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Introducing a Low Carbon Fuel Standard in the Northeast

Technical and Policy Considerations

Prepared by

NESCCAF
Northeast States Center for a Clean Air Future

January 2009

NORTHEAST STATES CENTER FOR A CLEAN AIR FUTURE

Board of Directors

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Acknowledgments

NESCCAF gratefully acknowledges the generous support provided by the Energy Foundation and by the William and Flora Hewlett Foundation for this research. NESCCAF appreciates the thoughtful input provided by the Research Advisory Group established as part of the Low Carbon Fuel Standard project. The Advisory Group provided input while the analyses for this project were being conducted and during the development of this report. Members of the Advisory Group include: Anthony Eggert (CARB), Rebecca Ohler (New Hampshire DES), Robert Judge (EPA), Carl Mas (NYSERDA), Christina Zhang-Tillman (CARB), Daniel Sperling (UC Davis), Dean Simeroth (CARB), Ellen Shapiro (AIAM), Eric Kingsley (Innovative Natural Resource Solutions), John Gorgol (New Jersey DEP), Nancy Seidman (Massachusetts DEP), Nathanael Greene (NRDC), Roger L. Leisenring, Jr. (Sunoco), Serpil Guran (New Jersey DEP), Sonia Yeh (UC Davis), Stephen Shaler (University of Maine), Steven Levy (Sprague Energy), William Space (Massachusetts DEP). NESCCAF would also like to thank the NESCAUM Mobile Source Committee and Heavy-Duty Workgroup, and the NESCCAF Directors for their assistance during this project. In addition, NESCCAF gratefully acknowledges the individuals who reviewed drafts of technical documents and the final report for this project. Among them, we especially thank Anant Vyas from Argonne National Laboratory who reviewed a draft of the VISION-NE model for NESCCAF. Luke Tonachel (NRDC), and Bill Boyce (SMUD) provided advice and valuable input on the scenario analysis and program structure. Finally, NESCCAF thanks members of industry for their thoughtful input throughout this process.

Printed: January 2009

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Executive Summary

ES-1 Overview

NESCCAF has undertaken a preliminary assessment of the merits of a low carbon fuel standard (LCFS) for the northeastern states. As part of this assessment, NESCCAF estimated the amount of low carbon fuels that would be needed to meet a low carbon fuel standard in the Northeast, evaluated the potential to generate regionally-derived low carbon fuels, and explored program implementation strategies and issues. The results are presented in this report, which is intended to assist the region's policymakers as they evaluate programs and options for reducing greenhouse gas (GHG) emissions from the transportation sector.

Motor vehicles and nonroad equipment account for about 40 percent of total anthropogenic GHG emissions in the Northeast. Climate experts believe that by mid-century, manmade GHG emissions will need to be reduced by about 80 percent from 1990 levels to stabilize atmospheric concentrations at protective levels. To meet this target, substantial reductions in motor vehicle emissions will be needed. There are three primary ways to achieve transportation-related GHG reductions: (1) reduce vehicle GHG emissions; (2) reduce demand for fuel by slowing the growth of vehicle miles traveled (VMT); and (3) change the properties of transportation fuel itself. A low carbon fuel standard is designed to achieve the latter.

The LCFS is a performance-based type of regulation: that is, it sets a target for lowering the carbon intensity of fuels and allows the market to determine the most cost-effective mix of fuels and strategies for achieving that target. Unlike other performance-based standards for transportation fuels the LCFS requires lifecycle accounting of emissions. Lifecycle GHG emissions include all emissions associated with the extraction, production, storage, transport, delivery, and combustion of fuels. The California Air Resources Board (CARB) is developing a low carbon fuel standard that would require a 10 percent reduction in the carbon intensity of transportation fuels by 2020. A regional LCFS can complement existing fuels programs such as the federal Renewable Fuels Standard (RFS).

As such, an LCFS can serve as an essential component of a broader, integrated strategy to reduce GHG emissions. The state of California has adopted this integrated type of approach under its Global Warming Solutions Act of 2006 (A.B. 32), which aims to reduce GHG emissions in California to 1990 levels by 2020 with more stringent targets to follow in later years. To implement A.B. 32, the California Air Resources Board (CARB) is developing a Climate Change Scoping Plan that "proposes a comprehensive set of actions designed to reduce overall carbon emissions in California." A similar approach is being taken in many northeastern states where development and implementation of a LCFS could be combined with other state and regional efforts such as the Low Emission Vehicle program, the Regional Greenhouse Gas Initiative (RGGI), renewable portfolio standards (RPS), VMT reduction strategies, and other programs. A

10 percent reduction in the carbon intensity of transportation fuels used in the Northeast would yield a 10 percent reduction in transportation-related GHG emissions. This is a significant reduction, similar to what the region can expect to achieve in the same timeframe with implementation of the California's motor vehicle GHG standards and RGGI.

Importantly, a LCFS can also protect against the potential for transportation fuels to become *more* carbon intensive as unconventional fossil-based and other fuels enter the market. For example, greater use of fuels derived from tar sands and of some biofuels has the potential to significantly increase fuel-related carbon emissions due to the large amount of GHGs emitted during upstream production of these fuels. As unconventional fuels such as tars sands-derived fuel become more cost competitive, their use threatens to add to transportation-related carbon emissions. Further, without limits on life-cycle fuel-related carbon emissions, fuels that are generally thought of as environmentally friendly – such as hydrogen or electricity could be produced in ways that are harmful to the environment (for example, using coal without carbon capture and sequestration).

Last, a low carbon fuel program has the potential to provide important economic and energy security benefits in the northeastern and mid-Atlantic states. Nearly all transportation fuel used in the region is imported, which results in a significant outflow of capital from the regional economy. This study concludes that substantial amounts of low carbon fuel may be manufactured from resources indigenous to the Northeast. A shift toward indigenous sources of fuel can provide jobs and ensure that resources are retained in the regional economy.

ES-2 Scenario Analysis

To estimate the amount of low carbon fuel that would be needed to achieve a 10 percent reduction in the carbon intensity of both gasoline and diesel in the region and to asses various compliance pathways, NESCCAF customized the Argonne National Laboratory's VISION model for the Northeast. The model predicts the amount of various fuels that could be used to comply with a LCFS.

For example, a 10 percent reduction in fuel carbon intensity might be achieved in part by using advanced biofuels with very low upstream GHG emissions, such as cellulosic ethanol, biodiesel derived from algae, and fuels derived from municipal solid waste. Another approach would be to displace liquid fuels with substitutes such as electricity generated from low-carbon sources to power plug-in hybrid and all-electric vehicles. NESCCAF evaluated a number of different compliance scenarios for both gasoline and diesel fuel. Two of these scenarios are shown below. These are hypothetical examples intended only to illustrate how a low carbon fuel standard might be met. Many other strategies may also achieve a given reduction target. The example scenarios are not meant as an endorsement of any preferred compliance pathway.

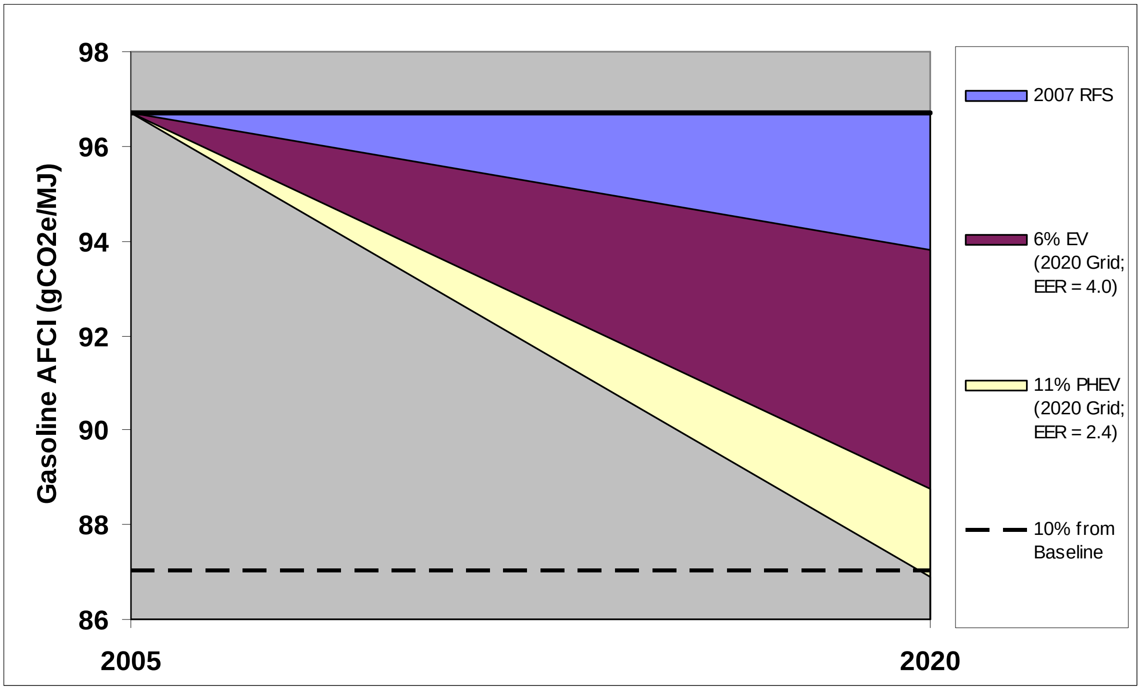

Figure ES-1. 10% Reduction in Gasoline AFCI with RFS, EVs and PHEVs.

The scenario shown in Figure ES-1, illustrates a compliance strategy based on the substitution of gasoline-powered cars with electric vehicles. In this example, 6 percent of the light-duty fleet is composed of electric vehicles and 11percent of the light-duty fleet is composed of plug-in hybrid vehicles. In addition, this scenario assumes that the federal RFS will result in 2 billion gallons of low carbon intensity biofuels delivered in the Northeast by 2020. The scenario relies on an aggressive, but potentially feasible penetration of electric and plug-in hybrid vehicles starting in 2010.

For the heavy-duty diesel vehicle fleet, NESCCAF likewise analyzed the amount of different types of low-carbon fuel that would be needed to achieve a 10 percent reduction in overall fuel carbon intensity. One scenario is shown in Figure ES-2.

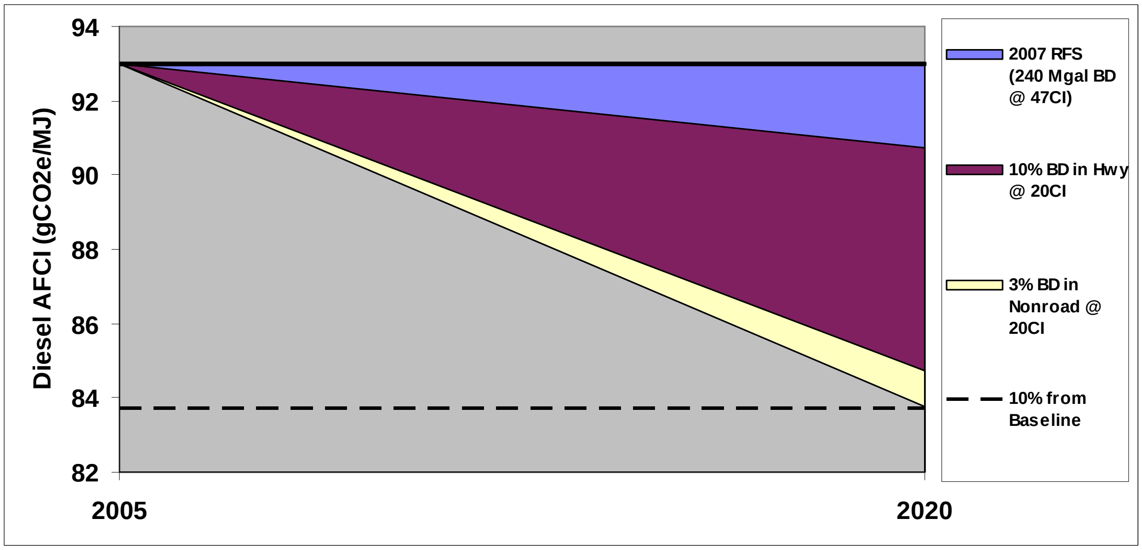

Figure ES-2. 10% Diesel AFCI reduction with RFS and advanced biodiesel.

This scenario assumes the federal RFS will result in the delivery of 240 million gallons of advanced biodiesel with a carbon intensity 50 percent lower than conventional diesel fuel in 2020. This by itself provides a 1.6 percent reduction in average diesel carbon intensity. This scenario further assumes that 10 percent of highway diesel and 3 percent of nonroad diesel will be displaced by advanced biodiesel that is 80 percent less carbon intensive than conventional diesel fuel.

California has not proposed to regulate the carbon intensity of No. 2 distillate fuel oil. In the Northeast, No. 2 distillate is used in substantial quantities for space heating and is often distributed through the same network as nonroad diesel fuel. An approach the Northeast states might consider would be to include No. 2 fuel oil in a low carbon fuel program. The inclusion of No. 2 fuel for space heating provides an opportunity to substitute lower carbon home heating fuels such as natural gas, electricity, and woody biomass for more carbon intensive conventional heating oil. Reductions in the carbon intensity of heating fuels could be required in the same timeframe as reductions for transportation diesel. Alternatively, the displacement of No. 2 oil by less carbon intensive alternatives could be used to generate credits toward compliance with a LCFS aimed at the vehicle market. This latter concept is illustrated in Figure ES-3.

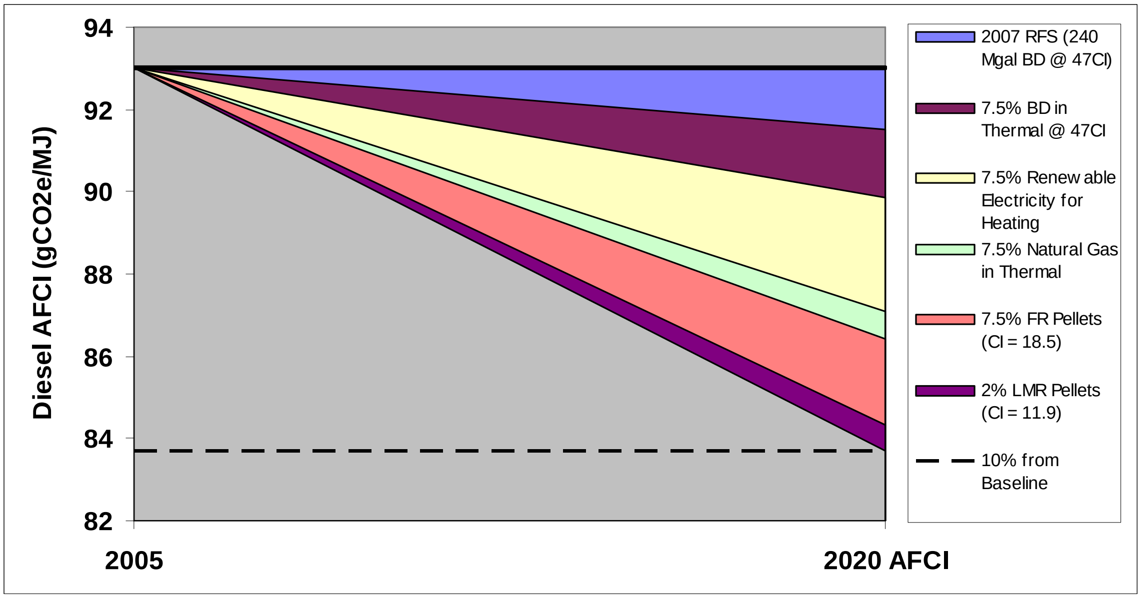

Figure ES-1-1. 10% Diesel AFCI reduction with credit generation from No. 2 fuel oil displacement.

In the scenario illustrated by Figure ES-3, credits generated through the displacement of No. 2 heating oil with low carbon substitutes, such as woody biomass, electricity, and natural gas would be available to transportation fuel providers to meet the requirements of the LCFS. This approach could ease compliance in the near term as technologies for producing low-carbon advanced biofuels progress to commercialization.

Other potential compliance scenarios for gasoline, diesel, and No. 2 fuel oil are presented in the *Scenario Analysis* described in Chapter 3.

This assessment yielded a number of additional important findings:

- In 2005, approximately 17 billion gallons of gasoline, 500 million gallons of ethanol, and 4.0 billion gallons of diesel fuel were used to power light and heavy duty vehicles in the eight NESCAUM member states. In 2020 under a business-as-usual projection, NESCCAF estimates that the region's light and heavy vehicles will require 18 billion gallons of gasoline, 3 billion gallons of ethanol, and 4.3 billion gallons of diesel fuel.
- In 2005, approximately 4.1 billion gallons of #2 fuel oil were used for space heating in the Northeast. This number is expected to decrease to 3.5 billion gallons in 2020.
- The federal RFS will require the use of approximately 17 billion gallons of advanced biofuels (not corn-ethanol) by 2020 *nationwide*. If this fuel is assumed to be distributed proportionally on a population basis throughout the United States, the Northeast could expect to receive approximately 2 billion gallons of low carbon biofuels by 2020 as a result of the RFS.

- If this is the case, the federal RFS by itself will produce a reduction of approximately 3 percent in the average carbon intensity of transportation fuel in the Northeast.
- There are a number of fuels and fuel pathways that could be used to comply with a regional LCFS. In the case of gasoline, a 10 percent reduction in overall carbon intensity could be achieved by introducing 6 billion gallons) of advanced ethanol (with an RFS-compliant carbon intensity of 48 gCO2e/MJ) in the region by 2020. Alternatively, an equivalent reduction could be achieved by increasing the fleet penetration of plug-in hybrid and all-electric vehicles to approximately 18 percent in the same timeframe.
- Given the substantial amount of research that is currently going into new fuels, a much larger number of low carbon substitutes for gasoline and diesel may be developed and commercialized during the next decade.

ES-3 Program Structure

NESCCAF has identified critical elements which will define how a LCFS program, if adopted, could be implemented in the Northeast.

- **Fuels to include:** Presently, gasoline and diesel provide the vast majority of energy to fuel the nation's transportation system. As a result, these are also the fuels targeted by California (through its LCFS program) and by the EPA (through the federal RFS) for achieving fuel-based GHG reductions in the transport sector. For obvious reasons, it makes sense under a Northeast LCFS to target these same transportation fuels. In addition, given the large volumes of No. 2 fuel oil consumed in the Northeast for space heating purposes in the residential, commercial, and industrial sectors, consideration should be given to including No. 2 fuel oil in a Northeast LCFS.
- **Role of Non-Liquid Fuels:** There is significant potential for non-liquid fuels to partially replace traditional, petroleum-based fuels as one key element of an effective strategy for reducing the average carbon intensity of the fuel supply in the Northeast. In the transportation sector, electricity can be used to power hybrid-electric or fully electric vehicles. Natural gas may also have an increased role as an alternative vehicle fuel. In thermal applications, wood pellets and natural gas may be able to replace a larger share of No. 2 fuel oil. A LCFS program could include mechanisms to encourage penetration of these alternative energy sources into sectors where their potential has yet to be fully realized.
- **Baseline:** A key initial step in establishing a carbon intensity reduction target for transportation fuels is to determine a reference case or baseline against which reductions in carbon intensity will be measured. The typical approach is to identify a year in which fuel supply and fuel characteristics are relatively stable and then determine the average carbon intensity of each of the fuels to be included in the program. The baseline year for implementing the federal RFS is defined by statute as 2007. California is considering a baseline year of 2010 for its LCFS, because at that point it is expected that the ethanol content of California reformulated gasoline will have reached a maximum of 10 percent by volume.

For a Northeast LCFS, 2006 merits consideration as the baseline because this was the first year in which ethanol fully replaced MtBE in the region's reformulated gasoline supply.

- **Treatment of the RFS in the business as usual case**. Biofuels introduced as a result of the federal RFS should "count" toward compliance with a regional RFS until such time as the supply of low carbon biofuels or non-liquid low carbon fuel alternatives is sufficient to allow for LCFS compliance without including the GHG reduction benefits realized from the RFS program.
- **Regulated entities and tracking:** Legal responsibility for demonstrating that prescribed program goals have been achieved will fall to regulated entities as defined under a LCFS program. Under the federal RFS, "obligated parties" are defined as refiners and importers of conventional petroleum fuels. Accordingly, these entities must demonstrate that they have met their "renewable volume obligation" by accumulating "renewable identification numbers" (RINs). The carbon intensity of the substitute renewable fuel is only a secondary consideration under the federal RFS. In contrast, reducing overall fuel carbon intensity is the primary objective under a LCFS. Therefore, it may be necessary to regulate additional entities, such as fuel producers and blenders in addition to providers of compressed natural gas, electricity, and other low carbon fuels. It may be possible to adapt the RIN system developed to support the federal RFS for the purpose of tracking compliance under a LCFS. Alternately, a separate tracking system may be necessary, particularly if the regulated entities are not the same under the two programs or if additional information is needed.
- **Maintaining consistency with California and within the region.** Given the fungible nature of transportation fuels and the relatively small geographic area of each of the Northeast states, state programs should strive for consistency with regard to lifecycle emissions accounting, stringency, and implementation dates.

ES-4 Analysis of Regional Low Carbon Fuel Supply

NESCCAF analyzed the volume of low carbon fuels that could potentially be produced using feedstocks and resources indigenous to the Northeast. While the Northeast is likely to import and use feedstocks and/or fuels from other regions under a LCFS, using locally sourced biomass and waste for low carbon fuel production would provide economic benefits to the region, both by increasing employment and reducing expenditures on imported fossil fuels.

This assessment was based on an evaluation of three categories of resources available in the region: (1) woody and agricultural biomass feedstocks; (2) waste-based resources; and (3) electricity.

Because the goal of a low carbon fuel standard is to reduce the GHG-intensity of fuels, the GHG impact of fuels on a full lifecycle basis is the one of the most critical aspects of the program. Recent scientific research, however, has raised substantial concerns that the GHG lifecycle impacts of woody and agricultural biomass may result in increases of GHG emissions. Since a fuel standard could increase global demand for these types of feedstocks, there is a concern that meeting the demand for biofuels will indirectly induce further changes in land use (e.g., clearing of forests for crop production) that increase net

GHG emissions, even after considering the GHG benefits gained from displacing fossil fuels with biofuels.

Research is ongoing to determine the lifecycle GHG impacts of biofuels production, but the issue of indirect land use change is not likely to be resolved soon. In consideration of this issue, NESCCAF's analysis focused on those regional biomass resources that are either waste products or are not currently being used to supply other markets. Screening the scope of the analysis to only waste resources and resources that are not being used to supply existing markets may provide insurance against unintended GHG emissions.

General Findings:

- The Northeast has a significant quantity of locally available resources for the production of low carbon fuels. NESCCAF estimates a conservative total of about 33 million dry tons of waste-based and woody and agricultural biomass is available for conversion into solid and liquid fuels. Additional resources include waste oils and biogas.
- Waste-based biomass is the region's most significant resource by far, with a likely availability of 26 million tons of organic municipal solid waste plus agricultural wastes and wastewater solids. In addition, nearly 30 million cubic feet of biogas will likely be available in the Northeast in 2020. These materials could be converted into over 484 MW of electricity.
- In addition to waste biomass, NESCCAF conservatively estimates that 5 to 8 million dry tons of woody and agricultural biomass are likely available[1] in the Northeast annually. If used in thermal applications, this biomass could be used to heat one million homes in 2020, which would displace about 590 million gallons of No. 2 fuel oil per year, as well as to produce 1,040 MW of electricity.
- There are uncertainties surrounding these estimates of available biomass resources—actual biomass availability will vary depending on key factors such as economics, environmental concerns, landowner preferences, and public policies.
- Geographically, the majority of the Northeast's available woody and agricultural biomass is located in New York and Pennsylvania. While New England states also have significant quantities of woody biomass, much of this wood is being used to supply existing markets. Since it is often not economic to transport biomass long distances (e.g., more than 50 miles), the geographic location of available biomass will influence the choice of locations for fuel processing and production plants.
- Because electric vehicles (EVs) have very efficient drivetrains compared to internal combustion engines, electricity is also a promising low carbon fuel for transportation applications. This is especially true in the Northeast, where new

[1] For the purposes of this report, *likely available biomass* refers to woody biomass from forest management, agricultural residues and biomass grown on marginal lands, and the organic portion of municipal solid waste, used cooking oils, and solids and/or gas from wastewater treatment facilities and livestock.

policies are in place to reduce the GHG intensity of electricity, including the Regional Greenhouse Gas Initiative (RGGI) and renewable energy standards.

- At low levels of EV penetration into the marketplace, the region has more than sufficient electricity generation capacity to accommodate these vehicles.
- Even at very high levels of EV penetration, the Northeast could support the use of these vehicles without building new capacity if the vehicles are charged at times that took advantage of unused electricity capacity, primarily at nighttime. NESCCAF modeled a variety of PHEV penetration scenarios, including a 20 percent light-duty market penetration of PHEV vehicles, equivalent to approximately 7 million vehicles in 2020, with 40-mile ranges and two-hour charging times. The Northeast's electricity grids could support this scenario with existing capacity.

Figure ES-4 below shows the maximum and likely availability of woody, agricultural, and waste-based biomass resources in the Northeast by 2020. Maximum availability estimates for each category reflect total theoretical availability in the region. Estimates of likely availability are based on a percentage of the maximum, reflecting considerations of resource cost and other important factors such as environmental sustainability and landowner preferences will limit actually resource availability.

Type of Resource	Maximum Availability	Likely Availability
Woody biomass (dry tons)	33,463,889	5,021,667
Agricultural biomass (dry tons)	3,278,400	1,639,200
Municipal solid waste (dry tons)	66,492,294	20,390,809
Agr. and wastewater solids (dry tons)	11,880,541	5,940,271
Total Solid Biomass (dry tons)	**115,115,124**	**32,991,947**
Wastewater biogas (cubic ft.)	55,785,179	27,892,590
Waste oils (metric tons)	620,486	62,049

Figure ES-4 Northeast Biomass Resources, Maximum and Likely Availability2

Within the Northeast region, likely biomass availability for low carbon fuel production is conservatively estimated at nearly 33 million dry tons annually. Available biomass can be used directly (as a source of energy for thermal applications or electricity generation) or converted into low carbon liquid biofuels for use in the transportation sector. Actual conversion to fuels will depend on relative costs and technological capabilities. Based on current economics, available technologies, and other factors such as industry maturity, we expect that in the early stages of a regional LCFS, the majority of biomass resources will be used for electricity generation and thermal energy (i.e., heating).

Figure ES-5 displays estimates of low carbon fuel production from available regional resources. Under conservative assumptions of likely biomass availability, by 2010 the region could produce approximately 850 MW of electricity per year and heat 400,000 residences using indigenous biomass resources. Available waste oils could be converted to 42 million gallons of B5 biodiesel on an annual basis.

As markets continue to develop, we assume that more of the region's biomass resources would be deployed to support low carbon fuel production. By 2020, the region could produce just over 1,500 MW of electricity, thermal energy for 1 million homes, and 46 million gallons of B5 biodiesel. Assuming technologies to produce cellulosic ethanol are commercially viable by 2020, local resources could also support up to 440 million gallons per year of ethanol production.

[2]States included in this assessment are the six New England states, New York, New Jersey, and Pennsylvania. Figures represent estimated resource availability on an annual basis.

Quantity of Low Carbon Fuel	2010	2020
Electricity (MW)	849	1,524
Thermal energy (no. of homes heated)	400,000	1,000,000
Liquid fuels (million gallons)		
B5 biodiesel	42	46
Cellulosic ethanol	--	440

Figure ES-5 Estimated Low Carbon Fuel Production from Available Regional Resources (using conservative estimates), in 2010 and 2010

Because NESCCAF did not conduct a formal resource sustainability assessment as part of this analysis, these estimates of low carbon fuel production are purposefully based on conservative estimates of likely resource availability. If sustainable levels of available resources are substantially higher than these estimates, than potential fuel production capacity would be accordingly higher.

ES-5 Conclusions

- The LCFS—since it is a performance based standard—leaves the door open for the use of many types of low carbon fuels and will allow industry and the market to determine the most cost effective options for compliance.
- The LCFS regulates lifecycle GHG emissions. As such it takes into account emissions from all stages in the production, transportation, and combustion of fuels.
- The LCFS can ensure that the average carbon intensity of transportation fuels does not increase with the introduction of unconventional alternatives, such as gasoline and diesel derived from tar sands or some forms of biofuels with high lifecycle carbon emissions.
- California has issued preliminary regulatory documents for its LCFS. The California program, if implemented, will require a 10 percent reduction in the carbon intensity of transportation fuels in 2020. The program design developed by CARB provides a potential template program for a Northeast LCFS.
- A 10 percent reduction in the average carbon intensity of highway and nonroad gasoline and highway and nonroad diesel fuel in the Northeast in 2020 would result in significant GHG reductions. The reductions are comparable to what the region expects to realize in 2020 by implementing California's motor vehicle GHG standards and the RGGI program.

- A 10 percent reduction in the carbon intensity of light duty vehicle fuel could be feasible with aggressive commercialization of advanced electric-drive vehicles, advanced biofuels, or both, in the 2020 timeframe.
- There are fewer known options to reduce the carbon intensity of diesel fuel. A 10 percent reduction in the carbon intensity of diesel fuel could be possible assuming aggressive commercialization of advanced diesel substitutes in the 2020 timeframe.
- Given ongoing, substantial research into the development of advanced biofuels, significant quantities of low carbon fuel substitutes could be available by 2020.
- The Northeast states should consider including No. 2 fuel oil in a low carbon fuel standard given the significant contribution No. 2 fuel oil makes to overall GHG emissions in the region.
- An option for achieving a diesel carbon intensity reduction target of 10 percent would be to allow credits generated by displacing No. 2 fuel oil with low carbon alternatives for home heating such as woody biomass, natural gas, and even electricity to be used for LCFS compliance purposes by gasoline and diesel fuel providers. A combination of advanced biofuels and credits generated by the substitution of non-liquid fuels for No. 2 fuel oil could allow regulated entities to comply with a 10 percent carbon-intensity reduction requirement for diesel fuel.
- Given that the Northeast fuel distribution system is highly integrated, elements of a low carbon fuel standard in our region should be harmonized from state to state.
- Waste-based biomass is the region's most significant resource by far, with a likely availability of 26 million tons of organic municipal solid waste plus agricultural wastes and wastewater solids. In addition, nearly 30 million cubic feet of biogas will likely be available in the Northeast in 2020. These materials could be converted into over 484 MW of electricity.
- In addition to waste biomass, NESCCAF conservatively estimates that 5 to 8 million dry tons of woody and agricultural biomass are likely available in the Northeast annually. If used in thermal applications, this biomass could be used to heat one million homes in 2020, which would displace about 590 million gallons of No. 2 fuel oil per year, as well as to produce 1,040 MW of electricity.
- The Northeast could support the use of substantial numbers of electric and plug-in hybrid vehicles without building new capacity. NESCCAF modeled a variety of PHEV penetration scenarios, including a 20 percent light-duty market penetration of PHEV vehicles, equivalent to approximately 7 million vehicles in 2020, with 40-mile ranges and two-hour charging times. The Northeast's electricity grids could support this scenario with existing capacity.
- Regionally produced low carbon resources such as electricity, municipal solid waste, and woody biomass are likely to have lower lifecycle carbon emissions, taking into account land-use changes, than do crop-based biomass resources from agricultural areas outside the region.

1. INTRODUCTION

The Northeast States Center for a Clean Air Future (NESCCAF) is a non-profit organization that promotes clean air through scientific research and policy development. This report aims to help regulators and policy makers—including state-level air pollution control officials and state legislators—understand what a low carbon fuel standard (LCFS) is and how it might be implemented in the Northeast.

1.1. Background

Worldwide, the use of fossil fuels for transportation, space heating, and electricity generation accounts for 38 percent of total greenhouse gas (GHG) emissions and 62 percent of emissions from all energy-related sources. In the Northeast, the use of gasoline to fuel passenger cars accounts for approximately 27 percent of energy-related GHG emissions. The combustion of distillate fuel in transportation (e.g., trucks and locomotive engines) and stationary applications, such as residential space heating, is responsible for another 21 percent of the regional total. Clearly, reducing GHG emissions from vehicles and transportation fuels is an essential component of any broad-based effort to address global climate change, regionally and globally.

With the adoption of California's Low Emission Vehicle (LEV) GHG standards, the Northeast states have already put in place an important cornerstone of the region's strategy for reducing transportation-related GHG emissions. The LCFS represents a potentially important complement to this vehicle-based initiative. To evaluate its potential contribution to an effective regional strategy for reducing transport sector emissions, state environmental officials need balanced, policy-relevant research and analysis. This study attempts to respond to that need by providing a technical basis to assess the merits of a LCFS. In this way, NESCCAF hopes to significantly advance the policy discussion concerning LCFS and other transportation-focused GHG mitigation options in the northeastern United States.

This study addresses several principal objectives:

- Evaluates opportunities and obstacles related to the implementation of a LCFS for the region;
- Provides recommendations for designing and implementing an effective LCFS for the Northeast; and
- Promotes and facilitates the adoption of regionally consistent state programs.

It is intended to complement the broader regional climate action plan adopted by the Conference of New England governors and Eastern Canadian Premiers in 2002 (described in Chapter 2). Additionally, this study builds on and adds to the substantial research being conducted on low carbon fuel options and related policies by the

California Air Resources Board (CARB), the University of California, the U.S. Environmental Protection Agency (EPA), the Canadian Provinces, and the European Community. Issues specific to the Northeast are considered in the analysis, such as a possible role for low carbon fuels in the region's substantial market for distillate oil.

A number of issues related to low carbon fuels are not addressed in this report. Among them, serious concerns over the GHG emissions associated with land-use changes prompted by expanded biofuels production have not been researched as part of this analysis. NESCCAF relied on existing inputs to emissions modeling tools for the analysis but did not conduct any new research into these issues. Further, NESCCAF did not research potential impacts to water or air quality from increased fertilizer use, mid-level ethanol blends, or other potential environmental impacts directly or indirectly linked to the region's transportation fuel mix and related policies.

To garner expert advice in this effort, NESCCAF formed a Project Advisory Committee made up of representatives from the regulatory community, industry, academia, and environmental organizations. The Committee has provided valuable input and guidance at key junctures in the research effort.

1.2. Report Organization

The remainder of this report is divided into six sections: Chapter 2 describes how a LCFS might be structured and summarizes the current political and regulatory context. Chapter 3 explores different potential compliance scenarios for a LCFS designed to achieve target reductions in average carbon intensity for Northeast transportation and heating fuels. Chapter 4, *Program Structure*, describes how the Northeast states can go about regulating the carbon content of fuels in the Northeast. Chapter 5 presents the results of an analysis of locally available feedstocks and fuels such as woody biomass, electricity, and municipal solid waste. Chapter 6 concludes with a summary of findings and recommendations on potential elements of a Northeast state LCFS program.

2. WHAT IS A LOW CARBON FUEL STANDARD?

2.1. Background - The Importance of Transport Sector Emissions

Transportation emissions comprise the second largest source of human-made GHG emissions in the United States. Figure 2-1 describes the contribution of different sources to total U.S. GHG emissions. Emissions associated with coal combustion (primarily for electricity generation) are the largest source, transportation-related emissions are second, followed by combustion of natural gas and other sources. Transportation emissions comprise approximately 40 percent of total GHG emissions. More than 80 percent of transport-sector emissions come from motor vehicles (61 percent) and trucks and buses (20 percent).

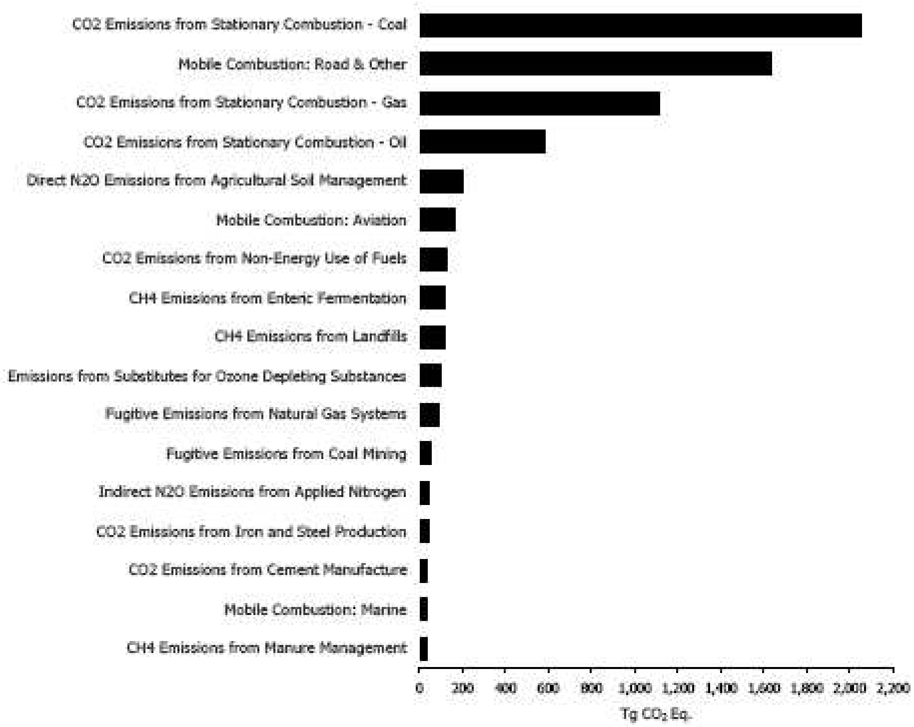

Figure ES-16: 2006 Key Categories - Tier 1 Level Assessment
Note: For a complete discussion of the key source analysis see Annex 1.

Figure 2-1 2006 U.S. GHG Inventory3

3 U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006," April, 2008, USEPA #430-R-08-005.

Reducing transportation GHG emissions is important from the standpoint of slowing climate change and reducing the nation's dependence on petroleum. There are three main options for reducing transportation-related GHG emissions. The first is to reduce vehicle GHG emissions. The second is to reduce demand for fuel by reducing (or slowing growth in) the number of miles people travel in cars each year. The other significant option is to change the properties of the transportation fuel itself—that is, to reduce the amount of GHGs emitted when a given quantity of fuel energy is used. A LCFS targets this last option.

2.2. Basic Elements of A Low Carbon Fuel Standard

The LCFS is similar to other fuel regulations in that it is a performance based standard. That is, it regulates the amount of pollutant emitted for a given amount of work produced or energy used. It is analogous to existing performance standards for fuels - reformulated gasoline for example - which require a percent reduction in the amount of vehicle smog-forming pollution emitted relative to a baseline fuel. Unlike other fuels regulations, however, the LCFS regulates *lifecycle* emissions. That means it attempts to account for all emissions produced in the production, storage, transport, delivery, and combustion of a given fuel. Figure 2-2 provides a graphic depiction of all the emissions that must be taken into account as part of a lifecycle analysis for corn ethanol. The specific emissions sources that must be taken into account as part of a similar analysis for petroleum and other fuels will differ.

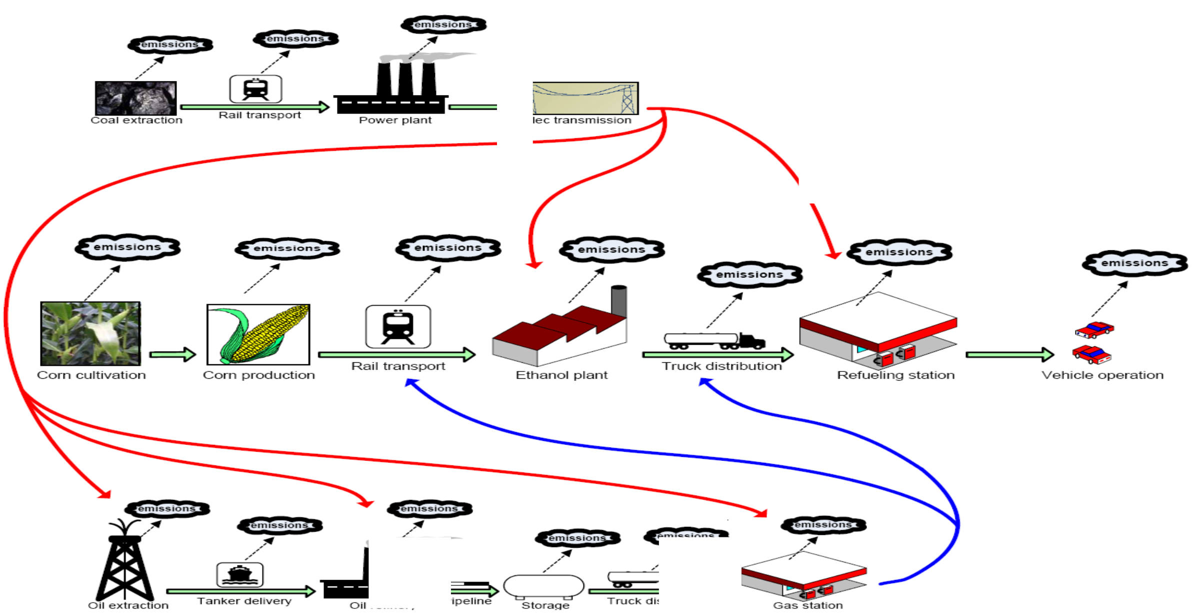

Figure 2-2 Emissions to include in full lifecycle carbon accounting for petroleum

Source: Wang, Guihua and Delucchi, Marc, 2006

The carbon or GHG intensity of different fuels is typically expressed as full lifecycle emissions per unit of energy content. The LCFS requires a percent reduction in the carbon intensity of fuel, measured in CO_2-equivalent emissions per megajoule of energy (CO_2e/MJ), relative to a baseline fuel. It is important to note that a LCFS, like other fuels regulations, does not cap total fuel-related emissions—actual emissions will depend on the total amount of fuel consumed, which in turn depends on vehicle efficiency and miles traveled. Rather, the LCFS limits the amount of emissions generated per unit of fuel energy used.

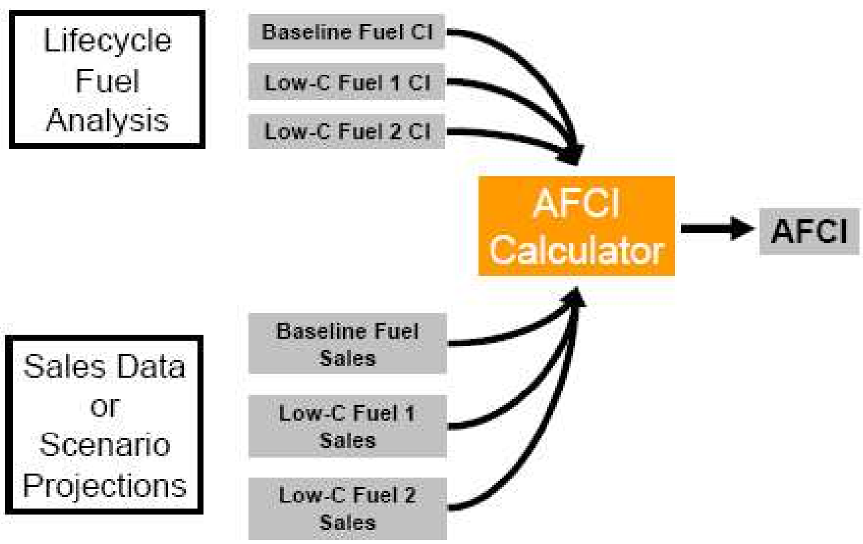

Figure 2-3 Calculating Average Fuel Carbon Intensity (AFCI)

Figure 2-3 illustrates the calculation of average fuel carbon intensity (AFCI) for a mixture of fuels with different lifecycle characteristics and sales volumes. This calculation is central to implementing a LCFS. Once a weighted average AFCI is calculated for all fuels sold in a given year, this result can be compared to a baseline AFCI to determine whether overall intensity-reduction targets have been met.

The state of California has adopted the LCFS as an essential component of a broader, integrated strategy for reducing GHG emissions under the state's Global Warming Solutions Act of 2006 (A.B. 32). The overall goal of A.B. 32 is to reduce California's GHG emissions a to 1990 levels by 2020. To implement this requirement, environmental regulators at CARB are developing a Climate Change Scoping Plan which "proposes a comprehensive set of actions designed to reduce overall carbon emissions in California."[4] The Scoping Plan references California's LCFS as one of these actions, within a set of programs targeting the transportation sector. California's

[4] *Climate Change Proposed Scoping Plan – A Framework for Change*, California Air Resources Board, October 2008.

actions and other recent initiatives aimed at reducing fuel-related GHG emissions are discussed further in later sections of this report.

2.3. Political and Regulatory Context

2.3.1. International Context

As early as 1992, international awareness of the many potential risks associated with global warming led 160 countries, including the United States, to adopt a Framework Convention on Climate Change with the stated objective of achieving "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[5]

Toward this objective, signatories pledged to work to stabilize greenhouse gas emissions. A number of industrialized countries, again including the United States, adopted the specific near-term goal of returning year 2000 GHG emissions to 1990 levels. It subsequently became evident that most countries, including the United States, were not on track to meet this objective. In response, parties to the Framework Convention adopted the Kyoto Protocol in 1997, which included targets and timetables for reducing GHG emissions to specific levels for each country. As of early 2003, 102 countries had ratified or acceded to the Protocol. However, the United States—citing economic concerns—has not ratified the Kyoto Protocol.

Notwithstanding the federal government's reluctance to impose mandatory limits on GHG emissions, many state and local leaders had become sufficiently concerned about the issue of climate change by the end of the 1990s to adopt a range of measures aimed at reducing GHG emissions within their jurisdictions. This trend began with a few leading states in the early 1990s, but has accelerated recently: in 2001 and 2002, approximately one-third of the states passed new legislation or executive orders specifically aimed at addressing climate change.[6] These policies ranged from comprehensive state action plans with quantitative GHG reduction targets to regulations or laws limiting emissions from a specific sector such as electric power generation or transportation.

2.3.2. Federal Efforts to Reduce Petroleum Consumption

Renewable Fuel Standard (RFS)

The federal Renewable Fuel Standard (RFS), first adopted in the Energy Policy Act of 2005 and subsequently amended in the Energy Independence and Security Act of 2007 (EISA), attempts to respond to energy security and environmental concerns by mandating a steady increase in the volume of renewable fuel included the U.S. transportation fuel supply over the next decade and a half. The mandate was significantly expanded under EISA, which requires 36 billion gallons of renewable fuels by 2022. EPA is currently in the process of amending the RFS and is expected

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5 United Nations, "Report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the Work of the Second Part of Its Fifth Session, Held at New York From 30 April to 9 May, 1992," UN Document A/AC.237/18, Part II (May 15, 1992).

6 Additionally, other states adopted measures that were not expressly aimed at climate change but clearly were driven at least in part by the issue of global warming. Barry G. Rabe, *Statehouse and Greenhouse: The Evolving State Government Role in Climate Change* (Arlington, VA: Pew Center on Global Climate Change, November 2002), p. 7.

to issue a proposed rule by the end of 2008. As part of that rule EPA is required to establish two general categories of renewable fuel: conventional biofuels (i.e., ethanol derived from corn starch) and advanced biofuels. Under the new rule, the federal RFS will account for direct emissions of GHGs and significant indirect emissions, such as emissions from land use changes. All stages of fuel and feedstock production and distribution are to be included. Specific RFS program requirements under current law are summarized in Table 2-1.

Table 2-1 Energy Independence & Security Act (EISA) of 2007 Requirements

Renewable Fuel Obligations					
	Conventional Biofuels		**Advanced Biofuels**		
	"Old" Corn Ethanol	"New" Corn Ethanol	Cellulosic Biofuel	Other Advanced Biofuels	Biomass Based Diesel
Volume Obligation (10^9 Gal)	± 13.4	± 1.6	≥ 16.0	≤ 4.0	≥ 1.0
Total Volume Obligation (10^9 Gal)	≤ 15.0		≥ 21.0		
Obligation Year	2015		2022	2022	2012
GHG Baseline Reduction	N/A	20%	60%	50%	50%

As can be seen from Table 2-1, the RFS will mandate the use of as many as13.4 billion gallons[7] of corn ethanol without any associated GHG reduction requirement. The RFS requires an additional 1.6 billion gallons of corn ethanol that achieves at least a 20 percent reduction in lifecycle GHG emissions compared to conventional gasoline. Use of an additional 21 billion gallons of "advanced biofuels" will be required by 2022. The term "advanced biofuels" is defined to include:

- Cellulosic biofuel[8] derived from plant cellulose, hemicellulose, or lignin
- Ethanol derived from sugar or starch other than corn starch
- Ethanol derived from specified waste materials (e.g., crop residues, vegetative waste, animal waste, food waste, yard waste)

[7] Renewable Fuels Association, Changing the Climate – Ethanol Industry Outlook, 2008.

[8] According to the definition of "cellulosic biofuel", the raw materials must be derived from "renewable biomass", which includes planted crops and crop residue produced on pre-existing agricultural land (i.e., land that was already cleared prior to the effective date of the law); planted trees and tree residue from tree plantations on non-federal, previously cleared land; animal waste material and animal byproducts; slash and pre-commercial thinnings from non-federal forestlands; biomass cleared from lands for the sole purpose of protecting people, buildings, and public infrastructure from risk of wildfire; algae; and separated yard waste or food waste.

- Biomass-based diesel
- Biogas (e.g., landfill gas, sewage waste treatment gas) derived from renewable biomass
- Butanol or other alcohols derived from renewable biomass
- Other fuel derived from cellulosic biomass

Obligated parties under the RFS are required to demonstrate compliance through a tracking system, whereby they accumulate renewable identification numbers (RIN), associated with the batches of renewable fuel that they purchase and blend with petroleum-based fuels. It is anticipated that EPA will require information in the RIN to indicate the specific category or type of biofuel being blended. For example, if a biofuel falls into the 60 percent GHG reduction category, the RIN will indicate this.

Importantly, the RFS does not impose any constraints on the carbon intensity of the non-renewable portion of the transportation fuel mix—which will continue to account for as much as 80 percent of all fuel use by the transport sector.[9] NESCCAF estimates that under a best case scenario, the RFS will reduce transportation fuel-related GHG emissions in the Northeast by 2.7 percent in 2020.[10] Thus, the federal RFS could complement efforts in the Northeast to achieve GHG emission reductions through a LCFS.

2.3.3. California's Executive Order S-1-07 on Low Carbon Fuels

In January 2007, California Governor Schwarzenegger signed an executive order calling for a LCFS to reduce the carbon intensity of California's transportation fuels by at least 10 percent in 2020. The order instructed the Secretary of the California Environmental Protection Agency to coordinate activities with the University of California, the California Energy Commission (CEC) and other state agencies to develop a compliance schedule to meet the 2020 target. CARB staff are expected to present regulatory documents for the Board's finalization in March 2009.

California's LCFS is anticipated to cover all gasoline and diesel fuel used by transportation sources, with the exception of fuels used in aviation and by ocean-going vessels. California has released draft papers outlining some aspects of its program; in addition, CARB released draft LCFS regulations in October 2008. These drafts are discussed in more detail in Chapter 5 of this report.

The evolution of the California LCFS is being closely watched by the ethanol industry. A March 2007 editorial in the publication Ethanol Today concluded that "Companies or individuals planning new ethanol plants in the coming years should consider taking steps to reduce the carbon intensity of the ethanol they will produce so they can take maximum advantage of the impending greenhouse gas emission limitations."

[9] Thus, increases in use of high carbon fuels, such as fuels derived from tar sands, to make diesel and gasoline will not be addressed by the RFS.

[10] This assumes that advanced biofuels are distributed evenly throughout the U.S. Additional information on this estimation can be found in Chapter IV, Scenario Analysis.

2.3.4. The California Global Warming Solutions Act

The California Global Warming Solutions Act of 2006 (AB 32) calls for a program of regulatory and market mechanisms to achieve quantifiable and cost-effective reductions of GHGs. Specifically, CARB is required to:

- Establish a statewide GHG emissions cap for 2020, based on 1990 emissions;
- Adopt mandatory reporting rules for significant sources of GHGs;Develop a plan for achieving emission reductions from significant GHG sources via regulations, market mechanisms and other actions;
- Adopt regulations by January 1, 2011 that achieve maximum technologically feasible and cost-effective reductions in GHGs, including provisions for using both market mechanisms and alternative compliance mechanisms;
- Evaluate various factors relevant to the implementation of a program to reduce the state's GHG emissions, including impacts on California's economy, the environment, and public health; equity between regulated entities; electricity reliability; and conformance with other environmental laws.CARB's Scoping Plan further develops three interrelated program components to address the major factors that determine emissions in the transportation sector: (1) vehicle technology, (2) fuels, and (3) vehicle use. The LCFS is the vital "second leg" in this three-part transportation related strategy.

2.3.5. European and Canadian LCFS Programs

Other countries are adopting low carbon fuels programs similar to California's; like California they are also grappling with concerns about the sustainability and indirect impacts of these policies—concerns that are increasingly being voiced by environmental organizations and governments in other nations. Specific LCFS-related initiatives in other countries include:

- **European Union:** The European Commission has revised its Fuel Quality Directive to include a required reduction in the lifecycle GHGs associated with fuels. The goal of this revision is to reduce the average GHG intensity of transportation fuels used in Europe 10 percent below 2010 levels by 2020.
- **United Kingdom**: The UK has established a Renewable Transport Fuel Obligation (RFTO), similar to the U.S. RFS, that requires 5 percent by volume of all road transportation fuel to be renewable by 2010.
- **British Columbia:** The province has adopted a LCFS that aims to achieve a 10 percent reduction in the carbon intensity of passenger vehicles by 2020.

Additional countries are actively examining the sustainability and GHG impacts of biofuels:

- **Netherlands:** "Cramer Commission" report published in June 2006 established sustainability principles and suggested criteria. This work was influenced by the International Energy Agency's (IEA's) Task 40 Fair BioTrade Project.
- **Germany:** Germany's Federal Environment Agency or Umweltbundesamt (UBA) is investigating the development of a sustainability certification for biofuels in conjunction with the Institute for Energy and Environmental Research (IFEU) and the International Council on Clean Transportation.

2.3.6. Northeast State Climate Action Plans

In 2001, the Conference of New England Governors and Eastern Canadian Premiers (NEG/ECP) adopted a regional Climate Change Action Plan. The plan establishes an initial target for stabilizing aggregate GHG emissions in New England, Quebec, New Brunswick, Nova Scotia, Newfoundland, and Prince Edward Island at

1990 levels by 2010. By 2020, the NEG/ECP plan calls for reducing emissions 10 percent below 1990 levels, with substantial further reductions (or as much as 75 percent–80 percent) to be achieved in subsequent years.

In response to the expected increase in regional emissions attributable to the transportation sector, the regional plan and state specific plans target mechanisms for reductions in vehicle miles traveled (VMT) and fuel economy.

In recent years, other Northeastern states have developed state-specific plans and/or GHG reduction targets, and New England states have formalized the NEG/ECP targets by signing them into law or establishing more stringent targets. These state-level initiatives are summarized in Table 2-2 below.

Table 2-2 Summary of Northeast State Climate Legislation and Actions

STATE	Legislation or Plan	YEAR SIGNED	REDUCTION TARGETS		
			2010	2020	2050
CT	Act Concerning CT Global Warming Solutions	2008		10% below 1990 levels	80% below 1990 levels
ME	Act to Provide Leadership in Addressing the Threat of Climate Change	2003	1990 levels	10% below 1990 levels	75-80% below 1990 levels
MA	Global Warming Solutions Act	2008		10-20% below 1990 levels	80% below 1990 levels
NH	NEG/ECP Climate Change Action Plan Targets				
NJ	Global Warming Response Act	2008		1990 levels	80% below 2006 levels
NY	State Energy Plan and Final Impact Statement	2002	5% below 1990 levels	10% below 1990 levels	
PA	Climate Change Roadmap	2007		25% below 2000 emissions by 2025	80% below 2007 emission levels by 2050
RI	Global Warming Solutions Act	Pending		20% below 1990 levels	80% below 1990 levels
VT	NEG/ECP Climate Change Action Plan Targets				

Baseload Generation (run-of-river hydro, nuclear, coal) and
Intermittent Resources (wind and solar)
Denotes non-legislative action

It is worth noting that the Massachusetts "2008 Global Warming Solutions Act"[11] includes requirements for biofuels. Specifically, this legislation mandates the use of 2 percent biodiesel in transportation fuels by 2010 and 5 percent by 2015; it also provides tax incentives for the production of cellulosic ethanol. Additional actions to reach Massachusetts' aggressive emissions reduction goals will be outlined in an implementing plan that the state expects to release in 2009.

[11] *See* How to Avoid Dangerous Climate Change*:* A Target for U.S. Emissions Reductions, Union of Concerned Scientists 2 (September 2007)(calling for at least 80 percent emissions reduction from 2000 levels by 2050); *See also*, The Economics of Climate Change: Stern Review 340 (Cambridge University Press 2006).

3. POTENTIAL LCFS COMPLIANCE SCENARIOS

This chapter presents results from a NESCCAF analysis of possible scenarios for complying with a Northeast LCFS designed to achieve a 10 percent reduction in the carbon-intensity of the region's transportation fuel supply. NESCCAF modeled potential combinations of low-carbon fuels and assessed the reductions in carbon intensity that they would achieve relative to baseline gasoline and diesel. The results provide insights into the challenges and opportunities that may accompany a 10 percent AFCI reduction target in the Northeast. Looking at what combination and quantities of fuels might be required to comply with an LCFS can inform key programmatic decisions and help identify potential obstacles to the successful implementation of a low-carbon fuels program.

Using a combination of modeling tools, NESCCAF developed 12 low-carbon fuel compliance scenarios. Of these, six are presented and discussed in this chapter, while three additional scenarios are discussed in Chapter 4. The remaining three scenarios are described in Appendix A. Key elements of the scenarios covered in this chapter are summarized in Table 3-1.

Table 3-1: Summary of Compliance Scenarios Presented in This Chapter

Scenario	Baseline	Description	EV Fleet %	PHEV Fleet %	Grid	Ethanol CI	Ethanol Bgal	% CNG
G1	Gasoline	EVs and PHEVs + 900 Mgal advanced ethanol	4.4	4.4	2005 Avg	0	0.9	0
G2	Gasoline	EVs and PHEVs + 1.5 Bgal advanced ethanol	4.4	4.4	2020 Avg w/ RPS + RGGI	48	1.5	0
G3	Gasoline	EVs and PHEVs	6	11	2020 Avg w/ RPS + RGGI	-	-	-

Scenario	Baseline	Description	BD CI	BD %	NG/CNG %	% Electricity in HHO	% Pellets in HHO	HHO in Baseline?
D1	Diesel	BD in Hwy and Nonroad	20	10% Hwy 15% Nonroad	-	-	-	No
D2	Diesel	BD & CNG in Hwy and Nonroad	20	10% Hwy 10% Nonroad	10% Hwy 10% Nonroad	-	-	No
D3	Diesel	Mix of Fuel Switching in Thermal	47	10% Thermal	10% Thermal	10%	14%	Yes

The scenarios will be described in more detail in Sections 3.4 and 3.5 of this chapter.

3.2. Overview of Method

For this analysis, NESCCAF: (1) estimated Northeast-specific lifecycle carbon intensity for selected fuels; (2) projected fuel and energy demand for transportation and home heating in the baseline and future scenario years; and (3) calculated fleet-average carbon intensity under selected scenarios for fleet penetration of alternative vehicle technologies (such as electric and plug-in hybrid-electric vehicles) and use of advanced fuels (such as low-carbon ethanol).

3.2.1. Modeling Tools

To develop illustrative LCFS compliance scenarios, NESCCAF utilized three models: GREET[12], VISION-NE, and a NESCCAF AFCI Calculator. In addition to the brief descriptions that follow, more detailed information about each of these models can be found in Appendix A. Carbon intensity was measured in grams of CO_2-equivalent emissions per MJ—the unit of measure California is proposing to use for a low carbon fuel standard.

The GREET model calculates lifecycle GHG emission for numerous conventional and alternative fuels. To facilitate the use of GREET for this project, NESCCAF worked with Life Cycle Associates to develop a set of Northeast-specific inputs and a specialized GREET Interface Tool. The results for selected fuel pathways are shown in Table 3-2. The first two pathways listed, reformulated gasoline blendstock (technically referred to as reformulated blendstock for oxygenate blending or RBOB) and ultra-low-sulfur diesel (or ULSD), represent the primary conventional fuels used in highway gasoline and diesel engines in the baseline year.

Table 3-2 Carbon intensity (CI) scores for selected fuel pathways

Fuel Pathway	Carbon Intensity (gCO2e/MJ)
Reformulated gasoline blendstock (RBOB)	**96.7**
Ultra-Low-Sulfur Diesel (ULSD)	**93.0**
Denatured Corn Ethanol	**72.6***
Soy Biodiesel	**35.1***
Compressed Natural Gas	**73.1**
Liquefied Natural Gas	**78.0**
Conventional gasoline	**92.7**
Oil sand RBOB	**108**
Oil sand ULSD	**105**
Liquefied petroleum gas (LPG)	**86.9**
Natural gas for heating	**71.1**
ULSD for heating	**91.2**
Woody biomass pellets	**19.8****
Woody biomass EtOH: (Fermentation)	**-1.7****
Woody biomass EtOH: (Gasification)	**11.5****
Electricity (100% NG)	**181**
Electricity (100% Coal)	**345**
Electricity (100% Renewables)	**0**
**Does not include effects of indirect Land Use Change*	
*** Woody Biomass includes forest residue and new forest growth*	

12 Greenhouse Gases, Regulated Emissions and Energy in Transportation. Spreadsheet model developed and maintained by Argonne National Laboratory. http://www.transportation.anl.gov/modeling_simulation/GREET/index.html.

The second model used in this analysis, VISION-NE, projects transportation energy demand for the Northeast vehicle fleet. NESCCAF developed this customized version of Argonne National Laboratory's VISION fleet turnover model for the specific purpose of characterizing the region's transportation energy demand under various scenarios. Finally, because an LCFS requires information about the specific carbon intensity as well as quantity of different types of fuels in the overall fuel mix, we developed an AFCI Calculator Tool that incorporates the GREET carbon intensity values and VISION-NE energy demand projections for different scenarios.

The use of the three tools is illustrated schematically in Figure 3-1, which depicts a three-step calculation. First, the GREET model (via the GREET Interface Tool) calculates lifecycle carbon emission factors for each fuel type or pathway. Second, VISION projects the amount of each fuel required to meet transportation and home-heating energy demand in the Northeast. Third, and last, we use the AFCI Calculator to arrive at a weighted average of the carbon intensities of each fuel.

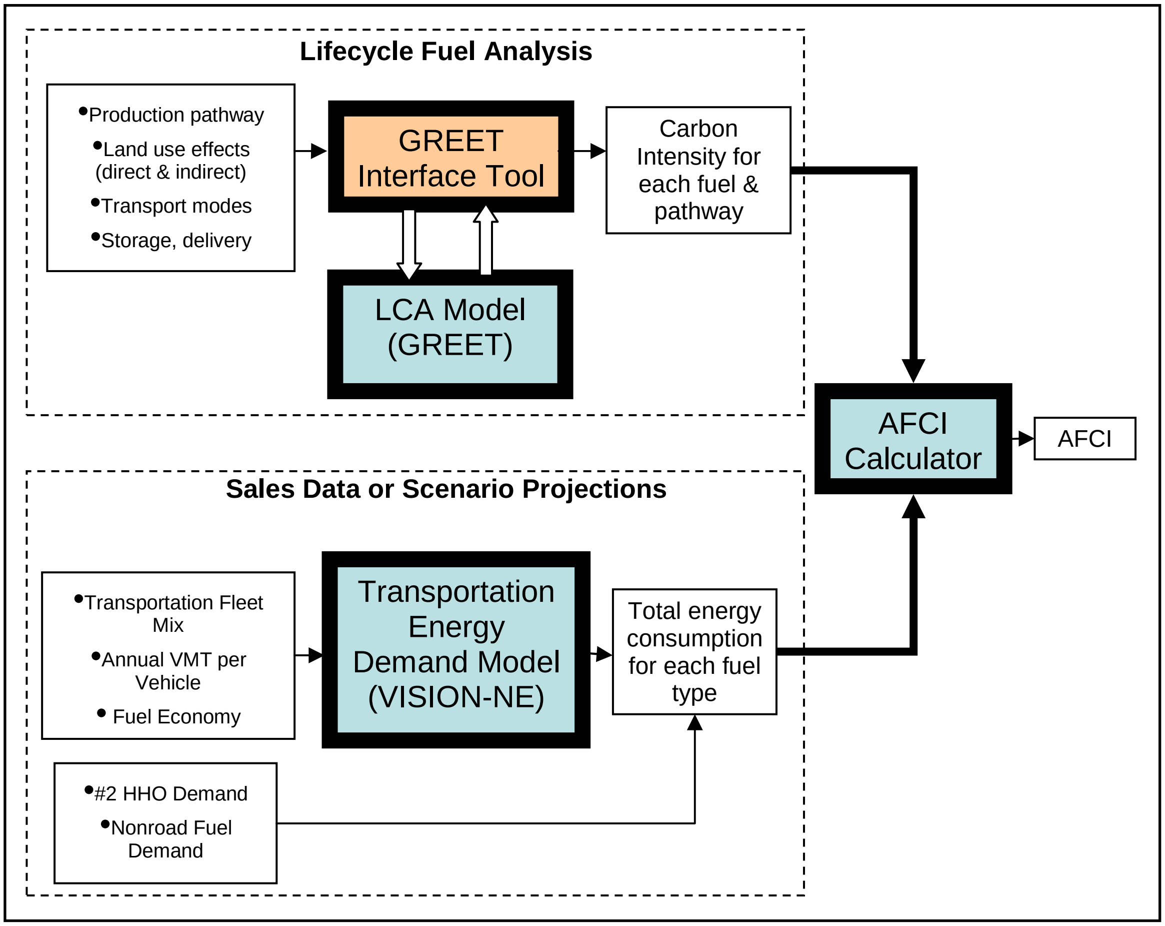

Figure 3-1 Schematic of modeling tools used in NESCCAF scenario analysis

Prior to presenting the findings of this scenario analysis, it is important to discuss the sensitivity of the results to the carbon intensity of biofuels. This is important in the context of the current debate about the amount of GHG emissions that are associated with land use changes resulting from biofuel production.

3.3. Sensitivity of Results to the Carbon Intensity of Biofuels

Recent studies have suggested that when a comprehensive lifecycle assessment that takes into account the land-use changes induced by increased demand for biomass feedstocks is applied to conventional biofuels such as corn-based ethanol, their carbon benefit may be substantially lower than previously thought, and could in fact be negative. At the time of this writing a spirited debate is taking place in academic and agricultural communities regarding the validity and importance of these findings. Because the outcome of this debate could ultimately change not only the magnitude of the lifecycle carbon benefit assigned to biofuels, but its sign (in the sense that the net effect of conventional biofuels use may be to increase emissions rather than reduce them), a decisive assessment of how these fuels would contribute (or not) toward achieving an LCFS cannot be made at this time.

Uncertainty about the influence of land use change on the lifecycle carbon intensity of certain biofuels has important implications not just for the effectiveness of possible compliance strategies, but also for the baseline AFCI score from which reductions are measured. Corn ethanol has been used throughout the Northeast as a blended oxygenate in commercial gasoline since 2004. (See Appendix C for a discussion of the phase-in of ethanol in the region.) If blended ethanol is found to have a carbon intensity that is different from that of gasoline (either lower or higher), the region's baseline gasoline AFCI would be affected for 2004 and subsequent years. This in turn could affect the difficulty of meeting a particular AFCI reduction target. We return to a discussion of the policy implications of the current land use debate in Chapter 5.

For the scenarios presented in this report, we assume that the baseline fuel carbon intensity is equal to that of RBOB at 96.7 gCO2e/MJ. Any new ethanol introduced to the Northeast fuel supply would therefore need a lifecycle carbon intensity lower than 96.7 gCO_2e/MJ to make any contribution toward meeting an LCFS designed to achieve carbon reductions relative to the baseline fuel. The range of uncertainty regarding the lifecycle carbon intensity of conventional ethanol is currently quite large: some maintain that historical estimates of lifecycle carbon intensity in the neighborhood of 73 gCO2e/MJ are valid, while others argue that the actual value could be many times that number. CARB has recently proposed a value of 35 gCO2e/MJ to account for the net *increase* in carbon emissions associated with upstream land use changes induced by expanded ethanol feedstock production—this figure would need to be added to any carbon intensity values for corn ethanol that do not include land use impacts (such as the 73 gCO2e/MJ figure assigned by GREET). The 35 gCO2e/MJ figure is a mid-range estimate: CARB's research indicated that carbon impacts from upstream land-use changes impacts could range from 20 gCO2e/MJ to as much as 88 gCO2e/MJ. This implies that accounting for land use change could increase the total lifecycle carbon intensity assigned to corn ethanol to 93–160 gCO2e/MJ.

illustrates the sensitivity of the gasoline AFCI to the carbon intensity of ethanol. The bars show the carbon intensity of an E10 (10 percent ethanol by volume) ethanol/gasoline blend under varying assumptions for the carbon intensity of the neat ethanol that is used. (Note that this would also represent the regional AFCI if 10 percent of the total gasoline supply were displaced by ethanol, either by providing E10 region wide, or some combination of lower-level blends and E85). For example, the top (light grey) bar shows that for an ethanol carbon intensity of 160 gCO2e/MJ (the highest of likely values published by CARB) the carbon intensity of an E10 blend would be 99.7 gCO2e/MJ, 3 percent higher than the carbon intensity of RBOB. The bottom (blue) bar shows that for an ethanol carbon intensity of 12 gCO2e/MJ (the carbon intensity estimated for ethanol produced by gasifying woody biomass) the overall carbon intensity of an E10 blend would be 92.8 gCO2e/MJ, 4 percent lower than for RBOB. The chart also shows carbon intensity values for E10 assuming CARB's proposed default ethanol carbon intensity (97.2 gCO2e/MJ); the low end of CARB's published range of carbon intensity values for conventional ethanol (96.5 gCO2e/MJ); the federal RFS requirement for new corn ethanol (95.8 gCO2e/MJ); the GREET default value for corn ethanol (95.6 gCO2e/MJ); the federal RFS value for "advanced" ethanol (94.5 gCO2e/MJ); and the RFS value for cellulosic ethanol (94.0 gCO2e/MJ).[13]

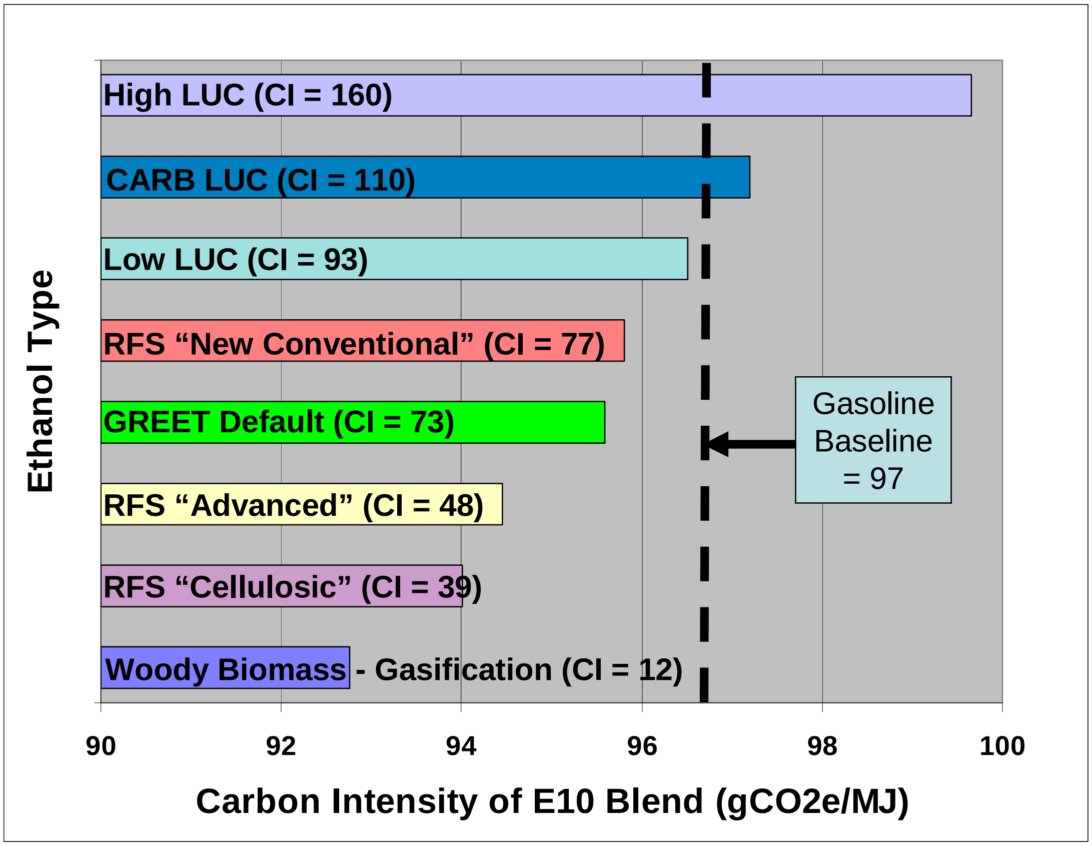

Figure 3-2 Sensitivity of the CI for a gasoline/10 percent ethanol blend to ethanol CI

The next sections discuss a number of other assumptions pertinent to the development of compliance scenarios for gasoline and diesel under a Northeast LCFS.

3.4. Gasoline Scenarios

The scenarios that follow describe three hypothetical pathways for achieving a 10 percent reduction in the average carbon intensity of the Northeast's gasoline supply by 2020. The reader will note that in some graphs a certain type of low carbon substitute fuel is specified, for example cellulosic ethanol. In other scenarios, only the carbon intensity of the low carbon fuel or combination of low carbon fuels is noted, reflecting the likelihood that different types of

[13] The Energy Independence and Security Act of 2007 calls for the RFS to be modified to include volumetric requirements for specified fuel types based on their lifecycle carbon emissions benefit as compared to baseline fuel. Specifically, EISA requires that corn ethanol produced in plants not built or under contrsuction as of the time of the bill's signing achieve a 20% reduction in lifecycle emissions; ethanol designated as "advanced" must achieve a 50% reduction; and in order to qualify for the "cellulosic" designation, ethanol must achieve a 60% reduction from the gasoline baseline. Biodiesel must achieve a 50% reduction from a diesel baseline.

advanced fuels will be used as substitutes for gasoline under an LCFS. Such fuels could be derived from different feedstocks (e.g., woody biomass, municipal solid waste) using different production processes; they could also include non-liquid fuel alternatives, such as electricity. NESCCAF did not study the technical feasibility or market readiness of advanced or emerging biofuel technologies. Rather our scenario analysis is intended only to illustrate the quantities of various types of fuels that would be required to meet a given AFCI reduction target. Any number of combinations of advanced fuels could produce an average carbon intensity value equivalent to that generically assumed to characterize low carbon fuels for purposes of this analysis.

3.4.1. Scenario Results

The first scenario illustrates a case where a 10 percent reduction in the carbon intensity of gasoline is achieved using a combination of non-liquid gasoline substitutes (electricity) and advanced biofuels with a carbon intensity of zero.

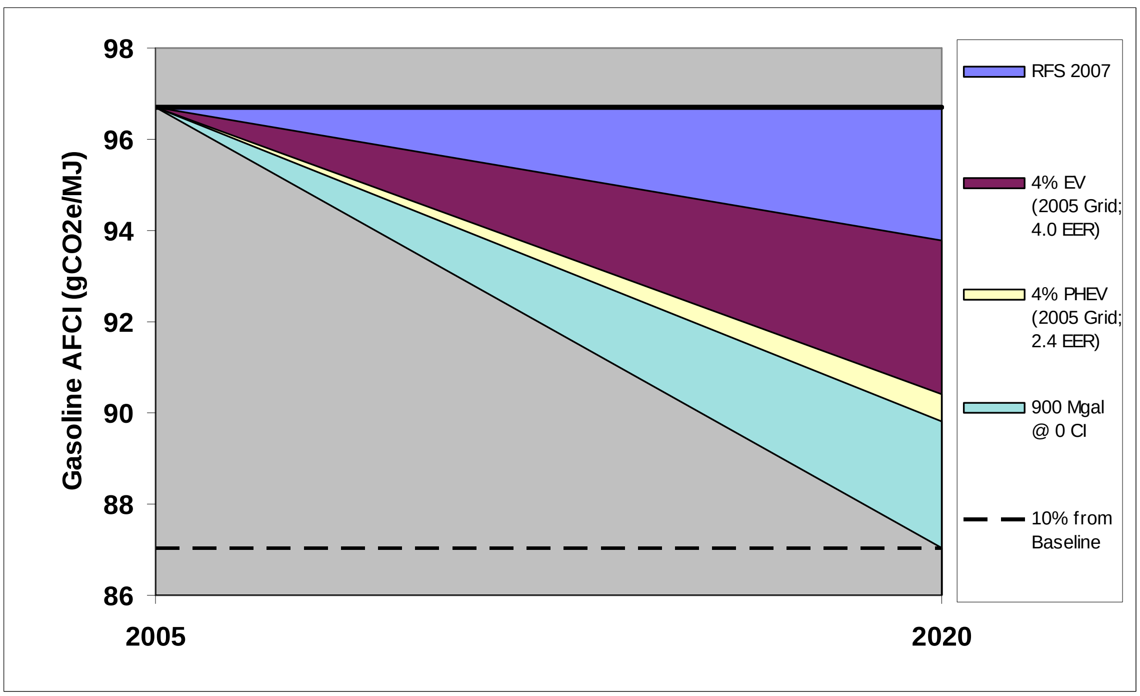

Figure 3-3 Low carbon ethanol, electric vehicle, and plug-in hybrid scenario (G1)

The scenario assumes that all-electric and plug-in hybrid vehicles will be charged with the 2005 average generation mix. A detailed discussion of the sensitivity of the electricity carbon intensity value to different assumptions about the types of fuel used to generate the electricity is provided in sections 3.3.2 and 3.3.3 of this chapter. The scenario also assumes that around 10 percent of total gasoline demand is met with an advanced substitute fuel that has a carbon intensity value equal to zero. In this scenario, EVs and PHEVs each account for 4.4 percent of the overall light-duty fleet and 12 percent of new light-duty vehicle sales in 2020. This level of fleet penetration can be achieved by linearly increasing EV and PHEV sales each year from a baseline projection of 1.2 percent of total new vehicle sales in 2011. In addition to increased numbers of EVs and PHEVs, this scenario requires 900 million gallons of a zero-carbon-intensity advanced gasoline substitute fuel to achieve an overall 10 percent reduction from the AFCI baseline.

Ethanol produced via cellulosic fermentation of woody biomass is an example of an advanced fuel that could achieve a carbon intensity of zero. Note, however, that the 900 million gallon volume of zero carbon intensity fuel assumed in this scenario far exceeds likely production capacity for cellulosic ethanol from woody biomass in the Northeast; NESCCAF estimates that the region could produce around 300 million gallons of this type of fuel per year. Other zero-carbon-intensity fuels from inside or outside the region would therefore be necessary to provide the AFCI benefit shown in Scenario G1.

As with all scenarios presented in this report, we assume an energy economy ratio[14] (EER) of 4.0 for EVs and 2.4 for PHEVs, and we assume that the federal RFS will result in 1.3 billion gallons of cellulosic ethanol (defined as achieving a 60 percent carbon intensity reduction from the gasoline baseline), 300 million gallons of "advanced" ethanol (defined as achieving a 50 percent lower carbon intensity than gasoline), and 200 million gallons of "new" corn ethanol (20 percent lower carbon intensity than gasoline) delivered in the Northeast by 2020. The specific carbon intensity reductions attributable to different components of Scenario G1—in other words, for each of the wedges shown in Figure 3-3—are summarized in Table 3-3. Column 4, labeled "incremental reduction" refers to the reduction in the baseline fuel carbon intensity achieved by the measure noted in Column 1. Column 5, labeled "total reduction" shows the cumulative reduction from the baseline fuel average carbon intensity with the combined strategies listed in Column 1.

Table 3-3 Carbon impacts for each component of compliance scenario G1

	2020 AFCI	Incremental Reduction	Total Reduction
Baseline	96.7		
RFS 2007	93.8	3.0%	3.0%
4% EV (2005 Grid; 4.0 EER)	90.4	3.5%	6.5%
4% PHEV (2005 Grid; 2.4 EER)	89.8	0.6%	7.1%
900 Mgal @ 0 CI	87.0	2.9%	10.0%

The next compliance scenario, G2, is designed to explore the impact of a cleaner electricity generating grid. As in scenario G1, Scenario G2 achieves compliance with the LCFS through

14 The energy economy ratio is a measure of the energy efficiency of an electric drive vehicle relative to a baseline conventional vehicle. It is defined as the distance an EV will travel divided by the distance a reference vehicle will travel for a given amount of energy. For example, an EV with EER of 4 will travel four times farther than a conventional vehicle using the same amount of energy.

the introduction of all-electric and plug-in hybrid vehicles, combined with a substantial amount of low carbon liquid fuels.

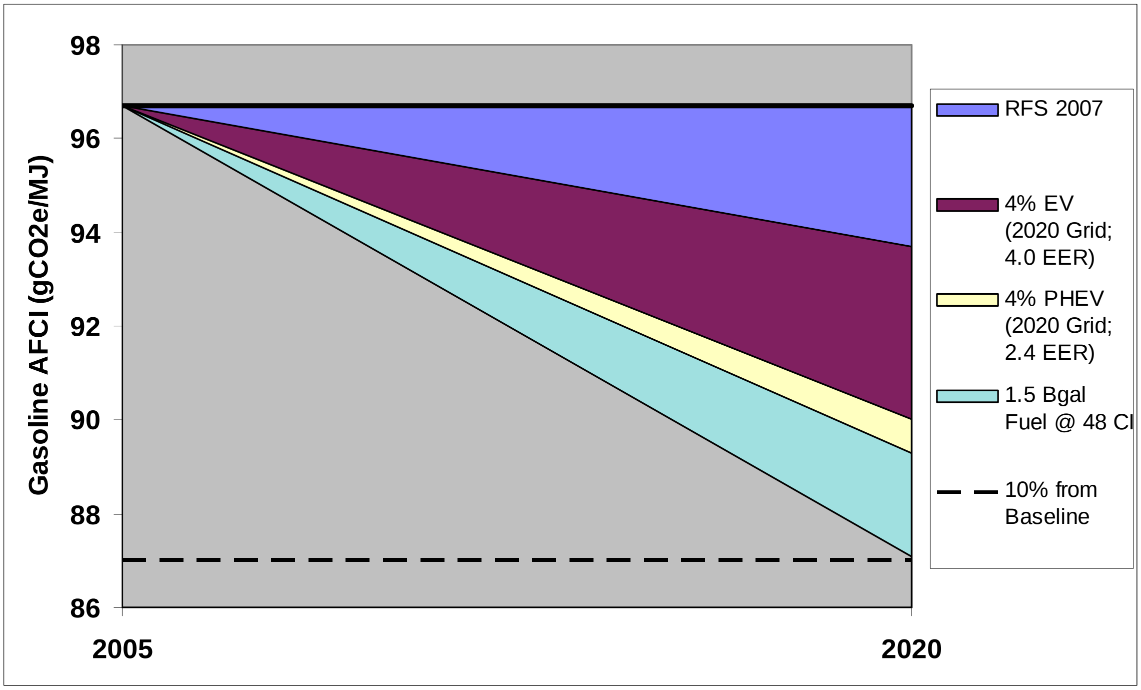

Figure 3-4 Low carbon ethanol and cleaner (lower-carbon) electric grid scenario(G2)

As in Scenario G1, Scenario G2 illustrates a 10 percent reduction in the gasoline AFCI using a combination of all-electric and plug-in hybrid vehicles, but in this case these vehicles are assumed to be charged with the 2020 projected average generation mix. In addition, we assume that 1 billion gallons of a low (but not zero) carbon liquid fuel displace conventional gasoline. (Note that in this scenario, a larger volume of low carbon liquid fuel is required since the carbon intensity of the fuel, at approximately 50 percent that of conventional gasoline, is significantly higher than that of the zero-carbon liquid fuel assumed for Scenario G1.) As in G1, this scenario assumes that EVs and PHEVs each account for 4.4 percent of the light-duty fleet in 2020. The liquid low carbon fuel component has a carbon intensity of 39 gCO2e/MJ, which is consistent with the RFS requirement for cellulosic ethanol—that is, a 60 percent carbon intensity reduction relative to gasoline. As already noted, other assumptions concerning the efficiency of EVs and PHEVs and the carbon characteristics of other categories of RFS-compliant ethanol (explained previously in our discussion of Scenario G1) are consistent across all the compliance scenarios analyzed. Under this set of assumptions, it would take 1 billion gallons of RFS-compliant cellulosic ethanol (in addition to the volume already supplied to comply with the RFS itself) to achieve the 10 percent AFCI reduction target in Scenario G2. The specific intensity reductions attributable to each component of Scenario G2 are shown in Table 3-4.

Table 3-4 Carbon impacts for each component of compliance scenario G2

	2020 AFCI	Incremental Reduction	Total Reduction
Baseline	96.7		
RFS 2007	93.7	3.1%	3.1%
4% EV (2020 Grid; 4.0 EER)	90.0	3.8%	6.9%
4% PHEV (2020 Grid; 2.4 EER)	89.3	0.7%	7.7%
1.5 Bgal Fuel @ 48 CI	87.1	2.3%	10.0%

The next scenario, G3, illustrates a compliance pathway that relies solely on electric and plug-in hybrid vehicles and the advanced biofuel contribution mandated under the federal RFS (that is, it assumes no additional biofuels beyond the minimum volume required by the RFS).

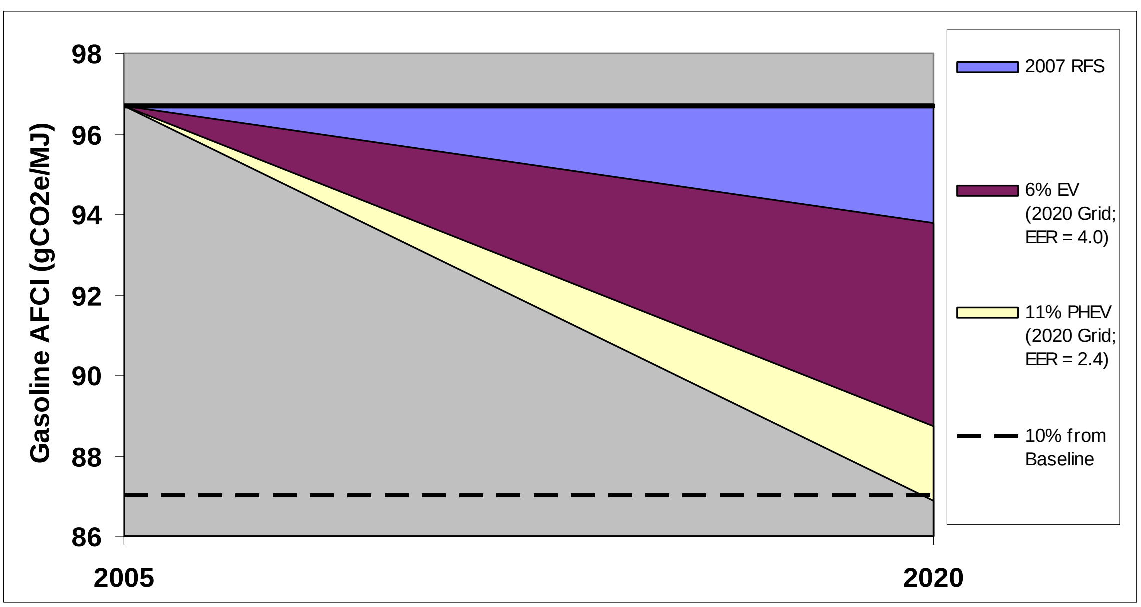

Figure 3-5 All-electric and plug-in hybrid vehicles only scenario (G3)

Scenario G3 relies on a higher fleet penetration of all-electric and plug-in hybrid vehicles, all charging with the 2020 projected average generation mix, to achieve a 10 percent reduction in overall AFCI. In this scenario, EVs and PHEVs account for 6 percent and 11 percent, respectively, of the light-duty fleet in 2020. EVs account for 16 percent of new light-duty vehicle sales in 2020, up from a projected 1.6 percent share of new vehicle sales in 2011; plug-in hybrids account for 20 percent of new LDV sales in 2020, up from a projected 2 percent share in 2011. The specific carbon intensity reductions attributable to each component of Scenario G1 are summarized in Table 3-5.

Table 3-5 Carbon impacts for each component of compliance scenario G3

	2020 AFCI	Incremental Reduction	Total Reduction
Baseline	96.7		
2007 RFS	93.8	3.0%	3.0%
6% EV (2020 Grid; EER = 4.0)	88.7	5.2%	8.2%
11% PHEV (2020 Grid; EER = 2.4)	86.9	1.9%	10.1%

2.6.2. Key Assumptions for the Gasoline Compliance Scenarios

A critical question for policy makers concerns the plausibility of the assumptions that underlie the gasoline compliance scenarios discussed above. First, there are the assumptions about EV and PHEV fleet penetration. The fleet share of any given vehicle type is a function of that vehicle's market share in prior years as well as the fleet turnover rate. We assumed that no significant sales of EVs or PHEVs occur before 2011, and that sales increase linearly from that year until 2020 for each scenario (thus for every scenario, market share in 2011 is equal to one-tenth the 2020 target value). In order to achieve an overall fleet penetration level of 4.4 percent in 2020 from a starting point of 1.2 percent of all new light-duty vehicle sales in 2011 implies that sales need to increase to 12 percent of the market in 2020. Similarly, to achieve an overall fleet penetration level of 6 percent in 2020 implies a 16 percent share of new vehicle sales in 2020; while a 7.5 percent fleet penetration rate in the same year implies a market share of 20 percent in 2020.

In Scenario G3 (which includes the most aggressive assumptions for penetration of electric-drive technologies), over one-third of total vehicle sales in 2020 will need to be either PHEVs or EVs. Given that no models of either type of car are available now in significant numbers, these penetration rates are very optimistic. For comparison, Toyota's first mainstream hybrid (the Prius) first went on sale in 1997; Toyota now offers six models of hybrids that together comprise 12 percent of Toyota's annual sales.[15] In scenarios G1 and G2, sales penetration rates of both plug-in hybrids and all-electric (or battery-electric) vehicles would need to match the sales trajectory of the Toyota hybrid for the entire fleet (all manufacturers) by 2020; in Scenario G3, sales rates for electric-drive vehicles would need to far outstrip Toyota's record in the same timeframe.

[15] Robert Wimmer "Advanced Technologies at Toyota," MSTRS presentation September, 2008.

While these sales numbers are optimistic, they are not inconceivable. Many automakers have announced ambitious product plans for advanced vehicles that, if aggressively implemented, could signal an unprecedented shift in the makeup of the U.S. light-duty fleet. As examples, GM has announced plans to offer Volt (with its 40-mile all-electric range) for sale in 2010. Toyota has announced the sale in 2009 of a PHEV with a 7-mile all-electric range. Chrysler is considering at least two EV models for release in 2010. BMW plans to sell 500 all electric "Cooper Minis" in the U.S. in 2008. Mitsubishi plans to introduce an electric vehicle with a range of 100 miles in 2010. Nissan has announced a pure electric car for fleets in 2010 and for sale to retail consumers in 2012.[16] Numerous variables will affect the fleet penetration trajectory of EV and PHEV sales, including gasoline prices, tax credits, availability of models, vehicle performance, federal and state incentives or mandates, the availability of "smart" charging infrastructure, and other factors.

The characteristics of the EVs and PHEVs that manufacturers are planning to introduce in coming years will likely vary considerably. This is an important consideration, because the results of EV/PHEV scenario modeling are highly sensitive to assumptions about both vehicle technology and electric generating mix. The next section discusses the significance of the electric generating mix in determining the carbon intensity of electricity used for charging EVs and PHEVs.

Determining the Carbon Intensity of Grid Electricity Used in Vehicle Applications

The carbon intensity of electricity as used in electric-drive vehicles depends on the generation mix and on the efficiencies of the vehicle itself and the conventional vehicle that it is displacing. For this analysis, we adopted CARB's assumptions of an Energy Economy Ratio or "EER" of 4.0 for EVs and 2.4 for PHEVs. (See Appendix A for a discussion of the rationale and basis for the use of an EER in calculating carbon intensity for electric-drive vehicles.) We then modeled several assumptions for the generation mix to illustrate the impact of the generating technology on electricity carbon intensity.

As discussed in Chapter 5, the precise mix of generating technologies that might provide electricity to charge electric-drive vehicles will depend on the design of the vehicles themselves (e.g., battery size and charging voltage), consumer preferences (e.g., how frequently and at what time of day the consumer chooses to plug in), as well as the total number of electric-drive vehicles in the fleet. Because PHEVs in particular will provide drivers with considerable discretion in choosing their energy source, and because there has been virtually no commercial experience with these vehicle technologies to date, it is very difficult to predict the precise way in which PHEVs will be used, and thus the appropriate grid mix that will accompany their use. To illustrate the range of possible values, we have calculated electricity carbon intensity for each major generator type and for the average grid mix in the 2005 baseline year and as projected in 2020. As discussed in Chapter 5, the marginal grid mix for a given charging event is likely to differ from the average mix, and in many cases may be a single technology.

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[16] Automotive News "Electrics Edge Closer by 2010," November 3, 2008

Table 3-6 shows the current mix of electricity generation in the Northeast, and the projected 2020 generating mix which includes the effects of RGGI and state-specific Renewable Portfolio Standards (RPSs). NESCCAF generated these grid projections using the MARKAL model.

Table 3-6 Current and projected sources of electricity, NESCAUM region

Source	2005 GWH	2005 Share	2020 GWH	2020 Share
Coal	54,200	16%	22,500	8%
Nuclear	103,000	31%	52,000	18%
Natural gas	105,000	31%	118,000	41%
Oil	31,900	10%	10,200	4%
Hydro	28,600	9%	20,900	7%
Renewable (non-hydro)	13,200	4%	67,500	23%
Total	335,000	100%	291,000	100%

As discussed above, the generation mix has a large impact on the carbon intensity associated with EVs and PHEVs. As can be seen from Table 3-6, 26 percent of Northeast electricity in 2005 was produced with either coal or oil, which are the two most carbon-intense conventional generating fuels, while over 40 percent of total electric generation came from nuclear along with hydro and other renewable sources, which are comparatively low-carbon generating technologies. Figure 3-6 shows how the carbon intensity of electricity changes with different generating technology and energy sources, along with the current and projected average generation mix. As discussed above and in Appendix A, we assume energy-efficiency ratios of 4.0 for EVs and 2.4 for PHEVs throughout this analysis. Figure 3-6 illustrates the sensitivity of electricity carbon intensity to EER and grid mix. The figure shows that all types of electricity will have a CI that is lower than the gasoline baseline when used to charge a vehicle with a 4.0 EER. When used in a vehicle with a 2.4 EER, however, coal and oil generation give a carbon intensity that is higher than that of gasoline. Even with the more efficient 4.0 EER EV, coal and oil offer only a slight improvement over gasoline, while natural gas, nuclear, and renewables (including hydro and many types of biomass) provide substantially lower CI compared to gasoline.

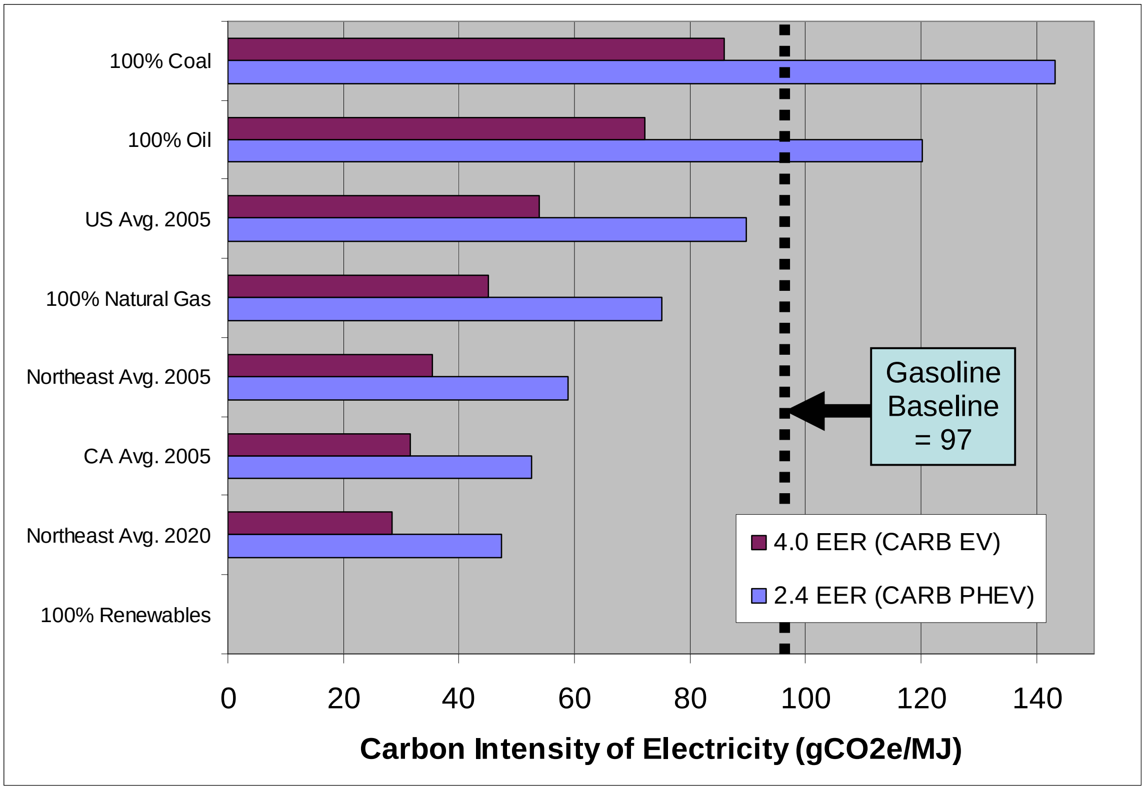

Figure 3-6 Carbon intensity of electricity with different energy sources for generation

It is clear from Figure 3-6 that shifting the grid mix from high-carbon to low-carbon generating fuels, or applying some policy mechanism to ensure that EV/PHEV charging is tied directly to low-carbon power, will enhance the effectiveness of electricity as an LCFS compliance option.

Effect of charging time on grid profile

In practice, the electricity used for vehicle charging will most likely not be generated by an average of all the region's power plants, but rather by the marginal generating unit (or units) at the time that the vehicle is plugged in for recharging. In turn, the number of vehicles plugged in at any given time, and the power they demand, will influence the marginal technologies used to provide power to the grid (thereby affecting CI) as well as the capacity of the grid itself to accommodate the power demands of these vehicles.

The high cost associated with building new generating capacity, if needed, could present a barrier to large-scale penetration of EVs and PHEVs into the region's fleet. In the Northeast (as elsewhere), excess electricity generating capacity exists at night but not during the day. EV and PHEV owners, however, could potentially choose to plug in their vehicles at any time of the day. They might also be able to control the charging speed, which determines the power demanded during a given charging event. If enough PHEV owners were to attempt to plug-in at a time when traditional electric loads are at their peak, there may be insufficient capacity to accommodate them. If these owners chose (or were persuaded) to charge their batteries at night, then a certain number could be accommodated with the existing grid and no additional capacity would be needed. It is likely that vehicles will be recharged during both daytime and nighttime, and thus some additional capacity will likely be needed.

The time of day that a vehicle owner chooses to plug in not only affects the amount of additional electricity generating capacity needed, but also the way (or ways) in which the electricity is generated. For example, the marginal generating technology during peak periods – such as in the afternoon of a hot summer day – could be a relatively low-CI natural gas turbine. On the other hand, recharging at night might draw electricity from a baseload coal plant (with a relatively high CI), or from renewable sources operating at night, such as wind turbines. See Chapter 5 for a discussion of the impact of charging time and power demand on grid mix, and the ability of the current and projected grid to accommodate substantial fleet penetration of these advanced vehicles.

The scenarios presented in this report are intended to illustrate important dynamics at play in the design and implementation of an LCFS – they should not be taken to suggest the readiness of any particular technology. Because the attractiveness of EV/PHEV technology as an LCFS compliance option depends heavily on technologies that have not matured commercially, and on consumer attitudes and behaviors that have not yet been tested, we stress that the results presented here are highly uncertain. While we believe that our assumptions for EV/PHEV charging behavior and grid mix are plausible, by no means do they represent the only set of plausible assumptions. With advances in vehicle design, which could result in higher EERs than those assumed in this analysis, EVs and PHEVs may deliver a greater CI reduction than is assumed here. If that turns out to be the case, then fewer electric-drive vehicles will be needed in order to meet a given CI reduction target. However, if the fleet penetration rates envisioned in these scenarios turn out not to be feasible due hurdles in technology development, deployment of charging infrastructure, cost, or consumer attitudes, or if sufficient low carbon generating technologies are not available, electric-drive vehicles will be a less effective strategy for LCFS compliance.

As mentioned above, the success of electric-drive vehicles as an LCFS compliance option depends not just on vehicle characteristics and driver behavior, but also on the availability of low-carbon electricity for battery charging. Scenarios G1 and G2 envision over 3 million electric drive vehicles on Northeast roads by 2020, consuming 48,000 GWh. Scenario G3 envisions nearly 5 million vehicles, with a total energy demand of roughly 67,000 GWh. These demand totals represent around 14 percent and 20 percent of the total electricity demand in the Northeast in 2005. There may be sufficient baseload capacity during off-peak hours to accommodate this demand, but if a significant fraction of total charging demand were to occur during times of peak electricity demand, there would likely be a need for additional generating capacity in the Northeast. As mentioned above, the behavior of individual EV and PHEV owners will be a significant factor in determining the capacity of the existing grid to accommodate significant numbers of electric-drive vehicles.

Assumptions about the federal renewable fuels standard

The scenarios in this report incorporate several important assumptions about the federal RFS. First, all scenarios in this report assume that the Northeast receives a proportional share of the advanced biofuels required nationally under the RFS. If the several types of fuel mandated by the RFS are disproportionately distributed to one region of the county (e.g., if the Northeast were to get more or less than its proportional share of the national supply any one type of biofuel), the result could be to increase or decrease the impact of the RFS on the region's AFCI. Second, we assume that the RFS-mandated advanced biofuels will be commercially available in substantial volumes within the next decade. While biofuel production technologies have made promising advances, it is far from certain that these types of fuels will in fact be commercialized so quickly. Finally, we assume that no additional changes are made to the RFS between the time of the passage of EISA in 2007 and our target scenario year of 2020.

Given the above assumptions, NESCCAF estimates the impact of the RFS in the Northeast will be to lower the gasoline AFCI by 3 percent, and the diesel AFCI by 1 percent. A key policy question is whether the GHG benefits of the RFS should be "counted" toward compliance with a Northeast LCFS. If so, this would reduce the total new GHG reductions required by an LCFS for a given reduction target.

A more detailed discussion of the additional GHG reductions that would be needed, and how they might be achieved if the RFS is not counted toward LCFS compliance, can be found in Chapter 4.

Other key assumptions used in the scenarios

Several additional assumptions bear directly on the design and outcomes of most selected scenario projections. When considering multiple variables, however, the number of potential scenarios can quickly become impractical to simulate and to interpret. For the purpose of the scenario discussions presented in this chapter, we chose to "lock in" certain assumptions in order to facilitate comparison among scenarios. This should not be taken as a recommendation of a specific policy option. The benefits and drawbacks to each approach are explored in detail in Chapter 4. The significant policy choices that were held constant for the analyses described in this chapter are listed in Table 3-7.

Table 3-7 Summary of assumptions made in the gasoline compliance scenarios

Decision Item	Default Assumption
Gasoline baseline fuel mix	100% RBOB
Count LDDV toward Gasoline AFCI?	No
Scenario region for transportation demand	NE-8
Energy Economy Ratio (EER) for EVs	4.0
Energy Economy Ratio (EER) for PHEVs	2.4

The next section presents scenario results for the Northeast diesel vehicle fleet.

3.5. Diesel Scenarios

This section presents three potential compliance options for diesel fuel. Approximately 4 billion gallons of diesel fuel are used in the Northeast each year in highway applications such as trucks and buses and an additional 2 billion gallons are used in nonroad sources such as construction equipment. In addition to transportation diesel, approximately 4 billion gallons of No. 2 fuel are used to heat homes and commercial buildings in the region.

In the first two scenarios, only the 7 billion gallons of transportation diesel (including highway and nonroad fuel) are included in the assessment. In the third scenario, No. 2 diesel used for thermal heating is included. Thus, the volume of transportation diesel fuel (roughly 7 billion gallons) is added to the 4 billion gallons of heating oil used in the eight state region for a total of 11 billion gallons of diesel fuel used. As a result, when heating fuel is included, a much greater quantity of low carbon fuel substitutes are needed in order to meet a 10 percent reduction in the diesel AFCI. While this makes the challenge associated with meeting a 10 percent AFCI reduction target greater, it also increases the number of compliance pathways that are available. Further, adding heating oil to the fuels regulated under the LCFS expands opportunities to use regionally produced low carbon fuels.

An added benefit of including heating fuels in the LCFS is to guard against carbon intensity increases that might otherwise occur due to greater use of high-carbon heating fuels such as coal (already seeing a resurgence in the home-heating market[17]) and No. 2 oil from tar sands.

A number of approaches may be available to reduce the carbon intensity of transportation and heating fuel between now and 2020. Possibilities include low carbon biofuels (either oils or hydrocarbon fuels such as paraffins) derived from algae, waste oils, and other feedstocks. There is much uncertainty about the actual form that these advanced biofuels will take – given that they are in development stage at this time. Other approaches such as hybridization of heavy-duty vehicles may allow for the use of electricity to power some types of diesel vehicles. For the purpose of this analysis, we have not assumed the introduction of a particular type of advanced biofuel. We use the term “biodiesel” in the scenarios and this can represent biodiesel as it is defined by EISA and CARB. Other low carbon biofuels may be used to the same effect as biodiesel for a given CI.

As was necessary in the last section on gasoline where the impact of the carbon intensity of ethanol was discussed, here it is necessary to discuss the impact of the carbon intensity of biodiesel on the diesel fuel average carbon intensity. This is provided in the following section.

3.5.1. Effect of Biodiesel CI on Diesel AFCI

Until recently, soy biodiesel was considered to be the most likely substitute for diesel fuel in transportation sources. Just as with corn ethanol, however, an ongoing debate among experts on the effect of indirect land use change has resulted in considerable uncertainty about the true lifecycle carbon intensity of soy biodiesel. Documented deforestation in Southeast Asia resulting from Europe’s biofuel requirements has given regulators pause in instituting further volumetric requirements for biodiesel. As with ethanol and the gasoline AFCI, the usefulness of

[17] The New York Times, “Burning Coal at Home is Making a Comeback “ By T. ZELLER Jr. and S. MILKOWSKI (December 26, 2008) http://www.nytimes.com/2008/12/27/business/27coal.html.

biodiesel in reducing the diesel AFCI is dependent on the lifecycle carbon intensity of the biodiesel itself. Figure 3-7 shows the carbon intensity for a B20 blend under varying assumptions for the CI of the neat biodiesel used for blending.

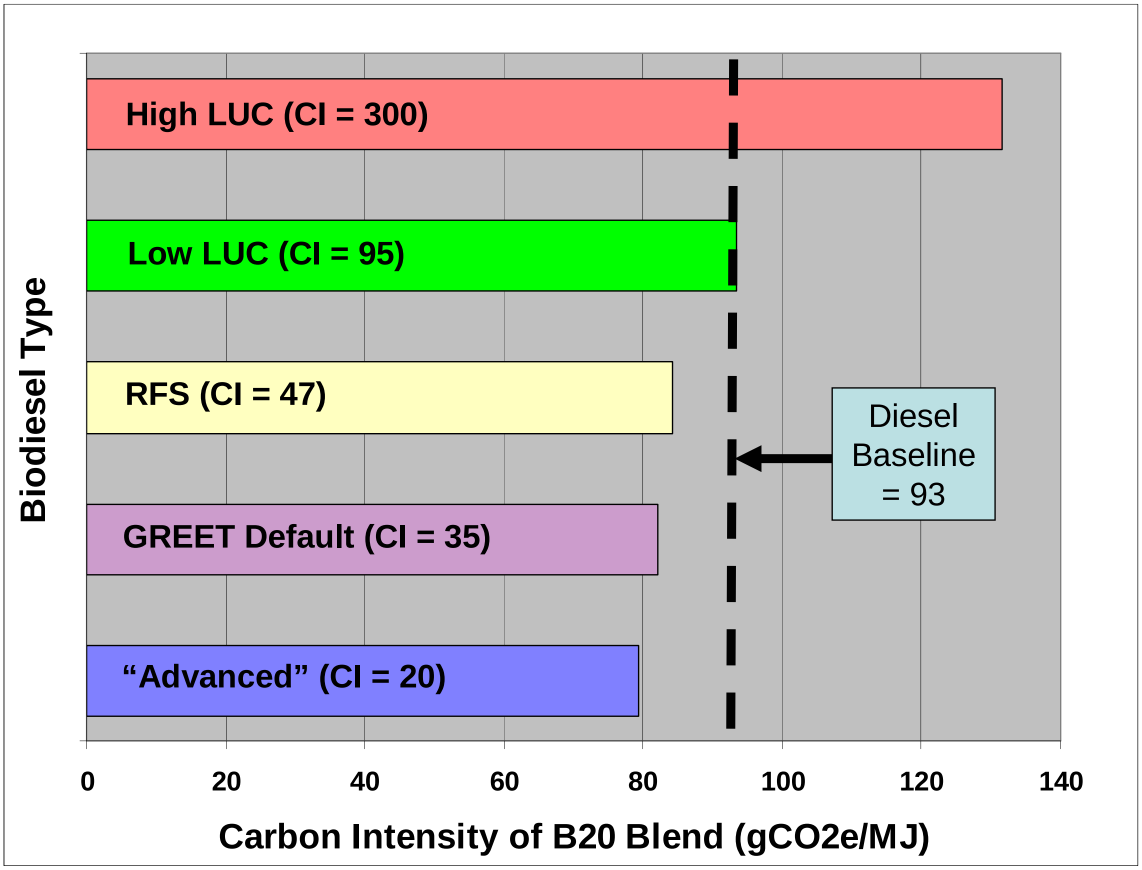

Figure 3-7 Sensitivity of diesel carbon intensity to the carbon intensity of biodiesel

Each bar of Figure 3-7 shows the carbon intensity in grams of CO2e per MJ associated with blends of 20 percent biodiesel, 80 percent diesel (by volume) – assuming different carbon intensities for the biodiesel fuel. The lower bar labeled "advanced (CI = 20)" shows very low carbon biodiesel blended into diesel fuel, the upper bars show comparatively carbon intensive biodiesel added to the fuel. With the addition of high carbon intensive biodiesel, as in the case of the top two bars, the average carbon intensity of the diesel blend is actually higher than conventional diesel fuel (which is equal to 93 gCO2e/MJ as indicated). The use of RFS-compliant or more "advanced" biodiesel lowers the carbon intensity of B20 below that of conventional diesel.

As discussed in section 3.2, there is not yet consensus with respect to the effect of indirect land-use change on the carbon intensity of crop-based biofuels. Given that production of soy biodiesel requires more land per unit of fuel energy produced than does corn ethanol, it is possible that any land use change effect that exists for corn would be even more pronounced for soy biodiesel. On the other hand, the co-products of soybean production tend to be of higher value than those for corn, which could lessen or even negate any disbenefit associated with indirect land-use change caused by soy biodiesel production. To illustrate the scale of the possible AFCI impact if land use change effects are found to be applicable, Figure 3-8 includes "high" and "low" cases for land use change effects. We estimated these effects by starting with the CARB upper and lower bounds for ethanol, and multiplying them by a factor of three to account for the increased acreage required to generate a similar amount of energy from soy oil as compared to corn ethanol. To the extent that land use change effects are less significant for soy biodiesel than for corn ethanol, the B20 carbon intensity would likely fall within the range of the more advanced options shown in the lower bars in Figure 3-8. We emphasize that these values are not intended to be predictive of any outcome of the current debate or of the actual land use change effect on the carbon intensity of biodiesel. Nor are they intended to suggest "best" or "worst-case" scenarios. Rather, they are presented to illustrate the potential role that biodiesel could play in light of the ongoing discussion.

3.5.2. Diesel Scenario Results

In this section, we present three possible diesel compliance scenarios. The first scenario (D1) shown in Figure 3-8 illustrates one possible combination of advanced biofuels in highway and nonroad engines that could be used to achieve a 10 percent reduction in the carbon intensity of transportation diesel in 2020.

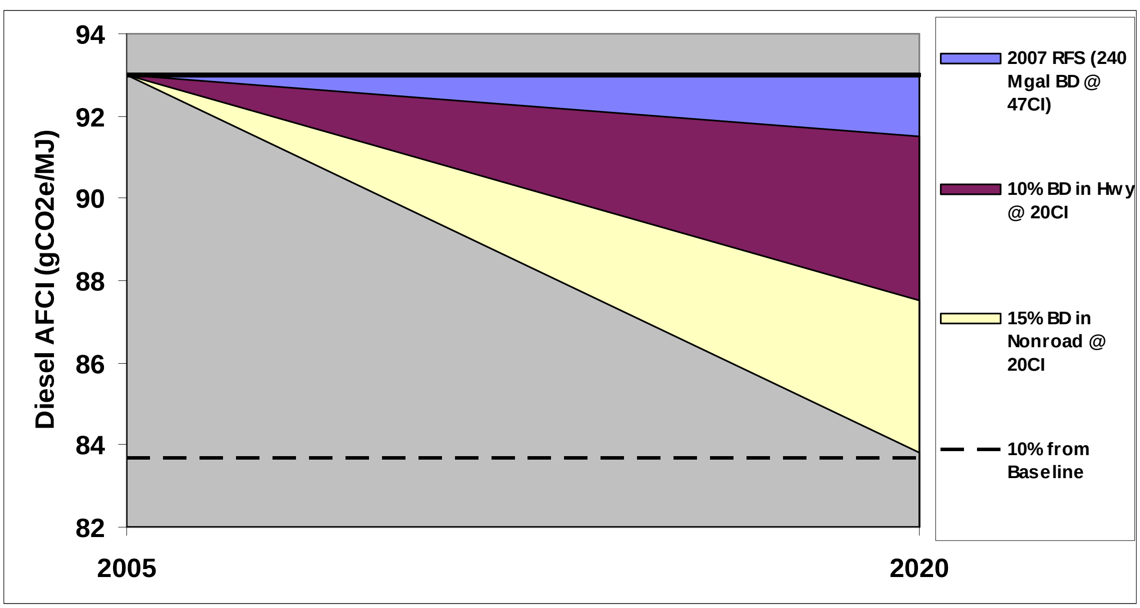

Figure 3-8 Diesel fleet potential compliance scenario with advanced biofuel (D1)

The graph illustrates a 10 percent reduction in Diesel AFCI through the combined effects of the RFS and significant displacement of both highway and nonroad diesel fuel with an advanced substitute that achieves a low CI of 20 gCO2e/MJ. The first wedge (in dark blue) represents a 1.6 percent reduction in the diesel AFCI resulting from the proportional deployment in the region of the advanced (50 percent CI reduction) biodiesel as required under the RFS. The second wedge (maroon) assumes that 10 percent of all highway diesel fuel will be replaced by an advanced biofuel with a CI of 20. This strategy would reduce the diesel AFCI by approximately 4 percent. The third approach (yellow wedge) represents 15 percent of nonroad diesel fuel being replaced with an advanced biofuel with a CI of 20 gCO2e/MJ. The specific carbon intensity reductions attributable to each component of Scenario D1 are summarized in Table 3-8.

Table 3-8 Summary results for scenario D1

	2020 AFCI	Incremental Reduction	Total Reduction
Baseline	93.0		
2007 RFS (240 Mgal BD @ 47CI)	91.5	1.6%	1.6%
10% BD in Hwy @ 20CI	87.5	4.3%	5.9%
15% BD in Nonroad @ 20CI	83.8	4.0%	9.9%

The next scenario (D2) illustrates a combined approach to meeting a 10 percent reduction requirement in diesel average carbon intensity. In this scenario, compressed natural gas and advanced biofuels are used. Figure 3-9 illustrates the amount of different types of fuels that would be needed to achieve a 10 percent reduction in the carbon intensity of transportation fuel in 2020.

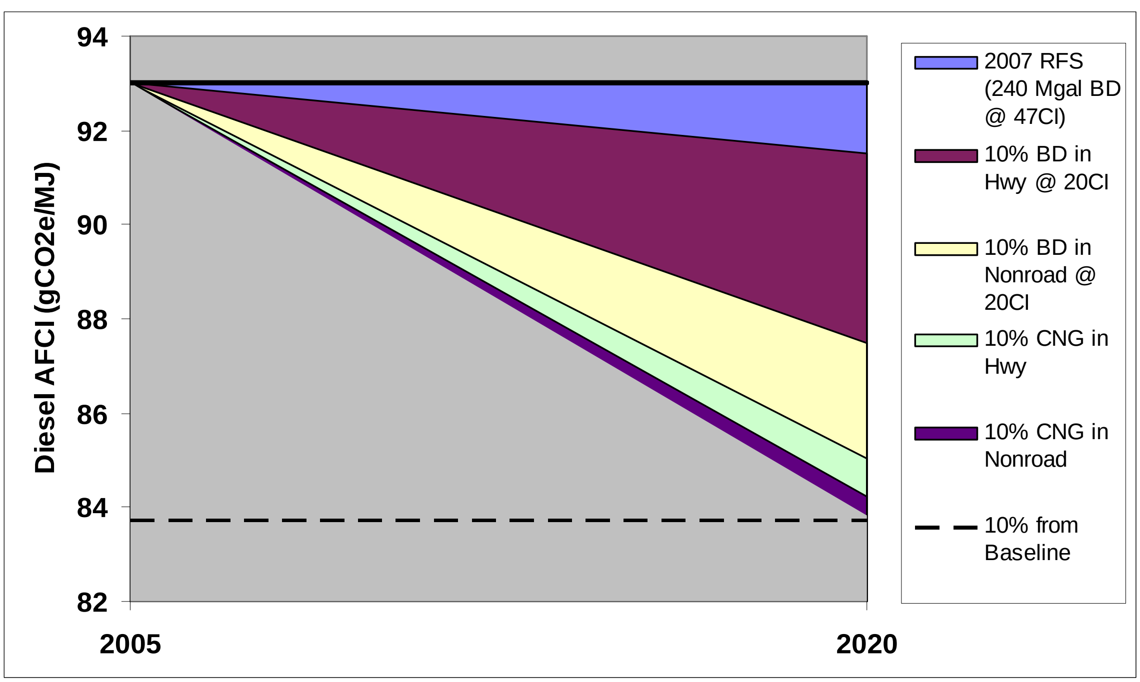

Figure 3-9 Advanced biofuel and natural gas use for LCFS compliance (D2)

As in scenario D, we assume here that the RFS results in the sale of 240 million gallons of 47-CI biodiesel in the Northeast in 2020. Assumptions about the volume of low carbon biodiesel into the highway diesel transportation pool – above and beyond that required by the federal RFS – are also the same as in scenario D1. Unlike scenario D1, we assume in this scenario that much less biodiesel will be used in nonroad machines – 10 percent rather than 15 percent. The other key diference between scenarios D1 and D2 is the assumption that 10 percent of highway vehicles and nonroad machines will operate on compressed natural gas. In scenario D1, we assumed no use of compressed natural gas. The specific carbon intensity reductions attributable to each component of Scenario D2 are summarized in Table 3-9.

Table 3-9. Summary of measures shown in scenario D2 and carbon impacts

	2020 AFCI	Incremental Reduction	Total Reduction
Baseline	93.0		
2007 RFS (240 Mgal BD @ 47CI)	91.5	1.6%	1.6%
10% BD in Hwy @ 20CI	87.5	4.3%	5.9%
10% BD in Nonroad @ 20CI	85.0	2.6%	8.6%
10% CNG in Hwy	84.2	0.9%	9.5%
10% CNG in Nonroad	83.8	0.4%	9.9%

The next scenario (D3), unlike scenarios D1 and D2, assumes the 4 billion gallons of heating oil used each year in the Northeast are included in the LCFS. Scenario D3 illustrates one possible combination of low carbon fuels that could be used meet a 10 percent reduction requirement for transportation and heating fuels combined.

Figure 3-10 shows how including heating oil in the LCFS would provide opportunities for the use of regionally available low carbon fuels. The scenario also illustrates the significant additional volumes of low carbon fuels that would be needed if the 4 billion gallon of heating oil used each year in the eight-state region were included in the LCFS.

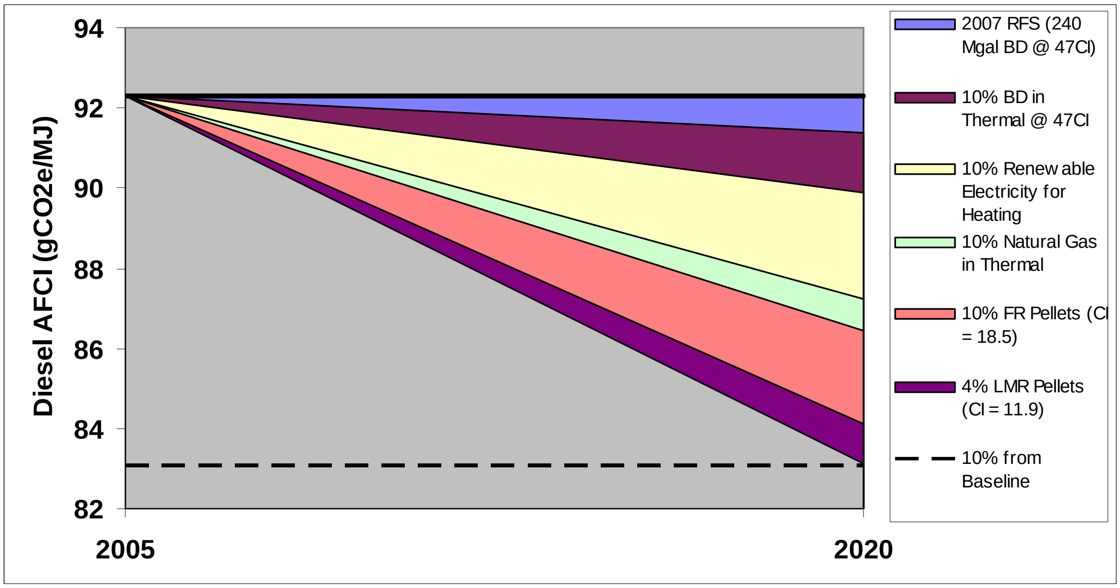

Figure 3-10 Including heating oil in an LCFS and a compliance scenario (D3)

For the transportation portions of diesel fuel, scenario D3 assumes that no changes to the fuel will be made. Instead, the 10 percent AFCI reduction from the combined pool of transportation diesel *and* heating oil will be achieved through displacement of heating oil with advanced biofuels, electricity, natural gas, and wood pellets. This scenario illustrates the different types of fuel switching options available for the heating oil sector. This sector provides an opportunity because technology exists today to switch from heating oil to natural gas, wood pellets, and electricity – all of which have the potential to reduce carbon emissions. In addition, some of these fuels are produced regionally rather than imported.

The specific AFCI reductions attributable to each measure for Scenario D3 are shown in Table 3-10.

As with all the scenarios presented in this chapter, we assume that the federal RFS will result in 240 million gallons of low-carbon biodiesel (achieving a 50 percent CI reduction from the diesel baseline) being delivered in the Northeast by 2020.

Table 3-10 Summary of measures shown in scenario D3 and carbon impacts

	2020 AFCI	Incremental Reduction	Total Reduction
Baseline	92.3		
2007 RFS (240 Mgal BD @ 47CI)	91.4	1.0%	1.0%
10% BD in Thermal @ 47CI	89.9	1.6%	2.6%
10% Renewable Electricity for Heating	87.2	2.9%	5.5%
10% Natural Gas in Thermal	86.4	0.9%	6.3%
10% FR Pellets (CI = 18.5)	84.1	2.5%	8.9%
4% LMR Pellets (CI = 11.9)	83.1	1.1%	10.0%

3.5.3. Discussion of Diesel Scenario Assumptions

How realistic are the assumptions made in the above three diesel scenarios? Currently in the U.S., approximately 300 million gallons of (mainly) soy biodiesel are produced annually. As discussed above, whether this fuel pathway will ultimately be part of a low-carbon fuel strategy is still unknown. No advanced biodiesel is currently being produced in large quantities, although a number of promising technologies are under development, such as production of biodiesel from algae, production of paraffins from wood, and other innovative approaches. Considering their pre-commercial status, an assumption that 1.5 billion gallons of advanced biodiesel will be sold in the Northeast in 2020 is a stretch goal at best.

The scenarios presented here do not include some potential technologies for heavy-duty vehicles that are currently under development, such as medium-duty plug-in hybrid trucks. A number of these vehicles are currently operating in pilot programs and in the future, the introduction of significant numbers of them may be possible. Their usefulness in complying with an LCFS depends on many of the same unknowns regarding grid mix, vehicle specifications, and user behavior that are discussed above with respect to light-duty EVs and PHEVs.

It is likely that some of the advanced biofuels that are currently under development will be available in significant quantities by 2020. But the precise types, CI values, and production volumes of these fuels are highly speculative – considering that for most fuel types production volumes would need to ramp from near zero to billions of gallons annually. The value of advanced biofuels as a near-term LCFS compliance strategy remains highly uncertain. Scenario D1 assume that over one billion gallons of advanced biodiesel will be available in 2020 to the Northeast states. This is more than three times the current U.S. production of conventional biodiesel. As with the assumptions for advanced ethanol penetration presented above in the discussion of gasoline scenarios, an expectation of large-scale penetration of low carbon biofuels, while possible, remains very optimistic.

Table 3-11 Summary of assumptions made in diesel scenarios

Decision Item	Default Assumption
Diesel baseline fuel mix	100% ULSD
#2 Fuel Oil Sulfur Content	15 ppm
Include LDDV in Diesel Baseline?	Yes
Include #2 heating oil in diesel baseline?	Only in Scenario D3
Include nonroad engines in diesel baseline?	Yes
Scenario region for transportation demand	NE-8

Inclusion of No. 2 HHO Baseline

As discussed in the next chapter, policymakers may choose whether to include home heating oil (HHO) in an LCFS program. Because the carbon intensity of HHO is slightly lower than that for highway diesel fuel (91.2 gCO2e/MJ as compared to 93.0 gCO2e/MJ), the inclusion of HHO in the baseline results in a lower baseline AFCI. Alternatively, No. 2 oil could be allowed as an optional credit generating mechanism. Thus, the baseline AFCI (the number to which a target reduction percentage is applied) can vary depending on the baseline assumptions. There may be alternative ways to include No. 2 oil within an LCFS program. As noted above in Table 3-11, all scenarios in this chapter assume that the baseline fuels for both diesel and #2 fuel oil applications meet ultra-low sulfur (15ppm) specifications.

The next chapter discusses issues associated with program implementation.

4. PROGRAM STRUCTURE

This chapter provides an overview of issues affecting the design of a LCFS for the Northeast states and makes recommendations concerning specific program elements. The information in the chapter are based on: (1) an evaluation of the fuel supply and distribution network in the Northeast region; (2) research into existing federal and state fuels program requirements; (3) a review of the LCFS program structure being considered by California; and (4) conversations with industry representatives.

Specifically, this chapter addresses the following program design options:

1. Potential fuels for inclusion in a Northeast LCFS;
2. Baseline fuels determination;
3. Lifecycle fuel carbon tracking mechanisms; and
4. Determining which entities to regulate.

Where information is available, we describe California's proposed program design to provide context for these issues.

4.1. Potential Fuels for Inclusion in a Northeast LCFS

4.1.1. Background

As discussed in the Introduction to this report, two other fuel programs with direct relevance to the potential implementation of a LCFS in the Northeast are in development at this time. These are the federal Renewable Fuel Standard and the California LCFS. Both of these programs propose to regulate transportation fuel. Transportation fuel, as it pertains to the RFS, is defined in the Energy Independence and Security Act of 2007 as "fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels)"—thus the primary focus of this program is on gasoline and diesel fuel. In addition, EPA has discretionary rulemaking authority to expand the credit and trading aspects of the RFS program to recognize carbon intensity reductions in home heating oil and jet fuel. CARB is proposing to regulate transportation fuels, including fuel used in motor vehicle engines, nonroad vehicles, locomotives, and marine engines. CARB is not proposing to regulate jet fuel or fuel used by ocean-going vessels as part of the California LCFS. While the federal RFS program does not address the carbon intensity of petroleum based (e.g., it makes no distinction between fuels produced from high carbon sources, such as tar sands, and those produced from conventional crude oil) California is proposing to establish separate baseline AFCI values for conventional petroleum fuels derived from non-conventional crude oil.[18] In neither program is No. 4 or No. 6 fuel oil being considered for regulation.

[18] CARB defines non-conventional crude oil as crude oil produced by a process other than primary, secondary, or tertiary oil recovery, including crude oil produced from oil sands, heavy oil, and oil shale.

Table 4-1 compares the different types of petroleum products sold in California, the United States, and the Northeast in 2005, in terms of their percentage market share.

Table 4-1 Prime Supplier Sales Volumes of Petroleum Products (2005)

Percent Allocation of Six Principal Products

Product	NESCAUM States	California	United States
Conventional and Reformulated Gasoline	56.0	63.3	60.7
No. 2 Fuel Oil	14.5	0.6	4.1
Diesel Fuel	11.5	15.8	21.6
Residual Fuel Oil	9.9	5.1	3.8
Kerosene Jet Fuel	8.1	15.2	9.8
Sum of 6 Products	100.0	100.0	100.0

Source: CEC and EIA

Table 4-1 indicates that the proportions of conventional and reformulated gasoline sold nationally and in California and the Northeast are relatively comparable. The same can be said of diesel fuel and kerosene jet fuel, though the relative volume of these products sold as a proportion of all petroleum products varies more from region to region than does gasoline. No. 2 fuel oil, used largely for boiler fuel and space heating in buildings, on the other hand, represents a much larger share of fuel sold in the Northeast compared to California and the U.S. as a whole. A total of 14.5 percent of all petroleum fuel sold in the Northeast is used for space heating. In fact, the Northeast uses a proportionately much higher volume of No. 2 and residual fuel oil generally for both electricity generation and space heating than does the rest of the country. The remainder of this chapter describes the different types of fuels shown in

Table 4-2 in more detail and provides a rationale for including or excluding different categories of fuel from a Northeast LCFS program.

4.1.2. Conventional and Reformulated Gasoline

A primary objective of a LCFS is to reduce GHG emissions from the transportation sector. Approximately 27 percent of anthropogenic GHG emissions in the Northeast result from the combustion of gasoline (both conventional and reformulated gasoline) in automobiles. An additional 0.5 percent is created by the combustion of gasoline in nonroad machines such as lawn and garden equipment and various types of commercial and industrial equipment. Gasoline sales by volume make up approximately 56 percent of all petroleum sold in the Northeast region. Given the importance of reducing carbon emissions from the transportation sector and the substantial efforts being made to reduce GHG emissions from motor vehicles, reducing the carbon intensity of gasoline provides an additional means of reducing overall GHG emissions from the transportation sector. Consistent with the CARB and EPA programs, NESCAUM recommends that both conventional and reformulated gasoline be included in a Northeast LCFS. Gasoline used in nonroad applications should also be included in an LCFS. Because it is identical to the gasoline used by highway vehicles, it would be very difficult, as a practical matter to separate the supply of gasoline intended for nonroad applications from the supply intended for highway use.

4.1.3. Transportation Diesel Fuel and No. 2 Heating Oil

In this section, the term distillate fuel is used to refer to both diesel fuel used in transportation sources and to No. 2 heating oil. Distillate is the general classification given to one of the petroleum fractions produced in the process of refining petroleum.

Diesel fuel used in highway and nonroad sources

Table 4-2 shows that approximately 45 percent of the distillate fuel used in the Northeast in 2005 was used for transportation (diesel fuel). The majority of diesel fuel was used in highway trucks, with nonroad sources such as construction equipment, locomotives, and marine engines accounting for approximately 14 percent of total consumption. CARB is proposing to include diesel fuel used in both highway and nonroad equipment—in its LCFS program. As part of the Renewable Fuel Standard requirements of the Energy Independence and Security Act of 2007, specified volumes of low carbon fuels must be introduced into the nation's diesel fuel supply for the transportation sector. Given the contribution of diesel fuel to overall transportation-related GHG emissions and given the inclusion of diesel fuel in current CARB and EPA proposals, NESCCAF recommends that any Northeast state LCFS include highway and nonroad diesel fuel. This would mean that nonroad, locomotive, marine, industrial, and commercial diesel fuel uses would be covered; in fact most distillate fuel use by the industrial and commercial sectors would be covered since transportation sources are largely responsible for diesel use in these sectors.

Table 4-2 shows the array of principal sector end uses for two types of diesel fuels (low and high sulfur) and for No. 2 fuel oil. High sulfur diesel fuel is defined as fuel with sulfur content up to 3000 parts per million (ppm), while low sulfur diesel fuel is defined as fuel with sulfur content up to 500 ppm. Since the baseline data from EIA are from 2005, these figures do not reflect sales of the newer ultra low sulfur diesel fuel that is already being required for use by highway vehicles and that will be required for nonroad equipment beginning in 2010.

Table 4-2 NESCAUM Region Consumption of Fuels by End Use (2005)

(Millions of Gallons)

Sector End Use	No. 2 Fuel Oil	Low Sulfur Diesel Fuel	High Sulfur Diesel Fuel	Residual Fuel Oil	Gasoline
Highway	0	3166.0	-	0	16,494
Non-Road	0	-	172.7	0	-
Locomotive	0	0	150.9	0	-
Marine	0	0	133.0	1015.0	-
Home Heating	3515.7	0	0	0	-
Farm	13.5	-	52.6	0	-
Electric Power	77.2	0	0	2452.9	-
Industrial	100.0	16.8	12.8	338.1	239
Commercial	960.1	105.9	36.7	653.4	25
Total Usage	4666.5	3288.7	558.7	4459.4	16,758

Source: Energy Information Administration, Petroleum Navigator (2005).

Table 4-2 also shows the amount of residual fuel which is used in marine vessels (bunker fuel) and for electric power generation. Gasoline is also shown for reference.

No. 2 fuel oil used in space heating applications

As indicated by Table 4-2 the use of No. 2 fuel oil for space heating in homes and in some commercial and industrial buildings represents 55 percent of total distillate fuel use in the Northeast (4.6 billion gallons per year)—as already noted, this exceeds the amount of distillate fuel used for highway transportation (3.2 billion gallons per year). In contrast, California's use of No. 2 distillate fuel oil in thermal applications (0.02 billion gallons per year) represents an extremely small fraction of its total distillate use. Transportation uses account for 69 percent (3.0 billion gallons per year) of distillate fuel use in California. In California and other regions of the country distillate fuel is not widely used for residential space heating; California is also not proposing to regulate No. 2 fuel oil as part of its LCFS.

There are a number of reasons why the Northeast states might consider including No. 2 fuel oil in an LCFS. First, the region has a unique opportunity to substitute regionally available low carbon fuels – such as woody biomass and electricity - for No. 2 fuel oil in home heating applications. Woody biomass and electricity are available in potentially high quantities in the Northeast. Further, the replacement of inefficient oil burning furnaces with modern, higher efficiency wood burning furnaces, such as pellet stoves, would reduce carbon emission in the region. From an economic standpoint, the use of available woody biomass feedstocks would assist the declining Northeast wood products industry and could help alleviate the cost burden on low-income households when heating oil prices rise. The LCFS is a policy mechanism that could help promote the substitution of heating oil by wood fuel. The use of woody biomass and electricity as substitutes, combined with increased natural gas use for space heating, provides near-term low carbon fuel options for the Northeast.

Further, some low carbon fuel feedstocks are better suited for use in furnaces than they are for use in the internal combustion engines used to power trucks, buses, and nonroad equipment. For example, woody biomass can be used directly in thermal applications (assuming conversion from oil burning furnaces to wood or pellet stoves). Biodiesel can also be used more easily in oil burning furnaces than in highway diesel engines. This is because the performance of highway diesel engines is more susceptible to adverse effects from variations in fuel quality, compared to furnaces. The use of biodiesel in thermal applications is subject to some caveats: for example, storing biodiesel as heating oil in cold weather can lead to gelling and associated problems with fuel quality.

Heating oil is refined at and imported to the same facilities that refine and import gasoline and highway and nonroad diesel and both fuels are typically sold at the same retail outlets. Maintaining the same requirements for diesel fuel and home heating oil has long been a goal of fuel providers and regulators in the Northeast. Fuel distributors maintain that achieving parity between highway and nonroad fuel in terms of fuel quality and specifications is critical because handling different grades and sulfur levels requires extra tanks and otherwise increases the complexity of the distribution system.

Finally, because heating and transportation fuels share the same supply network, it would be possible for refiners to direct high-carbon distillate fuels—such as distillate produced from tar sands-derived bitumen—into the heating oil market if the carbon intensity of heating oil is not regulated. Fuel derived from tar sands currently makes up approximately 0.5 percent of the Northeast distillate fuel supply. In the long term, the use of tar sands derived crude will depend on numerous factors affecting the Western Canadian oil industry.[19] If a larger fraction of No. 2 fuel oil used for thermal heating were to be comprised largely of tar sands derived fuel, then the average carbon intensity of the region's fuel oil supply could rise significantly. Thus, it may make sense for the Northeast states to regulate the carbon intensity of No. 2 fuel oil along with transportation distillate over the long term.

Residual fuel

Approximately 14 percent of all liquid fuel used in the Northeast is residual fuel (see Table 4-2. Of this fraction, more than half (55 percent) of residual fuel is used for electricity generation and 22 percent is used for commercial and industrial heating. Another 23 percent is used to fuel large ocean-going vessels. On a per capita basis, residual fuel consumption in the Northeast (at 105 gallons per person per year in 2005) is much greater than in California (39 gallons per person per year) or in the U.S. as a whole (35 gallons per person per year). This is largely because the Northeast is the only region of the U.S. that uses significant quantities of residual fuel for electricity generation. GHG emissions from the use of residual fuel for electricity generation will be subject to other policies and programs targeted to the electricity sector, including the Northeast Regional Greenhouse Gas Initiative and state-imposed renewable portfolio standards. These programs are designed to reduce overall electric-sector GHG emissions in the Northeast and increase the share of electricity produced from low-carbon renewable resources instead of conventional fossil fuels, like residual oil.

The remainder of the residual fuel used in the Northeast states (commercial and industrial heating applications and bunker fuel for ocean-going vessels) would remain unregulated and could remain a source of significant and possibly growing GHG emissions. However, NESCCAF does not recommend including residual fuel in a first generation LCFS for two reasons: first, it is difficult to track residual fuel and second, states have limited authority to regulate ocean-going vessels. Regulators should, however, consider including residual fuels at a later date, after an LCFS program is successfully established and initial implementation issues have been resolved. If the residual fuel market in the Northeast remains unregulated indefinitely while a carbon standard is imposed on other types of fuels, it could increasingly become a "dumping ground" for the region's high carbon fuels.

[19] Further expansion of production of crude derived from tar sands will largely depend on the market price of a barrel of oil. When prices were higher in 2008 ($140+ per barrel), expansion of production appeared viable. With prices falling below $50 per barrel later in 2008, prospects became considerably less viable. The industry needs a minimum sustained price in the $85 to $100 per barrel range in order to support expansion.

Different fuel characteristics provide further grounds for excluding residual fuel from a first generation LCFS. Residual fuel, which is made up of the fraction of crude oil that remains after the lighter, more valuable fractions have been distilled off, has a much higher viscosity than distillate oil. In fact, it is so viscous that it has to be heated in order to be used. Due to its high viscosity and high sulfur content, residual fuel also requires special processes for storing and pumping; at low temperatures it can cause damage to fuel lines, furnaces, and related equipment that were designed with lighter fuels in mind. Residual fuel is usually transported by barge and tanker truck, unlike distillate fuel which is transported mainly by pipeline.

In sum, NESCCAF recommends that gasoline and diesel used in highway and nonroad engines and machines—including marine engines and locomotives—be included in a Northeast LCFS. We also recommend that states consider the inclusion of No. 2 fuel oil. For the reasons discussed above, we recommend that residual fuel not be included in a Northeast LCFS, at least initially.

As already noted, the Northeast states rely on liquid fuels to a much greater extent for power generation and heating, compared to other regions of the country. As an illustration, the NESCAUM region consumes only about 9.4 percent of total U.S. energy allocated for electric power generation purposes. Yet 28.9 percent of residual fuel allocated nationally for power generation is consumed in the NESCAUM region.

4.2. Determining Baseline Fuel Characteristics

Making a determination about baseline fuel characteristics is an important step in the implementation of a LCFS. First, by specifying baseline fuel characteristics, regulators will set the marker for future carbon intensity reductions in Northeast fuel. The composition of fuel sold in the Northeast has changed significantly over the past five years in a number of ways, including with respect to ethanol content and fuel sulfur levels. Importantly, the widespread phaseout of methyl *tertiary*-butyl ether (MtBE) between 2000 and 2006 led to the introduction of gasoline with 10 percent ethanol by volume. MtBE has different life-cycle carbon characteristics than ethanol. Additional issues to be considered include how many baseline fuels there should be and how they should be defined. Finally, the federal RFS requires the introduction of 36 billion gallons of renewable fuel nationwide by 2022, 15 billion gallons of which can be corn ethanol. Selecting a baseline fuel is an important issue in how the LCFS meshes with this federal regulation.

As with other issues related to program structure, the Northeast states can look to EPA and CARB proposals for handling baseline issues in the context of the federal RFS and California LCFS. This section discusses considerations relevant for defining baseline fuel characteristics for a Northeast LCFS.

4.2.1. Number of baseline fuels

CARB is proposing to establish two baseline fuels for the California LCFS: one for diesel and one for gasoline. The reason these two separate baselines are being considered is because diesel fuel and gasoline have different carbon intensities on a per energy unit basis. CARB has considered creating one baseline that combines the characteristics of gasoline and diesel fuel.

However, this approach would have had the effect of providing an incentive for fuel providers to increase sales of diesel fuel relative gasoline, since gasoline has a higher AFCI than diesel. Thus, a fuel provider could achieve average carbon intensity reductions simply by switching more production to diesel fuel.

NESCCAF recommends that the Northeast states likewise establish separate baselines for diesel and gasoline.

4.2.2. Gasoline

Properties of Baseline Gasoline

A number of assumptions about baseline gasoline fuel properties were made in the discussion of possible compliance scenarios in Chapter 3. The basis for these assumptions and potential modifications are discussed below.

Ethanol Content of Baseline Gasoline

NESCCAF's scenario analysis assumed that all RFG in the region contains 10 percent ethanol by volume and used a baseline year of 2006.

Table 4-3 shows that by 2006 nearly all of the MTBE in reformulated gasoline had been replaced with 10 percent ethanol by volume. Approximately 60 percent of gasoline sold in the Northeast is RFG, thus the average ethanol content of all gasoline (conventional and reformulated) sold in the region in 2006 was 6 percent.

Table 4-3 Volumes of Oxygenates Added to Reformulated Gasoline in the NESCAUM Region

(Millions of Gallons)

	2003		**2004**		**2005**		**2006**	
State	**MTBE**	**Et-OH**	**MTBE**	**Et-OH**	**MTBE**	**Et-OH**	**MTBE**	**Et-OH**
CT	146.0	21	0.9	155	0.6	162	0.3	157
ME	0	0	0	0	0	0	0	0
MA	293.4	1	324.5	8	254.1	10	1.1	20
NH	57.5	0	57.2	0	53.0	0	0.1	0
NJ	483.8	1	501.5	6	481.7	7	0.9	15
NY	325.5	23	0.6	295	1.6	328	0.6	714
RI	47.9	1	56.5	8	49.7	10	0.2	20
VT	0	0	0	0	0	0	0	0
Total	**1354.1**	**47**	**941.2**	**472**	**840.7**	**517**	**3.2**	**926**

Sources: Energy Information Administration, Petroleum Navigator, Prime Supplier Sales Volumes

EPA, www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm

Choosing an earlier year as a baseline year for the LCFS means that only a small amount of ethanol is included in the baseline average fuel since M*t*BE was still in use in much of the Northeast prior to 2006. In fact, six of the region's eight states still were allowing the use of

M*t*BE in 2005; thus a baseline fuel carbon intensity calculated from 2005 fuel data will not account for the broad-based introduction of ethanol after 2005.

Federal RFS requirements, which require that 12 billion gallons of ethanol be introduced into the U.S. gasoline supply by 2010, will likely mean that ethanol will be present in even larger quantities in future years. In that case, the use of 2005 as the baseline year will result in further undercounting or overcounting of baseline carbon intensity, depending on the carbon intensity assigned to corn-based ethanol (if ethanol is assumed to have the same carbon intensity as gasoline, of course, the choice of baseline year has much less effect on the calculation). As discussed in Chapter 3, at the moment there is much discussion and substantial uncertainty about the carbon intensity of corn ethanol, particularly with respect to accounting for upstream fuel-cycle impacts and indirect effects on land use.

CARB in its October 10, 2008 LCFS document[20] sets the baseline year for the California LCFS at 2010. In 2010, 10 percent of gasoline will be comprised of ethanol in California. However, unlike what is proposed above, CARB is proposing to increase the stringency of the LCFS from a 10 percent reduction in AFCI to a 10.5 percent AFCI reduction to account for the fact that corn-ethanol has a higher carbon intensity than gasoline.

NESCCAF proposes that the Northeast states take a similar approach and set the baseline year to ensure that the ethanol content of baseline gasoline is 10 percent by volume.

Sulfur content of baseline gasoline fuel

Fuel sulfur content can affect lifecycle GHG emissions because the additional refining needed to lower sulfur levels increases the amount of fuel processing needed, which in turn generates higher GHG emissions. For purposes of this analysis, NESCCAF assumed that a baseline gasoline sulfur content of 30 ppm, consistent with federal requirements. We also conducted sensitivity analyses and determined that varying fuel sulfur levels did not have a significant impact on fuel carbon intensity. In addition, choosing an average value for refining efficiency (discussed below) means that differences in sulfur are not accounted for under the LCFS.

Carbon Intensity of Gasoline Baseline Fuel

Assuming 2005 fuel characteristics results in a baseline fuel AFCI of 91 grams of CO_2/Mj. The choice of 2006 or a later year results in a baseline AFCI of 96.7 because of the higher carbon intensity of ethanol fuel. As noted previously, NESCCAF recommends that the baseline gasoline fuel carbon intensity by 96.7.

In the NESCCAF scenario analysis presented in Chapter 3, the baseline AFCI for gasoline is slightly different from the proposed CARB baseline AFCI, not only because of differing ethanol content of the two types of gasoline, but also because the carbon intensity of northeast RBOB is slightly higher than the equivalent fuel in California (CARBOB). The NESCCAF carbon intensity values used in the analysis account for differences in transport and refining processes for the fuel. The northeast states could choose to use the northeast specific carbon intensity value developed by Lifeycle Associates for the northeast, or the states could choose to use the same value that CARB is proposing to use. For the purpose of carbon

[20] CARB, "The California Low Carbon Fuel Standard Regulation," Draft, October, 2008

accounting, it would be more accurate to use the northeast specific value for the baseline gasoline.

Refining Efficiency

Calculations of lifecycle carbon emissions for conventional fuels include an upstream component plus direct carbon emissions from combustion of the fuel. Upstream emissions include emissions associated with extraction, refining, and transport of feedstocks. The GREET model attributes to upstream processes roughly 20 percent of carbon emissions associated with the use of gasoline and diesel while 80 percent of lifecycle carbon emissions are estimated to come from the actual combustion of the fuel. It may be possible to reduce upstream emissions by making the petroleum refining process more efficient. This raises the question of whether changes in refinery efficiency should be taken into account when calculating lifecycle carbon intensity for purposes of implementing a LCFS.

CARB has proposed to assign a default value for refining efficiency in the implementation of its program. This makes sense for a few reasons related to how fuels are purchased and distributed. In addition, upstream emissions are likely to be covered as part of a program to reduce GHG emissions from major stationary sources, including refineries and industrial facilities.

Taking this approach will mean, however, that any carbon reductions resulting from upstream improvements in refining efficiency would not be counted in an LCFS. A more detailed discussion of refining efficiency and other assumptions that are central to the development of fuel carbon intensity factors is presented in Appendix B. NESCCAF recommends that states in the Northeast follow CARB's approach and assume a default value for refining efficiency for purposes of LCFS implementation. We believe this approach is more practical and that the regulation of refinery emissions is better suited to a regulatory program tailored to stationary sources.

4.2.3. Diesel

Four issues related to calculating the baseline lifecycle carbon intensity of diesel fuel are discussed in this section: (1) whether to establish separate baselines for diesel and gasoline; (2) whether and how to credit diesel vehicle efficiency; (3) assumptions about fleet type as opposed to fuel type; and (4) assumptions about the penetration of alternative fuels in the baseline diesel calculation.

Separate diesel baseline

CARB has proposed establishing two baselines: one for gasoline and one for diesel. There are a number of reasons to take this approach. First, two baselines would create incentives for the development of low carbon fuels suitable for both diesel and gasoline engines. In addition, air quality and public health officials are concerned about the potential for an increase in the number of light-duty diesel vehicles because of health data showing that particulate matter (PM) from diesel vehicles is a carcinogen and can result in significant non-cancer health effects. A policy designed to reduce GHG emissions that had the effect of simultaneously increasing diesel PM emissions would therefore be considered problematic; rather, fuel policies should provide both public health and environmental benefits. Finally, there is significant uncertainty among experts about how potent a greenhouse forcing agent black carbon is. Given this uncertainty, creating an incentive for the introduction of diesel vehicles at this time may not be an appropriate strategy.

As already noted, the use of a single baseline that combines diesel and gasoline characteristics creates an incentive for fuel providers to shift production to diesel fuel, which has a lower lifecycle carbon intensity. The use of separate baselines avoids this problem and is therefore the approach that California appears to be taking.

Fleet Characteristics

NESCCAF has assumed that the light-duty diesel fleet and the heavy-duty diesel fleet are separate from a carbon intensity standpoint. This is consistent with the way that CARB has conducted its LCFS analysis to date.

Alternative Fuel Assumptions in the Diesel Baseline

NESCCAF did not estimate the amount of alternative fuels used in 2005 as part of its baseline diesel analysis. Alternatives to conventional diesel fuel include compressed natural gas (CNG), liquid natural gas (LNG), and others. Excluding alternative fuels from the baseline will raise the diesel baseline AFCI slightly since natural gas and other alternative fuels have a lower carbon intensity than does diesel fuel. However, given the fact that most fuel providers sell diesel and not both diesel and alternative fuels, NESCCAF opted to exclude the alternative fuels. Including them would have penalized providers of diesel fuel in the sense that they would have a lower baseline had alternative fuels been included. In any case, the amount of alternative fuels currently used on an annual basis is small in the Northeast.

Sulfur Content of Baseline Diesel Fuel

NESCCAF assumed a sulfur content of 15 ppm for baseline on-highway diesel fuel and 500 ppm for nonroad diesel fuel. The allowed sulfur content of heating oil in the region ranges between 2,000 and 20,000 ppm. The majority of the heating oil used in the region is regulated at approximately 2,500 ppm.

4.2.4. Treatment of Heating Oil in the Baseline

As calculated by the GREET model, the lifecycle carbon intensity of No. 2 heating fuel (91.2 gCO_2e/MJ) is lower than the carbon intensity of diesel fuel (93.0 gCO_2e/MJ). This is because it takes less energy to refine heating oil than diesel fuel. If the northeast states consider including heating oil in the LCFS, there are three main options for defining a heating oil baseline AFCI. First, the states could choose to include heating oil in the diesel baseline. Doing this would lower the diesel baseline nearly 1 percent, which would mean that the required reductions in AFCI for diesel fuel would be less stringent than for gasoline.

Another approach would be to create two separate baselines and maintain the same 10 reduction requirement in the AFCI for both diesel and heating oil. This would allow for more accurate carbon accounting for heating oil and diesel fuel and would mean that for gasoline, diesel, and heating oil the same reduction in carbon intensity would be required.

Third, heating oil could be excluded from the diesel baseline and be excluded from the 10 percent AFCI reduction requirement. In this scenario, displacement of heating oil with low carbon alternatives could generate credits for compliance with the diesel AFCI reduction requirement. This approach is explained in more detail in section 4.5.

4.2.5. Increases in Carbon Intensity of Baseline Fuels Due to Tar Sands and Other Non-Conventional Sources

Presently, fuels derived from Canadian tar sands play a relatively minor role in supplying the northeast market. Finished petroleum products, imported from Canada into the northeast, are largely if not exclusively supplied by refiners in the Atlantic Canadian Provinces and derived from conventional sources of crude oil. Overall, Canadian refiners supply approximately 4 percent of northeast demand for gasoline and light distillates.

A single northeast refiner processes Western Canadian crude oil; United Refining in Warren, Pennsylvania. United's refining capacity represents about 4 percent of the total refining capacity in our region. In 2006, about half of United's crude slate was heavy crude oil. Of this amount, approximately 60 percent of the heavy crude was derived from conventional sources and the other 40 percent from Canadian tar sands. Overall, United supplies approximately 1 percent of northeast demand for gasoline and light distillates, primarily serving retail markets in Western Pennsylvania and Western New York.

United is adding a delayed coker to its refining operations in order to process a higher percentage of heavy crude oil. Their near term goal is to process approximately 80 percent heavy crude, both from conventional and tar sands sources. In the longer term, the plan is to process heavy crude as the exclusive feedstock. Thus, in the long term, the market share of finished products in our region derived from heavy Canadian crude and processed in the region will double, from the current half-percent to about 1 percent (i.e., United's total market share). The split between conventional heavy crude and tar sands derived crude will depend on numerous factors affecting the Western Canadian oil industry.

Further expansion of production of crude derived from tar sands will largely depend on the market price of a barrel of oil. When prices were higher in 2008 ($140+ per barrel), expansion of production appeared viable. The industry needs a minimum sustained price in the $85 to $100 per barrel range in order to support expansion.

CARB is proposing to establish a separate carbon intensity value for unconventional fuels. This will allow for more accurate carbon accounting of the baseline fuel. A northeast LCFS should also establish a separate carbon intensity number for unconventional fuels.

4.2.6. Baseline Fuels

Gasoline

The most important consideration in choosing a baseline gasoline for the LCFS is how pre-existing corn-ethanol in the gasoline pool is to be treated in the program. Currently in the northeast, gasoline contains 10 percent corn-ethanol by volume. As discussed earlier, the carbon intensity number assigned to corn-ethanol is higher than the carbon intensity value for gasoline. If the 10 percent of corn-ethanol in gasoline already in the fuel pool is to be grandfathered in e.g. if we are to assume that the carbon intensity of this fuel is the same as gasoline, then the baseline fuel carbon intensity number can be the same as gasoline. If existing corn-ethanol is not grandfathered in, then the carbon intensity of gasoline will be slightly higher than if corn-ethanol is grandfathered in. California is proposing to adjust the stringency of the LCFS requirement from a 10 percent reduction in gasoline AFCI to a 10.5 percent reduction in the gasoline AFCI to account for the additional estimated carbon intensity of the corn-ethanol in the gasoline pool

Diesel

The carbon intensity of low sulfur diesel (500 ppm cap) is different from the carbon intensity for ultra low sulfur diesel (15 ppm cap). This is due to different energy requirements for refining the two different fuels. CARB has proposed to designate ultra low sulfur diesel fuel as the baseline diesel fuel. NESCCAF recommends that the northeast states also use ultra low sulfur diesel fuel as the baseline diesel fuel, given that this fuel is now required in highway sources and will soon be required in nonroad diesel engines as well.

4.2.7. Carbon Intensity Values for Northeast Fuels

The NESCCAF scenario analysis presented in Chapter 3 and described in Appendix B, northeast specific carbon intensity values were developed by Lifecycle Associates. This analysis took into account northeast fuel feedstocks, transport distances, modes of transport, northeast specific fuels, such as woody biomass, and refining process. Some of the carbon intensity values used in the scenario analysis differ from the values being used by California and some are the same. The northeast specific values could be used as part of the northeast LCFS, or the states could choose to use the values California has developed. The decision will rest in part on ease of implementation of the program.

4.3. Determining Regulated Entities

This section discusses which entities could be regulated—that is, which entities would be "obligated parties"—under a Northeast LCFS. Several important factors must be taken into consideration, including: (1) ensuring regulated entities have the information they need to demonstrate compliance and report to regulators; (2) ensuring administrative feasibility; and (3) minimizing the regulatory burden associated with this program.[21] EPA, CARB, and the University of California have explored this issue in some detail. CARB has proposed for gasoline and diesel to regulate producers and importers of fuels, as well as certain recipients of fuels. For other fuels, such as compressed natural gas, other parties are identifies. A key consideration for the northeast states is whether the fuel distribution system in the northeast is similar enough to California's for us to regulate the same parties California is proposing to regulate.

In CARB's "Supporting Documentation for the Draft Regulation for the California Low Carbon Fuel Standard," CARB states there are potential enforcement differences between the LCFS and current standards for liquid fuels such as the RFG program. Compliance for the RFG program can be determined systematically through fuel sampling and testing. Unlike the RFG program, the LCFS regulates carbon intensity which – while based on measured properties – these properties cannot be abstracted directly from the fuel or measured by analytical instruments.

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[21] CARB, "Supporting Documentation for the Draft Regulation for the California Low Carbon Fuel Standard," October 2008.

Therefore, the definition of regulated parties must also take into consideration the availability of carbon intensity data and the extent to which the data are verifiable.

For gasoline (and biofuel blends), diesel (and diesel substitutes), CARB is proposing to regulate the producers of the fuel, the importers of fuel, or certain recipients (entities that take on the obligation of being the regulated entity). CARB also recommended a provision that prohibits any party from adding or making modifications to transferred fuel unless that party has become the regulated entity under the LCFS, among other requirements.

In California, for the majority of the transportation fuel, producers and importers retain control of the ownership throughout blending and distribution. In the instance where a producer or importer transfers ownership of fuel, the LCFS obligation can also transfer with the fuel unless agreed upon by the parties. Many of these same entities are regulated under either the RFG or RFS programs. Table 4-4 provides numbers for different types of regulated entities in different states under the RFS. These would also need to be regulated under a northeast LCFS.

Table 4-4 Obligated Parties Under the Federal Renewable Fuels Standard

State	Refiners*	Importers	Companies
Connecticut	40	31	30
Delaware	12	6	
Maine	14	18	11
Massachusetts	17	9	14
New Hampshire	3	8	2
New Jersey	204	84	69
New York	40	29	48
Pennsylvania**	11	7	11
Rhode Island	5	5	8
Vermont	0	5	4
Total	**346**	**208**	**203**

Source: EPA, RFS Program Registrants Database
**Refiners include non-renewable fuel blenders who finish gasoline, many of which are terminals.*
***Only includes PA facilities in southeast corner of PA near New Jersey*

In the Northeast, unlike California, producers and importers do not retain control of the ownership of transportation fuel throughout the blending and distribution process as frequently as in California. Given this, the flexibility CARB is proposing for transfer of compliance obligation for the LCFS will be important for compliance with a northeast LCFS. The LCFS compliance obligation will need to change hands with the ownership of the fuel as it moves through the northeast distribution system.

4.3.2. Description of Northeast Fuel Distribution Network

Gasoline and diesel fuel sold in the Northeast passes through several facilities between the time it arrives in the region until it reaches retail outlets (gas stations, truck stops, nonroad and heating oil distributors). Approximately 50 percent of fuel arrives as crude oil and is refined in the region. Another 25 percent of fuel arrives as finished product (e.g., RFG, conventional gasoline, high and low sulfur diesel, heating oil). Finished gasoline is often blended with renewable fuels such as ethanol. Another 15 percent of the fuel used in the region is imported as unfinished product (RBOB and CBOB) that is further blended with an oxygenate, such as ethanol, before being sold to retailers in the region. The facilities and entities that handle and process fuels before they reach the consumer include refiners, importers, blenders, and terminals. These are described below and their locations are shown graphically in Figure 4-1.

A **petroleum refinery** is a facility that produces petroleum products from crude oil; the most common products being gasoline, diesel and other distillate fuel oils, kerosene, residual fuel oil, asphalt, and lubricants. The products are produced at the refinery by distillation, cracking, or reforming of unfinished petroleum derivatives. Pursuant to the federal RFS, refiners are identified as **obligated parties**; meaning they must meet the volume obligations for renewable fuels. Under the federal RFS, the refinery definition is expanded to include facilities where blendstocks are combined to produce gasoline or diesel fuel or where blendstocks are added to finished gasoline or diesel fuel. Where the RFS identifies **blenders** as obligated parties, it is referring to these above-described blenders.

An **importer** is a person who imports gasoline, gasoline blending stocks or components, or diesel fuel from a foreign country into the United States. Under the federal RFS, an importer is a person who brings gasoline or renewable fuel into the 48 contiguous states from a foreign country or from an area of the United States that is not subject to the RFS. Importers of gasoline are deemed **obligated parties** under the federal RFS.

An **ethanol blending plant** is a type of refinery at which gasoline is produced solely through the addition of ethanol to gasoline, and at which the quality or quantity of gasoline is not altered in any other manner. These "refineries" are not deemed obligated parties under the federal RFS.

An **oxygenate blending facility** is any facility at which oxygenate is added to gasoline or blendstock, and at which the quality or quantity of gasoline is not altered in any other manner except for the addition of deposit control additives. These facilities are not deemed obligated parties under the federal RFS.

A **bulk gasoline terminal** is any gasoline storage and distribution facility that receives gasoline by pipeline, ship or barge, or cargo tank (i.e., delivery tank truck or railcar). For purposes of the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP), a throughput cutoff of 20,000 gallons per day is used to distinguish the larger **gasoline terminals** from the smaller **bulk gasoline plants**. Typically, **bulk plants** receive a greater proportion of their product or exclusive delivery of their product via cargo tank delivery.

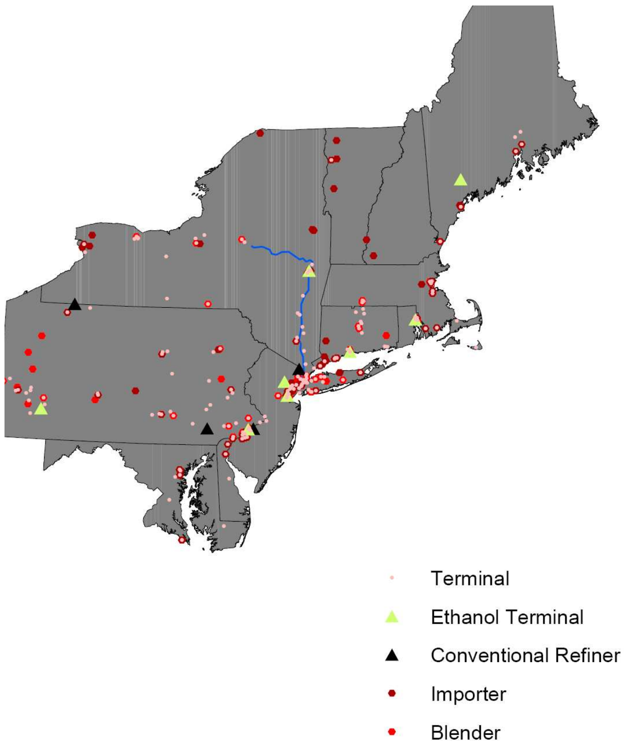

Figure 4-1 Schematic of Northeast Fuel Distribution System

To provide a sense of how many regulated entities there might be under a northeast LCFS, numbers for different potentially regulated entities are provided: There are approximately 223 distribution racks operated by 145 companies in the Northeast and 203 companies operating 544 refineries and importer facilities in the Northeast. A detailed description of the types of facilities, their locations, and the northeast fuel distribution system is provided in Appendix C.

4.4. Possible Tracking Mechanisms

Whether the regulated entity is the refiner, importer, blender, or terminal, or some combination of these entities, it will be necessary to estimate the carbon intensity of finished products. This in turn requires a mechanism to assign carbon intensities to different types of fuel, along with a mechanism to track the different types of fuels sold. In this section, we discuss possible sources for this type of information and different tracking mechanisms, along with their strengths and shortcomings.

As background, we begin with a brief description of the tracking required under each regulation. Further detail is provided in Appendix C to this report. Table 4-5 summarizes the reporting requirements that are already in place under existing federal fuels programs.

Table 4-5 Summary of Reporting Requirements for Existing Fuels Regulations

Regulation	**Regulated entities**	**Requirements**
RFS	Refiners, importers, blenders (proposed)	Renewable fuel volume required, renewable fuels identification numbers (RINs)
Conventional gasoline	Refiners	Total gallons produced or imported, applicable benzene emissions standard, sulfur content standard.
Reformulated gasoline	Refiners, Importers	Properties of fuel, batch number, date of production, volume of batch, grade of gasoline.
Mobile source air toxics	Importers	Reformulated gasoline toxics emissions performance averaging report, and other requirements.
Diesel fuel	Refiners, Importers	Volume of fuel produced (for each refinery or importer) for different sulfur levels.
Diesel sulfur: nonroad, locomotive, marine diesel fuel	Importers, Refiners	Volume of diesel fuel produced and designated, volume of heating oil produced, sulfur content of fuel.
Gasoline benzene program	Refiners, Importers	Benzene volume percent and volume of RFG, RBOB, and conventional gasoline, separately by batch, produced by the refinery or imported.
Gasoline sulfur	Refiners, Importers of gasoline	Applicable baseline, average standard, adjusted cap standard for selected years.

Under the RFS, renewable identification numbers or "RINs" are attached to each batch of renewable fuel sold. The RINs automatically transfer with each batch of renewable fuel. RINs are finally separated at the point the renewable fuel is blended with petroleum fuel; at that point they are retained by the final owner of the renewable fuel. Volumes of renewable fuel can be split or merged any number of times while remaining under the ownership of a single party, with no impact on RINs.

4.4.1. Renewable Identification Numbers

Each RIN is generated by the producer or importer of the renewable fuel and uniquely identifies not only a specific batch, but also every gallon in that batch. The RIN consists of a 38-character code. Only limited information on carbon intensity can be obtained from the current version of the RIN (RR Code-Equivalence Value). EPA is expected to address this issue to address provisions of the RFS program (established under the Energy Independence and Security Act of 2007) that call for an increase, over time, in the use of advanced renewable fuels that achieve greater GHG reductions than current corn ethanol. To implement these requirements, EPA will likely assign two additional digits at the end of the RIN that will provide further information on fuel type and carbon intensity. So, for example, if the fuel falls into the 60 percent lifecycle carbon intensity reduction category under the RFS, the two digits at the end of the RIN will indicate this. Alternatively, if the fuel is corn ethanol from an existing facility (which is grandfathered under current law), the RIN will indicate that the fuel is in the zero percent lifecycle GHG improvement bin.

EPA's RIN system will create four "bins" for fuels: (1) corn ethanol from an existing facility at zero percent GHG reduction; (2) 20 percent GHG reduction for corn ethanol from newly constructed facilities; (3) 60 percent GHG reduction for cellulosic biofuel; and (4) 50 percent GHG reduction for other advanced biofuels. Under the LCFS however, regulated entities will need to determine the actual carbon intensity of different fuels, rather than just which of these bins it qualifies for. Thus, additional information on lifecycle carbon emissions will be needed. For example, an advanced biofuel developed from algae could reduce GHG emissions 80 percent. Under the RFS, this fuel would simply be registered as meeting at least a 50 percent GHG reduction standard. Alternatively, corn ethanol produced at existing facilities will be assumed under the RFS to have no effect (zero percent change) on GHG emissions, when in fact this fuel may have higher lifecycle GHG emissions than gasoline. There is no mechanism to account for these variations under the RFS.

To address this problem, CARB has proposed using default values that would be based on information provided by the RIN, possibly supplemented by additional information, to implement a LCFS. This basic approach can be summarized as follows:

1) Report based on default values;
2) Set default values that are conservative;
3) Provide look-up tables that regulated entities can use to identify default values;
4) CARB to establish default values using the revised GREET model.

In the case of ethanol, CARB is proposing to establish different default values depending on the feedstock, feedstock origin, and processing characteristics of the fuel. Table 4-6 shows the potential default values that could be used. Defaults values would apply except where a producer could provide information showing that his fuel achieves greater GHG reductions.[22]

[22] CARB, "LCFS Carbon Intensity Default Values," May, 2008.

Table 4-6: CARB Default Carbon Intensity Values for Biofuels

Fuel Type	Feedstock	Feedstock Origin	Processing Characteristic
Ethanol	Corn	US Midwest	Dry Mill
			Wet Mill
		US Other Regions	Dry Mill
			Wet Mill
	Sugarcane	Brazil	-
	Cellulosic Biomass	US Domestic	-
		Outside of US	-

CARB is currently working to develop these default values. It is likely that the default values will rely in part on the RIN system developed by EPA to implement RFS requirements. It is anticipated that EPA will identify which ethanol production processes result in fuels that meet the criteria for different GHG reduction categories.

The approach used to establish default values has significant implications. For example, if default values are based on an industry average, then there is no incentive for less efficient producers to improve their production processes. On the other hand, if the worst case value is chosen, then this could increase the reporting burden on producers and obligated parties who would need to provide significant additional information to receive credit for fuels that outperform the industry worst case.

NESCCAF recommends that the Northeast states rely on default values developed by CARB to implement California's LCFS.

4.4.2. Determining Compliance

According to CARB's most recent LCFS documents, California will measure fuel carbon intensity in grams of CO_2 per megajoule of energy (gCO_{2e}/MJ). To facilitate compliance, a compliance calculator is being developed by CARB. The "compliance calculator" software tool will assist regulated entities in estimating the carbon intensity of fuels. This tool should enable users to specify certain parameters (e.g. feedstock type, conversion method, etc), and generate a carbon intensity value for each fuel based on pre-determined values for each step in the fuel pathway. As part of its LCFS scenario analysis, NESCCAF commissioned the development of an interface tool for the GREET model that can readily be used for compliance calculations in the Northeast; we refer to this tool as the Northeast Low Carbon Fuel GREET Interface Tool or "NE-LCFS GREET Interface Tool."

The NE-LCFS GREET Interface Tool enables a user (whether an obligated party, regulated entity, or other stakeholder) to determine the carbon intensity for a given fuel pathway based on specified or default values for key parameters. Because it directly calls upon the GREET model to generate its results, it ensures a consistent methodological approach with other programs that rely on GREET and can be updated to reference future versions of GREET as they are released. While there are some limitations to the use of the current version of GREET for compliance purposes (see Appendix B for a detailed discussion of this issue), GREET remains the most up-to-date and widely used tool for analyzing lifecycle fuel emissions at this time.

For a more detailed description of how the NE-LCFS GREET Interface Tool works and can be used by regulated entities see Chapter 3.

Reporting on Compliance with the LCFS

California is proposing to require regulated entities to submit written reports on the number of gallons and MJ equivalent of fuel sold and the carbon intensity of the fuel sold. A weighted average of the carbon intensities of all fuel sold or fuel sold plus credits purchased would need to be calculated and reported by the regulated entity. In person audits of supporting documentation could be required by the states - in addition to review of paper records - for compliance with the LCFS.

4.5. Potential Approaches to Including Heating Oil in the LCFS

As discussed elsewhere in this report, a significant quantity of home heating oil—as much as 3.5 billion gallons of the 4.7 billion gallons of distillate fuel consumed regionally every year—could be displaced through the use of woody biomass for thermal heating. Additional amounts of No. 2 fuel oil could be displaced through the use of low carbon fuel substitutes such as natural gas and electricity. The use of these fuels as low carbon substitutes for No. 2 fuel oil could help bridge the time period during which advanced biofuels such as hydrocarbons derived from algae (or others) are being developed for compliance with the LCFS; thus including No. 2 fuel oil in a LCFS could provide additional compliance flexibility and is an important strategy to consider.

This approach does raise some important policy questions, among them: (1) would No. 2 fuel oil be required to meet the same carbon intensity reduction targets as transportation fuel in the same timeframe? (2) what are some phase-in options for including No. 2 fuel oil in a Northeast LCFS? and (3) how would woody biomass and other non-liquid fuel providers receive and liquid fuel providers purchase carbon credits for non-liquid fuels used in heating applications? These issues are similar to those raised by the inclusion of electricity as a low carbon fuel to power plug-in hybrid vehicles—a possibility that will be discussed later in this chapter.

To help answer these questions, NESCCAF evaluated three approaches to including No. 2 fuel oil in a low carbon fuel standard. The first is a business as usual case where No. 2 fuel oil is left unregulated; in the second approach, No. 2 is included from the start of the LCFS; and in the third approach, No. 2 is phased in under the LCFS over time.

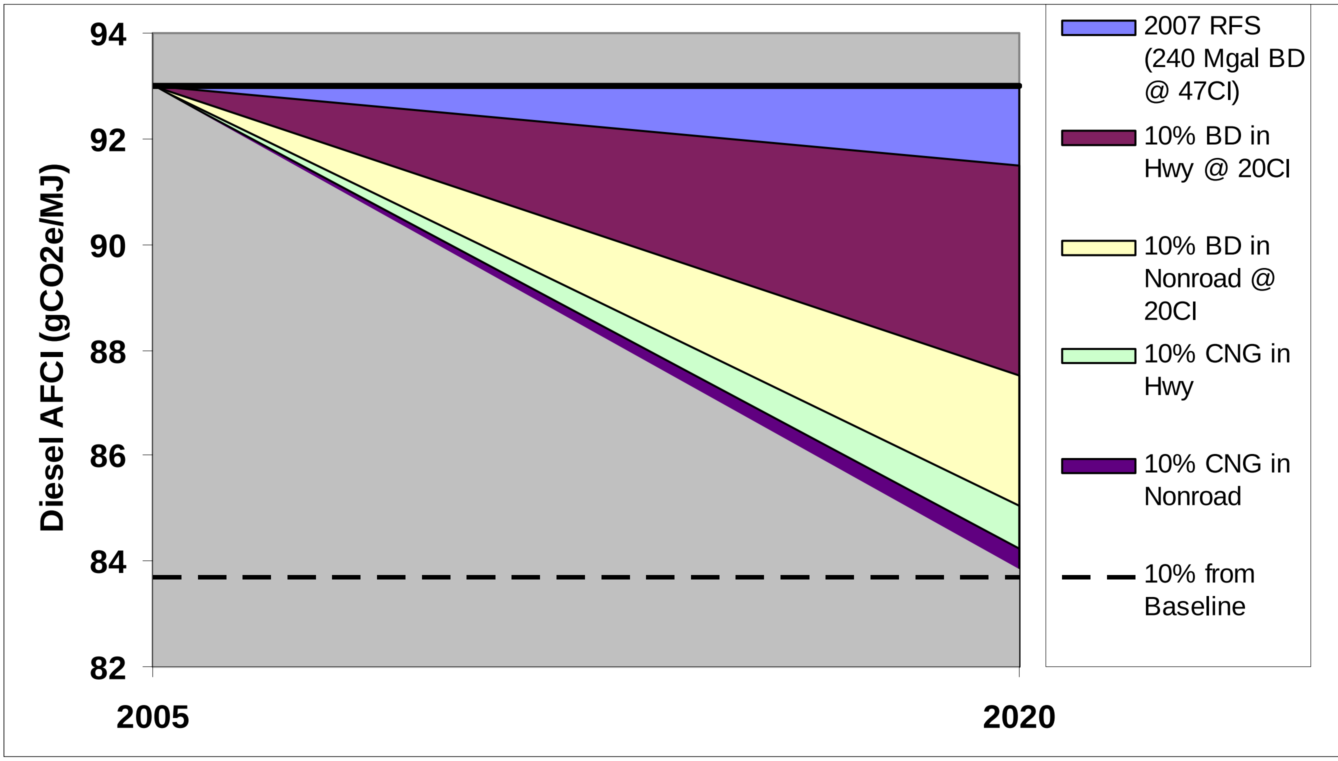

Figure 4-2 Exclude Heating Oil from the LCFS

Figure 4-2 shows compliance with the LCFS assuming only transportation fuels are regulated. In this scenario, approximately 650 million gallons of advanced biofuel used in highway and nonroad applications combined would be needed. In addition to this advanced biofuel, 10 percent of highway and 10 percent of nonroad vehicles would need to operate on compressed natural gas.

Approach #2: Regulation of Heating Oil Begins with the Introduction of the LCFS. In this approach, the approximate 4 billion gallons of No. 2 fuel oil sold in the region is regulated in the first year of the LCFS. Figure 4-3 below illustrates how the inclusion of the 4 billion gallons of No. 2 fuel affects the AFCI of Northeast diesel and heating oil combined.

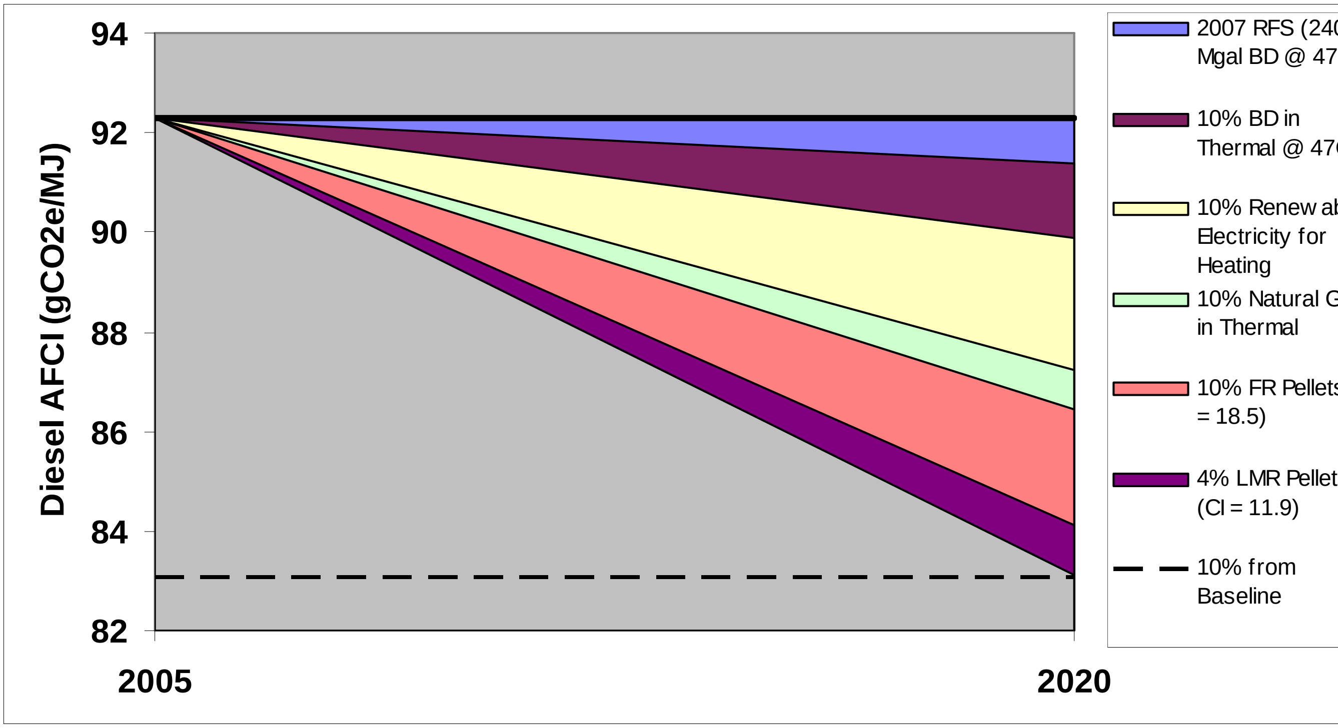

Figure 4-3 Inclusion of No. 2 Fuel Oil in the LCFS

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As can be seen from Figure 4-3 the inclusion of No. 2 oil in the pool of regulated fuel under the LCFS from the beginning of the program greatly increases the amount of low carbon fuel that is required in order to lower the average carbon intensity of transportation and No. 2 fuel combined. However, the inclusion of No. 2 oil also provides an opportunity for fuel switching with low carbon substitutes, such as natural gas, wood pellets, and electricity. As can be seen from Figure 4-3, the transportation diesel fuel AFCI is reduced by 10 percent without the introduction of advanced biofuels into the diesel fuel pool (with the exception of the advanced biofuel required by the Renewable Fuel Standard).

Approach #3: Regulation of Heating Oil is Phased In to the LCFS. In this approach, sellers of No. 2 oil would have a number of years before a requirement to reduce the carbon intensity of heating oil was phased in. During this time, however, sellers of woody biomass, natural gas, or other substitutes used in heating applications could generate credits which transportation diesel fuel producers could purchase to help comply with the LCFS. Delayed inclusion of AFCI reduction requirements for No. 2 fuel oil in the LCFS, combined with the early recognition of credits for the substitution of low carbon fuels for No. 2 oil in heating applications, where those credits could be used by transportation diesel providers to meet their compliance obligation under the LCFS, would allow obligated parties to meet a 10 percent reduction in AFCI by 2020. This scenario allows states and obligated parties in the region to benefit from regionally available low carbon feedstocks in the near term while advanced biofuels are still in development.

There is one main drawback to this approach: excluding heating oil from the pool of fuel regulated under the LCFS could result in the dumping of high carbon fuel, such as tar sands-derived fuel, into the heating oil pool. A possible remedy would be to establish a "no backsliding" requirement for GHG emissions from the heating oil sector. This would require reporting in the early years of the LCFS for heating oil producers. An analogy to this approach can be found in the existing low-emission vehicle (LEV) program, under which states gave automobile manufacturers a 3-year grace period on compliance with requirements for emissions of non-methane organic (NMOG) compounds. Manufacturers are required to report NMOG emissions during this grace period and if excess emissions occur, states reserve the right to enforce the program.

Figure 4-4 illustrates how the inclusion of No. 2 fuel oil in the LCFS impacts the required volumes of low carbon fuels, and how the use of low carbon fuels to displace No. 2 fuel oil could help regulated entities meet the 10 percent AFCI reduction required for transportation fuel.

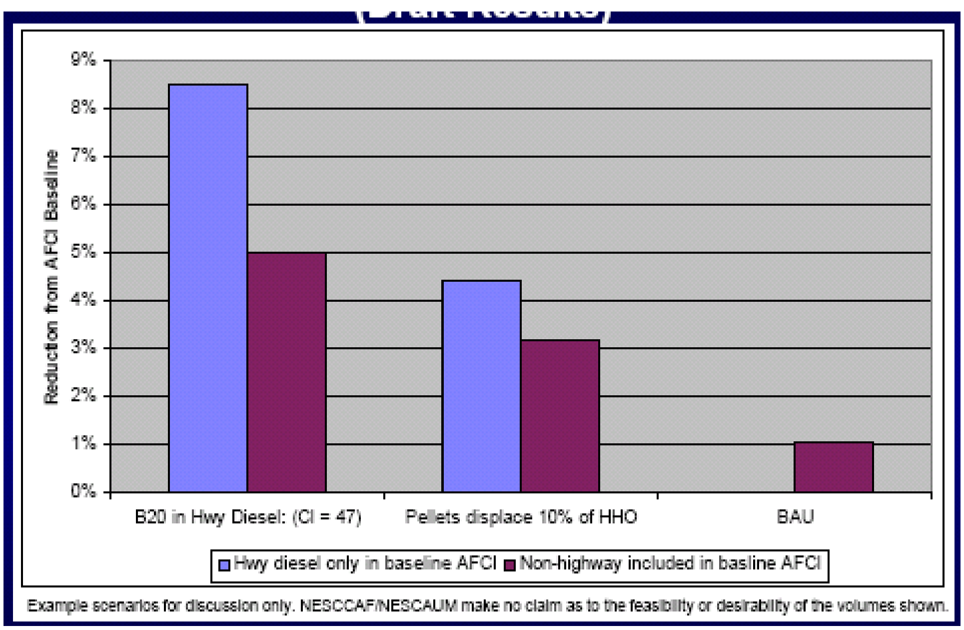

Figure 4-4 Illustration of the Impact on the AFCI with Inclusion of No. 2 Fuel

The light colored bars represent the percent reduction in the AFCI with introduction of different types of low carbon fuels, assuming only transportation diesel is included in the baseline. The darker bar shows the percent AFCI reduction assuming No. 2 fuel is included in the baseline. As can be seen from the bars on the left, introduction of an advanced biodiesel B20 blend in highway diesel vehicles results in an 8.5 percent reduction in the transportation fuel AFCI, but only a 5 percent reduction in the AFCI of the transportation and No. 2 fuel pool combined. The middle bar shows how credits generated from the displacement of 10 percent of No. 2 fuel oil used in space heating with wood pellets reduces the transportation fuel AFCI by 4.5 percent. When the fuel pool includes both transportation diesel and No. 2 fuel oil, the AFCI is reduced by 3 percent.

4.6. Timeframe for introduction of the Low Carbon Fuel Standard

California has proposed to design its LCFS to achieve a 10 percent reduction in the average carbon intensity of transportation fuel by 2020. CARB's October, 2008 LCFS regulatory document provides the following proposed compliance schedule.

LCFS Compliance Schedules

Year	CI for Gasoline and Fuels Substituting for Gasoline[1] (g/MJ)	Gasoline and Fuels Substituting for Gasoline % Reduction	CI for Diesel and Fuels Substituting for Diesel (g/MJ)	Diesel and Fuels Substituting for Diesel % Reduction
2010	96.7	0	95.8	0
2011	96.5	-0.3	95.6	-0.3
2012	96.2	-0.5	95.3	-0.5
2013	96.0	-0.8	95.1	-0.8
2014	95.5	-1.3	94.6	-1.3
2015	94.5	-2.3	93.6	-2.3
2016	93.1	-3.8	92.0	-4.0
2017	91.4	-5.5	90.5	-5.5
2018	89.4	-7.5	88.6	-7.5
2019	87.5	-9.5	86.7	-9.5
2020	86.5	-10.5	86.2	-10.0

Figure 4-5 CARB's Proposed LCFS Compliance Schedule

Source: CARB, "Supporting Documentation for the Draft Regulation for the California Low Carbon Fuel Standard" 2008

Figure 4-5 shows CARB's proposed phase-in schedule for an LCFS program. The proposed schedule would require modest reductions in transportation fuel carbon intensities between 2010 and 2014 (1.3 percent reduction for both gasoline and diesel). Larger reductions are required in 2015 to 2020. This approach presumably allows time for the development of advanced biofuels. This approach delays much of the carbon intensity reduction requirement until the later years of program implementation. The advantage of this approach is that regulated entities will have time in the early years of the program to develop strategies to meet the standard. The drawback, however, is that this approach could diminish incentives for firms to act early to accelerate the development and introduction of new low carbon fuels. The phase-in schedule ultimately chosen for California's program will reflect expert opinion on the likely timeframe for development of advanced biofuels and low carbon fuels.

For the purposes of the analysis described in Chapter 3 of this report, NESCCAF assumed a linear phase-in trajectory between 2010 and 2020 designed to achieve the same 10 percent overall carbon intensity reduction in the same timeframe as California has proposed. If possible, the northeast should choose a phase-in schedule that is the same as California, given the fungible nature of the transportation fuel market.

4.7. Incorporating Non-Liquid Fuels into an LCFS

Some of the fuels that offer the greatest, near term potential to reduce GHG emissions from the transportation and thermal heating sectors are not liquid fuels and cannot be blended with conventional fuels. These alternatives are: electricity, natural gas, and woody biomass. Electricity could be used to power plug-in hybrid and battery electric vehicles, while woody biomass and natural gas could be used directly as a substitute for No. 2 fuel oil in heating applications. This section discusses mechanisms to incorporate these important fuels into a Northeast LCFS.

4.7.1. Electricity

Electricity used to power plug-in hybrid and battery electric vehicles is an important potential source of low carbon fuel in the Northeast. The generating technologies used to produce electricity in the Northeast emit relatively low CO_2 on a gram/MJ basis as compared to other regions of the U.S. or the U.S as a whole. This is because the Northeast electricity supply mix includes a relatively high proportion of nuclear, natural gas, and hydro power. As a result, the use of electric plug-in hybrids and battery electric vehicles has the potential to reduce carbon emissions from vehicles significantly in our region.

Since electricity is not a liquid fuel and as such cannot be blended with conventional gasoline or diesel, several significant challenges exist to incorporating electricity into an LCFS. These include the need to establish a mechanism to measure the use of electricity in vehicles; a means of providing credits to utilities that generate electricity for use in plug-in hybrid and battery electric vehicles; and an agency or organization to coordinate the sale and purchase of electricity credits. A method for estimating the amount of electricity use in battery electric or plug-in hybrid vehicles will need to be developed. In the near term, electricity use could be estimated based on electric vehicle and plug-in hybrid vehicles registered in the state, combined with an average assumed VMT and electricity use per VMT. While this would only provide an approximate estimation of the electricity used - due to the variability in vehicle miles traveled, recharging behavior, driving behavior, and other factors - it would allow for a credit trading program to be started. In later years, more advanced measurements of vehicle electricity use – through the vehicle on board diagnostic (OBD) systems, smart metering, and other approaches could be used to improve electricity use estimation in motor vehicles.

Coordinating the sale and purchase of electricity credits

There are a few models that could be used to develop a northeast electricity credit trading mechanism. States in the region are currently considering several models including RGGI and others. This process is ongoing.

5. ANALYSIS OF REGIONAL SUPPLY OF LOW CARBON FUELS

This chapter presents results from a NESCCAF analysis of the supply of low carbon fuel that could be produced from resources located in the Northeast. Specifically, NESCCAF evaluated the supply of regionally available feedstocks as well as the status of the technologies available to convert these feedstocks into low-carbon fuels. Because the technologies needed to use electricity in vehicles are currently available (i.e., plug-in hybrid vehicles), we include electricity as a potential source of low-carbon fuel in this chapter.

This chapter is organized as follows: Section 5.1 provides an overview of key considerations and assumptions; Section 5.2 summarizes NESCCAF's findings on the availability of woody, waste-based, and agricultural biomass feedstocks in the eight NESCAUM states and Pennsylvania;[23] Section 5.3 evaluates the technologies available for converting bio-feedstocks into low carbon fuels in the near-term and the long-term; and Section 5.4 explores the use of electricity as a low-carbon transportation fuel for plug-in hybrid vehicles and discusses related issues impacts on grid capacity and infrastructure needs.

5.1. Overview of Analysis

Securing an adequate supply of low carbon fuels is a critical component of effective implementation of a LCFS. Recent scientific research on the potential lifecycle GHG emissions associated with forest and agricultural biofuel feedstocks finds that lifecycle GHG emissions for these fuels may be significant when additional lands are cleared to respond to growing global demand for food and fuel. Thus, to achieve the GHG goals of a low carbon fuel standard, it is important to promote the use of low carbon fuels that are less likely to induce substantial land use change.[24] This analysis assumes that it may be more feasible to establish the lifecycle GHG emissions of fuels derived from local feedstocks than of fuels derived from feedstocks sourced from international commodity markets, as long the analysis considers those feedstocks not currently supplying existing markets. Moreover, locally grown feedstocks and in-region production of fuels will generate positive regional economic impacts, especially in instances where locally produced fuels displace imported fossil fuels.

Another key consideration in the implementation of an LCFS is the rate of technological innovation in fuels and related technologies. Concerns about environmental degradation and climate change, national security, and long-term petroleum supply adequacy, cost, and price volatility are all contributing to a growing consensus that what is needed is nothing less than a profound transformation of current energy systems. In response, a variety of federal and state government initiatives—including direct subsidies, policy incentives, and volumetric fuel mandates—have been introduced to advance new biofuel technologies and related research,

[23] Maryland is also included in the assessment of waste-based biomass and electricity.

[24] Timothy Searchinger *et al.*, "Use of U.S. Croplands for Biofuels Increases Greenhouse GasesThrough Emissions from Land Use Change," *Science* 319 (5867), 2008: 1238 - 1240.

development, and deployment (RD&D) efforts. Expectations are that these RD&D efforts will result in "advanced" or "second-generation" biofuels that are lower in the energy required to produce them as well as in costs in comparison to first-generation biofuels such as corn ethanol. While there are uncertainties about the timing of advanced biofuels and related technologies, experts in the cellulosic ethanol industry, for example, hope to be in full-scale commercial production within five years. Similarly, General Motors, Chrysler, and Toyota all have announced plans to bring plug-in vehicles to market by 2010.[25]

Because of the state of innovation underway in the biofuels and related energy industries, we examine in this analysis the potential supply of low carbon fuels in two phases—those low carbon fuels that can be produced with existing technologies in the near-term, and those that may be produced with advanced technologies in the future. First, we assume that existing fuels and technologies will continue to dominate the marketplace over the next five plus years, while new fuels and technologies continue development towards commercial viability. Then, we evaluate the potential supply of low carbon fuels available by 2020, based on best available current projections of the likely characteristics of advanced biofuels and technologies. Obviously, the long-term projections are subject to a significantly higher degree of uncertainty than the near-term estimates.

Finally, we note that there are valid concerns over the potential for negative environmental tradeoffs associated with an increased production of forest and agricultural feedstocks from the region. Given the high population density in the Northeast, the region places high priority on other services—aesthetics and open space, watershed protection, wildlife habitat, and recreation—provided by forests and agricultural lands.
Increased harvesting in response to demand for food and fuel feedstocks has in many cases resulted in significant damages to forest and agricultural ecosystems and associated amenities.[26] A 2007 study, for example, found that nitrogen loadings resulting from increased corn cultivation for ethanol production are likely to significantly worsen the already-hypoxic conditions causing the "dead zone" in the northern Gulf of Mexico.[27] Recent studies of the lifecycle GHG impacts of biofuels have raised the prospect that increased global demand for biofuels creates market effects and subsequent land use changes that result in GHG releases that may far exceed GHG reductions associated with biofuels'displacement of fossil fuels.[28]

An original analysis of the sustainability of regional forest, agricultural, and biowaste resources and other environmental impacts associated with fuels derived from regional feedstocks was not possible within the scope of this study. Instead, this analysis was designed to explore a first-order estimate of a possible feedstock and fuel supply scenario for the region, based on relatively conservative screening-level assumptions about feedstock sustainability, technological innovation, and market transformation. This approach is not to suggest these estimates as appropriate levels for feedstock supply and regional fuel production in support of regional LCFS

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[25] Cite article on GM and Toyota competition on PHEVs.

[26] During the period from 1600 to 1909, forest land area in the Northeast fell by nearly 50 percent, from 97 million to 48 million acres (Irland, Lloyd, 1999. The Northeast's Changing Forest. Harvard University Press, Harvard Forest: Petersham, MA.).

[27] Donner et al., "Corn-based ethanol production compromises goal of reducing nitrogen export by the Mississippi River," *Proceedings of the National Academy of Sciences* 2008.

[28] Searchinger *et al.*,2008.

implementation. Rather, the intent is to provide policymakers with a first-order estimate for low-carbon fuels sourced from within the region in order to identify key policy implications and questions that can direct additional research and analysis.

5.2. Estimates of Regional Feedstocks for Low Carbon Fuels

5.2.1. Woody Biomass

The Northeast is one of the most densely forested regions in the United States, with over 70 percent of land covered by forest, equivalent to about 70 million acres.[29] As such, woody biomass is one of the region's few indigenous sources of fuel and one of its most significant renewable energy resources. This analysis considers the potential supply of woody biomass from the northeastern region[30] for potential conversion into both solid and liquid low-carbon fuels, based on existing technologies and projections of future fuels and technologies.

All estimates of woody biomass supply in the Northeast are derived from data and original analysis provided by Integrated Natural Resource Solutions LLC (INRS).[31] Estimates of the region's woody biomass supply rely primarily on INRS's analysis of publicly available data from a variety of sources, including the US Department of Agriculture Forest Service's *Forest Inventory Analysis* and *Timber Products Output* databases, and the Resource Planning Act Assessment, and state- and region-specific reports on biomass generation, sawmill production, timber harvesting activity, and wood waste generation.[32]

It is important to note that woody biomass is an aggregate description that represents numerous categories of biomass types. Not all woody biomass is appropriate for every end-use or technology. Each type of biomass fuel has unique characteristics, including moisture content and Btu content (British thermal units, a measure of heat content). For example, because of relatively high soil content, forest residues are not suitable for cellulosic ethanol production but are generally appropriate for biomass combustion in electricity generation units.

This analysis provides supply estimates by category type, and associates each type with appropriate uses and technologies. Categories of woody biomass considered in this analysis include forest residues, sawmill residues, secondary mill residues, net forest growth, and urban wood residues. Appendix D contains detailed descriptions of data and methods used to generate estimates for each of these biomass categories.

Because of concerns that renewable fuel policies may be causing secondary impacts in markets for agricultural and forest products that may result in an increase in GHG emissions, the estimates of biomass in this analysis include only sources that are incremental to existing

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29 Irland, Lloyd, 1999.

30 States included in this analysis of northeastern biomass resources include the six New England states, and the mid-Atlantic states of New Jersey, New York, and Pennsylvania. Estimates for Maryland and Delaware were not available for this analysis, but could be added.

31 INRS, LLC is a forestry and natural resource consulting and research firm located in Portland, Maine. For more information, see: www.inrsllc.com.

32 A detailed description of underlying data and assumptions in INRS' analysis can be found in Appendix D.

markets, i.e., wood, agriculture, and waste biomass resources that are not being used in existing markets. The purpose behind this approach is to generate estimates of biomass availability that are most likely to avoid creating market effects that could cause net increases in GHG emissions through significant land use changes.

Table 5-1 below describes woody biomass resources available in the region, both their "maximum" availability and their "likely" availability. The most significant category of resource is from new forest growth, which includes (but is not limited to) lower-grade wood not currently being used in markets. This analysis assumes that only a fraction of each the maximum from each category, ranging from 10 percent to 40 percent, would be likely available.

Table 5-1 Total Woody Biomass Resources by Resource Type, Maximum and Likely Availability

Region	Forest Residue	Sawmill Residues	Secondary Mill Residues	Urban Wood Residues	Net Forest Growth	Total
	Green Tons	Green Tons	Dry Tons*	Dry Tons*	Green Tons	Green Ton Equivalent*
Estimated Maximum Availability						
New England	7,400,000	2,990,000	140,000	1,640,000	3,870,000	17,500,000
Mid-Atlantic	4,600,000	4,390,000	330,000	4,590,000	23,640,000	42,735,000
Maximum Total	**12,000,000**	**7,380,000**	**470,000**	**6,230,000**	**27,510,000**	**60,235,000**
Estimated Likely Availability						
Availability Factor	20%	20%	40%	20%	10%	
New England	1,480,000	598,000	28,000	328,000	387,000	3,105,800
Mid-Atlantic	920,000	878,000	66,000	918,000	2,364,000	5,933,200
Likely Total	**2,400,000**	**1,476,000**	**94,000**	**1,246,000**	**2,751,000**	**9,039,000**
*For the green ton equivalent totals, dry tons have been converted to green tons using a factor of 1.8.						

Interestingly, as shown in Table 5-2 below, the geographic distribution of available woody biomass resources is highly concentrated in two states—New York and Pennsylvania. While New England has significant quantities of woody biomass, much of these resources are already being deployed in existing markets (e.g., for sawtimber, pulp and paper). Because current market conditions limit the distances over which it is economically viable to transport woody biomass to about 50 miles, this geographic concentration could have important implications for the development of low carbon fuel production facilities and related infrastructure.

Table 5-2 Maximum Woody Biomass Available, by State

State	Dry Ton Equivalent
Connecticut	1,072,000
Massachusetts	1,698,000
Rhode Island	193,000
Vermont	2,488,000
Maine	2,288,000
New Hampshire	2,761,000
New York	12,561,000
New Jersey	1,980,000
Pennsylvania	11,689,000
Maximum Availability	**36,730,000**
Likely Availability	**5+ million dry tons**

5.2.2. Agricultural Biomass

Land use patterns in the Northeast have shifted substantially over the last two centuries. As the midwestern US opened up to agricultural production over the course of the late 19th and 20th centuries, farms established in the 19th century in the Northeast became comparatively less competitive. Many of these farms were abandoned and have reverted back to forest, or in the latter part of the century, were converted into suburban development. In comparison to the Midwest, South, and California, the Northeast is no longer a major agricultural producer. Agriculture, however, still plays a relatively important role in the economies of some northeastern states – New York, Pennsylvania, Vermont, and Maryland in particular.[33] Many states are exploring the use of agricultural residues for bioenergy products, and research is underway in New York and other states to test the viability of fast-growing energy crops (e.g., willow, hybrid poplar) on marginal crop and pasture lands.[34]

Table 5-3 below shows the estimated maximum and likely availability of agricultural biomass from energy crops, based on ORNL and NRBP analyses.[35] Since the agriculture sector in the northeastern states is not large relative to the forestry sector, not surprisingly, the likely available quantities of agricultural resources are only about fraction of the woody resources, at 1.6 million dry tons per year.

[33] According to the US Department of Agriculture, agricultural employment and income still play a significant role in New York, Pennsylvania, Vermont, and Maryland in particular. For more information about the role of the agricultural sector in individual states, see: http://www.ers.usda.gov/StateFacts/.

[34] Insert cite on Tim Volk's work at SUNY ESF.

[35] Fast-growing woody energy crops, such as poplar and willow, are included in the discussion of agricultural biomass.

Table 5-3 Total Agricultural Biomass Resources by Region, Maximum and Likely Availability

Maximum Availability	**Dry Tons**
New England	449,200
Mid-Atlantic	2,829,200
Total	**3,278,400**
Likely Availability	**50% of Maximum**
New England	224,600
Mid-Atlantic	1,414,600
Total	**1,639,200**

5.2.3. Waste-based Biomass

The Northeast is one of the most densely populated regions of the US, so the volume of waste generated within a fairly limited geographic region is significant. Municipal solid wastes (MSW) have long been an input for energy production in the region. There are currently 40 waste-to-energy facilities in the Northeast, which have the capacity to manage almost 43,000 tons of MSW and produce 1,085 MW of electricity.[36]

Because of concerns that virgin biomass feedstocks may result in greenhouse gas emissions by inducing substantial land use changes, it is essential to include consideration of waste-based biomass in an analysis of low-carbon fuel production potential. The aim of waste reduction policies in the northeastern states is generally to reduce the quantities of waste generated and recycle as much as possible thereafter. [37]However, waste resources are and will continue to be generated to some degree regardless of waste reduction policies. To determine the potential contribution of waste-based resources to the potential production of low carbon fuels, we evaluate only that portion of the waste stream that is not a candidate for additional source reduction and/or recycling efforts.

In this report, waste-based biomass is defined as refuse that is organic in origin and becomes available after primary use and all economically and environmentally beneficial options for disposal, such as reuse or recycling, have been exhausted. Using this definition, we considered the organic portion of municipal solid waste (MSW), including yard waste, food waste, and paper waste, wood from construction and demolition (C&D) debris, used cooking oils, and bio-solids from wastewater treatment facilities and livestock. We analyzed the energy potential for each waste-based biomass source considering a suite of technologies for transforming waste-based biomass to electricity, ethanol, or other fuels for transportation and thermal uses.

[36] Insert cite for these statistics.

[37] For example, Massachusetts is in the process of developing a new "zero waste" hierarchy that includes source reduction and recycling as highest priority.

Waste-based biomass is a unique source for the region because population density translates directly into waste density. The Northeast as a whole produces almost 63 million tons of MSW annually, about 16 percent of the national waste stream.[38] Much of this waste is already being collected and partially sorted for disposal. Because these wastes are often exported long distances by truck for disposal, local conversion to a useful energy source could significantly reduce the lifecycle greenhouse gas emissions associated with its use.[39]

Estimates of quantities of waste-based feedstocks in the region were based on a number of sources. Because most wastes are population-dependent, i.e., the magnitude of the waste stream is highly correlated with population, feedstock quantities were estimated on a per capita basis using population data from the US Census Bureau's website.[40] Quantities of various categories of waste-based biomass were then extrapolated into the future using the US Census Bureau's population projections for the northeastern states and per capita waste quantities. More detail on the data and methods used to generate estimates of waste-based biomass quantities can be found in Appendix D.

Table 5-4 below provides estimates of waste-based biomass by different types of resources, including municipal solid waste (MSW), waste oils, wastewater treatment facility (WWTF) solids, livestock wastes, and wastewater biogas. Municipal solid waste is by far the dominant category, with likely availability of over 20 million dry tons in 2010, growing with population to 20.7 million tons in 2020.

Table 5-4 Total Waste-based Biomass Resources by Resource Type, Maximum and Likely Availability

	Units	Maximum Availability		Likely Availability	
		2010	2020	2010	2020
MSW	**Tons**	66,492,294	67,576,482	20,390,809	20,723,277
Waste Oil	**Tons**	620,486	629,178	62,049	62,918
Other Wastes (WWTF Solids)	**Tons**	10,430,126	10,590,876	5,215,063	5,295,438
Other Wastes (Livestock Waste)	**Tons**	1,450,415	1,470,707	725,208	735,354
Other Wastes (WWTF Biogas)	**Cubic feet**	55,785,179	56,565,669	27,892,590	28,282,835

5.3. Biomass Technology Assessment

38 Biocycle, 2006. Nationwide Survey of MSW Management in the United States.

39 An Appendix to this section includes an example of a lifecycle analysis specific to MSW that examines the average distances waste is transported out of the Northeast states, but also quantifies the carbon storage, sequestration, and avoided energy usage associated with burial in a landfill, reclamation to avoid use of virgin materials, and recovery of energy contained in the organic matter in the waste.

40 Note that this methodology may be less accurate for the livestock and grease categories of bio-waste.

This analysis makes an important distinction between technologies that are currently available in the commercial marketplace for converting biomass to a low carbon fuels, such as thermal energy and electricity, and those more advanced technologies that are under development but are not yet commercially viable. We assume that in the near-term (i.e., within 5 years), technologies that are currently commercially available will dominate the market for converting biomass to low carbon fuels. In Figure 5-1 below, pathways for numerous types of biomass resources are depicted, showing their conversion via numerous technologies into a variety of end-products. Typical conversion pathways for existing technologies are depicted in green. Over the long-term (i.e., within 10 to 15 years), this analysis assumes that advanced technologies which are currently under development will be commercially viable over that timeframe, and will therefore be relatively competitive with existing technologies. The conversion pathways for advanced technologies are shaded in blue.

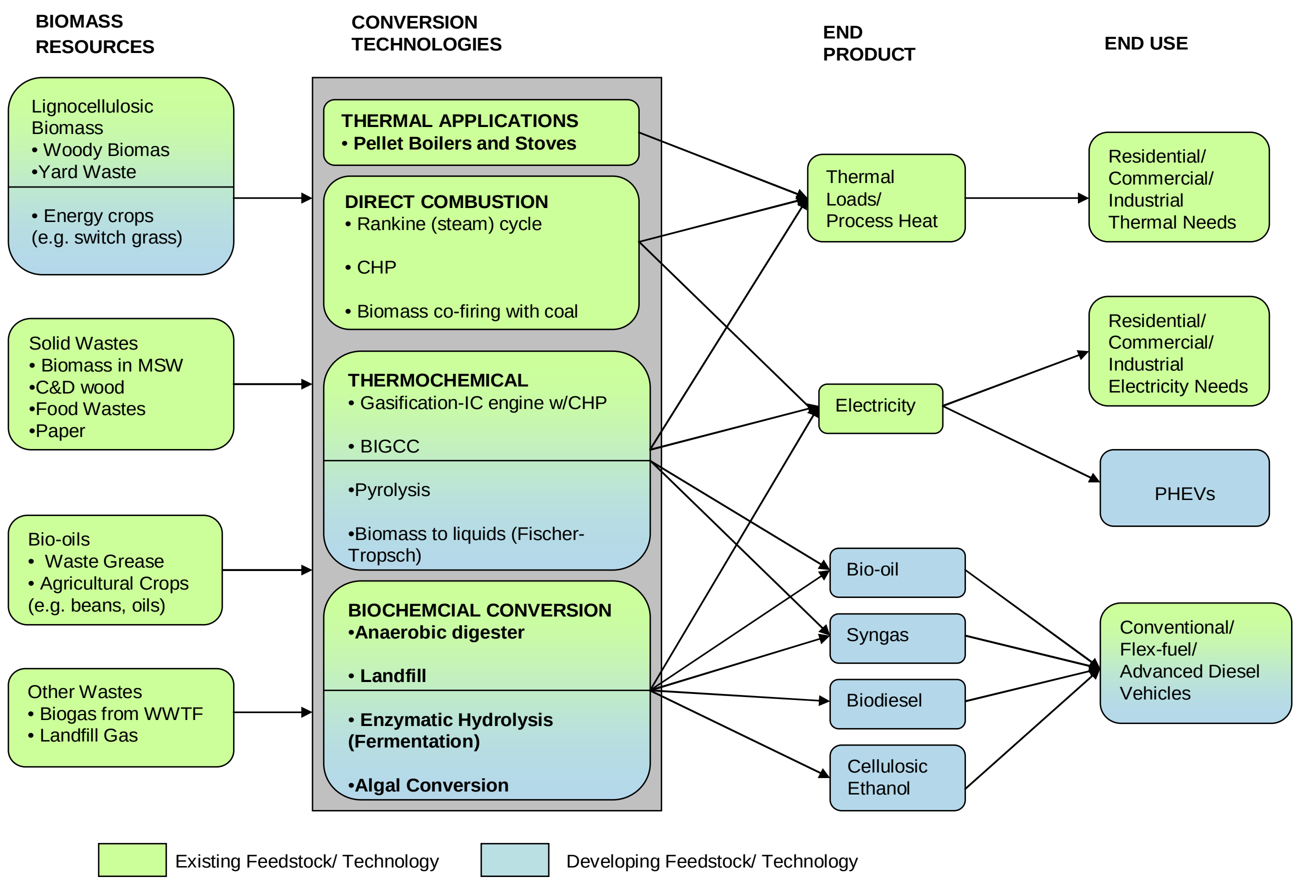

Figure 5-1 Existing and Advanced Biomass Conversion Technologies

In the next sections, we describe existing and advanced biomass conversion technologies in more detail.

5.3.1. Existing Biomass Conversion Technologies

Estimates in this analysis reflect that in 2010, the most likely technologies to be employed will be used to convert available biomass to thermal energy and/or electricity. These conversion processes involve well-proven and commercialized technologies, viable economics, a relatively well-developed supply infrastructure and – in the case of electricity – public policy that supports the deployment of these technologies.

Table 5-5 below displays each existing biomass conversion technologies, the types of biomass resources best suited to each technology, end-products (e.g., thermal energy), size range, and technology efficiency (i.e., rate of resource use). Each of these technologies is described in greater detail below.

Table 5-5 Existing Biomass Conversion Technologies[41]

	Direct Combustion for Electricity		**Thermal**	
Conversion Technology	**Combined Heat and Power**	**Large-Scale Electricity/ Waste-to-Energy**	**Institutional Thermal**	**Residential Thermal**
Biomass Types	• Forest residues • Urban wood • Sawmill residues • Ag. Residues	• Forest residues • Urban wood • Sawmill residues • Ag. Residues • MSW • WW/Ag Solids	• Sawmill residues • New forest growth (roundwood)	• Sawmill residues • New forest growth (roundwood)
Products	Electricity and thermal energy (process heat)	Electricity	Thermal energy (heat)	Thermal energy (heat)
Size range	500 kW to 60 MW	5MW to 50MW	25 to 1500 horsepower	0 to 350,000 Btu thermal input
Efficiency	40 to 80 percent, depending on technology and heat captured	Roughly 30 percent, varying slightly with size, technology, and configuration	60 to 90 percent	40 to 80 percent[42]
Resource Use	Varies, depending on technology and heat captured	13,400 green tons per MW (7,444 dry tons per MW)	40 to 19,000 tons of wood chips per year; average facility is approximately 600 tons per year	6 tons of pellets per home[43]

[41] Sources used for information on feedstocks and conversion factors for each technology type include: (1) INRS 2008; (2) New Jersey Agricultural Experiment Station at Rutgers, *Assessment of Biomass Energy Potential in New Jersey;* and (3) Antares, 2008.

[42] This range does not include the efficiency of outdoor wood boilers, which have efficiencies closer to 25 to 30 percent. These technologies have become popular in the Northeast due to high prices for home heating oil, but are being discouraged by state policies due to their high levels of air pollution.

Direct Combustion

Direct combustion of biomass for electricity production is a mature technology that includes many stand-alone grid power applications, and it is one of the few renewable electricity technologies well-suited to baseload electricity generation. Biomass resources best suited for direct combustion include roundwood from new forest growth, sawmill residues, forest residues, urban wood residues, and some municipal solid wastes. Agricultural residues can be used in direct combustion as well, but due to their limited availability in the region, they are not typical inputs for large biomass energy plants.

Biomass combined heat and power (CHP) systems are another form of direct combustion that have the advantage of greater efficiency than stand-alone biomass electric units due to the capture of both electricity and heat. They also have a long history of use in the forest industry, where pulp mills or sawmills have used their residues to generate electricity and process heat. Biomass CHP is now moving beyond the forest industry, and is especially attractive to industries with high heat and electricity demand.[44] Because a combustion technology is used, biomass CHP can take a variety of biomass types, including forest residues, new forest growth, sawmill residues, and urban wood residues.

Institutional and Residential Thermal

Institutional scale thermal energy technologies are also well-proven, and a number of facilities in the Northeast have installed biomass thermal technologies, including schools and other public institutions as well as the forest products industry. New technologies are coming to market that facilitate the use of wood pellets for institutional scale thermal applications. These technologies hold substantial promise to allow the installation of thermal biomass at locations previously considered challenging, because pellets provide an opportunity for easier storage. There are certainly challenges with the air pollution profiles associated with some of these technologies, especially those that fall below current size thresholds for regulatory emissions limits.[45] Emissions of fine particulate matter are of special concern, given their potential for creating adverse impacts on sensitive populations.[46]

Anaerobic Digestion

Anaerobic digestion of biomass feedstocks is a well-developed process that is in wide use in food waste digesters, wastewater treatment plants, and on livestock farms. Landfill gas (i.e., methane) is the product of natural anaerobic digestion, and many landfills employ technology to

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[43] Based on an assumption of an average 2,000 sq. ft. home in New England. Actual pellet use will vary depending on home size, location, quality of building shell, and other factors.

[44] For example, a large Anheuser Busch brewery in Merrimack, NH recently announced that it is evaluating biomass to meet the facility's sizeable electricity and thermal needs.

[45] NESCAUM is currently working with its states to identify the best available combustion technologies and emissions controls and to address market barriers that limit their presence in the marketplace.

[46] Potential health impacts and emissions from these units are described in more detail in a 2009 NESCAUM study on wood combustion (*in progress*)

capture the methane gas for use in power generation. Electric power production and CHP are common applications for the use of landfill gas.

5.3.2. Advanced Biomass Conversion Technologies

Over the long-term (2015 to 2020) timeframe, this analysis assumes that advanced biomass conversion technologies, including gasification, pyrolysis, enzymatic hydrolysis, and algae-derived fuels.

Table 5-6 Biomass Conversion Technologies under Development

	Thermochemical Conversion		**Biochemical Conversion**	
	Gasification	Pyrolysis	Enzymatic Hydrolysis	Algae
Biomass Types	Wide range of feedstocks	Wide range of feedstocks	• Ag.residues • "Pre-treated" woody feedstocks	Algae
Products	"Syngas"	Bio-oil for combustion or conversion into transportation fuel	Cellulosic ethanol	Biodiesel
Probable size range at commercial scale	Varies widely, depending on technology and application	n/a	20 million gallons per year	n/a
Efficiency	As high as 75 percent, depending on technology and application	Possibly as high as 75 percent (intermediate product	n/a	n/a
Resource Use	Variable	Variable	80 to 100 dry tons per gallon	Variable

Thermochemical Conversion: Gasification and Pyrolysis

Some gasification and pyrolysis technologies are commercially available, including gasification applications that use wood residues from MSW and C&D debris in power production. MSW may also be used to generate electricity if it is processed into refuse-derived fuel (RDF). In the near future, commercial gasification applications may also be used to produce liquid transportation fuels because the first step in gasification produces a gas. This gas, after cleaning and depending on the amount of heat and type of technology for infiltrating oxygen, may be used as a substitute for fuel or natural gas in existing boilers or further refined to be blended with, or used to replace, petroleum-based fuels.

Biomass integrated gasification combined cycle technology (BIGCC) utilizes a gas turbine and steam turbine to increase the efficiency of producing electricity from biomass gasification. BIGCC technologies are developed but thus far, have limited commercial deployment. The production of Fischer-Tropsch transportation fuels from the gas produced in gasification requires an oxygen-blown gasifier, a tar cracker, and considerable cleaning and refining.

Small-scale gasification for use with an internal combustion engine or a reciprocating engine is in limited use, but under development. This type of gasification is not as efficient as a BIGCC, but has the potential for more localized implementation.

Pyrolysis produces oils that can be used in power generation or, with significant upgrading, transportation fuels.

Biochemical Conversion: Hydrolysis

Dilute acid hydrolysis for biofuels is a future technology that is attractive for its ability to process a wide range of biomass feedstocks and convert them into a number of fuels suitable for transportation. These include MeTHF, a gasoline additive or replacement, and methyl- or ethyl-levulinate, which can be used as additives or replacements for diesel fuel or heating oil.

Cellulosic ethanol production, in particular technologies deploying enzymatic hydrolysis, is undergoing extensive research and development. Cellulosic ethanol could be developed from a range of feedstocks, including the organic portion of MSW and C&D debris. While pilot wood-to-ethanol facilities are under development in New York and Maine, and early commercial sites are under development outside of the region, we assume that cellulosic ethanol (or other biomass-based transportation fuels) will not be fully commercialized in the region within five years.

Modifications may be made to typical engines to use a blend of gasoline that contains 15 percent ethanol, and flexible fuel vehicles (FFVs) allow the use of E85, or 85 percent ethanol fuel. For this analysis, we use conversion factors developed for the New Jersey Agricultural Experiment Station. The conversion factors are specific to each biomass feedstock.

Transecterification

Conversion of lipid-containing feedstocks to biodiesel using transecterification is a mature technology. Most inputs, however, are virgin vegetable oils from food crops, such as canola, soy beans, sunflower, and palm, which are not currently produced in significant quantities in the Northeast. Although not usually produced at the commercial level, used cooking oils (yellow grease) may be used in place of diesel in a retrofit vehicle or be refined and converted to biodiesel.

1.3.3 Summary of Woody, Agricultural, and Waste-based Biomass and Fuel Assessment

To summarize the assessment of biomass resources available for the production of low carbon fuels in the Northeast region, Table 5-7 provides estimates of both “maximum” availability of woody, agricultural, and waste-based biomass categories, and the “likely” availability for those same resources. The figures for likely resource availability, while not reflecting any formal analysis of sustainability issues or market supply and demand, are relatively conservative percentages of the maximum applied to reflect the fact that a variety of factors, including (but not limited to) environmental concerns, market conditions, and landowner preferences, will limit actual quantities of resources available for the production of low carbon fuels in the region.

Based on the application of these conservative percentages, likely availability for solid biomass resources are estimated to be nearly 30 percent of maximum availability; for wastewater biogas, the likely availability is about 50 percent of maximum availability, and for waste oils, likely availability is estimated to be only 10 percent of maximum availability.[47]

A key insight from these estimates is that waste-based resources are by far the largest biomass resource available in the Northeast, totaling over 26 million dry tons between MSW and agricultural and wastewaster solids, in comparison to about 6.6 million dry tons of woody and agricultural biomass combined. These large quantities of waste-based biomass are due primarily to the Northeast's large population,[48] which generates significant quantities of waste even after removing from consideration those wastes that are candidates for reduction and recycling. Another notable result is that the estimated likely availability of waste oils, which are also a function of population density, is very low. This reflects the fact that these wastes are used in many existing markets and that bio-energy applications will need to compete in the market for these resources.

Table 5-7 Total Biomass Resources in the Northeast, Maximum and Likely Availability[49]

Type of Resource	Maximum Availability	Likely Availability
Woody biomass (dry tons)	33,463,889	5,021,667
Agricultural biomass (dry tons)	3,278,400	1,639,200
Municipal solid waste (dry tons)	66,492,294	20,390,809
Agr. and wastewater solids (dry tons)	11,880,541	5,940,271
Total Solid Biomass(dry tons)	**115,115,124**	**32,991,947**
Wastewater biogas (cubic ft.)	55,785,179	27,892,590
Waste oils (metric tons)	620,486	62,049

After applying the assumed conversion technologies for the near-term (i.e., 2010) and the longer-term (i.e., 2020) as described earlier to the likely available biomass quantities, Table 5-8 below shows the estimated volumes of low carbon fuel. Note that these estimates do not consider market conditions. Instead, they consider only the available resources and the most likely conversion pathway for each resource category, based on current practices and best expert judgment about future practices. Market conditions, the rate of technological development, and other factors will of course play a large role in determining the ultimate use of biomass and

[47] There are many existing markets for waste oils, such as cosmetics and animal food products, so the likely availability of waste oils for bioenergy is estimated to be as low as 10 percent.
[48] The population of New England and the Mid-Atlantic together is estimated to be 97 million people in 2010.
[49] States included in this assessment are the six New England states, New York, New Jersey, and Pennsylvania. Figures represent estimated resource availability on an annual basis.

resulting volumes of low carbon fuels, as prices will reflect the highest and best use of resources to serve specific end-use demands.

These volume figures are not mutually exclusive, meaning that the volumes of electricity, thermal energy, and liquid fuels shown below could all be produced simultaneously from the available resources. So, in the near-term, low carbon fuel production will include nearly 850MW of electricity, thermal heat equivalent to heating 400,000 residences, and 42 million gallons of B5 biodiesel.

Over the longer-term, more resources will become available to energy applications, so the volumes of low carbon electricity and thermal energy will more or less double by 2020, to 1,500MW of electricity and thermal energy to heat approximately one million residences, respectively. While liquid fuel production is very low by 2010, by 2020 there will be an estimated 440 million gallons of cellulosic ethanol as these advanced fuel technologies gain viability.

Table 5-8 Estimated Low Carbon Fuel Production from Available Regional Resources (conservative), 2010 and 2010

Quantities of Low Carbon Fuel	2010	2020
Electricity (MW)	849	1,524
Thermal energy (no. of average homes heated)	400,000	1,000,000
Liquid fuels (million gallons)		
B5 biodiesel	42	46
Cellulosic ethanol	--	440

5.4. Electricity

This analysis considers "fuel electricity"[50] as a potential low carbon fuel for transportation when the electricity is used to operate light-duty, plug-in hybrid electric vehicles (PHEVs). With improved battery storage for electricity and greater potential all-electric ranges (AERs), PHEVs could meet average daily travel needs for an increasing number of consumers. PHEVs are expected to be on the market as early as 2010 and will be rechargeable at home or at the workplace with upgrades to existing infrastructure. When the electricity used to fuel these vehicles is less carbon-intensive than other vehicle fuel options, the electricity used in a PHEV may be considered a low carbon fuel.

Because electricity demand varies on a daily and seasonal basis, not all electric power production facilities operate all the time. Instead, the electric grid is carefully managed to meet demand with the most inexpensive electricity available at any given time. During off-peak hours when

[50] Term used in "A Low Carbon Fuel Standard for California," Farrel, Alexander E. and Daniel Sperling. (2007) University of California at Berkeley and Davis.

electricity demand is lower, the system provides “baseload” generation, which draws from sources including coal, nuclear, run-of-river hydropower, and some renewable resources (wind and solar).

With RGGI and renewable energy requirements in place in the Northeast, new sources of electricity that are less carbon intensive should become cost-competitive and be employed by the grid in a growing proportion relative to traditional fossil-based resources. During peak hours, more expensive sources of power are called upon, including natural gas-fired combined cycle, some higher cost coal generation, along with natural gas turbines and diesel generators. Some of these sources generate very high levels of criteria air pollutants. Moreover, the capacity of the electricity grids in New England, New York, and the mid-Atlantic states are being increasingly challenged to meet growing demand during peak periods while maintaining high levels of reliability. Therefore, it will be important to consider when PHEVs are most likely to be charged by consumers to determine what power sources are being used to meet demand.

This analysis evaluates in a very general sense the effects on the power system of the Northeast from PHEV vehicles and the incremental demand for electricity they will create. Depending on the rate of penetration of PHEVs into the marketplace, the range of the vehicles (known as “all-electric range” or AER), charging duration, and time of initial charge, incremental demand from PHEVs may be met with existing generation and/or construction and dispatch of new generation resources. This analysis used a very simple approach based on an examination of the load profile of each of the three electricity grids serving the Northeast, including how demand typically changes for each grid over the course of each peak and non-peak day and over the course of an average year, and which kind of generation resource typically serves demand over the course of the average peak and non-peak day and average year. A more detailed description of this methodology and the underlying data can be found in Appendix D.

Based on PHEV penetration levels from EPRI and NRDC[51] and the NE-Vision model, penetration of PHEVs in 2020 was assumed to fall between about 2.3 million vehicles on the low-end and 7.2 million vehicles on the high-end for New England, New York, New Jersey, Pennsylvania, Maryland, and Delaware. Table 5-9 below shows the extra electricity capacity remaining (shown with a “+” symbol), or new capacity that would be required (shown with a “-“ symbol), under different charging scenarios that combine vehicle numbers, charging time, charging duration, and vehicle technology (i.e., electric range of the vehicle).

As shown in the estimates of capacity in Table 5-9, most of the PHEV charging scenarios represented in this analysis could theoretically be met with existing generation resources. The exception to this are PHEV charging scenarios with an initial charging time of 5pm. New capacity would be required for all scenarios of vehicles charging at this time, even if the number of vehicles is on the low-end, those vehicles charge more slowly (i.e., 6 hours), and have a shorter electric range (i.e., 20 miles).

Since PHEVs in these scenarios will be competing for peak generation resources throughout most of the region, charging vehicles at this time would require additional capacity to meet

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51 Electic Power Research Institute (EPRI) and Natural Resources Defense Council (NRDC). (2007). Environmental Assessment of Plug-In Hybrid Electric Vehicles.

demand with the same level of reliability, all else being equal. However, there are significant efforts underway in the Northeast to reduce demand for electricity by substantial new investments in energy efficiency. Depending on whether these energy efficiency measures reduce demand during peak or non-peak times will determine how they benefit the grid at different times of the day and throughout the year.

Table 5-9 Effects on Total Grid Capacity of PHEV Charging Scenarios (in MW)

PHEV Charging Scenario			2010		2020	
Time of Initial Charge	Charge Duration	All-Electric Range	PHEV Penetration Level			
			Low	High	Low	High
9 a.m.	2-hour	20 mile	+29,366	+15,804	+33,187	+17,349
		40 mile	+18,202	+8,916	+30,625	+9,304
	6-hour	20 mile	+33,590	+29,070	+38,120	+32,841
		40 mile	+32,859	+26,774	+37,266	+30,159
5 p.m.	2-hour	20 mile	-5,185	-18,746	-5,983	-21,821
		40 mile	-16,349	-25,635	-8,544	-29,865
	6-hour	20 mile	-961	-5,481	-1,050	-6,329
		40 mile	-1,692	-7,777	-1,904	-9,011
12 a.m.	2-hour	20 mile	+41,047	+27,486	+46,566	+30,728
		40 mile	+29,833	+20,597	+44,004	+22,683
	6-hour	20 mile	+45,271	+40,751	+51,499	+46,219
		40 mile	+44,540	+38,455	+50,645	+43,538

Note that a key limitation of this simplified approach is that it is not based on dispatch modeling. Dispatch modeling of grid impacts would provide a geographic dimension to identify the location of where new demand from PHEVs would occur, which in turn will drive where new electricity capacity may be required. Obviously, electricity can only be supplied where generation is connected to infrastructure—transmission and distribution resources—that deliver power. Therefore, the location of where PHEV technologies are charged will have important implications for electricity transmission and distribution systems.

Additional transmission and distribution investments may be required if commuters to cities such as New York or Boston charge their PHEVs during the day. Substantial transmission constraints currently exist in the greater Boston, New York City/Long Island and Northeastern portion of New Jersey.[52] In 2007, for example, major interfaces in the New York City load pocket were congested 20 percent of the time, and constraints in New York City and Long Island along with local load pockets were substantial enough to raise prices in these zones.[53] In the case of the PJM Mid-Atlantic, northern New Jersey incurred over $200 million in congestion costs in 2007.[54] The constraints in Boston require less immediate attention, but could cause concern in a high-penetration PHEV scenario.

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52 2007 Assessment of the Electricity Market in New England, p. 31.

53 2007 New York State of the Market Report, p. 109 & 27.

54 2007 PJM State of the Market Report, p. 320.

There are a range of options to influence when PHEV users charge their vehicles. Real-time metering and "cost at time of use" billing could compel some consumers to charge when there is less demand on the grid. Charging stations at major places of employment and in cities could provide incentives for consumers to charge when they arrive at work rather than when they arrive home, and timers placed in vehicles or wall sockets could be used to make charging late at night easier. Over time, investment in smart grid technologies could eventually lead to "vehicle-to-grid" (V2G) technologies that would allow consumers to charge PHEV batteries at low demand times and then sell stored electricity back to the grid during peak demand times.

6. CONCLUSIONS

6.1. General Conclusions

- Emissions from transportation sources account for about 40 percent of total anthropogenic GHG pollution in the Northeast.

- The LCFS can provide substantial GHG reductions – on the order of what will be realized from implementation of the California motor vehicle GHG standards and RGGI.

- The low carbon fuel standard can serve as an essential component of a broader, integrated strategy to reduce GHG emissions. In the Northeast, states have committed to reducing GHG emissions substantially by 2020 and 2050. The development of a LCFS could be an important part of these efforts, along with the LEV GHG standards, the Regional Greenhouse Gas Initiative (RGGI), renewable portfolio standards (RPS), VMT reduction strategies, and other programs.

- The LCFS can ensure that high carbon intensity fuels – such as those derived from tar sands and some biofuels will not increase the average carbon intensity of transportation fuels.

- The LCFS can complement federal fuels programs such as the renewable fuels standard.

- A low carbon fuel program has the potential to provide important economic and energy security benefits in the northeast and mid-Atlantic states. Nearly all transportation fuel used in the region is imported, which results in a significant outflow of capital from the regional economy.

6.2. Scenario Analysis

- In 2005, approximately 17 billion gallons of gasoline, 500 million gallons of ethanol, and 4.0 billion gallons of diesel fuel were used to power light and heavy duty vehicles in the eight NESCAUM member states. In 2020 under a business-as-usual projection, NESCCAF estimates that the region's light and heavy vehicles will require 18 billion gallons of gasoline, 3 billion gallons of ethanol, and 4.3 billion gallons of diesel fuel.

- In 2005, approximately 4.1 billion gallons of No. 2 fuel oil were used for space heating in the Northeast. This number is expected to decrease to 3.5 billion gallons in 2020.

- The federal RFS will require the use of approximately 17 billion gallons of advanced biofuels - as distinguished from conventional corn-ethanol and biodiesel - by 2020 *nationwide*. If this fuel is assumed to be distributed proportionally on a population basis throughout the United

States, the Northeast could expect to receive approximately 2 billion gallons of low carbon biofuels by 2020 as a result of the RFS. If this is the case, the federal RFS by itself will produce a reduction of approximately 3 percent in the average carbon intensity of transportation fuel in the Northeast.

- There are a number of fuels and fuel pathways that could be used to comply with a regional LCFS. In the case of gasoline, a 10 percent reduction in overall carbon intensity could be achieved by introducing 6 billion gallons of advanced ethanol (with an RFS-compliant carbon intensity of 48 gCO2e/MJ) in the region by 2020. This is in addition to the volume of advanced biofuels required by the Renewable Fuel Standard.

- Alternatively, an equivalent reduction could be achieved by increasing the fleet penetration of plug-in hybrid and all-electric vehicles to approximately 18 percent in the same timeframe (2 million all-electric and 4 million plug-in hybrid vehicles).

- The introduction of 8.5 million compressed natural gas vehicles (nearly 25 percent of the fleet in 2020) would also result in a 10 percent reduction of the average carbon intensity of light-duty vehicle fuel.

- Some combination of the above approaches or the use of advanced fuels that are not yet commercially available could also allow regulated entities to meet the LCFS.

For heavy-duty diesel vehicles, a 10 percent reduction in the carbon intensity of transportation diesel fuel in the 2020 timeframe will depend on the rapid commercialization and large-scale production of substantial quantities of low carbon diesel fuel substitutes. It could be met with the following approaches:

- The introduction of 800 million gallons of advanced biodiesel with a carbon intensity of 20 gCO2e/MJ in addition to the fuel expected from the Renewable Fuel Standard.
- The introduction of 480 million gallons of advanced biodiesel (20 gCO2e/MJ) and approximately 55 percent of the vehicles operating on natural gas.
- The introduction of advanced fuels that are not yet commercially available.

Reducing the carbon intensity of transportation diesel by 10 percent in the 2020 timeframe could be more difficult than for gasoline, given that there are fewer apparent near-term replacement options for diesel fuel. For example, the light-duty plug-in hybrid and pure electric vehicles that are being developed for near-term commercial deployment could plausibly displace a considerable portion of the light-duty fleet. This study did not evaluate the impact on the carbon intensity of heavy duty vehicle fuel from the introduction electric drive systems for heavy duty vehicles. If commercial development proceeds, this approach could be an important contributor to reducing the carbon intensity of the heavy-duty vehicle fleet.

The residential heating sector may accommodate a larger variety of low carbon fuel options in the near and the long term. Near term options include: natural gas, wood pellets, and electricity. Assuming that all transportation diesel and No. 2 fuel oil is accounted for in the baseline, and that the RFS results in 240 million gallons of advanced biodiesel in the region in 2020 a 10 percent AFCI reduction requirement in 2020 could be met by:

- The introduction of 1.9 billion gallons of an advanced biofuel with a carbon intensity score of 47 gCO2e/MJ. This biofuel could be produced from waste oils, municipal solid waste, algae, or another feedstock; or

- The introduction of 1.2 billion gallons of advanced biodiesel with a carbon intensity of 20 gCO2e/MJ.

6.3. Program Structure

California's LCFS regulatory documents provide a potential template for a northeast state LCFS program structure. Recommendations from NESCCAF's evaluation of the California program documents and the fuel distribution system in the northeast include:

- The northeast states should include gasoline fuel used in highway and nonroad sources in the LCFS. In addition, diesel fuel used in highway and nonroad applications should be included.

- Given the large volumes of No. 2 fuel oil consumed in the Northeast in thermal applications in residential, commercial, and industrial sectors, consideration should be given to including distillate fuel in a Northeast LCFS. The inclusion of No. 2 fuel for space heating provides an opportunity for substituting the regionally available low carbon fuels such as natural gas, electricity, and woody biomass for more carbon intensive heating oil. Reductions in the carbon intensity of No. 2 heating oil could be required in the same timeframe as transportation diesel or its displacement could generate credits in the early years of the program.

- Residual fuel should not be considered for inclusion in the LCFS in the near term, but possibly in later years.

- There is tremendous potential for non-liquid fuels to partially replace the traditional, petroleum-based fuels as one of the key strategies for reducing average carbon intensity of the fuel supply. In the transportation sector, vehicles may be powered by electricity in hybrid or fully electric applications. Natural gas may also have an increased role in powering vehicles. In thermal applications, wood pellets and natural gas may be able to replace distillate fuels in the residential, commercial, and industrial sectors in greater percentages. A LCFS program must include means to encourage penetration of these alternative energy sources into sectors where their potential has yet to be fully exploited.

- One of the initial steps in setting goals for reduction in fuel carbon intensity is to establish a baseline condition. For a northeast LCFS, 2006 merits consideration by virtue of it being the first year in which ethanol fully replaced MtBE in the reformulated gasoline supply.

- Fuel required as part of the The Renewable Fuel Standard should be "counted" toward LCFS compliance until the time when the supply of low carbon biofuels or non-liquid low carbon fuels are available in sufficient quantities to allow the LCFS compliance target to exclude the benefits realized from the RFS program.
- The northeast states should consider defining the same entities for regulation as CARB has proposed in its LCFS regulatory documents.
- Given that the Northeast fuel distribution system is highly integrated, elements of a low carbon fuel standard in our region should be harmonized from state to state.

6.4. Regionally Available Low Carbon Fuels

- Approximately 6 million tons of woody biomass are likely available* in the Northeast for thermal applications. This biomass could be used to heat one million homes in 2020, displacing 660 million gallons of No. 2 oil and lowering the carbon intensity of fuels used in diesel and thermal applications by 4.5 percent.
- Provided the Northeast implements policies to guarantee nighttime charging of PHEVs, the Northeast's electricity grids could support up to 7 million advanced PHEVs in 2020 without requiring additional capacity. This would represent over 20 percent of the light-duty fleet, and would require extremely aggressive market penetration beginning early in the next decade. This number of PHEVs could displace 2.2 billion gallons of gasoline annually.
- Approximately 7 million dry tons of woody biomass are likely available for use in electric generation, with the potential to generate over 5 GWH per year. This represents more than one-third of total non-hydro renewable generation in 2005, and 8 percent of the total non-hydro renewables expected by 2020. This resource could earn credit towards Renewable Portfolio Standards in many states. Full implementation of RPS and RGGI by 2020 is expected to reduce the carbon intensity of electricity used in electric vehicles by 20 gCO2e/MJ.
- 62,049 metric tons of of likely available* waste cooking oils in 2020 (assuming only the use of 5 percent of maximum available "yellow" grease) could be converted to 2 million gallons of neat biodiesel in 2020, enough for 40 million gallons of B5 biodiesel blend. This could displace .05 percent of transportation diesel demand in the region.
- Waste-based biomass is the region's most significant resource by far, with a likely availability of 26 million tons of organic municipal solid waste plus agricultural wastes and wastewater solids. In addition, nearly 30 million cubic feet of biogas will likely be available in the Northeast in 2020. These materials could be converted into over 484 MW of electricity.
- There are uncertainties surrounding these estimates of available biomass resources—actual biomass availability will vary depending on key factors such as economics, environmental concerns, landowner preferences, and public policies.

- Geographically, the majority of the Northeast's available woody and agricultural biomass is located in New York and Pennsylvania. While New England states also have significant quantities of woody biomass, much of this wood is being used to supply existing markets. Since it is often not economic to transport biomass long distances (e.g., more than 50 miles), the geographic location of available biomass will influence the choice of locations for fuel processing and production plants.

- Because electric vehicles (EVs) have very efficient drivetrains compared to internal combustion engines, electricity is also a promising low carbon fuel for transportation applications. This is especially true in the Northeast, where new policies are in place to reduce the GHG intensity of electricity, including the Regional Greenhouse Gas Initiative (RGGI) and renewable energy standards.

- At low levels of EV penetration into the marketplace, the region has more than sufficient electricity generation capacity to accommodate these vehicles.

- Even at very high levels of EV penetration, the Northeast could support the use of these vehicles without building new capacity if the vehicles are charged at times that took advantage of unused electricity capacity, primarily at nighttime. NESCCAF modeled a variety of PHEV penetration scenarios, including a 20 percent light-duty market penetration of PHEV vehicles, equivalent to approximately 7 million vehicles in 2020, with 40-mile ranges and two-hour charging times. The Northeast's electricity grids could support this scenario with existing capacity.

- Waste-based biomass is the region's most significant resource by far, with a likely availability of 26 million tons of organic municipal solid waste plus agricultural wastes and wastewater solids. In addition, nearly 30 million cubic feet of biogas will likely be available in the Northeast in 2020. These materials could be converted into over 484 MW of electricity.

- Regionally produced low carbon resources such as electricity, municipal solid waste, and woody biomass may have lower lifecycle carbon emissions, taking into account land-use changes, than do crop-based biomass resources from agricultural areas outside the region.

6.5. Areas of uncertainty

Significant uncertainty exists with respect to a number of key issues related to low carbon fuels. Advanced biofuels may be commercialized at a faster or slower pace, and in greater or lesser volumes, than assumed in this report. The impact of land use change on the carbon intensity of fuels is extremely important in determining the overall GHG reduction benefit of a LCFS, and remains unresolved at this time. Sustainable management of biomass resources is critical to ensure that lifecycle carbon emissions do not increase as forests and agricultural lands are harvested to produce fuels – however, methodologies for defining and enforcing sustainability criteria are still the subject of lively debate. Future developments in these and other areas could substantively affect the results and conclusions presented in this report.

6.6. Looking Forward

Throughout this study we have made reference to advanced fuels that are 50% to 100% less carbon intensive than conventional fuels. While fuels with carbon intensities this low are not currently available in significant quantities, numerous emerging fuel technologies hold the potential for commercial-scale production within the next decade. Examples of advanced fuel pathways that could achieve substantial reductions in carbon intensity include ethanol produced by fermentation of cellulosic materials (via gasification or hydrolysis); "renewable diesel" made from hydrogenation of vegetable oils; biodiesel derived from algae oil; electricity from renewables including photovoltaic, wind and geothermal; Fischer-Tropsch fuels produced via gasification of solid waste materials, or gasification of coal combined with sequestration; electrolytic hydrogen using renewable electricity; biomass cofiring, and other fuels and fuel processes. In addition, advanced vehicle technologies such as electric drive systems for heavy-duty vehicles could become commercially available and could be used to meet the requirements of a LCFS.

Appendix A: Scenario Analysis Appendix

There were three distinct components to our scenario modeling exercise, each of which required the use of a particular modeling tool. The use of the three tools is illustrated schematically in Figure A-1 and each tool is described in summary below.

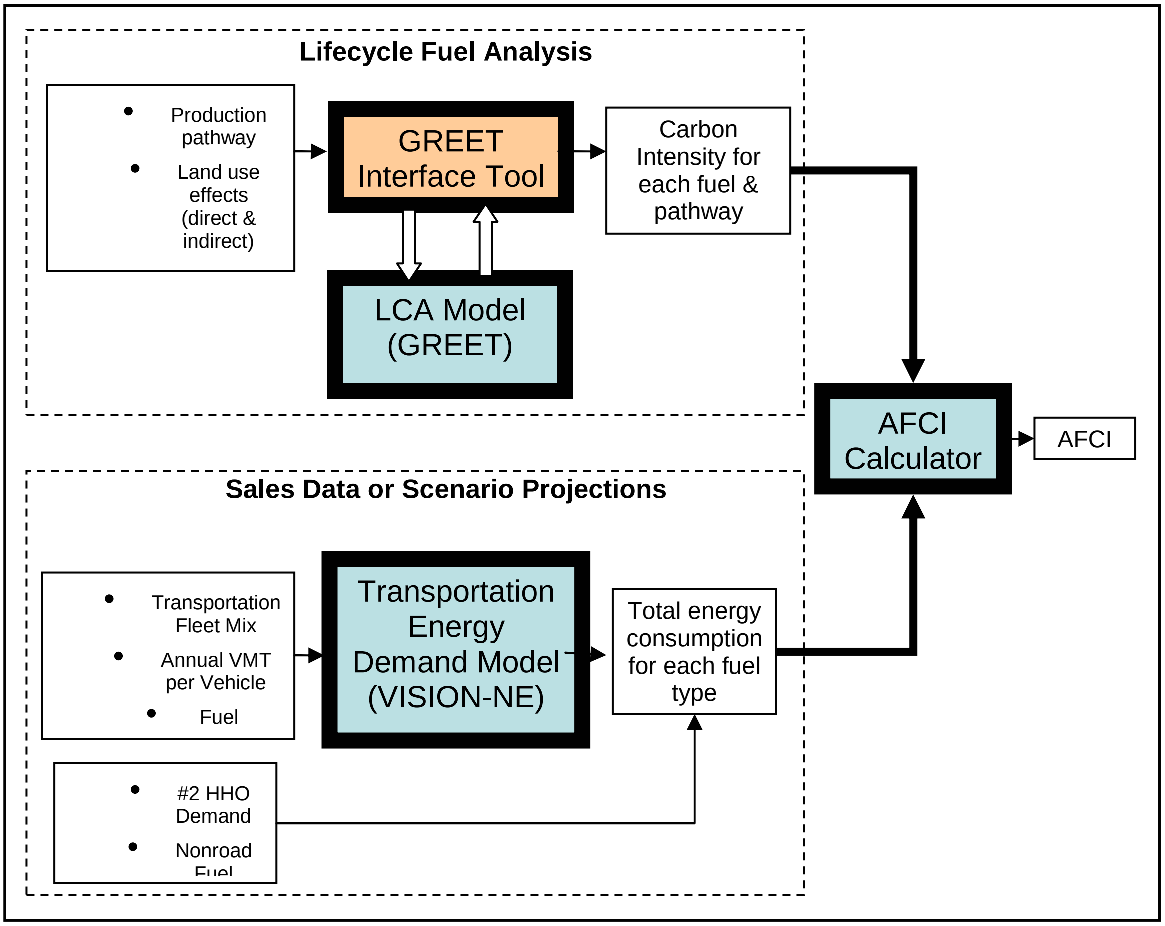

Figure A-6-1 AFCI Calculation Flowchart

GREET

First, we had to develop a lifecycle CI score for each potential fuel pathway as delivered and consumed in the northeast region. For this, we developed (with the assistance of subcontractor Life Cycle Associates) a set of northeast-specific input parameters and a specialized interface tool for the GREET model. With these, we were able to run GREET to develop northeast-specific CI scores for each selected fuel pathway. Because the Interface Tool was designed to enable convenient operation of the GREET model specifically for the purpose of determining CI as defined under a LCFS, it is well suited for future use by stakeholders to model additional pathway scenarios, and could be developed further for use as in a regulatory context. A full description of the Interface Tool and input parameters is provided in Appendix B.

VISION-NE

In order to assess the potential to displace specified amounts of the projected energy demand with low carbon alternatives, we first needed to estimate the region-wide demand for transportation and home heating energy under a base-case scenario. Estimates of home heating energy demand were based on projections developed by the Energy Information Administration (EIA) and published in their Annual Energy Outlook (AEO) report[i]. While AEO also includes projections of transportation energy demand, we required a more detailed profile of the fleet mix in order to assess certain technology-specific low carbon compliance options. The VISION model, developed by Argonne National Laboratory, is designed to generate detailed characterizations of future fleets, and to project the energy impacts of specified fleet penetrations of alternative vehicles and fuels. We developed a customized version of the VISION model, VISION-NE, in order to specifically characterize the northeast fleet, and made numerous additional changes to facilitate the consideration of issues particular to a low carbon fuels program.

Our approach to developing VISION-NE was to rely on the default VISION data and methodologies by default, and modify only where we had state- or region- specific data or when there was other clear justification to do so. The primary modification was the replacement of national fleet population data with region-specific numbers, which is described below. Key VISION default assumptions are summarized in table XX. Interested readers may refer to the VISION-NE spreadsheet, where all changes to the original VISION have been documented with color-coded worksheet tabs and the Excel Comments feature.

VISION projects vehicle future vehicle sales and energy consumption based on its stock profile. We obtained registry data on vehicle populations in six of the eight NESCAUM states for the baseline year of 2005. We then estimated the fleet populations in the remaining two states and added them together to arrive at a stock estimate for each vehicle category in the baseline year. Next, we applied the VISION-default growth rates for vehicle stock to our baseline year “seed” values, resulting in a projection of northeast vehicle stock for each year from our 2005 baseline to the target year of 2020. VISION calculates new vehicle sales, VMT, and energy demand projections based on its vehicle stock data. Thus, modifying the key “seed” vehicle stock values was sufficient to adjust VISION’s energy demand outputs to reflect the northeast fleet.

NESCCAF made numerous other adjustments to the core VISION model, and incorporated a number of post-processing calculators into the spreadsheet for ease of use. All changes and additions are highlighted and documented within the spreadsheet itself, which is available for download free of charge from the NESCCAF website, www.nesccaf.org.

Significant modifications to the core VISION model include:

- Extraction of fuel energy density values (by default hardwired for higher-heating values) and the addition of a LHV/HHV toggle to enable users to choose between HHV and LHV.

- Adjustment of light-duty vehicle fuel economy values to reflect changes to federal CAFE standards in the 2007 EISA.
- Adjustment of default ethanol volumes to reflect northeast-specific sales data following the regional phase-out of MTBE.
- Optional manual override of VISION defaults for EV and PHEV fuel economy, PHEV all-electric range, and E85 VMT shares for flex-fuel vehicles.
- User-selectable vehicle stock profiles to enable analysis of specified state or region.

Significant additional features include:

- Shortcuts to enable convenient modeling of specific policies such as California LEV/ZEV and Federal RFS;
- Demand projections for nonroad gasoline, nonroad diesel, and #2 heating oil; option to include or exclude from baseline AFCI;
- Oilsand option enabling user to specify penetration of Oilsand-based gasoline or diesel in both baseline and target years;
- Shortcuts for convenient modeling of user-specified penetration rates for biodiesel and CNG in highway, nonroad and thermal applications, as well as wood pellets and electricity in thermal applications;
- "EV Calculator" to determine the CI for electricity based on vehicle technology and generation mix;
- Carbon Intensity data for various fuel pathways, based on outputs from GREET as generated using the NE-GREET Interface Tool.
- "AFCI calculator" that incorporates energy demand and fuel pathway-specific carbon intensity values to arrive at the average fuel carbon intensity for a given scenario

Table A-1 Key default assumptions in VISION-NE.

	#	VISION Default	notes
Average PHEV All-Electric Range (AER)	22	No	Based on ARB ZEV ISOR Table 4.2. Increases linearly from 0 in 2010.
PHEV Electric VMT %	34%	Yes	Computed from AER per SAEJ1711
Baseline ethanol content	7.4%	No	Based on EIA volume sales data
Baseline ethanol CI	96.7 gCO2e/MJ	No	Equivalent to gasoline CI
Baseline LDV MPG	CAFÉ	No	Per AEO 2008, based on 2007 EISA
2020 LT market share	52.9%	No	Per AEO 2008, based on 2007 EISA
LDV VMT Growth Rate	0.81%	Yes	

Integrated AFCI Calculator

Because a LCFS requires the determination of an average AFCI score based on the fractions and individual CI ratings of every fuel type, we developed an AFCI calculator to incorporate the outputs of the GREET and VISION-NE modeling. We integrated this tool into the VISION-NE model for ease of use; however, it can be used as a stand-alone calculator, if desired, by providing alternative inputs for the CI scores and total demand volumes of individual fuel pathways. A screenshot of the Gasoline AFCI section of the

AFCI Calculator interface is shown in Figure A-2. Note that values for CI and fuel volumes shown in this figure are examples representing one scenario. All CI values and volumes can be adjusted to model different scenarios using the main VISION-NE interface.

2020 GASOLINE

Baseline AFCI	96.7			Scenario AFCI	96.7
Total Fuel Energy (mmBtu)	2.40E+09			AFCI Reduction	0.0%

Fuel	Energy Density (BTU per gal, gge, or kwh)	Carbon Intensity (g/MJ)	Volume (Bgal or GWh)	Energy (mmBtu)	Energy Share
LD Gasoline	113,602	96.7	18.7	2.13E+09	88.7%
LD Oilsand Gasoline	113,602	108	0.0	0	0%
HD Gasoline	113,602	96.7	0.399	4.53E+07	1.9%
HD Oilsand Gasoline	113,602	108	0.0	0	0%
LD CNG	113,602	73.1	0.0	6.13E+02	0%
Electricity for BEVs	3,412	28.4	0.0	0	0%
Electricity for PHEVs	3,412	47.4	0.0	0	0%
Baseline Ethanol	76,330	96.7	1.42	1.09E+08	4.5%
Advanced Ethanol	76,330	20.0	0.0	0	0%
RFS Cellulosic Ethanol	76,330	38.7	0.0	0	0%
RFS "Advanced" Ethanol	76,330	48.4	0.0	0	0%
RFS "New Conventional" Ethanol	76,330	77.4	0.0	0	0%
Nonroad gasoline	113,602	96.7	1.04	1.18E+08	4.9%

Figure A-6-2 AFCI Calculator gasoline interface with example values.

As Figure A-2 illustrates, the AFCI calculator combines the total demand and carbon intensity for each fuel pathway, to arrive at the weighted average, or AFCI value, for a given scenario. Energy demand projections for most fuel types are provided by the main VISION model, based on fleet characteristics and penetration rates of specific vehicle and fuel technologies in the scenario year. This includes baseline ethanol, for which the user may select either the default value (based on regional sales data as described above,) a region-wide E10 blend, or specify any other volume. The user may also choose the carbon intensity of baseline ethanol from a range of options. Volumes of oilsand-derived fuels are determined by the user-input oilsand share for both gasoline and diesel, and do not depend directly on the fleet profile. Similarly, the RFS ethanol types automatically displace gasoline when the user selects the RFS toggle. A third category of ethanol may be modeled by entering the volume and CI values directly into the AFCI calculator sheet. Finally, the AFCI Calculator adds nonroad fuel to the total by drawing demand estimates from the nonroad worksheet and database within VISION-NE.

Supplemental Analyses

In addition to these three main steps, several aspects of the scenarios analysis required additional post-processing or other special treatment. For example, the carbon intensity for electricity as used in BEVs and PHEVs is a function of both the electrical grid and the relative efficiency of the vehicle itself. We developed an EV calculator to facilitate analysis of EV-specific scenarios. Supplemental analyses were also required to estimate the impact of the federal RFS on baseline biofuel volumes in the northeast, and to project the electrical grid characteristics in the 2020 target year assuming implementation of state-specific renewable portfolio standards (RPS) and of the regional greenhouse gas initiative (RGGI) for the power sector. These supplemental analyses are described in more detail below.

Electric-Drive Vehicles

The carbon intensity of electricity as used in electric-drive vehicles is a function of vehicle characteristics, driver behavior, and the mix of generating technologies employed. GREET generates GHG emission factors for a given generation mix, reflecting the emissions associated with the production and transmission of electrical power up to the point of delivery (the "plug"). While GREET's calculation methodology is the same for electricity and liquid fuels, comparison of upstream emissions at the point of delivery is not especially meaningful due to the difference in quality of each energy type. Therefore, an adjustment is needed to in order to compare carbon intensity values for each fuel pathway on an equivalent basis.

Electricity at the plug is a very high-quality energy type, ready for immediate and efficient conversion to motive power. On the other hand, liquid transportation fuels are of inherently lower quality since their chemical potential energy must still be converted to useful energy through a process that invariably involves significant losses. Thus, a BTU of liquid fuel "at the pump" is less useful than a BTU of electricity "at the plug". This difference in energy quality is reflected in the superior energy economy of electric-drive vehicles compared to liquid-fueled vehicles – an EV will travel a greater distance per unit of energy than a comparable gasoline-powered vehicle. It should be noted that this difference does not necessarily suggest an inherent efficiency benefit for EVs on a lifecycle basis (although many EVs are indeed more efficient than comparable gasoline-powered vehicles). Rather, it reflects the fact that the thermodynamic losses associated with energy conversion have already occurred by the time electricity is consumed at the plug, whereas they have yet to occur for liquid fuel at the time of retail purchase.

For conventional power plants, the difference in energy quality and the precise location of thermodynamic losses may seem academic. It is tempting to consider the powerplant-EV pathway as a single system, where only the CI of the input fuel would be of interest and no vehicle efficiency adjustment would be necessary. However, electric vehicles are fundamentally different from conventional fuel-vehicle systems in that the fuel source is separated from the end-use technology. Whereas an internal combustion engine can operate only on fuels with very specific properties, electricity for an EV can be generated using a wide range of fuels, technologies, and distribution pathways, some of which may be much less carbon intensive than others. It is because electric-drive vehicles can run on *low-carbon* electricity, coupled with their efficient design, that they represent a potentially attractive LCFS compliance pathway.

Energy Economy Ratio

The difference in energy quality means that a transportation consumer of electricity would get more utility (i.e. travel a greater distance) than a gasoline consumer for the same amount of energy. Because the value of electricity in a low carbon fuels program is to displace conventional fuels with low carbon substitutes, it is important to know the amount of gasoline that would be displaced if a consumer were to switch from a conventional vehicle to an EV. If we assume that this consumer's travel demand is fixed (i.e. that she desires to travel a set distance regardless of the type of car she is using), then the amount of displaced gasoline energy would be equal to the energy consumed by the EV multiplied by the ratio of the EV energy economy (in miles per gasoline-gallon equivalent or mpgge) to the fuel economy of the gasoline vehicle (in miles per gallon). This ratio has been defined by CARB as the Energy Economy Ratio (EER). CARB has proposed to use an EER of 4.0 for battery-electric vehicles (BEVs) and 2.4 for PHEVs (for hybrid vehicles the EER only applies when operating in all-electric mode).

NESCCAF has adopted CARB's EER values for the scenario analyses developed for this report.[55] We further assumed that use of electric-drive vehicles would displace use of average conventional vehicles – therefore the average energy economy of these vehicles would be 4.0 or 2.4 times the fleet average fuel economy as determined by the federal CAFE standards. Because the carbon intensity is a measure of emissions per unit of energy consumed, it follows that the *effective* carbon intensity of electricity used in transportation would be equal to the CI of the grid (see below) divided by the EER.

Grid Mix

As discussed above, the carbon intensity of electricity depends heavily on the fuels and technologies used for power generation. We used the Northeast GREET Interface Tool to develop carbon intensity values for each grid profile. Figure XX in Chapter 3 compares the CI of electricity for a number of grid profiles, assuming EER values of 4.0 for EVs and 2.4 for PHEVs.

The mix of generating technologies used to provide electricity to EVs and PHEVs will depend on numerous factors including vehicle design, driver behavior, and the number of electric-drive vehicles in the fleet at a given time. Chapter 5 includes a discussion of the challenges inherent in identifying the appropriate grid mix to assume for EV and PHEV charging.

[55] In practice, the EER is likely to vary from one vehicle to the next, and possibly even from one user to another for a given vehicle type. While it seems reasonable to assume that an EV in general would displace a conventional vehicle with similar design and performance parameters, it is possible that EVs, particularly those with limited range or cargo capacity, would be purchased as a second or third vehicle for a household and used only for selected purposes, such as short local trips. In this case, the EV would displace gasoline that might be used by a much larger vehicle, resulting in an effective EER that is much higher than average.

GREET enables the user to characterize the grid mix by specifying the contribution of six technology categories: Oil, Natural Gas, Coal, Nuclear, Biomass, and “Other”. GREET then calculates the carbon intensity of each generation technology and provides an average based on the user-specified grid shares. NESCCAF used GREET to evaluate the carbon intensity for each individual generator type and four grid mixes: the GREET-default US and CA average mixes, and average NE generation mix in 2005 and as projected for 2020. Both northeast grid mixes were obtained by NESCCAF using the MARKAL model; the 2020 projection includes effects of RGGI and full implementation of Renewable Portfolio Standards (RPS) in each state as appropriate.

Renewable Fuel Standard

NESCCAF needed to project the impact of the federal Renewable Fuel Standard, recently modified by the Energy Independence and Security Act of 2007 (EISA). While the RFS sets very specific volume requirements for several categories of low carbon fuel, it does not specify where within the US these volumes are to be sold. Thus, the northeast could receive greater or lesser shares than the national average of each fuel type. NESCCAF did not attempt to predict the likely regional deployment profile for these RFS-mandated biofuels. Rather, we assumed in our scenario projections that RFS volumes were supplied to the northeast in proportion to the region’s share of national fuel demand, which we found to be 12%. Thus, we assume that the federal RFS will result in 1.3 billion gallons of cellulosic ethanol (achieving a 60% reduction in carbon intensity compared to the gasoline baseline), 300 million gallons of “advanced” ethanol (50% lower carbon intensity), and 200 million gallons of “new” corn ethanol (20% lower carbon intensity) delivered in the Northeast by 2020.

Thermal and nonroad demand projections

The VISION model considers only energy demand associated with highway vehicles. However, NESCCAF desired to evaluate the potential to include fuel used in nonroad equipment (e.g. for construction equipment, lawnmowers, etc) as well as home heating oil within the scope of a regional LCFS. We therefore needed to estimate the baseline and future-year energy demand for these liquid fuels. We relied on the EPA NONROAD model to develop baseline and scenario year estimates for nonroad land-based equipment; we used EIA’s Annual Energy Outlook to estimate regional demand for #2 heating oil, and distillate fuel used in marine and locomotive applications; our baseline inventory effort is described in detail in Appendix C.

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[i] US Department of Energy, Energy Information Administration, “Annual Energy Outlook 2007 with Projections to 2030”; DOE/EIA-0383(2007); http://www.eia.doe.gov/oiaf/aeo/

Appendix B: Requirements for Developing a Low Carbon Fuel Standard

LCA-6006-4P.2008
November 2008

Requirements for Developing a Low Carbon Fuel Standard for Northeast States

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1 Introduction

Under a regional Low-Carbon Fuel Standard (LCFS) regulated entities as well as unregulated fuel producers selling into the transportation fuel market will be required to compute specific global warming intensities (GWI) for a variety of transportation fuels. The GWI will be based on individual fuel production pathways, reflecting specific input parameters, transport distances and emission factors. Regulated entities will need to use these GWI values to calculate their overall Average Fuel Carbon Intensity to demonstrate compliance with the LCFS.

Fuel Life Cycle models such as GREET from Argonne National Laboratory have been used to determine the GHG emissions from fuels for a variety of fuels pathways. GREET involves many inputs to determine the GHG emissions from a variety of conventional and alternative fueled pathways. Inputting appropriate data to the GREET model requires careful attention to many parameters such as fuel conversion efficiency, resource mix, transportation distance and other factors.

Implementers of an LCFS will need to perform these calculations to assess the potential for GHG reductions, analyze the GWI of specific fuel pathways, and develop compliance calculators. These calculations will include a number of determinations about system boundaries, fuel categorization, co-products, and other inputs. Calculating the GWI associated with an array of assumptions becomes increasingly complex.

1.1 Objective

The objective of this project is to provide NESCCAF with a robust, easy-to-use modeling tool for assessing the GWI for a wide range of fuels and scenarios and to use this tool to calculate the GWI (in g/MJ fuel) for transport fuels in Northeast states under an LCFS. This analysis includes characterization of all fuel pathways considered, including determination of system boundaries, co-product credits, regional transportation distances and modes and electricity generation mixes.

1.2 Low Carbon Fuel Standard (LCFS) Logistical and Analytical Requirements

Implementing an LCFS in the Northeast States will involve many of the steps currently occurring in the rulemaking process for the California LCFS (details and documents associated with the LCFS are located at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm). The Northeast states can therefore save considerable time and effort by building upon, rather than duplicating, the California effort. Many of the analytical tasks are comparable for both California and the Northeast states, including:

- Develop life cycle analysis protocols for low carbon fuels
- Assess vehicle fuel economy adjustments for alternative fueled vehicles
- Develop certification tool for fuel providers
- Determine certification, labeling, and other implementation requirements

These topics have received considerable examination under the California LCFS and the Northeast states can likely exploit these prior efforts.

Several other analytical questions are location and context dependent. These include, but are not limited to:

- Develop life cycle analysis of regional baseline
- Develop regional default values for individual factors and fuel ratings
- Analyze fuel pathways that may not be considered in California
- Issues relating to a multi-state versus single-state initiative

To help the Northeast States develop the necessary tools and procedures for an LCFS, Life Cycle Associates examined the analysis requirements for a regional LCFS and developed a spreadsheet tool to interface with the GREET model to input data for a variety of fuel pathways that are relevant for the Northeast states. The Northeast specific parameters and analysis tool are documented in this report.

This report provides no documentation on the GREET model or fuel pathways. A detailed description of fuel pathways can be found on the California ARB's web page for the LCFS[1]. The GREET model is documented with several reports and presentation by Argonne National Laboratory[2]. The 1999 documentation provides the most comprehensive explanation of the model Wang 1999). Subsequent reports and papers detail the inputs for new data and pathways.

1.3 Report Contents

The contents of this report are outlined in the following sections:

1 Introduction
2 Life Cycle Definition
3 Life Cycle Input Parameters
4 Analysis Tools
5 Results and Discussion

1.4 Project Deliverables

Project deliverables are shown according to report section below in

[1] www.arb.ca.gov/fuels/lcfs/lcfs.htm
[2] http://www.transportation.anl.gov/modeling_simulation/GREET/index.html

Table 1.1.

Table 1.1. Project Deliverables and Report Section.

Deliverable	**Report Sections**
1. Documentation of input parameters required for assessment of lifecycle GWI for transportation fuels consumed in the Northeast region.	3.1, 3.2, 3.3, 3.4
2. Description and discussion of key differences in GWI values for baseline fuels consumed in the Northeast as compared to the California and transportation fuel markets.	5
3. Discussion of implications for the GWI of natural-gas-based fuel pathways of the northeast region's distinct mix of liquefied natural gas (LNG) and conventional pipeline gas.	3.2.2
4. Input configuration file to populate the GREET model with northeast-specific parameters for the 2005 baseline fuels mix, run the model and extract results.	4
5. Identify fuel pathway and parameter default values for low-carbon alternative fuels that are likely to differ for the Northeast market from those assigned in California. Provide guidance about modifying these parameters in GREET.	3, 3.6
6. Wood pellets for home heating fuel pathway tab in Interface Tool file for modeling the GWI of pellets produced from forestry residue, lumber mill residue and farmed trees.	3.5
7. Description and discussion of key issues that distinguish regionally-produced forest residue-based fuels	3.4, 3.5

2 Life Cycle Definition

This study supports calculations of the life cycle of fuels in support of a low carbon fuel standard. The life cycle components include the well to tank (WTT) and tank to wheel (TTW). The WTT phase includes the upstream or fuel cycle emissions. The TTW phase includes the emissions from the vehicle including fuel carbon converted to CO_2 as well as N_2O and CH_4 emissions generated by the combustion process. The terms WTT and TTW are also applied to the fuel cycle and fuel combustion phase for wood fuel pellets.

2.1 System Boundary Life Cycle Inputs Parameters

The system boundaries for the LCFS are likely to encompass regional and process specific parameters. Parameters needed for analysis of NE fuels include specific transportation distances, resource mix (including electricity), and fuel processing inputs and efficiencies and emission factors. This study provides calculations of GHG emissions using the GREET model. The use of the GREET model also enables the calculation of criteria pollutant emissions, which are not examined here. The life cycle analysis requirements for both the NE LCFS and the CA LCFS differ from the average results that are defaults in the GREET model.

2.2 LCFS Analysis Requirements

This section briefly discusses the state of life cycle model development and the need for a pathway-specific model Interface Tool.

Fuel cycle assessment tools such as GREET and LEM were designed to analyze average production pathways for a very wide range of fuels and vehicles on an average basis. Modifying these spreadsheets to represent specific fuel pathways is a laborious, hard-to-verify, error-prone task. For example, GREET provides estimates of the GWI for ethanol produced from several different feedstocks, but several key assumptions are exogenous to the model and must be computed off-sheet if different values are to be used. Moreover, such changes would not be readily visible to anyone reviewing the spreadsheet.

Due to this orientation toward average pathways, GREET allows only a single specification of each fuel type which is applied globally throughout the model. For example, a resource mix can be selected to calculate emissions for the electricity grid, but these values are then applied everywhere electricity is required. There is no way to specify, for example, use of the coal-heavy Midwest grid for corn production from the more natural gas intensive California grid for ethanol conversion. These types of customizations are simply beyond the design parameters for the model.

The LCFS requires pathway-specific LCA tools which address the process-specific factors for individual fuel providers as well as the energy resource conditions and environmental factors that pertain to where the fuel is used. Several features are required by LCFS stakeholders that are beyond the design parameters of fuel cycle models such GREET and LEM, including:

1. Data entry sheets tailored to specific fuel types and pathways that organize all key inputs in one place
2. Ability to specify different fuel and electricity emissions factors for distinct phases of the production pathway (e.g. Midwest electricity for corn production and California electricity for biorefining)
3. Ability to incorporate economic and land use change data into the GWI analysis.
4. Separation between the specific pathway for a fuel being certified (e.g. diesel from a specific refinery), and other uses of that fuel type elsewhere in the model (e.g. generic diesel used for transportation of inputs)
5. Ability to specify the pre-computed GWI of blendstocks, e.g. purchased ethanol
6. Database of default GWI values for various parameters and blendstocks.
7. Tracking of emissions by airshed, rather than simply "urban" vs. "total"
8. Reporting tools that generate certifiable data summaries, as well as digital data that can be transmitted to upstream entities for their own calculations

These features will need to be either layered on top of an existing fuel cycle model, or integrated with one. In order to analyze the GWI for fuel scenarios in the NE states, an Interface Tool interacts with GREET to calculate the emissions for a variety of fuel pathways. The approach for addressing the analysis issues and limitations are discussed below.

2.3 Modeling Requirements

2.3.1. Life Cycle Criteria

Life cycle criteria used to compare fuel pathways include the fuel cycle or WTT energy and greenhouse emissions and combustion emissions (TTW), which are presented in distinct categories.

For transportation fuels, the GWI is calculated with the functional unit of 1 megajoule (MJ) of fuel energy on a lower heating value (LHV) basis. The GWI includes both the WTT and TTW components. Combustion emissions include the fossil carbon in fuel (expressed as CO_2) and vehicle methane (CH_4) and nitrous oxide (N_2O) emissions. Note that the vehicle CH_4 and N_2O emissions are also expressed on a per MJ basis. Even though vehicles are regulated on a per mile basis, the energy specific representation correlates as well to actual emissions as mileage specific estimates (Unnasch 2005). An example of the GWI values calculated for RFG is shown in Table 2.1. The WTT energy indicates that 293,867 Btu of total energy are required to produce 1 mmBtu of fuel.

Table 2.1. GWI Results for RFG.

RFG GWI Results	GHG Emissions
WTT energy (Btu/mmBtu)	293,867
CH_4 (g/mmBtu)	110.015
N_2O (g/mmBtu)	2.097
CO_2 (g/mmBtu)	21,221
WTT GHG Emissions (g/mmBtu)	24,597
Fossil Carbon Content of Fuel (g/mmBtu)	74,030
Vehicle CH_4 and N_2O Emissions	2,610
Total WTT + Carbon in fuel + Vehicle emissions (g/MJ)	101,236
Total WTT + carbon in fuel (g/MJ)	**96.0**

The GWI calculations in Table 2.2 show the fossil carbon separately from biogenic carbon in fuel for corn based ethanol. The definition of GWI used here does not include the biogenic carbon in the WTT phase or the TTW phase as the net impact of biogenic carbon is zero. Carbon in fuel derived from biogenic sources (crop or biomass sources) is omitted because it was recently removed from atmosphere during feedstock cultivation. This distinction between biogenic carbon and fossil carbon does not account for increases in atmospheric carbon uptake due to increases in feedstock production or any impacts associated with land use conversion. GREET assigns a 195 g CO_2/bu burden for corn-based fuel pathways (ethanol and butanol), -112,500 g CO_2/ton for farmed trees ethanol and -48,500 g CO_2/ton for herbaceous biomass-based ethanol. These values are exogenous default inputs in GREET. Land use conversion and other potential multi-media impacts for alternative and conventional fuel pathways in GREET could be considered separately, outside of the life cycle model and added into the fuel cycle results; these impacts are not considered in this analysis as useful results in these areas are still emerging and not yet available. Section 3.7 briefly discusses the issues associated with direct and indirect land-use conversion.

This approach is simplest since biogenic carbon is not always consistently identified in fuel cycle models, even though these models treat the net WTW emissions with zero CO_2 emissions for biogenic carbon. The calculations are simpler without tracking the negative value associated with carbon uptake from the atmosphere. Charts showing negative GHG emission results are also confusing. In order to track biogenic carbon, Table 2.2 shows these emissions as a negative value during fuel production and a positive value during vehicle operation in a separate column. The total of fossil plus biogenic carbon corresponds to the accounting method used in the GREET model with the same overall GWI results as fossil carbon only method, because emission credits are given to the biogenic carbon in WTT results in GREET. The WTT results in the total column shows the comparable WTT results in the GREET model. The table shows that both accounting methods yield the same WTT results, as they both assume that biogenic carbon does not contribute to climate change or to a fuel pathway's GWI.

Table 2.2. GWI Results for anhydrous ethanol.

Anhydrous EtOH (E100)	**GWI with Fossil Carbon**	**Biogenic Carbon in Fuel**	**Total**
WTT Energy (Btu/mmBtu)	1,518,865		
CH_4 (g/mmBtu)	126.164		126.164
N_2O (g/mmBtu)	47.980		47.980
CO_2 (g/mmBtu)	57,746	-74,925	-17,179
WTT GHG Emissions (g/mmBtu)	75,198	-74,925	273
Fossil Carbon Content of Fuel (g/mmBtu)	0	74,925	74,925
Total WTT + Carbon in Fuel (g/mmBtu)	75,198	0	75,198
Total WTT + Carbon in Fuel (g/MJ)	**71.3**	**0**	**71.3**

The GWI can be adjusted based on the energy economy ratio (EER) for specific vehicle propulsion technologies to facilitate comparison of fuels used in vehicles with significantly different fuel economies. EERs are not applied in this report.

The Interface Tool also calculates the GWI for home heating fuels. This calculation includes both the WTT component from GREET and "TTW" or fuel combustion component[3]. The combustion component includes the fuel carbon as well as the CH_4 and N_2O emissions from combustion. For home heating fuels, the functional unit is MJ of heat in the fuel on an LHV basis with the assumption that 1 MJ provides the same level of heat and comparable fuel consumption for different fuels. The LHV is a better metric of heat available for home heating than the HHV because most heating appliances do not recover heat from the condensation of water vapor. Some furnaces are equipped with condensing heat exchangers which are more efficient than conventional and older

[3] The end use for home heating fuels is also examined here with the TTW component referring to the fuel's end use.

designs. The GWI can be adjusted for the efficiency of the home heating appliance as more data become available.

The Pellet Fuels Institute[4] provides a comparison of the energy costs and efficiencies for different fuels showing the cost and combustion efficiency on a higher heating value basis. Note that most metrics of home heating fuel in the U.S. are on a higher heating value basis. So, any adjustments for fuel efficiency would need to convert higher heating value efficiency to lower heating value efficiency.

2.3.2. GREET Model Inputs

Inputs to the GREET model (or any LCA model) include energy (consumption factors and process efficiencies) and chemical/material inputs to each stage of the fuel pathway, yield factors for production processes, regional resource mix, transportation modes and distances, equipment emission factors, co-product yields and method for calculating co-product credits. Most of these input parameters are regional and/or process specific in nature and must be specified for each individual fuel pathway scenario.

2.4 Fuel Pathways

The fuel pathways modeled in the Interface Tool and considered in this report are shown below in Table 2.3. These pathways include petroleum fuels, traditional biofuels imported from the Midwest, and alternative fuels produced in the Northeast. The tool also enables the calculation of blended fuels based on separate calculations and inputs for the blending components. The tool was also configured to determine the GWI of home heating fuels including home heating oil, natural gas, and wood pellets.

2.5 Northeast Average Energy and Emission Inputs

The transportation distances, resource mix, and other fuel cycle parameters for baseline gasoline and diesel, electricity, and other fuels used in the Northeast will differ from the U.S. average or the values used for California's LCFS. These data are consolidated and organized for input to the GREET model in the Northeast GREET Interface file, provided to NESCCAF. The LCFS analysis for California accounts for the transportation distances and modes for fuel delivery; a similar analysis is conducted for fuel delivery to the Northeast. The GREET Interface can readily populate the same GREET model used for the California LCFS analysis.

2.6 Modeling Approach

The GREET user Interface Tool enables the calculation of process specific fuel cycle calculations. Life Cycle Associates' Peek/Poke technique populates the GREET model with new inputs using a simple Visual Basic macro. The macro plugs in the new data and extracts the model results. The tool includes an organized user interface for both process specific and average process fuel pathways. The tool first "pokes", or inserts, the user input data into GREET via the macro for each model scenario. The results are then "peeked" from the GREET model.

[4] http://www.pelletheat.org/3/residential/compareFuel.cfm

Table 2.3. Fuel Pathways Considered.

Feedstock/ Blendstock	Fuel	Fuel Type	Description
Crude Oil	Reformulated Gasoline Blendstock for Oxygenate Blending (RBOB)	Conventional Petroleum Blendstock	RBOB is blended with denatured ethanol to yield RFG
Crude Oil	Ethanol Denaturant	Conventional Petroleum Blendstock	Conventional gasoline or RBOB used to denature ethanol
Crude Oil	Ultra-Low Sulfur Diesel (ULSD)	Conventional Petroleum Fuel/Blendstock	ULSD for use in the NE
Crude Oil	Conventional Diesel	Conventional Petroleum Fuel	Conventional diesel used for transport of other fuels
RBOB, Denatured Ethanol	Reformulated Gasoline (RFG)	Blended Fuel	RFG for light duty vehicle use in the NE
ULSD, FAME/NERD	Biodiesel Blends	Blended Fuel	Low to high level biodiesel blends of ULSD and FAME or NERD
Natural Gas	Compressed Natural Gas (CNG)	NG-Based Fuel	CNG from North American or non-North American NG
Natural Gas	Liquefied Natural Gas (LNG)	NG-Based Fuel	Non-North American NG imported by ocean tanker
Corn	Ethanol	Alternative Fuel	Ethanol produced from Midwest corn through fermentation
Farmed Trees	Ethanol	Alternative Fuel	Ethanol produced from farmed trees through fermentation
Forestry Residue	Ethanol	Alternative Fuel	Ethanol produced from forestry residue through fermentation
Forestry Residue	Ethanol	Alternative Fuel	Ethanol produced from forestry residue through gasification
Soybeans	Biodiesel/Renewable Diesel (FAME/NERD)	Alternative Fuel	Esterified (FAME) or non-ester renewable diesel (NERD)[1]
Power Generation Feedstocks[2]	Electricity	Energy Carrier	NE electricity generation mix
Crude Oil	Ultra-Low Sulfur Diesel (ULSD)	Home Heating Oil	ULSD for use in the NE
Natural Gas	Natural gas	Home Heating Fuel	North American natural gas
Forestry Residue/ Lumber Mill Residue/ Farmed Trees	Wood Pellets	Home Heating Solid Fuel	Wood pellets used for home heating

[1]FAME = fatty acid methyl ester, referred to as biodiesel; NERD = non-ester renewable diesel, referred to as renewable diesel.
[2]Electricity generation feedstocks include residual oil, natural gas, coal, nuclear, biomass and renewables (solar, wind, geothermal and hydro).

Table 2.4 summarizes the Interface Tool approach for key analysis issues and Table 2.5 summarizes the basic functionality of the tool. The tool solves many of the issues related to process specific fuel cycle analysis by allowing the calculation of regional specific parameters for each fuel pathways.

Table 2.4. GREET Interface Tool Treatment of Key Input Categories.

Fuel Cycle Parameters	Fuel Cycle Tool Approach
Process Specific Inputs	Organize key parameterized process inputs for fuel pathways in fuel input sheets
Regional Electricity Mix	Select separate electricity mix for feedstock and refining phases from a list or specify individual fuel generation shares
Transportation Distance	Transport distances and mode shares organized in intuitive matrix format for most fuels; petroleum transport is similarly organized with three input categories: share of product (e.g., % of crude from Alaska), mode share (e.g., share of Alaskan crude transported by pipeline), and distance (e.g., 4,000 miles).
NE Petroleum	Specify inputs for all petroleum refinery products in one input sheet
Ethanol Energy Input	Thermal process energy (Btu/gal) and electrical power (kWh/gal) inputs instead of a modeling ethanol production with fuel shares and a total energy input
Ethanol Co-Product Treatment	Specify the DGS yield, share of DGS dried to yield DDGS, energy input for drying, share of DDGS combusted as process fuel, co-product displacement ratios and DDGS share consumed by new feed markets
Biodiesel Inputs	Similarly to ethanol, energy and electricity for soy oil extraction are input in their respective units (Btu/lb and kWh/lb); energy inputs for biodiesel and renewable diesel (I and II) production
Biodiesel Co-Product Treatment	Select the method for calculating co-product credits for biodiesel and renewable diesel (I and II) and specify products displaced by co-products when using displacement method
Biofuel Sustainability Credit	Exogenous input parameter allows GHG credit (or burden) to be assigned to corn ethanol or soy biodiesel for feedstock cultivation

Table 2.5. Summary of GREET Interface Tool Functionality.

Model Calculations and Features	Fuel Cycle Tool Approach
Blended Fuels	Calculate separate life cycle results for each blending component, including all distribution steps, and inserts the results into the "RFG" and "BD Blends" sheet to determine blended fuel results
Self documentation	Input sheets for each pathway provide documentation of key assumptions and "Defaults" sheet documents average default fuel pathway inputs
Life Cycle Results	Extract life cycle energy and emission results for each fuel pathway are extracted and present in the relevant fuel input sheet
GHG Emissions	Determine fuel cycle GHG emissions as a sum as WTT emissions and combustion emissions, consisting of fossil carbon in fuel and vehicle methane (CH_4) and nitrous oxide (N_2O) emissions.

3 Life Cycle Input Parameters

All of the input parameters for Northeast petroleum-based fuels and the Northeast-specific parameters (parameter values that differ from GREET default values) for the remaining fuel pathways shown in Table 2.3 are presented in this section. It should be noted that default values are referred to many times in the following sections and there are two primary types of default values. GREET default values, colored yellow in the GREET Interface Tool input sheets, are default values from an unmodified version of GREET 1.8b. Defaults in the GREET interface fuel input sheets (colored light red) and in the "Defaults" tab are the default input values configured to represent fuels used in the Northeast U.S. These values are regional in nature and differ from the CA-specific pathways (CARBOB, CA ULSD input sheets), which have CA-specific input parameters.

Each fuel pathway is documented in a tab of the Northeast GREET Interface Tool. The tool identifies the key inputs to the fuel pathway and allows for a simple overview of the inputs to GREET. Certain regional and process specific calculations are also possible with the tool. Most significantly, the electricity resource mix is specified separately for feedstock production and fuel refining. The tool aggregates the results using the GREET model separately and then sums these together for a complete fuel pathway.

3.1 Electricity Mix

The electricity generation mix is represented by a set of fuel share inputs that determine the carbon intensity of electricity used throughout the fuel pathway and it varies significantly among the different generation mixes. A variety of assumptions on generation resource mix can be applied to life cycle analysis including:

- Regional or U.S. average
- Marginal – referring to an assessment of the resource mix for permanent and sustainable load growth
- Dispatch based attribution – based on measuring or modeling the response of the system load to a short term increment of load

The assumed transmission loss is 8.1% and the natural gas-fired generation efficiency inputs have been adjusted down slightly from the GREET default values to reflect industry best estimates—see Table 3.2. Generation efficiencies for residual oil, coal, biomass and the nuclear input parameters are based on the CA LCFS values, which may better reflect real world generation efficiencies than the GREET defaults.

The main electricity mixes pertinent to fuels used in the Northeast are the U.S. average, Midwest average, NE U.S. average and NE U.S. marginal mixes. The GREET model includes the U.S., NE U.S. and CA average electricity mixes (included in the user interface).

This report calculates the electricity pathway using the Northeast marginal electricity mix shown below in Table 3.1, which has a dominant coal (51.6%) component and significant natural gas (33.5%) share. The marginal resources are assumed to be the same as the average without nuclear or residual oil fired power. These resources would not grow in response to a growing electricity demand associated with new fuels. The GREET values for residual oil and nuclear shares are set to zero and the remaining electricity fuel shares renormalized to 100%. Other assessments of the distribution between coal, natural gas, biomass, and non combustion renewables could also be envisioned given the constraints of the RGGI program and other measures to reduce GHG emissions. The Interface Tool facilitates quick and easy assessment of different electricity mixes used in a fuel pathway, even when different mixes for feedstock production and fuel production are desired. Table 3.1 shows the electricity mixes used in this report and built into the Interface Tool and their sources.

Table 3.1. Electricity Generation Mixes Used in Analysis.

Source	**GREET 1.8b**	**GREET 1.8b**	**GREET 1.8b**	**Modified GREET 1.8b**[1]	**Modified GREET 1.8b**[2]	**eGRID**
Electricity Mix:	U.S. Average	NE Average	CA Average	CA Average	NE marginal	IL Average (SERC Region)
Residual oil	2.7%	6.6%	0.1%	0.0%	0.0%	1.5%
Natural gas	18.9%	20.9%	43.1%	78.7%	33.5%	11.8%
Coal	50.7%	32.2%	15.4%	0.0%	51.6%	57.3%
Nuclear power	18.7%	31.0%	14.8%	0.0%	0.0%	24.3%
Biomass	1.3%	3.6%	2.1%	0.0%	5.8%	1.8%
Others	7.7%	5.7%	24.5%	21.3%	9.1%	3.3%

[1]CA marginal electricity mix based on AB 1007 analysis
[2]NE U.S. marginal mix determined by setting GREET average NE U.S. residual oil and nuclear shares to zero and renormalizing the remaining fuel shares to 100% total.

Table 3.2. Adjusted Natural Gas-Fired Generation Efficiencies.

Generation Technology	**Adjusted Efficiency**	**GREET Default**
Natural gas-fired power plant (SCGT)	31.5%	33.1%
Natural gas-fired power plant (CCGT)	51.8%	53.0%

The analysis uses the Illinois SERC eGRID (Emissions & Generation Resource Integrated Database) region to represent the Midwest mix used for corn ethanol and soy biodiesel production. This region is a NERC (North American Electric Reliability Council) region and represents a significant part of the Midwest. The eGRID maintained by the U.S. EPA is a comprehensive inventory of electricity generation mixes, emission factors, fuel use, boiler, generator and integrated plant-level data for electric power systems (U.S. EPA 2007). The database provides average data by state, power company, parent company, eGRID sub-region, NERC region or the entire U.S. It contains data from 24 Federal databases from the EPA, EIA and FERC (Federal Regulation and Oversight of Energy). The latest data available (and shown above) is released as eGRID2007 Version 1.0, and contains 2005 data.

3.2 Conventional Fuels

3.2.1. Petroleum Fuels

The Northeast GREET Interface input sheet for NE petroleum fuels (conventional gasoline, RBOB, conventional diesel, ULSD and LPG) is shown below in Figure 3.1. The Northeast-specific input parameters are colored light red and as the figure shows, only the transport inputs and refinery energy shares have been modified. Other process parameters could also vary for the Northeast region. The Interface Tool enables convenient adjustment of key fuel pathway input parameters to assess different specific pathway scenarios, conduct sensitivity analysis or to facilitate new analyses when updated or improved data become available. The input sheet for NE petroleum fuels is shown as an example, and only the Northeast-specific input parameters for each fuel are shown in the following subsections.

The first component of the petroleum fuel cycle is the crude oil extraction efficiency. Here the GREET default is used as an input for the NE states. The GREET estimate is based on aggregate statistics for the U.S. These data vary considerably from year to year and the authors are not aware of significant efforts to relate operational data, type of oil extraction (primary, secondary, tertiary recovery) to crude oil extraction energy and the aggregate statistics used as life cycle inputs. In California, a lower crude oil extraction efficiency is assumed because a significant fraction of the state's production is based on thermally enhanced oil recovery.

As Figure 3.1 shows, the default NE petroleum input sheet uses the average U.S. electricity mix in GREET for crude extraction and assumes the NE average generation mix for refining. Note that the electricity fuel share inputs shown below the pull-down menus for electricity generation mix (for crude extraction and refining) are user inputs and are only input into GREET when "User Defined" is selected from the pull-down menu. The default "User Defined" electricity mix is NE marginal mix, which was discussed in Section 3.1.

Transportation distances are a key difference among regions in the U.S. The transport distances for crude oil and finished gasoline are based on NESCCAF's baseline petroleum supply report, summarized in Table 3.3 (based on NESCCAF's analysis of EPA data). The flow of petroleum products into the Northeast states could be analyzed further to achieve a slight improvement in transport distance accuracy for different finished fuels. For example, the GREET model could be run separately for each region with overall composite values developed for imported finished fuels and fuels produces in Northeast refineries.

Crude Extraction

General			
Target year	2010		
Share of oil sand products in crude oil blend	0.0%		
Crude Recovery Efficiency and Fuel Shares			
Crude recovery efficiency	98.0%		
Crude recovery fuel shares			
Crude Oil	1.0%		
Residual Oil	1.0%		
Diesel	15.0%		
Gasoline	2.0%		
Natural Gas	61.9%		
Coal (Pet Coke)	0.0%		
Electricity	19.0%		
Refinery Still Gas	0.0%		
Feed loss	0.1%		
Electricity Generation Mix for Crude Recovery			
Electricity mix	N.E. Average		
Fuel shares if electricity mix is "User Defined":			
Residual oil	0.0%		
Natural gas	33.5%		
Coal	51.6%		
Nuclear	0.0%		
Biomass	5.8%		
Other (renewables)	9.1%		

Crude Transport

Conventional Crude for Use in NE Refineries

Transport to U.S.	Share of Crude Oil	Share of Transport	Distance (mi)
Domestic Alaska	0.0%		
Ocean Tanker		100.0%	1,200
Pipeline		100.0%	4,000
California Production	0.0%		
Barge		5.0%	200
Pipeline		100.0%	50
Domestic US Other 48 States	48.0%		
Barge		0.0%	200
Pipeline		95.0%	1,613
Rail		5.0%	807
Imported Off Shore Countries	43.0%		
Ocean Tanker		100.0%	4,671
Pipeline		100.0%	178
Imported Canada and Mexico	9.0%		
Barge		0.0%	800
Pipeline		100.0%	2,530
Rail		0.0%	800

Figure 3.1. GREET Interface Input Sheet for NE petroleum-based fuels showing key fuel pathway parameters. Yellow values are input parameters, white values are calculated and Northeast-specific parameters are shown in light red.

Crude Refining

Crude Refining Energy and Fuel Shares	
RBOB (%)	84.5%
Conventional Gasoline (%)	87.7%
ULSD (%)	86.7%
Conventional Diesel (%)	90.3%
LPG (%)	94.3%
Crude refining fuel shares	
Crude Oil	0.0%
Residual Oil	1.9%
Diesel	0.0%
Gasoline	0.1%
Natural Gas	28.5%
Coal (Pet Coke)	22.4%
Electricity	4.1%
Refinery Still Gas	42.9%
Feed loss	0.1%
Electricity Generation Mix for Crude Refining	
Electricity mix	N.E. Average
Fuel shares if electricity mix is "User Defined":	
Residual oil	0.0%
Natural gas	33.5%
Coal	51.6%
Nuclear	0.0%
Biomass	5.8%
Other (renewables)	9.1%

Transport & Distribution

Transport to the U.S.

Conventional Gasoline

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	3.0%		
Ocean Tanker		100.0%	2,600
Imported: Canada	1.0%		
Pipeline		100.0%	750
Rail		0.0%	800

Reformulated Gasoline (RFG)

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	3.0%		
Ocean Tanker		100.0%	2,600
Imported: Canada	1.0%		
Pipeline		100.0%	750
Rail		0.0%	800

Figure 3.1. (Continued) GREET Interface Input Sheet for NE petroleum-based fuels showing key fuel pathway parameters.

Conventional Diesel

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	4.0%		
Ocean Tanker		100.0%	1,300

Ultra-Low Sulfur Diesel (ULSD)

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	4.0%		
Ocean Tanker		100.0%	1,300

Liquefied Petroleum Gas (LPG)

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	80.0%		
Imported: Caribbean countries	20.0%		
Ocean Tanker		100.0%	5,200

Transport and Distribution in the U.S. (All Fuels)

Transport to Bulk Terminal	Distance (mi)	Share of Total Fuel
Ocean Tanker	2,630	22.0%
Barge	200	0.0%
Pipeline	927	100.0%
Rail	0	0.0%
Heavy Duty Truck	50	0.0%
Distribution to Refueling Station		
Heavy Duty Truck	50	99.4%

TTW: Vehicle CH_4 and N_2O

Vehicle CH_4 and N_2O emissions	CG/RFG	CD/ULSD	LPG
Vehicle CH_4 emission rate (g/mi)	0.04	0.01	0.04
Vehicle N_2O emission rate (g/mi)	0.04	0.02	0.04
Vehicle total energy use (Btu/mi)	4,950	4,125	4,950

Figure 3.1. (Concluded) GREET Interface Input Sheet for NE petroleum-based fuels showing key fuel pathway parameters.

Petroleum products are produced in refineries around the world with significant imports of finished product to the U.S. PADD (Petroleum Administration for Defense District) data can be used to determine weighted average crude flow shares and transport distances. PADD 1, which comprises the east coast (including the NE), leads the U.S. in imported refined product with 48% of finished gasoline imported from PADD 3 (Texas) by pipeline and 12% of finished gasoline imported from overseas locations.

The transport inputs in Figure 3.1 represent the composite of PADD 1 domestic and overseas imports. The transport distances for overseas import are based on the weighted average of crude oil imports by country based on EIA data; individual shipping distances by country of origin were determined using Eship (see Section 3.6). Domestic and Canadian imports of finished gasoline are assumed to be based on U.S. petroleum shares. However, some finished gasoline from PADD 3 may also be derived from overseas imports. The analysis of imported gasoline and blendstocks in GREET is a simplistic representation as the total gasoline pool, which includes a mix of production resources, crude oil types, and refining. A more detailed analysis of all of the petroleum flows to the U.S., feedstocks, and products could provide a more accurate assessment of the attribution of crude oil resources to NE gasoline. Such an analysis would require the development of an attribution scheme for all petroleum products and a more extensive examination of the fate of petroleum products than was possible in this study.

Table 3.3. Petroleum Net Consumption in PADD 1 by Source (Millions of Gallons per year).

Source	Finished Gasoline	Light Distillates	Residual Fuel Oil	Jet Fuel	Crude Oil
Produced in PADD 1	21,349 (43%)	7499 (34%)	1503 (21%)	1396 (14%)	0
Transported from PADD 2	239 (<1%)	138 (<1%)	8 (<1%)	26 (<1%)	230 (1%)
Transported from PADD 3	23,863 (48%)	11,612 (52%)	690 (10%)	7514 (74%)	120 (<1%)
Transported from Canada	1426 (3%)	1409 (6%)	618 (9%)	131 (1%)	3253 (13%)
Other Import	5897 (12%)	3114 (14%)	4322 (61%)	1337 (13%)	20,531 (85%)
Transported out of PADD 1	(3256) (-7%)	(1626) (-7%)	(8) (<-1%)	(283) (-3%)	0
Net Consumption PADD 1	49,518 (100%)	22,146 (100%)	7133 (100%)	10,121 (100%)	24,134 (100%)
Consumption in NESCCAF Region (2006)	16,786	7272	2229	2395	

2005/2006 Annual Average (Millions of Gallons); Source: NESCCAF analysis of EPA data.

Refinery efficiency and fuel shares are the GREET inputs that represent the energy inputs and emissions associated with oil refining. The refinery efficiency inputs are based on a combination of experience with refinery modeling and EIA data on refinery energy inputs. The EIA data is combined with a distribution of energy intensity for each refinery product to determine refinery efficiency. EIA reports fuel inputs to oil refineries which are the basis for the fuel shares input in GREET. Refineries also use hydrogen that is generated by adjacent hydrogen plants or hydrogen pipeline systems.

Table 3.4 summarizes ANL's analysis of the EIA data on refinery energy inputs. The energy inputs for refineries are combined with the natural gas associated with imported hydrogen to determine the fuel shares input for PADD 1 in Table 3.5. Several inputs are aggregated to represent the GREET fuel shares inputs. LPG is included with still gas, which is a low molecular weight hydrocarbon stream produced in the refinery. The carbon content per MJ and upstream energy inputs are comparable. Catalyst coke, other coke, and coal burned in the refinery are combined as coal. Imported hydrogen and purchased steam are included with natural gas as natural gas is the source of these energy inputs. Natural gas associated with hydrogen production represents and additional energy input outside of the refinery inputs reported by EIA. Thus, the total energy inputs in Table 3.5 sum to over 100%. These values are normalized to a total of 100% to represent GREET inputs.

Table 3.4. Share of Process Fuels Used in Oil Refining**.**

Process Fuel Shares	PADD1	U.S. Total	U.S. Total w. H2	GREET Category
LPG	0.5%	0.3%	0.3%	Still gas
Distillate Fuel Oil	0.1%	0.1%	0.1%	Diesel
Residual Fuel Oil	2.2%	0.4%	0.3%	Residual Oil
Still Gas	48.6%	48.4%	39.3%	Still gas
Marketable Petroleum Coke	0.0%	0.1%	0.1%	Coal
Catalyst Petroleum Coke	25.3%	17.6%	14.2%	Coal
Natural Gas (million cubic feet)	14.2%	23.2%	37.8%	Natural Gas
Coal (thousand short tons)	0.3%	0.0%	0.0%	Coal
Purchased Electricity (million kWh)	4.7%	4.3%	3.5%	Electricity
Purchased Steam (million lbs)	4.1%	4.3%	3.5%	Still gas
Other Products (pentanes plus, other HCs)	0.1%	1.2%	1.0%	Gasoline

Source: ANL analysis of 2006 EIA Refinery Capacity Report
Note: Natural gas in PADD1 would be 23.1% including hydrogen

In practice, refinery energy inputs can vary significantly among U.S. refineries. The California AB1007 analysis examined the energy inputs for gasoline refining reformulated gasoline and estimated a refinery efficiency of 84.5% for CARBOB, compared with the 87.2% assumed in the GREET model. The JEC European well to wheels study estimates considerably different energy inputs for marginal gasoline production. For the purposes of implementing LCFS calculations for the Northeast states, a reasonably accurate default value could serve as the baseline for petroleum fuels. Alternatively, individual gasoline providers could calculate their aggregate GWI for gasoline production. California has avoided this approach for now, choosing to focus the LCFS on alternative fuels.

Table 3.5. Calculation of Fuel Shares GREET Input.

Fuel	PADD 1 Refinery and H_2 energy	PADD 1 GREET Input	Default GREET Input for U.S.
Crude Oil	0.0%	0.0%	0%
Residual Oil	2.2%	1.9%	3%
Diesel	0.1%	0.0%	0%
Gasoline	0.1%	0.1%	0%
Natural Gas + Hydrogen	32.6%	28.5%	30%
Coal (Pet Coke)	25.6%	22.4%	13%
Electricity	4.7%	4.1%	4%
Refinery Still Gas	49.0%	42.9%	50%
Total	114.3%	100.0%	100%

3.2.2. Natural Gas

A Northeast marginal electricity mix is assumed for the CNG (compressed natural gas) pathway because natural gas is considered an alternative transportation fuel; default

GREET 1.8b input parameters are used for non-electricity inputs. The CNG pathway assumes North American natural gas feedstock and an electric compressor for natural gas compression.

The LNG (liquefied natural gas) pathway uses all GREET default values, non-North American natural gas and a U.S. electricity mix (see the CNG and LNG tabs of the Northeast GREET Interface file to review key input parameters). Imported LNG represents a significant source of gas supply with 22% of supply in the Northeast and 3% in the U.S. Thus, both a share of CNG and electric power could be considered derived from imported LNG. Determining the marginal source of natural gas would require further analysis. For the purposes of this study, the GWI for CNG and electric power was calculated for 100% North American (NA) natural gas and 100% remote natural gas (RNG). A composite value weighted with 22% RNG is also calculated. Note that GREET is not configured to input a mix of natural gas resources so these values are based on separate GREET runs.

3.3 Imported Biofuels

3.3.1. Corn Ethanol

The corn ethanol pathway assumes Midwest corn is transported to the Northeast. Corn ethanol is assumed to use the Illinois SERC (Southeastern Electric Reliability Council) electricity mix. The fuel pathway uses GREET default input parameters for all inputs except for co-product inputs and ethanol transport—see Table 3.6 below. The ethanol transport mode shares and distances for transporting ethanol to the Northeast are shown in Table 3.7.

Table 3.6. Adjusted Corn Ethanol Input Parameters**.** Yield Values on an Anhydrous Ethanol Basis.

Inputs	Revised Parameters	GREET Default
Ethanol Yield (gal/bu)	2.67	2.72
DGS yield (lbs/gal)	6.72	5.34
Feed corn/DDGS displacement ratio	0.5	1.077
Soybean meal/DDGS displacement ratio	0.5	0.823

Ethanol yield and co-product inputs based on ARB's documentation of ethanol pathways. Input values are still under review. GREET default co-product credit reflects growth in corn crop resulting in DDGS plus stover production, which in combination displace feed corn and SBM.

Table 3.7. Corn Ethanol Transport Input Parameters.

Transport Leg	Revised Distance (mi)	Revised Share (%)
Transport to Bulk Terminal		
Barge	0	0.0%
Pipeline	0	0.0%
Rail	800	100.0%
Heavy duty truck	50	80.0%
Ethanol Distribution		
Heavy duty truck to fuel station (mi)	50	100.0%

3.3.2. Biodiesel and Renewable Diesel

Biodiesel uses GREET default input parameters for all steps of the fuel pathway except for soyoil transport and biodiesel transport. The Illinois SERC region electricity mix is assumed for the pathway. GREET assumes that soyoil extraction and oil transesterification take place in the facility, which is often not the case. Since GREET is not configured for separate transport modes for soy oil and biodiesel, we have created inputs for soy oil transport in the Northeast GREET Interface BD sheet that the interface combines in a weighted average with the biodiesel transport and distribution inputs for input into GREET; soy oil is transported via rail. The relevant transport parameters are shown below in Table 3.8.

Table 3.8. Soy Oil and Biodiesel Transport Input Parameters.

Transport Leg	Revised Distance (mi)	Revised Share (%)
Soy Oil to Processing Plant		
Rail	800	100.0%
Biodiesel Transport		
Barge	520	71.0%
Pipeline	0	0.0%
Rail	800	0.0%
Heavy duty truck	50	80.0%
Biodiesel Distribution		
Heavy duty truck to fuel station (mi)	50	100.0%

3.4 Northeast Biomass Liquid Fuels

The Northeast possesses significant woody biomass resources that can be converted to ethanol (or other fuels). Section 3.5 includes a discussion of the feedstock options and there GHG implications. The main process technologies for fuel conversion to ethanol are fermentation and gasification; the Northeast Interface Tool is set up to model ethanol from forestry residue via gasification and fermentation and from farmed trees via fermentation. These three fuel pathways use the Northeast marginal electricity mix and GREET default input values, except for ethanol transport inputs and forestry residue transport distance. Table 3.9 below shows the Northeast-specific transport inputs for forestry residue and ethanol. The ethanol transport inputs are the same for farmed trees ethanol and the feedstock transport distance is 40 miles.

Table 3.9. Forestry Residue Transport Input Parameters.

Transport Leg	Revised Distance (mi)	Revised Share (%)
Forestry Residue		
Heavy duty truck	60	100.0%
Transport to Bulk Terminal		
Barge	520	0.0%
Pipeline	600	0.0%
Rail	800	50.0%
Heavy duty truck	80	70.0%
Ethanol Distribution		
Heavy duty truck to fuel station (mi)	30	100.0%

The project team examined other inputs for the forest residue pathway. The moisture content in GREET (20%) appears lower than wood harvested during timber operations, which contains 45 to 50% moisture. Moisture content affects many aspects of the fuel cycle. Combustion efficiency, chipping energy, gasification yield, water consumption, and other parameters could be affected. In the context of GREET model inputs the most significant effect would involve transport efficiency. The GREET model is not configured to adjust all of the parameters for feedstock moisture but GREET accounts for the moisture content in determining the transport truck cargo capacity. Moisture content of wood can vary by 5 to 10% with an impact on dry cargo capacity and GHG emissions.

Despite the relatively low moisture content input in GREET, the resulting cargo capacity in the GREET model result in a reasonable estimate of wood chip transport efficiency. Actual delivery of wood chips involves trucks loaded to about 27 tons with 45% moisture content 14 tons on a bone dry basis. The GREET calculations are based on a 17 ton load with 20% moisture resulting in a reasonable estimate of the cargo capacity. The truck fuel economy of 5 mpg is consistent with a fully loaded 40 ton gross vehicle weight truck.

3.5 Wood Pellets

3.5.1. Logging and Feedstock Collection

The project team reviewed the energy inputs for the collection and processing of woody biomass feedstocks. Lumber harvesting activities typically include harvesting the trees with harvesting equipment (chainsaws or mechanical felling machines) and moving the logs to a central location (skidding). The equipment used here runs on diesel predominantly. Gasoline powered chain saws are not typically used in Northeast logging operations because commercial scale logging equipment provides greater productivity and safety than traditional methods in this heavily forested region. The portion of the tree that is converted to biomass feedstock is chipped on site and then transported for biomass energy or pulp/paper operations.

Innovative Natural Resource Solutions LLC (INRS) examined the energy inputs required for biomass production (Kingsley 2008). Based on surveys of 5 major contractors operating in the Northeast states, Table 3.10 provides an estimate of the energy inputs for commercial logging operations and forest residue collection. The level of activity was estimated to be comparable for large scale logging compared with more selective forest thinning as the size of the tree parts are relatively large diameters (3 to 6 inches).

Estimates of the energy inputs to handle lumber mill waste are also indicated. The portions of the log that are not converted to lumber still require handling and chipping and a preliminary estimate of the energy requirements is the same as that for forest residue. Of course the alternative fate of the lumber mill waste could also be considered. Mill residues can be stored in debris piles for many years, and even this activity requires energy. The INRS data found that most of the wood processing used diesel fuel.

Table 3.10. Diesel inputs for Harvesting Forest Products.

Activity	Forest Residue	Lumber Mill Waste	Units
Felling & Skidding	0.6	0	gal/green ton
Landing, yarding, sorting, handling	0.25	0.25	gal/green ton
Chipping	0.42	0.42	gal/green ton
Total	1.27	0.67	gal/green ton
	2.31	1.22	gal/dry ton
	294,326	155,274	Btu/dry ton

The energy requirements for processing forest residue correspond to about half of the GREET default value and are slightly higher than the default value for harvesting energy crop trees (234,770 Btu/dry ton). Since the INRS data is based on a survey of actual operating data in the Northeast region, these estimates appear appropriate as inputs for the life cycle analysis of forest residues.

The appropriate energy inputs for the life cycle analysis would be 100% diesel for the feedstock harvesting and collection and diesel for transport. New pellet mills tend to be equipped with electric powered motors for operating the mechanical equipment. Yard equipment would be diesel fueled, so the energy inputs for pelletizing operations would be a combination of diesel fuel and electricity.

3.5.2. Wood Pellet Feedstocks and Production

Wood pellets for home heating produced from lumber mill residue (sawdust), forestry residue and farmed trees were incorporated into the GREET interface using life cycle inventory data generated by GREET. Fuel pellets are primarily produced from saw mill residue today. However, several pellet mills have recently been built to convert harvested wood into fuel pellets. Pellets can be produced from any woody feedstock and Table 3.11 below briefly summarizes potential woody feedstocks, potential issues associated with life cycle analysis of these materials and alternative uses.

Life cycle analyses typically assume that feedstock component of biomass resources are carbon neutral. The short cycle carbon was removed from the atmosphere by the tree and its use as a biofuels returns the carbon to the air. However, this assessment does not fully consider the reference case for the biomass. What would happen absent a conversion to biomass? The calculation of net carbon storage would be comparable to the land use conversion analysis applied to other biofuels. Selectively harvesting wood from mature forests offers the opportunity for carbon neutrality of the feedstock because faster growing new trees replace mature trees. Carbon storage might even be accelerated with carefully managed forests. A shift in species, harvesting practices, and other parameters would affect the net carbon impact on the forest and requires further examination.

The inputs for forest residue used in the GREET model require further examination because all of the scenarios for forest residue are site specific. Energy inputs would include harvesting, removal, chipping, and transport equipment with the primary energy inputs being diesel fuel and gasoline.

The industry standard form of wood for the pulp and paper industry is referred to as a pulp chip. Portions of the tree that are used for chip production can be processed in the field or at interim chipping locations. Pulp chips are also potential feedstock for cellulose based ethanol production and biomass power plants.

Table 3.11. Woody Biomass Resource Options.

<table>
<tr><th>Biomass Resource</th><th>Feedstock Type</th><th>Life Cycle Analysis Issues</th><th>Alternative Uses</th></tr>
<tr><td>Forestry Residue</td><td>Tree tops, undersized lumber</td><td>• Alternative fates: decomposition, fire
• Forest thinning reduces fire risk
• Changes in carbon deposition and soil carbon
• Collection impacts (logging roads, etc)</td><td rowspan="5">Wood Form
• Fuel wood, posts, mulch, animal bedding (excluding sawdust)
• Heating pellets (all resources)

Chemically Converted Form
• Chemical pulp, C5 and C6 sugar solutions, liquid fuels
Biologically Converted Form
• Fermentation products, liquid fuels, composted litter

Power Generation
• Direct combustion, or gasification and combustion</td></tr>
<tr><td>Diseased or Decimated Forestry Biomass</td><td>Tree tops, undersized lumber</td><td>• Alternative fates: decomposition, fire
• Forest thinning reduces fire risk
• Changes in carbon deposition and soil carbon
• Collection impacts (logging roads, etc)</td></tr>
<tr><td>New Growth (Conversion of Pasture to Forest or managed new growth)</td><td>Energy Crop</td><td>• Direct and indirect land-use conversion impacts
• Change in local ecology
• Collection impacts (logging roads, etc)</td></tr>
<tr><td>Urban Wood Waste</td><td>Wood chips from recycling facilities</td><td rowspan="2">• Alternative fates: landfill, burn, recycle
• Indirect land-use change impacts</td></tr>
<tr><td>Lumber Mill Residue</td><td>Sawdust</td></tr>
</table>

The calculations in the GREET model for the farmed tree pathway provide the basis for determining the life cycle energy for pulp chips. This pathway allows inputs for tree farming, harvesting, and transport. In the case of forest residue, the fertilizer inputs are zero. In the case of lumber mill residue (sawdust), the farming inputs are assumed to be zero and only transportation energy is counted towards feedstock production. The fuel pellet life cycle includes the following steps:

- Feedstock production and transport (GREET calculation)
- Pellet mill operation
    - Chip grinding (zero for sawdust)
    - Pellet mill operation
    - Yard equipment
- Wholesale transport by rail and truck
- Home delivery

A pellet plant requires a tractor to move feedstock, dyes, extruders, feeders, grinders, etc. The tractor duty cycles are estimated based on a personal communication with a biomass equipment developer. The total electricity requirement for pelletizing is 120 kWh/ton of pellets for pulp chips (0.25" minus size) or saw dust, and an additional 30 kWh/ton is needed to grind forestry residue and farmed trees down to the 0.25" minus size for pelletizing. For pellet transport, the default truck distance reflects transport from Vermont to Maine and the rail distance represents transport from British Columbia to Vermont, as a case examination of the significant imports of B.C. pellets to Northeast in recent years. By setting rail mode share to 0, model inputs reflect NE-produced feedstocks. An SUV carrying 0.5 tons, or 25 bags of pellets, is assumed for pellet transport from a retailer to a residential home. Default emission factors for pellet stoves are based on biomass combustion emission factors from GREET.

3.6 Transportation and Distribution

3.6.1. Northeast Specific Parameters

Average Northeast parameters are needed for this analysis, including average transport distances and transport mode shares, petroleum resource types and regional-specific emission factors. GREET does not distinguish emissions by region or crude type and this analysis is data limited, due to the cost and difficulty in collecting regional data for analysis.

Biofuel transport input parameters include mode share and transport distance for feedstock and biofuel transport. These distances are well known for feedstock transport and biofuel transport distances can be estimated using electronic maps and measurement tools. Petroleum flows are more complicated, since crude is transported from several different sources, refined with several other crudes, and then blended with petroleum fuels made in other refineries. Calculating average Northeast transport shares and distances can be accomplished by aggregating U.S., Canadian, and offshore imports to the Northeast. Transport is accomplished by ocean tanker for imported offshore import and by barge, pipeline and rail for all other categories. These regions also correspond to GREET input categories, and inputs correspond to the share of total petroleum, transport mode share and distance.

3.6.2. Transport Distance Data Sources

As discussed in Section 3.2, crude oil and finished fuel import data to determine the Northeast mix required determining the source of the crude oil. Petroleum consumption data for PADD1 provided by NESCCAF was used to determine transport mode shares. EIA import data by PADD (the Northeast is in PADD 1) are summarized in Table 3.12 by PADD and in Figure 3.2 regarding total volume of imports (volume data are found on the Energy Information Administration (EIA) website) (EIA 2008). This data is presented only to provide context for the PADD 1 consumption values. Import volume data is used to estimate import crude and finished fuel volumes, given the known petroleum sources. Interestingly, imports of finished fuels in PADD 1 represent a much higher fraction of total gasoline consumption than other PADDs. Further analysis of the energy inputs as well as transportation mode and capacity would be of interest.

Table 3.12. Imported Fuel Volumes by PADD (Millions of Gallons/Year) (EIA 2008).

Product	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Crude Oil	17843	17870	67333	3289	13678
Motor Gasoline Blending Components	7524	6	719	0	750
Finished Motor Gasoline	4116	17	334	0	404
Distillate Fuel Oil	2784	73	292	101	372
Residual Fuel Oil	2564	83	1389	0	412
Unfinished Oil	2028	45	5672	0	833
Kerosene-Type Jet Fuel	1169				
Liquefied Petroleum Gases	827				
Asphalt and Road Oils	309				
Oxygenates-Fuel Ethanol	249				
Petroleum Coke	239				
Naphtha for Petrochem. Feedstock Use	51				
Special Naphthas	51				
Kerosene	36				
Lubricants	32				
Waxes	7				
Finished Aviation Gasoline	2				

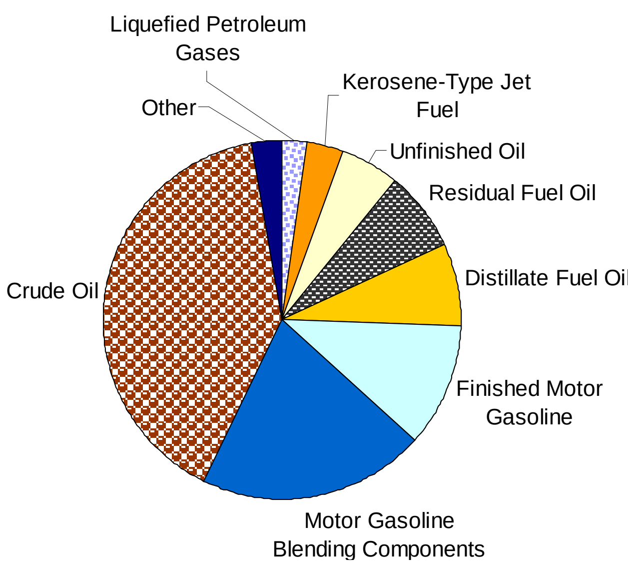

Figure 3.2. PADD 1 imports (Northeast Region).

The ocean tanker distances are based on an online distance, fuel and cost calculator for ship voyages (see Figure 3.3 below) (Eship 2008). Pipeline and rail distances have been generated through Google's distance measurement tool (Google 2008).

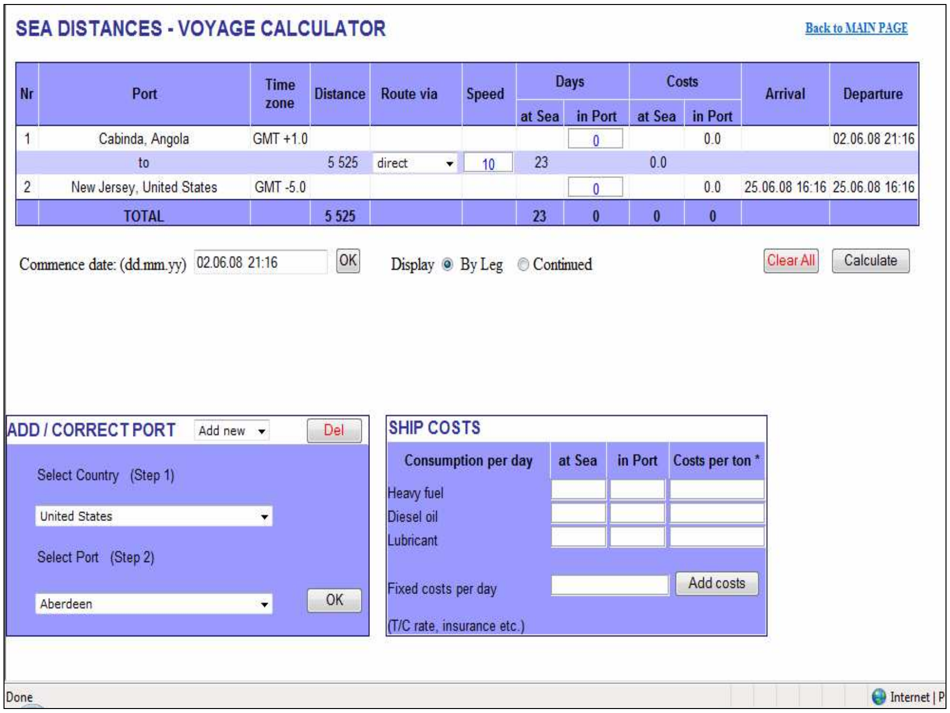

Figure 3.3. Screen Shot of Eship Online Calculator for Estimating Ocean Tanker Distances (Eship 2008).

The import volumes and transport distances by country of origin were used to calculate weighted transport distances. Marine vessel transport distances and crude oil import volumes are summarized in Figure 3.4.

3.7 Land Use Conversion for Biofuels

Land-use change (LUC) is an important element of a biofuel's life cycle impact, including the direct emissions associated land conversion to agricultural fields and indirect emissions associated with economic impacts induced by the land-use change. Direct emissions are associated with the clearing of land and preparation to grow crops and include changes in soil carbon and above ground flora. All of the above ground carbon and a significant fraction of soil carbon are converted to CO_2 when land is converted to agricultural production. The second category, *indirect* or *market-mediated* LUC occurs when the production of biofuels displaces some other land use, with effects potentially cascading through international markets, resulting in the same type of LUC as for the direct effects. These effects are extremely difficult to predict or measure with any accuracy, and are highly uncertain.

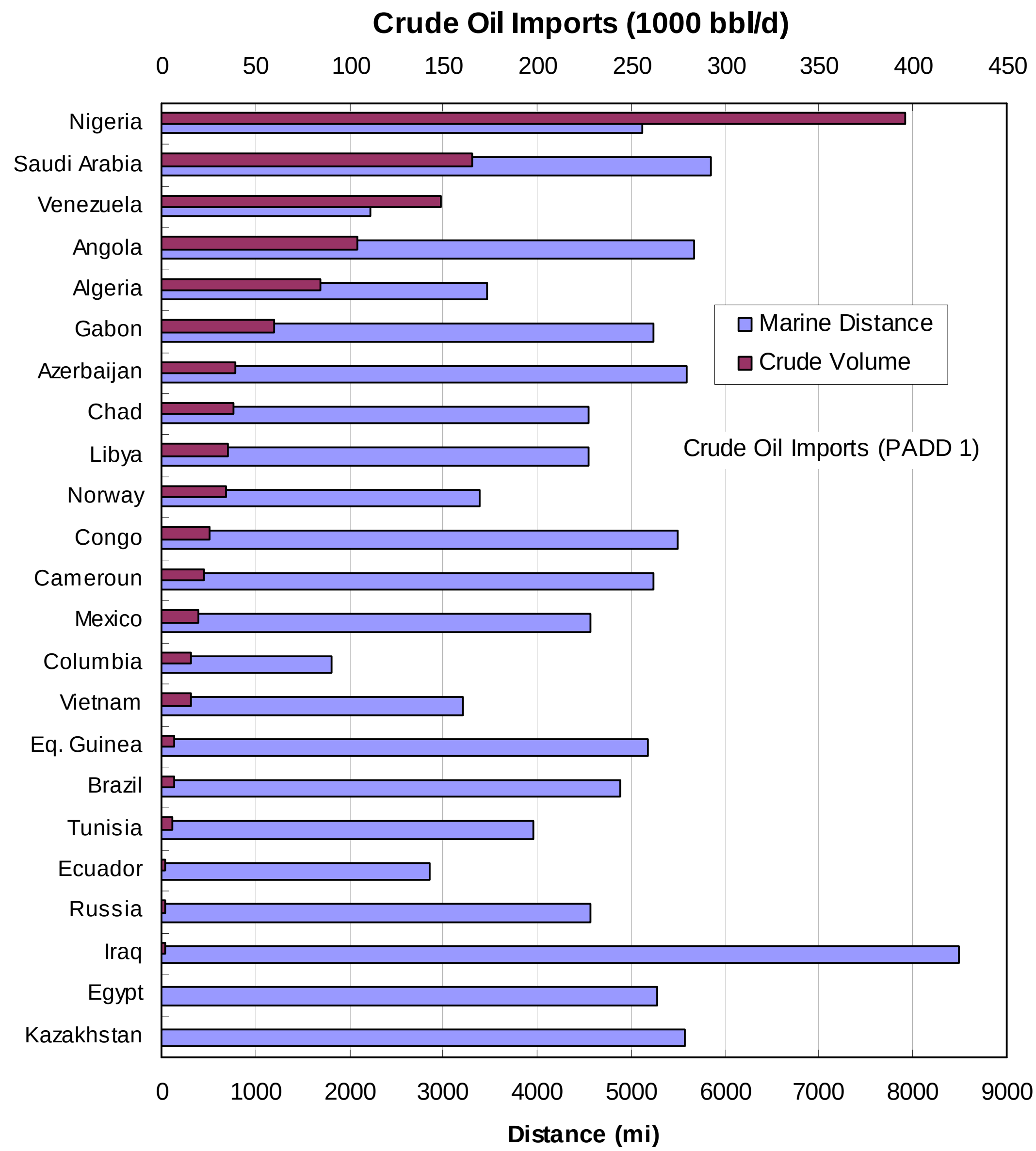

Figure 3.4. Marine vessel transport distances and crude oil volumes to PADD 1 (Source: 2007 EIA data).

LUC is being modeled as an economic phenomenon predicted by economic (partial or general) equilibrium models that represent food, fuel, feed, fiber, and livestock markets and their numerous interactions and feedbacks. Results from large-scale economic models, however, depend on a wide range of exogenous variables, such as growth rates, exchange rates, tax policies, and subsidies for dozens of countries.

EPA is using the FASOM and FAPRI models to estimate the changes in crop acreage in domestic and internationals market and to combine these results with estimates of soil carbon and nitrogen flows based on the DAYCENT model. The GTAP model is being used by UC Berkeley and

Purdue University to evaluate land use conversion impacts of biofuel production expansion. This effort is used in support of the California Low Carbon Fuel Standard.

Different ecosystem types store different quantities of carbon in the soil and in the above-ground biomass. Conversion of land between ecosystem types results in a new equilibrium carbon storage level over time, with associated storage or release of carbon.

The LUC effect is an input to the GREET model for corn, woody biomass, and herbaceous biomass crops. Even though crop yields for soybean production are one fourth those of corn, the LUC impact for soybean biodiesel is ignored in the current version of GREET. GREET default values include entries for corn ethanol that correspond to about 1 g/MJ of corn ethanol. These values are based on a decades old analysis and may not include the effect of international LUC. The input values for cellulosic energy crops reflect a negative LUC (or net carbon storage). These inputs reflect a build up of root material in the land. Again, the indirect LUC values need to be reexamined for cellulose feedstocks.

As the analysis is revised, data that reflect LUC can serve as GREET inputs. The scope of the in LUC inputs needs to be carefully examined to assure that they reflect only the emissions related to land conversion and not additional co-product impacts (such as avoided farming energy) that might be included in the LUC modeling systems as GREET calculates the process energy impacts of co-products.

4 Analysis Tools

An LCFS requires dynamic tools that facilitate process specific life cycle analysis, based on pathway configurations specific to individual processes. Life Cycle Associates developed a spreadsheet-based Interface Tool that runs on top of GREET and operates the model (see next section). As discussed earlier in this report, the GREET model is an excellent source of life cycle data, including feedstock inputs, process data, allocation and emission factors.

4.1 GREET Interface Tool

The GREET Interface Tool is an Excel spreadsheet organized with each tab containing a fuel pathway for simulation, including all of the fuels shown in Table 2.3. The tool file is opened after the GREET spreadsheet has been opened and is used exclusively to control GREET thereafter. Each fuel input tab allows the user to specify the 70+ key inputs for the selected fuel pathway, insert these parameters in the model, run GREET and extract the results. A separate User Manual documents the use of the interface file. A tab labeled “Defaults” contains the average default values for all pathways. These default values include both GREET default values (yellow values) and default Northeast and CA (CARBOB and CA ULSD) parameters (light red).

5 Results and Discussion

5.1 Interface Tool

The Interface Tool file provided to NESCCAF provides an easy way to explore the key fuel pathway inputs quickly and effectively in one place and to investigate the sensitivity of model results to individual parameters. NESCCAF can flexibly calculate life cycle energy and emissions for thousands of potential fuel pathway configurations using combinations of pathway options and resource and electricity mixes. As emission values associated with land-use conversion become available, they can easily be incorporated into the GREET Interface input sheets.

The Interface Tool allows for a calculation approach that is consistent with the CA LCFS but with regionally specific parameters. The key factors that would differ can be investigated by running the tool with different assumptions. Some of the key parameters are summarized below:

- Electricity resource mix
- Crude oil extraction efficiency (CA has significant tertiary oil recovery)
- Refinery efficiency (This value should depend on the refinery configuration and detailed modeling of refinery energy flows and crude oil types, and gasoline specifications would affect this input)
- Refinery fuel shares (EIA data for PADD 1 shows for FCC coke combustion)
- Transport distances for all feedstocks and fuels
- Process specific data for fuel suppliers

5.2 Comparison of GWI for Northeast and California fuels

All of the GWI results for Northeast fuels were determined using the Northeast GREET Interface. In general, the GWI for fuels used in the Northeast are slightly higher than CA fuels, due primarily to the Northeast electricity mix, differences in transportation distances and mode shares and differences in crude mix for petroleum pathways.

Table 5.1 below shows the results for fuels used in both regions. These calculations use average inputs for fuels used in the production of the given fuel; for example, the RBOB value uses default inputs for calculating diesel, which is used to make RBOB. Greater transport distances for Midwest corn ethanol and biodiesel used in California result in a larger GWI than their Northeast counterparts.

Table 5.1. GWI for Northeast and California Fuels (g/MJ).

Fuel	Northeast			CA
	NA NG	**RNG**	**22% RNG**	
ULSD	93.2	--	--	96.0
(CA)RBOB	96.8	--	--	96.1
Corn EtOH	71.2	--	--	72.1
Forestry Residue Fermentation EtOH	-4.4	--	--	-
Forestry Residue Gasification EtOH	9.9	--	--	-
Farmed Trees Fermentation EtOH	-13.3	--	--	-
Biodiesel	35.1	--	--	35.7
CNG	73.1	83.3	75.3	70.9
Electricity (average mix) NA NG	168.2	179.6	176.3	131.2

Northeast states have significant forestry and lumber resources, and as

Table 5.1 shows, ethanol fuel made from biomass resources has significantly lower GWI (-13.3 to 9.9 g/MJ) than corn ethanol (71.2 g/MJ) or petroleum fuels (93.2 – 96.8 g/MJ). These resources are abundant and can be converted to wood pellets for home heating with an attractive GWI (15.3 – 28.6 g/MJ heat). It should be noted that a standard methodology for dealing with feedstocks that are waste products has not yet been established and it's unclear what to assume as the baseline fate for a given waste stream. For example, the fate of forestry residue could be a forest fire, rotting on the forest floor, sequestration underground, etc. Each of these possible feedstock baseline scenarios has a very different emission profile.

The GWI of fuels used in the Northeast are on par with California fuels, but slightly higher for some fuels and lower for others, due to the differences in crude imports, electricity mix and transport characteristics. Any electricity-intensive process will yield greater emissions in the Northeast due to its coal-heavy electricity mix. The Northeast has abundant biomass resources, such as forestry residues and various woody waste streams including bark, sawdust, wood scraps and chips that can be advantageously converted to energy, fuel or heat. Technology is quickly developing to convert cellulosic materials to ethanol and other liquid fuels economically and the projected GWI for these fuels are very competitive—significantly below conventional and other alternative fuels.

Results for wood pellets are shown below in

Table 5.2. This table presents the GWI results in g/MJ pellet, although the Interface Tool calculates results in g/ton pellets and g/MJ heat provided (based on furnace efficiency) as well. As the results show, wood pellets from forestry residue are approximately 11.4 g/MJ higher than pellets made from sawdust, and all wood pellets result in significantly lower life cycle GHG emissions than fossil fuels. These tables present the regional fuel results for specific fuels assuming average life cycle inputs for external fuel pathways.

Table 5.2. GWI for Wood Pellets, NG and #2 HHO (Home Heating Oil). Pellets Transported from Vermont to Maine for Use.

Pellet Feedstock	GWI g/MJ pellet
Forestry Residue	23.5
Lumber Mill Residue	12.1
Farmed Trees	20.2
Natural Gas	71.1
Diesel #2	94.7

The values in Table 5.2 represent large pellet production operations (120,000 tons/yr) and they could vary considerably based on the scales of specific wood harvesting and pelletizing operations. Other site-specific factors, such as regional geography, forest density, wood quality and transport distances (feedstock and pellets) will cause an individual producer's GWI to vary from the average value. The GWI for pellets will also vary if electric equipment is used to harvest or move feedstock rather than diesel equipment. Finally, the life cycle analysis of any product must consider the alternative fate of the feedstock used to make that product and such data is not currently available. A standard life cycle methodology for addressing waste stream feedstocks has yet to be developed and is necessary for comparing the net GWI for various products made from waste stream and conventional feedstocks.

6 References

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Appendix C: Northeast Fuel Supply and Distribution Network

Five districts have been established by the U.S. government for the purpose of tracking petroleum product sales, consumption, and production, and distribution. These are called Petroleum Administration for Defense Districts (PADDs).[56] The Energy Information Administration (EIA) within the U.S. Department of Energy collects and disseminates information on petroleum use in the five districts.

The United States is divided into five PADDs, as illustrated in Figure C-1 below.

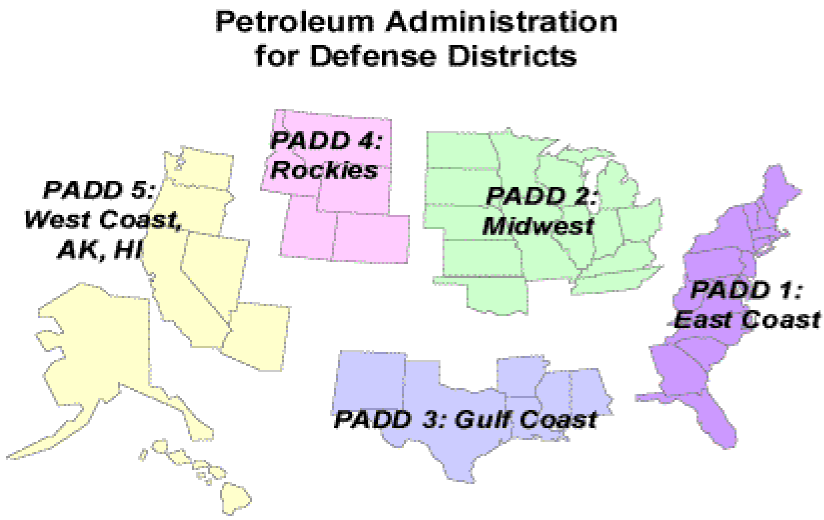


Figure C-1: Petroleum Administration for Defense Districts (PADD)

Source: Energy Information Administration, Energy Basics
http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/default.htm

As illustrated in Figure C-1 above, the NESCAUM States are in PADD 1, along with all of the other east coast states. The EIA reports some state-specific data, but much of it is reported only as PADD totals. Where possible in this section, data specific to the NESCAUM states are included, but in some circumstances only PADD 1 level information is readily available.

[56] In 1950, the Petroleum Administration for Defense (PAD) was established and five petroleum districts that had been established under the defunct Petroleum Administration for War (PAW) became the Petroleum Administration Districts for Defense or "PADDs." The PAD was abolished in 1954 and EIA now collects information on petroleum production and use.

In collecting and presenting data, the EIA uses varying sources and terminology to report fuel consumption, sales and supply. For example, the term *product supplied* is not synonymous with *consumption*. Rather, it approximates consumption of petroleum products by tracking the disappearance of products from primary sources (i.e., refineries, blending plants, pipelines, and bulk terminals). EIA reports *prime supplier sales volumes* from data collected from companies that produce, import, or transport selected petroleum products across state boundaries and local marketing areas, and sell products to local distributors, retailers, or end users. *Sales by end use* data for distillate fuels are compiled from survey forms sent to a representative sample of companies doing business in four or more states and/or companies accounting for 5 percent or more of the distillate or residual fuel oil sales volume within any one state. Consequently, a table reporting prime supplier sales volumes (from the EIA or in this report) is not necessarily comparable to tables that report sales by end use or product supplied.

The table below compares the percentage of prime supplier sales volumes of principal fuel types in the NESCAUM region to sales in two other regions of PADD 1. It shows there are significant variations in fuel sales by type within PADD 1. For example, about two-thirds of the reformulated gasoline (RFG) supplied in PADD 1 goes to the NESCAUM region. In contrast, only about one-fourth of the low sulfur diesel fuel supplied to PADD 1 ends up in the NESCAUM region and more than half goes to the Southern region. Therefore, in circumstances where the EIA reports fuels statistics at the PADD level only, caution must be exercised in drawing conclusions regarding fuel consumption, sales, and distribution within subregions.

Table C-1: Prime Supplier Sales Volumes of Petroleum Products (2005)

Percent Allocation within PADD 1

Product	**NESCAUM**	**Mid-Atlantic**[57]	**Southern**[58]
Conventional Gasoline	12.7	13.7	73.6
Reformulated Gasoline	67.6	20.9	11.5
No. 2 Distillate	38.1	19.1	42.8
- No. 2 Fuel Oil	60.2	20.5	19.3
- No. 2 Diesel Fuel	26.1	18.2	55.7
• Low Sulfur Diesel Fuel	24.8	18.3	56.9
• High Sulfur Diesel Fuel	35.7	17.3	47.0
Residual Fuel Oil	57.1	10.8	32.1
- Low Sulfur Residual Oil	75.6	12.4	12.0
- High Sulfur Residual Oil	38.5	9.2	52.3
Jet Fuel	43.3	13.9	42.7

57 For purposes of this section, "Mid-Atlantic" refers to Delaware, the District of Columbia, Maryland, and Pennsylvania.

58 For purposes of this section, "Southern" refers to Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.

Fuel Types and End Use

The above table also shows that there is a variety of fuels in use, but not every fuel tracked by the EIA is listed here. For example, kerosene was omitted because its consumption is low, relative to the fuels listed. This analysis will emphasize gasoline and distillate because of their higher consumption rates compared to the other fuels; the assumption being that these hold greater potential for partial replacement with alternatives that may achieve significant reductions in GHG emissions. The fuels in the table above are listed again in the two tables immediately below, along with their respective PADD 1 and NESCAUM sales volumes for the years 2003 through 2006, to provide a relative sense of their consumption volumes.

Table C-2: PADD 1 Prime Supplier Sales Volumes of Petroleum Products (Millions of Gallons)

Product	2003	2004	2005	2006
Conventional Gasoline	30,097.2	30,229.8	30,216.6	30,638.8
Reformulated Gasoline	19,045.6	18,963.2	19,147.3	18,497.0
No. 2 Distillate	20,915.8	20,467.1	20,426.1	19,889.6
- No. 2 Fuel Oil	8103.3	7588.0	7215.3	5956.1
- No. 2 Diesel Fuel	12,812.5	12,879.1	13,210.8	13,933.5
• Low Sulfur Diesel Fuel	10,948.1	11,254.1	11,583.7	12,085.9
• High Sulfur Diesel Fuel	1864.4	1625.0	1627.1	1847.6
Residual Fuel Oil	6190.2	5556.2	5155.4	3664.5
- Low Sulfur Residual Oil	3138.0	2662.6	2592.9	1500.0
- High Sulfur Residual Oil	3052.2	2893.6	2569.1	2164.5
Jet Fuel	4442.4	4923.2	5610.7	5268.2

Energy Information Administration, Prime Supplier Sales Volumes

Table C-3: NESCAUM Region Prime Supplier Sales Volumes of Petroleum Products (Millions of Gallons)

Product	2003	2004	2005	2006
Conventional Gasoline	3949.0	3895.1	3839.7	3960.4
Reformulated Gasoline	12876.0	12713.5	12950.5	12825.9
No. 2 Distillate	8648.8	8050.5	7792.4	7272.1
- No. 2 Fuel Oil	5029.8	4566.8	4340.4	3688.3
- No. 2 Diesel Fuel	3618.9	3483.7	3452.0	3583.7
• Low Sulfur Diesel Fuel	2884.7	2813.9	2871.4	3076.0
• High Sulfur Diesel Fuel	734.2	669.8	580.6	507.7

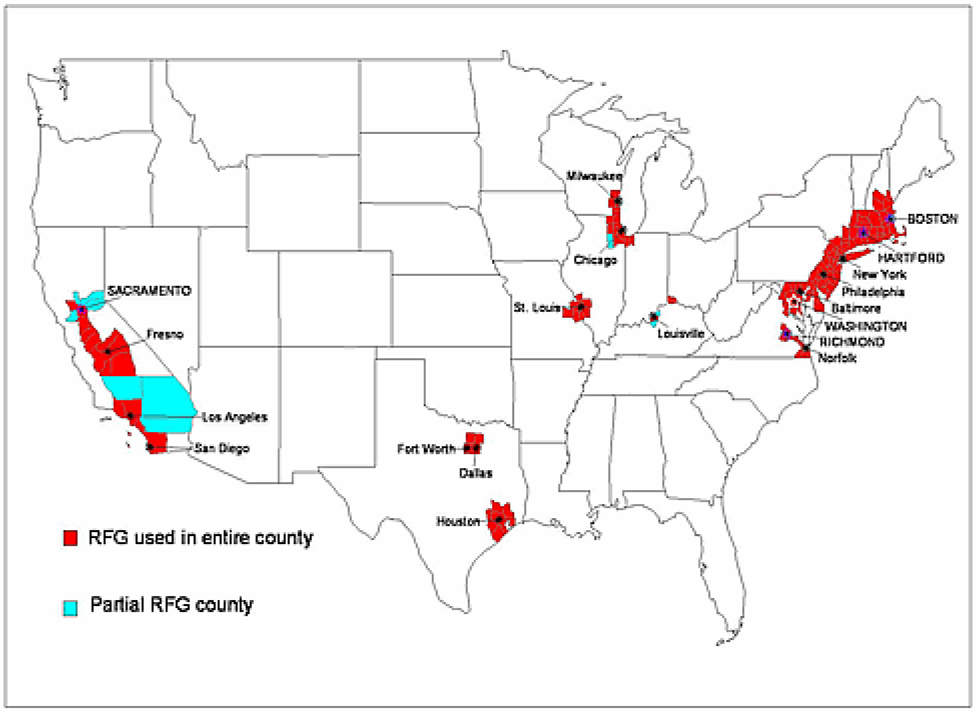
Residual Fuel Oil	2696.4	2803.7	2948.5	2229.2
- Low Sulfur Residual Oil	1740.2	1783.3	1959.6	1076.3
- High Sulfur Residual Oil	956.2	1020.4	989.0	1152.9
Jet Fuel	1904.6	2043.1	2431.8	2395.3

Energy Information Administration, Prime Supplier Sales Volumes

Gasoline is the primary transportation fuel for light to medium duty passenger cars and trucks and, by virtue of numbers of vehicles and vehicle miles traveled, represents the single largest fuel type supplied in PADD 1. Five general gasoline types are tracked by the EIA. They are reformulated gasoline (RFG), conventional gasoline (CG), their two respective blendstocks for oxygenate blending (RBOB and CBOB), and imported gasoline treated as blendstock (GTAB). The blendstocks are not listed separately in Prime Supplier Sales Volume statistics because they are not finished products, and therefore not sold to an end user.

The division of gasoline into the RFG and CG categories is rooted in historic strategies to assist ozone nonattainment areas in their efforts to attain federal air quality standards. Under Section 211(k) of the 1990 Clean Air Act amendments, the EPA Administrator promulgated regulations, establishing requirements for RFG in specified areas. The regulations required “the greatest reduction in emissions of ozone forming volatile organic compounds (during the high ozone season) and emissions of toxic air pollutants (during the entire year) achievable through the reformulation of conventional gasoline.” The figure below shows those areas in the U.S., presently required to use RFG. As indicated, much of the NESCAUM region is included, but a significant amount of CG also is used in parts of the NESCAUM region and other areas within PADD 1.

Figure C-2 Areas in the U.S. Subject to RFG Requirements



Source: U.S. EPA (http://www.epa.gov/otaq/rfg/whereyoulive.htm*)*

Originally, there was a requirement for RFG to be blended with an oxygenate. This requirement typically was met by blending with methyl tertiary butyl either (MTBE). Subsequently, several states banned the use of MTBE, because of associated environmental problems, and ethanol became the substitute oxygenating compound. The figure below illustrates which states have either banned or are in the process of phasing out the use of MTBE. Most of the NESCAUM states have taken this step.

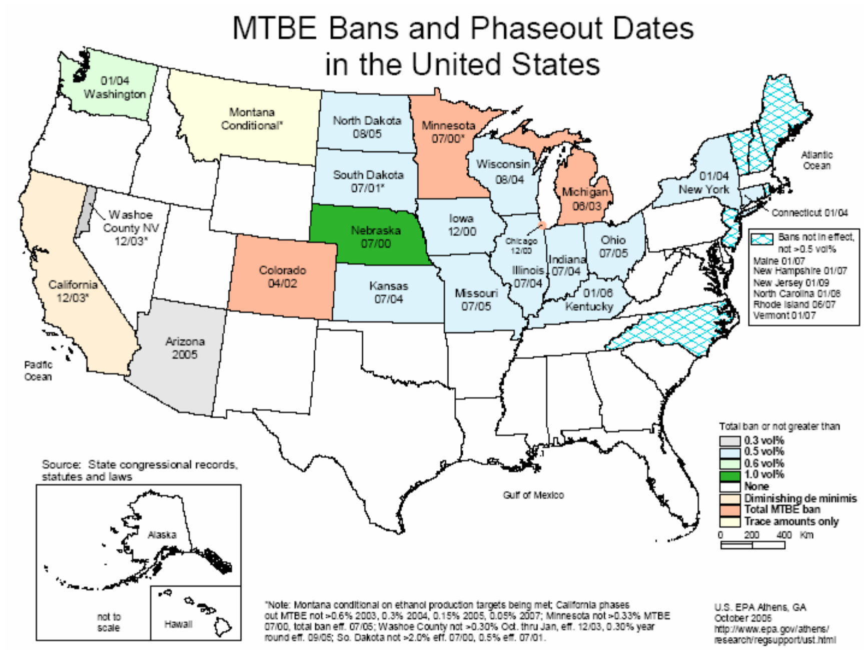


Figure C-3:

The RFG oxygenate requirement was removed under provisions in the Energy Policy Act (EPAct) of 2005. However, ethanol is still widely used in RFG, in part to make up the volume loss due to state imposed MTBE bans. The table below illustrates the increased trend in usage of ethanol in the NESCAUM States as a RFG blending agent, coinciding with the phase out of MTBE. Ethanol supply and distribution infrastructure will be addressed in more detail, later in this chapter.

Table C-4: Volumes of Oxygenates Added to Reformulated Gasoline in the NESCAUM Region

(Millions of Gallons)

	2003		2004		2005		2006	
State	**MTBE**	**Et-OH**	**MTBE**	**Et-OH**	**MTBE**	**Et-OH**	**MTBE**	**Et-OH**
CT	146.0	21	0.9	155	0.6	162	0.3	157
ME	0	0	0	0	0	0	0	0
MA	293.4	1	324.5	8	254.1	10	1.1	20
NH	57.5	0	57.2	0	53.0	0	0.1	0
NJ	483.8	1	501.5	6	481.7	7	0.9	15
NY	325.5	23	0.6	295	1.6	328	0.6	714
RI	47.9	1	56.5	8	49.7	10	0.2	20
VT	0	0	0	0	0	0	0	0

Total	**1354.1**	**47**	**941.2**	**472**	**840.7**	**517**	**3.2**	**926**

Sources: Energy Information Administration, Petroleum Navigator, Prime Supplier Sales Volumes
EPA, www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm

Distillate is the general classification given to one of the petroleum fractions produced in petroleum refinery distillation operations and includes diesel fuels and fuel oils. No. 2 distillate comprises fuel oil and diesel. Residual fuel oil is also categorized as No. 6 distillate. Distillates have a much greater variety of applications, compared to gasoline. Diesel fuel typically is used in on-highway diesel engines (e.g., trucks buses), as well as non-road engines (e.g., locomotives, agricultural machinery, construction equipment). Fuel oils are used primarily for space heating, steam production, and electric power generation. The NESCAUM states rely on liquid fuels to a much greater extent for power generation and heating, compared to other regions of the country. Significant amounts of heavier residual fuels are used for electricity generation, compared to other areas that rely more on natural gas or coal. The table below illustrates the array of principal sector end uses for four types of distillate fuel. Kerosene and No. 4 distillate are not included because their usage volumes are comparatively small.

Table C-5: NESCAUM Region Consumption of Distillate Fuels by End Use (2005)
(Millions of Gallons)

Sector End Use	No. 2 Fuel Oil	Low Sulfur Diesel Fuel	High Sulfur Diesel Fuel	Residual Fuel Oil
Highway	0	3166.0	-	0
Non-Road	0	-	172.7	0
Locomotive	0	0	150.9	0
Marine	0	0	133.0	1015.0
Home Heating	3515.7	0	0	0
Farm	13.5	-	52.6	0
Electric Power	77.2	0	0	2452.9
Industrial	100.0	16.8	12.8	338.1
Commercial	960.1	105.9	36.7	653.4
Total Usage	4666.5	3288.7	558.7	4459.4

Source: Energy Information Administration, Petroleum Navigator (2005).

No. 2 distillate is the most highly used of all the distillate types in the NESCAUM region. Its single largest usage is as home heating oil, followed closely by highway (low sulfur[59]) diesel fuel. The major difference between these two distillates is in the sulfur content. Highway diesel fuel is subject to a federally mandated sulfur limit of 15 ppm which will be fully phased in by 2010. There are no federal requirements, limiting the sulfur content of home heating oil, and sulfur levels in the NESCAUM region average around 3000 ppm.

[59] The term *low sulfur* is applied to any no. 2 distillate with a sulfur content of 500 ppm or less. Distillates with a sulfur content of 15 ppm or less are referred to as *ultra-low* sulfur. The table above includes both low sulfur and ultra-low sulfur diesel fuel in the low sulfur column.

In 2004, EPA finalized a rule to control emissions from non-road engines and fuels. Among its provisions, the rule required reductions in the sulfur content of non-road diesel fuels. As a first step, sulfur levels were reduced from uncontrolled levels (typically around 3000 ppm), down to 500 ppm, effective in 2007. The second step will cap sulfur levels at 15 ppm in 2010, with the exception that the locomotive and marine sectors have until 2012 to achieve the 15 ppm sulfur standard. The 2005 consumption data presented in the table above for non-road, locomotive and marine[60] sectors show exclusive use of high sulfur diesel fuel, but beginning in 2007, consumption will reflect the use of low sulfur diesel fuel for these sectors.

The farm sector includes establishments where the primary activity is growing crops and/or raising animals. Distillate use by all farm-related facilities and equipment is reflected in the table above, whether or not it is directly associated with growing crops and/or raising animals. Common types of fuel-consuming equipment include tractors, irrigation pumps, and crop dryers. Facility energy use encompasses all structures, including the farm house.

The electric power sector, referenced in the table above, includes electricity-only plants, as well as combined heat and power plants whose primary business is to sell electricity, or electricity and heat to the public. Distillate volumes directly imported and used by the electric power companies are included in the totals. Many power generation units utilize distillate and residual fuel either as primary or secondary fuel.

Almost all low sulfur diesel fuel, referenced as commercial sector, is highway fuel which is not subject to highway excise taxes and is used in school buses and government fleets. High sulfur diesel fuel in the commercial sector is used in engines that power non-road vehicles and in stationary engines, such as emergency generators. No. 2 fuel oil is used in the commercial sector primarily to fire boilers, space heating equipment, and combined heat and power units.

Virtually all industrial sector diesel fuel (both high and low-sulfur) is used in engines that power non-road vehicles or power generating equipment. As is the case with the commercial sector, industrial sector No. 2 fuel oil is used in boilers and combined heat and power equipment.

Non-road diesel internal combustion engines are also commonly used as the power source for on-site generation of electricity in the commercial and industrial sectors. These units typically are not directly connected to the transmission grid. However, they may be indirectly connected to the grid through their consumer's facilities which are connected for backup purposes or to sell excess power.

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[60] Technically, marine fuels are classified differently from land-based distillate fuels. However, one of the most commonly used marine fuels, marine distillate fuel A (DMA), has properties very similar to no. 2 distillate fuel. DMA is the common fuel for tugboats, fishing boats, crew boats, drilling rigs, and ferry boats.

In a 2003 report[61], NESCAUM estimated a total of 33,678 diesel engines, used in the NESCAUM region for commercial and industrial electric generation purposes with the capability to generate 11.8 GW. Of the total, the vast majority (80 percent of the units providing 74 percent of the capacity) are used primarily or exclusively to provide back-up power in emergency (i.e., outage) situations and in some cases to reduce reliance on grid-supplied electricity during periods of peak demand. Consequently, most of these diesel generators are operated infrequently and it is difficult to estimate their actual fuel consumption. The table below provides more detailed information on the population and size of these units in the region.

Table C-6: Estimated Diesel Generator Numbers & Capacity in NESCAUM Region

	Numbers of Units				**Generating Capacity**			
Rating (kW)	**Emergency**	**Peak**	**Baseload**	**Total**	**Emergency**	**Peak**	**Baseload**	**Total**
25-50	1768	0	0	1768	59	0	0	59
50-100	5798	1375	107	7280	462	114	9	584
100-250	9226	2236	95	11,577	1564	371	14	1949
250-500	5918	1231	7	7156	2126	443	3	2572
500-750	1296	316	47	1659	801	196	29	1026
750-1000	1164	292	51	1507	921	230	40	1191
1000-1500	641	677	39	1357	769	837	48	1654
1500+	1073	284	37	1394	2053	615	68	2736
Total	26,884	6411	383	33,678	8756	2805	211	11,772

According to the EIA in 2004, more than 1.5 billion gallons of high sulfur diesel fuel was consumed nationally in the commercial and industrial sectors. This total does not include distillate usage in the transportation, construction, or utility sectors. Of this total, approximately 4.7 percent was consumed for stationary energy production purposes by the two sectors. The NESCAUM region alone accounted for approximately 5.5 percent of the national total high sulfur diesel fuel usage in these two sectors but the actual consumption of fuel in diesel generators in the NESCAUM region is unknown, primarily because there is no centralized tracking system for fuel usage.

Combined heat and power (CHP) units are placed at or near commercial and industrial facilities to supply on-site energy needs, simultaneously producing useful thermal and

[61] Northeast States for Coordinated Air Use Management, Stationary Diesel Engines in the Northeast: An Initial Assessment of the Regional Population, Control Technology Options and Air Quality Policy Issues, June 2003.

electric power output, and thereby increasing overall efficiency. Onsite generation avoids the transmission and distribution losses associated with electricity purchased via a central grid, and units can be coupled with existing and planned technologies for many different applications. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling. The table below summarizes the typical capacities, fuels and uses of various CHP equipment.

Table C-7: Characteristics of Combined Heat and Power Technologies

Technology	Steam Turbine	Diesel Engine	Natural Gas Engine	Gas Turbine	Microturbine
Typical Capacity (MW)	0.2 – 800	0.03 – 5	0.05 – 5	1 – 500	0.03 – 0.35
Fuels	All	Diesel, Residual Oil	Natural Gas, Propane	Natural Gas, Propane, Oil	Natural Gas, Propane, Oil
Uses for Thermal Output	Steam	Hot Water, Steam	Hot Water, Steam	Hot Water, Heat, Steam	Hot Water, Heat, Steam

Source: U.S. EPA, Combined Heat & Power

The table below summarizes distillate fuel consumption by CHP units in the NESCAUM states for commercial, industrial, and electric power sectors.

Table C-8: Annual Distillate Fuel Consumption (10^3 Gallons) – CHP Units (2005)

State	Commercial	Industrial	Electric Power	Total
Connecticut	69	4427	327	4823
Maine	261	38,830	43	39,134
Massachusetts	12,824	14,145	7110	34,079
New Hampshire	1733	13,159	--	14,892
New Jersey	386	7569	13,944	21,899
New York	16,802	18,772	7683	43,257
Rhode Island	3095	206	171	3472
Vermont	--	--	--	--
Total	35,170	97,108	29,278	161,556

Source: Energy Information Administration (2005)

Industrial, commercial, and institutional boilers are primarily used for process heating, electrical or mechanical power generation, and/or space heating. Industrial boilers are used in all major industrial sectors but primarily by the paper products, chemical, food, and petroleum industries. Heat input capacity of industrial boilers is typically between 10 and 250 MMBtu/hr; however there are even larger industrial boilers, similar to utility boilers. Commercial and institutional boilers generally are smaller than the industrial units, with heat input capacities generally below 10 MMBtu/hr. These units normally supply the steam and hot water for space heating in a wide range of locations, including wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums, government buildings, and airports.

Process heaters are primarily used as heat transfer units in which heat from fuel combustion is transferred to process fluids in applications where boilers are inadequate. Process heaters are used in the petroleum refining and petrochemical industries, with minor applications in the asphalt concrete, gypsum, iron and steel, and wood and forest products industries.

Movement and Storage of Petroleum and Petroleum Products

PADD 1 states depend on a complex system of petroleum products transfer and imports to meet their fuel needs. Most of the crude oil that ultimately becomes finished product, destined for PADD 1, is refined in foreign countries or in other parts of the U.S., particularly the Gulf Coast States (PADD 3). Products are primarily moved via ocean going tanker, barge, and pipeline. The table immediately below summarizes the volumes of various petroleum products, moving into and out of PADD 1.

Table C-9: Sources of Finished Petroleum Products in PADD 1
2005/2006 Annual Average (Millions of Gallons)

Source	Finished Gasoline	Light Distillates	Residual Fuel Oil	Jet Fuel
Produced in PADD 1	21,349 (43%)	7499 (34%)	1503 (21%)	1396 (14%)
Transported from PADD 2	239 (<1%)	138 (<1%)	8 (<1%)	26 (<1%)
Transported from PADD 3	23,863 (48%)	11,612 (52%)	690 (10%)	7514 (74%)
Transported from Canada	1426 (3%)	1409 (6%)	618 (9%)	131 (1%)
Other Import	5897 (12%)	3114 (14%)	4322 (61%)	1337 (13%)
Transported out of PADD 1	(3256) (-7%)	(1626) (-7%)	(8) (<-1%)	(283) (-3%)
Total	49,518 (100%)	22,146 (100%)	7133 (100%)	10,121 (100%)

One of the principal reasons that PADD 1 is so dependent on fuel imports and transfers is that petroleum refining capacity is limited, relative to consumer need. The table below shows the refinery capacity in PADD 1 for the streams that become distillates and gasoline. Most important is the comparison (bottom rows of the table) between capacities in PADD 1 and PADD 3. PADD 3 refineries have the capability of producing more than six times the gasoline components and almost five times the distillate volumes of PADD 1 refineries. Thus, PADD 3 produces an excess of products beyond its regional needs and transfers the excess to other markets, such as those in PADD 1.

Table C-10: Capacities of Operable Petroleum Refineries – PADD 1 (2006)
And Comparison to PADD 3 Totals

Refinery	State	Production Capacity Gasoline Constituents (BBL/Stream Day)			Distillation Capacity (BBL/Calendar Day)
		Alkylates	Aromatics	Isomers	Distillates
Premcor (Valero) – Delaware City	DE	11,729	1700	6000	182,200
Chevron – Perth Amboy	NJ				80,000
Conoco Phillips – Linden	NJ	18,000		4000	238,000
Hess – Port Reading	NJ	7000			
Sunoco – Westville	NJ	4000	7500	10,000	145,000
Valero – Paulsboro	NJ	11,200			160,000
American – Bradford	PA				10,000
Conoco Phillips – Trainer	PA	12,000			185,000
Sunoco – Marcus Hook	PA	12,000	8000		178,000
Sunoco – Philadelphia	PA	26,000	4920	5000	335,000
United – Warren	PA	4100		6800	65,000
Giant – Yorktown	VA	4200			59,375
Ergon – Newell	West VA				20,000
Totals		**110,229**	**22,120**	**31,800**	**1,657,575**
Comparable PADD 3 Totals		**580,850**	**223,000**	**237,025**	**7,989,609**

Source: United States Refining & Storage Capacity Report, National Petroleum Refiners Association, August 2007

In addition, three Atlantic Province Canadian refineries supply petroleum products to the NESCAUM region. The refineries and their overall capacities are listed in the table immediately below.

Table C-11: Capacities of Atlantic Province Canadian Refineries Partially Supplying **The NESCAUM Region (BBL/Day)**

Company	Location	Capacity
Imperial Oil	Dartmouth, NS	88,017
Irving Oil	Saint-John, NB	280,034
North Atlantic Refining	Come-by-Chance, NFLD	105,051

Natural Resources Canada, Overview of the Canadian Downstream Petroleum Industry, June 2005.

As previously indicated, products are moved into PADD 1 from PADD 3 via pipeline, tanker, and barge. To a lesser extent, products are also moved into PADD 1 from the Midwest States (PADD 2). The table below displays the relevant product volumes.

Table C-12: Petroleum Products – Movement into PADD 1 from PADDs 2 & 3 **Pipeline, Tanker, & Barge – 2005/2006 Annual Average (Millions of Gallons)**

Product	Pipeline		Tanker & Barge		Total
	From PADD 2	From PADD 3	From PADD 2	From PADD 3	
Crude Oil	98.1	120.3	132.3	0	350.7
RFG	0	2460.8	0	3.9	2464.7
CG	22.5	16,181.2	216.9	5216.8	21,637.4
RBOB	0	1659.8	1.1	25.5	1686.4
CBOB/GTAB	0	0	0	31.3	31.3
HS Diesel/Fuel Oil	0.9	3563.0	52.2	261.5	3877.6
LS Diesel	1.6	6424.7	83.0	1362.8	7872.1
LS Residual	0	0	0	220.0	220.0
HS Residual	0	0	8.2	470.4	478.6
Jet Fuel	13.9	6184.7	12.1	1329.0	7539.7

In addition, petroleum and petroleum products are imported via tanker directly into PADD 1 from foreign sources. The table below lists, by world region, the principal sources of these imports.

Table C-13: Petroleum Products – Foreign Imports into PADD 1 **By Continent of Origin – 2005/2006 Annual Average (Millions of Gallons)**

Product	North	South	Caribbean	Europe	Africa	Middle	Other	Total

	America	**America**				**East**		
Crude Oil	3572 (15%)	2847 (12%)	0 (0%)	1624 (7%)	12,620 (53%)	2870 (12%)	250 (1%)	23,784 (100%)
RFG	1154 (53%)	147 (7%)	386 (18%)	499 (23%)	1 (<1%)	7 (<1%)	3 (<1%)	2192 (100%)
CG	274 (5%)	325 (6%)	975 (19%)	3357 (65%)	19 (<1%)	56 (1%)	126 (2%)	5131 (100%)
RBOB	724 (31%)	163 (7%)	450 (19%)	903 (39%)	13 (<1%)	11 (<1%)	57 (2%)	2319 (100%)
CBOB	66 (1%)	465 (9%)	88 (2%)	3851 (79%)	213 (4%)	39 (<1%)	179 (4%)	4900 (100%)
Ethanol	3 (1%)	191 (70%)	10 (4%)	1 (<!%)	0 (0%)	0 (0%)	69 (25%)	274 (100%)
Fuel Oil	152 (18%)	564 (67%)	23 (3%)	106 (13%)	0 (0%)	0 (0%)	1 (<1%)	845 (100%)
LS Diesel	835 (41%)	73 (4%)	821 (41%)	210 (10%)	7 (<1%)	0 (0%)	78 (4%)	2022 (100%)
HS Diesel	423 (26%)	117 (7%)	762 (46%)	274 (17%)	0 (0%)	0 (0%)	81 (5%)	1656 (100%)
LS Residual	164 (7%)	762 (35%)	323 (15%)	261 (12%)	486 (22%)	9 (<1%)	201 (9%)	2203 (100%)
HS Residual	602 (22%)	637 (23%)	971 (35%)	359 (13%)	52 (2%)	0 (0%)	118 (4%)	2737 (100%)
Jet Fuel	151 (10%)	500 (34%)	663 (45%)	24 (2%)	15 (1%)	91 (6%)	25 (2%)	1468 (100%)

Major Supply Points for Petroleum & Petroleum Products

There are numerous individual supply points, providing petroleum products to the region. Principal ones are in New York Harbor, Albany/Hudson River, and Delaware River/Bay. Secondary supply points include port terminals located in Boston, MA, Portland, ME, Portsmouth NH, New Haven, CT and Providence, RI. As fuels reach these ports, barges, tank trucks, pipelines and to a lesser extent, rail is used distribute fuels throughout the region. The region is also supplied by a major interstate pipeline (Colonial Pipeline) and three others, operated by Buckeye Partners, Sunoco, and ExxonMobil.

Port Facilities. New York Harbor could be considered as the central supply point in the region for receipt and distribution of petroleum products and is also the center for the water movement of heating oil and residual fuel for electricity generation facilities. Distribution of heating oil involves terminals of different sizes, heating oil distributors, and companies that have terminals to store heating oil and then distribute it. The figure immediately below illustrates the complex nature of the petroleum distribution infrastructure in New York Harbor.

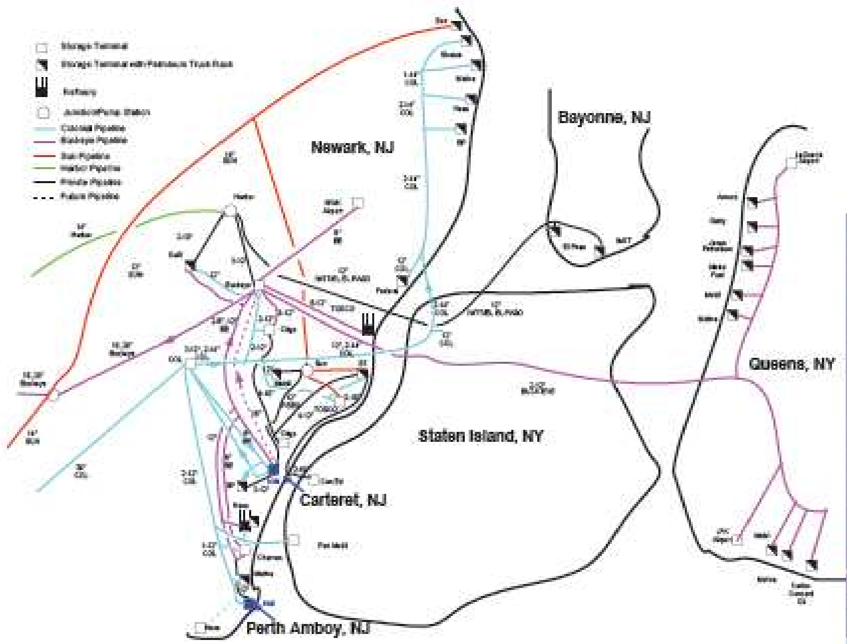


Figure C-4:

Source: Kinder Morgan (2005)

The Port of New York and New Jersey encompasses the ports of both states, with a total of 1,500 square miles, including 17 counties and 234 municipalities. Eight separate bays and associated waterways provide 755 miles of frontage of which 460 miles is in New York and 295 miles is in New Jersey, including navigable portions of the Hackensack, Passaic, and Raritan Rivers on the west; and Raritan and Sandy Hook on the south. The Port Authority administers piers in Manhattan, Brooklyn, Hoboken, Port Newark, and Port Elizabeth.

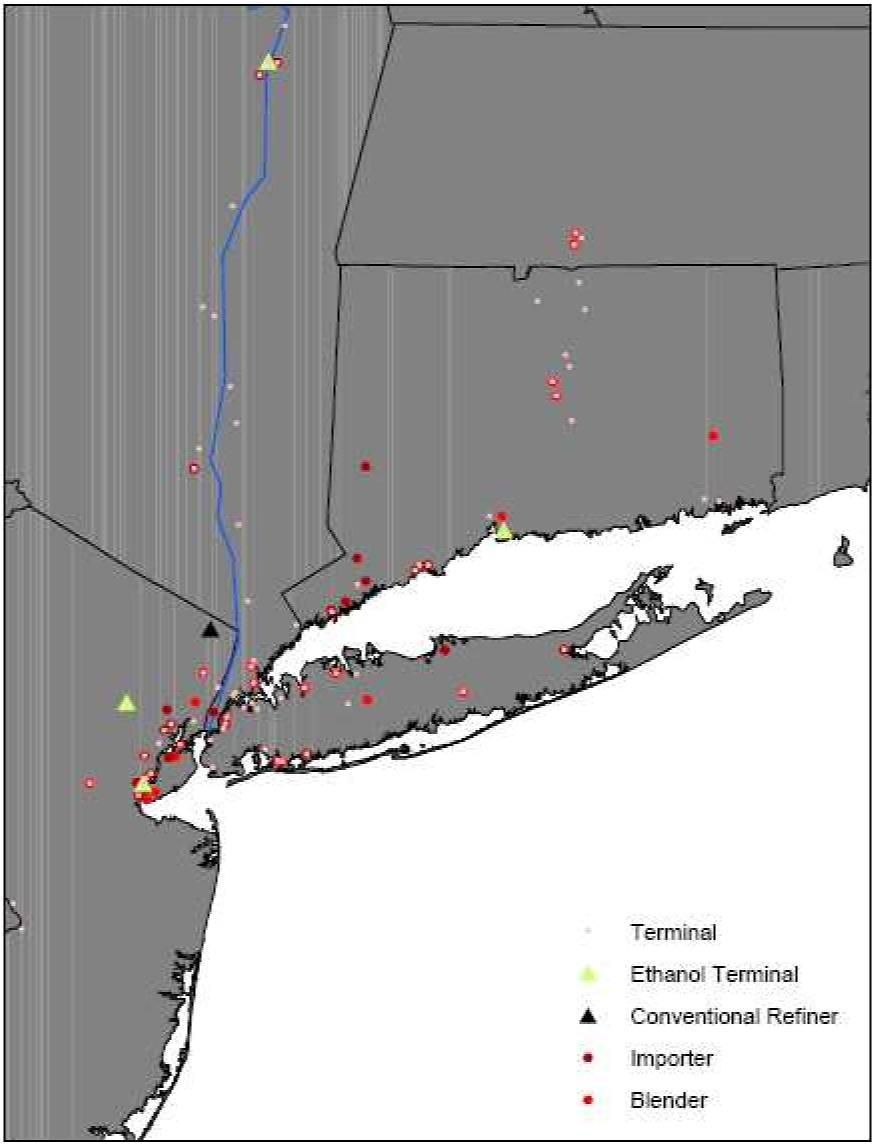


Figure C-5: Petroleum Facilities - New York/New Jersey & Albany/Hudson River Area Ports

The Hudson River rises in the Adirondack Mountains of New York and flows 315 miles in a southerly direction into New York Harbor. At Waterford, the river connects with the New York State Barge Canal system, which provides channels to the Great Lakes Port of Oswego, New York, and to improved waters in Canada leading to the St. Lawrence River. The Port of Albany, New York, is on the bank of the Hudson River about 143 statute miles north of New York Harbor. The port is the terminus of the deep-draft Hudson River and is the principal port above New York City. There are 98 waterfront piers, wharves, and docks on the Hudson River. Eight of these facilities are within the Port of Albany. A total of eighty port facilities are located on the Hudson River above and below the Port of Albany.

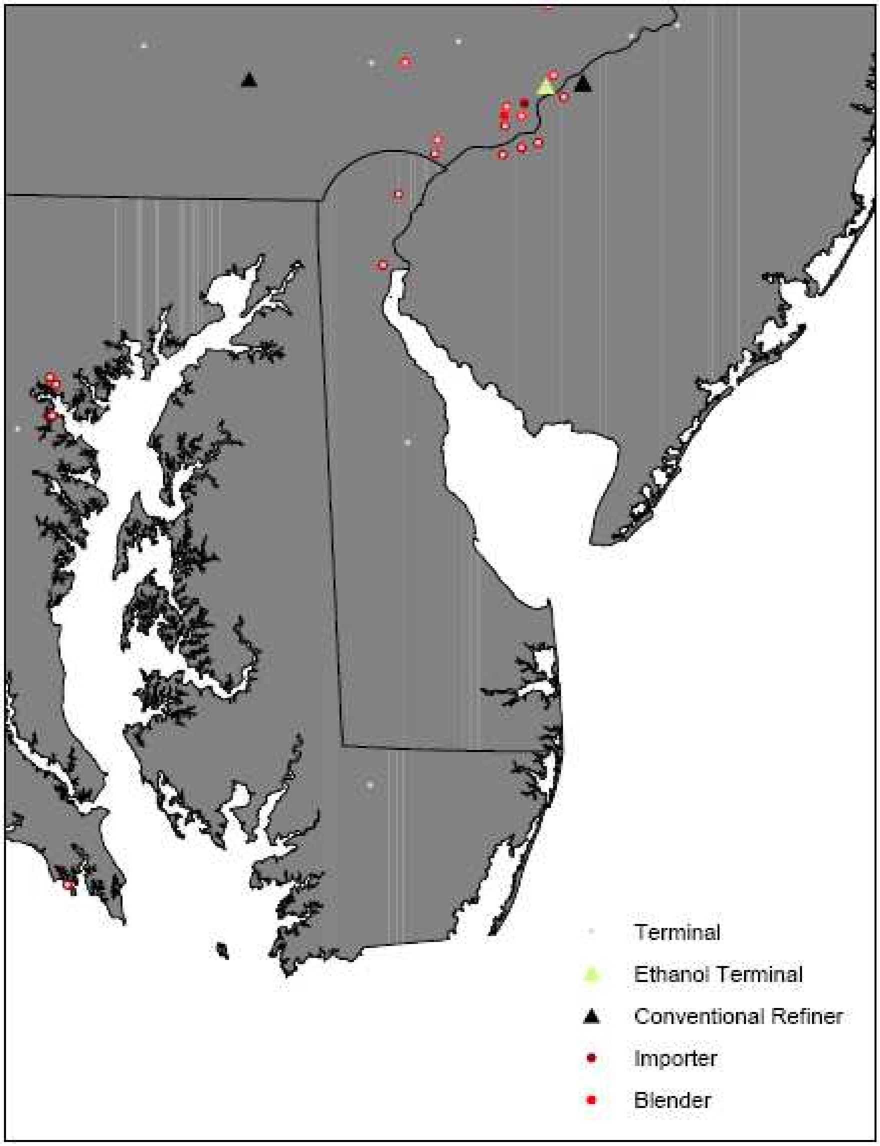


Figure C-6: Petroleum Facilities - Delaware Bay/River Ports

The Delaware Bay and the Delaware River form the boundary between the State of New Jersey on the east and the States of Delaware and Pennsylvania on the west. The Delaware Bay is an expansion of the lower part of the Delaware River, and the entrance is about 10 nautical miles wide between Cape May and Cape Henlopen. Deep draft vessels use the Atlantic Ocean entrance while vessels with drafts of less than 33 feet can enter the Delaware River from the Chesapeake Bay through the Chesapeake and Delaware Canal. This canal provides an alternate protected waterway connecting the Delaware River and Chesapeake Bay ports.

The Delaware Bay and the Delaware River represent the principal artery for waterborne commerce for Philadelphia, PA, Wilmington, DE, Chester and Marcus Hook, PA and

Camden, Trenton and Salem, NJ. More than 190 piers, wharves, and docks are available along the waterfront areas to handle petroleum products, miscellaneous bulk commodities, and a variety of dry bulk materials and liquid commodities. The entire Delaware River system ranks as the fifth largest US seaport, due to the River's concentration of oil refineries and oil import terminals. The City of Philadelphia's portion of the Delaware River system includes navigable sections of the Schuylkill River.

Located adjacent to Philadelphia International Airport, the Hog Island Shipping Terminal is predominantly used for oil and gas products. In addition, Marcus Hook is an important petroleum center where large quantities of crude oil are received and refined petroleum products are shipped. The Camden city waterfront includes the petroleum terminals at Pettys Island and Fisher Point Dike.

Pipelines. Colonial Pipeline moves petroleum products from the Gulf Coast in PADD 3 to New Jersey and New York (see New York Harbor figure above), along more than 5000 miles of pipeline. A network of smaller pipelines branches out from the end of the main line in Linden, NJ, to a number of locations throughout New York Harbor. Linden is a large junction where the Colonial pipeline connects with other intraregional pipelines which connect, in turn, to several terminals and refineries. This Intra Harbor Transport Service connects to petroleum products terminals on the Hudson River owned by companies such as Motiva, Hess, and BP. The pipeline also connects to the Buckeye and the Sunoco pipelines.

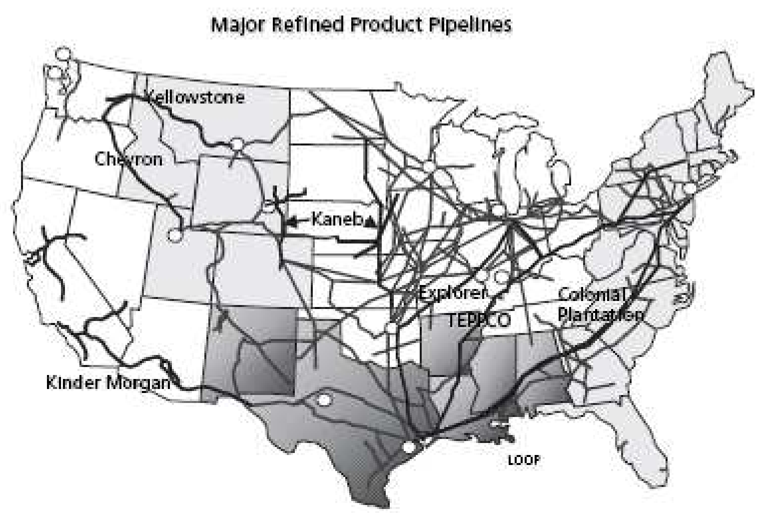


Figure C-7: Colonial & Other Major Interstate Petroleum Product Pipelines

Colonial Pipeline system annually moves approximately 900 million barrels of petroleum products from PADD 3. At Greensboro, NC, the volume on the line is reduced to around 365 million barrels annually, continuing to the New York Harbor terminus. It is estimated that 30 to 40 percent of this remaining capacity is distillate fuels and the remainder (60-70 percent) is gasoline, jet fuel and other light products.

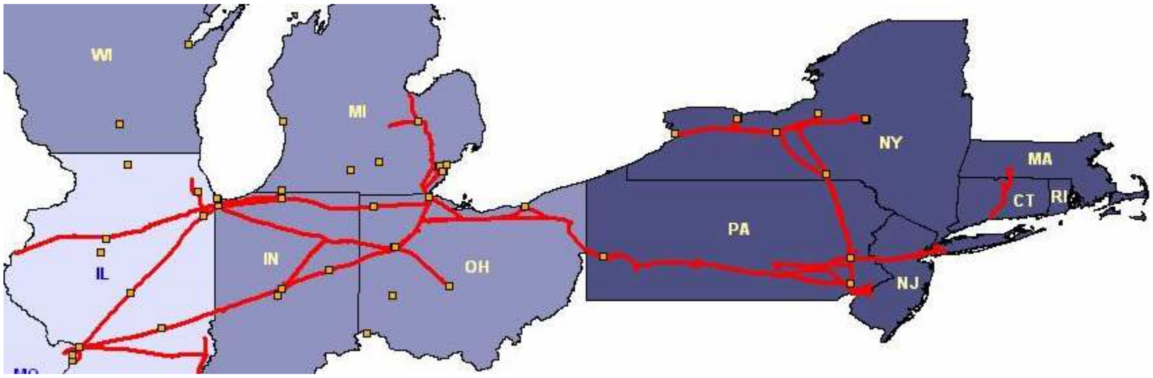


Figure C-8: Buckeye Pipeline

The Buckeye Pipeline serves Pennsylvania, New York, and New Jersey. Petroleum products are received at Linden, NJ, from approximately 17 major source points, including two refineries, six connecting pipelines, and nine storage and terminalling facilities and in turn, transported through one line to Newark and through two additional lines to JFK and La Guardia airports, and further onto terminals at Long Island City and Inwood, NY. JFK Airport is connected to the Inwood Terminal from which the airport gets all its aviation fuel and La Guardia to the Long Island City terminal.

Additionally, Buckeye operates a line that moves petroleum products from Pennsylvania into south central New York. In New York, the line splits, traveling east through Syracuse and terminating in Utica, and west (with a spur to Rochester) terminating in Buffalo. Buckeye also operates a line, transporting product from the port of New Haven, CT, through Hartford, and terminating in Springfield, MA.

Figure C-9: Sunoco Pipeline

Sunoco has three lines (Western, Terminal Facilities, and Eastern) totaling 1,740 miles and transporting product from Sunoco refineries and terminals in Philadelphia, PA, Marcus Hook, PA, Eagle Point, NJ, and Toledo, OH, and from third parties to markets in New York, New Jersey, Pennsylvania, Ohio, and Michigan. Two additional lines transport product north from Pennsylvania to Rochester, Buffalo, and Syracuse, NY.

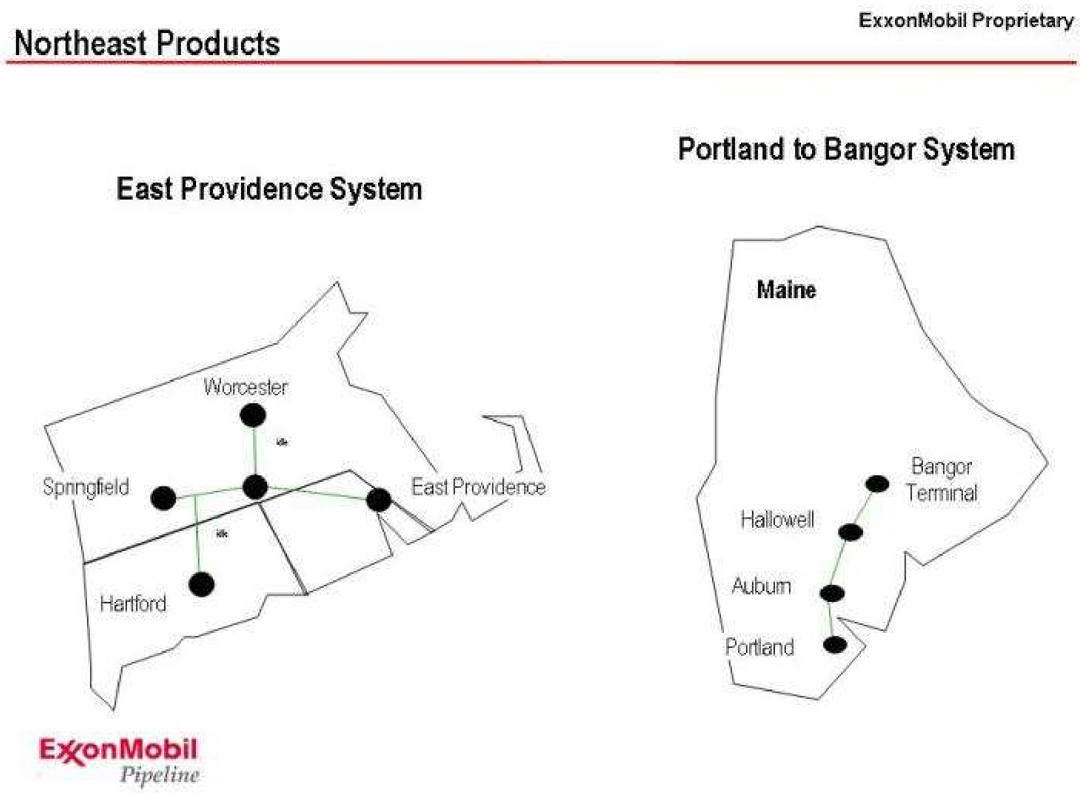


Figure C-10: ExxonMobile Pipelines

ExxonMobil has three pipeline systems in the region. The 124-mile Portland to Bangor system originates in Portland, ME, and terminates in Bangor, delivering product to ExxonMobil, Coldbrook Energies, and Weber Energy terminals. The 84-mile East Providence to Springfield system originates in East Providence, RI and terminates in Springfield, MA. The 472-mile Paulsboro NJ/PA/NY system serves ExxonMobil's Paulsboro, NJ, Pennsylvania, and New York terminals.

Terminals. Terminals are the point in the distribution system where product typically is dispensed into transport trucks for delivery to wholesale and retail customers or to smaller bulk plants. The table below lists the capacities of the principal terminal companies and includes a figure for the total terminal capacity within the NESCAUM region.

Table C-14: Petroleum Product Terminal Capacity in the NESCAUM Region (Thousands of Barrels)

Company	Capacity	Company	Capacity
IMTT	15,300	Irving Oil	2,609
Sprague Energy	12,269	New Haven	2,500
Amerada Hess	9,990	Buckeye Terminals	2,329

Kinder Morgan	9,949	Global Companies	1,341
Motiva Enterprises	8,840	TEPPCO	1,216
ExxonMobil	8,419	Sunoco Logistics	1,190
CITGO Petroleum	6,173	Pacific Atlantic	1,156
Carbo Industries	5,900	NOCO Energy	1,113
Magellan	3,900	Center Terminal	975
ST Linden Terminal	3,884	Castle Oil	807
Gulf Oil	3,550	All Others	12,562
NRG	3,043	Total	122,797
Portland Pipeline	2,634		

Table C-15: Petroleum Product Terminals in Delaware River Region of Southeastern Pennsylvania*

Potentially Supplying the NESCAUM Region

Company	Number of Terminals	Company	Number of Terminals
121 Point Breeze	1	Gulf Oil	1
Aircraft Service, Intl.	1	HOP Energy	1
Amerada Hess	1	Kinder Morgan	1
Buckeye	2	Meenan	1
ConoccoPhillips	1	Pacific Atlantic	3
Farm and Home Oil	3	Petroleum Products	2
Global	1	Sunoco Partners	9

**Counties of Berks, Bucks, Chester, Delaware, Lancaster, Lehigh, Montgomery, & Philadelphia.*

Ethanol Transport, Supply and Distribution

Ethanol is expected to be an ever increasing component of U.S. transportation fuels for many years to come, particularly due to recent federal mandates. The majority of the fuel ethanol presently supplied to the Northeast and other U.S. markets comes from Midwestern distillers who convert corn starch into ethanol. The Energy Policy Act of 2005 established minimum volumes of “renewable fuel” to be added to the fuel supply, beginning in 2006 with a 4 billion gallon requirement. This requirement was largely met by supplying ethanol. In fact, in the same year, the domestic ethanol industry produced 4.9 billion gallons of ethanol. An additional 0.7 billion gallons were imported into the U.S. in the same timeframe.

The Energy Independence & Security Act of 2007 increases the renewable fuel mandate. In 2008, the minimum requirement for consumption of renewable fuel is 9 billion gallons, ramping up to 36 billion gallons by 2022. Beginning in 2009, a modest portion of this mandate must be met through the consumption of “advanced biofuel,” which is the broad category of renewable fuels other than ethanol produced from corn starch. By 2022, the advanced biofuel requirement ramps up to 21 billion gallons, meaning among other things, that 15 billion of the overall 36 billion gallon requirement may still be satisfied through the use of ethanol produced from corn starch.

The demand for ethanol in the Northeast is largely driven by RFG requirements. As mentioned previously in this chapter, although the oxygenate mandate for RFG is no longer in effect, RFG states depend on ethanol to make up the volume losses that were the consequence of MTBE bans. Thus, ethanol is present in gasoline supplied to the entire states of Connecticut, Massachusetts, New Jersey and Rhode Island. In 2006, approximately 1.2 billion gallons of ethanol was added to Northeast RFG, of which 0.5 billion gallons were imported, reflecting a 10 fold increase in imports from the prior year.

There is no particular incentive for supplying ethanol to states where RFG is not required. If the cost of ethanol is less than gasoline, then ethanol is more likely to be present in non-RFG markets. However if the opposite is true, there is a disincentive to supply ethanol. Consequently in the NESCAUM Region, there is limited penetration of ethanol into markets in Upstate New York, Vermont, Maine, or outside the southeastern counties of New Hampshire.

More than 75 percent of the domestically produced ethanol is transported by rail. A typical ethanol “unit train” consists of approximately 100 tank cars, each with a capacity of about 30,000 gallons. Nationally, there are approximately 15,000 such tank cars in ethanol service. Two major railroad companies, Norfolk Southern and CSX, are the primary transporters of fuel ethanol from the Midwest to the Northeast. In 2006, Norfolk Southern moved more than one billion gallons of ethanol nationally. A third major railroad company, Canadian National Railroad, may become a major ethanol transporter to developing markets in Northern New England. Certain smaller railroad companies, such as Providence & Worcester and St. Lawrence & Atlantic also play a role in moving ethanol from the terminus of the major rail lines to local storage terminals.

There are four major ethanol terminals, supplying the markets in the NESCAUM Region located in Albany (NY), Providence (RI), Linden (NJ), and Sewaren (NJ). A fifth facility in Auburn (ME), opened in late 2007, has the potential to become a major supplier, depending on future demand for fuel ethanol in Northern New England. Major Terminals in Philadelphia (PA) and Baltimore (MD), and a major production facility undergoing construction in Westmoreland County (PA), primarily serving the Mid-Atlantic Region, may play a role in supplying northeast customers. Below is a brief description of each facility and its supply structure.

LogiBio Albany (NY) Terminal is the former Cibro Petroleum Products terminal. In 2006, the facility handled almost 336,000,000 gallons of ethanol. The terminal has over 21,000,000 gallons of ethanol storage capacity and receives product from the Midwest via CSX trains, with the ability to unload 80 railcars at a time. In addition, the facility has the ability to receive and load out product to barges traveling the Hudson River. It also has a truck loading facility for local deliveries. Via, barge, ethanol is delivered to markets in New York City, Bridgeport (CT), New Haven (CT), Providence (RI), and Boston/Revere (MA).

U.S. Development Group New York Harbor (Linden, NJ) Terminal originally was served only by barge and truck, receiving the bulk of its ethanol from foreign sources. Beginning in 2007, the terminal added rail capacity to receive 100-car unit trains of domestically produced ethanol from Norfolk Southern and CSX rails. The terminal is now capable of handling 250 ethanol rail cars at one time and is able to store 21,000,000 gallons of ethanol.

U.S. Development Group Baltimore (MD) Harbor Terminal is undergoing development from a small railcar facility in Curtis Bay, south of Baltimore, into a facility which can handle 120 railcar spots and ultimately the ability to handle 100-car unit trains. The Baltimore facility also has barge docks and truck racks. Storage capacity is 12,600,000 gallons. It is unknown if this terminal serves locations in the NESCAUM Region, but because of its proximity, it's possible.

Motiva Enterprises Providence (RI) Terminal is one of two principal petroleum products terminals located in Providence and serving Rhode Island, parts of Connecticut, and Southeastern Massachusetts. The terminal originally received ethanol shipments exclusively by barge. In 2007, Motiva completed a rail facility to accommodate unit trains of ethanol arriving on tracks owned by the Providence & Worcester Railroad. Ethanol is transported from the Midwest via trains operated by CSX and stored in a series of existing tanks at the facility with a capacity of 63,000,000 gallons.

Motiva Enterprises Sewaren (NJ) Terminal expanded its petroleum products handling operations in 2005 to become the largest ethanol storage terminal in the New York Harbor area, serving customers in New York and Connecticut. The facility is able to handle more than 2 million gallons of ethanol per day, brought in by unit trains of the Norfolk Southern Railway.

Aventine Renewable Energy Philadelphia (PA) Terminal receives ethanol by rail service provided by CSX.

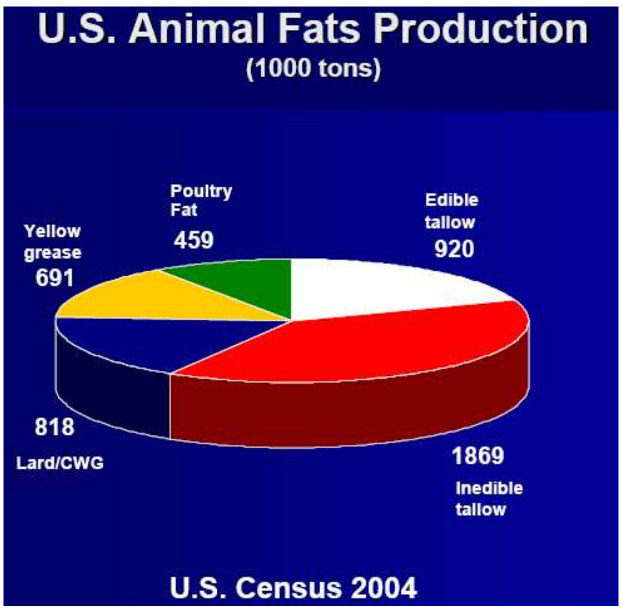
Safe Handling Auburn (ME) Terminal opened a rail-to-truck ethanol transloading terminal in December 2007 to serve potential Northern New England markets. The facility does not store ethanol in permanent onsite tanks. Rather, the facility can accommodate up to 210 rail cars at a time for a total capacity of 6,300,000 gallons. Ethanol will come from the Midwest and Canada via the Canadian National Railroad on haulage agreement with the St. Lawrence & Atlantic Railroad.

Commonwealth Renewable Energy Production Facility (Westmoreland County, PA) is undergoing construction in Southwestern Pennsylvania. Touted as "the country's largest ethanol plant," plans are to largely use locally grown corn as the raw materials source to produce 200 million gallons of ethanol annually. A major line of the Norfolk Southern Railway passes near the facility.

Magellan Midstream Partners (New Haven, CT) operates an ethanol supply network of vessels and trucks, serving Connecticut and Massachusetts. The facility has an ethanol storage capacity of 142,000 barrels. In 2007, their annual throughput was 1,557,699 barrels.

Yellow Grease & Inedible Tallow as a Potential Biodiesel Resource

Animal fats are a potentially significant source of renewable energy, either as a raw material for the production of methyl esters (biodiesel) or for direct firing in their unaltered fatty acid form as boiler fuel. The principal animal fats produced in the United States are yellow grease, poultry fat, edible tallow, inedible tallow, and lard. The chart[62] below illustrates their relative proportions. Animal fats are not considered a waste product. Virtually all are used in the manufacture of various products, including human food, animal feed, cosmetics and lubricants. Tallow is considered edible if it is fit for human consumption. So-called inedible tallow is most commonly used in animal feed. Yellow grease is derived primarily from used cooking oil and fryer grease from restaurants and is mostly used as a supplement in animal feed. Inedible tallow and yellow grease typically have lower economic value, compared to the other animal fats and therefore are the better candidates for use as fuel.



As indicated above, yellow grease is a byproduct of the restaurant industry. There is a direct correlation between the amount of restaurant food produced in an area and that area's population. Therefore, one approach to estimating the amount of yellow grease produced in a state is to base the estimate on state population. According to the U.S. Census Bureau, 1335.6 million pounds of yellow grease were produced in the United States in 2005. The estimated U.S. population, also according to the U.S. Census Bureau, on July 1, 2005 was 295.9 million. Thus the U.S. per capita yellow grease production in 2005 was approximately 4.5 pounds. Using this number in conjunction with 2005 population estimates for each state, the chart below estimates the annual yellow grease production for the eight NESCAUM states plus Maryland and Pennsylvania. According to the EIA, 7.65 pounds of fat will yield a gallon of biodiesel. Thus, the equivalent biodiesel volume is included in the same chart below.

Table C-16: Estimated Yellow Grease Resource & Equivalent Biodiesel Production Potential

State	Yellow Grease (10^6 Pounds)	Biodiesel Equivalent (10^6 Gallons)

62 *Source: National Renderers Association, December 2006*

Connecticut	15.7	2.0
Maine	5.9	0.8
Massachusetts	28.9	3.8
New Hampshire	5.9	0.8
New Jersey	39.0	5.1
New York	86.7	11.3
Rhode Island	4.8	0.6
Vermont	2.8	0.4
Maryland	25.1	3.3
Pennsylvania	55.7	7.2
Total:	270.5	35.3

Population is not a good indicator for estimating the inedible tallow resource in a state. Independent of population, this resource in any given state is more directly related to the level of activity of the state's animal slaughtering and processing industry. The U.S. Census Bureau's 2002 Economic Census compiled data on the animal slaughtering and processing industry in each state, including each state's total value of products shipped. Thus, the approach used to estimate the available tallow resource for each state was to apportion the 2005 U.S. total of 3637.1 million pounds of inedible tallow produced, according to the 2002 Economic Census report of total value of products shipped for each state. Consistent with the methodology used to estimate potential biodiesel production from yellow grease, the Energy Information Administration's factor of 7.65 pounds of fat yielding a gallon of biodiesel was used to estimate the equivalent biodiesel volume from the inedible tallow resource. The results are given in the table below.

Table C-17 Estimated Inedible Tallow Resource & Equivalent Biodiesel Production Potential

State	Inedible Tallow (10^6 Pounds)	Biodiesel Equivalent (10^6 Gallons)
Connecticut	4.9	0.6
Maine	3.2	0.4
Massachusetts	15.2	2.0
New Hampshire	0	0
New Jersey	26.8	3.5
New York	30.2	3.9
Rhode Island	2.0	0.3
Vermont	1.2	0.2
Maryland	20.8	2.7
Pennsylvania	112.2	14.6
Total:	216.5	28.2

Possibly the most expedient means of utilizing yellow grease and inedible tallow for biodiesel production or for direct firing in a boiler is to produce/use it at existing rendering plants. This strategy utilizes existing processing, transport, and supply infrastructure and avoids the problems associated with attempting to cite new rendering plants in communities where they may not be welcome. In the northeast, existing rendering plants are not uniformly distributed. Out of a national population of approximately 229 plants there are only 15 in the northeast and 9 of those 15 are located in a single state (Pennsylvania). The table below assumes that the entire yellow grease and inedible tallow resources in the eight NESCAUM states, plus the Maryland and

Pennsylvania, are directed to these 15 facilities and all of the resource is converted to biodiesel at the facilities.

Table C-18: Biodiesel Production Potential (10^6 Gallons) for Northeast Rendering Plants
Based on Numbers of Plants in Each State and 2005 Raw Material* Supply

State	Numbers of Plants	Raw Material	Biodiesel Volume
Massachusetts	2	64.9	8.5
New Jersey	1	32.5	4.2
Maryland	3	97.4	12.7
Pennsylvania	9	292.2	38.1
Total:	15	487.0	63.5

**Raw Material is the combined estimated 2005 total yellow grease & inedible tallow (10^6 pounds)*

Liquefied Natural Gas in the Northeast (Outline)

General Facts & Figures (2005)

Total natural gas consumed in the 8 NESCAUM states: 2,446,193 million cubic feet
Total natural gas consumed in the 6 New England states: 763,590 million cubic feet
Percentage of LNG in the total U.S. natural gas supply: 3 percent

Everett (MA) LNG Facility

This facility, operated by Distrigas of Massachusetts, is the exclusive supplier of LNG to the New England States. In 2005, Distrigas imported 168,542 million cubic feet of natural gas into the facility, all from Trinidad and Tobago and accounting for 22 percent of total natural gas consumption in New England.

This facility is the exclusive supplier of natural gas to Boston Generating LLC Mystic Generating Station (power plant). Of all the LNG imported into the Everett facility in 2005, 35 percent (59,559 million cubic feet) went to the Mystic Generating Station. The remainder was distributed by pipeline or truck to other customers.

If the LNG delivered to Mystic is subtracted from the total, then 15 percent of the remaining natural gas demand in New England is supplied by LNG from the Everett Facility.

Cove Point (MD) LNG Facility

This facility, operated by Dominion Cove Point LNG, supplies LNG to the Mid-Atlantic States. There is no indication that any of the LNG is supplied to markets in the NESCAUM states. In 2005, Dominion imported 221,689 million cubic feet of natural gas into the facility, mostly from Trinidad and Tobago. Dominion supplies natural gas to power plants operated by Dominion Virginia Power and Fairless Energy (PA). In 2005, the seven natural gas fired power generating units consumed 35,588 million cubic feet of natural gas, of which an undetermined percentage was LNG, originating from the Dominion Cove Point facility.

Lake Charles (LA) LNG Facility

This facility, operated by Trunkline LNG Company, supplies LNG via the Trunkline natural gas pipeline, which follows the Mississippi River up to Illinois and then across Illinois and northwestern Indiana, terminating at the Indiana-Michigan border. A branch line (Panhandle Eastern) runs from Oklahoma and Texas in the west, terminating at Detroit in the east. There is one power generating facility in Oswego, NY (Independence Station – Sithe Energies, Inc) that receives an undetermined amount of natural gas, originating from the Lake Charles LNG Facility. In 2005, Trunkline imported 103,770 million cubic feet of natural gas into its LNG facility, mostly from Algeria and Egypt. In 2005, Independence Station consumed 21,653 million cubic feet of natural gas for power generation purposes, an undetermined amount of which originated from the Lake Charles LNG Facility.

Biodiesel

In early 2007, approximately 400 public and federal fueling stations across the country offered biodiesel blends of B20 through B100[63]. The number of fueling stations that offered biodiesel increased by an average of about 186 per year between 2004 and 2006. Despite this rapid increase, it is estimated that the number of fueling stations that offered biodiesel was only about 1 percent of the total number of fueling stations that offered diesel. Biodiesel fueling stations are dispersed nationwide because production facilities are not concentrated in any specific region[64].

Biodiesel is primarily transported by rail, but also by truck and barge, and limited capacity in this distribution system has led to supply disruptions and concerns about the system's ability to effectively transport greater amounts of biodiesel if production significantly increases[65].

The bulk of the data relating to producers and distributors of biodiesel was compiled from the National Biodiesel Accreditation Program (NBAP) which is a cooperative and voluntary program for the accreditation of producers and marketers of biodiesel fuel called BQ-9000. The program is a unique combination of the ASTM standard for biodiesel, ASTM D 6751, and a quality systems program that includes storage, sampling, testing, blending, shipping, distribution, and fuel management practices. To receive accreditation, companies must pass a rigorous review and inspection of their quality control processes by an independent auditor. This ensures that quality control is fully implemented. On further investigation, the number of potential producers of Biodiesel is significantly higher than the information presented by the NBAP; however, this is attributed to the voluntary nature of the organization and admission requirements that producer meet the ASTM standard BQ-9000 quality and grade for the product.

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[63] GAO, Biofuels: DOE lack a strategic approach to coordinate increasing production with infrastructure development and vehicle needs, http://www.gao.gov/new.items/d07713.pdf, retrieved at April 28, 2008

[64] id

[65] id

The highest concentrations of Biodiesel production and distribution networks for that grade are predominantly located in the Midwest clustering along the agrarian belt of the U.S. the figure below also indicates that the locations where agricultural products are produced and shipped from in order to help fuel the industry.

[66]

Figure C-11:

Most of the NBAP accredited companies are capable of supplying biodiesel anywhere in the country; in addition, the proximity of the potential biodiesel usage in relation to the company's listed mailing address is not necessarily relevant to their supply logistics or price structure. Some of these companies may not be actively producing Biodiesel consistently on a national scale, it is more probably that production, distribution, and capacity in the NESCAUM states is limited when a comparison is made with the production and distribution capability in the New England region with that of the Mid-West. Fortunately, the infrastructure needed to get biodiesel to consumers is emerging at a rapid pace. Currently, there are several suppliers of biodiesel, approximately twenty blenders and distributors of biodiesel, and a similar number of biodiesel retail fueling sites in New England[67]. Some organizations with capital and commitment to the environment are building their own infrastructure to support biodiesel use. For example, in 2003, Harvard University spent $60,000 to build a state-of-the-art campus fueling station in Boston. Harvard is currently fueling its fleet of 48 diesel vehicles, including 8 shuttle buses, with B20[68].

[66] http://biodiesel.org/buyingbiodiesel/producers_marketers/default.aspx?AspxAutoDetectCookieSupport=1

[67] EPA Region 1: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont & Tribal Nations, Greenbytes, http://www.epa.gov/Region1/ra/gb/archives/2005/20050304.html

[68] id

Currently, the impetus for the use of Biodiesel in the New England region has been sustained throughout the region by institutions, municipalities, state-run agencies, that have established and funded their own production and distribution capabilities. Biodiesel is being used throughout New England in a number of locations including: Connecticut Department of Transportation; L.L. Bean, Inc.; Maine Department of Transportation; City of Bangor, Maine; Harvard University; UMASS Amherst; NSTA;, Cities of Medford, Cambridge, and Brookline; Mount Cranmore Ski Resort; New Hampshire Department of Transportation; Keene State College and the City of Keene; Pease Air Force Base; Warwick Rhode Island; University of Vermont; Vermont Law School; Sugarbush Ski Resort; and Vermont Coffee Company. Below is an example of the production and distribution capabilities of the State of Vermont which is actually typical of most states with the NESCAUM region[69]. In Vermont it seems that production and supply of Biodiesel products to contracted consumers is beginning to take shape; in addition, the map below indicates that Vermont has rudimentary infrastructure for the distribution of biodiesel for mass consumption. However, the distribution of biodiesel is limited to specific small intra-state markets for residential heating and commercial businesses.

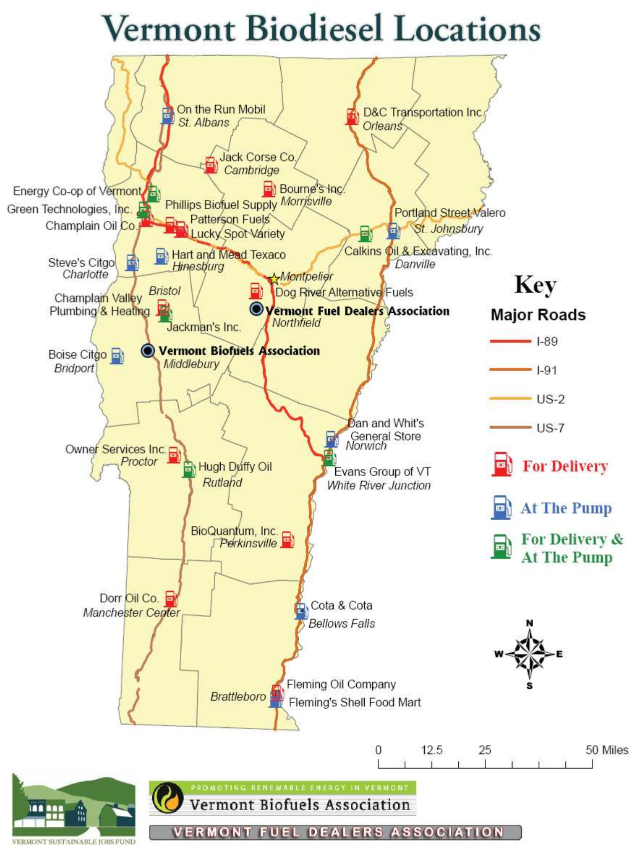

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Figure C-12:

69 id

70 http://www.vtbiodieselproject.org/participants/participants.shtml

Table C-19:

For Delivery					
Business Name	Address	City	State	Zip	Phone
BioQuantum, Inc.	P.O. Box 99	Perkinsville	VT	05151	(800) 901-2616
Bourne's Inc.	171 Bridge Street	Morrisville	VT	05661	(800) 326-8763
Champlain Oil Company	45 San Remo Drive	South Burlington	VT	05407	(802) 864-5380
Champlain Valley Plumbing & Heating	125 Monkton Road	Bristol	VT	05443	(802) 453-2325
D&C Transportation Inc.	32 Railroad Avenue	Orleans	VT	05860	(802) 754-6664
Dog River Alternative Fuels	1701 Chase Road	Berlin	VT	05602	(802) 229-4148
Dorr Oil Company	209 Riverside Heights	Manchester Center	VT	05255	(802) 362-1950
Fleming Oil Company	One Putney Road	Brattleboro	VT	05301	(802) 254-6095
Jack Corse Co.	5812 Vermont Route 15	Jeffersonville	VT	05464	(802) 644-2749
Owner Services, Inc.	41 School Street	Proctor	VT	05765	(802) 747-4987
Patterson Fuels	Route 117	Richmond	VT	05477	(800) 427-WARM
Rymes Heating Oils, Inc.	P.O. Box 2948	Concord	NH	03302	(603) 228-2224
Simple Energy	99 North Main Street	West Lebanon	NH	03784	(603) 298-7200
At The Pump					
Business Name	Address	City	State	Zip	Phone
Boise Citgo	3039 VT Route 22A	Bridport	VT	05734	(802) 758-2361
Dan and Whit's General Store	319 Main Street	Norwich	VT	05055	(802) 649-1602
Fleming's Shell Food Mart	429 Canal Street	Brattleboro	VT	05301	(802) 254-9727
Hart and Mead Texaco	234 Commerce Street	Hinesburg	VT	05461	(802) 482-2318
Lucky Spot Variety	174 River Road	Richmond	VT	05477	(802) 434-2332
On the Run Mobil	555 Fairfax Road	St. Albans	VT	05478	(802) 527-9932
Portland Street Valero	757 Portland Street	St. Johnsbury	VT	05819	(802) 748-1943
Steve's Citgo	3171 Ethan Allen Highway	Charlotte	VT	05445	(802) 425-2741
For Delivery & At The Pump					
Business Name	Address	City	State	Zip	Phone
Calkins Oil & Excavating, Inc.	36 Route 2 West	Danville	VT	05828	(802) 684-3375
Cota & Cota	4 Green Street	Bellows Falls	VT	05101	(802) 463-9150
Energy Co-op of Vermont	73 Prim Road, Suite 3	Colchester	VT	05446	(866) 626-4328
Evans Group of Vermont	171 Bridge Street	White River Junction	VT	05001	(800) 258-7552
Green Technologies Inc.	150 W. Canal Street	Winooski	VT	05404	(802) 655-1995
Hugh Duffy Coal & Oil Company Inc.	190 West Street	Rutland	VT	05701	(802) 773-2567
Jackman's Inc.	32 Pine Street	Bristol	VT	05443	(802) 453-2381

[71]

71 id

Appendix A: Chapter 5 Appendix (to be added)

Appendix B: References (to be completed)