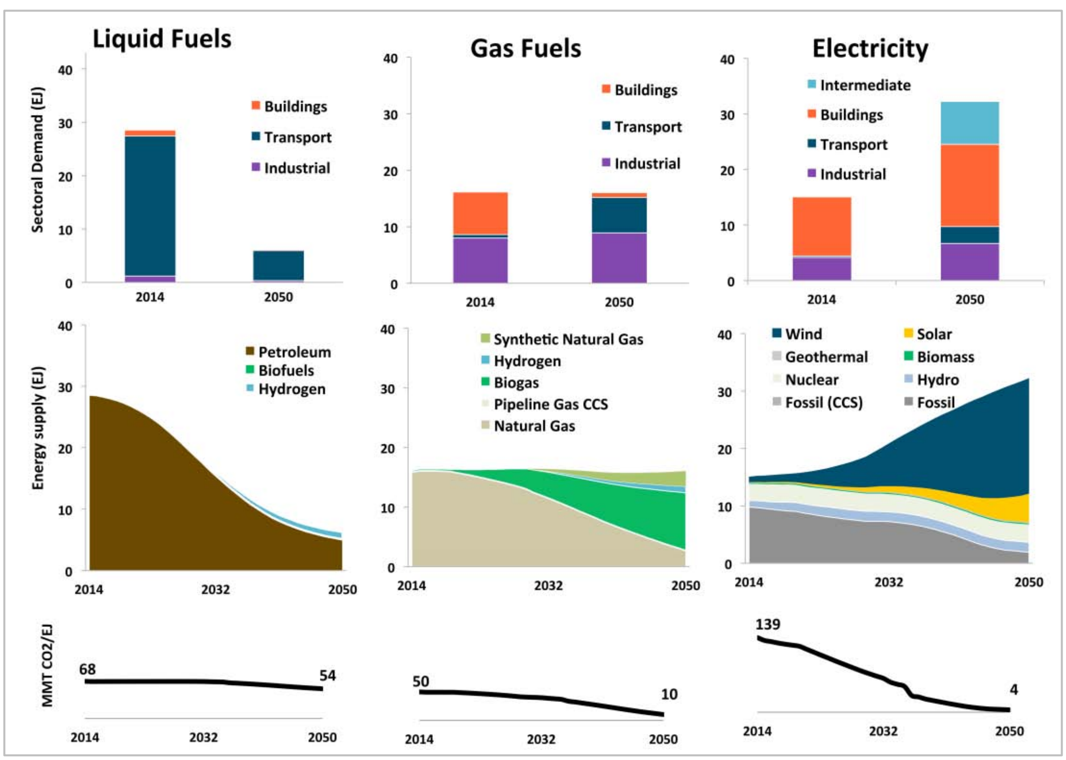


Figure 54. Energy Supply Sector Low Carbon Transition in High Nuclear Case

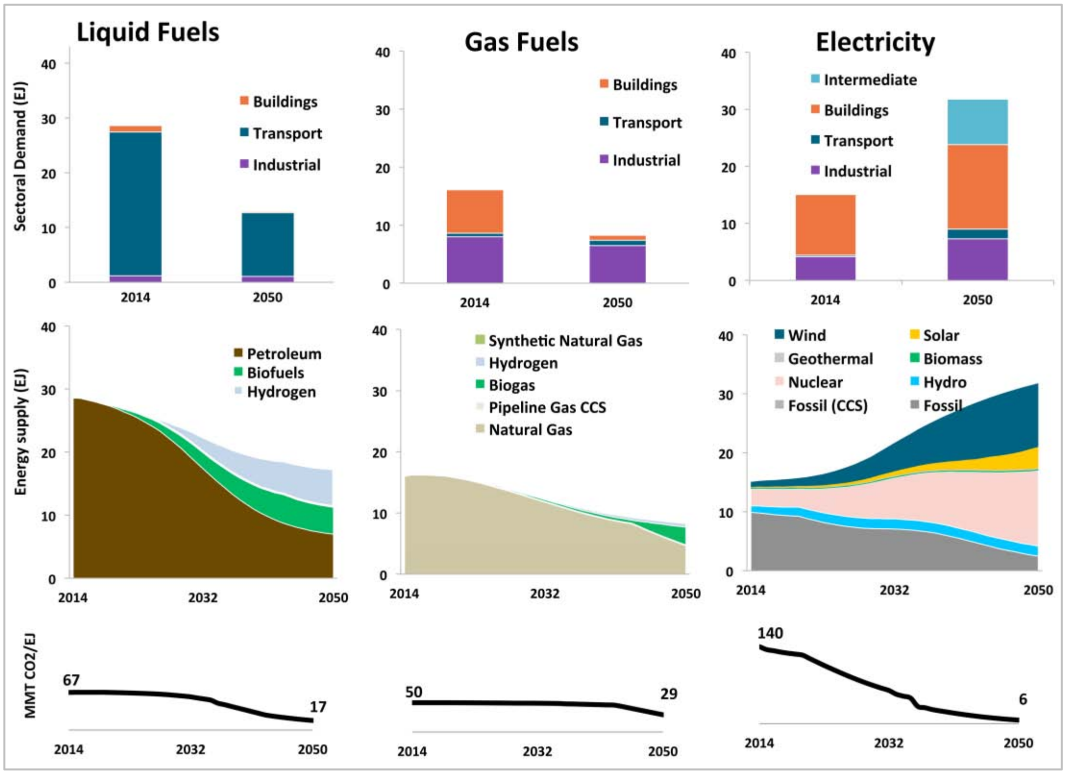


Figure 55. Energy Supply Sector Low Carbon Transition in High CCS Case

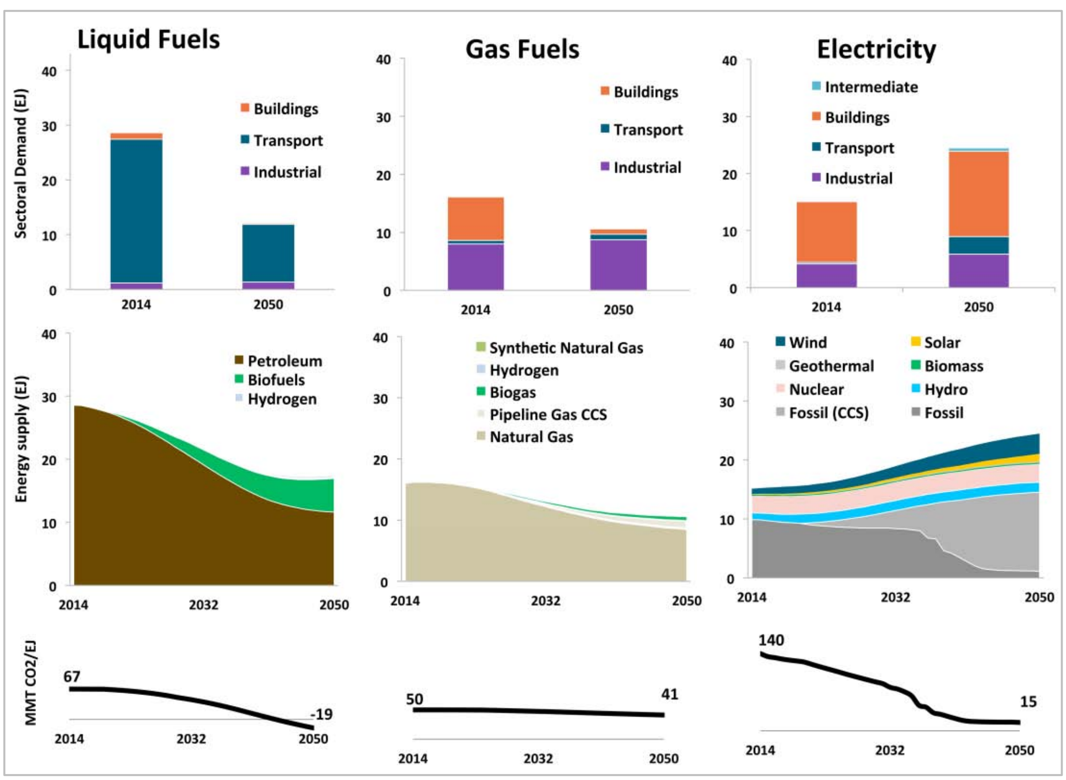


Figure 54 shows the low carbon transition in the High Nuclear Case. The decrease in electricity carbon intensity is similar to the previous cases, and the increase in total generation and renewables, along with the level of residual fossil generation, being similar to that in the Mixed Case. Without CCS, nuclear power expands rapidly after about 2020 to take over the remaining share of retired fossil generation. The strategies for gas and liquid fuels are different from the Mixed and High Renewables Cases, which is a consequence of pursuing a very different strategy for transportation fuels. In the High Nuclear Case, biomass is used primarily for the production of liquid fuels (mostly renewable diesel), and electricity-produced hydrogen is mostly allocated to use in transportation fuel cells. Because of the growth in biofuels and hydrogen, the quantity of liquid fuels declines only modestly over time, as the combined carbon intensity decreases by a factor of more than three. Pipeline gas supply declines more in quantity than in the earlier cases, while the pipeline fuel mix remains dominated by natural gas. As a consequence, the reduction in pipeline gas carbon intensity over time is modest, especially before the 2040s when more gasified biomass is introduced to the pipeline.

Figure 55 shows the low carbon transition in the High CCS Case. Since substantial fossil fuel use remains in this scenario, with carbon emissions being captured, it is the case most similar in pattern to the existing energy system, including the continued use of coal in generation. The presence of CCS to capture emissions elsewhere in the economy allows for a less steep drop in electricity carbon intensity than in other cases, though it still declines by order of magnitude below present. Renewables increase modestly and nuclear is kept at current levels, while the overall increase in generation is less than in other cases. Pipeline gas declines only modestly in quantity and remains dominated by natural gas, since CCS is assumed to capture some combustion emissions in industry. As a consequence the decline in carbon intensity of pipeline gas is even less than in the High Nuclear Case. The High CCS Case also has the lowest decline in petroleum use, though still about half relative to present. However, the carbon intensity of liquid fuels overall decrease dramatically, to a negative emissions level. This is due to the application of CCS to the refining of biomass to produce biodiesel. This is the only application of BECCS in the four scenarios. The High CCS Case is also unique among the scenarios in not using electric fuels to balance non-dispatchable generation.

11.4. Demand Sector Transition

The figures below show the low carbon transition in energy end use over time for the Mixed Case, illustrating energy efficiency and fuel switching strategies. Starting with changes in the physical stock, they show the magnitude and rate of demand-side infrastructure turnover needed to meet the 2050 emissions target.

The figures describe five key demand subsectors: light duty vehicles, heavy duty vehicles, residential space heating, commercial lighting, and iron and steel. While not covering all of the demand subsectors modeled in this study, the five subsectors chosen are both very important for overall energy and emissions, and indicative of the transition within their respective sectors. Each figure shows six kinds of indicators as they evolve over the period from 2014 to 2050: from top to bottom these are total service demand, new stock by fuel type, total stock by fuel type (includes retirements, not shown separately in this figure), service demand decomposed by fuel type, final energy by fuel type, and emissions by fuel type.

Figure 56 shows the low carbon transition in light duty vehicles. Total vehicle miles traveled increase over time, following the trend in the *AEO* Reference Case. Between the mid-2020s and mid-2030s, sales of fuel cell, battery electric, and plug-in hybrid electric vehicles rise from a small share to the majority share of new LDVs, and by the 2040s they constitute all new LDV sales, about one-third of each type. Total vehicle stock composition shows a time lag of approximately one decade in reflecting new vehicle sales. Reflecting the change in stocks, VMT by fuel shows electricity and hydrogen growing from a small share in 2030 to the dominant share in 2040. Final energy by fuel declines much sooner than the uptake of non-ICE vehicles, as fuel economy in conventional gasoline vehicles improves, starting with current federal standards. Emissions from LDVs decline more or less linearly from the present to 2050, reflecting the sequence of developments described above, in combination with the declining carbon intensities of electricity and hydrogen production, which reach negligible levels by 2050 in the Mixed Case.

Figure 56. Light Duty Vehicle Low Carbon Transition in Mixed Case

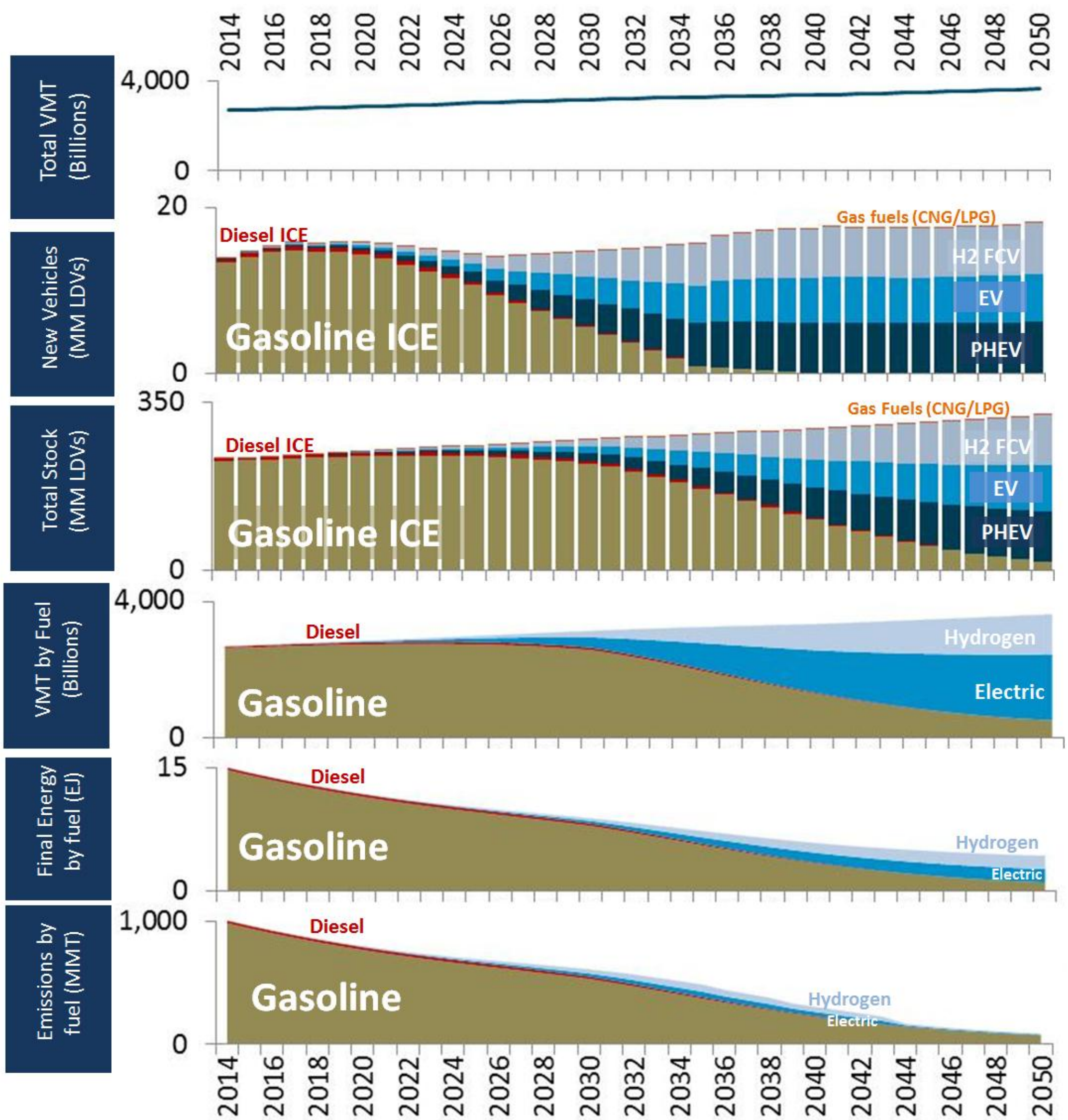


Figure 57 shows the low carbon transition in heavy duty vehicles. HDV miles nearly double over time, following the trend in the *AEO* Reference Case. CNG/LNG and hydrogen fuel cell HDVs are introduced in the 2020s and rise in share to the majority of new vehicle sales by the early 2030s, and the majority of stocks and VMT by fuel by the late 2040s. Final energy rises with increasing mileage to the mid-2020s, then levels out, reflecting efficiency improvements in both conventional diesel and non-diesel alternative vehicles. Emissions from HDVs peak in the 2020s and decline thereafter, despite the plateau in final energy, as the carbon intensity of both pipeline gas supply and hydrogen production fall in the mixed case.

Figure 57. Heavy Duty Vehicle Low Carbon Transition in Mixed Case

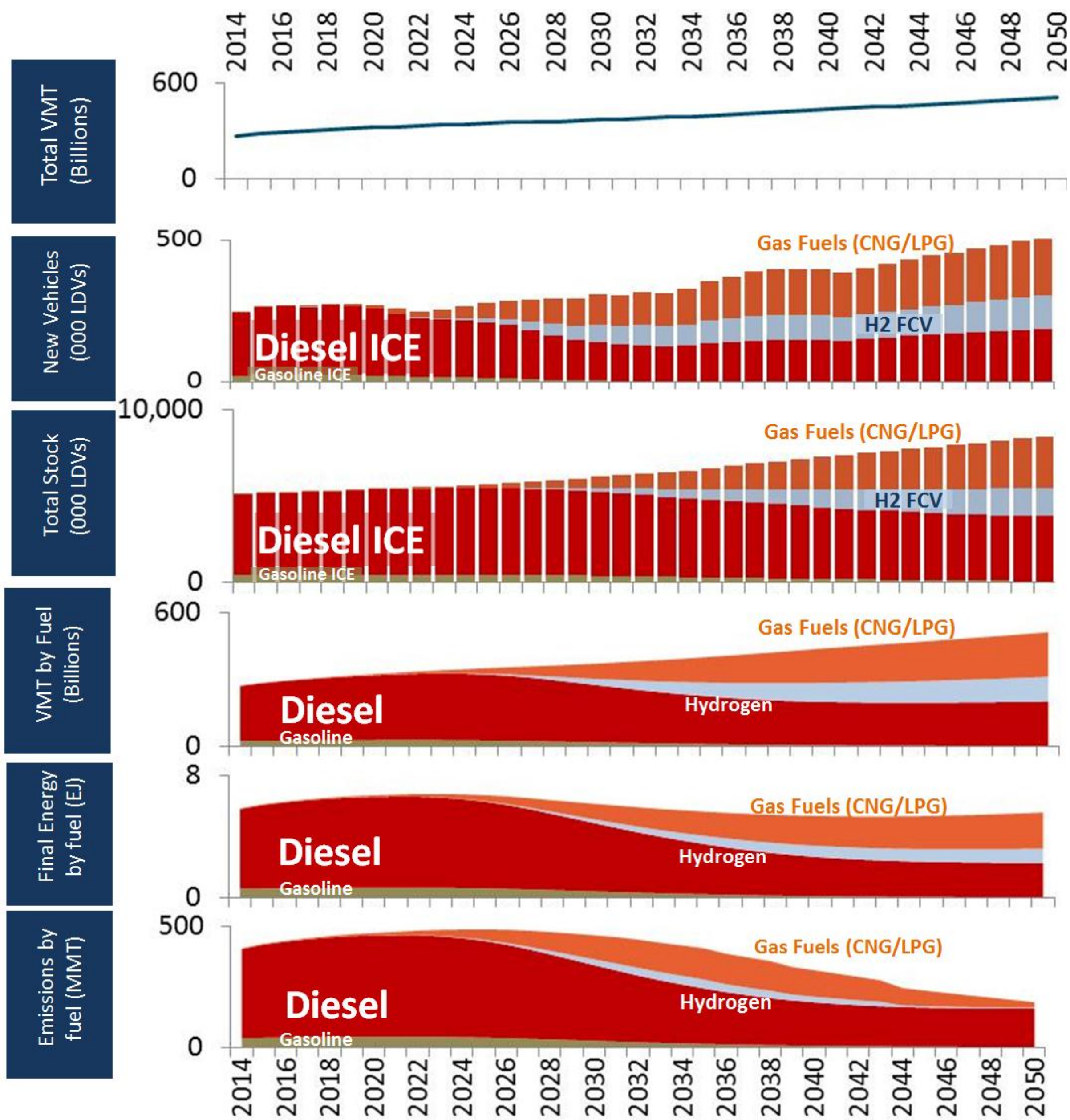


Figure 58 shows the low carbon transition in residential space heating. Both residential housing units and residential floor space increase by almost half over time, following the trend in the *AEO* Reference Case. The principal strategy employed is fuel switching from natural gas furnaces and radiators to electric radiators and heat pumps. This is a rapid and relatively near term transition, as electric heat constitutes the majority of new heating sales by 2020, and of total residential heating stock and final energy use by the 2030s, with almost all heating from electricity by 2050. Reflecting the carbon intensity trajectory of generation in the Mixed Case, both direct and indirect emissions from residential space heating become negligible after the mid-2040s. The bottom chart in Figure 58 shows space heating's share of total residential emissions over time, which shows a similar linear reduction path over the next three decades.

Figure 58. Residential Space Heat Low Carbon Transition in Mixed Case

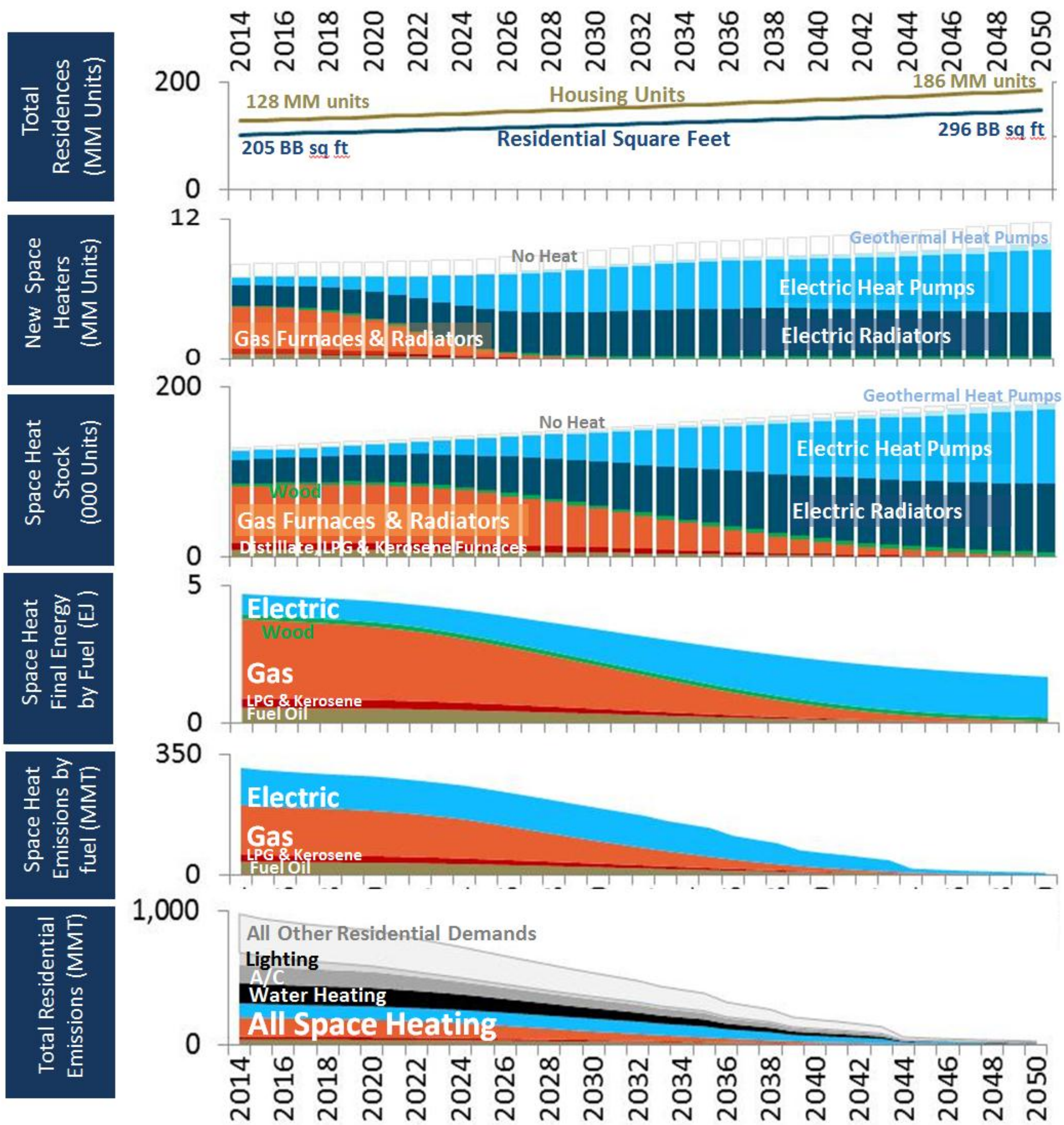


Figure 59 shows the low carbon transition in commercial lighting. Commercial lighting demand increases 40% by 2050, following the trend for commercial floor space in the AEO Reference Case. The strategy employed is replacement of existing lighting technologies with LEDs, which constitute all new lighting after the mid-2020s. The entire commercial lighting stock consists of LEDs by the early 2030s. Reflecting the carbon intensity trajectory of generation in the mixed case, indirect emissions from lighting become negligible by 2040. The bottom chart in Figure 59 shows lighting's contribution of total commercial emissions over time, a negligible share by 2040.

Figure 59. Commercial Lighting Low Carbon Transition in Mixed Case

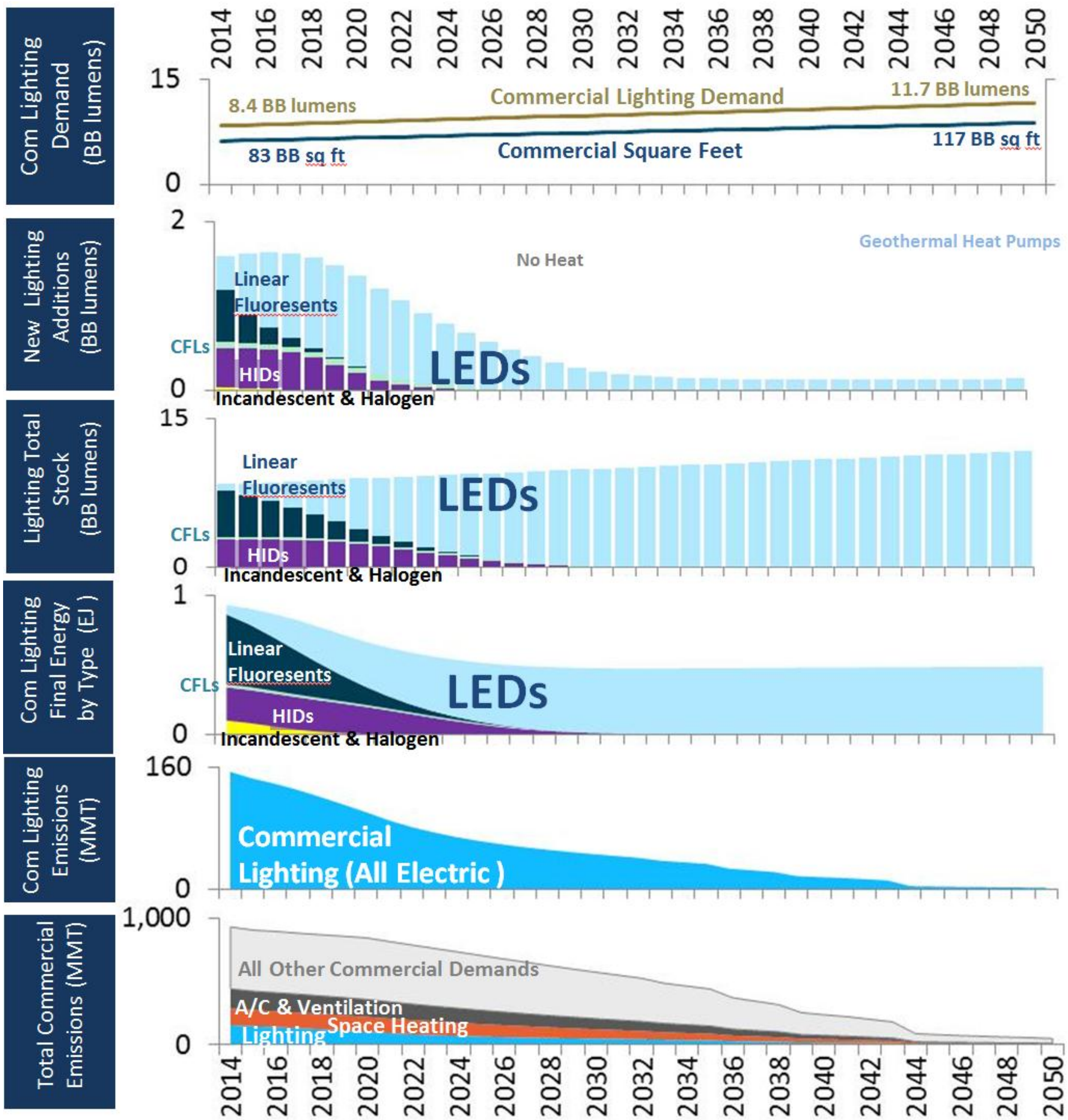
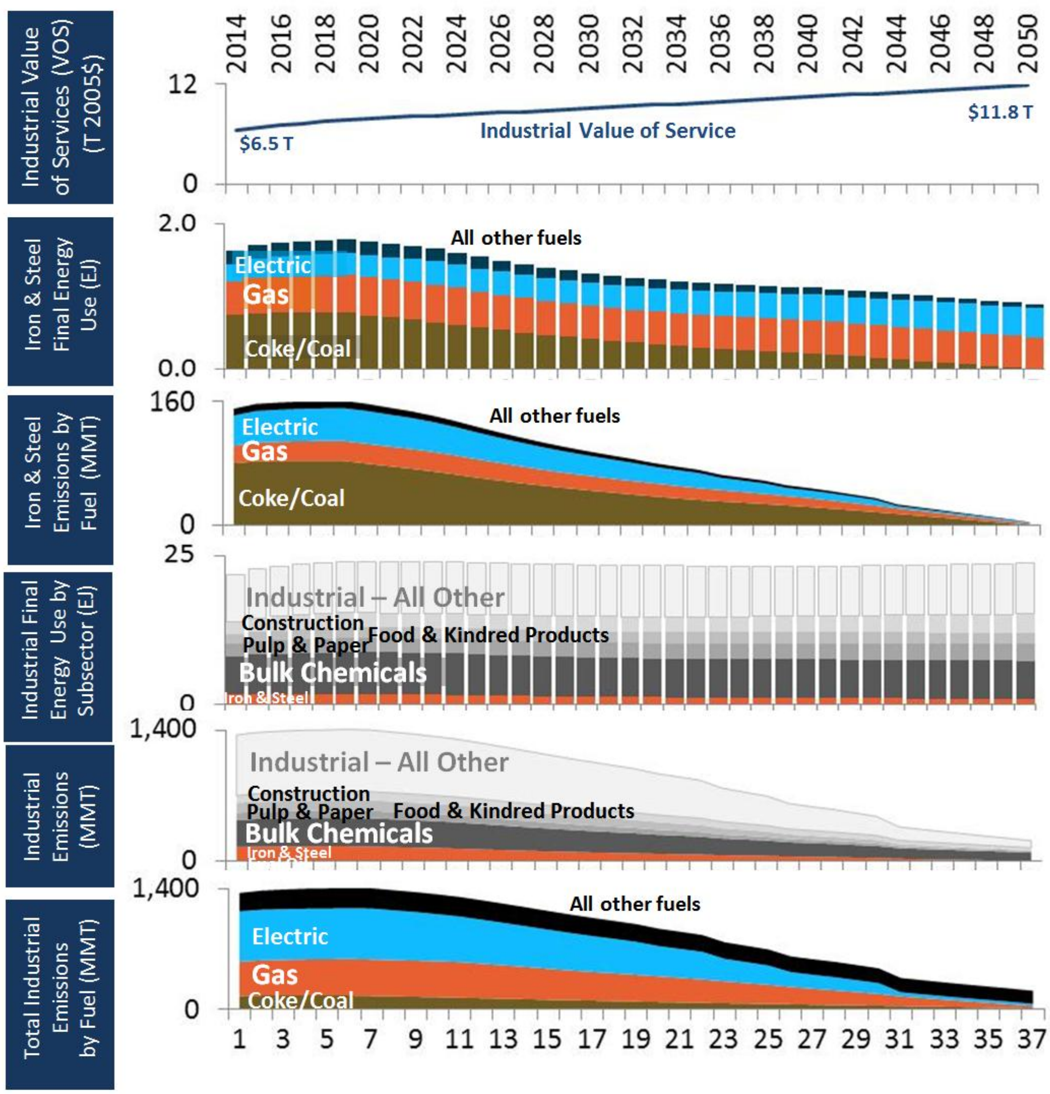


Figure 60 shows the low carbon transition in the iron and steel industry. By 2050, iron and steel value of shipments increase by 80% over current levels based on the *AEO* Reference Case. In all cases except for the High CCS Case, the main strategy for iron and steel is an acceleration of the reference case trend of converting basic oxygen furnaces (BOF) utilizing pig iron as a feedstock into electric arc furnaces (EAFs), which use scrap steel or direct reduced iron (DRI). The High CCS Case maintains the Reference Case production technology and utilizes CCS to capture combustion-related emissions, with an increase in final energy demand. In the Mixed Case and all other cases, final energy demand significantly decreases and coal and coke are phased out by 2050, with final energy supplies coming primarily from equal shares of electricity and pipeline gas. The lower three graphs of Figure 60 show the share of iron and steel in industrial energy use and emissions, and the share of industrial emissions by fuel type. Industrial final energy demand increases slightly over time while it declines in all other sectors, so that industry is responsible for nearly half (about 43-46% across scenarios) of all final energy use in the U.S. economy by 2050.

Figure 60. Iron and Steel Industry Low Carbon Transition in Mixed Case



12. Conclusions

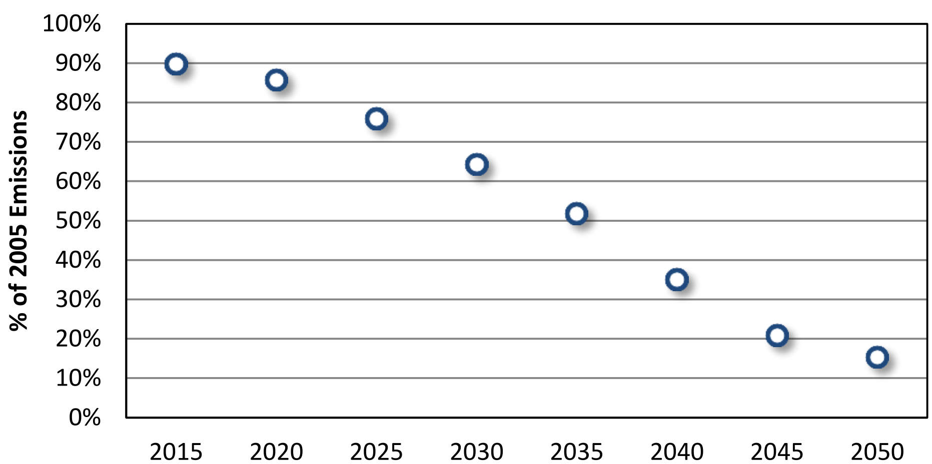
1. Is it technically feasible to reduce U.S. GHG emissions to 80% below 1990 levels by 2050, subject to realistic constraints?

This study finds that it is technically feasible for the U.S. to reduce GHG emissions 80% below 1990 levels by 2050 with overall net GHG emissions of no more than 1,080 $MtCO_2e$, and fossil fuel combustion emissions of no more than 750 $MtCO_2$. Meeting a 750 $MtCO_2$ target requires a transformation of the U.S. energy system, which was analyzed using PATHWAYS. The analysis employed conservative assumptions regarding technology availability and performance, infrastructure turnover, and resource limits. Four distinct scenarios employing substantially different decarbonization strategies—High Renewable, High Nuclear, High CCS, and Mixed Cases, which were named according to the different principal form of primary energy used in electricity generation, and also differed in other aspects of energy supply and demand—all met the target, demonstrating robustness by showing that redundant technology pathways to deep decarbonization exist.

Analysis using the GCAM model supports the technical feasibility of reducing net non-energy and non-CO_2 GHG emissions to no more than 330 Mt CO_2e by 2050, including land use carbon cycle impacts from biomass use and potential changes in the forest carbon sink.

The U.S. total emissions trajectory for the Mixed Case, assuming a constant terrestrial CO_2 sink, is shown in Figure 61.

Figure 61. U.S. Total GHG Emissions for the Years 2015-2050, as a Percentage of 2005 Emissions



2. What is the expected cost of achieving this level of reductions in GHG emissions?

Achieving this level of emissions reductions is expected to have an incremental cost to the energy system on the order of 1% of GDP, with a wide uncertainty range. This study uses incremental energy system costs—the cost of producing, distributing, and consuming energy in a decarbonized energy system relative to that of a reference case system based on the *AEO*—as a metric to assess the cost of deep reductions in energy-related CO_2 emissions. Based on an uncertainty analysis of key cost parameters in the four analyzed cases, the interquartile (25^{th} to 75^{th} percentile) range of these costs extends from negative \$90 billion to \$730 billion (2012 \$) in 2050, with a median value of just over \$300 billion. To put these estimates in context, levels of energy service demand in this analysis are consistent with a U.S. GDP of \$40 trillion in 2050. By this metric, the median estimate of net energy system costs is 0.8% of GDP in 2050, with 50% probability of falling between -0.2% to +1.8%. GCAM analysis indicates that the complementary reductions in non-energy and non-CO_2 GHGs needed to meet the 80% target are achievable at low additional cost.

These cost estimates are uncertain because they depend on assumptions about consumption levels, technology costs, and fossil fuel prices nearly 40 years into the future. To be conservative, energy service demands in this analysis were based on an economy and lifestyles that resemble the present day and on technology cost assumptions that reflect near-term expectations, with relatively flat cost trajectories for many technologies out to 2050. Even at the higher end of the probability distribution (the 75th percentile estimate of \$730 billion), which assumes little to no technology innovation over the next four decades, the incremental energy system cost of a transition needed to meet the 750 $MtCO_2$ target is small relative to national income.

These incremental energy system costs did not include non-energy benefits, for example, the avoided human health and infrastructure costs of climate change and air pollution. Additionally, the majority of energy system costs in this analysis were incurred after 2030, as deployment of new low-carbon infrastructure expands. Technology improvements and market transformation over the next decade could significantly reduce expected costs in subsequent years.

3. What changes in energy system infrastructure and technology are required to meet this level of GHG reduction?

Deep decarbonization requires three fundamental changes in the U.S. energy system: (1) highly efficient end use of energy in buildings, transportation, and industry; (2) decarbonization of electricity and other fuels; and (3) fuel switching of end uses to electricity and other low-carbon supplies. All of these changes are needed, across all sectors of the economy, to meet the target of an 80% GHG reduction below 1990 levels by 2050.

The transformation of the U.S. energy system, while gradual, entails major changes in energy supply and end use technology and infrastructure. With commercial or near-commercial technologies and limits on biomass availability and carbon capture and storage (CCS) deployment, it is difficult to decarbonize both gas and liquid fuel supplies. For this reason, meeting the 2050 target requires almost fully decarbonizing electricity supply and switching a large share of end uses from direct combustion of fossil fuels to electricity (e.g., electric vehicles), or fuels produced from electricity (e.g., hydrogen from electrolysis). In our four decarbonization cases, the use of electricity and fuels produced from electricity increases from around 20% at present to more than 50% by 2050.

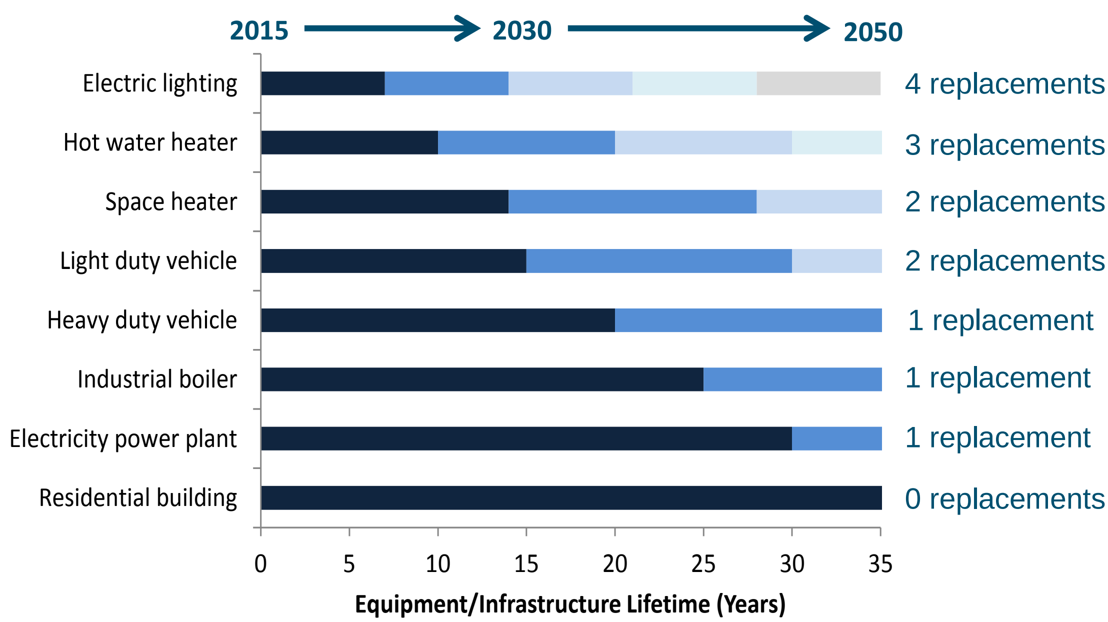
As a result, electricity generation would need to approximately double (an increase of 60-110% across scenarios) by 2050 while its carbon intensity is reduced to 3-10% of its current level. Concretely, this would require the deployment of roughly 2,500 gigawatts (GW) of wind and solar generation (30 times present capacity) in a high renewables scenario, 700 GW of fossil generation with CCS (nearly the present capacity of non-CCS fossil generation) in a high CCS scenario, or more than 400 GW of nuclear (four times present capacity) in a high nuclear scenario.

Similar levels of transformation would be required in other sectors. For example, light duty vehicles (LDVs) would need to become more efficient and switch to low carbon fuels. The average fleet fuel economy of LDVs would need to exceed 100 miles per gallon gasoline equivalent in 2050, while shifting 80-95% of miles driven from gasoline to alternative fuels such as electricity and hydrogen. This would require the deployment of roughly 300 million alternative fuel vehicles by 2050.

4. What are the implications of these technology and infrastructure changes for the energy economy and policy?

There is still sufficient time for the U.S. to achieve 80% GHG reductions by 2050 relying on natural infrastructure turnover. However, to achieve emissions goals and avoid the costs of early retirement, it is critical to account for economic and operating lifetimes in investment decisions. The figure below illustrates the limited number of opportunities between now and 2050 for replacement or addition of infrastructure based on natural stock rollover for different types of equipment.

Figure 62. Stock Lifetimes and Replacement Opportunities



For some important kinds of long-lived infrastructure—for instance, power plants—there is likely to be only one opportunity for replacement in this time period. Adding new high carbon generation (e.g., coal plants) creates infrastructure inertia that either makes the 2050 target more difficult to reach, requires expensive retrofits, or puts investments at risk. Reflecting full lifecycle carbon costs up-front in investment decisions for long-lived infrastructure would reduce these risks. Transitions that involve shorter-lived equipment—for example, LDVs—raise other considerations. This analysis shows that adoption rates for alternative LDVs can initially ramp up slowly, constituting only a small share of the LDV fleet by 2030, but that they must comprise the bulk of new sales shortly thereafter in order to ensure that only a small share of conventional gasoline vehicles remain in the stock by 2050. This suggests that current barriers to adoption of low carbon LDV technologies need to be addressed well before 2030. One key barrier is upfront costs, which can be reduced by timely R&D, market transformation programs, and financial innovation. Anticipating and addressing such barriers in advance is essential to meeting emissions targets at low overall cost.

A deeply decarbonized energy economy would be dominated by fixed cost investments in power generation and in efficient and low-carbon end-use equipment and infrastructure, while fossil fuel prices would play a smaller role. Petroleum consumption is reduced by 76–91% by 2050 across all scenarios in this study, declining both in absolute terms and as a share of final energy. Meanwhile, incremental investment requirements in electricity generation alone rise to $30–70 billion per year above the reference case by the 2040s. The overall cost of deeply decarbonizing the energy system is dominated by the incremental capital cost of low carbon technologies in power generation, light and heavy duty vehicles, building energy systems, and industrial equipment. This change in the energy economy places a premium on reducing capital and financing costs through R&D, market transformation, and creative financing mechanisms. The new cost structure of the energy system reduces the exposure to volatile energy commodity prices set on global markets, while also suggesting a critical role for investment in domestic energy infrastructure.

The recent U.S. government commitment to reduce U.S. total GHG emissions by 26–28% below 2005 levels by 2025 is consistent with the results of this report. Figure ES-1 shows the reduction in total GHG emissions over time relative to 2005 for the Mixed Case in this study, assuming a constant terrestrial carbon sink. In this scenario, U.S. total GHG emissions (net CO_2e) were reduced by 25% in 2025 relative to 2005.

In its announcement, the U.S. government also reaffirmed the goal of "economy-wide reductions on the order of 80% by 2050." Since the U.S. commitment level for 2025 lies on the same trajectory as the deep decarbonization pathways in this analysis, this suggests that successfully achieving the 2025 target would put the U.S. on the road to 80% reductions by 2050. From the perspective of this study, there are different ways that the U.S. can achieve the 2025 target, some of which would lay the necessary groundwork for deeper reductions to follow, and others that might meet the target but tend to produce flat, rather than declining, emissions in the long term. This indicates the importance of evaluating near-term approaches in the light of deep decarbonization analysis. For example, proposals to prevent the construction of new coal power generation unless it is equipped with CCS are consistent with this report's finding that long-lived infrastructure additions must be low-carbon if the 2050 target is to be met while avoiding stranded assets. Other measures, such as increasing the stringency of vehicle fuel economy and appliance efficiency standards, are effective low-cost measures for reaching the 2025 goal, but to continue along the deep decarbonization trajectory after 2025 will require complementary efforts in policy, technology development, and market transformation to enable deeper decarbonization measures (e.g. deeper generation decarbonization, extensive switching of end uses to electricity and low carbon fuels) later on.

This study did not find any major technical or economic barriers to maintaining the U.S. long-term commitment to reducing GHG emissions consistent with limiting global warming to less than 2°C. In terms of technical feasibility and cost, this study finds no evidence to suggest that relaxing the 80% by

2050 emissions target or abandoning the 2°C limit is justified. In addition, the 2°C goal plays a critical role as a guide for near-term mitigation efforts, providing a benchmark for the necessary scale and speed of infrastructure change, technical innovation, and coordination across sectors that must be achieved in order to stay on an efficient path to climate stabilization.

Energy system changes on the scale described in this analysis imply significant opportunities for technology innovation and investment in all areas of the U.S. energy economy. Establishing regulatory and market institutions that can support this innovation and investment is critical. Both areas—technology innovation and institutional development—are U.S. strengths, and place the U.S. in a strong leadership and competitive position in a low carbon world.

Fossil fuel use not controlled by CCS would be greatly reduced and limited to a smaller number of sources. Decarbonized energy systems of 2050 would look fundamentally different from those of today. Historically, U.S. primary energy supply has been dominated by fossil fuels, which have accounted for well over 80% of primary energy use throughout the past 60 years. By contrast, meeting a 750 Mt CO_2 target would require reducing uncontrolled combustion of fossil fuels to at least 80% below current levels, a 10-fold decrease in carbon emissions per capita and a 15-fold decrease in carbon emissions per dollar of GDP. Residual fossil fuel combustion would be concentrated in a smaller number of emissions sources than at present due to fuel switching to electricity in transportation and buildings. This implies a very different kind of energy system, as more than one-third of current U.S. CO_2 emissions are from mobile sources in the transportation sector alone.

The majority of final energy would be delivered in a form that is currently delivered by network providers today (e.g. the utilities that operate the electricity grid and gas pipeline system). Across the scenarios in this study, 58-71% of final energy is delivered to end users in 2050 in the form of either electricity or pipeline gas, primarily as a consequence of reductions in liquid fuel demand due to energy efficiency and fuel switching. This implies a potentially significant role for electric and gas utilities in policy implementation, not only in decarbonization of electricity generation and pipeline gas, but also in demand side energy efficiency and fuel switching (such as electric vehicles), where the low financing costs of utilities might be leveraged for customers in ways that promote consumer adoption.

Deep emission reductions would depend on interactions across sectors and fuel types that today may not share the same markets or regulatory environments, suggesting a need for policy innovation. Interactions across sectors and fuel types—for example, electrification of LDVs while decarbonizing the electricity supply, or switching to pipeline gas for HDVs while decarbonizing the gas supply—become increasingly important sources of CO_2 emission reductions over time in all of our cases, in comparison to same-sector or same-fuel measures (e.g., improving internal combustion engine efficiency). For an energy sector that has historically been relatively insular across energy sources and end uses (e.g., a transportation sector powered predominantly by petroleum-based liquid fuels), this greater integration creates unprecedented but, if anticipated, eminently soluble regulatory and planning challenges.

Further research is needed in many areas. This study identifies five pathway determinants, or key elements of a low carbon energy system in which technology choices or resource endowments disproportionately enable or constrain technology options elsewhere in the system: (1) the availability of CCS and where it is applied, (2) the amount of biomass judged to be sustainable for bioenergy use and how it is applied, (3) the dominant form of primary energy in the electricity generation mix, (4) the approach used to balance electricity generation and end use demand, especially with high penetrations of non-dispatchable (inflexible) generation, and (5) the extent of, and technologies used for, fuel switching and end use efficiency. These five areas are potential focal points for research, innovation, policy, and regulation.

Additional areas identified in the analysis as requiring further research include a better understanding of land use emissions and the terrestrial sink; low-carbon HDV technologies; hydrogen and synthetic natural gas production; and industrial emission reduction potential associated with new product design, materials, and production processes. For the modeling approach used in the PATHWAYS analysis, frontier research areas include downscaling the analysis to the sub-national level, and also internationalizing it through cooperative efforts like the DDPP, in order to develop a more granular understanding of decarbonization challenges and opportunities across jurisdictions and potentially identify new opportunities for joint R&D, trade, market development, and policy collaboration.

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Appendix A. Acronyms

AEO: Annual Energy Outlook, report issued by U.S. Energy Information Administration

BECCS: Bio-Energy with Carbon Capture and Storage

BOF: Basic oxygen furnaces

BTS2: U.S. DOE Billion Ton Study Update

CCS: Carbon capture and storage (or Carbon capture and sequestration)

CDIAC: Carbon Dioxide Information Analysis Center

CHP: Combined heat and power

CNG: Compressed Natural Gas

DDPP: Deep Decarbonization Pathways Project

DOE: U.S. Department of Energy

DRI: Direct reduced iron

EAF: Electric arc furnace

EDGAR: Emission Database for Global Atmospheric Research

EIA: U.S. Energy Information Administration

EMF21: Energy Modeling Forum Study 21

EMF24: Energy Modeling Forum Study 24

EPA: U.S. Environmental Protection Agency

EV: Electric vehicle

F-T: Fischer-Tropsch

GCAM: global integrated assessment model

GDE: Gallon diesel equivalent

GDP: Gross Domestic Product

GGE: Gallon gasoline equivalent

GHG: Greenhouse gas

HDV: Heavy-duty vehicle

HFCV: Hydrogen fuel cell vehicle

HVAC: Heating, Ventilation, Air Conditioning

ICE: Internal combustion engine

IDDRI: Institute for Sustainable Development and International Relations

ILUC: Indirect land use change

LDV: Light-duty vehicle

LED: Light Emitting Diode; high efficiency lighting

LNG: Liquefied Natural Gas

LPG: Liquefied propane gas

LULUCF: Land Use, Land Use Change and Forestry

MACs: Marginal abatement cost curves

NEMS: U.S. National Energy Modeling System

P2G: Power-to-Gas

PATHWAYS: bottom-up stock rollover model of the U.S. energy system

PHEV: Plug-in hybrid electric vehicle

R&D: Research and Development

RCP: Representative Concentration Pathway

RFS: Renewable Fuel Standard

SDSN: Sustainable Development Solutions Network

SNG: Synthetic natural gas

VMT: Vehicle miles traveled

VOS: Value of service

Appendix B. Data Sources

Table 11. Data Sources for PATHWAYS Model Inputs and Cases

Sector	Subdivisions	Categories	Data Types	Data sources[1]
Macro-economy	Population GDP	Nationwide Census division Value added	Current Growth forecasts	EIA 2013
Residential	Single family Multi-family Other	Heating Cooling Lighting Water Heating Other	Stocks Lifetimes Capital costs Fuel types Efficiencies	EIA 2013 DOE 2010 DOE 2012
Commercial	Buildings Utilities Other	Heating Cooling Lighting Water Heating Other	Stocks Lifetimes Capital costs Fuel types Efficiencies	EIA 2013 DOE 2010 DOE 2012
Transportation	Passenger Freight Military Other	Vehicles Rail Air Shipping Other	Stocks Lifetimes Capital costs Fuel types Efficiencies	EIA 2013 NRC 2010 NRC 2013 FHA 2010 FHA 2011
Industry	Iron and steel Cement Refining Chemicals Other	Heat/steam CCS Other	Stocks Lifetimes Capital costs Fuel types Efficiencies	EIA 2013 EIA 2010 Kuramochi 2012
Electricity Supply	Generation Transmission Distribution	Fossil Renewable CCS Nuclear Other	Efficiencies Capital cost Operating cost Other	EIA 2013 EIA 2014b,c B&V 2013 NREL 2012 NREL 2013a NREL 2014a,b, c EPA 2014b CARB 2012 CARB 2014
Fossil Fuel Supply	Petroleum Natural Gas Coal	Gasoline Diesel Jet fuel LNG Other	Efficiencies Capital cost Operating cost Emission factors Other	EIA 2013 EPA 2014a
Biomass	Feedstock Conversion	Purpose grown Crop waste Forestry waste Committed uses Other	Efficiencies Capital cost Operating cost Other	DOE 2011 Gassner 2009 Tuna 2014 Liu 2011 Swanson 2010
Others	Fuels Produced from Electricity	Hydrogen Synthetic Natural Gas	Efficiencies Capital cost Operating cost Other	SGC 2013 NREL 2009

[1]Primary Data Sources for Table 11

(B&V 2012) = Black and Veatch (2012), *Cost and Performance Data for Power Generation Technologies*
(CARB 2012) = California Air Resources Board (2012), *Vision for Clean Air: A Framework for Air Quality and Climate Planning*
(CARB 2014) = California Air Resources Board (2014), *EMFAC Model* and *EMFAC Database*
(DOE 2010) = Department of Energy (2010), *Lighting Market Characterization Report*
(DOE 2011) = Department of Energy (2011), *Billion Ton Update*
(DOE 2012) = Department of Energy (2012), *Energy Savings Potential of Solid-State Lighting in General Illumination Applications*
(EIA 2010) = Energy Information Administration (2010), *Manufacturing Energy Consumption Survey Data 2010*
(EIA 2013) = Energy Information Administration (2013), *Annual Energy Outlook 2013*, *Assumptions to the Annual Energy Outlook 2013,* and supporting data files from National Energy Modeling System
(EIA 2014a) = Energy Information Administration (2014), *Annual Energy Outlook 2014,* and supporting data files from National Energy Modeling System
(EIA 2014b) = Energy Information Administration (2014), *Form EIA-860*
(EIA 2014c) = Energy Information Administration (2014), *Form EIA-923*
(EPA 2014a) = Environmental Protection Agency (2014), *Emissions Factors for Greenhouse Gas Inventories*
(EPA 2014b) = Environmental Protection Agency (2014), *Power Sector Modeling Platform v.5.13*
(FERC 2014) = Federal Energy Regulatory Commission (2014), *FERC Form No. 714*
(FHA 2010) = Federal Highway Administration (2010), *Highways Statistics 2010*
(FHA 2011) = Federal Highway Administration (2011), *Highways Statistics 2011*
(NRC 2010) = National Research Council (2010), *Technologies and Approaches to Reducing the Fuel Consumption of Medium- and Heavy-Duty Vehicles*
(NRC 2013) = National Research Council (2013), *Transitions to Alternative Vehicles and Fuels*
(NREL 2009) = National Renewable Energy Laboratory (2009), *Current State-of-the-Art Hydrogen Production Cost Estimates from Water Electrolysis*
(NREL 2012) = National Renewable Energy Laboratory (2012), *Renewable Electricity Futures Study*
(NREL 2013a) = National Renewable Energy Laboratory (2013), *Western Wind, Eastern Wind, and ERCOT datasets* by AWS Truepower
(NREL 2013b) = National Renewable Energy Laboratory (2013), *Potential for Energy Efficiency Beyond the Light-Duty Sector*
(NREL 2014a) = National Renewable Energy Laboratory (2014), *National Solar Radiation Database*
(NREL 2014b) = National Renewable Energy Laboratory (2014), *Solar Prospector*
(NREL 2014c) = National Renewable Energy Laboratory (2014), *System Advisor Model Version 2014.1.14*
(SGC 2013) = Svenskt Gastekniskt Center AB (2013), *Power-to-Gas – A technical review*

Appendix C. CO_2 Emissions by End Use

A limited number of energy end uses contribute to the bulk of U.S. CO_2 emissions from fossil fuel combustion. As shown, the top 15 emitting end uses contributed to an estimated 63% of emissions in 2010. This relatively high level of concentration of emissions among end uses is consistent with our sector-based, bottom-up modeling approach.

Table 12. CO_2 Emissions by Energy End Use in the U.S., 2010

Energy End Use	CO_2 Emissions ($MtCO_2$)	% Total Energy CO_2 Emissions
Light-Duty Vehicles	1,060	19%
Freight Trucks	351	6%
Commercial Space Heating	286	5%
Industrial Refining	262	5%
Bulk Chemicals Production	259	5%
Air travel	178	3%
Residential Lighting	170	3%
Commercial Space Cooling	162	3%
Commercial Water Heating	160	3%
Residential Space Heating	129	2%
Iron and Steel	118	2%
Commercial Lighting	116	2%
Residential Space Cooling	101	2%
Food Products Production	100	2%
Commercial Ventilation	87	2%
Total Above	**3,538**	**63%**
Total Energy CO_2 Emissions	**5,634**	

Source: EIA, Annual Energy Outlook, 2013

Appendix D. 2015 Technical Supplement

This technical supplement was prepared in order to show additional detail by case for key metrics of cost, GHG emissions, final energy demand, primary energy flows and investment from the Pathways analysis. The table of contents below shows the figures available in this supplement. In addition, a series of output spreadsheets that show additional detail by region and subsector is available from E3.

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Figure 2 GHG Emissions by Final Energy, Year, and Case A-7
Figure 3 Incremental Costs ($2012B), by Cost Category, Year, and Case A-8
Figure 4 Incremental Cost by Uncertainty Run, Year, and Case A-9
Figure 5 Low-Carbon Technology Investment by Technology Type, Year, and Case A-10
Figure 6 Generation Investment by Region, Technology, Year, and Case A-11
Figure 7 Cumulative Biomass Economy Investments by Region A-12
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Figure 9 Reference Case Transition Chart A-14
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Figure 14 CCS Sankey Diagram, 2050 A-19
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Figure 18 Example Week Electric Generation by Case, Year, and Interconnection A-21
Figure 19 Example Week Electric Load by Case, Year, and Interconnection A-22

Figure 1 Final Energy Demand by Final Energy, Year, and Case

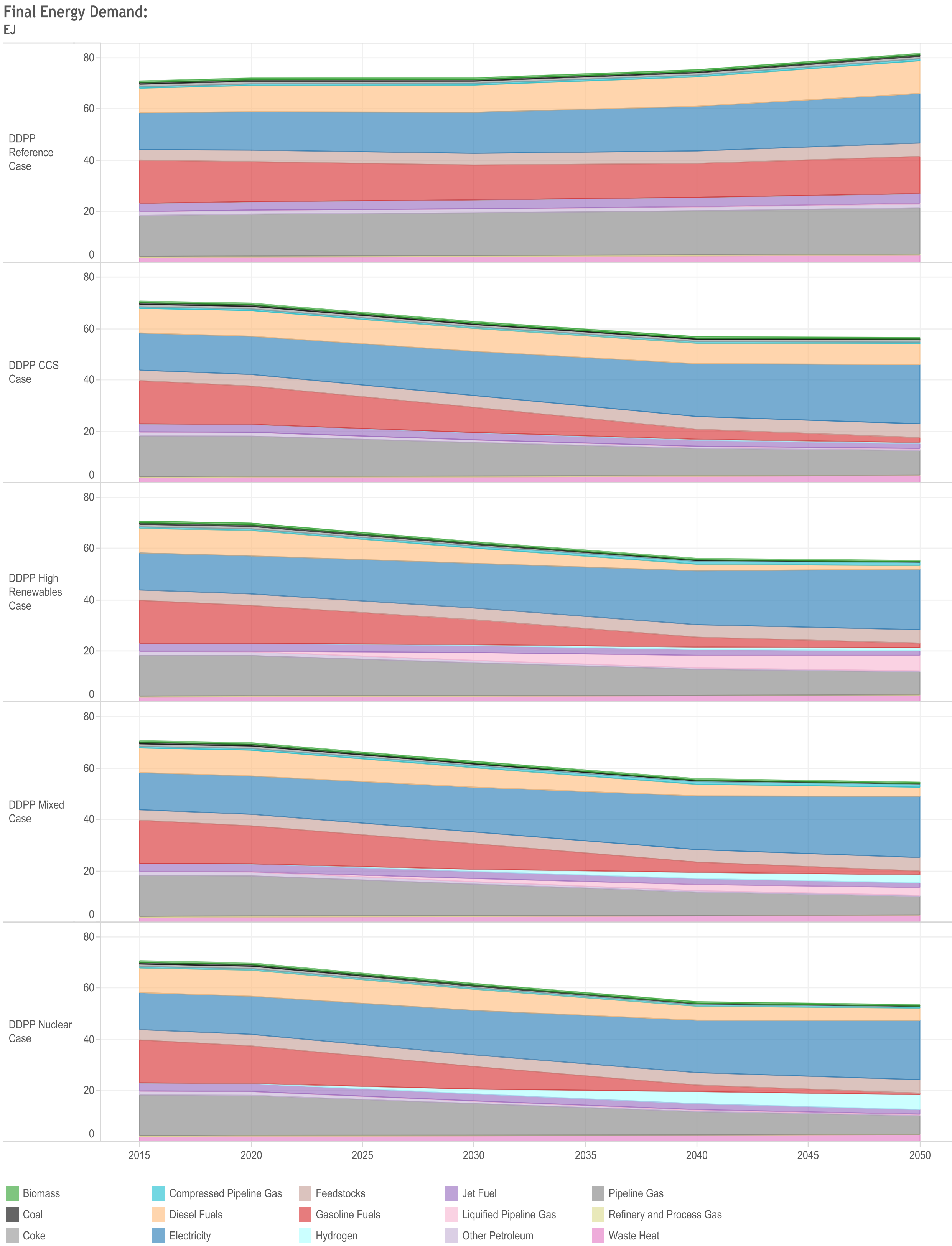


Figure 2 GHG Emissions by Final Energy, Year, and Case

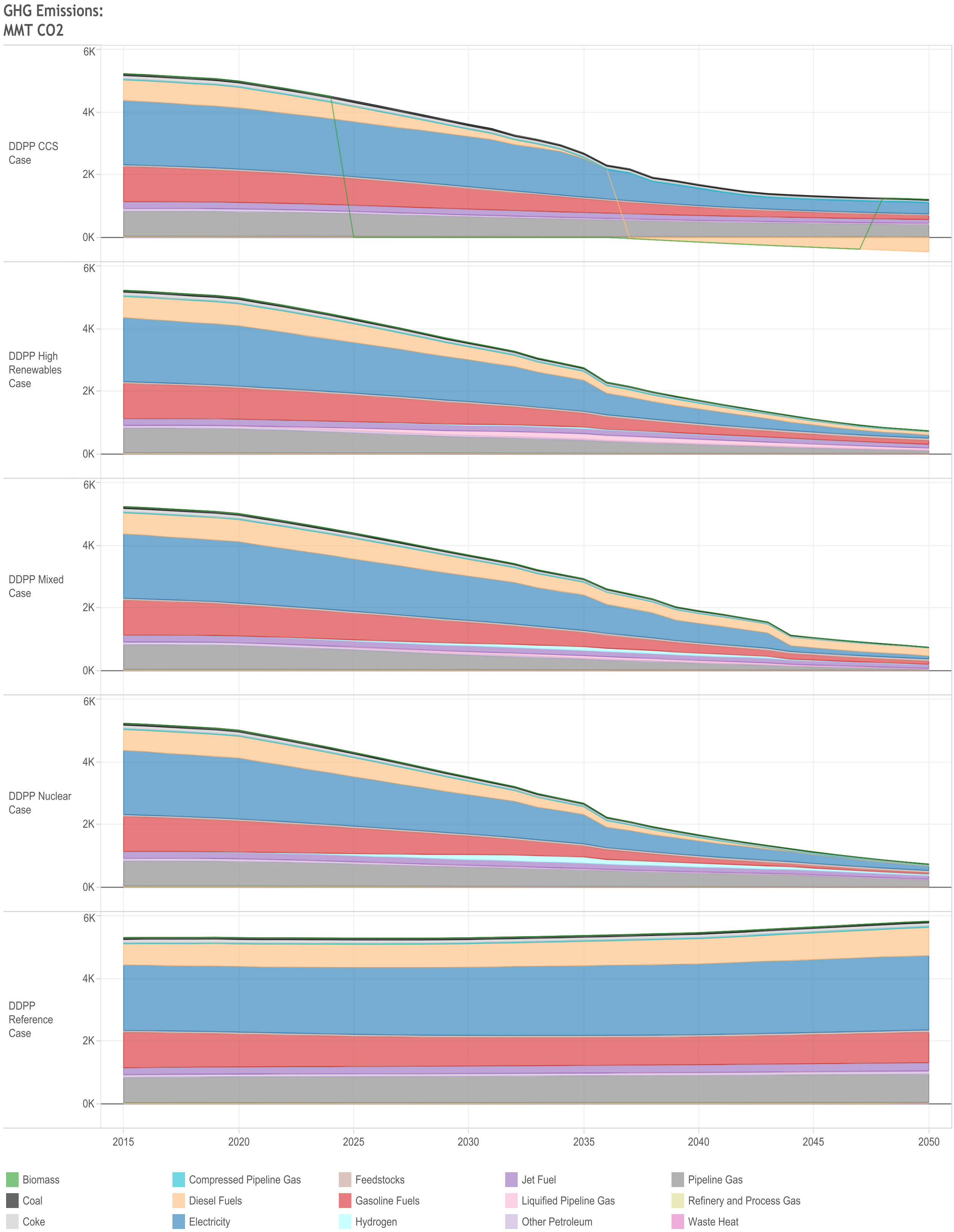


Figure 3 Incremental Costs ($2012B), by Cost Category, Year, and Case

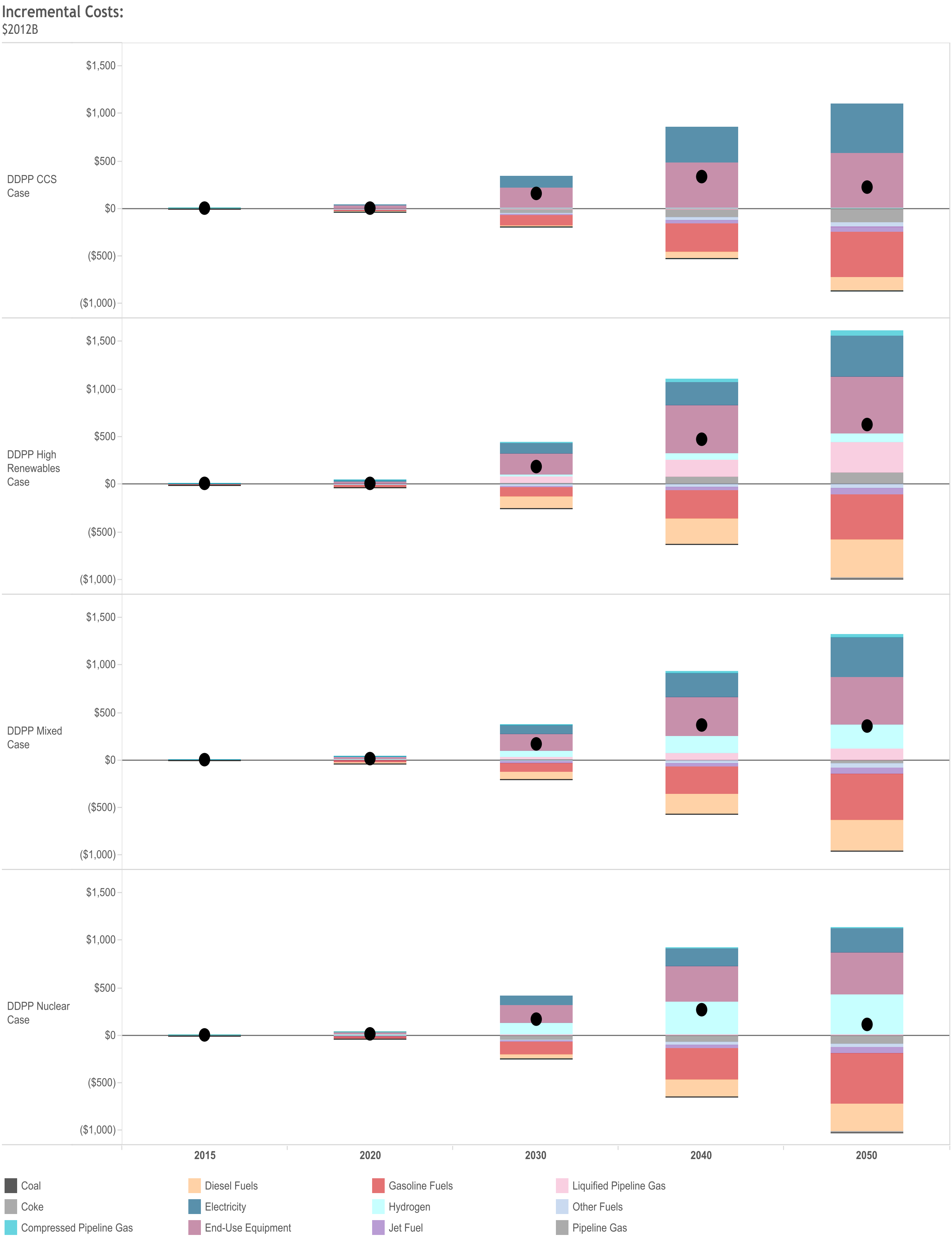


Figure 4 Incremental Cost by Uncertainty Run, Year, and Case

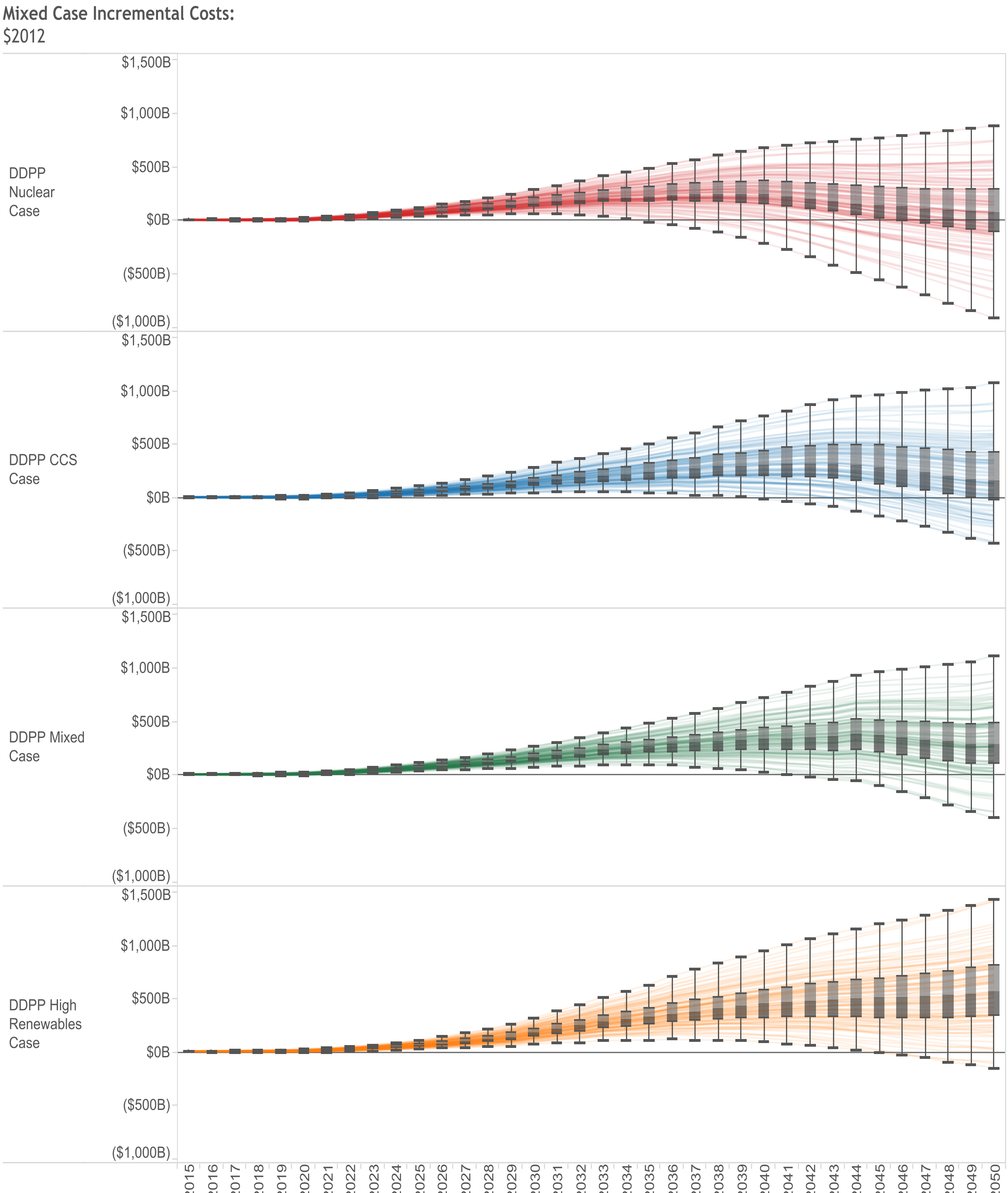


Figure 5 Low-Carbon Technology Investment by Technology Type, Year, and Case

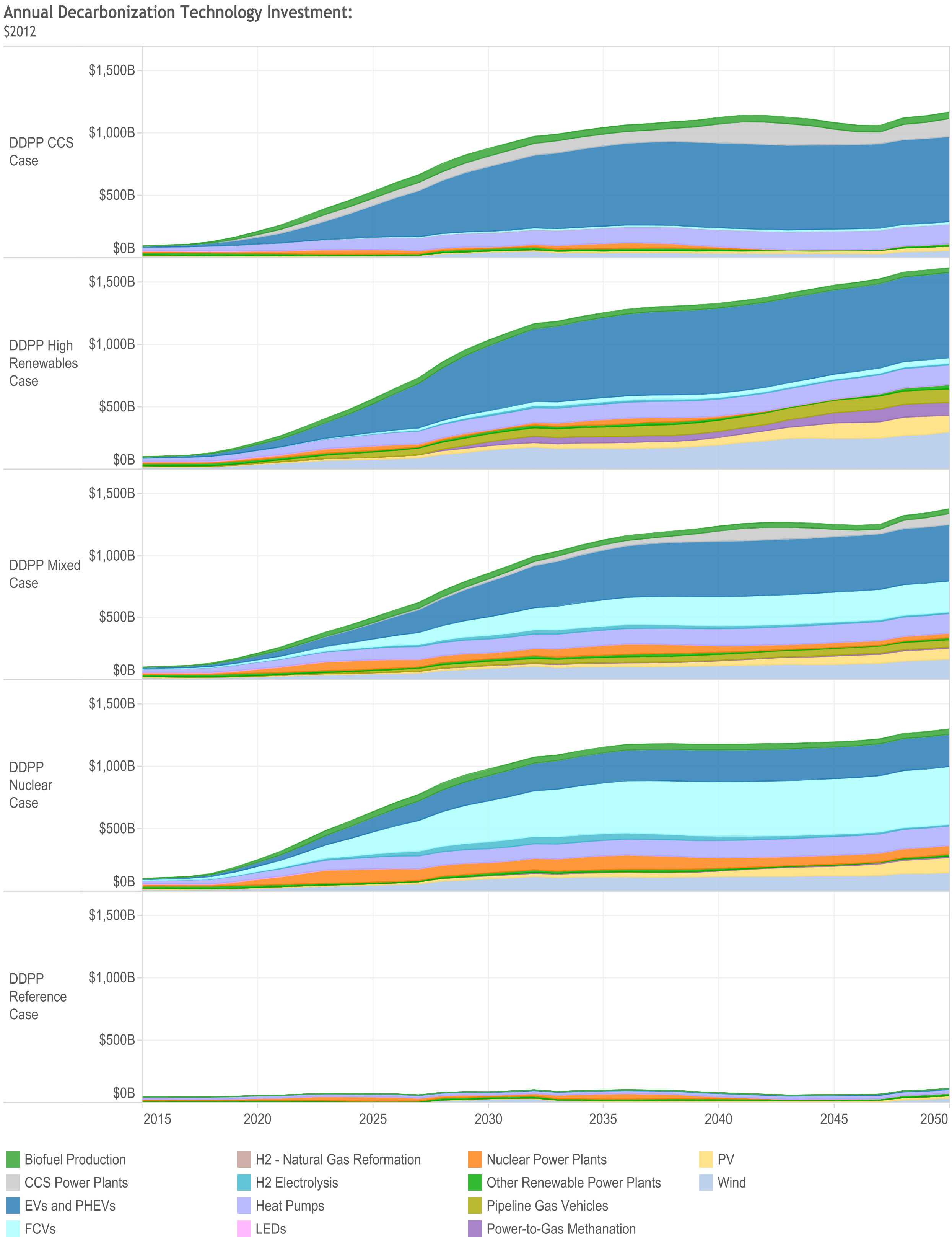


Figure 6 Generation Investment by Region, Technology, Year, and Case

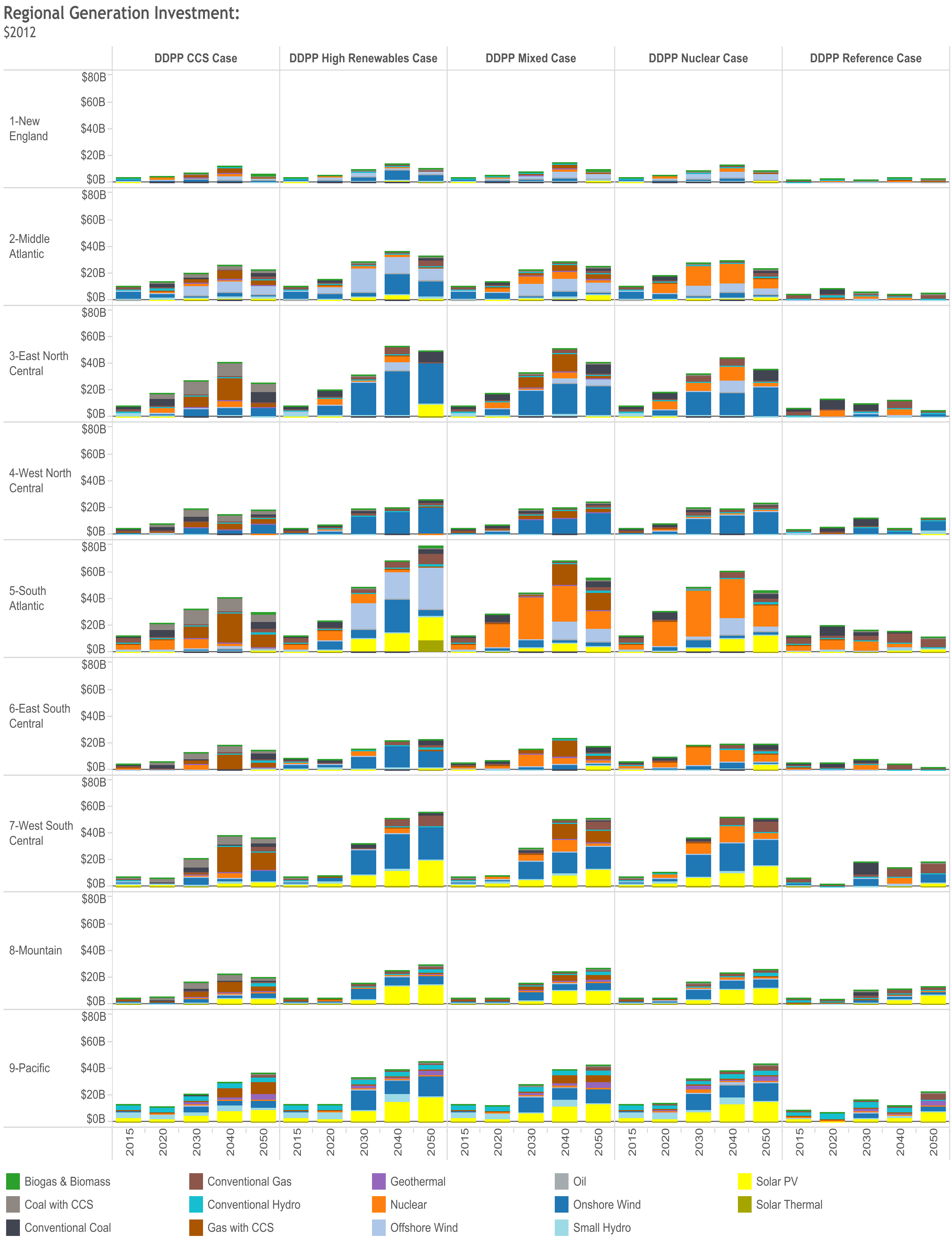
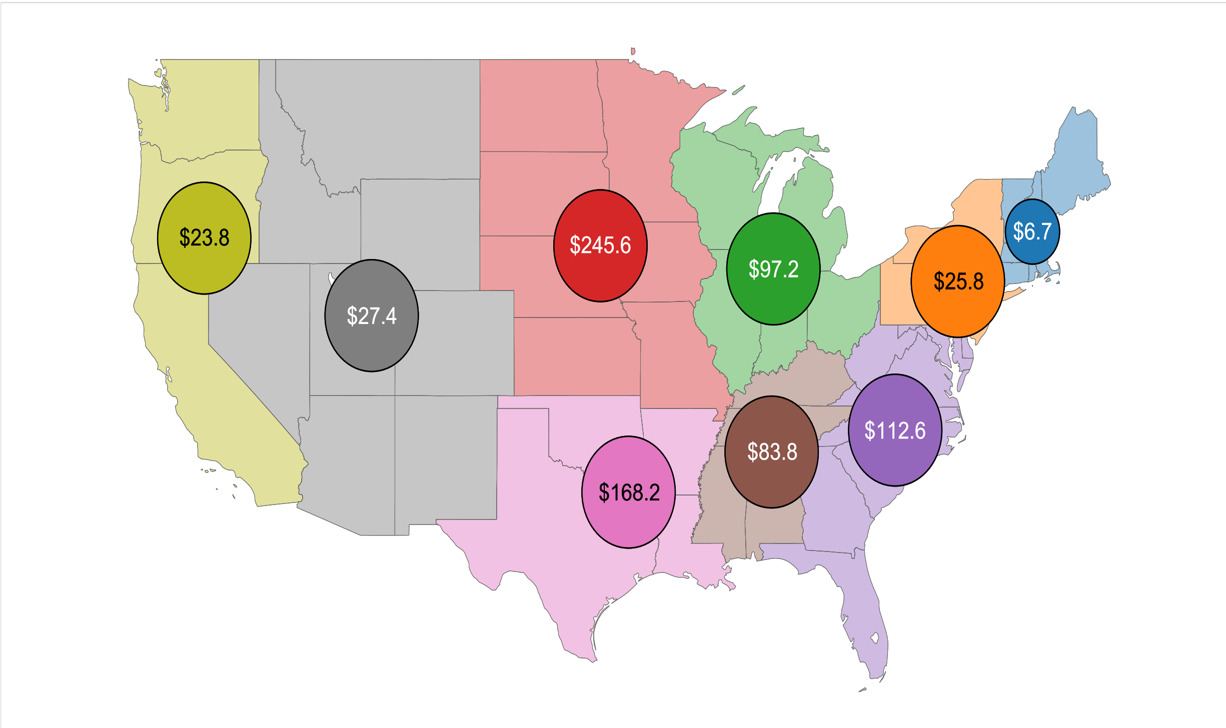


Figure 7 Cumulative Biomass Economy Investments by Region

Cumulate 2015-2050 Biomass Commodity Payments:
$2012B



Cumulative 2015-2050 Biofuel Production Investment:
$2012B

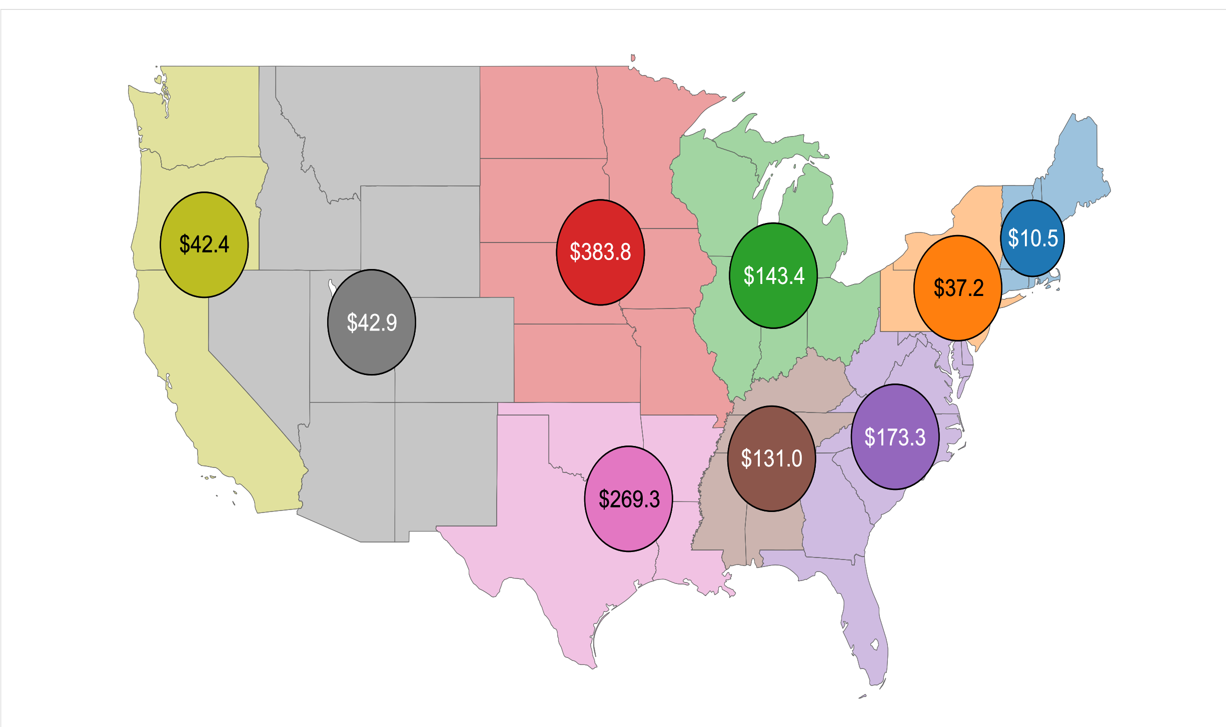


Figure 8 Emissions Reduction Wedges

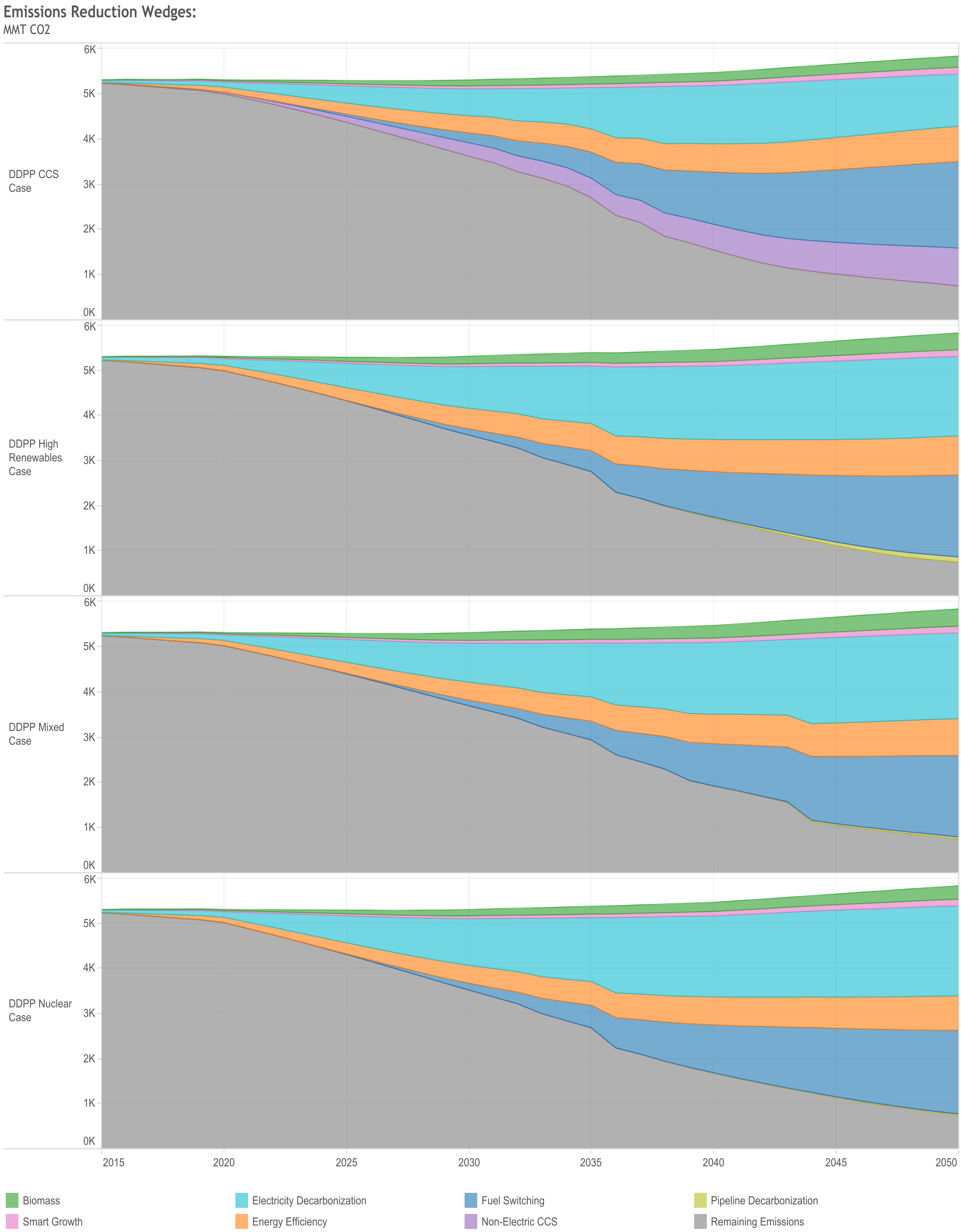


Figure 9 Reference Case Transition Chart

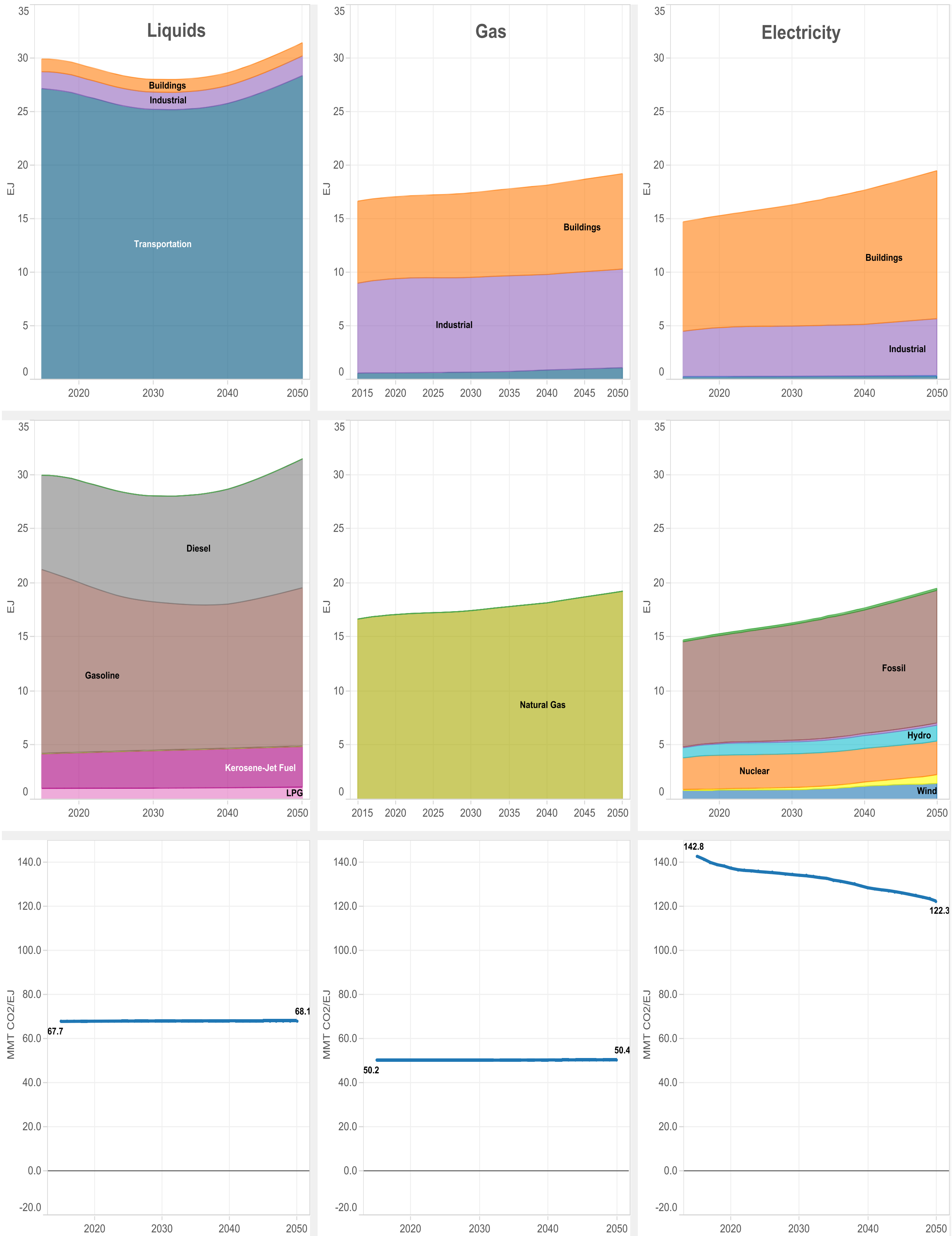


Figure 10 CCS Case Transition Chart

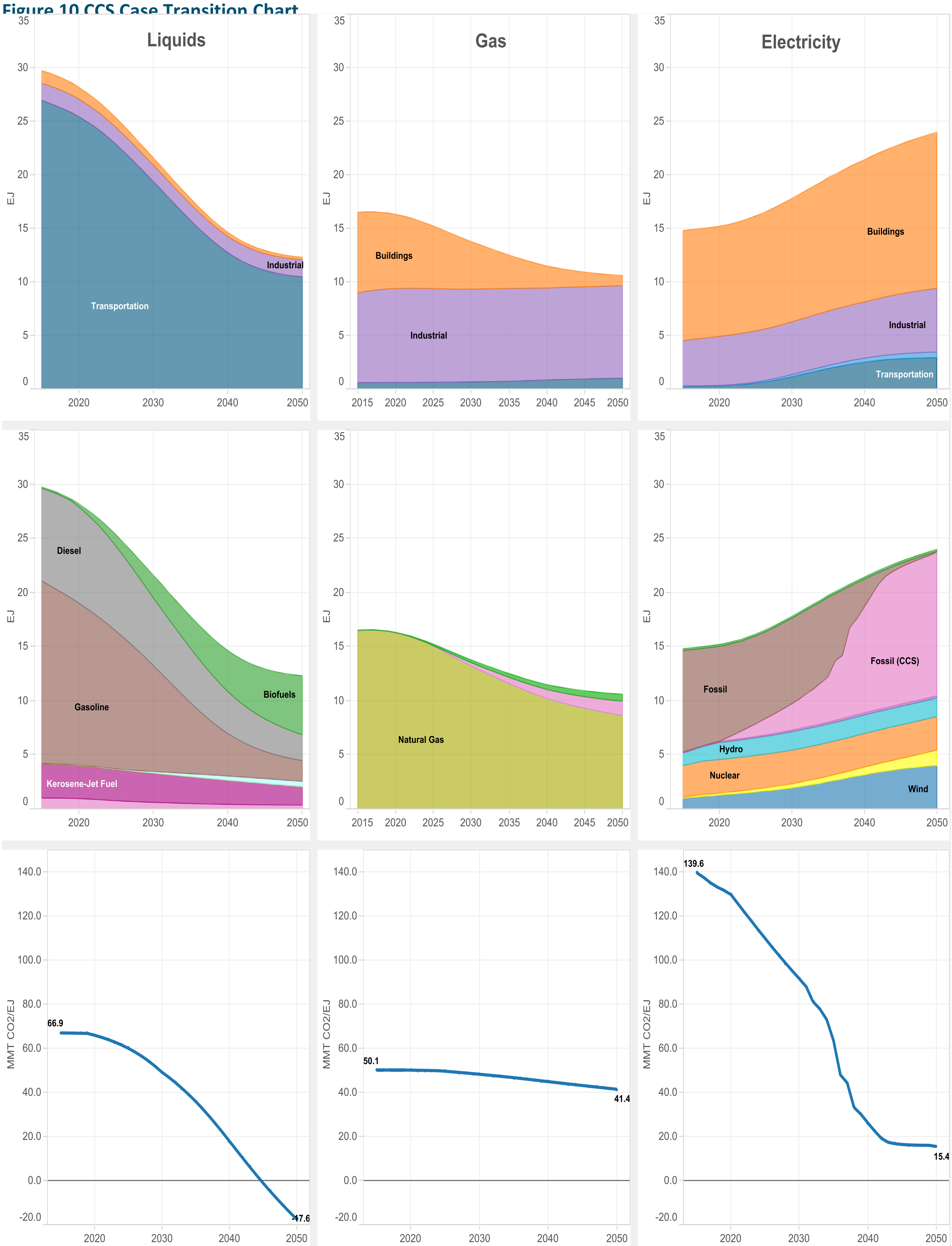


Figure 11 High Renewables Case Transition Chart

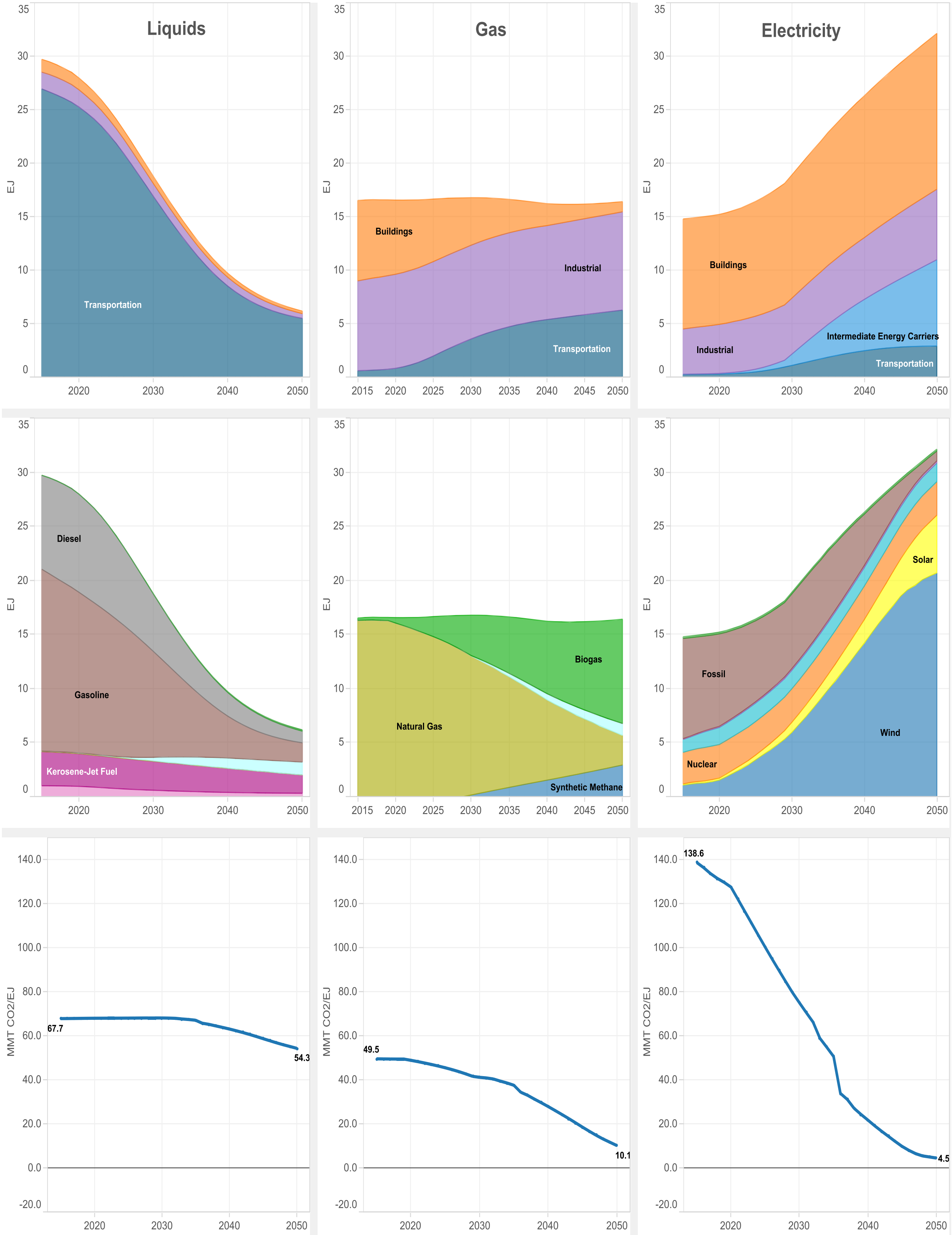


Figure 12 Mixed Case Transition Chart

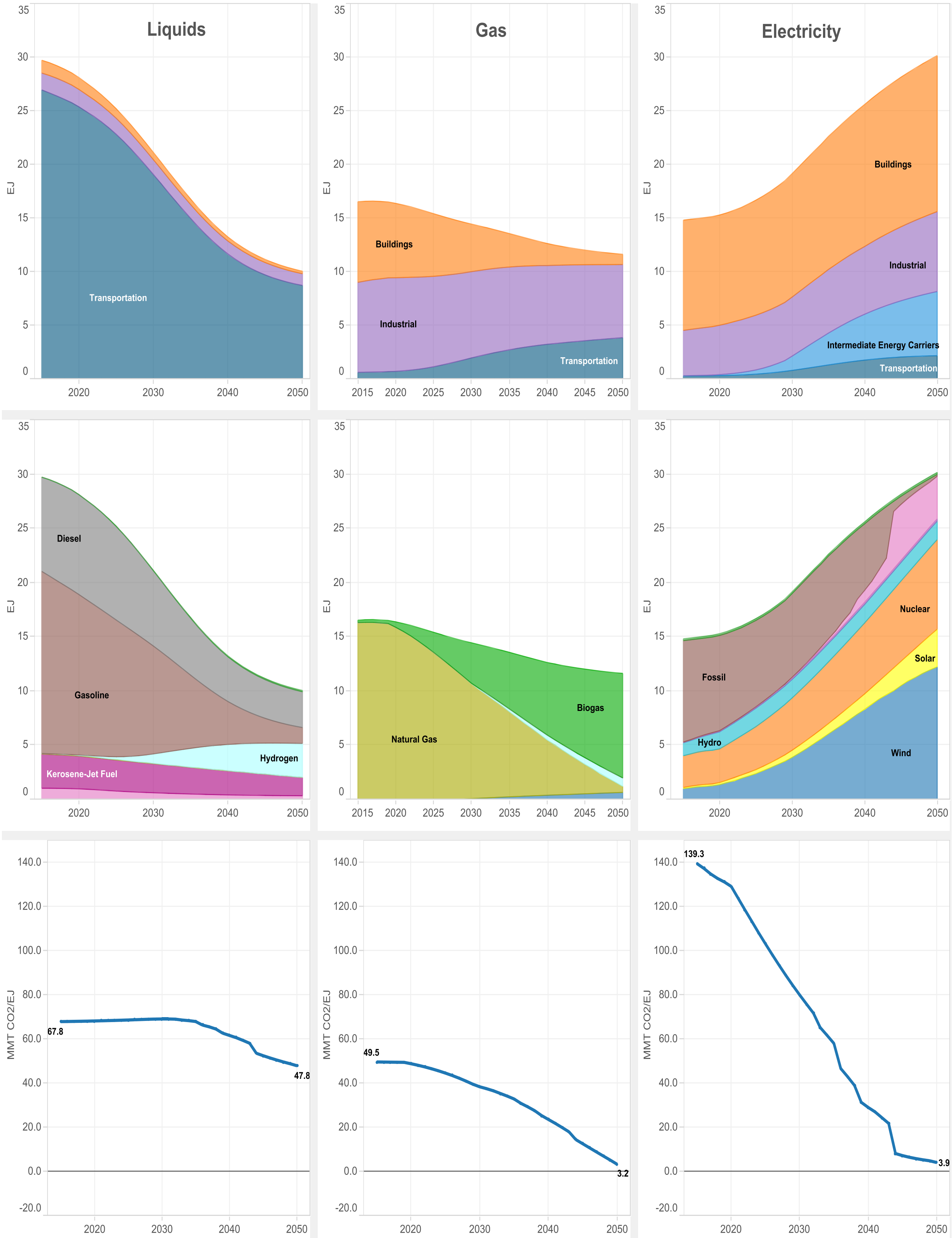


Figure 13 Nuclear Case Transition Chart

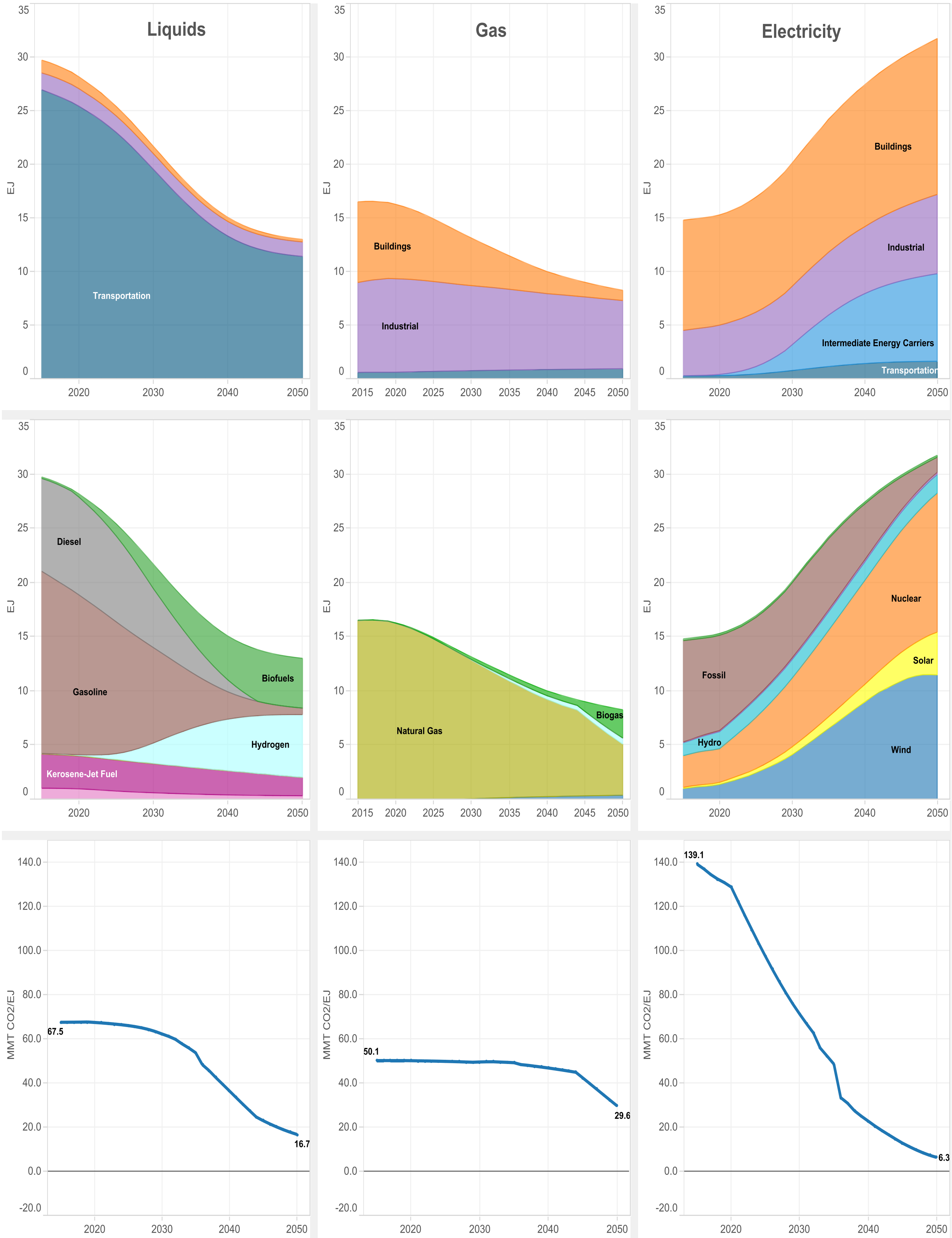


Figure 14 CCS Sankey Diagram, 2050

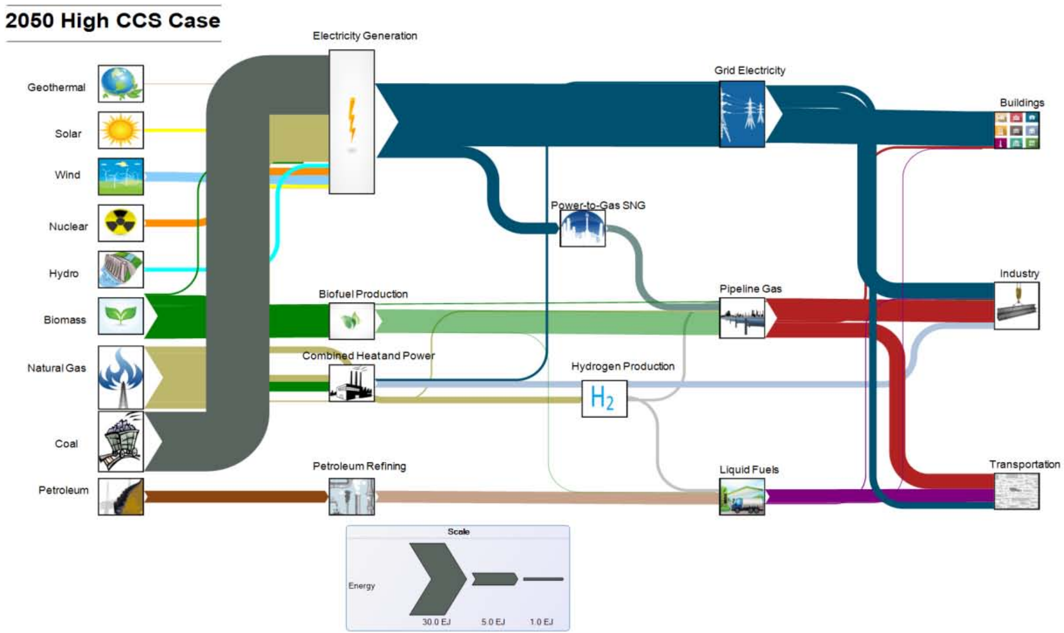


Figure 15 High Renewables Sankey Diagram, 2050

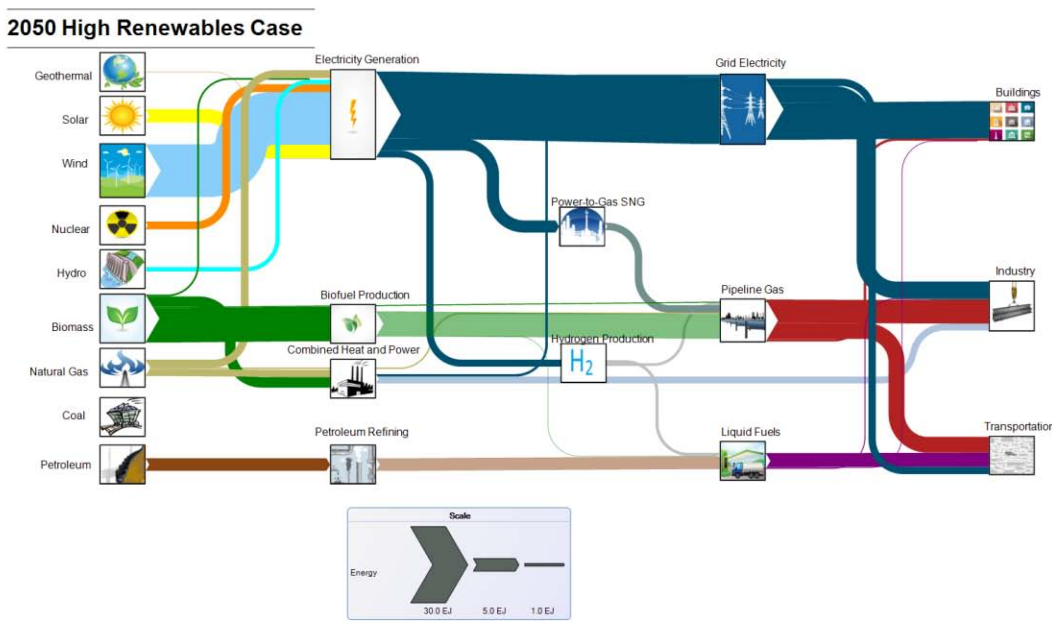


Figure 16 Mixed Case Sankey Diagram, 2050

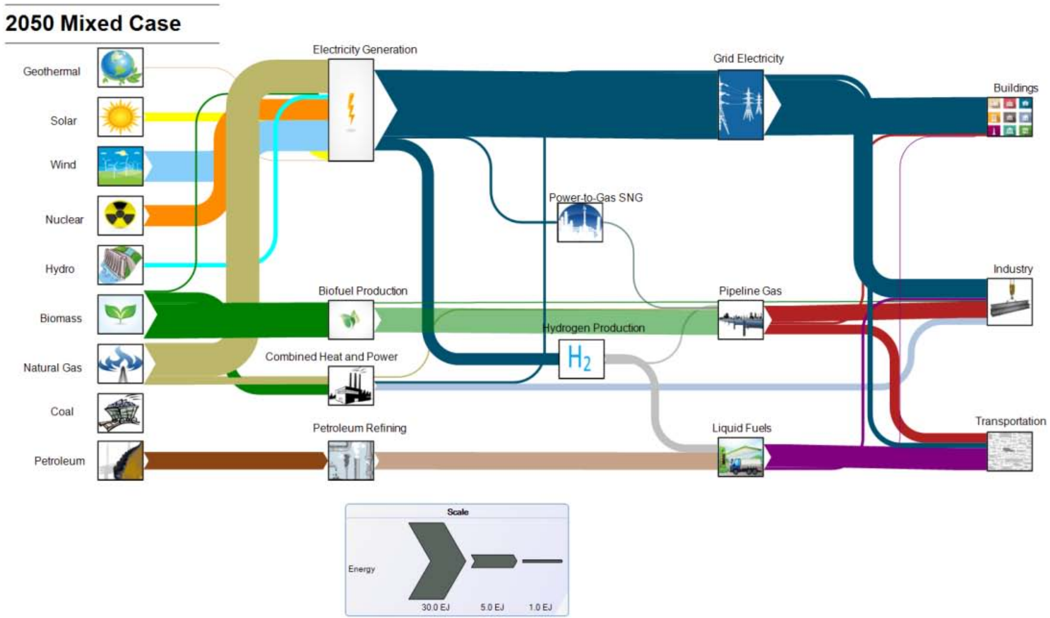


Figure 17 Nuclear Case Sankey Diagram, 2050

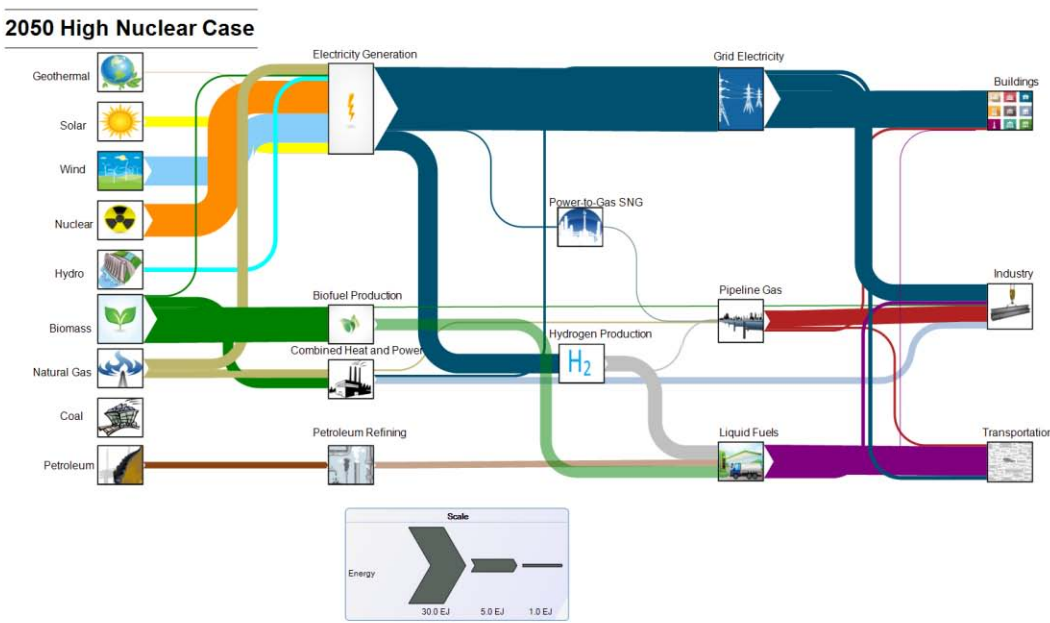


Figure 18 Example Week Electric Generation by Case, Year, and Interconnection

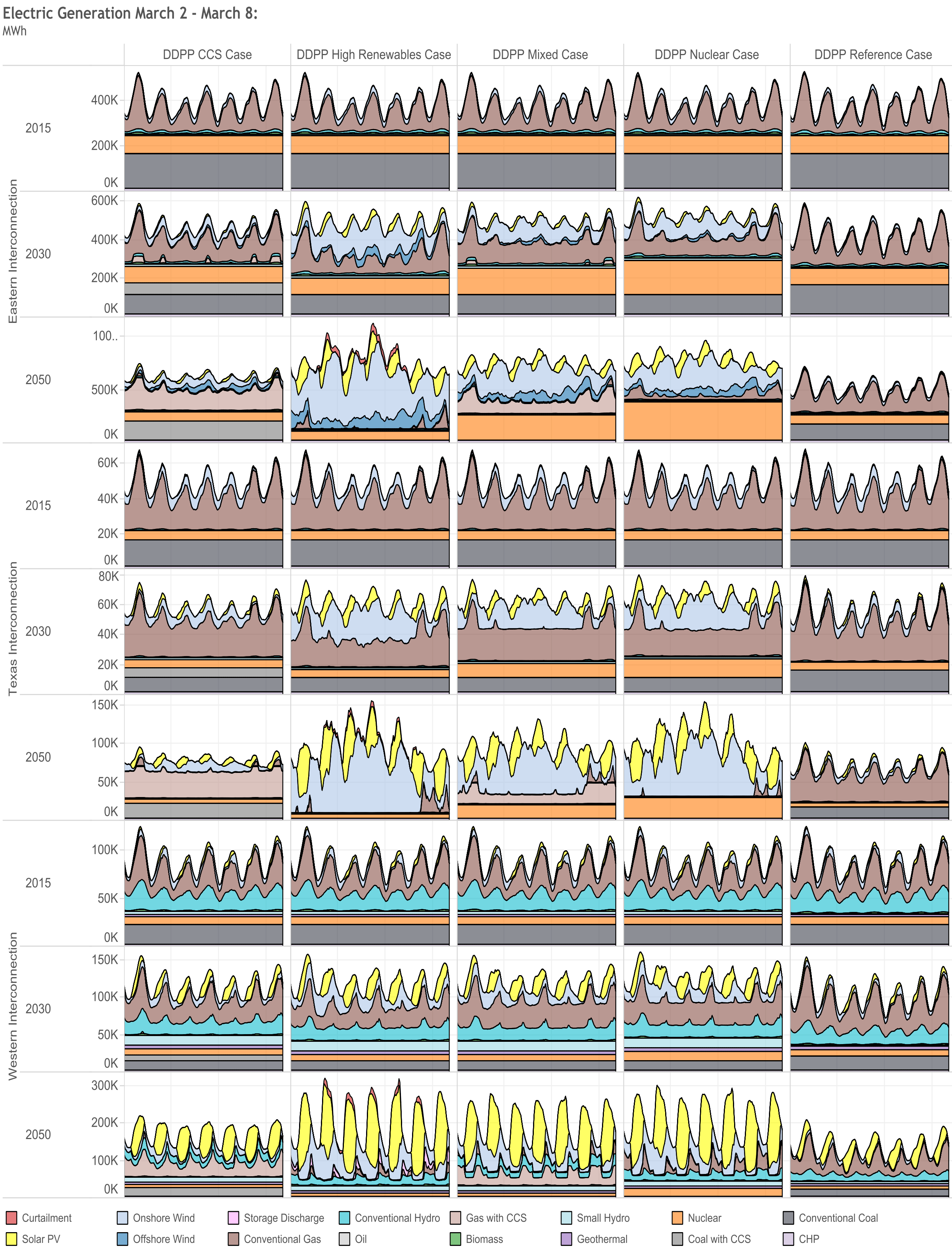


Figure 19 Example Week Electric Load by Case, Year, and Interconnection