Analysis of the Economic Impact of a Regional Low Carbon Fuel Standard on Northeast/Mid-Atlantic States

FINAL REPORT

Consumer Energy Alliance

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NOMENCLATURE

AEO	Annual Energy Outlook
AFV	Alternative Fuel Vehicle
BEV	Battery Electric Vehicle
BOP	Baseline Oil Price
Btu	British Thermal Units
BY	Beginning Year
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CD	Census Division
CI	Carbon Intensity
CEA	Consumer Energy Alliance
CSAPR	Cross-State Air pollution Rule
DOE	Department of Energy
EIA	Energy Information Administration
EV	Electric Vehicle
FIP	Federal Implementation Plan
GDP	Gross Domestic Product
HOP	High Oil Price
KWh	Kilowatt-Hour
LCFS	Low Carbon Fuel Standard
LDV	Light Duty Vehicle
LNG	Liquefied Natural Gas
LPG	Liquid Propane Gas
MPG	Mile per Gallon
MACT	Maximum Available Control Technology
MAM	Macroeconomic Model
NE/MA	Northeast / Mid-Atlantic
NEMS	National Energy Modeling System
NESCAUM	Northeast States for Coordinated Air Use Management
NG	Natural Gas

PHEV	Plug-in Hybrid Electric Vehicle
PMM	Petroleum Market Module
RFS	Renewable Fuel Standard
SAIC	Science Applications International Corporation
SEDS	State Energy Data System
VMT	Vehicle Miles Travelled

EXECUTIVE SUMMARY

Since 2009, eleven Northeast and Mid-Atlantic (NE/MA) states have been participating in a transportation initiative to evaluate implementation of a regional Low Carbon Fuel Standard (LCFS).[1] The initiative is being coordinated by the Northeast States for Coordinated Air Use Management (NESCAUM). NESCAUM held a series of meetings with stakeholders and received public comments in 2010. NESCAUM released a Final Report in August 2011 entitled *"Economic Analysis of a Program to Promote Clean Transportation Fuels in the Northeast/Mid-Atlantic Region."*[2] The Northeast/Mid-Atlantic LCFS initiative seeks a ten percent reduction in carbon intensity (CI) levels[3] within a ten year time period. A study by IHS/CERA,[4] released in October 2011, expressed concerns about the overly optimistic assumptions of low CI fuels availability and costs assumed in NESCAUM's 2011 analysis.

The Consumer Energy Alliance[5] (CEA) believes that the 2011 NESCAUM analysis is not sufficiently thorough. It is important to fully examine the range of incentives and other actions needed to achieve the regional LCFS goal of a ten percent CI reduction within ten years, and to quantify the resultant energy supply and economic impacts to the region, the eleven states, and individual households in the NE/MA region. It is especially important to provide, through this study, an analysis in the context of the integrated energy picture for the nation and the region, particularly with respect to ensuring that the full energy needs of the region continue to be met while implementing the LCFS. Similarly, it is important to conduct parametric analysis by sequentially applying alternative scenarios and assumptions, first applying those that CEA believes are realistic within the ten-year period, then applying "drivers" ─ the combination of energy/environmental policies, alternative fuel vehicle (AFV) technologies and incentives, AFV fuels availability/infrastructure incentives ─ as needed, in the effort to reach the ten percent CI reduction goal.

The analytical process undertaken in this study examines options and identifies the most influential elements in determining whether the regional LCFS goal can be achieved, and the associated social costs, including the costs to the region and to each of the eleven states with respect to energy supply, employment, and respective economies (regional and state GDPs). The project is designed to assist policymakers in understanding the range of potential actions needed and the potential economic impacts in seeking to reduce CI by ten percent within ten years. It further provides some insights with respect to a broader horizon out to 2035. The

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[1] The eleven states participating in NESCAUM are Connecticut, Delaware, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island and Vermont.

[2] The report is available at http://www.nescaum.org/activities/major-reports

[3] Carbon intensity of energy supply is defined as the amount of carbon emitted per unit of energy consumed (e.g. Grams CO_2 / Mega-Joule)

[4] IHS CERA, "Assessment of the NESCAUM Economic Analysis of a Clean Transportation Fuels Program for the Northeast/Mid-Atlantic Region," Prepared by IHS for the Consumer Energy Alliance, October 14, 2011.

[5] Consumer Energy Alliance (CEA) is a nonprofit, nonpartisan organization that supports the thoughtful utilization of energy resources to help ensure improved domestic and global energy security and stable prices for consumers. We seek to help improve consumer understanding of our nation's energy security, including the need to reduce reliance on imported oil and natural gas, maintain reasonable energy prices for consumers, properly balance our energy needs with environmental & conservation goals and continue efforts to diversify our energy resources.

project is offered to provide a balanced guide to policy discussion and choices in seeking to reduce carbon emissions in the transportation sector.

Study Details and Modeling Scenarios

The study uses the "CEA-NEMS" model[6], a project-specific version of the National Energy Modeling System (NEMS), the model used by the U.S. Energy Information Administration (EIA) for its energy forecasting and policy analysis. CEA-NEMS was used in this study because it integrates every energy sector in the U.S. economy, including the gas, oil and power industries, the renewable energy sector, the transportation demand sector and the residential, commercial and industrial energy demand sectors. The model is capable of analyzing overall impacts on the U.S. economy of different energy and environmental policies. Since CEA-NEMS provides national and regional outcomes, a post-processing methodology was used to disaggregate CEA-NEMS regional energy results into constituent states using state historic energy consumption data from DOE's State Energy Data System (SEDS 2005-2009).[7] Additionally, the post-processing methodology similarly disaggregates the CEA-NEMS economic forecast using the IMPLAN input-output/social accounting matrix tool.[8]

Using the approach and tools described above, the study executed alternative scenarios with different input assumptions under two crude oil price projections, Baseline Oil Price and High Oil Price. The oil price projection impacts model results since the cost of crude oil products is directly impacted, which also influences the costs of competitive fuels. The Baseline Oil Price projection is identical to that used for EIA's AEO2011 Reference Case (nominal $89 to $200 from 2012 to 2035) and the High Oil Price projection is identical to that used for EIA's AEO2011 High Oil Price side case (nominal $128 to $305 from 2012 to 2035). For ease of presentation, the Executive Summary refers only to the Baseline Oil Price scenario.

Five modeling scenarios were identified as the most instructive in analyzing the impacts of seeking to achieve the ten percent CI reduction within ten years. These five scenarios, which are fully described in the body of the report, are defined below:

1. **AEO2011RCMOD:** This is the "business-as-usual" scenario identified by EIA in its *Annual Energy Outlook* for 2011. All assumptions are identical, but CO_2 emission factors are modified to be consistent with values assumed for this study (consistent with values used by EIA to implement the California LCFS). Average real GDP growth rate for the nation is projected to be 2.8 percent per year for the 10-year period covering 2012 through 2021 (to 2022) and 2.7% for the period from 2012 to 2035.

[6] The term "CEA-NEMS" is used in this report to distinguish the version of the NEMS model used in this project from the version used by DOE's Energy Information Administration (EIA).

[7] The State Energy Data System (SEDS) is the U.S. Energy Information Administration's (EIA) source for comprehensive state energy statistics. SEDS data sources and estimation procedures are described in the SEDS Technical Notes & Documentation section located on EIA's website. http://www.eia.gov/state/seds/seds-technical-notes-complete.cfm

[8] The IMPLAN® (**IM**pact analysis for **PLAN**ning) economic impact modeling system is used to create complete, extremely detailed social accounting matrices and multiplier models of local economies. The IMPLAN economic input/output dataset enables in-depth examinations of state, multi-county, county, sub-county, and metropolitan regional economies.

2. **BASELINE:** This represents the study baseline scenario, which modified AEO2011RCMOD by including: 1) the Cross-State Air Pollution Rule (CSAPR) promulgated by the Environmental Protection Agency in July 2011 and 2) a constraint on using E15 (gasoline with 15 percent ethanol by volume) until model year 2015 and thereafter.
3. **CAFE54:** This scenario modifies the BASELINE scenario assumptions and implements the new 54.5 mpg CAFE standard to be achieved in 2025 (assumes a 6%/year increase in average annual miles per gallon (mpg) for new light duty vehicles, achieving 54.5 mpg in year 2025). *This scenario quantifies the impact of the 54.5 mpg CAFE standard relative to the BASELINE scenario*.
4. **ALL**: This scenario combines the CAFE54 scenario and specific LCFS elements, as follows: implements the new 54.5 mpg CAFE standard to be achieved in 2025; implements economic incentives to reduce the incremental capital costs of alternative fuel vehicles (AFVs) relative to conventional motor vehicles; increases the availability of the AFV fuels relative to the BASELINE scenario input assumptions; extends bio-fuel subsidies through year 2021 (instead of stopping them in 2011 per the BASELINE scenario); imposes no import tariffs on ethanol past 2011; and, implements an LCFS optimization methodology for the NE/MA region. The purpose of the optimization methodology is to automate the ten percent CI reduction solution by pricing any excess carbon emissions attributed to motor gasoline and diesel fuels via a carbon offset valuation (higher prices for conventional fossil-derived fuels yields greater opportunity for AFVs to compete and lower the regional CI fuel value). *This scenario quantifies the impact of the ALL scenario changes relative to the BASELINE scenario.*
5. **ALLNOCAFE54**: Same as the ALL scenario, but excludes the 54.5 mpg CAFE standard. *This scenario quantifies the impact of the LCFS elements alone relative to the BASELINE scenario.*

Overview of Findings

The results of this study indicate that, even under the most aggressive/optimistic scenarios, the goal of achieving a ten percent CI reduction in the ten period from 2012-2021, cannot be achieved for the NE/MA LCFS region while sustaining the full energy needs of the states and the region. Furthermore, the results project adverse economic impacts for the NE/MA region as a whole and for each of the eleven states. Study findings for the NE/MA LCFS region project an overall ten-year economic impact of at least $306 Billion (nominal 2009 dollars) and a cumulative loss of employment of at least 147,000 jobs. Nominal gasoline prices would at least double and diesel and jet fuel prices would increase by at least 18-23% by year 2022 versus 2012.

<u>CI Reduction</u>

The chart below summarizes the study's analytical findings with respect to CI reduction. For the ALL scenario, the chart shows a weighted average CI reduction of 4.9 percent for the ten year period from 2012 to 2021 — only a 4 percent reduction compared to the BASELINE change — and well below the 10 percent CI regional reduction goal.[9] The projected reductions for each state range from 3.5 percent for Delaware to 5.9 percent reduction for Pennsylvania. *Furthermore, the outcome of the ALL scenario projects that even by the year 2035, the maximum time period available for analysis under the model, the 10 percent CI reduction goal for the region is not achieved, reaching only a 7.1 percent weighted average regional reduction.*

Carbon Intensity (CI) Reduction in LCFS Region and State-by-State - BOP Projection

State	AEO2011RCMOD		BASELINE		CAFE54		ALLNOCAFE54		All	
	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035
Connecticut	-1.0%	-3.3%	-0.9%	-3.1%	-1.4%	-7.3%	-5.0%	-4.3%	-5.2%	-7.4%
Delaware	-0.5%	-1.8%	-0.4%	-1.9%	-0.7%	-2.8%	-4.1%	-3.1%	-3.5%	-3.7%
Maine	-0.8%	-2.7%	-0.7%	-2.5%	-1.1%	-5.5%	-4.4%	-3.0%	-4.5%	-5.5%
Maryland	-0.5%	-1.7%	-0.4%	-1.8%	-0.7%	-3.6%	-4.1%	-3.2%	-3.6%	-4.6%
Massachusetts	-0.8%	-2.6%	-0.7%	-2.4%	-1.0%	-4.7%	-4.2%	-2.9%	-4.3%	-4.5%
New Hampshire	-1.0%	-3.3%	-0.9%	-3.1%	-1.6%	-9.5%	-4.6%	-3.5%	-5.1%	-9.4%
New Jersey	-0.5%	-4.0%	-0.7%	-4.1%	-0.8%	-5.2%	-4.3%	-4.7%	-4.2%	-5.8%
New York	-0.7%	-5.2%	-1.0%	-5.2%	-1.1%	-7.6%	-5.5%	-6.3%	-5.5%	-8.5%
Pennsylvania	-0.8%	-5.2%	-1.4%	-5.7%	-1.6%	-8.7%	-5.9%	-7.0%	-5.9%	-9.5%
Rhode Island	-0.9%	-3.0%	-0.8%	-2.7%	-1.0%	-4.3%	-4.9%	-3.8%	-4.8%	-4.3%
Vermont	-0.9%	-3.2%	-0.8%	-3.0%	-1.5%	-9.0%	-4.4%	-3.3%	-4.9%	-9.0%
LCFS Region	**-0.7%**	**-3.9%**	**-0.9%**	**-4.0%**	**-1.1%**	**-6.4%**	**-4.9%**	**-5.0%**	**-4.9%**	**-7.1%**

The significant modeling conclusion, that the CI reduction target cannot be met within a ten year period, is the direct result of the practical supply and demand constraints represented in the CEA-NEMS model, which must satisfy the region's energy demand. This is a key oversight of the 2011 NESCAUM economic analysis.

To maintain an integrated and complete perspective, the CEA-NEMS model imposes practical supply and demand "constraints" based on years of consumer and manufacturing market data surveys and analytical assessments. These practical constraints are: **1**) demand for energy by the transportation sector, based on travel projections for different vehicle types and classes, ***must* always be satisfied**; **2**) the change in the mix of transportation vehicles in operation in any given year is limited based on the historical rate of stock turnover, consumer choice of replacement stock, technology advancement, and technology market penetration rate; **3**) supply and cost of different types of alternative fuels (e.g., cellulosic ethanol, biodiesel) is subject to biomass resource availability, production technology availability and advancement rate, and rate of market penetration; and **4**) the cost and availability of competing fuels and vehicle technologies (e.g., hybrid electric vehicles) must be taken into account. Based on such constraints, an overriding factor represented in these results is the shear dominance of gasoline-fueled vehicles/fuel supply infrastructure and the practical time that it takes to adjust and replace the demand for gasoline. Even with large alternative fuel subsidies and realistic fuel cost penalties imposed by the LCFS optimization to make lower CI alternatives more cost-competitive, the model could not meet the 10 percent CI reduction goal. On the other

[9] For reference, the 10 percent CI reduction also cannot be achieved by 2021 under the High Oil Price scenario for the region (5.2 percent reduction) or any of the individual states. See the body of the report for these details.

hand, the model was able to satisfy the CI goal for diesel fuel, with suitable production of biodiesel, due to the relatively low consumption of diesel fuel relative to that of gasoline.

Economic Impact

Key economic impact findings of the regional NE/MA LCFS are summarized in the table below for the ten year period from 2012 through 2021. The table presents the results for the ALL scenario, which reflects changes relative to the Baseline Scenario 2012 values and Baseline cumulative values.

The table shows that to achieve the maximum CI weighted average regional reduction of only 4.9% would require an overall cost of at least **$306 Billion** (nominal 2009 dollars) and a cumulative loss of at least **147,000 jobs** for the NE/MA region. Fuel prices would increase significantly in 2021: gasoline prices would at least double, while diesel and jet fuel would minimally increase by 18% and 23%, respectively. These fuel price changes result from all of the supply/demand market factors that influence transportation fuel prices in the model. Additionally, the most significant price impact for gasoline results from of the price penalty imposed by the optimization methodology to help adjust the competitive position of AFVs to help drive down CI values towards the ten percent goal. The combination of these changes in fuel prices and fuel consumption results in an overall increase in cumulative regional fuel expenditures of $156 Billion, a 13.6 percent increase compared with the Baseline Scenario's cumulative total. The biggest fuel expenditure impact is for E85, which is due to both the gasoline price increase and significant increase in E85 fuel consumption.

NE/MA LCFS REGION	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATORS **Amount: Presented as Change from 2012 Baseline Value** **Percent of Baseline Value: Change / Baseline Value x 100**	**Amount**	**Percent of Baseline Value**
CI Reduction relative to 2012 : (gCO2e/KBtu)	- 4.9	-4.9%
Cumulative Change in Economic Activity (Nominal 2009 $)		
Real GDP: $Billions	-27.0	-0.07%
Disposable Personal Income: $Billions	-28.8	-0.10%
Industrial Value of Shipments: $Billions	-73.1	-0.58%
Total Cumulative Loss in Economic Activity: $Billions	**-128.9**	
Cumulative Change in Fuel Expenditures (Nominal 2009 $)		
Total Cumulative Fuel Expenditure Increase: $Billions	**+156**	**13.6%**
Gasoline Price Change, % (2012 – 2021)		112
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		23

NE/MA LCFS REGION	CUMULATIVE RESULTS (2012 – 2021)	
ECONOMIC INDICATORS **Amount: Presented as Change from 2012 Baseline Value** **Percent of Baseline Value: Change / Baseline Value x 100**	**Amount**	**Percent of Baseline Value**
Cumulative Change in Vehicle and Fuel Infrastructure Expenditures (Nominal 2009 $)		
Implied Alternative Fuel Vehicle Subsidies: $Billions	20.2	
Incremental Fuel Infrastructure Cost: $Billions	0.8	
Total Cumulative Vehicle and Fuel Infrastructure Expenditure Increase: $Billions	**21**	
Total Cumulative Economic Impact: $ Billions	**305.9**	
Employment Change: (Thousands of Jobs)	**-147**	**-0.05%**

The cumulative cost from 2012 to 2021 of $306 Billion is a combination of the loss of economic activity in this period (-$27 Billion in GDP, -$28.8 Billion in Personal Income, and -$73.1 Billion in the Value of Industrial Shipments) totaling $128.9 Billion, and the increased expenditures in this period on fuels, vehicle subsidies, and infrastructure, ($156.3 Billion, $20.2 Billion, and $801 Million, respectively) totaling $177.3 Billion.

The 'Implied Alternative Fuel Vehicle Subsidies' include subsidies for alternative fuel vehicles to help make them more competitive by reducing or eliminating their incremental costs relative to conventional vehicles. Additionally, to accommodate greater market penetration of these vehicles, incremental infrastructure costs for refueling stations was calculated outside of the model and is also listed in the above table. It is important to note that these costs were not explicitly accounted for in the CEA-NEMS model, but realistically would have to come out of state budgets, which would ultimately impact taxpayers and reduce disposable income and other economic indicators even more than indicated by these modeling outcomes. *In sum, these cost projections are believed to be conservative with the actual costs likely to be higher.*

Furthermore, it should be noted that the AFV price subsidies do not necessarily represent the entire incremental cost over a comparable gasoline vehicle; rather, they represent a portion of the cost difference and provide an economic incentive to purchase AFV's. For some AFV types, such as E85 and CNG vehicles, the subsidy may come close to the total incremental costs; in other cases, such as with PHEV's and BEV's, the price incentive was applied to the incremental cost of the battery system, so the overall impact on vehicle price is more modest.

In summary, the study findings raise questions about whether the projected carbon intensity reduction is worth the substantial societal costs that are projected. It is important to note that the CI Reduction chart above shows that the 54.5 mpg CAFE standard alone is projected to achieve a 6.4 percent CI reduction by 2035, a reduction within 0.7 percent of the 7.1 percent reduction achieved under the ALL scenario. These findings show that the 54.5 mpg CAFE standard, while only contributing a 1.1 percent CI reduction by 2021, is projected to achieve close to the CI reduction achieved by the ALL scenario in 2035 once it has been fully implemented. However, it would do so without the steep societal cost that would be imposed by the NE/MA LCFS.

The $306 Billion cost and the loss of 147,000 jobs imposed by the NE/MA LCFS would gain only a 3.8 percent CI reduction beyond the reduction that would otherwise be achieved by 2021 under the CAFE54 scenario alone. This equates to a cost of $80 Billion and a loss of 38,680 jobs per percent in CI reduction under the NE/MA LCFS initiative.

As noted previously, the CEA-NEMS study results were post-processed to apportion the regional outcomes to the individual states that make up the NE/MA LCFS region. The state economic results are summarized in similar tables in **Section 5.3.1** of the report.

PART I – STUDY REGIONAL RESULTS

1. INTRODUCTION

In December 2009, eleven Northeast and Mid-Atlantic states signed a Memorandum of Understanding (MOU) to explore a regional low carbon fuel standard (LCFS) that considers a ten percent reduction in regional carbon intensity (CI) levels within a ten year time period. This effort has been coordinated by the Northeast States for Coordinated Air Use Management (NESCAUM). NESCAUM held a series of stakeholder meetings in 2010 and received feedback. In August 2011, NESCAUM released their economic analysis/report, "Economic Analysis of a Program to Promote Clean Transportation Fuels in the Northeast/Mid-Atlantic Region."[4]

The **Consumer Energy Alliance (CEA)** has conducted an analysis of the energy supply/demand and economic impacts of reducing carbon emissions from transportation fuels through imposition of a Northeast/Mid-Atlantic (NE/MA) Regional Low Carbon Fuel Standard (LCFS) on the NE/MA Region. The analysis examines whether the NE/MA LCFS goal of reducing the carbon intensity (CI) by ten percent within the region and within ten years can be achieved and the associated social costs for the region. Further, the analysis includes state-specific analyses of economic impacts of the Regional LCFS on each of the eleven states participating in the NESCAUM program.[10]

The Northeast/Mid-Atlantic region's ability to comply with the imposition of a NESCAUM-type of LCFS is directly impacted by constraints on regional refining capacity, availability of indigenous biofuel crops and biofuel production facilities, reliance on fuel resources from other regions of the country, the mix of fossil and non-fossil electricity generation sources that deliver electricity to the region, and transportation system types and stock turnover rate.

The goal of this study was to use a project-specific version of the National Energy Modeling System (CEA-NEMS) as the primary tool used to conduct the LCFS analysis. NEMS was developed by DOE's Energy Information Administration (EIA) and is maintained and used by EIA to prepare its *Annual Energy Outlook* and to provide analyses to Congress. NEMS is referred to as CEA-NEMS for the purposes of this study to distinguish it from EIA's version of the model; this is an EIA requirement for other users of the model.

CEA enlisted Science Applications International Corporation (SAIC) to execute the CEA-NEMS model using input assumptions provided by the CEA Technical Study Group (TSG).[11]

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[10] The eleven states participating in NESCAUM are Connecticut, Delaware, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island and Vermont.

[11] Science Applications International Corporation (SAIC) is a FORTUNE 500® scientific, engineering and technology applications company that uses its deep domain knowledge to solve problems of vital importance to the nation and the world, in national security, energy and the environment, health, and cybersecurity. For more information, visit www.saic.com. SAIC: From Science to Solutions®

SAIC is a policy-neutral organization. Analysis provided in this report is based on the output from the CEA-NEMS model, as executed by SAIC, as a result of input assumptions provided by the CEA Technical Study Group. SAIC is responsible for the execution of the model and the content of the professional analysis regarding the results produced from the model runs. Since the results are contingent upon the input assumptions provided by the CEA Technical Study Group, they are an extension of their views, and do not necessarily represent SAIC views.

SAIC and the Technical Study Group were in frequent communication and coordination in developing the CEA-NEMS model scenarios, planning the runs to be executed, and analyzing/interpreting the results.

The CEA-NEMS model was used to provide the most current analysis available regarding the economic impact of the NE/MA regional LCFS on the region. The model's regional results were used as the basis for evaluating the impact of the NE/MA Regional LCFS on energy supply and costs and economic metrics in the individual states. Since CEA-NEMS provides national and regional outcomes, a post-processing methodology was used to disaggregate CEA-NEMS regional energy results into constituent states using state historic energy consumption data from DOE's State Energy Data System (SEDS 2005-2009).[12] Additionally, the post-processing methodology similarly disaggregates the CEA-NEMS economic forecast using the IMPLAN input-output/social accounting matrix tool.[13]

This report provides a consolidated analysis of the impacts of the Regional LCFS on the NE/MA region and on each of the eleven NESCAUM states. The report includes a description of the project background, a comprehensive overview of the analyses performed, including appropriate graphs and charts, and conclusions that result from the analyses.

As appropriate, this report references analysis issued by NESCAUM on August 2011 regarding the potential economic impacts of the proposed regional LCFS. This report is not intended to be a critique of the NESCAUM analysis, *per se*. Rather, the references are made primarily to emphasize the depth of the integrated analysis contained in this report relative the NESCAUM analysis.

1.1 PROJECT OBJECTIVES

The study objectives for the analysis of the NESCAUM region and the eleven NESCAUM states were defined by CEA as follows:

1. Identify the combination of alternative fuels and actions that would need to be taken within the NESCAUM region to achieve the NESCAUM LCFS objective of a ten (10) percent reduction in carbon intensity (CI) within ten years. "**Estimate the lowest cost combination of transportation fuels (ethanol, biodiesel, CNG, electricity, etc.) that will be required to reduce 'BY+10' CO_2 carbon intensity by 10% while matching the region's energy needs."**

   The LCFS beginning year (BY) is assumed to be 2012 and the BY+10 year is 2021.

2. Identify the costs (social costs), including the impact on **energy supply, employment and the economy for the region**, needed to achieve the 10 percent CI reduction within the 10-year period while matching the region's energy needs.

[12] The State Energy Data System (SEDS) is the U.S. Energy Information Administration's (EIA) source for comprehensive state energy statistics. SEDS data sources and estimation procedures are described in the SEDS Technical Notes & Documentation section located on EIA's website. http://www.eia.gov/state/seds/seds-technical-notes-complete.cfm

[13] The IMPLAN® (**IM**pact analysis for **PLAN**ning) economic impact modeling system is used to create complete, extremely detailed social accounting matrices and multiplier models of local economies. The IMPLAN economic input/output dataset enables in-depth examinations of state, multi-county, county, sub-county, and metropolitan regional economies.

3. Quantify the impact on **energy supply, employment and the economy for each of the eleven states** as a result of attempting to achieve the 10 percent CI reduction while matching the region's energy needs.

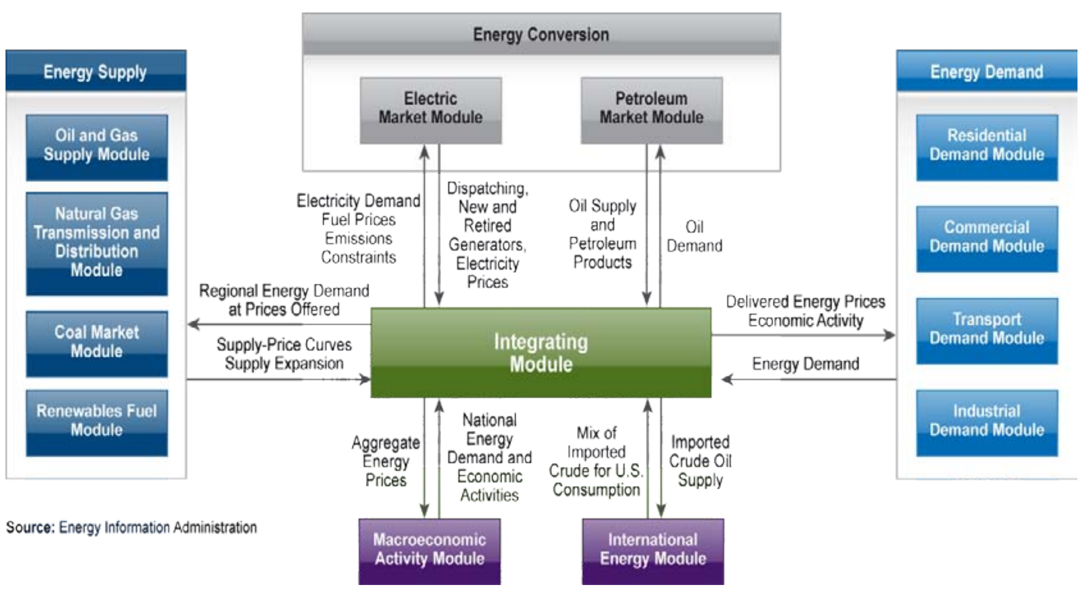
2. APPROACH FOR MODELING THE TECHNICAL AND ECONOMIC IMPACTS OF A REGIONAL LCFS

This section describes the modeling approach as it evolved in coordination with the CEA Technical Study Group.

2.1 CEA-NEMS MODEL

The CEA-NEMS model is based on the AEO2011 version of NEMS as developed, maintained, and executed by EIA. The diagram below in FIGURE 2-1 shows the 12 energy industry sectors/submodules modeled by CEA-NEMS. The CEA-NEMS model is specifically designed to evaluate the economic, social, and environmental effects of changes to energy resources, energy supply and demand technologies, and government policies that impact the U.S. energy markets. CEA-NEMS balances the energy supply and demand for each fuel and consuming sector, accounting for the economic competition between the various energy fuels and sources. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes a macroeconomic and an international module. CEA-NEMS provides results at both the national and regional levels.

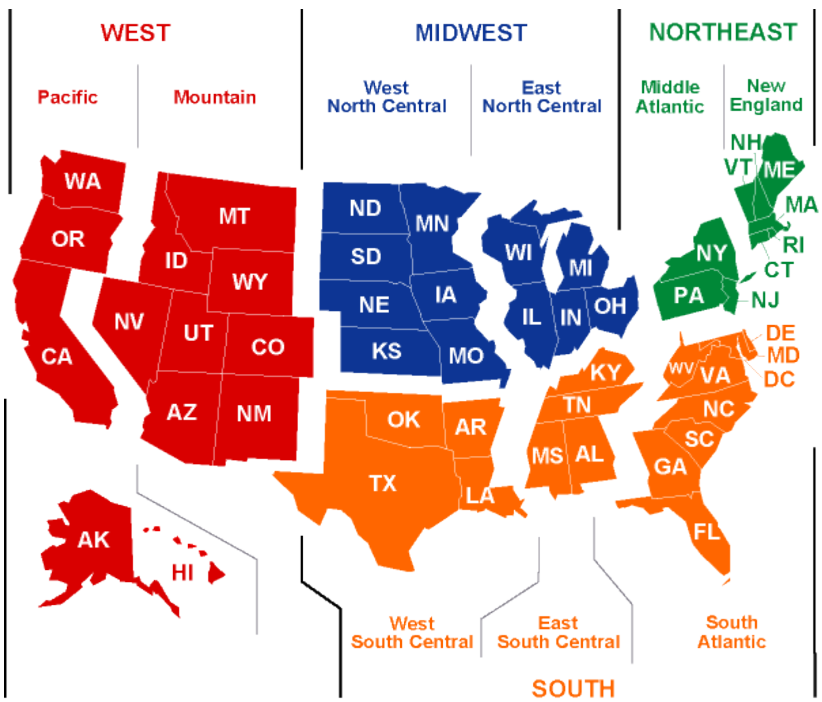
FIGURE 2-1: OVERVIEW OF THE NATIONAL ENERGY MODELING SYSTEM



CEA-NEMS' Macroeconomic Activity Module (MAM) links CEA-NEMS to the rest of the economy by providing projections of economic driver variables for use by the supply, demand, and conversion modules of NEMS. The MAM is comprised of three sets of models: 1) IHS Global Insight's model of the U.S. economy, 2) IHS Global Insight's industrial output and employment by industry models, and 3) EIA's regional models. IHS Global Insight's model of the U.S. economy is the same model used by IHS Global Insight to produce its economic forecasts for the company's monthly assessment of the U.S. economy. The Global Insight U.S. model used for EIA's *AEO2011* is the US2009A version. EIA's industrial output and employment by industry models are derivatives of Global Insight's industrial output and employment by industry models. The models have been tailored to provide the industrial output and employment-by-industry detail required by CEA-NEMS. EIA's regional models consist of models of economic activity, industrial output, employment-by-industry, and commercial floorspace. *Importantly, all of the MAM models are linked to provide an integrated approach to forecasting economic activity at the national, industrial and regional levels.*

The primary flows of information between each of the CEA-NEMS modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, convert, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production, competitive choice, and international petroleum supply availability. We provide a summary documentation in Attachment 1 of this report.

FIGURE 2-2: CENSUS DIVISIONS[14]



2.2 DEVELOPMENT OF THE STUDY BASELINE SCENARIOS – KEY ASSUMPTIONS

The CEA-NEMS model incorporates numerous technical assumptions associated with the U.S. energy markets as originally established by EIA for the *AEO2011 Reference Case* version of the model, which serves as the foundation for this study's two Baseline Scenarios. The Baseline Scenarios, in turn, serves as the basis for all of the other study scenarios. Note that the model already incorporates the implementation of the Renewable Fuels Standard as

[14] http://www.eia.gov/emeu/reps/maps/us_census.html

required by the EISA2007 law (RFS2), the California LCFS, and all other current federal and state energy and environmental policies and regulations that were in effect as of December 2010. See Attachment 1 - Description of Modeled Legislation and Energy Policies.

In order to both keep the Baseline Scenarios current, as well as satisfy the CEA's market outlook, the study's Baseline Scenarios incorporate CEA guidance for some key technical parameters. These are discussed in detail in this section.

2.2.1 EPA NOx and SOx Cross-State Air Pollution Rule

A key change that was required to the AEO2011 Reference Case was coding of the Cross-State Air Pollution Rule (CSAPR) as finalized by EPA in July 2011. This rule replaces EPA's 2005 Clean Air Interstate Rule (CAIR), the CAIR Federal Implementation Plans (FIPs), and the associated SO_2, annual NO_X, and ozone season NO_X trading programs. The CSAPR takes effect January 1, 2012; CAIR will be implemented through the 2011 compliance periods, and then be replaced by the CSAPR. The Baseline Scenarios were coded to incorporate the CSAPR to update the model to include the most current regulations. It is expected that EIA will include the CSAPR in *AEO2012*. Since CSAPR is a final rule and will be in effect within the time period of this study, it was decided to include the CSAPR as part of the Baseline Scenarios.

2.2.2 Crude Oil Price Projection and Unconventional Crude Production

The world oil price projection through 2035 is an exogenous input to CEA-NEMS as the price of light, low-sulfur crude oil delivered at Cushing, Oklahoma. The business-as-usual (BAU) projection used for the Baseline Scenario is *identical* to that used by EIA for their AEO2011 Reference Case as shown below in FIGURE 2-3 as the "Reference projection."[15]

In addition to the Baseline Scenario projection as defined above, a "High Oil Price Scenario" (HOP) was also developed, similar to NESCAUM's 2011 high oil price case. The HOP Baseline Scenario uses EIA's high oil price sidecase projection as also shown in FIGURE 2-3.

The CEA-NEMS also accounts for production of unconventional crudes, consistent with NEMS. **Unconventional oil** only **includes production of synthetic crude from oil shale (syncrude).** The oil shale supply submodule in CEA-NEMS is based on underground mining and surface retorting technology and costs. According to the model documentation, almost all of the domestic high-grade oil shale deposits with 25 gallons or more of petroleum per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick. Consequently, CEA-NEMS' Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 time frame of the projections.

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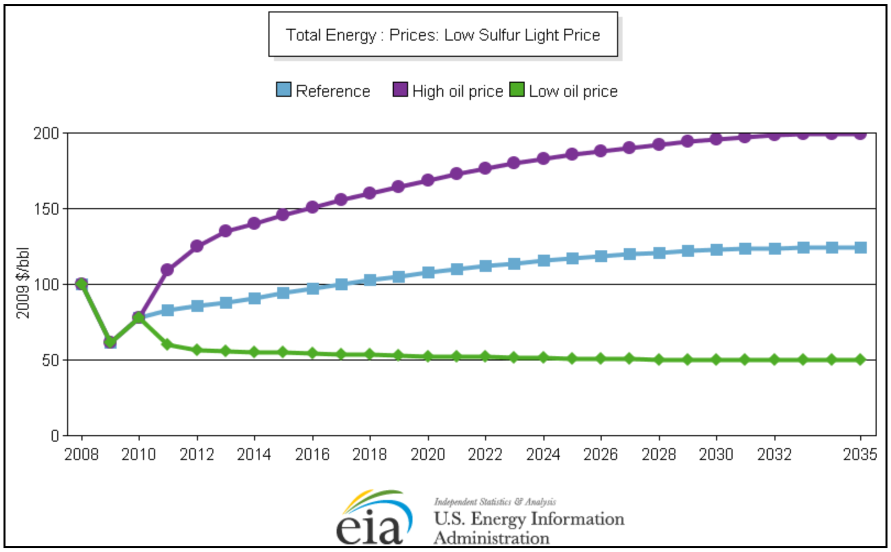
[15] From EIA's Annual Energy Outlook 2011: "The global oil market projections in the AEO2011 Reference case are based on the assumption that current practices, politics, and levels of access will continue in the near to mid-term. The Reference case assumes that continued robust economic growth in the non-OECD nations, including China, India, and Brazil, will more than offset relatively tepid growth projected for many OECD nations. In the Reference case, non-OECD liquids consumption is about 25 million barrels per day higher in 2035 than it was in 2009, but OECD consumption grows by less than 3 million barrels per day over the same period. Total liquids consumption grows to 103 million barrels per day by 2030 and 111 million barrels per day by 2035."

FIGURE 2-3: WORLD OIL PRICE PROJECTION FOR CEA-NEMS BASELINE SCENARIO (NOMINAL 2010 DOLLARS)



2.2.3 Proposed 2025 Fuel Efficiency Standard of 54.5 mpg for Cars and Light Trucks

The study's Baseline Scenarios do not include the proposed 2025 Fuel Efficiency Standard of 54.5 mpg for cars and light trucks. However, alternative study scenarios, identified in Section 4, do specifically account for this proposed CAFE standard.

The proposal calls for a 5 percent annual increase for cars and a 3.5 percent increase per year for light trucks. The new target is a significant increase from the current standard which is 27.3 miles per gallon and the 2016 level where cars and trucks must average 31.4 miles per gallon. Note that there is an out-clause: *the standards would be reviewed part way through the implementation to determine if the rules are too strict or lenient due to gas prices, consumer behavior or changes in technology.*

2.2.4 CO_2 Intensities for Transportation Fuel Resources (CI Values)

This study uses the CI values currently used in NEMS for implementation of the California LCFS. These are based on the following source: U.S. Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 2009*, DOE/EIA-0573(2009) (Washington, DC, March 2011), http://www.eia.gov/environment/emissions/ghg_report/.

When estimating greenhouse gas (GHG) emissions from the U.S. energy sector, EIA has generally treated emissions from the combustion of energy resources sourced from biomass as zero. These emissions, termed "biogenic", are assumed to be equally balanced by the carbon sequestration that occurs during the growth of the biomass, and therefore the net GHG emissions associated with their combustion is net zero. As such, although biomass (e.g., wood chips) or biofuels (e.g., corn ethanol) contain carbon, and thus release carbon dioxide upon combustion, EIA's NEMS model has followed the international convention that replenishing exploited biomass[16] stocks will generally balance these emissions.

[16] The term "biomass" is used here to indicate both the direct utilization of biomass and the use of biofuels and other products derived from biomass.

It should be noted that the model's treatment of biofuels is not entirely "carbon neutral," because the model's comprehensive accounting of the energy used in the production, processing and transportation of all commodities includes biofuels-related energy consumption and related emissions. Note that the model does not provide a separate, distinct accounting of the energy used in each step of the process necessary to bring biofuels to market; rather the energy use is computed at a more aggregate level.

A tabular comparison of CI values used by the California Air Resources Board (CARB), EPA, EIA and NESCAUM (Low-end and High-end) is presented in TABLE 2-3 below. The CEA-NEMS modeling uses the EIA CI values — thus relying on numbers derived by the government. The CI values presented below in TABLE 2-1 are used for the specific fuel types used in the model:

TABLE 2-1: FUEL CARBON INTENSITY VALUES USED IN CEA-NEMS

FUEL TYPE	CI VALUE (grams CO2e / MJ)	CI VALUE (grams CO2e / KBtu)
Distillate Fuel Oil (Petroleum)	94.71	100
Electricity	See note	See note
Jet Fuel	92	97
Liquefied Petroleum Gases	78	82
Motor Gasoline (Gasoline Only)	97	102
Residual Fuel Oil	102	108
Pipeline Fuel Natural Gas	65	69
Compressed Natural Gas	67.7	71
E85 (Gasoline Only)	97	102
Liquid Fuels Subtotal (Gen Fuel)	102	108
Natural Gas (Gen Fuel)	65	69
Steam Coal (Gen Fuel)	117	123
Corn-Based Ethanol	80.6	85
Cellulose-Based Ethanol (Conventional and Advanced Technologies, Domestic and Imported Sources)	21.3	22.5
Non-Cellulosic Ethanol (Sugar Cane-Based, Imported Source)	58.4	62
Biodiesel (Virgin)	83.3	88
Biodiesel (Non-Virgin)	13.8	15

Electricity: CEA-NEMS directly calculates electricity-produced carbon emissions based on the mix of fossil generation technologies used in a region. The resulting CI for electricity depends on the selection and dispatch of generation technologies as optimized by the model on the basis of cost and pollutant regulatory constraints.

Hydrogen: The TSG discussed that NESCAUM did not use hydrogen, and that it is unlikely that hydrogen fuel cells would penetrate the market within the time frame of the analysis. The TSG decided that it should not be included in the modeling.

Biodiesel: There was discussion about the EIA, CARB and EPA derivations of the CI values for biodiesel. It was pointed out that NESCAUM recognized the difference between the CARB and EPA values and elected to use the EPA values for the "low-end" case and the CARB values for the "high-end" case. The TSG decided to use the EIA values for the modeling.

Corn Ethanol: Use EIA 80.59 (This is the lower EIA value and is within the range of EPA values of 58- 92).

Sugarcane Ethanol: The TSG decided to use EIA's 58.4 value which comports with the CARB value.

Note that the EIA CI values are currently only used by NEMS in the Petroleum Market Module (PMM) for the purposes of implementing the California LCFS. Other emission factor values are used in NEMS Electricity Market Module (EMM) for the calculation of regional and national CO_2 emissions. As a result, SAIC modified the EMM emission factors to be consistent with TABLE 2-3. As such, the CEA-NEMS Baseline Scenario CO_2 emissions are higher than those calculated by EIA's Reference case. The CI reduction calculation for alternative scenarios is therefore only calculated relative to this study's two Baseline Scenario projections.

Note also that *CI values for each fuel type are kept constant during the projection period.*

Both corn-based ethanol and sugarcane-based ethanol are used in the model. CEA-NEMS balances the costs of competing fuels to determine their relative use. Further, CEA-NEMS has different supply curves and penetration constraints for the different feed-stocks of ethanol and selects the most economic among them. Note that NESCAUM used only cellulosic ethanol - - a limitation that is unrealistic according to the National Academy of Sciences, as well as EPA, CARB and EIA.

2.2.5 Ethanol Use and Blend Wall Limit

The CEA-NEMS model is currently coded to allow up to 15 percent ethanol blends for motor gasoline. Sub-specification blends of reformulated and high-oxygenated-conventional gasoline are calculated for ethanol blends for these fuels using the percent ethanol blended. The model currently accounts for approval of a waiver by EPA in January 2011[17] allowing the use of motor gasoline blends containing up to 15 percent ethanol for vehicles of model year (MY) 2001 and newer. For the *EIA AEO2011* Reference Case, ethanol blending in gasoline increases gradually from 13.1 billion gallons in 2010 (about 9 percent of the gasoline pool) to 17.8 billion gallons in 2020 (about 12 percent of the gasoline pool).

In the *EIA AEO2011* Reference Case, the model parameter specifies the MY for which E15 can be used, which is currently set at 2001. Thus, under the *EIA AEO2011* Reference Case it is assumed that vehicles built in 2001 and after consume E15 primarily in 2020, and the remaining growth in ethanol consumption shifts to E85 use, which increases from about 0.8 billion gallons in 2017 to 9.6 billion gallons in 2035. Note that, on June 23, 2011, EPA stated that: *"As of August 10, 2011, E15 is not registered with EPA and is therefore not legal for distribution or sale as a transportation fuel."* [18]

[17] U.S. Environmental Protection Agency, "E15 (A Blend of Gasoline and Ethanol)," website, www.epa.gov/otaq/regs/fuels/additive/e15

[18] From EPA's E15 website: In response to a request by Growth Energy and 54 ethanol manufacturers under the Clean Air Act, EPA granted two partial waivers that allow but do not require the introduction into commerce of gasoline that contains

For the purposes of this project, it was decided to *use MY 2015 as the most reasonable model year in which E15 is deemed a certified, registered fuel for purposes of the Study Baseline Scenario*. The rationale for choosing MY2015 is as follows:

- Automakers are not expected to relax warranties for vehicles already in the fleet;
- Automakers won't warrant E15 vehicles until they can design engine/fuel systems specifically to tolerate E15;
- Automakers need lead time to make such a change; we chose 3 years; and
- Time is required to certify and register a fuel with EPA in order for it to be legal.

2.2.6 Expiration of Ethanol/Biodiesel Tariffs and Subsidies

The study's two *Baseline Scenarios assume that ethanol/biodiesel tariffs and subsidies expire at the end of 2011 per current law.*

Alternative study scenarios, as identified in Section 4, extend the subsidies to further encourage the use of biofuels to help meet CI reduction goals.

2.2.7 Ethanol Share of Motor Gasoline and E85

TABLE 2-2, shown below, identifies the breakout, by volume and energy content, of the gasoline and ethanol constituents of E10 and E85 used in the model.

TABLE 2-2: PROPERTIES OF MOTOR GASOLINE AND E85

Motor Gasoline (E10)				**E85**			
Pure Gasoline		**Ethanol**		**Pure Gasoline**		**Ethanol**	
Volume	**Btu**	**Volume**	**Btu**	**Volume**	**Btu**	**Volume**	**Btu**
90%	93.3%	10%	6.7%	26%	50.1%	74%	49.9%

2.2.8 Renewable Fuels Standard Required By Law

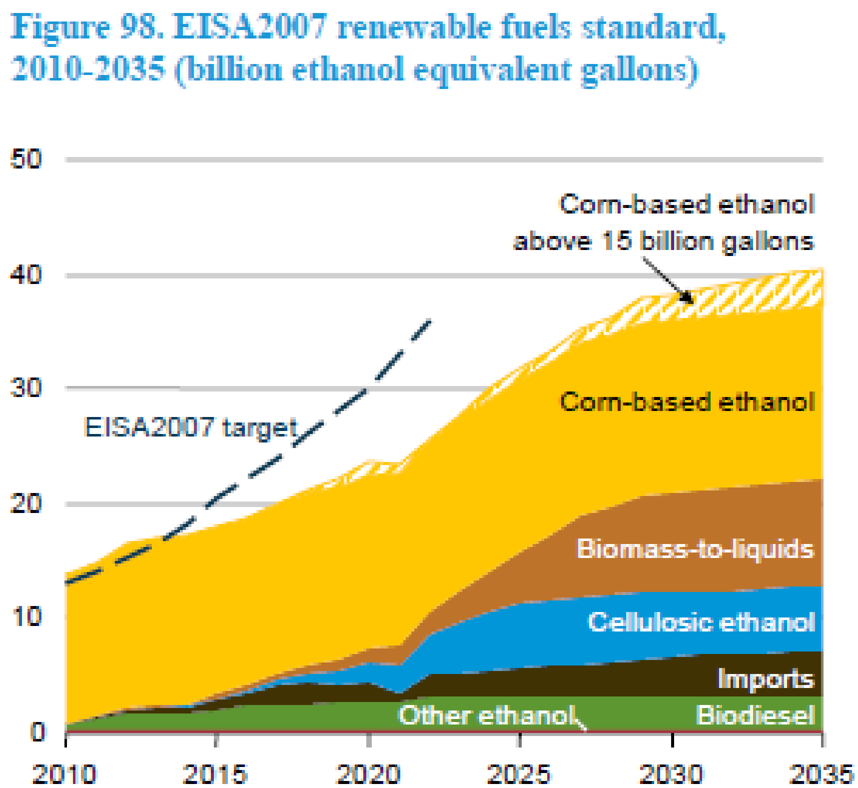
CEA-NEMS uses the identical coding as the *AEO2011* NEMS to satisfy the Renewable Fuels Standard required by the EISA2007 law. However, it is important to note that the *EIA AEO2011* Reference Case does not meet the legislation's call for compliance by 2022.

FIGURE 2-4, copied from the *EIA 2011 Annual Energy Outlook* report, shows that the projected EISA2007 target (dotted line) will likely not be met by 2022, but could be met in 2035. The chart shows that the RFS is met by the substantial projected growth of Biomass-to-

greater than 10 volume percent (volume %) ethanol and up to 15 volume% ethanol (E15) for use in model year (MY) 2001 and newer light-duty motor vehicles, subject to certain conditions. On October 13, 2010, EPA granted the first partial waiver for E15 for use in MY2007 and newer light-duty motor vehicles (i.e., cars, light-duty trucks and medium-duty passenger vehicles). On January 21, 2011, EPA granted the second partial waiver for E15 for use in MY2001-2006 light-duty motor vehicles. These decisions were based on test results provided by the U.S. Department of Energy (DOE) and other test data and information regarding the potential effect of E15 on vehicle emissions. On June 23, 2011, EPA issued regulations to help reduce the potential for vehicles, engines, and equipment not covered by the partial waiver decisions to be misfueled with E15. However, EPA clearly states that: *"As of August 10, 2011, E15 is not registered with EPA and is therefore not legal for distribution or sale as a transportation fuel."*

Liquids, cellulosic ethanol, and ethanol imports. The elements of this chart are part of the *EIA AEO2011* Reference Case, and thus are included in the study's Baseline Scenarios.

FIGURE 2-4: EIA AEO2011 REFERENCE CASE PROJECTION FOR MEETING THE RENEWABLE FUELS STANDARD[19]



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[19] DOE/EIA Annual Energy Outlook 2011, page 83, DOE/EIA-0383(2011), April 2011.

TABLE 2-3: CARBON INTENSITY VALUATION COMPARISON – CARB, EPA, AND EIA

FUEL	PATHWAY DESCRIPTION	Carbon Intensity Values (gCO2e/MJ) (incl. Indirect Land Use Charge)				
		CARB	EPA	EIA[1]	NESCAUM Low-End	NESCAUM High-End
Gasoline		95.86	93	95.86		
Diesel	• ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71	92	94.71		
	• Liquids from Coals			233.93		
	• Liquids from 80-20 Coal/Biomass Mix			186.54		
	• Advanced Fischer-Tropsch, Waste Feedstock (BTL?)			-3	8	n/a
	• Advanced Fischer-Tropsch, Virgin Feedstock (BTL?)			-3	27	n/a
Biodiesel	• Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is required	15.84	13	13.8		
	• Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is not required	11.76	13	13.8		
	• Conversion of Midwest soybeans to biodiesel (fatty acid methyl esters –FAME)	83.25	28-40	83.25	40	70
	• Conversion of white grease			39.85		
Renewable Diesel	• Conversion of tallow to renewable diesel using higher energy use for rendering	39.33		39.33		
	• Conversion of tallow to renewable diesel using lower energy use for rendering	19.65				
	• Conversion of Midwest soybeans to renewable diesel	82.16		82.16		
	• Conversion of yellow grease			13.62		
	• Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	99.4	58-92			

FUEL	PATHWAY DESCRIPTION	Carbon Intensity Values (gCO2e/MJ) (incl. Indirect Land Use Charge)				
		CARB	EPA	EIA[1]	NESCAUM Low-End	NESCAUM High-End
Ethanol from Corn	• California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	95.66		81.66		
	• California; Dry Mill; Wet DGS; NG	80.7				
	• Midwest; Dry Mill; Dry DGS, NG	98.4		80.59		
	• Midwest; Wet Mill, 60% NG, 40% coal	105.1				
	• Midwest; Wet Mill, 100% NG	94.52				
	• Midwest; Wet Mill, 100% coal	120.99		115.1		
	• Midwest; Dry Mill; Wet, DGS	90.1				
	• California; Dry Mill; Dry DGS, NG	88.9				
	• Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	93.6				
	• Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	86.8				
	• California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	84.2				
	• California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	77.44				
Ethanol from Sugarcane	• Brazilian sugarcane using average production processes	73.4		53.73		
	• Brazilian sugarcane with average production process, mechanized harvesting and electricity co-product credit	58.4	8-38	58.4		
	• Brazilian sugarcane with average production process and electricity co-product credit	66.4				
Cellulosic Ethanol	• Waste Feedstock			21.3	-27	37.2
	• Virgin Feedstock			21.3	-9	37.2
	• Out-of-Region				-18	37.2
Compressed Natural Gas	• California NG via pipeline; compressed in CA	67.7		67.7	68	78
	• North American NG delivered via pipeline; compressed in CA	68	68			

FUEL	PATHWAY DESCRIPTION	Carbon Intensity Values (gCO2e/MJ) (incl. Indirect Land Use Charge)				
		CARB	EPA	EIA[1]	NESCAUM Low-End	NESCAUM High-End
	• Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA	11.26		11.26	11	n/a
	• Dairy Digester Biogas to CNG	13.45			18	n/a
Liquefied Natural Gas	• North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency	83.13				
	• North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency	72.38				
	• Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency	93.37				
	• Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency	82.62				
	• Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA	77.5				
	• Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency	26.31				
	• Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency	15.56			11	
	• Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency	28.53				
	• Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency	17.78			18	
Electricity	• California average electricity mix	124.1	57-55	41.37	57-55	80.5-75
	• California marginal electricity mix of natural gas and renewable energy sources	104.71				

FUEL	PATHWAY DESCRIPTION	Carbon Intensity Values (gCO2e/MJ) (incl. Indirect Land Use Charge)				
		CARB	EPA	EIA[1]	NESCAUM	
					Low-End	High-End
Hydrogen	• Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	142.2		42.74		
	• Liquid H2 from central reforming of NG (no liquefaction and re-gasification steps)	133				
	• Compressed H2 from central reforming of NG	98.8				
	• Compressed H2 from on-site reforming of NG	98.3				
	• Compressed H2 from on-site reforming with renewable feedstocks	76.1				
LPG from refinery				78		
Product Refined from Pyrolysis oil				31		

1 EIA carbon intensity values used for California LCFS implementation in AEO2011 version of NEMS

2.3 SUMMARY OF THE FULL STUDY BASELINE SCENARIOS

Using the *EIA AEO2011* Reference Case as a starting pointing point, SAIC coded the study *Baseline Scenarios* using the assumptions, as described above and summarized in TABLE 2-4 below. The year 2012 was assumed to represent the Baseline Year (BY).

In addition to the assumptions identified above, all of the pertinent study Baseline Scenario model assumptions are documented below.

TABLE 2-4: KEY STUDY BASELINE SCENARIO ASSUMPTIONS

MODEL METHOD/PARAMETER ASSUMPTIONS	STUDY BASELINE SCENARIO SPECIFICATION
Crude Oil Price Projection and Unconventional Crude Production	The crude oil price projection is a key exogenous input parameter to the model. Elected to use *EIA's Reference Case oil price projection* for the study Baseline Scenario – see FIGURE 2-4. The model also projects unconventional crude oil production in domestic and international markets. An alternative high oil price Baseline Scenario uses *EIA's High Oil Price projection* – see FIGURE 2-4.
State vs. Census Division Mapping	Mapping based on state population
RFS2 Representation	Elected to use CEA-NEMS' implementation of RFS2 as formulated by EIA AEO2011 Reference Case.
Ethanol Use and Blend Wall Limit	Use *EIA AEO2011 Reference Case* specification of the blend wall.
Imported ethanol volumes and tariff levels	CEA-NEMS projects the imports of both cellulosic and non-cellulosic ethanol. The level of imports is constrained by the tariff on imported ethanol. The model maintains current tariffs only through 2011. *Elected to use same inputs as the EIA AEO2011 Reference Case.*
CO_2 Intensities For Fuel Resources	Already accounted for in NEMS in the *EIA AEO2011 Reference Case* for the current slate of fuel resources domestically available for the California LCFS representation. EMM CI values were modified to be consistent with TABLE 2-3 values.
PADD I Crude Slate	Used *EIA AEO2011 Reference Case* specification. The Reference Case projects a shift to lighter crudes (lower CI values) over a 10 year period.
EPA NOx and SOx Cross-State Air Pollution Rule	*Elected to include the Cross-State Air Pollution Rule as finalized by EPA* - This rule replaces EPA's 2005 Clean Air Interstate Rule (CAIR). Including CPSAR in the Baseline Scenarios updates the model to include all current laws and regulations in effect at the

MODEL METHOD/PARAMETER ASSUMPTIONS	STUDY BASELINE SCENARIO SPECIFICATION
	time of modeling.
EPA Mercury and Air Toxics Rule (MATS)	The U.S. EPA is proposing Mercury and Air Toxics Standards (MATS) for power Plants to limit mercury, acid gases and other toxic pollution from power plants, keeping 91 percent of the mercury in coal from being released to the air. This proposed rule would replace the court-vacated Clean Air Mercury Rule (CAMR). Implementation of this rule could have significant impact on fossil-based power generation and will likely increase near-term coal-based power plant retirements. *Elected not to include this proposed rule as premature at the time of modeling.*
EPA GHG Standards for Refineries and Power Plants	EPA has proposed the tailoring rule for refineries and power generation and boiler MACT standards for industrial boilers and process heaters. *Elected not to include this proposed rule as premature at the time of modeling.*
Biomass Availability and Cost	Biomass resources and costs are calculated endogenously in the model for each region.
Advanced biomass conversion technology performance (yields) and cost (e.g., advanced cellulosic ethanol conversion)	CEA-NEMS represents the production of ethanol from corn, cellulosic biomass, and advanced sources (e.g., non-corn grains), linked to the refinery products market, thus allowing the forecast of transportation ethanol demand throughout the model forecast period. Plant capital and operating costs are key inputs, as are transportation costs. *Elected that the study Baseline Scenarios use the EIA technology inputs for biomass conversion.*
Advanced transportation vehicle performance, cost, and market penetration rates: Flex Fuel vehicles, hybrid vehicles, electric vehicles, CNG vehicles	CEA-NEMS includes a full complement of current and advanced vehicle stock to satisfy transportation demands. Market penetration depends on competitive fuel efficiency and vehicle costs. Projections account for manufacturer lead-time and tooling constraints that limit the rate of increase in the market penetration of new technologies. *Elected that the study Baseline Scenarios use the EIA Reference Case assumptions.*
Proposed 2025 Fuel Efficiency Standard of 54.5 mpg for cars and light trucks	These new standards will cover cars and light trucks for Model Years 2017-2025, requiring performance equivalent to 54.5 mpg in 2025 while reducing greenhouse gas emissions to 163 grams per mile. The proposal calls for a 5 percent annual increase for cars and a 3.5 percent increase per year for light trucks. The new target is a significant increase from the current standard which is 27.3 miles per gallon and the 2016 level where cars and trucks must average 31.4 miles per gallon. *Elected that the study Baseline Scenarios use the EIA Reference Case assumptions. The study executed alternative scenario sensitivity scenarios to assess*

MODEL METHOD/PARAMETER ASSUMPTIONS	STUDY BASELINE SCENARIO SPECIFICATION
	the impact of this proposed standard.
Natural Gas Supply and Pricing	Natural gas supply and pricing derivation is fully endogenous to the CEA-NEMS model based on production and distribution models. *Elected that the study Baseline Scenarios use the EIA Reference Case assumptions.*
Electricity Supply and Pricing	NEMS represents the capacity planning, generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, natural gas, and biomass; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The CEA-NEMS model will determine the least-cost optimum electricity generation from all available regional sources. *Elected to use EIA's AEO2011 Reference Case input assumptions for power generation capital and O&M costs and other pertinent generation technology input values.*
Macroeconomic Parameters	Some of the key exogenous input parameters used for the macroeconomic calculations in CEA-NEMS are: Initial national GDP growth projection, National population by age cohort, total factor productivity, federal tax rates and nominal expenditures, money supply, GDP of major and other important trading partners, and State population estimates and projections from the U.S. Bureau of the Census. The other modules of the model provide over seventy energy prices and quantities from the output of the demand and supply modules. *Elected to use the existing macroeconomic inputs to the model.*

3. APPROACH TO MODELING THE REGIONAL LCFS USING CEA-NEMS

Using the Baseline Scenarios, the goal of the modeling effort was to quantify the lowest-cost combination of transportation fuels and other actions that would need to be taken within the NESCAUM region to achieve the NESCAUM LCFS objective of a ten (10) percent reduction in carbon intensity (CI) for all transportation-related fuels consumed. This must be done while also satisfying projected energy demand in the region, all existing energy policies and environmental regulations, vehicle stock turnover, biofuels conversion development, and financial constraints on consumers. The period of time required to achieve this goal was defined to be ten years starting with the beginning year (BY), which is designated as 2012; therefore, the ten year period runs from 2012 through 2021.

3.1 CARBON INTENSITY DEFINITION AND CALCULATION

For the purposes of this study, a regional, weighted-average carbon intensity for a specified region is defined as follows:

$$\text{Carbon Intensity (CI)} = \frac{\text{Total Annual Regional Transportation Fuel } CO_2 \text{ Emissions (Grams)}}{\text{Total Annual Regional Transportation Energy Consumption (MJ)}}$$

The calculation of both regional and state CI values is performed outside of CEA-NEMS using the scenario results of the model's highly detailed projection of transportation sector fuel consumption. This calculation accounts for:

- **Direct vehicle fuel consumption**
  - Gasoline, diesel, LPG, compressed natural gas, corn-based ethanol, cellulosic ethanol, non-cellulosic ethanol, biodiesel
- **Indirect vehicle fuel consumption**, including fossil and non-fossil electricity production for use in the transportation sector
  - Coal, natural gas, petroleum, non-fossil fuels (Nuclear and Renewables)
- **Emissions**
  - For each fuel, CO_2 emissions = Fuel Consumption x Emission Factor
- **Carbon Intensity**
  - Total Emissions (sum of all fuels' emissions) / Total Fuel Consumption (sum of all fuels' consumption)
- **Special Handling in Calculations**
  - Motor Gasoline
    - Motor gasoline contains up to 10% ethanol by volume. To avoid double counting, we include 90% of motor gasoline consumption as pure gasoline in the total transportation fuel consumption, and the ethanol (10%) is included with the ethanol consumption. In emission calculations, only the pure gasoline carbon emissions are calculated here using a pure gasoline emission factor.
  - E85
    - E85 contains 74% ethanol and 26% pure gasoline by volume. To avoid double counting, we count only the 26% of this consumption as pure gasoline in the total transportation fuel consumption. The ethanol portion (74%) is included in ethanol consumption and emissions.
  - Ethanol
    - Emissions are calculated by ethanol source using associated emission factors. This includes: Corn-based ethanol, Cellulose-Based Ethanol (Conventional and Advanced Technologies,[20] Domestic and Imported Sources), Non-Cellulosic Ethanol (Sugar Cane-Based, Imported Sources)
  - Biodiesel
    - Transportation Diesel consumption actually contains diesel from petroleum and biodiesel-Virgin (from seed oil or white grease), and Non-Virgin (from yellow grease). Their emissions are uniquely calculated using associated emission factors.

[20] Advanced ethanol is assumed to be the ethanol from non-corn grains such as sorghum and barley. The grain prices are based on the corn price, and the capital cost of an advanced ethanol processing unit is a function of the cost of a next generation dry mill corn ethanol unit.

Reduction in the regional CI value requires reduced carbon emissions per unit of energy consumed per vehicle mile traveled (VMT). For any individual transportation vehicle, this effectively can only be achieved via a change to a fuel source with a lower CI value (e.g., biodiesel versus petroleum-based diesel). For a transportation network that makes use of multiple types of vehicles (e.g., gasoline, E85, diesel, electric hybrid, etc.), this can be achieved via a combination of reduced CI fuels and changes to the mix of operating vehicle types (e.g., increased market penetration of E85 vehicles.) The latter approach is taken with CEA-NEMS to try to achieve the study's CI goal.

3.2 LCFS MODELING METHODOLOGY

Two different (but compatible) approaches were taken in the study to "drive" the model towards lower regional weighted-average CI performance in the transportation sector as required by the LCFS:

- *Manual input changes* that enhance the market penetration of more efficient vehicles and vehicles that use lower-CI fuels (within constraints imposed by the model, such as vehicle turnover rates, fuel recharging infrastructure availability, and vehicle choice):
  1. Reduced cost for alternative fuel vehicles relative to conventional vehicles;
  2. Increased refueling infrastructure availability to enhance the vehicle choice options in the model;
  3. Continuation of alternative fuel subsidies for corn-based ethanol, advanced cellulosic ethanol, and biodiesel – existing subsidies cease at the end of 2011; and
  4. Implementation of the enhanced CAFE (corporate average fuel economy) standard (54.5 mpg average by 2025) negotiated between the Administration and the vehicle manufacturers.[21]
  5. Implementation of an alternative projection for world crude oil price through 2035, an exogenous input into the model; EIA's High Oil Price (HOP) projection is used. (Only comparable with the Baseline Scenario modified with HOP projection, which is referred to as the Baseline High Oil Price Scenario).
- Implementation of an *LCFS optimization methodology* via code changes that automates the process of attempting to achieve the study's CI goal. This approach can be used with or without the manual input changes described above. The purpose of the optimization methodology is to automate the ten percent CI reduction solution by pricing any excess carbon emissions attributed to motor gasoline and diesel fuels via a carbon offset valuation (higher prices for conventional fossil-derived fuels yields greater opportunity for AFVs to compete and lower the regional CI goal).

3.2.1 Manual CI Reduction Driver - Reduced Cost for Alternative Fuel Vehicles

The manual model input changes were implemented individually and in tandem to identify the parametric impacts on the overall NE/MA region CI valuation and those of the individual states. These were also implemented in conjunction with the LCFS optimization methodology. For item number 1 above, the adoption of alternative fuel technologies (AFVs) in the transportation sector was incentivized by reducing (or eliminating) associated *incremental costs* relative to

[21] http://www.whitehouse.gov/the-press-office/2011/07/29/president-obama-announces-historic-545-mpg-fuel-efficiency-standard

conventional vehicles within the same size class,[22] which can be interpreted as the implementation of a price subsidy to encourage the purchase of an alternative fuel vehicle. For maximum impact, incremental cost was set to zero for the following alternative fuel vehicles: *Ethanol Flex-Fuel, CNG Bi-Fuel, LPG Bi-Fuel, Dedicated CNG,* and *Dedicated LPG*. Attachment 4 (see page 163) presents some examples of the vehicle incremental costs for some of the AFVs; note that the subsidies for the PHEV and BEV type vehicles only offset a small portion of the incremental vehicle costs (since only the battery cost differences were accounted for), while the other AFVs see the subsidies almost fully covering the cost differential.

The incremental costs help determine the sales share (and sales volume) of a given type of vehicle (e.g., compact E85 flex fuel) in the model. The average vehicle price, under either the Reference or alternative scenario is dependent, in part, on sales volume as well as other cost factors. The difference in vehicle price between the Reference and alternative scenario provides the implied per-vehicle subsidy. The total vehicle sales under the alternative scenario multiplied by the implied per-vehicle subsidy value provides an estimate of the total subsidy cost.

These calculated per-vehicle subsidies are summarized below in TABLE 3-1, which are discussed in detail in Section 4.4.2.

TABLE 3-1: ALTERNATIVE FUEL VEHICLE SUBSIDIES USED TO HELP INCENTIVIZE MARKET PENETRATION AND ASSESS CI IMPACTS

VEHICLE TYPE	SUBSIDY VALUE[1] ($2009)
Plug-In 10 Gasoline Hybrid	318
Plug-In 40 Gasoline Hybrid	165
Ethanol Flex[2]	1,024
Compressed Natural Gas	7,701
Compressed Natural Gas Bi-Fuel	6,574
Liquefied Petroleum Gases	4,121
Liquefied Petroleum Gases Bi-Fuel	5,625
100-Mile Electric Vehicle[3]	(2)
200-Mile Electric Vehicle[3]	33
Diesel-Electric Hybrid	199
Gasoline-Electric Hybrid	182

Table 3-1 Notes:

1 NEMS calculates the price of cars by size class and the implied subsidy is based on the average incremental cost within a fuel-type over the period of the study. The subsidy value is the cumulative arithmetic average covering the 10-year study period. Changes in vehicle penetration can result in a

[22] There is no competitive crossover between vehicle size class categories (e.g., compact and large) in the model. More generally, and within the car or light truck group, the consumer choice algorithms operate within the six individual size classes, so the characteristics of a Chevy Volt would, in essence, be judged against the characteristics of other vehicles in its size class (e.g., "compact"). However, there is some provision in the model for shifting of sales shares amongst size classes, but that was not an aspect of the code that was modified for this study.

counterintuitive outcome difference. Values presented in the table reflect a comparison of the ALLNOCAFE54 and BASELINE scenarios – see TABLE 4-1 of the report.

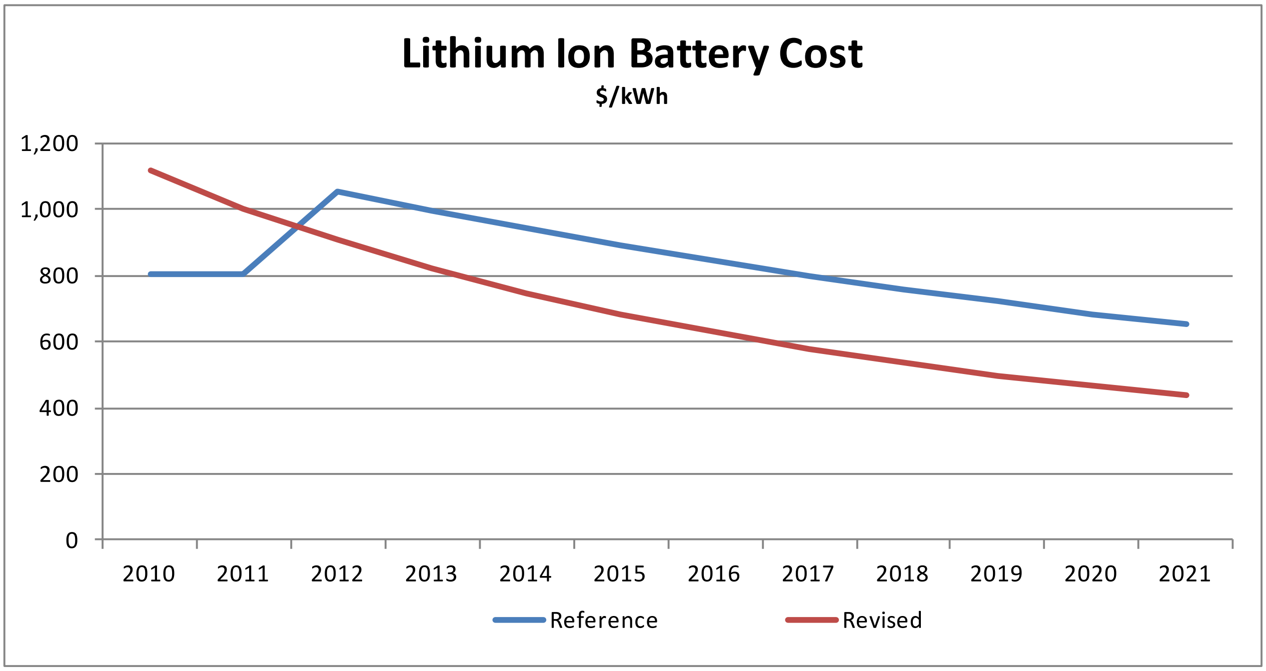
Incremental costs of non-electric vehicles are influenced by their rate of market penetration; more rapid penetration results in a lower average per-vehicle cost.

2 NEMS subsidies are $1,600 to $2,000 for low sales volumes and transitions to $250 to $300 as sales volumes increase. Values in the table reflect near-term incremental costs.

3 For electric vehicles, cost adjustments are only applied to the battery systems. The model subsequently determines the size class and other vehicle attributes affecting overall vehicle cost. This shifting of consumer choice parameters results in a negligible incremental cost associated with the battery electric vehicle (BEV).

The other cost "subsidy" affects electric vehicles (EV) and Plug-in Hybrid Electric Vehicles (PHEV), where battery costs and incremental vehicle costs are assumed to decline more rapidly (than EIA's Reference Case and the study Baseline Scenario) in order to reflect technological considerations and the impact of scale economies on the production costs of electric vehicles. Below, in FIGURE 3-1 to FIGURE 3-4, are the comparative cost projection inputs for batteries ($/kWh)) and incremental costs for the electric vehicles used for modeling scenarios. The blue line is the EIA Reference Case values and the red line represents the revised input values.

FIGURE 3-1: **LITHIUM ION BATTERY COST – BEGINNING IN 2010, ACCELERATED COST REDUCTIONS (IN $/KWH) TO REDUCE FLOOR PRICE**[1]



1 Battery floor price is reduced to $250/kWh from the original modeled value of $500/kWh. The $250 floor price is a parameter of the battery cost curve, which only approaches this limit later in the forecast. Since the chart only extends through 2021, the revised curve does not reflect attainment of this goal.

FIGURE 3-2: **HYBRID EV INCREMENTAL COST – 30% REDUCTION IN BASELINE, ACCELERATED REDUCTION CURVE**

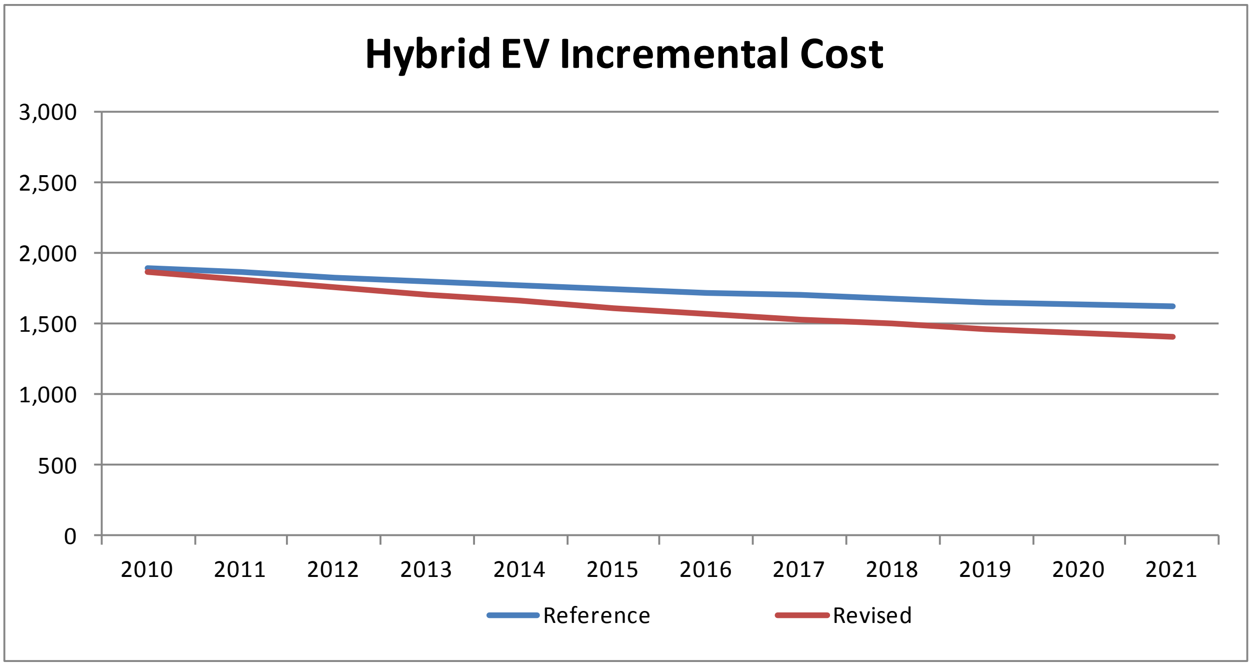


FIGURE 3-3: **PHEV10 COST – 30% REDUCTION IN BASELINE, ACCELERATED REDUCTION CURVE**

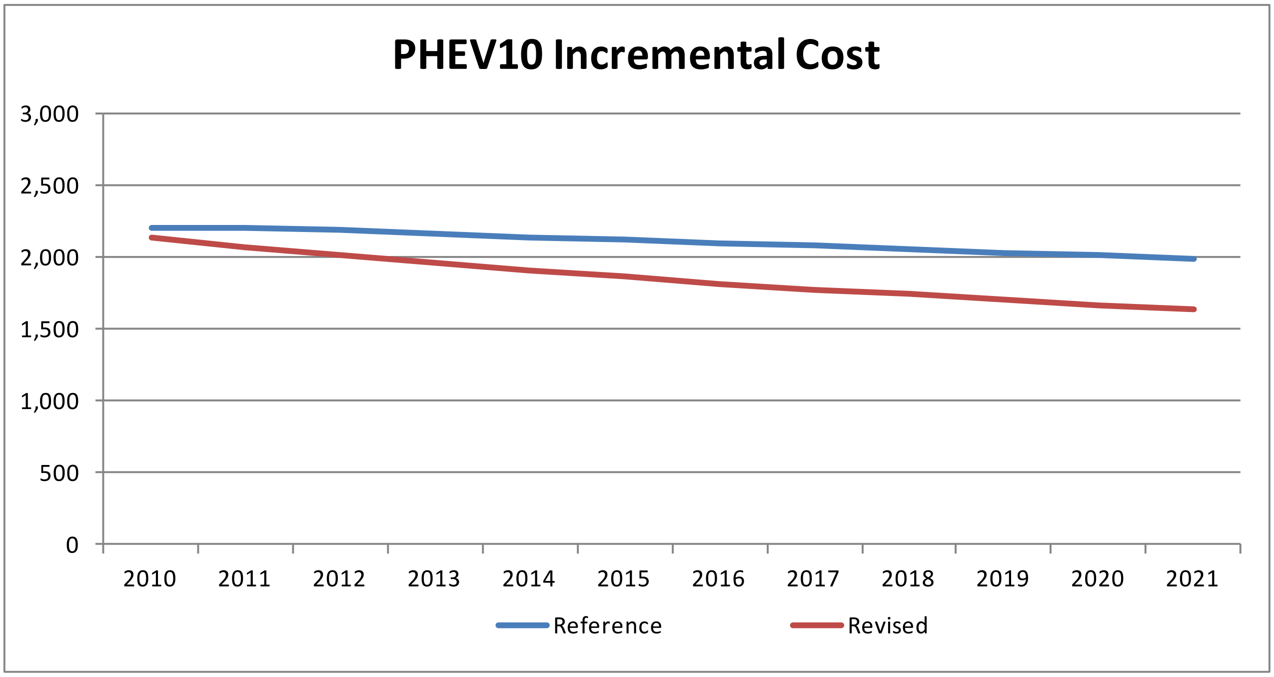
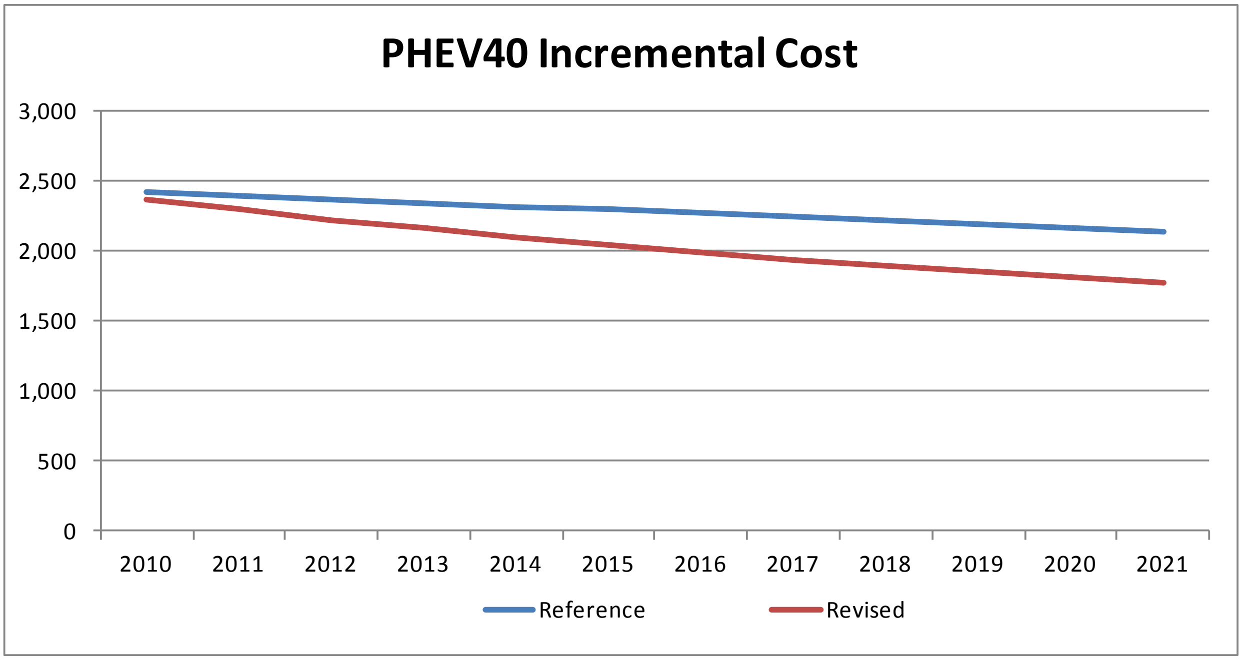


FIGURE 3-4: **PHEV40 COST – 30% REDUCTION IN BASELINE, ACCELERATED REDUCTION CURVE**



3.2.2 Manual CI Reduction Driver - Increased Refueling Infrastructure Availability

For manual model input item number 2 (increased refueling infrastructure availability), the transportation model input file was modified to increase the availability of alternative fuels in census divisions 1, 2, and 5. Fuel availability of alternative fuels is expressed relative to the availability of gasoline; in other words, if all vehicles in a region can be assumed to have ready access to gasoline refueling facilities (i.e., availability = 100% by definition), a ten percent availability for E85 would imply that there is $1/10^{th}$ the number of E85 refueling facilities in the region. This value is an input in the vehicle choice model in CEA-NEMS, and influences the ultimate share of alternative fuel vehicle sales. The NEMS Reference Case exogenously specifies the availability of ethanol refueling facilities by Census Division, capping the maximum availability at a predetermined limit. This analysis tested the impact of increased fuel availability on vehicle choice by doubling the upper limit by approximately 2030 (based on CEA-NEMS logistic curve for fuel availability), as presented in FIGURE 3-5 below.

For CNG and LPG in the Reference Case Scenario, the fuel availability increases in a series of steps, ending with a short linear trend to an assumed maximum value in 2015, as shown in FIGURE 3-6. This revised input extends the linear trend to a point where the maximum fuel availability is doubled (after 2021), then remains constant. An example for CD2 is provided below for the study period. Values for LPG and CNG are identical within each division.

Please note that model test cases indicate these fuel availability factors did not have any significant impact on vehicle choice, which appears to be due to the overwhelming influence of vehicle and fuel price on the selection decision algorithm. They have been included in this discussion for the purposes of completeness.

FIGURE 3-5: ETHANOL FUEL AVAILABILITY CHANGE FOR CD1

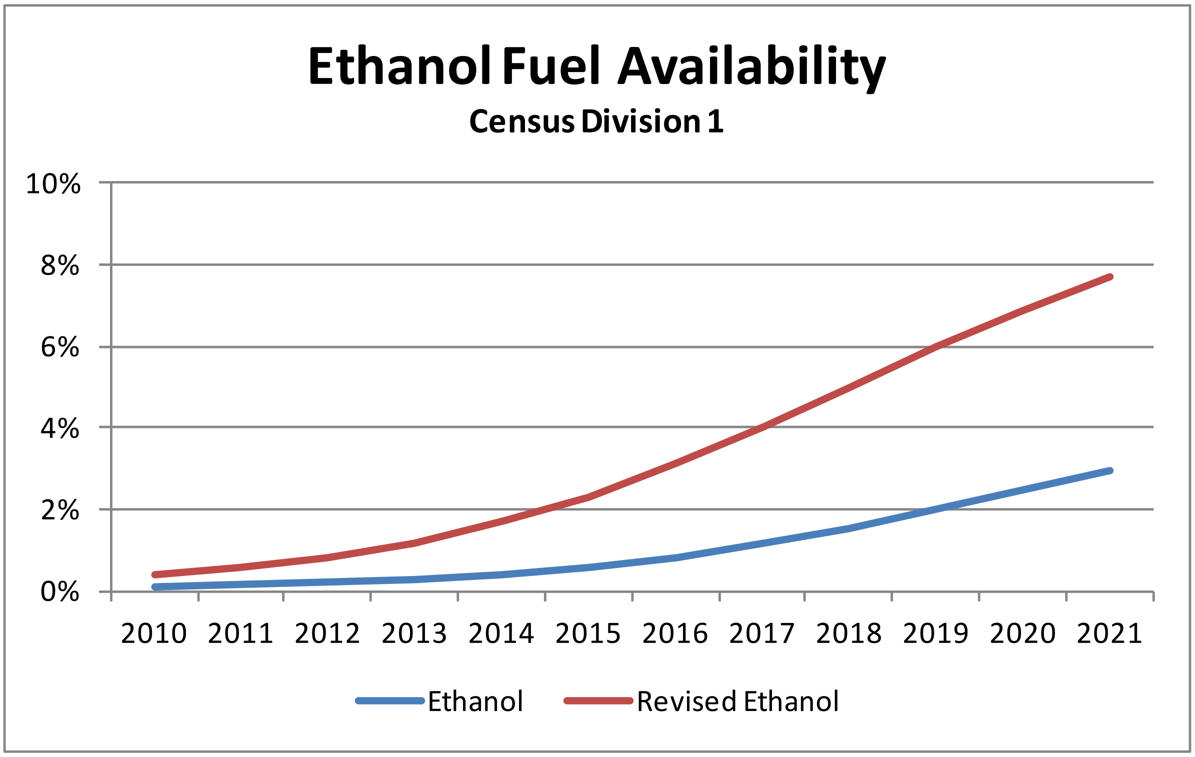
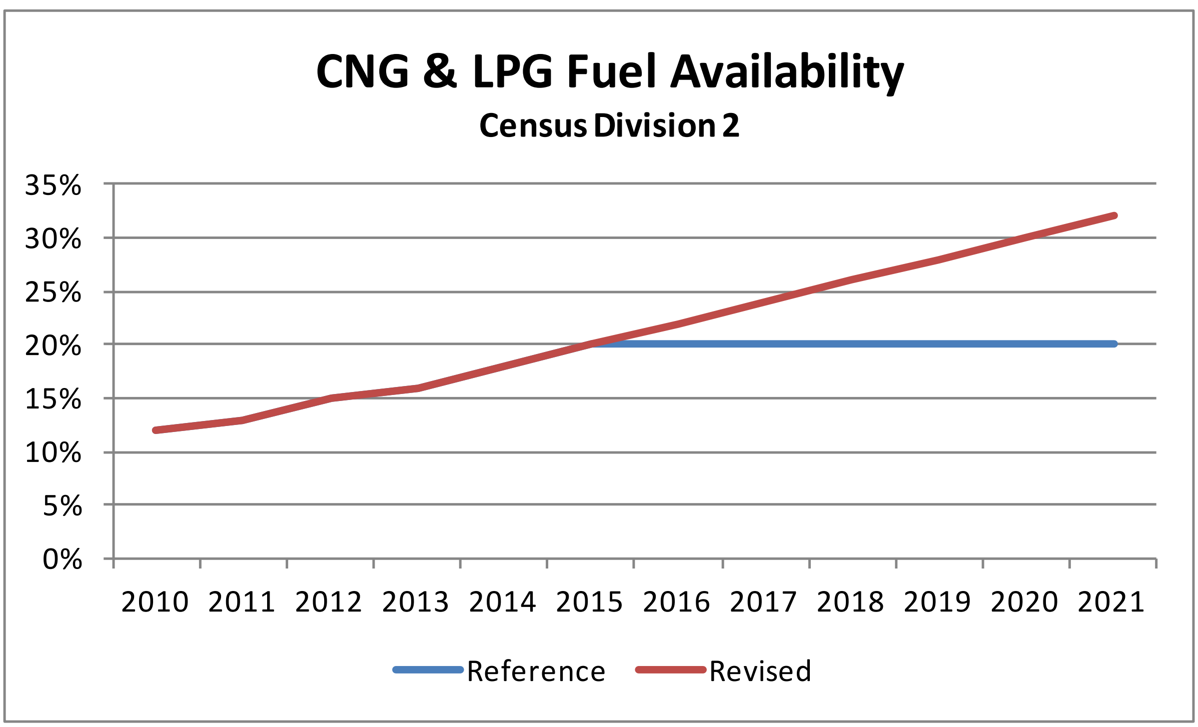


FIGURE 3-6: CNG AND LPG FUEL AVAILABILITY CHANGE FOR CD2



3.2.3 Manual CI Reduction Driver - Continuation of Alternative Fuel Subsidies

The third manual CI reduction driver employed in the modeling effort is the extension of biofuel subsidies through 2021 with no ethanol import Tariffs past 2011. The table below identifies the subsidy values used for the modeling.

TABLE 3-2: ALTERNATIVE FUEL SUBSIDIES USED IN CEA-NEMS TO ENHANCE CI REDUCTION

ALTERNATIVE FUEL TYPE	ALTERNATIVE FUEL SUBSIDY ($2010)
Corn-Based Ethanol	$0.51/gallon
Cellulosic Ethanol	$1.01/gallon
Biodiesel (virgin)	$1/gallon
Biodiesel (non-virgin)	$0.50/gallon

These biofuel subsidies are implemented at both the national level and the regional level. The national ethanol subsidy provisions are already modeled in the PMM. The PMM reflects an assumption that the corn ethanol credit and ethanol import tariff will no longer be available after 2011, and the cellulosic ethanol credit will expire after 2012. The incentive for the ethanol blended into motor gasoline is set at 51 cents per gallon for 2005 through 2008, 45 cents per gallon for 2009 through 2011, and 0 cents per gallon for 2012 and beyond (nominal dollars). The cellulosic ethanol incentive is set to a maximum of $1.01 per gallon from 2009 through 2012. Only the ethanol portion of E85 receives the ethanol tax incentive. The maximum blend levels are allowed to grow at a rate of 15% per year.[23] The biodiesel blending credits are modeled through 2011.

For the NE/MA regions, corn and cellulosic ethanol incentive and biodiesel blending credits are extended until 2022. A new code was developed to set values for the ethanol and biodiesel subsidy beyond 2011 (2012 for cellulosic ethanol) for the NE/MA region and keep it at zero for all the other regions. All the other assumptions are kept the same.

3.2.4 Manual CI Reduction Driver - Implementation of Enhanced 54.5 mpg CAFE

The fourth manual CI reduction driver employed in the modeling effort is the implementation of the enhanced corporate average fuel economy (CAFE) standard for light duty vehicles – 54.5 mpg weighted-average by 2025 – negotiated between the Administration and the vehicle manufacturers.

The proposed 2025 Fuel Efficiency Standard of 54.5 mpg for cars and light trucks calls for a 5 percent annual increase for cars and a 3.5 percent increase per year for light trucks. The new target is a significant increase from the current standard which is 27.3 miles per gallon and the 2016 level where cars and trucks must average 31.4 miles per gallon. Note that there is an out-clause: *the standards would be reviewed part way through the implementation to determine if the rules are too strict or lenient due to gas prices, consumer behavior or changes in technology.*

[23] In the model, a PMM subroutine updates the LP coefficient that handles the ethanol tax incentive (from corn or cellulose) blended into motor gasoline and puts limits on splash blending levels at 15% per year.

The mpg standard for light duty vehicles is based on a mix of light duty cars and trucks of different types. In order to approximately meet the new light duty vehicle mpg standard of 54.5 mpg by 2025 (cars and light trucks), the model increases mpg by approximately 6% per year. At that rate, new light duty trucks must meet an average mpg of 44 mpg and new cars must meet an average mpg of 72 mpg. The combination yields the weighted-average of 55 mpg. The mpg ratings are assumed to be EPA-based values.

Gasoline internal combustion engine (ICE) cars achieve an average economy of 45 mpg, while gasoline ICE trucks achieve an average economy of 37 mpg by 2025. The higher levels of average fuel economy are ultimately met by the penetration of higher-mileage alternate fuel vehicles, particularly electrics and hybrids. In NEMS, 100-mile electric vehicles are rated at 147 mpg by 2025 and plug-in 40 gasoline hybrids are rated at over 80 mpg by 2025. Therefore, the modeling is based on achieving an average 55 mpg fuel economy by 2025, via a combination of improved conventional vehicles and advanced technology vehicles.

Note that concerns have been raised regarding the proposed 2025 Fuel Efficiency Standard of 54.5 mpg by the Alliance of Automobile Manufacturers (saying it could add to vehicle sticker prices) and the United Auto Workers (the standards could ultimately mean fewer jobs).[24]

3.2.5 Implementation of an Alternative Projection for Benchmark Crude Oil Price through 2035

An initial world crude oil price projection is required as an exogenous input to the CEA-NEMS model. This price projection has a significant impact on the model results since the cost of crude oil products is directly impacted, which also influences the costs of competitive fuels. The relative demand for petroleum-based fuels versus biofuels and other non-fossil fuels is also impacted, which influences the mix of fuels used in a region and the associated CI value of the energy consumed. Therefore, it is appropriate to consider the impact of an alternative future that represents higher oil prices than assumed for the CEA-NEMS Baseline Scenario.

EIA's *AEO2011* High Oil Price assumption is used as the alternative price projection. They assume "*high demand for liquids, combined with more constrained supply availability, results in a sharp, continued increase in world oil prices.… GDP growth is used as a proxy for liquids demand growth in the non-OECD nations. Annual GDP growth in non-OECD nations is assumed to be 1.0 percentage points higher in the High Oil Price case than in the Reference case, or 5.7 percent on average. Coupled with more constrained supply, oil prices increase to $200 per barrel in 2035 as a consequence*."[25]

The high oil price projection is shown in FIGURE 2-3. This projection is applied to the CEA-NEMS Baseline to create an alternative baseline called "Baseline High Oil Price" for comparison with other scenarios that incorporate the HOP assumptions.

3.2.6 LCFS Optimization Methodology

An LCFS optimization methodology for the NESCAUM regions in CEA-NEMS was developed based on the California LCFS (CA-LCFS) already represented in CEA-NEMS. Mandated CIs

[24] Vehicle prices are increased in the model as a result of CAFE implementation. Auto prices are a model output and the output indicates a significant increase in some of the model classes, such as large cars, due to implementation of the enhanced CAFE standards.

[25] AEO2011 Annual Energy Outlook, page 24.

and approved fuel pathways included in LCFS2, as used for the California LCFS implementation, have been utilized for the NE/MA regions as well. The CI values identified in TABLE 2-1 are used for the NESCAUM-LCFS, which is implemented in CEA-NEMS' Petroleum Market Module (PMM). The LCFS optimization covers the period 2012 to 2021.

CEA-NEMS' PMM contains a linear programming (LP) model of the U.S. petroleum refining, liquid fuels production, and marketing system that meets demand for refined products while minimizing costs. In the PMM, a fuel supply model, refined product prices (e.g., gasoline, diesel, ethanol, etc.) are obtained from the marginal prices of an optimal solution to the PMM LP, with transportation costs and taxes added as appropriate at the census division level. These product prices are sent to the NEMS demand models, such as the Transportation Demand Module. The LP matrix is updated with the new demands for refined products and the cycle continues until convergence is reached for every year in the model projection period. Since CEA-NEMS is a fully integrated model, demand-side changes in transportation vehicles, such as the projected penetration of gasoline-electric hybrid and electric vehicles, will impact the demand for liquid fuels, such as gasoline and diesel, and impact their prices and cost-competitiveness in the converged, least-cost solution.

The LCFS sets yearly targets for the carbon intensity (amount of carbon per unit of energy) for on-road motor fuels. CEA-NEMS' PMM accounts for the carbon intensity of motor gasoline and diesel fuel, and their replacement fuels consumed in the affected regions, such that the total carbon intensity from the combined product mix (for motor gasoline and diesel fuel, independently) does not exceed the LCFS ruling during each forecast year. The primary **input data** are the carbon intensities (1000 tonnes C per trillion BTU) for motor gasoline, diesel fuel, and all replacement fuels, including ethanol, biodiesel, liquids from coal, biomass, and NG, as well as CNG, electric, and LPG fueled vehicles. All input data used is assumed to be the same for both California and the NESCAUM regions. The carbon capture and sequestration option is also taken into account when determining carbon intensity for liquids from coal and biomass. A "safety valve" vector is included for the LCFS (motor gasoline and diesel fuel) to price excess carbon emissions via a carbon offset valuation. In other words, if the model can't meet the constraint, then a penalty is incurred. Penalty costs are read in from a CEA-NEMS input file (rfcarbon.xml). For all modeled regions, the penalty for diesel is $5,200 per ton-day and for motor gasoline $9,100 per ton-day of carbon in 2010 dollars.[26] The penalty is added to the fuel cost, which results in more competitive pricing for the alternative fuels and increased consumption.

For each iteration of the model's PMM, the total amount of energy used for on-road travel is known; thus, the constraint on carbon intensity is modeled as a constraint on the total amount of carbon emitted in excess of the LCFS regulation.[27]

While the assumption for the CA-LCFS representation is that only reformulated high oxygen gasoline is consumed in California (meaning that only reformulated high oxygen gasoline is included in the constraint), the NE/MA region LCFS representation includes all types of gasoline

[26] The penalty cost values are adapted from CA Health and Safety Code Section 43029 as used for the CA LCFS implementation. The value is time-based to be consistent with the PMM operation. Value of the penalty depends on any incremental emissions; estimated at about $3/gallon gasoline and $2/gallon diesel by 2021 if applied.

[27] The LP constraints that represent the LCFS for motor gasoline and diesel fuel for NESCAUM regions are NELCFSMG and NELCFSDS, respectively. The corresponding safety (excess CO_2) is represented by vectors NLCSAFMG and NLCSAFDS, respectively.

consumed in these regions (i.e., conventional gasoline, reformulated gasoline, conventional high oxygen gasoline, and reformulated high oxygen gasoline).

Note that meeting total transportation energy demand with the available fuels is a primary model constraint that cannot be altered, regardless of the imposed fuel penalties.

4. EXECUTION OF THE CEA-NEMS MODEL TO QUANTIFY TECHNICAL AND ECONOMIC IMPACTS OF A REGIONAL LCFS: LCFS REGIONAL RESULTS

The CEA-NEMS model was executed under a variety of alternative input assumption scenarios to evaluate the potential for meeting the specified LCFS goal of a 10 percent CI reduction within ten years. The parametric assumptions associated with these scenarios have been presented in Sections 2 and 3 of this report. **None of the scenarios were able to achieve the regional LCFS goal within the specified time period based on the practical supply and demand side performance represented in the CEA-NEMS model**.

4.1 DESCRIPTION OF MODELED SCENARIOS

This section of the report identifies the unique CEA-NEMS scenarios that were created and executed and presents detailed technical and economic results at the regional level. TABLE 4-1 identifies all the CEA-NEMS scenarios that were executed in fulfillment of the study objectives. EIA's AEO2011 Reference Case (S1) represents the basis for developing this study's Baseline Scenarios, described in detail in Section 2. Scenarios 2, 3, and 4 are considered baselines against which to compare the results of the other compatible scenarios to calculate the potential CI reductions and associated energy and economic impacts; each offer insight into the requirements for achieving the LCFS goal. For example, the 'ALL' scenario (S10) is compared with the 'BASELINE' scenario for the purpose of consistently assessing the impacts of all modeling options under the influence of the S2 assumptions. Similarly, the 'ALLHOP' scenario (S13) is compared with the 'BASELINEHOP' scenario (S3) for the purpose of consistently assessing the impacts of all modeling options under the influence of the high oil price projection (in addition to the other S2 assumptions). The non-baseline scenarios represent a variety of potential pathways, including different mixes of vehicle types, the level of vehicle and fuel incentives, and other policy pathways required to attempt to achieve the LCFS 10% CI reduction goal.

All of the scenarios provided useful insight into identification of the combination of parametric components necessary to potentially achieve a regional CI reduction goal of 10 percent in ten years. Since none of these scenarios were able to achieve the CI reduction goal, those that yield the greatest potential reduction were selected to represent detailed regional results. All are summarized in TABLE 4-2 below. Results are presented independently for those scenarios based on the baseline oil price (BOP) projection (as represented in the BASELINE scenario) and for those based on the high oil price (HOP) projection (as represented in the BASELINEHOP scenario); *the former are presented in this section of the report, while the latter are presented in Attachment 5 (figures and tables only).*

4.2 SCENARIO CARBON INTENSITY RESULTS

Initial execution of the BASELINE scenario showed that using the current projections in the model for alternative fuel vehicles, there will be an insufficient number of alternative fuel vehicles to satisfy the level of use of ethanol and other alternative fuels needed to achieve the 10% reduction in CI within the 10-year period. As a result, SAIC made sequential model modifications to apply "drivers" in the form of vehicle purchase incentives (S5), refueling infrastructure availability enhancement (S6) and biofuel subsidies (S7) to increase the projected market penetration and use of alternative fuel vehicles to attempt to achieve the 10% reduction in CI. These showed only modest impacts on CI reduction. See FIGURE **4-1**and FIGURE **4-2** for a comparison of LCFS region results for the different scenarios.

The automated LCFS Optimization Methodology was implemented in S8, as described in Section 3.2.6, to further impact transportation vehicle competition by penalizing carbon emissions in excess of that required by the LCFS goal. This approach has a significant impact on regional CI reduction, but only advanced approximately half-way to the goal as shown in FIGURE 4-2. Implementation of the accelerated CAFE standard, described in Section 3.2.4, also has a significant impact relative to the baseline, but primarily in the time period following year 2021. As shown in FIGURE 4-3 and FIGURE 4-4, the 'CAFE54' and 'ALL' scenarios project a 7 to 8 percent CI reduction by year 2035, albeit by significantly different pathways.[28] Therefore, given more time, the CAFE has the potential to come close to meeting the reduction goals at a significantly reduced cost by year 2035 since the fuel penalty is not required as to drive conversion to alternative fuel vehicles.

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[28] For the ALL and ALLNOCAFE54 Scenarios, the LCFS optimization implementation period is 10 years from 2012 to 2021 and expires in 2022. Therefore, new consumer choices are being made under the relaxed fuel constraints and CI increases. Note that the CAFE54 Scenario shows continued improvements with similar outcome to ALL by 2035.

TABLE 4-1: CEA-NEMS SCENARIOS

CEA-NEMS SCENARIO NAME (Short Name for Charts)	SCENARIO NUMBER	CEA-NEMS SCENARIO DESCRIPTION	COMMENTS
AEO2011 RC MODIFIED (AEO2011RCMOD)	**S1**	AEO2011 NEMS Reference Case (with CAIR on, SAIC execution, reference case crude oil price projection) + Carbon Emission Factors consistent with the study assumptions	Basis for this study's Baseline Scenarios
BASELINE (BASELINE)	**S2**	**S1** + Cross State Rule limits on SO_2 and NOx (SAIC implementation) + E15 constraint (year 2015 start for E15 availability)	See **Section 2** for a detailed description. This scenario is used as the basis for calculating the CI reduction for the other scenarios that use the reference case crude oil price projection.
BASELINE HIGH OIL PRICE (BASELINEHOP)	**S3**	**S2** + High Oil Price Projection	**See Section 2.2.2.** This scenario represents an alternative baseline based on EIA's High Oil Price (HOP) sidecase. Only scenarios that include the HOP projection can be compared with this scenario.
CAFE 54 MPG (CAFE54)	**S4**	**S2** + 54.5 mpg CAFE agreement (6%/year increase in average annual mpg for new light duty vehicles, achieving 54.5 mpg in year 2025)	**See Section 3.2.4.** The intent of this scenario is to uniquely assess the impact of the 54.5 mpg CAFE agreement. Results show that its biggest impact on CI reduction is in the years after 2020.
ALT FUEL VEHICLE 1	**S5**	**S2** + Reduced Alternative Vehicle Incremental Costs (incremental costs = $0, best possible projection)	**See Section 3.2.1.** Indicates that alternative vehicle costs, relative to conventional vehicle costs, have a significant impact on CI reduction by increasing demand for reduced-CI alternative fuels.
ALT FUEL VEHICLE 2	**S6**	**S5** + Reduced Alternative Vehicle Incremental Costs (incremental costs = $0, best possible projection) + Increased refueling availability (30% to 100% increase)	**See Section 3.2.2.** Indicates that increasing refueling infrastructure availability is not nearly as significant relative to the price of the alternative fuel vehicles and the fuel cost. This parameter is not considered in further scenarios.

CEA-NEMS SCENARIO NAME (Short Name for Charts)	SCENARIO NUMBER	CEA-NEMS SCENARIO DESCRIPTION	COMMENTS
BIOFUEL SUBSIDY	**S7**	**S5** + Extension of Biofuel Subsidies through 2021 and no import Tariffs past 2011: *Input as national renewable fuel subsidies* **Corn-based ethanol:** $0.51/gallon (2010 dollars) **Cellulosic ethanol:** $1.01/gallon (2010 dollars); also receives the corn-based ethanol credit **Biodiesel (virgin):** $1/gallon (2010 dollars) **Biodiesel (non-virgin):** $0.50/gallon (22010 dollars)	**See Section 3.2.3**. National biofuel subsidies show a modest impact on CI reduction in the NE/MA region.
ALL INCLUDED - NATIONAL - NO CAFÉ 54 MPG (ALLNATNOCAFE54)	**S8**	**S7** + LCFS optimization methodology implementation	**See Section 3.2.6**. LCFS optimization methodology has a significant impact on achieving CI reduction within the model framework. Higher conventional fuel costs may result due to possible application of penalties based on carbon emissions in excess of CI specification.
ALL INCLUDED - NATIONAL (ALLNAT)	**S9**	**S7** + **S4** CAFE54 assumptions	This scenario includes all of the other scenario assumptions with the exception of increasing refueling infrastructure availability.
ALL INCLUDED - REGIONAL (ALL)	**S10**	Comparable with **S9**, except that the renewable fuel subsidies are only applied to the NE/MA region	This case showed only showed minor difference with S9. This scenario is used to present results for all options included.
ALL INCLUDED - REGIONAL - NO CAFÉ 54 MPG (ALLNOCAFE54)	**S11**	**Comparable with S8**: except that the renewable fuel subsidies are only applied to the NE/MA region	This case showed only showed minor difference with S8. This scenario is used to present results for all options except CAFE54.

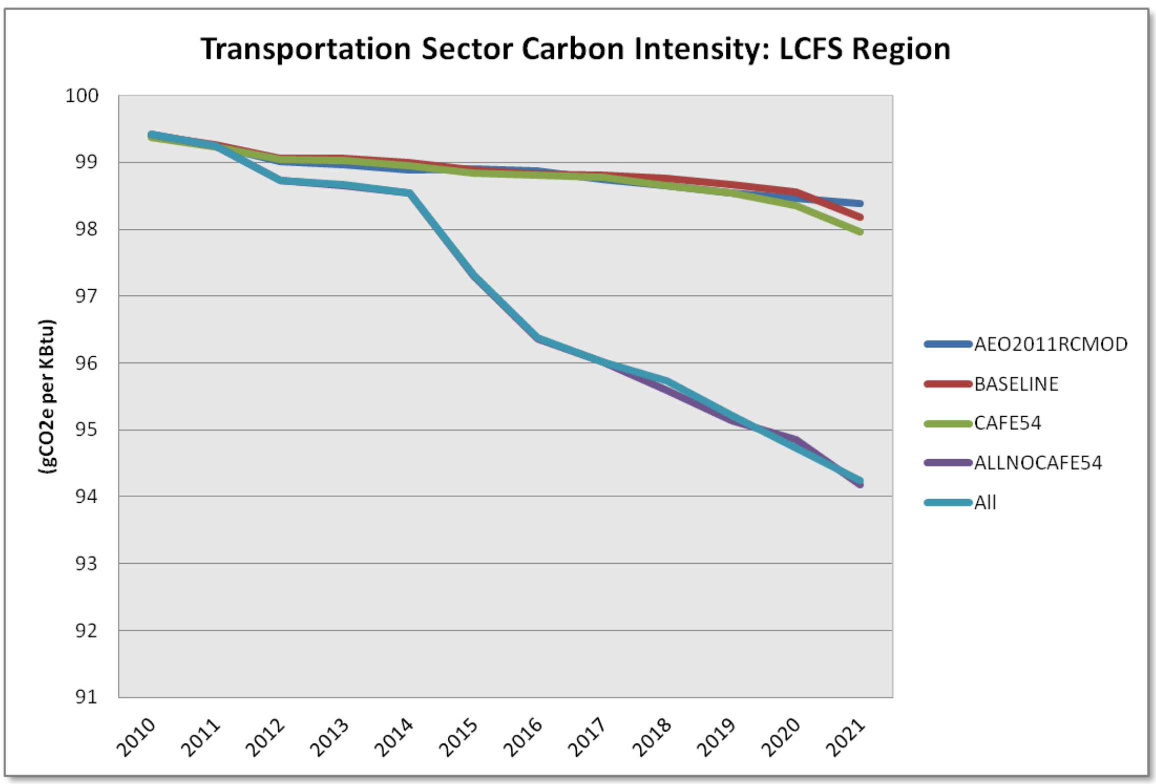
CEA-NEMS SCENARIO NAME (Short Name for Charts)	SCENARIO NUMBER	CEA-NEMS SCENARIO DESCRIPTION	COMMENTS
ALL INCLUDED – NATIONAL - NO CAFE54 MPG - DOUBLE CELLULOSIC SUBSIDY (ALLNOCAFE54SUB)	**S12**	**S8** + Double cellulosic ethanol subsidy ($2.02/gallon); this case shows no significant impact compared with the original subsidy scenario	Not considered further. Market penetration constraint in NEMS (Mansfield-Blackman) and cost of cellulosic ethanol production seem to be limiting through 2021.
ALL INCLUDED - REGIONAL - HIGH OIL PRICE (ALLHOP)	**S13**	**S10** + EIA High Oil Price Projection	**See Section 2.2.2.** Compared with BASELINE HOP (S3) to assess the impact of the HOP projection.
ALL INCLUDED - NO CAFÉ 54 MPG - REGIONAL - HIGH OIL PRICE (ALLNOCAFE54HOP)	**S14**	**S11** + EIA High Oil Price Projection	**See Section 2.2.2.** Compared with BASELINE HOP (S3) to assess the impact of the HOP projection.

TABLE 4-2: CEA-NEMS SCENARIOS SELECTED FOR COMPARATIVE RESULTS PRESENTATION IN THIS REPORT

SCENARIO NAME	SCENARIO DESCRIPTION
AEO2011RCMOD	1. AEO2011 NEMS Reference Case (with CAIR on, SAIC execution, reference case crude oil price projection) 2. Carbon Emission Factors consistent with the study assumptions
BASELINE	1. AEO2011 NEMS Reference Case (with CAIR on, SAIC run) 2. CEA Emission Factor Modifications (necessary for consistency with the Baseline 3. Cross State Rule limits on SO_2 and NOx (SAIC implementation) 4. E15 constraint (year 2015 start for E15 vehicle availability)
BASELINEHOP	1. BASELINE Scenario Assumptions 2. High oil price (HOP) projection replaces the business-as-usual oil price projection
CAFE54	3. BASELINE Assumptions 4. 54.5 mpg CAFE agreement (6%/year increase in average annual mpg for new light duty vehicles, achieving 54.5 mpg in year 2025)
ALLNOCAFE54	1. BASELINE Scenario Assumptions 2. Reduced Alternative Vehicle Incremental Costs (incremental costs = $0, best possible projection) 3. Extension of Biofuel Subsidies through 2021 and no import Tariffs past 2011(Input as regional subsidies) • Corn-based ethanol: $0.51/gallon (2010 dollars) • Cellulosic ethanol: $1.01/gallon (2010 dollars); also receives the corn-based ethanol credit • Biodiesel (virgin): $1/gallon (2010 dollars) • Biodiesel (non-virgin): $0.50/gallon (22010 dollars) 4. LCFS Optimization Code Methodology Implementation • Fuel price penalties are applied if carbon emissions exceed the annual CI specification
ALL	1. BASELINE Scenario Assumptions 2. Reduced Alternative Vehicle Incremental Costs (incremental costs = $0, best possible projection) 3. Extension of Biofuel Subsidies through 2021 and no import Tariffs past 2011(Input as national subsidies) • Corn-based ethanol: $0.51/gallon (2010 dollars)

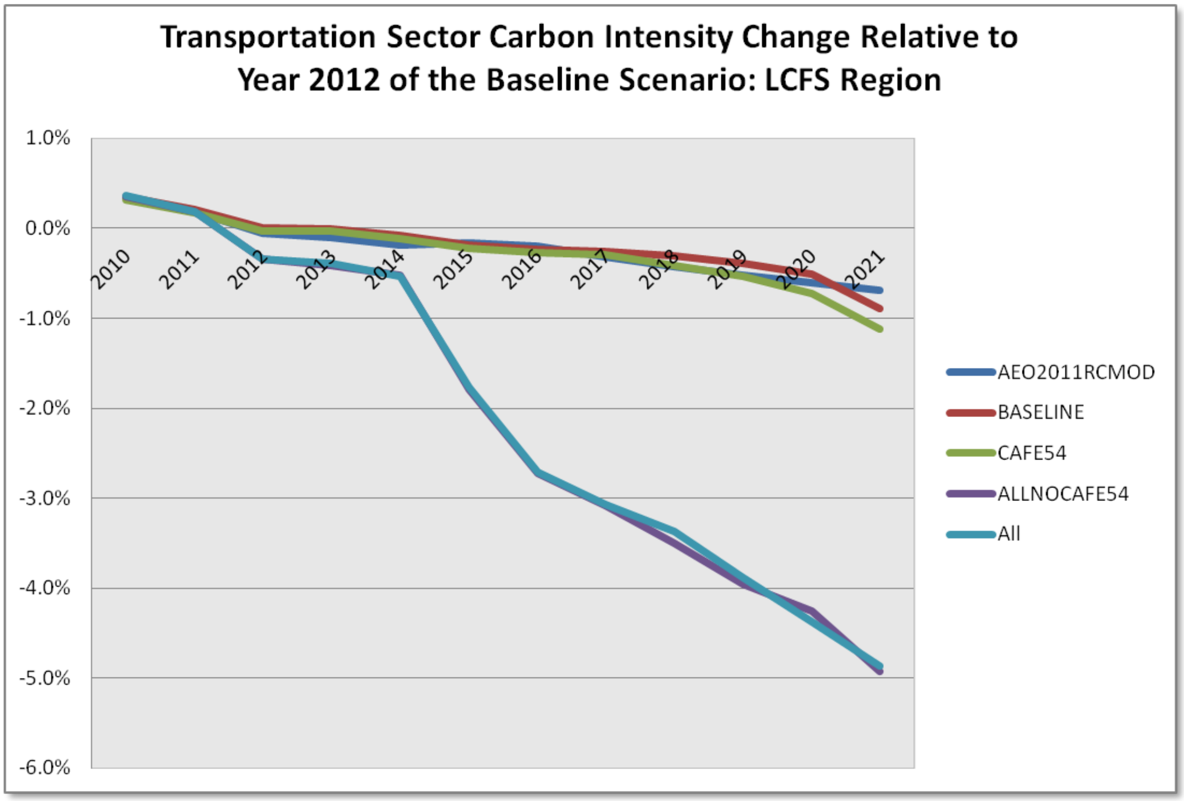
SCENARIO NAME	SCENARIO DESCRIPTION
	• Cellulosic ethanol: $1.01/gallon (2010 dollars); also receives the corn-based ethanol credit • Biodiesel (virgin): $1/gallon (2010 dollars) • Biodiesel (non-virgin): $0.50/gallon (22010 dollars) 4. LCFS optimization code implementation 5. 54.5 mpg CAFE agreement (6%/year increase in average annual mpg for new light duty vehicles, achieving 55 mpg in year 2025)
ALLNOCAFE54HOP	1. ALLNOCAFE54 Scenario Assumptions 2. High Oil Price (HOP) Projection
ALLHOP	1. ALL Scenario Assumptions 2. High Oil Price (HOP) Projection

FIGURE 4-1: TRANSPORTATION SECTOR CARBON INTENSITY VALUE PROJECTIONS FOR THE LCFS REGION: 2012 - 2021



The strong overlap of the ALLNOCAFE54 and ALL scenarios indicates that the 54.5 CAFE standards have little impact through year 2021.

FIGURE 4-2: TRANSPORTATION SECTOR CARBON INTENSITY PRECENTAGE CHANGE PROJECTIONS FOR THE LCFS REGION: 2012 - 2021



The strong overlap of the ALLNOCAFE54 and ALL scenarios indicates that the 54.5 CAFE standards have little impact through year 2021.

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FIGURE 4-3: TRANSPORTATION SECTOR CARBON INTENSITY VALUE PROJECTIONS FOR THE LCFS REGION: 2012 - 2035

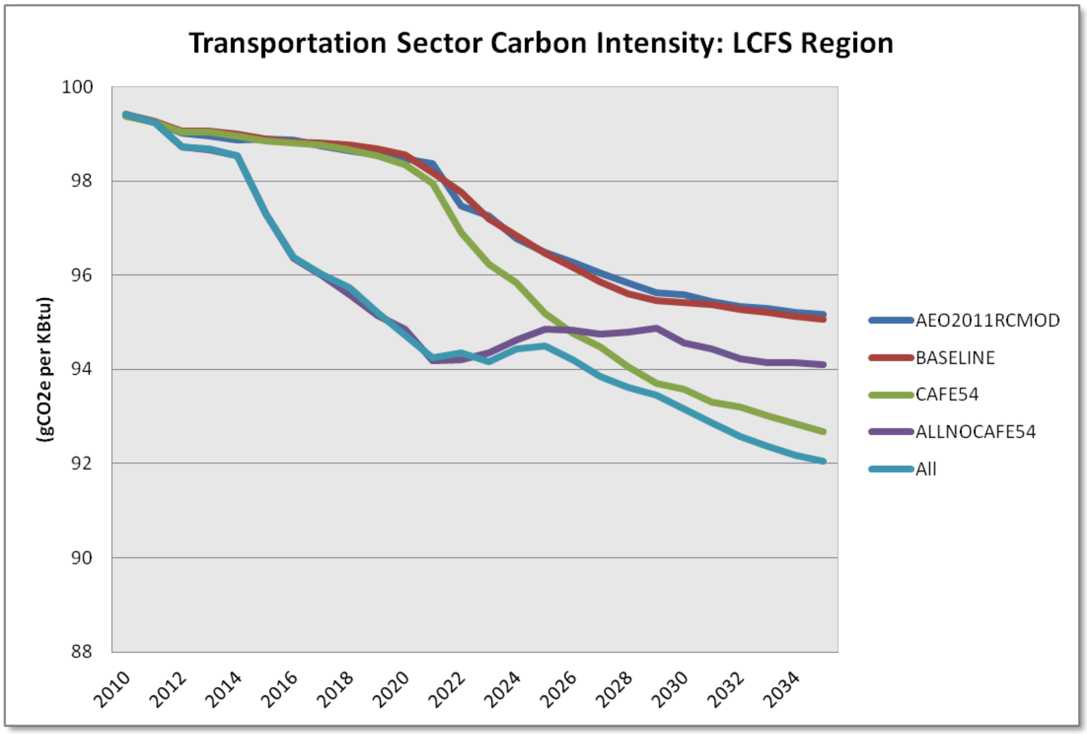
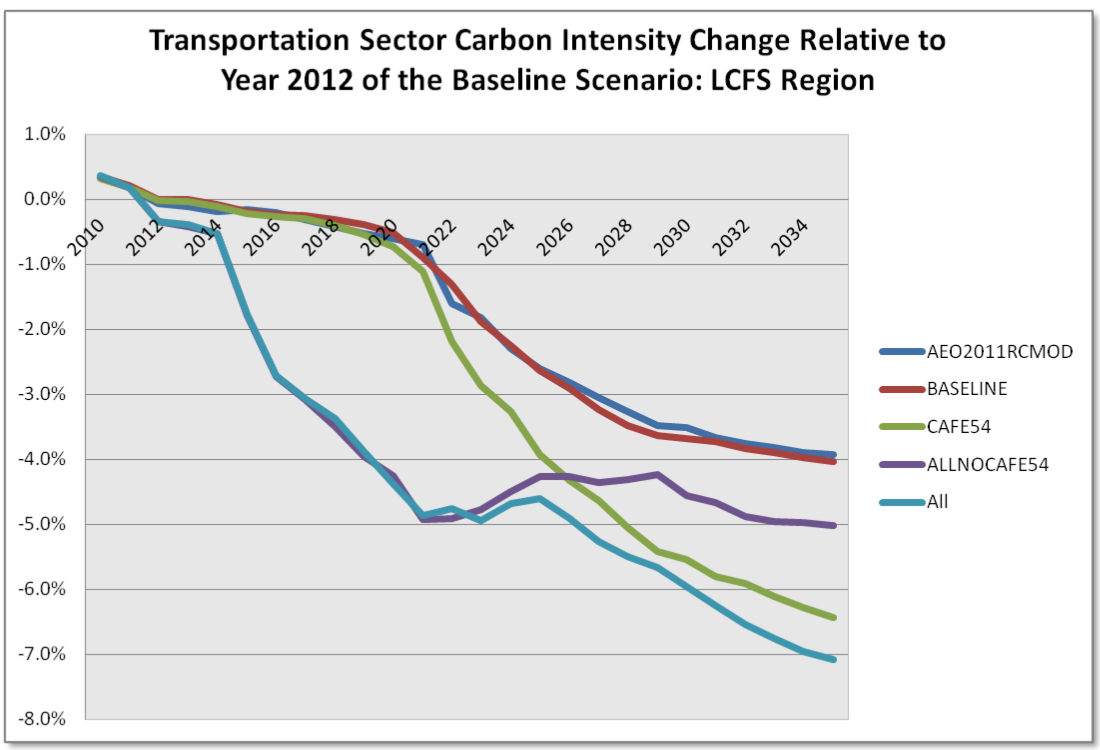


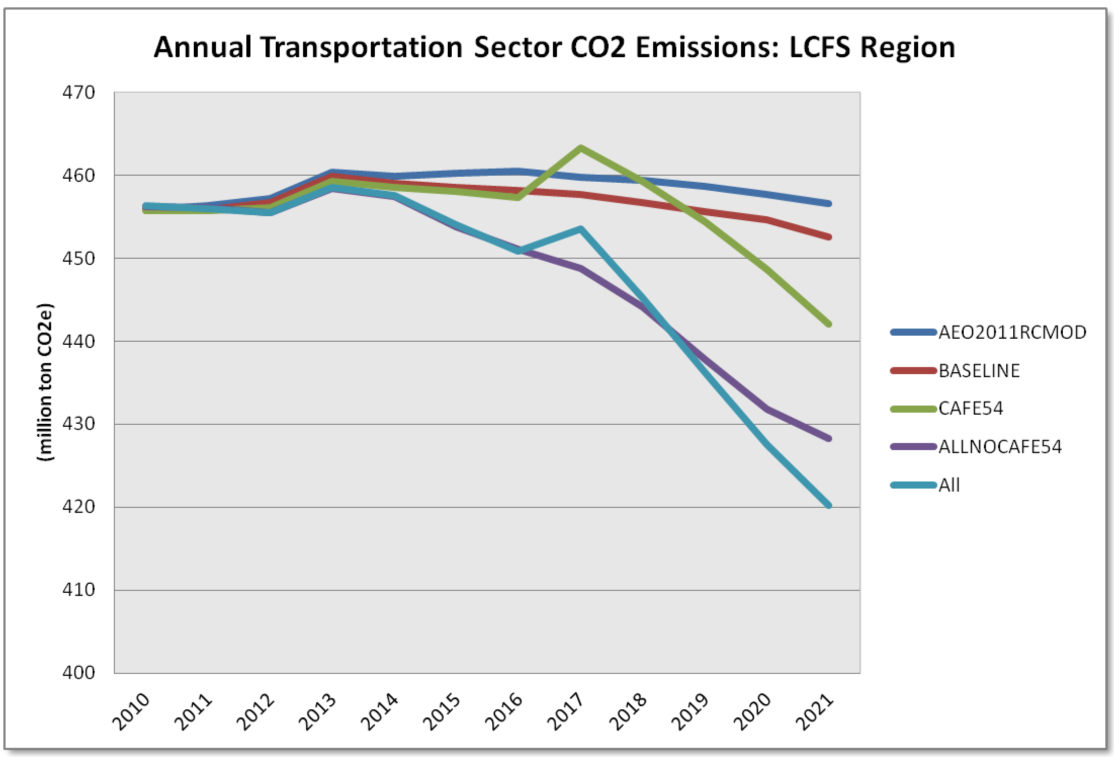
FIGURE 4-4: TRANSPORTATION SECTOR CARBON INTENSITY PRECENTAGE CHANGE PROJECTIONS FOR THE LCFS REGION: 2012 - 2035



4.3 SCENARIO CO_2 AND FUEL CONSUMPTION RESULTS

The remaining technical results, presented in FIGURE 4-5 through FIGURE 4-12 below, show regional transportation sector impacts on CO_2 emissions and fuel consumption. Of high significance is that the CO_2 emissions reduction projection for the 'ALL' scenario approaches 8 percent by 2021 and 18 percent by 2035; and 3 percent and 17 percent, respectively, for the CAFE54 Scenario. Therefore, while the CI metric did not achieve desired reduction levels, greater advanced technology penetration and efficiency improvements spawned by the CAFE's specifications are shown to be a critical complementary component of the ability to achieve substantial carbon emissions reduction. In fact, the CAFE Scenario is projected to effectively achieve a similar annual CO_2 emissions outcome over the long-term to 2035, albeit the cumulative CO_2 emissions reduction is substantially less than that achieved in the ALL Scenario. As shown in FIGURE 4-5 and FIGURE 4-8, the latter yields more rapid reduction, achieving at least twice the level of CO_2 reduction by 2021. The outcome of the ALLNOCAFE54 Scenario indicates the limited impact of the CAFE54 standard over the near-term. FIGURE 4-12, presenting long-term fuel consumption reduction, identifies this as the ultimate driver in achieving significant long-term CO_2 reduction in the transportation sector, being more important than CI reduction alone.

FIGURE 4-5: TRANSPORTATION SECTOR ANNUAL CO_2 EMISSIONS PROJECTIONS FOR THE LCFS REGION: 2012 - 2021[29]



[29] Increase shown in 2016 is consistent with EIA's implementation of the accelerated CAFE standard. It is believed this is has to do with the modifications to the macroeconomic model that fixes total vehicle expenditures rather than total vehicle sales. This would manifest itself in a reduction in new car sales and an effective reduction in stock average mpg during a transitional period.

FIGURE 4-6: TRANSPORTATION SECTOR ANNUAL CO2 EMISSIONS PERCENTAGE CHANGE PROJECTIONS FOR THE LCFS REGION: 2012 - 2021[29]

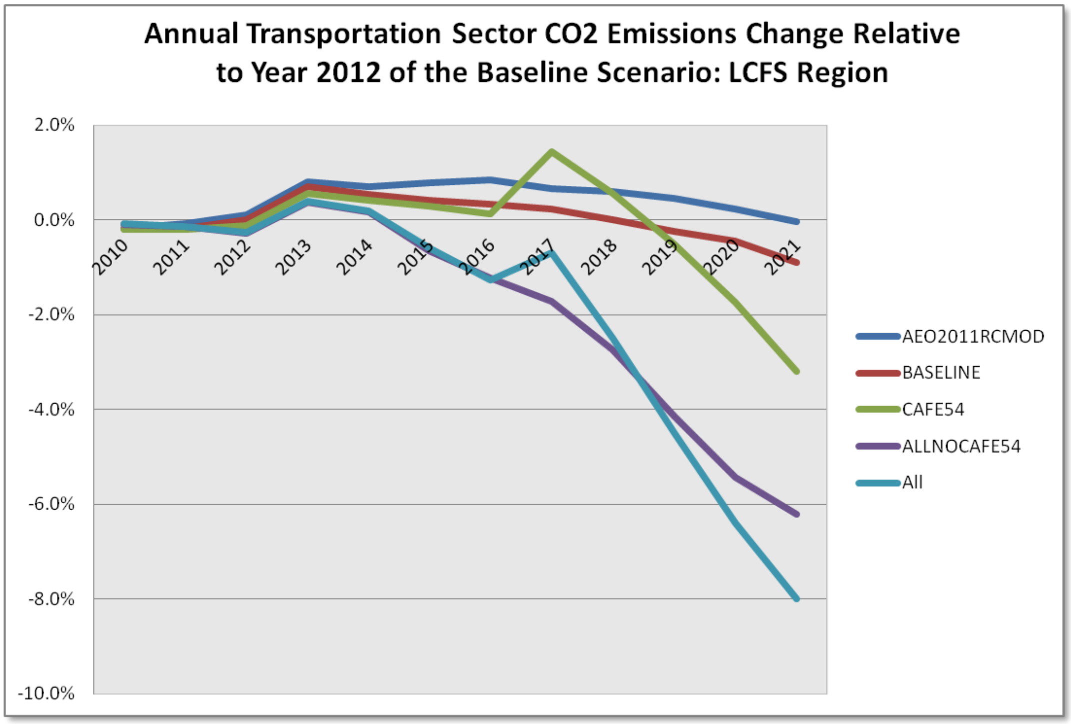


FIGURE 4-7: TRANSPORTATION SECTOR ANNUAL CO_2 EMISSIONS PROJECTIONS FOR THE LCFS REGION: 2012 - 2035

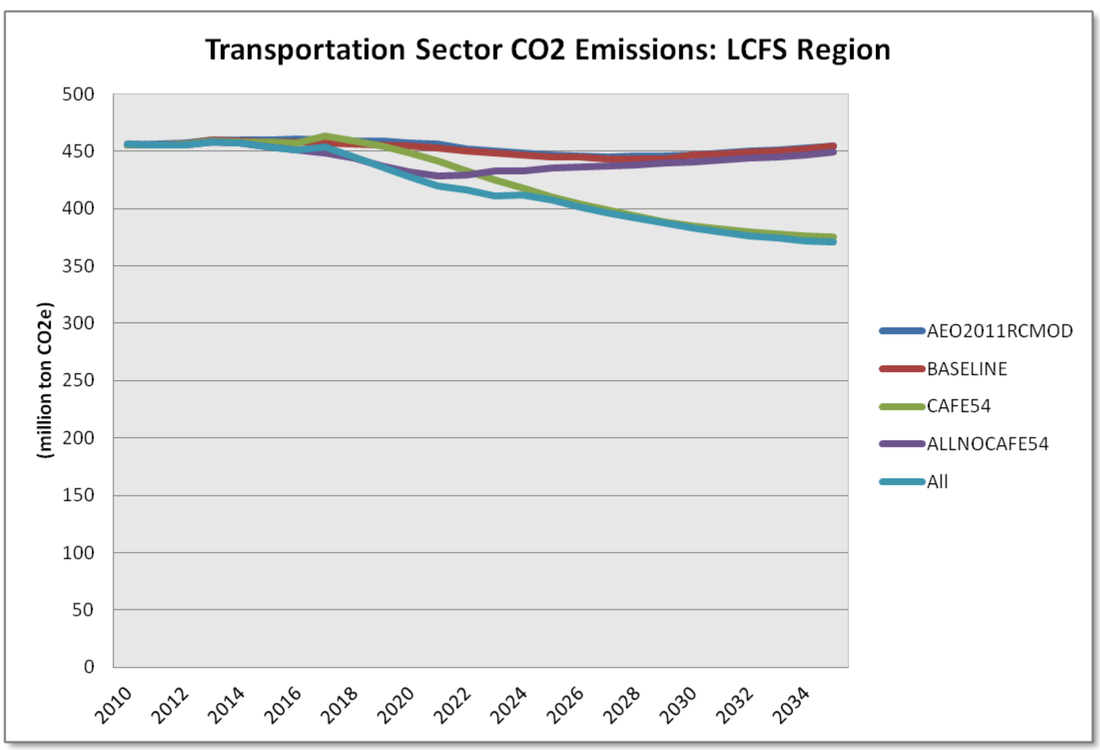


FIGURE 4-8: TRANSPORTATION SECTOR ANNUAL CO2 EMISSIONS PERCENTAGE CHANGE PROJECTIONS FOR THE LCFS REGION: 2012 - 2035

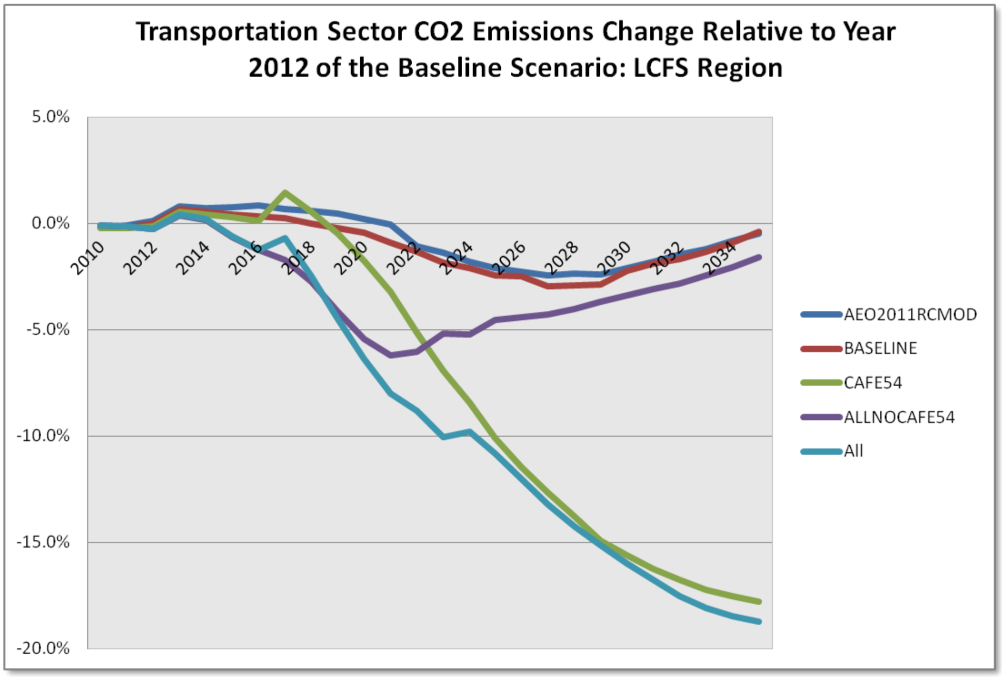
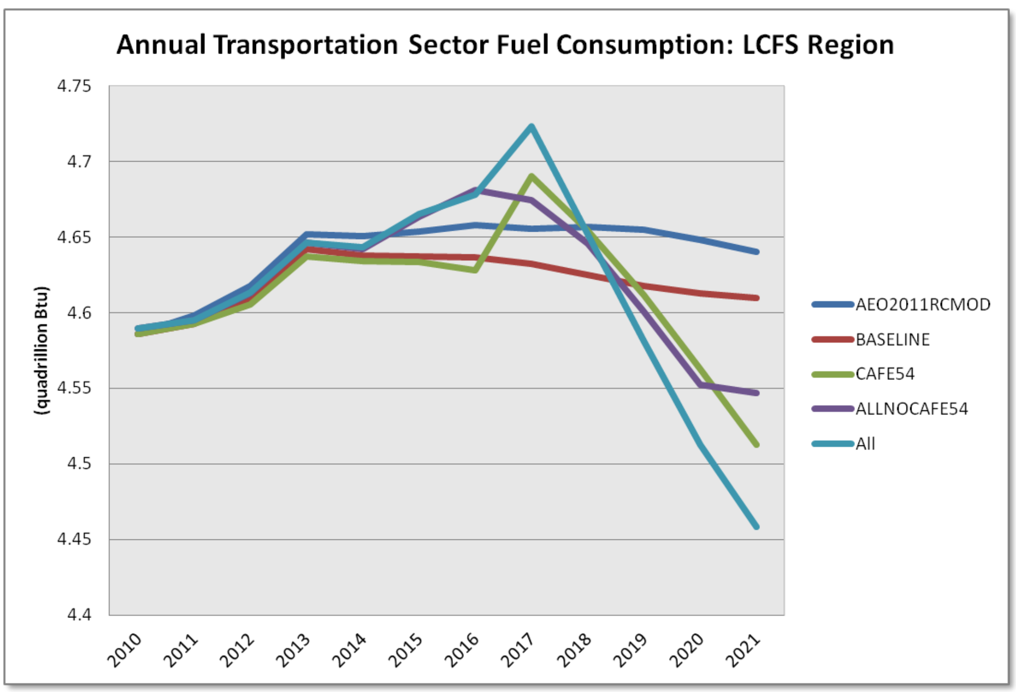


FIGURE 4-9: TRANSPORTATION SECTOR ANNUAL FUEL CONSUMPTION PROJECTIONS FOR THE LCFS REGION: 2012 - 2021[30]



[30] Moderate reduction in fuel consumption is initiated after 2017 is a result of vehicle fuel efficiency improvements resulting from both the LCFS optimization and the CAFE standard, both of which increase the market penetration of advanced vehicles that are more fuel efficient. Note that the model always satisfies the energy demand.

FIGURE 4-10: TRANSPORTATION SECTOR ANNUAL FUEL CONSUMPTION PERCENTAGE CHANGE PROJECTIONS FOR THE LCFS REGION: 2012 - 2021

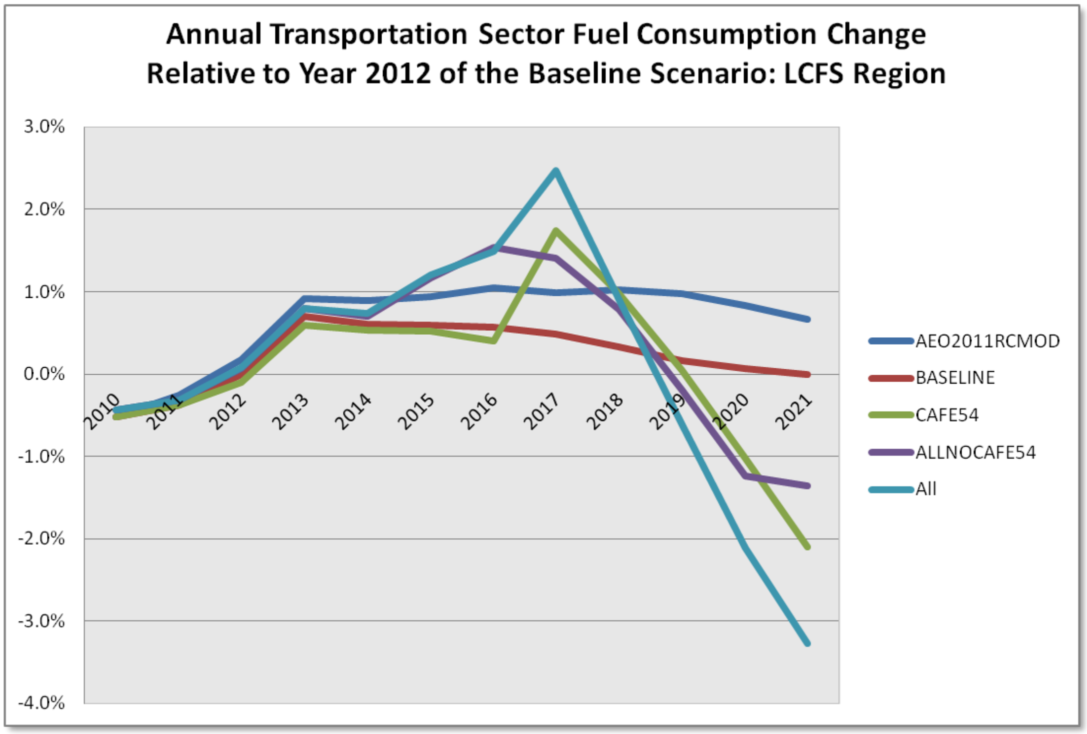


FIGURE 4-11: TRANSPORTATION SECTOR ANNUAL FUEL CONSUMPTION PROJECTIONS FOR THE LCFS REGION: 2012 - 2035

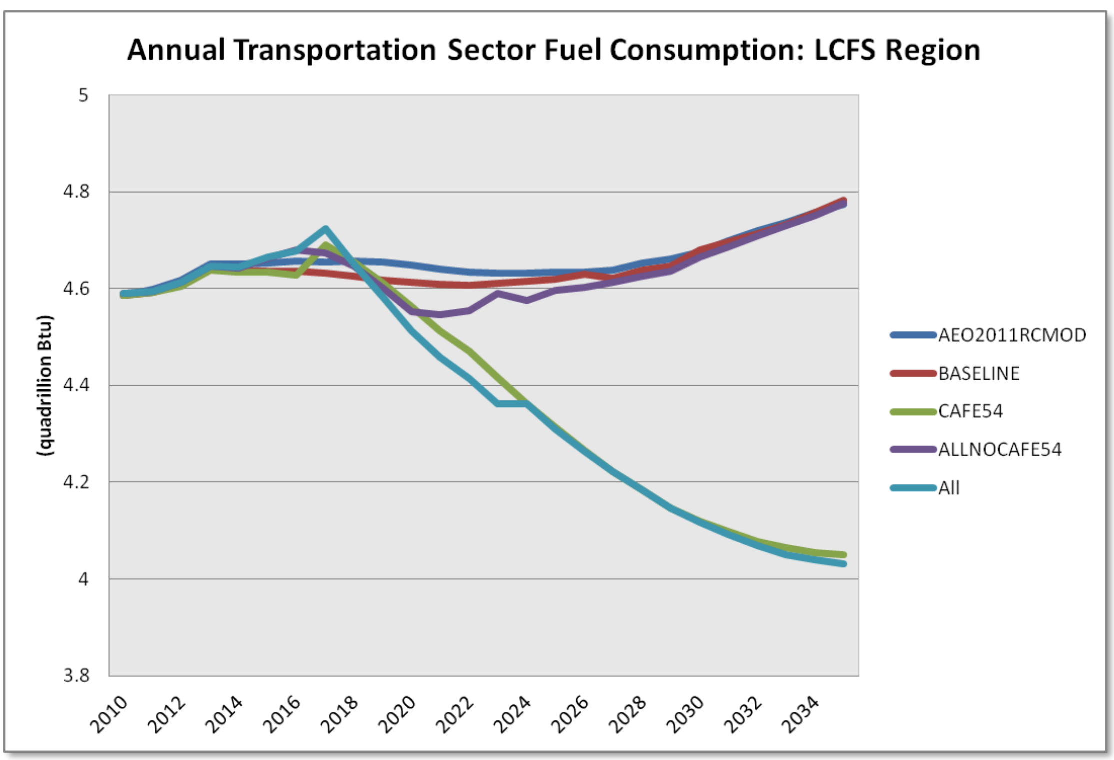
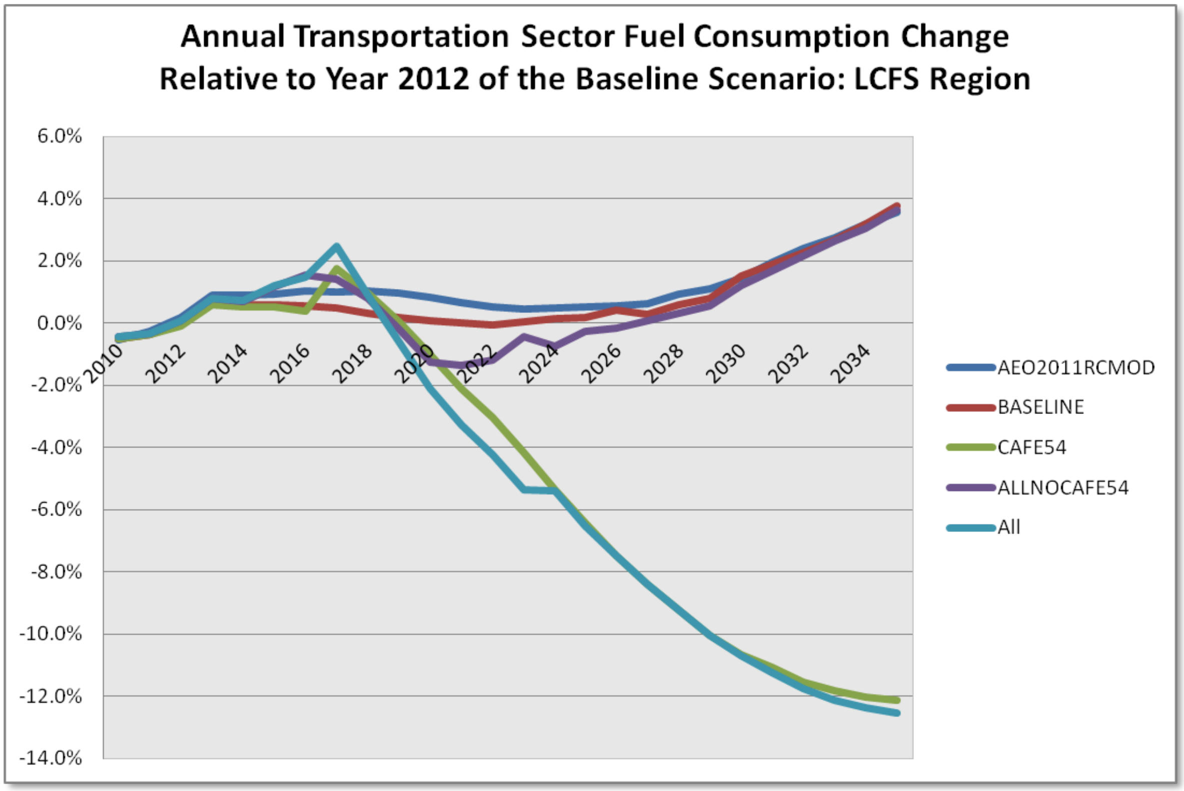


FIGURE 4-12: TRANSPORTATION SECTOR ANNUAL FUEL CONSUMPTION PERCENTAGE CHANGE PROJECTIONS FOR THE LCFS REGION: 2012 - 2035



While FIGURE 4-9 and FIGURE 4-10 highlight the impact of the different scenarios on total transportation energy consumption in the NE/MA LCFS region from 2012 to 2021, the results presented below in FIGURE 4-13 show the impacts on the individual fuels consumed in the region. The results are presented for the ALLNOCAFE54 Scenario.

The largest impact is on gasoline consumption, which is projected to be reduced by 30 percent over the ten year period on an energy content basis. This fuel is replaced by:

- **E85 –** projected increase from close to zero in 2012 to 6.5 percent of total transportation energy consumption in 2021
- **Compressed Natural gas** (for vehicles) – projected increase from 0.3 percent in 2012 to 1.2 percent of total transportation energy consumption in 2021
- **Ethanol** (all types) – projected increase from 4.7 percent in 2012 to 12.6 percent of total transportation energy consumption in 2021
- **Fossil fuel for power generation –** projected increase from 0.52 percent in 2012 to 0.54 percent of total transportation energy consumption in 2021
- **Renewable and Nuclear power generation –** projected increase from 0.5 percent in 2012 to 0.57 percent of total transportation energy consumption in 2021

FIGURE 4-14 and TABLE 4-3 show a modest impact on electricity generation for the transportation sector, with coal-based generation being replaced primarily with natural gas, and to a far lesser extent renewables.

FIGURE 4-13: NE/MA LCFS REGION – TRANSPORTATION FUEL CONSUMPTION BY FUEL TYPE CHART: 2012 - 2021

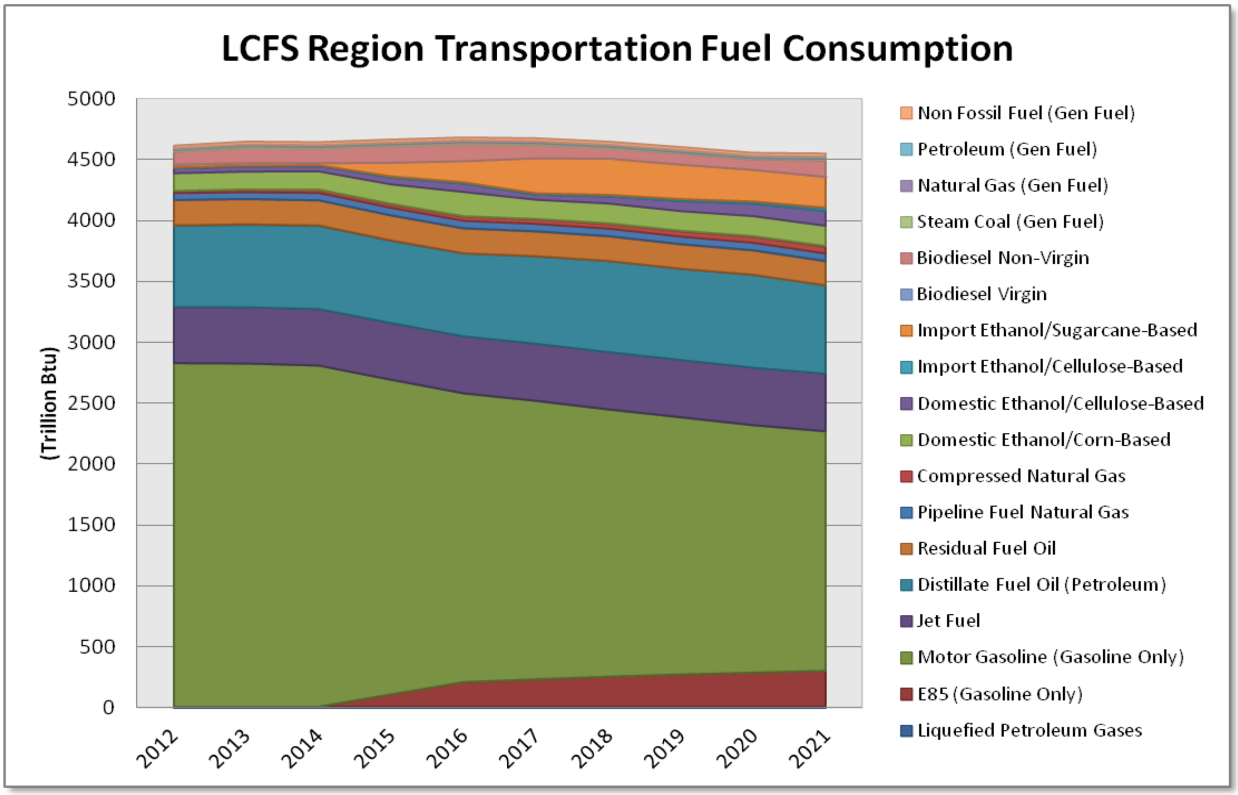


TABLE 4-3: NE/MA LCFS REGION – TRANSPORTATION FUEL CONSUMPTION BY FUEL TYPE TABLE: 2012 - 2021

LCFS Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	2.1	2.2	2.2	2.3	2.4	2.7	2.8	3.0	3.2	3.4
E85 (Gasoline Only)	0.7	0.8	2.5	104.2	204.7	227.5	248.8	267.4	281.7	295.9
Motor Gasoline (Gasoline Only)	2,826.0	2,822.3	2,803.6	2,585.2	2,372.9	2,287.4	2,195.7	2,111.7	2,032.4	1,967.2
Jet Fuel	464.5	465.1	467.3	469.4	471.3	473.5	475.0	475.9	476.9	478.4
Distillate Fuel Oil (Petroleum)	666.5	678.2	683.5	675.7	681.0	717.2	747.7	747.9	762.8	725.3
Residual Fuel Oil	205.6	204.8	203.8	202.9	201.8	200.8	199.7	198.5	197.3	196.3
Pipeline Fuel Natural Gas	58.6	58.8	62.5	63.9	63.8	64.0	64.3	64.6	64.6	64.9
Compressed Natural Gas	15.4	20.4	25.6	30.1	33.8	36.6	39.4	43.4	49.1	55.2
Domestic Ethanol/Corn-Based	152.6	153.5	157.1	167.2	206.5	164.4	170.0	168.5	171.0	172.9
Domestic Ethanol/Cellulose-Based	40.4	40.8	42.4	55.9	68.9	42.4	58.4	82.6	101.7	123.6
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	3.0	4.1	5.3	7.4	11.3	14.2	21.3
Import Ethanol/Sugarcane-Based	24.4	23.0	19.4	115.0	177.4	290.3	300.7	284.8	261.8	255.2
Biodiesel Non-Virgin	3.5	2.8	1.7	1.7	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	105.7	125.9	124.0	139.7	143.0	113.2	87.3	92.2	87.0	136.9
Steam Coal (Gen Fuel)	13.5	14.1	9.6	9.2	10.1	10.2	10.3	10.6	11.1	11.8
Natural Gas (Gen Fuel)	9.4	9.1	11.4	12.0	12.1	12.0	11.8	11.7	11.5	11.6
Petroleum (Gen Fuel)	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Non Fossil Fuel (Gen Fuel)	22.9	23.6	24.5	25.3	25.8	25.8	25.7	25.8	25.4	26.1
Total	4,613.0	4,646.3	4,642.1	4,663.5	4,680.9	4,674.4	4,645.9	4,600.8	4,552.6	4,547.1

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. Advanced biofuels are defined to be any renewable fuel, other than ethanol derived from corn starch that has lifecycle greenhouse gas emissions that are at least

50% less than baseline lifecycle greenhouse gas emissions. Cellulosic biofuel is defined as a renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions that are at least 60% less than the baseline lifecycle greenhouse gas emissions.

FIGURE 4-14: NE/MA LCFS REGION ELECTRICITY GENERATION PROJECTION BY FUEL TYPE: 2012 - 2021

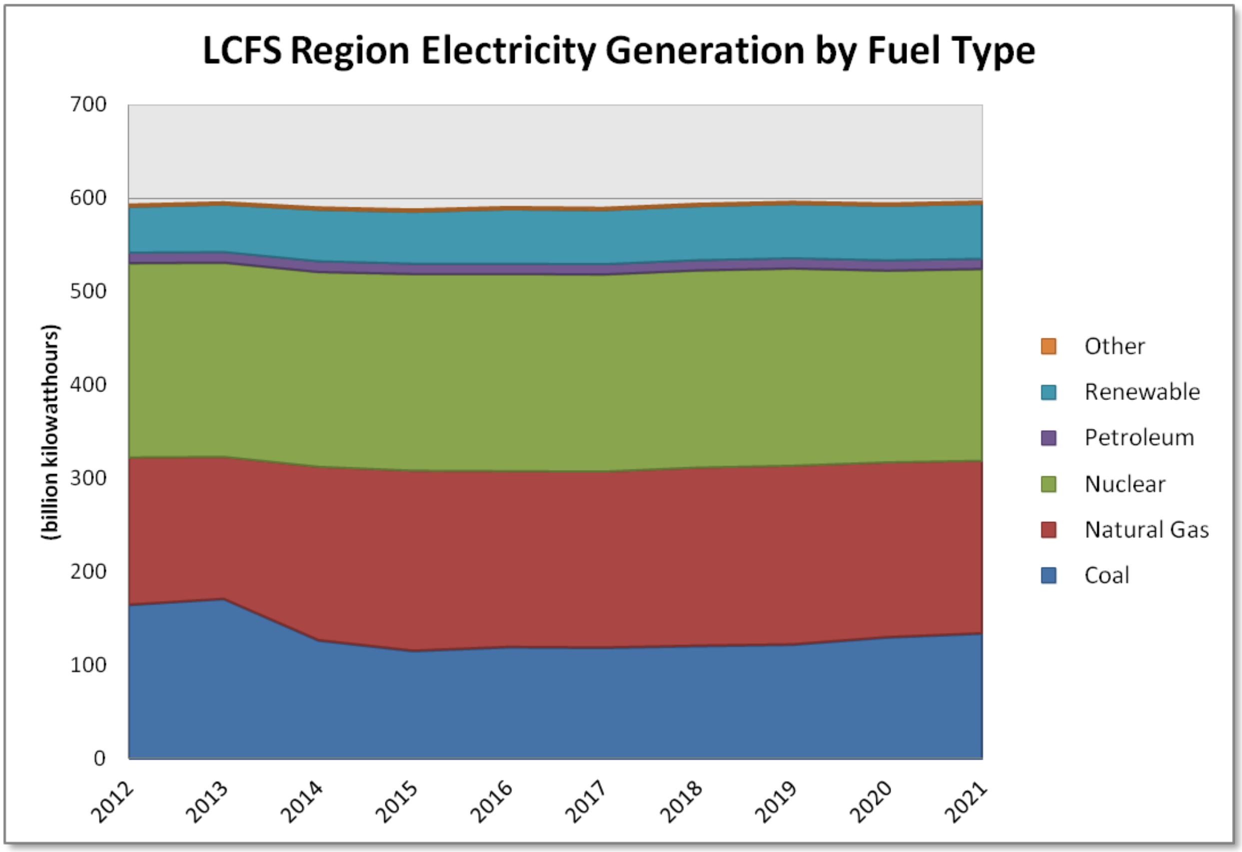


TABLE 4-4: NE/MA LCFS REGION ELECTRICITY GENERATION PROJECTION BY FUEL TYPE: 2012 - 2021

LCFS Region Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	164.46	170.79	126.38	115.02	119.11	118.46	120.38	121.87	129.62	133.73
Natural Gas	158.30	152.61	186.37	193.52	189.02	189.07	191.50	192.06	187.89	185.46
Nuclear	207.57	207.57	208.31	210.42	210.85	210.85	210.85	210.85	205.03	205.03
Petroleum	11.27	11.30	11.28	10.73	10.75	10.75	10.78	10.79	10.80	10.81
Renewable	49.42	51.21	55.49	55.90	58.60	58.22	58.30	58.53	58.85	59.28
Other	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.52
Total	**593.53**	**595.98**	**590.34**	**588.09**	**590.85**	**589.87**	**594.33**	**596.61**	**594.70**	**596.83**

4.4 LCFS REGION ECONOMIC IMPACTS ANALYSIS – BASELINE OIL PRICE

This section presents economic impact results covering the 11-state NE/MA LCFS region as a whole, although some state-by-state results are also included. Results are shown only for the 'ALL' scenario in FIGURE 4-15 through FIGURE 4-20 and TABLE 4-5 through TABLE 4-10 for the following metrics:

- Real Gross Domestic Product (GDP)
- Disposable Personal Income (DPI)
- Value of (Industrial) Shipments (VOS)
- Employment
- Transportation fuel prices
- Incremental Fuel Expenditure
- Implied Alternative Vehicle Subsidies
- Incremental Infrastructure Cost

4.4.1 GDP, DPI, VOS, Employment, and Incremental Fuel Expenditure

In general, the model initially projects positive outcomes for these metrics: GDP, DPI. This occurs because some of the changes modeled, such as the reduction in AFV costs and fuel subsidies, are essentially "free" because this effort did not account for their overall cost to society; this can be done in the model by adjusting income tax revenue and/or government expenditures, but was not undertaken due to added complexity. *Realistically, such these subsidy costs will have to come out of state budgets, which will ultimately impact taxpayers and reduce disposable income even further than indicated by the scenario modeling outcomes.*

However, the LCFS Optimization Methodology imparts fuel price penalties on excess CO_2 emissions, which eventually overwhelms the "free changes" and yields significant negative impacts on GDP, DPI, VOS, and employment. This is clearly identified via the calculation of the 'incremental fuel expenditure' required in the region to achieve the CI reduction. The changes in fuel prices in each state is shown in TABLE 4-9[31] and the incremental fuel expenditures is represented in FIGURE 4-19 and TABLE 4-10 for the LCFS region as a whole and for each state. ***The results indicate that a cumulative regional incremental amount of $206 billion (2009 nominal dollars) is spent on transportation fuels.***

4.4.2 Calculation of Implied Alternative Vehicle Subsidies for LCFS Region

As identified earlier in this section, the 'ALLNOCAFE' and 'ALL' scenarios include the reduction of incremental costs for alternative fuel vehicles. This cost reduction is considered a subsidy and must be explicitly recognized, although the model currently does not do so. Therefore we have performed an off-line calculation to estimate the value of the subsidy on a regional basis. The results of these calculations are presented in this section.

[31] As pointed out in the report, motor gasoline, E85, and natural gas fuel prices were penalized because their CI annual constraints were not satisfied. Other fuel costs represented in the table were not penalized, since the CI constraint was uniquely satisfied for them based on significantly lower consumption levels.

Because of differences in methodology and data input between the BASELINE and the High CAFE scenarios, it is appropriate to estimate subsidy costs under an accelerated CAFE growth assumption by reference to a comparable baseline, the CAFE54 Scenario.

The BASELINE Scenario is the scenario against which incremental costs and subsidies of the ALLNOCAFE scenario is measured. The scenario called CAFE54 is the scenario against which the ALL scenario is compared in order to eliminate any distortion caused by the implementation of the accelerated CAFE standard.

The following steps are taken to calculate the implied vehicle subsidies:

- Regional estimates of Light-Duty Vehicle (LDV) sales by technology type are taken from CEA-NEMS Table 48.
- National estimates of new LDV prices by size class and technology type come from CEA-NEMS Table 114.
- The price premium for each vehicle technology and size class is calculated by subtracting the price of a gasoline vehicle from the price of the corresponding alternative fuel vehicle (AFV) for each year.
- The incremental cost of each vehicle technology is determined as the average price premium across available vehicle size classes within a given technology. It is assumed that there are no regional differences in costs.
- The implied subsidy for each vehicle is the difference between the baseline incremental costs and those of the other scenarios.
- The total cost of the subsidy is calculated by multiplying the per-vehicle subsidy by the sales of corresponding vehicles in each region.
- Sales of vehicles in the South Atlantic census division (CD5) are adjusted to reflect the share of regional sales represented by the states of Maryland and Delaware. This share is approximately 12 percent of vehicle sales in CD5, based on historical data.

Results of these comparisons are provided in FIGURE 4-21 to FIGURE 4-26.

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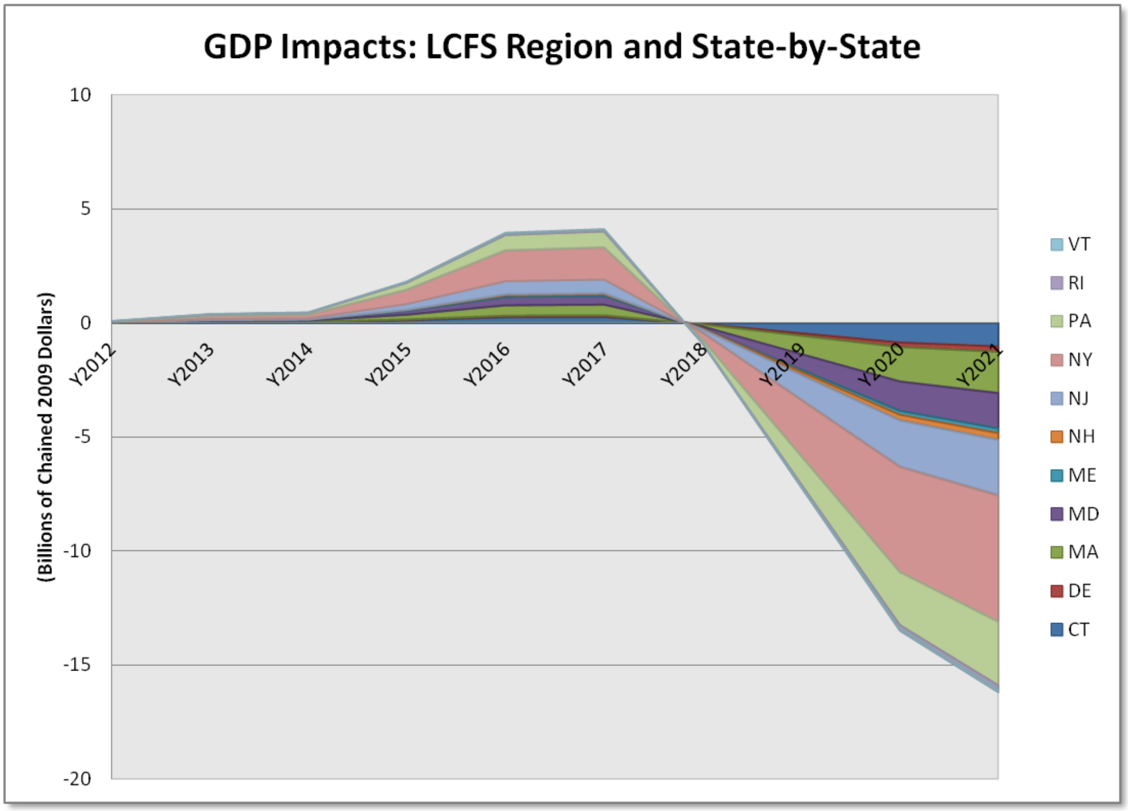
FIGURE 4-15: GDP IMPACTS - LCFS REGION AND STATE-BY-STATE: 2012 - 2021[1,2]



1. Based on the comparison between the ALLNOCAFE54 and BASELINE scenarios
2. Initial positive GDP impact occurs because some of the changes modeled, such as the reduction in AFV costs and fuel subsidies, are essentially "free" because this effort could not account for their overall cost to society in the model. However, the LCFS Optimization Methodology imparts fuel price penalties based on excess CO_2 emissions, which eventually overwhelms the "free impacts" and yields significant negative impacts on the region's GDP. See 4.4.1.

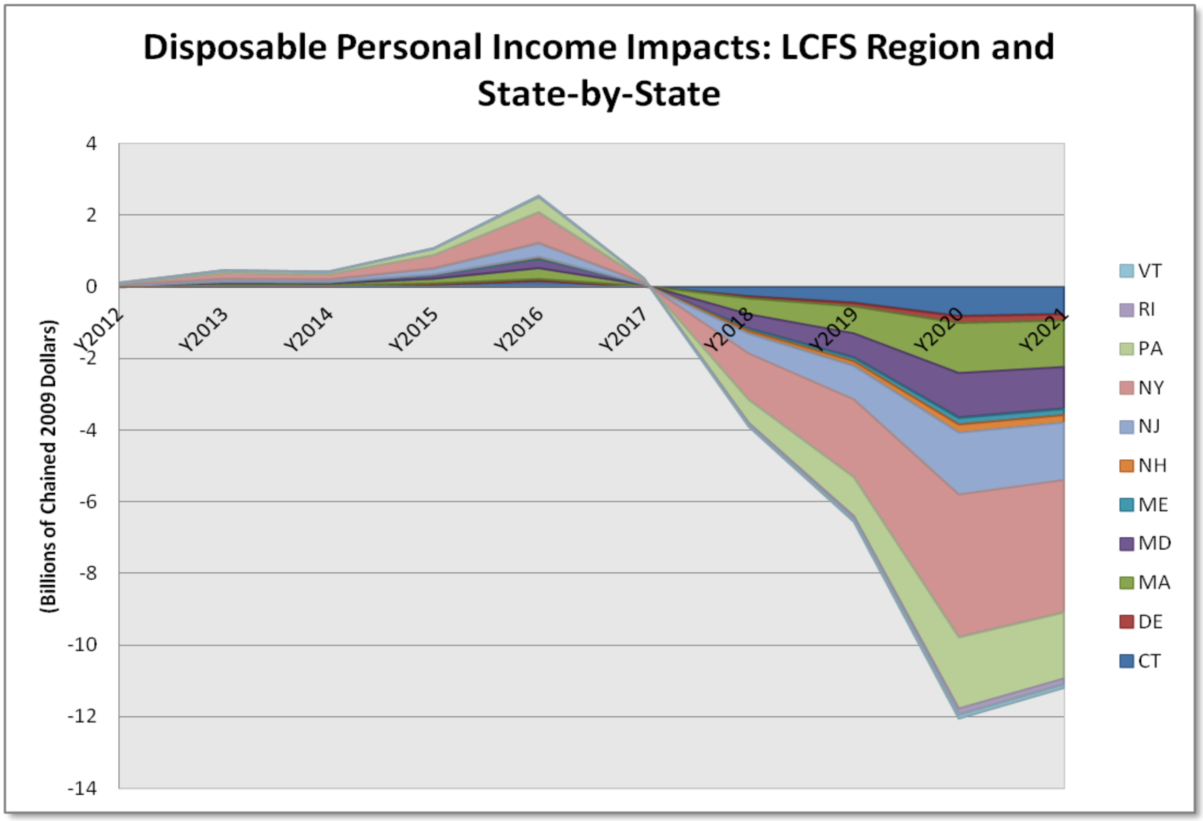
TABLE 4-5: GDP IMPACTS TABLE - LCFS REGION AND STATE-BY-STATE (BILLIONS OF CHAINED 2009 DOLLARS)

GDP IMPACTS TABLE - LCFS REGION AND STATE-BY-STATE

(Billions of 2009 Dollars)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.01	0.03	0.03	0.12	0.26	0.27	-0.06	-0.47	-0.87	-1.05	-1.74
DE	0.00	0.01	0.01	0.03	0.06	0.06	-0.01	-0.11	-0.20	-0.24	-0.40
MA	0.01	0.04	0.05	0.20	0.44	0.46	-0.10	-0.81	-1.50	-1.80	-3.00
MD	0.01	0.04	0.04	0.17	0.37	0.38	-0.08	-0.68	-1.28	-1.54	-2.58
ME	0.00	0.01	0.01	0.03	0.06	0.06	-0.01	-0.10	-0.19	-0.23	-0.38
NH	0.00	0.01	0.01	0.03	0.07	0.08	-0.02	-0.13	-0.25	-0.29	-0.49
NJ	0.01	0.06	0.07	0.27	0.59	0.61	-0.13	-1.08	-2.02	-2.42	-4.04
NY	0.03	0.13	0.16	0.62	1.35	1.40	-0.31	-2.46	-4.61	-5.53	-9.23
PA	0.01	0.07	0.08	0.31	0.68	0.71	-0.15	-1.24	-2.32	-2.78	-4.64
RI	0.00	0.01	0.01	0.02	0.05	0.05	-0.01	-0.09	-0.18	-0.21	-0.35
VT	0.00	0.00	0.00	0.01	0.03	0.03	-0.01	-0.05	-0.10	-0.12	-0.20
Grand Total	**0.08**	**0.39**	**0.46**	**1.82**	**3.95**	**4.11**	**-0.90**	**-7.22**	**-13.52**	**-16.22**	**-27.05**

FIGURE 4-16: DISPOSABLE PERSONAL INCOME - LCFS REGION AND STATE-BY-STATE: 2012 - 2021[1,2]



1. Based on the comparison between the ALLNOCAFE54 and BASELINE scenarios
2. Initial positive DPI impact occurs because some of the changes modeled, such as the reduction in AFV costs and fuel subsidies, are essentially "free" because this effort could not account for their overall cost to society in the model. However, the LCFS Optimization Methodology imparts fuel price penalties based on excess CO_2 emissions, which eventually greatly overwhelms the "free impacts" and yields significant negative impacts on the region's DPI. See 4.4.1.

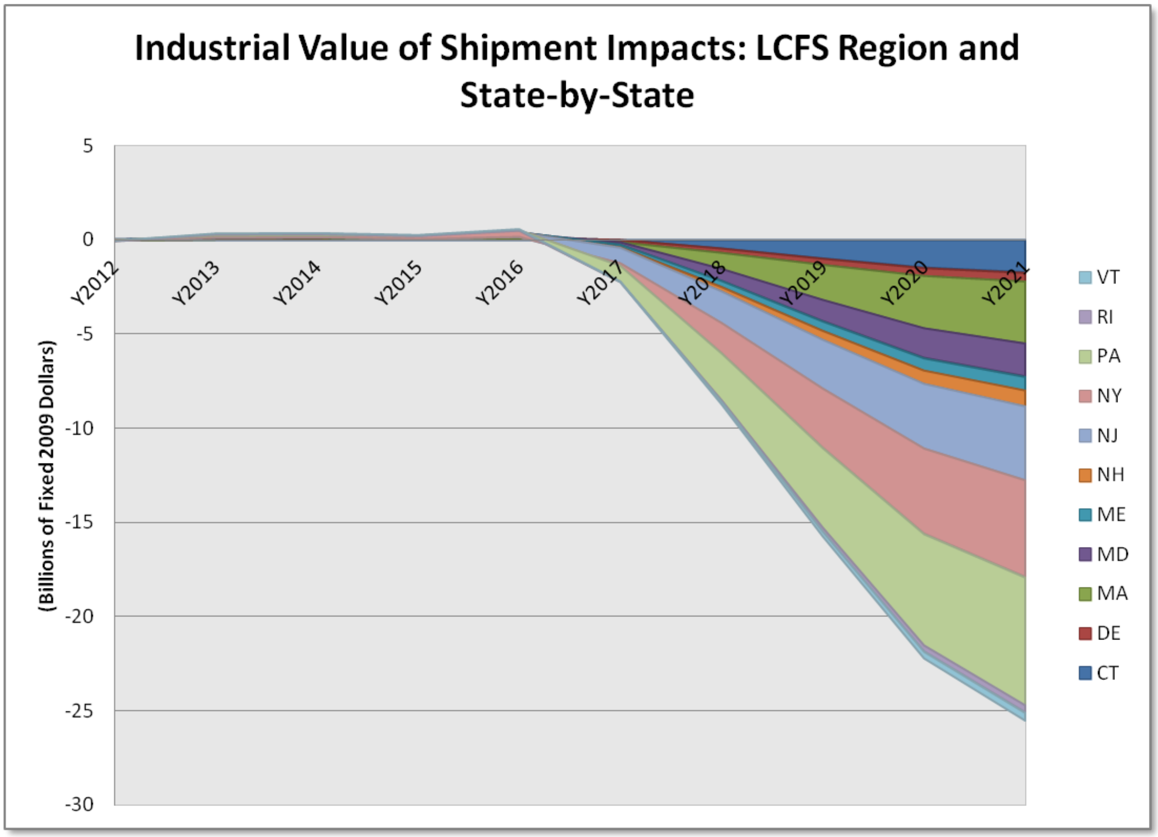
TABLE 4-6: DISPOSABLE PERSONAL INCOME – LCFS REGION AND STATE-BY-STATE (BILLIONS OF CHAINED 2009 DOLLARS[1])

DISPOSABLE PERSONAL INCOME – LCFS REGION AND STATE-BY-STATE
(Billions of 2009 Dollars)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.01	0.03	0.03	0.07	0.17	0.02	-0.26	-0.45	-0.82	-0.76	-1.96
DE	0.00	0.01	0.01	0.02	0.04	0.00	-0.06	-0.10	-0.19	-0.18	-0.46
MA	0.01	0.05	0.05	0.13	0.30	0.03	-0.46	-0.77	-1.41	-1.31	-3.38
MD	0.01	0.04	0.04	0.11	0.25	0.02	-0.39	-0.67	-1.23	-1.15	-2.97
ME	0.00	0.01	0.01	0.02	0.04	0.00	-0.06	-0.10	-0.18	-0.17	-0.43
NH	0.00	0.01	0.01	0.02	0.05	0.00	-0.07	-0.13	-0.23	-0.21	-0.55
NJ	0.02	0.07	0.06	0.16	0.37	0.03	-0.56	-0.95	-1.74	-1.61	-4.16
NY	0.04	0.15	0.14	0.36	0.85	0.08	-1.29	-2.16	-3.97	-3.68	-9.50
PA	0.02	0.08	0.07	0.18	0.43	0.04	-0.65	-1.09	-2.00	-1.85	-4.78
RI	0.00	0.01	0.01	0.01	0.03	0.00	-0.05	-0.09	-0.17	-0.15	-0.40
VT	0.00	0.00	0.00	0.01	0.02	0.00	-0.03	-0.05	-0.10	-0.09	-0.23
Grand Total	**0.11**	**0.46**	**0.42**	**1.08**	**2.55**	**0.24**	**-3.89**	**-6.55**	**-12.04**	**-11.18**	**-28.81**

1 See the link for definition of chained dollars: http://www.eia.gov/emeu/consumptionbriefs/recs/natgas/chained.html

FIGURE 4-17: VALUE OF SHIPMENTS - LCFS REGION AND STATE-BY-STATE: 2012 - 2021[1,2]



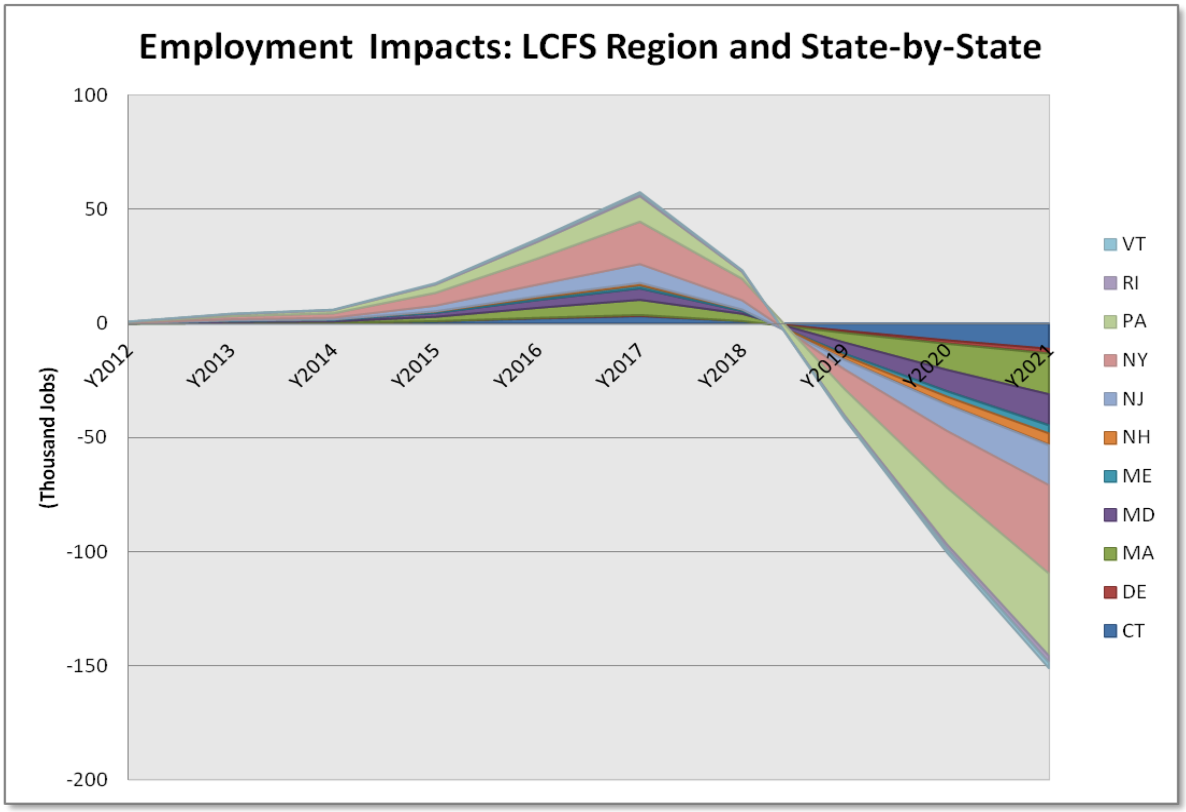
1. Based on the comparison between the ALLNOCAFE54 and BASELINE scenarios
2. Initial slightly positive VoS impact occurs because some of the changes modeled, such as the reduction in AFV costs and fuel subsidies, are essentially "free" because this effort could not account for their overall cost to society in the model. However, the LCFS Optimization Methodology imparts fuel price penalties based on excess CO_2 emissions, which eventually greatly overwhelms the "free impacts" and yields significant negative impacts on the region's VoS. See 4.4.1.

TABLE 4-7: VALUE OF SHIPMENTS - LCFS REGION AND STATE-BY-STATE: 2012 - 2021

INDUSTRIAL VALUE OF SHIPMENT IMPACTS - LCFS REGION AND STATE-BY-STATE
(Billions of 2009 Dollars)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.00	0.03	0.03	0.06	0.13	0.00	-0.45	-0.99	-1.49	-1.74	-4.42
DE	-0.01	0.00	0.00	-0.02	-0.04	-0.12	-0.22	-0.33	-0.42	-0.46	-1.61
MA	0.01	0.04	0.05	0.11	0.21	-0.03	-0.88	-1.89	-2.80	-3.32	-8.50
MD	0.00	0.03	0.03	0.04	0.08	-0.13	-0.63	-1.12	-1.57	-1.74	-5.01
ME	-0.01	0.01	0.00	-0.01	-0.02	-0.12	-0.31	-0.50	-0.66	-0.74	-2.35
NH	0.00	0.01	0.01	0.02	0.04	-0.02	-0.23	-0.49	-0.72	-0.86	-2.23
NJ	-0.05	0.02	0.01	-0.16	-0.25	-0.83	-1.69	-2.60	-3.44	-3.93	-12.92
NY	0.02	0.08	0.10	0.18	0.35	-0.14	-1.60	-3.13	-4.51	-5.12	-13.79
PA	-0.04	0.08	0.08	-0.01	0.00	-0.84	-2.49	-4.23	-5.92	-6.81	-20.18
RI	0.00	0.01	0.01	0.01	0.03	0.00	-0.09	-0.21	-0.31	-0.37	-0.93
VT	0.00	0.00	0.01	0.01	0.01	-0.03	-0.13	-0.25	-0.35	-0.41	-1.15
Grand Total	**-0.07**	**0.31**	**0.33**	**0.23**	**0.54**	**-2.26**	**-8.74**	**-15.74**	**-22.20**	**-25.50**	**-73.10**

FIGURE 4-18: EMPLOYMENT IMPACTS - LCFS REGION AND STATE-BY-STATE: 2012 - 2021[1,2]



1. Based on the comparison between the ALLNOCAFE54 and BASELINE scenarios
2. Initial slightly positive employment impact occurs because some of the changes modeled, such as the reduction in AFV costs and fuel subsidies, are essentially "free" because this effort could not account for their overall cost to society in the model. However, the LCFS Optimization Methodology imparts fuel price penalties based on excess CO_2 emissions, which eventually overwhelms the "free impacts" and yields overall negative impacts on the region's employment. See 4.4.1.

TABLE 4-8: EMPLOYMENT IMPACTS - LCFS REGION AND STATE-BY-STATE: 2012 - 2021

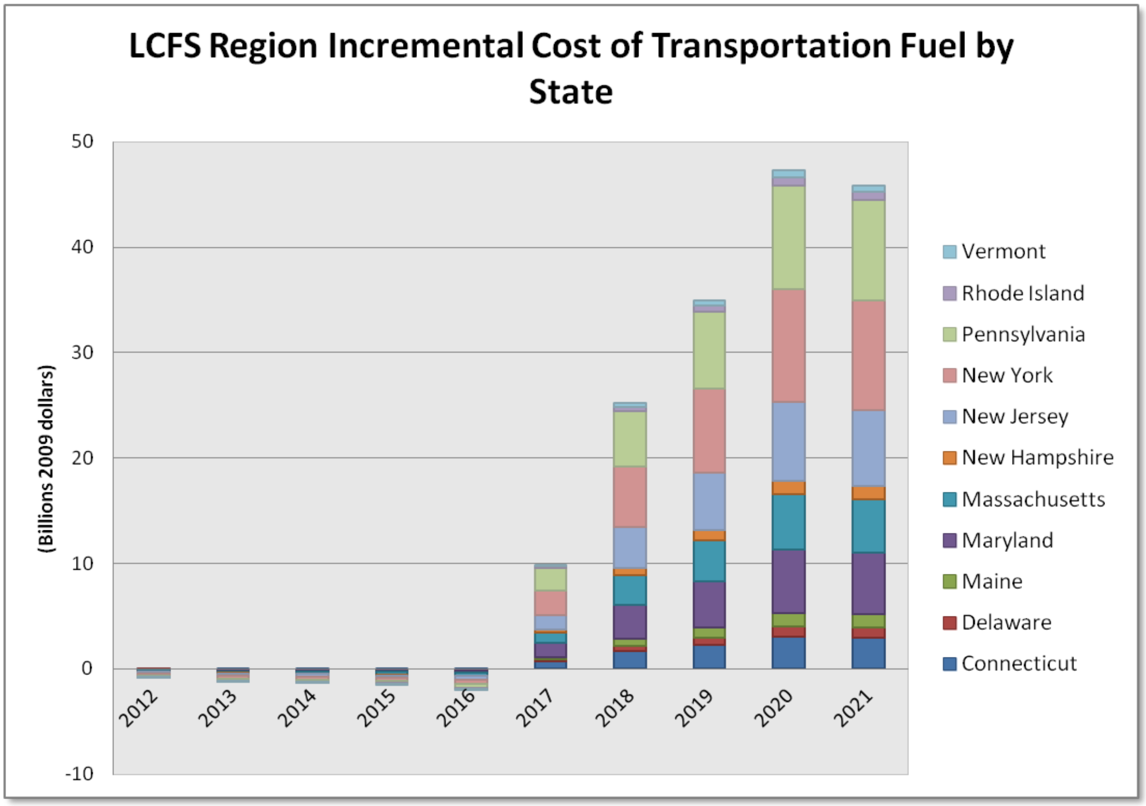
EMPLOYMENT IMPACTS - LCFS REGION AND STATE-BY-STATE

(Thousand Jobs)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.03	0.25	0.33	0.93	2.17	3.18	1.05	-3.26	-7.40	-11.09	-13.83
DE	0.01	0.06	0.08	0.24	0.49	0.73	0.17	-0.71	-1.34	-1.95	-2.23
MA	0.09	0.48	0.64	1.93	4.38	6.64	3.19	-4.23	-11.44	-17.86	-16.19
MD	0.09	0.44	0.56	1.67	3.35	4.94	1.14	-4.91	-9.31	-13.52	-15.55
ME	0.02	0.09	0.13	0.35	0.82	1.22	0.47	-1.09	-2.63	-3.90	-4.52
NH	0.01	0.10	0.14	0.37	0.85	1.20	0.24	-1.58	-3.33	-4.87	-6.86
NJ	0.12	0.54	0.81	2.47	5.13	8.29	4.02	-4.24	-11.51	-17.66	-12.04
NY	0.26	1.26	1.83	5.54	11.38	18.52	9.36	-8.74	-24.92	-38.86	-24.39
PA	0.11	0.87	1.32	3.58	7.31	11.14	3.03	-11.60	-24.96	-36.12	-45.31
RI	0.01	0.07	0.09	0.27	0.61	0.90	0.38	-0.71	-1.75	-2.68	-2.82
VT	0.01	0.05	0.07	0.19	0.43	0.62	0.17	-0.72	-1.58	-2.31	-3.08
LCFS Region	**0.76**	**4.21**	**5.98**	**17.53**	**36.91**	**57.37**	**23.22**	**-41.79**	**-100.17**	**-150.82**	**-146.81**

TABLE 4-9: **OVERVIEW OF STATE TRANSPORTATION FUEL PRICE BY SCENARIO AND STATE (2009 DOLLARS PER MILLION BTU)**

FIGURE 4-19: INCREMENTAL FUEL EXPENDITURE CHART- LCFS REGION AND STATE-BY-STATE: 2012 - 2021[1]



1. Based on the comparison between the ALLNOCAFE54 and BASELINE scenarios
2. Includes LCFS Optimization Methodology fuel penalties.

TABLE 4-10: INCREMENTAL FUEL EXPENDITURE TABLE - LCFS REGION AND STATE-BY-STATE: 2012 - 2021

LCFS Region Incremental Cost of Transportation Fuel by State

(Billions 2009 dollars)

State	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Connecticut	-0.040	-0.055	-0.056	-0.098	-0.116	0.675	1.656	2.255	3.042	2.967	**10.228**
Delaware	-0.018	-0.025	-0.027	-0.025	-0.029	0.204	0.512	0.699	0.954	0.931	**3.174**
Maine	-0.026	-0.039	-0.044	-0.065	-0.077	0.242	0.676	0.940	1.285	1.248	**4.141**
Maryland	-0.104	-0.146	-0.156	-0.138	-0.127	1.316	3.229	4.401	5.996	5.876	**20.146**
Massachusetts	-0.102	-0.147	-0.160	-0.246	-0.292	1.014	2.773	3.841	5.233	5.072	**16.985**
New Hampshire	-0.029	-0.038	-0.043	-0.066	-0.076	0.252	0.696	0.963	1.311	1.266	**4.236**
New Jersey	-0.134	-0.232	-0.250	-0.244	-0.362	1.384	3.851	5.455	7.438	7.176	**24.083**
New York	-0.181	-0.274	-0.288	-0.284	-0.421	2.267	5.742	7.983	10.762	10.399	**35.705**
Pennsylvania	-0.142	-0.225	-0.235	-0.232	-0.355	2.190	5.305	7.328	9.838	9.549	**33.022**
Rhode Island	-0.013	-0.018	-0.019	-0.031	-0.037	0.158	0.409	0.562	0.762	0.739	**2.511**
Vermont	-0.014	-0.019	-0.021	-0.031	-0.037	0.120	0.335	0.464	0.633	0.613	**2.043**
LCFS Region	**-0.803**	**-1.218**	**-1.299**	**-1.461**	**-1.929**	**9.822**	**25.183**	**34.891**	**47.253**	**45.835**	**156.274**

FIGURE 4-20: NE/MA LCFS REGION – INCREMENTAL COST OF TRANSPORTATION FUEL

Summary of LCFS Region Incremental Cost of Transportation Fuel

(Cumulative Costs for Years 2012-2021)

State	Baseline Expenditure (Billion 2009 Dollars)	Incremental Cost	
		Billion 2009 Dollars	Percentage
Connecticut	67.240	10.228	15.21%
Delaware	18.633	3.174	17.03%
Maine	32.737	4.141	12.65%
Maryland	123.202	20.146	16.35%
Massachusetts	123.677	16.985	13.73%
New Hampshire	27.324	4.236	15.50%
New Jersey	215.834	24.083	11.16%
New York	262.306	35.705	13.61%
Pennsylvania	246.135	33.022	13.42%
Rhode Island	16.588	2.511	15.14%
Vermont	14.238	2.043	14.35%
LCFS Region	**1147.914**	**156.274**	**13.61%**

4.4.2.1 AllNOCAFE54 vs. BASELINE Scenarios

CNG and LPG vehicles receive the greatest credit, followed by E85 vehicles. Electric vehicles of all types receive the smallest benefit because of the approach used in the model to price these vehicles relative to conventional technologies (see Section 3.2.1). The annual costs of these subsidies are provided below as calculated based on regional vehicle sales.[32]

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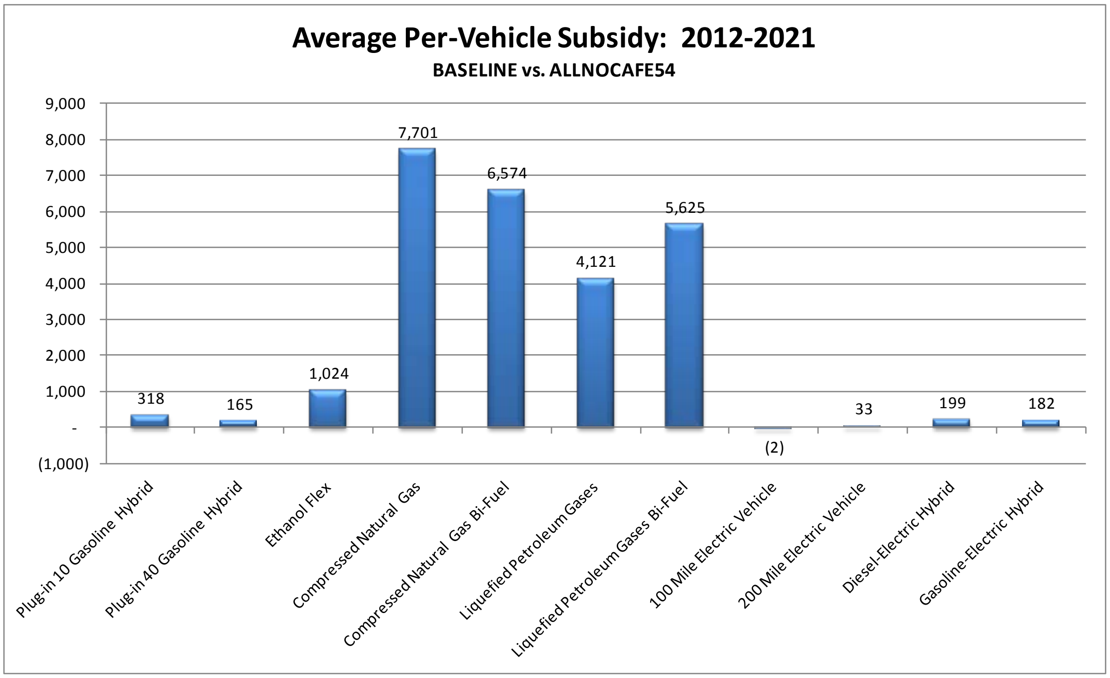
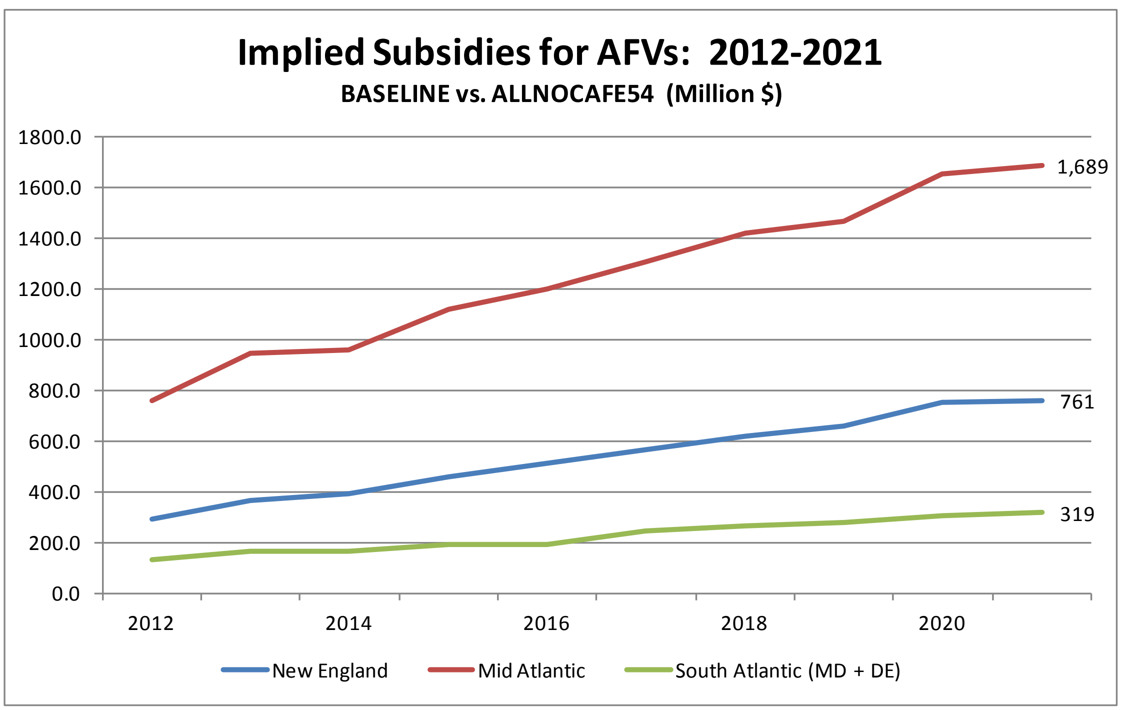
[32] As pointed out previously, NEMS calculates the price of cars by size class and the implied subsidy is based on the average incremental cost within a fuel-type over the period of the study. The subsidy value is the cumulative arithmetic average covering the 10-year study period. Changes in vehicle penetration can result in a counterintuitive outcome difference.

FIGURE 4-21: AVERAGE PER-VEHICLE SUBSIDY: 2012-2021[1]



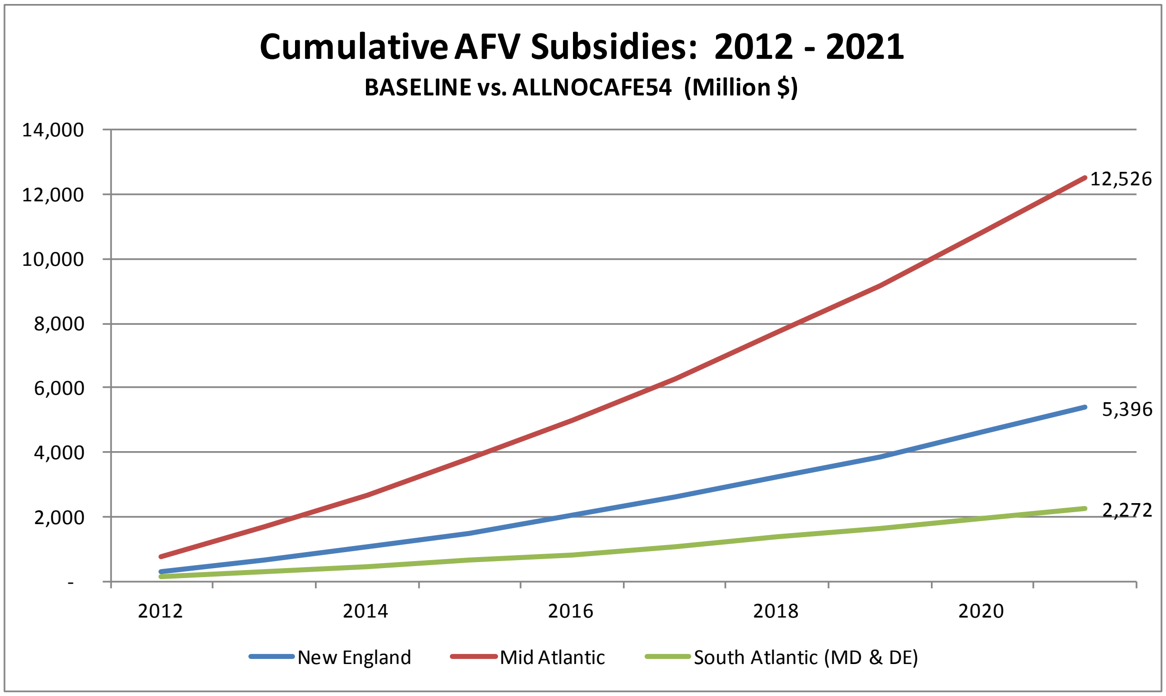
1. Based on the comparison between the ALLNOCAFE54 and BASELINE scenarios

FIGURE 4-22: IMPLIED SUBSIDIES FOR ALTERNATIVE FUEL VEHICLES: 2012 - 2021



Looking at the 2012-2021 period, the subsidies accumulate as shown in the figure below.

FIGURE 4-23: ANNUAL CUMMULATIVE ALTERNATIVE FUEL VEHICLE SUBSIDIES: 2012 - 2021

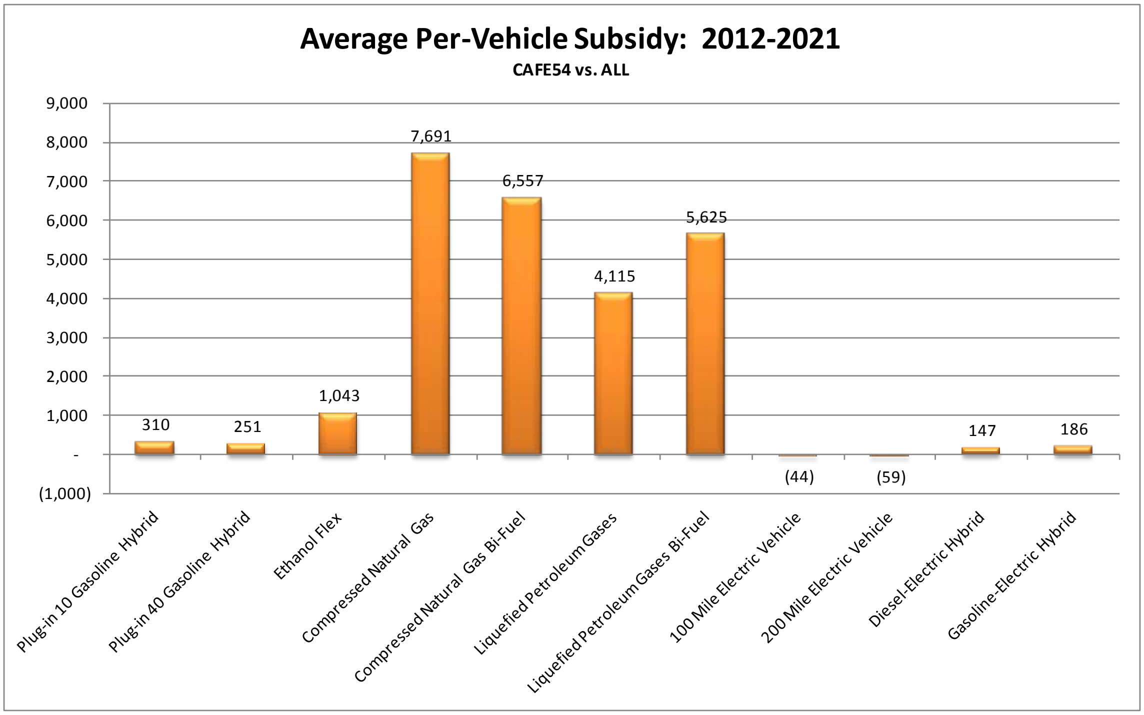


4.4.2.2 CAFE54 vs. ALL Scenarios

This section compares the CAFE54 Scenario with one containing all of the provisions in addition to the CAFE growth assumption – the ALL Scenario. It should be noted that this comparison shows a small, but negative result for battery electric vehicles (BEVs), implying that the average per-vehicle cost is lower under the baseline scenario. This may be a consequence of different size classes of BEV's being selected , or it may be an artifact of the model, which iteratively balances consumer demand for horsepower and fuel-economy within a vehicle size class in order to maximize performance while remaining within the CAFE constraints. Since the incremental cost of a BEV ranges between 10 and 50 thousand dollars, a negative balance of less than 100 dollars may be considered to be in the realm of a rounding error.

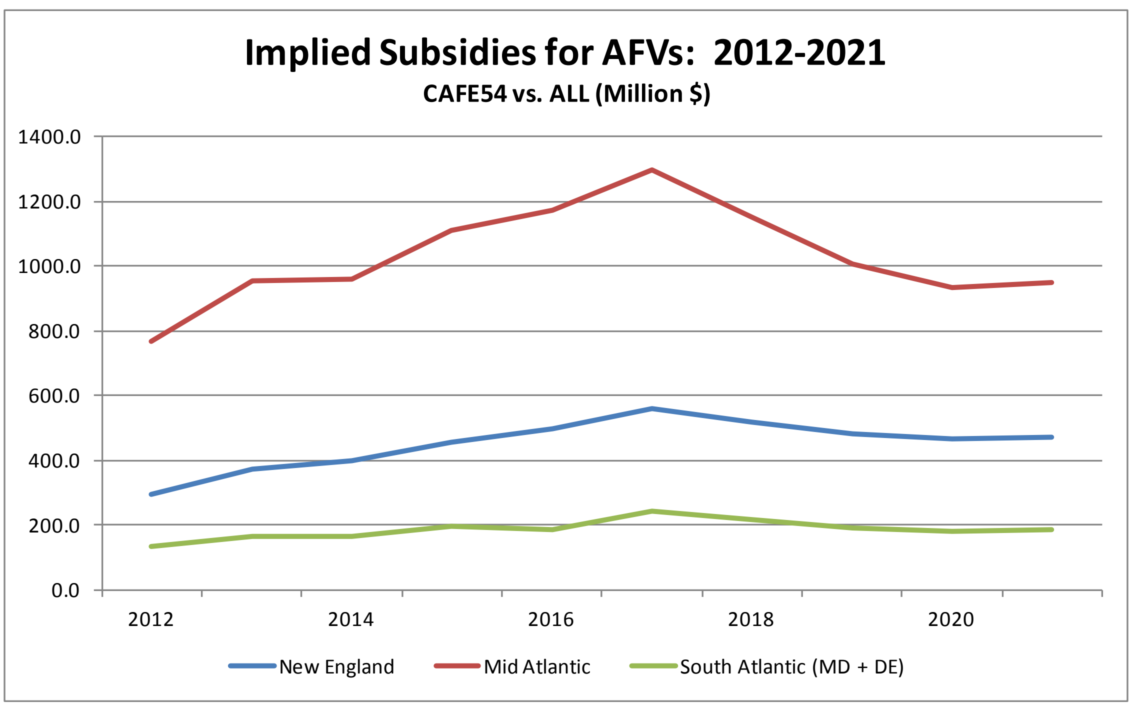
The average subsidy under this scenario is very close to that provided under the BASELINE Scenario, presented above in Section 4.4.2.1.

FIGURE 4-24: AVERAGE PER-VEHICLE SUBSIDY – 2012-2022: CAFE54 VS. ALL SCENARIOS



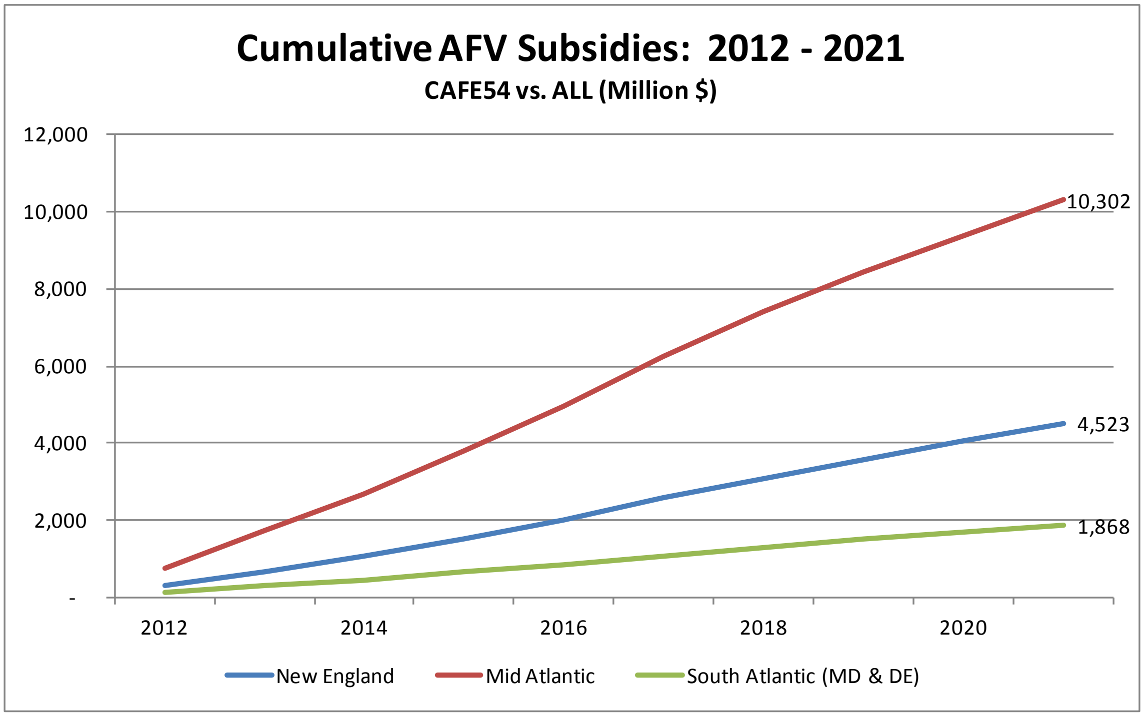
Multiplying the implied subsidies by the sale of corresponding vehicles results in the total expected annual expenditure under this scenario as shown in the figure below.

FIGURE 4-25: IMPLIED SUBSIDIES FOR ALTERNATIVE FUEL VEHICLES: 2012 - 2021



Looking at the 2012-2021 period, the subsidies accumulate as shown in the figure below.

FIGURE 4-26: ANNUAL CUMMULATIVE ALTERNATIVE FUEL VEHICLE SUBSIDIES: 2012 - 2021



4.4.3 Calculation of Incremental Infrastructure Cost for LCFS Region

Estimating the cost of required infrastructure depends on the stock of vehicles in each region, assumptions about the number of facilities required to service the stock, and assumptions about the unit cost of each refueling facility.

The following steps were taken to estimate the incremental infrastructure costs required for E85, CNG and LPG vehicles, for each of the scenarios:

- National estimates of AFV stock come from CEA-NEMS Table 49 - Light-Duty Vehicle Stock by Technology Type. Values are summed within fuel types, and Car and Light Truck stock figures are combined. This is done to obtain an aggregate count of the total number of vehicles that would need access to refueling facilities. CEA-NEMS does not directly calculate vehicle stock on a regional basis, so it is allocated according to regional sales shares.
- Annual sales by vehicle type and technology are reported regionally in Table 48 - Light-Duty Vehicle Sales by Technology Type. Combining Car and Light Truck sales within each fuel type (as described above), sales shares by census division are calculated.
- Regional stocks of AFVs are estimated by multiplying national-level stock values by the regional shares. MD and DE stocks are assumed to represent approximately 12 percent of

the South Atlantic division's (CD5) value, based on historical data which is assumed to remain unchanged in the future.

- The number of refueling stations required to service each region's vehicles is calculated by dividing the number of vehicles in a given year by a fixed ratio of Vehicles/Station (V/S). In this report, the ratio used is **430 V/S**, which is the value used in the CEA-NEMS transportation model for E85 stations. By comparison, CEA-NEMS assumes a V/S ratio of 1,000 for gasoline and diesel vehicles. The NESCAUM report assumes a V/S ratio of approximately 1,540 for gasoline vehicles, and 770 for CNG, while E85 stations are linked to a pre-determined demand for the fuel, and not to any direct estimate of vehicle stocks.
- As described in the section on implied subsidy costs, the incremental infrastructure costs of CEA scenarios are calculated by reference to two baseline scenarios: 1) CAFE standards follow the CEA-NEMS reference case (study BASELINE), and 2) CAFE standards grow at an accelerated rate of 6% (CAFE54). The respective tested scenarios are AllNOCAFE, and All.
- The difference between the number of additional facilities needed under the tested scenario and the corresponding baseline is calculated for each forecast year. Since it is assumed that, once constructed, a facility will remain available throughout the forecast, the number of incremental facilities in each year is calculated by reference to the maximum number of stations to-date—this permits vehicle stocks to fluctuate up and down without requiring the construction of new stations with every up-tick.
- The incremental cost of this infrastructure is calculated by multiplying the cost per station by the additional number of stations built under the tested scenarios. In this exercise, the cost of an E85 facility is assumed to be $185,000;[33] the cost of an LPG station is assumed to be the same. The cost of a CNG facility is less clear, but we referred to the NESCAUM study for guidance: it is assumed that a new facility is $1,000,000, and a facility upgrade is $370,000. As an *ad hoc* estimate, an average cost was used, giving a 1/3 weight to the upgrade and a 2/3 weight to the new facility cost, resulting in an average cost of $790,000.[34]

The total number of incremental facilities and cumulative costs for the period of 2012-2021 were calculated, and are shown in the charts below; FIGURE 4-27 to FIGURE 4-30.

It should be noted that the total additional infrastructure investment presented here is significantly lower than the estimate in the NESCAUM study. This is the consequence of the algorithmic approach to vehicle choice used in NEMS, where it is difficult to compel an "arbitrary level of market penetration." The NESCAUM study seems to be under no such constraints, and apparently assumes that consumers will flock to CNG and E85 vehicles enthusiastically.

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[33] API E85 Retail Fueling Facility Cost Study, Gilson Environmental LLC, September 16,2009

[34] Infrastructure costs are small relative to the cumulative vehicle subsidy costs. Accordingly, the results of the analysis are not particularly sensitive to these infrastructure cost assumptions.

FIGURE 4-27: NUMBER OF INCREMENTAL REFUELING FACILITIES: 2012 – 2021
COMPARISON OF BASELINE AND ALLNOCAFE54 SCENARIOS

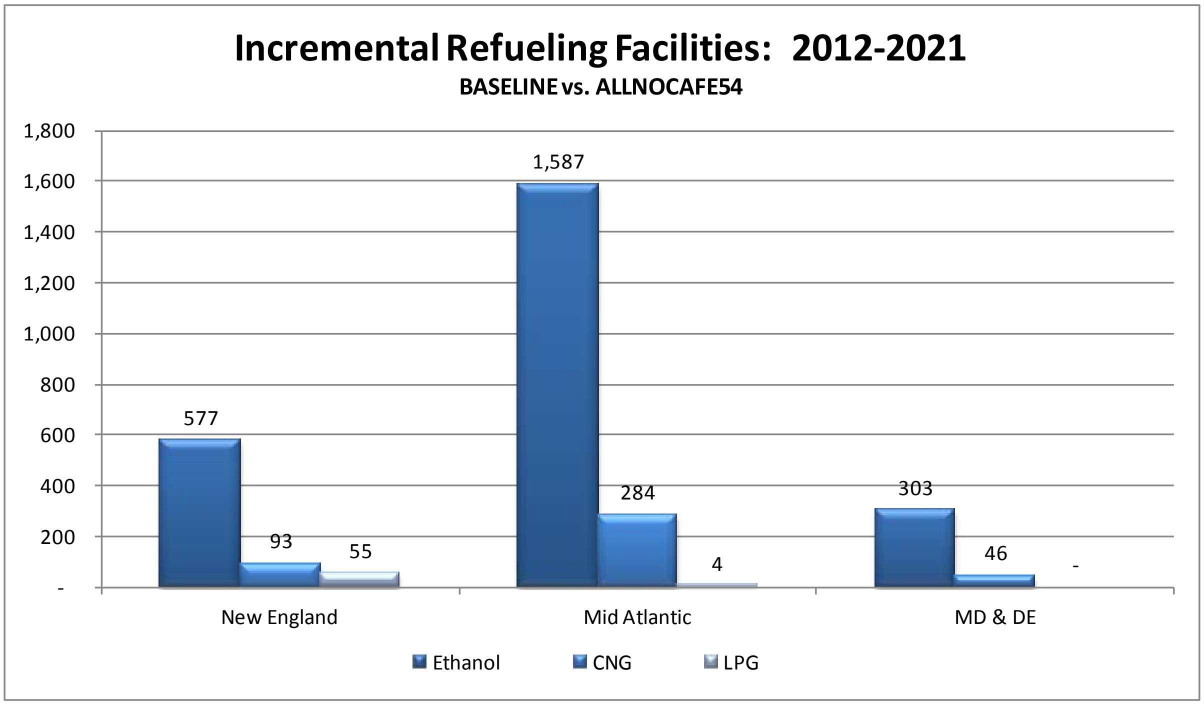


FIGURE 4-28: COST OF INCREMENTAL REFUELING FACILITIES: 2012 – 2021
COMPARISON OF BASELINE AND ALLNOCAFE54 SCENARIOS

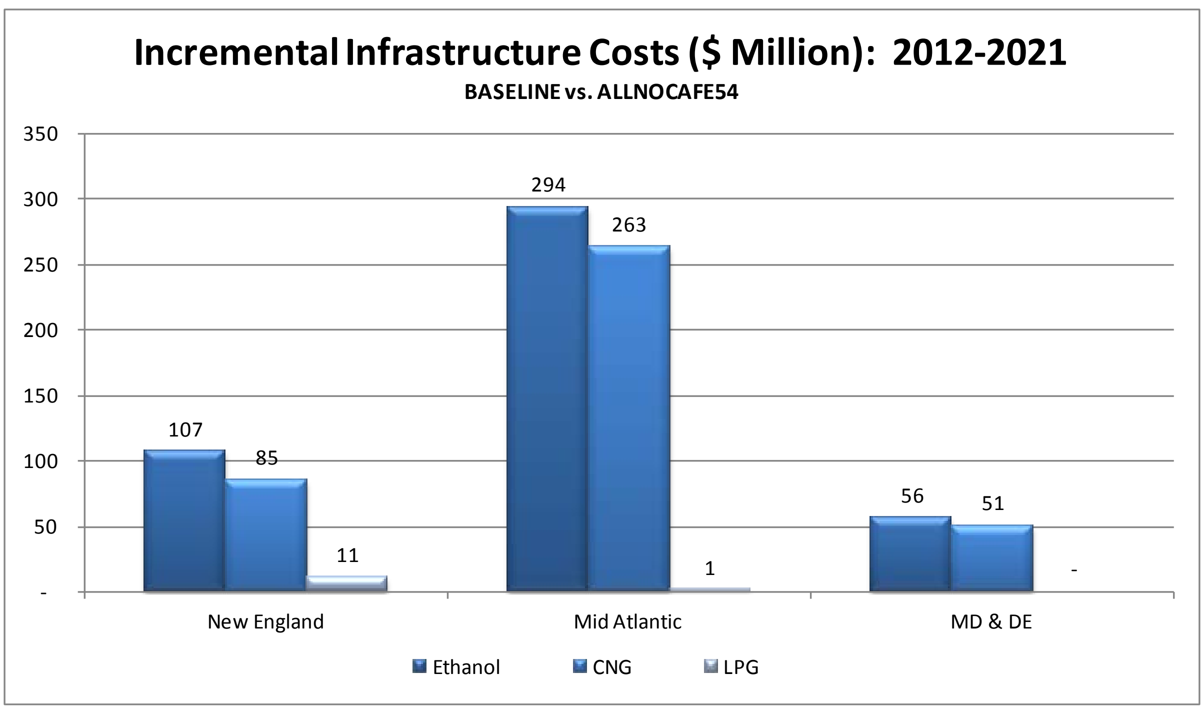


FIGURE 4-29: NUMBER OF INCREMENTAL REFUELING FACILITIES: 2012 – 2021
COMPARISON OF CAFE54 AND ALL SCENARIOS

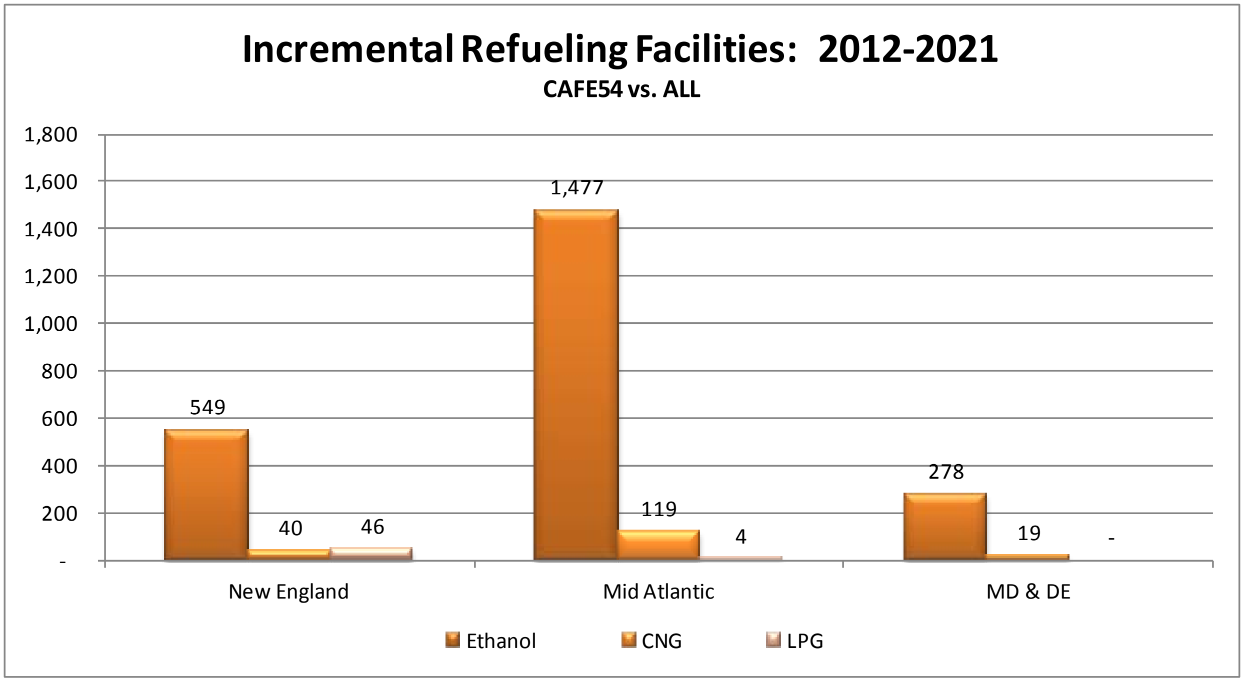
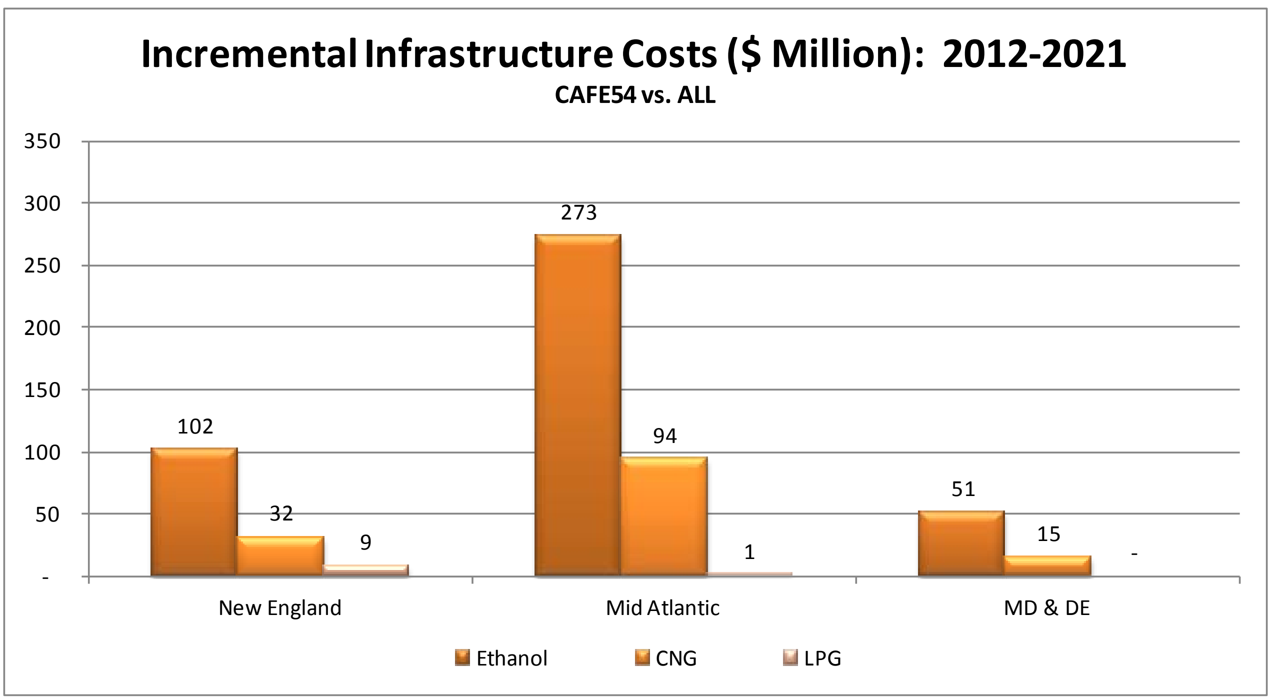


FIGURE 4-30: COST OF INCREMENTAL REFUELING FACILITIES: 2012 – 2021
COMPARISON OF CAFE54 AND ALL SCENARIOS



4.5 IMPACT OF INCLUDING MASS TRANSIT IN THE CI ANALYSIS

The use of electricity in transportation is constrained to two modes: 1) mass transit (Intercity Rail, Transit Rail, and Commuter Rail), and 2) Light Duty Vehicles. CEA-NEMS reports this consumption at the national, not regional level. Comparisons of the various scenarios' transportation electricity demand are depicted in FIGURE 4-31 and FIGURE 4-32 below.

FIGURE 4-31: MASS TRANSIT ELECTRICITY DEMAND BY SCENARIO

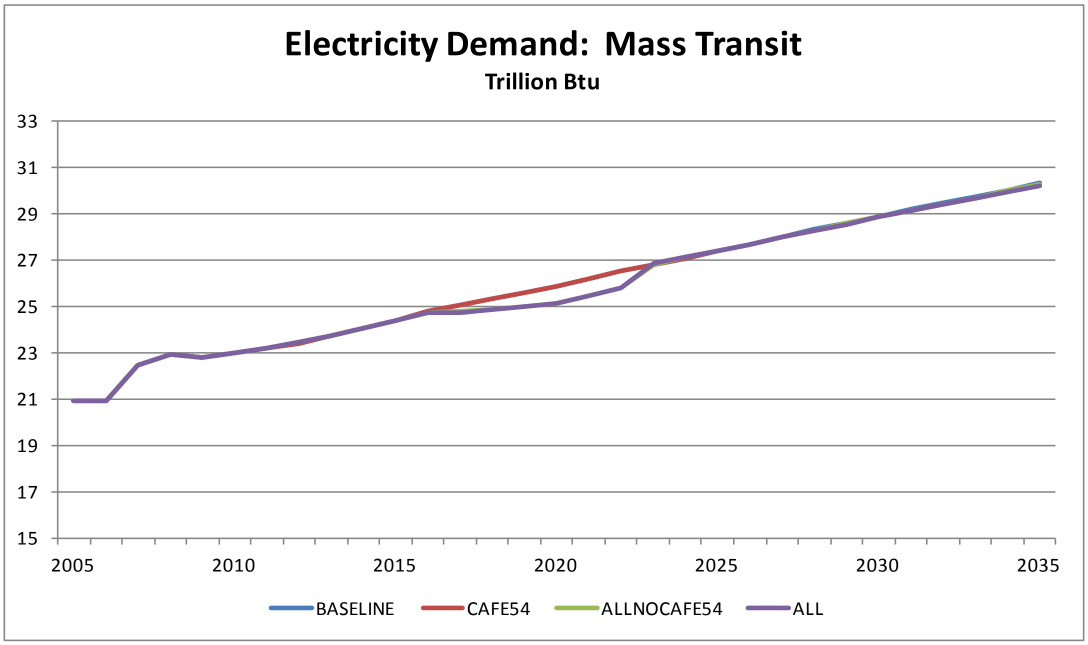
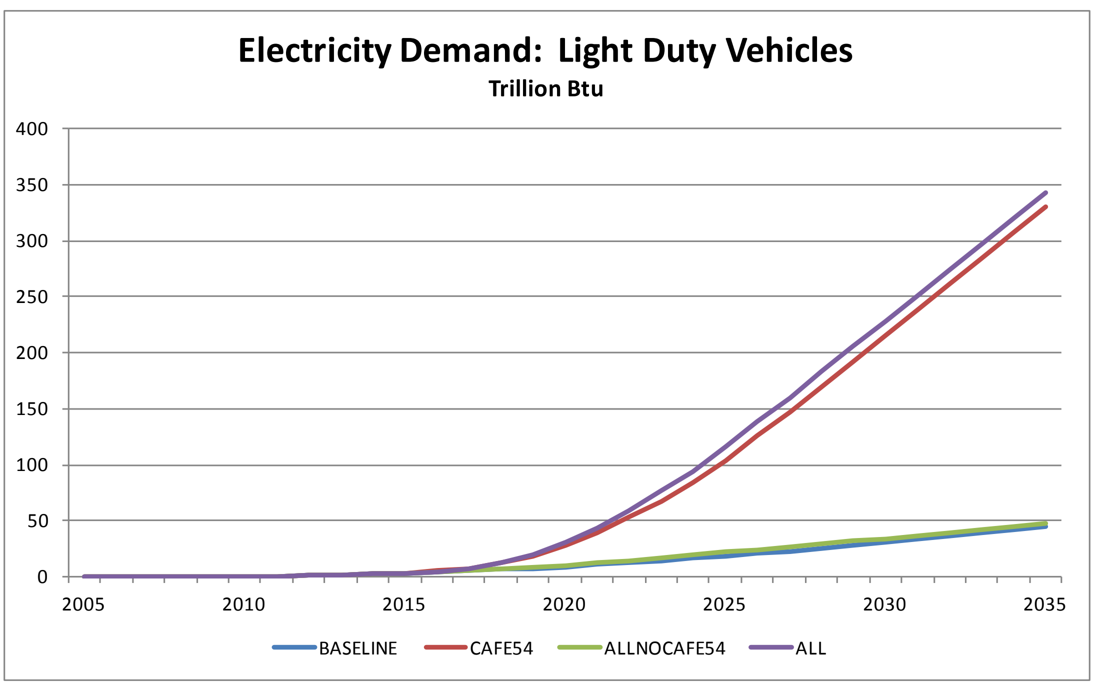
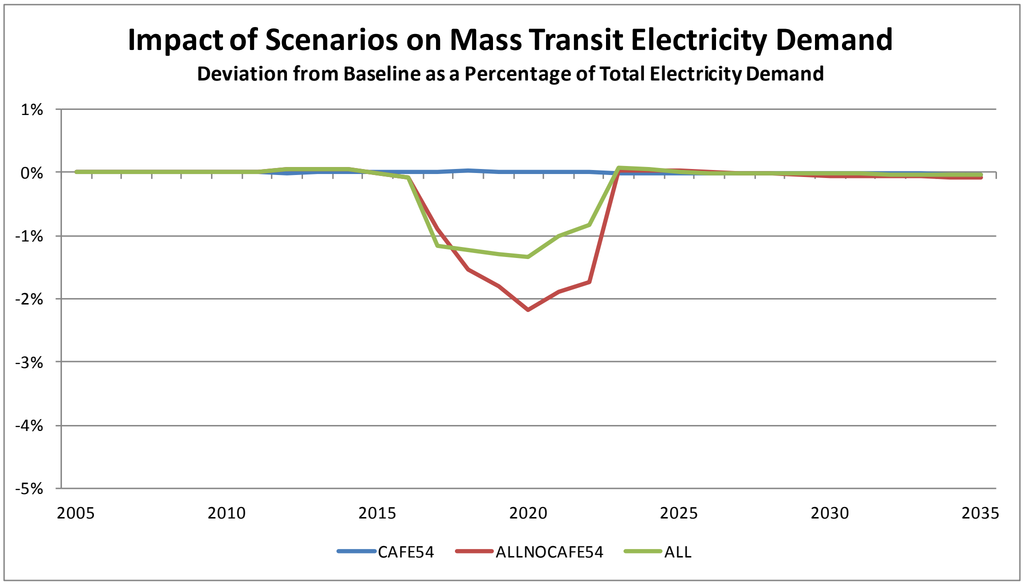


FIGURE 4-32: LIGHT DUTY VEHICLE ELECTRICITY DEMAND BY SCENARIO



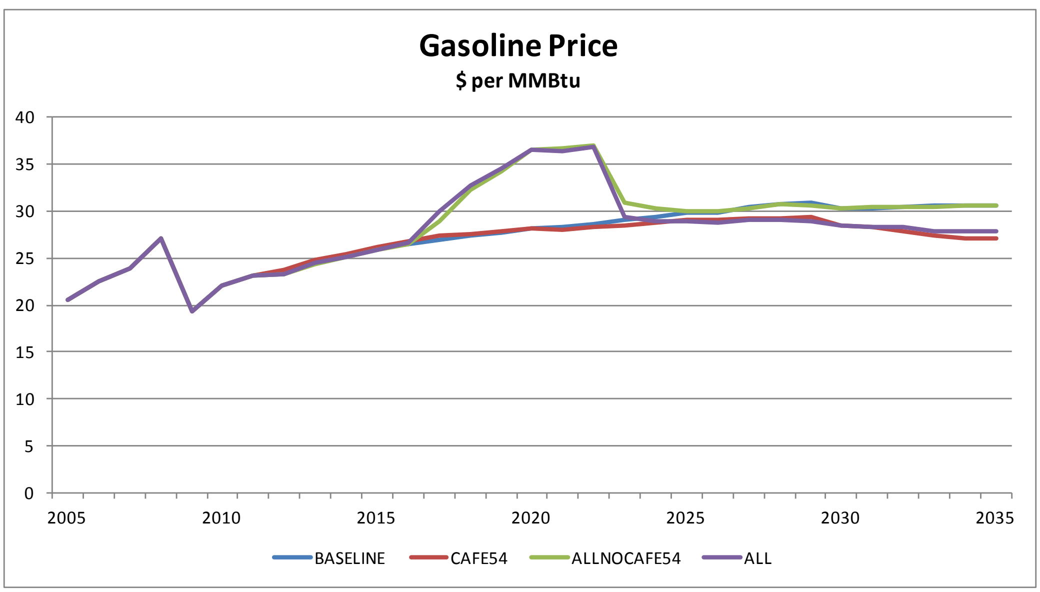
The mass transit chart above indicates that the two scenarios containing the LCFS provisions (AllNOCAFE54 and All) exhibit a small reduction in mass transit electricity use between 2015 and 2022. This small difference is emphasized in the following chart, FIGURE 4-33, which expresses the deviation of mass transit electricity demand from the Baseline value in terms of the percentage of total transportation electricity demand.

FIGURE 4-33: IMPACT OF SCENARIOS ON MASS TRANSIT ELECTRICITY DEMAND



This effect is due, in large part, to the differences in gasoline prices between the scenarios. The price of gasoline is one of the components in the mass transit demand equation, and has a negative coefficient (although counterintuitive). Gasoline prices differences are shown below in FIGURE 4-34.

FIGURE 4-34: GASOLINE PRICE CHANGE BY SCENARIO



Overall, the impact of deviations in mass transit electricity use between scenarios appears to be modest, and is unlikely to result in any distortions in the analysis.

4.6 STUDY CONCLUSIONS FOR REGIONAL RESULTS REFLECTING THE BASELINE CRUDE OIL PRICE PROJECTION

The results for the scenarios using the BOP projection indicate that, even under the most aggressive/optimistic 'ALL' Scenario, the goal of achieving a ten percent CI reduction within ten years, while sustaining the full energy needs of the states and the region, cannot be achieved for the NE/MA LCFS region. For the BOP-based scenario projections through 2021, the results range from 3.5 percent for Delaware to 5.9 percent reduction for Pennsylvania with a NE/MA regional weighted average of 4.9 percent CI reduction. The CI reduction goal is projected to be almost achieved for a few states by year 2035 under the BOP projection, such as Pennsylvania at 9.5% reduction, but not for the majority of the eleven states.

This significant modeling conclusion is the direct result of the practical supply and demand constraints represented in the CEA-NEMS model. These are: **1**) demand for energy by the transportation sector, based on travel projections for different vehicle types and classes, ***must*** **always** be satisfied; **2**) the change in the mix of transportation vehicles in operation in any given year is limited based on the historical rate of stock turnover, consumer choice of replacement stock, technology advancement, and technology market penetration rate; **3**) supply and cost of different types of alternative fuels (e.g., cellulosic ethanol, biodiesel) is subject to biomass resource availability, production technology availability and advancement rate, and rate of market penetration; and **4**) the cost and availability of competing fuels and technologies (e.g., hybrid electric vehicles). Based on such constraints, an overriding factor represented in these results is the shear dominance of gasoline-fueled vehicles/fuel supply infrastructure and the practical time that it takes to adjust and replace the demand for gasoline. Even with large alternative fuel subsidies and realistic fuel cost penalties imposed by the LCFS optimization to make lower CI alternatives more cost competitive, the model could not meet the reduction goal. On the other hand, the model was able to satisfy the CI goal for diesel fuel, with suitable production of biodiesel, due to the relatively low consumption of diesel fuel relative to that of gasoline.

The projected impact on CO_2 emission reductions, the ultimate objective of CI reduction, was more favorable. The transportation sector CO_2 emissions reduction projection for the 'ALL' scenario approaches 8 percent by 2021 and 18 percent by 2035, whereas the CAFE54 Scenario achieves 3 percent and 17 percent reduction, respectively, for years 2012 and 2021. While the outcome of the 'ALLNOCAFE54' Scenario indicates the limited impact of the CAFE54 standard over the near-term 10-year period, greater advanced technology penetration and efficiency improvements spawned by the CAFE's specifications are shown to be a critical complementary component of the ability to achieve substantial carbon emissions reduction over the long-term. Therefore, long-term fuel consumption reduction is identified as the ultimate driver in achieving significant long-term CO_2 reduction in the transportation sector, being more important than CI reduction alone. In fact, the 'CAFÉ' Scenario is projected to effectively achieve a similar annual CO_2 emissions outcome in year 2035, albeit the cumulative CO_2 emissions reduction is through 2035 is less than that achieved in the 'ALL' Scenario.

Although the CI reduction goal of ten percent over a ten year period could not be satisfied, the level of reduction obtained for the "ALL" Scenario results in adverse economic impacts for the NE/MA region as a whole, as well as for each of the eleven states. Study findings for the region project an overall ten-year economic impact of $306 Billion (2009 dollars) and projects cumulative loss of employment of almost 147,000 jobs. TABLE 4-11 shows the breakdown for these economic impacts:

TABLE 4-11: NE/MA REGION ECONOMIC IMPACT PROJECTED FOR THE 'ALL' SCENARIO

NE/MA LCFS REGION	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	- 4.9	-4.92%
Real GDP: $Billions (2009$)	-27.0	-0.07%
Disposable Personal Income: $Billions (2009 $)	-28.8	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-73.1	-0.58%
Employment: (Thousand Jobs Lost)	-146.8	-0.05%
Fuel Expenditure Increase: $Billions (2009 $)	156.3	13.61%
Implied Alternative Vehicle Subsidies: $Billions (2009 $)	20.2	
Incremental Infrastructure Cost: $Millions (2009 $)	801	

The "implied subsidies" for alternative fuel vehicles, used to enhance their competitive position, as well the projected incremental infrastructure for such vehicles, were assessed using an off-line calculation to estimate their value on a regional basis. It needs to be noted that these costs were not explicitly accounted for in the CEA-NEMS model, but realistically would have to come out of state budgets, which will ultimately impact taxpayers and reduce disposable income even further than indicated by the modeling outcomes.

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5. EXECUTION OF THE CEA-NEMS MODEL TO QUANTIFY TECHNICAL AND ECONOMIC IMPACTS OF A REGIONAL LCFS: NE/MA REGION STATE-BY-STATE RESULTS FOR BASELINE OIL PRICE PROJECTION

Results for each of the eleven states that make up the NE/MA LCFS region are presented in this section for the scenarios that use the baseline oil projection. Results for the comparable high oil price scenarios are presented in Attachment 6 (figures and tables only).

These states are:

- Connecticut
- Delaware
- Maine
- Maryland
- Massachusetts
- New Hampshire
- New Jersey
- New York
- Pennsylvania
- Rhode Island
- Vermont

Since CEA-NEMS calculates national and regional results, the model's results were post-processed to apportion the regional outcomes to the individual states. Two approaches were used –one for the energy data and one for the economic data. These approaches are presented below. Note that some of the state-by-state results appear in Section 4; they were the result of these processes.

5.1 MAPPING OF CEA-NEMS ENERGY RESULTS FROM CENSUS DIVISIONS TO STATES

This post-processing methodology disaggregates CEA-NEMS regional energy demand forecast into its constituent states using state historic energy consumption data from DOE's State Energy Data System (SEDS 2005-2009). The State Energy Data System (SEDS) is the U.S. Energy Information Administration's (EIA) source for comprehensive state energy statistics. Included are estimates of energy production, consumption, prices, and expenditures broken down by energy source and sector. Production and consumption estimates begin with the year 1960 while price and expenditure estimates begin with 1970. The multidimensional completeness of SEDS allows users to make comparisons across States, energy sources, sectors, and over time.

While some SEDS data series come directly from surveys conducted by EIA, many are estimated using other available information. These estimations are necessary for the compilation of "total energy" estimates. The SEDS data sources and estimation procedures are described in the SEDS Technical Notes & Documentation section located on EIA's website.[35]

[35] http://www.eia.gov/state/seds/seds-technical-notes-complete.cfm

The general mapping methodology is provided in the sections below.

5.1.1 State Fuel Price Projections

- Calculate "State-Region Factor" by energy type for each state in a CEA-NEMS region and apply the factor to the region's price projection to estimate a state's energy price, where

  Factor = State Weighted Average Price / Region Weighted Average Price (2005-2009)

5.1.2 State Ethanol/E85 Consumption

- **Ethanol Sources**
  - **Domestic Production:** Starch-Based (mostly corn)/Cellulose Based/Advanced
  - **Imports:** Cellulosic/Non-cellulosic
  - **Exports**
  - **Domestic Regional Transfer** (inter-regional, corn ethanol)
- **Methodology**

  CEA-NEMS reports ethanol production by source and total ethanol consumption by census division, while SEDS doesn't report ethanol data at the state level. We estimated state ethanol consumption by sources in two steps:

  - Step 1: Estimate a region's ethanol consumption by source. Note that CEA-NEMS Table 102 doesn't balance between total supply and total consumption, which implies there is domestic transfer between regions. Depending on this transfer (total supply - total consumption), a region's "export" to other regions occurs if this transfer > 0, or a region's "import" from other regions occurs if this transfer < 0. We assume this transfer is corn ethanol by default. So a region's ethanol consumption = Starch-based ethanol (mostly corn) – ethanol transfer. Other types of ethanol consumption would map directly to the supply side. Only the Mid-Atlantic region has a problem with this methodology since its corn ethanol consumption would be negative, which implies the region actually "exports" cellulose-based or advanced ethanol rather than Starch-based (mostly corn).
  - Step 2: Estimate each state's ethanol consumption by type. This calculation is relatively simple. Having Step 1 completed, we apply a state's gasoline share in its region year by year in the projection period (calculated using output of the state fuel model) to allocate the region's ethanol consumption by type in the projection period.
  - We similarly estimated E85 consumption by state

5.1.3 State Biodiesel Consumption

- **Biodiesel Sources (CEA-NEMS Table 102 - Census Division)**

Note: The 10% Ethanol in gasoline and 85% ethanol in E85 are measured in volume. In fuel consumption and emission calculations we need convert them to represent in Btu. Thus,10% should be modified as 10%*0.6737 = 6.74%, and 85% as 85%*0.6737 = 57.27% (Ethanol Btu / Gasoline Btu = 3.539 / 5.253 = 0.6737)

- Consumption of Biodiesel
    - Virgin (from seed oil or white grease)
    - Non-Virgin (from yellow grease)
    - Total

- **Methodology**

  Biodiesel is used by transportation. CEA-NEMS reports biodiesel consumption by census division, while SEDS doesn't report Biodiesel data at state level. But both report Distillate Fuel Oil consumption by transportation. State Biodiesel consumption was estimated by sources in two steps:

  – Step 1: Estimate a state transportation diesel consumption. Distillate Fuel Oil consumption by transportation is diesel. Using state historic diesel consumption data from SEDS we can disaggregate the regional consumption into its constituent states. This has been done in state fuel demand model component

  – Step 2: Estimate a state biodiesel consumption. We assume that biodiesel consumption of a state is directly linked to the state's diesel consumption. Applying the state to region relationship on transportation diesel consumption we can estimate the state's biodiesel consumption in the projection period. Both Virgin and non-Virgin are estimated.

5.1.4 State Electricity Generation

- **New England States (CT/MA/ME/NH/RI/VT)**

  States of New England fall into NEMS EMM region "05 - Northeast Power Coordinating Council / Northeast", and this EMM region only contains these states. So there is a perfect state-region mapping and we estimate each state's generation as a breakout of the CEA-NEMS EMM region using the states' historic generation data based on SEDS 2009 data.

- **NY state** falls into three CEA-NEMS EMM regions

  – 06 - Northeast Power Coordinating Council / NYC-Westchester

  – 07 - Northeast Power Coordinating Council / Long Island

  – 08 - Northeast Power Coordinating Council / Upstate New York

  Since these EMM regions only contain NY State, we aggregate them to get the NY state projection.

- **Other states (NJ/PA/DE/MD)**

  The majority of these states fall into CEA-NEMS EMM region "09 - Reliability First Corporation/East", but with part of PA and MD in other EMM regions. To handle this cross-state issue:

  – First estimate each state's generation in a way similar to the New England (break out of EMM region 9)

  – Then try to incrementally adjust each state's generation to remove the discrepancy. The delta is calculated as the difference between the sum of the historic total generation of all the four states in 2009 (SEDS) and the total generation simulation of the EMM region 9 in 2009

- CEA-NEMS doesn't report details of renewable generation at the EMM regional level in CEA-NEMS Table 62. To simplify mapping SEDS to NEMS, we calculate

Renewable = Total - Coal - Petroleum - Natural Gas – Nuclear

5.1.5 State Transportation CI calculation

- **Fuel Consumption**
  - Direct transportation fuel consumption
  - Indirect fuel consumption: Electricity generation fuel consumption
    - Coal/Natural Gas/Petroleum/Non-Fossil fuel (Nuclear and Renewable)
- **Emissions**
  - For each fuel, its emission = Fuel consumption x Emission factor
- **Carbon Intensity**
  - Total Emissions (sum of all fuel emissions) / Total Fuel Consumptions (sum of all fuel consumption)
- **Special Handlings in Calculations**
  - Motor Gasoline
    - Motor gasoline contains 10% of ethanol. To avoid double counting, we count 90% of this consumption as pure gasoline into the total transportation fuel consumption, and let the ethanol (10%) be counted in ethanol consumptions. In emission calculations, only the pure gasoline carbon emissions are calculated here using a pure gasoline emission factor
  - E85
    - E85 effectively contains 74% ethanol and 26 % pure gasoline. To avoid double counting, we count only the 26% of this consumption as pure gasoline included in the total transportation fuel consumption. The ethanol (74%) is accounted for as part of ethanol consumption and emissions.
  - Ethanol
    - Emissions are calculated by ethanol source using associated emission factors. This includes
      - » Corn ethanol/ Cellulose Based/Advanced/ Cellulosic / Non-cellulosic
  - Biodiesel
    - Transportation Diesel consumptions actually contain diesels from petroleum and from biodiesel of virgin (from seed oil or white grease), and Non-Virgin (from yellow grease). Their emissions are calculated using associated emission factors.

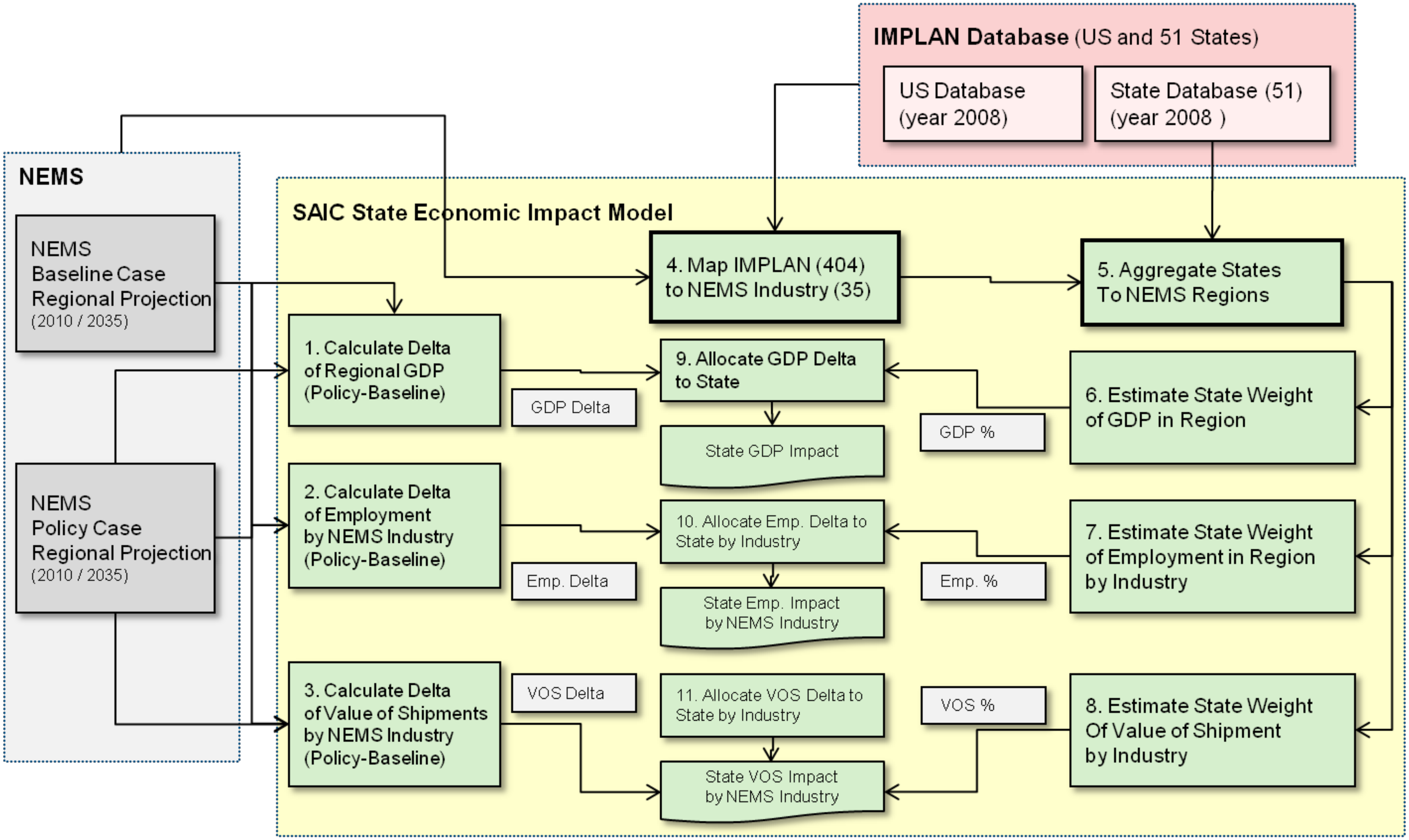
5.2 MAPPING OF CEA-NEMS ECONOMIC RESULTS FROM CENSUS DIVISIONS TO STATES

This post-processing methodology disaggregates the CEA-NEMS economic forecast into its constituent states using the IMPLAN input-output/social accounting matrix tool. IMPLAN is a production model; that is, it evaluates how businesses respond – i.e., what the “impacts” are - to demand for their products and services. IMPLAN data covers:

- 440 industries, containing data on:
  - Total Industry Output (gross sales)
  - Employment (average annual full- & part-time jobs)
  - Value Added
  - Employee Compensation (wages, salaries, other labor income, employer & employee contributions to social insurance)
  - Proprietors Income (sole proprietorships, self employed)
  - Other Property Income (dividends, interest, rent)
  - Indirect Business Taxes (sales, gasoline, excise taxes, custom duties, fees collected by businesses)
- Institutions:
  - Household Consumption (PCE for 440 commodities)
  - Government Consumption (Federal Military & Non-Military, State & Local Government, Education & Non-Education for 440 commodities)
  - Capital Investment & Inventory Additions (for 440 commodities)
  - Institutional Sales (HH used goods, Government sales, sales of inventory)
- Trade:
  - Foreign Imports & Exports (for 440 commodities)
  - Domestic Imports & Exports (gross trade flows county-to-county for 440 commodities)
  - Regional Purchase Coefficients (rate of local purchase of 440 commodities)

FIGURE 5-1 shows the general methodology for mapping the CEA-NEMS economic output to the individual states.

FIGURE 5-1: NRA-NEMS REGION-TO-STAE MAPPING METHODOLOGY



5.3 STATE-BY-STATE RESULTS

This section of the report presents the results of the process defined above to apportion the CEA-NEMS projected outcomes to the individual states that make up the NE/MA LCFS region. The results presented in this section only account for the scenarios that use the Baseline Oil Price (BOP) projection, while those that use the High Oil Price (HOP) projection are presented in Attachment 6 (figures and tables only).

TABLE 5-1 and TABLE 5-2 provide the CI reduction outcomes for the individual states for the years 2021 and 2035 by scenario. As observed previously, the model projects that none of the states can satisfy the 10 percent CI reduction goal within ten years. This is also projected to be the case for year 2035, although significantly greater reduction occurs and several of the states come close to meeting the goal.

TABLE 5-1: CARBON INTENSITY (CI) VALUES IN NE/MA STATES

Carbon Intensity (CI) in LCFS Region and State-by-State (gCO2e/KBtu)

State	AEO2011RCMOD		BASELINE		CAFE54		ALLNOCAFE54		All	
	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035
Connecticut	97.6	95.3	97.6	95.5	97.2	91.4	93.6	94.4	93.5	91.3
Delaware	100.5	99.2	100.6	99.1	100.3	98.2	96.8	97.9	97.4	97.3
Maine	98.2	96.4	98.3	96.6	97.9	93.5	94.7	96.0	94.5	93.6
Maryland	99.7	98.4	99.8	98.3	99.4	96.5	96.0	96.9	96.5	95.6
Massachusetts	98.2	96.4	98.3	96.6	98.0	94.3	94.8	96.1	94.8	94.5
New Hampshire	98.1	95.8	98.2	95.9	97.5	89.6	94.5	95.5	94.0	89.7
New Jersey	99.4	95.9	99.2	95.8	99.1	94.8	95.6	95.2	95.7	94.1
New York	98.2	93.7	97.9	93.7	97.7	91.4	93.4	92.6	93.4	90.5
Pennsylvania	97.2	93.0	96.7	92.4	96.5	89.6	92.3	91.2	92.3	88.7
Rhode Island	98.0	95.9	98.0	96.1	97.8	94.5	94.0	95.1	94.1	94.6
Vermont	98.1	95.8	98.2	96.0	97.5	90.0	94.6	95.7	94.1	90.1
LCFS Region	**98.4**	**95.2**	**98.2**	**95.1**	**98.0**	**92.7**	**94.2**	**94.1**	**94.2**	**92.1**

TABLE 5-2: CARBON INTENSITY (CI) REDUCTION IN NE/MA STATES

Carbon Intensity (CI) Reduction in LCFS Region and State-by-State

State	AEO2011RCMOD		BASELINE		CAFE54		ALLNOCAFE54		All	
	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035
Connecticut	-1.0%	-3.3%	-0.9%	-3.1%	-1.4%	-7.3%	-5.0%	-4.3%	-5.2%	-7.4%
Delaware	-0.5%	-1.8%	-0.4%	-1.9%	-0.7%	-2.8%	-4.1%	-3.1%	-3.5%	-3.7%
Maine	-0.8%	-2.7%	-0.7%	-2.5%	-1.1%	-5.5%	-4.4%	-3.0%	-4.5%	-5.5%
Maryland	-0.5%	-1.7%	-0.4%	-1.8%	-0.7%	-3.6%	-4.1%	-3.2%	-3.6%	-4.6%
Massachusetts	-0.8%	-2.6%	-0.7%	-2.4%	-1.0%	-4.7%	-4.2%	-2.9%	-4.3%	-4.5%
New Hampshire	-1.0%	-3.3%	-0.9%	-3.1%	-1.6%	-9.5%	-4.6%	-3.5%	-5.1%	-9.4%
New Jersey	-0.5%	-4.0%	-0.7%	-4.1%	-0.8%	-5.2%	-4.3%	-4.7%	-4.2%	-5.8%
New York	-0.7%	-5.2%	-1.0%	-5.2%	-1.1%	-7.6%	-5.5%	-6.3%	-5.5%	-8.5%
Pennsylvania	-0.8%	-5.2%	-1.4%	-5.7%	-1.6%	-8.7%	-5.9%	-7.0%	-5.9%	-9.5%
Rhode Island	-0.9%	-3.0%	-0.8%	-2.7%	-1.0%	-4.3%	-4.9%	-3.8%	-4.8%	-4.3%
Vermont	-0.9%	-3.2%	-0.8%	-3.0%	-1.5%	-9.0%	-4.4%	-3.3%	-4.9%	-9.0%
LCFS Region	**-0.7%**	**-3.9%**	**-0.9%**	**-4.0%**	**-1.1%**	**-6.4%**	**-4.9%**	**-5.0%**	**-4.9%**	**-7.1%**

5.3.1 Summary of Projected State-By-State Economic Impacts

As discussed earlier, the CEA-NEMS study results were post-processed to apportion the regional outcomes to the individual states that make up the NE/MA LCFS region. These results are summarized in the tables below.

TABLE 5-3: SUMMARY OF CONNECTICUT ECONOMIC IMPACTS

CONNECTICUT	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO_2e/KBtu)	-5.4	-5.00%
Real GDP: $Billions (2009$)	-1.7	-0.07%
Disposable Personal Income: $Billions (2009 $)	-2.0	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-4.4	-0.50%
Employment: (Thousand Jobs Lost)	-13.8	-0.08%
Fuel Expenditure Increase: $Billions (2009 $)	10.2	15.21%
Gasoline Price Change, % (2012 – 2021)		109
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		21
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	1.7	
Incremental Infrastructure Cost: $Millions (2009 $)	66	

TABLE 5-4: SUMMARY OF DELAWARE ECONOMIC IMPACTS

DELAWARE	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO_2e/KBtu)	-2.2	-4.12%
Real GDP: $Billions (2009$)	-0.4	-0.07%
Disposable Personal Income: $Billions (2009 $)	-0.5	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-1.6	-0.65%
Employment: (Thousand Jobs Lost)	-2.2	-0.05%
Fuel Expenditure Increase: $Billions (2009 $)	3.2	17.03%
Gasoline Price Change, % (2012 – 2021)		116
Diesel Price Change, % (2012 – 2021)		20
Jet Fuel Price Change, % (2012 – 2021)		22
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	0.2	

Incremental Infrastructure Cost: $Millions (2009 $)	8	

TABLE 5-5: SUMMARY OF MAINE ECONOMIC IMPACTS

MAINE	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-4.4	-4.35%
Real GDP: $Billions (2009$)	-0.4	-0.07%
Disposable Personal Income: $Billions (2009 $)	-0.4	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-2.4	-0.76%
Employment: (Thousand Jobs Lost)	-4.5	-0.07%
Fuel Expenditure Increase: $Billions (2009 $)	4.1	12.65%
Gasoline Price Change, % (2012 – 2021)		109
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		21
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	0.5	
Incremental Infrastructure Cost: $Millions (2009 $)	19	

TABLE 5-6: SUMMARY OF MARYLAND ECONOMIC IMPACTS

MARYLAND	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-3.0	-4.09%
Real GDP: $Billions (2009$)	-2.6	-0.07%
Disposable Personal Income: $Billions (2009 $)	-3.0	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-5.0	-0.52%
Employment: (Thousand Jobs Lost)	-15.5	-0.05%
Fuel Expenditure Increase: $Billions (2009 $)	20.1	16.35%
Gasoline Price Change, % (2012 – 2021)		116
Diesel Price Change, % (2012 – 2021)		20
Jet Fuel Price Change, % (2012 – 2021)		22
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	2.0	
Incremental Infrastructure Cost: $Millions (2009 $)	84	

TABLE 5-7: SUMMARY OF MASSACHUSETTS ECONOMIC IMPACTS

MASSACHUSETTS	CUMULATIVE RESULTS (2012 – 2021)	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-4.3	-4.23%
Real GDP: $Billions (2009$)	-3.0	-0.07%
Disposable Personal Income: $Billions (2009 $)	-3.4	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-8.5	-0.61%
Employment: (Thousand Jobs Lost)	-16.2	-0.05%
Fuel Expenditure Increase: $Billions (2009 $)	17.0	13.73%
Gasoline Price Change, % (2012 – 2021)		109
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		21
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	2.0	
Incremental Infrastructure Cost: $Millions (2009 $)	70	

TABLE 5-8: SUMMARY OF NEW HAMPSHIRE ECONOMIC IMPACTS

NEW HAMPSHIRE	CUMULATIVE RESULTS (2012 – 2021)	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-4.6	-4.60%
Real GDP: $Billions (2009$)	-0.5	-0.07%
Disposable Personal Income: $Billions (2009 $)	-0.6	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-2.2	-0.68%
Employment: (Thousand Jobs Lost)	-6.9	-0.10%
Fuel Expenditure Increase: $Billions (2009 $)	4.2	15.50%
Gasoline Price Change, % (2012 – 2021)		109
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		21
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	0.5	

Incremental Infrastructure Cost: $Millions (2009 $)	13	

TABLE 5-9: SUMMARY OF NEW JERSEY ECONOMIC IMPACTS

NEW JERSEY	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-3.5	-4.29%
Real GDP: $Billions (2009$)	-4.0	-0.07%
Disposable Personal Income: $Billions (2009 $)	-4.2	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-12.9	-0.65%
Employment: (Thousand Jobs Lost)	-12.0	-0.03%
Fuel Expenditure Increase: $Billions (2009 $)	24.1	11.16%
Gasoline Price Change, % (2012 – 2021)		112
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		23
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	2.6	
Incremental Infrastructure Cost: $Millions (2009 $)	91	

TABLE 5-10: SUMMARY OF NEW YORK ECONOMIC IMPACTS

NEW YORK	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-5.6	-5.50%
Real GDP: $Billions (2009$)	-9.2	-0.07%
Disposable Personal Income: $Billions (2009 $)	-9.5	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-13.8	-0.49%
Employment: (Thousand Jobs Lost)	-24.4	-0.03%
Gasoline Price Change, % (2012 – 2021)		112
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		23
Fuel Expenditure Increase: $Billions (2009 $)	35.7	13.61%

Implied Alt. Vehicle Subsidies: $Billions (2009 $)	4.4	
Incremental Infrastructure Cost: $Millions (2009 $)	177	

TABLE 5-11: SUMMARY OF PENNSYLVANIA ECONOMIC IMPACTS

PENNSYLVANIA	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-6.8	-5.89%
Real GDP: $Billions (2009$)	-4.6	-0.07%
Disposable Personal Income: $Billions (2009 $)	-4.8	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-20.2	-0.62%
Employment: (Thousand Jobs Lost)	-45.3	-0.07%
Fuel Expenditure Increase: $Billions (2009 $)	33.0	13.42%
Gasoline Price Change, % (2012 – 2021)		112
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		23
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	5.5	
Incremental Infrastructure Cost: $Millions (2009 $)	250	

TABLE 5-12: SUMMARY OF RHODE ISLAND ECONOMIC IMPACTS

RHODE ISLAND	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-5.1	-4.92%
Real GDP: $Billions (2009$)	-0.4	-0.07%
Disposable Personal Income: $Billions (2009 $)	-0.4	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-0.9	-0.52%
Employment: (Thousand Jobs Lost)	-2.8	-0.06%
Fuel Expenditure Increase: $Billions (2009 $)	2.5	15.14%
Gasoline Price Change, % (2012 – 2021)		109
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		21

Implied Alt. Vehicle Subsidies: $Billions (2009 $)	0.4	
Incremental Infrastructure Cost: $Millions (2009 $)	16	

TABLE 5-13: SUMMARY OF VERMONT ECONOMIC IMPACTS

VERMONT	**CUMULATIVE RESULTS (2012 – 2021)**	
ECONOMIC INDICATOR **Amount: Presented as Change from 2012 Baseline Value** **Percent of Current Value: Amount/Current Value x 100**	**Amount**	**Percent of Reference Value**
CI Reduction: (gCO2e/KBtu)	-4.5	-4.44%
Real GDP: $Billions (2009$)	-0.2	-0.07%
Disposable Personal Income: $Billions (2009 $)	-0.2	-0.10%
Industrial Value of Shipments: $Billions (2009 $)	-1.1	-0.65%
Employment: (Thousand Jobs Lost)	-3.1	-0.09%
Fuel Expenditure Increase: $Billions (2009 $)	2.0	14.35%
Gasoline Price Change, % (2012 – 2021)		109
Diesel Price Change, % (2012 – 2021)		18
Jet Fuel Price Change, % (2012 – 2021)		21
Implied Alt. Vehicle Subsidies: $Billions (2009 $)	0.3	
Incremental Infrastructure Cost: $Millions (2009 $)	7	

5.3.2 State Fuel Consumption, Fuel Prices, and Incremental Fuel Expenditure (2012-2021 under Scenario ALLNOCAFE54)

Results presented in this section only represent the outcomes of the 'ALLNOCAFE54' Scenario, but the results for the 'ALL' Scenario would be very similar.

Results for state transportation fuel consumption and fuel expenditures are shown in FIGURE 5-2 to FIGURE 5-32, as accompanied by TABLE 5-14 to TABLE 5-48. Impacts on electricity generation (by fuel type) for each state are presented in FIGURE 5-33 to FIGURE 5-43, as accompanied by TABLE 5-49 to TABLE 5-59.

The transportation fuel consumption types included in these results includes:

- Liquefied Petroleum Gases
- E85
- Liquefied Petroleum Gases
- E85 (Gasoline Only)
- Motor Gasoline (Gasoline Only)
- Jet Fuel

- Distillate Fuel Oil (Petroleum)
- Residual Fuel Oil
- Pipeline Fuel Natural Gas
- Compressed Natural Gas
- Corn-based Ethanol (Domestic)
- Cellulose-based Ethanol (Imported and Domestic)
- Sugar Cane-based Ethanol (Imported)
- Biodiesel Virgin
- Biodiesel Non-Virgin
- Steam Coal (Generation Fuel for Transportation Electricity)
- Natural Gas (Generation Fuel for Transportation Electricity)
- Petroleum (Generation Fuel for Transportation Electricity)
- Non Fossil Fuel (Generation Fuel for Transportation Electricity)

Transportation Fuel Prices include:

- Liquefied Petroleum Gases
- E85
- Motor Gasoline
- Jet Fuel
- Distillate Fuel Oil
- Natural Gas

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FIGURE 5-2: CONNECTICUT – TRANSPORTATION FUEL CONSUMPTION CHART

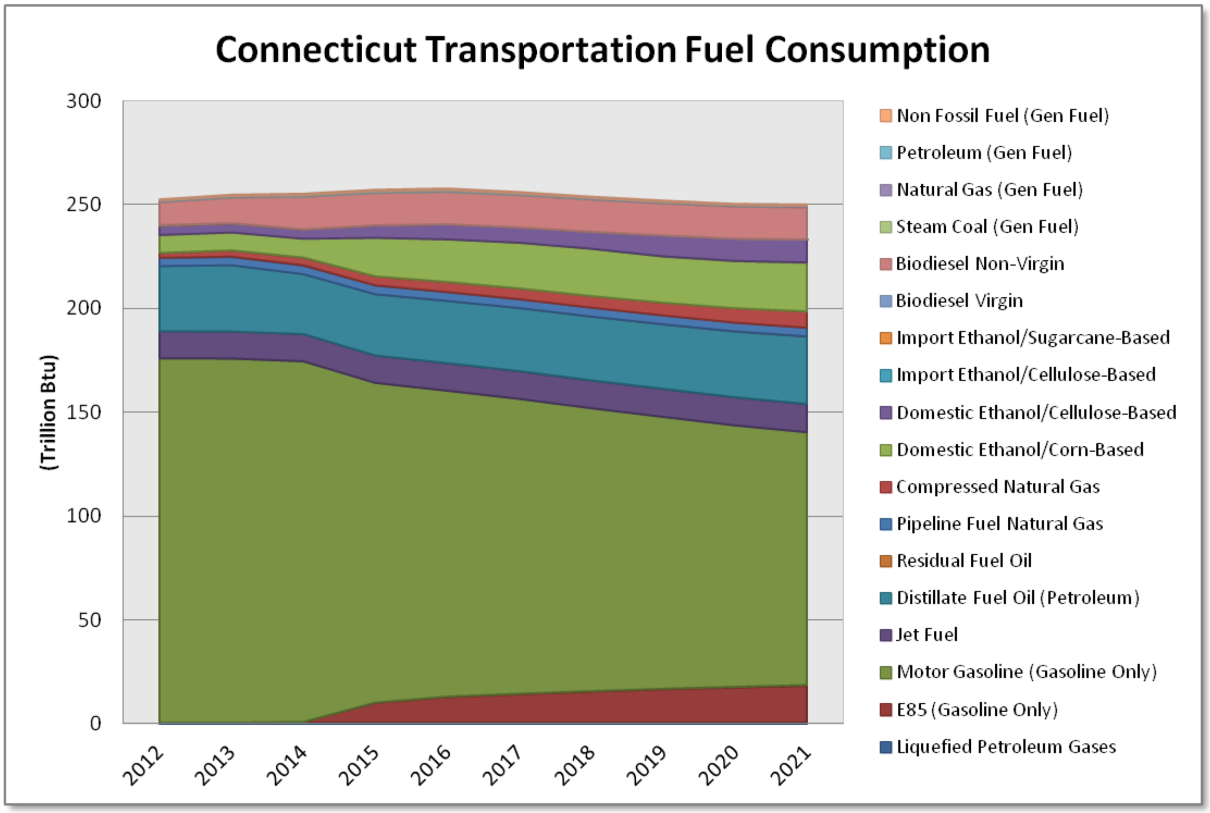


TABLE 5-14: CONNECTICUT – TRANSPORTATION FUEL CONSUMPTION TABLE

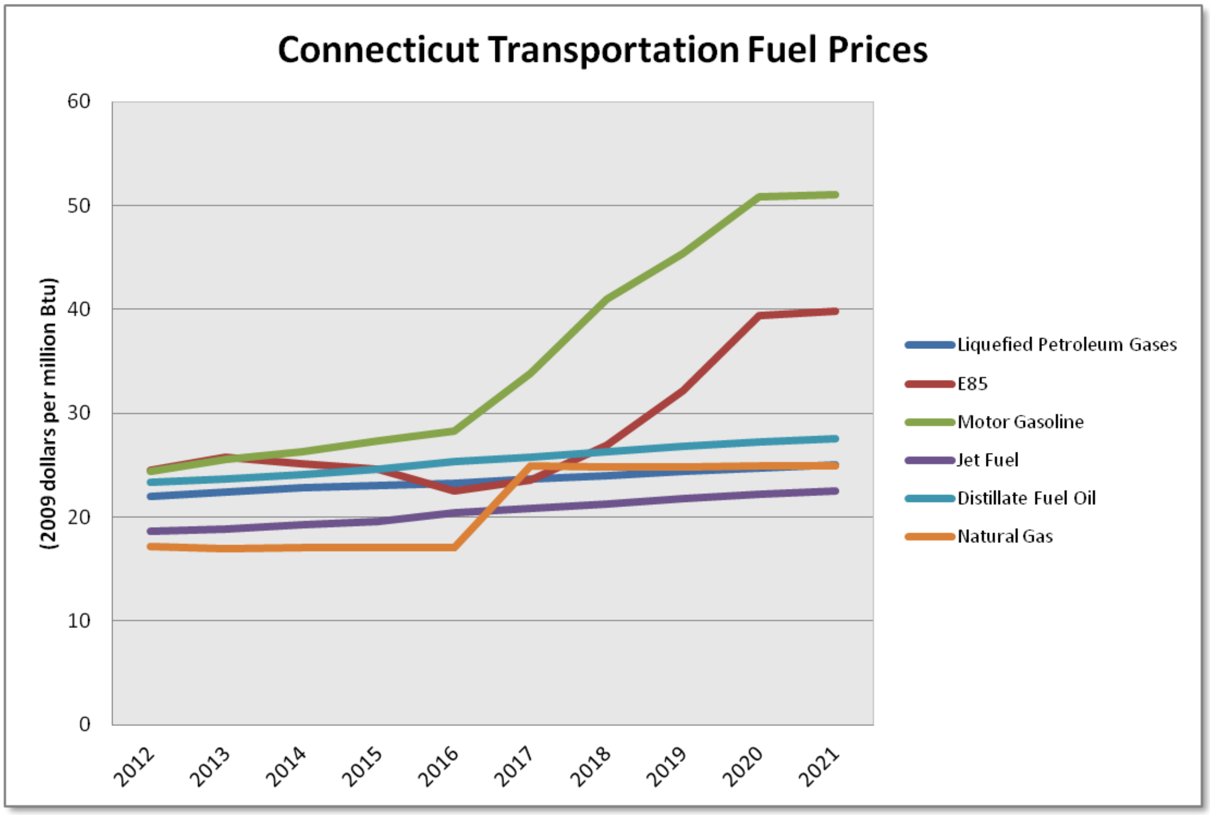
Connecticut Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
E85 (Gasoline Only)	0.0	0.1	0.4	9.7	12.6	14.0	15.2	16.4	17.2	18.1
Motor Gasoline (Gasoline Only)	175.7	175.5	173.9	154.2	147.6	142.3	136.5	131.2	126.2	122.1
Jet Fuel	13.0	13.0	13.0	13.1	13.2	13.2	13.3	13.3	13.4	13.4
Distillate Fuel Oil (Petroleum)	31.6	32.2	29.1	29.6	30.1	30.5	30.8	31.1	31.7	32.5
Residual Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Fuel Natural Gas	3.9	4.0	4.2	4.3	4.3	4.3	4.4	4.4	4.3	4.4
Compressed Natural Gas	2.2	2.9	3.7	4.3	4.8	5.2	5.6	6.2	7.0	7.9
Domestic Ethanol/Corn-Based	8.8	8.8	9.2	18.6	20.5	22.0	22.7	22.1	22.5	23.3
Domestic Ethanol/Cellulose-Based	4.5	4.5	4.7	6.2	7.5	7.7	8.5	10.5	11.2	11.5
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.4	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	11.0	12.3	15.6	15.6	15.6	15.6	15.5	15.4	15.4	15.5
Steam Coal (Gen Fuel)	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Natural Gas (Gen Fuel)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.6	0.6	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Total	252.4	254.7	255.1	257.0	257.6	255.9	253.7	251.9	250.3	250.0

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-3: CONNECTICUT – TRANSPORTATION FUEL PRICE TABLE[1]



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-15: CONNECTICUT – TRANSPORTATION FUEL PRICE TABLE

Connecticut Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	22.01	22.41	22.78	23.00	23.29	23.63	23.97	24.38	24.71	24.98
E85	24.55	25.73	25.13	24.63	22.54	23.55	26.86	32.14	39.38	39.83
Motor Gasoline	24.41	25.60	26.31	27.30	28.30	33.85	41.02	45.34	50.80	51.02
Jet Fuel	18.63	18.85	19.21	19.59	20.41	20.80	21.25	21.72	22.16	22.47
Distillate Fuel Oil	23.38	23.64	24.11	24.58	25.38	25.79	26.27	26.78	27.26	27.57
Natural Gas	17.20	17.00	17.06	17.05	17.08	24.95	24.85	24.80	24.88	24.95

FIGURE 5-4: CONNECTICUT – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

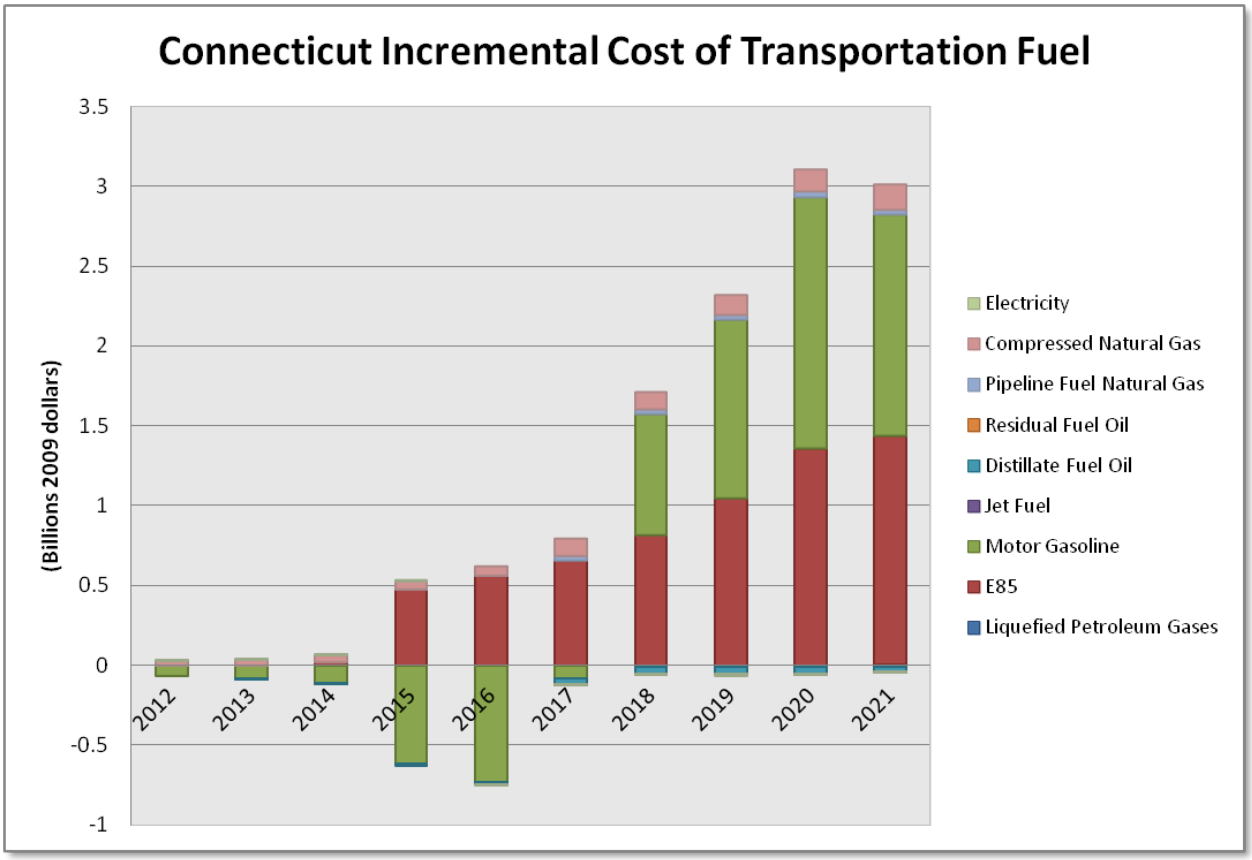


TABLE 5-16: CONNECTICUT – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Connecticut Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.001	0.001	0.001	0.002	0.002	0.003	0.003	0.004	0.004	**0.021**
E85	0.001	0.001	0.019	0.475	0.562	0.652	0.813	1.046	1.351	1.433	**6.353**
Motor Gasoline	-0.066	-0.082	-0.108	-0.617	-0.726	-0.077	0.754	1.115	1.578	1.383	**3.154**
Jet Fuel	0.001	-0.001	0.000	0.002	0.001	-0.005	-0.008	-0.007	-0.008	-0.006	**-0.032**
Distillate Fuel Oil	0.001	-0.006	-0.011	-0.012	-0.014	-0.031	-0.043	-0.046	-0.043	-0.028	**-0.233**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.001	0.001	0.034	0.034	0.033	0.033	0.033	**0.171**
Compressed Natural Gas	0.022	0.032	0.042	0.051	0.058	0.103	0.109	0.119	0.136	0.154	**0.826**
Electricity	0.000	0.000	0.000	0.000	0.000	-0.003	-0.006	-0.008	-0.008	-0.006	**-0.032**
Grand Total	**-0.040**	**-0.055**	**-0.056**	**-0.098**	**-0.116**	**0.675**	**1.656**	**2.255**	**3.042**	**2.967**	**10.228**

FIGURE 5-5: DELAWARE – TRANSPORTATION FUEL CONSUMPTION CHART

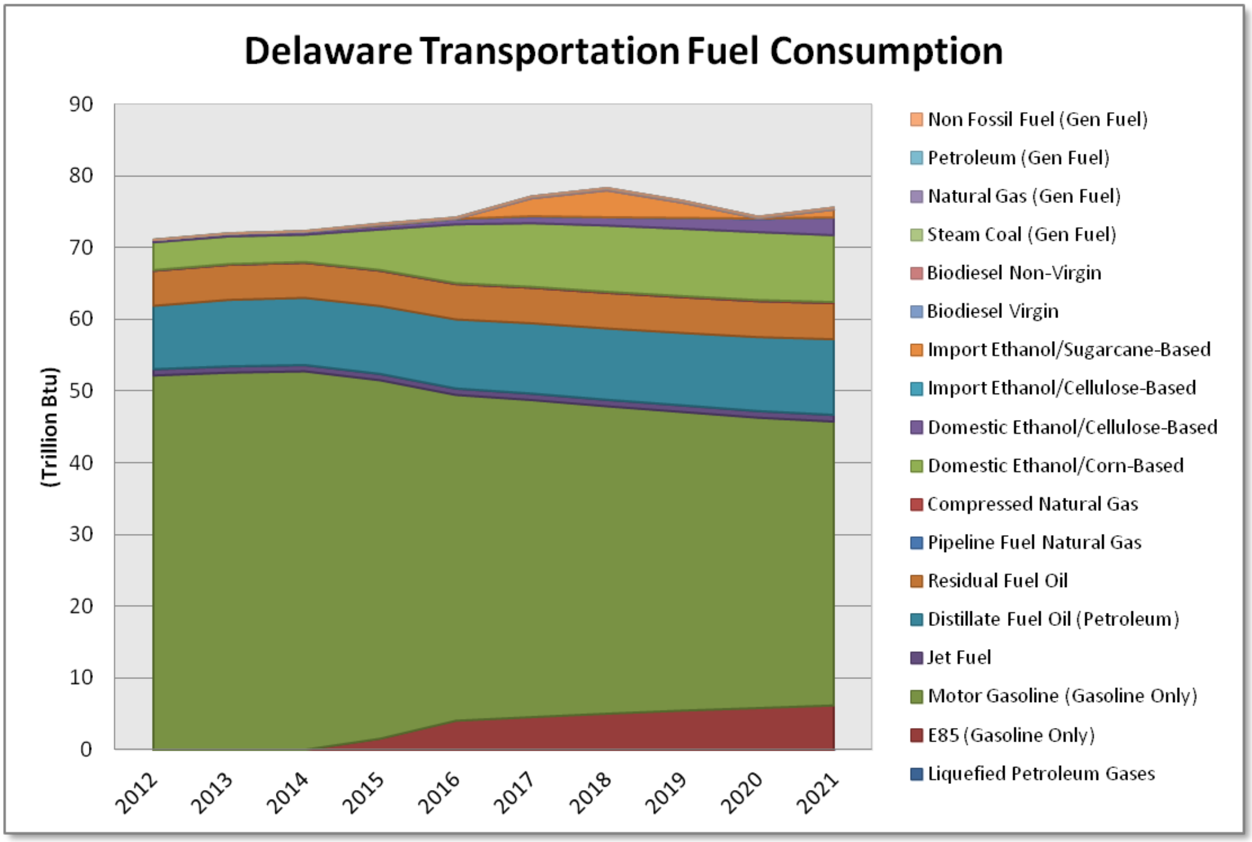


TABLE 5-17: DELAWARE – TRANSPORTATION FUEL CONSUMPTION TABLE

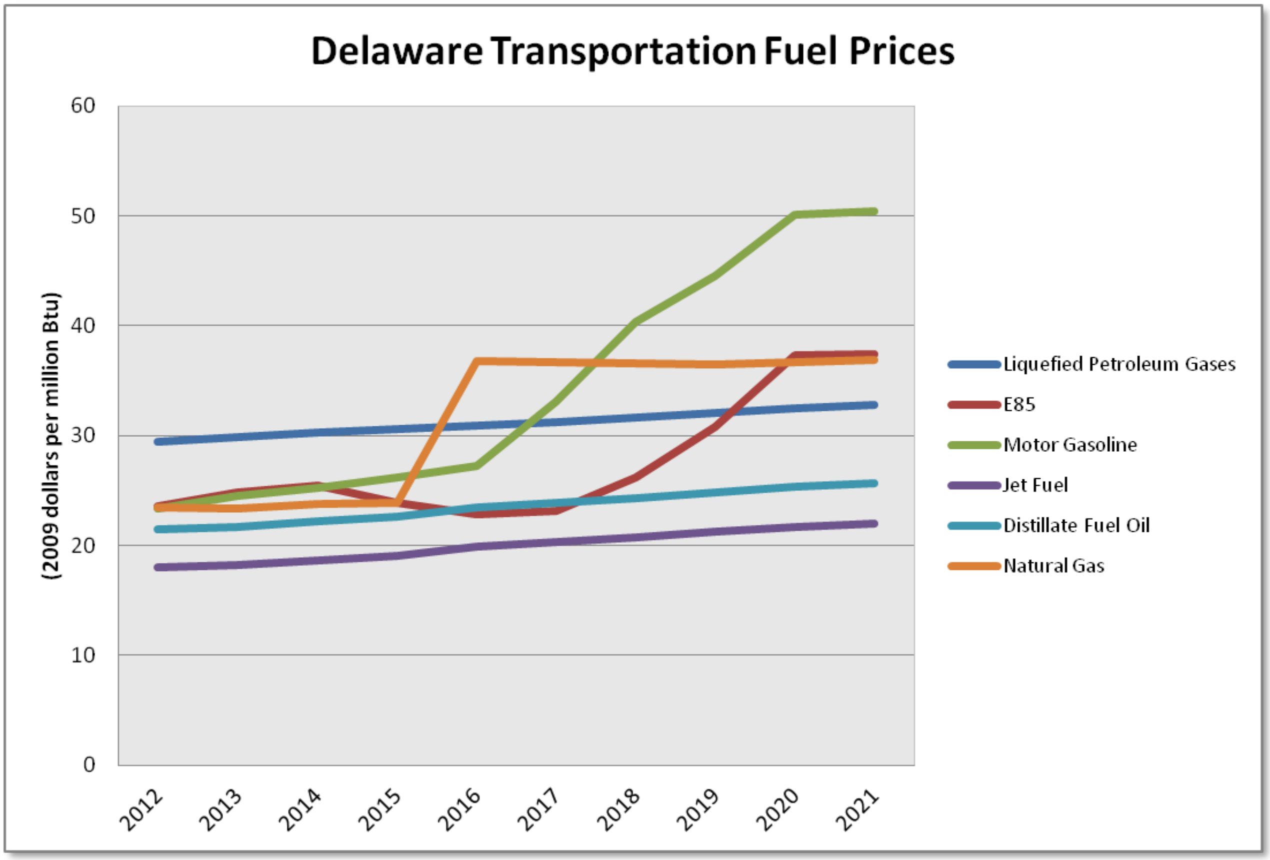
Delaware Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E85 (Gasoline Only)	0.0	0.0	0.0	1.6	4.1	4.6	5.0	5.5	5.8	6.2
Motor Gasoline (Gasoline Only)	52.1	52.5	52.7	49.9	45.4	44.2	42.8	41.6	40.5	39.6
Jet Fuel	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Distillate Fuel Oil (Petroleum)	8.9	9.3	9.4	9.5	9.7	9.8	10.0	10.1	10.3	10.6
Residual Fuel Oil	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.1
Pipeline Fuel Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compressed Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Ethanol/Corn-Based	3.9	3.9	3.8	5.7	8.2	8.9	9.3	9.4	9.5	9.3
Domestic Ethanol/Cellulose-Based	0.3	0.3	0.4	0.5	0.8	1.0	1.2	1.5	1.9	2.5
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.1	0.0	2.5	3.8	2.2	0.0	1.1
Biodiesel Non-Virgin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Steam Coal (Gen Fuel)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	71.1	72.0	72.3	73.4	74.2	77.1	78.3	76.5	74.3	75.6

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-6: DELAWARE – TRANSPORTATION FUEL PRICE CHART[1]



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-18: DELAWARE – TRANSPORTATION FUEL PRICE TABLE

Delaware Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	29.45	29.91	30.32	30.56	30.89	31.27	31.65	32.12	32.48	32.79
E85	23.58	24.79	25.50	23.89	22.89	23.15	26.17	30.79	37.30	37.42
Motor Gasoline	23.31	24.51	25.22	26.23	27.25	33.07	40.35	44.59	50.09	50.39
Jet Fuel	18.01	18.25	18.65	19.04	19.88	20.28	20.75	21.24	21.68	22.00
Distillate Fuel Oil	21.46	21.73	22.21	22.67	23.47	23.87	24.35	24.86	25.34	25.64
Natural Gas	23.44	23.36	23.76	23.89	36.83	36.71	36.57	36.47	36.63	36.86

TABLE 5-19: DELAWARE – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

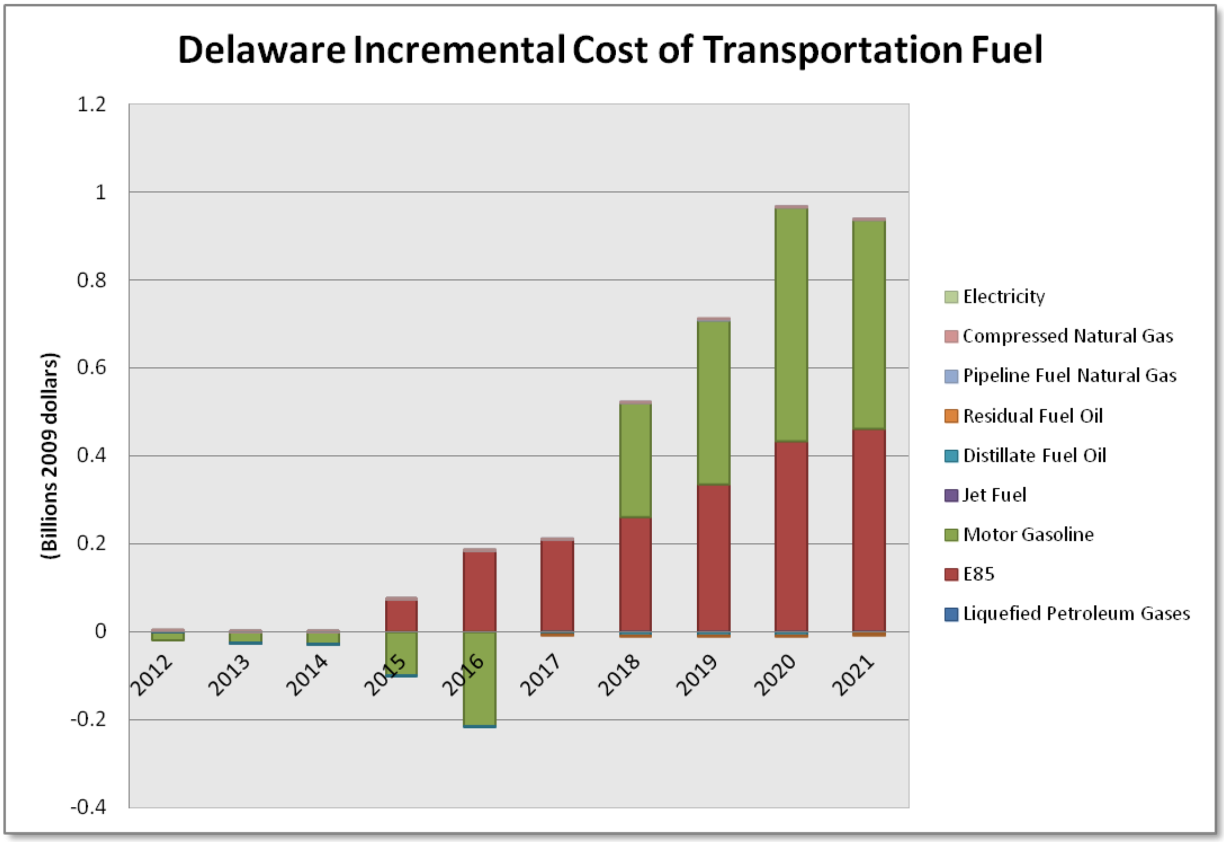


TABLE 5-20: DELAWARE – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Delaware Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.001**
E85	0.000	0.000	0.000	0.074	0.184	0.210	0.262	0.335	0.432	0.460	**1.958**
Motor Gasoline	-0.020	-0.025	-0.026	-0.098	-0.213	0.000	0.259	0.374	0.530	0.476	**1.257**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	0.000	-0.001	0.000	**-0.002**
Distillate Fuel Oil	0.001	-0.001	-0.002	-0.002	-0.002	-0.005	-0.007	-0.007	-0.007	-0.004	**-0.036**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	-0.001	-0.003	-0.003	-0.003	-0.003	**-0.012**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.002**
Compressed Natural Gas	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	**0.006**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.018**	**-0.025**	**-0.027**	**-0.025**	**-0.029**	**0.204**	**0.512**	**0.699**	**0.954**	**0.931**	**3.174**

FIGURE 5-7: MASSACHUSETTS TRANSPORTATION FUEL CONSUMPTION CHART

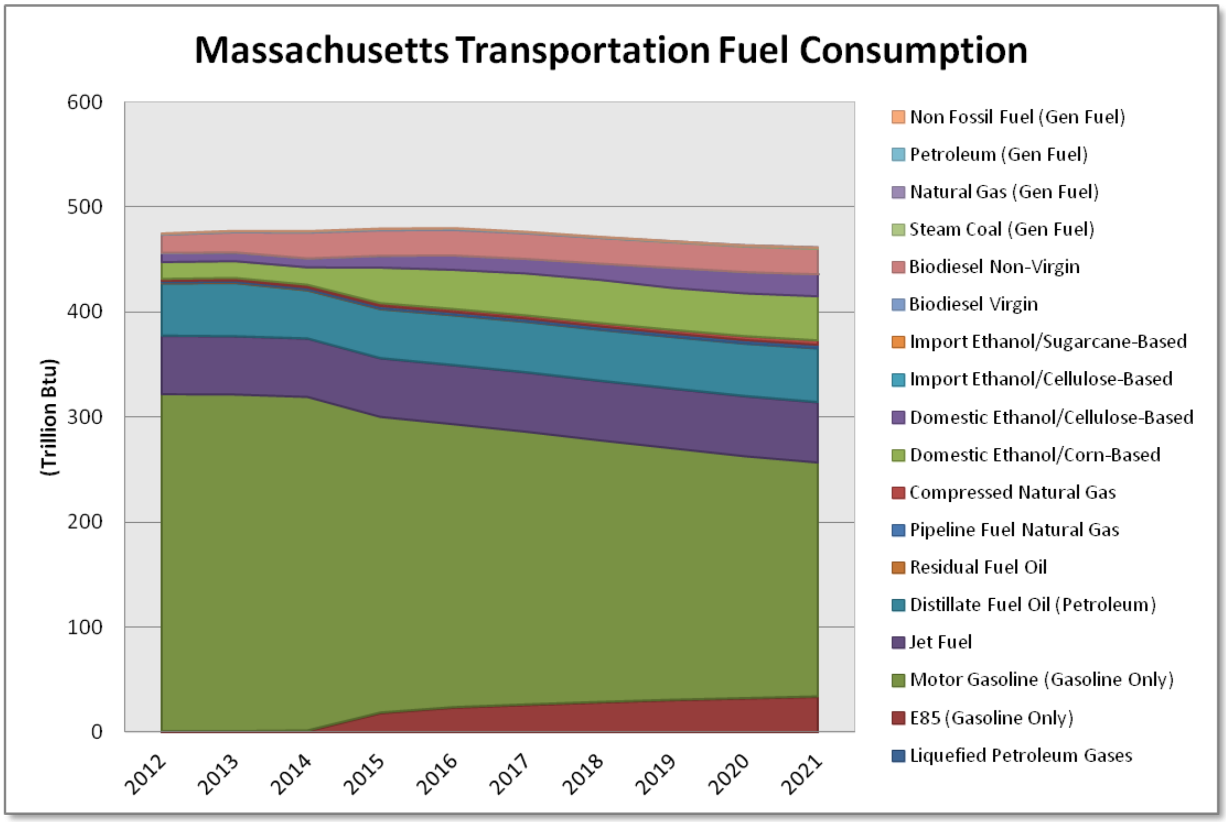


TABLE 5-21: MASSACHUSETTS TRANSPORTATION FUEL CONSUMPTION TABLE

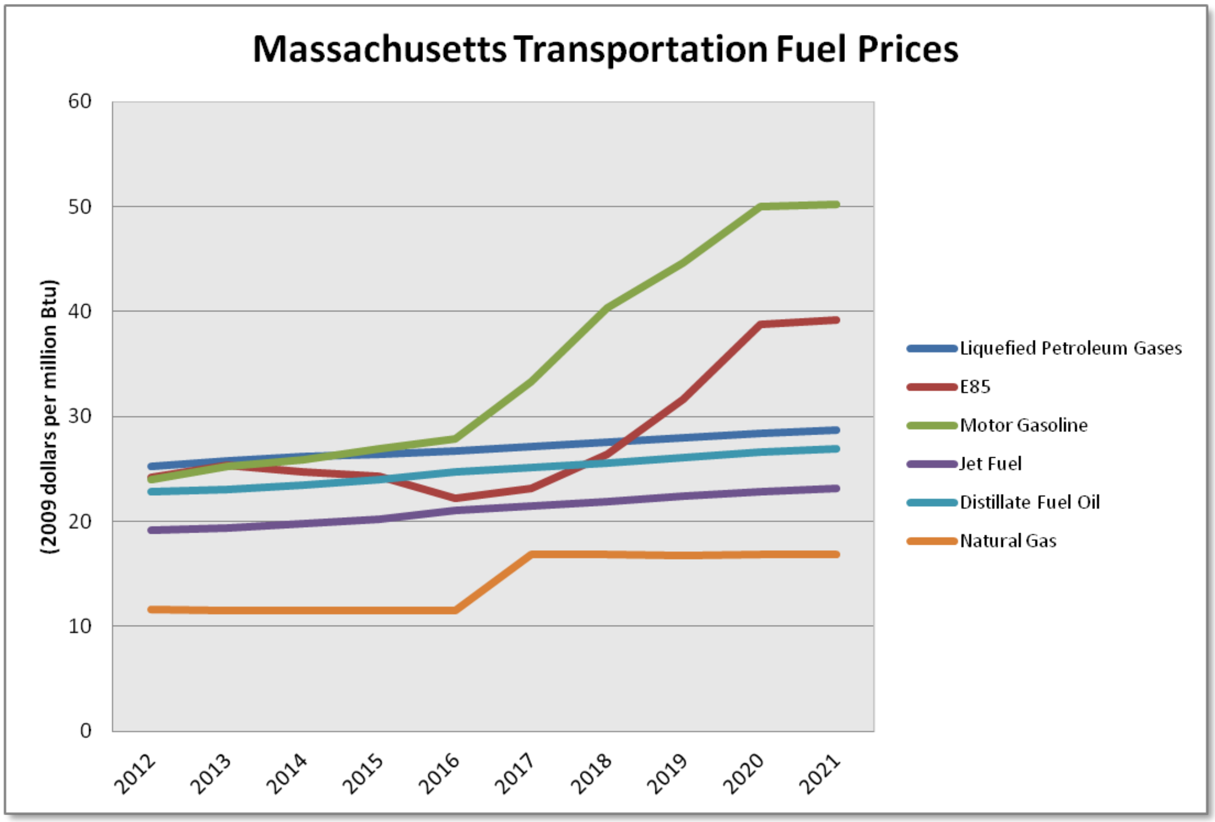
Massachusetts Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
E85 (Gasoline Only)	0.1	0.1	0.8	17.8	23.0	25.5	27.9	30.0	31.6	33.1
Motor Gasoline (Gasoline Only)	322.0	321.6	318.6	282.5	270.4	260.7	250.1	240.4	231.3	223.7
Jet Fuel	55.5	55.3	55.5	55.7	56.0	56.4	56.6	56.8	57.0	57.2
Distillate Fuel Oil (Petroleum)	49.5	50.6	45.7	46.5	47.3	47.8	48.3	48.8	49.7	50.9
Residual Fuel Oil	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pipeline Fuel Natural Gas	2.1	2.1	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Compressed Natural Gas	1.2	1.6	2.0	2.3	2.6	2.8	3.0	3.3	3.8	4.2
Domestic Ethanol/Corn-Based	16.1	16.0	16.8	34.0	37.6	40.2	41.5	40.5	41.2	42.6
Domestic Ethanol/Cellulose-Based	8.3	8.3	8.6	11.3	13.8	14.0	15.6	19.3	20.5	21.1
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.7	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	17.3	19.4	24.6	24.4	24.6	24.4	24.3	24.2	24.2	24.3
Steam Coal (Gen Fuel)	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Natural Gas (Gen Fuel)	0.7	0.7	0.7	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Petroleum (Gen Fuel)	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1
Non Fossil Fuel (Gen Fuel)	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.4	0.3	0.4
Total	474.9	477.4	477.1	479.5	479.9	476.5	471.9	467.8	463.9	461.9

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-8: MASSACHUSETTS – TRANSPORTATION FUEL PRICE CHART[1]



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-22: MASSACHUSETTS – TRANSPORTATION FUEL PRICE TABLE

Massachusetts Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	25.27	25.73	26.15	26.40	26.74	27.13	27.51	27.99	28.37	28.68
E85	24.17	25.33	24.74	24.26	22.19	23.19	26.45	31.65	38.77	39.22
Motor Gasoline	24.04	25.21	25.91	26.88	27.87	33.33	40.39	44.65	50.02	50.25
Jet Fuel	19.19	19.42	19.80	20.18	21.03	21.43	21.90	22.38	22.83	23.15
Distillate Fuel Oil	22.79	23.05	23.51	23.96	24.75	25.14	25.61	26.11	26.58	26.88
Natural Gas	11.63	11.50	11.54	11.54	11.55	16.88	16.81	16.78	16.83	16.88

TABLE 5-23: MASSACHUSETTS – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE

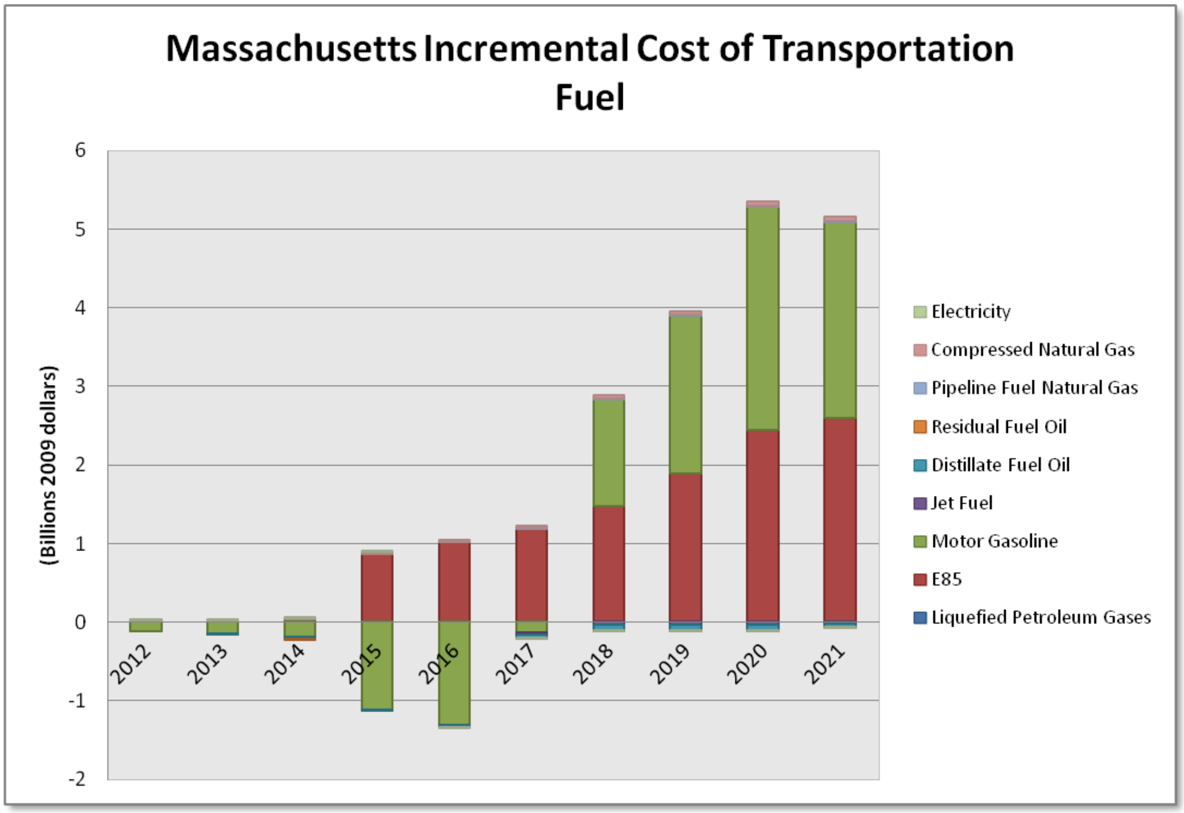


TABLE 5-24: MASSACHUSETTS – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Massachusetts Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.001	0.001	0.001	0.002	0.002	0.003	0.003	0.004	0.004	0.005	**0.027**
E85	0.001	0.001	0.035	0.857	1.013	1.175	1.465	1.884	2.433	2.583	**11.447**
Motor Gasoline	-0.119	-0.148	-0.195	-1.113	-1.311	-0.139	1.361	2.011	2.848	2.495	**5.691**
Jet Fuel	0.005	-0.004	-0.001	0.007	0.003	-0.022	-0.033	-0.032	-0.037	-0.028	**-0.142**
Distillate Fuel Oil	0.002	-0.010	-0.016	-0.018	-0.021	-0.048	-0.066	-0.070	-0.066	-0.042	**-0.356**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	0.000	0.000	**-0.002**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.012	0.012	0.012	0.012	0.012	**0.062**
Compressed Natural Gas	0.008	0.011	0.015	0.018	0.021	0.037	0.039	0.043	0.049	0.055	**0.298**
Electricity	0.000	0.000	0.000	0.000	0.000	-0.004	-0.008	-0.010	-0.010	-0.008	**-0.040**
Grand Total	**-0.102**	**-0.147**	**-0.160**	**-0.246**	**-0.292**	**1.014**	**2.773**	**3.841**	**5.233**	**5.072**	**16.985**

FIGURE 5-9: MARYLAND – TRANSPORTATION FUEL CONSUMPTION CHART

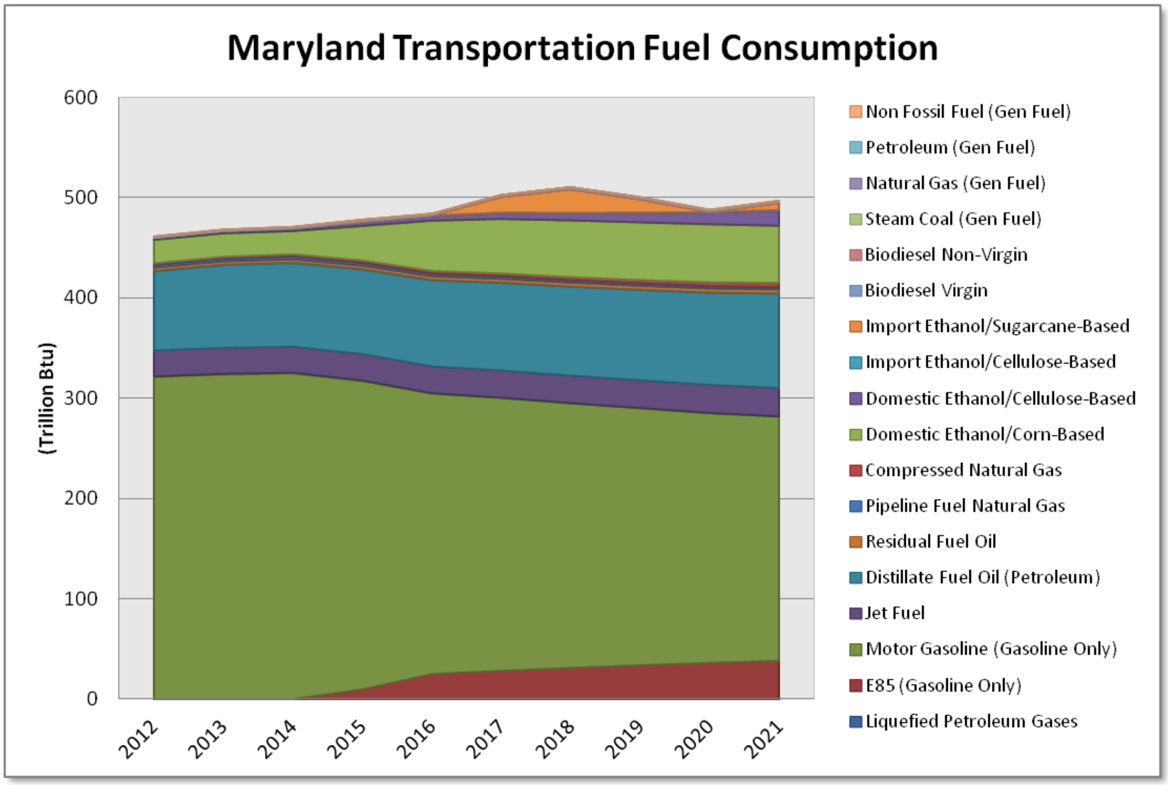


TABLE 5-25: MARYLAND – TRANSPORTATION FUEL CONSUMPTION TABLE

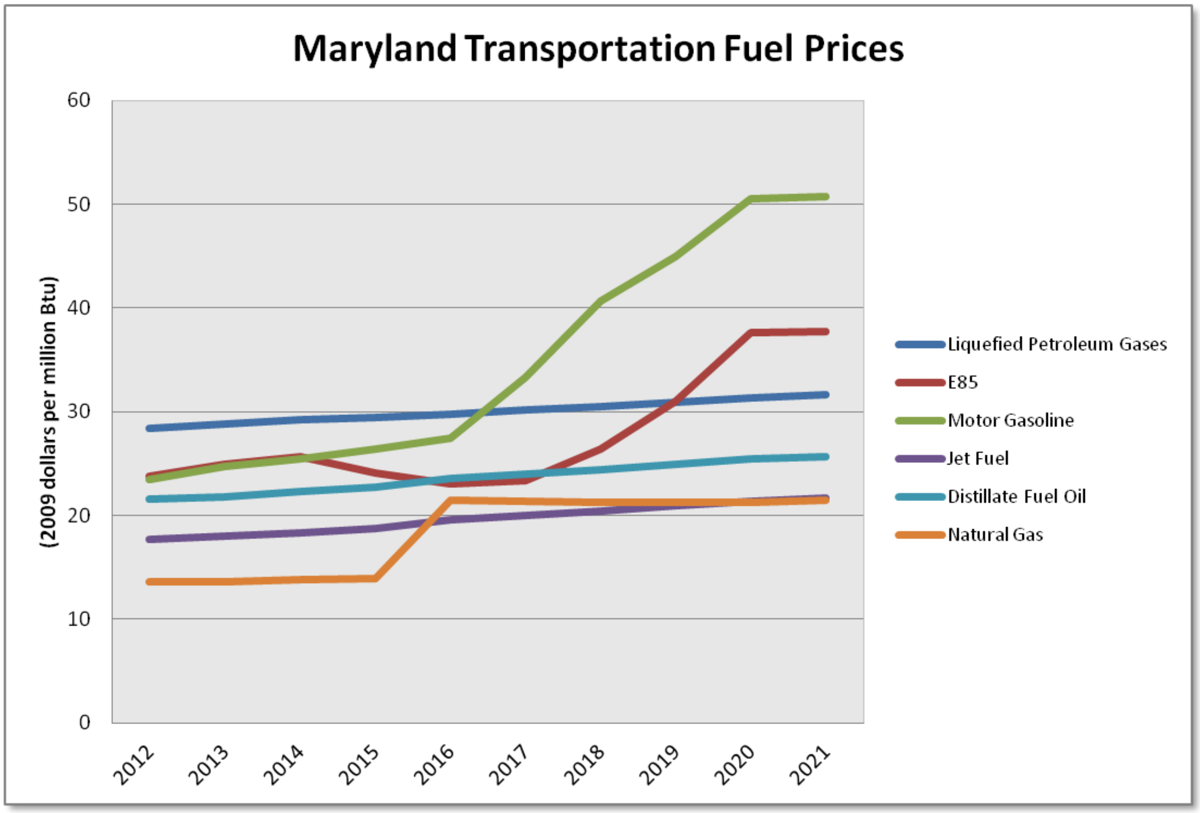
Massachusetts Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
E85 (Gasoline Only)	0.1	0.1	0.8	17.8	23.0	25.5	27.9	30.0	31.6	33.1
Motor Gasoline (Gasoline Only)	322.0	321.6	318.6	282.5	270.4	260.7	250.1	240.4	231.3	223.7
Jet Fuel	55.5	55.3	55.5	55.7	56.0	56.4	56.6	56.8	57.0	57.2
Distillate Fuel Oil (Petroleum)	49.5	50.6	45.7	46.5	47.3	47.8	48.3	48.8	49.7	50.9
Residual Fuel Oil	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pipeline Fuel Natural Gas	2.1	2.1	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Compressed Natural Gas	1.2	1.6	2.0	2.3	2.6	2.8	3.0	3.3	3.8	4.2
Domestic Ethanol/Corn-Based	16.1	16.0	16.8	34.0	37.6	40.2	41.5	40.5	41.2	42.6
Domestic Ethanol/Cellulose-Based	8.3	8.3	8.6	11.3	13.8	14.0	15.6	19.3	20.5	21.1
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.7	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	17.3	19.4	24.6	24.4	24.6	24.4	24.3	24.2	24.2	24.3
Steam Coal (Gen Fuel)	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Natural Gas (Gen Fuel)	0.7	0.7	0.7	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Petroleum (Gen Fuel)	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1
Non Fossil Fuel (Gen Fuel)	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.4	0.3	0.4
Total	474.9	477.4	477.1	479.5	479.9	476.5	471.9	467.8	463.9	461.9

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-10: MARYLAND – TRANSPORTATION FUEL PRICE CHART[1]



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-26: MARYLAND – TRANSPORTATION FUEL PRICE TABLE

Maryland Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	28.40	28.83	29.23	29.46	29.78	30.15	30.51	30.96	31.32	31.61
E85	23.76	24.98	25.70	24.08	23.06	23.33	26.37	31.03	37.58	37.71
Motor Gasoline	23.49	24.70	25.42	26.43	27.46	33.33	40.66	44.94	50.48	50.78
Jet Fuel	17.75	17.99	18.38	18.76	19.59	19.99	20.45	20.93	21.36	21.68
Distillate Fuel Oil	21.53	21.80	22.28	22.74	23.54	23.95	24.42	24.94	25.41	25.72
Natural Gas	13.64	13.59	13.82	13.90	21.43	21.36	21.28	21.22	21.31	21.45

FIGURE 5-11: MARYLAND – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

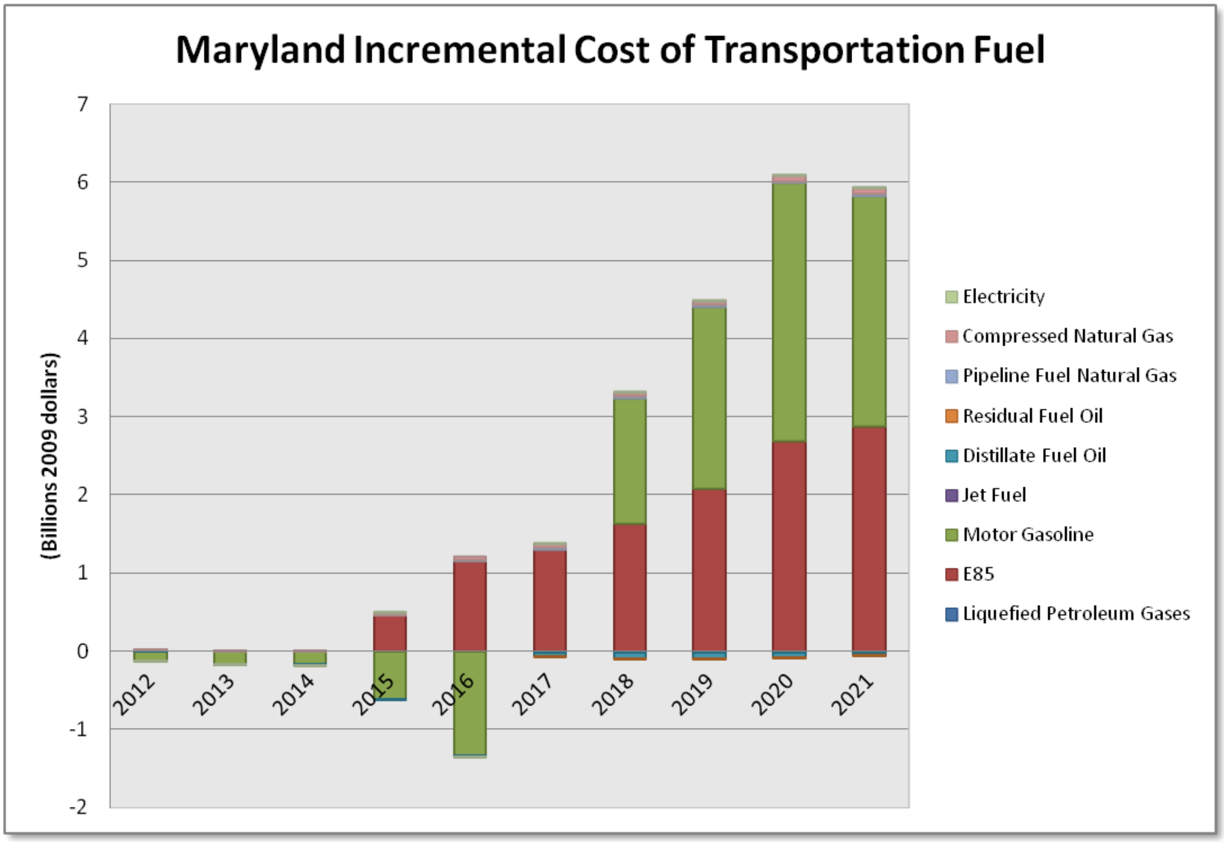


TABLE 5-27: MARYLAND – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Maryland Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002	**0.013**
E85	0.001	0.001	0.002	0.459	1.147	1.305	1.630	2.083	2.689	2.863	**12.180**
Motor Gasoline	-0.122	-0.152	-0.163	-0.610	-1.323	-0.001	1.608	2.321	3.296	2.958	**7.810**
Jet Fuel	0.002	-0.002	0.000	0.003	0.001	-0.010	-0.016	-0.015	-0.017	-0.013	**-0.066**
Distillate Fuel Oil	0.005	-0.008	-0.014	-0.016	-0.018	-0.046	-0.064	-0.066	-0.061	-0.034	**-0.322**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	-0.001	-0.002	-0.002	-0.002	-0.002	**-0.008**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.020	0.019	0.019	0.019	0.018	0.018	**0.114**
Compressed Natural Gas	0.009	0.014	0.019	0.023	0.044	0.048	0.051	0.056	0.065	0.074	**0.405**
Electricity	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.003	0.006	0.009	**0.020**
Grand Total	**-0.104**	**-0.146**	**-0.156**	**-0.138**	**-0.127**	**1.316**	**3.229**	**4.401**	**5.996**	**5.876**	**20.146**

FIGURE 5-12: MAINE – TRANSPORTATION FUEL CONSUMPTION CHART

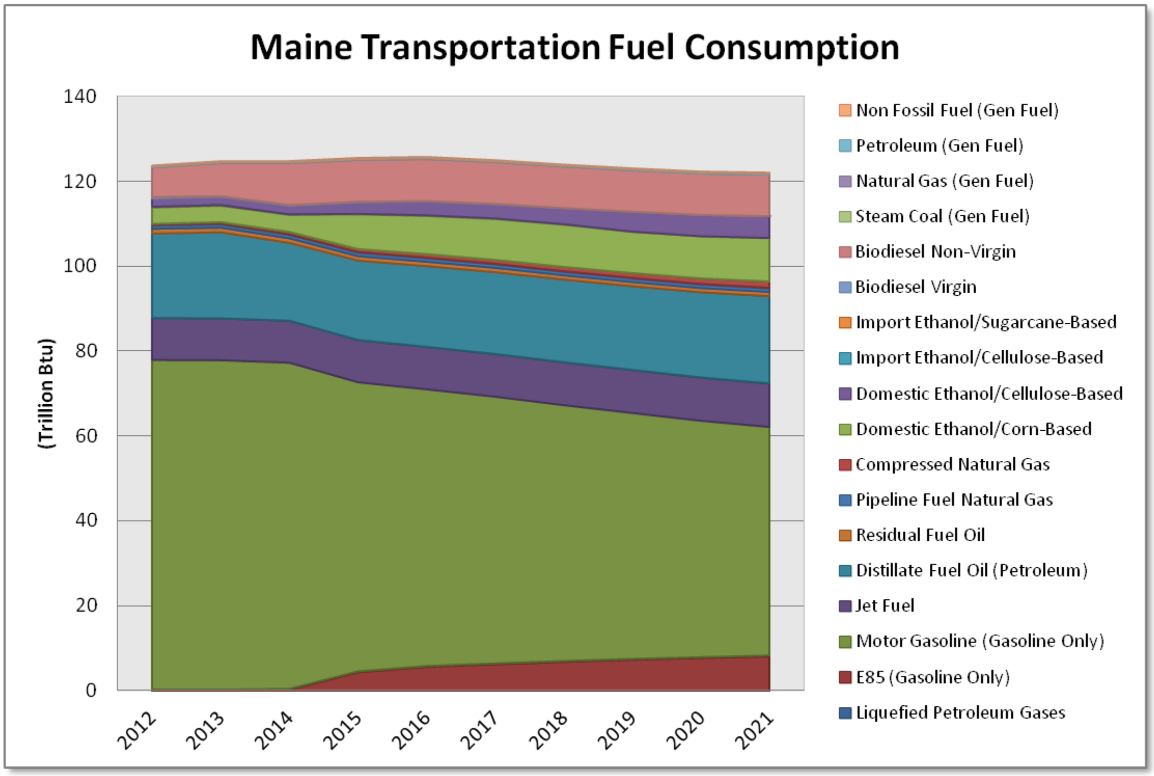


TABLE 5-28: MAINE – TRANSPORTATION FUEL CONSUMPTION TABLE

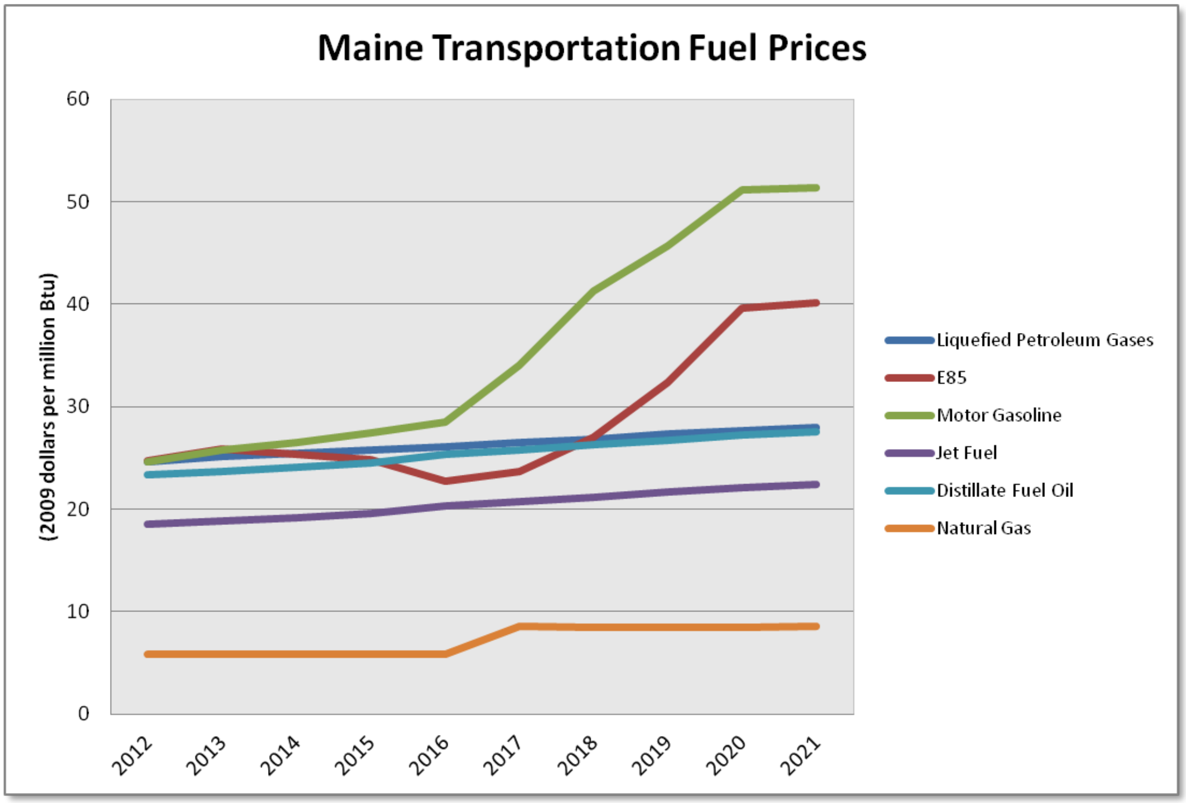
Maine Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
E85 (Gasoline Only)	0.0	0.0	0.2	4.3	5.6	6.2	6.8	7.3	7.7	8.0
Motor Gasoline (Gasoline Only)	77.8	77.8	77.0	68.3	65.4	63.0	60.5	58.1	55.9	54.1
Jet Fuel	9.8	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2
Distillate Fuel Oil (Petroleum)	20.0	20.4	18.4	18.8	19.1	19.3	19.5	19.7	20.1	20.6
Residual Fuel Oil	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Pipeline Fuel Natural Gas	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Compressed Natural Gas	0.4	0.5	0.7	0.8	0.9	1.0	1.0	1.1	1.3	1.4
Domestic Ethanol/Corn-Based	3.9	3.9	4.1	8.3	9.1	9.8	10.1	9.8	10.0	10.3
Domestic Ethanol/Cellulose-Based	2.0	2.0	2.1	2.7	3.3	3.4	3.8	4.7	5.0	5.1
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.3	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	7.0	7.8	9.9	9.9	9.9	9.9	9.8	9.8	9.8	9.8
Steam Coal (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (Gen Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	123.6	124.6	124.6	125.4	125.6	124.9	123.8	122.9	122.2	121.9

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-13: MAINE TRANSPORTATION FUEL PRICE CHART[1]



2. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-29: MAINE TRANSPORTATION FUEL PRICE TABLE

Maine Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	24.65	25.10	25.51	25.76	26.09	26.47	26.84	27.31	27.67	27.98
E85	24.72	25.91	25.30	24.80	22.70	23.72	27.05	32.36	39.65	40.11
Motor Gasoline	24.59	25.78	26.49	27.49	28.50	34.08	41.31	45.66	51.16	51.38
Jet Fuel	18.59	18.81	19.17	19.55	20.37	20.75	21.21	21.68	22.11	22.42
Distillate Fuel Oil	23.36	23.63	24.09	24.56	25.37	25.77	26.25	26.76	27.25	27.55
Natural Gas	5.89	5.82	5.84	5.84	5.85	8.54	8.51	8.49	8.52	8.54

FIGURE 5-14: MAINE – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

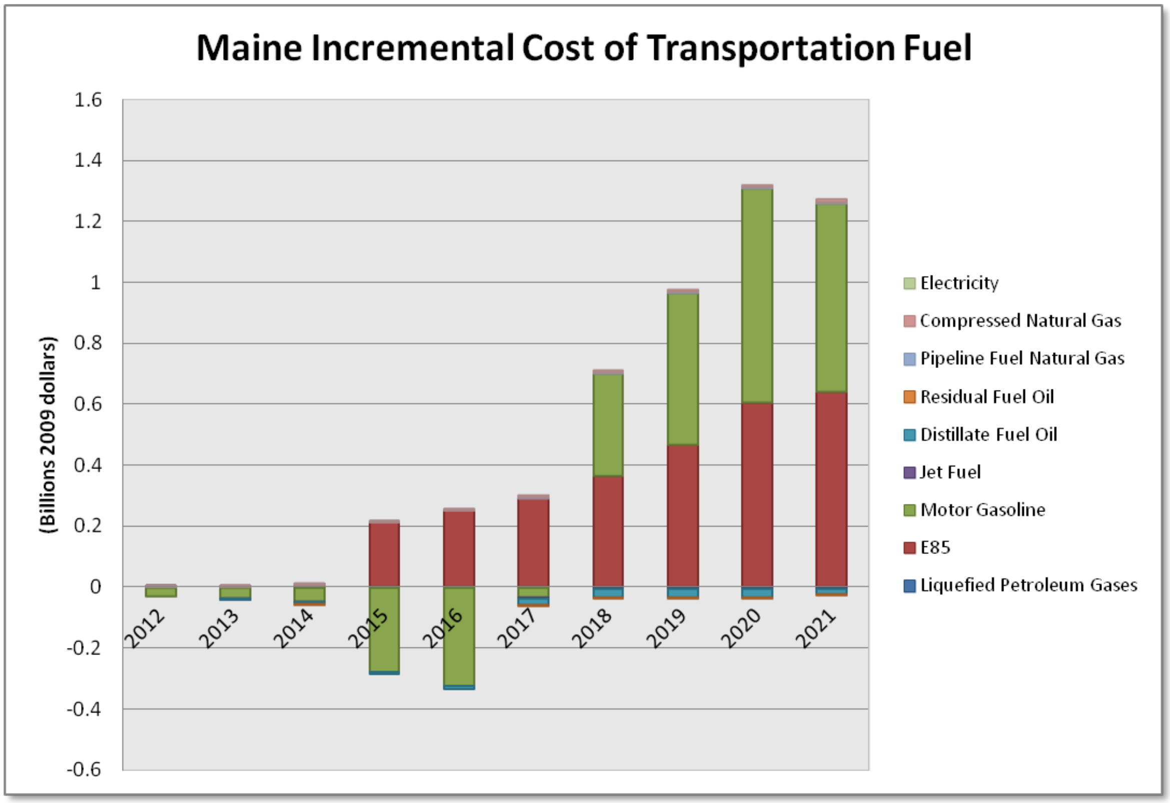


TABLE 5-30: MAINE – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Maine Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	**0.006**
E85	0.000	0.000	0.009	0.212	0.251	0.291	0.363	0.467	0.604	0.641	**2.840**
Motor Gasoline	-0.029	-0.036	-0.048	-0.275	-0.324	-0.034	0.337	0.497	0.704	0.617	**1.407**
Jet Fuel	0.001	-0.001	0.000	0.001	0.001	-0.004	-0.006	-0.006	-0.006	-0.005	**-0.024**
Distillate Fuel Oil	0.001	-0.004	-0.007	-0.007	-0.009	-0.020	-0.027	-0.029	-0.027	-0.017	**-0.147**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	**-0.002**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	**0.011**
Compressed Natural Gas	0.001	0.002	0.003	0.003	0.004	0.006	0.007	0.007	0.008	0.010	**0.052**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.026**	**-0.039**	**-0.044**	**-0.065**	**-0.077**	**0.242**	**0.676**	**0.940**	**1.285**	**1.248**	**4.141**

FIGURE 5-15: NEW HAMPSHIRE – TRANSPORTATION FUEL CONSUMPTION CHART

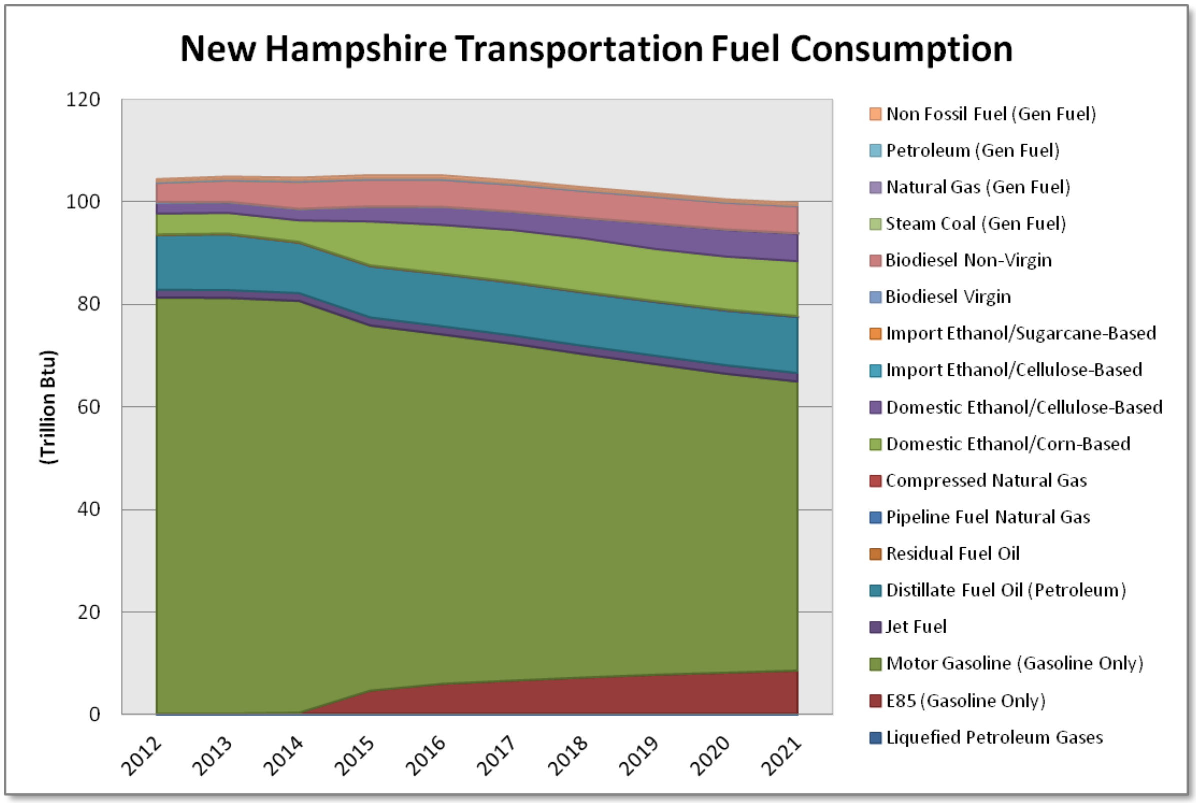


TABLE 5-31: NEW HAMPSHIRE – TRANSPORTATION FUEL CONSUMPTION TABLE

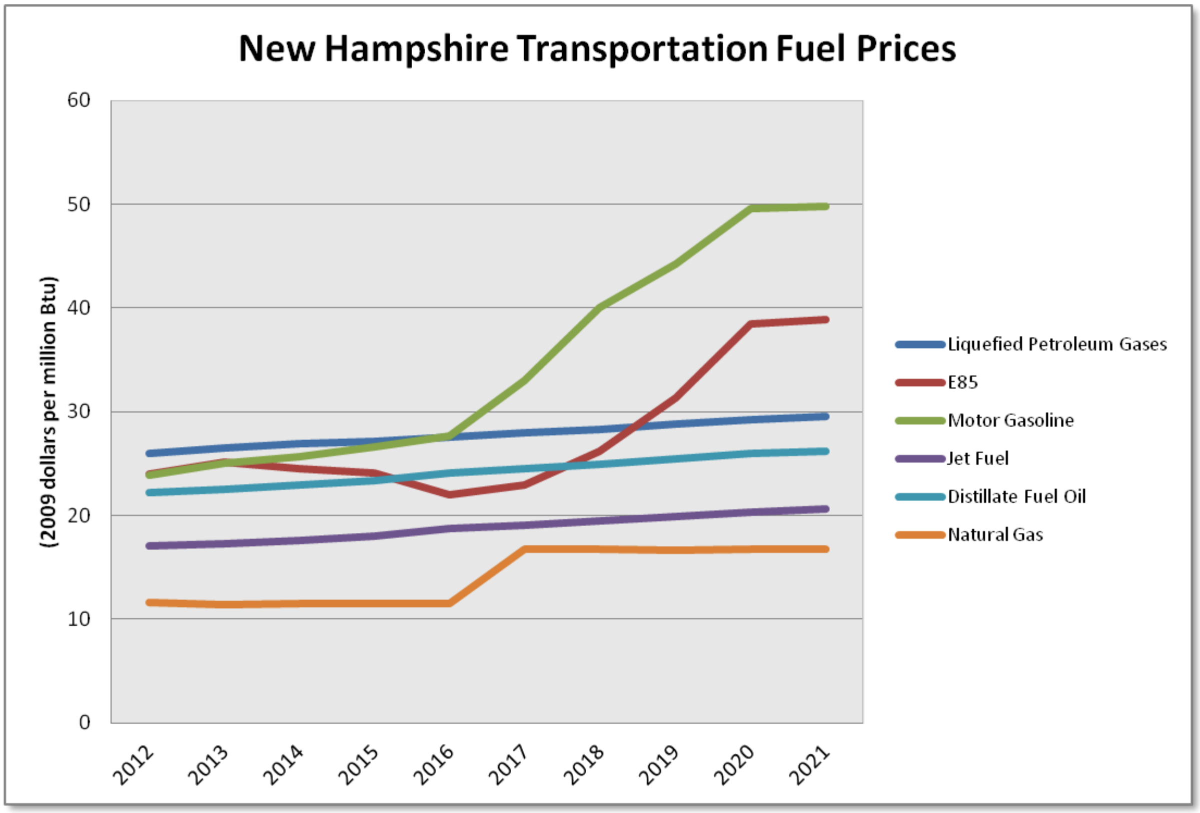
New Hampshire Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
E85 (Gasoline Only)	0.0	0.0	0.2	4.5	5.8	6.5	7.1	7.6	8.0	8.4
Motor Gasoline (Gasoline Only)	81.2	81.1	80.4	71.3	68.2	65.8	63.1	60.6	58.3	56.4
Jet Fuel	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7
Distillate Fuel Oil (Petroleum)	10.7	10.9	9.9	10.1	10.2	10.4	10.5	10.6	10.8	11.0
Residual Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Fuel Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compressed Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Domestic Ethanol/Corn-Based	4.1	4.1	4.3	8.6	9.5	10.2	10.5	10.2	10.4	10.8
Domestic Ethanol/Cellulose-Based	2.1	2.1	2.2	2.9	3.5	3.6	3.9	4.9	5.2	5.3
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	3.7	4.2	5.3	5.3	5.3	5.3	5.3	5.2	5.2	5.3
Steam Coal (Gen Fuel)	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Natural Gas (Gen Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.5
Total	104.4	104.9	104.7	105.2	105.2	104.2	102.9	101.7	100.5	99.9

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-16: NEW HAMPSHIRE TRANSPORTATION FUEL PRICE CHART



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-32: NEW HAMPSHIRE TRANSPORTATION FUEL PRICE TABLE

New Hampshire Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	26.02	26.50	26.93	27.19	27.53	27.93	28.33	28.82	29.21	29.53
E85	23.97	25.12	24.53	24.05	22.00	22.99	26.22	31.38	38.44	38.88
Motor Gasoline	23.83	24.99	25.68	26.65	27.63	33.04	40.04	44.27	49.59	49.81
Jet Fuel	17.10	17.30	17.64	17.98	18.74	19.09	19.51	19.94	20.34	20.63
Distillate Fuel Oil	22.24	22.49	22.93	23.38	24.15	24.53	24.99	25.48	25.93	26.23
Natural Gas	11.58	11.45	11.49	11.48	11.50	16.79	16.73	16.69	16.75	16.79

FIGURE 5-17: NEW HAMPSHIRE – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

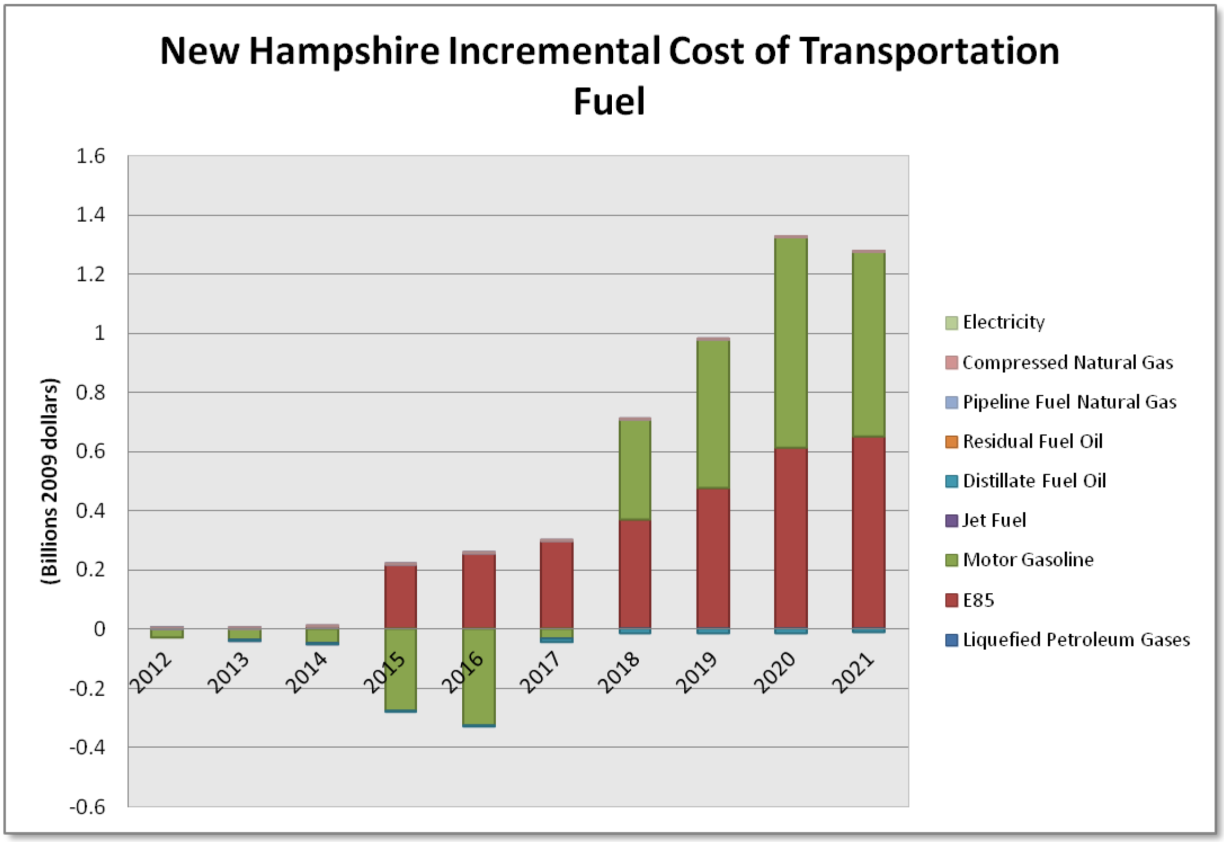


TABLE 5-33: NEW HAMPSHIRE – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

New Hampshire Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002	**0.012**
E85	0.000	0.000	0.009	0.215	0.254	0.295	0.368	0.473	0.611	0.649	**2.875**
Motor Gasoline	-0.030	-0.037	-0.049	-0.278	-0.328	-0.035	0.340	0.503	0.712	0.624	**1.423**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	**-0.004**
Distillate Fuel Oil	0.000	-0.002	-0.003	-0.004	-0.004	-0.010	-0.014	-0.015	-0.014	-0.009	**-0.075**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.001**
Compressed Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	**0.004**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.029**	**-0.038**	**-0.043**	**-0.066**	**-0.076**	**0.252**	**0.696**	**0.963**	**1.311**	**1.266**	**4.236**

FIGURE 5-18: NEW JERSEY – TRANSPORTATION FUEL CONSUMPTION CHART

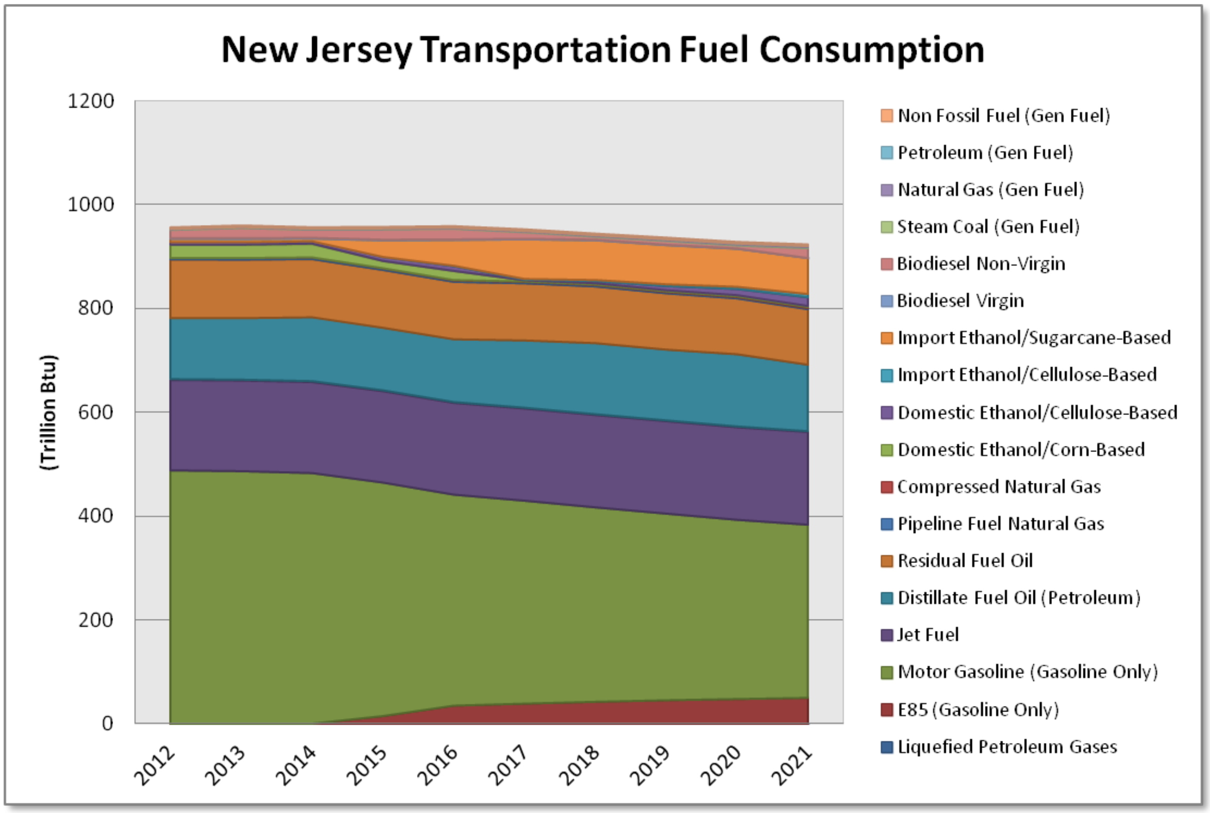


TABLE 5-34: NEW JERSEY – TRANSPORTATION FUEL CONSUMPTION TABLE

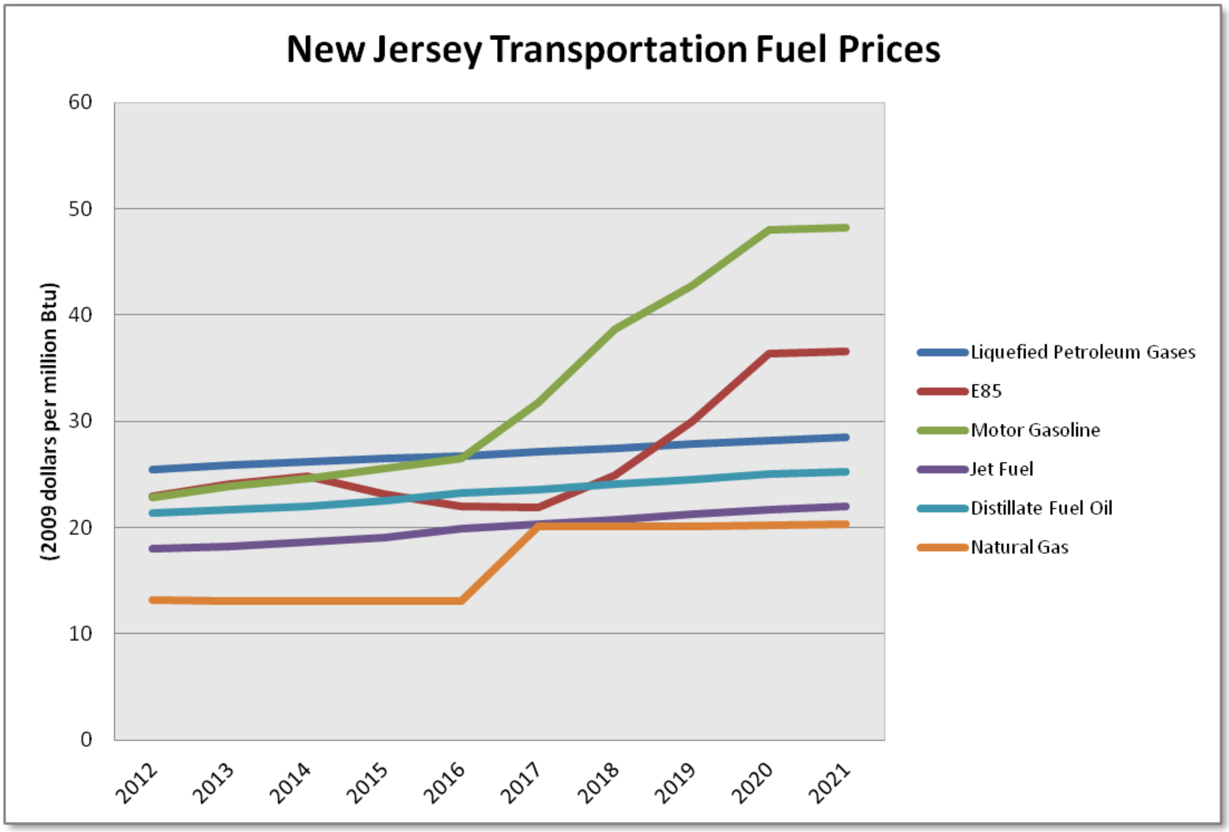
New Jersey Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5
E85 (Gasoline Only)	0.1	0.1	0.2	14.8	34.9	38.7	42.2	45.3	47.6	49.9
Motor Gasoline (Gasoline Only)	488.5	486.9	483.1	450.2	406.8	391.3	374.8	359.7	345.4	333.7
Jet Fuel	174.4	174.8	175.7	176.4	177.0	177.7	178.1	178.3	178.5	178.9
Distillate Fuel Oil (Petroleum)	118.3	119.5	123.9	121.1	121.5	130.2	137.4	136.8	139.5	128.3
Residual Fuel Oil	113.9	113.4	112.8	112.3	111.6	111.0	110.4	109.7	108.9	108.3
Pipeline Fuel Natural Gas	1.6	1.6	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Compressed Natural Gas	0.3	0.4	0.6	0.7	0.7	0.8	0.9	0.9	1.1	1.2
Domestic Ethanol/Corn-Based	25.0	25.3	25.9	13.7	17.3	2.2	2.2	2.2	2.2	2.2
Domestic Ethanol/Cellulose-Based	5.4	5.5	5.6	7.4	9.0	0.9	4.0	7.7	11.6	16.3
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.8	1.2	1.5	2.1	3.2	4.0	6.1
Import Ethanol/Sugarcane-Based	6.9	6.6	5.5	32.5	50.5	77.4	77.8	76.6	74.4	70.3
Biodiesel Non-Virgin	0.4	0.6	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	16.0	19.9	16.0	20.0	20.8	13.1	6.4	7.8	6.4	19.4
Steam Coal (Gen Fuel)	0.9	0.9	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Natural Gas (Gen Fuel)	1.8	1.7	2.2	2.3	2.3	2.4	2.3	2.3	2.3	2.3
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	3.4	3.5	3.1	3.2	3.3	3.3	3.3	3.4	3.3	3.5
Total	957.3	961.1	957.6	958.3	959.8	953.3	944.8	936.7	928.2	923.2

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-19: NEW JERSEY – TRANSPORTATION FUEL PRICE CHART



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-35: NEW JERSEY – TRANSPORTATION FUEL PRICE TABLE

New Jersey Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	25.43	25.85	26.23	26.46	26.76	27.12	27.47	27.90	28.24	28.52
E85	22.98	24.11	24.79	23.17	22.00	21.90	24.92	29.97	36.38	36.61
Motor Gasoline	22.79	23.92	24.60	25.55	26.50	31.76	38.62	42.77	48.00	48.21
Jet Fuel	18.00	18.25	18.65	19.05	19.89	20.29	20.76	21.25	21.69	22.01
Distillate Fuel Oil	21.41	21.63	22.03	22.48	23.23	23.62	24.07	24.56	25.01	25.30
Natural Gas	13.16	13.04	13.12	13.11	13.12	20.16	20.12	20.14	20.23	20.32

FIGURE 5-20: NEW JERSEY – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

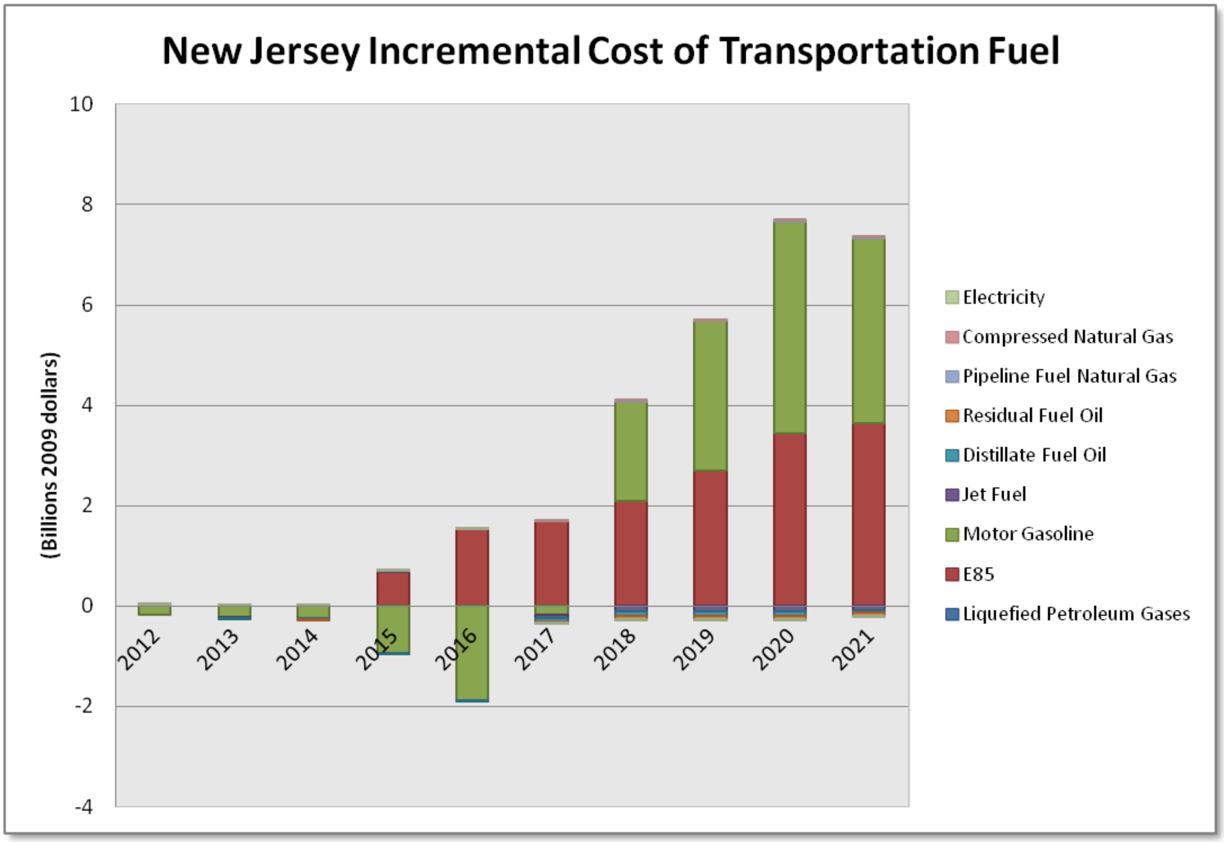


TABLE 5-36: NEW JERSEY – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

New Jersey Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.001	0.002	0.002	0.003	0.003	0.005	0.006	0.006	0.007	0.008	**0.043**
E85	0.002	0.002	0.002	0.676	1.522	1.681	2.088	2.695	3.442	3.629	**15.738**
Motor Gasoline	-0.175	-0.216	-0.229	-0.922	-1.869	-0.167	1.986	2.982	4.216	3.700	**9.305**
Jet Fuel	0.016	-0.013	-0.001	0.022	0.010	-0.067	-0.102	-0.097	-0.110	-0.085	**-0.427**
Distillate Fuel Oil	0.008	-0.016	-0.028	-0.031	-0.038	-0.069	-0.101	-0.097	-0.087	-0.049	**-0.508**
Residual Fuel Oil	0.011	0.005	-0.002	0.002	0.003	-0.024	-0.050	-0.061	-0.057	-0.057	**-0.230**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.013	0.013	0.013	0.013	0.013	**0.064**
Compressed Natural Gas	0.003	0.004	0.005	0.006	0.007	0.013	0.014	0.015	0.017	0.019	**0.101**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	**-0.004**
Grand Total	**-0.134**	**-0.232**	**-0.250**	**-0.244**	**-0.362**	**1.384**	**3.851**	**5.455**	**7.438**	**7.176**	**24.083**

FIGURE 5-21: NEW YORK – TRANSPORTATION FUEL CONSUMPTION CHART

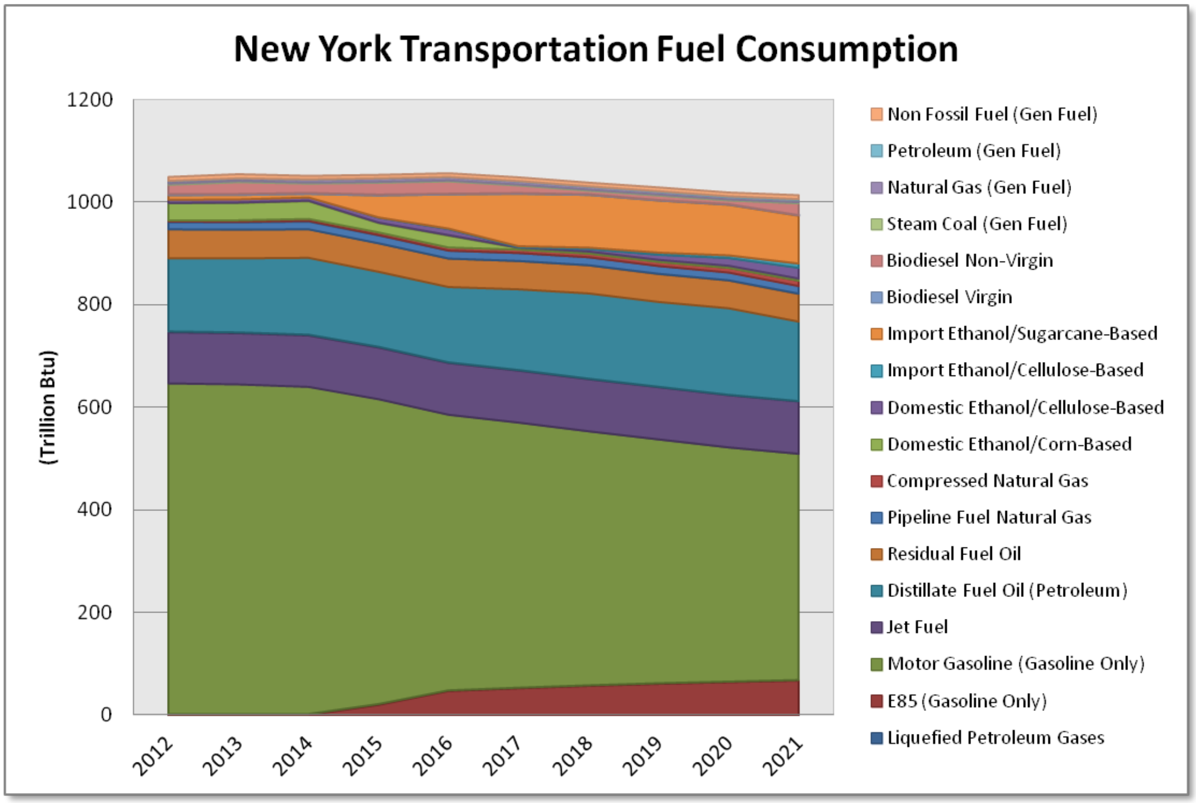


TABLE 5-37: NEW YORK – TRANSPORTATION FUEL CONSUMPTION TABLE

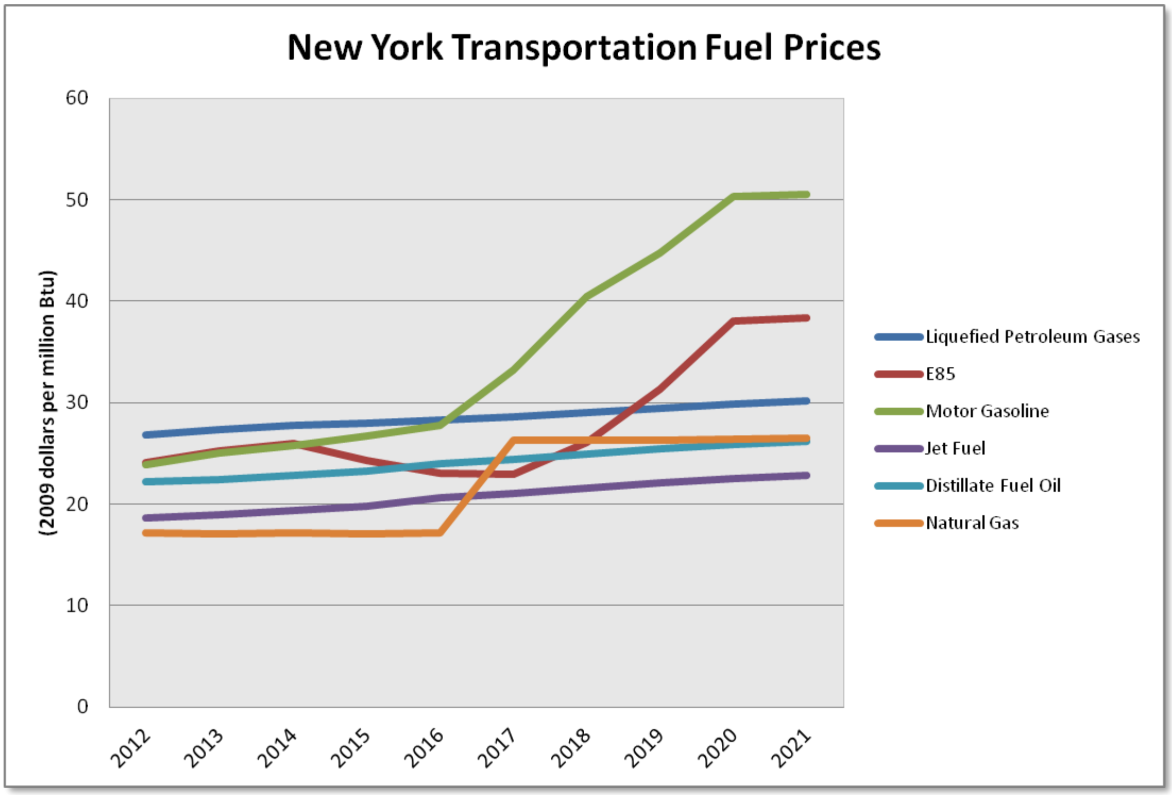
New York Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.4	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.7
E85 (Gasoline Only)	0.2	0.2	0.2	19.7	46.4	51.5	56.2	60.2	63.3	66.3
Motor Gasoline (Gasoline Only)	646.3	644.1	639.2	595.6	538.2	517.7	495.9	475.9	457.0	441.4
Jet Fuel	100.2	100.5	101.0	101.4	101.8	102.2	102.4	102.5	102.6	102.8
Distillate Fuel Oil (Petroleum)	144.3	145.8	151.2	147.7	148.3	158.8	167.7	166.9	170.2	156.6
Residual Fuel Oil	56.5	56.3	56.0	55.7	55.4	55.1	54.7	54.4	54.0	53.7
Pipeline Fuel Natural Gas	14.1	14.2	15.1	15.5	15.5	15.5	15.6	15.7	15.7	15.8
Compressed Natural Gas	2.9	3.9	4.9	5.7	6.5	7.0	7.5	8.3	9.3	10.5
Domestic Ethanol/Corn-Based	33.3	33.6	34.4	18.2	23.0	3.0	2.9	2.9	3.0	2.9
Domestic Ethanol/Cellulose-Based	7.2	7.3	7.5	9.9	12.0	1.2	5.4	10.3	15.5	21.6
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	1.1	1.6	2.0	2.8	4.3	5.3	8.1
Import Ethanol/Sugarcane-Based	9.2	8.7	7.3	43.2	67.2	103.0	103.5	102.0	99.0	93.6
Biodiesel Non-Virgin	0.5	0.7	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	19.6	24.3	19.5	24.4	25.4	16.0	7.9	9.5	7.8	23.6
Steam Coal (Gen Fuel)	1.7	1.8	1.2	1.1	1.3	1.3	1.3	1.3	1.3	1.4
Natural Gas (Gen Fuel)	4.5	4.2	5.5	5.8	5.7	5.8	5.7	5.7	5.6	5.6
Petroleum (Gen Fuel)	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Non Fossil Fuel (Gen Fuel)	7.6	8.0	6.8	6.8	7.2	7.2	7.2	7.3	7.3	7.6
Total	1,049.2	1,054.7	1,051.4	1,053.4	1,056.5	1,048.4	1,038.0	1,028.4	1,018.5	1,013.1

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-22: NEW YORK – TRANSPORTATION FUEL PRICE CHART



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-38: NEW YORK – TRANSPORTATION FUEL PRICE TABLE

New York Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	26.87	27.32	27.72	27.96	28.28	28.65	29.02	29.48	29.84	30.14
E85	24.06	25.25	25.95	24.26	23.03	22.93	26.09	31.38	38.09	38.33
Motor Gasoline	23.87	25.05	25.76	26.75	27.75	33.26	40.44	44.78	50.26	50.48
Jet Fuel	18.69	18.95	19.36	19.77	20.65	21.07	21.55	22.07	22.52	22.85
Distillate Fuel Oil	22.16	22.39	22.80	23.26	24.04	24.44	24.91	25.42	25.89	26.19
Natural Gas	17.18	17.03	17.13	17.11	17.13	26.31	26.27	26.29	26.40	26.53

FIGURE 5-23: NEW YORK – INCREMENTAL COST OF TRANSPORTATION FUEL

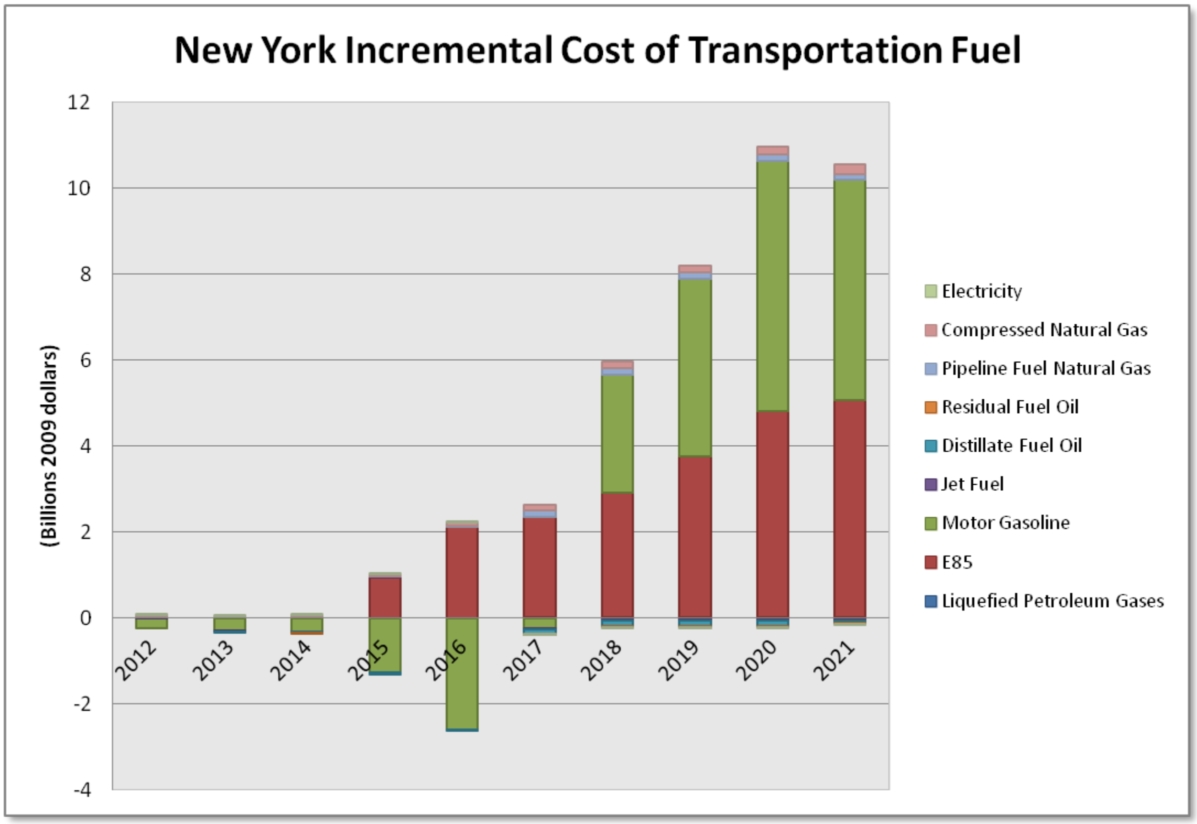


TABLE 5-39: NEW YORK – INCREMENTAL COST OF TRANSPORTATION FUEL (BILLION 2009 DOLLARS)

New York Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.002	0.002	0.003	0.004	0.005	0.007	0.008	0.009	0.010	0.012	**0.063**
E85	0.002	0.003	0.003	0.941	2.121	2.342	2.909	3.755	4.796	5.057	**21.929**
Motor Gasoline	-0.243	-0.299	-0.317	-1.278	-2.589	-0.231	2.751	4.131	5.840	5.125	**12.890**
Jet Fuel	0.010	-0.008	-0.001	0.013	0.006	-0.040	-0.061	-0.058	-0.066	-0.051	**-0.255**
Distillate Fuel Oil	0.010	-0.020	-0.035	-0.039	-0.048	-0.088	-0.128	-0.122	-0.110	-0.062	**-0.641**
Residual Fuel Oil	0.007	0.003	-0.001	0.001	0.002	-0.015	-0.031	-0.038	-0.036	-0.036	**-0.142**
Pipeline Fuel Natural Gas	0.002	0.002	0.002	0.003	0.004	0.146	0.145	0.145	0.145	0.146	**0.738**
Compressed Natural Gas	0.029	0.042	0.057	0.068	0.077	0.146	0.156	0.171	0.194	0.219	**1.160**
Electricity	0.000	0.001	0.001	0.002	0.003	-0.003	-0.007	-0.010	-0.012	-0.012	**-0.037**
Grand Total	**-0.181**	**-0.274**	**-0.288**	**-0.284**	**-0.421**	**2.267**	**5.742**	**7.983**	**10.762**	**10.399**	**35.705**

FIGURE 5-24: PENNSYLVANIA – TRANSPORTATION FUEL CONSUMPTION CHART

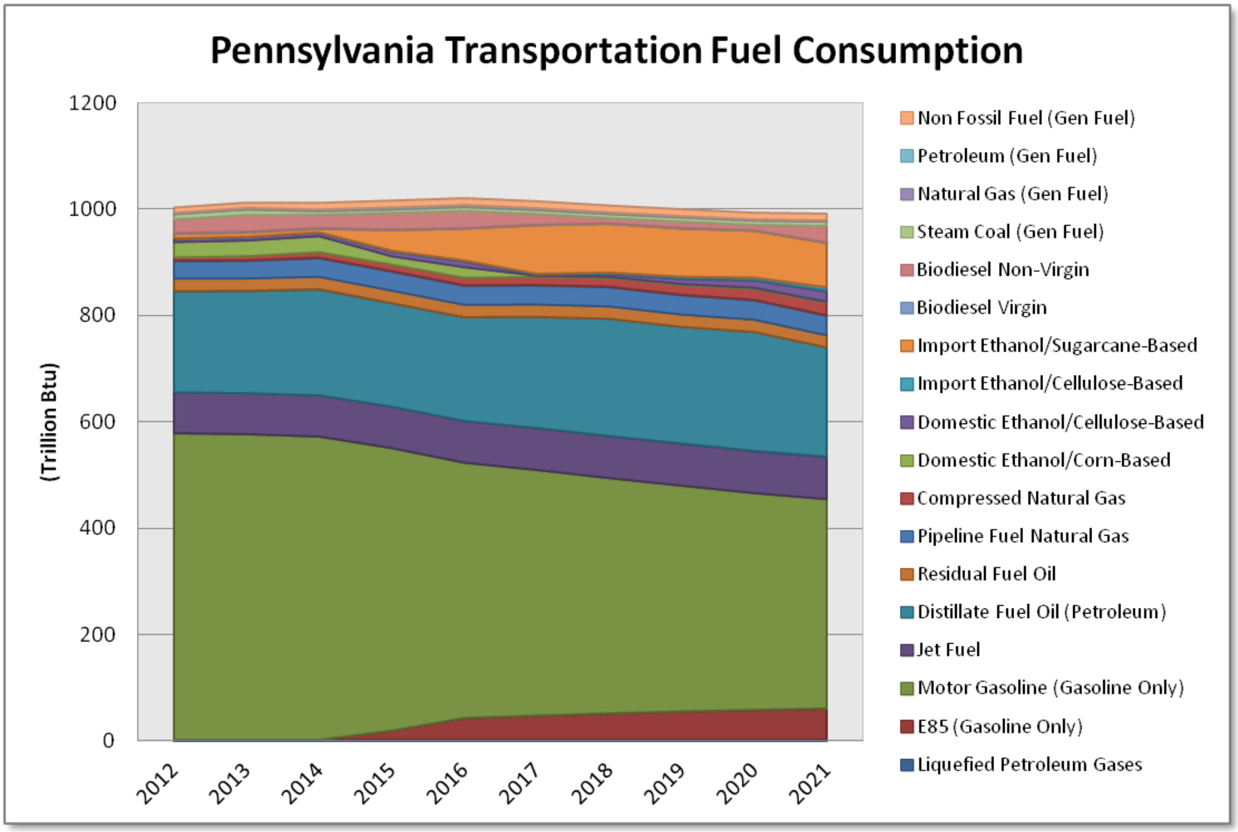


TABLE 5-40: PENNSYLVANIA – TRANSPORTATION FUEL CONSUMPTION TABLE

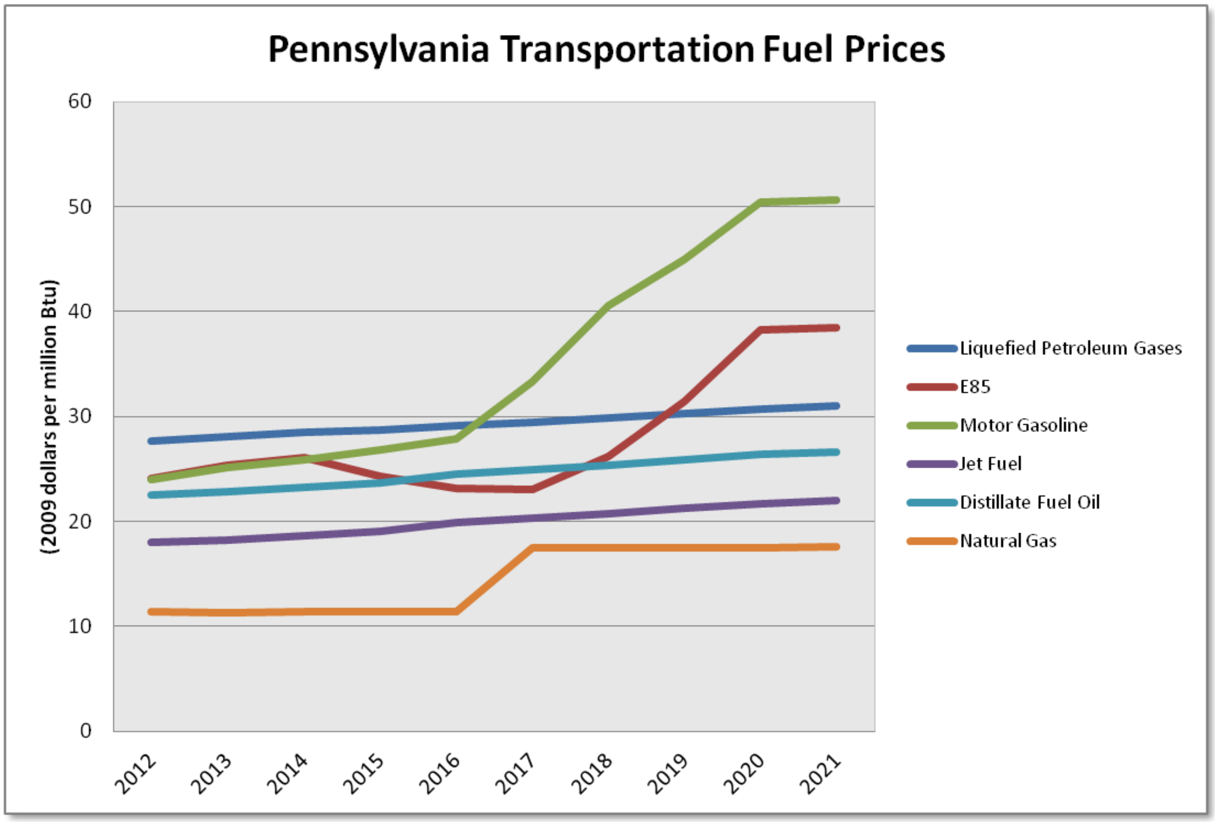
Pennsylvania Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.7	0.7	0.7	0.7	0.8	0.9	1.0	1.0	1.1	1.2
E85 (Gasoline Only)	0.1	0.2	0.2	17.5	41.3	45.8	50.0	53.6	56.3	59.0
Motor Gasoline (Gasoline Only)	577.4	575.4	571.1	532.1	480.9	462.5	443.0	425.2	408.3	394.4
Jet Fuel	76.8	77.0	77.4	77.7	78.0	78.3	78.5	78.6	78.6	78.8
Distillate Fuel Oil (Petroleum)	190.7	192.7	199.8	195.2	195.9	209.9	221.6	220.5	224.9	206.9
Residual Fuel Oil	24.6	24.5	24.4	24.3	24.1	24.0	23.8	23.7	23.5	23.4
Pipeline Fuel Natural Gas	32.5	32.6	34.8	35.5	35.6	35.7	35.9	36.1	36.2	36.4
Compressed Natural Gas	6.8	9.0	11.2	13.2	14.8	16.1	17.3	19.0	21.5	24.1
Domestic Ethanol/Corn-Based	29.6	29.9	30.7	16.2	20.5	2.6	2.6	2.6	2.6	2.6
Domestic Ethanol/Cellulose-Based	6.4	6.5	6.6	8.8	10.7	1.1	4.8	9.2	13.8	19.2
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	1.0	1.4	1.8	2.5	3.8	4.7	7.2
Import Ethanol/Sugarcane-Based	8.2	7.8	6.5	38.5	59.8	91.7	92.1	90.7	88.1	83.2
Biodiesel Non-Virgin	0.7	0.9	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	25.9	32.1	25.8	32.3	33.6	21.1	10.4	12.5	10.3	31.2
Steam Coal (Gen Fuel)	10.3	10.8	7.2	6.9	7.7	7.7	7.7	7.8	8.2	8.6
Natural Gas (Gen Fuel)	1.6	1.6	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Petroleum (Gen Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Non Fossil Fuel (Gen Fuel)	9.9	10.0	12.3	12.9	12.9	12.9	12.9	12.9	12.6	12.7
Total	1,002.5	1,011.8	1,011.4	1,015.5	1,020.1	1,014.4	1,006.3	999.5	992.9	991.1

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3

FIGURE 5-25: PENNSYLVANIA – TRANSPORTATION FUEL PRICE CHART[1]



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-41: PENNSYLVANIA – TRANSPORTATION FUEL PRICE TABLE

Pennsylvania Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	27.64	28.10	28.51	28.76	29.09	29.47	29.85	30.32	30.69	31.00
E85	24.14	25.33	26.04	24.34	23.11	23.01	26.18	31.48	38.22	38.46
Motor Gasoline	23.94	25.13	25.85	26.84	27.84	33.37	40.58	44.93	50.43	50.65
Jet Fuel	18.01	18.26	18.66	19.06	19.90	20.31	20.78	21.27	21.71	22.03
Distillate Fuel Oil	22.57	22.80	23.22	23.69	24.48	24.89	25.37	25.88	26.36	26.66
Natural Gas	11.41	11.31	11.37	11.36	11.37	17.47	17.45	17.46	17.53	17.62

FIGURE 5-26: PENNSYLVANIA – INCREMENTAL COST OF TRANSPORTATION FUEL

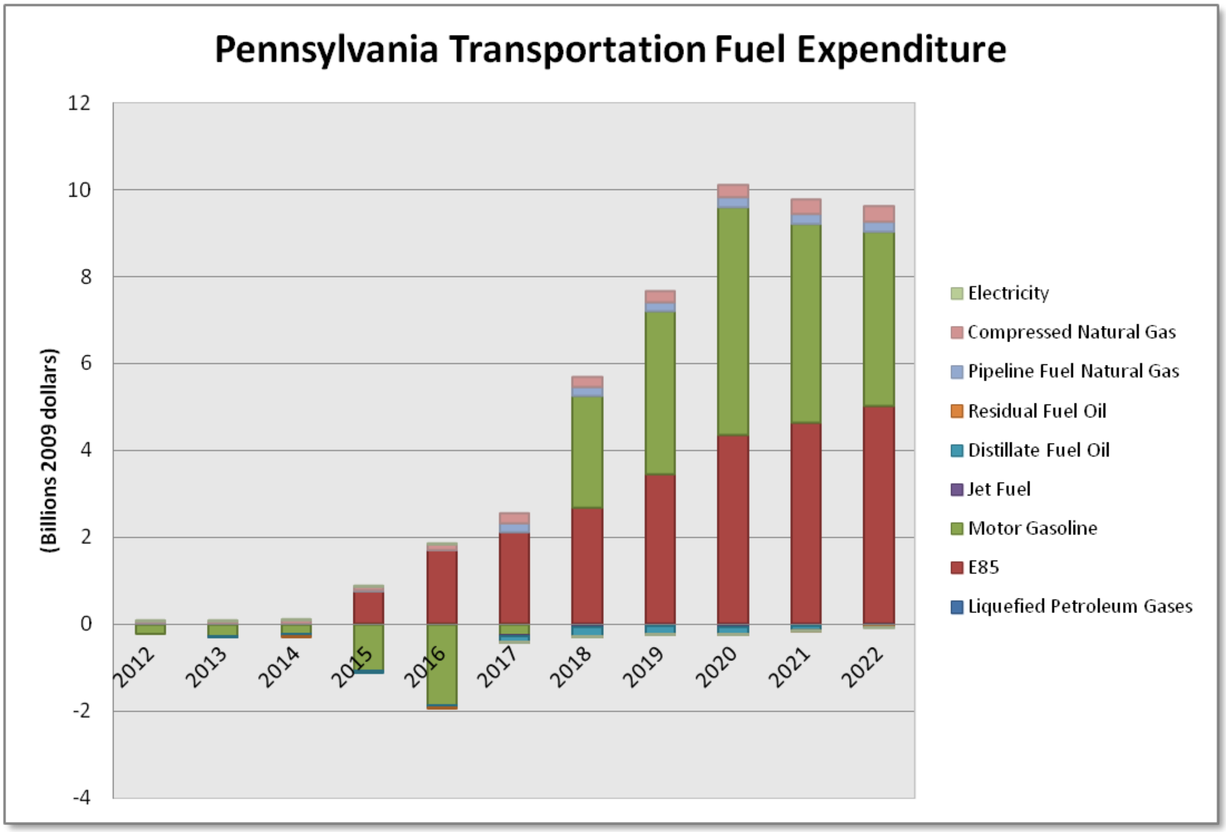


TABLE 5-42: PENNSYLVANIA – INCREMENTAL COST OF TRANSPORTATION FUEL (BILLION 2009 DOLLARS)

Pennsylvania Transportation Fuel Expenditure

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Cumulative
Liquefied Petroleum Gases	0.003	0.004	0.005	0.007	0.009	0.013	0.014	0.016	0.018	0.020	0.023	**0.133**
E85	0.002	0.002	0.003	0.764	1.694	2.101	2.668	3.427	4.338	4.606	5.009	**24.614**
Motor Gasoline	-0.210	-0.262	-0.212	-1.057	-1.854	-0.232	2.558	3.751	5.242	4.587	3.995	**16.306**
Jet Fuel	0.007	-0.003	0.000	0.003	0.008	-0.034	-0.054	-0.044	-0.053	-0.045	-0.018	**-0.232**
Distillate Fuel Oil	0.014	-0.028	-0.051	-0.064	-0.048	-0.126	-0.198	-0.161	-0.156	-0.088	-0.020	**-0.927**
Residual Fuel Oil	0.003	0.000	-0.002	0.000	-0.001	-0.006	-0.013	-0.015	-0.014	-0.013	-0.012	**-0.073**
Pipeline Fuel Natural Gas	0.002	0.002	0.003	0.002	0.006	0.221	0.220	0.218	0.220	0.220	0.223	**1.337**
Compressed Natural Gas	0.044	0.063	0.083	0.099	0.113	0.216	0.229	0.249	0.285	0.321	0.364	**2.066**
Electricity	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002	**-0.010**
Grand Total	**-0.134**	**-0.221**	**-0.171**	**-0.246**	**-0.074**	**2.154**	**5.423**	**7.439**	**9.877**	**9.606**	**9.562**	**43.214**

FIGURE 5-27: RHODE ISLAND – TRANSPORTATION FUEL CONSUMPTION CHART

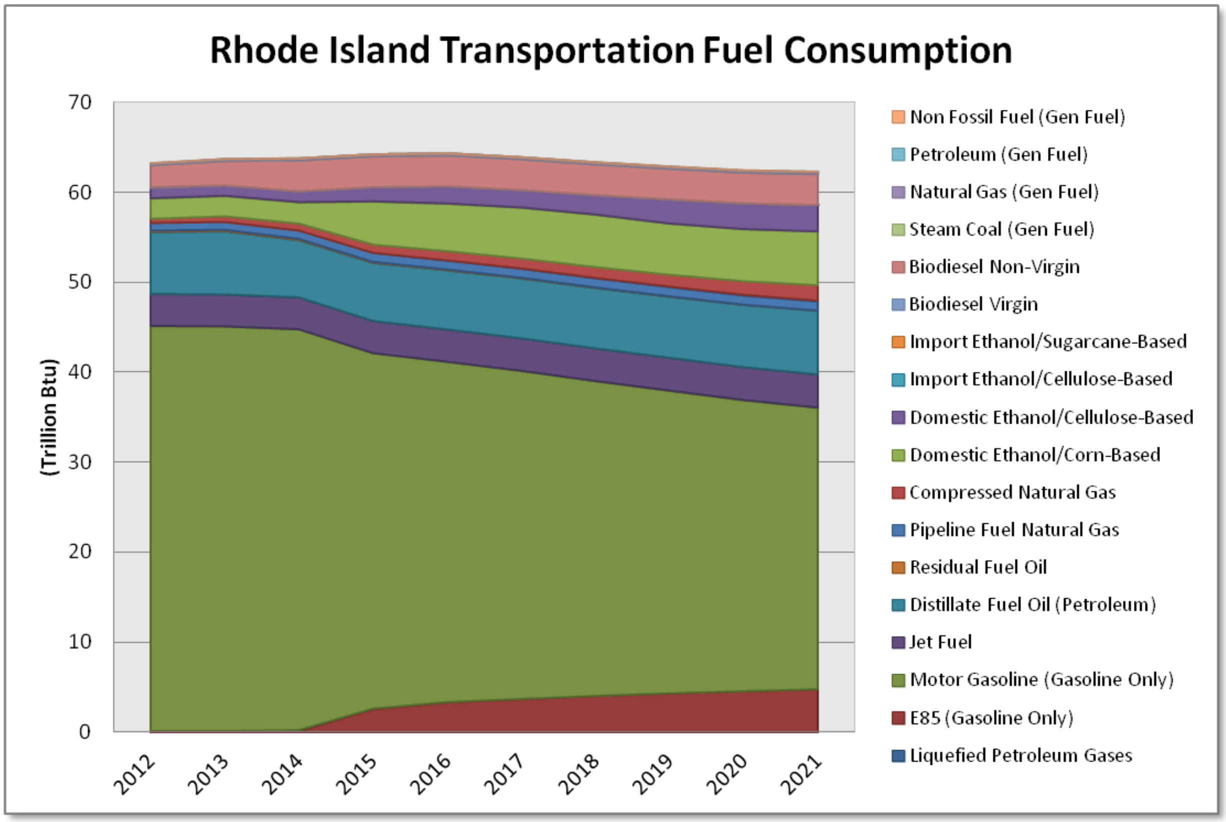


TABLE 5-43: RHODE ISLAND – TRANSPORTATION FUEL CONSUMPTION TABLE

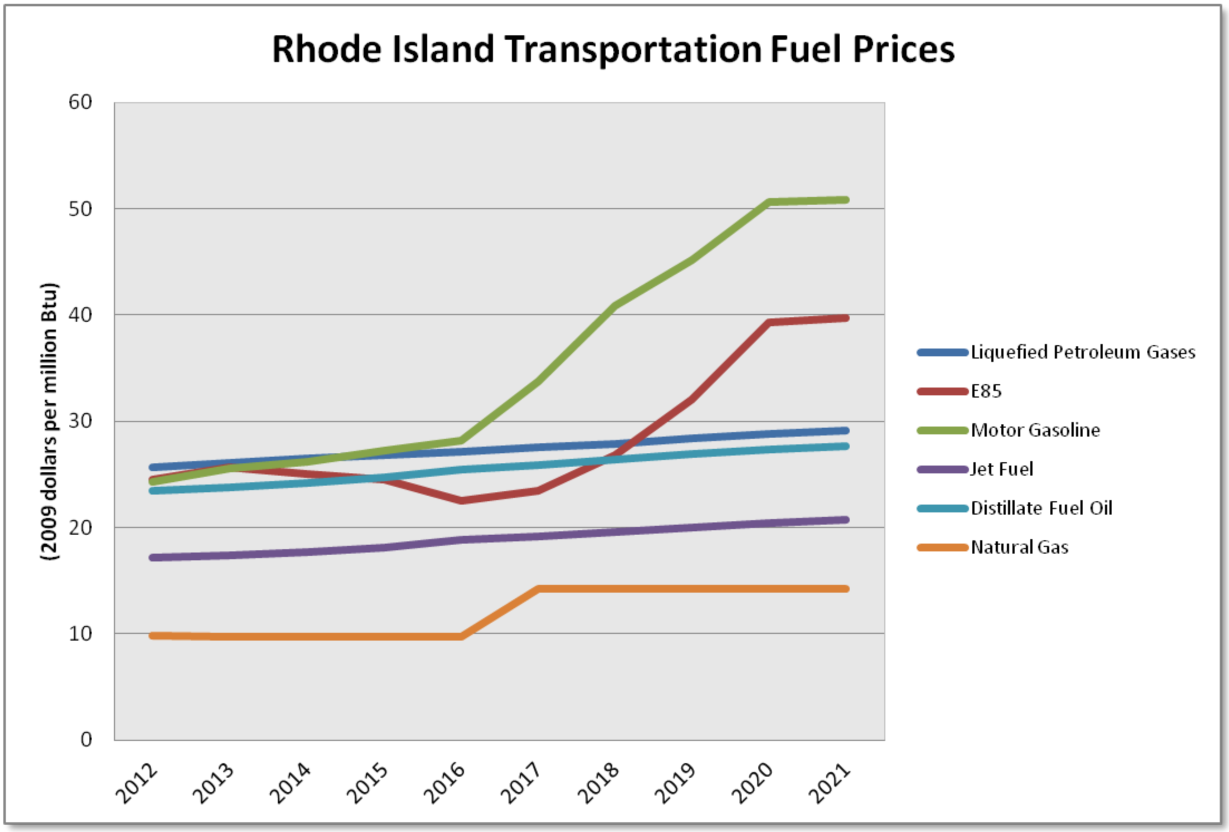
Rhode Island Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E85 (Gasoline Only)	0.0	0.0	0.1	2.5	3.2	3.6	3.9	4.2	4.4	4.7
Motor Gasoline (Gasoline Only)	45.1	45.1	44.6	39.6	37.9	36.5	35.0	33.7	32.4	31.3
Jet Fuel	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.7
Distillate Fuel Oil (Petroleum)	6.9	7.1	6.4	6.5	6.6	6.7	6.7	6.8	6.9	7.1
Residual Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pipeline Fuel Natural Gas	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Compressed Natural Gas	0.5	0.7	0.8	1.0	1.1	1.2	1.3	1.4	1.6	1.8
Domestic Ethanol/Corn-Based	2.3	2.3	2.4	4.8	5.3	5.6	5.8	5.7	5.8	6.0
Domestic Ethanol/Cellulose-Based	1.2	1.2	1.2	1.6	1.9	2.0	2.2	2.7	2.9	3.0
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	2.4	2.7	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Steam Coal (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (Gen Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.0
Total	63.2	63.7	63.8	64.2	64.3	63.9	63.3	62.8	62.4	62.2

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.

FIGURE 5-28: RHODE ISLAND – TRANSPORTATION FUEL PRICE CHART[1]



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-44: RHODE ISLAND – TRANSPORTATION FUEL PRICE TABLE

Rhode Island Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	25.63	26.10	26.52	26.78	27.12	27.51	27.91	28.39	28.77	29.09
E85	24.48	25.66	25.06	24.57	22.48	23.49	26.79	32.05	39.27	39.72
Motor Gasoline	24.35	25.53	26.24	27.22	28.23	33.76	40.91	45.22	50.67	50.89
Jet Fuel	17.18	17.38	17.72	18.07	18.83	19.18	19.60	20.03	20.43	20.72
Distillate Fuel Oil	23.48	23.75	24.22	24.69	25.50	25.91	26.39	26.90	27.39	27.70
Natural Gas	9.85	9.74	9.77	9.77	9.78	14.29	14.23	14.20	14.25	14.29

FIGURE 5-29: RHODE ISLAND – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

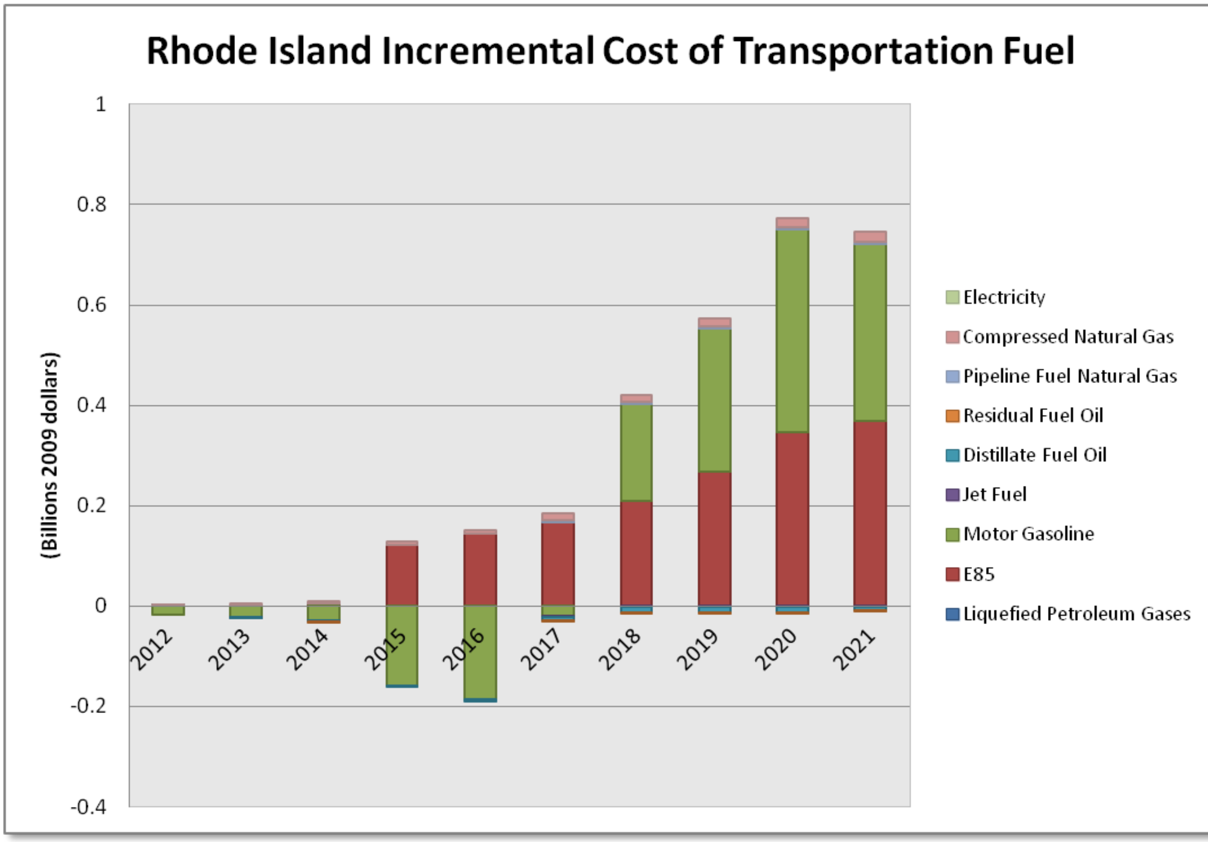


TABLE 5-45: RHODE ISLAND – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Rhode Island Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	**0.004**
E85	0.000	0.000	0.005	0.122	0.144	0.167	0.208	0.268	0.346	0.367	**1.628**
Motor Gasoline	-0.017	-0.021	-0.028	-0.158	-0.186	-0.020	0.193	0.285	0.404	0.354	**0.808**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	-0.001	-0.002	-0.002	-0.002	-0.002	**-0.008**
Distillate Fuel Oil	0.000	-0.001	-0.002	-0.003	-0.003	-0.007	-0.010	-0.010	-0.010	-0.006	**-0.051**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.005	0.004	0.004	0.004	0.004	**0.022**
Compressed Natural Gas	0.003	0.004	0.006	0.007	0.008	0.014	0.014	0.016	0.018	0.020	**0.108**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.013**	**-0.018**	**-0.019**	**-0.031**	**-0.037**	**0.158**	**0.409**	**0.562**	**0.762**	**0.739**	**2.511**

FIGURE 5-30: VERMONT – TRANSPORTATION FUEL CONSUMPTION CHART

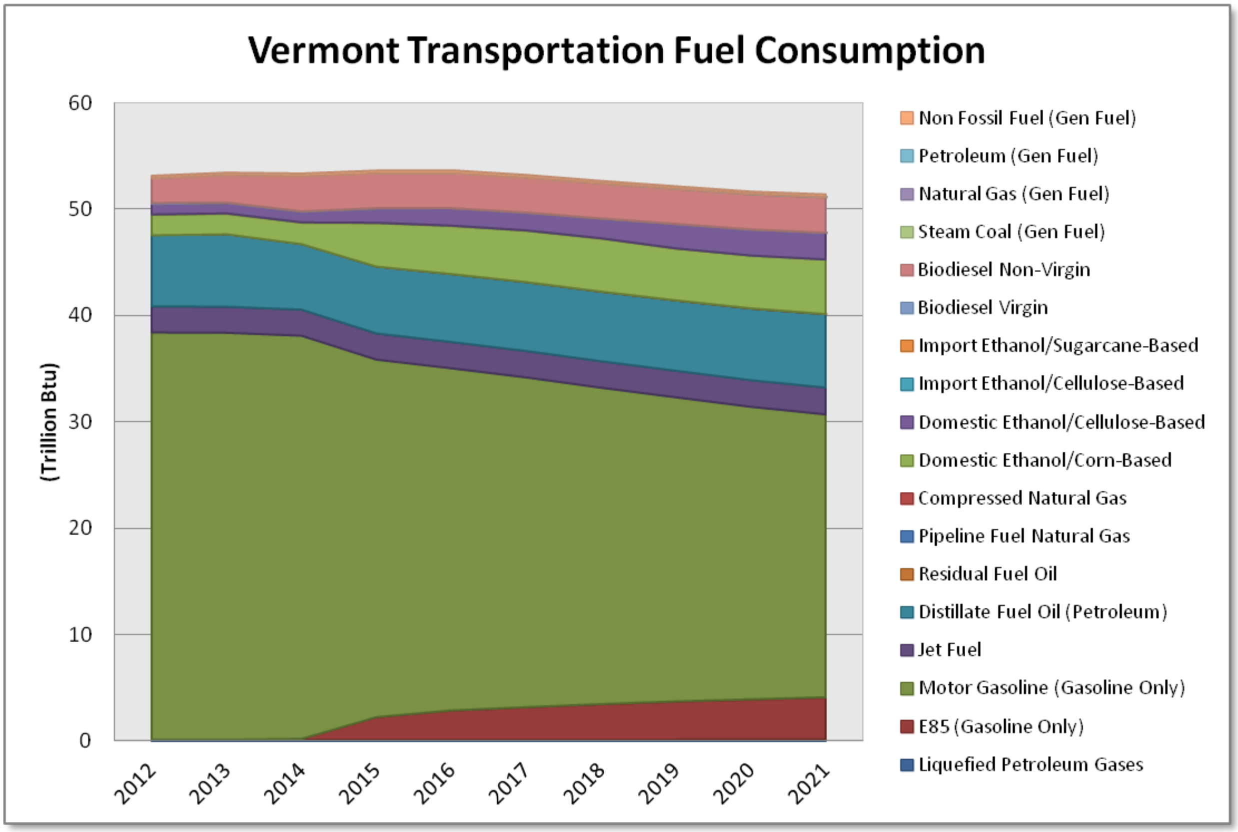


TABLE 5-46: VERMONT – TRANSPORTAYION FUEL CONSUMPTION TABLE

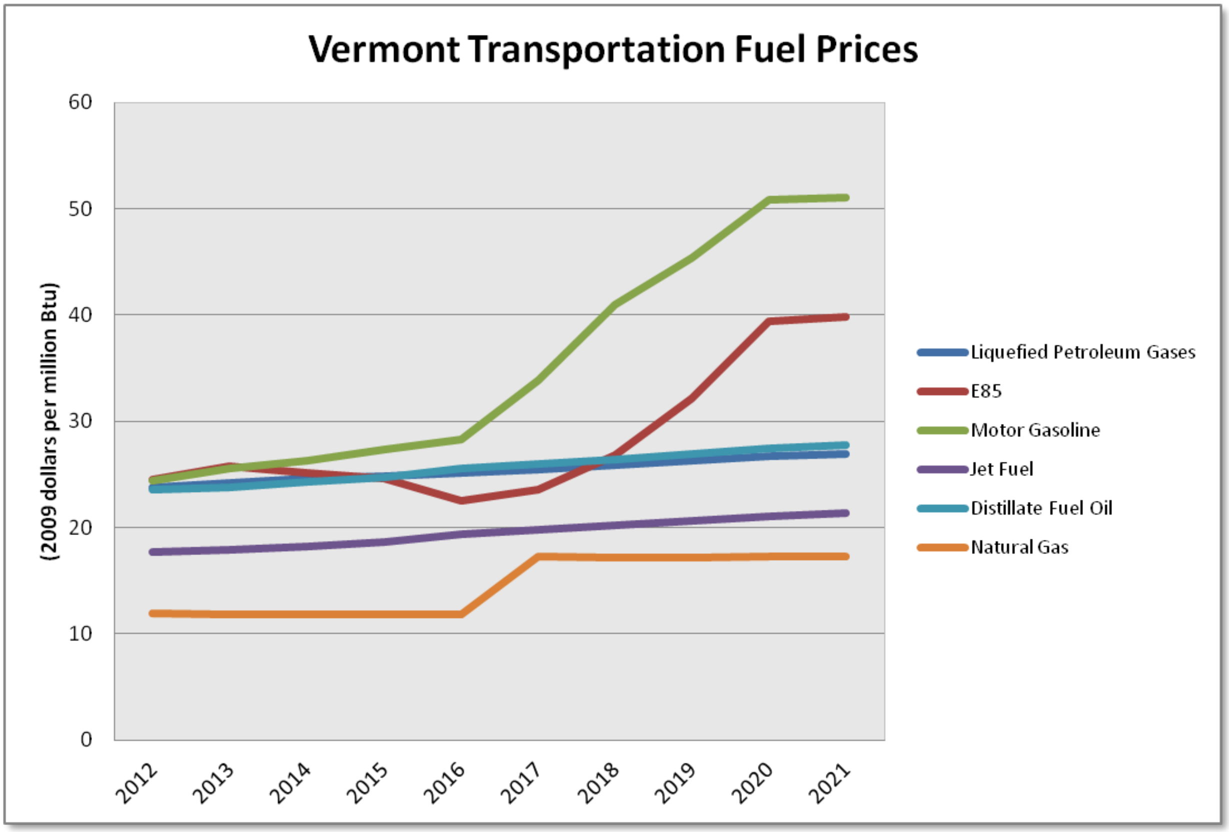
Vermont Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
E85 (Gasoline Only)	0.0	0.0	0.1	2.1	2.8	3.1	3.4	3.6	3.8	4.0
Motor Gasoline (Gasoline Only)	38.4	38.3	37.9	33.7	32.2	31.0	29.8	28.6	27.5	26.6
Jet Fuel	2.5	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Distillate Fuel Oil (Petroleum)	6.7	6.8	6.2	6.3	6.4	6.5	6.5	6.6	6.7	6.9
Residual Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Fuel Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compressed Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Ethanol/Corn-Based	1.9	1.9	2.0	4.1	4.5	4.8	5.0	4.9	5.0	5.1
Domestic Ethanol/Cellulose-Based	1.0	1.0	1.0	1.4	1.7	1.7	1.9	2.3	2.5	2.5
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	2.3	2.6	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Steam Coal (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.3
Total	53.2	53.5	53.4	53.7	53.7	53.3	52.7	52.1	51.6	51.4

The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3

FIGURE 5-31: VERMONT – TRANSPORTATION FUEL PRICE CHART



1. While motor gasoline, E85, and natural gas fuel prices were penalized because their CI constraints were not satisfied, other fuel costs were not penalized since the CI constraint was uniquely satisfied.

TABLE 5-47: VERMONT – TRANSPORTATION FUEL PRICE TABLE

Vermont Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	23.76	24.20	24.59	24.83	25.15	25.51	25.87	26.32	26.68	26.97
E85	24.56	25.73	25.13	24.64	22.54	23.56	26.87	32.15	39.39	39.84
Motor Gasoline	24.42	25.60	26.32	27.30	28.31	33.86	41.03	45.35	50.81	51.04
Jet Fuel	17.71	17.92	18.27	18.63	19.41	19.77	20.21	20.65	21.06	21.36
Distillate Fuel Oil	23.52	23.79	24.26	24.73	25.54	25.95	26.43	26.95	27.43	27.74
Natural Gas	11.92	11.78	11.82	11.82	11.83	17.28	17.21	17.18	17.24	17.28

FIGURE 5-32: VERMONT – INCREMENTAL COST OF TRANSPORTATION FUEL CHART

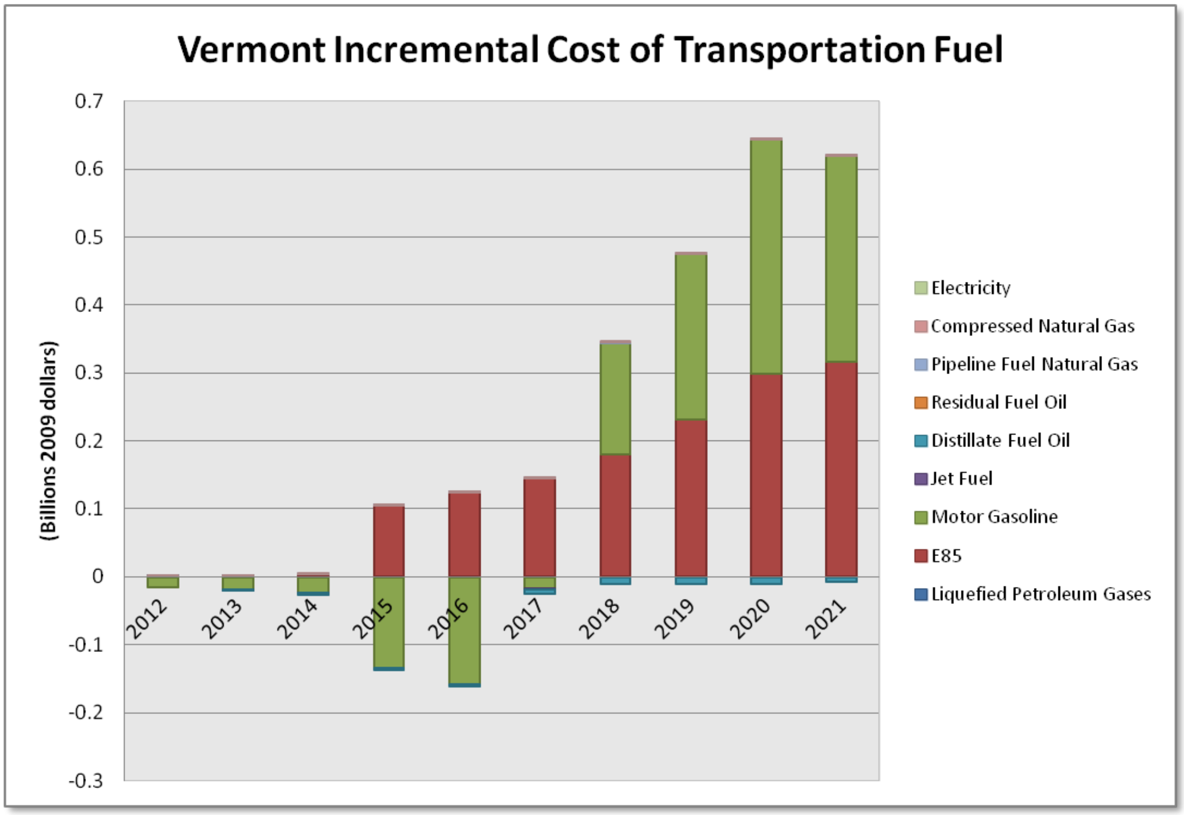


TABLE 5-48: VERMONT – INCREMENTAL COST OF TRANSPORTATION FUEL TABLE (BILLION 2009 DOLLARS)

Vermont Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	**0.007**
E85	0.000	0.000	0.004	0.105	0.124	0.144	0.179	0.230	0.298	0.316	**1.400**
Motor Gasoline	-0.014	-0.018	-0.024	-0.135	-0.159	-0.017	0.165	0.243	0.345	0.302	**0.689**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	**-0.006**
Distillate Fuel Oil	0.000	-0.001	-0.002	-0.002	-0.003	-0.007	-0.009	-0.010	-0.009	-0.006	**-0.050**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Compressed Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.002**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.014**	**-0.019**	**-0.021**	**-0.031**	**-0.037**	**0.120**	**0.335**	**0.464**	**0.633**	**0.613**	**2.043**

5.4 ELECTRICITY GENERATION BY STATE AND FUEL TYPE

This section of the report provides state-by-state electricity generation by fuel type.

FIGURE 5-33: CONNECTICUT ELECTRICITY GENERATION BY FUEL TYPE CHART

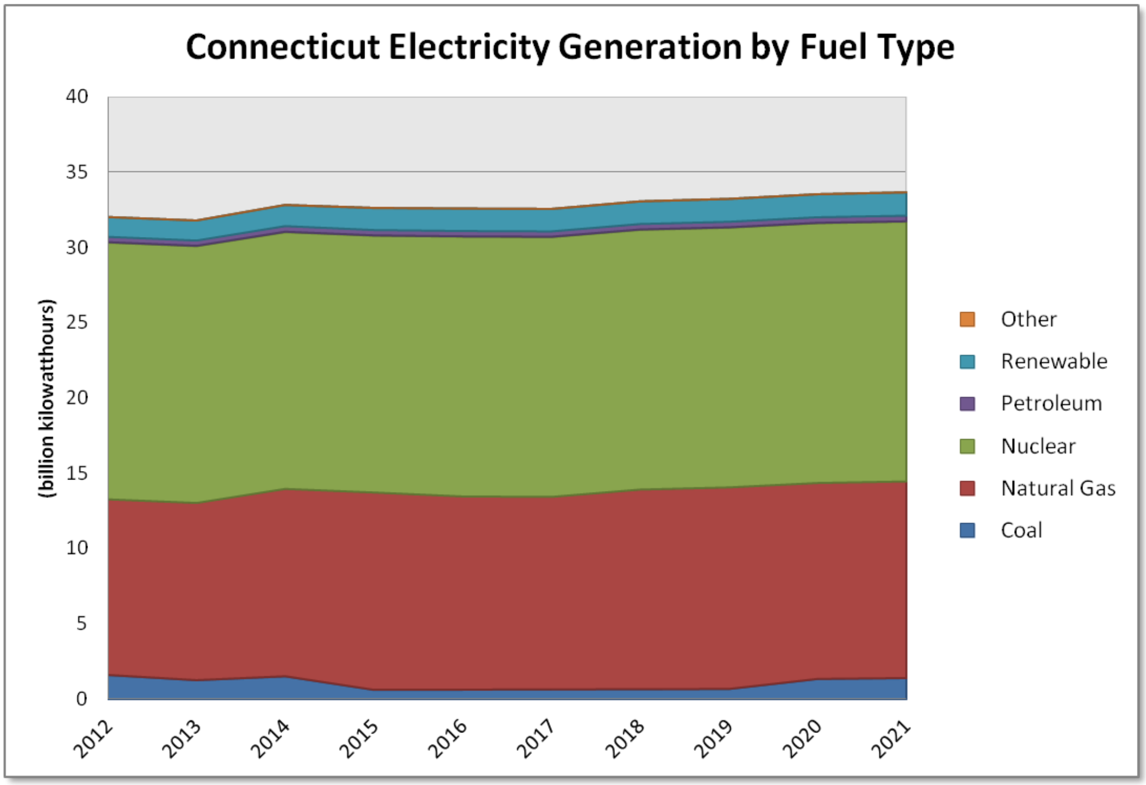


TABLE 5-49: CONNECTICUT ELECTRICITY GENERATION BY FUEL TYPE TABLE

Connecticut Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	1.60	1.26	1.52	0.62	0.63	0.65	0.66	0.68	1.34	1.40
Natural Gas	11.69	11.79	12.47	13.13	12.85	12.81	13.28	13.41	13.04	13.08
Nuclear	17.04	17.04	17.04	17.04	17.24	17.24	17.24	17.24	17.24	17.24
Petroleum	0.40	0.40	0.41	0.39	0.39	0.39	0.39	0.40	0.39	0.40
Renewable	1.30	1.32	1.39	1.45	1.48	1.48	1.48	1.50	1.51	1.53
Other	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Total	**32.02**	**31.79**	**32.81**	**32.61**	**32.58**	**32.55**	**33.04**	**33.20**	**33.51**	**33.63**

FIGURE 5-34: DELAWARE ELECTRICITY GENERATION BY FUEL TYPE CHART

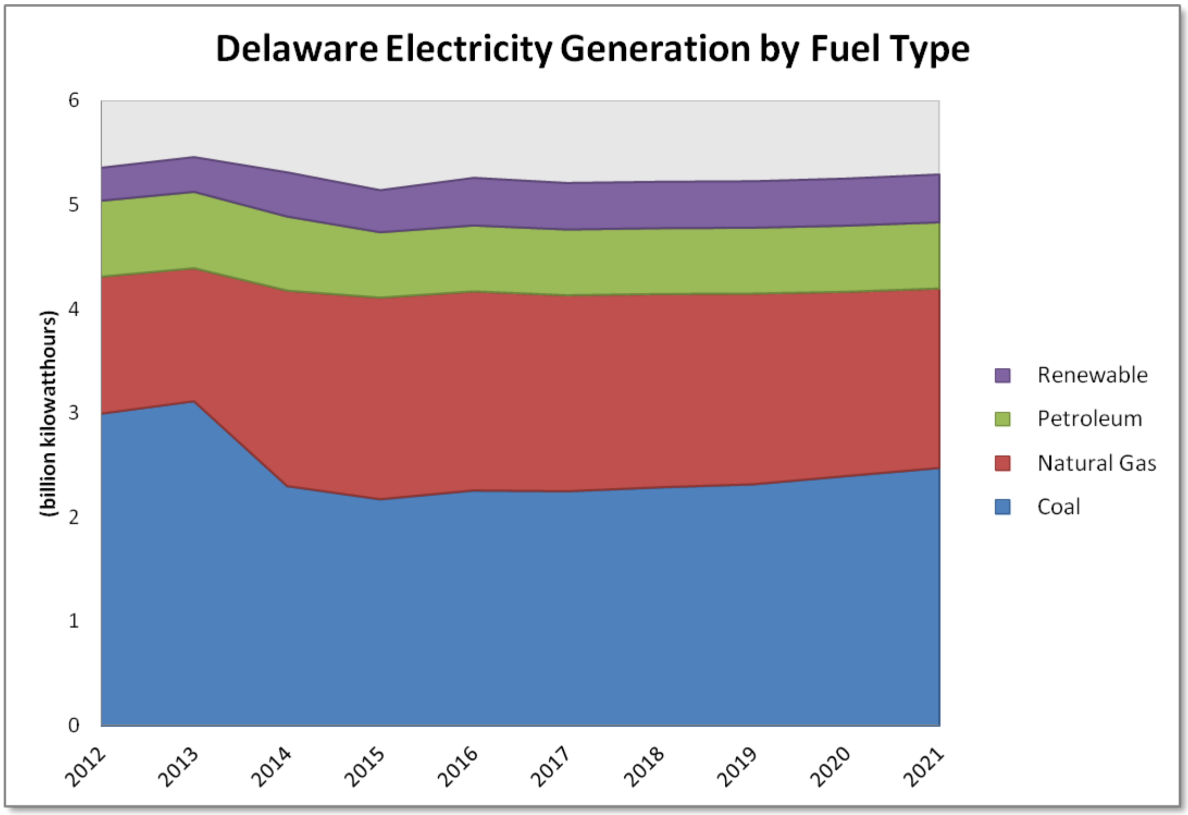


TABLE 5-50: DELAWARE ELECTRICITY GENERATION BY FUEL TYPE TABLE

Delaware Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	2.99	3.11	2.29	2.17	2.25	2.24	2.28	2.31	2.39	2.47
Natural Gas	1.32	1.28	1.88	1.94	1.91	1.88	1.86	1.83	1.77	1.73
Petroleum	0.73	0.74	0.71	0.63	0.64	0.64	0.64	0.64	0.64	0.64
Renewable	0.32	0.33	0.43	0.40	0.46	0.45	0.45	0.45	0.45	0.46
Total	5.36	5.46	5.31	5.14	5.26	5.21	5.22	5.23	5.25	5.29

FIGURE 5-35: MASSACHUSETTS ELECTRICITY GENERATION BY FUEL TYPE CHART

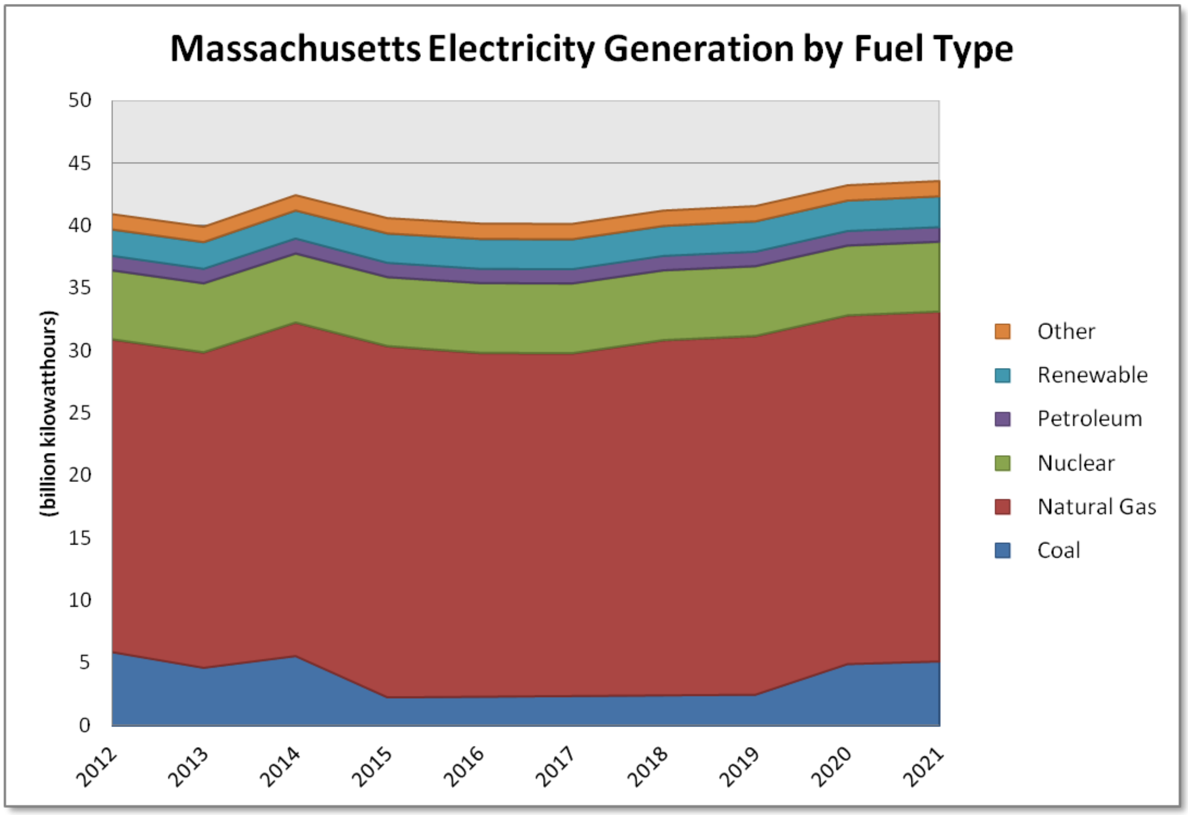


TABLE 5-51: MASSACHUSETTS ELECTRICITY GENERATION BY FUEL TYPE TABLE

Massachusetts Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	5.90	4.64	5.58	2.27	2.32	2.37	2.43	2.49	4.93	5.15
Natural Gas	25.01	25.23	26.68	28.09	27.50	27.40	28.41	28.68	27.89	27.99
Nuclear	5.52	5.52	5.52	5.52	5.58	5.58	5.58	5.58	5.58	5.58
Petroleum	1.19	1.19	1.22	1.17	1.17	1.17	1.18	1.19	1.18	1.19
Renewable	2.10	2.12	2.24	2.34	2.38	2.38	2.39	2.41	2.43	2.47
Other	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23
Total	**40.94**	**39.92**	**42.46**	**40.62**	**40.18**	**40.14**	**41.22**	**41.59**	**43.26**	**43.60**

FIGURE 5-36: MARYLAND ELECTRICITY GENERATION BY FUEL TYPE CHART

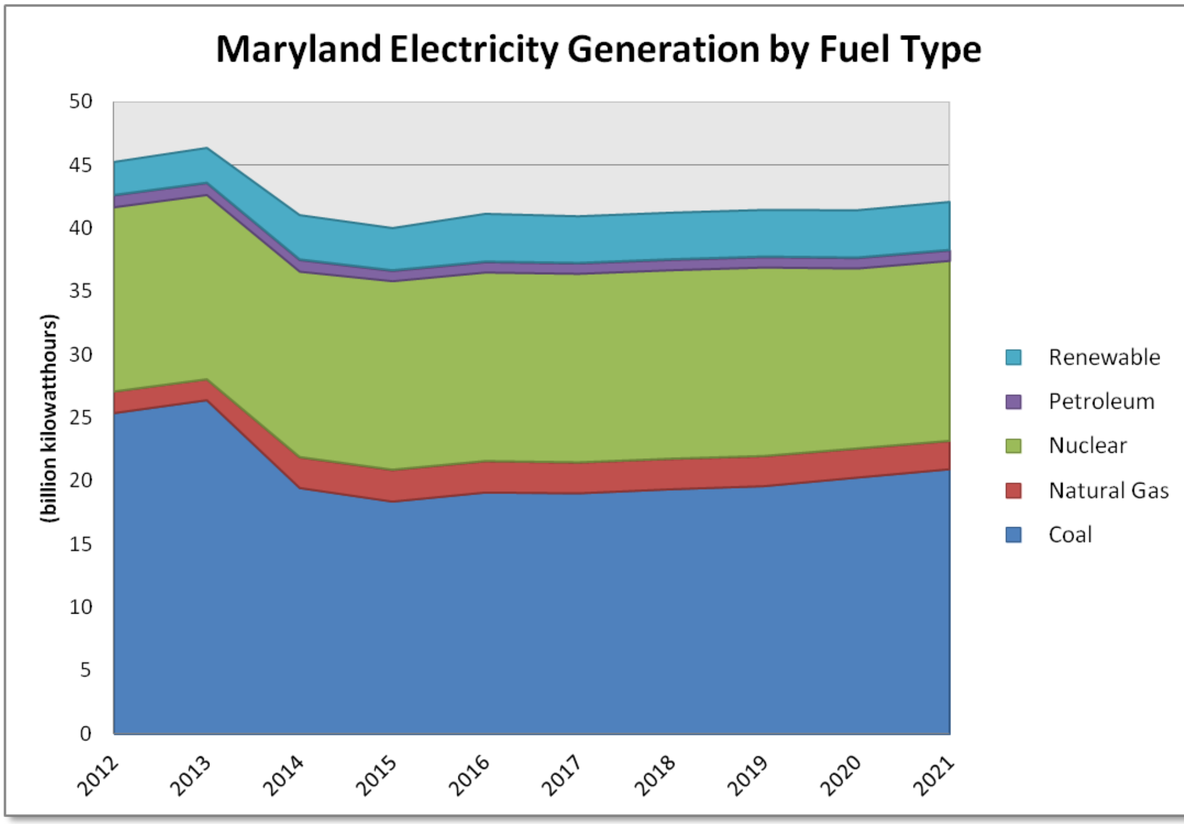


TABLE 5-52: MARYLAND ELECTRICITY GENERATION BY FUEL TYPE TABLE

Maryland Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	25.36	26.38	19.46	18.39	19.10	19.04	19.36	19.61	20.28	20.94
Natural Gas	1.69	1.64	2.41	2.49	2.46	2.42	2.39	2.36	2.28	2.22
Nuclear	14.63	14.63	14.72	14.96	14.96	14.96	14.96	14.96	14.29	14.29
Petroleum	0.94	0.94	0.91	0.81	0.81	0.81	0.81	0.81	0.81	0.82
Renewable	2.62	2.76	3.51	3.35	3.79	3.70	3.69	3.70	3.74	3.80
Total	45.25	46.36	41.02	39.99	41.12	40.93	41.21	41.43	41.40	42.07

FIGURE 5-37: MAINE ELECTRICITY GENERATION BY FUEL TYPE CHART

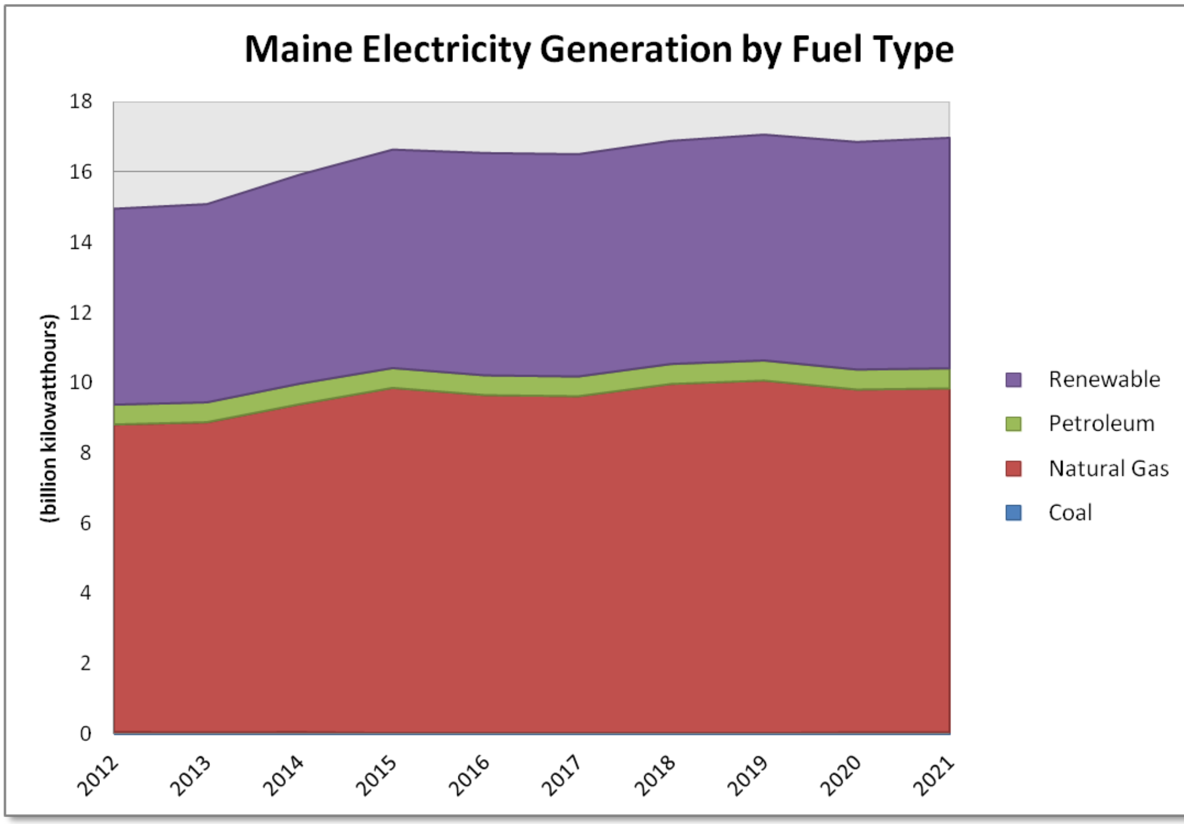


TABLE 5-53: MAINE ELECTRICITY GENERATION BY FUEL TYPE TABLE

Maine Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	0.05	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.04	0.04
Natural Gas	8.76	8.84	9.35	9.84	9.64	9.60	9.96	10.05	9.77	9.81
Petroleum	0.57	0.57	0.59	0.57	0.57	0.57	0.57	0.57	0.57	0.57
Renewable	5.58	5.64	5.95	6.22	6.33	6.33	6.35	6.42	6.48	6.56
Total	14.96	15.09	15.93	16.64	16.55	16.51	16.89	17.07	16.86	16.98

FIGURE 5-38: NEW HAMPSHIRE ELECTRICITY GENERATION BY FUEL TYPE CHART

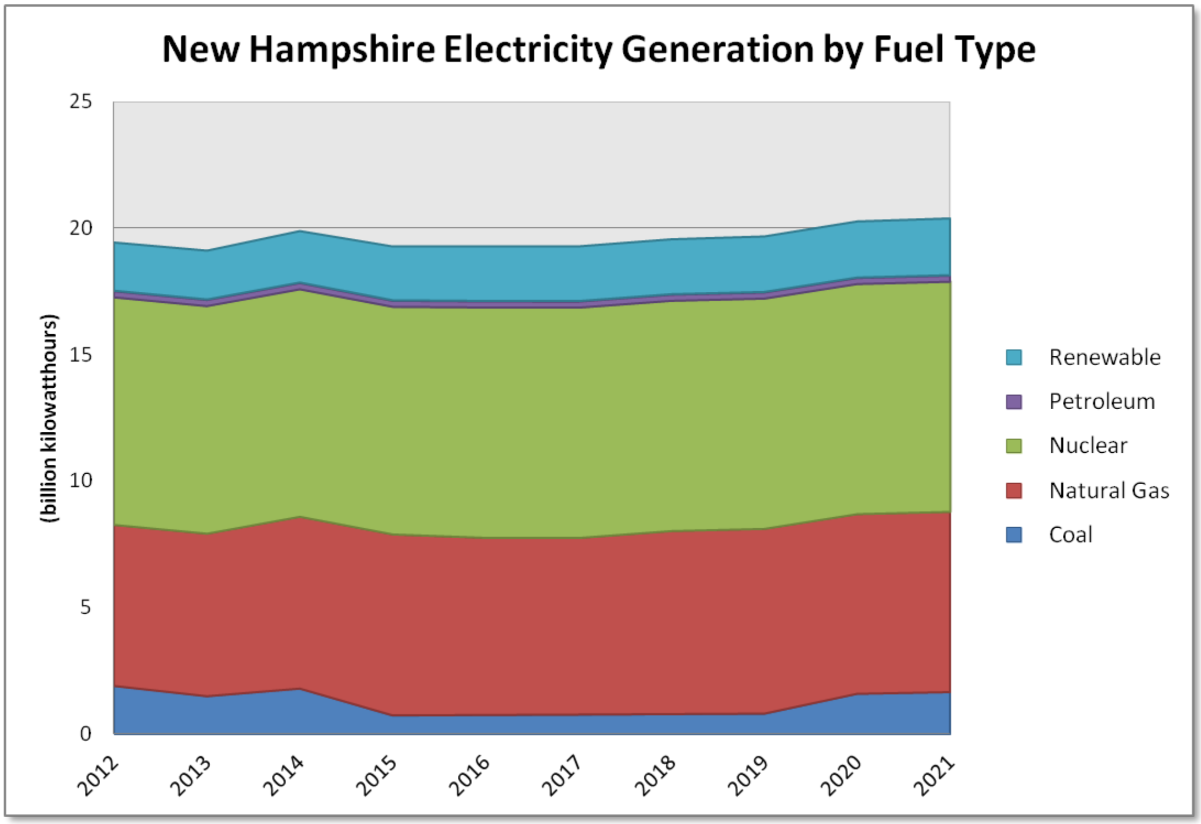


TABLE 5-54: NEW HAMPSHIRE ELECTRICITY GENERATION BY FUEL TYPE TABLE

New Hampshire Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	1.89	1.48	1.78	0.72	0.74	0.76	0.78	0.79	1.58	1.65
Natural Gas	6.37	6.42	6.79	7.15	7.00	6.98	7.23	7.30	7.10	7.12
Nuclear	9.02	9.02	9.02	9.02	9.12	9.12	9.12	9.12	9.12	9.12
Petroleum	0.24	0.24	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Renewable	1.93	1.95	2.06	2.15	2.19	2.19	2.20	2.22	2.24	2.27
Total	19.44	19.12	19.90	19.28	19.29	19.29	19.57	19.69	20.28	20.40

FIGURE 5-39: NEW JERSEY ELECTRICITY GENERATION BY FUEL TYPE CHART

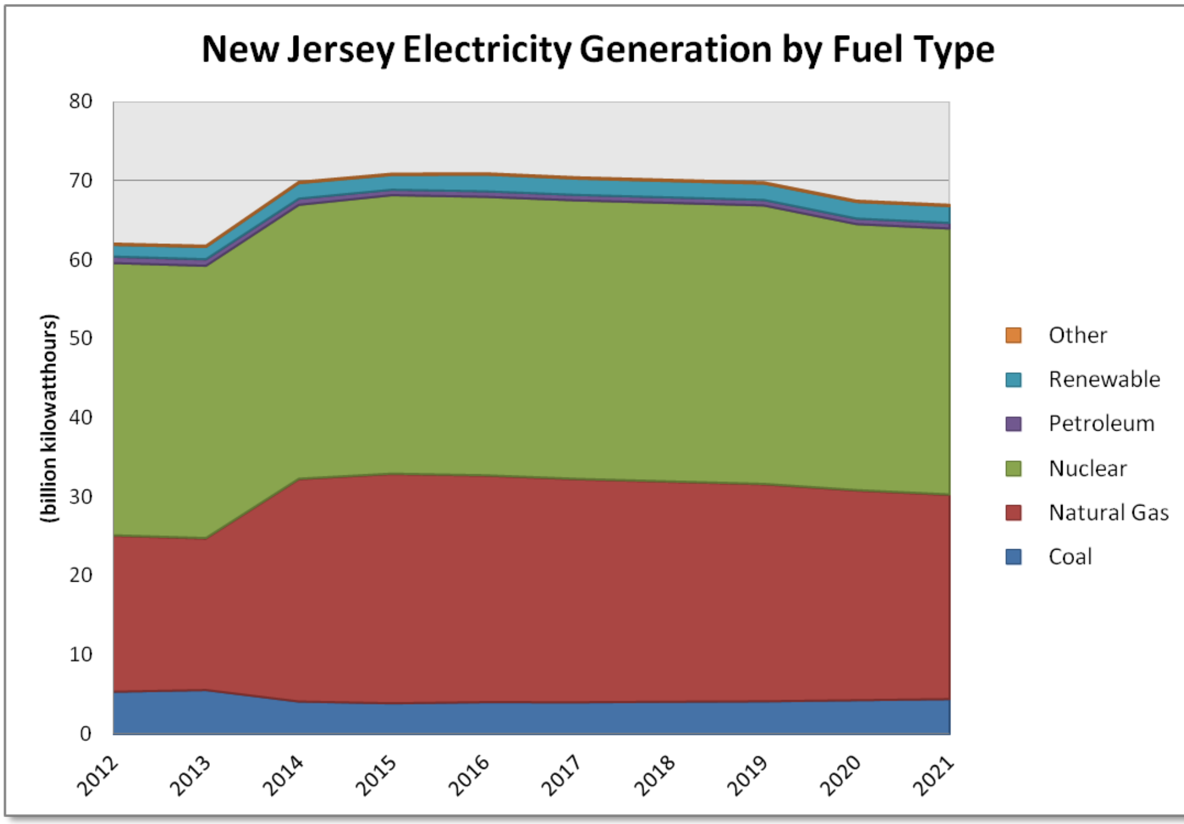


TABLE 5-55: NEW JERSEY ELECTRICITY GENERATION BY FUEL TYPE TABLE

New Jersey Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	5.35	5.57	4.11	3.88	4.03	4.02	4.09	4.14	4.28	4.42
Natural Gas	19.75	19.19	28.17	29.04	28.69	28.24	27.86	27.49	26.56	25.86
Nuclear	34.52	34.52	34.73	35.30	35.30	35.30	35.30	35.30	33.72	33.72
Petroleum	0.79	0.79	0.77	0.68	0.68	0.68	0.68	0.68	0.69	0.69
Renewable	1.49	1.57	1.99	1.90	2.15	2.10	2.10	2.10	2.12	2.16
Other	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Total	**62.08**	**61.82**	**69.95**	**70.98**	**71.03**	**70.52**	**70.20**	**69.89**	**67.54**	**67.03**

FIGURE 5-40: NEW YORK ELECTRICITY GENERATION BY FUEL TYPE CHART

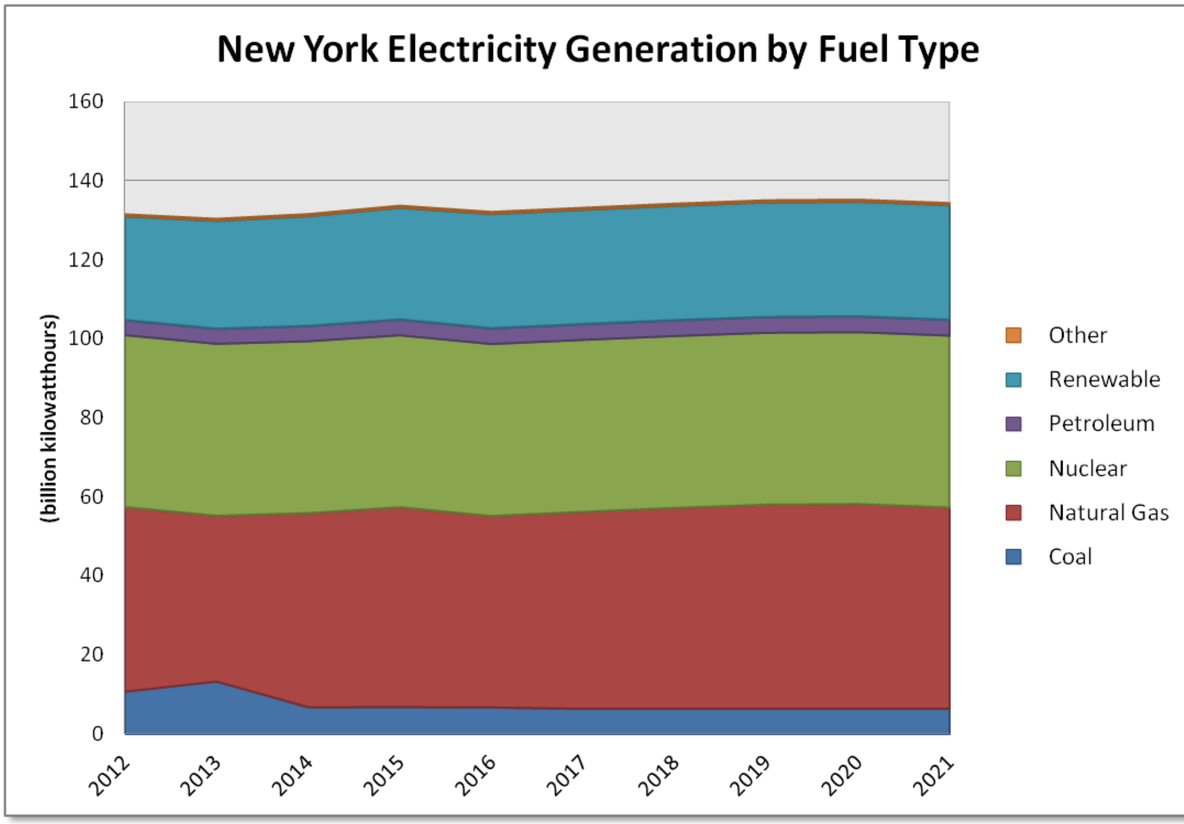


TABLE 5-56: NEW YORK ELECTRICITY GENERATION BY FUEL TYPE TABLE

New York Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	10.60	13.15	6.66	6.70	6.62	6.25	6.25	6.25	6.26	6.25
Natural Gas	46.75	41.99	49.14	50.61	48.47	49.89	50.87	51.70	51.85	50.98
Nuclear	43.58	43.58	43.58	43.58	43.58	43.58	43.58	43.58	43.58	43.58
Petroleum	3.79	3.79	3.85	3.98	3.98	3.98	3.98	3.98	3.98	3.98
Renewable	26.30	27.36	27.84	28.35	28.98	28.98	29.03	29.07	29.07	29.08
Other	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Total	**131.48**	**130.32**	**131.53**	**133.67**	**132.08**	**133.14**	**134.17**	**135.05**	**135.21**	**134.33**

FIGURE 5-41: PENNSYLVANIA ELECTRICITY GENERATION BY FUEL TYPE CHART

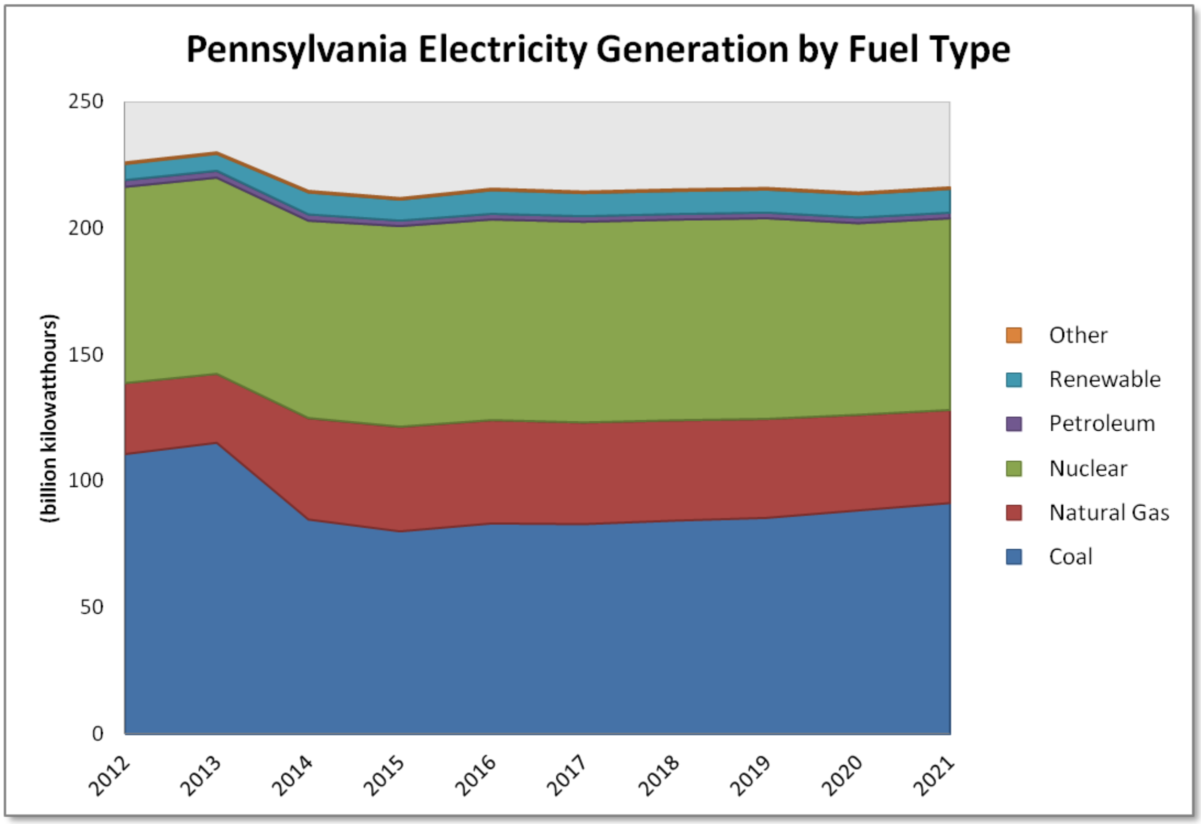


TABLE 5-57: PENNSYLVANIA ELECTRICITY GENERATION BY FUEL TYPE TABLE

Pennsylvania Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	110.72	115.17	84.95	80.26	83.40	83.11	84.51	85.58	88.52	91.42
Natural Gas	27.98	27.18	39.90	41.14	40.64	40.00	39.46	38.94	37.62	36.64
Nuclear	77.77	77.77	78.22	79.52	79.52	79.52	79.52	79.52	75.95	75.95
Petroleum	2.59	2.61	2.53	2.24	2.25	2.25	2.25	2.25	2.26	2.26
Renewable	6.44	6.79	8.65	8.23	9.32	9.10	9.09	9.10	9.21	9.36
Other	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.66
Total	**226.16**	**230.16**	**214.90**	**212.04**	**215.77**	**214.63**	**215.48**	**216.03**	**214.21**	**216.28**

FIGURE 5-42: RHODE ISLAND ELECTRICITY GENERATION BY FUEL TYPE CHART

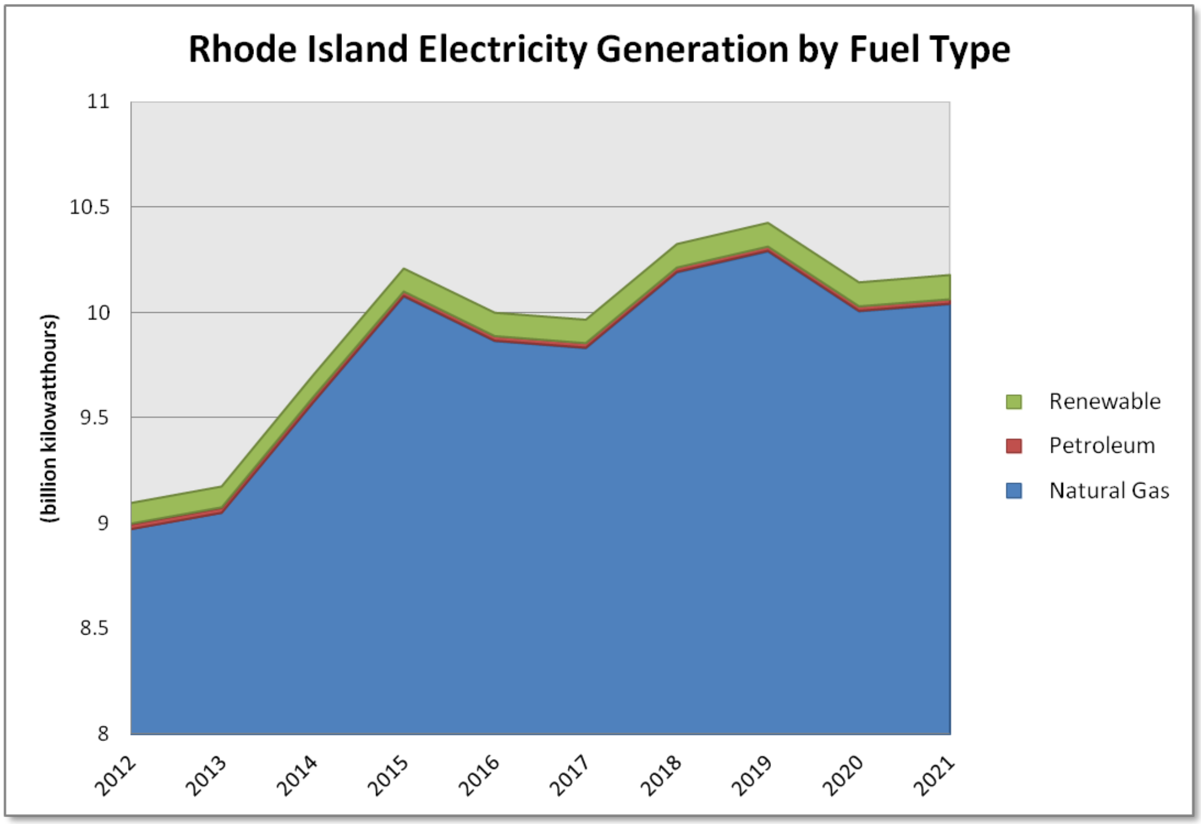


TABLE 5-58: RHODE ISLAND ELECTRICITY GENERATION BY FUEL TYPE TABLE

Rhode Island Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Natural Gas	8.97	9.05	9.57	10.08	9.87	9.83	10.19	10.29	10.01	10.04
Petroleum	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Renewable	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.12
Total	9.09	9.17	9.70	10.21	10.00	9.97	10.33	10.43	10.14	10.18

FIGURE 5-43: VERMONT ELECTRICITY GENERATION BY FUEL TYPE CHART

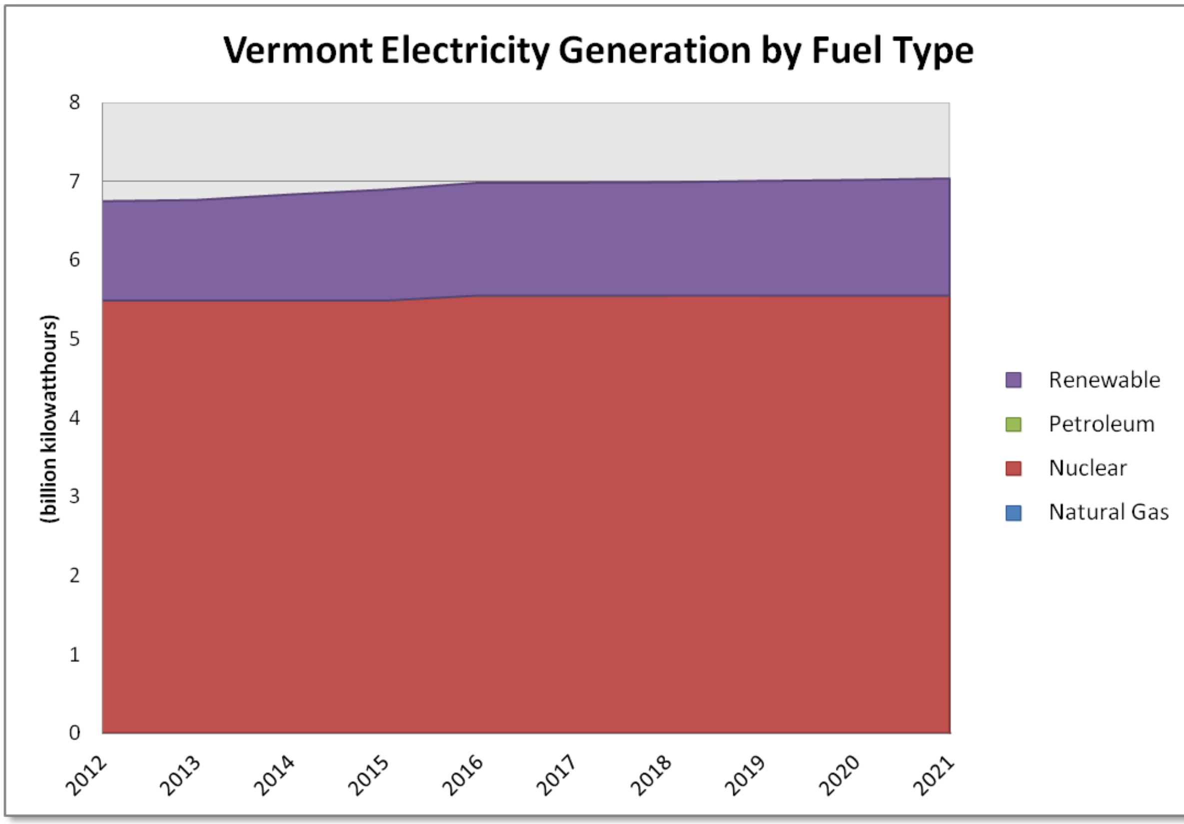


TABLE 5-59: VERMONT ELECTRICITY GENERATION BY FUEL TYPE TABLE

Vermont Electricity Generation by Fuel Type

(Billion KWh)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Natural Gas	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Nuclear	5.48	5.48	5.48	5.48	5.55	5.55	5.55	5.55	5.55	5.55
Petroleum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable	1.26	1.27	1.34	1.40	1.43	1.43	1.43	1.45	1.46	1.48
Total	6.75	6.76	6.83	6.90	6.98	6.98	6.99	7.01	7.02	7.04

5.5 ALLOCATION OF IMPLIED VEHICLE SUBSIDIES AND INCREMENTAL INFRASTRUCTURE COSTS TO STATES

Allocation of implied vehicle subsidies and incremental infrastructure costs to the various states within each region was accomplished by multiplying the incremental cost associated with each fuel type by the share of regional consumption represented by each state. Consumption data came from the State Energy Data System (SEDS), and the average consumption over the most recent five-year period was used to characterize each state's share. This is based on the implicit assumption that historical fuel use patterns will remain static over the forecast period. Therefore, results are proportional to the transportation energy needs and travel demands of each state. Results do not take into consideration any potential demographic shifts in each region, which could alter these estimates.

The following sets of charts depict the incremental financial impacts on each state under the two policy scenarios by reference to their respective baseline scenarios. The Vehicle Subsidies and Infrastructure Costs are presented in separate graphs because of the difference in scale.

The first collection of charts shows the incremental impact of the AllNOCAFE54 scenario relative to the Baseline scenario.

FIGURE 5-44: VEHICLE SUBSIDIES – NEW ENGLAND STATES

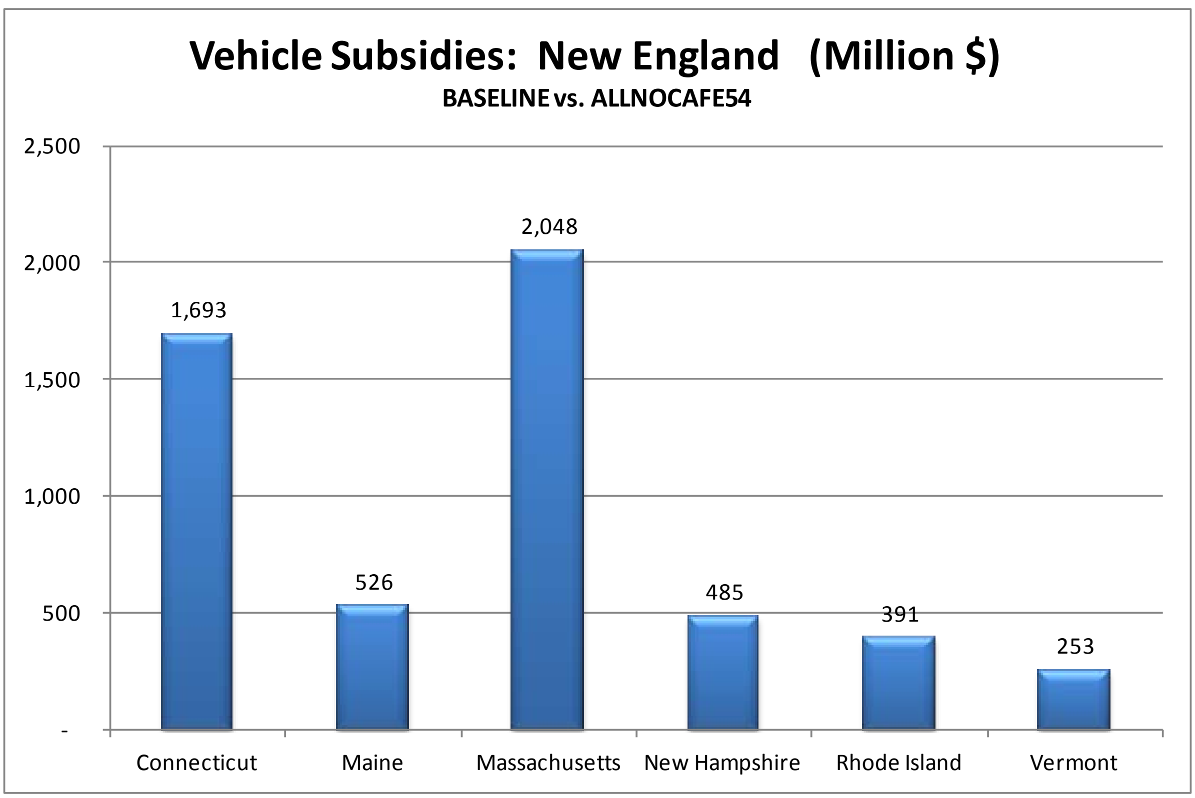


FIGURE 5-45: INFRASTRUCTURE COSTS – NEW ENGLAND STATES

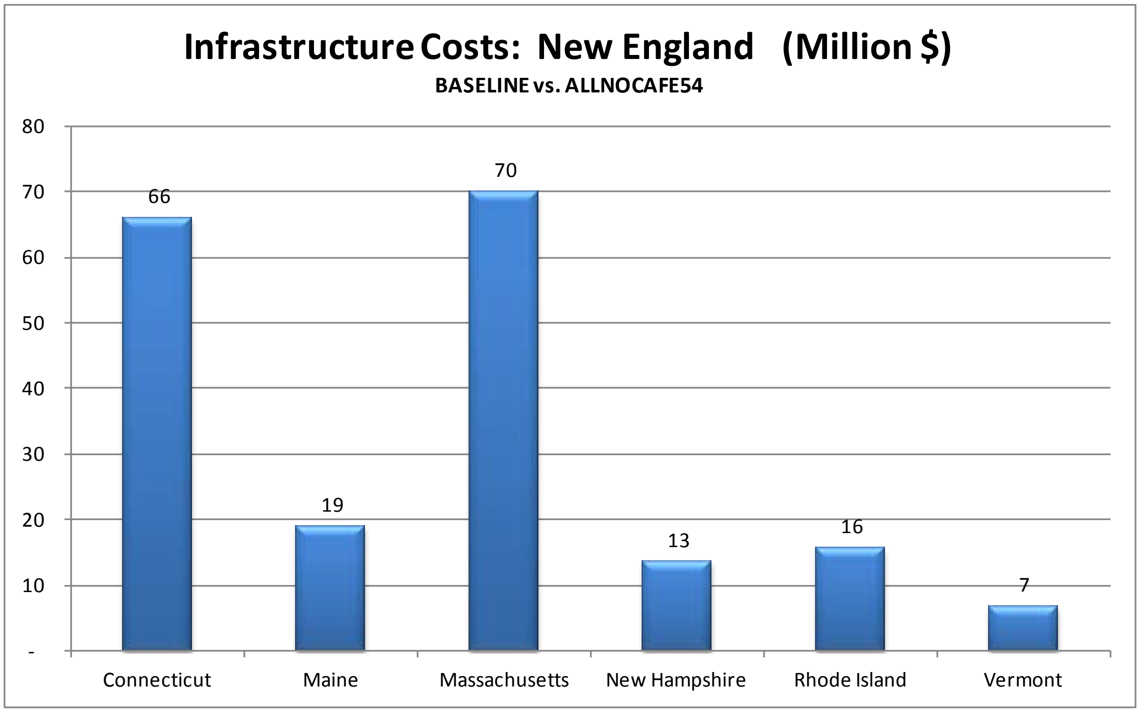


FIGURE 5-46: VEHICLE SUBSIDIES – MID-ATLANTIC STATES

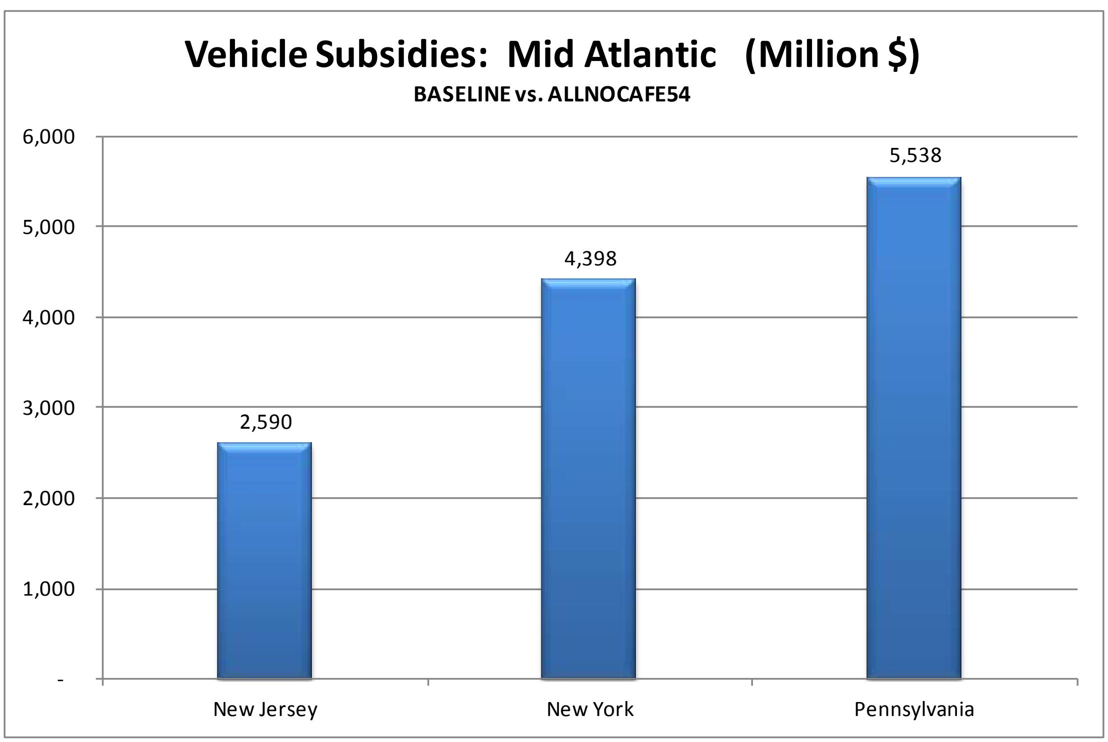


FIGURE 5-47: INFRASTRUCTURE COSTS – MID-ATANTIC STATES

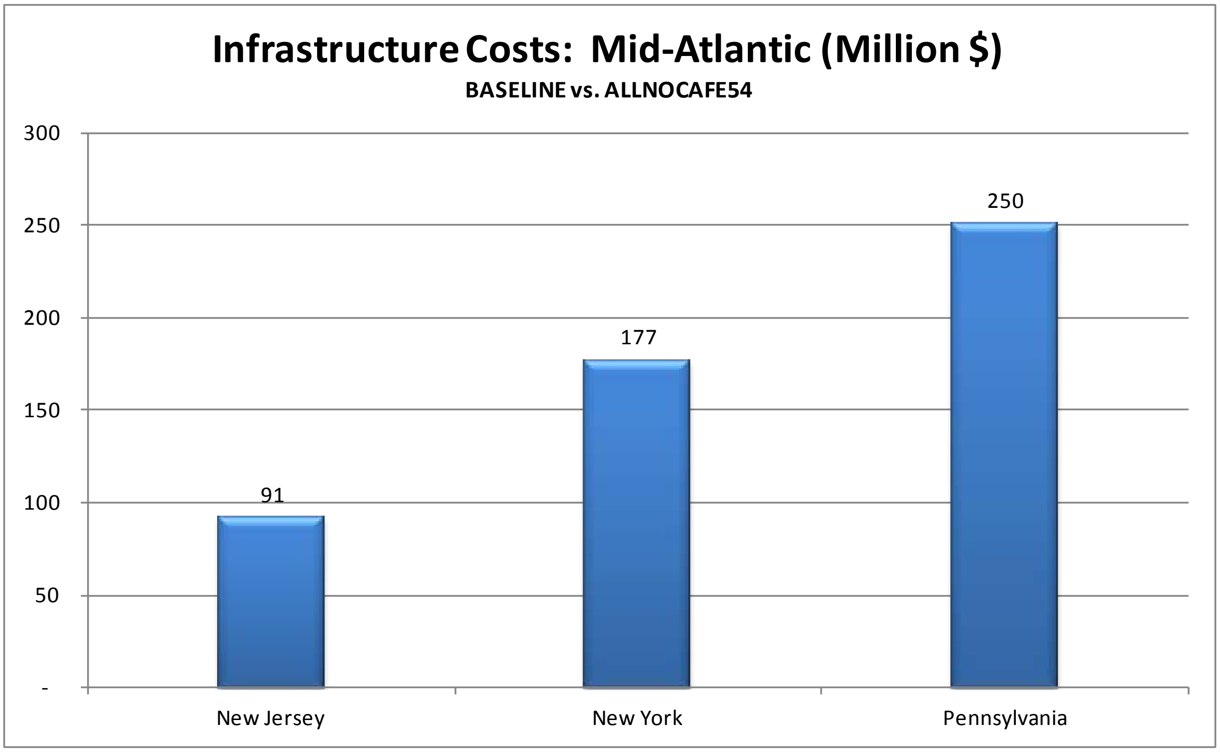


FIGURE 5-48: VEHICLE SUBSIDIES – DELAWARE AND MARYLAND

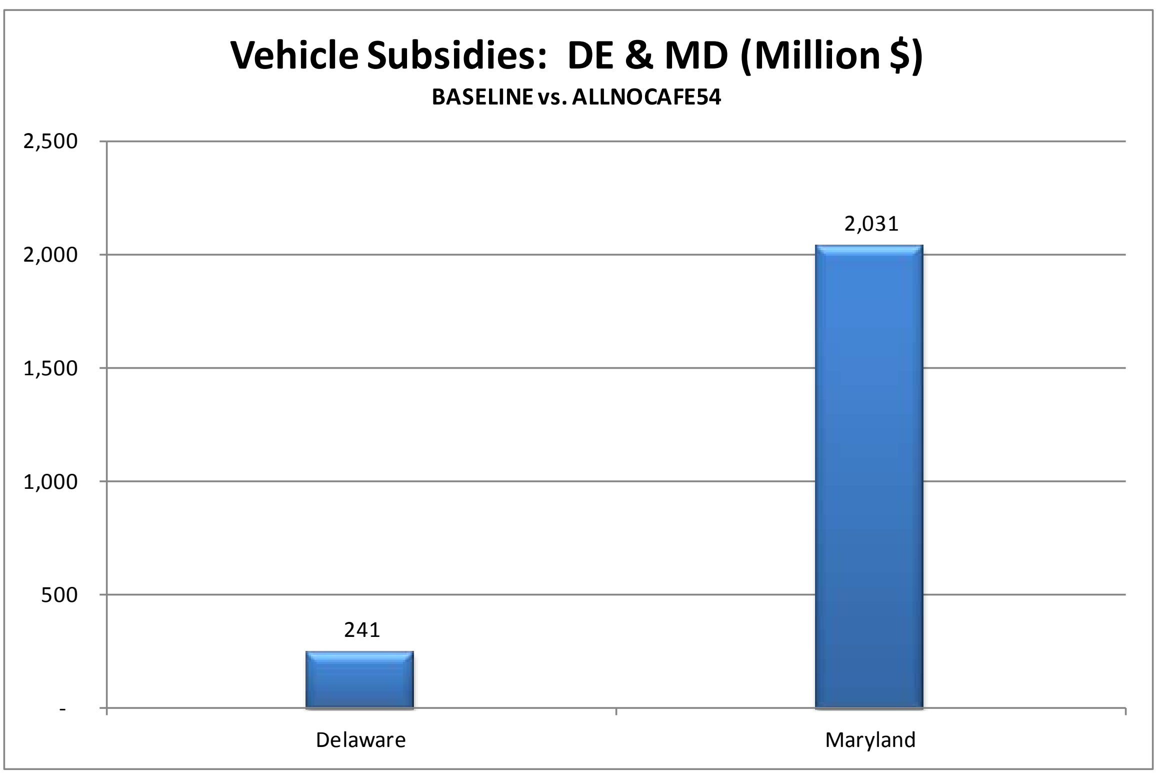
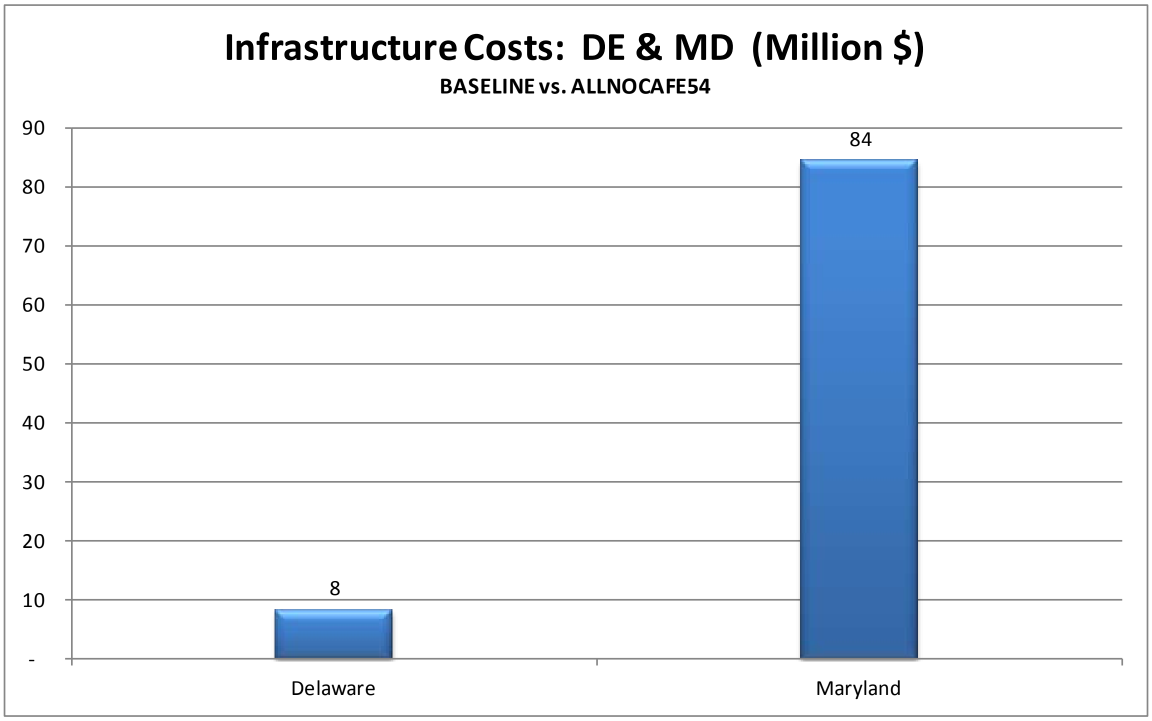


FIGURE 5-49: INFRASTRUCTURE COSTS – DELAWARE AND MARYLAND



The next collection of charts shows the incremental impact of the All scenario relative to the CAFE54 scenario. In general, this set of results is not as impactful in comparison with the ALLNOCAFE54 scenario since the inclusion of the CAFE54 efficiency specification reduces overall fuel consumption, resulting in reduced relative subsidy and infrastructure costs.

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FIGURE 5-50: VEHICLE SUBSIDIES – NEW ENGLAND STATES

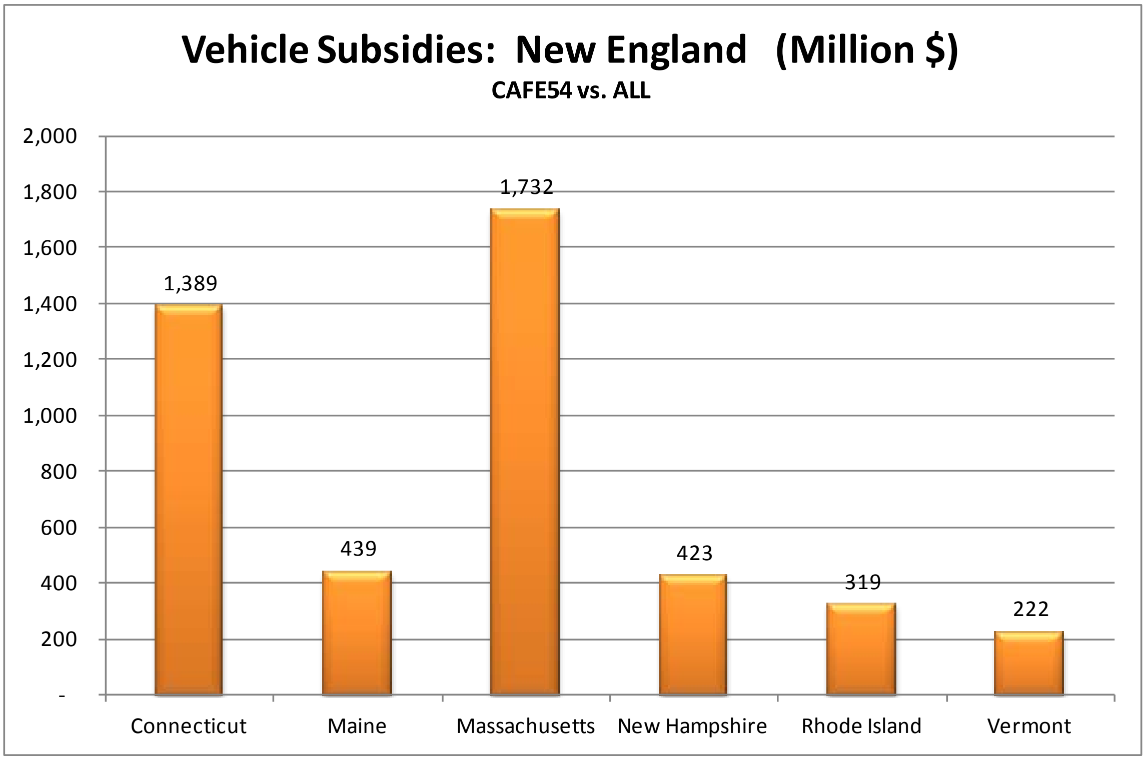


FIGURE 5-51: INFRASTRUCTURE COSTS – NEW ENGLAND STATES

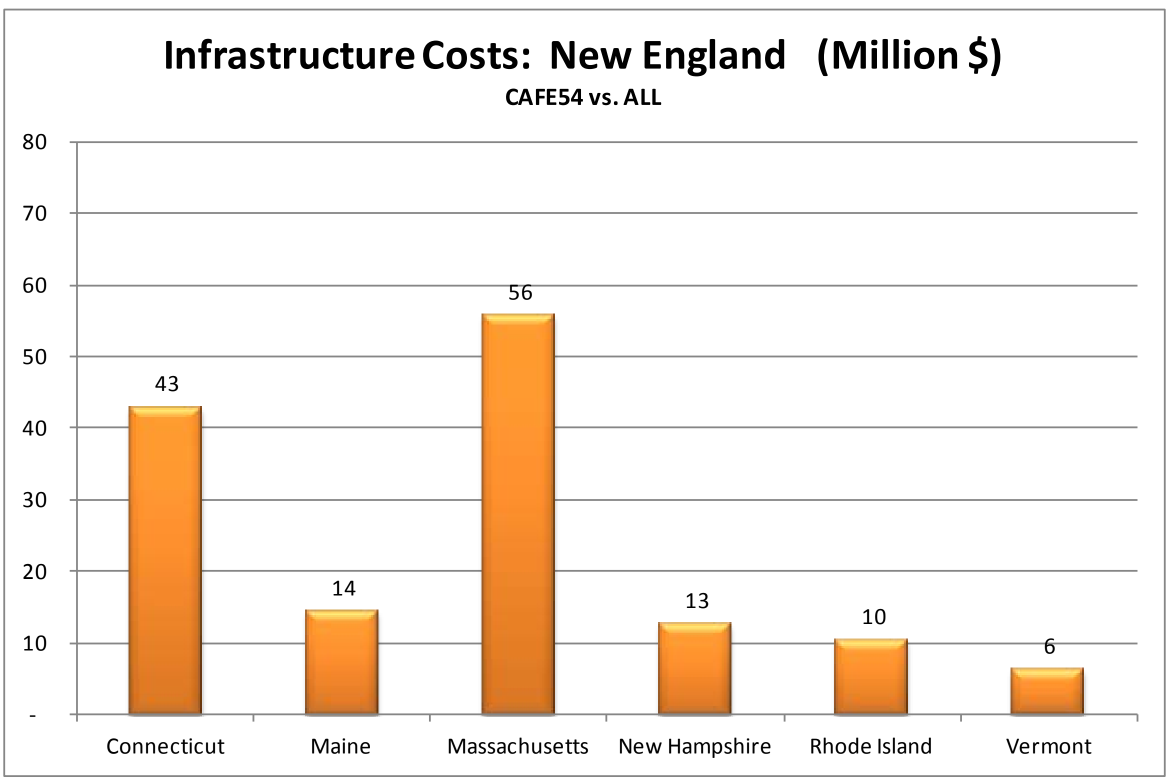


FIGURE 5-52: VEHICLE SUBSIDIES – MID-ATLANTIC STATES

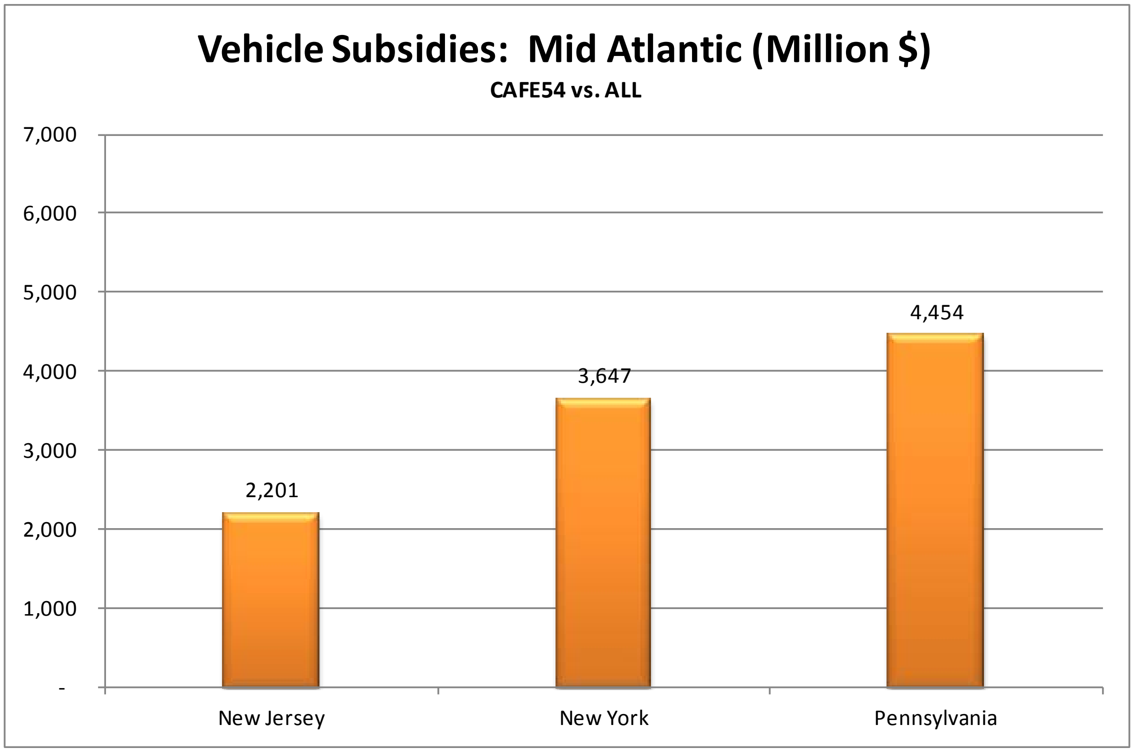


FIGURE 5-53: INFRASTRUCTURE COSTS – MID-ATANTIC STATES

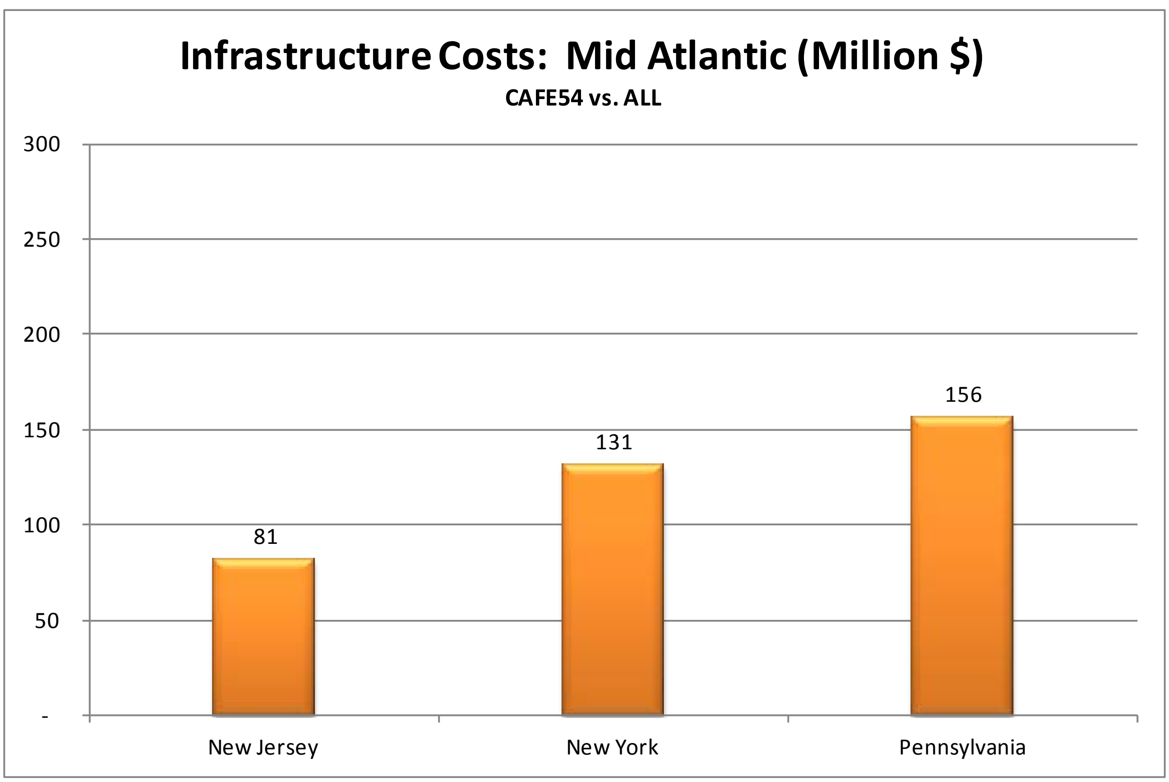


FIGURE 5-54: VEHICLE SUBSIDIES – DELAWARE AND MARYLAND

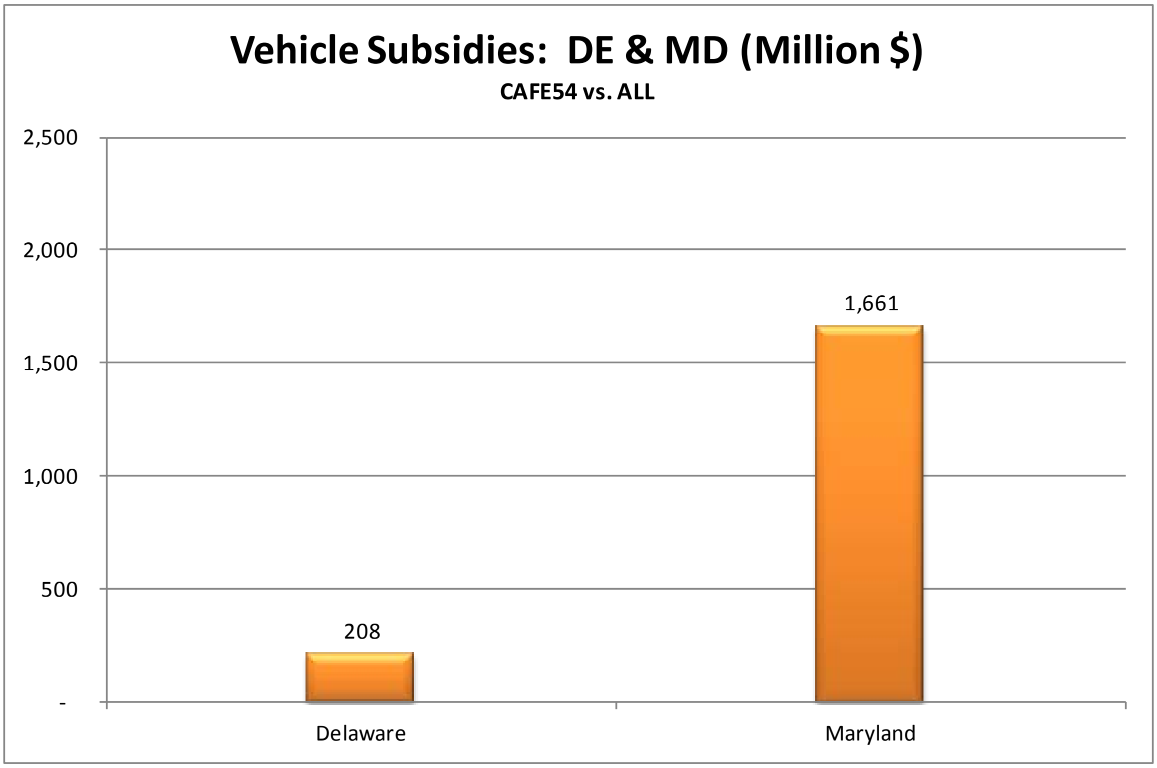
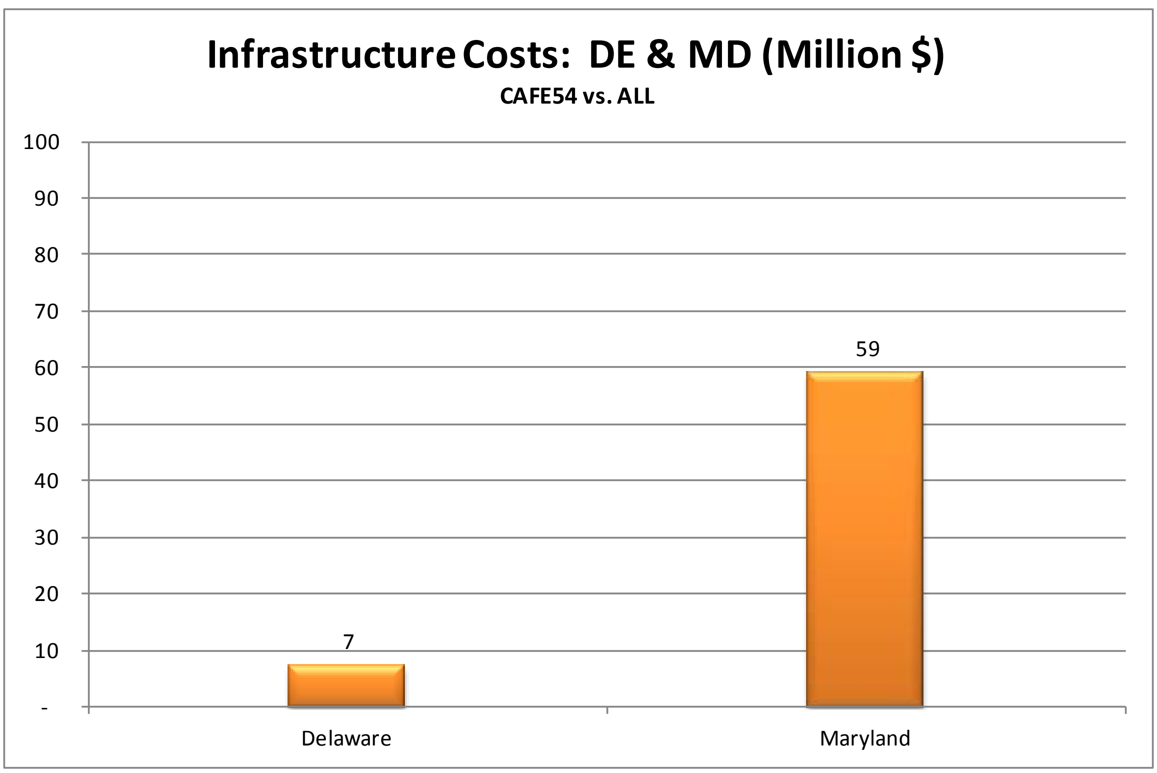


FIGURE 5-55: INFRASTRUCTURE COSTS – DELAWARE AND MARYLAND



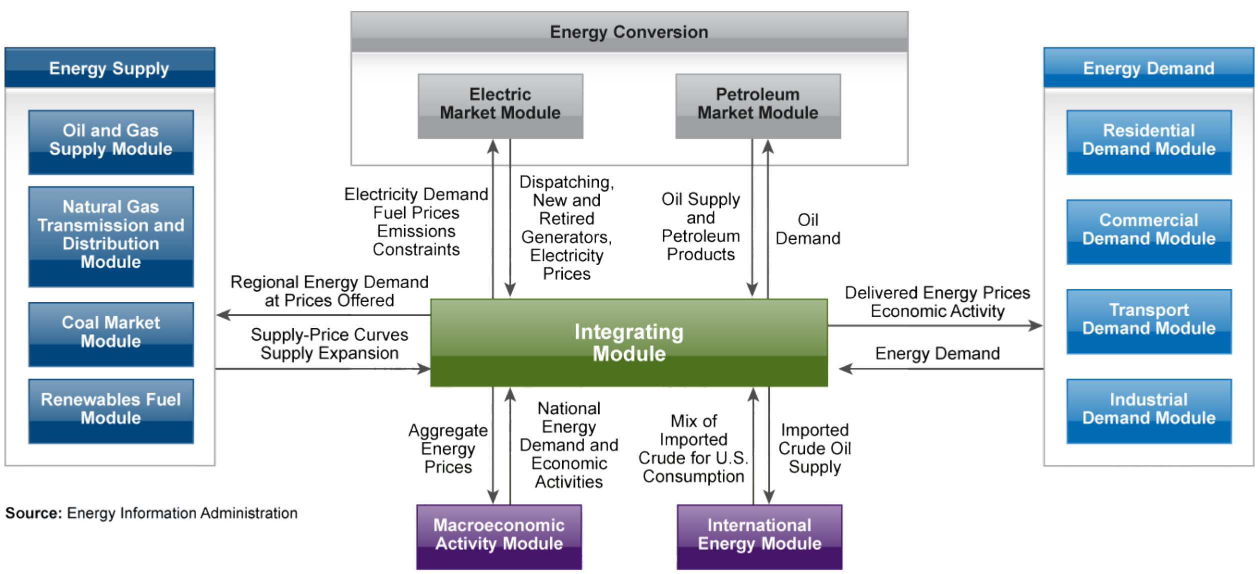
ATTACHMENT 1: OVERVIEW OF NEMS MODEL

1. DESCRIPTION OF THE NEMS MODEL

The National Energy Modeling System (NEMS) is a publicly-available, economy-wide, integrated energy model that includes 12 sub-modules covering energy supply, conversion, and demand. It is used by the U.S. Energy Information Administration (EIA) to provide energy market and infrastructure forecasts out to 2035, and is the principal tool for the analysis of energy and greenhouse gas policies used by the U.S. government, including Congress. SAIC[36] is a leading consultant to EIA on the design and implementation of NEMS, and has over 125 staff years supporting the model. (When SAIC uses the model, we refer to it as SAIC-NEMS, or by a client-based designation, to distinguish our use of the model from that of EIA, and to distinguish the use of the model for different clients).

NEMS integrates every energy sector in the U.S. economy, including the gas, oil and power industries, the renewable energy sector, the transportation demand sector and the residential, commercial and industrial energy demand sectors. The model is capable of analyzing overall impacts on the US economy of different energy and environmental policies.

SAIC-NEMS Modular Component Design



[36] SAIC, founded in 1969, is a FORTUNE 500® scientific, engineering and technology applications company that uses its deep domain knowledge to solve problems of vital importance to the nation and the world, in national security, energy and the environment, health and cybersecurity. The company's approximately 41,000 employees serve customers in the U.S. Department of Defense, the intelligence community, the U.S. Department of Homeland Security, other U.S. Government civil agencies and selected commercial markets. The company is a leading provider of energy services with clients around the world and has exceptional experience and a proven track record in utilizing multi-dimensional teams to provide deep knowledge and thought leadership to our clients. SAIC provides energy analysis and solutions, including energy modeling, energy analysis, energy IT and energy related survey work, to commercial and government clients, such as the Energy Information Administration (EIA). Headquartered in McLean, Va., SAIC had annual revenues of approximately $11 billion for its fiscal year ended January 31, 2011. For more information, visit www.saic.com. SAIC: From Science to Solutions®.

The time horizon of SAIC-NEMS is approximately 25 years (now 2010 – 2035). Because of the diverse nature of energy supply, demand, and conversion in the United States, the model supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, natural gas, and coal supply and distribution, the North American Electric Reliability Council (NERC) regions and sub-regions for electricity, and the Petroleum Administration for Defense Districts (PADDs) for refineries. (SAIC has developed methodologies that allow analyses to be extended to the state level, if desired).

For each fuel and consuming sector, SAIC-NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. SAIC-NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The model also includes a macroeconomic and an international module. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production, and international petroleum supply availability.

SAIC-NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the projection horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impact and cost of Federal legislation and regulation that affect the sector and reports key emissions. NEMS generally reflects all current legislation and regulation that are defined sufficiently to be modeled as of February 2009, such as the Energy Improvement and Extension Act of 2008 (EIEA2008), the biofuel provisions of the Food, Conservation, and Energy Act of 2008, the Energy Independence and Security Act of 2007 (EISA2007), the Energy Policy Act of 2005, Military Construction Appropriations Act of 2005, the Working Families Tax Relief Act of 2004, and the America Jobs Creation Act of 2004, and the costs of compliance with regulations such as new stationary diesel regulations issued by the U.S. Environmental Protection Agency (EPA) on July 11, 2006, which limit emissions of nitrogen oxides, particulate matter, sulfur dioxide, carbon monoxide, and hydrocarbons to the same levels required by the EPA's non-road diesel engine regulations and court decisions that impact regulations such as the recent decisions by the D.C. Circuit of the U.S. Court of Appeals on February 8, 2008, to vacate the Clean Air Mercury Rule (CAMR) and on July 11, 2008, to vacate the Clean Air Interstate Rule (CAIR). The NEMS components also reflect selected State legislation and regulations where implementing regulations are clear such as the October 2008 decision by the California Air Resources Board (CARB) on California's Low Carbon Fuel Standard (LCFS) requiring a 10-percent ethanol blend, by volume, in gasoline,. However, the potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the model. (Attachment 2 lists Federal and selected State legislation and regulations included in the model).

1.1 COMPONENT MODULES

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption. This section provides brief summaries of each of the modules.

1.1.1 Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules, and there is a macroeconomic feedback mechanism within SAIC-NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments,[37] new housing starts, new light-duty vehicle sales, interest rates, and employment.

1.1.2 International Module

The International Module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are a set of crude oil and product supply curves that are available to U.S. markets for each case/scenario analyzed. The petroleum import supply curves are made available to U.S. markets through the Petroleum Market Module (PMM) of NEMS in the form of 5 categories of imported crude oil and 17 international petroleum products, including supply curves for oxygenates and unfinished oils. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand, current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

1.1.3 Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and non-building uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

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[37] EIA gives the definition of industrial shipment value as: The value received for the complete systems at the company's net billing price, freight-on-board factory, including charges for cooperative advertising and warranties. This does not include excise taxes, freight or transportation charges, or installation charges. NEMS aggregates and reports all sectors into 35 industries and 11 services. In our calculation and report, the "Industrial Value of Shipments" is for the 35 industrial sectors, excluding the 11 services.

1.1.4 Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 21 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry.

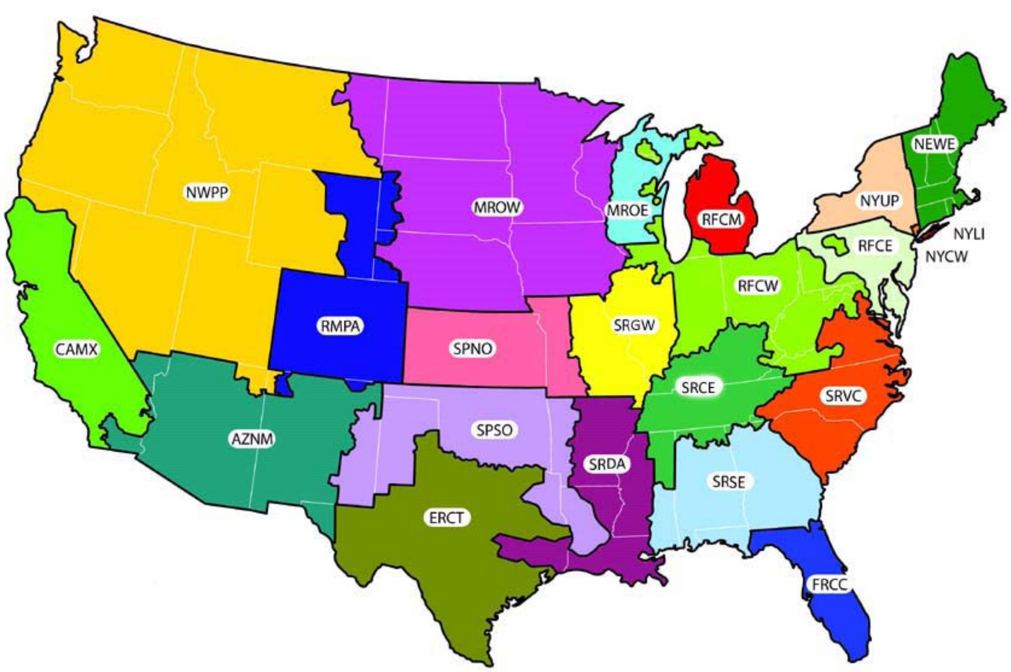
1.1.5 Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments.

1.1.6 Electricity Market Module

The Electricity Market Module (EMM) represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs and macroeconomic variables for costs of capital and domestic investment; environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Twenty two EMM regions, as shown below, are currently represent the power generation market geographical disposition.

22 ELECTRICITY MARKET MODULE REGIONS



1.1.7 Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development.

1.1.8 Oil and Gas Supply Module

The Oil and Gas Supply Module (OGSM) represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and unconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and gas production functions are computed for 12 supply regions, including 3 offshore and 3 Alaskan regions. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

1.1.9 Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 U.S. demand regions. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and imports and exports LNG.

1.1.10 Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and biofuels (ethanol, biodiesel, and biomass-to-liquids (BTL)). The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It explicitly models the requirements of EISA2007 and CAAA90 and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes the production of biofuels for blending in gasoline and diesel.

1.1.11 Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements), and other mine supply costs. Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by demand region and sector, environmental restrictions, and accounting for mine-mouth prices, transportation rates, and coal supply contracts. Over the projection horizon, coal transportation rates in the CMM are projected to vary in response to changes in railroad investment and market share (for western rates only).

Additional Details on the Modules

1.2 ELECTRICITY MARKET MODULE: KEY EMM RELATED OUTPUTS AND INPUTS (FROM OTHER COMPONENTS OF NEMS AND EXOGENOUS INPUTS)

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components	Electricity sales	Financial data
Fuel demands	Fuel prices	Tax assumptions
Capacity additions	Cogeneration supply and fuel consumption	Capital costs
Capital requirements	Electricity sales to the grid	Operation and maintenance costs
Emissions	Renewable technology characteristics, allowable capacity, and costs	Operating parameters
Renewable capacity	Renewable capacity factors	Emissions rates
Avoided costs	Gross domestic product	New technologies
	Interest rates	Existing facilities
		Transmission constraints

1.2.1 Electricity Market Module: Technologies included

Key electricity market model input assumptions are the overnight capital cost, operating and maintenance costs (fixed and variable), and performance (heat rate). Electricity supply technologies included in NEMS are:

Fossil Fuel Technologies

- Existing coal plants: 32 types with different combinations of pollution control equipment: baghouses, dry scrubbers, wet scrubbers, SCR, cold-side ESP, hot-side ESP, activated carbon injection with fabric filter, activated carbon injection with spray cooling
- Generic PC plant with wet flue gas desulfurization
- Advanced Coal
- Advanced Coal with carbon sequestration
- Gas/Oil Steam Turbine
- Combustion Turbines:
  - Existing
  - Conventional
  - Advanced
- Combined Cycle Turbine Systems:
  - Existing Gas/Oil
  - Conventional Gas/Oil
  - Advanced Gas/Oil
  - Advanced with Sequestration
- Fuel Cells

Nuclear

- Conventional Nuclear
- Advanced Nuclear

Renewables

- Biomass (Wood)
- Geothermal
- Municipal Solid Waste
- Hydroelectric
- Pumped Storage
- Wind
- Solar Thermal
- Photovoltaic

Distributed Generation

- Base load: represents heavy-duty micro-turbines, combustion turbines, compression ignition engines, small fuel cells
- Peak load: represented micro-turbines, frame-type combustion turbines operating on natural gas, and three types of reciprocating engines

These assumptions can be modified to adjust initial input values only or specific year-by-year profiles can be input to override exiting adjustments that are made to the capital investment during projection execution to account for factors like technology "learning." Constraints can also be applied on both a national and regional basis to limit capacity builds of a technology for various regions.

1.2.2 NEMS Electricity Market Inputs and Outputs

Some of the key electricity generation technology **input data specifications** are as follows:

- Overnight capital Cost ($/kW)
- Fixed O&M ($/kW-Year)
- Variable O&M ($/MWh)
- Heat Rate (Btu/kWh)
- Calendar Year of 1st Commercial Operation (Year)
- Economic Life (Years)
- Forced Outage Rate (%)
- Planned Outage Rate (%)
- Maximum Capacity Factor
- Financial Construction Lead Time (Years)
- Construction Profile by Year (%/Year)
- Generation Subsidy (Mills/kWh)
  - Subsidy Period:
  - Max Annual Payment for Subsidy
  - Max Amt Of Capacity Receiving Subsidy
- Project Contingency Factor: (%)

Model **outputs** are numerous, but include:

- Energy generation by type (e.g., electricity), region, year
- Energy prices by economic sector (e.g., residential, commercial), region, year
- Fuel demands by type, region, sector, and year
- Technology capacity additions/retirements by type (e.g., nuclear), region, year
- Capital requirements
- Pollutant emissions (SO_2, NOx, mercury)
- CO_2 generated by sector and region

Other key model inputs and outputs are briefly summarized in the tables below:

1.3 MACROECONOMIC MODULE:

Module	Outputs	Inputs from NEMS	Exogenous Inputs
Macroeconomic Activity	Gross domestic product Other economic activity measures, including housing starts, commercial floorspace growth, vehicle sales, and population Price indices and deflators Industry production rates Interest rates	Petroleum, natural gas, coal, and electricity prices Oil, natural gas, and coal production Electric power and natural gas industry output Refinery output End-use energy consumption by fuel	Macroeconomic variables defining alternative economic growth cases

1.4 INTERNATIONAL ENERGY MODULE:

International Energy Activity	World oil price Crude oil import supply curves Refined product import supply curves Oxygenate import supply curves International conventional and unconventional liquids supply by region International liquids demand by region	Domestic production of crude oil, natural gas plant liquids, liquids from natural gas, liquids from coal, ethanol, and other liquids production Domestic refinery processing gain Domestic product supplied GDP price deflators	OPEC production path Reference non-U.S. liquids supply and demand Non-U.S. economic parameters Base import supply curves for crude oils, refined products, and oxygenates

1.5 TRANSPORTATION DEMAND MODULE:

Exogenous Inputs	**Inputs from NEMS**	**TDM Outputs**
• **Current and projected demographics** • **Existing vehicle stocks by vintage and fuel efficiency** • **Vehicle survival rates** • **New vehicle technology characteristics** • **Fuel availability** • **Commercial availability** • **Vehicle safety and emissions regulations** • **Vehicle miles-per-gallon degradation rates**	• **Energy product prices** • **Gross domestic product** • **Disposable personal income** • **Industrial output** • **Vehicle sales** • **International trade** • **Natural gas pipeline consumption**	• **Fuel demand by mode** • **Sales, stocks and characteristics of vehicle types by size class** • **Vehicle-miles traveled** • **Fuel efficiencies by technology type** • **Alternative-fuel vehicle sales by technology type** • **Light-duty commercial fleet vehicle characteristics**

1.6 NEMS OIL AND GAS SUPPLY MODULE (OGSM)

OGSM provides a framework to analyze oil and gas supply on a regional basis:

- OGSM provides crude oil and natural gas supply parameters to both the Natural Gas Transmission and Distribution Module (NGTDM) and the Petroleum Market Module (PMM). The OGSM simulates activity of numerous firms that produce oil & natural gas from domestic fields throughout the U.S.
- Resource assumptions are primarily based on estimates of technically recoverable resources from the USGS and the Minerals Management Service (MMS) of the Department of the Interior.
- Resource estimates also include:
    - Projections for synthetic crude (syncrude) from oil shale based on underground mining and surface retorting technology and costs.
    - Alaska crude oil production based on estimates of available resources in undeveloped areas and the time and expense required to begin production in these areas. Alaska production includes existing producing fields, fields that have been discovered but are not currently being produced, and fields that are projected to exist, based upon the region’s geology.
    - Supplemental gas supply from: synthetic natural gas (SNG) from liquids, SNG from coal, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas).

1.7 NATURAL GAS TRANSMISSION AND DISTRIBUTION MODULE (NGTDM)

- The NGTDM links natural gas suppliers (including importers) and consumers in the lower 48 States and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural gas and the regional market clearing prices between suppliers and end-users.
- key NGTDM objectives & capabilities include:
    - *Represents interregional flows of gas and pipeline capacity constraints*
    - *Represents regional and import supplies*
    - *Determines the amount and the location of required additional pipeline and storage capacity on a regional basis, capturing the economic tradeoffs between pipeline and storage capacity additions*
    - *Provides a peak/off-peak, or seasonal analysis capability*
    - *Represents transmission and distribution service pricing*

1.8 COMMERCIAL DEMAND MODULE

Inputs from NEMS	Exogenous Inputs	CDM Outputs
• Energy product prices • Interest rates • Floorspace growth	• Existing commercial floorspace • Floorspace survival rates • Appliance stocks and survival rates • New appliance types, efficiencies, costs • Energy use intensities	• Energy demand by service and fuel type • Changes in floorspace and appliance stocks

1.9 RESIDENTIAL DEMAND MODULE

Inputs from NEMS	Exogenous Inputs	RDM Outputs
• Energy product prices • Housing starts • Population	• Current housing stocks and retirement rates • Current appliance stocks and life expectancy • New appliance types, efficiencies, and costs • Housing shell retrofit indices • Unit energy consumption • Square footage	• Energy demand by service and fuel type • Changes in housing and appliance stocks • Appliance stock efficiency

1.10 INDUSTRIAL DEMAND MODULE

Inputs from NEMS	Exogenous Inputs	IDM Outputs
• Energy product prices • Economic output by industry • Refinery fuel consumption • Lease and plant fuel consumption • Cogeneration from refineries and oil and gas production	• Production stages in energy-intensive industries • Technology possibility curves • Unit energy consumption • Stock retirement rates	• Energy demand by service and fuel type • Electricity sales to grid • Cogeneration output and fuel consumption

NEMS aggregates and reports all sectors into 35 industries and 11 services. Note that the value of "Industrial Value of Shipments" reported by the model is for the 35 industrial sectors, excluding the 11 services.

Industries

Manufacturing Industries

1. Food Products
2. Beverage and Tobacco Products
3. Textile Mills & Textile Products
4. Apparel
5. Wood Products
6. Furniture and Related Products
7. Paper Products
8. Printing
9. Basic Inorganic Chemicals
10. Basic Organic Chemicals
11. Plastic and Synthetic Rubber Materials
12. Agricultural Chemicals
13. Other Chemical Products
14. Petroleum Refineries
15. Other Petroleum and Coal Products
16. Plastics and Rubber Products
17. Leather and Allied Products
18. Glass & Glass Products
19. Cement Manufacturing
20. Other Nonmetallic Mineral Products
21. Iron & Steel Mills, Ferroalloy & Steel Products
22. Alumina & Aluminum Products
23. Other Primary Metals
24. Fabricated Metal Products
25. Machinery
26. Other Electronic & Electric Products
27. Transportation Equipment
28. Measuring & Control Instruments
29. Miscellaneous Manufacturing

Nonmanufacturing Industries

30. Crop Production
31. Other Agriculture, Forestry, Fishing & Hunting
32. Coal Mining

33. Oil & Gas Extraction & Support Activities
34. Other Mining & Quarrying
35. Construction Define “chained 2009 dollars”

Services

1. Transportation & Warehousing
2. Broadcasting & Telecommunications
3. Electric Power Generation & Distribution
4. Natural Gas Distribution
5. Water, Sewage & Related System
6. Wholesale Trade
7. Retail Trade
8. Finance & Insurance, Real Estate
9. Other Services
10. Public Administration, Federal Government
11. Public Administration, State & Local Government

EIA gives the definition of industrial shipments as: “The value received for the complete systems at the company's net billing price, freight-on-board factory, including charges for cooperative advertising and warranties. This does not include excise taxes, freight or transportation charges, or installation charges.”

1.11 DESCRIPTION OF MODELED LEGISLATION AND ENERGY POLICIES

All Federal and State energy and environmental legislation enacted as of November 2010 are incorporated into SAIC-NEMS. Examples of such legislation enacted in the past few years and incorporated in SAIC-NEMS include:

- The Federal Renewable Fuel Standard (RFS2): The federal revised Renewable Fuel Standard (RFS2) places minimum volume requirements on the renewable fuel content of transportation fuels in the U.S. (EPA 2010). The Energy Independence and Security Act (EISA) of 2007 that mandates the RFS2 requires that at least 36 billion gallons of the transportation fuels marketed in the U.S. be renewable fuels by the year 2022. This requirement focuses on the primary intent of the standard, to reduce petroleum fuel use in the nation. The revised statutory requirements establish new specific annual volume standards for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel. These requirements focus on the secondary intent of the standards, to reduce nationwide GHG emissions. The revised statutory requirements also include new definitions and criteria for both renewable fuels and the feedstocks used to produce them, including new greenhouse gas (GHG) emission thresholds as determined by lifecycle analysis. For example, fuel derived from biomass that meets a 50% reduction in GHG emissions would fall under the advanced biofuel category.

  The provisions of the RFS2 program apply to refiners, blenders, and importers of transportation fuels, and the percentage standards apply to the total amount of gasoline and diesel they produce for such use. In order to qualify for these new volume categories, fuels must demonstrate that they meet certain minimum GHG reduction standards based on a lifecycle assessment, in comparison to the petroleum fuels they displace.

- California Low Carbon Fuel Standard (LCFS): The California LCFS calls for a 10% reduction in the weighted carbon intensity of California's on-road transportation fuels (gasoline and diesel) by 2020 (ARB 2010) by increasing the volumes of alternative low-carbon fuels being introduced into the marketplace. One means of reducing the CI of the California transportation fuel supply is to increase the use of biofuels that generally have lower CI than petroleum-derived fuels.

  Life cycle analysis of a fuel pathway provides the basis for establishing the CI of a fuel under the LCFS. The LCFS uses the CA-GREET model to determine CI values for fuel pathways. An additional adjustment for land use conversion (LUC) is applied to biofuels, such as corn that are produced on arable land. The LCFS is calculated on a weighted-basis rather than a threshold basis, which is the method used under the RFS2.

  The CIs of petroleum fuel pathways provide inputs for biomass processing because petroleum fuels are used in various steps in biofuel pathways, primarily in feedstock and finished fuel transportation. The CIs of petroleum fuel pathways also represent the baseline to which the biofuel CIs are compared. Fuel pathways of interest here include the ones listed in the following table.

Carbon Intensities for Fuel Pathways for Comparison with Biomass Synthesis Fuels

Pathway	**CI (g CO_2e/MJ)**
CARBOB from petroleum (crude oil) (ARB 2009a)	95.86
CARFG (blend of CARBOB and ethanol)	96.09
Ultra low sulfur diesel from petroleum (crude oil) (ARB 2009b).	94.71
Cellulosic ethanol from forest residue pathway (ARB 2009c).	21.4
Cellulosic ethanol from farmed trees (ARB 2009e)	6
Renewable diesel (RD) from soybeans (ARB 2009d)	20.16

  Under the LCFS, light- and heavy-duty vehicle fuels must achieve the mandated weighed average reductions in CI. The baseline light-duty vehicle fuel is California reformulated gasoline CARFG, which is a blend of California reformulated gasoline blendstock for oxygenate blending (CARBOB), which is a petroleum gasoline formulation, and ethanol. The CI for CARFG depends on the CI associated with the ethanol used in the blend and varies slightly with different ethanol CIs; the CI shown for CARFG in the above table corresponds to CARBOB blended with Midwest average ethanol. The baseline heavy-duty vehicle fuel is ultra-low sulfur diesel (ULSD) fuel produced for use in California.

  Two cellulosic ethanol pathways in the CA-GREET model examine forest residue and farmed trees as feedstocks. These pathways are also used by ARB under the LCFS.

- The American Recovery and Reinvestment Act (ARRA) was signed into law in mid-February 2009. ARRA provides significant new Federal funding, loan guarantees, and tax credits to stimulate investments in energy efficiency and renewable energy. The energy-specific provisions of ARRA that were represented in some fashion in SAIC-NEMS include:

  - Weatherization and assisted housing
  - Energy efficiency and conservation block grant programs
  - State energy programs
  - Plug-in hybrid vehicle tax credit
  - Electric vehicle tax credit
  - Updated tax credits for renewables
  - Loan guarantees for renewables and biofuels
  - Support for carbon capture and storage (CCS)
  - Smart grid expenditures.

- Other major changes in the model to reflect changes in energy markets, laws, and regulations since the development of the reference case include:
  - Update of macroeconomic assumptions
  - Update of near-term fuel price projections
  - Temporary reinstatement of the Clean Air Interstate Rule (CAIR)
  - Update of Corporate Average Fuel Economy (CAFE) standards.
- The tax provisions of EIEA2008, signed into law on October 3, 2008, as part of Public Law 110-343, the Emergency Economic Stabilization Act of 2008
- The biofuel provisions of the Food, Conservation, and Energy Act of 2008 (Public Law 110-234) [*2*], which reduce the existing ethanol excise tax credit in the first year after U.S. ethanol production and imports exceed 7.5 billion gallons and add an income tax credit for the production of cellulosic biofuels
- The provisions of EISA2007 (Public Law 110-140) including: a renewable fuel standard (RFS) requiring the use of 36 billion gallons of ethanol by 2022; an attribute-based minimum CAFE standard for cars and trucks of 35 miles per gallon (mpg) by 2020; a program of CAFE credit trading and transfer; various appliance efficiency standards; a lighting efficiency standard starting in 2012; and a number of other provisions related to industrial waste heat or natural gas efficiency, energy use in Federal buildings, weatherization assistance, and manufactured housing
- Those provisions of the Energy Policy Act of 2005 (EPACT2005), Public Law 109-58, that remain in effect and have not been superseded by EISA-2007, including: mandatory energy conservation standards; numerous tax credits for businesses and individuals; elimination of the oxygen content requirement for Federal reformulated gasoline (RFG); extended royalty relief for offshore oil and natural gas producers; authorization for DOE to issue loan guarantees for new or improved technology projects that avoid, reduce, or sequester GHGs; and a PTC for new nuclear facilities.
- Public Law 108-324, the Military Construction Appropriations Act of 2005, which contains provisions to encourage construction of an Alaska natural gas pipeline, including Federal loan guarantees during construction.
- State RPS programs, representing laws and regulations of 27 States and the District of Columbia that require renewable electricity generation.

Examples of recent Federal and State regulations as well as earlier provisions that have been affected by court decisions that are considered include the following:

- Decisions by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, to vacate and remand the Clean Air Mercury Rule (CAMR) and on July 11, 2008, to vacate and remand the Clean Air Interstate Rule (CAIR)
- Release by the California Air Resources Board (CARB) in October 2008 of updated regulations for RFG that went into effect on August 29, 2008, allowing a 10-percent ethanol blend, by volume, in gasoline.

1.12 DESCRIPTION OF BIOFUEL COSTS IN NEMS

NEMS calculates biofuel prices endogenously. This is handled by a combination of modules within the model and is somewhat complex. The discussion below is derived from EIA's NEMS model documentation.

The cost of corn ethanol is comprised of processing plant capital cost, feedstock cost, operating cost, energy cost, and a credit for marketable co-products of ethanol production. Energy costs include the cost of energy needed to grow and transport corn to market and the cost of energy needed to run the ethanol plant. The sum of these costs contributes to the total value of ethanol, as determined by the model's optimized solution. Conversion of corn to ethanol is accomplished by either a wet milling or dry milling process. The co-products produced from the wet milling process are corn gluten feed (CGF), corn gluten meal (CGM), and corn oil, while the dry milling process produces distillers' dried grains with solubles (DDGS). Initial co-product credits for wet mills and dry mills are estimated from ethanol industry financial data, with some updates made as a function of corn costs in forecast years. Note that only the agricultural, or feedstock production costs are modeled as a function of the total quantity of ethanol produced. The conversion plant process costs (capital, operating, and process energy) are independent of production quantities.

Ethanol capital and conversion costs are assumed to be constant across all Census Divisions and for all forecast years. Processing plant energy costs vary across Census Divisions as a function of industrial-sector coal, natural gas, and electricity prices. Natural gas prices are obtained from the NEMS Natural Gas Transmission and Distribution Model, coal prices are from the NEMS Coal Market Model, and electricity prices are from the NEMS Electricity Market Model.

The cost of cellulosic ethanol is similarly comprised of capital cost, feedstock (biomass) cost, operating cost, and a credit for excess electricity generated at the ethanol plant. As with the corn model, each of the above factors contributes to a part of the total price of ethanol. Biomass price/quantity data are obtained from the Renewable Fuels Model of NEMS and are used as input to the ethanol model.

An important modeling consideration for cellulose ethanol production is the imposition of a constraint on the amount of ethanol production capacity assumed for the early years of the forecast. Ethanol from cellulose is a relatively new technology and ethanol production from cellulose is currently at the demonstration level. A constraint on cellulose ethanol production prevents unrealistically large increases in production capacity from occurring suddenly in response to favorable market prices.

The cost of advanced ethanol is also subdivided into capital cost, feedstock cost, and operating cost. Each of these factors contributes to a part of the total price of ethanol. The capital cost of an advanced ethanol processing unit is estimated to be a function of the cost of a next generation dry mill corn ethanol unit. The variable operating costs are input data that are consistent with the process unit yield assumptions. The grain supply curve is set based on an initial stock of *barley* available in each supply region (Census Division), and is defined by 5 discrete steps. The price on each step is a function of the corn price and a transport cost, and the size of each step is a function of total stock. The growth rate in stock each year is defined by the growth in corn ethanol production.

The delivered prices of feedstock (corn, cellulosic biomass, and grains) are provided to the ethanol supply model of the PMM in the form of separate supply curves for each of the nine U.S. Census Divisions. The price of corn at the farm is projected from "*The U.S. Farm Economic Effects of a 6 Billion Gallon Renewable Fuel Standard, a 8 Billion Gallon Renewable Fuel Standard, and Elimination of the Federal Ethanol Tax Credit,*" *Department of Agriculture, July 2005*. This paper estimates the effect on agricultural markets of expanding ethanol production by 6 or 8 billion gallons over baseline levels by 2012. The results of the 8-billion-gallon case are used in PMM.

Cellulosic biomass resources are derived from four sources: 1) urban and mill wastes, 2) forestry residues (both from Federal and private lands), 3) agricultural residues, and 4) dedicated energy crops. The latter two sources are comprised of perennial grasses, coppice and other woody crops, corn stover, wheat try, oat straw, sorghum stubble, and barley straw - the vast majority of the total feedstocks available comprise switchgrass, corn stover and wheat straw. Because cellulosic ethanol producers may be limited in their ability to use particular feedstocks, the model user can specify a fraction of each of the four sectors to use to determine the ethanol feedstock price. The price for biomass fuel to the *power-sector* is determined from the residual biomass supply, after accounting for cellulosic demand. Because the power sector can handle lower-quality/lower-price resources, prices to the power sector are constrained to be less than or equal to cellulosic resource prices.

NEMS' Biomass Submodule (located in the Renewable Fuels Module - RFM) sends *regional fuel price and quantity information* to the Electricity Market Module (EMM) and the Petroleum Market Module (PMM). *The submodule utilizes a regional biomass supply schedule from which the biomass price is determined.* The biomass supply schedule is based on the accessibility of biomass resources by the consuming sectors from existing wood resources, agricultural residues, and biomass energy crops; Cost and performance characteristics of a representative biomass combustion system were determined through a study performed by SAIC. Cost and performance characteristics of cellulosic ethanol production facilities reside in the PMM.

Cellulosic biomass supply quantities is based on the assumption of prices ranging from $40 to $60 per dry ton ($2010) and it is assumed that prices above $60 for agriculturally-based biomass would not spur large harvest increases. For forestry residues, however, the model assumes that additional feedstocks will become available as prices climb to about $100 per dry ton.

The model also assumes a fixed "typical" biomass transportation distance in calculating biomass costs. For agricultural residues, forestry residues, energy crops, and urban wood waste, it is assumed that the maximum distance that this type of material can be transported economically is 50 miles. Within a circular area with a radius of 50 miles, it is assumed that the transportation cost is $12/dry ton. This fixed amount has been added to the supply curves for agricultural residues, forestry residues, and energy crops to reflect the transportation cost from the farm-gate to processing plant.

Currently, EIA assumes that cellulosic ethanol plants will not be able to use supplies from urban wood and mill waste as well as feedstocks from Federal forests, but the power sector can utilize all biomass resources included in the model.

As for biodiesel, the PMM can produce biodiesel from virgin vegetable oil, yellow grease, white grease, and imported palm oil. Virgin oil supplies to biodiesel producers consist of regional quantities of soybean, cottonseed, canola, and sunflower oils. Yellow grease consists primarily of used cooking oil from restaurants. As such, its availability is nationwide and is assumed to grow at the same rate that population grows. White grease consists of fats from rendering. Biodiesel production capacity by feedstock is allocated among Census Divisions in PMM according to the National Biodiesel Board's map of existing and potential producers and according to potential feedstock supplies. NEMS' biodiesel model uses a process costing approach to model the impacts of net feedstock production costs plus capital and operating costs. Biodiesel is produced in a type of chemical reaction called a transesterification. Fats or oils are reacted with an alcohol, usually methanol, to produce esters of the fat or oil (biodiesel) and glycerin (byproduct).

For *AEO2011*, soybean oil prices were econometrically linked with corn prices. Costs for other virgin oils (cotton seed, sunflower, and canola) are defined as a function of the soybean oil price. These relationships are based on historical comparisons between these other virgin oils (cotton seed, sunflower, and canola) with respect to soybean oil. The price curve is an exponential curve based on: 1) the price and quantity of feedstock as if biodiesel consumes the entire soybean oil supply, and 2) the price and quantity of feedstock as if biodiesel consumes the entire virgin oil supply (soybean, cottonseed, sunflower, and canola).

The costs of distributing and marketing transportation fuel products are represented by adding distribution costs to the wholesale prices of products. The distribution costs are applied at the Census Division level and are assumed to be constant throughout the forecast and across scenarios. Distribution costs for each product, sector, and Census Division represent average historical differences between end-use (excluding taxes) and wholesale prices. State and Federal taxes are also added to transportation fuels to determine final end-use sector prices. Tax trend analysis indicates that State taxes increase at the rate of inflation, while Federal taxes do not. In the PMM, therefore, State taxes are held constant in real terms throughout the forecast while Federal taxes are deflated at the rate of inflation. The local taxes for transportation fuels are assumed to be a small percentage of the wholesale fuel prices that are updated every year.

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ATTACHMENT 2: TABLES GENERATED FOR EACH RUN - NEMS TABLE LIST

2. NEMS TABLE LISTING

1. Total Energy Supply and Disposition Summary
2. Energy Consumption by Sector and Source
3. Energy Prices by Sector and Source
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5. Commercial Sector Key Indicators and Consumption
6. Industrial Sector Key Indicators and Consumption
7. Transportation Sector Key Indicators and Delivered Energy Consumption
8. Electricity Supply, Disposition, Prices, and Emissions
9. Electricity Generating Capability
10. Electricity Trade
11. Petroleum Supply and Disposition Balance
12. Petroleum Product Prices
13. Natural Gas Supply, Disposition, and Prices
14. Oil and Gas Supply
15. Coal Supply, Disposition, and Prices
16. Renewable Energy Generating Capability and Generation
17. Carbon Dioxide Emissions by Sector and Source
18. Macroeconomic Indicators
19. International Petroleum Supply and Disposition Summary
20. Conversion Factors
21. Average Household Expenditures for Energy by Household Characteristic (output: hemtable.txt)
22. blank table
23. Total Energy Supply and Disposition Summary, Crude Oil Equivalence
24. Renewable Energy Consumption by Sector and Source
25. Total Energy Supply and Disposition Summary - Metric Tons Oil Equivalent
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33. Other Commercial Sector Consumption
34. Industrial Sector Macroeconomic Indicators
35. Refining Industry Energy Consumption
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37. Paper Industry Energy Consumption
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80. Refinery Process Unit Capacity
81. Natural Gas Underground Storage and Pipeline Capacity
82. Natural Gas Consumption by End-Use Sector, Region, and Service Type
83. Natural Gas Delivered Price by End-Use Sector, Region, and Service Type
84. Natural Gas Pipeline Capacity By NGTDM Region
85. Natural Gas Pipeline Flows by NGTDM Region
86. Natural Gas Pipeline Capacity Utilization By NGTDM Region
87. Natural Gas Pipeline Capacity By Census Division
88. Natural Gas Pipeline Flows by Census Division
89. Natural Gas Pipeline Capacity Utilization by Census Division
90. Natural Gas Flows Entering NGTDM Region from Neighboring Regions
91. Natural Gas Capacity Entering NGTDM Region from Neighboring Regions
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93. Domestic Coal Supply, Disposition, and Prices
94. Coal Production and Minemouth Prices by Region
95. Coal Production by Region and Type
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97. World Metallurgical Coal Flows By Importing Regions and Exporting Countries
98. World Total Coal Flows By Importing Regions and Exporting Countries
99. Coal Prices by Region and Type
100. Indicators of Macroeconomic Activity
101. Inputs to Macroeconomic Activity Module
102. new Table 102 coming soon
103. Investment
104. Dummy Table for Imported Petroleum by Source
105. Crude Oil Import Quantities and Prices by PADD
106. Petroleum Product Import Quantities and Prices by PADD
107. Supply and Disposition Exposition in Btus and Physical Units
108. blank table
109. Energy Performance Indicators
110. NEMS/STIFS Comparison (not a fort.2table: steotable.txt)
111. blank table
112. blank table
113. New Light-Duty Vehicle Fuel Economy
114. New Light-Duty Vehicle Prices
115. New Light-Duty Vehicle Range
116. Total Resource Costs - Electric Sector
117. National Impacts of the Clean Air Act Amendments of 199(CAAA90)
118. Greenhouse Gas Compliance Results
119. Unadjusted Energy Prices by Sector and Source
120. International Energy Agency Submission (not a fort.2table: ieatable.txt)

ATTACHMENT 3: COMMONLY USED NEMS INDICATORS

3. TABLES IDENTIFYING COMMONLY USED NEMS INDICATORS

Gross Domestic Product

1 Macro Economic Indicators - Real Gross Domestic Product
2 Components of Real Gross Domestic Product - Real Consumption
3 Components of Real Gross Domestic Product - Real Investment
4 Components of Real Gross Domestic Product - Real Government Spending
5 Components of Real Gross Domestic Product - Real Exports
6 Components of Real Gross Domestic Product - Real Imports

Value of Shipments

7 Value of Shipments (billion 2000 dollars) - Total Industrial
8 Value of Shipments (billion 2000 dollars) - Nonmanufacturing
9 Value of Shipments (billion 2000 dollars) - Manufacturing
10 Value of Shipments (billion 2000 dollars) - Energy Intensive
11 Value of Shipments (billion 2000 dollars) - Non-energy Intensive

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12 Population and Employment (millions) - Employment, Nonfarm
13 Population and Employment (millions) - Employment, Manufacturing
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15 Key Indicators for Energy Demand - Housing Starts (millions)
16 Key Indicators for Energy Demand - New England

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17 Real Disposable Income by Census Division - Middle Atlantic
18 Real Disposable Income by Census Division - East North Central
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26 Sector Average Prices - Residential

27 Sector Average Prices - Commercial
28 Sector Average Prices - Industrial
29 Sector Average Prices - Transportation
30 Sector Average Prices - Overall Delivered Average Price
31 Sector Average Prices - Electric Power

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32 Energy Price - Low Sulfur Light Price ($ per bbl) 12/
33 Energy Price - Imported Crude Oil Price ($ per bbl) 12/
34 Energy Price - Gas Price at Henry Hub ($ / mmBtu)
35 Energy Price - Gas Wellhead Price ($ / mmBtu) 13/
36 Energy Price - Gas Wellhead Price ($ / Mcf) 13/
37 Energy Price - Coal Minemouth Price ($ / ton) 14/
38 Energy Price - Coal Delivered Price ($ / million Btu) 15/
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Natural Gas Prices by Sector

40 Natural Gas Prices - Residential
41 Natural Gas Prices - Commercial
42 Natural Gas Prices - Industrial 1/
43 Natural Gas Prices - Transportation
44 Natural Gas Prices - Electric Power 9/

Electricity Prices by Sector

45 Electricity Prices - Residential
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48 Electricity Prices - Transportation

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49 Domestic Crude Oil Production - Lower 48 Onshore
50 Domestic Lower 48 Onshore Crude Oil Production - Northeast
51 Domestic Lower 48 Onshore Crude Oil Production - Gulf Coast
52 Domestic Lower 48 Onshore Crude Oil Production - Midcontinent
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54 Domestic Lower 48 Onshore Crude Oil Production - Rocky Mountain
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56 Domestic Crude Oil Production - Lower 48 Offshore
57 Domestic Lower 48 Offshore Crude Oil Production - Gulf
58 Domestic Lower 48 Offshore Crude Oil Production - Shallow
59 Domestic Lower 48 Offshore Crude Oil Production - Deep

60 Domestic Lower 48 Offshore Crude Oil Production - Pacific

61 Domestic Lower 48 Offshore Crude Oil Production - Atlantic

62 Domestic Crude Oil Production - Alaska

63 Domestic Crude Oil Production - United States Total

Natural Gas Production

64 Domestic Natural Gas Production - Lower 48 Onshore

65 Domestic Lower 48 Onshore Natural Gas Production - Northeast

66 Domestic Lower 48 Onshore Natural Gas Production - Gulf Coast

67 Domestic Lower 48 Onshore Natural Gas Production - Midcontinent

68 Domestic Lower 48 Onshore Natural Gas Production - Southwest

69 Domestic Lower 48 Onshore Natural Gas Production - Rocky Mountain

70 Domestic Lower 48 Onshore Natural Gas Production - West Coast

71 Domestic Natural Gas Production - Lower 48 Offshore

72 Domestic Lower 48 Onshore Natural Gas Production - Gulf

73 Domestic Lower 48 Onshore Natural Gas Production - Shallow

74 Domestic Lower 48 Onshore Natural Gas Production - Deep

75 Domestic Lower 48 Onshore Natural Gas Production - Pacific

76 Domestic Lower 48 Onshore Natural Gas Production - Atlantic

77 Domestic Natural Gas Production - Alaska

78 Domestic Natural Gas Production - United States Total

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79 Energy Consumption by Sector - Residential

81 Energy Consumption by Sector - Industrial 4/

82 Energy Consumption by Sector - Transportation

83 Energy Consumption by Sector - Electric Power 14/

84 Delivered Energy Consumption - Liquid Fuels Subtotal

85 Delivered Energy Consumption - Natural Gas Subtotal

86 Delivered Energy Consumption - Coal Subtotal

87 Delivered Energy Consumption - Renewable Energy 13/

88 Delivered Energy Consumption - Electricity

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89 GDP Energy intensity - Delivered Energy

90 GDP Energy intensity - Total Energy

Oil & Gas Reserves

91 Oil Resources - Lower 48 Reserves

92 Oil Resources - Lower 48 Reserve Additions

93 Gas Resources - Lower 48 Reserves

94 Gas Resources - Lower 48 Reserve Additions

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95 Vehicle Miles Traveled - Average New Car MPG

177 Light-Duty Vehicle Miles per Gallon - Average New Car MPG

Energy Imports

96 Energy Imports - Total

97 Natural Gas Imports - Net Imports

98 Natural Gas Imports - Pipeline 3/

99 Natural Gas Imports - Liquefied Natural Gas

100 Crude Oil Imports - Net Imports

Renewables Utilization

101 Renewables Utilization - Total Energy Consumption

102 Renewables Utilization - Total Electricity Generation by Fuel

Energy Production by Fuel

103 Energy Production - Total

104 Energy Production by Fuel - Crude Oil and Lease Condensate

105 Energy Production by Fuel - Natural Gas Plant Liquids

106 Energy Production by Fuel - Dry Natural Gas

107 Energy Production by Fuel - Coal 1/

108 Energy Production by Fuel - Nuclear Power

109 Energy Production by Fuel - Hydropower

110 Energy Production by Fuel - Biomass 2/

111 Energy Production by Fuel - Other Renewable Energy 3/

112 Energy Production by Fuel - Other 4/

113 Energy Production by Fuel - Total

Electricity Generating Capacity

114 Electricity Generating Capacity - Total

115 Electricity Generating Capacity - Coal

116 Electricity Generating Capacity - Advanced

117 Electricity Generating Capacity - IGCC without sequestration

118 Electricity Generating Capacity - IGCC with sequestration

119 Electricity Generating Capacity - Conventional

120 Electricity Generating Capacity - Oil and Natural Gas Steam

121 Electricity Generating Capacity - Combined Cycle

122 Electricity Generating Capacity - Advanced

123 Electricity Generating Capacity - NGCC without sequestration

124 Electricity Generating Capacity - NGCC with sequestration

125 Electricity Generating Capacity - Conventional
126 Electricity Generating Capacity - Combustion Turbine/Diesel
127 Electricity Generating Capacity - Advanced
128 Electricity Generating Capacity - Conventional
129 Electricity Generating Capacity - Nuclear Power
130 Electricity Generating Capacity - Pumped Storage
132 Electricity Generating Capacity - Renewable Sources
133 Electricity Generating Capacity - Distributed Generation
134 Electricity Generating Capacity - Base Load
135 Electricity Generating Capacity - Peak Power

Electricity Generation by Fuel

136 Electricity Generation (Power Sector) - Coal
137 Electricity Generation (Power Sector) - Petroleum
138 Electricity Generation (Power Sector) - Natural Gas 3/
139 Electricity Generation (Power Sector) - Nuclear Power
140 Electricity Generation (Power Sector) - Pumped Storage/Other 4/
141 Electricity Generation (Power Sector) - Renewable Sources 5/
142 Electricity Generation (Power Sector) - Distributed Generation (Natural Gas)
143 Electricity Generation (Power Sector) - Total
144 Electricity Generation (Power Sector) - Combined Heat and Power 6/
145 Electricity Generation (Power Sector) - Total Net Generation
146 Electricity Generation (End Use) - Total
147 Electricity Generation (End Use) - Conventional Hydropower

Renewable Generating Capacity by Type

148 Renewable Generating Capacity - Geothermal 2/
149 Renewable Generating Capacity - Municipal Waste 3/
150 Renewable Generating Capacity - Wood and Other Biomass 4/
151 Renewable Generating Capacity - Solar Thermal
152 Renewable Generating Capacity - Solar Photovoltaic 5/
153 Renewable Generating Capacity - Wind
154 Renewable Generating Capacity - Offshore Wind
155 Renewable Generating Capacity - Total
156 Renewable Generating Capacity - Conventional Hydropower
157 Renewable Generation - Geothermal 2/
158 Renewable Generation - Biogenic Municipal Waste 6/
159 Renewable Generation - Wood and Other Biomass 4/
160 Renewable Generation - Solar Thermal
161 Renewable Generation - Solar Photovoltaic 5/
162 Renewable Generation - Wind

163 Renewable Generation - Offshore Wind

164 Renewable Generation - Total

CO2 Emissions

165 CO2 Emissions - Residential

166 CO2 Emissions - Commercial

167 CO2 Emissions - Industrial 2/

168 CO2 Emissions - Transportation

169 CO2 Emissions - Electric Power 6/

170 CO2 Emissions - Petroleum 3/

171 CO2 Emissions - Natural Gas

172 CO2 Emissions - Coal

173 CO2 Emissions - Other 7/

174 CO2 Emissions - Total by Fuel

GHG Compliance Options

175 GHG Emissions Cap Compliance - Covered Emissions less offsets

179 GHG Emissions Cap Compliance - Covered Emissions less offsets plus Banking

186 Banking - Allowance Banking (borrowing)

187 Banking - Cumulative Bank Balance

188 GHG Offsets - Offsets Purchased

189 GHG Offsets - International Offset Price

Carbon Tax

176 Carbon Tax - Allowance Price

OPEC Payments

178 Payment to Imported Oil - OPEC

Energy Consumption by Sector

180 Energy Consumption by Sector and Source - Residential - Natural Gas

181 Energy Consumption by Sector and Source - Residential - Electricity

182 Energy Consumption by Sector and Source - Commercial - Natural Gas

183 Energy Consumption by Sector and Source - Commercial - Electricity

184 Energy Consumption by Sector and Source - Industrial 4/ - Natural Gas

185 Energy Consumption by Sector and Source - Industrial 4/ - Electricity

Primary Energy Consumption

190 Primary Energy Consumption - Liquid Fuels 9/

191 Primary Energy Consumption - Natural Gas

192 Primary Energy Consumption - Coal 10/

193 Primary Energy Consumption - Nuclear Power
194 Primary Energy Consumption - Hydropower
195 Primary Energy Consumption - Biomass 10/
196 Primary Energy Consumption - Other Renewable Energy 3/
197 Primary Energy Consumption - Other 11/
198 Primary Energy Consumption - Total

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ATTACHMENT 4: COST COMPARISON BETWEEN ALTERNATIVE FUEL VEHICLES AND CONVENTIONAL FUEL VEHICLES OF THE SAME SIZE CLASS

4. AFV-CONVENTIONAL VEHICLE COST COMPARISON AND IMPLIED SUBSIDIES

Implied vehicle subsidies are calculated based on the difference in price premiums paid for alternative fueled vehicles (AFVs) under two competing scenarios: BASELINE and ALLNOCAFE54. NEMS calculates a per-vehicle sales price for each of six size classes of automobiles and light trucks, for all fuel types. The standard vehicle size classes are listed in the following table.

Cars	Light Trucks
1. Mini-compact Cars	1. Small Pickup
2. Subcompact Cars	2. Large Pickup
3. Compact Cars	3. Small Van
4. Midsize Cars	4. Large Van
5. Large Cars	5. Small Utility
6. Two Seater Cars	6. Large Utility

VEHICLE COST COMPARISON

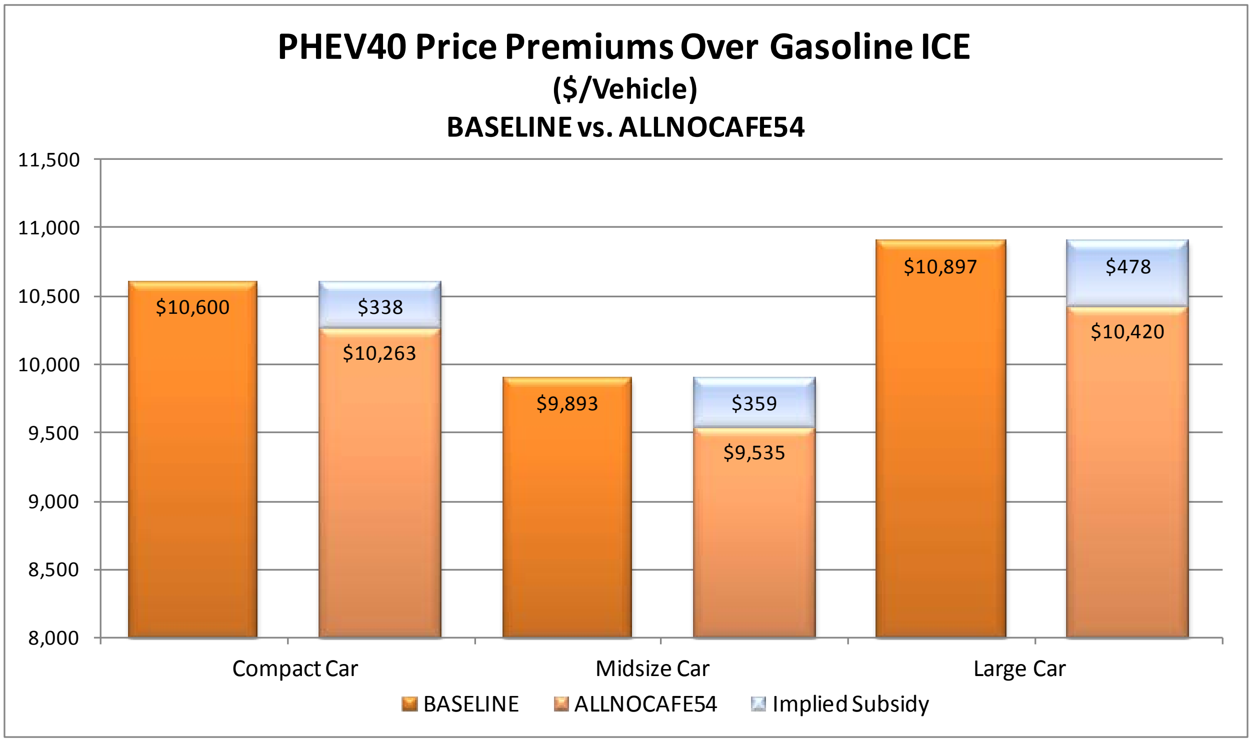
First, for each size class (SC) and AFV type, the incremental cost (Premium) of a vehicle relative to a conventional gasoline internal combustion engine (ICE) vehicle is calculated. Therefore, for the BASELINE scenario the cost premium is calculated as:

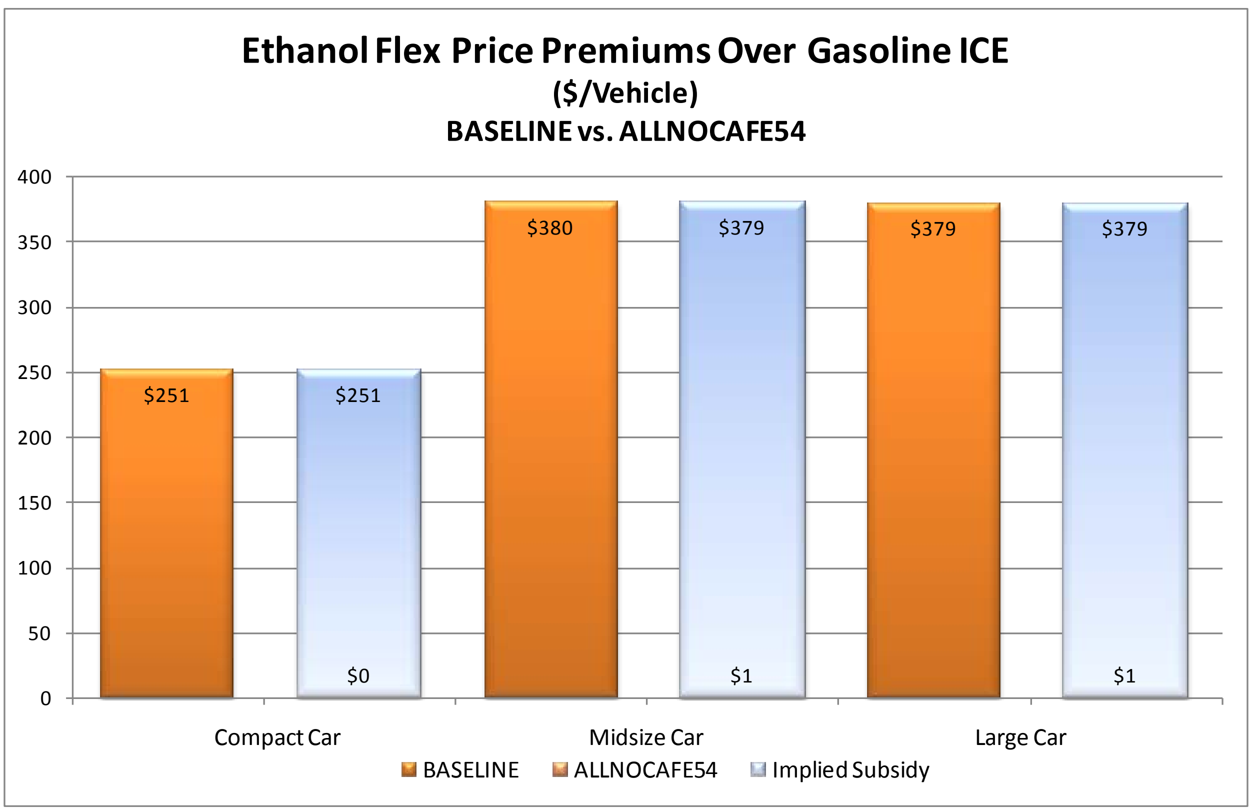
and for the policy scenario the cost premium is calculated as:

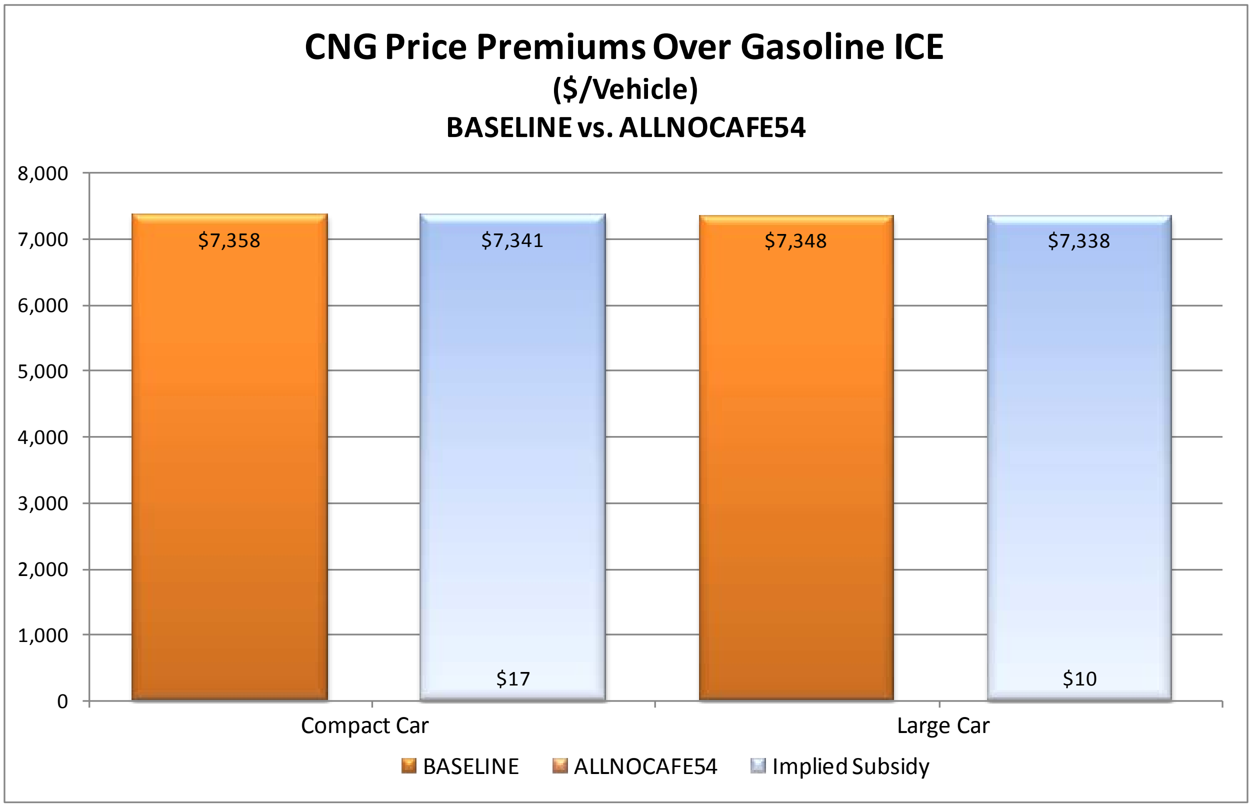
IMPLIED SUBSIDY CALCULATION

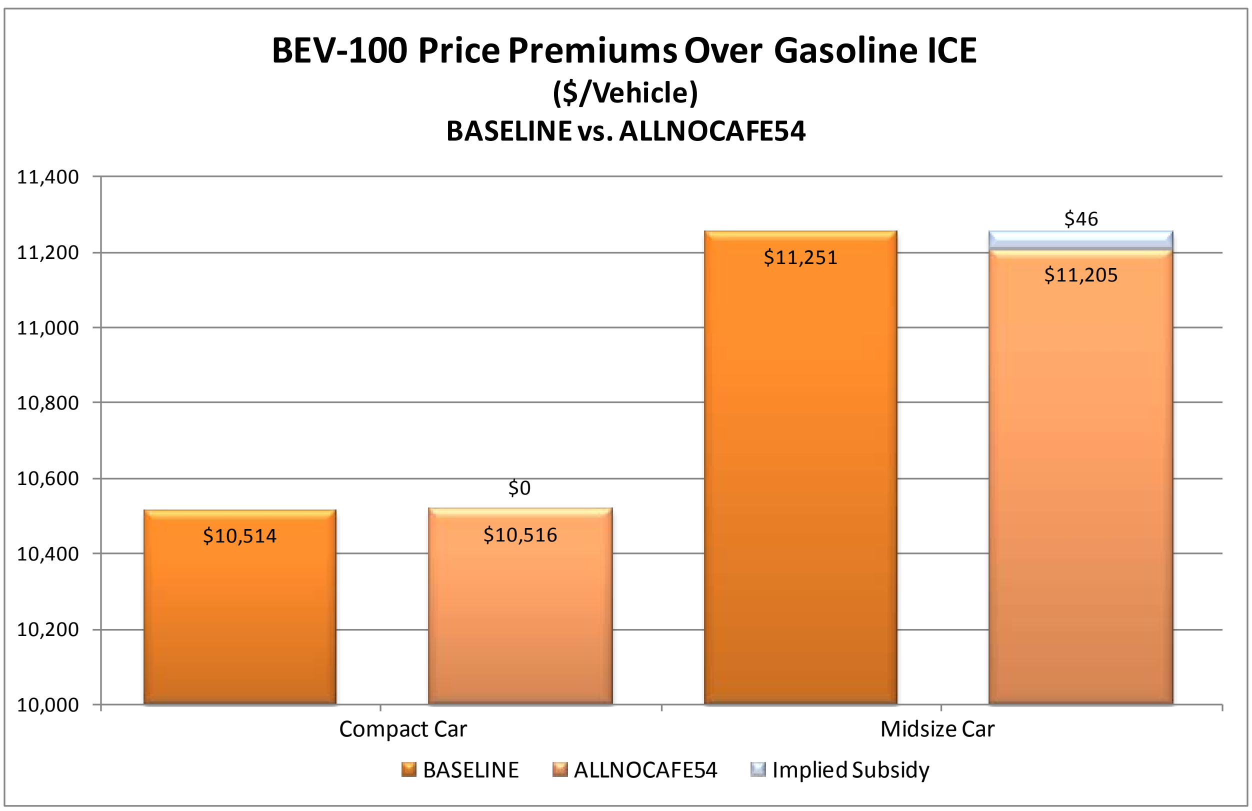
The implied per-vehicle subsidy is calculated as the difference between these two premiums:

This approach compensates for the changing price of conventional gasoline vehicles across the two scenarios in order to provide a more accurate representation of consumers' perception of the AFV's incremental cost. The following charts depict the calculated incremental costs of a representative sample of AFV types and vehicle size classes, along with the resulting implied per-vehicle subsidy. In each case, the values are averaged over the 10-year period of the study. The figures provided in the Section 3 of this study (FIGURE 3-1 to FIGURE 3-4) have been averaged across all twelve possible vehicle classes and types, so there may appear to be some discrepancies with the examples shown below.


PHEV40 Price Premiums Over Gasoline ICE
($/Vehicle)
BASELINE vs. ALLNOCAFE54
11,500
11,000
10,500
10,000
9,500
9,000
8,500
8,000
$10,600
$338
$10,263
$9,893
$359
$9,535
$10,897
$478
$10,420
Compact Car
Midsize Car
Large Car
BASELINE
ALLNOCAFE54
Implied Subsidy


Ethanol Flex Price Premiums Over Gasoline ICE
($/Vehicle)
BASELINE vs. ALLNOCAFE54
400
350
300
250
200
150
100
50
0
$251
$251
$0
$380
$379
$1
$379
$379
$1
Compact Car
Midsize Car
Large Car
BASELINE
ALLNOCAFE54
Implied Subsidy


CNG Price Premiums Over Gasoline ICE
($/Vehicle)
BASELINE vs. ALLNOCAFE54
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
$7,358
$7,341
$17
$7,348
$7,338
$10
Compact Car
Large Car
BASELINE
ALLNOCAFE54
Implied Subsidy


BEV-100 Price Premiums Over Gasoline ICE
($/Vehicle)
BASELINE vs. ALLNOCAFE54
11,400
11,200
11,000
10,800
10,600
10,400
10,200
10,000
$10,514
$0
$10,516
$11,251
$46
$11,205
Compact Car
Midsize Car
BASELINE
ALLNOCAFE54
Implied Subsidy

ATTACHMENT 5: LCFS REGIONAL RESULTS FOR HIGH OIL PRICE PROJECTION

5. EXECUTION OF THE CEA-NEMS MODEL TO QUANTIFY TECHNICAL AND ECONOMIC IMPACTS OF A REGIONAL LCFS: LCFS REGIONAL RESULTS FOR HIGH OIL PRICE PROJECTION

This attachment to the report presents detailed technical and economic results at the regional level for those scenarios that were executed using the High Oil Price (HOP) projection. These scenarios include the following:

- BASELINE HIGH OIL PRICE (BASELINEHOP)
- ALL INCLUDED -REGIONAL - HIGH OIL PRICE (ALLHOP)
- ALL INCLUDED - NO CAFÉ 54 MPG - REGIONAL - HIGH OIL PRICE (ALLNOCAFE54HOP)

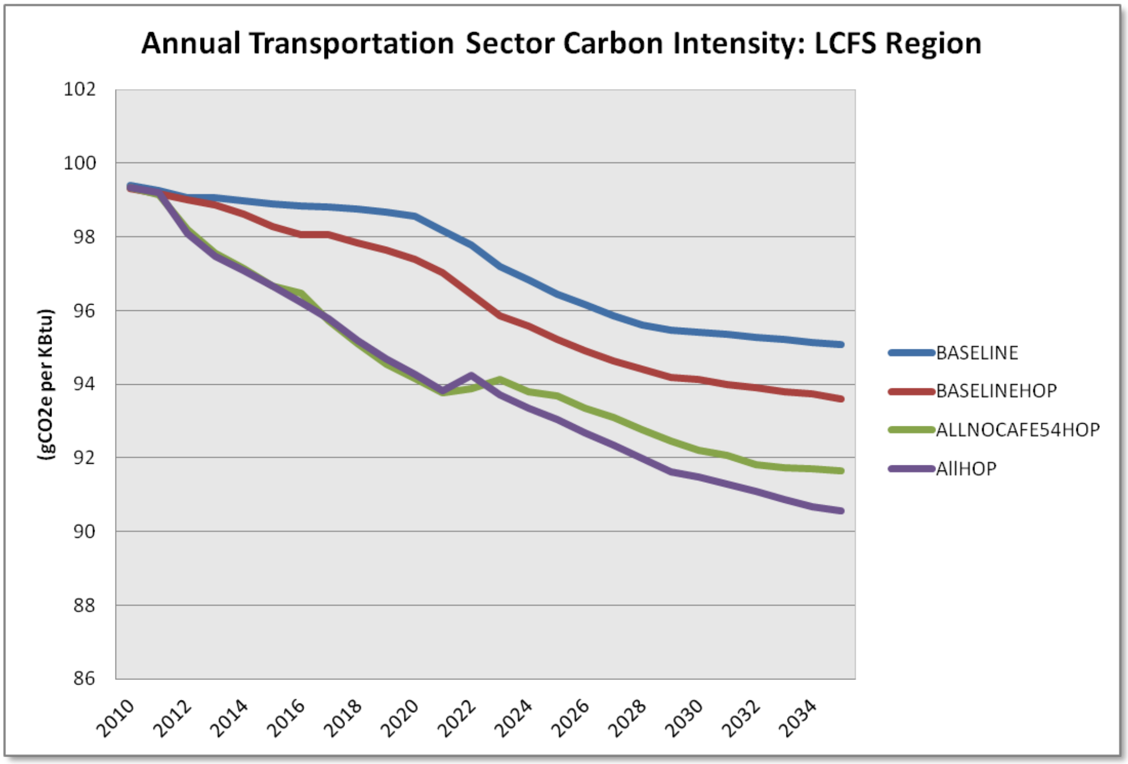
Results are presented for the following technical indicators:

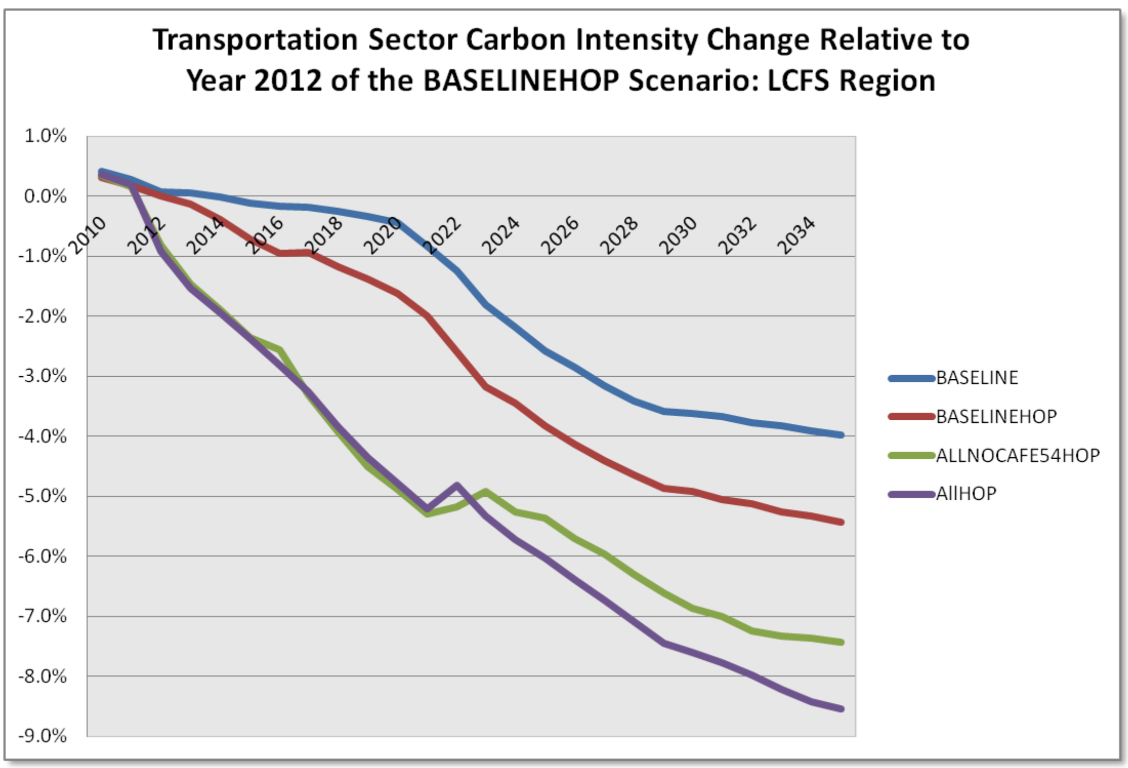
- NE/MA LCFS Region Carbon Intensity
- NE/MA LCFS Region Carbon Intensity Change (%)
- NE/MA LCFS Region CO2 Emissions
- NE/MA LCFS Region CO2 Emissions Change (%)
- NE/MA LCFS Region Fuel Consumption
- NE/MA LCFS Region Fuel Consumptions Change (%)
- Incremental cost of Transportation Fuel by State

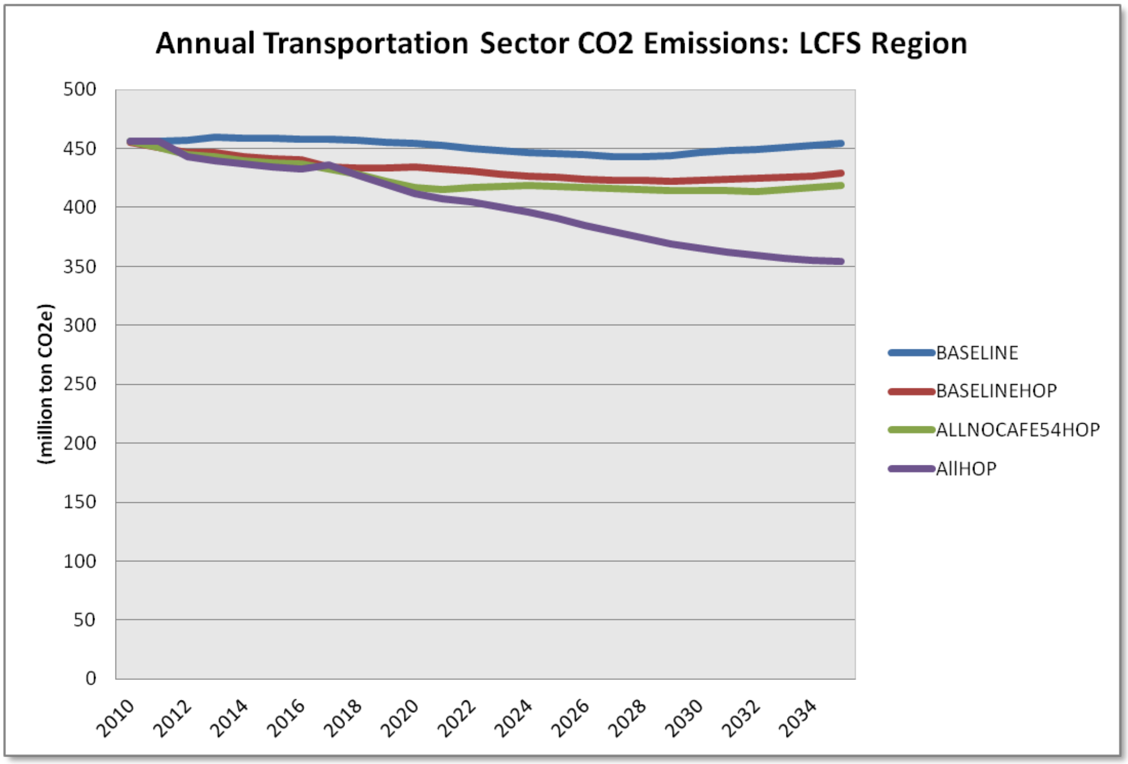
Results are presented for the following economic indicators:

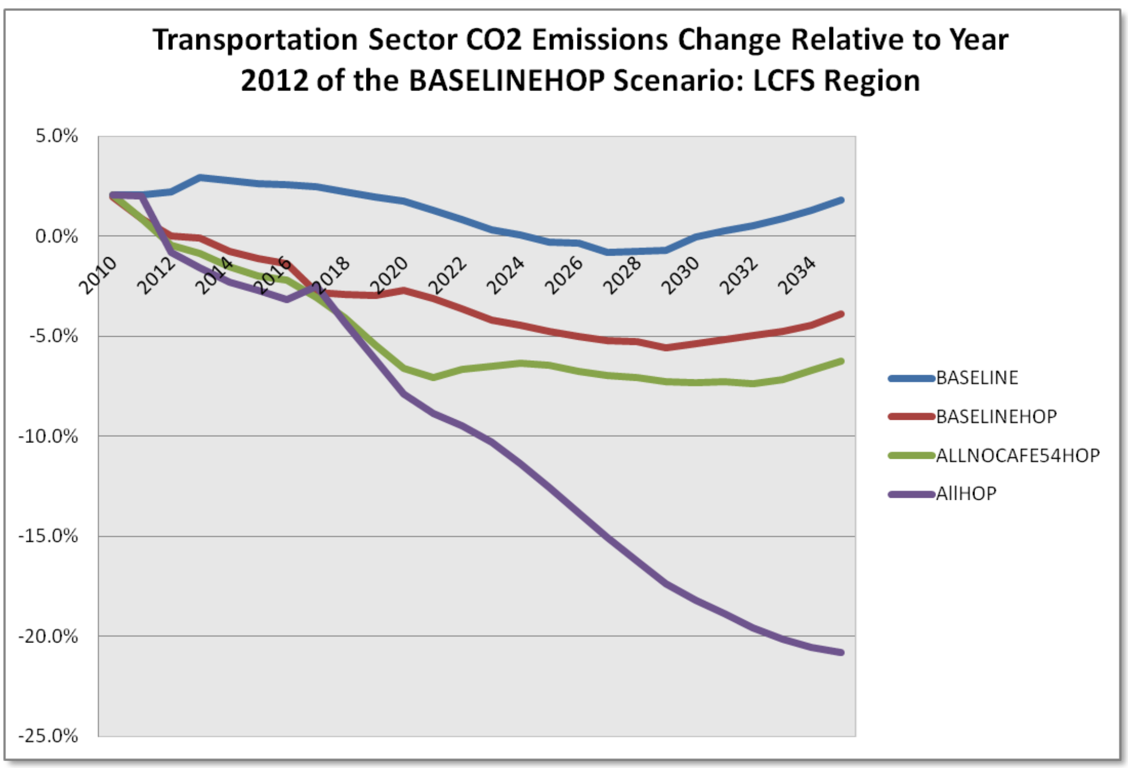
- Real Gross Domestic Product (GDP)
- Disposable Personal Income (DPI)
- Value of (Industrial) Shipments (VOS)
- Employment
- Incremental Fuel Expenditure
- Implied Alternative Vehicle Subsidies
- Incremental Infrastructure Cost

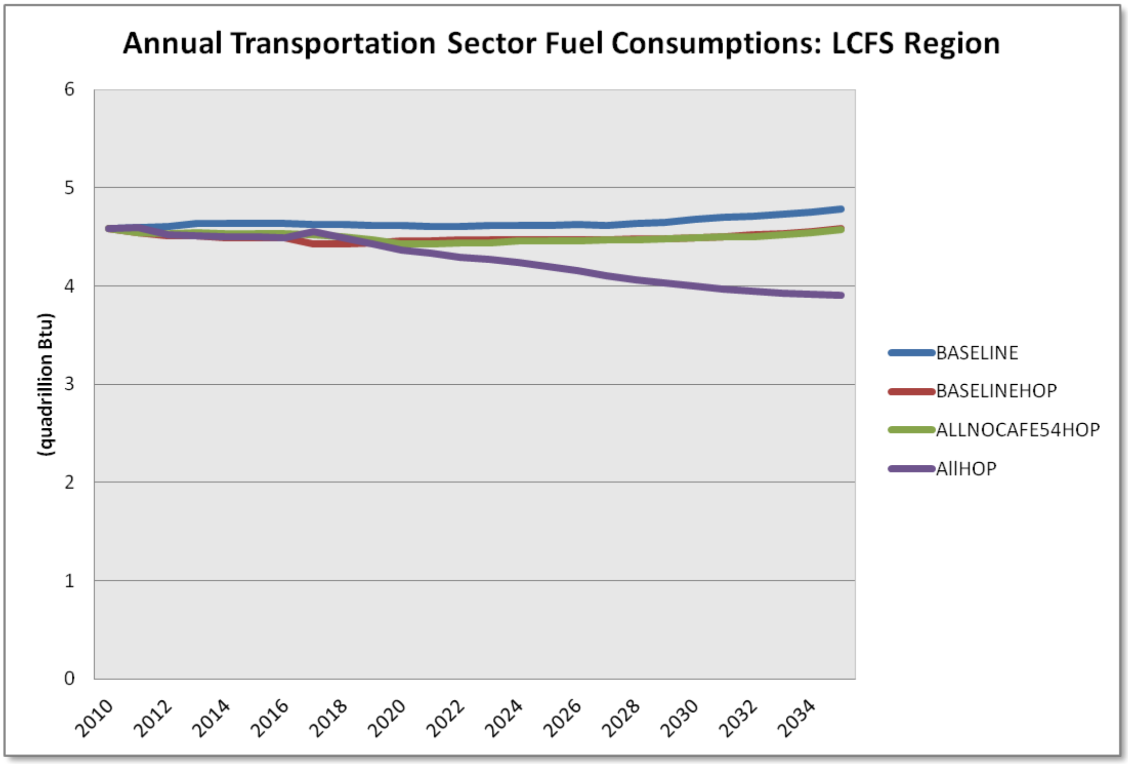
The figures and tables are not numbered in this attachment.


Annual Transportation Sector Carbon Intensity: LCFS Region
(gCO2e per KBtu)
102
100
98
96
94
92
90
88
86
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP

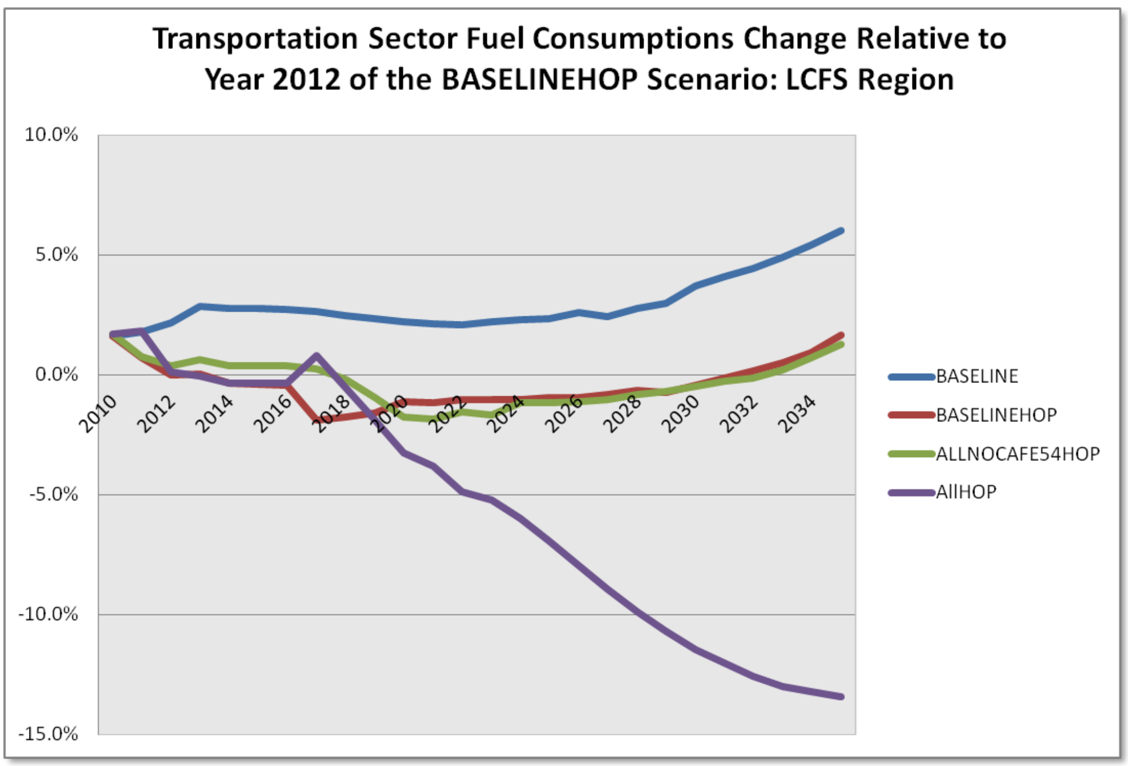

Transportation Sector Carbon Intensity Change Relative to Year 2012 of the BASELINEHOP Scenario: LCFS Region
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
-6.0%
-7.0%
-8.0%
-9.0%
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP


Annual Transportation Sector CO2 Emissions: LCFS Region
(million ton CO2e)
500
450
400
350
300
250
200
150
100
50
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP

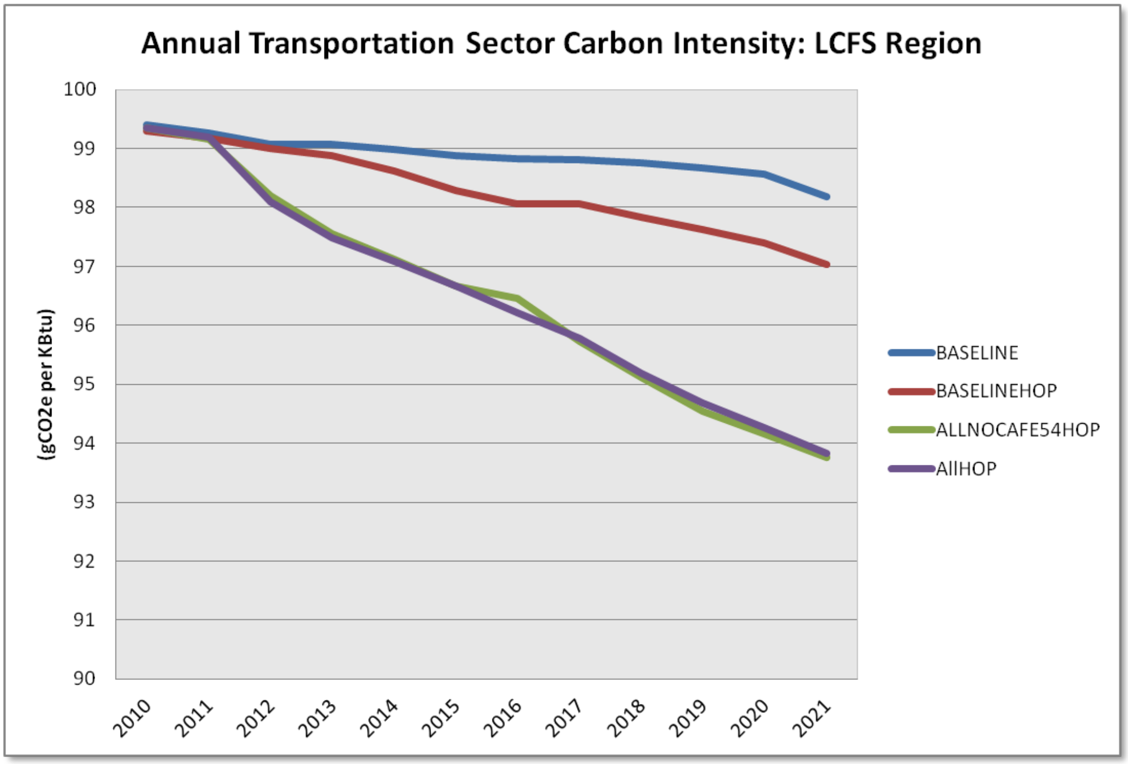

Transportation Sector CO2 Emissions Change Relative to Year 2012 of the BASELINEHOP Scenario: LCFS Region
5.0%
0.0%
-5.0%
-10.0%
-15.0%
-20.0%
-25.0%
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP



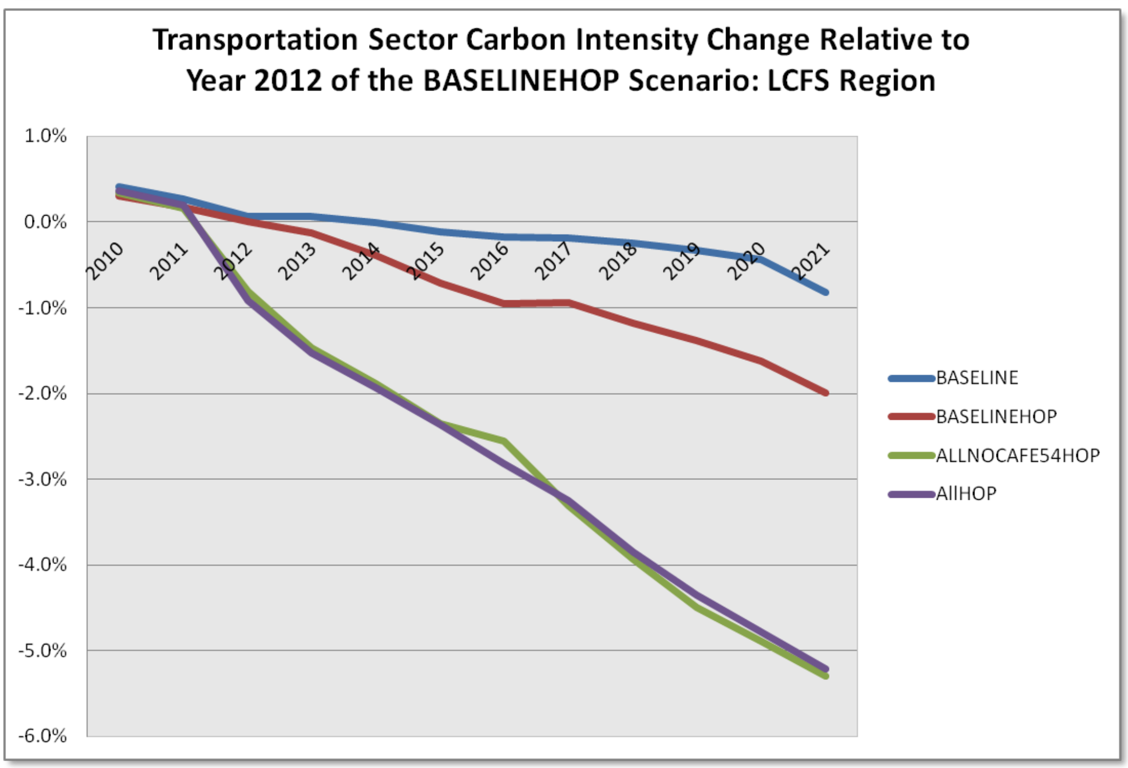
Annual Transportation Sector Fuel Consumptions: LCFS Region
(quadrillion Btu)
6
5
4
3
2
1
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP



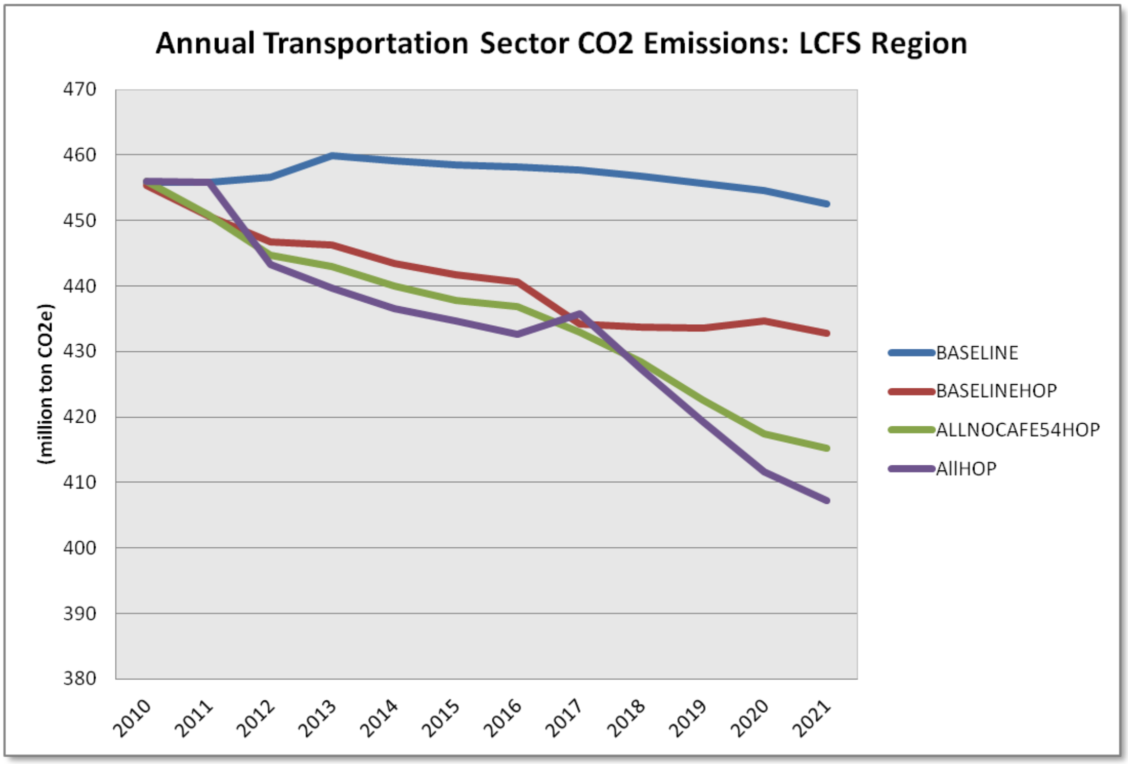
Transportation Sector Fuel Consumptions Change Relative to Year 2012 of the BASELINEHOP Scenario: LCFS Region
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP



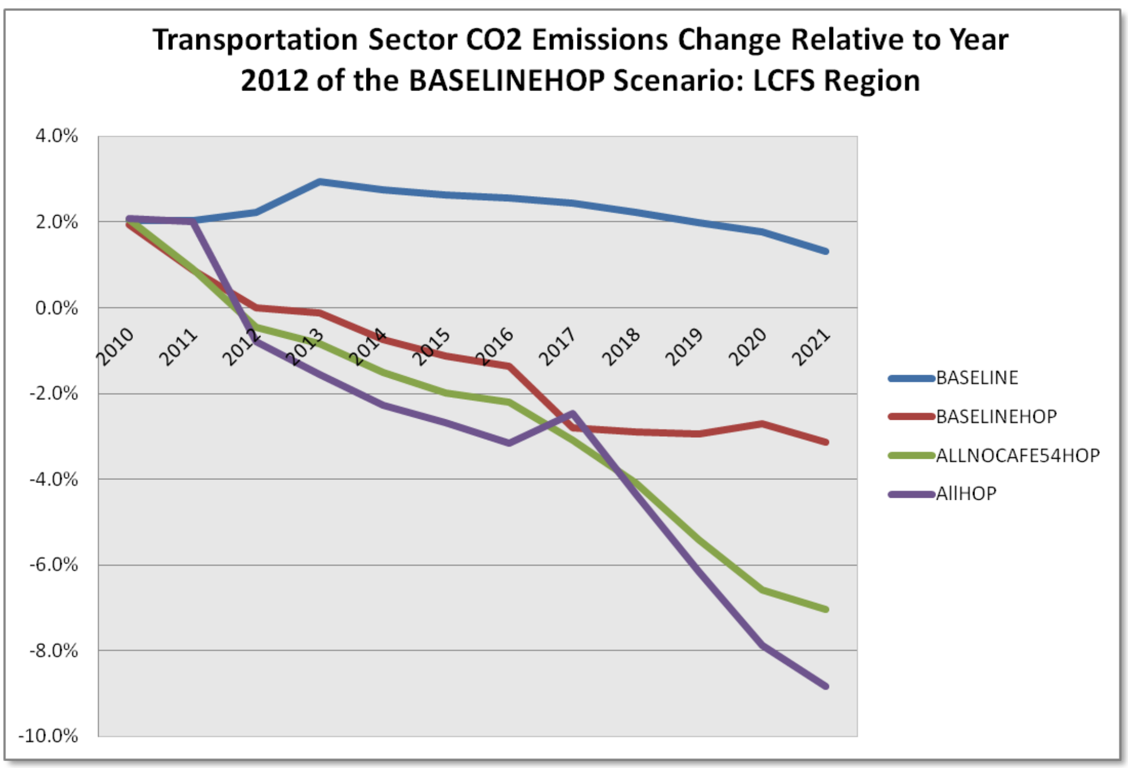
Annual Transportation Sector Carbon Intensity: LCFS Region
(gCO2e per KBtu)
100
99
98
97
96
95
94
93
92
91
90
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP



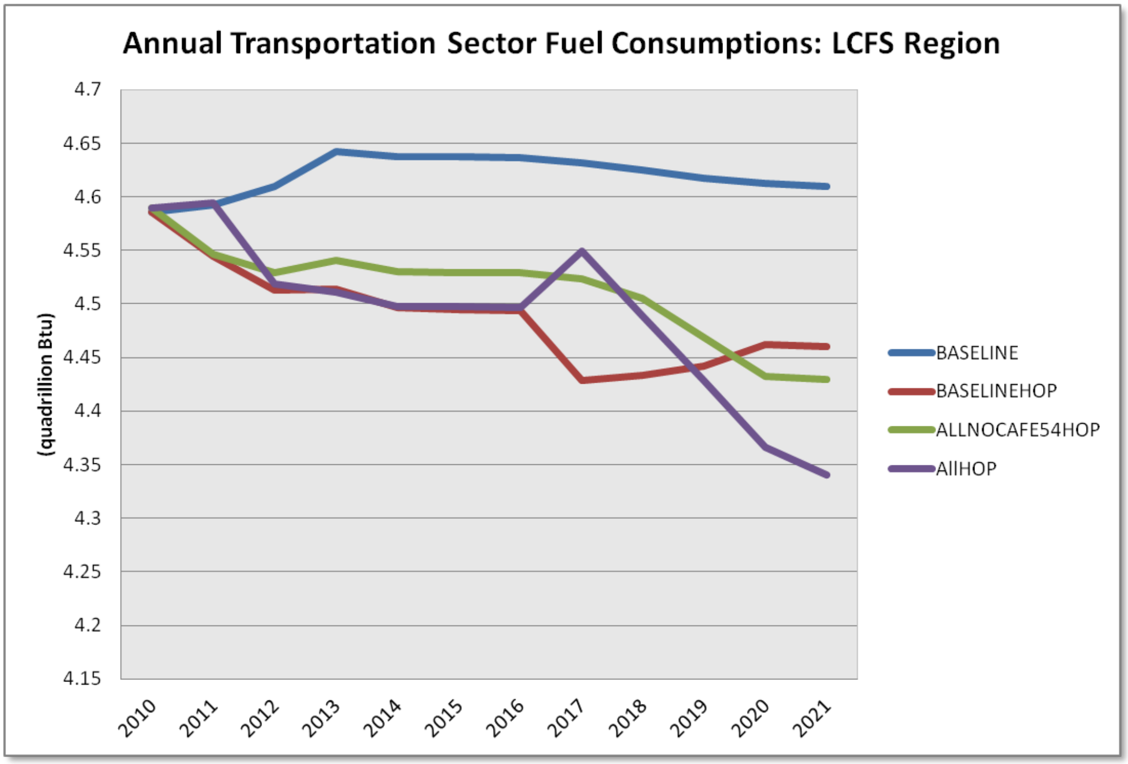
Transportation Sector Carbon Intensity Change Relative to Year 2012 of the BASELINEHOP Scenario: LCFS Region
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
-6.0%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP

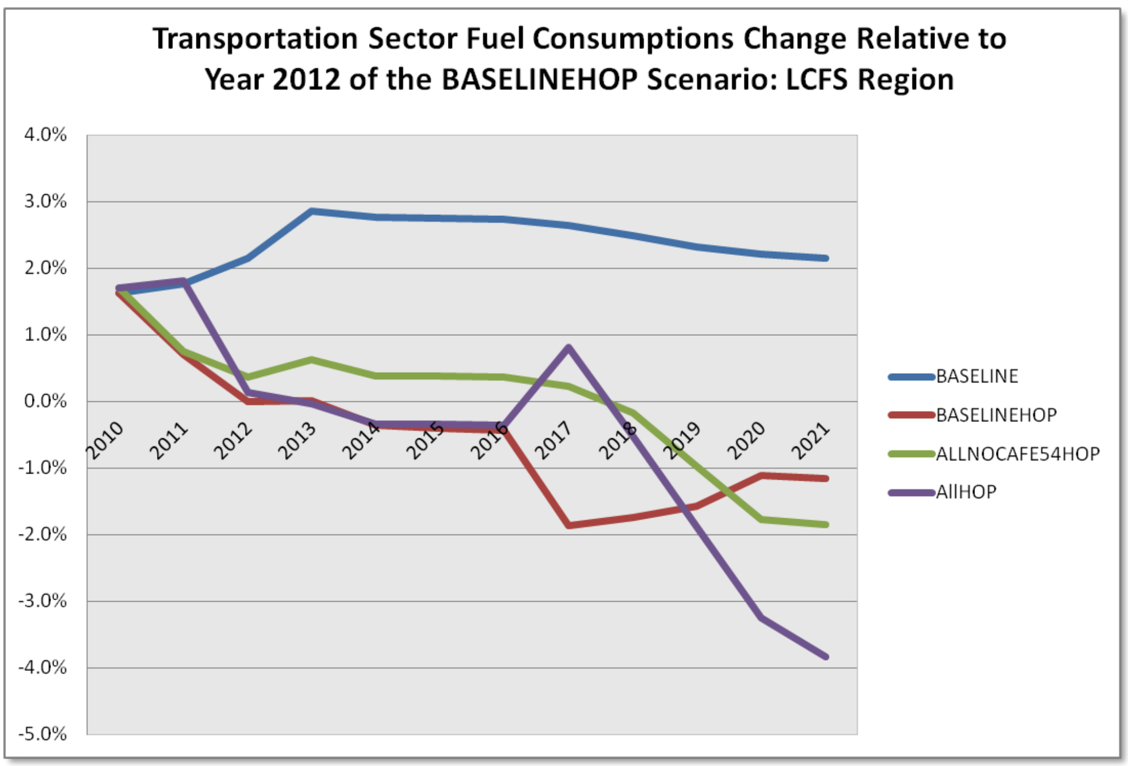


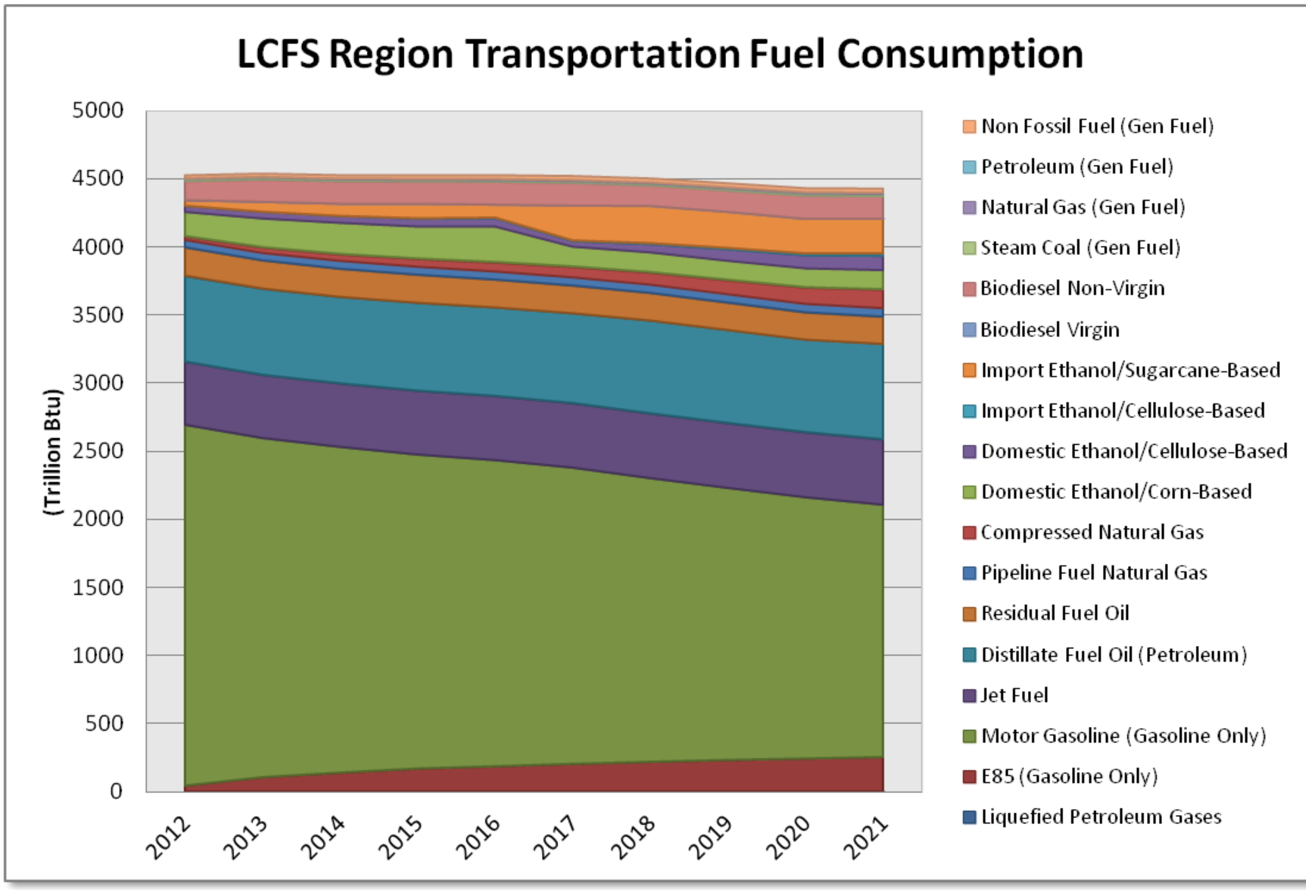
Annual Transportation Sector CO2 Emissions: LCFS Region
(million ton CO2e)
470
460
450
440
430
420
410
400
390
380
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP



Transportation Sector CO2 Emissions Change Relative to Year 2012 of the BASELINEHOP Scenario: LCFS Region
4.0%
2.0%
0.0%
-2.0%
-4.0%
-6.0%
-8.0%
-10.0%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP


Annual Transportation Sector Fuel Consumptions: LCFS Region
(quadrillion Btu)
4.7
4.65
4.6
4.55
4.5
4.45
4.4
4.35
4.3
4.25
4.2
4.15
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP


Transportation Sector Fuel Consumptions Change Relative to Year 2012 of the BASELINEHOP Scenario: LCFS Region
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
BASELINE
BASELINEHOP
ALLNOCAFE54HOP
AllHOP

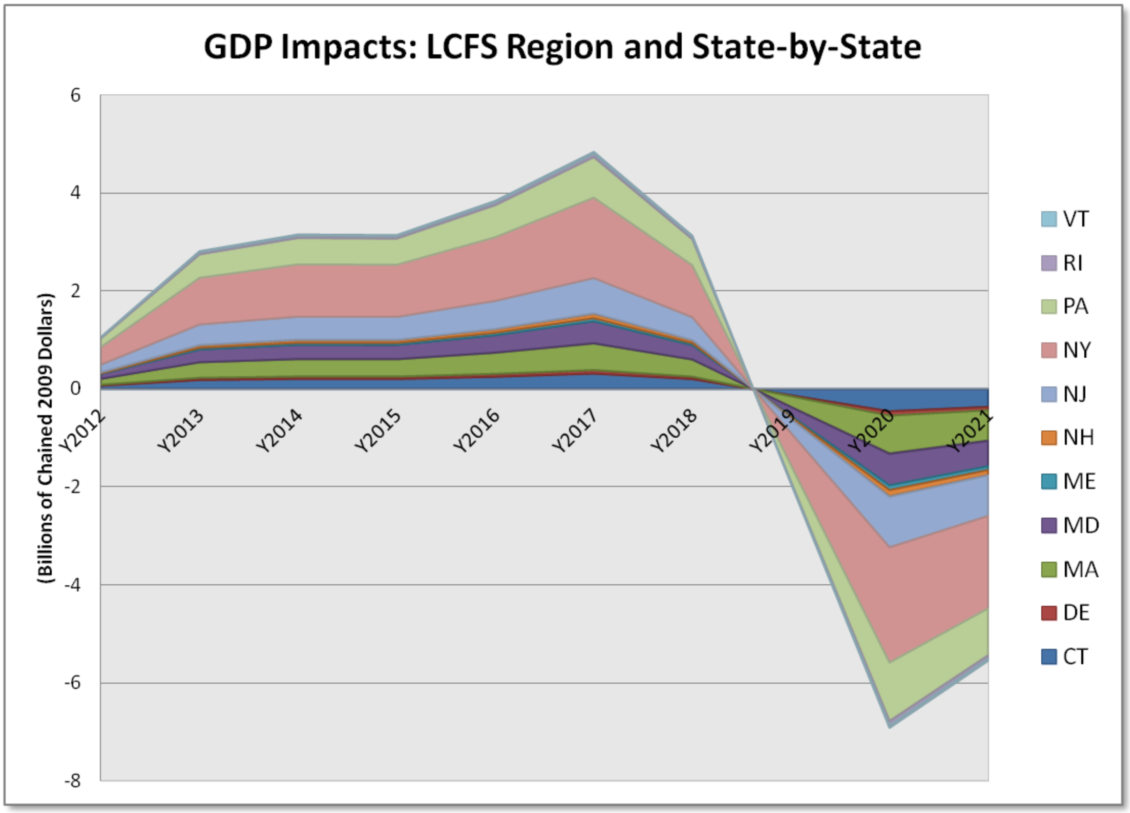


LCFS Region Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	2.0	2.0	1.9	2.0	2.0	2.1	2.3	2.3	2.4	2.4
E85 (Gasoline Only)	42.5	105.0	138.7	168.6	185.4	202.3	217.7	231.5	242.0	252.4
Motor Gasoline (Gasoline Only)	2,652.0	2,492.5	2,393.7	2,307.6	2,250.1	2,177.8	2,085.2	1,999.6	1,920.6	1,855.5
Jet Fuel	461.8	461.6	463.9	466.3	468.4	470.9	472.6	473.9	474.9	476.9
Distillate Fuel Oil (Petroleum)	628.9	632.1	634.2	645.0	649.4	659.9	682.1	682.9	680.4	702.3
Residual Fuel Oil	205.5	204.6	203.6	202.8	201.7	200.8	199.7	198.6	197.4	196.5
Pipeline Fuel Natural Gas	59.3	59.1	62.7	63.9	63.9	64.3	65.1	65.7	66.1	66.3
Compressed Natural Gas	23.9	38.1	46.5	55.6	65.4	75.8	87.7	101.7	118.4	135.0
Domestic Ethanol/Corn-Based	177.7	210.8	228.6	235.7	260.5	146.9	146.4	141.9	141.6	143.2
Domestic Ethanol/Cellulose-Based	44.4	48.9	50.3	57.0	61.0	40.9	60.2	83.7	94.5	103.2
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	3.0	4.2	5.3	7.5	10.5	14.5	20.0
Import Ethanol/Sugarcane-Based	42.6	74.4	91.3	108.1	97.2	257.1	274.5	265.6	254.6	254.2
Biodiesel Non-Virgin	3.5	2.2	1.7	1.7	1.7	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	138.5	162.3	164.2	161.9	166.1	165.6	149.8	156.3	169.9	163.7
Steam Coal (Gen Fuel)	13.6	14.3	10.2	9.9	10.5	10.8	11.0	11.6	12.3	13.1
Natural Gas (Gen Fuel)	9.1	8.8	11.7	12.6	12.8	13.1	13.2	13.3	13.4	13.6
Petroleum (Gen Fuel)	1.0	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.3
Non Fossil Fuel (Gen Fuel)	22.7	23.7	25.4	26.7	27.9	28.4	28.5	28.8	28.6	29.7
Total	4,528.9	4,541.1	4,529.6	4,529.5	4,529.4	4,523.1	4,504.9	4,469.1	4,432.7	4,429.3

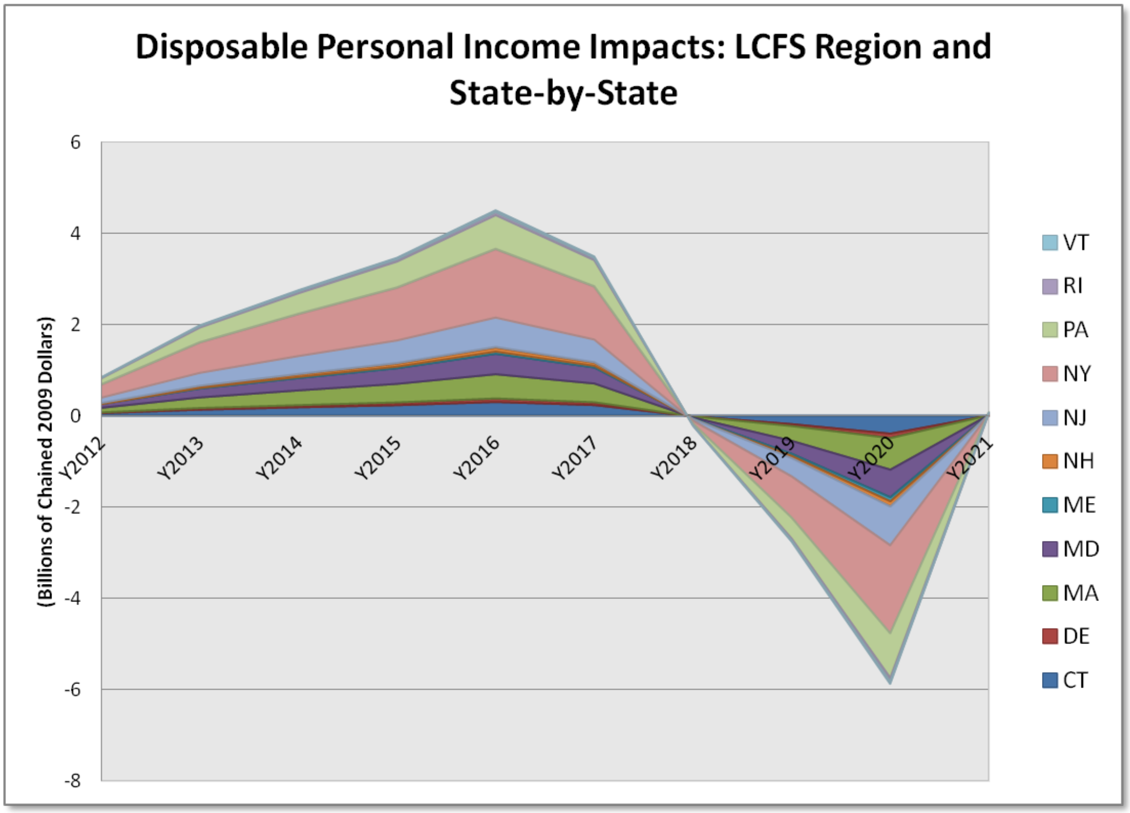
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



GDP IMPACTS TABLE - LCFS REGION AND STATE-BY-STATE

(Billions of 2009 Dollars)

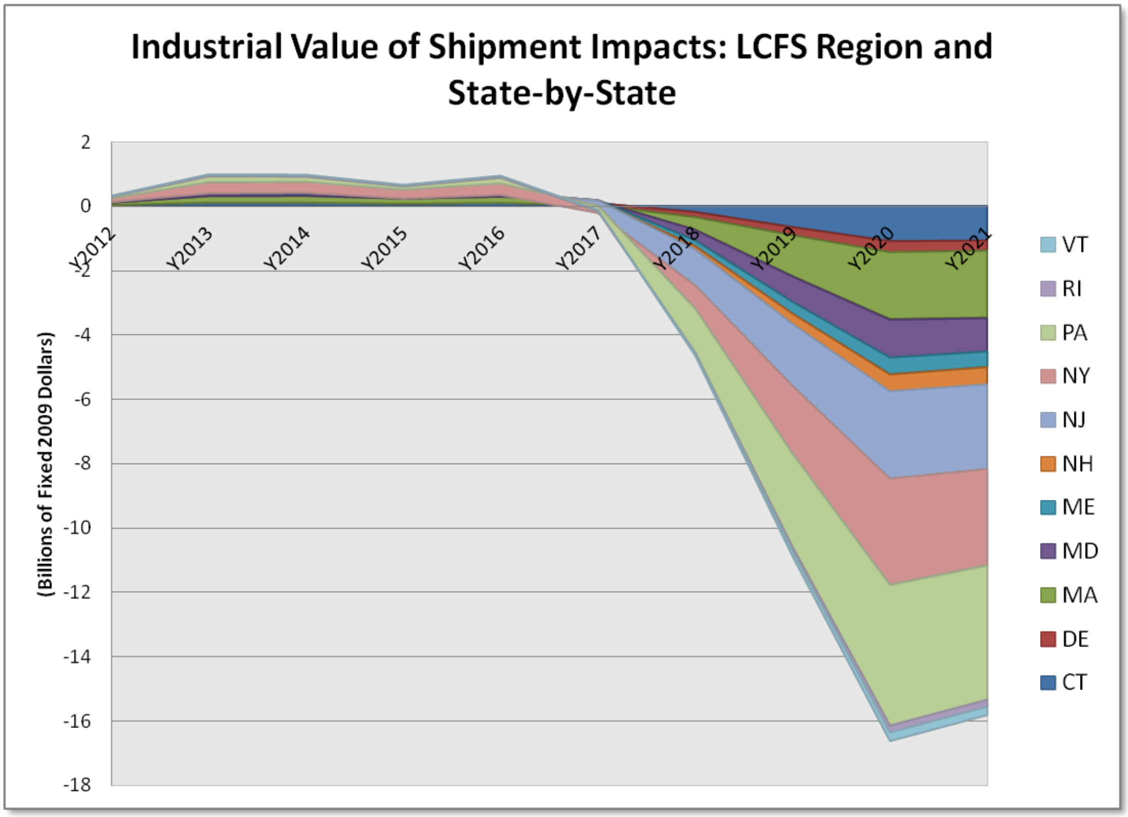
State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.07	0.18	0.21	0.21	0.25	0.32	0.20	-0.12	-0.45	-0.36	0.50
DE	0.02	0.04	0.05	0.05	0.06	0.07	0.05	-0.03	-0.10	-0.08	0.11
MA	0.12	0.32	0.36	0.35	0.43	0.54	0.35	-0.21	-0.77	-0.62	0.87
MD	0.10	0.26	0.29	0.29	0.36	0.45	0.29	-0.18	-0.65	-0.53	0.68
ME	0.02	0.04	0.05	0.05	0.06	0.07	0.04	-0.03	-0.10	-0.08	0.11
NH	0.02	0.05	0.06	0.06	0.07	0.09	0.06	-0.04	-0.13	-0.10	0.14
NJ	0.16	0.42	0.47	0.47	0.57	0.72	0.47	-0.29	-1.03	-0.83	1.13
NY	0.36	0.96	1.07	1.07	1.31	1.65	1.07	-0.66	-2.36	-1.90	2.57
PA	0.18	0.48	0.54	0.54	0.66	0.83	0.54	-0.33	-1.19	-0.95	1.30
RI	0.01	0.04	0.04	0.04	0.05	0.06	0.04	-0.03	-0.09	-0.07	0.10
VT	0.01	0.02	0.02	0.02	0.03	0.04	0.02	-0.01	-0.05	-0.04	0.06
Grand Total	**1.06**	**2.81**	**3.15**	**3.14**	**3.84**	**4.84**	**3.13**	**-1.93**	**-6.93**	**-5.56**	**7.57**



DISPOSABLE PERSONAL INCOME – LCFS REGION AND STATE-BY-STATE

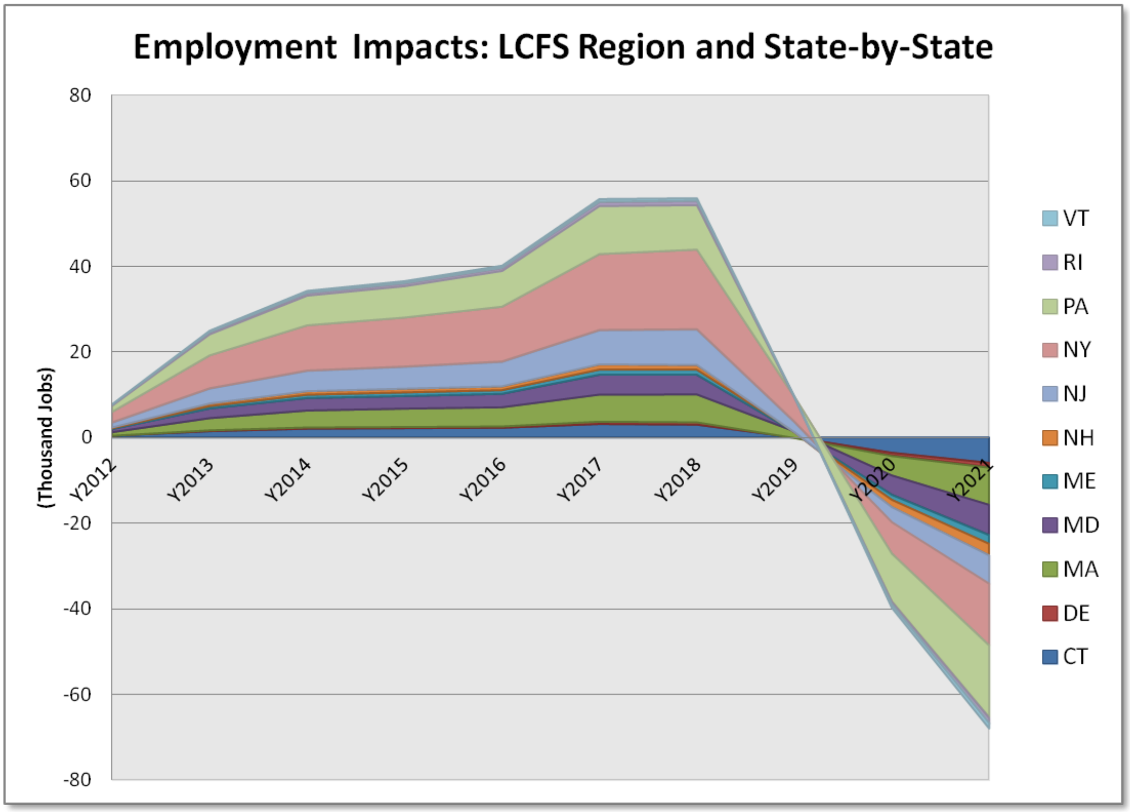
(Billions of 2009 Dollars)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.06	0.13	0.19	0.24	0.31	0.24	-0.01	-0.19	-0.40	0.00	0.56
DE	0.01	0.03	0.04	0.05	0.07	0.05	0.00	-0.04	-0.09	0.00	0.12
MA	0.10	0.23	0.32	0.40	0.53	0.41	-0.02	-0.32	-0.69	0.01	0.96
MD	0.08	0.19	0.27	0.34	0.45	0.35	-0.02	-0.28	-0.60	0.01	0.78
ME	0.01	0.03	0.04	0.05	0.07	0.05	0.00	-0.04	-0.09	0.00	0.12
NH	0.02	0.04	0.05	0.07	0.09	0.07	0.00	-0.05	-0.11	0.00	0.16
NJ	0.12	0.29	0.40	0.50	0.66	0.51	-0.03	-0.40	-0.85	0.01	1.22
NY	0.28	0.66	0.92	1.15	1.50	1.16	-0.07	-0.91	-1.94	0.02	2.78
PA	0.14	0.33	0.46	0.58	0.75	0.58	-0.04	-0.46	-0.98	0.01	1.40
RI	0.01	0.03	0.04	0.05	0.06	0.05	0.00	-0.04	-0.08	0.00	0.11
VT	0.01	0.02	0.02	0.03	0.04	0.03	0.00	-0.02	-0.05	0.00	0.07
Grand Total	**0.84**	**1.98**	**2.75**	**3.46**	**4.51**	**3.49**	**-0.21**	**-2.75**	**-5.88**	**0.07**	**8.27**



INDUSTRIAL VALUE OF SHIPMENT IMPACTS - LCFS REGION AND STATE-BY-STATE
(Billions of 2009 Dollars)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.04	0.12	0.12	0.10	0.12	0.09	-0.18	-0.65	-1.08	-1.07	-2.38
DE	0.00	-0.01	-0.01	-0.02	-0.02	-0.06	-0.15	-0.25	-0.34	-0.32	-1.17
MA	0.07	0.20	0.21	0.16	0.20	0.13	-0.39	-1.27	-2.09	-2.08	-4.85
MD	0.03	0.09	0.09	0.07	0.10	0.03	-0.32	-0.79	-1.18	-1.04	-2.92
ME	0.00	0.01	0.01	-0.01	0.00	-0.04	-0.19	-0.37	-0.52	-0.48	-1.59
NH	0.02	0.04	0.05	0.03	0.04	0.02	-0.11	-0.33	-0.53	-0.54	-1.31
NJ	-0.03	-0.06	-0.04	-0.10	-0.08	-0.38	-1.11	-1.92	-2.71	-2.63	-9.07
NY	0.13	0.35	0.35	0.29	0.37	0.23	-0.70	-2.09	-3.29	-2.98	-7.36
PA	0.05	0.18	0.16	0.10	0.18	-0.17	-1.38	-2.91	-4.38	-4.18	-12.37
RI	0.01	0.02	0.03	0.02	0.03	0.02	-0.03	-0.13	-0.22	-0.23	-0.49
VT	0.01	0.02	0.02	0.01	0.02	0.00	-0.07	-0.18	-0.27	-0.26	-0.70
Grand Total	**0.32**	**0.99**	**0.98**	**0.66**	**0.95**	**-0.12**	**-4.65**	**-10.89**	**-16.63**	**-15.82**	**-44.22**

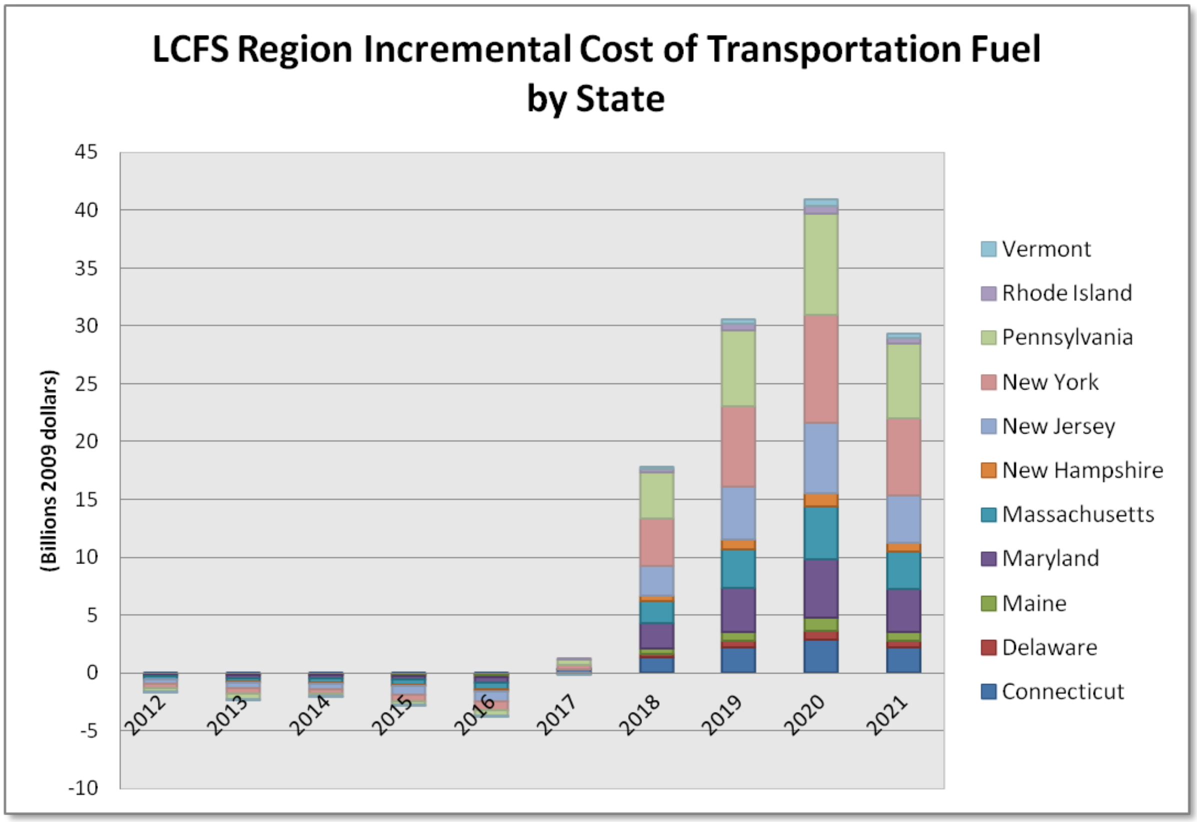


EMPLOYMENT IMPACTS - LCFS REGION AND STATE-BY-STATE
(Thousand Jobs)

State	Y2012	Y2013	Y2014	Y2015	Y2016	Y2017	Y2018	Y2019	Y2020	Y2021	Cumulative
CT	0.41	1.46	2.03	2.14	2.25	3.12	2.97	0.01	-3.56	-5.91	4.93
DE	0.11	0.33	0.43	0.43	0.46	0.69	0.69	0.00	-0.63	-1.00	1.50
MA	0.85	2.86	3.97	4.29	4.49	6.35	6.55	1.59	-4.55	-8.72	17.66
MD	0.73	2.26	2.91	2.94	3.14	4.65	4.60	-0.16	-4.49	-7.03	9.56
ME	0.15	0.53	0.76	0.82	0.84	1.17	1.16	0.10	-1.22	-2.10	2.20
NH	0.16	0.57	0.79	0.83	0.86	1.19	1.06	-0.22	-1.74	-2.72	0.79
NJ	1.11	3.46	4.73	5.08	5.69	7.93	8.25	2.37	-3.62	-6.73	28.26
NY	2.45	7.68	10.54	11.44	12.81	17.72	18.60	5.80	-7.35	-14.42	65.28
PA	1.61	5.09	7.11	7.50	8.51	11.39	10.55	-0.05	-11.11	-16.79	23.81
RI	0.12	0.40	0.55	0.60	0.63	0.89	0.90	0.16	-0.74	-1.34	2.16
VT	0.08	0.29	0.40	0.43	0.44	0.61	0.56	-0.05	-0.79	-1.27	0.71
LCFS Region	**7.78**	**24.93**	**34.23**	**36.52**	**40.12**	**55.70**	**55.88**	**9.54**	**-39.81**	**-68.02**	**156.85**

Overview of State Transportation Fuel Price by Scenario

(2009 dollars per million Btu)



LCFS Region Incremental Cost of Transportation Fuel by State

(Billions 2009 dollars)

State	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Connecticut	-0.090	-0.118	-0.080	-0.085	-0.148	0.216	1.295	2.134	2.824	2.167	**8.115**
Delaware	-0.031	-0.043	-0.049	-0.069	-0.089	-0.002	0.335	0.586	0.796	0.566	**2.000**
Maine	-0.057	-0.082	-0.105	-0.119	-0.159	-0.010	0.454	0.811	1.096	0.774	**2.602**
Maryland	-0.172	-0.242	-0.235	-0.349	-0.462	0.083	2.188	3.771	5.108	3.695	**13.385**
Massachusetts	-0.222	-0.318	-0.398	-0.447	-0.605	0.010	1.903	3.354	4.512	3.228	**11.017**
New Hampshire	-0.058	-0.082	-0.110	-0.124	-0.165	-0.013	0.462	0.822	1.109	0.793	**2.633**
New Jersey	-0.308	-0.461	-0.521	-0.696	-0.869	-0.137	2.546	4.570	6.176	4.119	**14.420**
New York	-0.371	-0.513	-0.366	-0.578	-0.764	0.298	4.120	6.983	9.304	6.663	**24.775**
Pennsylvania	-0.302	-0.408	-0.127	-0.297	-0.438	0.532	3.990	6.593	8.729	6.398	**24.670**
Rhode Island	-0.028	-0.039	-0.041	-0.046	-0.066	0.024	0.297	0.507	0.677	0.502	**1.787**
Vermont	-0.028	-0.040	-0.053	-0.060	-0.080	-0.007	0.221	0.395	0.534	0.379	**1.261**
LCFS Region	**-1.668**	**-2.347**	**-2.085**	**-2.869**	**-3.845**	**0.993**	**17.812**	**30.526**	**40.866**	**29.283**	**106.666**

Summary of LCFS Region Incremental Cost of Transportation Fuel

(Cumulative of year 2012-2021)

State	BASELINEJOP Expenditure (2009$)	Incremental Cost	
		2009$	Percentage
Connecticut	88.005	8.115	9.22%
Delaware	24.867	2.000	8.04%
Maine	43.092	2.602	6.04%
Maryland	164.373	13.385	8.14%
Massachusetts	162.805	11.017	6.77%
New Hampshire	35.647	2.633	7.39%
New Jersey	292.542	14.420	4.93%
New York	348.388	24.775	7.11%
Pennsylvania	325.908	24.670	7.57%
Rhode Island	21.712	1.787	8.23%
Vermont	18.644	1.261	6.76%
LCFS Region	**1525.982**	**106.666**	**6.99%**

ATTACHMENT 6: NE/MA REGION STATE-BY-STATE RESULTS FOR HIGH OIL PRICE PROJECTION

6. EXECUTION OF THE CEA-NEMS MODEL TO QUANTIFY TECHNICAL AND ECONOMIC IMPACTS OF A REGIONAL LCFS: NE/MA REGION STATE-BY-STATE RESULTS FOR HIGH OIL PRICE PROJECTION

Results for each of the eleven states that make up the NE/MA LCFS region are presented in this section. These states are:

- Connecticut
- Delaware
- Maine
- Maryland
- Massachusetts
- New Hampshire
- New Jersey
- New York
- Pennsylvania
- Rhode Island
- Vermont

Since CEA-NEMS calculates national and regional results, the model's results were post-processed to apportion the regional outcomes to the individual states. Two approaches were used –one for the energy data and one for the economic data. These approaches are presented below. Note that some of the state-by-state results appear in Section 4; they were the result of these processes.

Please see Report Section 5.1 and Section 5.3 for the methodology underlying the development of these state-by-state results.

6.1 STATE-BY-STATE RESULTS (HOP PROJECTION)

Carbon Intensity (CI) in LCFS Region and State-by-State (gCO2e/KBtu)

State	BASELINE		BASELINEHOP		ALLNOCAFE54HOP		AllHOP	
	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035
Connecticut	97.6	95.5	96.1	93.4	92.2	90.2	92.2	88.3
Delaware	100.6	99.1	99.7	97.2	95.7	97.2	97.5	96.7
Maine	98.3	96.6	97.1	95.0	94.0	93.2	93.9	91.6
Maryland	99.8	98.3	98.8	96.3	94.6	95.4	96.2	94.3
Massachusetts	98.3	96.6	97.1	95.0	94.2	93.3	94.3	92.6
New Hampshire	98.2	95.9	96.7	94.0	94.0	92.7	93.5	87.2
New Jersey	99.2	95.8	98.3	95.0	96.0	93.7	95.8	93.4
New York	97.9	93.7	96.7	92.3	93.4	90.1	93.2	89.0
Pennsylvania	96.7	92.4	95.4	91.0	91.7	88.3	91.6	87.3
Rhode Island	98.0	96.1	96.6	94.2	92.7	91.0	93.0	91.8
Vermont	98.2	96.0	96.8	94.2	94.2	93.1	93.6	87.6
LCFS Region	**98.2**	**95.1**	**97.0**	**93.6**	**93.8**	**91.6**	**93.8**	**90.6**

Carbon Intensity (CI) Reduction in LCFS Region and State-by-State

State	BASELINE		BASELINEHOP		ALLNOCAFE54HOP		AllHOP	
	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035	Y2021	Y2035
Connecticut	-0.9%	-3.1%	-2.4%	-5.2%	-6.4%	-8.5%	-6.4%	-10.3%
Delaware	-0.4%	-1.9%	-1.3%	-3.8%	-5.2%	-3.8%	-3.5%	-4.3%
Maine	-0.7%	-2.4%	-1.9%	-4.0%	-5.0%	-5.8%	-5.1%	-7.5%
Maryland	-0.3%	-1.8%	-1.3%	-3.8%	-5.4%	-4.6%	-3.9%	-5.7%
Massachusetts	-0.6%	-2.3%	-1.8%	-3.9%	-4.7%	-5.7%	-4.7%	-6.4%
New Hampshire	-0.8%	-3.1%	-2.3%	-5.1%	-5.0%	-6.4%	-5.6%	-12.0%
New Jersey	-0.7%	-4.0%	-1.6%	-4.9%	-3.9%	-6.1%	-4.0%	-6.5%
New York	-0.9%	-5.2%	-2.1%	-6.5%	-5.4%	-8.8%	-5.6%	-9.9%
Pennsylvania	-1.3%	-5.6%	-2.6%	-7.1%	-6.4%	-9.9%	-6.5%	-10.9%
Rhode Island	-0.7%	-2.6%	-2.2%	-4.6%	-6.1%	-7.8%	-5.8%	-7.0%
Vermont	-0.8%	-2.9%	-2.2%	-4.8%	-4.8%	-5.9%	-5.4%	-11.4%
LCFS Region	**-0.8%**	**-4.0%**	**-2.0%**	**-5.4%**	**-5.3%**	**-7.4%**	**-5.2%**	**-8.5%**

6.2 STATE FUEL CONSUMPTION, FUEL PRICES, AND INCREMENTAL FUEL EXPENDITURE (2012-2021 UNDER SCENARIO ALLNOCAFE54HOP)

The transportation fuel consumption included in these results includes:

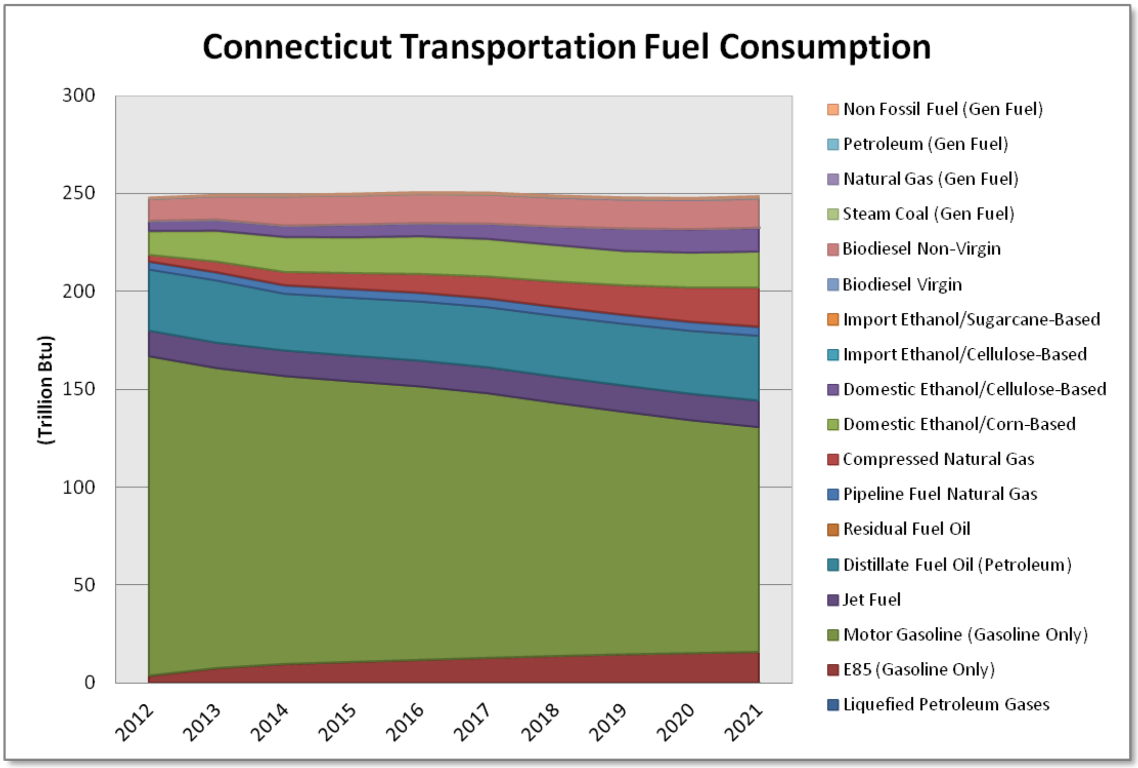
- Liquefied Petroleum Gases
- E85
- Liquefied Petroleum Gases
- E85 (Gasoline Only)

- Motor Gasoline (Gasoline Only)
- Jet Fuel
- Distillate Fuel Oil (Petroleum)
- Residual Fuel Oil
- Pipeline Fuel Natural Gas
- Compressed Natural Gas
- Corn Ethanol Consumption
- Cellulose Based
- Advanced
- Cellulosic
- Non-cellulosic
- Biodiesel Virgin
- Biodiesel Non-Virgin
- Steam Coal (Gen Fuel)
- Natural Gas (Gen Fuel)
- Petroleum (Gen Fuel)
- Non Fossil Fuel (Gen Fuel)

Transportation Fuel Prices include:

- Liquefied Petroleum Gases
- E85
- Motor Gasoline
- Jet Fuel
- Distillate Fuel Oil

Natural Gas

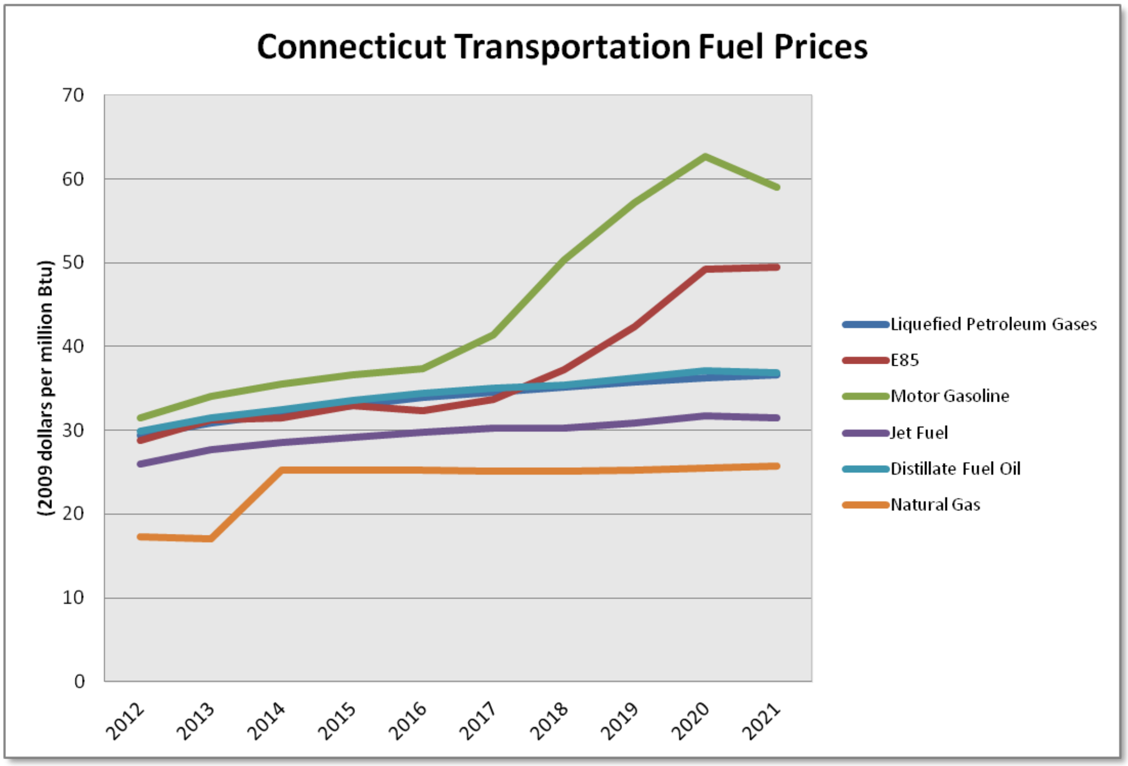


Connecticut Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
E85 (Gasoline Only)	3.3	7.2	9.3	10.3	11.4	12.4	13.3	14.2	14.8	15.4
Motor Gasoline (Gasoline Only)	163.4	153.5	147.4	143.6	140.0	135.4	129.7	124.3	119.3	115.2
Jet Fuel	13.0	12.9	13.0	13.0	13.1	13.2	13.2	13.3	13.3	13.4
Distillate Fuel Oil (Petroleum)	31.4	31.9	29.2	29.8	30.3	30.8	31.2	31.6	32.3	33.2
Residual Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Fuel Natural Gas	3.9	4.0	4.1	4.3	4.3	4.3	4.4	4.4	4.4	4.4
Compressed Natural Gas	3.4	5.5	6.7	8.1	9.6	11.1	12.9	15.0	17.4	19.9
Domestic Ethanol/Corn-Based	12.2	15.8	18.0	18.4	19.4	19.4	18.8	17.7	18.0	18.7
Domestic Ethanol/Cellulose-Based	5.0	5.5	5.6	6.3	6.5	7.7	9.2	11.4	11.8	11.9
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	11.1	12.0	15.0	14.9	14.9	15.0	14.9	14.9	14.9	15.0
Steam Coal (Gen Fuel)	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Natural Gas (Gen Fuel)	0.2	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.5	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Total	247.9	249.4	249.5	250.1	251.0	250.7	249.0	248.1	247.7	248.7

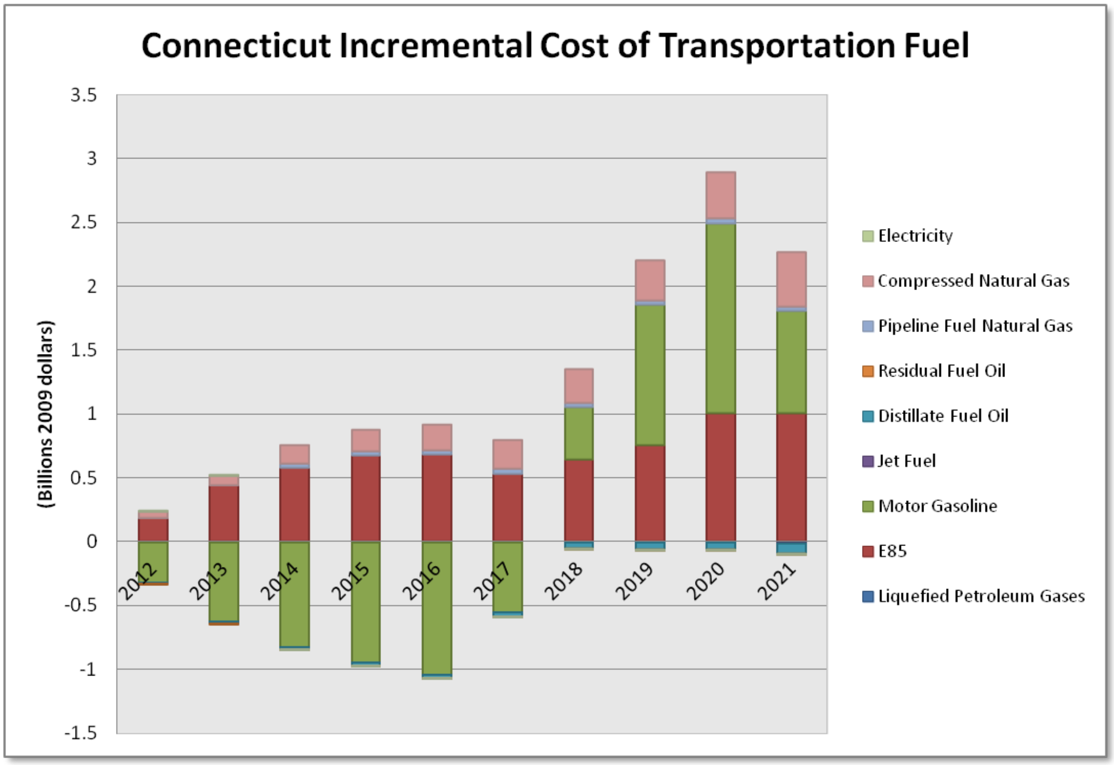
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Connecticut Transportation Fuel Prices

(2009 dollars per million Btu)

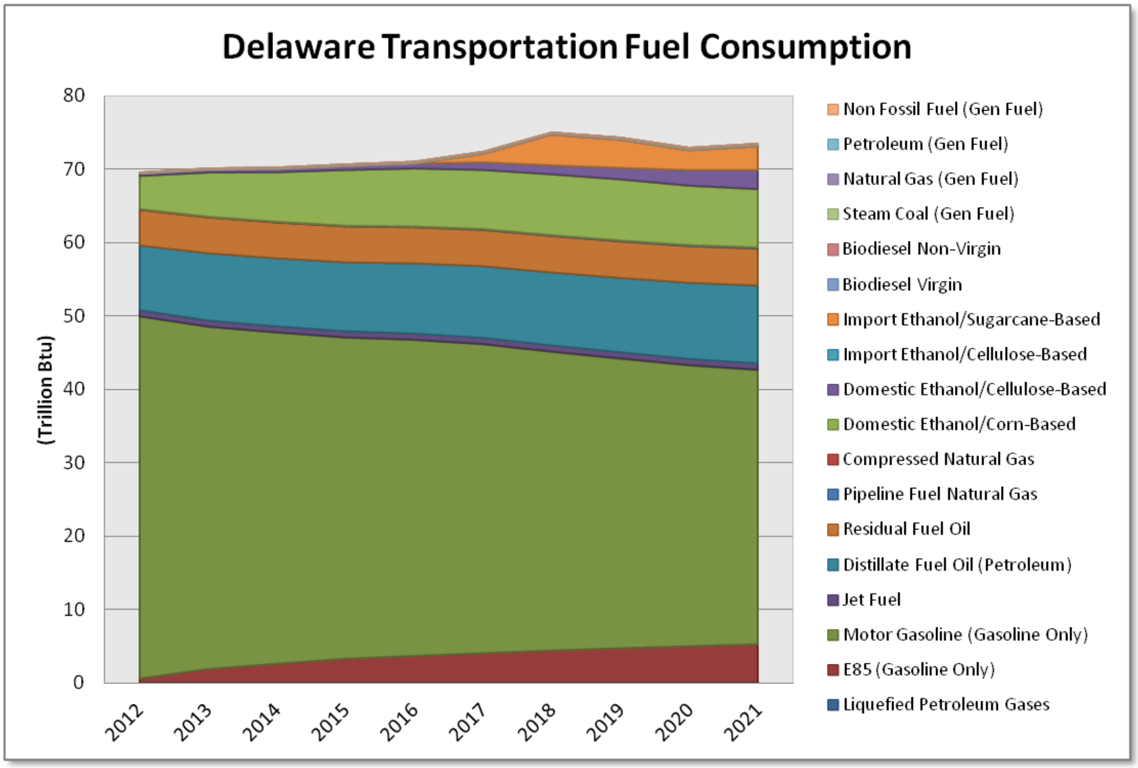
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	29.37	30.91	31.99	32.97	33.92	34.59	35.14	35.70	36.21	36.62
E85	28.81	31.29	31.50	32.92	32.33	33.64	37.25	42.31	49.28	49.52
Motor Gasoline	31.43	34.02	35.48	36.63	37.39	41.45	50.29	57.16	62.69	59.04
Jet Fuel	25.96	27.69	28.58	29.19	29.75	30.20	30.27	30.84	31.77	31.53
Distillate Fuel Oil	29.90	31.47	32.47	33.54	34.37	35.05	35.44	36.19	37.07	36.91
Natural Gas	17.24	17.05	25.26	25.18	25.20	25.16	25.18	25.24	25.50	25.69



Connecticut Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.003	0.003	0.003	**0.019**
E85	0.191	0.447	0.580	0.676	0.682	0.533	0.641	0.757	1.000	1.004	**6.509**
Motor Gasoline	-0.318	-0.624	-0.818	-0.942	-1.038	-0.547	0.411	1.095	1.487	0.797	**-0.495**
Jet Fuel	0.000	-0.001	-0.002	-0.002	-0.002	-0.003	-0.006	-0.005	-0.007	-0.016	**-0.044**
Distillate Fuel Oil	-0.006	-0.011	-0.014	-0.019	-0.022	-0.030	-0.048	-0.053	-0.053	-0.074	**-0.331**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.001	0.034	0.035	0.035	0.035	0.036	0.037	0.037	0.037	**0.288**
Compressed Natural Gas	0.041	0.070	0.140	0.167	0.196	0.228	0.264	0.308	0.364	0.420	**2.197**
Electricity	0.000	0.000	-0.001	-0.001	-0.002	-0.002	-0.005	-0.006	-0.007	-0.006	**-0.029**
Grand Total	**-0.090**	**-0.118**	**-0.080**	**-0.085**	**-0.148**	**0.216**	**1.295**	**2.134**	**2.824**	**2.167**	**8.115**

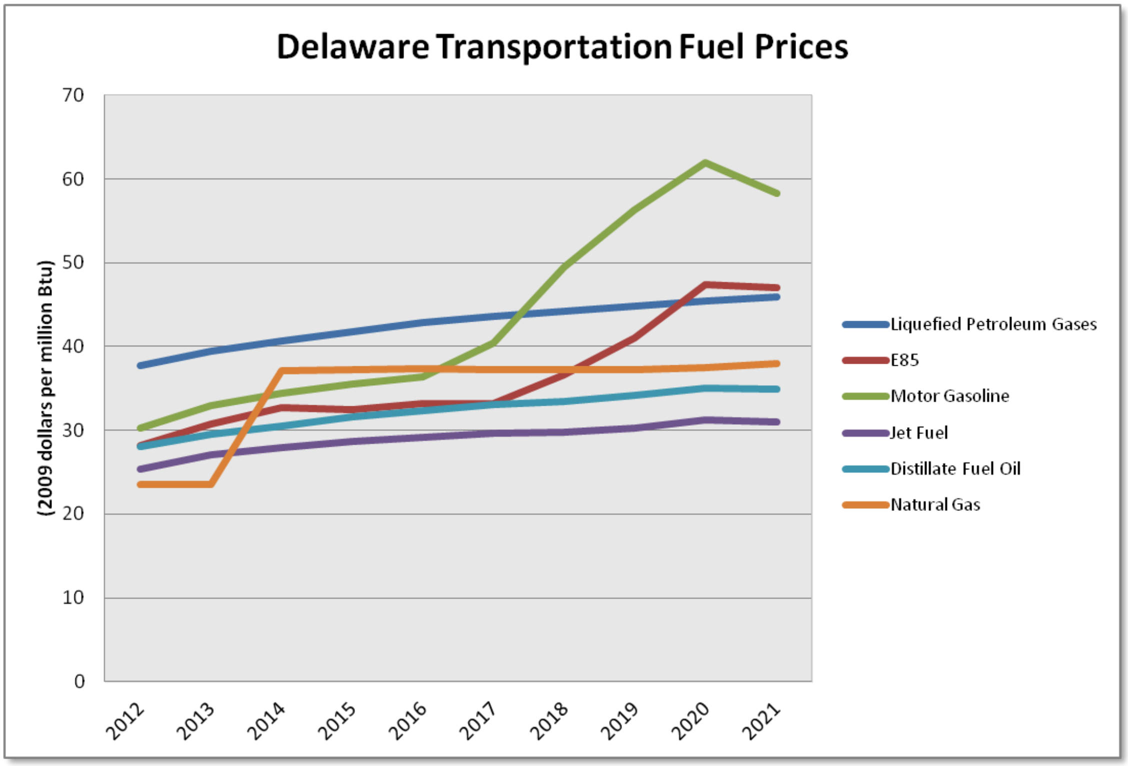


Delaware Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E85 (Gasoline Only)	0.6	1.9	2.6	3.3	3.7	4.1	4.4	4.7	5.0	5.3
Motor Gasoline (Gasoline Only)	49.3	46.6	45.1	43.7	43.0	42.1	40.7	39.4	38.2	37.3
Jet Fuel	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Distillate Fuel Oil (Petroleum)	8.8	9.2	9.3	9.4	9.6	9.8	9.9	10.1	10.4	10.6
Residual Fuel Oil	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.1
Pipeline Fuel Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compressed Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Domestic Ethanol/Corn-Based	4.5	6.0	6.7	7.6	7.9	8.0	8.2	8.3	8.1	7.9
Domestic Ethanol/Cellulose-Based	0.3	0.4	0.5	0.5	0.7	1.0	1.2	1.6	2.1	2.6
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	1.2	4.2	3.8	2.7	3.2
Biodiesel Non-Virgin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Steam Coal (Gen Fuel)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Natural Gas (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	69.5	70.1	70.2	70.6	71.0	72.3	75.0	74.3	72.9	73.4

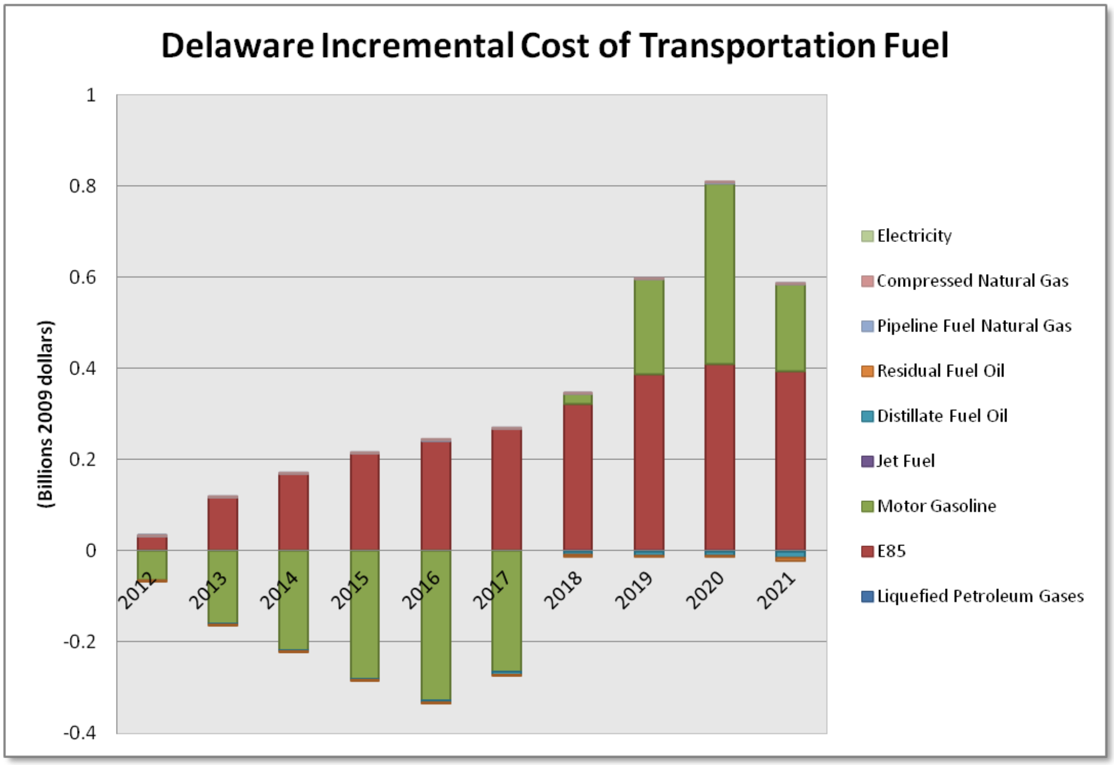
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Delaware Transportation Fuel Prices

(2009 dollars per million Btu)

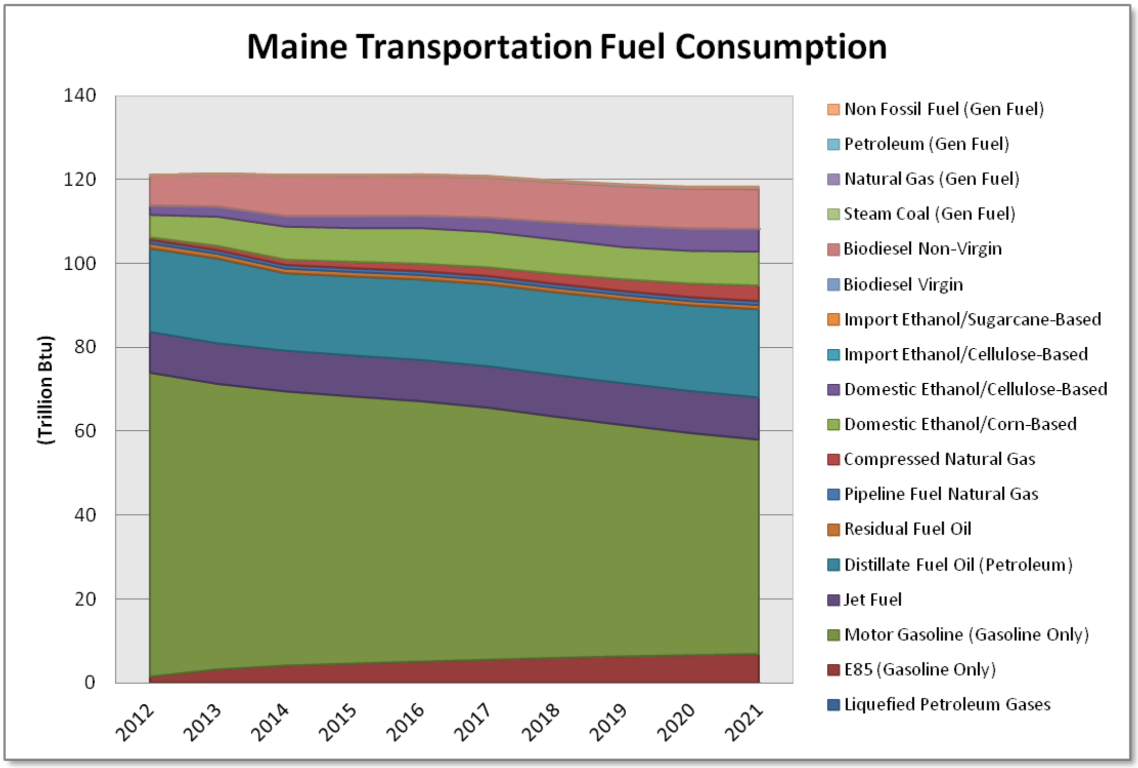
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	37.71	39.44	40.66	41.75	42.82	43.57	44.19	44.82	45.39	45.85
E85	28.20	30.73	32.70	32.47	33.14	33.20	36.60	41.05	47.36	47.04
Motor Gasoline	30.31	32.92	34.40	35.55	36.32	40.44	49.42	56.36	61.98	58.26
Jet Fuel	25.32	27.07	27.98	28.61	29.18	29.64	29.72	30.31	31.25	31.02
Distillate Fuel Oil	28.04	29.50	30.49	31.56	32.37	33.05	33.43	34.18	35.05	34.90
Natural Gas	23.56	23.51	37.09	37.27	37.31	37.23	37.20	37.22	37.51	37.97



Delaware Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.001**
E85	0.033	0.117	0.170	0.214	0.242	0.267	0.321	0.387	0.409	0.394	**2.554**
Motor Gasoline	-0.064	-0.158	-0.217	-0.280	-0.328	-0.264	0.023	0.209	0.396	0.189	**-0.493**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	**-0.003**
Distillate Fuel Oil	0.000	-0.002	-0.002	-0.003	-0.004	-0.006	-0.008	-0.009	-0.009	-0.014	**-0.056**
Residual Fuel Oil	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.003	-0.003	-0.003	-0.006	**-0.021**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.002**
Compressed Natural Gas	0.000	0.000	0.001	0.001	0.001	0.002	0.002	0.002	0.003	0.003	**0.016**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.031**	**-0.043**	**-0.049**	**-0.069**	**-0.089**	**-0.002**	**0.335**	**0.586**	**0.796**	**0.566**	**2.000**

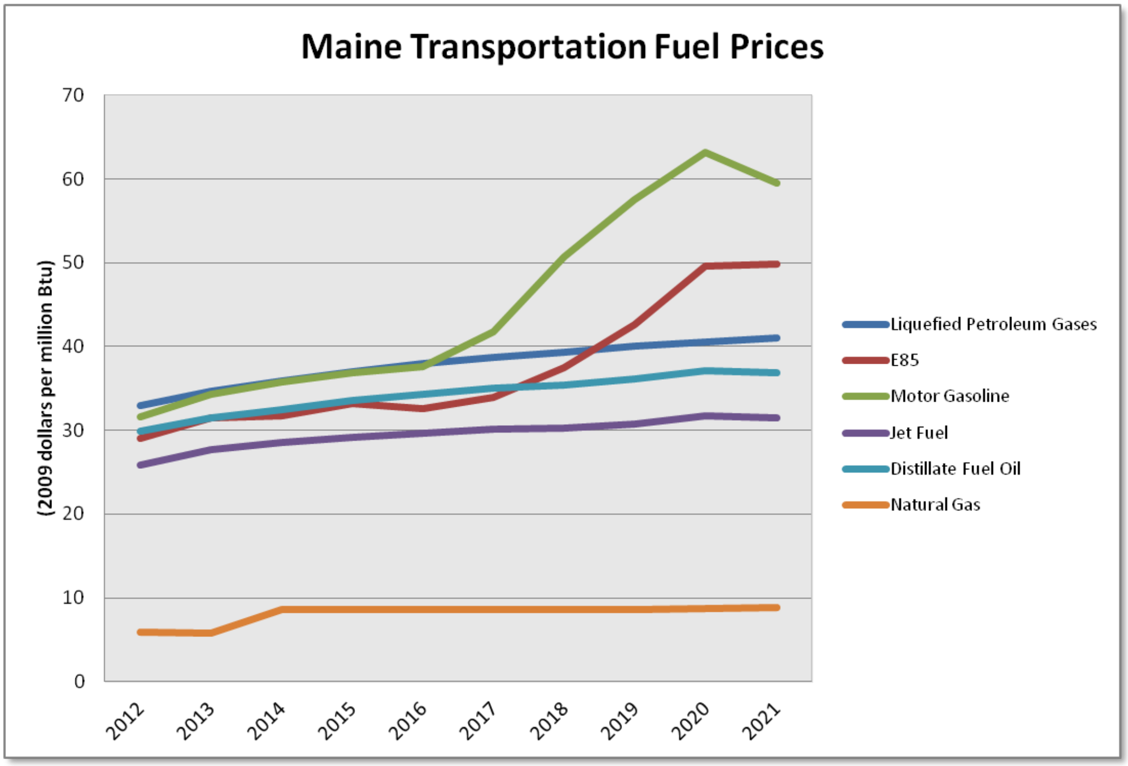


Maine Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E85 (Gasoline Only)	1.5	3.2	4.1	4.6	5.1	5.5	5.9	6.3	6.6	6.9
Motor Gasoline (Gasoline Only)	72.4	68.0	65.3	63.6	62.0	60.0	57.4	55.0	52.8	51.0
Jet Fuel	9.8	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1
Distillate Fuel Oil (Petroleum)	19.9	20.2	18.5	18.8	19.2	19.5	19.7	20.0	20.4	21.0
Residual Fuel Oil	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Pipeline Fuel Natural Gas	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Compressed Natural Gas	0.6	1.0	1.2	1.5	1.7	2.0	2.4	2.7	3.2	3.6
Domestic Ethanol/Corn-Based	5.4	7.0	8.0	8.1	8.6	8.6	8.4	7.9	8.0	8.3
Domestic Ethanol/Cellulose-Based	2.2	2.4	2.5	2.8	2.9	3.4	4.1	5.0	5.3	5.3
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	7.0	7.6	9.5	9.4	9.4	9.5	9.4	9.4	9.4	9.5
Steam Coal (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (Gen Fuel)	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	121.2	121.5	121.2	121.2	121.3	120.9	119.8	118.9	118.3	118.3

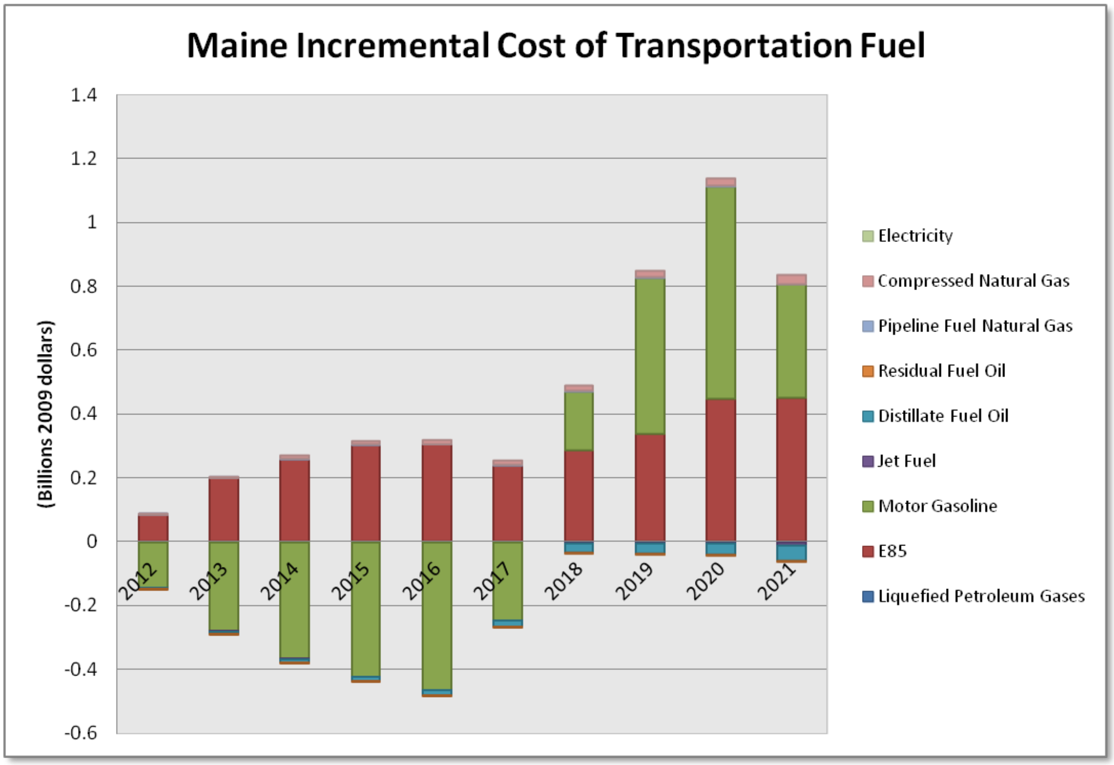
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Maine Transportation Fuel Prices

(2009 dollars per million Btu)

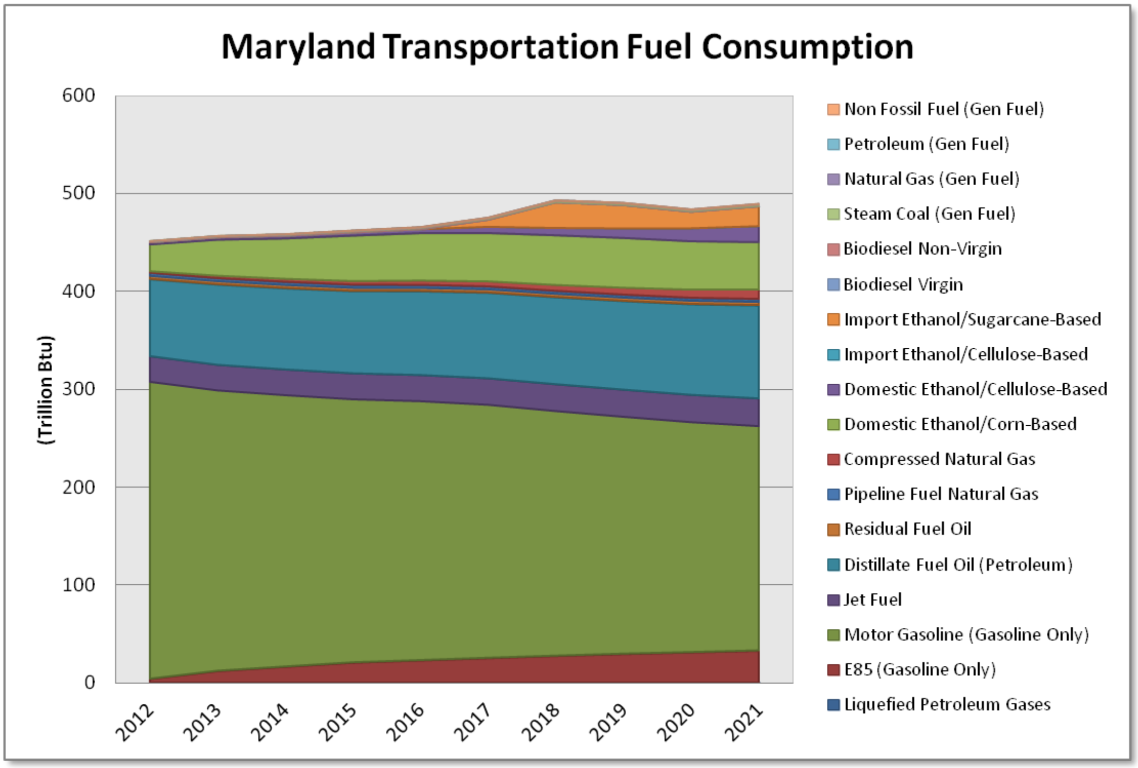
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	32.89	34.61	35.83	36.93	37.99	38.74	39.35	39.98	40.55	41.02
E85	29.01	31.51	31.72	33.15	32.56	33.88	37.52	42.61	49.63	49.87
Motor Gasoline	31.65	34.26	35.73	36.89	37.65	41.74	50.65	57.57	63.13	59.45
Jet Fuel	25.91	27.63	28.52	29.13	29.69	30.13	30.20	30.77	31.70	31.46
Distillate Fuel Oil	29.88	31.45	32.45	33.52	34.35	35.03	35.42	36.17	37.04	36.89
Natural Gas	5.90	5.84	8.65	8.62	8.63	8.61	8.62	8.64	8.73	8.80



Maine Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	**0.005**
E85	0.085	0.200	0.259	0.302	0.305	0.238	0.286	0.338	0.447	0.449	**2.909**
Motor Gasoline	-0.142	-0.278	-0.365	-0.420	-0.463	-0.244	0.184	0.488	0.663	0.356	**-0.221**
Jet Fuel	0.000	-0.001	-0.001	-0.002	-0.002	-0.002	-0.004	-0.004	-0.005	-0.012	**-0.033**
Distillate Fuel Oil	-0.004	-0.007	-0.009	-0.012	-0.014	-0.019	-0.030	-0.034	-0.034	-0.047	**-0.209**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	**-0.004**
Pipeline Fuel Natural Gas	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	**0.018**
Compressed Natural Gas	0.003	0.004	0.009	0.010	0.012	0.014	0.016	0.019	0.023	0.026	**0.137**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.057**	**-0.082**	**-0.105**	**-0.119**	**-0.159**	**-0.010**	**0.454**	**0.811**	**1.096**	**0.774**	**2.602**

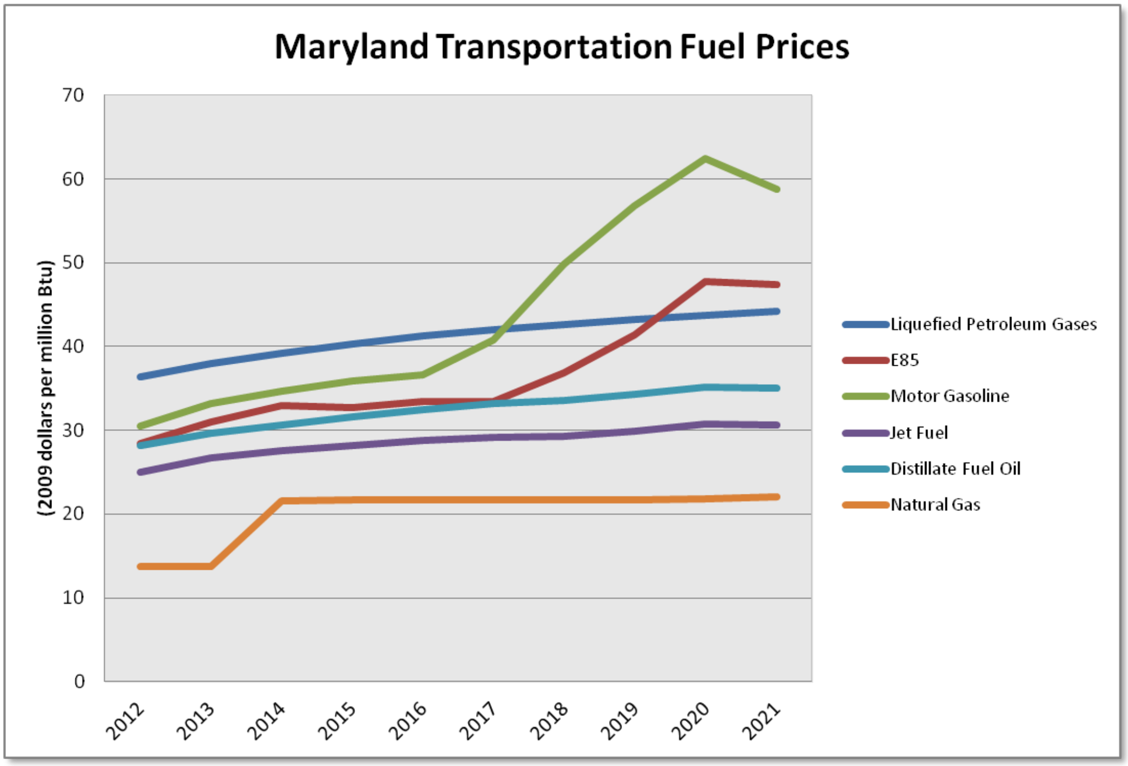


Maryland Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
E85 (Gasoline Only)	3.7	11.8	16.2	20.5	22.7	25.1	27.2	29.3	30.9	32.6
Motor Gasoline (Gasoline Only)	304.2	287.3	278.1	269.6	265.4	259.4	250.8	242.9	235.7	230.1
Jet Fuel	26.1	26.0	26.2	26.4	26.7	27.0	27.3	27.6	27.9	28.1
Distillate Fuel Oil (Petroleum)	78.4	81.7	82.5	83.6	85.2	87.0	88.5	90.2	92.2	94.7
Residual Fuel Oil	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8
Pipeline Fuel Natural Gas	2.8	2.6	2.7	2.7	2.6	2.5	2.5	2.5	2.4	2.4
Compressed Natural Gas	1.6	2.6	3.2	3.9	4.6	5.3	6.2	7.3	8.6	9.9
Domestic Ethanol/Corn-Based	27.8	37.1	41.5	46.6	48.6	49.5	50.9	51.1	49.7	48.8
Domestic Ethanol/Cellulose-Based	2.0	2.5	2.9	3.2	4.1	6.4	7.5	9.7	13.0	15.9
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	7.2	25.8	23.5	16.6	19.9
Biodiesel Non-Virgin	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.1	1.1	1.1
Steam Coal (Gen Fuel)	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.8	0.9	1.0
Natural Gas (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.7	0.7
Total	451.6	456.8	458.6	462.4	465.8	475.4	493.1	490.4	483.9	489.5

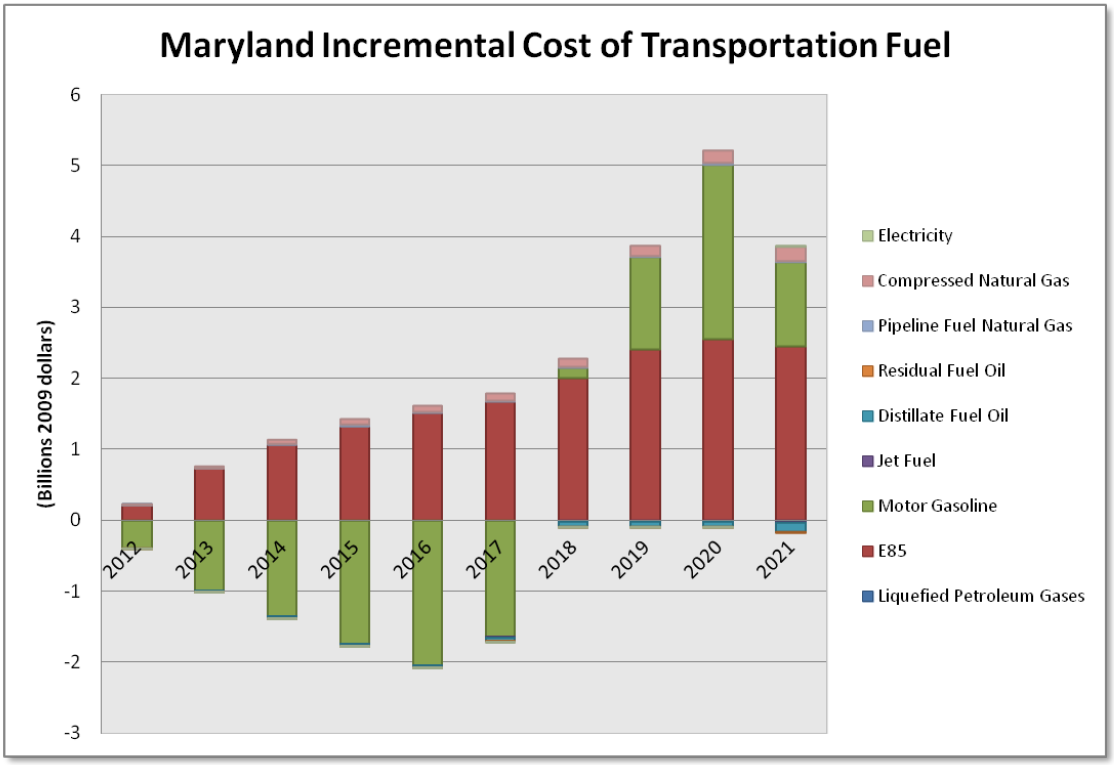
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Maryland Transportation Fuel Prices

(2009 dollars per million Btu)

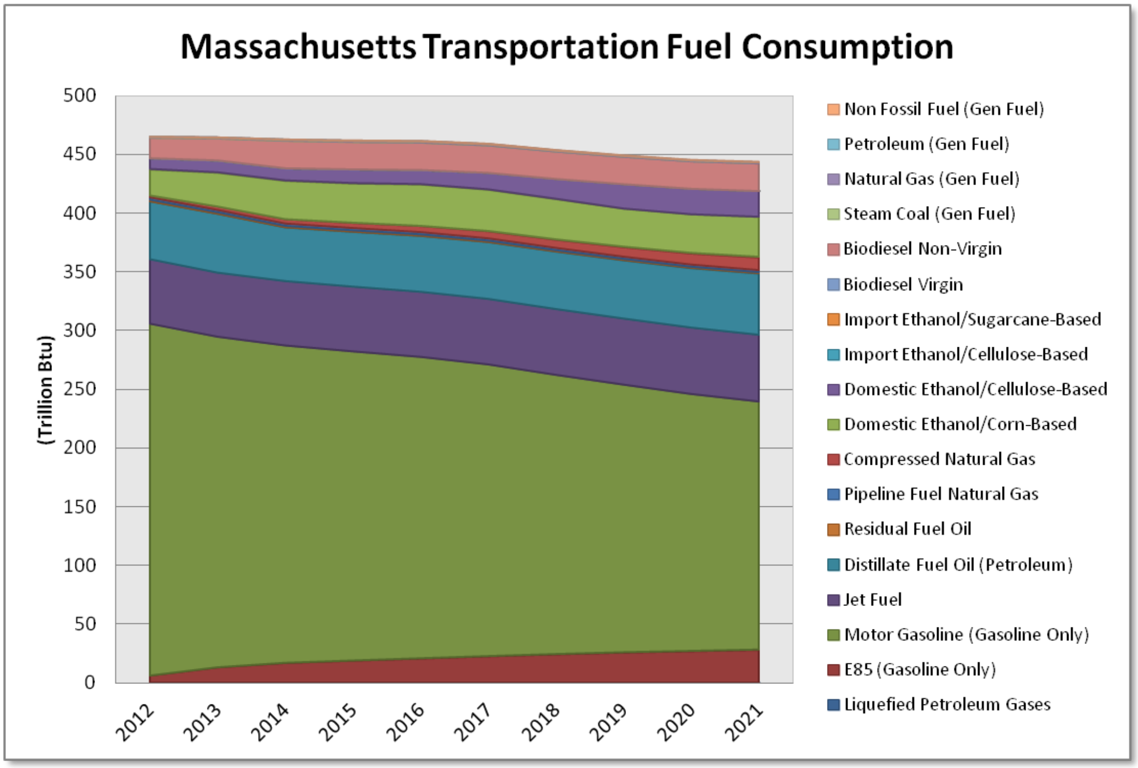
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	36.36	38.02	39.20	40.25	41.28	42.01	42.60	43.21	43.75	44.21
E85	28.42	30.97	32.95	32.72	33.40	33.45	36.89	41.37	47.72	47.40
Motor Gasoline	30.54	33.18	34.66	35.83	36.61	40.75	49.80	56.80	62.46	58.71
Jet Fuel	24.95	26.67	27.57	28.19	28.76	29.21	29.29	29.87	30.79	30.56
Distillate Fuel Oil	28.13	29.59	30.59	31.65	32.47	33.15	33.53	34.29	35.16	35.00
Natural Gas	13.71	13.68	21.58	21.68	21.71	21.66	21.65	21.66	21.83	22.09



Maryland Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002	**0.010**
E85	0.206	0.726	1.058	1.328	1.507	1.664	1.995	2.405	2.547	2.454	**15.890**
Motor Gasoline	-0.398	-0.982	-1.348	-1.737	-2.036	-1.642	0.143	1.297	2.462	1.176	**-3.065**
Jet Fuel	0.000	-0.003	-0.004	-0.004	-0.005	-0.007	-0.013	-0.013	-0.017	-0.035	**-0.100**
Distillate Fuel Oil	0.001	-0.014	-0.020	-0.027	-0.032	-0.050	-0.074	-0.079	-0.078	-0.126	**-0.499**
Residual Fuel Oil	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.002	-0.002	-0.002	-0.004	**-0.014**
Pipeline Fuel Natural Gas	0.000	0.001	0.021	0.021	0.021	0.020	0.020	0.020	0.020	0.020	**0.165**
Compressed Natural Gas	0.018	0.031	0.063	0.076	0.090	0.105	0.123	0.145	0.173	0.203	**1.029**
Electricity	0.000	-0.001	-0.005	-0.006	-0.007	-0.007	-0.006	-0.004	0.000	0.004	**-0.032**
Grand Total	**-0.172**	**-0.242**	**-0.235**	**-0.349**	**-0.462**	**0.083**	**2.188**	**3.771**	**5.108**	**3.695**	**13.385**

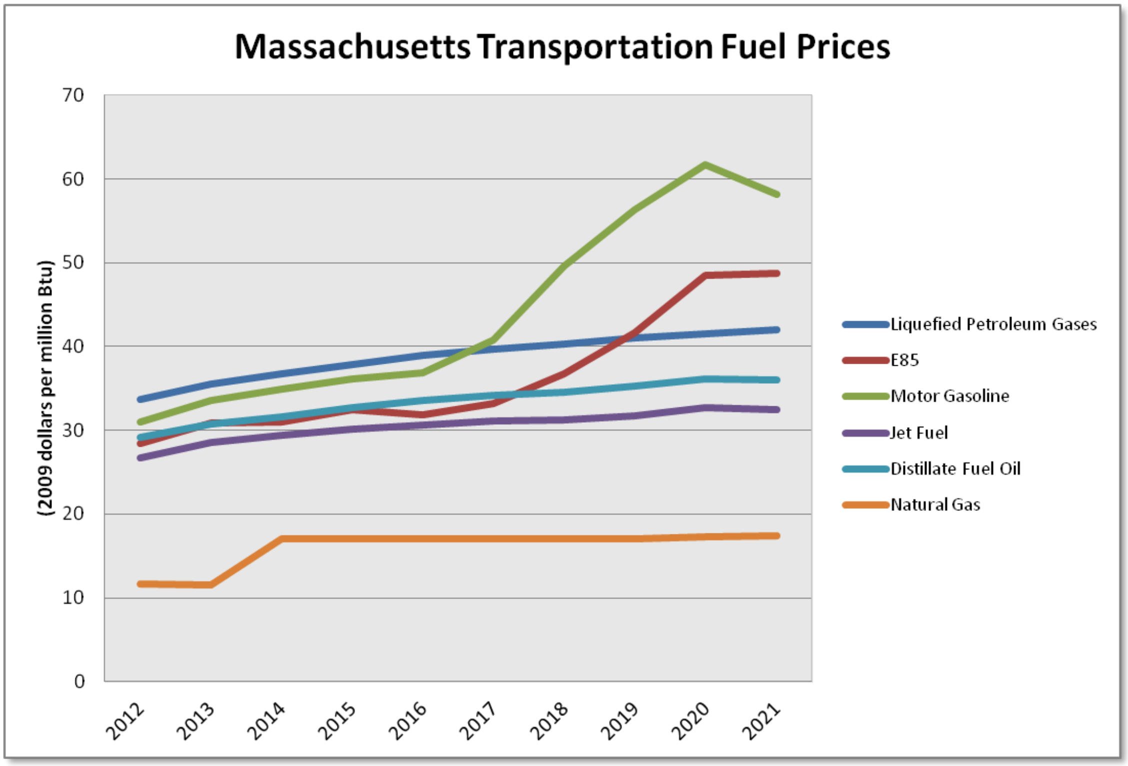


Massachusetts Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
E85 (Gasoline Only)	6.1	13.2	17.0	18.9	20.8	22.7	24.4	25.9	27.1	28.3
Motor Gasoline (Gasoline Only)	299.5	281.3	270.1	263.1	256.5	248.2	237.6	227.7	218.6	211.0
Jet Fuel	55.2	54.9	55.1	55.4	55.7	56.1	56.3	56.5	56.8	57.1
Distillate Fuel Oil (Petroleum)	49.3	50.1	45.8	46.7	47.6	48.4	48.9	49.6	50.7	52.1
Residual Fuel Oil	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pipeline Fuel Natural Gas	2.1	2.1	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Compressed Natural Gas	1.8	2.9	3.6	4.3	5.1	5.9	6.9	8.0	9.3	10.6
Domestic Ethanol/Corn-Based	22.3	29.0	32.9	33.6	35.4	35.4	34.5	32.5	33.0	34.2
Domestic Ethanol/Cellulose-Based	9.1	10.0	10.2	11.6	11.9	14.0	16.9	20.8	21.7	21.8
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	17.4	18.8	23.5	23.4	23.4	23.5	23.4	23.3	23.4	23.5
Steam Coal (Gen Fuel)	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.3
Natural Gas (Gen Fuel)	0.6	0.6	0.7	0.9	0.9	0.9	0.9	0.9	0.8	0.9
Petroleum (Gen Fuel)	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non Fossil Fuel (Gen Fuel)	0.3	0.4	0.4	0.5	0.6	0.6	0.5	0.5	0.5	0.5
Total	465.1	464.5	462.8	461.9	461.5	459.1	453.7	449.2	445.4	443.7

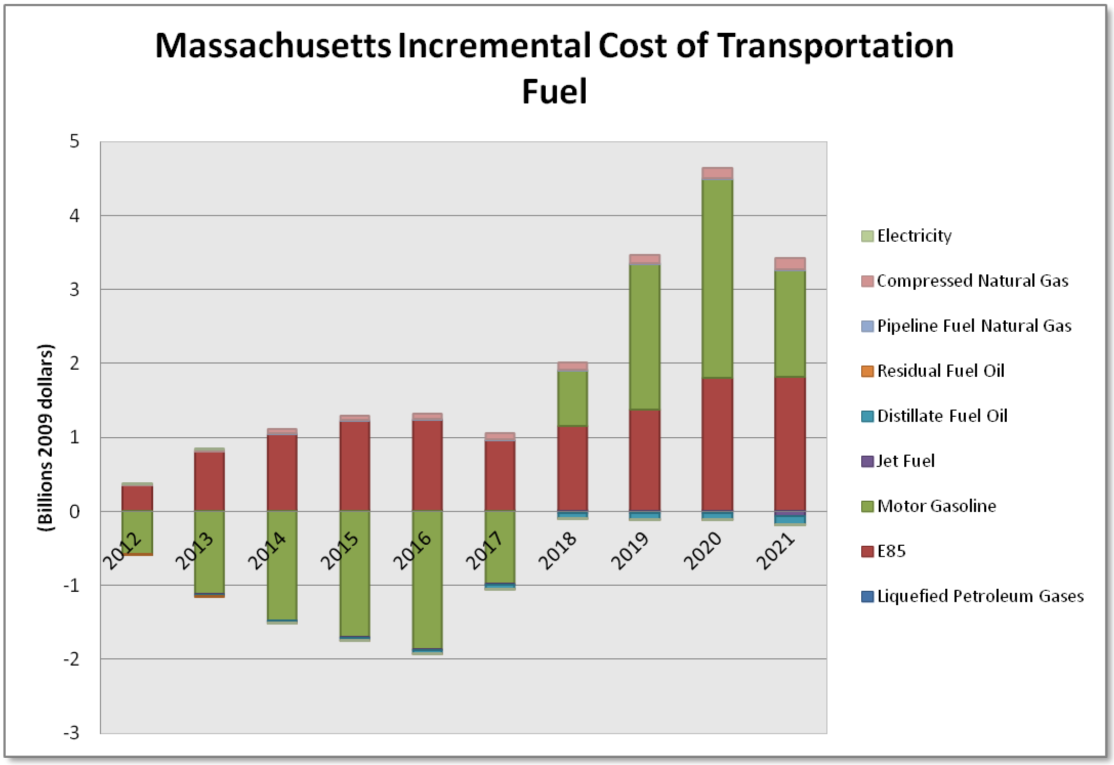
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Massachusetts Transportation Fuel Prices

(2009 dollars per million Btu)

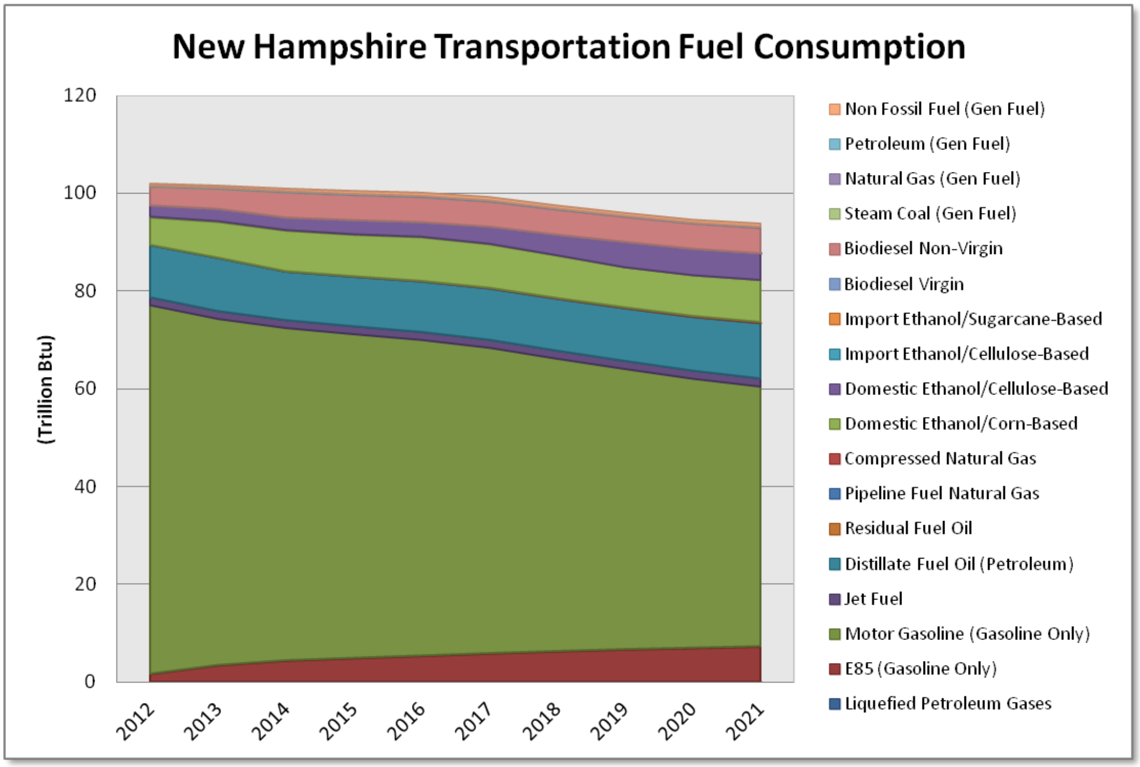
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	33.71	35.48	36.73	37.85	38.94	39.71	40.34	40.98	41.56	42.04
E85	28.37	30.82	31.02	32.41	31.84	33.13	36.68	41.66	48.53	48.77
Motor Gasoline	30.95	33.50	34.94	36.07	36.82	40.81	49.53	56.29	61.74	58.14
Jet Fuel	26.75	28.52	29.44	30.07	30.65	31.11	31.18	31.78	32.73	32.48
Distillate Fuel Oil	29.16	30.68	31.66	32.70	33.51	34.17	34.55	35.29	36.14	35.99
Natural Gas	11.66	11.53	17.09	17.03	17.05	17.02	17.03	17.08	17.25	17.38



Massachusetts Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.001	0.001	0.001	0.002	0.002	0.003	0.003	0.003	0.004	0.004	**0.024**
E85	0.343	0.805	1.044	1.218	1.228	0.961	1.154	1.363	1.802	1.809	**11.728**
Motor Gasoline	-0.573	-1.126	-1.476	-1.700	-1.872	-0.987	0.742	1.975	2.684	1.439	**-0.893**
Jet Fuel	0.001	-0.006	-0.008	-0.009	-0.011	-0.012	-0.025	-0.023	-0.031	-0.068	**-0.193**
Distillate Fuel Oil	-0.009	-0.017	-0.022	-0.029	-0.033	-0.047	-0.074	-0.081	-0.082	-0.113	**-0.506**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	**-0.003**
Pipeline Fuel Natural Gas	0.000	0.000	0.012	0.013	0.013	0.013	0.013	0.013	0.013	0.013	**0.104**
Compressed Natural Gas	0.015	0.025	0.051	0.060	0.071	0.082	0.095	0.111	0.131	0.152	**0.793**
Electricity	0.000	0.000	-0.001	-0.002	-0.002	-0.003	-0.006	-0.007	-0.008	-0.007	**-0.036**
Grand Total	**-0.222**	**-0.318**	**-0.398**	**-0.447**	**-0.605**	**0.010**	**1.903**	**3.354**	**4.512**	**3.228**	**11.017**

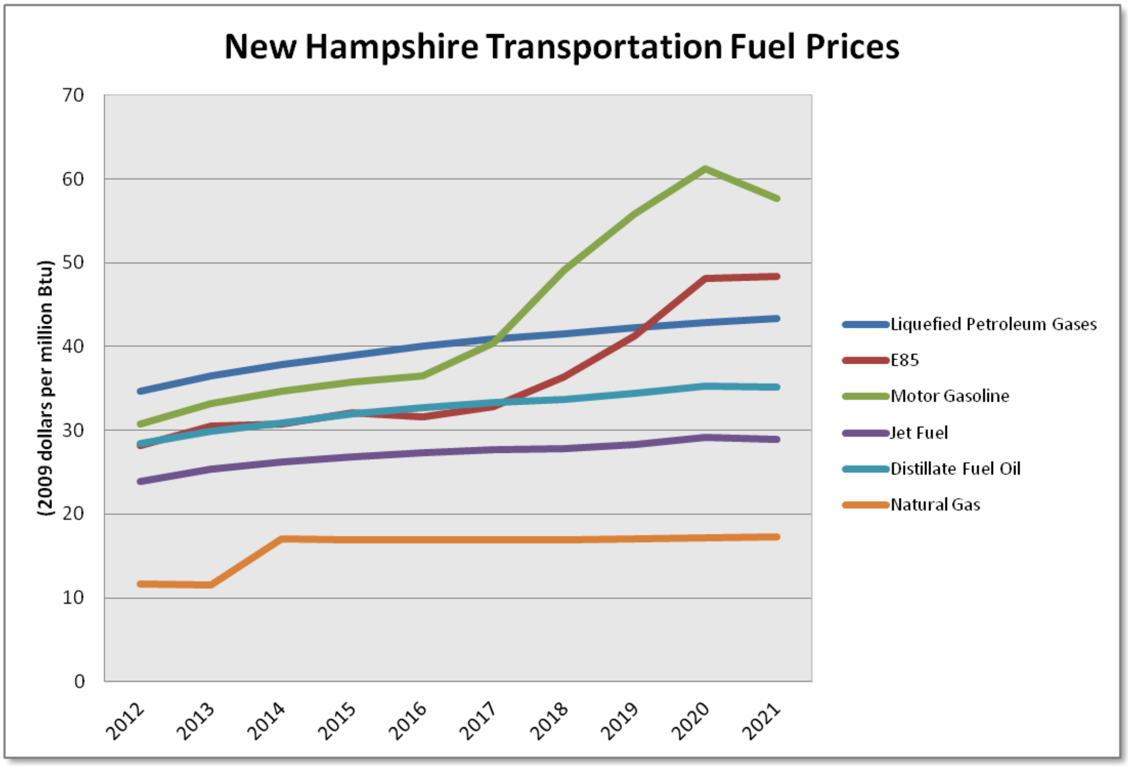


New Hampshire Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
E85 (Gasoline Only)	1.6	3.3	4.3	4.8	5.3	5.8	6.2	6.6	6.9	7.2
Motor Gasoline (Gasoline Only)	75.5	71.0	68.1	66.4	64.7	62.6	59.9	57.4	55.1	53.2
Jet Fuel	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7
Distillate Fuel Oil (Petroleum)	10.7	10.8	9.9	10.1	10.3	10.5	10.6	10.7	11.0	11.3
Residual Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Fuel Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compressed Natural Gas	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Domestic Ethanol/Corn-Based	5.6	7.3	8.3	8.5	9.0	9.0	8.7	8.2	8.4	8.7
Domestic Ethanol/Cellulose-Based	2.3	2.5	2.6	2.9	3.0	3.6	4.3	5.3	5.5	5.5
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	3.8	4.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Steam Coal (Gen Fuel)	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Natural Gas (Gen Fuel)	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.4	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	101.9	101.5	100.9	100.4	100.1	99.2	97.5	96.0	94.6	93.9

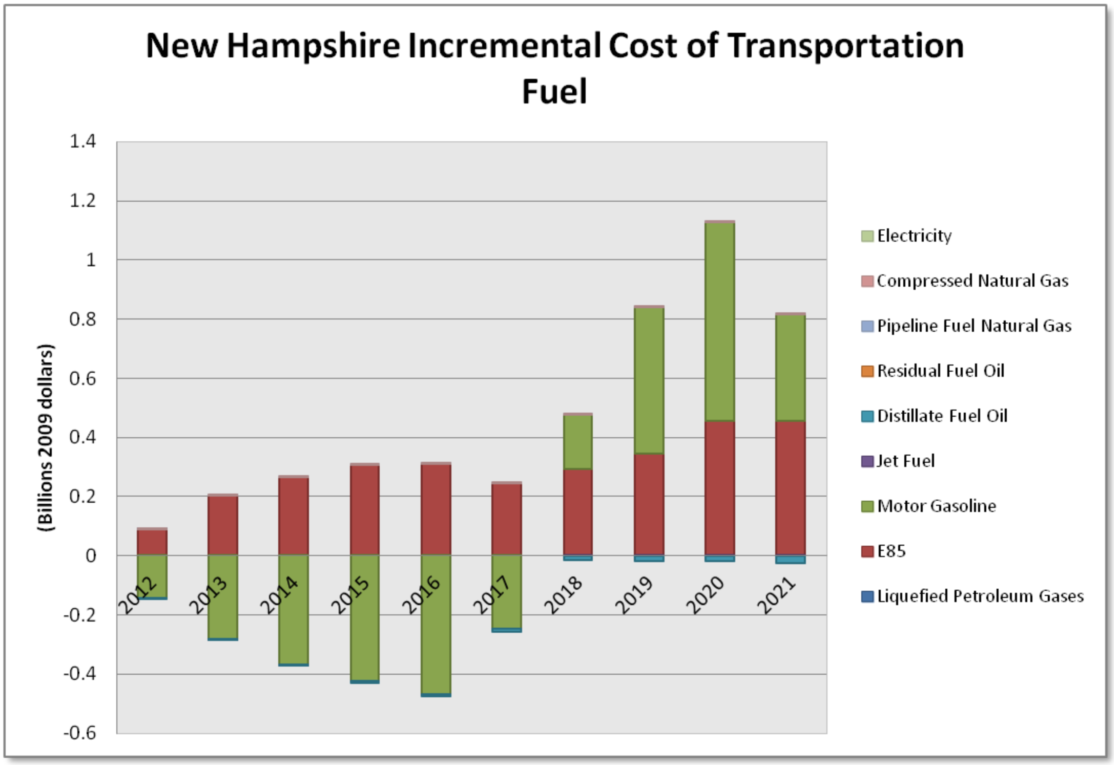
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



New Hampshire Transportation Fuel Prices

(2009 dollars per million Btu)

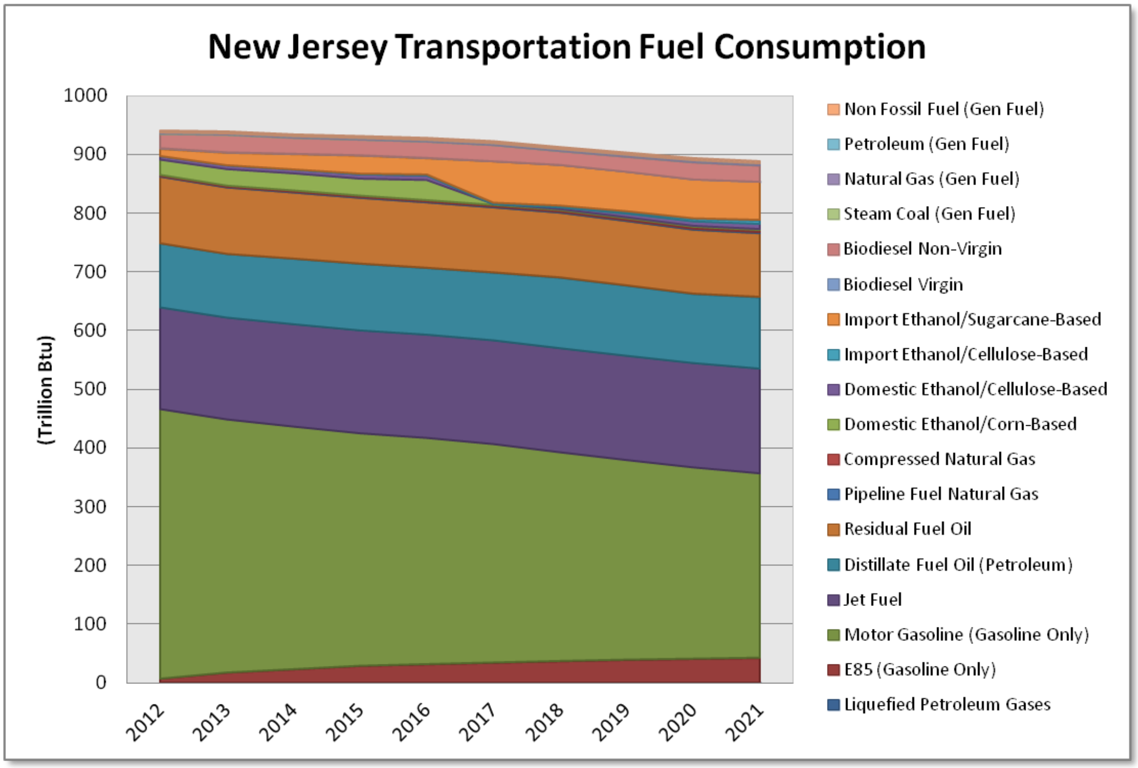
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	34.71	36.53	37.82	38.97	40.10	40.89	41.53	42.20	42.80	43.29
E85	28.13	30.55	30.75	32.13	31.56	32.84	36.37	41.31	48.11	48.35
Motor Gasoline	30.68	33.21	34.64	35.76	36.50	40.46	49.10	55.81	61.21	57.64
Jet Fuel	23.83	25.41	26.23	26.79	27.31	27.72	27.78	28.31	29.16	28.94
Distillate Fuel Oil	28.45	29.94	30.89	31.91	32.69	33.34	33.71	34.43	35.26	35.11
Natural Gas	11.60	11.48	17.00	16.95	16.96	16.94	16.95	16.99	17.17	17.30



New Hampshire Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.002	**0.011**
E85	0.086	0.202	0.262	0.306	0.308	0.241	0.290	0.342	0.453	0.454	**2.946**
Motor Gasoline	-0.143	-0.282	-0.369	-0.425	-0.468	-0.247	0.186	0.494	0.671	0.360	**-0.223**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.002	**-0.005**
Distillate Fuel Oil	-0.002	-0.004	-0.005	-0.006	-0.007	-0.010	-0.016	-0.017	-0.017	-0.024	**-0.107**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.001**
Compressed Natural Gas	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	**0.010**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.058**	**-0.082**	**-0.110**	**-0.124**	**-0.165**	**-0.013**	**0.462**	**0.822**	**1.109**	**0.793**	**2.633**

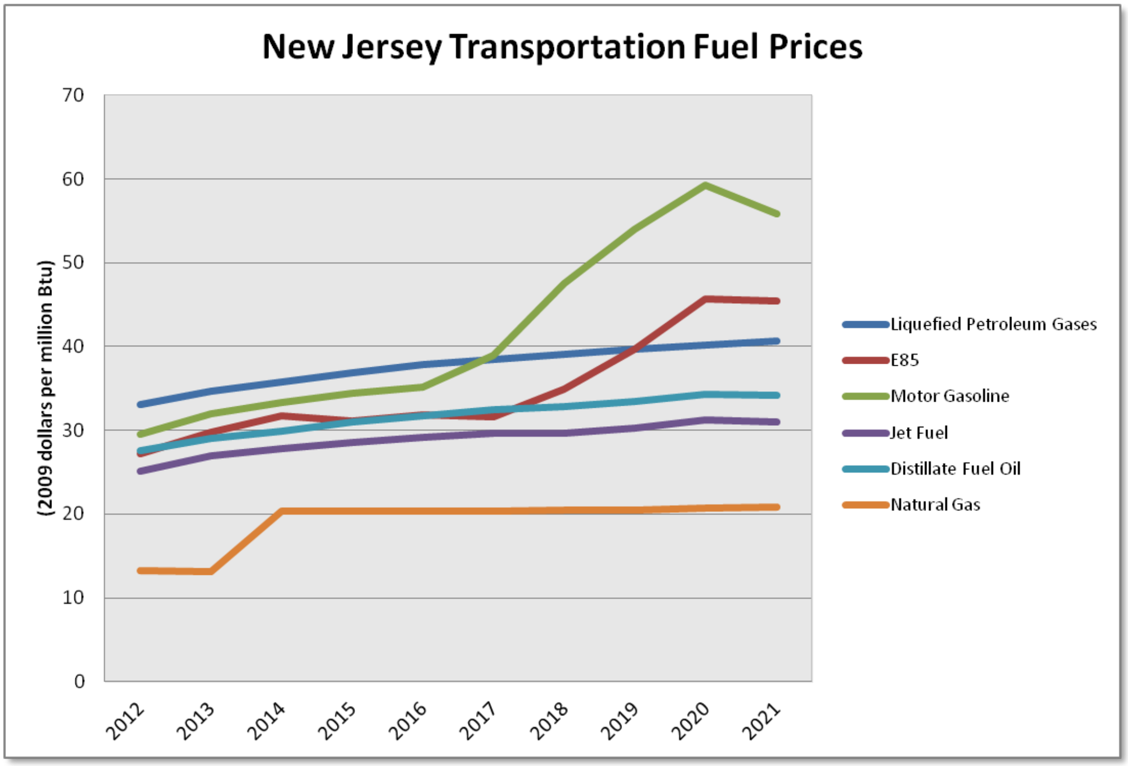


New Jersey Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
E85 (Gasoline Only)	6.8	17.3	23.0	28.8	31.6	34.4	36.9	39.2	40.9	42.5
Motor Gasoline (Gasoline Only)	459.4	431.4	413.6	396.4	385.7	372.6	355.9	340.6	326.4	314.7
Jet Fuel	173.3	173.5	174.4	175.2	175.9	176.7	177.2	177.5	177.7	178.3
Distillate Fuel Oil (Petroleum)	108.8	108.1	111.3	113.2	113.3	115.0	120.0	119.2	117.3	121.3
Residual Fuel Oil	113.8	113.3	112.7	112.2	111.6	111.0	110.4	109.7	109.0	108.5
Pipeline Fuel Natural Gas	1.6	1.6	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Compressed Natural Gas	0.5	0.8	1.0	1.2	1.4	1.6	1.9	2.2	2.5	2.9
Domestic Ethanol/Corn-Based	26.8	28.7	29.8	29.6	34.8	2.2	2.2	2.2	2.2	2.2
Domestic Ethanol/Cellulose-Based	6.0	6.5	6.7	7.6	8.2	0.3	3.6	7.0	8.4	9.8
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.8	1.2	1.5	2.1	2.9	4.1	5.6
Import Ethanol/Sugarcane-Based	12.1	21.2	26.0	30.8	27.7	70.8	69.6	67.8	66.9	65.7
Biodiesel Non-Virgin	0.8	0.4	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	24.5	29.8	27.2	26.5	27.6	27.4	23.3	25.1	28.6	26.8
Steam Coal (Gen Fuel)	0.9	0.9	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8
Natural Gas (Gen Fuel)	1.8	1.7	2.3	2.4	2.4	2.5	2.6	2.6	2.6	2.6
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	3.4	3.6	3.2	3.3	3.5	3.6	3.6	3.6	3.6	3.8
Total	940.7	939.2	934.1	931.1	928.0	922.3	912.1	902.6	893.2	887.7

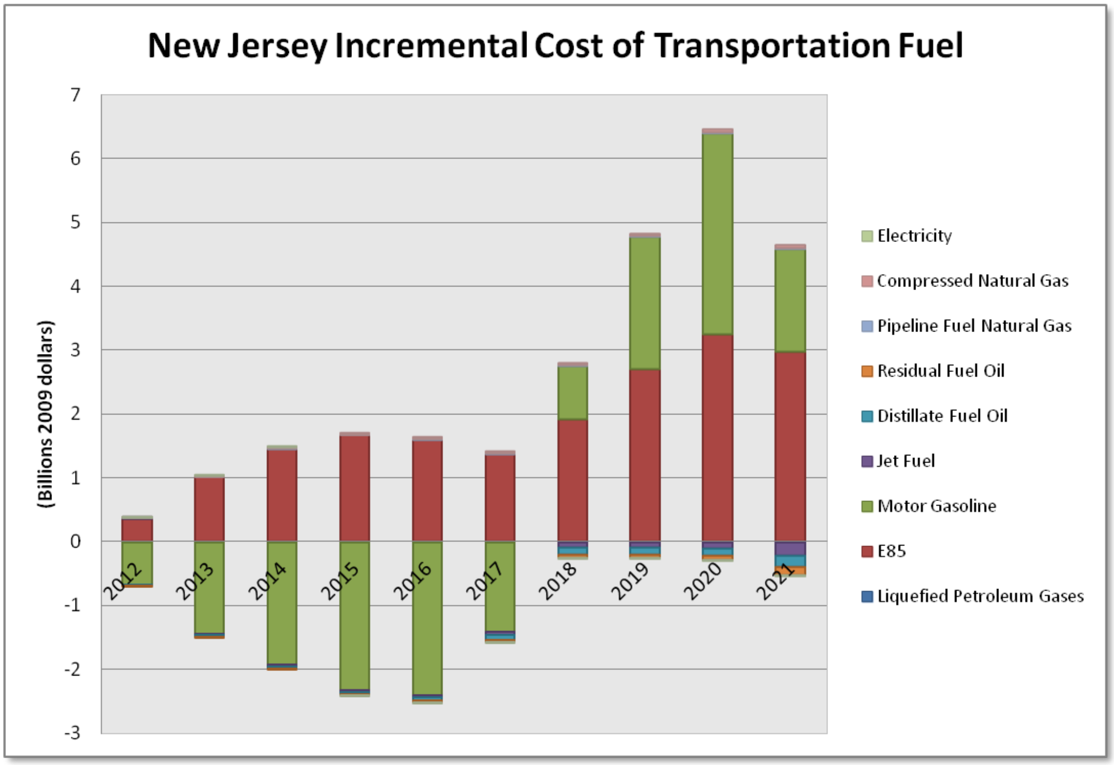
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



New Jersey Transportation Fuel Prices

(2009 dollars per million Btu)

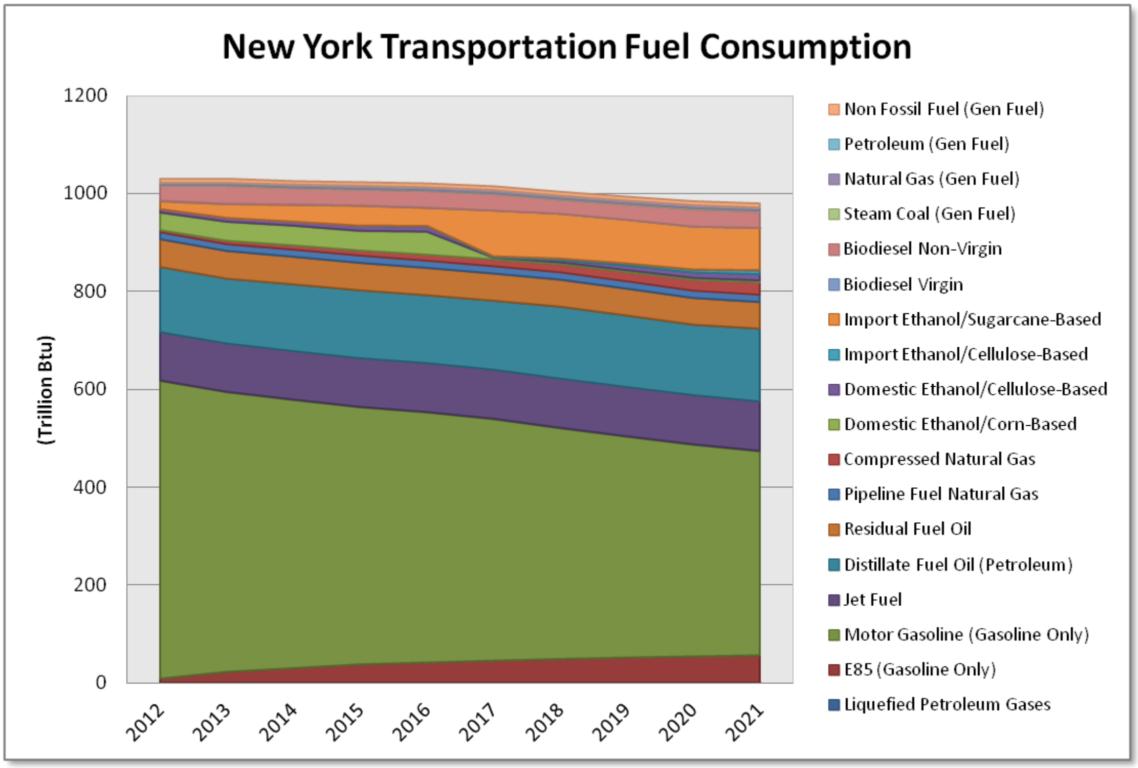
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	33.07	34.67	35.80	36.82	37.80	38.50	39.07	39.65	40.18	40.61
E85	27.25	29.79	31.67	31.16	31.83	31.55	34.87	39.65	45.71	45.45
Motor Gasoline	29.46	31.94	33.33	34.44	35.16	38.98	47.45	54.02	59.28	55.77
Jet Fuel	25.17	26.94	27.84	28.54	29.11	29.59	29.66	30.25	31.19	30.96
Distillate Fuel Oil	27.51	28.99	29.94	30.95	31.75	32.40	32.77	33.47	34.30	34.15
Natural Gas	13.21	13.09	20.39	20.38	20.40	20.40	20.45	20.52	20.71	20.86



New Jersey Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.001	0.002	0.002	0.003	0.003	0.004	0.005	0.005	0.006	0.006	**0.037**
E85	0.367	1.023	1.445	1.667	1.596	1.375	1.904	2.692	3.240	2.967	**18.276**
Motor Gasoline	-0.669	-1.434	-1.918	-2.317	-2.393	-1.410	0.842	2.077	3.153	1.600	**-2.469**
Jet Fuel	0.002	-0.025	-0.034	-0.024	-0.035	-0.047	-0.087	-0.082	-0.107	-0.220	**-0.660**
Distillate Fuel Oil	-0.009	-0.022	-0.030	-0.041	-0.049	-0.074	-0.108	-0.113	-0.109	-0.179	**-0.734**
Residual Fuel Oil	-0.005	-0.014	-0.016	-0.017	-0.027	-0.025	-0.055	-0.060	-0.063	-0.118	**-0.400**
Pipeline Fuel Natural Gas	0.000	0.000	0.013	0.013	0.013	0.013	0.014	0.014	0.014	0.014	**0.108**
Compressed Natural Gas	0.005	0.008	0.017	0.020	0.024	0.028	0.032	0.038	0.044	0.051	**0.267**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	**-0.005**
Grand Total	**-0.308**	**-0.461**	**-0.521**	**-0.696**	**-0.869**	**-0.137**	**2.546**	**4.570**	**6.176**	**4.119**	**14.420**

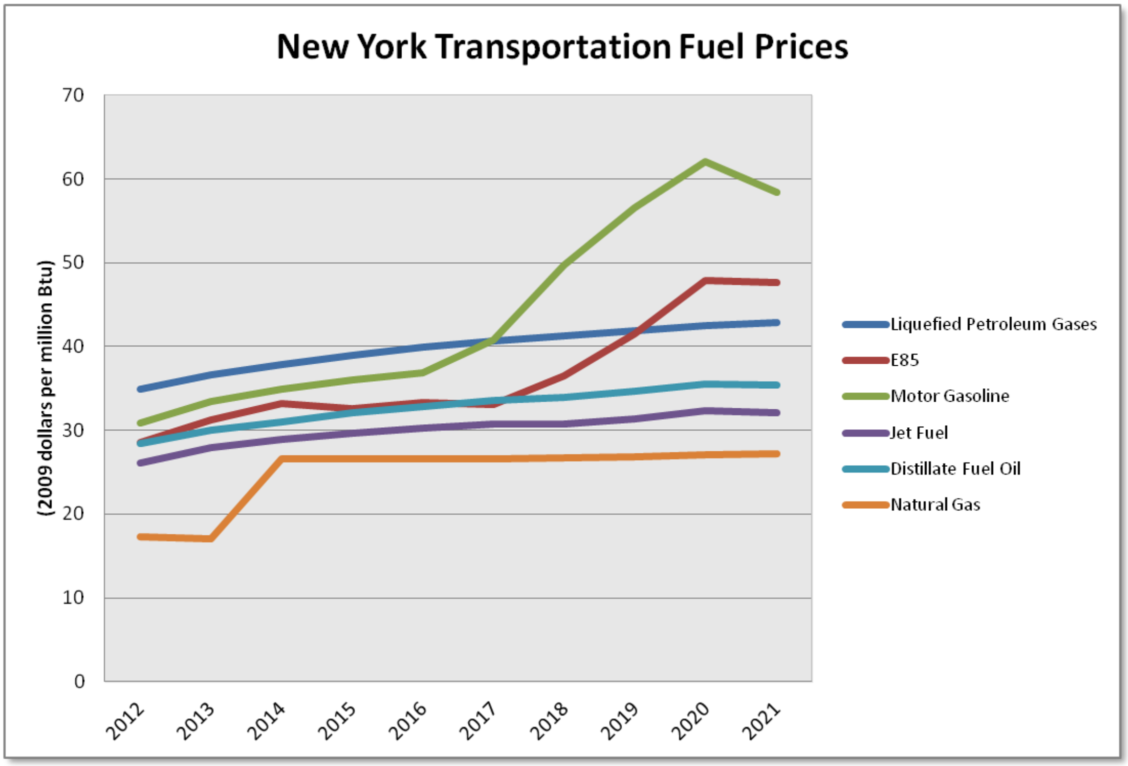


New York Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
E85 (Gasoline Only)	9.1	23.1	30.6	38.3	42.0	45.8	49.2	52.1	54.4	56.6
Motor Gasoline (Gasoline Only)	607.7	570.7	547.2	524.5	510.3	492.9	470.9	450.6	431.8	416.3
Jet Fuel	99.6	99.7	100.2	100.7	101.1	101.6	101.9	102.0	102.1	102.5
Distillate Fuel Oil (Petroleum)	132.7	131.9	135.8	138.1	138.2	140.3	146.4	145.5	143.1	148.0
Residual Fuel Oil	56.5	56.2	55.9	55.7	55.3	55.1	54.7	54.4	54.1	53.8
Pipeline Fuel Natural Gas	14.3	14.2	15.2	15.5	15.5	15.6	15.9	16.0	16.1	16.2
Compressed Natural Gas	4.6	7.2	8.8	10.5	12.3	14.3	16.5	19.1	22.2	25.2
Domestic Ethanol/Corn-Based	35.6	38.2	39.6	39.4	46.3	3.0	3.0	3.0	3.0	3.0
Domestic Ethanol/Cellulose-Based	8.0	8.7	8.9	10.1	10.9	0.4	4.8	9.3	11.2	13.0
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	1.1	1.6	2.0	2.8	3.9	5.4	7.5
Import Ethanol/Sugarcane-Based	16.1	28.2	34.6	40.9	36.8	94.2	92.6	90.3	89.1	87.5
Biodiesel Non-Virgin	0.9	0.5	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	29.9	36.4	33.1	32.3	33.7	33.4	28.5	30.6	34.8	32.7
Steam Coal (Gen Fuel)	1.7	1.8	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5
Natural Gas (Gen Fuel)	4.4	4.2	5.6	6.0	6.0	6.2	6.3	6.4	6.4	6.4
Petroleum (Gen Fuel)	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Non Fossil Fuel (Gen Fuel)	7.6	8.1	7.1	7.2	7.6	7.7	7.7	7.9	7.9	8.3
Total	1,029.8	1,030.2	1,025.4	1,023.2	1,020.7	1,014.9	1,003.7	993.8	984.4	979.9

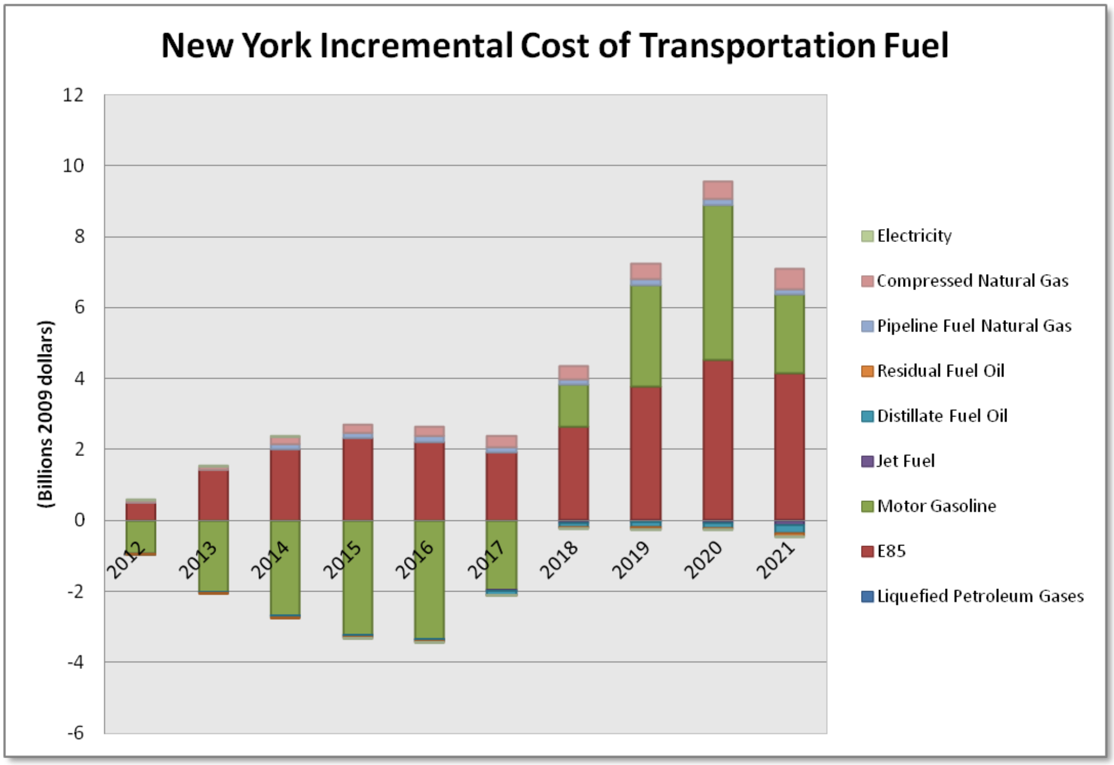
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



New York Transportation Fuel Prices

(2009 dollars per million Btu)

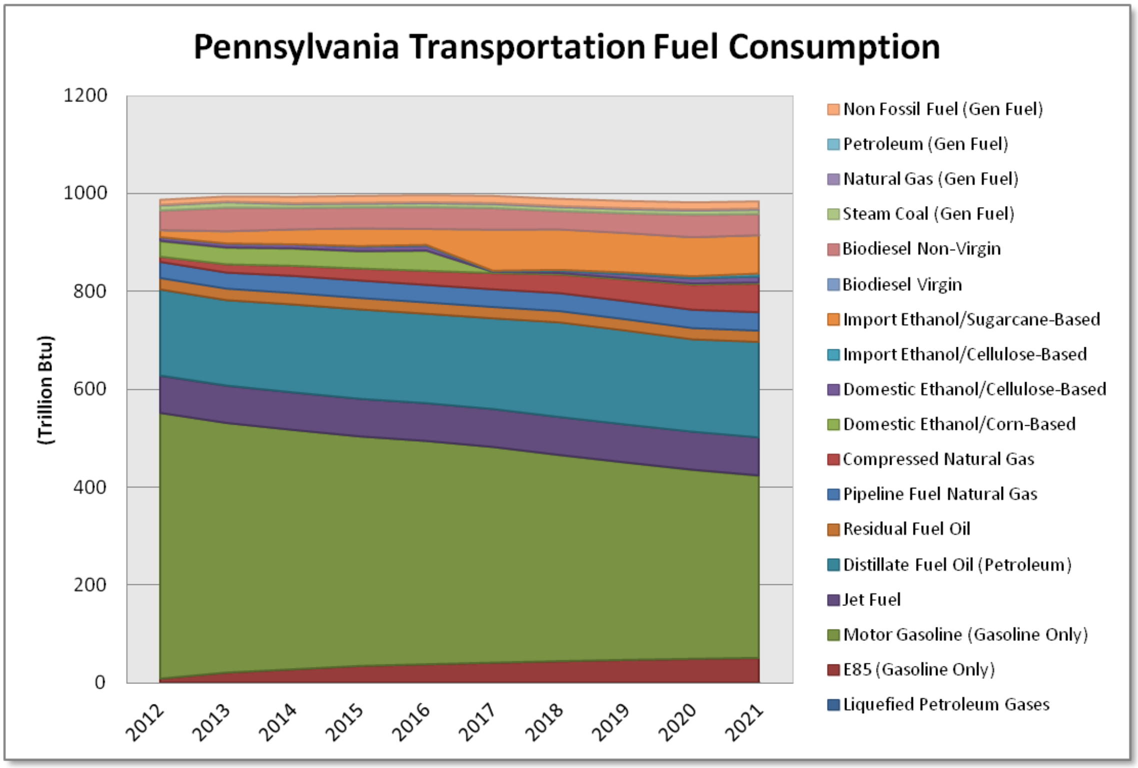
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	34.95	36.64	37.83	38.90	39.94	40.68	41.28	41.90	42.45	42.91
E85	28.54	31.19	33.16	32.62	33.33	33.03	36.51	41.52	47.86	47.59
Motor Gasoline	30.85	33.44	34.90	36.06	36.81	40.82	49.69	56.56	62.07	58.40
Jet Fuel	26.13	27.97	28.90	29.63	30.23	30.72	30.80	31.41	32.38	32.14
Distillate Fuel Oil	28.47	30.01	30.99	32.04	32.86	33.54	33.91	34.64	35.50	35.34
Natural Gas	17.24	17.09	26.62	26.60	26.63	26.64	26.70	26.79	27.03	27.23



New York Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.002	0.002	0.003	0.004	0.005	0.005	0.008	0.008	0.008	0.008	**0.053**
E85	0.512	1.426	2.014	2.323	2.224	1.917	2.653	3.751	4.514	4.134	**25.466**
Motor Gasoline	-0.927	-1.986	-2.657	-3.210	-3.315	-1.954	1.166	2.878	4.368	2.217	**-3.421**
Jet Fuel	0.001	-0.015	-0.020	-0.015	-0.021	-0.028	-0.052	-0.049	-0.064	-0.131	**-0.394**
Distillate Fuel Oil	-0.012	-0.027	-0.038	-0.051	-0.062	-0.093	-0.136	-0.143	-0.138	-0.225	**-0.927**
Residual Fuel Oil	-0.003	-0.009	-0.010	-0.011	-0.017	-0.016	-0.034	-0.037	-0.039	-0.073	**-0.247**
Pipeline Fuel Natural Gas	0.001	0.002	0.146	0.148	0.149	0.151	0.155	0.158	0.162	0.163	**1.234**
Compressed Natural Gas	0.055	0.094	0.197	0.235	0.275	0.318	0.369	0.430	0.507	0.583	**3.063**
Electricity	0.000	0.000	0.001	-0.002	0.000	-0.002	-0.009	-0.013	-0.014	-0.012	**-0.051**
Grand Total	**-0.371**	**-0.513**	**-0.366**	**-0.578**	**-0.764**	**0.298**	**4.120**	**6.983**	**9.304**	**6.663**	**24.775**

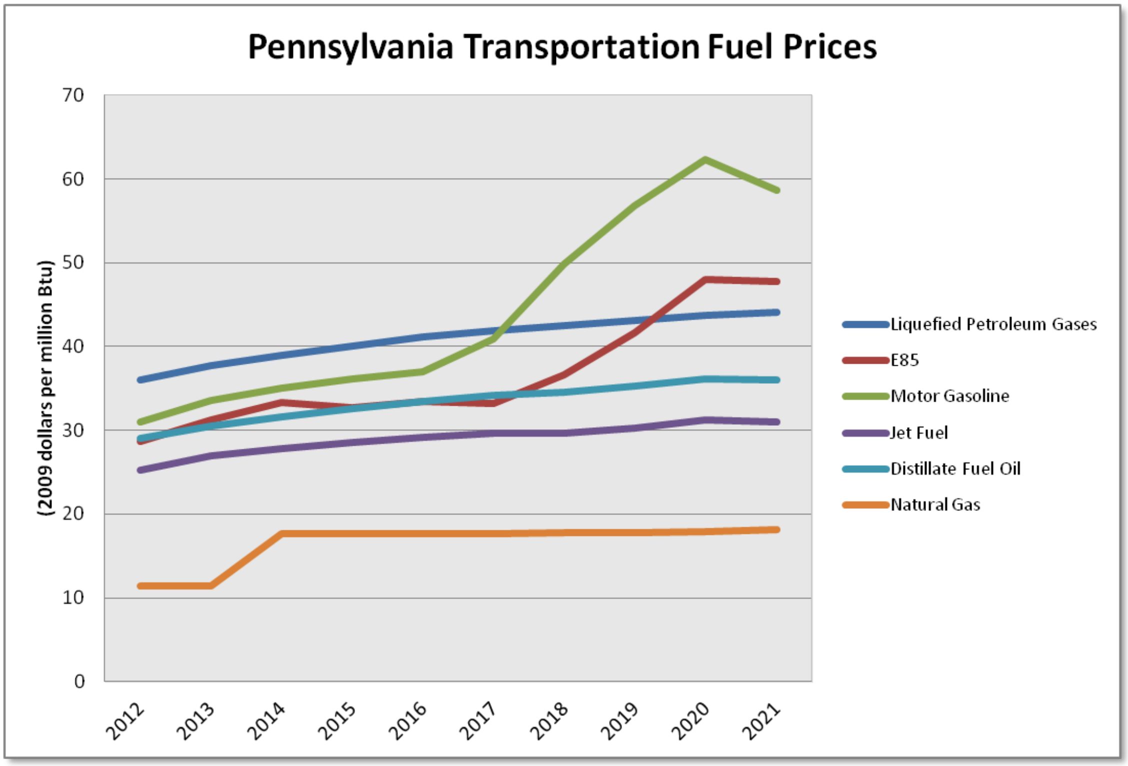


Pennsylvania Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8
E85 (Gasoline Only)	8.1	20.5	27.2	34.1	37.4	40.7	43.7	46.4	48.4	50.4
Motor Gasoline (Gasoline Only)	542.9	509.8	488.9	468.6	455.9	440.4	420.7	402.6	385.8	371.9
Jet Fuel	76.4	76.4	76.8	77.2	77.5	77.9	78.1	78.2	78.3	78.6
Distillate Fuel Oil (Petroleum)	175.4	174.3	179.4	182.5	182.6	185.4	193.4	192.2	189.1	195.6
Residual Fuel Oil	24.6	24.5	24.4	24.2	24.1	24.0	23.8	23.7	23.5	23.4
Pipeline Fuel Natural Gas	32.9	32.7	34.9	35.6	35.6	35.9	36.5	36.8	37.1	37.3
Compressed Natural Gas	10.5	16.6	20.2	24.2	28.3	32.8	37.9	43.9	50.9	58.0
Domestic Ethanol/Corn-Based	31.7	34.0	35.3	35.1	41.2	2.6	2.6	2.6	2.6	2.6
Domestic Ethanol/Cellulose-Based	7.1	7.7	7.9	9.0	9.7	0.4	4.2	8.3	9.9	11.6
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	1.0	1.4	1.8	2.5	3.5	4.8	6.7
Import Ethanol/Sugarcane-Based	14.3	25.0	30.8	36.4	32.8	83.8	82.4	80.3	79.2	77.8
Biodiesel Non-Virgin	1.2	0.7	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	39.5	48.1	43.8	42.7	44.5	44.2	37.6	40.4	46.0	43.3
Steam Coal (Gen Fuel)	10.4	10.9	7.5	7.4	7.7	7.9	8.0	8.4	8.7	9.2
Natural Gas (Gen Fuel)	1.6	1.5	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4
Petroleum (Gen Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Non Fossil Fuel (Gen Fuel)	9.9	10.0	12.7	13.5	13.9	14.1	14.2	14.3	14.1	14.4
Total	987.3	993.8	993.2	995.0	996.3	995.0	989.1	984.9	982.1	984.1

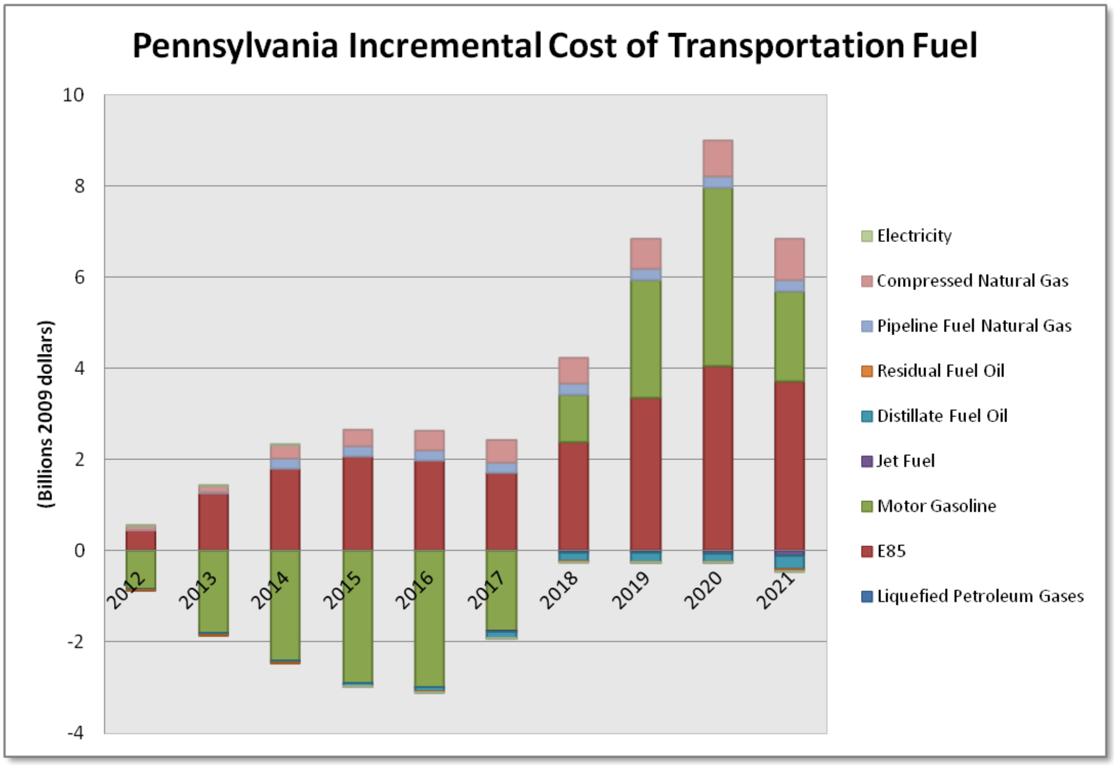
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Pennsylvania Transportation Fuel Prices

(2009 dollars per million Btu)

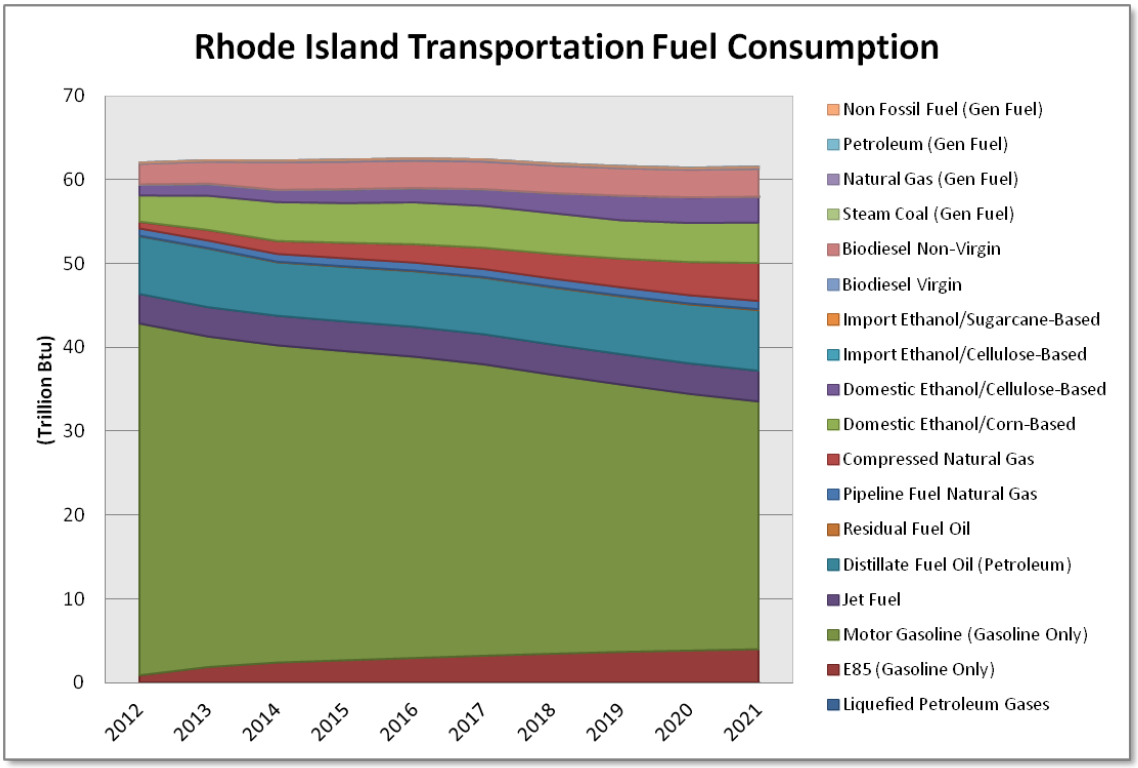
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	35.95	37.69	38.91	40.02	41.09	41.85	42.46	43.10	43.67	44.14
E85	28.63	31.29	33.27	32.73	33.44	33.14	36.63	41.65	48.02	47.74
Motor Gasoline	30.95	33.55	35.02	36.18	36.94	40.95	49.85	56.75	62.28	58.59
Jet Fuel	25.19	26.96	27.86	28.56	29.14	29.61	29.69	30.28	31.21	30.99
Distillate Fuel Oil	28.99	30.56	31.55	32.62	33.46	34.15	34.53	35.28	36.15	35.99
Natural Gas	11.45	11.35	17.68	17.67	17.69	17.69	17.73	17.79	17.95	18.08



Pennsylvania Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.003	0.004	0.005	0.007	0.008	0.009	0.013	0.014	0.014	0.015	**0.094**
E85	0.457	1.273	1.797	2.074	1.985	1.711	2.368	3.349	4.030	3.690	**22.733**
Motor Gasoline	-0.831	-1.780	-2.382	-2.877	-2.972	-1.751	1.045	2.580	3.915	1.987	**-3.066**
Jet Fuel	0.001	-0.011	-0.015	-0.011	-0.016	-0.021	-0.038	-0.036	-0.047	-0.097	**-0.291**
Distillate Fuel Oil	-0.016	-0.037	-0.052	-0.069	-0.084	-0.125	-0.183	-0.192	-0.186	-0.303	**-1.247**
Residual Fuel Oil	-0.001	-0.004	-0.004	-0.004	-0.007	-0.006	-0.014	-0.015	-0.016	-0.030	**-0.102**
Pipeline Fuel Natural Gas	0.001	0.003	0.222	0.226	0.227	0.231	0.237	0.241	0.247	0.249	**1.883**
Compressed Natural Gas	0.084	0.143	0.301	0.358	0.420	0.486	0.563	0.656	0.774	0.890	**4.675**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	-0.002	-0.002	-0.003	-0.002	**-0.009**
Grand Total	**-0.302**	**-0.408**	**-0.127**	**-0.297**	**-0.438**	**0.532**	**3.990**	**6.593**	**8.729**	**6.398**	**24.670**

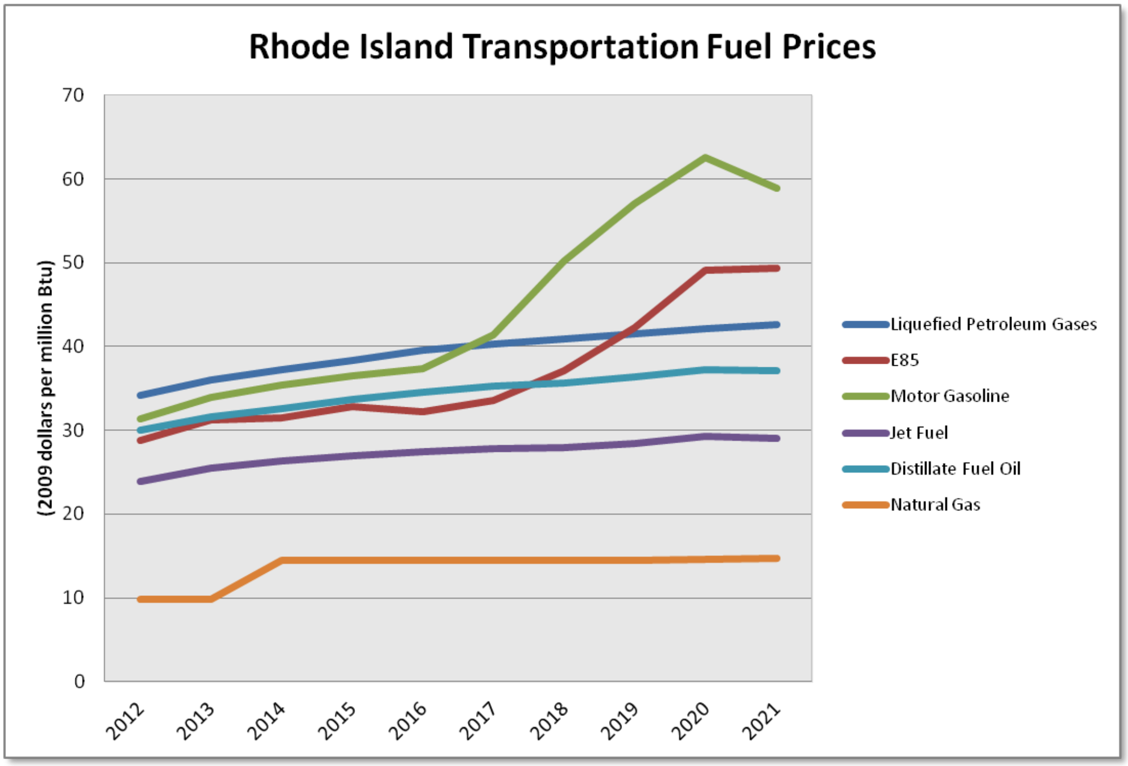


Rhode Island Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E85 (Gasoline Only)	0.9	1.8	2.4	2.7	2.9	3.2	3.4	3.6	3.8	4.0
Motor Gasoline (Gasoline Only)	42.0	39.4	37.8	36.9	35.9	34.8	33.3	31.9	30.6	29.6
Jet Fuel	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6	3.7
Distillate Fuel Oil (Petroleum)	6.9	7.0	6.4	6.5	6.6	6.7	6.8	6.9	7.1	7.3
Residual Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pipeline Fuel Natural Gas	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Compressed Natural Gas	0.8	1.3	1.5	1.9	2.2	2.5	3.0	3.4	4.0	4.6
Domestic Ethanol/Corn-Based	3.1	4.1	4.6	4.7	5.0	5.0	4.8	4.6	4.6	4.8
Domestic Ethanol/Cellulose-Based	1.3	1.4	1.4	1.6	1.7	2.0	2.4	2.9	3.0	3.1
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	2.4	2.6	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Steam Coal (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (Gen Fuel)	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.0
Total	62.0	62.3	62.3	62.3	62.5	62.4	61.9	61.6	61.4	61.5

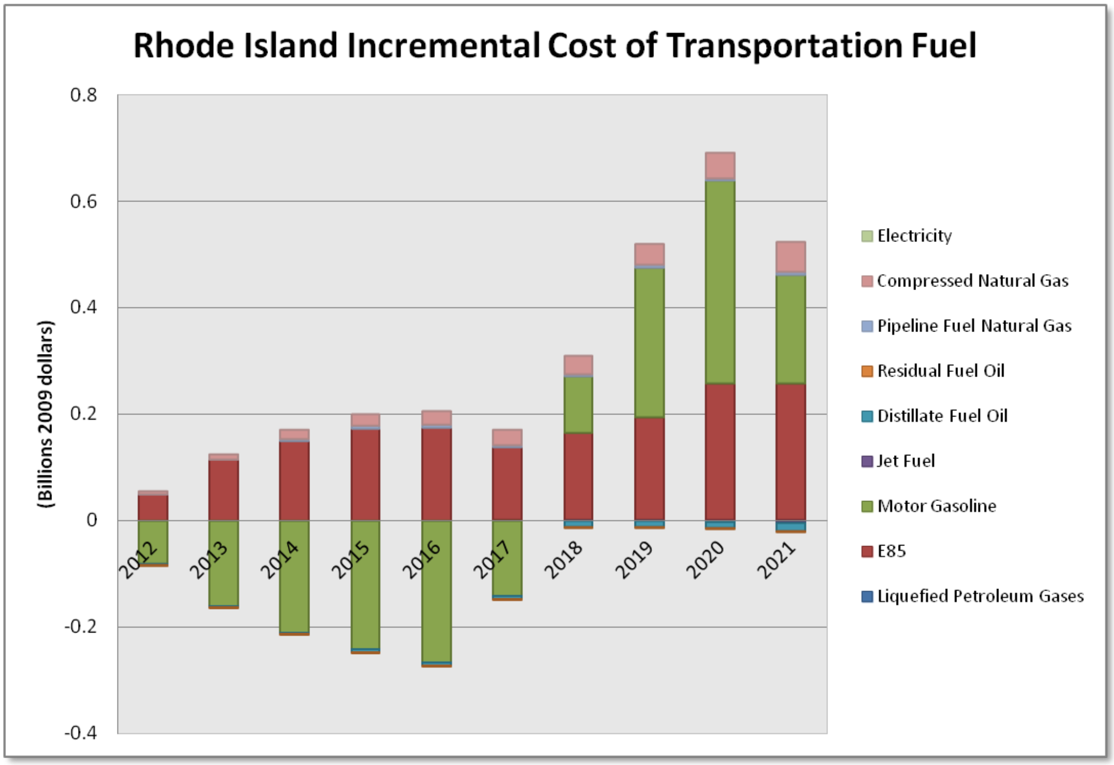
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Rhode Island Transportation Fuel Prices

(2009 dollars per million Btu)

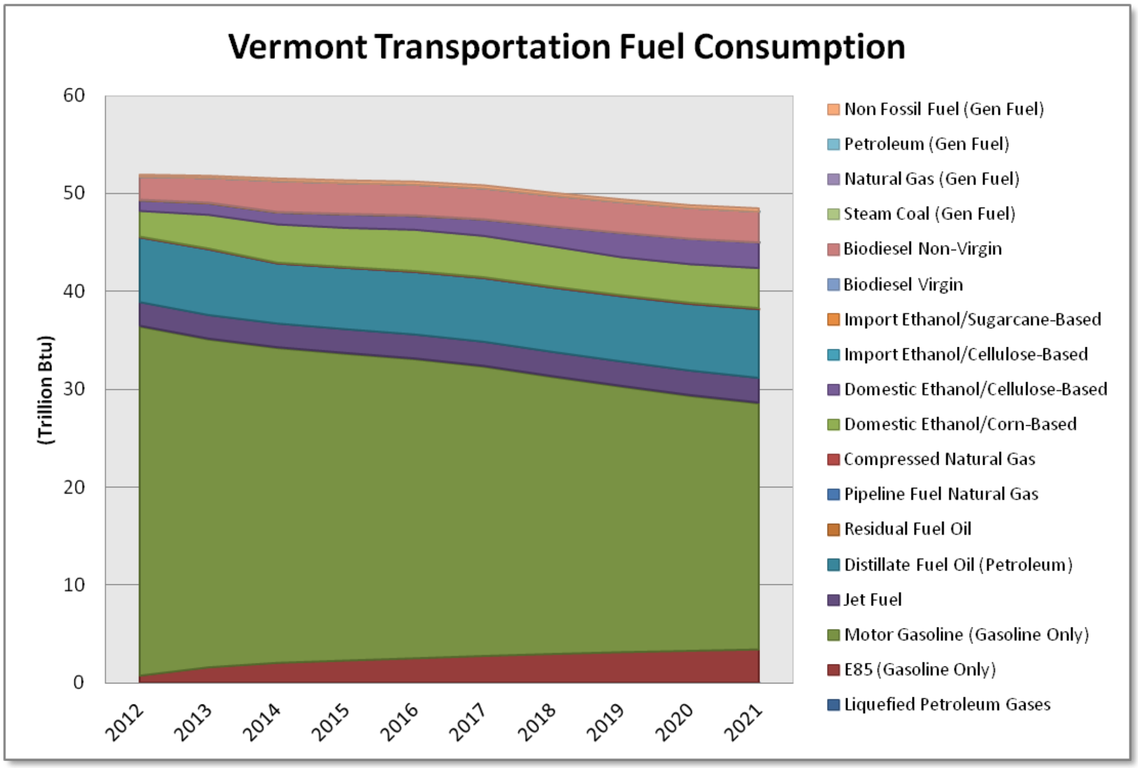
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	34.19	35.99	37.25	38.39	39.49	40.28	40.91	41.57	42.15	42.64
E85	28.74	31.21	31.42	32.83	32.25	33.56	37.16	42.20	49.15	49.39
Motor Gasoline	31.35	33.93	35.39	36.54	37.29	41.34	50.16	57.01	62.53	58.88
Jet Fuel	23.94	25.53	26.36	26.92	27.44	27.85	27.91	28.44	29.30	29.08
Distillate Fuel Oil	30.04	31.61	32.62	33.70	34.53	35.21	35.60	36.36	37.24	37.08
Natural Gas	9.87	9.76	14.47	14.42	14.43	14.41	14.42	14.46	14.60	14.71



Rhode Island Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	**0.003**
E85	0.049	0.114	0.149	0.173	0.175	0.137	0.164	0.194	0.256	0.257	**1.668**
Motor Gasoline	-0.081	-0.160	-0.209	-0.241	-0.266	-0.140	0.105	0.280	0.381	0.204	**-0.127**
Jet Fuel	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.002	-0.004	**-0.011**
Distillate Fuel Oil	-0.001	-0.002	-0.003	-0.004	-0.005	-0.007	-0.011	-0.012	-0.012	-0.016	**-0.073**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	**0.038**
Compressed Natural Gas	0.005	0.009	0.018	0.022	0.026	0.030	0.035	0.040	0.048	0.055	**0.288**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.028**	**-0.039**	**-0.041**	**-0.046**	**-0.066**	**0.024**	**0.297**	**0.507**	**0.677**	**0.502**	**1.787**

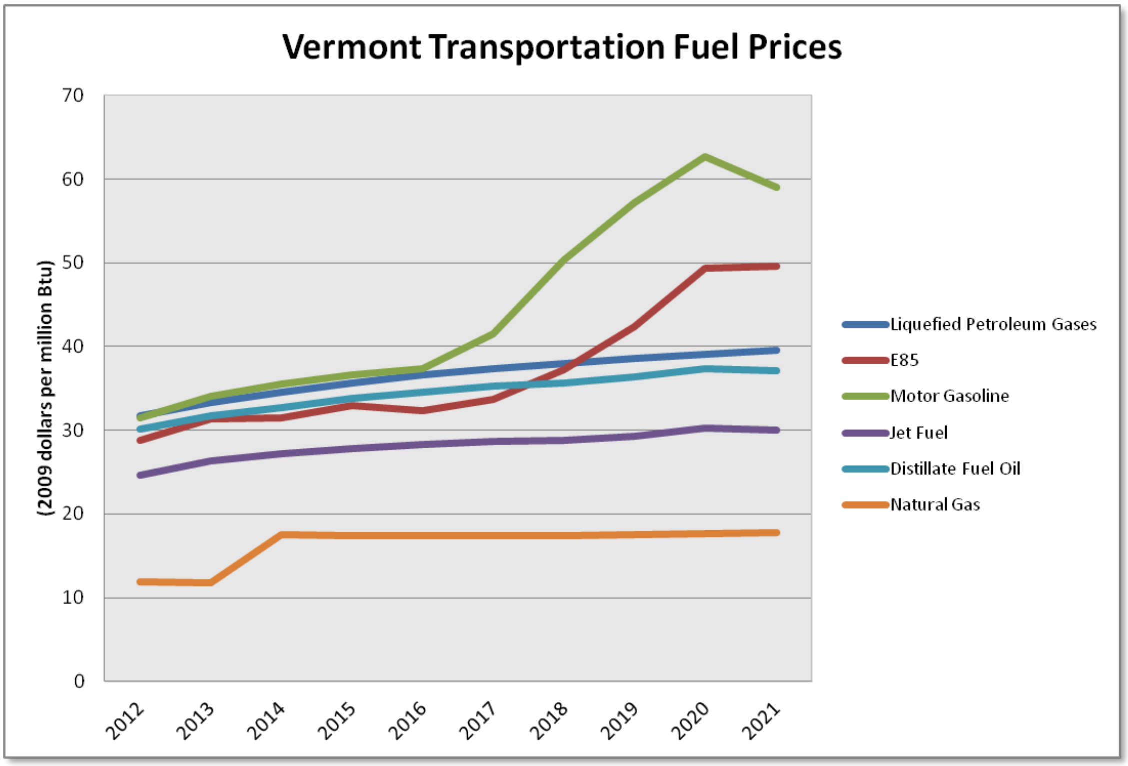


Vermont Transportation Fuel Consumption

(Trillion Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
E85 (Gasoline Only)	0.7	1.6	2.0	2.3	2.5	2.7	2.9	3.1	3.3	3.4
Motor Gasoline (Gasoline Only)	35.7	33.5	32.2	31.3	30.6	29.6	28.3	27.1	26.0	25.1
Jet Fuel	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Distillate Fuel Oil (Petroleum)	6.7	6.8	6.2	6.3	6.4	6.5	6.6	6.7	6.8	7.0
Residual Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Fuel Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compressed Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Domestic Ethanol/Corn-Based	2.7	3.5	4.0	4.0	4.3	4.3	4.1	3.9	4.0	4.1
Domestic Ethanol/Cellulose-Based	1.1	1.2	1.2	1.4	1.4	1.7	2.0	2.5	2.6	2.6
Import Ethanol/Cellulose-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import Ethanol/Sugarcane-Based	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Non-Virgin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biodiesel Virgin	2.4	2.5	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Steam Coal (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum (Gen Fuel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fossil Fuel (Gen Fuel)	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	51.9	51.8	51.5	51.4	51.2	50.8	50.1	49.4	48.8	48.5

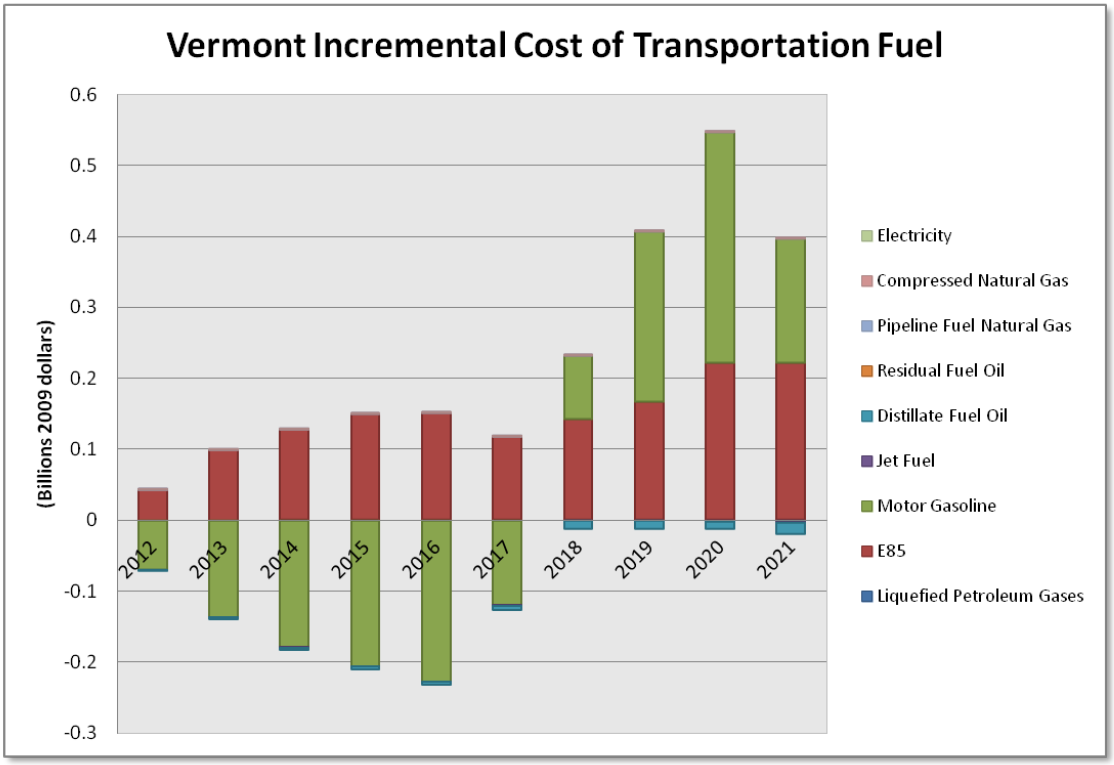
The Domestic Ethanol/Cellulose based fuel designation includes production from both cellulosic and advanced biofuels process technologies as included in the model. See full note with TABLE 4-3.



Vermont Transportation Fuel Prices

(2009 dollars per million Btu)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liquefied Petroleum Gases	31.70	33.37	34.54	35.59	36.62	37.34	37.93	38.54	39.08	39.54
E85	28.82	31.30	31.51	32.92	32.34	33.65	37.26	42.32	49.29	49.54
Motor Gasoline	31.44	34.03	35.49	36.64	37.40	41.46	50.31	57.18	62.71	59.05
Jet Fuel	24.69	26.32	27.17	27.75	28.29	28.71	28.78	29.32	30.21	29.98
Distillate Fuel Oil	30.09	31.67	32.68	33.75	34.59	35.27	35.66	36.42	37.30	37.14
Natural Gas	11.94	11.81	17.50	17.45	17.46	17.43	17.44	17.49	17.67	17.80



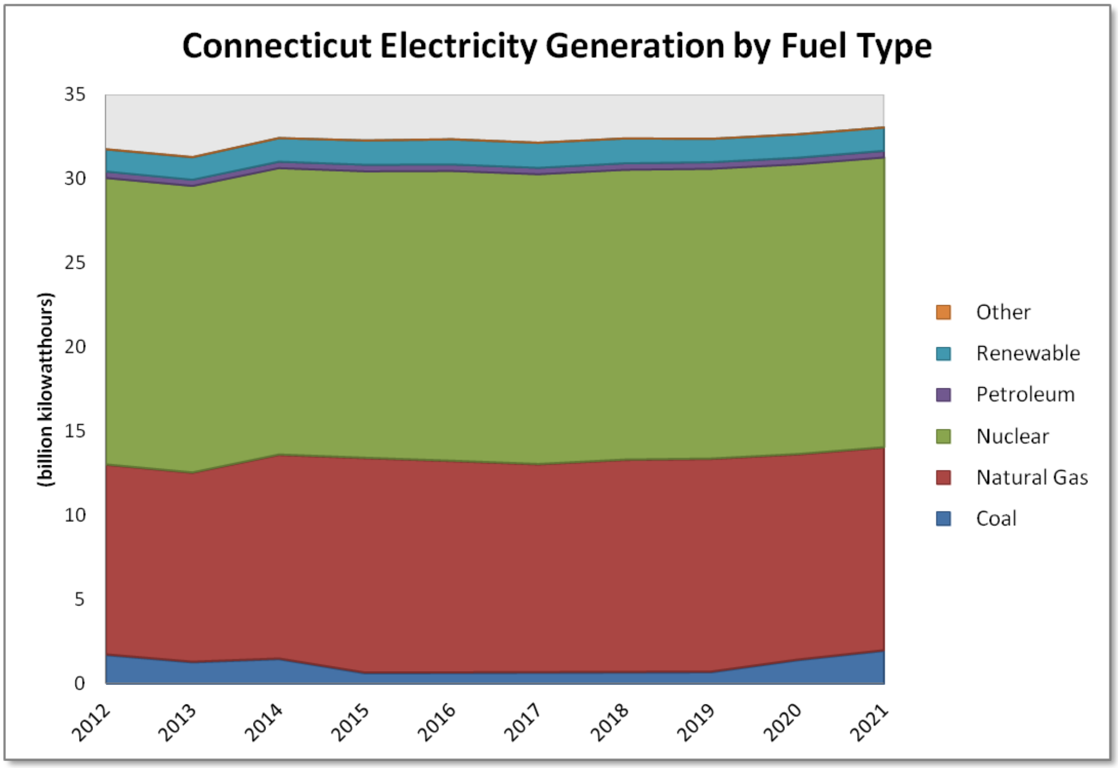
Vermont Incremental Cost of Transportation Fuel

(Billions 2009 dollars)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
Liquefied Petroleum Gases	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	**0.007**
E85	0.042	0.098	0.128	0.149	0.150	0.117	0.141	0.167	0.220	0.221	**1.434**
Motor Gasoline	-0.069	-0.136	-0.179	-0.206	-0.227	-0.119	0.090	0.239	0.325	0.174	**-0.108**
Jet Fuel	0.000	0.000	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.003	**-0.008**
Distillate Fuel Oil	-0.001	-0.002	-0.003	-0.004	-0.005	-0.006	-0.010	-0.011	-0.011	-0.016	**-0.071**
Residual Fuel Oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Pipeline Fuel Natural Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.001**
Compressed Natural Gas	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	**0.006**
Electricity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Grand Total	**-0.028**	**-0.040**	**-0.053**	**-0.060**	**-0.080**	**-0.007**	**0.221**	**0.395**	**0.534**	**0.379**	**1.261**

6.3 ELECTRICITY GENERATION BY STATE AND FUEL TYPE

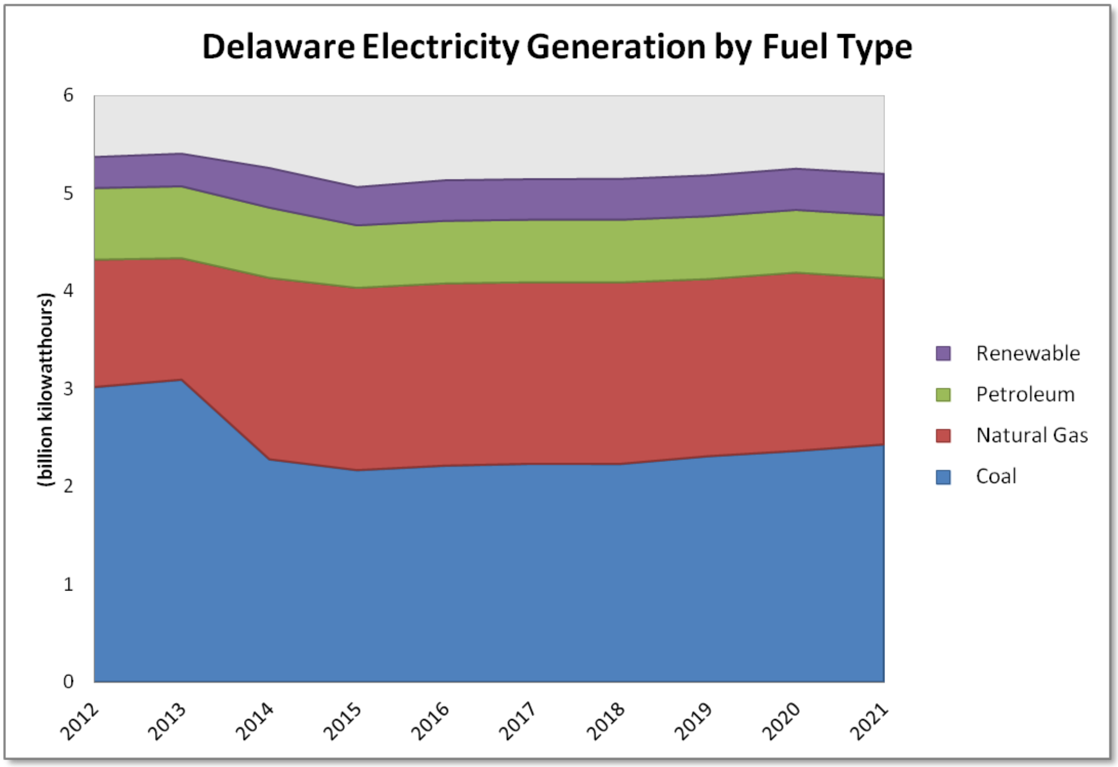
This section of the report provides state-by-state electricity generation by fuel type.



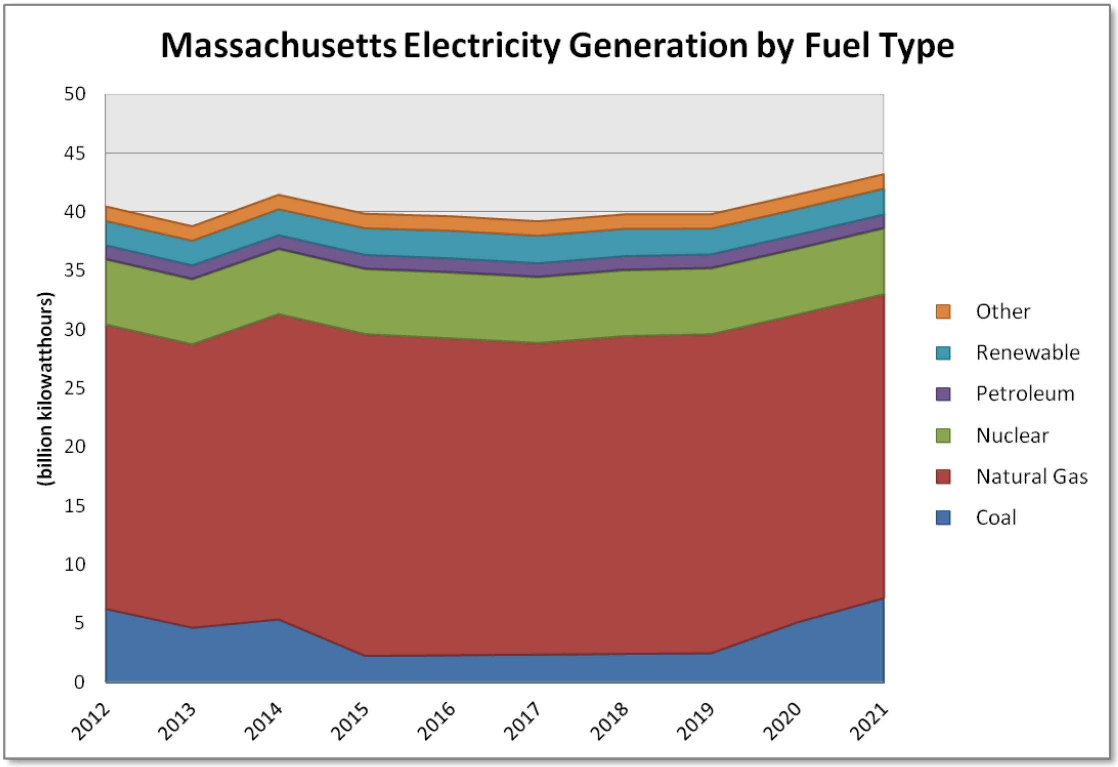
Connecticut Electricity Generation by Fuel Type

(billion kilowatthours)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	1.70	1.27	1.46	0.62	0.63	0.65	0.66	0.68	1.39	1.95
Natural Gas	11.31	11.27	12.15	12.80	12.60	12.39	12.64	12.69	12.24	12.09
Nuclear	17.04	17.04	17.04	17.04	17.24	17.24	17.24	17.24	17.24	17.24
Petroleum	0.39	0.38	0.38	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Renewable	1.30	1.32	1.38	1.42	1.47	1.47	1.46	1.37	1.37	1.37
Other	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Total	**31.73**	**31.27**	**32.40**	**32.25**	**32.33**	**32.12**	**32.38**	**32.35**	**32.62**	**33.02**



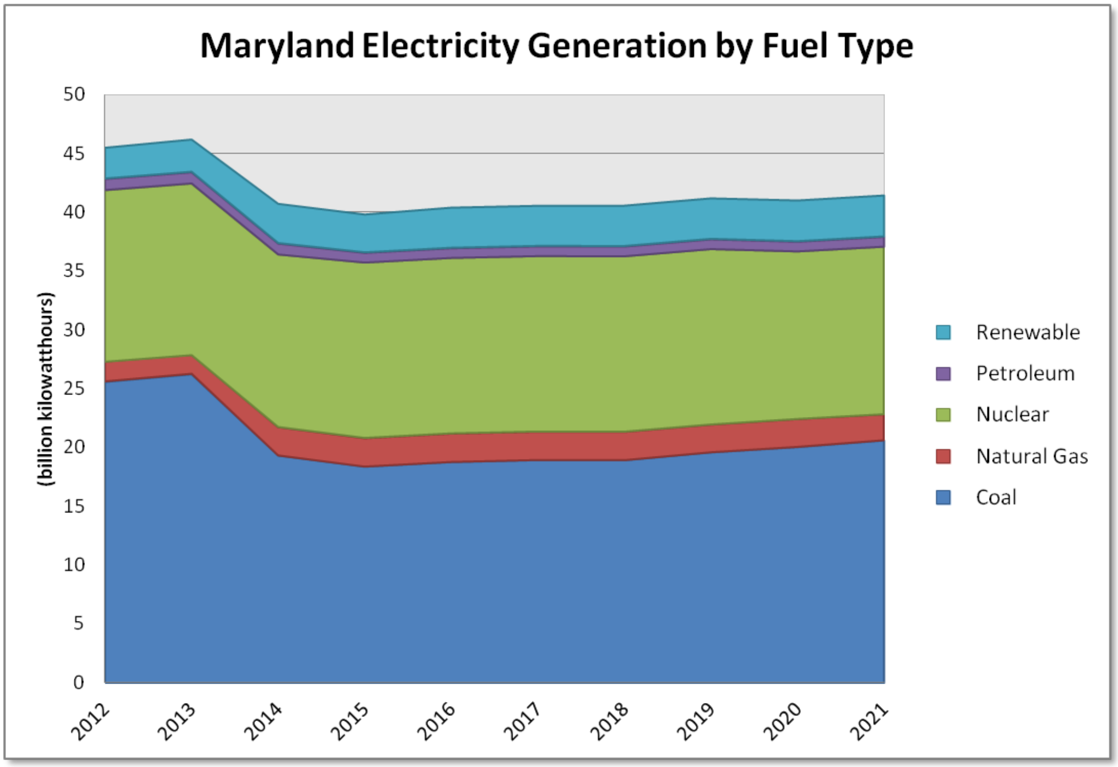
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	3.02	3.09	2.28	2.17	2.21	2.23	2.23	2.31	2.36	2.43
Natural Gas	1.30	1.24	1.86	1.87	1.87	1.86	1.86	1.81	1.83	1.70
Petroleum	0.73	0.73	0.72	0.64	0.64	0.64	0.64	0.64	0.64	0.65
Renewable	0.32	0.33	0.40	0.39	0.41	0.41	0.42	0.42	0.42	0.42
Total	5.37	5.40	5.26	5.06	5.13	5.14	5.15	5.18	5.25	5.20



Massachusetts Electricity Generation by Fuel Type

(billion kilowatthours)

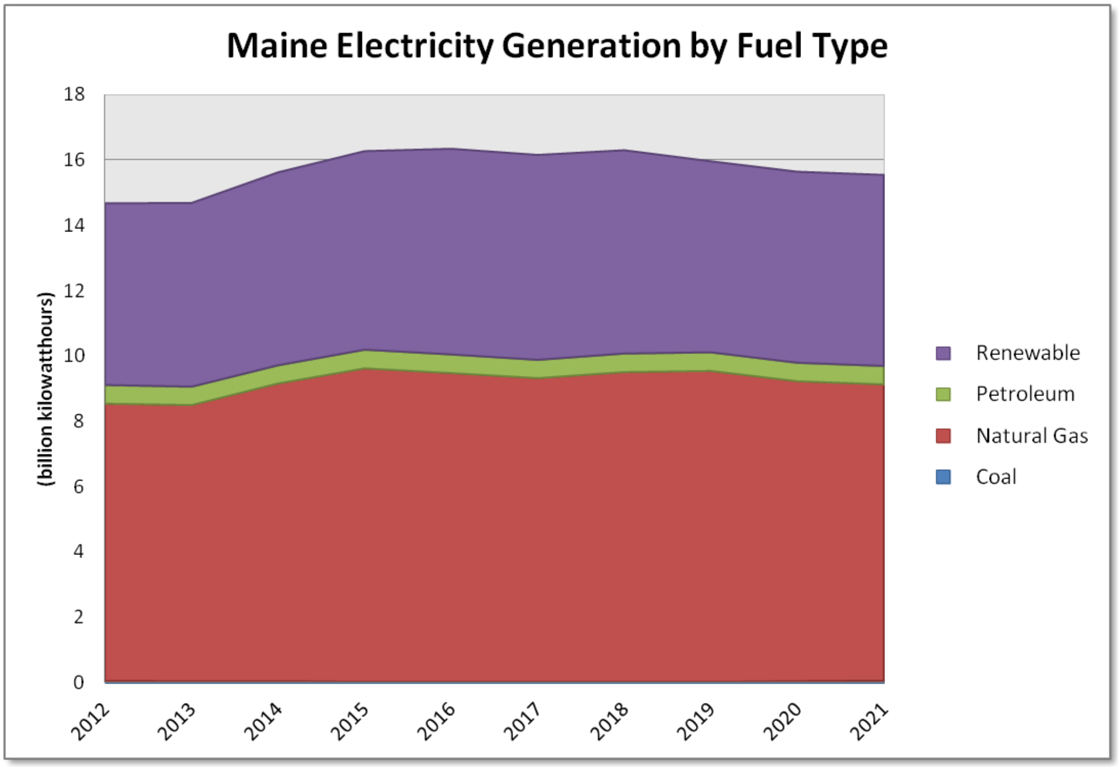
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	6.26	4.66	5.36	2.27	2.32	2.37	2.43	2.49	5.12	7.18
Natural Gas	24.20	24.11	25.99	27.38	26.96	26.52	27.05	27.15	26.19	25.87
Nuclear	5.52	5.52	5.52	5.52	5.58	5.58	5.58	5.58	5.58	5.58
Petroleum	1.17	1.16	1.15	1.18	1.18	1.16	1.17	1.17	1.16	1.16
Renewable	2.10	2.12	2.23	2.29	2.37	2.36	2.35	2.20	2.20	2.20
Other	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23
Total	**40.48**	**38.80**	**41.47**	**39.86**	**39.65**	**39.23**	**39.81**	**39.83**	**41.49**	**43.22**



Maryland Electricity Generation by Fuel Type

(billion kilowatthours)

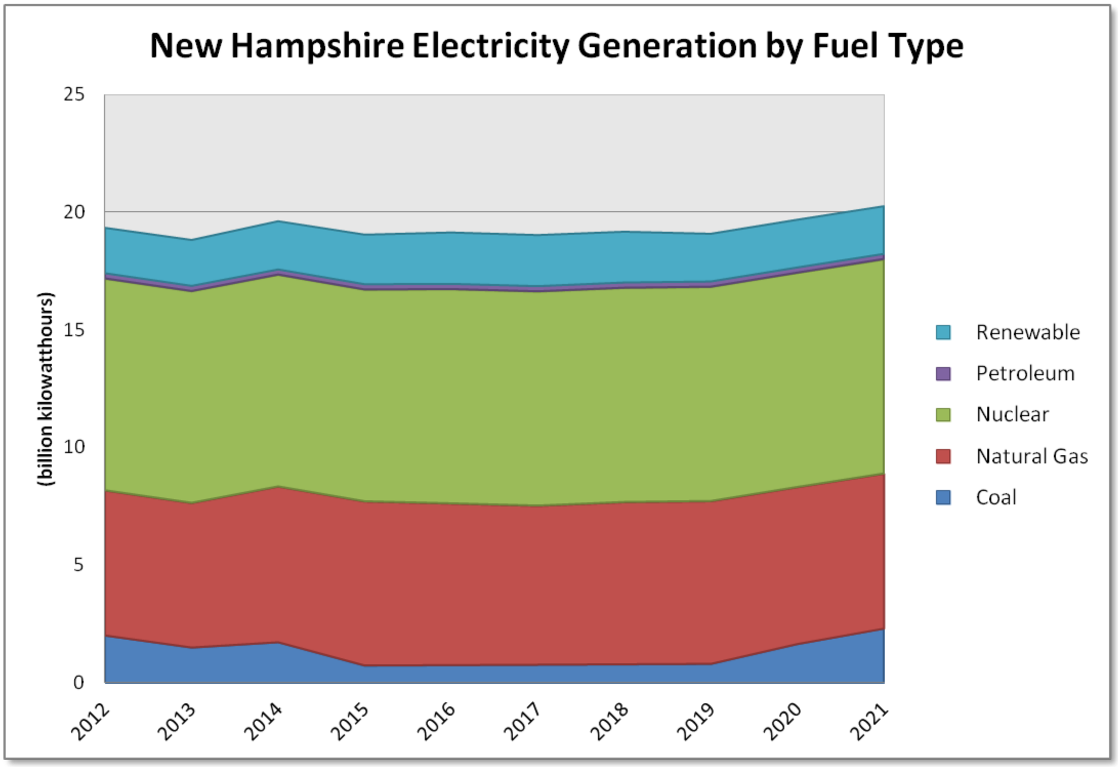
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	25.60	26.25	19.33	18.38	18.78	18.94	18.93	19.60	20.05	20.62
Natural Gas	1.68	1.60	2.39	2.40	2.40	2.39	2.39	2.33	2.34	2.19
Nuclear	14.63	14.63	14.72	14.96	14.96	14.96	14.96	14.96	14.29	14.29
Petroleum	0.94	0.94	0.92	0.82	0.82	0.82	0.82	0.82	0.82	0.82
Renewable	2.61	2.74	3.33	3.22	3.41	3.40	3.43	3.44	3.46	3.48
Total	45.45	46.15	40.68	39.78	40.36	40.52	40.53	41.15	40.97	41.39



Maine Electricity Generation by Fuel Type

(billion kilowatthours)

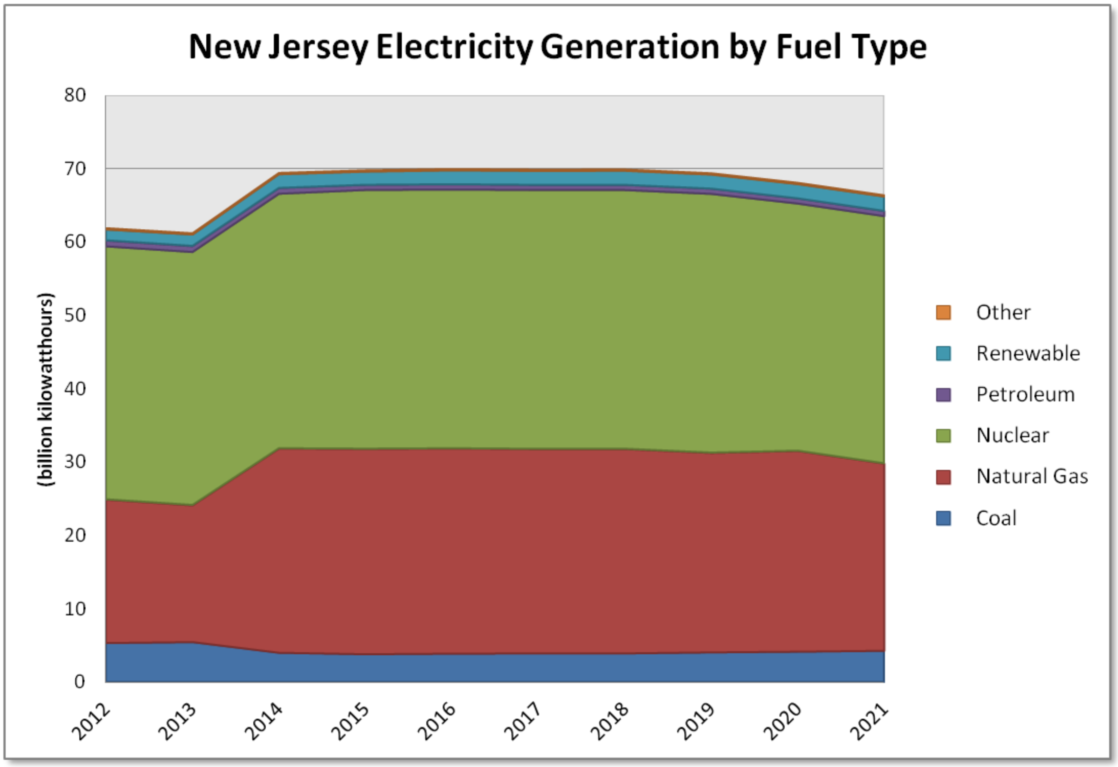
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	0.05	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.04	0.06
Natural Gas	8.48	8.45	9.11	9.59	9.45	9.29	9.48	9.51	9.18	9.07
Petroleum	0.57	0.56	0.55	0.57	0.57	0.56	0.57	0.57	0.56	0.56
Renewable	5.58	5.64	5.92	6.09	6.31	6.29	6.24	5.86	5.86	5.86
Total	14.67	14.69	15.63	16.28	16.35	16.16	16.30	15.96	15.64	15.55



New Hampshire Electricity Generation by Fuel Type

(billion kilowatthours)

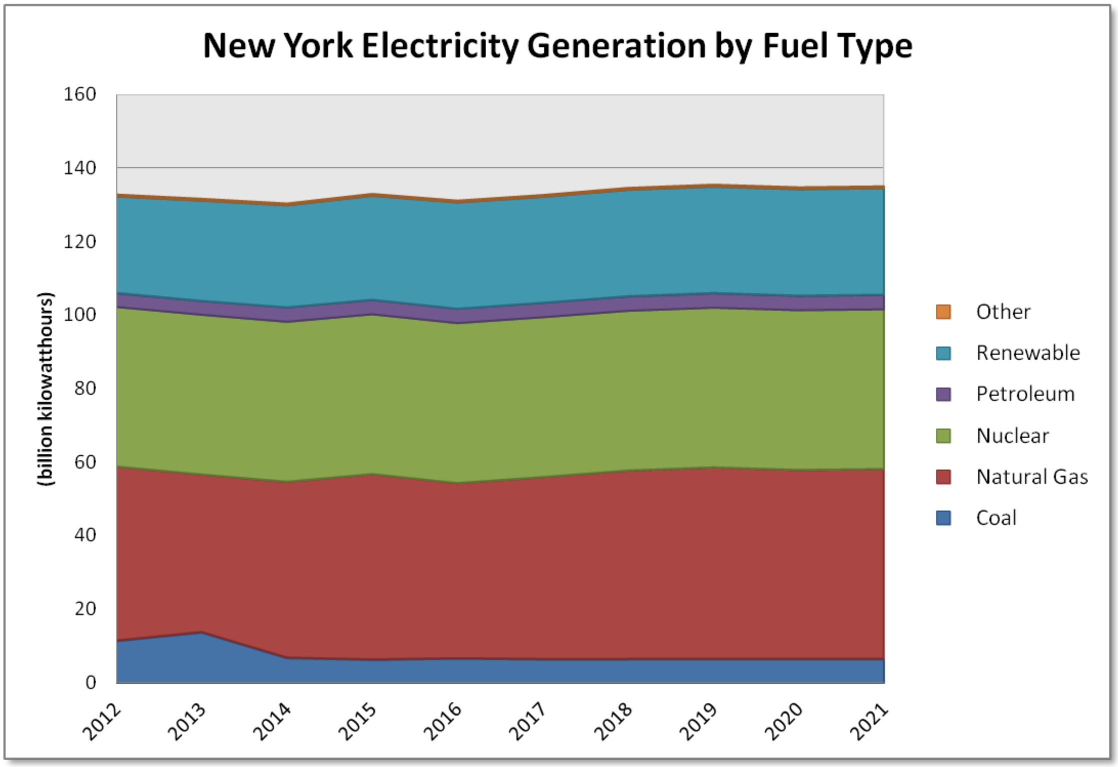
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	2.00	1.49	1.71	0.72	0.74	0.76	0.78	0.79	1.64	2.29
Natural Gas	6.16	6.14	6.61	6.97	6.86	6.75	6.89	6.91	6.67	6.58
Nuclear	9.02	9.02	9.02	9.02	9.12	9.12	9.12	9.12	9.12	9.12
Petroleum	0.24	0.24	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Renewable	1.93	1.95	2.05	2.11	2.18	2.18	2.16	2.03	2.03	2.03
Total	19.35	18.83	19.63	19.06	19.15	19.04	19.18	19.10	19.69	20.27



New Jersey Electricity Generation by Fuel Type

(billion kilowatthours)

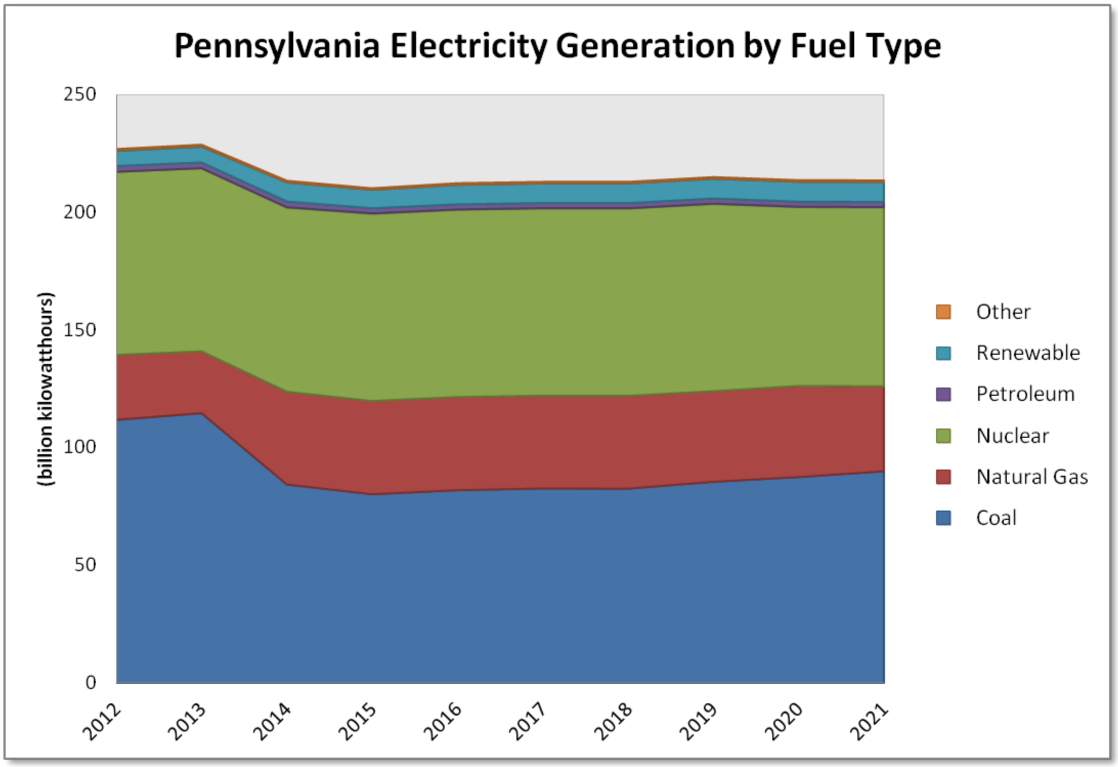
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	5.40	5.54	4.08	3.88	3.96	4.00	4.00	4.14	4.23	4.35
Natural Gas	19.54	18.63	27.84	27.97	27.95	27.84	27.85	27.19	27.35	25.51
Nuclear	34.52	34.52	34.73	35.30	35.30	35.30	35.30	35.30	33.72	33.72
Petroleum	0.79	0.79	0.77	0.69	0.69	0.69	0.69	0.69	0.69	0.69
Renewable	1.48	1.55	1.89	1.82	1.93	1.93	1.95	1.95	1.96	1.97
Other	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Total	**61.92**	**61.22**	**69.49**	**69.85**	**70.02**	**69.94**	**69.96**	**69.44**	**68.14**	**66.43**



New York Electricity Generation by Fuel Type

(billion kilowatthours)

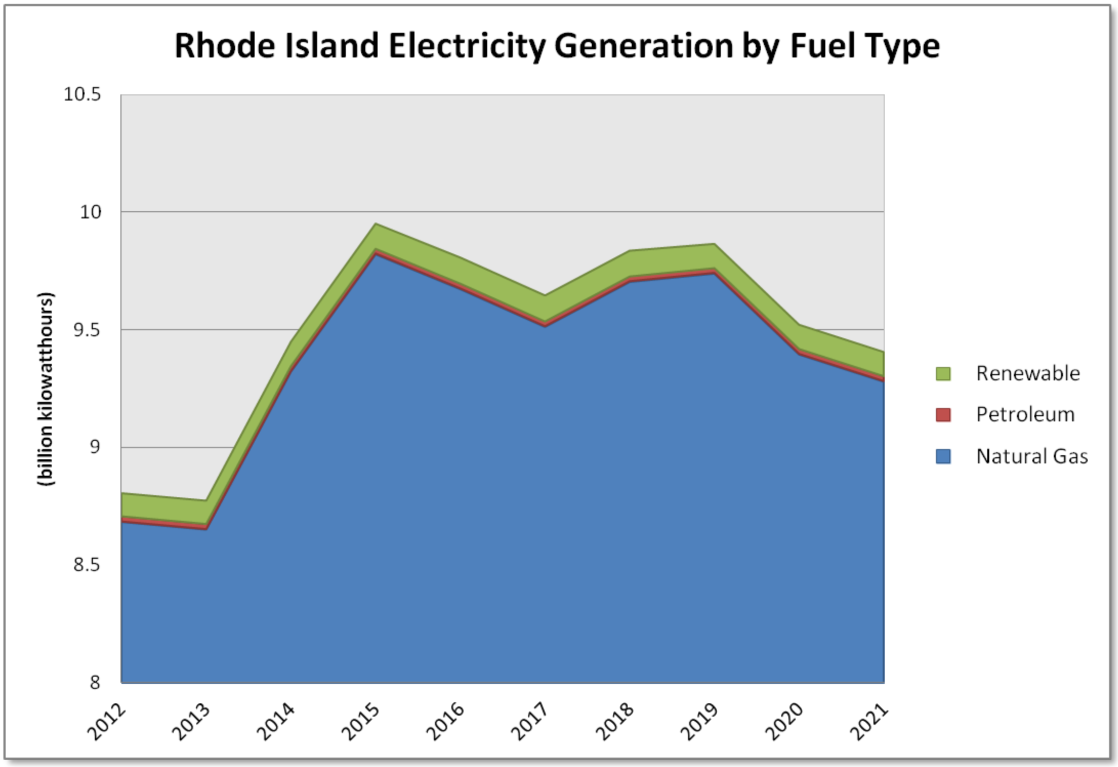
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	11.34	13.66	6.71	6.22	6.56	6.33	6.35	6.36	6.36	6.35
Natural Gas	47.34	42.85	47.83	50.42	47.62	49.48	51.25	52.10	51.40	51.66
Nuclear	43.58	43.58	43.58	43.58	43.58	43.58	43.58	43.58	43.58	43.58
Petroleum	3.80	3.79	3.98	3.98	3.97	3.98	3.98	3.99	3.98	3.98
Renewable	26.27	27.29	27.80	28.31	28.96	28.84	28.97	28.97	28.97	28.98
Other	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Total	**132.78**	**131.64**	**130.36**	**132.96**	**131.15**	**132.67**	**134.59**	**135.45**	**134.75**	**135.01**



Pennsylvania Electricity Generation by Fuel Type

(billion kilowatthours)

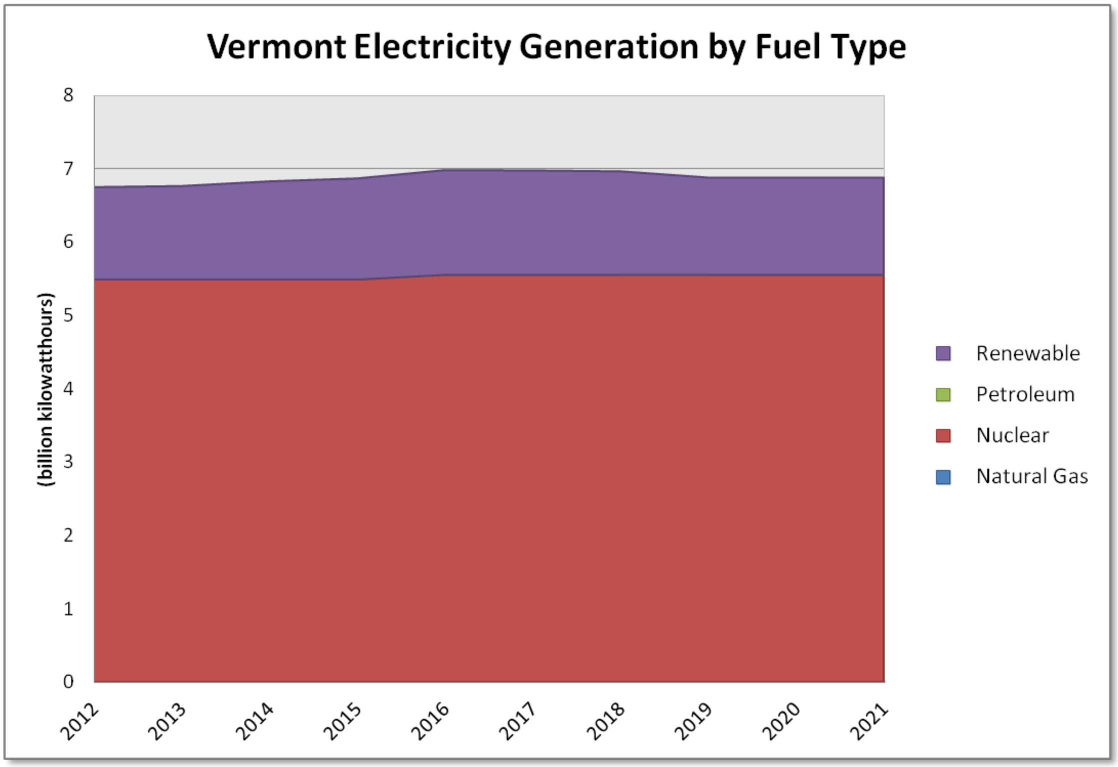
Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	111.76	114.57	84.37	80.25	81.96	82.69	82.63	85.54	87.54	89.99
Natural Gas	27.68	26.40	39.43	39.62	39.60	39.44	39.45	38.51	38.74	36.14
Nuclear	77.77	77.77	78.22	79.52	79.52	79.52	79.52	79.52	75.95	75.95
Petroleum	2.59	2.60	2.55	2.27	2.27	2.27	2.28	2.28	2.28	2.29
Renewable	6.42	6.73	8.20	7.91	8.38	8.37	8.45	8.46	8.51	8.55
Other	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.66
Total	**226.88**	**228.72**	**213.42**	**210.22**	**212.38**	**212.95**	**212.96**	**214.96**	**213.67**	**213.58**



Rhode Island Electricity Generation by Fuel Type

(billion kilowatthours)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Natural Gas	8.68	8.65	9.32	9.82	9.67	9.51	9.71	9.74	9.40	9.28
Petroleum	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Renewable	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.10	0.10	0.10
Total	8.81	8.77	9.45	9.95	9.81	9.65	9.84	9.87	9.52	9.41



Vermont Electricity Generation by Fuel Type

(billion kilowatthours)

Fuel Type	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Natural Gas	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Nuclear	5.48	5.48	5.48	5.48	5.55	5.55	5.55	5.55	5.55	5.55
Petroleum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable	1.26	1.27	1.34	1.37	1.42	1.42	1.41	1.32	1.32	1.32
Total	6.75	6.76	6.83	6.87	6.98	6.98	6.96	6.88	6.88	6.88

6.4 ALLOCATION OF IMPLIED VEHICLE SUBSIDIES AND INCREMENTAL INFRASTRUCTURE COSTS TO STATES

Allocation of implied vehicle subsidies and incremental infrastructure costs to the various states within each region was accomplished by multiplying the incremental cost associated with each fuel type by the share of regional consumption represented by each state. Consumption data came from the State Energy Data System (SEDS), and the average consumption over the most recent five-year period was used to characterize each state's share. This is based on the implicit assumption that historical fuel use patterns will remain static over the forecast period. Therefore, results are proportional to the transportation energy needs and travel demands of each state. Results do not take into consideration any potential demographic shifts in each region, which could alter these estimates.

The following sets of charts depict the incremental financial impacts on each state under the two policy scenarios by reference to their respective baseline scenarios. The Vehicle Subsidies and Infrastructure Costs are presented in separate graphs because of the difference in scale.

The first collection of charts shows the incremental impact of the AllNOCAFE54HOP scenario relative to the Baseline scenario.

FIGURE 6-1: VEHICLE SUBSIDIES – NEW ENGLAND STATES

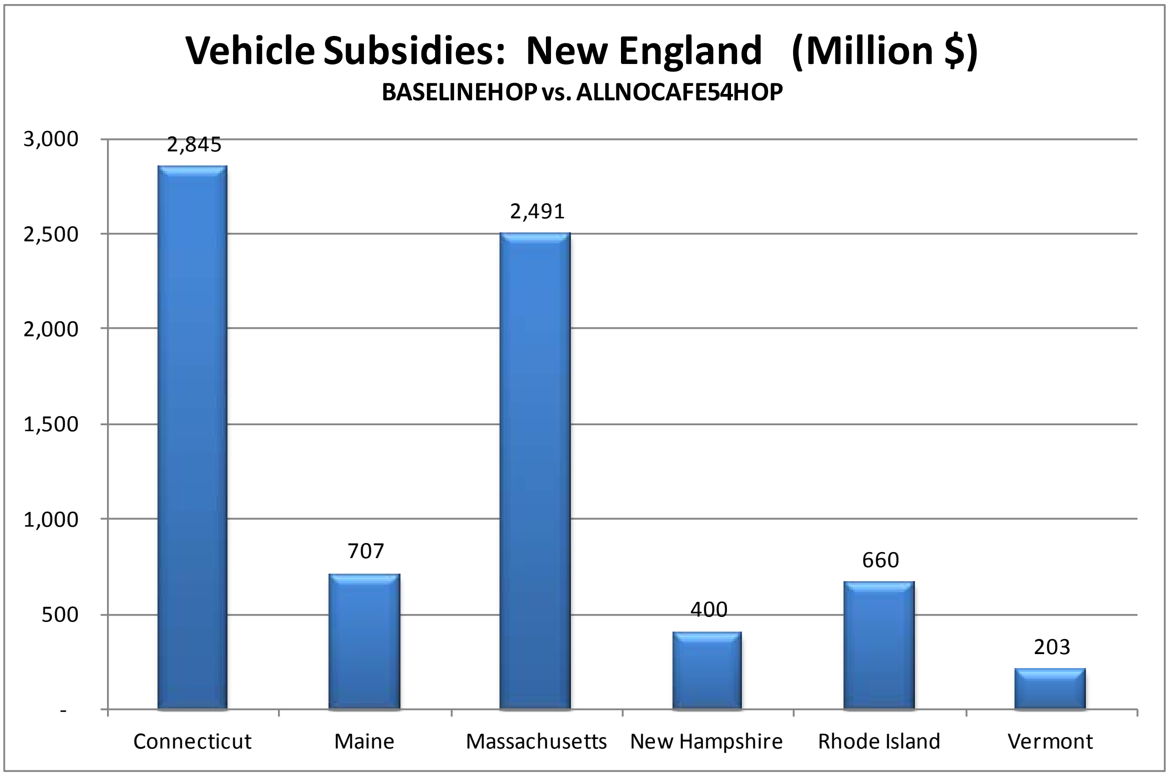


FIGURE 6-2: INFRASTRUCTURE COSTS – NEW ENGLAND STATES

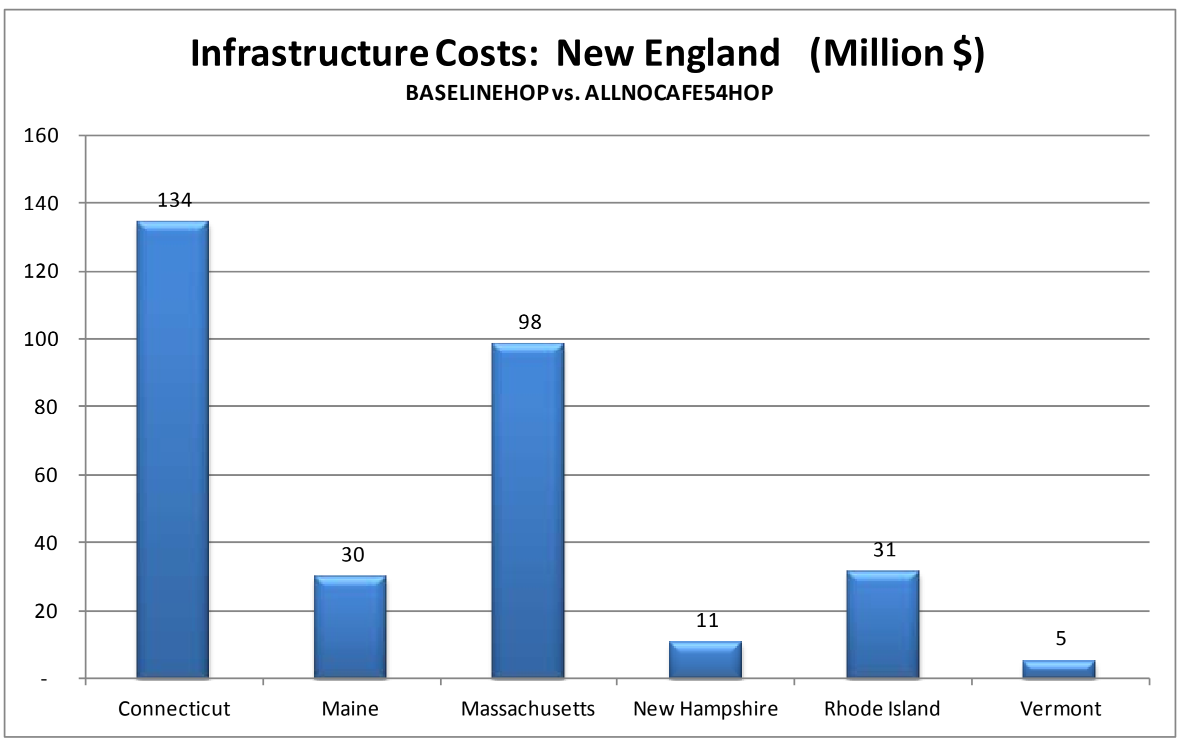


FIGURE 6-3: VEHICLE SUBSIDIES – MID-ATLANTIC STATES

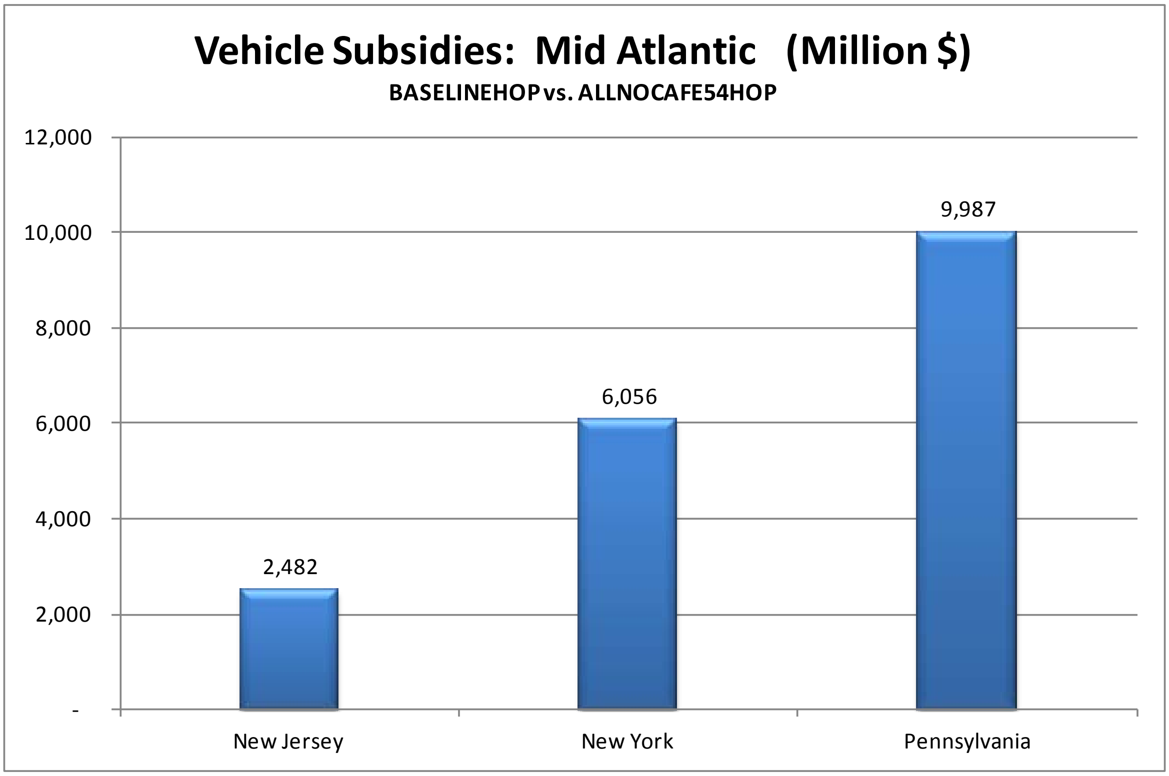


FIGURE 6-4: INFRASTRUCTURE COSTS – MID-ATANTIC STATES

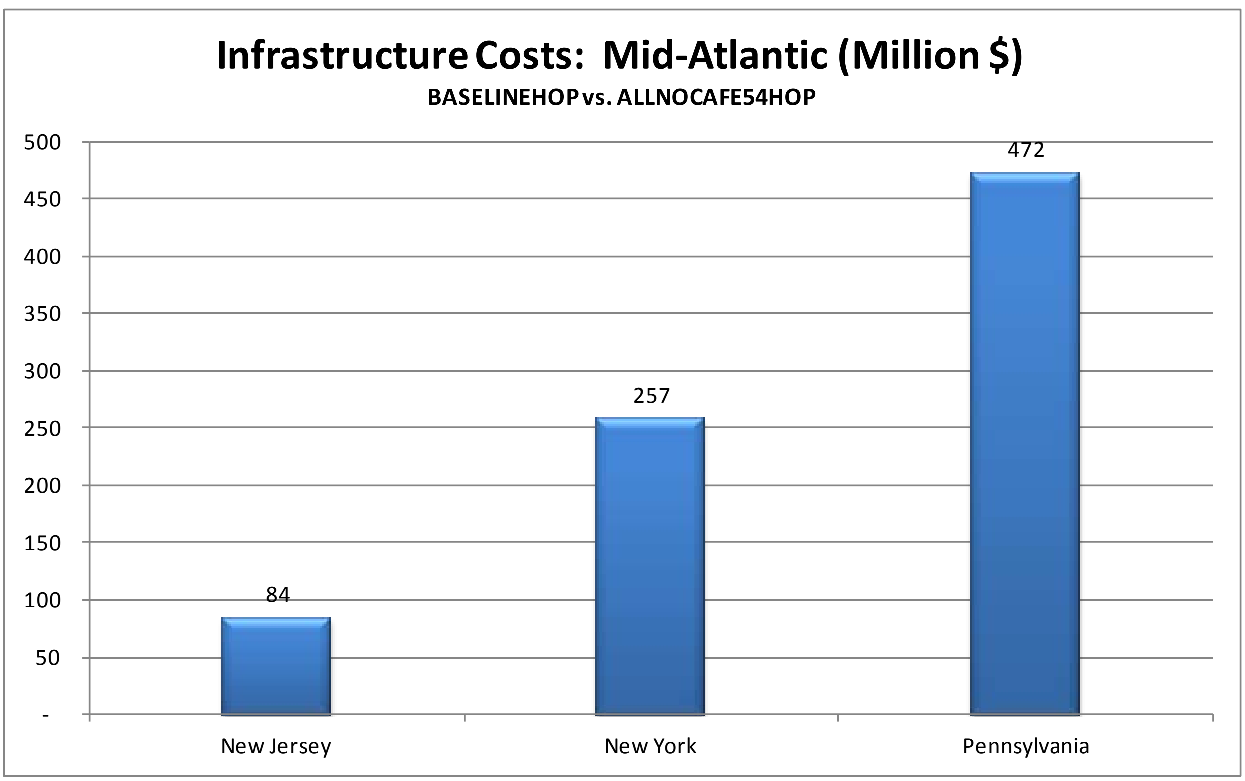


FIGURE 6-5: VEHICLE SUBSIDIES – DELAWARE AND MARYLAND

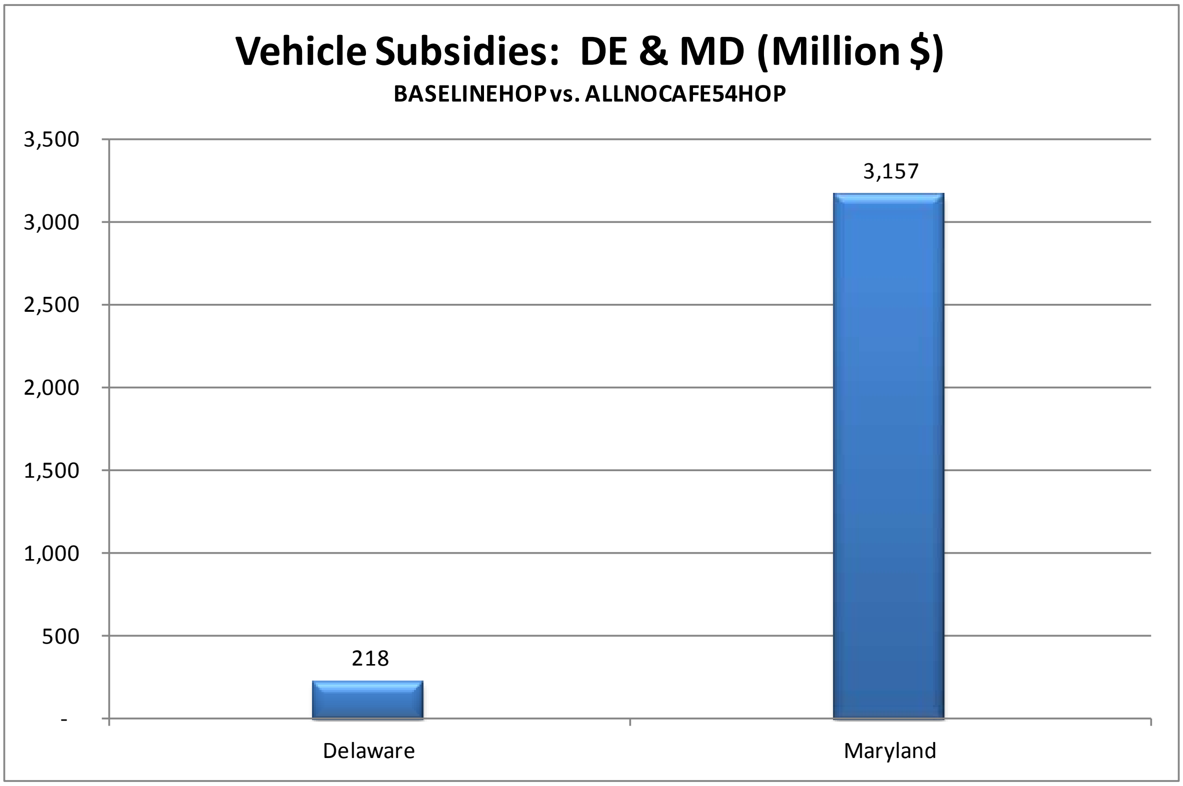
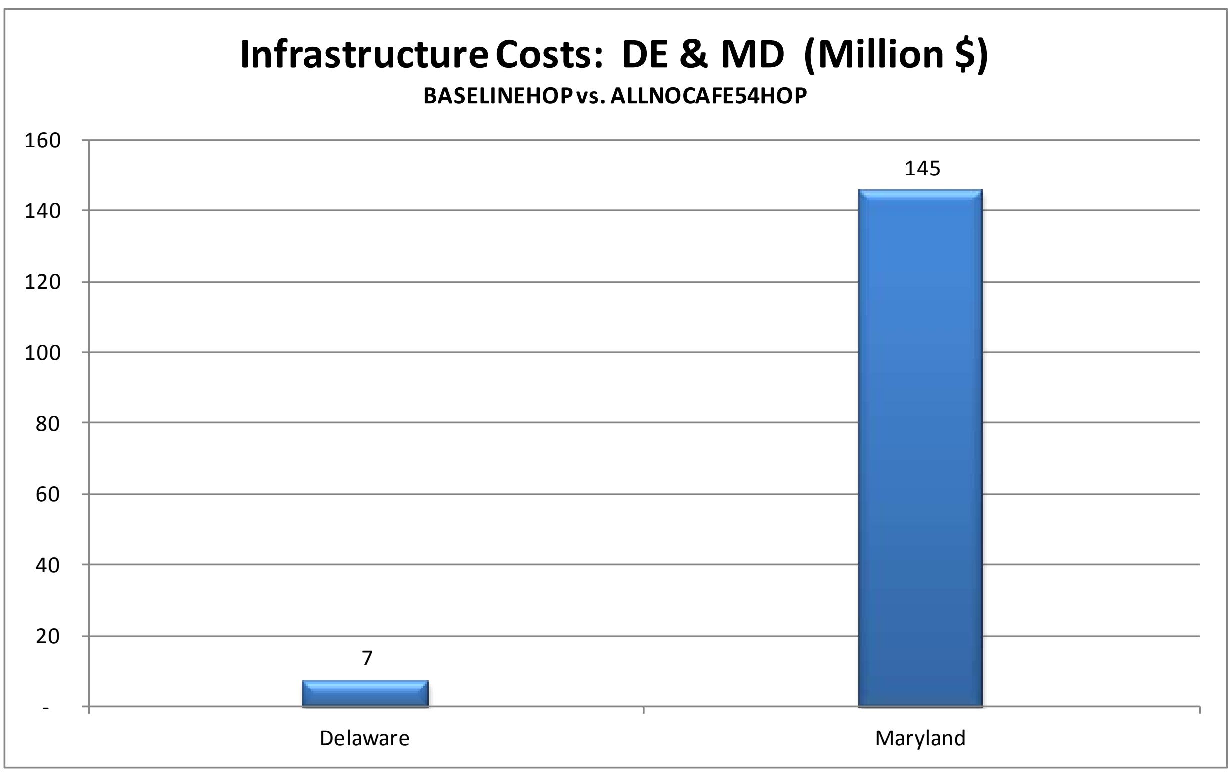
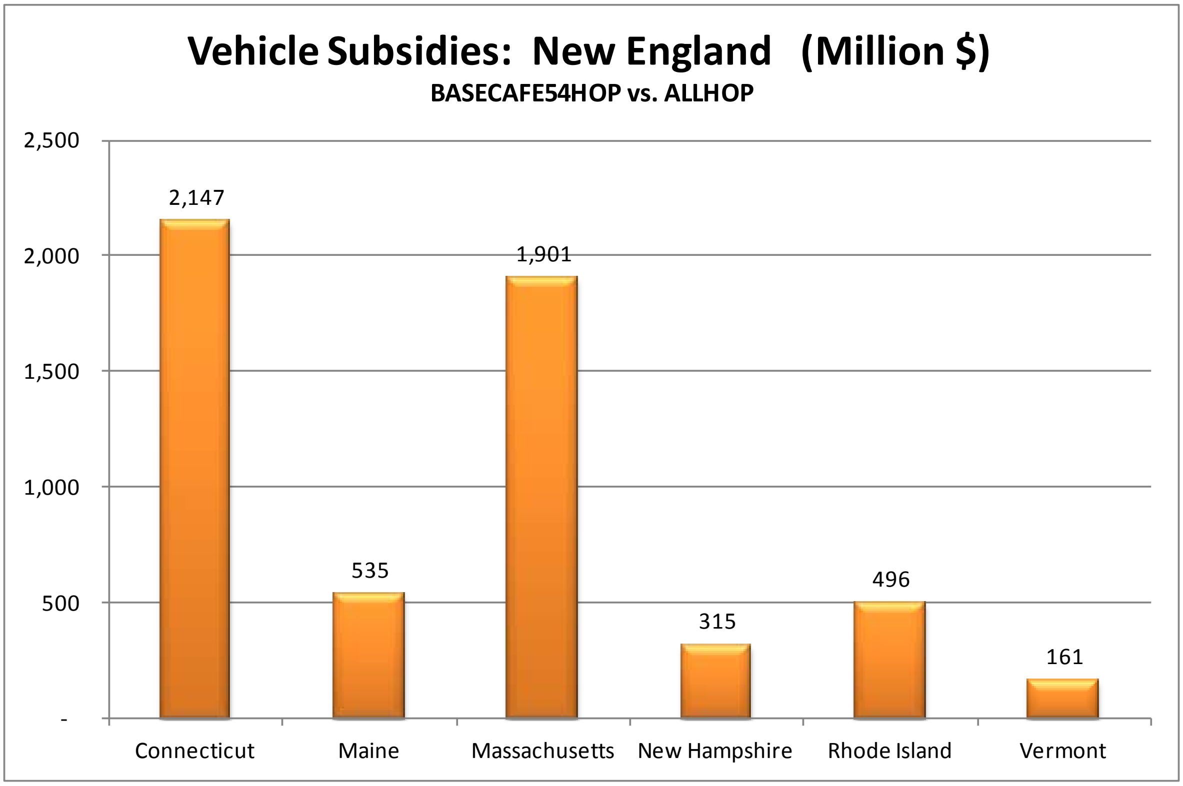
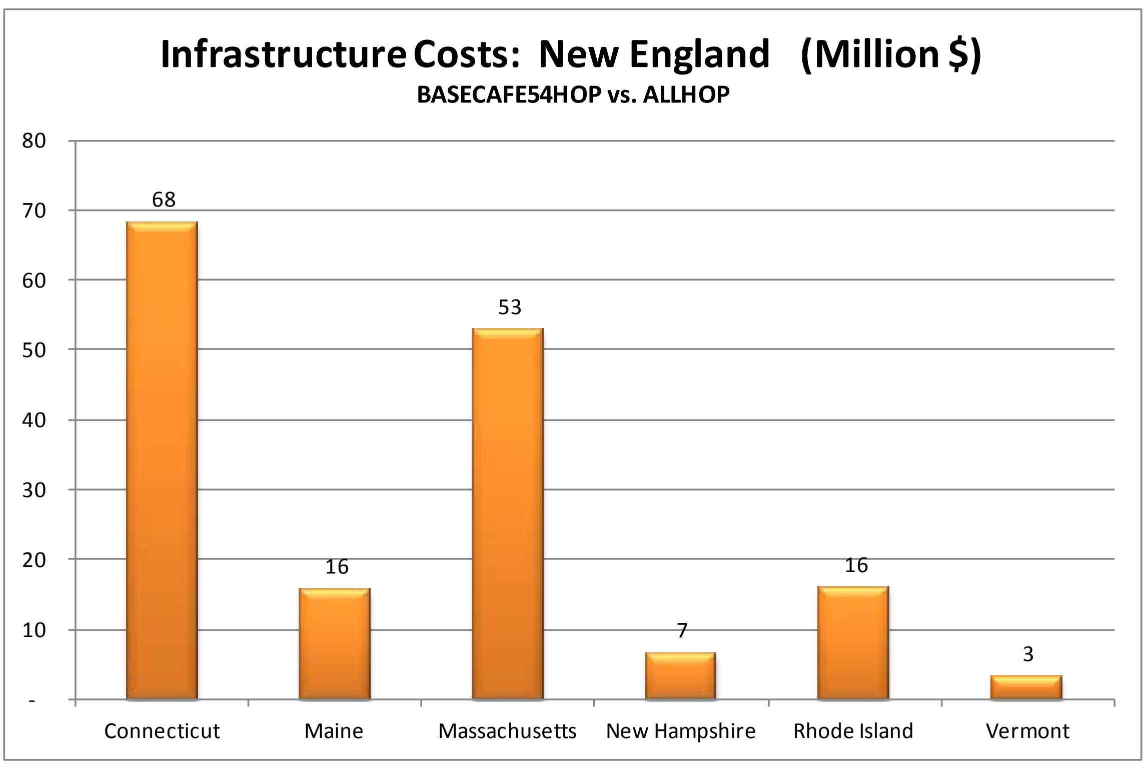


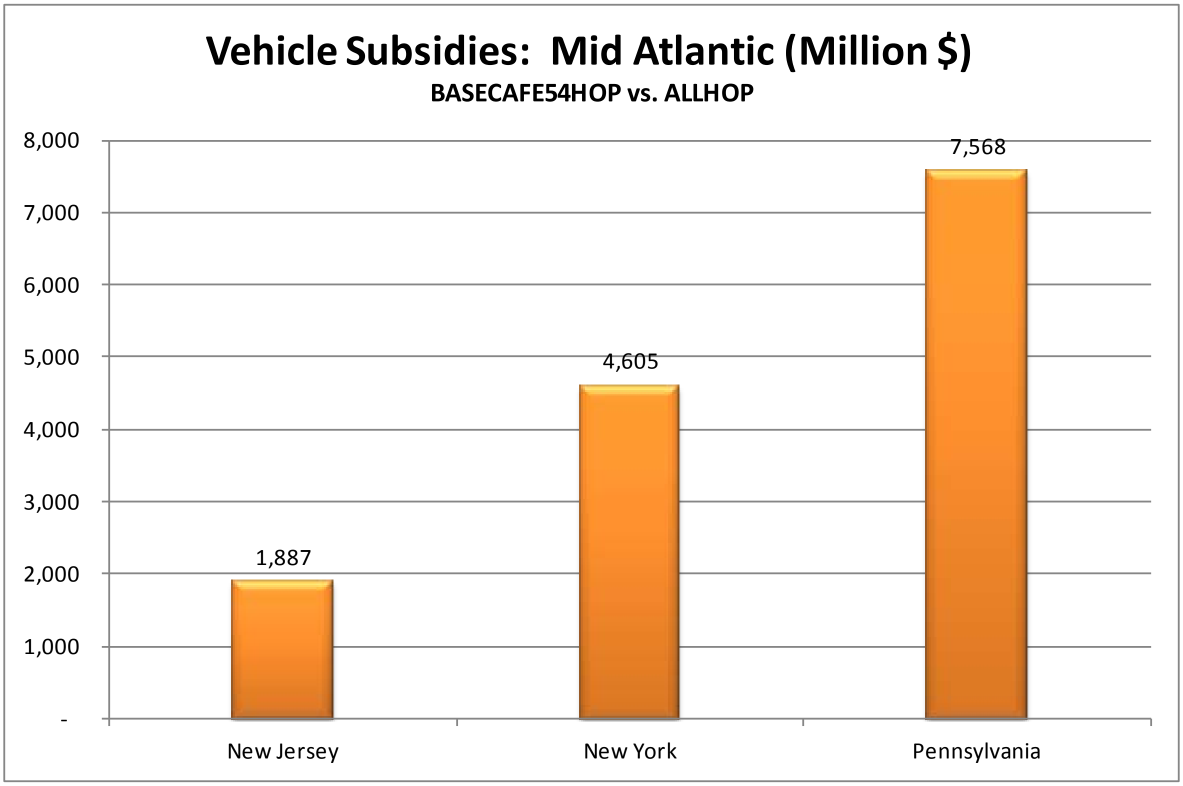
FIGURE 6-6: INFRASTRUCTURE COSTS – DELAWARE AND MARYLAND



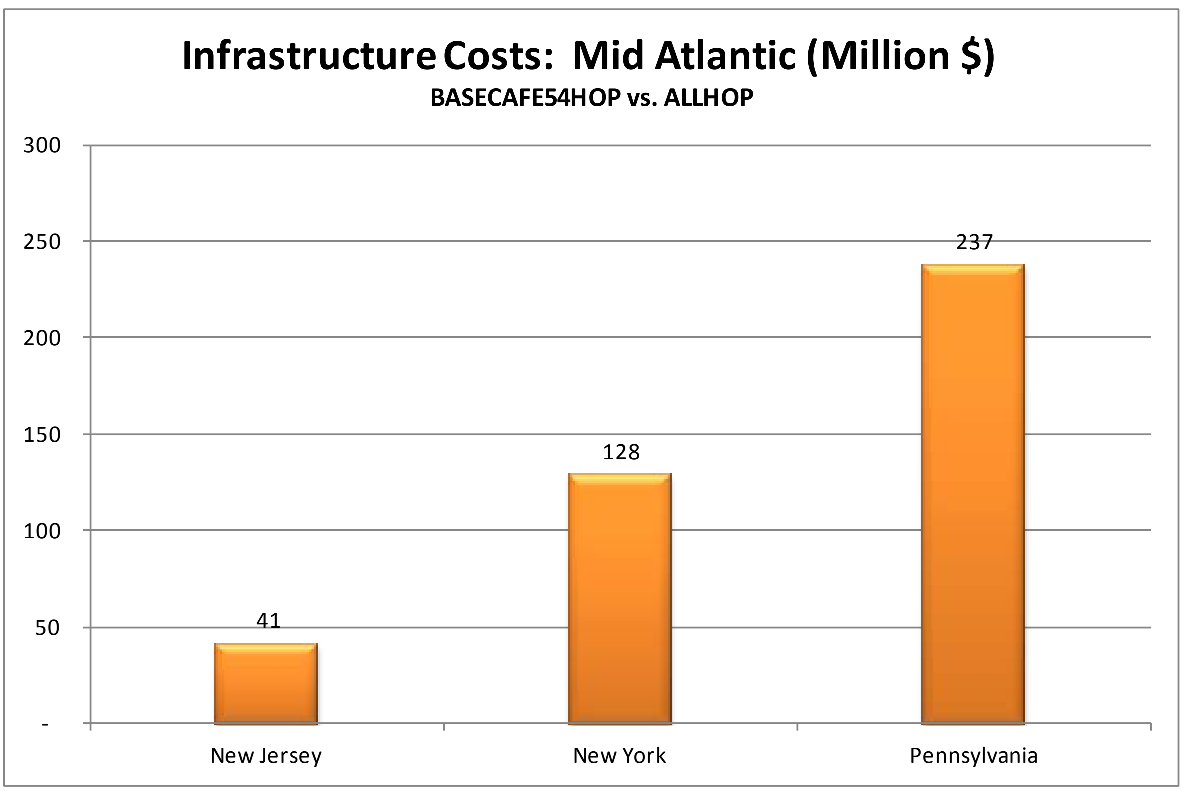
The second collection of charts shows the incremental impact of the ALLHOP scenario relative to the BASECAFE54HOP scenario.



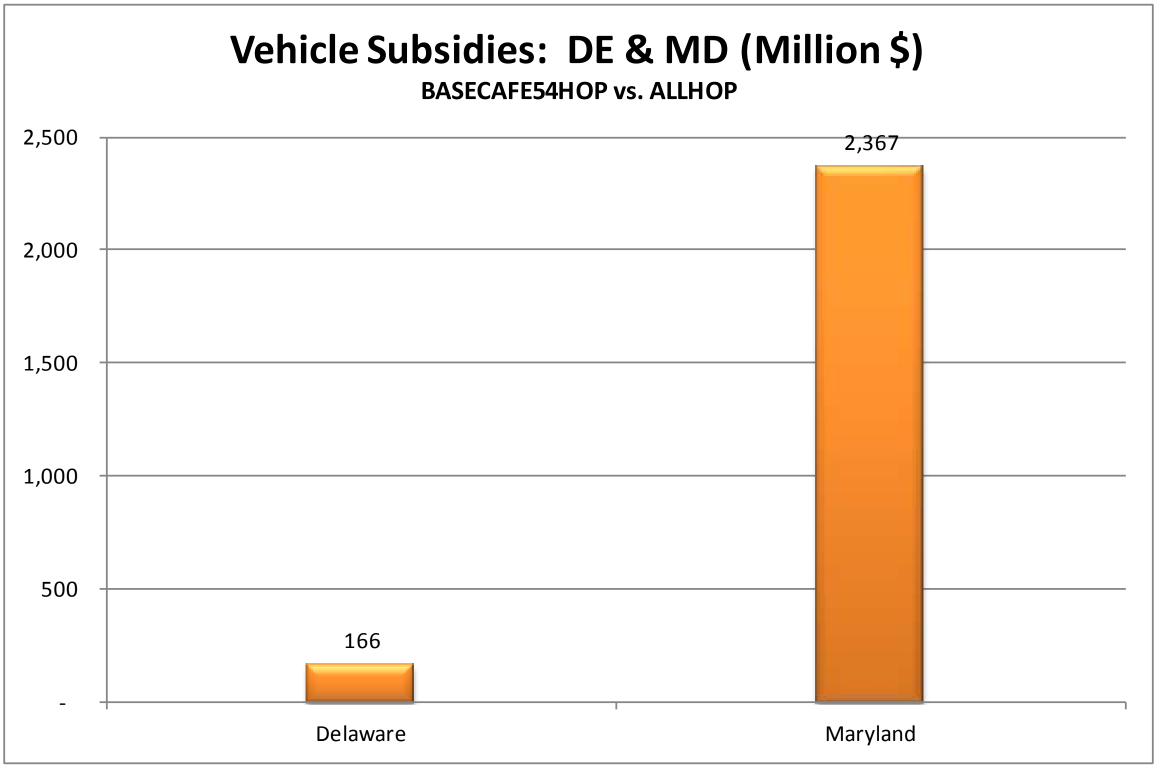


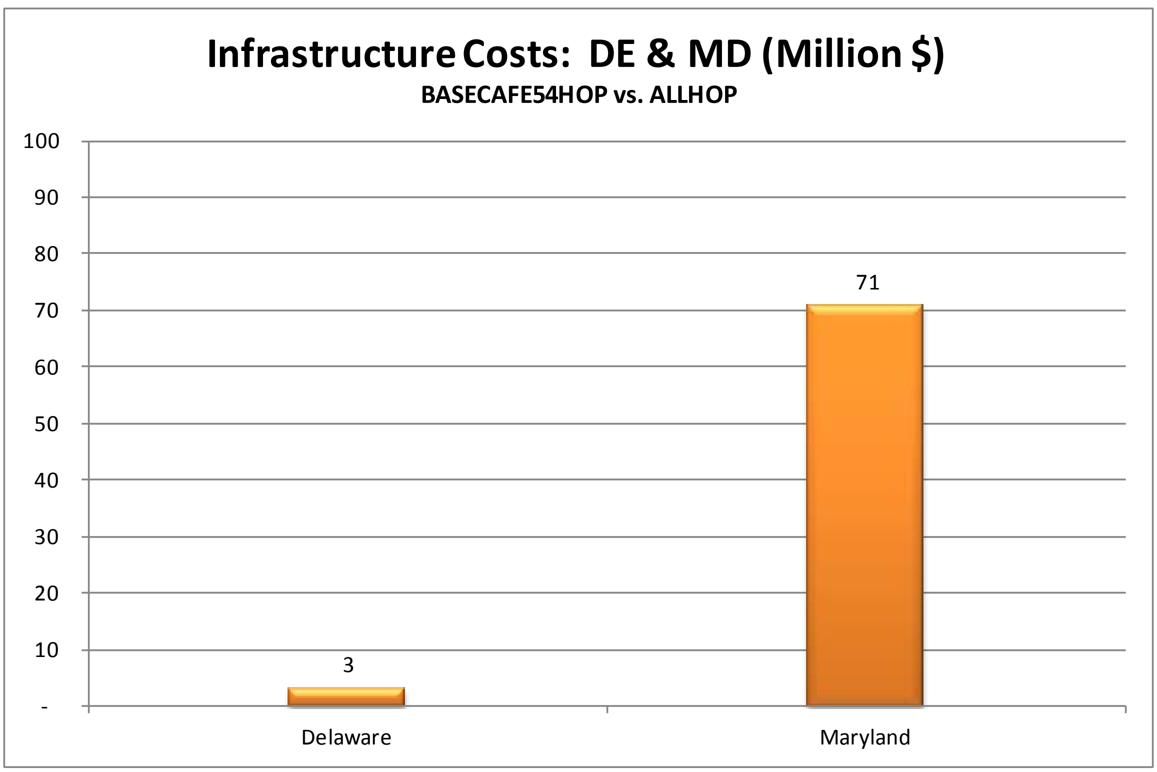


Vehicle Subsidies: Mid Atlantic (Million $)
BASECAFE54HOP vs. ALLHOP
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1,887
4,605
7,568
New Jersey
New York
Pennsylvania



Infrastructure Costs: Mid Atlantic (Million $)
BASECAFE54HOP vs. ALLHOP
300
250
200
150
100
50
-
41
128
237
New Jersey
New York
Pennsylvania


Vehicle Subsidies: DE & MD (Million $)
BASECAFE54HOP vs. ALLHOP
2,500
2,000
1,500
1,000
500
-
166
2,367
Delaware
Maryland


Infrastructure Costs: DE & MD (Million $)
BASECAFE54HOP vs. ALLHOP
100
90
80
70
60
50
40
30
20
10
-
3
71
Delaware
Maryland