Appendix O:
Biofuels Markets in New York State and Integration in the Northeast Region

Renewable Fuels Roadmap and Sustainable Biomass Feedstock Supply for New York

Final Report

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Contract # 10994
NYSERDA Report 10-05

March 2010

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TABLE OF CONTENTS

Section **Page**

TABLES

Table **Page**

FIGURES

Figure **Page**

1 INTRODUCTION

As of early 2010, efforts by the U.S. Congress to implement a federal program for reducing greenhouse gas (GHG) emissions have stalled, but states and regions continue to move ahead with the design and implementation of major climate and clean energy policy initiatives. Thus far, the Northeast states along with California have led the majority of efforts in the United States to develop mandatory climate and clean energy policies and programs. Recently, these leading climate and clean energy states have been joined by a number of western and mid-western states as well as Canadian provinces that are working together on regional GHG programs for stationary and mobile sources, renewable and low carbon fuels, and clean energy.

In the first section of this Appendix, we describe existing and emerging climate and energy policies at the state, regional, and national levels that have important implications for the development of New York's renewable fuels market and also for the characteristics of renewable fuels that will be eligible under these programs. In the second section, we provide empirical analysis of how these policies along with existing markets could create complementary and/or competing demands for New York's biomass resources and emerging market for renewable fuels. Note that this analysis focuses primarily on woody biomass resources, but it also addresses some issues that could also be relevant for New York's agricultural biomass resources. For additional discussion on policy measures, please see Appendices M and N.

2 POLICIES AFFECTING NEW YORK RENEWABLE FUELS

2.1 NORTHEAST/MID-ATLANTIC LOW CARBON FUEL STANDARD

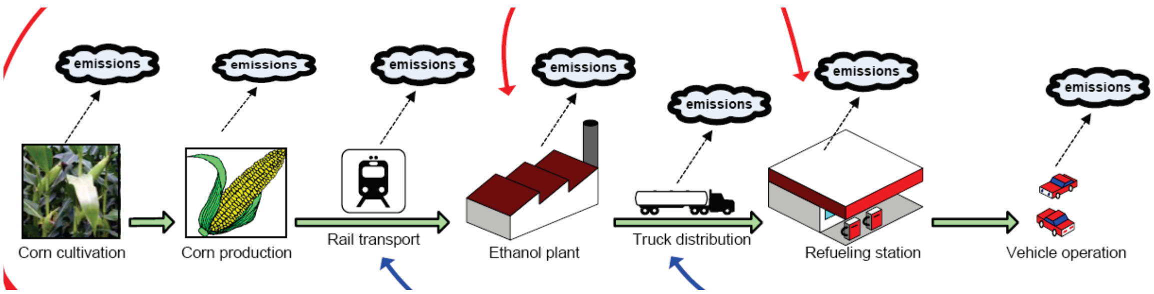
In December 2008, Commissioners from the environmental agencies of 11 northeastern states signed a *Letter of Intent* committing their respective states to explore the development of a Low Carbon Fuel Standard (LCFS) to reduce the GHG-intensity of fuels sold into and used in the region.[1] In December 2009, the Governors of these same 11 northeastern states issued a *Memorandum of Understanding* that requires the states to examine the economic impacts of a regional LCFS and to make recommendations on the key elements of the LCFS by December 2010.

A key feature of the Northeast's regional LCFS and California's LCFS (covered in the next section) is that the GHG-intensity of fuels used for compliance with the program will be evaluated on a full lifecycle basis. As shown in Figure O-1 below, full GHG lifecycle analysis (LCA) involves accounting for the emissions associated with each stage in the life of a fuel, including production, transport, storage, delivery, and use. While this type of GHG accounting is data-intensive, it provides a much more accurate and holistic view of

[1]The Letter of Intent and MOU were signed by officials from the six New England states (MA, RI, CT, NH, ME, and VT) and five mid-Atlantic states (NY, NJ, PA, DE, and MD).

a fuel's overall impact on GHG emissions than an approach focused on emissions from fuel combustion alone.

Figure O-1. Example of Full GHG Lifecycle Analysis: Corn Ethanol.



Source: Wang and DeLucchi 2005.

Currently, the Northeast states are considering the feasibility of a similar target for the regional LCFS as California's LCFS, which requires a 10% reduction in the GHG intensity of transportation fuels by 2020, relative to 2010. However, a key difference between California and the Northeast is our region's significant use of fuels for heating. The Northeast's use of No. 2 oil for heating, for example, is more or less equal in size to the region's use of distillate fuels for transportation.

Given the potential opportunity of the LCFS to reduce the GHG intensity of heating fuels, the Northeast states are considering whether to include this sector in the scope of the regional LCFS. In the event that heating fuels are included in the program, market demand for New York's biomass could increase if biomass-based heating fuels such as wood pellets were eligible for generating credits under the program.[2] These types of fuels would be especially attractive for compliance with a regional LCFS in the near-term, until more advanced biomass-based fuels such as cellulosic ethanol are commercially available in significant quantities.

Even without the inclusion of the heating fuel sector, the regional LCFS would create strong demand for advanced biofuels in New York. Tables O-1 and O-2 below show a hypothetical combination of advanced biofuels that would meet the obligations of New York providers of gasoline and diesel fuel, respectively,

[2] Policymakers are weighing a number of factors to decide whether to include heating oil in the regional LCFS, such as GHG benefits, possible economic impacts on oil producers, distributors, and consumers; and other environmental impacts. Some policymakers are especially concerned about the potential for increasing air pollution from increased use of biomass for heating. There are also a number of design options for the possible inclusion of heating oils in the LCFS, including an option that would set a not-to-exceed baseline for the GHG intensity of heating fuels, where sellers of lower-GHG heating fuels would "opt-in" to the program voluntarily. It is also plausible that the structure of the initial LCFS will be limited to transportation fuels, with heating fuels possibly phased in later.

under a 10% regional LCFS reduction target, according to NESCAUM analysis.[3] Based on New York's gasoline fuel use in 2005, which equaled 5.8 billion gallons of gasoline fuel, a 10% LCFS could be met through approximately 600 million gallons of low-carbon cellulosic ethanol, and nearly 1.2 million electric vehicles. New York's diesel fuel target could be met through 270 million gallons of advanced low-carbon biodiesel and 30,000 Mscf (one thousand standard cubic feet) of natural gas.

Obviously, compliance with a regional LCFS under a reduction target of 10% by 2020 would require significant quantities of advanced renewable fuels, accompanied by commercial viability of many advanced technologies, including plug-in electric vehicles. This reflects the fact that a key objective of a LCFS is to encourage innovation in low-carbon fuels and related technologies.

[3] Note that this is only a hypothetical scenario for New York LCFS compliance based on NESCAUM calculations of fuel GHG-intensity, and does not incorporate any analysis of the economic competitiveness of these fuels versus other low carbon fuel options.

Table O-1. Potential Gasoline Compliance Pathway for New York with Regional LCFS, 2020.

Measure	CI Reduction	Key Assumptions
RFS2	3.1%	• Assumes NY receives proportional share of federally mandated biofuel volumes: – 470 Mgal cellulosic ethanol – 110 Mgal "advanced" ethanol – 71 Mgal "new" conventional ethanol
580,000 EVs 2020 Grid	3.3%	• Assumes 4.4% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.2% in 2011 to 12% in 2020 • Assumes Energy Economy Ratio (EER) = 3.0 • Assumes NE-8 2020 average generation mix, with RGGI + RPS o 18% Nuke, 41% Gas, 8% Coal, 4% Oil, 29% Renewables • Total energy demand = 4,700 GWh • Maximum power demand = 2.3GW (every vehicle charging at 4kW)
580,000 PHEVs 2020 Grid	0.9%	• Assumes 4.4% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.2% in 2011 to 12% in 2020 • Assumes Energy Economy Ratio (EER) = 3.0 • Assumes 2020 average generation mix, with RGGI + RPS o 18% Nuke, 41% Gas, 8% Coal, 4% Oil, 29% Renewables • Total energy demand = 1,100 GWh • Maximum power demand = 2.3GW (every vehicle charging at 4kW)
600 Mgal Ethanol, carbon intensity (CI) = 48	2.7%	• CI is 50% lower than for gasoline, equivalent to RFS2 "advanced" biofuel category • Could be from sugarcane, cellulosic, or other feedstocks, 300 million gallons estimated available regional biomass capacity • 110 million gallons already expected under RFS2 • 300 million gallons estimated available from regional biomass

Table O-2. Potential Diesel Compliance Pathway for New York with Regional LCFS, 2020.

Measure	CI Reduction	Key Assumptions
RFS2	1.6%	• Assumes Northeast receives proportional share of federally mandated biofuel volumes: o 80 Mgal of biodiesel with CI 50% lower than for diesel
160 Mgal Biodiesel, CI = 20 (10% of highway diesel)	4.5%	• Assumes 10% of highway diesel energy demand met with advanced biodiesel • CI is 80% lower than for ultra low sulfur diesel (ULSD) • CI is theoretically achievable through conversion of waste materials or other advanced processes • Estimated total net biodiesel production from regional waste feedstocks = 6.7 Mgal
110 Mgal Biodiesel, CI = 20 (10% of nonroad diesel)	3.0%	• Assumes 10% of nonroad diesel energy demand met with advanced biodiesel • CI is 80% lower than for ULSD • CI is theoretically achievable through conversion of waste materials or other advanced processes • Estimated total neat biodiesel production from regional waste feedstocks = 6.7 Mgal
20,000 Mscf Natural Gas (10% of highway diesel)	0.9%	• Assumes 10% of highway diesel energy demand met with natural gas • CI for compressed natural gas = 73.1 gCO_2e/MJ • Would require substantial fleet penetration of heavy-duty natural gas vehicles
10,000 Mscf Natural Gas (10% of nonroad diesel)	0.5%	• Assumes 10% of nonroad diesel energy demand met with natural gas • CI for compressed natural gas = 73.1 gCO_2e/MJ • Would require substantial fleet penetration of nonroad natural gas engines

Finally, it is important to note where concerns about the environmental sustainability and GHG impacts of biofuels may influence the types of feedstocks, fuels, and processes that are eligible under the LCFS. The concept of indirect land use change (iLUC) acknowledges that greater demand for biofuels may result in increased market pressure to convert lands that currently support other uses, such as agriculture for food crops or forests or growing feedstocks for fuels. Climate policymakers are concerned that, in some cases, existing farm and forest lands could be cleared to grow new feedstocks for biofuel production, which may in turn result in greater GHG emissions than are displaced by replacing fossil fuels with biofuels.

Although the concept of addressing iLUC within the framework of a LCFS and similar policies is quite controversial, environmental commissioners in both the northeastern states and California have publicly committed to doing so as a safeguard against undermining the GHG benefits of their respective low carbon fuel programs.[4] California is devoting considerable resources to quantitative models for estimating the potential magnitude of iLUC for specific feedstocks, fuel types, and processes, and analysts at the California Air Resources Board (CARB) have developed preliminary estimates of iLUC for some feedstocks in certain fuel pathways. While the Northeast is not conducting original modeling of iLUC on its own, the states are closely tracking the efforts of California, U.S. Environmental Protection Agency, the United Kingdom, and the European Union to develop credible estimates of the potential magnitude of iLUC for feedstocks, fuels, and processes that are likely to be used for compliance with the regional LCFS.

There are important implications of the inclusion of iLUC in the regional LCFS for the development of New York's biofuels industry. First, fuel providers using feedstocks from New York (and the Northeast) may have an advantage over producers using feedstocks sourced from geographic areas where substantial land conversion is taking place as a result of new demand for biofuels. To the extent that biomass resources can be produced in New York using sustainable harvesting practices, and without disrupting supply to existing markets for biomass and timber, this biomass would be at much lower risk of creating market impacts that result in iLUC and possible increases in GHG emissions.

2.2 OTHER LOW CARBON FUEL STANDARDS

2.2.1 California

In January 2008, Governor Arnold Schwarzenegger issued Executive Order S-01-07 requiring the establishment of a Low Carbon Fuel Standard (LCFS) to reduce the GHG intensity of transportation fuels in California. California's LCFS requires regulated entities to reduce the carbon intensity of California's transportation fuels by at least 10% in 2020. The scope of California's LCFS covers all gasoline and diesel fuel used by transportation sources, with the exception of fuels used in aviation and by ocean-going vessels. Many of the entities regulated under the federal renewable fuel standard (RFS) program will also be regulated under the California LCFS.

Staff from the California Air Resources Board (CARB) developed a proposal for the program, which was approved by CARB's Board in April 2009 (CARB 2009). California addressed outstanding issues raised by the CARB Board and finalized their LCFS regulation in December 2009.[5] As noted in the previous section, CARB has committed to inclusion of calculations of iLUC impacts within their LCFS, and are applying a global agricultural model to generate estimates of indirect land use emissions associated with

[4] In April 2009, the northeastern environmental Commissioners sent a letter to CARB's Board of Directors, which publicly stated their support of California's treatment of iLUC in their LCFS.
[5] California Natural Resources Agency. Final Statement of Reasons for Regulatory Action, December 2009. Available at: http://ceres.ca.gov/ceqa/docs/Final_Statement_of_Reasons.pdf. Note that some aspects of California's LCFS, such as sustainability requirements, are still under development although the core LCFS framework has been finalized.

specific fuel pathways.[6] CARB has committed to working with stakeholders on further refinements to its modeling assumptions and implementing revisions to lifecycle GHG estimates as the underlying science improves.[7] And, beginning in February 2010, CARB will assemble an expert working group to review existing tools for estimating iLUC and other indirect impacts. This expert workgroup will provide recommendations to the CARB Board on approaches to indirect impacts within the LCFS program by December 2010.

California's fuel market is significant enough, relative to the U.S. market as a whole, that between the requirements for GHG impacts of fuels, combined with the volumes of low carbon fuels required, the California LCFS could have a discernible impact on the market for New York's renewable fuels. In 2008, California's market for gasoline was nearly 15 billion gallons, which was 11% of the total U.S. market for gasoline (EIA, 2008). CARB estimates that the volumes of advanced, low carbon ethanol that could be needed to meet compliance with the California LCFS in 2020 range from 2.2 to 3.1 billion gallons. This volume of low carbon ethanol represents about 20% of the volume of advanced biofuels required under the federal RFS2 in 2020, or 10.5 billion gallons, as described later in this report.

2.2.2 Oregon and Washington

Oregon's legislature recently passed a Low Carbon Fuel Standard. Similar to California's LCFS, Oregon's LCFS requires a reduction in the lifecycle GHG intensity of transportation fuels by 10% below 2010 levels by the year 2020 (Oregon 2009). The Washington Department of Ecology is required by Executive Order to assess what LCFS provisions, including low carbon fuel standards currently under consideration in other states, would best help Washington State meet its greenhouse gas emissions reduction goals (Washington 2009). The Department of Ecology will submit recommendations to Washington's governor by July 2010 on whether to pursue adoption of a LCFS, what LCFS provisions would best fit, and how to implement a program if recommended. Both Oregon and Washington are following the development of the California and northeastern regional LCFS programs, and are likely to rely upon the basic frameworks of California and Northeast LCFS if they proceed with implementing their own programs.[8]

Neither Oregon's LCFS program nor a potential LCFS in Washington would themselves require quantities of advanced biofuels that would rival those required by California's LCFS. Therefore, the presence of low carbon fuel programs in these states alone would not be likely to strongly shift the magnitude of demand for New York's biomass feedstocks and/or renewable fuels. But, these state policies are important because

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[6] The Global Trade Analysis Project (GTAP) model, designed by Purdue University, is CARB's primary analytical tool for estimating iLUC emissions associated with different traditional and advanced biofuel products.
[7] CARB is also overseeing the work of an expert working group to further explore the indirect effects of fuels—including indirect land use change—and methods for characterizing and quantifying such effects. CARB's expert advisory group is beginning its review of indirect effects in February 2010.
[8] Personal correspondence with David Nordberg, Oregon Department of Environmental Quality (OR DEQ), September 16, 2009.

each additional state-based LCFS program adds credence to this policy approach for driving the development of advanced fuels as an alternative to an approach of volumetric fuel requirements, as embodied in the federal RFS. Moreover, if these states implement LCFS programs that are similar in their fuel GHG lifecycle requirements to California and the Northeast, it will further bolster a market preference for fuels with the lowest GHG lifecycle impacts.

2.3 MASSACHUSETTS BIOFUELS MANDATE

In 2008, the Massachusetts legislature passed the *Clean Energy Biofuels Act of 2008*, which establishes volumetric mandates for biofuel use in the Commonwealth (Massachusetts 2008). Specifically, this legislation mandates the use of 2% biodiesel in transportation fuels by 2011 and 5% by 2015.[9] The Massachuetts law also provides substantial tax incentives for the in-state production of cellulosic ethanol. An important policy goal of the Massachusetts legislation is that biofuels must contribute to reductions in the GHG emissions of fuels, as measured on a full lifecycle basis. To be eligible, advanced biofuels must provide a 50% reduction in GHG emissions over conventional transportation fuels on a full lifecycle basis.

In late 2009, the Massachusetts Division of Energy Resources issued policy guidance that has important implications for biodiesel producers in New York and elsewhere in the region. Given the relatively high level of scientific uncertainty on the lifecycle GHG emissions of advanced biofuels produced from virgin feedstocks such as soy-based biodiesel, Massachusetts has limited eligible biofuels to those derived from waste feedstocks, provided a preliminary analysis based on both California's and EPA's methodologies, which indicate that such waste feedstocks will yield the 50% GHG reduction required.[10] Biofuels that are produced from a mix of waste and non-waste feedstocks can seek to qualify that portion of the finished biofuel that is derived from waste feedstocks.

Massachusetts policymakers are closely tracking federal and California efforts to refine methodologies for evaluating biofuel GHG emissions on a lifecycle basis including iLUC, and plan to adopt new protocols as appropriate. So, over time the provisions limiting eligible feedstocks to only waste could change as both GHG methodologies and the fuels themselves improve. In the interim, however, New York and other producers of advanced fuels seeking to sell into the Massachusetts market will need to adhere to these requirements.

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[9]The original MA biofuels legislation mandated compliance with the biodiesel requirements by 2010, but a subsequent policy decision has waived the 2010 volume requirements. The Massachusetts Division of Energy Resources (MA DOER) will determine whether the volume requirement will be at 2% or 3% for 2011. "Early action credit" will be given for any qualified biofuels enrolled in 2010, before the program requirements take hold, and will be applied to the 2011 volume requirements.

[10]Massachusetts Division of Energy Resources, 2009. "MA Biofuels Mandate: Program Design Decisions and Implementation Plan," August 18, 2009. Available at: http://www.mass.gov/Eoeea/docs/doer/alternative_fuels/BiofuelsMandateStakeholdeAnnouncemen08180DOER.pdf

2.4 REGIONAL GREENHOUSE GAS INITIATIVE

The Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade program limiting carbon dioxide (CO_2) emissions from large power plants in 10 northeastern states.[11] RGGI, which went into effect in 2009, requires a 10% reduction in CO_2 emissions across the region by 2018, relative to 2009 levels. Power plant operators regulated under RGGI must reduce CO_2 emissions or purchase CO_2 allowances in order to meet the emissions cap (Regional Greenhouse Gas Initiative 2008).

Importantly, RGGI includes provisions that allow operators of coal-fired power plants to reduce CO_2 emissions through co-firing with sustainable biomass. Given that low-cost opportunities for direct emission reductions by power plants are very limited at present, these co-firing provisions could be a primary strategy for compliance with RGGI, particularly for those coal-fired plants that are located relatively close to biomass resources.

New York has 12 coal-fired power plants regulated under RGGI, and another five coal-fired RGGI plants are located within 50 miles of the New York border in the neighboring states of Connecticut, Massachusetts, and New Jersey. Many of these plants could be viable candidates for retrofits that would enable co-firing with biomass at low levels (e.g., 5%).[12] However, in 2009 a decline in the demand for electricity due to a severe economic recession, combined with a substantial decline in natural gas prices, has significantly reduced prices for RGGI allowances and accordingly, the costs of RGGI compliance. As a result, owners of coal-fired RGGI plants are not very likely to invest in biomass co-firing to meet near-term RGGI compliance targets. Because RGGI allowances are fully fungible across compliance periods, however, some of these plant owners may find it worthwhile to invest in biomass co-firing in order to generate low-cost allowances that could serve as a hedge against higher RGGI allowance prices in the future, or to create “early action credits” that may be tradable under a future federal GHG system.

The definition of eligible biomass as it pertains to sustainable harvesting is another factor that will affect the likelihood of New York’s 12 coal-fired RGGI plants to co-fire with woody biomass. Each participating state must make a determination of what constitutes eligible biomass for RGGI facilities in their state. Guidance on this matter in New York is under development by the New York State Department of Environmental Conservation (NYSDEC). RGGI facilities may deduct, as a compliance mechanism, the CO_2 emissions attributable to the burning of eligible biomass from their total CO_2 allowance obligation. The technical premise for this deduction is that biomass can be a low-carbon fuel compared to fossil fuels. This premise

[11] The ten states participating in RGGI include the six New England states (MA, CT, RI, NH, ME, and VT), New York, New Jersey, Delaware, and Maryland. RGGI regulates fossil fuel-fired power plants greater than 25MW in nameplate capacity, of which there are 41 in the 10-state region.

[12] It is unlikely that owners of RGGI coal-fired plants would invest in a full fuel conversion from coal to biomass. This is because a complete retrofit requires a significant upfront capital investment that, given current relative prices of coal, biomass, and CO_2 allowances, would not provide a sufficient return on investment. Moreover, it is generally more

only holds true over time, however, if adequate future growth and attendant carbon sequestration occurs to offset the CO_2 emissions from biomass combustion. To ensure RGGI facilities are achieving CO_2 reduction benefits, NYSDEC preliminary guidance includes requirements that could substantially limit the quantity of woody biomass used as a CO_2 compliance mechanism for co-firing in New York's RGGI facilities.

2.5 ONTARIO GHG COMMITMENTS

In 2008, the Ontario Ministry of the Environment issued *Go Green: Ontario's Action Plan on Climate Change* (OME, 2007). This action plan included a public commitment by Ontario to reduce GHG emissions to 6% below 1990 levels by 2014, and 15% below 1990 by 2020. In addition, Ontario is now participating in the *Western Climate Initiative (*WCI), an initiative on the part of seven western U.S. states and four Canadian provinces to develop a regional GHG cap-and-trade program aimed at reducing GHG emissions by 15% by 2020, relative to a 2005 baseline.[13]

A principal strategy for Ontario to achieve its 2014 GHG emissions target is to phase out coal-fired power plants and replace coal-fired generating capacity with a combination of new natural gas plants and renewable energy sources. Ontario Power Generation (OPG), one of Ontario's largest utilities, has announced plans to shut down 2,000MW of coal-fired capacity in 2010, and to fully convert its Atikokan Generating Plant to biomass by 2012 (OPG 2008).

Of Ontario's three coal-fired power plants, only two are located within 50 miles of New York's border. Because 50 miles is generally considered to be a reasonable limit for economical transport of virgin biomass resources, these plants are the most likely candidates for biomass co-firing using virgin feedstocks sourced from New York.[14] One of these plants is OPG's Lambton plant near Sarnia, Ontario, which is a 1,920MW coal-fired plant. However, OPG has slated this plant for shut-down by October 2010, so it is not a likely candidate for biomass co-firing (OPG 2008). The other Ontario plant at Nanticoke (see Figure O-2) is a large 3,964MW facility that, if retrofitted for co-firing, would demand substantial quantities of biomass for co-firing. Full biomass conversion is generally not a viable option for so large a plant, as it would require both substantial quantities of biomass and a costly, capital-intensive retrofit. However, due to its considerable size, even at low levels of co-firing with biomass (such as 2.5 or 5%), the Nanticoke plant would still demand substantial biomass resources.

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feasible to secure a long-term contract for biomass supply at low levels of co-firing than for the quantities of biomass required to support a full plant conversion.

[13] Western states participating in the WCI include Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington; Canadian provinces participating in the WCI include British Columbia, Manitoba, Ontario, and Quebec.

[14] In their National Energy Modeling System (NEMS) model, the Energy Information Administration assumes a 50-mile distance as being the maximum economic distance for forest residues, agricultural residues, and energy crops (EIA 2006). Urban wood waste and mill residues are often economic at even greater travel distances, i.e., up to 100 miles. If 100 miles is an economic distance for biomass transport, then additional plants in New Hampshire and Pennsylvania would also be likely candidates to purchase New York's biomass.

2.6 FEDERAL RENEWABLE FUEL STANDARD

The federal Renewable Fuel Standard (RFS2), first adopted in the *Energy Policy Act of 2005* (EPAct) and subsequently amended in the *Energy Independence and Security Act of 2007* (EISA), intends to address energy security and environmental concerns by mandating a steady increase in the volume of imported and domestic renewable fuel for the U.S. transportation fuel supply over the next decade and a half. The EPAct mandate was significantly expanded under EISA, which requires 36 billion gallons of renewable fuels by 2022.

In February 2010, EPA issued a final rule for the RFS2. As part of that rule, the EPA established four general categories of renewable fuel types complying with the lifecycle GHG reduction thresholds:

- Cellulosic biofuel (must be derived from "renewable biomass") [15]
- Biomass-based diesel (soy, waste grease, oils, fats, algae)
- Advanced biofuels (ethanol from sugarcane)
- Other renewable fuels (corn starch biobutanol and new natural gas-fired facilities producing corn starch ethanol)

Table O-3 below summarizes all volumes required annually under the revised and final RFS. Another major change from the RFS to RFS2 includes a reduction in the volume of cellulosic ethanol required for each year. This change resulted from industry and other experts' outlook about the likely development and timing of commercially viable cellulosic ethanol production. In addition, the volumes of biomass-based diesel fuel required will be determined by EPA on an annual basis after 2012, presumably based on the industry's production outlook, including the potential for renewal of federal tax credits for biodiesel production.

[15] 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.

Table O-3. Fuel Volume Requirements of the EISA (billion gallons).

Year	Cellulosic biofuel requirement	Biomass-based diesel requirement	Total advanced biofuel requirement	Total renewable fuel requirement
2008	n/a	n/a	n/a	**9.0**
2009	n/a	0.5	0.6	**11.1**
2010	0.1	0.65	0.95	**12.95**
2011	0.25	0.80	1.35	**13.95**
2012	0.5	1.0	2.0	**15.2**
2013	1.0	a	2.75	**16.55**
2014	1.75	a	3.75	**18.15**
2015	3.0	a	5.5	**20.5**
2016	4.25	a	7.25	**22.25**
2017	5.5	a	9.0	**24.0**
2018	7.0	a	11.0	**26.0**
2019	8.5	a	13.0	**28.0**
2020	10.5	a	15.0	**30.0**
2021	13.5	a	18.0	**33.0**
2022	16.0	a	21.0	**36.0**
2023+	b	b	b	**b**

a To be determined by EPA through a future rulemaking, but no less than 1.0 billion gallons.
b To be determined by EPA through a future rulemaking
Source(s): EISA 2007; Renewable Fuels Association analysis 2008; EPA RFS2 2010.

Table O-4 specifies the greenhouse gas lifecycle thresholds that apply to each of the major categories of biofuels required under RFS2, relative to a 2005 baseline. These thresholds apply to all phases of fuel production, including emissions from land use, fuel production, transport, and use. One key change from the proposed RFS is that, under the final RFS2, corn starch-based ethanol no longer requires a 50% reduction in lifecycle GHG emissions, but rather must adhere to a 20% reduction.

Table O-4. Lifecycle GHG Thresholds Specified in EISA.

Renewable fuel*	**20%**
Advanced biofuel	**50%**
Biomass-based diesel	**50%**
Cellulosic biofuel	**60%**

**The 20% criterion generally applies to renewable fuel from new facilities that commenced construction after December 19, 2007.*

Source: EPA RFS2 2010.

There are some important differences in how the RFS2 views the GHG impacts of fuel to determine eligibility in comparison to other policy approaches like the LCFS. The RFS2 establishes a single threshold requirement for GHG reductions over conventional fuels, so any fuels that fall short of the threshold, even by a small degree, cannot count towards RFS2 compliance. In contrast, the LCFS allows any fuel with a lower GHG-intensity score than gasoline (or diesel) to count towards the compliance target, but it effectively gives preference, or greater weight, to fuels with the lowest GHG-intensity. This difference could be important for New York's producers of renewable fuels because the LCFS may provide a market for those fuels that perform better than gasoline (or diesel) in terms of GHG emissions, but do not meet the threshold levels of GHG improvement required by the RFS2.

3 ANALYSIS OF POTENTIAL COMPETING USES FOR NEW YORK WOODY BIOMASS

This section of the report provides a characterization of other markets for New York's woody biomass resources that may present significant competition to the state's emerging industry in advanced liquid biofuels. Results from an on-line survey (see Appendix M-C) conducted in July 2009 by NESCAUM, the Pace Energy and Climate Center, and Farm Credit of Western New York found that ethanol industry members predict that liquid biofuel producers in the region will compete aggressively with other industries for New York's biomass resources (NESCAUM et al. 2009). In contrast, these same survey results indicated that many biomass market experts outside the ethanol industry predict that competition for New York's biomass from heating fuel producers (i.e., pellets, firewood), biomass electricity producers, and traditional wood product industries will be formidable, particularly over the next 5 to 10 years as advanced biofuel technologies have yet to attain commercial viability.

It should be noted that this analysis is not based on formal economic modeling/forecasting of existing biomass market trends into the future. Rather, it provides an empirical review or "snapshot" of current competing markets for New York's biomass resources and qualitative insights about key factors that are likely to influence future markets for biomass. The focus of this analysis is primarily on woody biomass because these resources are a key input to both existing industries and a number of advanced biofuel technologies under development (e.g., cellulosic ethanol). The next sections of this report provide a snapshot of competing uses for biomass resources from existing industries (wood products, electricity generation) and emerging applications (thermal fuels, biomass co-firing for GHG mitigation).

Figure O-2. Potential Competing Demands for New York's Woody Biomass from Current and Emerging Users.

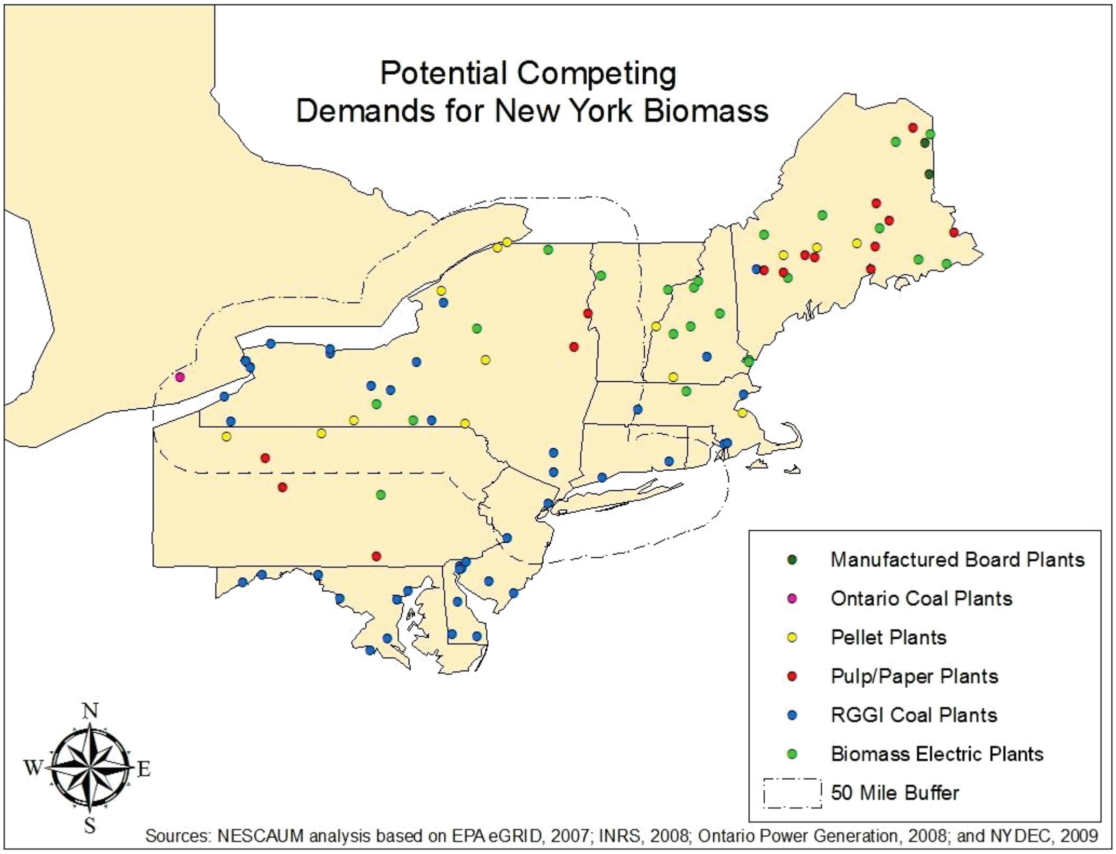

Figure O-2 displays existing facilities in and near New York that are either current users of New York's woody biomass resources or are emerging candidates for using New York biomass in the future. Current users of woody biomass include biomass electricity plants, pulp/paper plants, existing pellet plants, sawmills and manufactured board plants, and firewood producers. Emerging markets for using greater quantities of New York's biomass resource in the future include new wood pellet facilities, coal-fired power plants regulated under RGGI, and Ontario's GHG plans.

The dashed line indicates an approximate 50-mile buffer from the New York border, which is assumed to be a reasonable limit for economic transport of New York wood and biomass products to facilities in neighboring states given current fuel and product prices.[16] If the distance for economic transport of New York biomass were to extend to 100 miles, for example, this would bring in many additional candidates, including additional biomass plants in Vermont, New Hampshire, Pennsylvania, and Ontario; additional pulp/paper and wood pellet facilities in Pennsylvania and New Hampshire; and a few additional coal-fired power plants in Massachusetts and possibly New Jersey as well.

A key consideration in evaluating the potential competition between current and emerging users of New York's woody biomass is that some biomass resources are less appropriate for certain production processes and end-uses than others. For example, many traditional wood product manufacturers and advanced biofuel producers are able to use only higher-quality sawtimber and wood chips in their production processes, whereas electricity generators, some pulp/paper manufacturers, and pellet producers are more flexible with respect to feedstock type and quality and thus are able to use lower quality biomass resources. While users that require high-quality feedstocks for their production processes are not likely to compete for low-quality feedstocks, producers that currently rely solely upon residues and low-grade biomass could begin to compete for higher grade biomass if prices for their end-products were to increase substantially. Overall, supplies of biomass may increase in response to market prices. More information on biomass supply trends is provided in Appendix E.

3.1 CURRENT MARKETS

Existing users of New York's woody biomass resources include traditional wood product manufacturers such as sawmills, pulp/paper and wood chip producers, and firewood producers, as well as biomass electricity plants.

3.1.1 Traditional Wood Products and Exports

Use of wood by New York's large and small sawmills, wood chip producers, and pulp/paper producers, and for net wood exports is significant, totaling 2.3 million dry tons in 2007. Despite the fact that the Northeast's sawmill and pulp/paper industries have experienced a substantial decline from their highest levels of production in recent years,[17] these industries still make up the largest demand for woody biomass feedstocks in New York. In addition to the wood that industrial wood product facilities use as feedstocks for their products, many pulp mills and board facilities also have large multi-fuel boilers that can be significant consumers of biomass fuel.

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[16] While this assumption is an oversimplification of the fact that actual export of biomass to neighboring states and countries will depend on a variety of factors in addition to geographic proximity, such as vendor reputation, product price, availability, and quality, among others, it is nonetheless helpful to note what facilities are likely candidates for importing New York biomass strictly due to their location.

[17] In 1999, New York produced 900 million board feet (mbf) of lumber; by 2003, lumber production had declined to 650 mbf (NYSDEC 2007).

The market for firewood is also a significant source of demand for New York woody biomass resources, although the informal nature of this market makes accurate estimates of firewood production rather challenging. NYSDEC estimates that the firewood market is more than 60% of the market for industrial uses, or equal to approximately 1.6 million dry tons in 2007.[18]

In summary, New York's wood consumption by industrial users and for firewood totaled nearly 4 million dry tons in 2007. Additional discussion of competing uses is provided in Appendix P.

3.1.2 Electricity Generation

As shown in Table O-5 below, there are two biomass electricity plants in New York and another plant in close proximity to the New York border in Burlington, Vermont. The two New York plants total nearly 40 MW in capacity, and require about 0.5 million green tons of biomass annually. The McNeil plant in Burlington has a capacity of 50 MW, which is relatively large for a biomass electricity plant, and requires nearly 0.7 million green tons of biomass each year. A new, 9.6MW biomass CHP system is expected to be operational at a businesss park in Rome, NY in early 2010. Together, biomass demand from these plants totals approximately 1.3 million green tons (equivalent to approximately 0.8 million dry tons).

Table O-5. Biomass Electricity Plants In and Near New York State.

Location	Plant	Capacity (MW)	Woody Biomass Demand (green tons)
Chateaugay, NY	Boralex	20	268,000
Lyonsdale, NY	Catalyst Renewables	19	254,600
Burlington, VT	McNeil/Burlington Electric	50	670,000
Rome, NY*	Griffiss Business Park CHP	9.6	140,000
Totals		**98.6**	**1,332,600 green tons (0.8 million dry tons)**

Sources: Integrated Natural Resource Solutions (INRS) 2008; Biomass Magazine 2010.
*This plant is scheduled to come on-line in early 2010.

It can be challenging for biomass plant developers to secure the long-term contracts for biomass supply that are usually necessary to obtain capital financing for plant construction. In addition, when compared to coal on a cost per unit of energy basis, biomass fuel is currently more expensive, although incentives provided by state renewable energy programs in some cases counterbalance the cost disadvantages of biomass. In addition to the plants shown in Table O-5, a few additional biomass electricity plants are currently under development in the region. For example, a 37MW biomass power facility is being developed by Catalyst Renewables in Geddes, New York, at the site of a former natural gas plant.

[18] The Energy Information Agency also provides estimates of wood use for energy in the residential sector.

Other biomass electricity plants under development include the 50MW Russell biomass plant proposed for Greenfield, MA, and another 47MW biomass plant has been proposed for Berkshire County in western Massachusetts. Both of these plants could become customers for New York biomass, but some industry experts believe that only one of these two plants is likely to receive financing adequate for actual development, due in part to public concerns about the potential environmental and public health impacts of supplying adequate biomass to both plants. In response to these concerns, the Massachusetts Department of Energy Resources issued guidance in December 2009 that suspends review of new biomass electricity plants for eligibility under the Massachusetts Renewable Portfolio Standard (RPS) until the completion of a study on the sustainability of woody biomass in the state.[19]

Although large-scale biomass electricity plants in the region face some challenges, a growing opportunity for biomass generation is combined heat and power (CHP), which is an efficient use of biomass for heat and electricity and generally occurs at a smaller scale as well. An example of this is a 9.6MW biomass CHP system, noted earlier in this discussion, scheduled to come on-line in 2010 at a business park in Rome, NY. Additional discussion of competing uses is provided in Appendix P.

3.2 EMERGING MARKETS

Co-firing with biomass is currently the only low-cost opportunity for direct GHG reductions by RGGI coal plants.[20] For many of these plants, the capital costs to retrofit for co-firing are only a fraction of that required to fully convert a plant over to biomass-based generation. Table O-6 below shows the biomass needs associated with all New York RGGI coal plants and those in surrounding states and Ontario within 50 miles of New York, at levels of co-firing of 2.5%, 5%, and 10%.[21] Two of these plants, AES Greenidge and Niagara Generating Facility, are in fact already co-firing with biomass.[22] Demand for biomass to support co-firing at all of these plants even at a 2.5% level would be formidable, equaling 4.3 million green tons (or 2.6 million dry tons), roughly equal to the volumes used by the entire New York wood products industry. Co-firing at a level of 10% is much less likely due to engineering constraints, but would require even higher levels of biomass, nearly 17 million green tons (or 10 million dry tons) if all RGGI plants listed were to shift to co-firing.

[19]On December 3, 2009, the Massachusetts Department of Energy Resources suspended consideration of biomass energy applications under the MA Renewable Portfolio Standard until the Department completes a commissioned study on biomass sustainability and carbon accounting, and revises its regulations to appropriately address the sustainability of biomass energy. More detail on this suspension can be found at:
http://www.mass.gov/Eoeea/docs/doer/renewables/biomass/biomass-suspend-clarify-2009dec22.pdf

[20]Compliance with the RGGI program can also be achieved through the use of credits from GHG offset projects.

[21]Biomass demand levels in Table O-6 assume 13,400 green tons of biomass per MW, and a 95% plant capacity.

[22] The Niagara plant also co-fires with tires in addition to woody biomass.

Table O-6. Northeast RGGI and Ontario Coal Plants.

State	RGGI Coal Plants	Capacity (MW)	Biomass Demand 2.5% co-fire (green tons)*	Biomass Demand 5.0% co-fire (green tons)	Biomass Demand 10% co-fire (green tons)
Connecticut	AES Thames	214	71,657	143,313	286,626
	Bridgeport Station	582	194,836	389,672	779,344
Massachusetts	Brayton Point	1,611	539,652	1,079,303	2,158,606
	Mount Tom	136	45,560	91,120	182,240
	Somerset Station	199	66,665	133,330	266,660
New Jersey	PSEG Hudson Generating Station	1,114	373,324	746,648	1,493,296
	PSEG Mercer Generating Station	768	257,280	514,560	1,029,120
New York**	AES Cayuga	323	108,038	216,075	432,150
	AES Greenidge	163	54,605	109,210	218,420
	AES Somerset LLC	655	219,459	438,917	877,834
	AES Westover	119	39,798	79,596	159,192
	Black River Generation	56	18,593	37,185	74,370
	C R Huntley Generating Station	816	273,360	546,720	1,093,440
	Danskammer Generating Station	537	180,029	360,058	720,116
	Dunkirk Generating Station	627	210,112	420,224	840,448
	Kodak Park Site	201	67,168	134,335	268,670
	Niagara Generating Facility	56	18,760	37,520	75,040
	S A Carlson	101	33,835	67,670	135,340
	Trigen Syracuse Energy	101	33,869	67,737	135,474
Ontario	Nanticoke Generating Station	3,640	1,219,400	2,438,800	4,877,600
TOTALS		**12,018**	**4,025,996**	**8,051,993**	**16,103,986**
	Dry tons		**2,415,598**	**4,831,196**	**9,662,392**

Sources: EPA EGrid database, Regional Greenhouse Gas Initiative, and NESCAUM analysis, 2009.
Note: Dry tons are calculated as 60% of green tons.

As explained earlier in this report, current fuel prices and GHG policy drivers alone are probably not yet compelling enough for many of these plants to invest in co-firing, but as it is one of the few GHG reduction opportunities for coal-fired plants, some plant owners are likely to invest in co-firing capabilities as a hedge against more stringent GHG requirements in the future. Thus, demand for biomass co-firing as a GHG mitigation strategy for coal-fired power plants could be a significant source of growth in demand for New York's woody biomass in coming years. As mentioned above, however, NYSDEC's preliminary guidance suggests the definition of sustainable biomass could be quite limited depending on the provisions of the NYSDEC program policy currently under development. Such requirements could substantially limit the quantity of woody biomass that could be used for co-firing in New York's 12 RGGI plants.

3.2.1 Heating fuels

In addition to biomass electricity, another probable growth area for New York biomass demand is as a feedstock for producing heating fuels. As mentioned earlier, New York's production of firewood, a traditional wood heating fuel, is estimated to be more than 60% of industrial needs and a relatively steady and significant use of wood. Wood pellets, which have been used extensively in Europe for many years, are a relatively new type of heating fuel in the U.S. and are gaining in popularity as an alternative to oil heating in the Northeast. Demand for wood as a heating fuel, either as firewood or in pellet form, historically has been highly sensitive to the price of heating oil in the Northeast. Because the region's heavy dependence on oil as a heating fuel exposes consumers to the volatility of prices for a commodity whose value is controlled by global markets, wood is increasingly seen as an option that can increase the Northeast's energy security.

Another reason that pellet fuels are a likely growth area for New York's biomass sector is that new pellet plants are relatively simple manufacturing operations that do not require a large capital investment to establish. In addition, in this region pellet plants are generally built at a scale (e.g., 100,000 green tons per year or less) that does not require a supply of biomass at the levels required by even small biomass electricity plants. So, wood pellet plants are, generally, relatively easy to supply and finance and as yet have not been prone to substantial community opposition.

Table O-7 below shows existing pellet facilities in New York and nearby in Pennsylvania. In total, these 10 facilities require less than 0.6 million green tons of biomass per year.[23] In 2009, New England Wood Pellet announced the addition of another pellet facility in Delaware County, New York, which will be a 100,000-ton/year facility. In addition, a very large pellet plant (i.e., more than 1M green tons/year) has been proposed for Cornwall, Ontario. If this plant is eventually built, it could seek as much as one-third of its biomass requirements from New York (NYSDEC 2009). More information on competing uses is found in Appendix P.

[23] A few of the pellet facilities in Pennsylvania are currently using sawmill residues as feedstocks, but could shift to virgin biomass if mill residues become more scarce.

Table O-7. Woody Biomass Demand from Wood Pellet Facilities In and Near New York State.

State	Location	Company	Biomass Consumption (green tons)
New York	Lafargeville	Associated Harvest Co.	10,000
	Arcade	Dry Creek Products	50,000
	Schuyler	Schuyler Wood Pellet	100,000
	Massena	Curran Renewable Energy LLC	10,000
	Addison	InstantHeat Wood Pellets, Inc.	50,000
	Stamford	Hearthside Wood Pellets	10,000
	Deposit*	New England Wood Pellet	100,000
		NY Total	**330,000**
Pennsylvania	Nazareth	Treecycle	145,000
	Marion	AJ Stoves & Pellets	n/a
	Ulysses	PA Pellets, LLC	80,000
	Troy	Barefoot Pellet	70,000
	Youngsville	Allegheny Pellet Corp.	60,000
		PA Total	**355,000**
		PA and NY Totals (green tons)	**685,000**
		PA and NY Totals (dry tons)	**411,000**

Source: Sloane Crawford, NYSDEC -- personal communication; various pellet manufacturers, 2009; INRS 2008.
Note: Dry tons are calculated as 60% of green tons.
* Anticipated opening last quarter 2010

4 FUTURE RESEARCH NEEDS

The following additional research could help to further refine estimates of both current and emerging market demands for New York's biomass resources.

Landowner preferences: Because the distribution of land ownership in New York (and throughout the Northeast) is dominated by many landowners with relatively small parcels of land (i.e., under 100 acres), many of whom do not own the land with the intent of becoming biomass producers, it is difficult to anticipate how and whether these owners might respond to greater demand and higher prices for resources. Additional research on landowner preferences under high biomass demand scenarios could help to refine our understanding of biomass availability relative to competing uses.

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