REGIONAL ANALYSIS OF RENEWABLE TRANSPORTATION FUELS – PRODUCTION AND CONSUMPTION

by

Xiaoshuai Liu

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Approved by:

____
Dr. Jy S. Wu

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Dr. Craig Allan

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Dr. Hui-Kuan Tseng

____
Dr. James Bowen

____
Dr. Sandra Clinton

ABSTRACT

XIAOSHUAI LIU. Regional analysis of renewable transportation fuels – production and consumption. (Under the direction of DR.JY S. WU)

The transportation sector contributes more than a quarter of total U.S. greenhouse gas emissions. Replacing fossil fuels with renewable fuels can be a key solution to mitigate GHG emissions from the transportation sector. Particularly, we have focused on land-based production of renewable fuels from landfills and brownfield in the southeastern region of the United States. These so call marginal lands require no direct land-use change to avoid environmental impact and, furthermore, have rendered opportunities for carbon trading and low-carbon intensity business. The resources potential and production capacity were derived using federal and state energy databases with the aid of GIS techniques.

To maximize fuels production and land-use efficiency, a scheme of co-location renewable transportation fuels for production on landfills was conducted as a case study. Results of economic modeling analysis indicate that solar panel installed on landfill sites could generate a positive return within the project duration, but the biofuel production within the landfill facility is relatively uncertain, requiring proper sizing of the onsite processing facility, economic scale of production and available tax credits. From the consumers' perspective, a life-cycle cost analysis has been conducted to determine the economic and environmental implications of different transportation choices by consumers. Without tax credits, only the hybrid electric vehicles have lifetime total costs equivalent to a conventional vehicles differing by about 1 to 7%. With tax credits, electric and hybrid electric vehicles could be affordable and attain similar lifetime total costs as compared to conventional vehicles. The dissertation research has provided policy-makers and consumers a pathway of prioritizing investment on sustainable transportation systems with a balance of environmental benefits and economic feasibility.

DEDICATION

To my parents for their love, support and encouragement.

ACKNOWLEDGMENTS

First of all, I would like to express my gratitude to my advisor, Dr. Jy Wu. It has been a long journey to finish my dissertation. I am grateful for his patience and encouragement during many stages of my study. It would not be possible without his academic and financial support. He has changed my thinking pattern towards engineering research.

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And last but not least, I want to thank Dr. Johnny Graham for his long time guidance and support for my study. I was blessed to work for him. He is an exceptional role model for me.

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CHAPTER 1: INTRODUCTION

1.1. Background

Fossil fuels have been used in vast quantities to power the economy and sustain human activities ever since the beginning of industrial revolution in the 18th century. Acid rain was attributed to the burning fossil fuels in earlier days (Likens and Bormann, 1974), followed by other consequences such as climate change and public health. Emissions of anthropogenic greenhouse gas (GHG) represent the greatest challenge to human race (IPCC 2007, Shalizi and Lecocq, 2010). The international communities are calling for global reduction of GHG emissions to avert dangerous consequences of climate change. In addition, fossil fuel reserves are not unlimited and renewable (Withagen, 1994). The depletion of oil, coal and natural gas are estimated in the order of 35, 107 and 37 years, respectively (Shafiee and Topal, 2009).

Environmental awareness, climate change and energy security are three major drivers urging our society to develop renewable energy portfolios, with a hope to ultimately replace fossil fuels (Williams, et al. 1990; Turner, 1999; Panwar et al., 2011; Sims, 2004). New development in renewable energy projects will not only improve the local economy but also increase community participation in energy initiatives (Cosmi et al., 2003, Khan et al., 2007). Renewable energy in the United States can be obtained from solar, wind, biomass, hydropower and geothermal sources. Renewable energy only makes up a small portion of the US energy market, accounted for 11.2% of the 2013 energy consumption (Esterly and Gelman, 2014). Renewable energy consumptions by other sectors were 5% by transportation, 11% by industries, 9% by residential and commercial uses, 11% by electric utilities, and 13% by electric power (EIA, 2014).

1.2. Need of Research

The transportation sector consumed about 20% of the world energy (EIA, 2011). In the United States, this sector is responsible for 27.7% of the national annual energy consumption (David et al., 2014) and emits 1,827 million metric tons of CO_2 equivalent or 28% of the US GHG emissions (EIA, 2014). Any serious GHG mitigation strategies must include the impact from the transportation sector. Measures to mitigate GHG emissions from transportation include energy efficiency improvements, low-carbon alternative fuels, increasing operating efficiency of the transportation systems, and reducing mileage traveled. This dissertation research examines measures of providing renewable energy as green alternative fuels by evaluating the regional potential of renewable energy resources that can be derived from marginal lands and strategies leading consumers to switch to alternative fuel vehicles. Specifically, the research seeks to understand the supply and demand of the renewable transportation fuels market in the southeastern United States. Research questions are formulated as follows.

1. What are the resources potentials and economics associated with producing renewable fuels from landfill sites, brownfields and marginal agriculture lands in the southeastern United States?

2. To what extent that energy use efficiency, economic competitiveness and environmental concerns can impact the consumer choice of vehicle mixes at the consumer scale?

1.3. Justification

Supply and demand of renewable transportation fuels is mainly driven by government policy rather than market demands (Taheripour and Tyner, 2008; Tyner, 2015). The market for renewable transportation fuels is still in its early stage. There is a need to evaluate market perspectives for the production and consumption of renewable transportation fuels.

Despite the transportation sector consumes more than a quarter of total energy produced and accounts for more than a quarter of total U.S. greenhouse gas emissions (EPA, 2014), the sector uses the lowest percentage (5%) of renewable energy among all other sectors (EIA, 2014). Considering biofuels, natural gas and electricity as the major alternative fuels, the consumption of these fuels were 5% biofuels, 4% natural gas, and less than 1% electric energy in 2014. The majority of which was still in the form of petroleum (89%) (EIA, 2015). In order to reduce GHG emission and lessen the dependency of fossil fuels, the transportation sector must improve its energy use efficiency and adopt a higher percentage of renewable transportation fuels in the mix.

Among many constrains to produce renewable energy, land availability is often overlooked. Renewable energy production is mostly land-based and land resources are limited and diminishing in time (Bot et al., 2000). It takes more land areas per energy unit than conventional energy production (Fthenakis and Kim, 2009). It also generates indirect land-use change emissions, when its production competes with the agriculture sector for limited land resource (Harvey and Pilgrim, 2011). In order to achieve the full environmental benefit of renewable energy, non-arable lands, such as landfill sites, brownfields and marginal agriculture lands, are potential land resources for the production of renewable energy.

The cost of renewable energy restricts its adaptation by both energy producers and consumers. Even though the solar and wind electricity costs have been falling in the last few years, it is still not competitive to conventional electricity sources (Lazard et al, 2014). Similarly, biofuels have had a historically higher price than gasoline (Bourbon 2015). A better understanding of the economics of renewable energy produced from marginal lands at the regional level will help guide renewable fuels investment and policy prioritization for governments and investors.

1.4. Scope of the Study

The research focuses on the U.S. southeast region that includes 9 states: Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, South Carolina, North Carolina, and Tennessee. Marginal land is generally defined as lands that are unsuitable for food production, low quality and economically marginal (Shortall, 2013). Typical marginal lands include abandoned cropland, barren land, road and transmission Right-of-Way, brownfield, abandoned mine sites and superfund sites. Numerous studies have estimated the acreage of marginal land worldwide using different land selection criteria (Larson, 1988; Mibrandt and Overend, 2009; Zhuang et al, 2011; Cai et al, 2011; Lewis and Kelly, 2014), Their studies often lead to inconsistent estimates of marginal land availability.

Three types of marginal lands including landfills, brownfields and marginal agriculture lands will be studied. Renewable energy sources to be assessed will include biomass, solar, wind, and landfill gas (LFG). Of the two types of solar power technology, only include the solar photovoltaic (PV) installations is considered. As for the wind energy, only offshore wind turbine is investigated.

Several fuel types can be used to power transportation systems including gasoline, diesel, natural gas, propane, ethanol, electricity and hydrogen. In this study, only ethanol and electricity are investigated. Solar, wind power, and LFG are converted into electricity. Biomass is converted to ethanol rather than being used to generate electricity. Biomass is referred to as cellulosic feedstocks which include agriculture residue, forest residue, and energy crops. Two specific energy crops cultivars are selected to represent the energy crops: *Miscanthus* × *giganteus* and Switchgrass (*Panicum virgatum L.*). These are referred to as Miscanthus and switchgrass, respectively. In summary, four transportation fuel options are examined in this research: (1) cellulosic ethanol, (2) solar photovoltaic electricity, (3) onshore wind electricity, and (4) landfill gas generated electricity.

Light duty vehicles are defined as vehicles with maximum weight of 8,500 lbs. Vehicle types are conventional gasoline vehicle, ethanol flex vehicle, hybrid vehicle, plug-in hybrid vehicle, and electric vehicle.

1.5. The Structure of the Dissertation

The structure of this dissertation is divided into two main parts, production and consumption. A map of structure of the dissertation is shown in figure 1-1. Chapter 1 explains the research background, the objectives of research, and the scope of research, and. The research question 1 was answered by Study 1 and Study 2, which include chapter 2 to 4. Chapter 2 examines the production of renewable energy on landfills and brownfields, and assesses the regional renewable fuel transportation demand. Chapter 3 presents a case study of integrated transportation fuel production and an economic analysis for integrated transportation fuel production on landfills. Chapter 4 provides an economic analysis of biofuel production on marginal agriculture lands. The research question 2 was answered by Chapter 5, which compares the competitiveness of different vehicle competitiveness for consumers from economic and environmental perspectives. The last chapter concludes with a summary of research findings and strategy and policy recommendations.

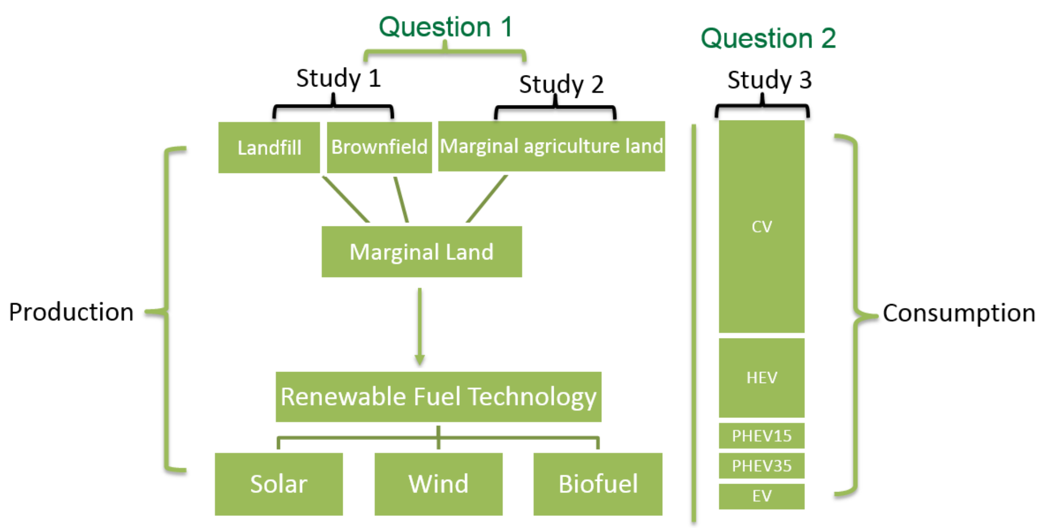

FIGURE 1-1: Structure of the Dissertation

CHAPTER 2: THE LANDFILLS AND BROWFIELDS BASED RENEWABLE FUELS PRODUCTION AND REGIONAL DEMAND

2.1. Background and Literature Review

Land is the essential resource to produce renewable energy. The development of renewable energy often requires more land areas than conventional energy facilities (Fthenakis and Kim, 2009). As the society continues to increase renewable energy production, land-use change is becoming a more contentious issue. The US production of renewable energy has increased to 60% in the past decade (EIA, 2015). About 1.16% of global land area having renewable energy potential is required to meet the worldwide energy needs (Jacobson and Delucchi, 2014). The study did not specify the land characteristics for energy production.

Although it may vary according to regional and technological conditions, the production of renewable energy would require a substantial more land resources than conventional energy. As for the development of the biofuel industry, biofuel feedstocks are competing with agricultural products from limited farm land resource. Land areas required to produce biomass-based energy is 25 time of that for conventional energy (Fthenakis and Kim, 2009). The direct land-use by a utility scale photovoltaic (PV) plants is significantly more than that for a coal power plants. It was estimated, in the southwestern U.S. that PV plant requires 45 square kilometers of land per terawatt hour (TWh), while coal power plants only occupies 4 square kilometers of land per TWh

(Gagnon et al., 2002). But when the indirect land impact is taken into consideration, the utility scale PV plant is comparable to coal power plants (Fthenakis and Kim, 2009). The land area required for wind farms varies with the turbine's configuration. The direct land utilization for wind turbines is insignificant, in the range of 1% to 10% of wind farm areas (McGowan and Connors, 2000). But the indirect land impact of the wind turbines, due to turbine blade and layout, could be 2-3 times that of similar solar PV power plant capacity (Gagnon et al., 2002). The unused area, which typically is utilized for grazing and agriculture, provides an opportunity to co-installation of another types of renewable energy facility, such as biomass and solar power.

The types of land used for renewable energy production is a key factor to determine its environmental sustainability, in addition to GHG emission. Using habitable or arable land to produce renewable energy would have the potential for causing negative impacts on the environment and social welfare. A cropland-based dedicated energy crop is not a sustainable energy source to meet the requirement of EISA 2007 mandate. Emissions due to indirect land-use change when growing dedicated energy crops on croplands will increase lifecycle GHG emissions by 50% more than gasoline production (Searchinger et al, 2008). Corn-based biofuel production can contribute to the increase in commodity food prices (Muller, et al., 2011).

The development of renewable energy will exert pressure on our limited and desirable land resources. This has led the search for alternative land options, which has few or no competing uses. Marginal lands are given a lot of attention as potential sites for renewable energy development. Marginal lands are considered as alternatives to locate renewable energy facility and have less environmental impact. Marginal lands are generally defined as one of the followings: land unsuitable for food production, low quality land or economically marginal land (Shortall, 2013). Numerous studies have estimated the acreages of marginal land worldwide subject to different selection criteria (Larson, 1988; Mibrandt and Overend, 2009; Zhuang et al, 2011; Cai et al, 2011; Lewis and Kelly, 2014), leading to inconsistent estimates of marginal land availability. In the farmland context, lands with low crop productivity are considered as marginal. Other circumstances, such as erodibility, salinity and water excess will also qualify a farmland to be marginal (Kang et al, 2013). Marginal agriculture lands can be categorized into idle or fallow cropland, abandoned farmland, or abandoned pastureland. Campbell et al. (2008) suggested that about 384 to 471 million hectares are available globally and approximately 56 to 60 million hectares in the United States. Cai et al. (2011) estimated 43 to 127 million hectares of marginal agriculture lands existed in US. Milbrandt et al. (2014) calculated the total marginal lands in the contiguous US to be 78 million hectares, while 68.3 million hectares of which are abandoned cropland. Perlack et al. (2005) projected that land enrolled in Conservation Reserve Programs (CRP) in the United States could be utilized for energy crop production. The total CRP enrollment by November 2013 is 10.36 million hectares (or 25.6 million acres).

Brownfield is defined by USEPA as sites that were previously used for industrial or commercial purposes and have been contaminated. Brownfields and landfills are considered as marginal lands because they are not suitable for food production (Martin et al. 2006; Lord et al. 2008). The total landfill acreage is roughly 0.23 million hectares in the U.S. (EPA, 2013). Increasing the production of sustainable energy on brownfield and landfill will reduce the stress on the farmlands and habitable lands.

2.2. Data and Methodology

Geospatial data of selected landfills and brownfields were obtained from US EPA's RE-Powering America's Land program, EPA's Landfill Methane Outreach Program (LMOP), and the National Renewable Energy Laboratory. The mapped acreages for landfill is the highest acreage value among landfill designed area, landfill current area and landfill total area. All feasible sites for renewable energy production should be less than 10 miles from the main transmission line or graded roads.

Three scales of solar PV, wind power, and biorefinery are assessed to determine the fitness of each site in the southeastern US.

The three scales of solar PV defined by RE-Powering program are as following:

- Large scale PV: PV technology with at least 1 megawatt at the site and strong solar potential and sufficient acreages.
- Policy scale PV: PV technology with at least 6.5 megawatt at the site and strong solar potential and abundant acreages.
- Utility scale PV: PV technology with at least 6.5 megawatt at the site and high solar potential and abundant acreages.

A high solar potential is defined as the direct normal solar energy that is equal to or larger than 5 $kWh/m^2/day$. A strong solar potential is defined as the direct normal solar energy larger than or equal to 3.5 $kWh/m^2/day$. The sufficient PV acreage availability is defined as sites with at least 10 acres but less than 40 acres; and abundant PV acreage availability is defined as sites with at least 40 acres.

The three scales of wind farms defined by RE-Powering program are as following:

- Small scale: 1 to 2 turbines, at least 1 MW capacity, with abundant wind resource potential and land resource.
- Large scale: at least 5 MW capacity, with abundant wind resource potential and sufficient land resource.
- Utility scale: at least 10 MW capacity, with abundant wind resource potential and land resource.

The abundant wind resource potential is defined as the annual average wind speed of at least 5.5 m/s at 80 meter height. The limited wind land resource is defined as sites that are at least 10 acres and less than 40 acres. The sufficient wind land resource is defined as sites that are at least 40 acres and less than 100 acres. The abundant wind land resource is defined as sites that are at least 100 acres.

Biorefinery plant sizes of 30, 60 and 90 million gallons per year are considered. Landfills and brownfields are considered as the potential biorefinery facility sites. According to the available biorefinery facility data (Table 1-1), the increase of biorefinery capacity has less impact on the area of facility sites. So the site area is set as minimum 50 acres.

TABLE 1-1: Current biorefinery facilities site data

Company	Location	Feedstock	Capacity, million gallons per year	Facility area, acre
POET	Cloverdale, IN	Corn	90	23
	Hudson, SD	Corn	58	30
	Emmetsburg, Iowa	Corn cobs	20	45
Abengoa	Hugoton, Kansas	Stover, Switchgrass, Woody Biomass	25	36
DuPont	Nevada, Iowa	Agricultural residue	30	50
Mascoma	Kinross, Michigan	Forest Resources	20	50

Feedstocks for biorefineries siting on landfills or brownfield include crops residue, forest residue, mill residue and urban wood residue. Sites with biomass potential greater than 0.7 million tons per year but less than 1.5 million tons per year, within 50 miles radius, are suitable for a 30 million gallons biorefinery plant. Site with biomass potential larger than 1.5 million tons/year but less than 2.5 million tons/year, within its 50 miles radius, are suitable for a 60 million gallons biorefinery plant. Sites with biomass potential larger than 2.5 million tons per year, within its 50 miles radius, are suitable for a 90 million gallons biorefinery plant.

The marginal land screening criteria for renewable transportation fuels facilities are summarized in the table 2-2.

TABLE 2-2: Marginal land use option screening criteria

RE technology	Scale	area constraints	RE resource potential	RE facility capacity threshold
		acres	kWh/m2/day or m/s	MW
Solar PV	Large scale	≥10(brownfield) ≥20 (landfill)	3.5	1
	Policy scale	≥40	3.5	5
	Utility scale	≥40	5.0	5
Wind power	Small scale	≥10	5.5 at 80m	3
	Large scale	≥40	5.5 at 80m	5
	Utility scale	≥100	5.5 at 80m	10
		acres	within 50 miles, M tons/year	Mgals/year
Biorefinery	Small scale	≥50	≥0.7	30
	Large scale	≥50	≥1.5	60
	Commercial scale	≥50	≥2.5	90

2.3. Results and Discussion

Most research has only considered one single type of renewable energy production at a given site. Co-production of different renewable technologies has not been given much attention due to the fact that renewable energy sources are distributed unevenly across the country and within a state. For example, the Southwest U.S. has the highest solar resource, but more wind resource is found in the Central Plains while biomass sources are predominantly in the East. However, with the advancement of renewable energy technology, there will be more sites that could fit for the production of more than one renewable energy, especially, wind technology, which can be co-located with biomass or solar on the same site.

2.3.1. Land Use Options

Two hundred forty two (242) landfills with a minimum area of 20 acres were identified in the study region. Twenty one (21) sites are not suitable for renewable energy development. One hundred seventy (170) landfills can be used for siting as biorefinery facilities; 157 landfills can be used as solar PV plants; and 34 landfills are suitable for development of wind power plants. The categorized total landfill areas are listed in Tables 2-3 to 2-5.

TABLE 2-3: Landfills qualified for biorefinery siting

Biorefinery siting	Number of landfill qualified	Area, acres	Area, ha
Commercial scale	51	16778	6790
Large scale	84	26280	10635
Small scale	35	7948	3216
total	170	51006	20641

TABLE 2-4: Landfills qualified for solar plants

Solar plant size	Number of landfill qualified	Area, acres	Area, ha
Utility scale	3	985	399
Policy scale	142	42655	17262
Large scale	12	303	123
total	157	43943	17783

TABLE 2-5: Landfills qualified for wind farms

Wind farm size	Number of landfill qualified	Area, acres	Area, ha
Utility scale	21	6185	2503
Policy scale	12	922	373
Small scale	1	19	8
total	34	7126	2884

There are thirty five (35) landfills qualified for biorefinery siting only; Twenty six (26) landfills for solar plants; and three (3) landfills for wind farms. Many landfills can be qualified for more than one renewable energy facility. There are on hundred and twenty three (123) landfills that are feasible for 2 land use options; One hundred and nine (109) of them can be used as sites for either biorefineries or solar plants; Nine (9) of them can be used as sites for either biorefineries or wind farms; and five (5) of them can be used as sites for either solar plants or wind farms. Seventeen (17) landfills have three land use options for either biorefinery, solar plant or wind farm. The land use options are shown in Figure 2-1.

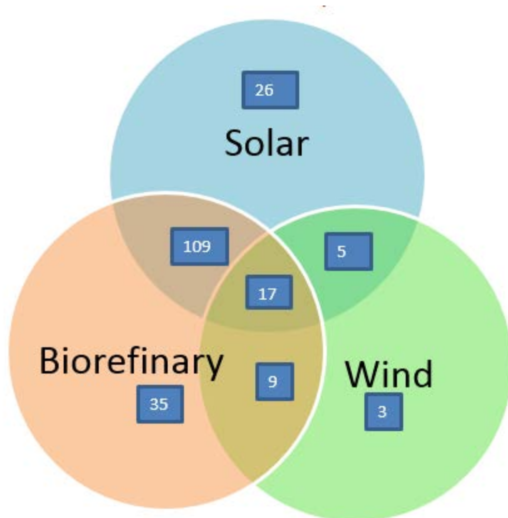

FIGURE 2-1: Land use options-landfills

Five hundred and five (505) brownfields with a minimum area of 10 acres were identified in the study region. Seventy nine (79) of them are not currently suitable for renewable energy development. One hundred thirty seven (137) brownfields can be used as sites for biorefinery facilities; Four hundred and eight (408) brownfields can be used for solar PV plants; and 53 brownfields are suitable for development of wind power plants. The categorized total brownfield areas are listed in Tables 2-6 to 2-8.

TABLE 2-6: Brownfields qualified for biorefinery siting

Biorefinery siting	Number of Brownfields qualified	Area, acres	Area, ha
Commercial scale	50	6641	2688
Large scale	55	11598	4694
Small scale	31	10331	4181
total	136	28570	11562

TABLE 2-7: Brownfield qualified for solar PV plants

Solar size	Number of Brownfield qualified	Area, acres	Area, ha
Utility scale	7	853	345
Policy scale	142	27830	11262
Large scale	258	5026	2034
total	407	33709	13642

TABLE 2-8: Brownfield qualified for wind farm

Wind farm size	Number of Brownfields qualified	Area, acres	Area, ha
Utility scale	10	5796	2346
Large scale	17	950	384
Small scale	25	448	181
total	52	7194	2911

Three are seventeen (17) brownfields that are only qualified for biorefinery siting; 254 brownfields are only qualified for solar plants; 1 brownfield is qualified for wind farm. Many brownfields are qualified for more than one renewable energy facility. There are 136 brownfields that have 2 land use options; 102 of them can be used as sites for either biorefinery siting or solar plants; 34 of them can be used as sites for either solar plants or wind farms. Eighteen (18) brownfields have three land use options which means they can be used as the site for biorefinery siting, solar plant or wind farm. The land use options for brownfields are shown in Figure 2-2.

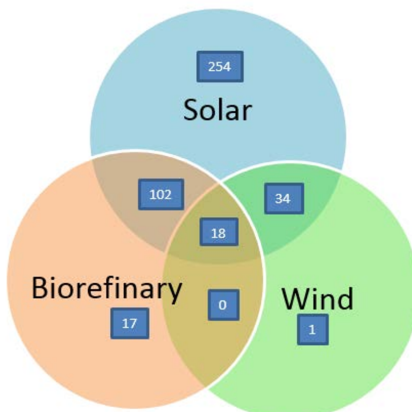

Figure 2-2: Land use options-brownfields

2.3.2. Land Distribution

The spatial distribution of landfills and brownfields are generated by ArcMap 10.1. A total of three (3) landfills and seven (7) brownfields are qualified to host utility scale solar PV facilities. They are all located in Florida (Figure 2-3). The total acreages of these three (3) landfills are 958 acres and the total acreage of seven (7) brownfields are 853 acres.

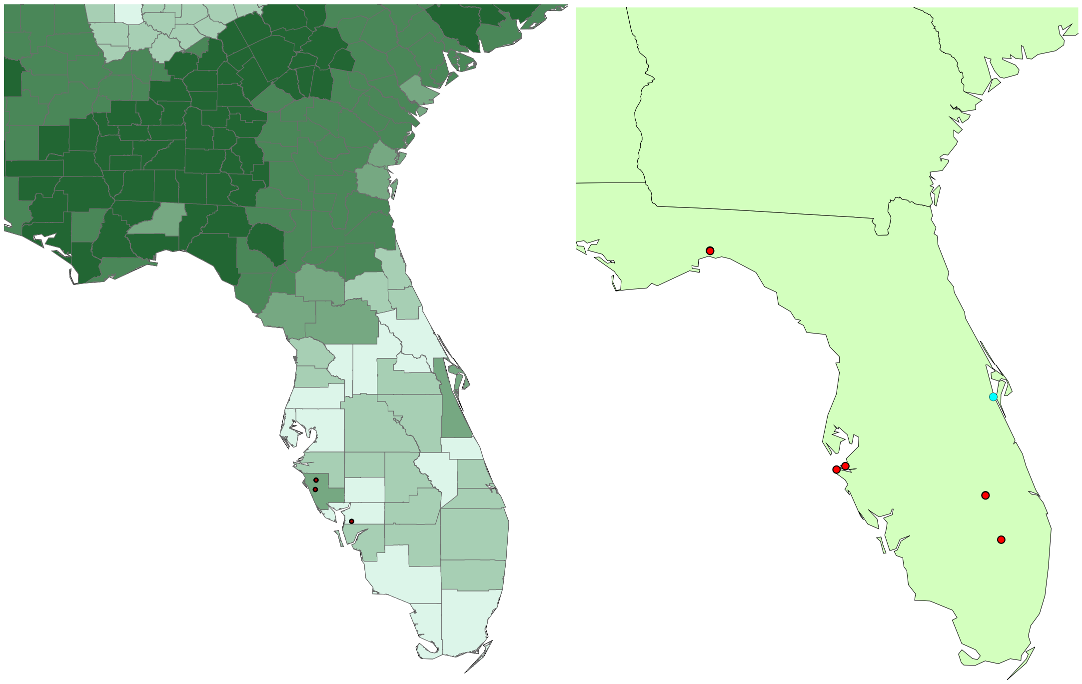

FIGURE 2-3: The distribution of landfills (left) and brownfields (right) that are qualified as utility scale solar PV facilities.

One hundred forty two (142) landfills are qualified to host the policy scale solar PV facility. Half of them are located in North Carolina and South Carolina (Figure 2-4). None of those landfills in Tennessee are qualified for policy scale solar PV development. The total acreages of the policy scale solar PV landfills are 42,655 acres. One hundred forty two (142) brownfields are qualified for policy scale solar PV facility. The total acreages of the policy scale solar PV brownfields are 27,830 acres.

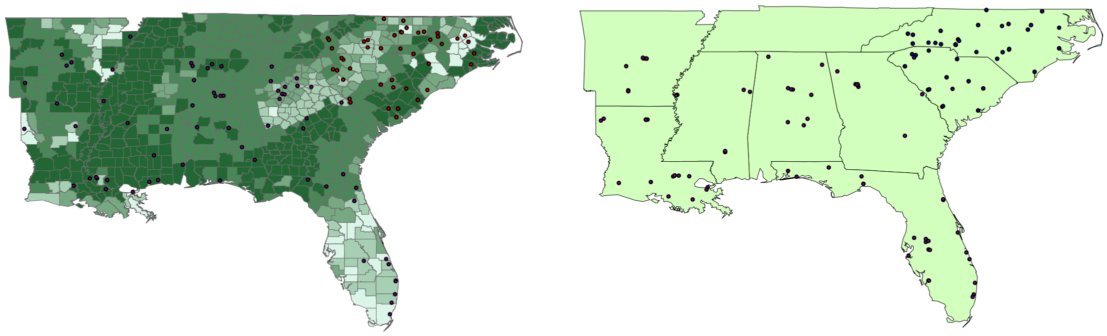

FIGURE 2-4: The distribution of landfills (left) and brownfields (right) that are qualified as policy scale solar PV facility

There are twelve (12) landfills scattered in the North Carolina, Florida, Georgia and Louisiana that are qualified for large scale solar PV development (Figure 2-5). Seven (7) of them are located in North Carolina. The total acreage of these twelve (12) landfills that are eligible for large scale solar PV site totals up to 303 acres. Brownfields that qualified for large scale solar PV are 258 sites with a total area of 5,026 acres.

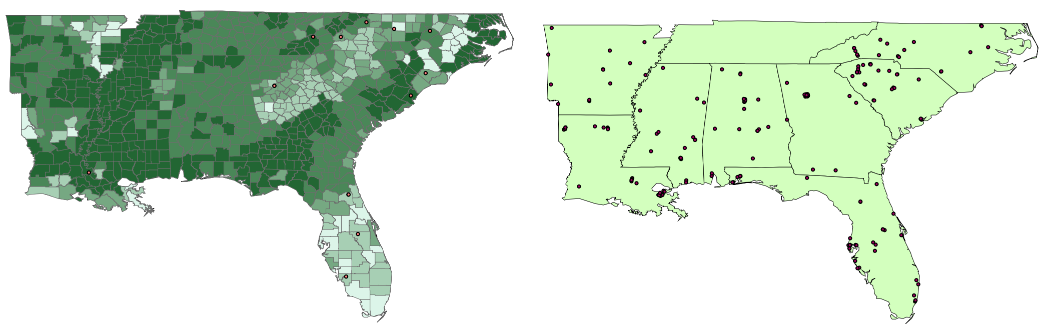

FIGURE 2-5: The distribution of landfills (left) and brownfields (right) that are qualified as large scale solar PV facility

Twenty one (21) landfills are qualified to host the utility scale wind farm. 16 of them are located in the west part of the region (Figure 2-6). Four (4) of them are located in the Florida and 1 in Georgia. The total acreage of the 21 landfills is 7,126 acres. Landfills and brownfields are qualified to host the large scale wind farm are mostly located in Louisiana, Arkansas and Florida (Figure 2-7).

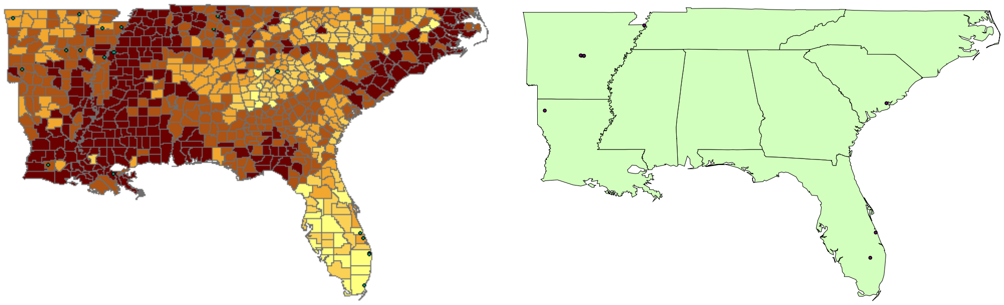

FIGURE 2-6: The distribution of landfills (left) and brownfields (right) that are qualified as utility scale wind farm facility

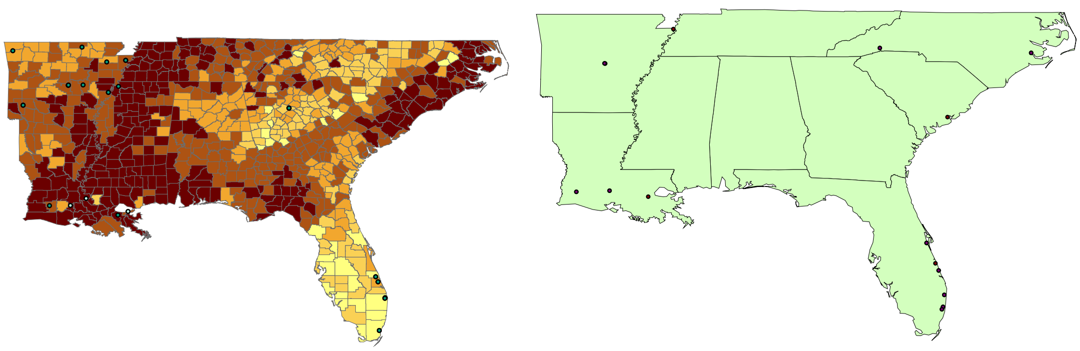

FIGURE 2-7: The distribution of landfills (left) and brownfields (right) that are qualified as large scale wind farm facility

Only one landfill, the Stock Island Landfill (20 acres), is suitable for developing a small scale wind farm. It is located in Florida. Twenty (20) out of 25 brownfields that are qualified for small scale wind farm are located either in Arkansas or Florida (Figure 2-8)

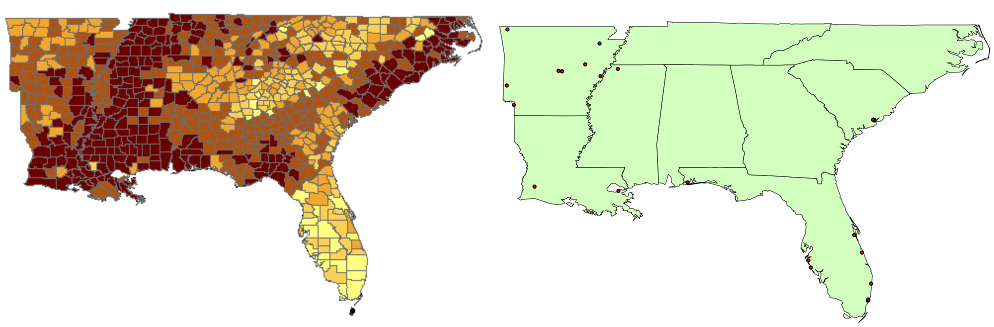

FIGURE 2-8: The distribution of landfills (left) and brownfields (right) that are qualified as small scale wind farm facility

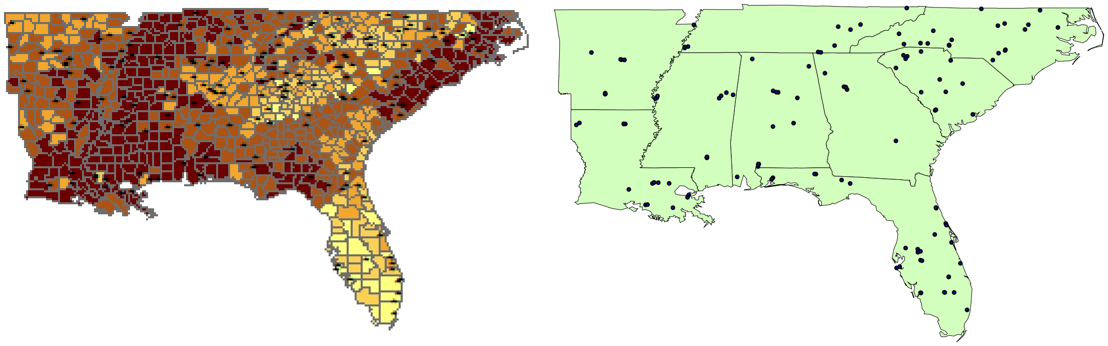

FIGURE 2-9: The Landfills (left) and brownfields (right) that fit biorefinery siting

Landfills and brownfields suitable for biorefinery siting are evenly distributed in the study region (Figure 2-9). Although all the 170 landfills and 136 brownfields are suitable for the biorefinery siting, due to the limited feedstocks availability (the maximum of feedstock collecting radius is 50 miles. Circles in Figure 2-10 are 50 miles in radius) only 35 landfills or 29 brownfields of them can be considered as biorefinery sites.

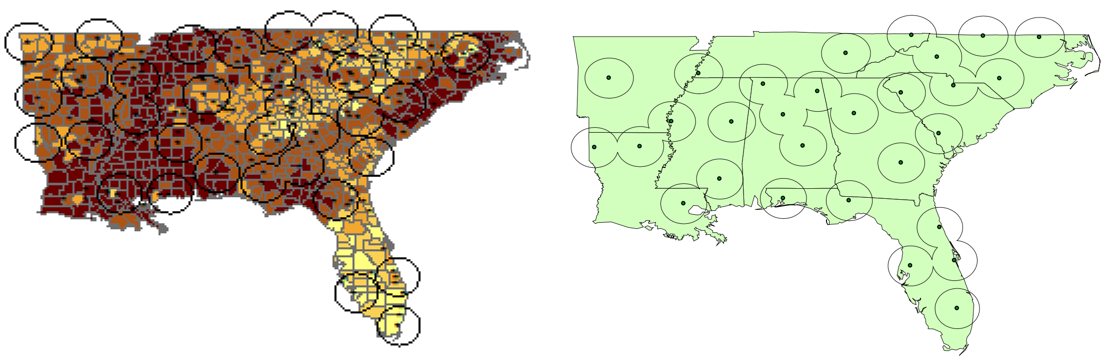

FIGURE 2-10: Landfills (left) and brownfields (right) qualified for biorefinery sites with a minimum 30 million gallons capacity

2.3.3. Renewable Transportation Fuels Potential

The renewable energy potential derived from marginal lands has been estimated based on a variety of criteria. Milbrandt et al. (2014) estimated the total U.S. marginal lands to be 86 million ha, not include landfills, and these could be potentially utilized to generate 4.5 PWh electricity per year from photovoltaics (PV), 4 PWh per year from concentrated solar power (CSP), 2.7 PWh per year from wind, or 1.9 PWh per year from biomass. The renewable energy potential of marginal lands in same study was evaluated by each state and the marginal lands were assumed to be suitable for any renewable energy production meeting basic technology specific criteria, such as site characteristics and land use compatibilities.

2.3.3.1. Biofuel Potential

Due to the low energy density of biofuel feedstocks, the land needed for feedstock production is large. For example, Switchgrass and Miscanthus have median yield rates of 16 and 25 Mg/ha, respectively, in the southeastern region. The theoretical feedstock demand is listed in Table 2-9. A minimum of 12,000 ha (or 46 mile^2) of dedicated lands are needed to supply enough Miscanthus feedstock for a small scale, high conversion rate biorefinery.

TABLE 2-9: Feedstock demand of biorefineries, Mg/year

Feedstock conversional rate, gal/Mg	Biorefinery feedstock demand, million Mg/year		
	Small (30)	Medium (60)	Large (90)
60	0.50	1	1.5
80	0.38	0.75	1.1
100	0.30	0.6	0.9

The biofuel potential from landfills and brownfield is estimated by the number of biorefinery facilities that can be built on the sites. Considering the distribution of the two types of sites and limited available feedstock resources, although many sites are suitable for biorefinery facility, only a limited number of facilities can be built in a given region. In this study, brownfields are not considered as the sites for biorefinery facilities due to most of these brownfields are in urban areas and smaller in size compared to landfills.

Based on Figure 2-10, a total of 35 biofuel facilities and their capacities are identified (Table 2-10).

TABLE 2-10: Regional biofuel facility and biofuel potential

Capacity, million gallons	30	60	90	Total potential
	Number of facilities			
Alabama	0	3	0	180
Arkansas	0	3	1	270
Florida	2	1	2	300
Georgia	0	3	1	270
Louisiana	0	1	2	240
Mississippi	0	1	2	240
North Carolina	0	2	1	210
South Carolina	0	1	2	240
Tennessee	5	0	0	150
The regional total	7	15	11	2100

2.3.3.2. Renewable Electricity potential

The total land-use requirement for solar power plants varies widely with different technologies. The capacity-weighted average land use for a PV plant in this study is assumed to be 8 acres/MW (Ong et al., 2013). The life time of PV plants is assumed to be 25 years.

The land use intensity of a wind farm depends on many factors, such as array type and wind turbine scales. In this study, it is assumed that a single string array is preferred rather than a multiple array or a cluster array. The turbines are placed along the perimeters of each site. The layout for wind turbines are separated by a distance of 5 rotor diameters within a row, and 10 rotor diameters within a column. When the number of turbines is less than or equal to 5, the layout of the turbines should be considered as single string around the site. When the number of turbines is larger than 5, the layout of the turbines would be considered as multiple strings or cluster arrays (Figure 2-11).

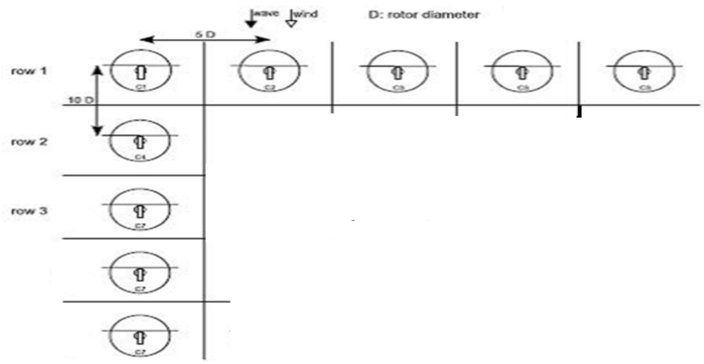

FIGURE 2-11: Wind turbine layout description.

In this study, General Electric's 1.7-100 model turbine is used as reference. The rotor diameter (D) is 100 meters and the peak capacity of the turbine is 1.7 MW. One or two turbines can be considered as a small-scale wind farm with capacity of less than 5 MW. The single-turbine land impact area is 10,000 square meters (2.47 acres), and two-turbine land impact area is 6D×D=60,000 square meters (14.83 acres). Three (3) acre per MW is assumed to be the average land use intensity for small scale wind farms. Similarly, calculations are performed for the large and utility scale wind farm land-use intensity (see Table 2-11). Six (6) acre/MW and 22 acre/MW are assumed to be the average land use intensity for large and utility scale wind farms, respectively. The life time of wind farms is assumed to be 25 years.

TABLE 2-11: Wind power land use intensity

	Turbine #	MW	Total land use, acre Single string Array	Total land use, acre Multiple string Array	land use intensity acre/MW
Small	1	1.7	2	/	1
	2	3.4	15	/	4
Large	3	5.1	27	/	5
	4	6.8	40	/	6
	5	8.5	52	/	6
Utility	6	10.2	/	77	8
	7	11.9	/	200	17
	8	13.6	/	324	24
	9	15.3	/	447	29
	10	17.0	/	571	34

The national average capacity factors for solar PV in 2014 and 2015 are 25.9% and 28.6%. In this study, a conservative value of 20% is used. The 2013-2015 wind farm capacity factors range from 32.4% to 34%. Since the wind resource availability is lower in the southeastern US, a 30% capacity factor will be assumed.

The renewable electricity potential is calculated by following equation:

$$E = \frac{land}{land\_\text{intensity}} \times capacity\_\text{factor} \times 4380$$

Where, *E* denotes the annual electricity potential, GWh/year.

Land denotes the available land areas of the region, acres.

Land_intensity, denotes the land requirement for 1 MW electricity facility, acre/MW.

Capacity_factor, denotes the ratio of actual electricity production during a given period, % / per year. *4380* is the hours in one year.

The renewable electricity potential of the southeastern US from landfills and brownfields are presented in Table 2-12. The results show solar power is much more favorable than the wind power.

TABLE 2-12: Regional renewable electricity potential from landfills and brownfields

	Total regional solar capacity, GW	Total regional solar potential, GWh/year	Total regional wind capacity, GW	Total regional wind potential, GWh/year	Total electricity potential, GWh/year
Landfills	5.48	4799	0.44	572	5371
Brownfields	4	3691	0.58	763	4454
Total	9.48	8490	1.02	1335	9825

2.3.4. Renewable Fuel Demand in the Southeastern US

The renewable fuel demand for the next 25 years in the southeastern US is estimated based on data available from the Annual Energy Outlook 2015 (AEO, 2015) report. The report presents six different scenarios to address the uncertainty of the energy market. The reference scenario assumes that the real gross domestic product (GDP) will grow at an average annual rate of 2.4% from 2015 to 2040 and the current laws and regulations will not change throughout the period. The crude oil price will rise to $141 per barrel in 2040. Other scenarios are listed in the Table 2-13 below.

TABLE 2-13: Economic and energy scenarios

Scenarios	GDP	Crude oil price in 2040
Reference	2.4%	$141
Low economic growth	1.8%	$141
High economic growth	2.9%	$141
Low oil price	2.4%	$76
High oil price	2.4%	$252

Seven vehicle types are considered: 1) conventional internal combustion engine vehicle(CV) that runs on gasoline with 10% ethanol blend, 2) Ethanol-Flex Fuel ICE vehicle (FFV) that runs on gasoline with 85% ethanol blend, 3) Electric vehicle with 100 miles range (EV100), 4) Electric vehicle with 200 miles range (EV200), 5) Plug-in gasoline hybrid vehicle with electric only 10 miles range (PHV10), 6) Plug-in gasoline hybrid vehicle with electric only 40 miles range (PHV40), and 7) Hybrid electric-gasoline vehicle (HEV).

The average fuel economy in terms of miles traveled per year and vehicle sales data are adopted from the AEO 2015 report (Appendix A). Different economic and energy market scenarios has no or minimal impact on the fuel economy. The average fuel economy of internal combustion engine(ICE) based vehicles, such as conventional vehicles and Flex Fuel vehicles is expected to increase almost 50% in next 10 years, from 36 miles per gallon in 2015 to 53 miles per gallon in 2025 and will stay stable from 2025 to 2040 (AEO,2015). The average fuel economy of another type of ICE based vehicle, electric-gasoline hybrid, is expected to increase 39% in the next 10 years and will stay stable from 2025 to 2040. The average fuel economy of the 10 mile range and 40 mile range plug-in hybrids is expected to increase 35% and 20%, respectively, over the next 10 years and will stay stable from 2025 to 2040. The average fuel economy of 100 mile range and 200 mile range electric vehicles is expected to increase 5% and 12%, respectively, over the next 10 years and will stay stable from 2025 to 2040. The overall change rate is listed in Table 2-14.

TABLE 2-14: MPG change from 2015 to 2040 (AEO, 2015)

	CV	FFV	EV100	EV200	PHV10	PHV40	HEV
Reference case	47%	49%	5%	12%	36%	21%	39%
High economic growth	47%	49%	5%	12%	36%	21%	39%
Low economic growth	47%	49%	5%	12%	36%	21%	39%
High oil price	47%	48%	4%	13%	35%	20%	37%
Low oil price	47%	49%	5%	12%	36%	21%	40%
High oil and gas resource	47%	49%	5%	12%	36%	21%	40%

Given other condition remaining unchanged, the increasing in fuel economy will reduce demand for transportation fuel. However, the sales of vehicles, especially the long range electric vehicles, are expected to grow steadily in the next 25 years (Table 2-15), which could offset reduction in fuel demand achieved by fuel economy improvements.

TABLE 2-15: Average annual sale growth rate (2015-2040) in the southeastern US

	CV	FFV	EV100	EV200	PHV10	PHV40	HEV
Reference case	1%	1%	8%	18%	5%	7%	3%
High economic growth	1%	1%	9%	18%	5%	7%	4%
Low economic growth	0%	0%	8%	17%	4%	6%	2%
High oil price	1%	2%	9%	19%	6%	8%	4%
Low oil price	0%	0%	6%	16%	3%	6%	2%
High oil and gas resource	1%	1%	8%	18%	4%	7%	3%

The other negative impact on fuel consumption is the vehicle miles traveled. The conventional vehicles are expected to have more miles traveled, while all other alternative fuel vehicles are expected to travel less over the next 25 years (Table 2-16). The oil price has a significant impact on the vehicle miles traveled. High oil prices are expected to reduce vehicle miles traveled as much as 29% in the case of FFV. Low oil price encourages the travel of all kinds of vehicles which, in turn, increases the fuel consumption and generates more GHG emissions.

Table 2-16: VMT change from 2015 to 2040

	CV	FFV	EV100	EV200	PHV10	PHV40	HEV
Reference case	11%	-4%	-10%	-2%	-6%	-7%	1%
High economic growth	10%	-5%	-11%	-3%	-7%	-8%	-7%
Low economic growth	12%	-2%	-9%	0%	-5%	-6%	-6%
High oil price	-14%	-29%	-20%	-13%	-16%	-17%	-18%
Low oil price	36%	28%	0%	8%	3%	2%	5%
High oil and gas resource	14%	0%	-9%	-1%	-5%	-6%	-5%

Given different factors that impact the overall regional fuel consumption growth rate, it is necessary to find the demand growth over time. The regional fuel demand growth rate is calculated by the following equation:

$$\frac{VMT}{MPG} \times \mu_i \times \text{Regional\_Sales} = \text{Regional\_Fuel\_Demand\_Growth}$$

VMT: Vehicle Miles Traveled, miles/year

MPG: miles per gasoline equivalent

μ_i: the percentage of ethanol or electricity in the fuel for vehicle type i

Regional_sales: vehicle sales per year of the region

Regional_Fuel_Demand_Growth: million gallons or gigawatt hours per year

Figure 2-12 indicates that the demand for new ethanol production will be slowing down for the next 10 years. This mainly is caused by the expectation of dramatically increased vehicle fuel economy. After 2025, the demand for new ethanol production will rise again. The estimated new ethanol demand for the next 5 years is ranging from 1,778 million gallons (low economy growth) to 1,892 million gallons (high economy growth). This increase rate in the next 5 years can be met by the landfill based biorefinery (2100 million gallons). For example, to meet the new demand in the region in 2016, about four large scale or six medium scale biofineries will be needed. Figure 2-12 also indicates that the demand for building new biofineries is at a high point and the investment of new biofineries will be slowing down over the next 10 years.

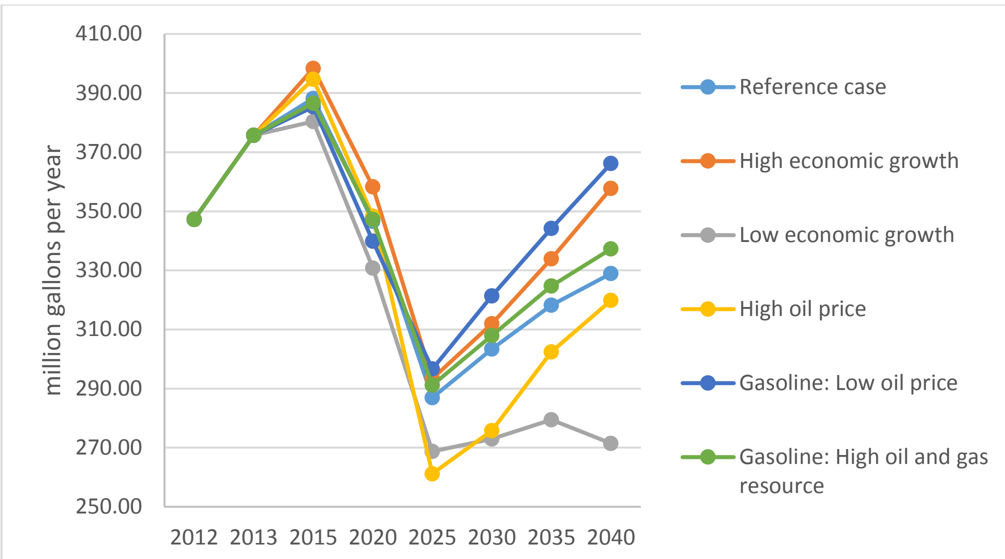

FIGURE 2-12: Annual ethanol demand growth rate

Figure 2-13 demonstrates the transportation demand growth rate for electricity is accelerating from 2015 to 2040. The oil price has a significant impact on the electricity demand growth rate. The high oil price might double the new demand of transportation electricity compared to the low oil price scenario, which will put pressure on infrastructure and more new facilities will be needed to be built each year to meet the demand increase. In the low gasoline price scenario, the transportation electricity demand will increase by 4,131 gigawatt-hours in 2040 comparing to 2015. The landfill-based solar power (4,798 gigawatt-hours) could potentially supply this increase demand. Similarly, in the high gasoline price scenario, the transportation electricity demand will increase 9,400 gigawatt-hours in 2040 comparing to 2015, which will be more than double that of the low oil price scenario. The wind power and solar power from both landfills and brownfields combined (9,824 gigawatt-hours) might also meet this demand.

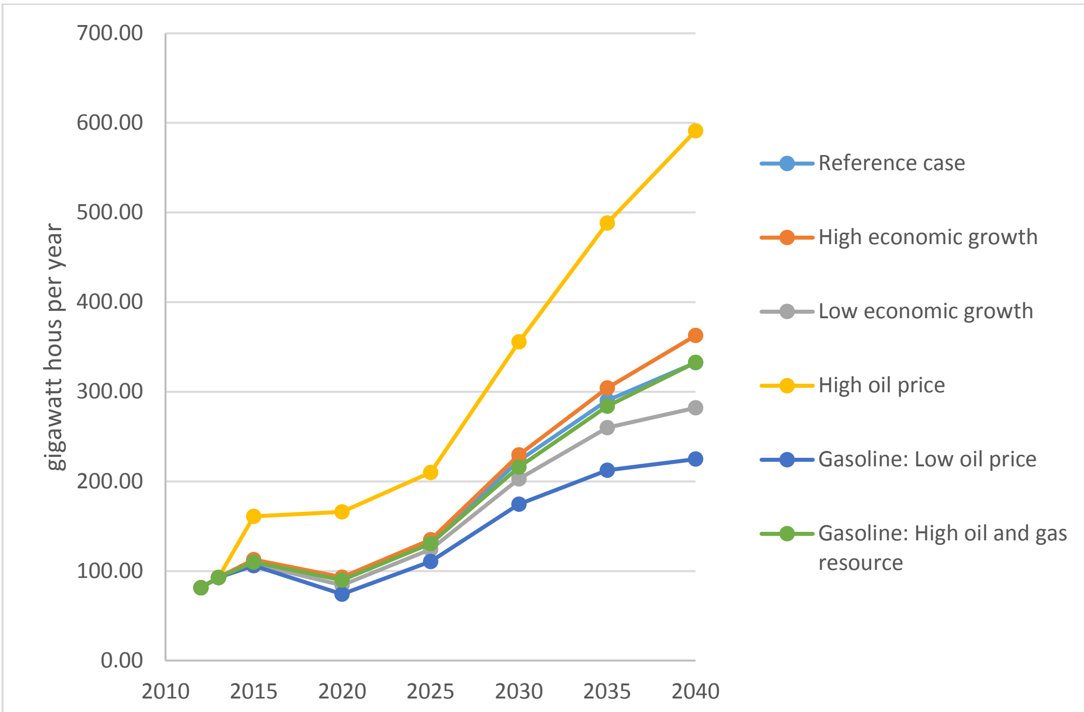

FIGURE 2-13: Annual transportation electricity demand growth rate

2.4. Concluding Remarks

This chapter has quantified the potentials of renewable transportation fuels produced from landfills and brownfield and the annual demand increasing rate for the renewable transportation fuels in the southeastern US.

The biofuel potential of biorefinery siting on the landfills (2100 million gallons) can only meet the new demand increase of next 5 years. More low impact land and feedstock resources are required in order to meet the increasing demand of renewable transportation fuels. Additional land resource, marginal agriculture lands, for biofuel potential and economic feasibility investigations are given in the next chapter.

Landfills and brownfields based renewable electricity production can potentially supply all the exceeded new electricity demand increase for transportation sector in the southeastern US region. Solar power can provide more energy (4799 GWh/year from landfills and 3691 GWh/year from Brownfield) and is more preferable than wind power installed on marginal lands (572 GWh/year from landfills and 723 GWh/year from brownfield). A case study on economics of integrating transportation fuels production on landfills is given in chapter 4.

CHAPTER 3: INTEGRATED RENEWABLE ENERGY PRODUCTION ON A LANDFILL

3.1. Background and Literature Review

Landfills in the United States represent the third-largest human-related source of methane emissions in 2013. The ever increasing energy costs coupled with the required reduction in greenhouse gas (GHG) emissions have imposed new challenges to modern waste management facilities. These facilities can transition into an eco-friendly complex that maximizes resource recovery and renewable energy production. Landfill gas (LFG) collected from landfill areas is a reliable fuel source for electrical energy generation. Photovoltaic (PV) installations on closed landfill cells without cap penetrations offer a feasible option for solar electricity production (Salasovich and Mosey, 2011). Idle and buffer lands surrounding landfill cells can be used to grow bioenergy crops before they are developed for soil removal or ultimately become new landfill cells. Collectively, these green energy projects will likely help offset landfill costs and the financial burden related to the lengthy process of post-closure requirements.

This chapter employs the current economic and performance data to perform a system analysis of the net economic benefits derived from implementing green energy initiatives throughout the lifecycle of an operating landfill facility. The environmental benefits associated with reduction in GHG emissions are quantified for each of the LFG-to-energy, solar-to-energy and biodiesel manufacturing projects. These landfill-based energy projects require no direct land-use change to avoid environmental impact and, furthermore, render the opportunities for carbon trading and low-carbon intensity business. Net present value (NPV) analysis is conducted to determine payback periods, internal rates of return (IRR) and benefit-to-cost ratios, with and without considerations of carbon credit and tax incentives. Finally, a systematic development strategy is explored to simulate the sequential implementation of green energy projects as a promising financial instrument for landfilling operations and post-closure care.

3.1.1. LFG-to-Energy

LFG production has been reported in the range of 45-360 m^3/ton of waste placed into a landfill (Ham and Barlaz, 1989). Once captured, landfill methane can become a fuel source to power generators for electricity production. During combustion, each unit weight of methane is converted to 2.75 equivalent weight of CO_2. The economics of energy recovery from landfill gas has been shown to be significantly better in terms of CO_2 reduction than other alternative energy production forms (Gardner et al. 1993). Obviously, the collection and conversion of LFG to electric power renders the benefits of energy saving, capital recovery, and protection of the environment by reducing GHG emissions.

There is extensive literature for electricity production using LFG (Tsave and Karapidakis, 2008; Abreu et al., 2011; Jaramillo and Matthews, 2005; Bove and Lunghi, 2006) including the U.S. Landfill Methane Outreach Program that encourages methane capture and utilization from uncontrolled emissions (EPA, 2014). An earlier study to evaluate the net private and social benefits of LFG-to-energy projects concluded that the breakeven price of electricity was lower than $0.04 per kWh (kilowatt hour) (Jaramillo and Matthews, 2005). However, the study assumed a zero energy tax credit, a capital cost of $1,000 per kW, and a discount rate of 12%; its validity in relation to today's realistic economy needs to be revisited.

Utilization of landfill gas for electric power generation may qualify to earn carbon credits if the facility is not under New Source Performance Standards or other regulatory requirements for gas collection and destruction. Eligible landfill-to-energy credits must satisfy the requirement of "additionality". In other words, only carbon credits from projects that are "additional to" the business-as-usual scenario can provide incremental environmental benefits (Sherlock, 2014). Producers of electricity from LFG may take the advantage of the Business Energy Investment Tax Credits or the Renewable Electricity Production Tax Credit (REPTC) that allows a 1.1-cent credit per kWh for up to 30% of the project cost. Using LFG to generate electricity or other applications can turn a potential liability into a benefit.

At the closure of a landfill, monitoring and maintenance are required for a 30-year post-closure period with an annual cost of approximately $100,000. A performance-based strategy for post-closure care was proposed to attain increased environmental benefits at compatible cost (Morris and Barlaz, 2011). The required funding may come from landfill tax or aftercare rebate as an instrument to finance accelerated landfill care, which could lead to a shorter time for post-care (Beaven et al., 2014). The waste management industry must explore viable financing mechanisms for landfill operation and post-closure requirements by integrating green energy projects throughout the lifecycle of landfilling operations as presented in this paper.

3.1.2. Solar-to-Energy

The solar market has evolved and expanded rapidly in various parts of the world. The US solar-to-energy generation amounts to 18,000 megawatts hours (MWh) per day in 2013, representing a tremendous economic opportunity for the United States (Loveless, 2012). Electric generation costs for solar energy are in the range of 8.7-40.00 cents per kWh as compared to 4.9 cents per kWh for pulverized coal (Sims, 2004). Environmentally, the solar PV system emits zero carbon per kWh that can equate to an emission saving of 229 grams of carbon per kWh or $175-$1,400 per ton of carbon avoided (Sims, 2004).

Closed landfill cells have limited development potential due to differential soil settlement over time and regulatory concerns regarding soil erosion and disruption of the cover cap. These are ideal locations for solar electric energy production. As of fall 2013, there are 85 solar-to-energy projects generating 507 megawatts (MW) on lands with no agroeconomic value such as Superfund sites, landfills and mine sites across the nation. For example, these projects include the 8-MW Maywood Solar Farm on a 43-acre (17-hectare) former Superfund site, the 1,000 kWh per day solar system atop the Tennessee Hermitage landfill, and the 10-MW system on 47 acres (19 hectare) of Freshkills in Staten Island, New York (USEPA, 2013; Kroh, 2013). Trading of solar renewable energy certificates (SRECs) is available through open exchange markets in several eastern states. The current SREC settlement prices from the FLETT Exchange have ranged from $40 to $475 per SREC (Flett Exchange, 2014). One SREC is equivalent to 1 MWh of solar electricity.

3.1.3. Biofuel Production

The utilization of idle or buffer lands for growing bioenergy crops at a landfill facility is similar to operating marginal lands for biofuel production (Milbrabdt et al., 2014; Cai et al., 2011; Zhou and Thomson, 2009; Rowe et al., 2009). This non-traditional agronomic land does not compete with food and already incurs a management cost (Hank, 2014). The total production cost of biodiesel can vary from $2.80 per gallon ($0.74 per liter) for a B100 plant with an annual capacity of 50 million gallons (189 million liters) to over $4.00 per gallon ($1.06 per liter) for small scale production. The feedstock cost of commodity oil is currently around $2.40 per gallon ($0.63 per liter) (Pienaar and Brent, 2012). U.S. producers of biodiesel and renewable diesel meeting the ASTM specifications are eligible for the Renewable Identification Number (RIN) certificate with a current value of $0.60 per RIN or the fuel tax incentive at $1.00 per gallon ($0.26 per liter) (Transport Policy, 2014).The latter has lapsed and been reinstated several times over the past four years to create an uncertain climate for industry investment (Progressive, 2014).

3.2. Data and Methodology

For this research, a model facility was developed as the basis to evaluate the economic and environmental benefits of these green energy projects. The model facility includes the 100-acre (40 hectares) landfill area containing 3.6 million tons of MSW, a 3-MW electric generator, and 150 acres (60 hectares) of buffer lands for growing bioenergy crops. Table 3-1 summarizes the basic data for this model facility. Additional assumptions are made to characterize the model facility and its energy conversion requirements: (a) a daily average of 432,000 cubic feet per day (12,233 cubic meters per day) LFG per million tons of MSW is used to derive the landfill methane supply (EESI, 2013); (b) conversion of thermal energy from methane to electricity is 35% or 0.65 MW per million tons of MSW as compared to 0.78 MW suggested by EPA (USEPA, 2013); (c) land requirement for solar panels is 2.8 acres (1.1 hectares) per GWh (gigawatt-hour) per year (Ong et al., 2013); (d) unit cost for the solar panel and frame is taken as $1.00 per watt as this cost can vary from 60 cents to $3.00 per watt; (e) conversion of vegetable oil to biodiesel is at 90% efficiency; (f) each ton of methane combusted avoids 17.25 tons of CO_2 and each kWh of solar electricity eliminates 0.69 tons of CO_2 (USEPA, 2014); and (g) net present value analysis is based on a 1% inflation rate, 3.5% marginal rate of return, 100% down payment and zero salvage value. Environmental benefits for these green energy projects are evaluated in terms of the number of charged electric vehicles (EV) such as the Nissan Leaf (Tseng et al., 2013), the number of homes powered, the number of trucks fueled by biodiesel, and the avoidance of CO_2 emission. The solar project includes a 10-MW solar electric farm on 50 acres (20 hectares) of landfill cap areas and a 3-MW scale down system for direct comparison with the LFG project.

3.3. Results and Discussion

3.3.1. Economic Analysis without Energy Credits

The LFG-to-energy project generates 19,896 MWh per year at a LFG flow rate of 1,080 scfm (31 cubic meters per minute) or 2.33 MW with 25% downtime, see Table 3-1 and Table 2. The capital cost of 6 million dollars, shown in Table 3, is based on a unit cost of $2,000 per kW (kilowatt) (USEPA, 2014) applied to the 3-MW generator capacity. The resulting annual operating cost of $489,008 is shown in Table 3-3. The sale of electricity at 6 cents per kWh generates 1.19 million dollars of annual revenue.

Network connection and maintenance fees are not accounted for in this preliminary economic evaluation.

TABLE 3-1: Characterization data for the model facility

Parameters	LFG Energy	Solar Energy (3 MW)	Solar Energy (10 MW)	Biodiesel Production
		Basic		
Land, hectares	40	6	20	60
MSW, million tons	3.6	-	-	-
Generation capacity, MW	3	3	10	-
Generator downtime, %	25	-	-	-
Vegetable oil, liters per hectare-year	-	-	-	608
Project duration, years	25	25	25	25
		Technical		
LFG, m^3 per day per million tons of MSW	12,233	-	-	-
Methane in LFG, %	50	-	-	-
Methane heating value, million joules per m^3	34	-	-	-
Thermal-electrical conversion, %	35	-	-	-
Land Required, hectares per GWh per year	-	1.13	1.13	-
Available solar hours per year, hrs	-	1,533	1,533	-
Vegetable oil to biodiesel, %	-	-	-	90
Household energy usage, MWh per year	11	11	11	-
EV charged, kilometers per kWh	7.85	7.85	7.85	-
Utility truck, kilometers per liter	-	-	-	10
Vehicle usage, kilometers per year	19,312	19,312	19,312	19,312
		Economic		
Down payment of capital investment, %	100	100	100	100
Salvage value, $	0	0	0	0
Inflation rate, %	1.0	1.0	1.0	1.0
Marginal rate of return, %	3.5	3.5	3.5	3.5

TABLE 3-2: Economic and production data for the model facility

Parameters	LFG Energy	Solar Energy (3 MW)	Solar Energy (10 MW)	Biofuel Production
	Economic			
Capital, $ per kWh	2,000	1,000	1,000	-
Annual O&M cost, $ per kW	210	-	-	-
O&M cost, $ per MWh	-	11.4	11.4	-
Production including O&M, $ per liter	-	-	-	0.79
Sale of electricity, $ per kWh	0.06	0.06	0.06	-
Avoidance cost, $ per liter diesel	-	-	-	0.98
	Production			
LFG, m^3 per minute	31	-	-	-
Methane, m^3 per minute	15	-	-	-
Methane energy, million joules per minute	519	-	-	-
Electrical production, giga joules per year	71,624	-	-	-
MWh per year	19,896	3,909	13,031	-
Biodiesel production, liters per year	-	-	-	33,217

TABLE 3-3: Results of economic and environmental modeling analyses (without energy credits)

Parameters	LFG Energy	Solar Energy (3 MW)	Solar Energy (10 MW)	Biofuel Production
	Economic			
Initial Investment, $	6,000,000	3,000,000	10,000,000	250,000
Annual O&M cost, $	489,000	52,430	174,760	26,320
Gross Annual Savings, $	1,193,740	234,550	781,830	32,550
IRR, %	10.85	3.50	3.50	-
NPV Payback, years	10	22	22	-
Benefit-cost Ratio	1.47	1.09	1.09	0.92
	Environmental			
Home powered by Green Energy, # per year	1,810	350	1,190	-
EV Charged, # per year	8,080	1,590	5,290	-
Utility Truck Fuel, # per year	-	-	-	18
Avoidance of CO_2 Emission, tons per year	91,500	2,700	90,000	78

The installation of solar panels atop the 50-acre landfill cap (20 hectares) is estimated at 3 and 10 million dollars, respectively, for the 3-MW and 10-MW solar systems (Table 3-3). The annual operating cost is based on $11.4 per MWh (USEIA, 2014) and the electricity generation is calculated from the generation capacity and the available solar hours that amount to 4.2 hours per day throughout 365 days in a year. The 3-MW solar system produces much less electricity than the same capacity LFG plant because of its smaller annual percentage of available solar hours, 17.5% solar insolation versus 75% generator uptime.

Economic modeling analyses are summarized in Table 3-3 and Figures 3-1, 3-2 and 3-3. Without tax credits, the LFG-to-energy project is shown to be financially viable with NPV payback of 10 years and an IRR equal to 10.85%. These returns compare well to typical yields between 8% and 11% reported by the 500 S&P's. The solar-to-energy project requires a longer payback of 22 years and incurs a lower IRR of 3.50%. Both projects exhibit their benefit-to-cost ratios of greater than one. Environmentally, the LFG project will avoid 91,500 tons of equivalent CO_2 emission or 39,270 tons per MW output. The solar project is a feasible option for implementation on landfill cap areas and allows an avoidance of 1,057 tons CO_2 emission per MW. Together, both projects can power 2,000-3,000 homes or charge 9,500-23,000 electric vehicles operating at 12,000 miles (19,310 kilometers) per year.

Biodiesel production is based on yield data from an EcoComplex facility in North Carolina. The 150-acre (60-hectare) plot yields an average of 9,750 gallons (36,900 liters) of vegetable oil or 8,775 gallons (33,210 liters) of biodiesel per year, see Table 3-2. The integrated biodiesel and crush facilities were initially funded by grants and landfill post-closure funds. It is likely that similar financing mechanism is possible for the model facility. The capital cost is estimated at $250,000 for the oil-seed crush and biodiesel facility. The operating cost is based on \$3.00 per gallon (\$0.79 per liter) which includes on-site harvest of feedstock, chemicals, processing and maintenance. The benefit-to-cost ratio is slightly less than one with a payback period of greater than the project duration, see Table 3-3 and Figure 3-5. Production of biodiesel without tax credits is not practically viable due to economic scale of production and under-utilization of the capacity of the processing facility. Environmentally, the biodiesel project will provide the waste management facility with an internal source of liquid fuel for running their trucks, and reduce 78 tons of annual CO_2 emissions.

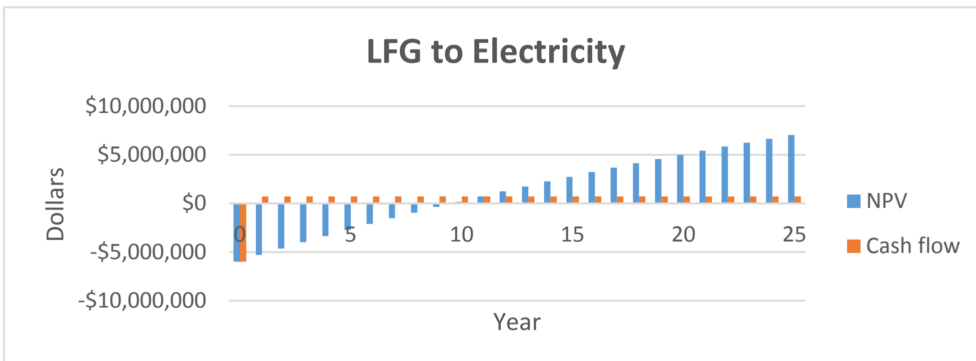

FIGURE 3-1: Net present value analysis for LFG-to-Energy project (without energy credit)

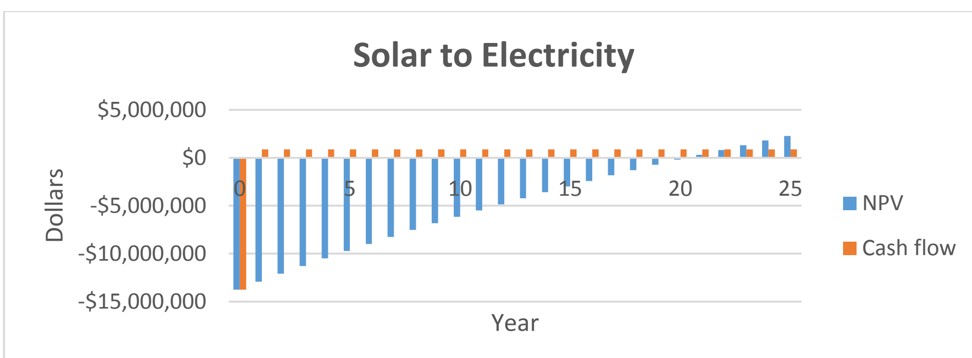

FIGURE 3-2: Net present value analysis for Solar-to-Energy project (without energy credit)

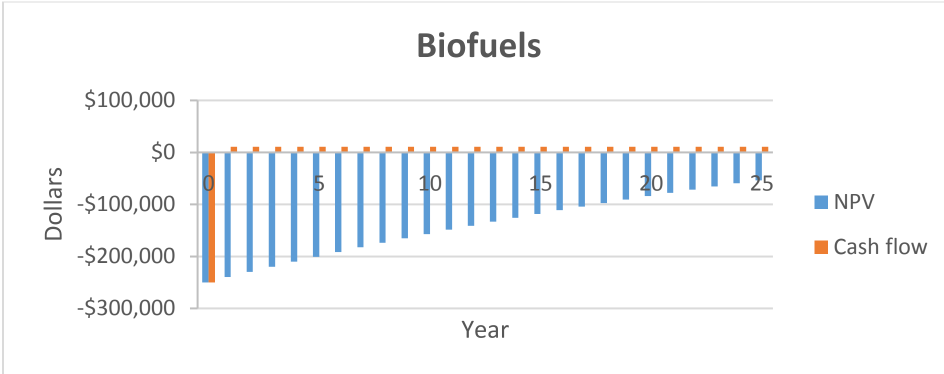

FIGURE 3-3: Net present value analysis for biodiesel production project (without energy credit)

3.3.2. Economics with Energy Credits

The economic perspective for all three energy projects becomes more promising by discounting with energy credits, see Table 3-4. Applying the REPTC credit of 1.1 cents per kWh for the LFG-energy project, the NPV payback period is shortened by 2 years and the IRR increases by 3.1%. For the solar-energy project, a SREC value of 4 cents per kWh helps shorten the payback period by 7 years with an increment of 2.79% for IRR. Although SREC prices may fluctuate with uncertainty, the solar-energy project is an attractive and viable investment even in the absence of financial subsidies. The most encouraging economic improvement is observed for the biodiesel fuel production. By including the $1.00 per gallon ($0.26 per liter) tax credit, the biodiesel production becomes economically viable with a NPV payback of 16 years and a benefit-to-cost ratio of greater than 1, see Figure 3-4.

TABLE 3-4: Improvements in economic modeling results with energy credits

Parameters	LFG Energy	Solar Energy (3 MW)	Solar Energy (10 MW)	Biofuel Production
Initial Investment, $	6,000,000	3,000,000	10,000,000	250,000
Annual O&M cost, $	489,000	52,430	174,760	26,320
Gross Annual Savings, $	1,193,740	234,550	781,830	32,550
Economic Incentives, $ per kWh	0.011	0.04	0.04	-
Tax Credit, $ per liter	-	-	-	0.26
IRR, %	13.96	6.29	6.29	5.90
Improved IRR compared to baseline, %	28	80	80	100
NPV Payback, years	8	15	15	16
Reduced Payback compared to baseline, %	20	32	32	>100
Benefit-cost Ratio	1.74	1.30	1.30	1.17

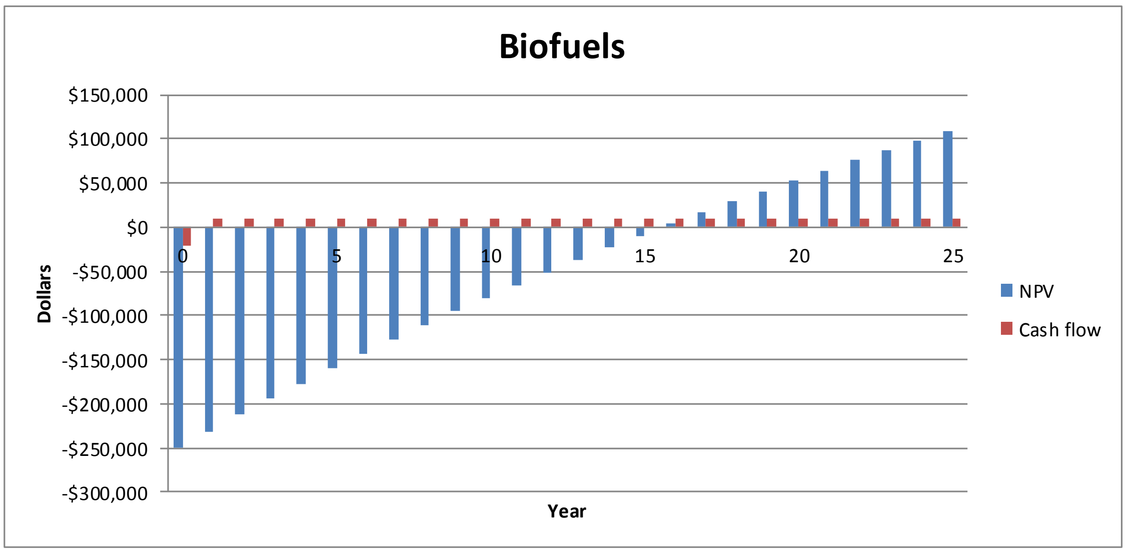

Figure 3-4: Net present value analysis for biodiesel production project (with $0.26 per liter tax credit)

3.3.4. Economics for Landfill Closure Care

In a typical landfill facility, landfilling operation starts at one section or cell and progresses gradually from section to section until the entire site is fully utilized. LFG collected from either or both of the active and closed sections provides a reliable energy source for many applications including electrical energy production. Idle or buffer lands that border the active or closed landfill areas essentially have no current opportunity cost unless they eventually become the new landfill areas. It is in this window that bioenergy crops are viable. The closed sections once capped with a geomembrane and covered by soil layers for drainage, filtration and protection have limited use. It is under this situation that movable or geomembrane solar panel systems can be ideally installed atop the covered area for renewable energy production. The sequence of developing energy projects can be systematically aligned with the staging operation of landfilling. Using the model facility as an illustration, we can simulate the site development activities by a time sequence: (a) landfilling on the 50 acres landfill cell from year 1 to year 20, (b) post-closure care from year 21 to year 50 at a cost of $100,000 per year, (c) LFG and biodiesel projects implemented from year 5 to year 30, and (d) solar-to-energy project from year 21 to year 45, see Figure 3-5.

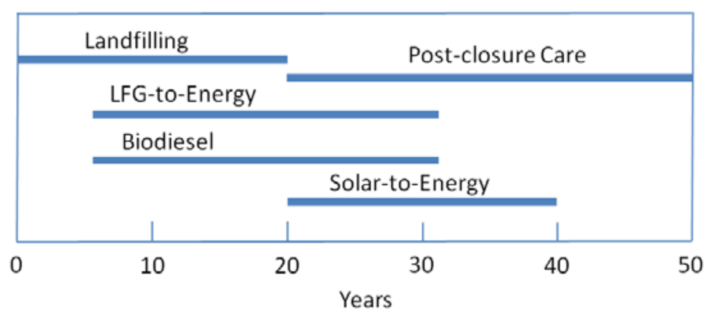

Figure 3-5: Time sequence of green energy projects implemented on a model Landfill Site

NPV benefits for each project activity, including with energy credits, as adjusted to year zero are $7.9 million for LFG-to-energy, $2.1 million for post-closure care, $0.75 million for solar-to-energy, and $0.01 million for biodiesel production. The LFG-to-energy is most promising and provides sufficient return for paying the post-closure expenses. The LFG project also helps to comply regulatory requirements for gas collection and utilization, resulting in a significant reduction of GHG. The solar project is less profitable than the LFG project. However, solar radiation is an unlimited energy source to produce solar electricity on the closed landfill site for as long as the site has no other use. The project can provide continuing electrical demand to the local community with reduction in GHG. The biodiesel project is the least profitable but it essentially can provide the required transportation liquid fuels for the municipality and helps to reduce the dependence on foreign imported oil. The sequential implementation of these green energy projects can provide the optimal and maximum utilization of the land and energy resources for landfilling operations.

3.4. Concluding Remarks

This chapter provides a systems analysis of the sequential development of green energy projects at a modern solid waste management site. Although the analysis was based on currently available sustainable technologies, this chapter has presented a unified methodology for planning new renewable fuel production pathways from landfills including compressed natural gas and liquefied natural gas or other applications. It is found from our analysis that a typical 3-MW LFG-to-energy project using LFG as fuel source is sufficient to power 6500 EV (or 97 million miles traveled by EV) and avoid 39,270 tons of CO_2 emission per MW output. The NPV payback is 10 years or less with an acceptable IRR. Economic modeling analysis of solar electricity suggests a positive return with a NPV payback within the project duration. These two energy projects have the potential to stabilize solid waste tipping fees and galvanize interest and support for other renewable energy and resource projects.

The viability of biodiesel production within the landfill facility is relatively uncertain requiring proper sizing of the in-house processing facility, the economic scale of production and available tax credits. Biodiesel production at the facility scale is not favorable under current economic conditions. Nonetheless, with the aid of $1.00 tax credit per gallon ($0.26 per liter), the operation can result in a NPV payback of 16 years and a benefit-to-cost ratio of 1.17. A regional facility that aggregates feedstock materials from neighboring municipalities provides a more promising model for biodiesel production.

As the concept and function of landfill facilities evolves to resource recovery and renewable energy production, there is a business case for these sites to transition into eco-friendly complexes with implementation of sustainable technologies. A systematic planning and implementation of green energy projects will maximize the land and energy sources, and provide the required funding for post-closure expenses. Landfill sites have excellent infrastructure in terms of road and utility access that facilitate transport of materials to a biomass processing plant or grid interconnection for electricity generation. Energy policies pertaining to carbon credits or tax incentives are the crux to sustained growth of green energy from waste management facilities.

CHAPTER 4: THE ECONOMICS OF MARGINAL CROPLAND BASED BIOFUEL PRODUCTION

4.1. Background and Literature Review

4.1.1. Feedstocks

Biofuels feedstocks can be divided into two broad categories, first and second generation biomass. First-generation feedstocks are generally arable crops, such as sugar cane, sugar beet, and corn grains. Second-generation feedstocks refer to non-arable crops, such as agricultural residues, dedicated energy crops, and cellulosic wastes and algae. Currently, majority of biofuels produced in the US, about 13.3 billion gallons, are from first-generation feedstocks, explicitly corn grain (EIA, 2013). Therefore, the current ethanol production is concentrated in Midwest. However, the increasing of the arable crops based biofuels production can threaten food security and trigger food price increase (Boddiger et al. 2007; Mueller et al. 2008; Gilbert et al. 2010). To address these concerns, EISA 2007 mandate has set a cap for first-generation biofuels production. The corn derived ethanol will not exceed 15 billion gallons (Schnepf and Yacobucci, 2013).

On the other hand, the demand for second-generation biofuel feedstocks will surge. Dedicated energy crops are a promising candidate to meet the increasing demand for cellulosic biofuels. In order to reach 60% lifecycle GHG emissions reduction threshold, the production of feedstocks for cellulosic ethanol is critical. Switchgrass and Miscanthus have been identified as among the best choices for low-input and high dry matter yield per hectare (Lewandowski et al. 2003; Gunderson et al. 2008; Heaton et al. 2008). Both of them have high resilience on soil condition and low demand of water (Lal, 2007; Scheffran et al, 2009; VanLooke et al, 2012). Additionally, Switchgrass and Miscanthus, have been reported to increase soil carbon overtime (Clifton-Brown et al, 2007; Dohleman et al, 2009; Garten et al, 1999; Ma et al, 2000; Liebig et al 2008).

Switchgrass (Panicum virgatum L.), shown in Figure 4-1, is a perennial grass and native to most of North America (Sanderson et al. 1996). It has high biomass yield rate (Heaton et al. 2004). Switchgrass can produce a reasonable amount of biomass on marginal soil and under other unfavorable conditions, such as water-stressed condition (Moser and Vogel, 1995; Mclaughlin et al. 2006; Blanco-Canqui, 2010).There are two ecotypes of switchgrass, lowland and highland. Lowland switchgrass are more suitable for the southeast region than upland switchgrass (Bransby and Huang, 2014).

Miscanthus is a sterile perennial rhizomatous herbaceous crop with the potential to produce comparatively higher biomass per acre than other temperate feedstocks (Heaton et al. 2008; Jain et al. 2010; Somerville et al. 2010). Miscanthus has a genus of 15 species native to Asia and Africa (Hecht, 2011). Certain species have been planted in Japan for thousands of years primarily for forage and thatching. Miscanthus was identified for its high energy yield per hectare and relative low energy input compared to other bioenergy crops (Hastings et al., 2008). The type most commonly grown for biomass is Miscanthus ×giganteus, as shown in Figure 4-1 (Heaton et al., 2012).

FIGURE 4-1: Photo of Switchgrass (Panicum virgatum L.) (left) and Miscanthus x giganteus (right) (USDA)

Beside perennial energy crops, other cellulosic feedstocks, such as agriculture residues, will also contribute significant amount of cellulosic biomass. Crop stover and wood residues are predominantly used in US cellulosic ethanol biorefineries, with a total production capacity of 211.3 million gallons per year in 2014 (Brown et al, 2013). However, a recent research (Liska, et al, 2014) suggests that the lifecycle GHG emissions of corn residue-based biofuel will not reach the 60% reduction threshold to be considered as 2nd generation biofuel without restoring the lost soil organic carbon due to the high residue removal rate.

It is estimated, at an average yield rate of 30 Mg/ha on fertile agriculture land, approximate 12 million hectares of agriculture land (9.3% of current US cropland) are needed to grow Miscanthus as feedstocks in order to produce 133 gigalitre (or 35.1 billion gallons) of ethanol (Heaton, 2008). Less land might be needed, since the yield rates are expected to increase up to 5% per year due to the development in genetics and production technologies (DOE, 2012).

Indirect land use change emission caused by growing dedicated energy crops on cropland will increase 50% more cellulosic biofuel life cycle emissions compared to gasoline (Searchinger et al, 2008). Cropland based dedicated energy crop is not a sustainable energy source to meet the requirement of the EISA 2007 mandate. Producing dedicated energy crops on marginal land is considered to be a sustainable way of providing biofuels feedstock.

To produce the same energy on marginal cropland, perennial energy crops (e.g. switchgrass and miscanthus) based bioethanol requires less energy input and land than corn grain and stover based bioethanol. (Bandaru et al, 2013). As of 2013, the total land enrolled in Conservation Reserve Program (CRP) is 25.58 million acres (or 10.35 million hectares) (USDA, 2013). A research suggested that 14.2 million hectares CRP land are sufficient to produce Miscanthus feedstocks to meet the all of the 35 billion gallons required by EISA 2007 mandate (Somerville et al, 2010). The mandate requirement of cellulosic biofuel is 16 billion gallons per year by 2022, thereby the agriculture land requirement for cellulosic biofuels will be approximately 5.5 million hectares or 6.5 million hectares of the CPR lands. These results are closed to another estimation that about 180 million dry tons of biomass will be produced as feedstocks every year to meet the EISA 2007 mandate (Buchanan, 2010).

Although a significant amount of switchgrass and Miscanthus field trials have been performed (Wullschleger et al. 2010; Miguez et al. 2008), there has been only a limited number of trials that are planted on marginal land (Varvel et al. 2008; Campell, et al. 2008). It was estimated that the marginal land in US Midwest has the potential of producing 5.5 billion gallons/year of cellulosic ethanol (Gelfand et al. 2013).

4.1.2. Marginal Agriculture Land

To address the concerns of indirect land use change, marginal land has been investigated intensively as an alternative for crop land. The detailed definitions of marginal land widely vary (Shortall, 2013). The marginal land is first defined from a purely economic perspective as land on the “margins of cultivation”, which include the “poorest land which can be remuneratively operated under given price, cost and other conditions.” (Peterson and Galbraith, 1932).

But in practice, marginal lands are also classified based on soil productivity or land physical limitations (Kang et al, 2013). In crop production context, the land with low crop productivity is considered as marginal. Other circumstances, such as contamination, erodibility, salinity and water excess etc. will also qualify a land as marginal. Some other terms that mutually exchangeable for marginal land are unproductive, under-utilized lands, idle, abandoned or degraded lands.

Numerous studies have been performed to estimate the acreage of marginal land worldwide. Different studies have different marginal land selection criteria (Larson, 1988; Mibrandt and Overend, 2009; Zhuang et al, 2011; Cai et al, 2011; Lewis and Kelly, 2014), which leads to diverse estimates of marginal land availability (Table 4-1). Marginal cropland, as defined by these studies, refers to idle or fallow cropland, abandoned farmland, or abandoned pastureland. Campbell et al. (2008) suggested that about 384 to 471 million hectares are available globally while approximately 56 to 60 million hectares in the United States. Cai et al. (2011) estimated 43 to 127 million hectares marginal agriculture land are available in US. Milbrandt et al. (2014) calculated the total marginal land in contiguous US to be approximately 78 million hectares, 68.3

million hectares of which are abandoned cropland. Perlack et al. (2005) projected that land enrolled in Conservation Reserve Programs (CRP) in the United States could be utilized for energy crop production. The total CRP enrollment by November 2013 is 10.36 million hectares (or 25.6 million acres).

Other types of marginal land, such as Right-Of-Way (Myer, 2011), landfill (Martin et al. 2006), and brownfield (Lord et al. 2008), have also been investigated for energy crop production. Milbrandt et al. (2014) estimated that the road and railroad Right-of-Way in the US totals 2.7 million hectares. The total amount of space given over to landfill is roughly 0.23 million hectares (EPA, 2013).

Various studies (Campbell et al. 2008; Perlack et al. 2005; Cai et al. 2011; Milbrant et al. 2014) have suggested that adequate marginal cropland is available that can be used for energy crop production without significantly impacting current land uses and reduce lifecycle greenhouse gas emissions. The economic feasibility and competitiveness of other types of marginal lands are not clear. In this research, the economics of integrated marginal cropland based energy production methods will be analyzed.

Defining marginality of land is complex. In this study, the marginal cropland is defined by U.S. Department of Agriculture (USDA) 2012 Census, under the following three categories, a) cropland idle or used for cover crops or soil-improvement but not harvested and not pastured or grazed; b) cropland on which all crops failed or were abandoned; and c) land enrolled in Conservation Reserve or Conservation Reserve Enhancement Programs. Data were collected through a literature review and examining land use and land cover databases. The total qualified marginal cropland in the study area is 2.45 million hectares. Table 4-1 shows the breakdown of marginal croplands in each of the studied state.

TABLE 4-1: Marginal agriculture land data

	Idle Cropland ha	Failed Cropland ha	CRP ha	Marginal cropland million ha
AR	126,290	35,922	96,566	0.2588
LA	179,450	15,064	125,162	0.3197
MS	225,916	15,329	388,387	0.6296
AL	152,874	13,370	157,361	0.3236
TN	130,610	21,293	72,738	0.2246
GA	145,642	16,386	122,067	0.2841
SC	85,533	13,780	55,650	0.1550
NC	79,955	12,775	42,859	0.1356
FL	76,361	18,494	21,971	0.1168

Source: 2014 USDA census data.

The USDA census data shown of Table 4-1 is significant less than the other marginal cropland estimation, such as data shown in Milbrandt (2014) data which was derived from the gridded map and is not accurate due to the outdated dataset used by the research. The table 4-1 is more close to the reality of currently available marginal cropland.

4.1.3. Biorefineries

The infrastructure for corn ethanol production is well developed. There are 198 corn ethanol refineries, most of which are located in the Midwest US and only 5 corn ethanol refineries in the Southeast US. The quantity of corn used by these biorefineries was relatively small compared to the total corn production of the US. The total production of corn in 2013 was reported to be 13 billion bushels, 27% of which was used to produce ethanol (USDA, 2014).

In contrast, the cellulosic biofuel industry is still in its infancy and the cellulosic feedstock demand is small and unstable. The 2013 US cellulosic biofuel production is less than 0.3 million gallons and the combined nameplate capacity of 2 online commercial-scale cellulosic ethanol biorefineries, which are located in Mississippi and Florida, is about 21 million gallons per year (Peplow, 2014). In order to meet the mandate, it is estimated that the number of cellulosic ethanol refineries starts with 20 in 2015 and increases to 273 in 2022. The smallest cellulosic ethanol plant has an annual production capacity of 25 MG, whereas the average plant size is 61 MG. (USDA, 2010; Chen and Onal, 2014). About half of these new cellulosic biorefineries are going to be built close to the supply of biomass feedstock in the southeast US (Chen and Önal, 2014).

4.2. Data and Methodologies

This chapter proposes to formulate an economic model, which will estimate the levelized cost of cellulosic bioethanol. The cost structure for cellulosic biofuel production has two components that are essential to the model structure. First, a cellulosic biofuel plant will depend on a local market for sufficient biomass supply. However, currently cellulosic biomass is not a commodity and regional or national biomass markets do not exist (Ortiz et al., 2011). Potential cellulosic biofuel biorefineries will therefore make production decisions based on local biomass supply conditions rather than regional or national supplies and prices. Secondly, as the size of biorefineries increase, not only the initial investment will rise, the feedstock procurement will also increase due to delivery and storage cost increase. The reason of delivery cost increase is because larger supply demands will require feedstock delivered from more distinct sites.

On the basis of the two components, the model minimizes feedstock procurement and processing costs per gallon by choosing optimal biorefinery size and price paid to farms to purchase feedstock.

The levelized cellulosic biofuel cost economic model is expressed as follows:

$$C\left(Q_{l,i},\mathrm{P}_{l,i}\right)=\left\{\underbrace{\frac{1}{\gamma}\times\left[P_{l,i}+S+T(Q_{l,i})\right]}_{Feedstock\_procurement\_\mathrm{cost}}+\underbrace{\left[Co_{l,i}+C_{ca}(Q_{l,i})\right]}_{Biofuel\_\mathrm{conversion\_costs}}\right\} \tag{1}$$

$$T(Q)=TRC\times R \tag{2}$$

$$\mathrm{R}=\sqrt{\frac{Q_{l,i}}{\pi\times y_{l,i}\times\gamma\times\omega}} \tag{3}$$

$$C_{ca}(Q_{l,i})=\frac{Aw(Cap(Q_{l,\mathrm{i}}))}{Q_{l,i}}=\frac{Aw(Cap(Q_0)\times(\frac{Q_{l,i}}{Q_0})^k)}{Q_{l,i}} \tag{4}$$

$$Aw=NPV\times\frac{r}{1-\frac{1}{(1+r)^t}} \tag{5}$$

Where *l* donates identification the identification of a biorefinery,

i denotes the state in which the biorefinery locates,

$Q_{l,i}$ denotes the capacity of biorefinery *l* in state *i*, M gal/year,

$\mathrm{P}_{l,i}$ denotes the price that biorefinery *l* has to pay to the pay in State *i*, $/Mg,

C($Q_{l,i}$, $P_{l,i}$) denotes the annualized cellulosic biofuel production cost, $/gal, when the biorefinery capacity is $Q_{l,i}$ and the biomass price is $P_{l,i}$,

γ denotes the conversion rate of $/Mg to $/gal, depending on biomass to fuel conversion rate of the biorefinery,

T(Q) denotes average biomass per Mg transportation cost, $/Mg,

TRC denotes the transportation cost of biomass, $/Mg/mile, *S* denotes the biomass storage cost for the biorefinery with Q capacity, \$/Mg,

ω donates the marginal land percentage in the biorefinery supply area

$Co_{l,i}$ denotes the per gallon operation cost of a biorefinery, \$/gal,

$C_{ca}(Q_{l,i})$ denotes the annualized per gallon capital cost of a plant with Q capacity, \$/gal,

$y_{l,i}$ denotes the feedstock yield around biorefinery *l* at State *i*

Aw denotes annul worth equation,

t denotes the life time of the refinery

r denotes the interest rate

k denotes an economic scale factor,

$Cap(Q_{l.i})$ donate the capital cost of the plant with the capacity of Q at State *i*,

NPV denotes net present value, here is the capital cost of a refinery.

4.2.1. Feedstock Procurement Cost

Feedstock procurement cost is the collective cost of purchasing, transporting and storing the biomass used to produce one gallon cellulosic biofuel for a plant size Q biorefinery. The storage cost and transportation cost are adopted from literatures, which are \$18.43 per Mg and \$0.9 per Mg per mile (Miranowsk, 2010). The study is focusing the feedstock purchasing price.

Currently the sustainably harvested agriculture residues were estimated to be about 120 million dry Mg/year in US, which could produce 5 billion gallons of cellulosic ethanol per year (Kim and Kim, 2014); woody biomass is expected to be about 44.7 to

102.8 million dry tons per year by 2022, which could produce 4 to 9.2 billion gallons of cellulosic ethanol per year (Buchanan, 2010). After considering agriculture residues and woody residues, the portion that actually dedicated energy crop based cellulosic biofuel will contribute to the EISA 2007 mandate is about 1.8 to 7 billion gallons per year by 2022 and 0.62 to 2.39 million hectares of agriculture land are needed to produce the required dedicated energy crop.

In order to provide sufficient feedstocks, the large-scale deployment of dedicated energy crops is inevitable. The land change and land management practices associate with the large-scale deployment of dedicated energy crops could have impacts on ecological systems (Chapin et al. 2000; Searchinger et al. 2008), water quality and the soil organic carbon balance (Bhardwaj et al. 2011). Some researchers indicated that cellulosic biofuels would increase greenhouse gas emissions by 50% if grown on US corn lands (Searchinger et al. 2008), while other research suggested dedicated energy crops have the potential to avoid more GHG emissions than conventional crops. Fargione et al. (2008) noted that growing these crops on degraded and abandoned lands might gain little or no carbon debt. Similarly, it was also suggested that growing cellulosic feedstocks on degraded lands or environmentally sensitive croplands could increase carbon sequestration and improve water quality (Robertson et al. 2008; Robertson et al. 2010).

It is hard to predict the exact amount dedicated energy crops yield, given the fact that dedicated energy crop yield varies considerably across regions and from year to year (Hoogwijk et al. 2003; Price et al. 2004). Upland switchgrass and lowland switchgrass have mean biomass yields of 8.7±4.2 Mg/ha and 12.9±5.9 Mg/ha, respectively (Wullschleger, 2010). Lowland cultivar, specifically Panicum virgatum L., has higher yield than other cultivars (Fike et al., 2006). Miscanthus has a potential yield rate of 10-40 Mg/ha/year (RFS2, 2013). The literature review of field yield data from cropland is listed in Table 4-2.

Miscanthus× giganteus biomass productivity data in the United States is scarce and testing of the model has been limited to Illinois (Heaton et al., 2008; Dohleman et al., 2009; Dohleman & Long, 2009). The Miscanthus× giganteus could be 2.2 times more productive than Switchgrass (Arundale, 2012 and Miguez et al., 2012). The switchgrass yield is larger than 12 Mg/ha in 84% of the 9 southeastern States. And almost 40% of the counties has miscanthus yield rate larger than 29 Mg/ha (Table 4-3).

TABLE 4-2: Energy crops established yield rate in study area

Switchgrass yield, Mg dm/ha	AL	AR	GA	MS	NC	SC	LA	TN	FL
min	11	12	3	12	8	8	11	8	2
max	19	18	19	19	21	20	21	19	19
average	16	16	14	18	15	15	18	16	12
median	16	16	15	18	15	16	18	17	12
variance	5	3	10	2	13	10	4	5	21
standard deviation	2	2	3	1	4	3	2	2	5

Miscanthus yield, Mg dm/ha	AL	AR	GA	MS	NC	SC	LA	TN	FL
min	19	1	8	16	2	10	4	15	2
max	34	32	32	34	35	34	34	33	33
average	26	25	22	30	22	23	25	27	18
median	26	28	23	32	23	25	30	27	15
variance	9	73	52	16	92	46	87	14	93
standard deviation	3	9	7	4	10	7	9	4	10

Data source maps.nrel.gov update 2015 dm = dried mass

TABLE 4-3: Energy crops yield rate distribution

Switchgrass yield	County	Percentage
<8 t/ha	28	4%
9-11 t/ha	90	11%
12-14 t/ha	142	18%
15-17 t/ha	277	35%
18-21 t/ha	260	33%
Miscanthus yield	County	Percentage
<8 t/ha	40	5%
9-14 t/ha	83	10%
15-21 t/ha	90	11%
22-28 t/ha	271	34%
29-35 t/ha	313	39%

Although the food crops yield rate on marginal land is much lower than on fertile agriculture land, marginal land has less impact on perennial energy crops yield potential than conventional crops. Soil type and soil texture have non-significant impact on Switchgrass and Miscanthus biomass yield (Parrish and Fike, 2005). Corn-soy cropping systems produce 12 -15% less on marginal cropland than on croplands, while perennial systems yield only 7 to 9% less (Bandaru et al, 2013). A non-irrigated marginal cropland field study in Nebraska shows the switchgrass potential ethanol yield was equal to or greater than the potential ethanol yield of corn grain and harvested stover (at 51% harvest rate). Another study suggested at current yield rate the overall mean reduction of switchgrass yield is 1 Mg/ha on marginal land (Wullschleger, 2010). In this study, switchgrass (Panicum virgatum L.) and Miscanthus×giganteus yield on marginal cropland are estimated by regional field studies with the assumption that the energy crops yield 9% less.(Table 4-4) (Bransky and Huang, 2014; Palmer et al., 2014).

TABLE 4-4: Estimated marginal land energy crop potential, million tons DM

Switchgrass	AL	AR	GA	MS	NC	SC	LA	TN	FL
min	3.11	2.92	0.90	6.99	1.01	1.11	3.34	1.55	0.19
max	5.69	4.34	4.98	11.17	2.61	2.80	6.19	3.90	2.01
average	4.61	3.70	3.59	10.33	1.80	2.16	5.22	3.35	1.30

Miscanthus	AL	AR	GA	MS	NC	SC	LA	TN	FL
min	5.68	0.18	2.05	9.38	0.19	1.38	1.25	3.14	0.24
max	9.98	7.56	8.15	19.28	4.33	4.73	10.00	6.78	3.55
average	7.75	5.79	5.74	17.17	2.68	3.27	7.28	5.58	1.92

Stand length for switchgrass ranges between 10 and 20 years (Khanna, 2008; Khanna et al., 2008; Khanna and Dhungana, 2007; Lewandowski et al., 2003); Miscanthus stand length ranges from 15 to 25 years (Heaton et al., 2004). In this study, the life time of Miscanthus× giganteus and switchgrass (Panicum virgatum L.) is assumed to be 15 and 10 years, respectively (Jain et al., 2010). It will take one year for both of the crops to become established after initial planting, which mean there will be no yield in the first year. In the second year, Miscanthus× giganteus and switchgrass (Panicum virgatum L.) will reach peak biomass yield.

The cost of switchgrass production varies by locations and management. The establishment costs and maintenance costs were estimated based on available data. Busby et al. (2007) estimated the cost of switchgrass production in Mississippi is about $671 per hectare. The cost in Tennessee was projected to be $655.36 per hectare (UT Extension, 2009). Perennial energy crops tend to have high costs in the establishment year, with lower annual costs the remainder of the productive life (Soldatos, et al., 2004). Miscanthus× giganteus cost 50% to 200% more than Switchgrass(Panicum virgatum L.) to establish due to higher seeding cost and land preparation cost (Khanna et al., 2008; Bansal, 2014). Due to lack of Miscanthus× giganteus field data, it is assumed that the establishment cost of Miscanthus× giganteus is 2 times of the switchgrass for the same state (Figure 4-2). The management cost after the first year is 2/3 of establishment cost. Figure 4-2 shows the average Switchgrass costs in each State. Figure 4-3 shows the estimated Miscanthus× giganteus cost for each State.

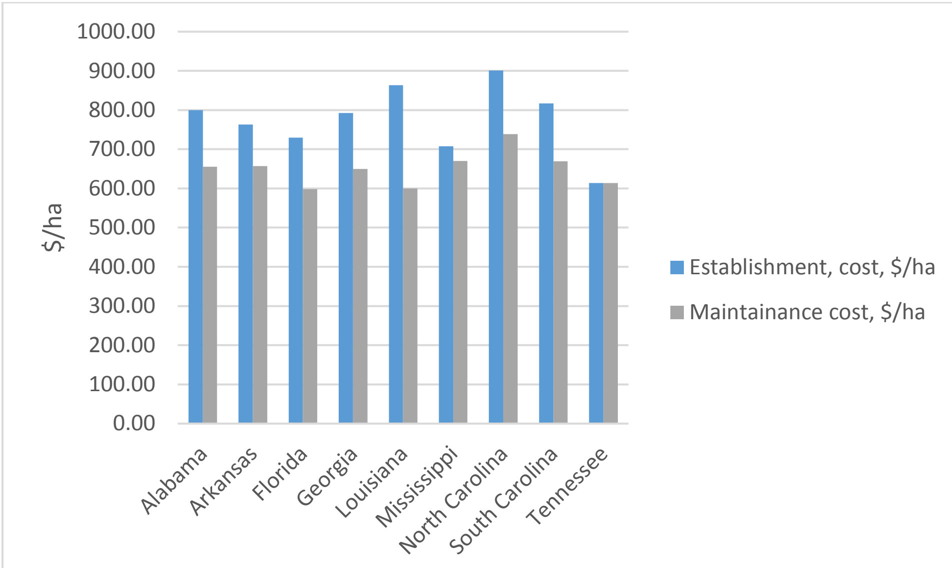

FIGURE 4-2: Switchgrass production costs (2014$)

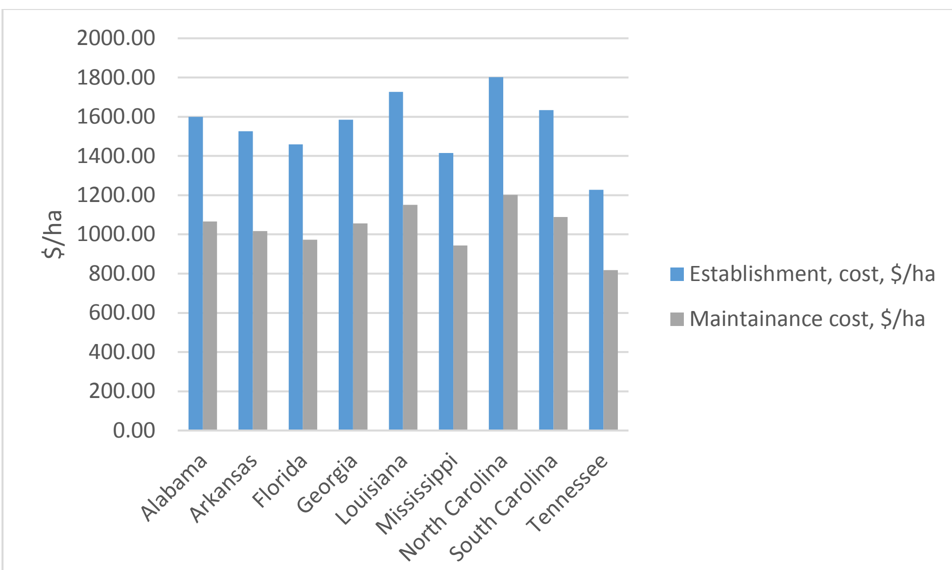

FIGURE 4-3: Miscanthus production cost (2014 dollars)

The federal government subsidizes cellulosic biomass production through the Biomass Crop Assistance Program (BCAP). The study included BCAP incentives for switchgrass and Miscanthus. The BCAP paid 75% of establishment costs, up to a predetermined maximum, for planting either perennial grass cropping system. These establishment costs were in the first or second years of production. The establishment costs for both Miscanthus and switchgrass can be treated as initial investment considering there is no biomass production in the first year. The annualized costs for both Miscanthus× giganteus and switchgrass is shown in Figure 4-4.

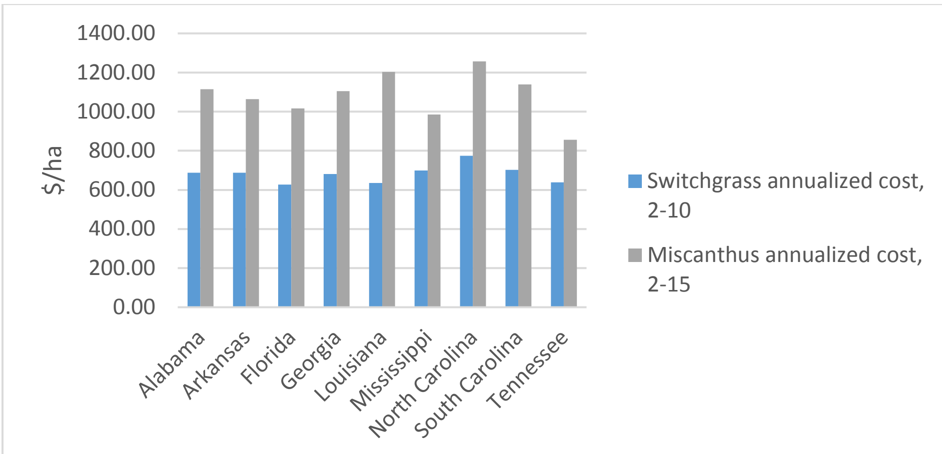

FIGURE 4-4: Switchgrass and Miscanthus annualized cost (with BCAP subsidies)

The Miscanthus× giganteus and Switchgrass production costs were estimated using the annualized cost and average yield rate in each State (Table 4-5).

The market for cellulosic feedstocks trade as bioenergy crops do not exist (Epplin et al. 2007; Ortiz et al., 2011). As a result, no reliable prices are available to use in calculating fair market price. Determining a price for cellulosic feedstock for biofuel production is challenging. Many studies use the breakeven price that is expected to make switchgrass competitive with corn as an ethanol feedstock (Mooney et al., 2009; Bangsund et al., 2008; James et al., 2010). The breakeven price of switchgrass ranges from $46 per dry Mg to $69 per dry Mg in a Tennessee study (Mooney et al., 2009). Another study show the breakeven price for switchgrass and Miscanthus is $130 per dry

Mg and $200 per dry Mg, respectively (James et al., 2009) while corn price ranges from $140 per dry Mg to $ 271 per dry Mg in the past 8 years (USDA, 2015).

In order to make cellulosic feedstocks competitive to corn and attractive to farmer, this study considers setting the upper bound price at the price of corn. A lower bound on cellulosic feedstock price would be the price that farmers are willing to accept, which is set to at least 8% higher than the feedstock production cost. The cost of Switchgrass and Miscanthus production in each state are calculated in Table 4-5. In this study, the biomass price is set by the lower cost of the two bioenergy crops. The Price-Willing-to-Accept is about 8% higher than the lower cost of the two bioenergy crops. The market price of feedstock is decided by the lower cost feedstock. Therefore, Switchgrass is more economical in the states of Florida, Georgia, Louisiana, North Carolina and South Carolina; and Miscanthus will be the feedstock choice for the other 4 states. The price willing to accept is assumed to be equal to biorefinery feedstock purchase price ($P_{l,i}$).

TABLE 4-5: Feedstock production cost comparison and Price-Willing-to-Accept (PWA), $/Mg

	without deduction			with deduction		
	Switchgrass	Miscanthus	PWA	Switchgrass	Miscanthus	PWA
Alabama	$54.99	$52.61	$56.8	$48.25	$46.54	$50.3
Arkansas	$54.54	$53.75	$58.1	$48.13	$47.55	$51.3
Florida	$64.30	$69.86	$69.4	$56.42	$61.80	$60.9
Georgia	$61.51	$61.79	$66.4	$53.97	$54.65	$58.3
Louisiana	$45.18	$59.77	$48.8	$38.83	$52.87	$41.9
Mississippi	$47.74	$40.88	$44.2	$42.56	$36.16	$39.1
North Carolina	$66.33	$71.88	$71.6	$58.21	$63.59	$62.9
South Carolina	$57.39	$61.07	$62.0	$50.36	$54.02	$54.4
Tennessee	$49.29	$47.56	$51.4	$43.25	$42.07	$45.4

Note: underlining price set the biomass market price

4.2.2. Biofuel Conversion Cost

Biofuel conversion costs include biorefinery capital costs and operation cost. Operation costs ($Co_{l,i}$) is assumed to independent of plant size (Kazi et al., 2010). The capital costs of advanced biochemical and thermochemical biorefineries is comparable in term of same plant capacity (Wright and Brown, 2007). In this study, it is assumed all the biorefineries use the advanced biochemical technology. Capital costs of biorefinery are assumed to be related to the plant size and exhibit an economic power function (Brown, 2003), which is shown in equation 4, k=0.7. Cap(Q_0) is an economic estimation for per gallon capital cost for a plant of size Q_0.

The study was designed to consider three currently popular plant sizes, 30, 60 and 90 million gallons per year. Two commercialized cellulosic biorefineries have suggested that the capital cost for a 30 million gallons per year plant is about $200 million (Peplow, 2014). The capital cost of each plant size is $200, $325, and $432 million, respectively, calculated by equation (4) and (5). Values for selected parameters are reported in Table 4-6. The equations show that the feedstock to ethanol conversional rate has no impacts on the biofuel capital cost. However, higher conversional rates will require less feedstock, which in turn reduce the cost of purchasing, transporting and storage cost.

TABLE 4-6: Different sizes biorefinery capital cost

	Capital cost, million $	Biorefinery capacity, Million gals	Biofuel capital cost, $/gal
Small	200	30	0.68
Medium	325	60	0.55
Large	432	90	0.49

All plants are assumed to be single-feedstock conversion plants using either corn Switchgrass or Miscanthus feedstock; Capital costs for a 30 million gal/year plant is about $200 million ($2014). Assuming a t=20 year plant life, an interest rate of 8% (r), and an ethanol yield of 60-100 gallons per Mg of biomass (γ) (Wright and Brown, 2007). Excess electricity from burning lignin (a co-product of processing) is assumed to be sold to the power grid. After accounting for this co-product credit, operating costs ($Co_{l,i}$) are estimated as $0.11 per gallon (Kazi et al., 2010). The operation cost was inflated to 2014 dollas $0.13 per gallon using CPI inflation ratio through US Department of Labor.

The feedstock demand of a biorefinery is determined by the biorefinery capacity and its feedstock conversion rate. With the development of cellulosic ethanol process, the conversional rate of feedstock to ethanol will increase (Lynd et al., 2004). Three scenarios were considered in this study. Scenario 1: the low conversion rate of feedstock, 60 gallons per Mg dry feedstock. Scenario 2: the high conversion rate of feedstock, 80 gallons per Mg dry feedstock. Scenario 3: the advanced conversion rate of feedstock, 100 gallons per Mg dry feedstock. The feedstock demand of different size of biorefinery and conversion technology are listed in Table 4-7.

TABLE 4-7: Feedstock demand of biorefineries, Mg/year

	Biorefinery Feedstock demand, million Mg/year		
Feedstock conversional rate, gal/Mg	Small (30)	Medium (60)	Large (90)
60	0.50	1	1.5
80	0.38	0.75	1.1
100	0.30	0.60	0.9

The marginal croplands in most of the study area are not distributed evenly across the state. However, in this study, it was assumed that the marginal croplands are distributed evenly in each state. The percentage of land that can supply biomass to the biorefinery equals to: ω= area of marginal land/ half of state land area (Table 4-8). Equation 6 was used to calculated the biorefinery collection radius and assume the radius is the feedstock average transportation mileage. The results were listed in Table 4-9.

TABLE 4-8: Marginal land distribution rate

State	ω	State	ω
Alabama	0.048	Mississippi	0.100
Arkansas	0.038	North Carolina	0.019
Florida	0.014	South Carolina	0.037
Georgia	0.037	Tennessee	0.041
Louisiana	0.047		

TABLE 4-9: Average transportation mileage, miles

	Low conversional rate (60gal/Mg)			High conversional rate (80gal/Mg)			Advanced conversional (100gal/Mg)		
	small	medium	large	S	M	L	S	M	L
Alabama	21	30	57	18	26	31	16	23	28
Arkansas	32	45	56	28	39	48	25	35	43
Florida	71	100	122	61	87	106	55	77	95
Georgia	34	48	58	29	41	50	26	37	45
Louisiana	23	32	59	20	28	34	18	25	31
Mississippi	20	29	42	18	25	31	16	22	27
North Carolina	41	58	71	36	50	62	32	45	55
South Carolina	28	40	65	25	35	43	22	31	38
Tennessee	22	32	61	19	28	34	17	25	30

4.3. Results and Discussion

Table 4-10 summarizes the biofuel production cost in each state under different production scenarios. The State of Florida has the highest biofuel production cost ($4.62 per gallon) in the region, while Tennessee has the lowest biofuel production cost ($3.25 per gallon).

TABLE 4-10: Biofuel production cost, $/gal (without tax deduction)

	60gal/Mg			80gal/Mg			100gal/Mg		
	small	medium	large	S	M	M	S	M	L
Alabama	$3.59	$3.59	$3.94	$3.15	$3.11	$3.11	$2.90	$2.83	$2.82
Arkansas	$3.56	$3.63	$3.72	$3.11	$3.11	$3.15	$2.86	$2.82	$2.83
Florida	$4.62	$4.93	$5.21	$3.85	$4.01	$4.17	$3.42	$3.49	$3.59
Georgia	$3.61	$3.69	$3.79	$3.15	$3.16	$3.20	$2.89	$2.86	$2.87
Louisiana	$3.62	$3.63	$3.97	$3.17	$3.13	$3.15	$2.91	$2.85	$2.84
Mississippi	$3.47	$3.46	$3.60	$3.06	$3.01	$3.02	$2.83	$2.76	$2.74
North Carolina	$3.64	$3.77	$3.91	$3.16	$3.20	$3.27	$2.89	$2.88	$2.91
South Carolina	$3.54	$3.58	$3.89	$3.10	$3.09	$3.11	$2.85	$2.80	$2.81
Tennessee	$3.25	$3.26	$3.64	$2.89	$2.86	$2.86	$2.69	$2.63	$2.62

The average cost of cellulosic biofuel production is not competitive comparing to gasoline prices in the last decade. However, cellulosic biofuel production might be eligible for federal biofuel producer tax credits, which is up to $1.01 per gallon. The cellulosic biofuel production cost with the consideration of a tax deduction is listed in Table 4-11.

TABLE 4-11: Biofuel production cost, $/gal (with tax deduction)

	60gal/Mg			80gal/Mg			100gal/Mg		
	small	medium	large	S	M	L	S	M	L
Alabama	$2.58	$2.58	$2.93	$2.14	$2.10	$2.10	$1.89	$1.82	$1.81
Arkansas	$2.55	$2.62	$2.71	$2.10	$2.10	$2.14	$1.85	$1.81	$1.82
Florida	$3.61	$3.92	$4.20	$2.84	$3.00	$3.16	$2.41	$2.48	$2.58
Georgia	$2.60	$2.68	$2.78	$2.14	$2.15	$2.19	$1.88	$1.85	$1.86
Louisiana	$2.61	$2.62	$2.96	$2.16	$2.12	$2.14	$1.90	$1.84	$1.83
Mississippi	$2.46	$2.45	$2.59	$2.05	$2.00	$2.01	$1.82	$1.75	$1.73
North Carolina	$2.63	$2.76	$2.90	$2.15	$2.19	$2.26	$1.88	$1.87	$1.90
South Carolina	$2.53	$2.57	$2.88	$2.09	$2.08	$2.10	$1.84	$1.79	$1.80
Tennessee	$2.24	$2.25	$2.63	$1.88	$1.85	$1.85	$1.68	$1.62	$1.61

The feedstock conversion rate has a significant impact on the biofuel production cost (Table 4-12). For small scale plants, increasing the conversion rate by 34% will reduce the biofuel production cost from 16% to 18%; increasing the conversion rate by 67% will reduce the biofuel production cost from 25% to 29% (except Florida). For medium scale plants, increasing the conversion rate by 34% will reduce the biofuel production cost from 18% to 20%; increasing the conversion rate by 67% will reduce the biofuel production cost from 28% to 31% (except Florida). For large scale plants, increasing the conversion rate by 34% will reduce the biofuel production cost from 21% to 29%; increasing the conversion rate by 67% will reduce the biofuel production cost from 33% to 39%.

TABLE 4-12: Sensitivity analysis of conversion rate impacts on biofuel production cost

	60gal/Mg			80gal/Mg			100gal/Mg		
	small	medium	large	S	M	L	S	M	L
Alabama	$2.58	$2.58	$2.93	-17%	-19%	-28%	-27%	-29%	-38%
Arkansas	$2.55	$2.62	$2.71	-17%	-20%	-21%	-27%	-31%	-33%
Florida	$3.61	$3.92	$4.20	-21%	-24%	-25%	-33%	-37%	-39%
Georgia	$2.60	$2.68	$2.78	-18%	-20%	-21%	-28%	-31%	-33%
Louisiana	$2.61	$2.62	$2.96	-17%	-19%	-28%	-27%	-30%	-38%
Mississippi	$2.46	$2.45	$2.59	-16%	-18%	-23%	-26%	-29%	-33%
North Carolina	$2.63	$2.76	$2.90	-18%	-21%	-22%	-29%	-32%	-34%
South Carolina	$2.53	$2.57	$2.88	-17%	-19%	-27%	-27%	-30%	-38%
Tennessee	$2.24	$2.25	$2.63	-16%	-18%	-29%	-25%	-28%	-39%

When the plants have the same conversion rate, increasing plant scale doesn't necessarily guaranty a decrease in the cellulosic biofuel production cost (Table 4-13). When the conversion rate is at low level, 60 gallon/Mg, increasing the plant size will increase the cost of biofuel production. When the conversion rate reaches a high level, 80 gallon/Mg, the cost change varies among different states. At high conversional level, increasing the plant scale in Alabama, Louisiana, Mississippi and Tennessee will reduce the cost of biofuel production; the cost of biofuel production in Florida, Georgia and North Carolina will not decrease with the scale of the plant. Three different size plants in Arkansas have similar biofuel production cost, while it cost about 1.9% more to produce biofuel from large scale plant than small and medium size plants in Arkansas.

TABLE 4-13: Sensitivity analysis of plant size impacts on biofuel production cost

	60gal/Mg			80gal/Mg			100gal/Mg		
	small	medium	large	S	M	L	S	M	L
Alabama	$2.58	-0.01%	13.61%	$2.14	-2.13%	-1.92%	$1.89	-3.69%	-4.41%
Arkansas	$2.55	2.73%	6.39%	$2.10	-0.01%	1.87%	$1.85	-2.01%	-1.40%
Florida	$3.61	8.57%	16.24%	$2.84	5.47%	11.06%	$2.41	3.08%	7.10%
Georgia	$2.60	3.03%	6.88%	$2.14	0.26%	2.32%	$1.88	-1.75%	-0.98%
Louisiana	$2.61	0.45%	13.58%	$2.16	-1.75%	-1.26%	$1.90	-3.37%	-3.86%
Mississippi	$2.46	-0.14%	5.64%	$2.05	-2.33%	-2.18%	$1.82	-3.92%	-4.74%
North Carolina	$2.63	4.77%	9.94%	$2.15	1.68%	4.81%	$1.88	-0.59%	1.07%
South Carolina	$2.53	1.83%	14.22%	$2.09	-0.75%	0.58%	$1.84	-2.61%	-2.46%
Tennessee	$2.24	0.44%	17.37%	$1.88	-2.08%	-1.57%	$1.68	-3.87%	-4.47%

CHAPTER 5: ECONOMIC AND ENVIRONMENTAL ANALYSIS OF ALTERNATIVE FUEL VEHICLES

5.1. Background

The US transportation sector currently consumes 14 million barrels of crude oil per day, which amounts to 70% of the total domestic fuel consumption (US EIA, 2012). Electric vehicles are one possible option to lengthen the available oil reserves. Annual sales of electric-hybrid vehicles have grown from 1% of total sales in 2004 to 4.4% in 2011 in the United States. These vehicles did not, however, include the possibility of charging the electric-hybrid vehicles by plugging in the vehicle to an external electric outlet. Plug-in hybrid electric vehicles only became available in the US automobile market in 2010 with sales of less than 400 cars; however, plug-ins were so popular that by 2011 more than 17,700 were sold. Federal tax incentives have also played a role in improving consumer affordability, which is essential to build a sustainable road transport system for the next 5 to 10 years. Nonetheless, the economic feasibility and environmental impact of a large-scale deployment of electric vehicles remains problematic.

The purpose of this research is to analyze the economic and environmental benefits of electric-hybrids as compared to conventional cars, emphasizing the impact of tax incentives upon consumer affordability for the next 5 to10 years. A life-cycle cost analysis is used to determine the lifetime total costs of ownership, energy consumption, and emission abatement. Relevant cost data for energy consumption, environmental damage due to air emissions, and non-operating expenditures are obtained from the most currently published data sources. Specifically, the research attempts to answer the following three questions:

1. What are the economic prospects for electric/hybrid vehicles in the next 5–10 years?
2. What is the impact of uncertainty in the lifetime costs that result from fluctuations in energy prices?
3. What are the environmental benefits for electric vehicles?

5.2. Literature Review

Electric vehicles (EVs) and hybrid electric vehicles (HEVs) are more environmentally friendly transportation means with low tailpipe emissions of air pollutants and greenhouse gases (GHGs). When compared to conventional internal combustion engines (ICEs), EVs are rated by higher energy conversion efficiency and better running performance, but can be limited by short driving range, long recharge time, high battery cost, and heavier curb weights. Capital costs for battery electric powertrains are more expensive than the conventional ICE powertrain. However, the battery cost was predicted to drop significantly by 2030 as battery technology improves (Offer et al., 2010). In comparison to HEVs, EVs may be more advantageous in environmental terms provided the required electrical charge can be obtained from renewable energy sources or with on-board electricity generating operations (Granovskii et al., 2006).

The plug-in hybrid electric vehicles (PHEV) are very similar to the regular HEVs and include an internal battery pack to be plugged into an electrical outlet for extending traveling mileage and, at the same, decrease GHG emission. PHEVs are believed to be the competitive electric-car technology in the multipurpose vehicle field (Bento, 2010). PHEVs are competitive when driving longer distances on electricity and/or if the cost of batteries are reduced significantly (Oscar et al., 2010). A single overnight charge that provides 80% of the total driving miles using a domestic power supply requires the least effort to upgrade the electricity network.

Hybrid electric vehicles, such as the 2001 Toyota Prius, was shown to be less cost-effective in improving fuel economy or lowering emissions unless the gasoline price increased to a real price of about $3.60 per gallon (Lave and Maclean, 2002). In addition, the societal cost for abating tailpipe emissions ought to be 14 times greater than conventional values, or the cost of abating GHG exceeded $217 per ton. This 2002 analysis, which assumed a driving distance of 250,000 km (155,000 miles) spreading uniformly over 14 years, apparently exaggerated the pollution abatement costs in order to break even between fuel savings and the price premium. As a result, the consumer market for HEVs has not been observed to greatly improve when the gasoline price was $3.60 per gallon in 2012.

Ogden et al. (2004) incorporated environmental and oil insecurity externalities to demonstrate that vehicles equipped with advanced ICEs or adopting hybrid electric options could be lower in life-cycle cost than conventional ICEs for driving at 12,000 miles/year over 10 years. The insecurity cost was valued at $0.35–$1.05 per gallon of gasoline-equivalent, based on military expenditures needed for retaining access to the Persian Gulf oil resources. As the current energy policy is calling for diversification of oil-importing sources, this so-called insecurity cost must be carefully assessed to avoid overestimates of the life-cycle cost for conventional ICEs. Constestabile et al. (2011) conducted a review of alternative fuel vehicles in terms of energy use, GHG emissions, energy security, and environmental and economic implications, and also a study to analyze the impact of different approaches and assumptions for alternative fuels and vehicles. The study employs a lifetime vehicle mileage of 109,000 miles (175,420 km) and a scrappage age of 13.2 years, as well as includes projections for the year of 2030 by which time it is assumed that all technologies would be fully developed and mass produced. The authors concluded that driving patterns and building different vehicle segments ought to be considered in the total-cost-ownership analysis. Without these considerations, cost comparisons of alternative options are similar within the margin of error.

Previous studies tend to use different datasets and criteria, making their results not likely to be comparable particularly for assessing the consumer affordability of electric-hybrid vehicles. There is a need to re-evaluate the lifetime cost analyses performed by previous researchers (e.g. Lave and Maclean, 2002 and Ogden et al., 2004) as new energy policies and consumer awareness emerge. Our research intends to fill such an information gap by performing the lifetime cost analysis using a consistent and reliable dataset that is available to the public. We also include tax incentives and variability in driving patterns to determine the consumer affordability of electric and electric-hybrid vehicles.

5.3. Data and Methodology

5.3.1. Vehicle Types

Our study includes representative electric vehicles of the 2012 models: the Ford Focus Electric (EV), the Toyota Camry Hybrid LE (HEV), the Toyota Prius Plug-in

Hybrid with 15-mile electric driving range (PHEV15), and the Chevy Volt Plug-in Hybrid with 35-mile electric driving range (PHEV35). The 2012 Toyota Camry LE is the chosen conventional vehicle (CV) used for comparison purposes.

The Ford Focus Electric is powered by a lithium-ion battery that can be fully charged with a 240-V charging station in less than 12 h. The Toyota Camry Hybrid LE includes a 2.5-liter 4-cylinder engine, a 105-kW electric motor, and a 245-V battery pack of nickel–metal hybrid modules. The Toyota Prius Plug-in Hybrid (PHEV15) is a parallel-hybrid powertrain design with a 1.8-liter 4-cylinder engine, and it uses a 4.4-kWh lithium-ion battery pack that can be fully charged in three hours from a household 110-V outlet or half of its normal charging time using a 220-V plug. The Chevy Volt (PHEV35) includes a 16-kWh liquid-cooled lithium-ion battery pack and a 1.4-liter/84-HP in-line 4-cylinder internal-combustion range extender that takes over when battery power is at a low level. The battery pack takes a longer time (10–12 h) to be replenished using a standard 110-V outlet, but the charging time can be reduced to 3–4 h using a 240-V dedicated unit. The Volt can be operated in normal, sport, and mountain driving modes. The Toyota Camry LE runs on a 2.5-liter 4-cylinder engine with a fuel efficiency of 26 mpg-city and 35 mpg-highway.

Table 5-1 summarizes the specific features and characteristics of each vehicle type. All of these vehicles can be classified as compact family cars based on their curb weights, ranging from 3165 to 3781 pounds (1436–1715 kg). Conventional and electric hybrid cars without plug-in are generally priced at $22,500 for CV and $25,900 for HEV. Electric hybrid cars with plug-in are listed at $32,000 with shorter driving distance on electric mode (PHEV15) and about $40,000 with an extended driving range (PHEV35).

Electric cars (EVs) running solely on battery are priced around $39,000. With federal tax credits, the owner prices for PHEV15, PHEV35, and EV can be reduced to around $30,000. No federal tax credit is available for CV and HEV.

TABLE 5-1: Features and prices for selected vehicle types[a]

Type	Curb weight (lbs)	Retail price 2012$	After tax credit[b] 2012$	Fuel efficiency[c] (mpg/mpg$_e$)	Driving range (miles)	Tank volume (gal)	Horse power (HP)
CV	3190	22,500	22,500	30	532	17	178
HEV	3417	25,900	25,900	41	697	17	200
PHEV 15	3165	32,000	29,500	50/87	530	10.6	134
PHEV35	3781	39,995	32,495	37/94	375	9.3	149
EV	3624	39,200	31,700	100	100	0	123

a: Sale prices are in 2012 dollars and specifications were obtained from manufacturer's website on May 01, 2012.
b:Federal tax credits are $2,500 (PHEV15) and $7500 (PHEV35 and EV).
c:mpg=miles per gallon, mpge=miles per gallon equivalent; combined mileage is based on 45% highway and 55% city driving.

As a baseline scenario, the lifetime mileage for each vehicle type is assumed to be 120,000 miles (193,120 km), or 10,000 miles (16,090 km) per year for 12 years, or 27 miles (43 km) per day. The US Federal Highway Administration posted the age-weighted annual driving mileage of 13,476 miles (21,688 km) per driver (7600–15,300 miles per driver) in 2011. The average age of cars on US roads was up from 10.6 years in 2010 to 10.8 years in 2011. Ogden et al. (2004) employed a lifetime mileage of 120,000 miles (193,120 km) over 10 years. We follow Ogden's criterion of 120,000 miles (193,120 km) because the use of electric-hybrid vehicles may be limited by its current battery capacity. However, we also increase the lifetime mileage to 150,000 miles (241,400 km) to determine if cost estimates are sensitive to these assumptions. Under the baseline scenario, the non-operating cost for scheduled maintenance can be derived from Michalek et al. (2011), as summarized in TABLE 5-2.

TABLE 5-2: Non-operating cost (in 2010 dollars)[a]

Vehicle type	Maintenance	Home charging station	Total
CV	4380	0	4380
HEV	3962	0	3962
PHEV15	3235	1200	4435
PHEV35	3235	2400	5635
EV	2332	2400	4732

a: Assuming zero inflation rate between 2010 and 2012 dollars.

5.3.2. Energy Consumption and Cost

The following assumptions were made to estimate the lifetime energy consumption for vehicle operation and the associated costs. These assumptions are comparable to criteria considered by other researchers.

(a) Under the baseline scenario, the lifetime energy consumptions for the CV and HEV can be obtained by dividing 120,000 miles by their respective fuel efficiency, resulting in 4000 gal (CV) and 2927 gal of gasoline (HEV) consumptions.

(b) Power consumption for the EV is 25.2 kWh per charge cycle (240 V×20 A×3.5 h). With a driving range of 100 miles per charge, a fully charged EV can sustain a daily driving of 27 miles for three consecutive days before recharge. For practical purpose, the battery needs to be charged once every 3rd day. Over a 12-year period, the lifetime energy consumption is 25.2 kWh×365 days/yr÷3 days×12 years=36,792 kWh.

(c) The PHEV15 requires 5.4 kWh per charge cycle (120 V×15 amps×3 h) or a fuel economy of 2.78 miles per kWh (15 miles per charge ÷ 5.4 kWh). A daily charge is required for the first 15 miles and the remaining 12 miles would run on gasoline. The lifetime mileage for the vehicle running on electric mode is then 65,700 miles (15 miles/day×365 days/year×12 years) and the associated energy consumption is 65,700 miles÷2.78 miles/kWh or 23,652 kWh. Lifetime gasoline consumption is calculated as (120,000−65,700)÷50 miles/gal=1086 gal.

(d) The PHEV35 is charged once every other day. Similar calculations for PHEV35 yield a fuel economy of 2.71 miles per kWh, and a lifetime energy consumption of 28,251 kWh and 1172 gal of gasoline.

After determining the lifetime energy consumptions, we then calculate the lifetime energy costs using the unit energy cost indexes provided by Offer et al. (2011). The optimistic and mid-range prices for gasoline and electricity are $3.00–$4.50 per gallon and $0.10–$0.24 per kWh, respectively. The pessimistic prices are $6.00 per gallon for gasoline and $0.37 per kWh for electricity. The nationwide average price for gasoline is currently at $3.68 per gallon, and electric power is $0.13 per kWh. The price range denoted “optimistic and mid-range” adequately represents the current energy costs for gasoline and electricity, which can be viewed as the current or immediate future energy cost scenarios. The pessimistic price is viewed as the future cost scenario for the next 5 to 10 years.

The lifetime energy cost for the different classes of vehicles is presented in Table 3. Lifetime energy costs are found by multiplying the energy consumptions calculated above by the respective unit energy cost index. Consequently, we can combine the vehicle prices (Table 5-1), non-operating costs (Table 5-2) and the lifetime energy consumption costs (Table 5-3) to derive the lifetime consumer ownership costs as summarized in Table 5-4. Table 5-4 also includes a cost ratio to compare alternative fuel vehicles with respect to conventional vehicles. Alternative fuel vehicles are more cost attractive than conventional vehicles if this ratio is less than one.

TABLE 5-3: Lifetime energy consumption cost (2012 dollars)

Vehicle type	Optimistic	Mid-range	Pessimistic
CV	12,000	18,000	24,000
HEV	8780	13,171	17,561
PHEV15	5623	10,563	15,267
PHEV35	6340	12,053	17,483
EV	3679	8830	13,613

TABLE 5-4: Lifetime customer ownership cost (2012 dollars)

Vehicle type	Optimistic	Mid-range	Pessimistic
CV	38,880	44,880	50,880
	(38,880)	(44,880)	(50,880)
HEV	38,642	43,033	47,423
	(38,642)	(43,033)	(47,423)
PHEV15[a]	42,058	46,998	51,702
	(40,558)	(44,498)	(49,202)
PHEV35[a]	49,570	57,683	63,113
	(44,470)	(50,183)	(55,613)
EV[a]	47,611	52,762	57,545
	(40,111)	(45,262)	(50,045)

TABLE 5-4: Continued

Cost ratio	Optimistic	Mid-range	Pessimistic
CV/CV	1	1	1
	(1)	(1)	(1)
HEV/CV	0.99	0.96	0.93
	(0.99)	(0.96)	(0.93)
PHEV15/CV	1.08	1.05	1.02
	(1.04)	(0.99)	(0.97)
PHEV35/CV	1.27	1.29	1.24
	(1.14)	(1.12)	(1.09)
EV/CV	1.22	1.17	1.13
	(1.03)	(1.01)	(0.98)

a: Federal tax credits are considered for the data in parentheses, $2,500 (PHEV15) and $7500 (PHEV35 and EV).

5.3.3. Societal and Environmental Cost

The lifetime emission cost of a car includes three major emission sources including (1) upstream production of car components and disposal, (2) tailpipe exhaust, and (3) upstream energy production. The sum of these three categories of emission costs is also referred to as the lifetime societal and environmental cost.

The US Department of Energy (2010) initiated the full-cycle analysis for energy use and GHG emission. The Department funded the Argonne National Laboratory to develop a computer model for Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET). The model considers the efficiency of upstream processes for differing fuel cycles including a gasoline vehicle that uses its fuel on-board and an electric vehicle that burns its fuel off-board. The GREET model can be used to estimate emission factors associated with upstream production of vehicle components; vehicle assembly, disposal and recycling; production and disposal of fluids; and batteries. We ran the GREET model version 2_7 to obtain emission estimates for vehicles made of conventional materials based on matched vehicle weights available in the model. Results are shown in Table 5-5. As compared to a conventional vehicle, alternative fuel vehicles contribute more upstream emissions of air pollutants such as GHG, PM10 and PM2.5. The EV contributes 32% more in GHG, 41% more in PM10, and 49% in PM2.5. The PHEV's contribute 10% more in GHG, and about 12% each in PM2.5 and PM10.

TABLE 5-5: Lifetime vehicle upstream pollutant emissions (tons).

Vehicle	CO	NOx	PM10	PM2.5	SOx	VOC	GHG
CV	0.0232	0.0093	0.0106	0.0037	0.0260	0.0340	7.59
HEV	0.0260	0.0100	0.0113	0.0049	0.0365	0.0342	8.21
PHEV15	0.0258	0.0103	0.0118	0.0042	0.0350	0.0343	8.37
PHEV35	0.0258	0.0103	0.0118	0.0042	0.0350	0.0343	8.37
EV	0.0256	0.0123	0.0149	0.0055	0.0473	0.0344	9.98

Tailpipe emission during a driving cycle is another source of air pollutants affecting human health. Michalek et al. (2011) compiled vehicular emissions from a wide range of vehicle types based on gasoline consumption. We interpreted their data by adjusting the emission mass according to gasoline consumptions calculated from this study, as presented in Table 5-6. This table also includes the percentages of tailpipe emissions with regard to the total of tailpipe and upstream emissions. It is noted from Table 6 that tailpipe emissions of GHGs from most vehicle types, except EVs, account for at least more than 50% of the lifetime GHG emissions. Health effects include mortality, morbidity, and environmental impact (visibility, crop loss, forest recreation, timber loss, materials depreciation, etc.). To account for health impacts, we employed the average health cost factors of $448 per ton CO; $2557 per ton NOx; $4763 per ton PM10; $31,966 per ton PM2.5; $12,735 per ton SOx; $2400 per ton VOC; and $42 per ton GHGs to calculate the lifetime vehicle emission costs for upstream vehicle production and tailpipe emission. Results are shown in Table 5-7.

TABLE 5-6: Lifetime vehicle tailpipe emissions (tons).

Vehicle	CO	NOx	PM10	PM2.5	SOx	VOC	GHG
CV	0.3465	0.0069	0.0028	0.0015	0.0000	0.0151	35.53
	(94%)	(43%)	(21%)	(28%)	(0%)	(31%)	(82%)
HEV	0.3550	0.0059	0.0029	0.0015	0.0000	0.0109	26.09
	(93%)	(37%)	(21%)	(28%)	(0%)	(24%)	(76%)
PHEV15	0.1161	0.0019	0.0012	0.0006	0.0000	0.0036	9.66
	(82%)	(16%)	(9%)	(12%)	(0%)	(9%)	(54%)
PHEV35	0.1080	0.0018	0.0014	0.0007	0.0000	0.0033	10.41
	(81%)	(15%)	(11%)	(14%)	(0%)	(9%)	(56%)
EV	0.0000	0.0000	0.0031	0.0011	0.0000	0.0000	0.000
	(0%)	(0%)	(17%)	(17%)	(0%)	(0%)	(0%)

Note: Numbers inside parenthesis are percentages of tailpipe emission relative to (upstream+ tailpipe).

TABLE 5-7: Lifetime emission costs for vehicle upstream and tailpipe exhaust (2012 dollars).

Vehicle	CO	NOx	PM10	PM2.5	SOx	VOC	GHG	Total
CV	166 (6%)	41 (2%)	64 (2%)	165 (6%)	331 (12%)	118 (4%)	1811 (67%)	2696 (100%)
HEV	171 (7%)	41 (2%)	68 (3%)	173 (7%)	465 (19%)	108 (4%)	1440 (58%)	2466 (100%)
PHEV15	64 (4%)	31 (2%)	62 (4%)	152 (10%)	446 (28%)	91 (6%)	757 (47%)	1603 (100%)
PHEV35	60 (4%)	31 (2%)	63 (4%)	155 (9%)	446 (27%)	90 (6%)	789 (48%)	1634 (100%)
EV	11 (1%)	32 (2%)	85 (6%)	212 (15%)	603 (42%)	83 (6%)	419 (29%)	1445 (100%)

Note: Numbers inside parenthesis are percentages of individual emission relative to total emission cost.

Upstream emission costs associated with energy sources, i.e. the production of gasoline and electricity, are derived from published data (Michalek et al., 2011). The average emission abatement cost for gasoline production is \$597 per 6385 gal, which is equivalent to about \$10.00 per 100 gal with an estimated deviation of ±\$5.00 per 100 gal for pessimistic and optimistic valuations. The production of electricity is based on upstream and direct emissions from power plant valuation. These emission costs are estimated at \$0.02 per kW with zero GHG (optimistic), \$0.06/kW with low GHG (mid-range), and \$0.10 per kW with high GHG (pessimistic). Finally, emission cost factors described earlier are used to calculate the respective lifetime emission costs for the production of gasoline and electricity, as summarized in Table 5-8.

TABLE 5-8: Lifetime emission cost for upstream energy sources (2012 dollars).

Vehicle	Optimistic	Mid-range	Pessimistic
CV	200	400	600
HEV	146	293	439
PHEV15	514	1569	2624
PHEV35	607	1861	3115
EV	715	2272	3828

5.3.4. Lifetime Cost

The lifetime total cost incorporates all cost categories including the lifetime ownership cost (car price, non-operating, and fuel costs) and the lifetime societal and environmental cost (upstream vehicle emissions, tailpipe emissions, and upstream energy production costs). The lifetime societal and environmental cost, shown in Table 5-9, is obtained by summing the emission costs given in Table 5-7 and Table 5-8. The last column in Table 9 accounts for the proportion of emission cost due to energy sources (mid-range estimates), which explains that depending on the methods of electricity generation for battery charging, the emission costs associated with energy production could amount to more than 50% of the overall combined emission cost. Finally, the lifetime total cost, as shown in Table 5-10, is obtained by combining Table 5-4 (lifetime owner cost) and Table 5-9 (lifetime combined emission cost). Results are expressed in 2012 dollars assessed with and without tax credits, and as cost ratios relative to the valuation of conventional vehicles.

TABLE 5-9: Lifetime combined emission cost (2012 dollars).

Vehicle	Optimistic	Mid-range	Pessimistic	Energy source (mid-range), %
CV	2896	3096	3296	13
HEV	2613	2759	2905	11
PHEV15	2117	3172	4227	50
PHEV35	2241	3495	4749	53
EV	2160	3716	5273	61

TABLE 5-10: Lifetime total cost (ownership+emission) (2012 dollars).

Vehicle	Optimistic	Mid-range	Pessimistic
CV	41776 (41776)	47976 (47976)	54176 (54176)
HEV	41255 (41225)	45792 (45792)	50328 (50328)
PHEV15	44175 (41675)	50171 (47671)	55929 (53429)
PHEV35	51811 (46711)	61178 (53678)	67867 (60362)
EV	49671 (42171)	56378 (48878)	62718 (55218)

Note: Federal tax credits are considered for the data in parentheses, $2,500 (PHEV15) and $7500 (PHEV35 and EV).

TABLE 5-10: Continued

Cost Ratio	Optimistic	Mid-range	Pessimistic
CV/CV	1.00 (1.00)	1.00 (1.00)	1.00 (1.00)
HEV/CV	0.99 (0.99)	0.95 (0.95)	0.93 (0.93)
PHEV15/CV	1.06 (1.00)	1.05 (0.99)	1.03 (0.99)
PHEV35/EV	1.24 (1.12)	1.28 (1.12)	1.25 (1.11)
EV/CV	1.19 (1.01)	1.18 (1.02)	1.16 (1.02)

Note: Federal tax credits are considered for the data in parentheses, $2,500 (PHEV15) and $7500 (PHEV35 and EV).

5.4. Results and Discussion

The rule of fuel economy calls for 1–2% reduction in gas mileage for every 100-lb increase of extra weight. However, electric and electric hybrid vehicles are noticeably more fuel efficient than a conventional vehicle even if they are heavier. The EV and HEV car models weight 7–15% heavier than a conventional vehicle but offer significantly more than 37% fuel efficiency. The PHEV15 is only 25 lbs lighter than its equivalent CV, yet the PHEV15 has attained a hybrid mileage that is almost 20 mpg better (Table 5-1). The extended-range battery installed in the PHEV35 causes the car weight to increase by 616 lbs as compared to the PHEV15, but its fuel efficiency is disappointing at 13 mpg lower than the PHEV15. If electric and electric-hybrids are considered to be the near-term solutions for a sustainable transport system, a reduction in battery size/weight and an increase in driving distance per battery charging cycle will be needed.

The scheduled maintenance needs for all electric and electric-hybrid vehicles, as seen from Table 5-2, can be characterized by a lower cost of expenditure as compared to the CVs. The HEV is 10% lower, followed by the PHEV15 and PHEV35 (26%), and the EV (47%). However, the need for home charging stations has offset the lower maintenance cost, resulting in an overall increase of the non-operating costs for the PHEV15 (1%), the PHEV35 (29%) and the EV (8%), as compared to the CVs. The HEV remains to be the lowest in overall operating cost among all vehicle types listed in Table 5-2.

The lifetime energy consumption costs for the EV is substantially (43–69%) lower than that of the CVs for all cost scenarios tested (Table 3). The EV can be a cost-effective transportation means for daily commute to work as far as energy consumption is concerned. Hybrid electric plug-in vehicles (PHEV15/35) are 33–53% (optimistic/mid-range) lower in energy cost than that of a typical CV and still keep up with a 27–36% lower energy cost for the pessimistic scenario. Currently, PHEVs are limited by their driving distance per battery charge cycle. Hybrid electric vehicles without plug-in (HEVs) are about 27% lower in energy cost than CVs as a result of optimizing the usage between electricity and gasoline.

The lifetime consumer ownership cost accounts for the purchase price, the non-operating cost, and the associated energy cost. Without federal tax credits, the lifetime ownership costs are the highest for the PHEV35 (24–29%), followed by the EV (13–23%), and PHEV15 (2–8%), as compared to the CVs. The HEV is typically 1–7% lower in lifetime consumer ownership cost than that of a CV for all energy price scenarios and with or without federal tax credits. When federal tax credits are taken into consideration, lifetime consumer ownership costs for the PHEV15 and the EV are reduced to be no more than 5% higher than that of a CV, except for the PHEV35 which remains 9–14% higher (Table 4). The lifetime ownership cost is less sensitive to energy price fluctuations with the provision of cost incentives in the form of federal tax credits. For instance, the ratio of ownership costs, EV/CV, is within the range of 0.98–1.03 with tax credits, as compared to 1.13–1.22 without tax credits. Apparently, the provision of appropriate tax credits can help not only the buffering of fluctuations in energy cost but also the improvement of the consumer affordability for alternative fuel vehicles. Results of the consumer ownership cost analysis have highlighted the importance of tax credits for policymakers to consider the inadequacy of cost differentials and for car-makers to implement innovation and cost-effective manufacturing processes for cost reduction.

Sources of vehicular pollutant emissions include upstream manufacturing processes (Table 5-5), tailpipe emissions (Table 5-6), and upstream energy sources (Table 5-8). The upstream process emissions are quite similar for most vehicle types and contribute a significant source of NOx, PM10, PM2.5, SOx and VOC when compared to tailpipe emissions. Any attempts to reduce upstream process emissions would lower the overall release of these pollutants. The tailpipe emission of GHG accounts for more than 50–82% of the combined emissions, except EV. As compared to the CVs, the HEVs and PHEV15/35s can achieve a reduction of tailpipe GHG emission by 28% and 42–50%, respectively (see Table 5-6). The EV essentially emits zero GHG from its tailpipe. The upstream emission due to the production of gasoline and electricity represents a significant cost factor for alternative fuel vehicles. Table 5-11 provides a breakdown of the relative emission costs, as derived from Table 5-9, according to energy sources and combined tailpipe and upstream emissions, under the mid-range gasoline cost scenario. CVs and HEVs are observed to display a significant cost factor for tailpipe and upstream emission, while the energy source emission only accounts for 11–13% of the total cost. In contrast, the PHEVs and EVs exhibit a significant cost proportions for the energy source emission implying that although these vehicles are less polluting the environment while operating on roads, they may cause a great concern from their energy source emissions depending on how the required energy is being generated. Overall, when compared to CVs, the lifetime emission costs for HEVs are 9–11% lower (Table 5-9). The lifetime emission costs for EVs and PHEVs are generally 22–27% lower (optimistic), 2–20% higher (mid-range), and 28–59% higher (pessimistic).

TABLE 5-11: Cost comparisons for emissions (mid-range gasoline price scenario).

Vehicle	Energy source emission, %	Tailpipe+upstream emissions, %
CV	13	87
HEV	11	89
PHEV15	50	50
PHEV35	53	47
EV	61	39

The life-cycle cost analysis without tax credits indicates that HEVs and CVs have an equivalent lifetime total cost, which differs by about 1–7% (Table 5-10). The PHEV15 is about 5–6% higher than a CV under the optimistic/mid-range scenario, but as the gas price goes up to $6.00 per gallon, the cost differentials could be reduced to around 3% higher. The PHEV35 is about 24–28% higher but would reduce to 25% as the gas price goes up to $6.00 per gallon. The EV is about 18–19% higher but can be as low as 16% as the gasoline price increases to $6.00 per gallon. Interestingly, with federal tax credits, the lifetime total cost for all vehicles is generally affordable with no more than 5% higher than a CV, with the exception of PHEV35 which remains around 11–12% higher.

5.5. Concluding Remarks

A life-cycle cost analysis has been conducted to determine the economic and environmental implications of building a sustainable transport system for the next 5–10 years. This system is expected to serve as the stepping stone leading to a gradual switching from traditional to alternative fuel sources and/or an improvement in fuel efficiency and performance over gasoline/diesel fueled automobiles. The analysis was based on comparing representative 2012 vehicle types (conventional, hybrid with and without plug-in, and electric) using the market price information, and the latest published cost data for energy consumption and emission mitigation. Results of our analysis are substantiated by the use of an open-source and highly reliable database from the US government sponsored research.

This study has revealed the importance of tax credits to address the inadequacy of cost differentials. Without tax credits, only the HEVs have lifetime total costs equivalent to a CV differing by about 1–7%. The consumer affordability for other alternative fuel vehicles is less encouraging and depends on changes in gasoline prices. With tax credits, electric and hybrid electric vehicles could be affordable and attain similar lifetime total costs as compared to conventional vehicles, except for the hybrid plug-ins with extended battery range which is about 11–12% more costly than conventional vehicles. The increase of gasoline price renders some impact on ownership cost when societal and environmental costs are not considered (see Table 4). For instance, the PHEV35 is 12–14% more costly under current assumptions, but as gas prices rise to $6.00 per gallon, consumer ownership cost will be reduced to 9% with the provision of federal tax credits.

With tax credits and under the driving scenario of 120,000 miles, the PHEV35 would not be competitive with CVs at all ranges of the GHG abatement cost. The PHEV15 starts to be competitive with CVs at a cost break of about $70 per ton GHG. Under the scenario of 150,000 miles, all vehicle types of EVs, HEVs and PHEV15s are competitive with CVs and the PHEV35 starts to be compatible with CVs at a GHG abatement cost of about $125 per ton. A further analysis for the PHEVs with an extended driving distance of greater than 35 miles per charge will be needed.

In summary, the HEV and CV exhibit a very similar lifetime total cost with or without tax credits. However, electric and hybrid electric vehicles are more environmentally friendly because of lower emissions in GHG and VOC. In addition to economic advantages, the environmental benefits provided by the electric and hybrid electric vehicles should satisfy consumers' interest in protecting the environment, reducing the dependence on imported fossil fuels, and switching from traditional to alternative fuel vehicles.

CHAPTER 6: SUMMARY

This dissertation research explores the energy supply and demand for the transportation industry. Energy resources serving as supplementary fuels for gasoline include biofuels and cleaner electric energy. The supply potential of these renewable energies was derived from the acreages of suitable marginal lands and the energy demand analysis was to meet the anticipated switch to electrification of transport vehicles. The study is for the southeastern region of the United States.

There exists a total of approximately 2.5 million hectares acres of marginal agricultural lands in the southeastern region, ranging as high as 0.63 million hectares for Mississippi followed by Alabama, Louisiana, Georgia, Arkansas, Tennessee, South Carolina, North Carolina and Florida (Table 4-1). These marginal lands have a potential of producing 2.0-6.0 million tons per year of dedicated energy crops at the state level (Table 4-4), resulting in a maximum theoretical yield of 200-600 million gallons of biofuels per year or an average of 3,600 million gallons per year in the region. The estimated annual demand for biofuels in the region amounts to an increment of 320 million gallons per year for the next 10 years (Figure 2-12), based on the estimation of 1-2% annual increase of conventional car sales and fuel economy improvement of 5% per year in the next 10 years (Tables 2-14 and 2-15). The maximum theoretical yield of biofuels can be expected to meet the incremental fuel demands in the next 10 years

The potential of cleaner electric energy production in the region was estimated to be 8,500 GWh per year, including 4,800 GWh from existing landfill sites and 3,700 GWh from brownfields (Table 2-12). These estimates are based on solar-electric production scenarios for solar PV installations. If wind turbines are co-installed at the same site, an additional wind-electric energy of 1,300 GWh per year can be expected (Table 2-12). An incremental demand of 100 GWh per year is anticipated for the next 10 years (Figure 2-13) based on assumed 8% annual market penetrations of electric vehicles (Table 2-15). Cleaner electric energy that can theoretically derived from solar and wind energies appear to meet the incremental electric energy demand for electrification of transport vehicles in the region.

Our case study of cleaner energy production from waste management facilities has demonstrated that it is economically feasible to co-produce of solar-electric and LFG-electric investments even without tax incentives. Biofuel production at the facility scale is not economically viable without tax incentives; however, it helps provide in-house fuel demands for cost savings. All these energy production projects can be environmentally beneficial to offset the emission of GHG.

From the consumer perspectives, electric drive vehicles would not be economically attractive without tax incentives due to higher purchase prices. With tax incentives, electric drive vehicles are comparable to conventional vehicles when comparing their lifetime ownership total costs. With future improvement of battery technology and potential cost reduction, the market demand and consumer preference can be expected to increase in the near future. Policy support for electric vehicles with tax incentives and battery technology development is critical for achieving electrification of the transportation system.

Our study assumed that all eligible lands can be utilized to its full potential for energy production. In reality, site characteristics and energy intensity vary greatly among all states within the region, which would increase the uncertainty of energy production and yield overestimates of the land productivity. Secondly, the energy market in the region was considered as a closed system that precludes energy flux between states and outside of the region. Lastly, the technical and economic data retrieved from various sources may not be compatible and need to be frequently updated. It is recommended to consider the following directions for continuing studies:

1. The benefits and feasibility of on-shore wind energy for coastal states in the region.
2. Investigation of the logistic of biorefineries to attain stable operation subject to the time gaps due to feed stock production and rotation.
3. Energy policy promoting cleaner energy production for transportation while achieving proper prioritization of energy investment with viable economic returns.
4. Environmental impacts resulting from disposal and handling of waste materials generated from the production and consumption of renewable energy by the transportation industry.
5. Ecological impacts resulting from converting CRP lands to bioenergy crop lands.

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APPENDIX A: TABLES

TABLE A-1: MPG projection under different scenarios, MPGe (AEO,2015)

	2015	2020	2025	2030	2035	2040
Conventional Cars: Gasoline						
(1) Reference case	35.84	42.83	52.75	52.94	52.87	52.80
(2) High economic growth	35.84	42.80	52.75	52.94	52.87	52.81
(3) Low economic growth	35.85	42.79	52.75	52.95	52.87	52.78
(4) High oil price	36.08	42.57	52.93	53.13	53.08	53.01
(5) Low oil price	35.81	42.91	52.64	52.98	52.88	52.80
(6) High oil and gas resource	35.84	42.81	52.58	52.93	52.85	52.78
Ethanol-Flex Fuel ICE						
(1)	35.98	43.21	53.45	53.67	53.61	53.55
(2)	35.98	43.19	53.46	53.68	53.62	53.58
(3)	35.99	43.14	53.43	53.67	53.59	53.52
(4)	36.22	42.91	53.61	53.83	53.77	53.68
(5)	35.95	43.30	53.36	53.73	53.65	53.58
(6)	35.98	43.20	53.26	53.64	53.57	53.51
100 Mile Electric Vehicle						
(1)	130.82	134.88	137.29	137.16	137.30	137.42
(2)	130.87	134.87	137.30	137.17	137.32	137.46
(3)	130.87	134.85	137.26	137.15	137.32	137.46
(4)	132.77	134.20	137.53	137.96	138.28	138.59
(5)	130.67	135.28	137.51	137.03	137.06	137.08
(6)	130.85	134.86	137.24	137.10	137.26	137.41
200 Mile Electric Vehicle						
(1)	125.64	134.60	140.80	141.17	141.25	141.25
(2)	125.64	134.60	140.83	141.20	141.29	141.29
(3)	125.64	134.35	140.72	141.10	141.17	141.16
(4)	125.64	134.08	141.02	141.40	141.50	141.52
(5)	125.64	134.51	140.84	141.25	141.33	141.33
(6)	125.64	134.57	140.62	141.01	141.08	141.06

TABLE A-1: Continued

Plug-in 10 Gasoline Hybrid						
(1)	60.55	68.37	81.89	82.17	82.18	82.13
(2)	60.54	68.34	81.90	82.18	82.21	82.16
(3)	60.57	68.36	81.88	82.16	82.16	82.09
(4)	61.00	68.11	82.11	82.63	82.63	82.60
(5)	60.50	68.53	81.74	82.17	82.10	82.02
(6)	60.55	68.36	81.69	82.15	82.16	82.12
Plug-in 40 Gasoline Hybrid						
(1)	72.50	79.80	87.32	87.64	87.69	87.70
(2)	72.51	79.77	87.32	87.64	87.70	87.72
(3)	72.54	79.74	87.31	87.63	87.67	87.66
(4)	73.56	79.68	87.54	87.97	88.09	88.16
(5)	72.41	79.89	87.27	87.66	87.67	87.63
(6)	72.52	79.78	87.19	87.62	87.66	87.68
Electric-Gasoline Hybrid						
(1)	51.18	59.92	71.11	71.47	71.37	71.27
(2)	51.18	59.90	71.08	71.45	71.36	71.27
(3)	51.20	59.73	71.14	71.58	71.46	71.34
(4)	51.56	58.71	70.72	70.85	70.77	70.67
(5)	51.14	60.13	71.36	72.04	71.90	71.78
(6)	51.18	59.92	70.97	71.67	71.56	71.46

TABLE A-2: Miles traveled per year per vehicle, (AEO, 2015)

	2015	2020	2025	2030	2035	2040
Conventional Cars: Gasoline						
(1) Reference case	20,266	21,060	21,722	22,273	22,636	22,490
(2) High economic growth	20,220	20,917	21,482	21,994	22,418	22,204
(3) Low economic growth	20,276	21,243	22,008	22,571	22,897	22,661
(4) High oil price	19,745	18,625	17,859	17,587	17,435	17,051
(5) Low oil price	20,323	22,197	23,693	25,150	26,578	27,583
(6) High oil and gas resource	20,262	21,180	22,020	22,733	23,193	23,038
Ethanol-Flex Fuel ICE						
(1)	61,853	62,262	61,901	61,738	61,347	59,643
(2)	61,712	61,843	61,226	60,986	60,769	58,747
(3)	61,843	62,796	62,811	62,741	62,309	60,463
(4)	59,078	50,790	45,701	43,854	43,109	41,700
(5)	62,163	67,920	70,709	73,778	77,244	79,755
(6)	61,828	62,846	63,273	63,805	63,809	62,018
100 Mile Electric Vehicle						
(1)	15,430	13,984	13,546	13,872	14,072	13,861
(2)	15,382	13,846	13,342	13,640	13,881	13,668
(3)	15,446	14,161	13,791	14,148	14,322	14,033
(4)	15,043	12,826	11,927	12,029	12,175	12,004
(5)	15,468	14,467	14,258	14,819	15,318	15,399
(6)	15,427	14,032	13,634	13,990	14,211	14,022
200 Mile Electric Vehicle						
(1)	14,227	13,306	13,675	14,178	14,235	13,909
(2)	14,149	13,207	13,441	13,920	14,038	13,715
(3)	14,152	13,532	13,968	14,491	14,508	14,092
(4)	14,000	12,548	12,261	12,478	12,491	12,186
(5)	14,182	13,611	14,300	15,054	15,375	15,315
(6)	14,273	13,385	13,743	14,277	14,364	14,061

TABLE A-2: Continued

Plug-in 10 Gasoline Hybrid						
(1)	13,998	13,116	12,785	12,943	13,146	13,173
(2)	13,958	12,978	12,581	12,718	12,973	13,002
(3)	14,016	13,292	13,029	13,182	13,338	13,287
(4)	13,795	12,277	11,517	11,506	11,598	11,553
(5)	14,023	13,473	13,323	13,674	14,126	14,437
(6)	13,999	13,155	12,846	13,010	13,234	13,289
Plug-in 40 Gasoline Hybrid						
(1)	13,905	13,026	12,608	12,841	13,091	12,985
(2)	13,866	12,889	12,403	12,618	12,916	12,813
(3)	13,922	13,189	12,853	13,095	13,300	13,108
(4)	13,737	12,305	11,423	11,393	11,539	11,416
(5)	13,928	13,324	13,087	13,517	14,009	14,171
(6)	13,906	13,065	12,671	12,910	13,182	13,108
Electric-Gasoline Hybrid						
(1)	14,715	13,708	13,428	13,596	13,851	13,831
(2)	14,671	13,572	13,226	13,374	13,678	13,647
(3)	14,733	13,887	13,663	13,821	14,026	13,920
(4)	14,444	12,680	11,898	11,810	11,912	11,820
(5)	14,746	14,157	14,116	14,561	15,162	15,521
(6)	14,714	13,755	13,515	13,715	13,998	13,991

TABLE A-3: The vehicle sales projection in southeastern region, thousand units per year (AEO, 2015)

	2015	2020	2025	2030	2035	2040
Conventional Cars:						
(1) Reference case	2453.75	2572.66	2595.78	2729.05	2849.87	2998.64
(2) High economic growth	2524.49	2676.38	2682.35	2839.79	3016.92	3304.72
(3) Low economic growth	2405.62	2433.25	2402.34	2429.74	2483.93	2468.97
(4) High oil price	2605.41	3032.29	3040.60	3020.64	3105.52	3171.75
(5) Low oil price	2424.18	2352.16	2393.39	2486.24	2531.75	2603.32
(6) High oil and gas resource	2445.29	2556.77	2577.60	2701.22	2819.40	2981.94
Ethanol-Flex Fuel ICE						
(1)	122.88	129.37	130.93	137.37	143.32	150.74
(2)	126.37	134.57	135.39	143.12	151.96	166.47
(3)	120.42	122.15	120.73	121.50	123.68	122.29
(4)	130.62	153.41	155.48	179.69	208.02	233.43
(5)	121.36	118.00	120.38	124.70	126.72	130.05
(6)	122.41	128.51	129.97	135.38	141.20	149.28
100 Mile Electric Vehicle						
(1)	5.63	3.78	8.51	21.04	29.90	36.82
(2)	5.82	3.98	8.90	22.13	31.79	40.74
(3)	5.54	3.47	7.84	19.20	27.30	32.55
(4)	9.67	8.76	17.71	41.81	63.48	84.91
(5)	5.37	2.95	6.45	14.94	19.54	21.37
(6)	5.66	3.76	8.32	20.47	29.37	37.25
200 Mile Electric Vehicle						
(1)	0.01	0.01	0.06	0.21	0.31	0.38
(2)	0.01	0.01	0.06	0.22	0.33	0.42
(3)	0.01	0.01	0.05	0.19	0.28	0.32
(4)	0.01	0.02	0.11	0.36	0.56	0.70
(5)	0.01	0.01	0.05	0.16	0.23	0.25
(6)	0.01	0.01	0.06	0.20	0.30	0.38

TABLE A-3: continued

Plug-in 10 Gasoline Hybrid						
(1)	8.73	7.74	15.52	16.96	21.83	26.39
(2)	9.00	8.07	16.03	17.69	23.18	29.27
(3)	8.57	7.21	14.31	14.91	18.75	21.45
(4)	11.58	12.15	23.51	27.08	36.01	44.81
(5)	8.47	6.56	13.11	13.45	15.87	17.52
(6)	8.72	7.65	15.06	16.04	20.58	25.06
Plug-in 40 Gasoline Hybrid						
(1)	12.92	14.85	20.40	34.52	41.01	43.78
(2)	13.33	15.51	21.08	36.11	43.48	48.37
(3)	12.68	13.60	18.82	30.54	35.48	35.69
(4)	20.12	30.82	37.00	62.59	78.82	88.50
(5)	12.44	11.70	16.10	25.39	27.64	26.97
(6)	13.00	14.86	20.13	33.29	39.83	43.57
Electric-Gasoline Hybrid						
(1)	125.56	140.37	185.97	236.19	264.87	289.31
(2)	129.29	146.24	193.18	247.54	282.76	322.49
(3)	123.17	132.34	169.73	205.36	223.07	227.03
(4)	149.73	197.02	248.88	305.44	346.11	377.38
(5)	123.05	122.62	162.67	200.06	214.11	223.20
(6)	125.17	138.43	182.36	229.55	257.26	282.57