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LIFE CYCLE EMISSIONS AND GHG ABATEMENT COSTS OF DENSIFIED SWITCHGRASS FOR HEAT AND POWER

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Abstract

Renewable portfolio standards have emerged as the preferred method for incorporating renewables into the US energy mix. A portion of these mandates will be met with biomass electricity generation. Switchgrass is one source of biomass feedstock that is considered for utilization in biomass generating facilities. Depending on the application and the fossil fuel that is replaced, the use of switchgrass for energy may increase costs or generate savings. The life cycle emissions and associated greenhouse gas abatement costs resulting from the utilization of densified switchgrass for thermal and electrical energy are examined in this study. Abatement costs for electric generation are $145/Mg CO_2e. The analysis finds large, negative abatement costs (savings) associated with the use of biomass in thermal applications ((-$90) – (-$145)/ Mg CO_2e). Negative costs are not a consequence of irrationality but are instead indicative of the new technology for biomass combustion not yet widely adopted, recent increases in the cost of fuel oil that favor biomass combustion, and barriers to adoption in the form of relatively high capital costs associated with heating system installation.

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Chapter 1

Introduction

Governments around the world are investigating ways in which to incorporate biomass into the transportation (Sperling and Yeh, 2009), heat, and power sectors to meet ambitious climate change mitigation targets and reduce dependence on imported fossil fuels (Clarke et al., 2009). One method that has been used is to subsidize the production and use of biofuels. Despite significant subsidies (~$1.45 per gallon) for both ethanol and biomass production (Robertson et al., 2008), efforts to scale up cellulosic ethanol production have not been successful. Another approach taken in the US is the implementation of state-level renewable portfolio standards (RPS). RPS legislation dictates that a specified percentage of electricity generation come from renewable sources. Pennsylvania, for example, requires that ~8% of electricity production must be generated from renewable energy resources by 2021. To date, 24 states have enacted binding RPS legislation. Compliance is mandated by state public utility commissions. Together, these states account for more than half of all US electricity sales (USDOE, 2009). In addition, there have been recent proposals for the enactment of a federal RPS (Power, 2009).

These initiatives have prompted utilities to investigate the retrofitting of coal generating stations to partially or entirely burn biomass to generate electricity (Energy Business Review, 2009, EPRI, 2008). One source of biomass that has gained particular attention is switchgrass. Switchgrass is attractive as a dedicated energy crop because it can be grown on marginal soils, avoiding competition with food production, and requires relatively few inputs to achieve attractive yields (Mclaughlin and Kszos, 2005).

To date, biomass has not been widely utilized as fuel for electric power generation or other uses due to the low cost of fossil fuels relative to biomass. Biomass is more costly than fossil fuels because: 1) fossil fuels are generally found in large deposits in one location, whereas biomass is geographically dispersed; 2) biomass in its natural form lacks energy density when compared with fossil fuels, which increases costs at each step of the supply chain; and 3) biomass does not lend itself well to materials handling. Fuel oil and natural gas are transported via pipeline, and coal is crushed to allow flowability. Switchgrass, by contrast, is commonly packaged in bale form, and bales must be handled one or two at a time with a loader, resulting in compounding labor and operating expenses during each transfer. These factors amount to large logistical challenges (Allen et al., 1998, Sokhansanj et al., 2009).

Biomass densification offers a means to overcome many of these logistical challenges (Rosentrater et al., 2009). Densification involves forcing biomass through a die to form a denser, more homogeneous product with improved logistical features. Densified products have greater energy density than raw biomass, and can be handled using bins, hoppers, and conveyance equipment developed for bulk materials such as coal and grains (Fasina and Sokhansanj, 1996). Densified products include briquettes, cubes and pellets. While densification overcomes many of these logistical challenges, it also consumes energy and resources.

Densified switchgrass can be employed in several energy applications. Pellets can be used in residential pellet stoves to replace fossil fuels for home heating. Briquettes and cubes can replace fossil fuels in larger, commercial scale boilers or be employed in electric power production. Pellets are not considered for use in commercial scale boilers or electricity production. Cubes and briquettes achieve the desired logistical features of weight-limiting a semi-trailer while retaining the favorable materials handling characteristics associated with pellets at a significantly lower cost. The analysis examines the GHG reductions and associated abatement costs of replacing fossil fuels with densified switchgrass products in both thermal and electric applications and compares these options.

Combustion of biomass is relatively “carbon neutral,” because it absorbs the same amount of carbon dioxide in its growth that is released in combustion (Chum and Overend, 2001). However, fossil inputs and other GHG sources associated with its production, transportation, and conversion must be properly accounted for to determine the net impact of biomass energy to the atmospheric carbon account. Several authors have estimated the emissions associated with switchgrass establishment, production and delivery to final consumption (Adler et al., 2007, Schmer et al., 2008, Farrel and Sperling, 2007); however, no study has integrated production and densification costs of switchgrass with life-cycle emissions to arrive at abatement costs for heat and power applications. The current study uses data from a large switchgrass producer to arrive at production costs specific to the Northeastern US.

The analysis is intended as a first order assessment. Thus, in all cases, market prices and costs of production are assumed to be at current market conditions. Inherent in this assumption is that the growth in the use of biomass as an energy source does not impact input and output prices tied to the production and conversion of biomass to energy. This assumption is reasonable if the production and conversion of switchgrass to energy at a sufficiently small scale that the market is little affected by the adoption of the progress, or if the price elasticities of supply of all inputs to the production process are perfectly elastic.

Chapter 2

Literature Review

The section examines prior research related to the topics of life cycle assessment, abatement costs and environmental economics, switchgrass production and densification, and the conversion of biomass to heat and power. The section identifies the current state of the science in biomass life cycle costs and GHG emissions in addition to providing context for the importance of the evaluation of abatement costs.

2.1 ISO 14040 – Life cycle methodology

Life cycle assessment (LCA) has emerged as a popular tool for evaluating the system-wide impact of products or processes (Rebitzer et al., 2004). The 14040 family of International Standards Organization (ISO) standards provides guidance for the LCA practitioner, borne from a wide range of approaches prior to their publication (Marsmann, 2000). Generally, LCA consists of four main steps (Figure 2-1).

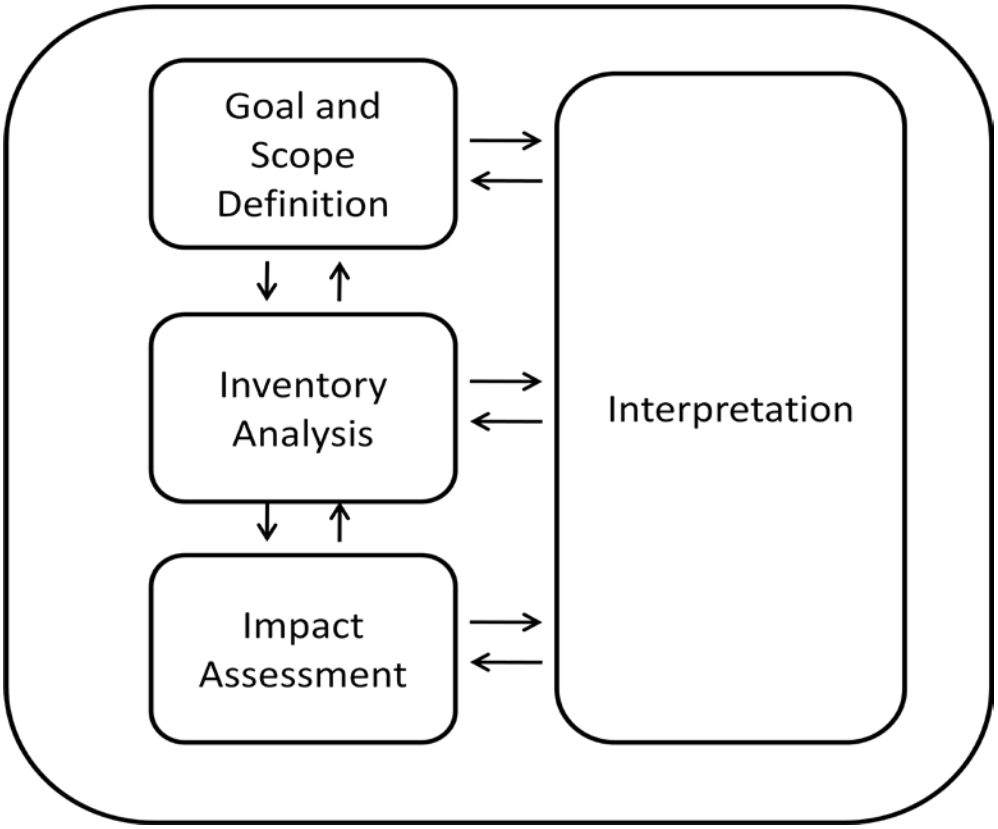

Figure 2-1 – Life Cycle Phases

LCA begins with the definition of the goal and scope of the effort being undertaken. The goal of a particular LCA may vary widely, and can be thought of in terms of impact categories within several areas of protection. Impact categories may span a broad range, but generally fall under climate change, stratospheric ozone depletion, smog formation, acidification, eutrophication, water use, and toxicity (Pennington et al., 2004). Udo de Haes and Lindeijer (2002) identify three areas of protection under which these impact categories fall: human health (toxicity), natural environment (climate change), and man-made environment (acidification as it affects structures).

Defining the scope of a particular LCA is a critical step in the life cycle process. The scope, or boundary, of an LCA identifies the extent to which up- and downstream activities are considered to contribute. ISO 14040 provides limited guidance as to the selection of an LCA boundary; however, the extent to which a particular, associated process impacts analysis results is the most logical test of the inclusion of a related activity.

Within the context of the goal and scope definition, the selection of a functional unit is an essential step. A functional unit is necessary to compare impacts within the analysis. *Functional* relates to the ability of the good or process under consideration to serve the same function as another, similar good or process. In the context of the present analysis, one MWh is selected as the functional unit for the conversion of fuel to electricity. In this way, one MWh of electricity from coal can be directly compared to one MWh produced from biomass.

Following goal and scope definition, a life cycle inventory (LCI) is conducted. The LCI accounts for all emissions related to the selected impact categories. For example, an LCA intended to evaluate the impacts of a particular process to climate change will consider the emission of all greenhouse gases (GHGs) within the defined boundary.

Impact assessment translates the results of the LCI into a meaningful result. For the case of LCAs where several impact categories are considered, the impact assessment requires the normalization of impacts across categories so that the relative importance of each category may be taken into account. In the case of climate change, this step involves the conversion of all GHG emissions into carbon dioxide equivalents using global warming potentials as defined by ISO 14040:2006.

Interpretation of LCA results occurs at each of the previous steps (Pennington et al., 2004). Interpretation will depend on the application of the analysis. Applications may include product development and improvement, strategic planning, public policy formulation, and marketing (Rebitzer et al., 2004). Interpretation involves placing the results of the impact assessment in the context of the application for which the LCA is intended.

2.2 Policy Mechanisms

One of the primary goals of policy to increase the utilization of renewables is the reduction of GHG emissions attributed to climate change. Currently, environmental degradation due to GHG emissions is not accounted for in energy markets; it is an external cost borne by society. Accounting for the externalities associated with GHG emissions may result in the increase of real prices to the consumer. The current analysis addresses these costs.

2.2.1 Environmental Externalities

A significant portion of the field of environmental economics is dedicated to the proper account of environmental externalities within real prices. The environment is a public good; it is by nature non-rival and non-excludable. Therefore, ownership of the right to pollute or the right to be free from pollution is not clearly defined. To cite the current example, firms that produce carbon dioxide and other GHG emissions are currently "consuming" the environment for free. This results in environmental degradation (climate change) and reduces the provision of the environmental good to society as a whole. While societal willingness to pay for the environment is almost certainly non-negative, each individual's valuation of the environment differs from the next, and arriving at a single value is extremely difficult. Environmental economics provides some interesting insight into what the optimal valuation of the environment should be.

2.2.2 Carbon Taxes and Markets

As with most public goods, the provision of the environment falls to the government. Two basic policy frameworks have been proposed for addressing said provision: a carbon tax or a marketable permit system. Taxes are price mechanisms, they specify the overall level of provision by assigning a value to the environment, thus signaling its scarcity. Marketable permit systems, by contrast, signal scarcity by allocating a total quantity of emissions permits to the regulated industries. As such, marketable permit systems are quantity mechanisms. The term "marketable" refers to the feature that these permits may be traded among polluters so that firms that are able to reduce emissions at least cost may do so, thus allowing for emissions reductions at least cost. The predominant example of a successfully executed tradable permit system is the US Acid Rain Program implemented by the US EPA in 1990 (Schmalensee et al., 1998, Joskow and Schmalensee, 1998).

In his analysis of the expected value of economic policy, Weitzman (1974) generates an interesting result that may be applied to the question at hand. He finds that, when large amounts of uncertainty surround the underlying problem, the sign of the correlation between costs and benefits tends to favor one mechanism over the other. When uncertainty between the two is positively correlated, that is, when benefits tend to escalate with costs, a quantity mechanism provides the greatest expected value. By contrast, when this correlation is negative, a price mechanism yields the highest *ex ante* return.

In the case of climate change, large amounts of uncertainty surround both the costs and benefits of mitigation. In his review of 28 studies examining the damage costs of GHG emissions, Tol (2005) identifies marginal damage cost estimates of climate change range from as little as $1 to as much as $962/Mg CO_2e. Similarly, Lempert et al. (1994) present a range of global abatement costs between $0 and $1,800 billion/y. Large amounts of uncertainty seem certain. Combining this with the familiar, Pigouvian result that, in order for economic efficiency to be attained, marginal damages and marginal abatement costs are equal, it would seem that marginal damages avoided (benefits) and marginal abatement costs (costs) are perfectly, positively correlated.

In the absence of transaction costs or other market distortions, price and quantity mechanisms are equivalent. However, in any large program such as the proposed regulation of US GHG emissions, transaction costs and preexisting market distortions are certainly prevalent. While these costs can be reduced by carefully selecting the regulated industries and the point of regulation (Pizer et al., 2006), they will certainly be present whether a mechanism is price- or quantity-based. When only regulating selected industries, a market-based system can provide least cost reductions by allowing for offsets to enter the market from unregulated emitters. Offsets are reductions in emissions outside the cap that generate permits to be sold within the cap. Since GHGs are assumed to mix perfectly in the atmosphere, the geographic or economic location of their origin is not of importance. By allowing for offsets, the overall quantity of emissions inside the cap is effectively increased and access to least cost reductions beyond the regulated industries is achieved.

2.2.3 Renewable Portfolio Standards

Renewable Portfolio Standards (RPSs) have emerged as the preferred method for incorporating renewable energy into electricity markets. RPS format varies, but all consist of a mandated quantity of renewable electricity for electricity suppliers (generators or consumers in some cases). This quantity may be a percentage of electricity sales or take the form of a quantity (MWh) or capacity requirement (MW) (Wiser et al. 2007). Mandatory RPS policy has been implemented by 24 states, which account for more than half of all electricity sales in the US. Oversight is typically conducted by state Public Utility Commissions, and most state policies impose pecuniary penalties for noncompliance.

Nearly all RPS requirements contain provisions for trading renewable electricity certificates (RECs) among regulated entities, and trading in RECs between states is common.

RECs are a purely financial mechanism (independent of actual electron flow). REC trading allows entities that can more easily access renewable generation to sell their certificates to those that cannot. By allowing for the trade of RECs, costs of compliance are reduced. The concept is similar to the offset markets for carbon offsets discussed previously that allow for access to least cost reductions. One REC is created by the generation and sale of one MWh of renewable electricity.

The impact of RPSs to consumers is unclear. Using the National Energy Modeling System (NEMS), both the Union of Concerned Scientists (Nogee, 2007) and the Energy Information Administration (Nogee, 2007) find that RPSs result in a net benefit to the consumer through the reduction of both natural gas and electricity prices. The reduction in costs is driven by several underlying assumptions. The first is that renewable sources (largely wind power) compete with natural gas generation at the margin, thus reducing demand for natural gas for electricity generation and driving both electricity and natural gas prices downward. The second is that wind power is less costly than adding new generating capacity of either coal or natural gas. The final assumption is that competition among renewable technologies drive renewable electricity prices downward over time. NEMS shows cumulative reductions in electricity and natural gas costs to the consumer of $27 billion and $28 billion by 2020 using EIA and UCS assumptions, respectively, as a result of a 20% national RPS.

Palmer and Burtraw (2005) develop their own model to evaluate the cost of RPS policy to consumers. Unlike NEMS, the Haiku model was developed specifically for the electricity sector, and takes into account electricity demand, prices, the composition of supply, interregional trade, constraints on emissions, and three consumer classes to characterize US electricity markets. The model also accounts for the addition of new capacity in response to demand growth and solves for generation dispatch via the minimization of short run variable costs of electricity generation. Palmer and Burtraw (2005) find that a 20% RPS by 2020 could increase electricity prices by as much as 8%.

2.3 Switchgrass

Switchgrass has gained attention as a dedicated energy crop due to its perennial nature, relatively few inputs, and the ability to produce attractive yields on marginal soils (McLaughlin and Ksozs, 2005).

The switchgrass production process begins with crop establishment. Depending on the prior use of the land being cultivated, production operations will vary widely. Switchgrass establishment on fallow land that has not been in production for some time requires conventional tillage and the application of at least two treatments of broad-spectrum herbicide. At the other end of the spectrum, establishing switchgrass on land that was previously in row crops may require only no-till drilling into the existing seedbed.

Once established, switchgrass stands will regenerate each year. A common approach is to assume that switchgrass will require replanting every ten years to take advantage of yield gains from crop breeding and genetic improvement (Duffy and Nanhou, 2001). Following establishment, switchgrass requires annual maintenance and harvesting. Annual maintenance consists of nitrogen fertilizer application. A number of options has been proposed for the harvest and collection of switchgrass (Qin et al., 2006, Sokhansanj, 2009), but the most common method is currently baling. While the more novel harvesting technologies may look good on paper, the highly competitive dairy industry has been collecting dry forage for hundreds of years, and invariably bales dry hay. Bales may be round or square. Square bales provide greater density and a more attractive shape for transportation, but high capital costs and dry storage requirements associated with square bales prevent many farmers from employing large square balers.

2.3.1 Production Costs

A wide range of switchgrass production costs may be found in the literature. Qin et al. (2006) estimate the harvested cost of switchgrass to be $32.53/Mg DM when loose chopping and approximately $47.50/Mg DM when round baling. Sokhansanj et al. (2009) present costs of approximately $65/Mg DM for square baled switchgrass. In the only study of actual switchgrass production operations identified in the literature, Perrin et al. (2008) present a range of between $51.95 and $88.25/Mg DM for the five average lowest and highest cost sites evaluated.

2.3.2 Life Cycle Emissions

Several authors have estimated the GHG emissions associated with switchgrass production. Life cycle emissions vary widely depending on basic assumptions surrounding emissions sources and sinks. Ney and Schnoor (2002) estimate switchgrass production emissions to be approximately -95 kg CO_2e/Mg DM, Spatari et al. (2005) estimate emissions to be 145 kg CO_2e/Mg DM, while Qin et al. (2006) present switchgrass production emissions of 73 kg CO_2e/Mg DM. The large, negative estimate by Ney and Schnoor (2002) can be attributed to their assumption that switchgrass sequesters carbon in the soil at a rate of more than 180 kg CO_2e/Mg DM. In the absence of the soil sequestration assumption, their estimate of switchgrass production emissions is 90 kg CO_2e/Mg DM. This result highlights the need for clarity in any LCA effort. One assumption changes the key result by more than 200% and results in negative emissions.

The bulk of LCAs of biomass combustion apply a credit to the biogenic carbon that is absorbed in growth, thus the combustion of the biomass itself does not generate emissions. Both

Mann and Spath (2001) and Heller et al. (2004) take a different approach, citing an emissions credit for avoided landfilling of the organic matter. In the current wood residue market, this assumption has limited credibility, since nearly all waste wood fiber enjoys a use.

2.4 Densification

Densification has been employed by the animal feed industry for decades as a means to deliver nutrients in a compact and flowable medium. Densification is attractive from a biomass energy perspective since biomass in its natural form lacks energy density and poses material handling challenges. By forcing the biomass feedstock through an open die, heat and pressure serve to pack the loose, fibrous material and partially melt feedstock constituents to form a denser, more consistent product. Densification improves upon the logistical challenges presented by the relatively low energy density and poor materials handling characteristics of biomass in its unprocessed form.

Three types of densified biomass are commonly produced: pellets, briquettes, and cubes. Pellets are smaller than either briquettes or cubes; they are typically 0.64 cm in diameter and approximately 2.5 – 3.8 cm in length. Pellets are also denser than their larger counterparts; Pellet Fuel Institute Standards call for a minimum density of 640 kg/m^3 for standard pellets, while briquette and cube densities are typically 400-500 kg/m^3. Briquettes, also referred to as pucks or logs, are approximately 7.62 cm in diameter and can vary in length. Cubes may range in size, but common dimensions are 3.8 cm on all axes.

While densification improves the logistical features of biomass and reduces shipping costs, the energy requirement of the process is substantial. To prepare feedstock for extrusion, the appropriate particle size distribution and moisture content are critical. The desired particle size varies with the type of product. Since pellets are smaller, they require more grinding than either cubes or briquettes. Optimal moisture content varies with feedstock and product type, but is generally about 12% on a wet basis. Together with the actual extrusion process, these are the most energy intensive steps in densification.

2.4.1 Life Cycle Emissions

In order for switchgrass to be densified, bales must be ground before entering the plant. This is typically accomplished via tub grinder. Tub grinder energy consumption for rice straw was measured to be 345 and 532 MJ/Mg DM using a 25.4 and 50.8 mm screen, respectively (Arthur et al., 1982). Rice straw is used for comparison to switchgrass since both are comprised of fibrous, woody stems. Tub grinding is the only size reduction required for the cubing and briquetting processes. Pelleting, however, requires additional size reduction beyond tub grinding, which is typically accomplished via hammermill. Mani et al. (2004) measure the energy consumption of hammermilling switchgrass with a 0.318 cm screen to be 97 MJ/Mg DM. Both the tub grinder and hammermill are driven by electric motor in the densification plant.

Following initial grinding, material is typically fed into a drum dryer to achieve the desired moisture content for densification. Dryer fuel consumption will vary with airflow and feed rate, but Zhang et al. (2010) estimate the energy consumption of drying to be 3.5 MJ/Mg DM DM. The authors do not state the assumed initial or desired moisture content. Natural gas or biomass may be used as a dryer fuel. Given the relatively lower cost of biomass per unit energy compared to natural gas, densification plants typically employ a biomass boiler to provide process heat for drying.

Following drying, the feedstock may enter further size reduction (pellets) or move directly into the densification mill. Estimates for the energy consumption of cube and briquette mills were not identified in the peer reviewed literature. Mani et al. (2006) estimate the energy consumption of the pelleting process without drying to total 956 MJ/Mg DM.

Two estimates of the life cycle emissions of pellet production are identified. Both Mani et al. (2006) and Zhang et al. (2010) present similar estimates of approximately 55 and 65 kg CO_2e/Mg DM, respectively. Electricity consumption is a large component of densification emissions; these results are highly sensitive to the generation mix of the electricity grid.

2.4.2 Production Costs

Detailed cost estimates for biomass densification are sparse in the literature. However, researchers at the University of Saskatchewan have developed detailed cost estimates for both cubing and pelleting operations. Mani et al. (2006) estimate the total production cost of pellets, excluding feedstock purchases, to be $33.80/Mg DM (Table 2-1).

Table 2-1 – Pellet production costs

Pellet Process Operations	Capital Cost ($/Mg)	Operating Cost ($/Mg)	Total Cost ($/Mg)	Percent Cost Distribution
Raw material	0.37	21.33	21.70	39.0%
Drying operations	2.71	8.62	11.33	20.4%
Hammermill	0.28	0.77	1.05	1.9%
Pellet mill	1.57	2.07	3.64	6.5%
Pellet cooler	0.14	0.23	0.37	0.7%
Screening	0.12	0.06	0.18	0.3%
Packing	0.62	1.51	2.12	3.8%
Pellet storage	0.08	0.01	0.09	0.2%
Miscellaneous equipment	0.46	0.36	0.83	1.5%
Personnel cost	0.00	14.01	14.01	25.2%
Land use and building	0.23	0.06	0.29	0.5%
Total cost	6.58	49.03	55.61	100%

Of these costs, feedstock purchases are the largest item, contributing to nearly 40% of total production costs.

Sokhansanj et al. (2004) estimate the total cost of cubing operations. Without considering feedstock, cubing costs are estimated to be \$23.87/Mg DM (Table 2-2).

Table 2-2 – Cube production costs

Item	Capital Cost ($)	Annual Cost ($)	Operating Cost ($/Mg DM)
Scales	110,000	18,520	$0.34
Concrete pad	45,000	4,373	$0.08
Dryer	1,079,200	141,551	$2.58
Dryer fuel	-	-	$2.00
Grinder	82,200	9,140	$6.19
Cuber and instrumentation	498,600	55,426	$9.49
Cube conveyor and cooler	77,100	10,111	$0.18
Building ($/m^2)	140	15,559	$0.28
Installation	434,300	35,454	$0.81
Supervisor	-	-	$1.92
Total			$23.87

Cuber and grinder operations, which include labor, comprise more than two-thirds of plant operation costs.

2.5 Thermal Application of Biomass

No study was identified that considers the use of biomass in thermal applications in the United States. However, in Europe, where the use of biomass for heat is more prevalent, two studies were discovered that evaluate the life cycle emissions associated with biomass thermal technologies. Eriksson et al. (2007) present GHG emissions associated with the combustion of peat, wood fuel, and pitch to be approximately 3 g CO_2e/kWh. Groscurth et al. (2000) evaluate a wide range of biomass thermal applications, finding that the use of unprocessed woody biomass produces virtually no net GHG emissions, while the gasification of short rotation woody crops results in approximately 1.1 kg CO_2e/kWh heat produced. In addition, these authors calculate substantial negative abatement costs for the replacement of fuel oil and coal with woody biomass of approximately \$50 and \$20/Mg CO_2e, respectively.

2.6 Biomass Electricity

Two pathways for biomass to electricity are commonly considered in the literature, co-firing with coal and repowering existing coal plants to become dedicated biomass operations. Authors contend that co-firing is less costly than operating a dedicated biomass plant (Mann and Spath, 2001, Qin et al., 2006, Hughes, 2000) due to the detrimental efficiency impact of high biomass moisture content, small unit size of biomass plants (Hughes, 2000), and low energy density of biomass. The moisture argument is valid; however the effect of moisture on solid fuel combustion systems is small. In their work with the combustion efficiency of coal-water slurries, Liu et al. (1986) find that, at the slurry equivalent moisture content of 46%, final combustion efficiency is reduced by 2-3%. Further, the small unit-size argument is related to steam turbine efficiency and not the fact that the plant is using biomass. Larger steam Rankine cycle plants allow for higher temperature and better steam quality, and repowering efforts are typically focused on the conversion of relatively large, existing coal fired plants (Energy Business Review, 2009, EPRI, 2008). Finally, the low energy density of biomass will not affect overall heat input to the boiler, it simply dictates that more mass be fired to achieve the same amount of electricity production.

Interestingly, Heller et al. (2004) actually report an increase in efficiency of 2.8% when comparing cofiring to coal only operations. Zhang et al. (2010) present modest efficiency losses from dedicated biomass operations of approximately 3%. Mann and Spath (2001) present a dedicated biomass plant efficiency of 27.7%, which includes the parasitic loads required for grinding and materials handling of biomass.

2.6.1 Life Cycle Emissions

Regardless of biomass source, co-firing and dedicated biomass electricity studies report similar reductions in GHG emissions over coal generation. At 10% co-firing, Heller et al. (2004) estimate emissions reductions of nearly 10% when replacing coal with short rotation willow crops, very similar to the reductions of 9% presented by Zhang et al. (2010) for replacing coal with wood pellets. Qin et al. present more modest reductions of 6.3% when replacing coal with switchgrass, largely due to the replacement on a mass basis as opposed to the heat input basis assumed by other authors. At higher cofire rates of 15% (Mann and Spath, 2001) and 20% (Zhang et al., 2010), present reductions of 18% over the coal baseline. Reductions over coal for the dedicated biomass scenario range from 90-95%.

2.6.2 Production Costs

Production costs for biomass electricity are comprised of capital costs, fixed operations and maintenance (O&M), nonfuel variable O&M, and fuel costs. Fuel costs will vary depending on the biomass source. Capital costs are those associated with the plant retrofit necessary to fire biomass and vary widely depending on the particular application. Cost estimates for the retrofit of an existing coal to a dedicated biomass plant range from as little as $125/kW (World Business Council for Sustainable Development, 2006) to as much as $1500/kW (Peltier, 2007) of biomass capacity. Cofiring retrofits are less costly; grinding and materials handling retrofits for cofiring operations are in the range of $150-300/kW (Robinson et al., 2003). EIA (EIA, 2009) presents estimates of $6.86/kWh and $65.89/kW for nonfuel variable O&M and fixed O&M, respectively. Estimates for GHG abatement costs from the replacement of coal with biomass range from $13.8/Mg CO_2e (Qin et al., 2006) for 10% cofiring with switchgrass to approximately $150/Mg CO_2e (Zhang et al., 2010) when firing wood pellets in a dedicated biomass plant. Cofiring estimates are generally lower, due to the large fraction of coal that reduces production costs. Cofiring abatement cost estimates range from \$13.8 to \$45/Mg CO_2e (Robinson et al., 2003).

2.7 Calculating Abatement Costs

The calculation of abatement costs when replacing fuel sources requires production cost estimates for both the fossil fuel and biomass technologies in addition to the life cycle emissions associated with each. Zhang et al. (2010) present the following equation (1) to illustrate the calculation.

$$Abatement\ Costs = -\frac{COE_a - COE_b}{LCE_a - LCE_b} \quad (1)$$

Where

COE – cost of electricity

LCE – life cycle emissions

a – alternative

b – baseline

In addition to the biomass emissions and production costs, life cycle emissions and production costs for the fossil systems being replaced are necessary to develop abatement costs.

2.8 Fossil Systems

Baseline fossil energy systems targeted for replacement with biomass include coal generation on the electric side, and natural gas and fuel oil systems for the case of thermal energy. Biomass replaces coal in electricity generation since both are solid fuels, provide baseload power, and coal plants can be retrofitted to fire biomass at a relatively low cost. Natural gas and fuel oil are targeted in thermal applications since these are the most common heating fuels.

The emissions associated with fossil fuel combustion are often presented as fuel cycle and combustion emissions. Fuel cycle emissions are those that result from energy inputs in extraction, processing, and transportation operations, while combustion emissions are released from the power plant stack. Estimates for total life cycle emissions identified in the literature range from 978 kg CO_2e/MWh (Heller et al., 2004) to 1039 kg CO_2e/MWh (Mann and Spath, 2001). Heller et al. (2004) estimate fuel cycle emissions to comprise approximately 5% of total coal plant emissions. Fuel cycle emissions from the production and transportation of natural gas are much higher, resulting in 124.5 kg CO_2e/MWh (Spath and Mann, 2000). Sheehan et al. (2004) present the life cycle emissions of diesel fuel to be 81.25 g CO_2e/MJ. Diesel fuel and heating oil are both No. 2 residual fuel oil.

Production costs for various electricity generating technologies are developed by EIA (EIA, 2009). Thermal energy production costs were not identified in the literature. Fossil fuel price data can be found on the EIA website (EIA, 2010).

2.9 Objectives

The overarching goal of this analysis is the calculation of GHG abatement costs for the production of thermal and electrical energy from densified switchgrass. Abatement costs are calculated using the method developed by Zhang et al. (2010) and presented above. The specific objectives in support of this goal are:

1. Life cycle inventory of GHG emissions for switchgrass production, densification, and energy conversion
2. Production cost analysis for switchgrass production, densification, and energy conversion
3. Development of cost and emissions baselines for the fossil alternatives
4. Calculation of abatement costs based on 1-3
5. Sensitivity analysis of results to key assumptions

The completion of the five objectives presented above develops abatement costs for the utilization of switchgrass for heat and power applications and evaluates the robustness of the analysis to key parameters.

Chapter 3

Methodology

We use life cycle assessment (LCA) following ISO procedures (ISO, 2006) to estimate greenhouse gas (GHG) emissions associated with switchgrass production, densification and conversion to heat and power. Several types of fuels and scales of energy utilization are considered for comparison.

1. Residential thermal: heat production for a typical home consuming 50 GJ of heat annually. Fuel oil, natural gas, and switchgrass pellets are evaluated.
2. Commercial thermal: heat and hot water production for a commercial scale load of 8000 GJ per year. Fuel oil, natural gas, switchgrass cubes and switchgrass briquettes are considered.
3. Electric power: the production of electricity employing conventional coal, conventional natural gas, natural gas combined cycle, and biomass repower technologies are considered.

In addition to life-cycle GHG emissions, production costs are developed for each technology to evaluate abatement costs.

3.1 Life-cycle Inventory

"Cradle to gate" modules are developed for each utilization scenario from crop establishment through end-use. Emissions at each step are estimated from a combination of producer data and existing literature. The LCA is closed at the point of combustion, i.e. distribution losses are not considered, since these will vary with individual systems. Inputs associated with the manufacture and construction of equipment and facilities are considered but negligible.

Functional unit for each module is dependent on the output of the particular operation. For crop production and densification, the functional unit is Mg DM, and for final consumption in thermal and electricity production, functional units are GJ and MWh, respectively. 100-year global warming potentials (IPCC, 2006) for selected GHGs (CO_2, CH_4, N_2O) are used to evaluate the contribution of emissions to the reduced transmittance of the atmosphere. As is common in biomass LCA (Spatari et al., 2005, Qin et al., 2006, Heller et al., 2004), it is assumed that all biogenic carbon that is released during combustion was absorbed during crop growth. Also, establishment on marginal soils that were not previously in production is assumed and therefore emissions associated with land use change are not considered.

3.1.1 Switchgrass Production

Switchgrass production consists of seed production, establishment, and annual maintenance and harvest. Assumed stand lifetime is 10 years. Harvesting fuel consumption and productivity were measured as part of a previous study at Ernst Conservation Seeds (ECS, Meadville, PA). Seed production emissions are estimated based on field operations and seed cleaning motor ratings and system throughput through conversations with Michael Ernst of ECS. Diesel consumption associated with seed harvesting is estimated based on Nagy (1999). All other fuel consumption resulting from field operations are adapted from Adler et al. (2007). Emissions associated with chemical and fertilizer inputs are evaluated based on West and Marland (2002), and direct and indirect N_2O emissions are estimated based on IPCC protocols (IPCC, 2006). Transport to and storage at satellite locations is considered the farm gate.

3.1.2 Densification

Densification plant emissions are developed hypothetically. Very few operations consistently process perennial grasses as a feedstock. Electricity inputs to the densification plant are developed based on manufacturer's quotes of motor ratings and throughput and through conversations with pellet and briquette producers. Other energy inputs include fuel consumption of loaders and the switchgrass necessary to dry the feedstock to the appropriate moisture. Given limited experience with the densification of grasses, the largest source of uncertainty in the densification analysis is due to estimated plant throughput. The effect of this assumption is evaluated via sensitivity analysis (Appendix B, Figure B-1). Transport from the farm gate to the densification plant is also included in this module.

3.1.3 Residential Thermal

Residential thermal options for the utilization of densified switchgrass are limited to pellet appliances. Currently, appliances are not available to utilize briquettes or cubes at this scale. We assume that pellet appliances capture 80% of total demand, with natural gas capturing the peaks and periods of low demand. Fuel oil and natural gas emissions include fuel cycle and combustion emissions and are estimated based on Sheehan et al. (2004), Meier et al. (2005), and Spath and Mann (2000), respectively.

3.1.4 Commercial Thermal

Commercial scale thermal options for biomass utilization account for the combustion of briquettes and cubes in modern biomass boilers. Pellets are not considered a viable option for these applications due to their relatively high cost and the lack of an advantage in materials handling characteristics. Again, we assume that the biomass system is designed to capture 80% of total fuel demand, with natural gas capturing the remainder. Fuel oil and natural gas emissions per unit of energy are the same as in the residential thermal case. Transportation of densified products is based on loading cycle and fuel efficiency of tractor-trailers in each thermal scenario.

Nitrous oxide and methane emissions for the combustion of biomass in small appliances are estimated from US EPA AP-42 emissions factors (EPA, 2010). All thermal appliances are assumed to be 80% efficient in combustion. While natural gas and fuel oil furnaces may achieve combustion efficiencies of 90% or more, it is assumed that the fossil systems are boiler units and lose efficiency due to the circulation of hot water.

3.1.5 Electric Power

Electric power emissions include fuel-cycle and combustion emissions. Conventional coal, NGCC, conventional gas turbines, and dedicated biomass are the technologies evaluated.

3.1.5.1 Coal Baseline

Coal emissions are taken from (Heller et al., 2004), who assume the following. Coal type is eastern bituminous, 82.9% of which is mined underground with the remainder extracted via surface mining. Total transport distance is 425 km, with 84.4% of transport accomplished by rail, 6.7% by truck, and 8.9% shipped by barge. Plant efficiency is 33.7%. Capacity factor is assumed to be 80% to align with the abatement cost analysis.

3.1.5.2 Natural Gas

Two natural gas technologies are considered, NGCC and conventional gas turbines. The NGCC plant is assumed to be 48.8% efficient, while the conventional gas turbine efficiency is taken as 35%. Fuel cycle emissions reflect that of the US extraction and distribution system reported by Meier et al. (2005) and developed from US EPA data. A capacity factor of 60% is assumed for both natural gas technologies to reflect their nature as peaking and following plants. We assume that cited values include other GHG emissions.

3.1.5.3 Biomass Repower

The retrofitting of an existing coal plant to produce electricity solely from biomass is commonly referred to as repowering. Repowering can span a range of activities, depending on the nature of the existing plant. Typically, however, repower includes the addition of storage capacity to account for the lack of energy density associated with biomass, as well as conversion of coal pulverizing equipment to handle the more fibrous biomass. Following EPRI (1997), a plant efficiency of 27.7% is assumed; this value accounts for the parasitic loads associated with grinding the fuel and delivering it to the boiler. Other GHG emissions are estimated using US EPA AP-42 emissions factors (EPA, 2010). Since biomass generation offers baseload power, a capacity factor of 80% is assumed. A co-firing situation is not considered, since no real technological difference exists between the repowering and co-firing scenarios. Further, it is most instructive to conceptualize the abatement costs of biomass per unit of biomass fired, since these represent actual marginal costs associated with emissions reductions.

3.2 Abatement Costs

Production costs for each module are developed in order to arrive at abatement costs for each technology. The baseline for comparison is taken to be the largest emitter on a per unit energy basis. For thermal systems, fuel oil and natural gas systems produce similar emissions per unit of output; both are considered for replacement with biomass. Coal is the baseline in the electric generation scenario due to the carbon intensity of the fuel in combustion. Costs are taken to be the net of all profits, taxes and subsidies.

3.2.1 Crop Production

Switchgrass production costs include those associated with crop establishment, harvest and transport to the densification plant. Crop establishment costs include land, tillage, chemical and fertilizer application, and seed and seeding inputs. Establishment cost estimates vary widely in the literature (Perrin et al., 2008, Epplin, 1996, Duffy and Nanhou, 2001) and can be expected to differ depending on prior land-use. An estimate of $633.01/ha is used based on costs provided by Calvin Ernst of ECS for establishment on marginal land plus $98.80/ha land rent. Establishment costs are amortized over a ten year period assuming that the crop will be reseeded every ten years to take advantage of yield gains from crop breeding.

Harvesting costs are obtained from the ECS database, which includes detailed information regarding inputs for annual maintenance, switchgrass round baling, and collection at a satellite location. Trucking costs to the densification plant are estimated based on a semi-trailer loaded to dimensional capacity with round bales and shipped 48 km (30 mi) one way.

3.2.2 Densification

Densification costs are developed from manufacturer quotes and a producer's business plan for a pellet plant currently under construction. No real data exist for switchgrass densification operations since large-scale production is not yet a reality. Energy inputs to plant equipment are estimated based on motor rating and plant throughput. Plant throughput is estimated based on densification mill throughput and 6,000 h per year of plant operations. Pellet plant throughput is 27,273 Mg DM/y (5 short tons/h), while cube and briquette plant throughputs are each 32,727 Mg DM/y (6 short tons/h). Labor inputs consist of nine full time operators, one plant manager, and one part-time secretarial position and include benefits. With the exception of the densification mill itself and size reduction requirement, plant infrastructure is the same for all three plants. Pellet operations include packaging. Capital costs are amortized at 6% interest over the assumed plant lifetime of 20 years.

3.2.3 Thermal Energy

Commercial and residential thermal production costs are estimated based on installed capital and fuel costs. Capital costs are obtained from vendors and amortized accordingly. Fossil fuel costs are taken from EIA data (EIA, 2010), while densified switchgrass costs are developed from within the analysis. Transport to final consumption is assumed to be highway freight. Transport distance is 81 km (50 mi) for commercial scale heat and 322 km (200 mi) for residential applications.

3.2.4 Electric Power

Electricity production costs are developed from existing estimates of capital, fixed operating and maintenance (O&M) costs, nonfuel variable O&M costs, and fuel costs. All fossil system costs are estimated from EIA generating technology cost estimates (EIA, 2009). Biomass repower and co-fire capital cost estimates span a wide range since the cost modifications necessary for a coal plant to accept biomass are highly site- and situation-specific. Following the approach of Zhang et al. (2010), capital costs are estimated to be $640/kW as reported by FirstEnergy for the conversion of the R.E. Burger coal plant in Northeastern Ohio. Fixed and variable O&M estimates are also taken from Zhang et al. (2010). Switchgrass fuel costs are developed from within the analysis.

Chapter 4

Results

4.1 Life Cycle Emissions

4.1.1 Crop Production

Switchgrass production operations from establishment through harvest and delivery to the densification plant total 82.8 kg CO_2e/Mg DM. More than 75% of production emissions result from direct and indirect N_2O emissions due to nitrogen fertilizer application. Of the remaining emissions, machinery operations are the single largest contributor to production emissions.

4.1.2 Densification

Densification emissions for pellets, briquettes, and cubes are 134, 93, and 84 kg CO_2e/Mg DM, respectively. For pelleting operations, 80% of all emissions result from electricity consumption by the grinding and pelleting processes. The bulk of the remaining emissions (19.8%) accrue as a result of drum dryer operation. The dryer fuel is the biomass itself.

For cubes and briquettes, the grinding and extrusion processes play a similarly large role, contributing to 73% and 76% of total process emissions, respectively. The major difference in emissions between pellets and the larger densified products is a consequence of the specific energy consumption of the densification and grinding processes. Pelleting and the associated size reduction consume 143 kWh/Mg DM, whereas the same operations for cubes and pellets consume 75 and 89 kWh/Mg DM, respectively.

Due to a lack of experience with pelleting switchgrass, mill throughput is a source of uncertainty within this calculation. A sensitivity analysis of plant throughput is provided in supporting information (Appendix B, Figure B-2).

4.1.3 Thermal Energy

Life cycle GHG emissions resulting from fuel combustion for thermal energy are presented in Figure 4-1. Natural gas is the largest emitter due to fuel cycle emissions from pipeline leakage. Both natural gas and fuel oil emissions are slightly greater than 100 kg CO_2e/GJ. All biomass system emissions generate approximately one-third the emissions of their fossil alternatives.

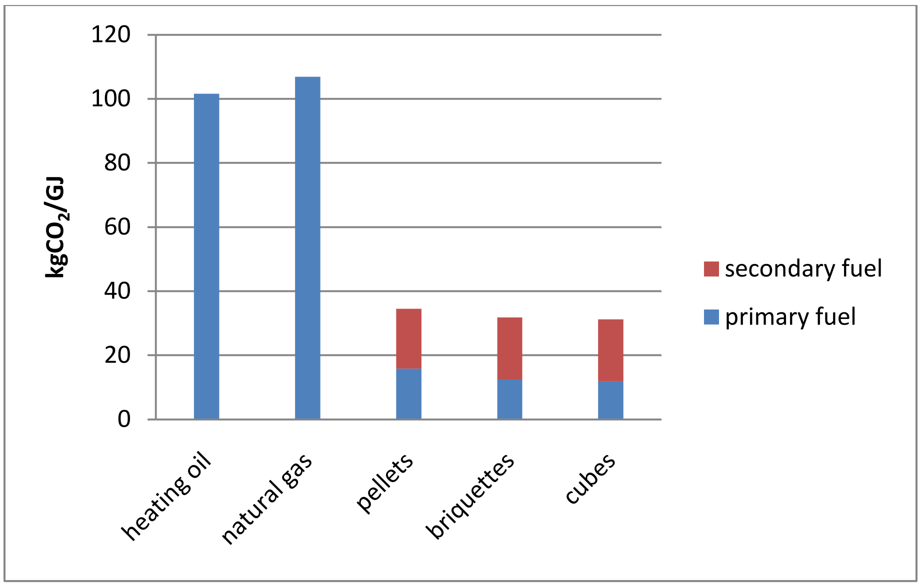

Figure 4-1 – Life cycle emissions resulting from combustion in thermal systems

For pellets, slightly more than 50% of these emissions are the result of fossil fuel combustion while this value is nearly 60% for biomass and cube systems. Due to the relatively low turndown capacity of biomass systems, properly sized biomass boilers and furnaces are designed to capture shoulder loads, leaving periods of peak and low demand to fossil backup systems. The fossil backup system is assumed to be natural gas in this case.

4.1.4 Electric Power

For electric power systems, coal is by far the largest emitter (Figure 4-2). Emissions from briquettes and cubes are similar, 134 and 127 kg CO_2e/MWh, respectively.

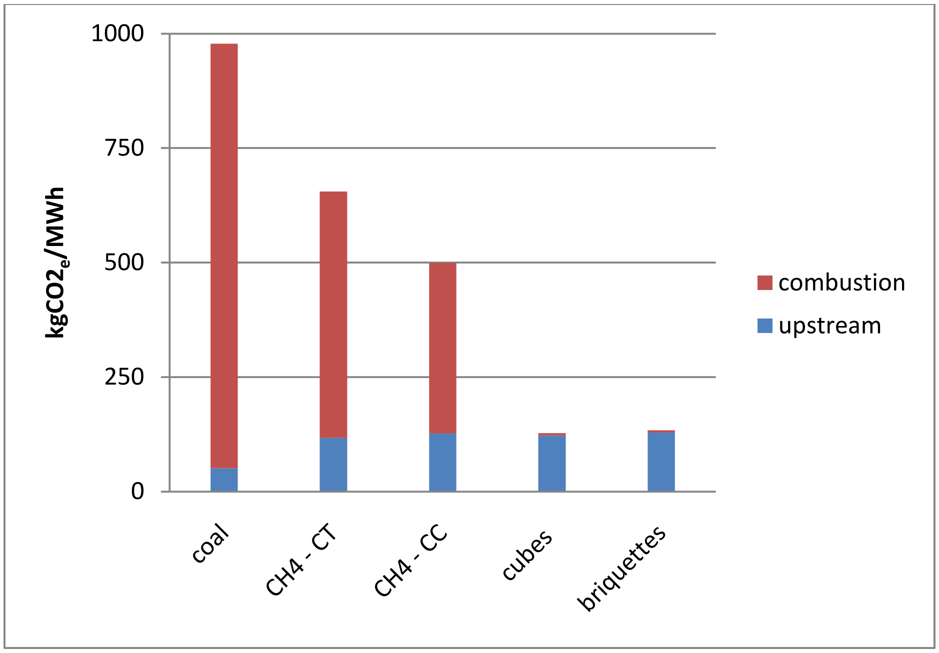

Figure 4-2 – Life cycle emissions resulting from electricity production

Combustion emissions for briquettes and cubes result from nitrous oxide and methane emissions; all other emissions occur from upstream activities. Densified switchgrass for electric power provides reductions over conventional coal, conventional natural gas turbine, and natural gas combined cycle technologies of approximately 85, 80, and 70%, respectively.

4.2 Production Costs

4.2.1 Crop Production

Total switchgrass production costs at the farm gate are $75.73/Mg DM. The largest contributor to switchgrass production inputs is the baling process at a cost of $47.98/Mg DM. Land rent, establishment costs, and annual fertilizer inputs account for the remaining costs, with land rent of $11.00/Mg DM, establishment costs of $8.71/Mg DM and fertilizer application contributing $8.05. These costs are within the range of those estimated in the literature (Perrin et al., 2008), and accurately reflect production costs in the Northeastern US with currently available technology. Observed yield is adjusted to align with assumed life-cycle yield; costs are adjusted accordingly. The impact of this adjustment is investigated via sensitivity analysis (Appendix B, Figure B-2).

4.2.2 Densification

For each densification technology, the bulk of input costs result from biomass purchases (Figure 4-3). Biomass inputs account for approximately 55% of pellet inputs and more than 70% of inputs for both briquettes and cubes.

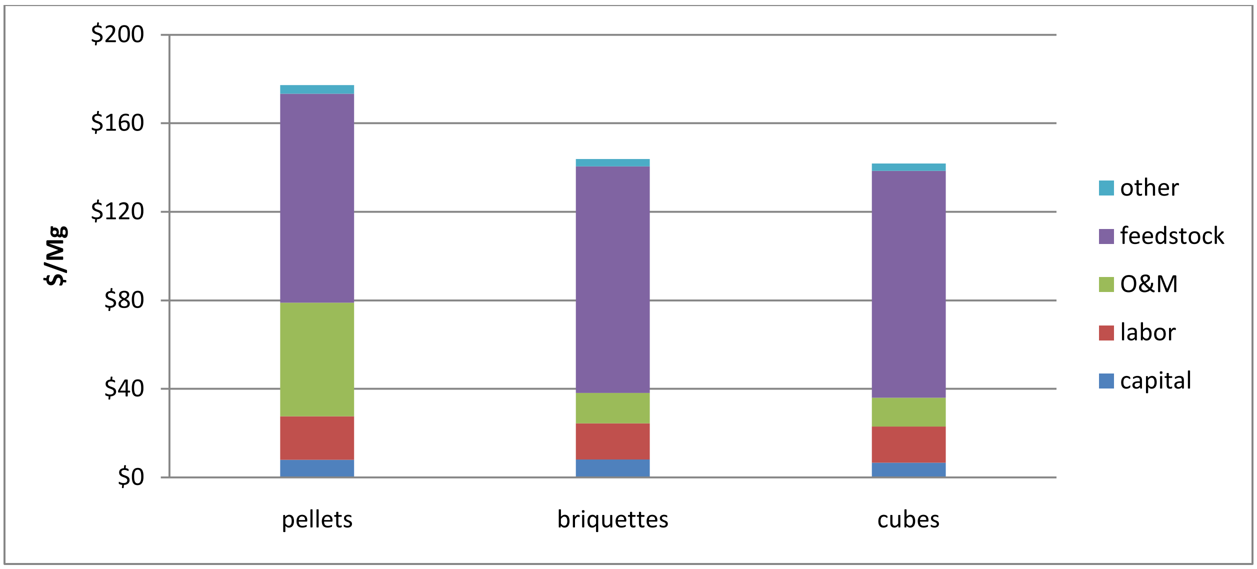

Figure 4-3 – Densification input costs

Production costs for briquettes are slightly greater than cubes due to the higher capital cost of the briquetting system. A single briquetter achieves a throughput of only 1.4 Mg DM/h (1.5 short tons/h) compared to the manufacturer estimated 5.5 Mg DM/h (6 short tons/h) for the cuber. Four briquette mills are needed to match the throughput of one cuber, resulting in annualized capital costs of $262,759 for the briquette mill compared to $216,943 for the cubing system. This plays a small role in total production costs; cubes and briquettes have production costs of $129.17 and $131.28, respectively.

Production costs for pellets are greater ($177.30) than the larger densified products due to electricity and packaging costs. Electricity consumption of the pelleting process is nearly twice that of cubes and briquettes, and pellets are commonly packaged for residential consumption. Packaging costs are large, $26.40/Mg DM, but residential bulk delivery systems for pellets do not currently exist in the US.

4.2.3 Thermal Energy

Natural gas systems represent the lowest cost of production for both residential and commercial applications. In residential installations, annualized capital plus fuel costs result in per GJ costs of $17.69, $31.14, and $21.27 for natural gas, fuel oil and pellet systems, respectively. For commercial systems, cost savings of biomass over fuel oil are less dramatic; cubes and briquettes represent savings over fuel oil systems of approximately $6/GJ compared to the $10/GJ savings in the residential case. This is the result of large capital expenditures required for commercial biomass systems. Installed capital costs for a biomass boiler, storage and fuel handling equipment are more than five times their fossil counterparts. However, the substantial fuel savings over fuel oil (~$11/GJ) make biomass a viable alternative despite the high initial outlays. In the absence of subsidies, biomass is generally not economically competitive with natural gas systems.

4.2.4 Electric Power

Due to the low cost of fuel inputs and sunk capital costs, electricity generation from coal is the lowest cost alternative ($30.90/MWh) by a wide margin. The high efficiency of NGCC systems gives them a relative advantage over conventional gas turbines by more than $10/MWh ($51.15/MWh vs. $61.31). Biomass electricity generation is by far the most expensive generation option, with costs (~$150/MWh) nearly five times that of coal. The high cost of biomass generation is primarily due to fuel input costs. The impact of the production cost data is investigated via sensitivity analysis in supporting information.

4.3 Abatement Costs

Abatement costs are calculated as deviations from fossil fuel costs. For the electric power case, coal is selected as the baseline, since nearly all proposed biomass power applications replace baseload coal generation. Thermal energy baselines are both natural gas and fuel oil; biomass may replace either in heating.

4.3.1 Thermal Energy

In heating applications at both the residential and thermal scale, the replacement of fuel oil with biomass provides negative abatement costs (Figure 4-4). The presence of negative abatement costs can be largely attributed to two factors. First is the phenomenon of putty-clay economics associated with energy, specifically heating, systems. Furnaces and boilers, at both the residential and commercial scales, represent relatively large capital outlays, and, once in place, the consumer is committed to the chosen fuel. To provide sufficient incentive for the consumer to switch, fuel price differences must be substantial and sustained. Since the rise in fuel oil prices in the past several years has resulted in larger disparity between the cost of biomass and fuel oil heat, we can expect more consumers to switch to biomass in coming years.[1] Second is the emergence of more efficient, cleaner burning, and automated combustion technologies that allow biomass systems large and small to burn less fuel, meet emissions regulations, and reduce the labor required for operations. In short, the market is currently adjusting to the recent rise in fuel oil price and improvements in biomass combustion technologies, thus the presence of negative costs.

[1] Assuming high fuel oil prices are sustained. In Appendix B, sensitivity to fuel oil prices is investigated.

In both cases the cost savings are substantial; commercial biomass systems deliver associated savings of $89 with each tonne of carbon dioxide equivalent reduced. Pellets perform even better from an abatement cost perspective; each tonne of emissions reductions is accompanied by negative costs of $147. The replacement of natural gas with biomass at current market prices ($10.31/mcf) is not an economically viable alternative in either case. In both residential and thermal applications, replacing natural gas with biomass produces positive abatement costs of approximately $60/ Mg CO_2e.

4.3.2 Electric Power

Due to the low cost of coal generation, replacement with either biomass or natural gas produces positive costs. NGCC produces the lowest abatement costs of all other alternatives at $42/ Mg CO_2e. This is primarily due to the low fuel costs associated with the high efficiency of advanced combined cycle generation. Conventional natural gas turbines result in mitigation costs of $94/ Mg CO_2e. While natural gas generation alternatives provide the lowest abatement costs of the fuels investigated in this analysis, the wisdom of generating baseload power from such a high-value fuel as natural gas remains to be seen.

The replacement of coal generation with biomass is the highest cost mitigation option for electric power; the generator sees production costs increase nearly five-fold at a reduction cost of approximately $131/ Mg CO_2e.

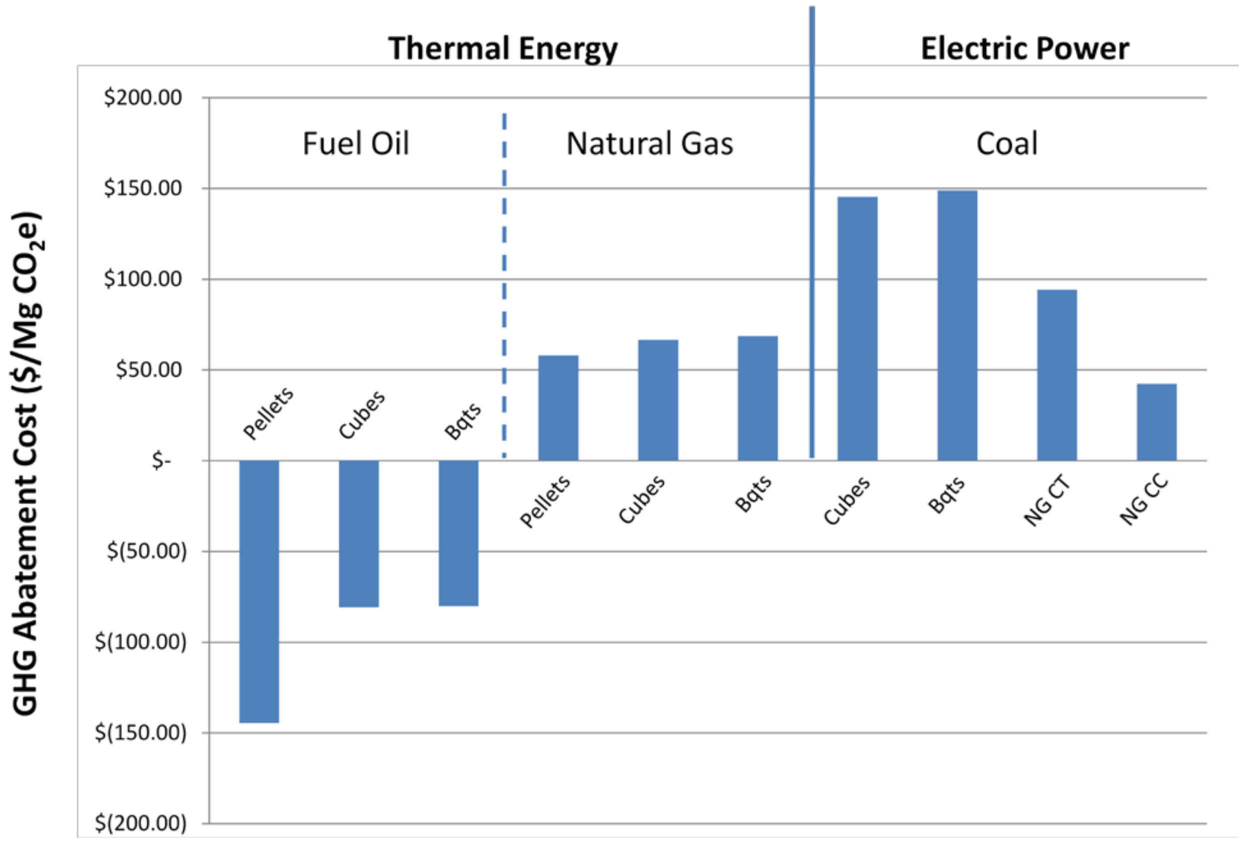

Figure 4-4 – GHG abatement costs of thermal energy and electric power. Thermal energy considers the replacement of both fuel oil and natural gas. Electric power considers the replacement of coal generation.

This result is driven by the high cost of biomass fuel and capital costs necessary for the biomass retrofit relative to low-cost coal and sunk capital costs of the US coal fleet.

Biomass costs calculated herein are similar to those reported by Perrin et al. (2008) for the Midwest, the only other known study to develop production costs from actual operations. The authors find that production costs ranged from $51.95 to $88.25/Mg DM for the five lowest and highest cost sites, respectively. The average reported costs by Perrin et al. (2008) are $65.86, 13% lower than those reported here. Agricultural production costs are generally higher in the Northeast due to smaller, more irregularly shaped, and widely dispersed fields. Using the low value reported by Perrin et al. (2008) for on-farm costs drives abatement costs downward by 19% to approximately \$106/ Mg CO_2e. This corresponds to a 31% reduction in farm-gate costs.

Chapter 5

Discussion

No life cycle or abatement cost analysis was identified that considered the utilization of biomass in thermal applications for the US. Two European studies are identified (Eriksson et al., 2007, Groscurth et al., 2000). Of these, none considers the use of a dedicated energy crop such as switchgrass. As such, it is difficult to draw accurate comparisons. Regardless, Eriksson et al. (2007) present emissions associated with the combustion of biomass (peat, wood fuel, pitch) of approximately 10 kg CO_2e/GJ, similar to the 9.4 kg CO_2e/GJ reported here. Groscurth et al. (2000) also support the results herein, presenting heating costs[2] of between \$0.03 and \$0.09/kWh. Our value of \$15.29/GJ for commercial heating with cubes corresponds to \$0.055/kWh. The authors find negative abatement costs of approximately -\$50/Mg CO_2e when replacing fuel oil with biomass compared to the estimated -\$89. Some of this disparity is almost certainly due to differences in fuel oil prices over time. The European analysis uses 1998 fossil prices. Given differences in tax structure between the US and Europe, it is difficult to ascertain the precise fuel oil price used in the study.

Of the studies identified that consider the replacement of coal-generated electricity with biomass, only (Qin et al., 2006) consider switchgrass as the biomass fuel. Qin et al. report an abatement cost of \$33/Mg CO_2e when firing only switchgrass, largely due to the switchgrass cost estimate of \$34.70/Mg DM. This cost estimate is developed theoretically and thought to be unrealistic, likely due in part to the high yield assumption (22 Mg DM/ha). The same study's estimate of 72.8 kg CO_2e/Mg DM for life cycle emissions associated with round baled switchgrass aligns closely with our value of 86 kg CO_2e/Mg DM. In the only other study

[2] Assuming an exchange rate of \$1.5/Euro

identified that evaluates the combustion of densified biomass for electricity generation (Zhang et al., 2010), the authors present abatement costs of approximately \$125/Mg CO_2e for a dedicated biomass plant, similar to the \$131/Mg CO_2e estimated here.

Chapter 6

Conclusion

Depending on the application, densified switchgrass may provide positive or negative GHG abatement costs. Biomass is a limited, renewable resource. Therefore, the implementation of biomass energy applications should take into careful consideration the ability of a particular technology to align with our renewable energy goals. Two of the primary goals of renewable energy policy are the reduction of GHG emissions and reduced reliance on foreign sources of energy. In the interest of reducing debt for current and future generations, the ability of a particular renewable application to meet these goals at the least cost is of no small importance. To this end, one Mg DM of densified switchgrass applied in either heat or power applications will reduce GHG emissions by approximately 1.2 Mg. In the electric power case, these reductions will cost the ratepayer approximately $160. Conversely, the same Mg of biomass in heating applications, delivering the same 1.2 Mg of GHG emissions reductions, is accompanied by savings of $175 when replacing fuel oil in residential applications and savings of $110 in commercial systems.

While cost savings are greater with pellets, the current ability of pellet heat to penetrate the marketplace is limited by the lack of automated delivery systems. Pellets must be manually loaded into stove or boiler fuel hoppers, and convenience is of high importance to the US consumer of environmental control systems. This may change if automated pellet delivery and ash removal services become a reality in the US. By contrast, the use of biomass on a commercial scale is gaining popularity in the US. The low cost of wood chip biomass and the convenience of modern fuel handling systems provide a bright market outlook for the future of commercial-scale biomass thermal systems.

To the end of replacing foreign sources of energy, only the biomass to heat pathway has the potential to accomplish this goal, cellulosic ethanol aside. Cellulosic ethanol is much less efficient than either the heat or power pathway (Campbell et al., 2009), thus should only be considered once more efficient pathways have been exhausted. To the high-value transportation fuel argument, fuel oil, diesel fuel, and gasoline are all derived from a barrel of oil. From an energy independence perspective, the offset of one is as valuable as the other. One Mg DM of biomass that replaces fuel oil will offset substantially greater volumes of oil than its conversion to ethanol. As to electricity production, biomass power generation will directly offset coal, a domestically produced fuel. Further, when replacing fuel oil, biomass heat is an economically attractive option in the absence of subsidy.

In sum, current renewable portfolio standards will dictate the utilization of biomass power as a replacement for coal in US electricity generation. While biomass electricity provides abatement costs similar to other renewable technologies (Samson et al., 2008), its use in heating applications provides substantial negative abatement costs. In the absence of renewable portfolio standards, biomass will almost certainly be used in highly efficient thermal applications[3] first.

This analysis highlights one unintended consequence of the enactment of sweeping renewable legislation. Clearly the intent of RPS legislation is to reduce dependence on foreign sources of energy and reduce GHG emissions. The result, highlighted here, is both increased costs and a missed opportunity to offset large amounts of fuel oil while instead offsetting coal, a domestically produced energy source.

[3] We do not evaluate the potential of combined heat and power (CHP) within this analysis. CHP provides abatement levels equivalent to or greater than thermal energy, and should be employed wherever feasible.

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Appendix A

Critical Assumptions

Life Cycle Inventory

Life-cycle boundary

The analysis begins with the seed production process and follows the switchgrass life cycle through establishment, production, and densification before concluding with the conversion of the densified products to thermal or electrical energy (Figure A-1).

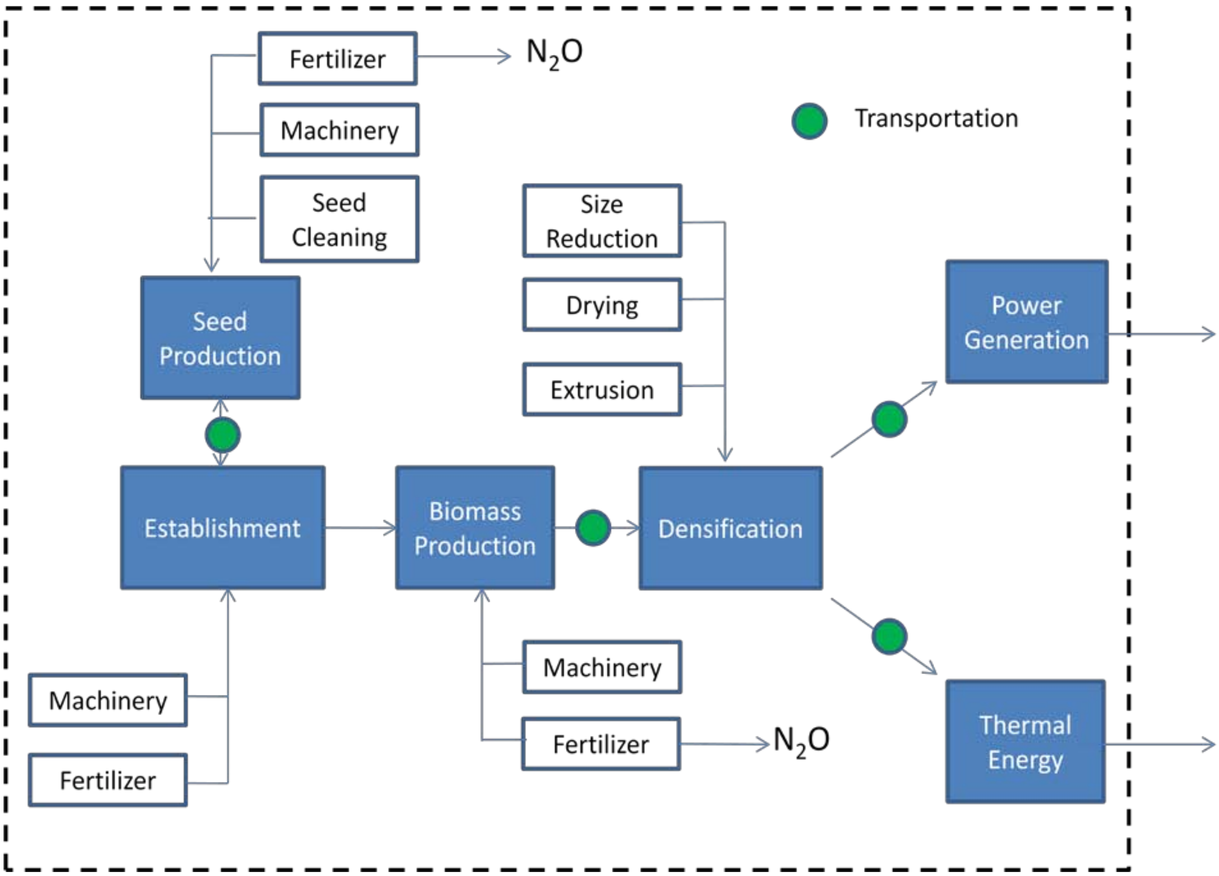

Figure A-1 – Life cycle boundary

The life cycle closes with the combustion of switchgrass for heat or power; it does not include losses associated with the distribution of the energy produced.

All transportation in the switchgrass life cycle is assumed to be accomplished by over the road freight. Seeds are transported 480 km to the farmer, and baled switchgrass moves 48 km to the densification plant. Densified product transportation distance varies with both type and application. Pellets are transported 320 km to the residential consumer, while briquettes and cubes travel 80 km to commercial applications and 320 km to electrical generating facilities.

Crop Production

Separate modules are developed for seed production (Table A-1), crop establishment and biomass production. Seed production involves both crop production and seed cleaning. Establishment protocols for seed crops are assumed to be the same as those for biomass cultivars and seed cleaning emissions are estimated based on horsepower and throughput of equipment. Harvesting emissions are estimated based on data from Nagy (1999) for a 150 hp combine and three tending trucks.

Table A-1 – Seed production emissions

Operation	emissions (kg CO_2e/kg seed)
Establishment	0.22
Harvest	0.52
Fertilizer	0.51
N_2O	4.51
seed cleaning	0.01
Transport	0.03
total	5.81

A seed yield of 140 kg/ha is assumed. As with crop establishment and production, nitrous oxide emissions resulting from nitrogen fertilizer application are the largest contributor. Assumed application rate is 55 kg N/ha.

Crop establishment and biomass production emissions are adapted from existing literature (Adler et al., 2007). Modifications to establishment emissions include an additional broad spectrum herbicide application in the fall to eliminate competition from existing vegetation as well as the planting of winter wheat for a cover crop. Assumed biomass yield is 8.98 Mg DM/ha (4 t/ac). Biomass production emissions are modified using baler fuel consumption and productivity data from a previous experiment. Measured baler fuel consumption was 1.90 l/Mg DM. Total emissions associated with switchgrass production are 86 kg CO_2e/Mg DM.

Densification

Three types of densification operations were considered for this analysis: cubing, briquetting, and pelleting. Each of the densification technologies has similar supporting infrastructure, and all involve the same six basic steps.

1. Loading – material must be loaded into a hopper via front-end/skid loader for entry into the densification plant
2. Drying – typically, densification operations will have a drum dryer to remove moisture content from the feedstock
3. Size reduction – particle size of the feedstock entering the densification process is a critical operating parameter
4. Conveyance – material must be conveyed between each step, requiring materials handling equipment
5. Extrusion – feedstock is forced through a die with a piston or roller, forming the densified product
6. Cooling – densified product must be cooled following extrusion to allow product to cure

Given a paucity of data and limited, variable observations in the literature, the energy associated with each of these steps was calculated theoretically based on motor rating and plant throughput obtained from manufacturer quotes.

Energy consumption associated with each of these steps and the resulting life cycle emissions are presented (Table A-2).

Table A-2 – Life cycle emissions of densification operations

	pellets		briquettes		cubes	
operation	energy consumption (kWh/Mg)	emissions (kg CO_2e/Mg)	energy consumption (kWh/Mg)	emissions (kg CO_2e/Mg)	energy consumption (kWh/Mg)	emissions (kg CO_2e/Mg)
loading[1]	4.48	1.31	5.38	1.57	5.38	1.57
drying[2]	22.06	26.53	18.38	23.99	18.38	23.99
size reduction	60.81	42.01	33.86	23.39	33.86	23.39
conveyance	0.36	0.25	0.38	0.26	0.38	0.26
extrusion	87.31	60.32	59.63	41.19	45.95	31.75
cooling	5.25	3.63	4.38	3.02	4.38	3.02
Total	**180.27**	**134.05**	**122.01**	**93.44**	**108.33**	**83.99**

1 – Loading is accomplished via front-end loader
2 – Drying emissions include biomass fuel at a rate of 7% of total DM required to dry feedstock from 30 to 12% MC
3 – Remaining emissions estimated based on motor ratings and densification plant throughput

From an emissions perspective, the difference between briquettes and cubes is related only to the specific energy requirement of the extrusion process itself. Briquetter and cuber specific energy requirements are developed from productivity and motor ratings. Size reduction consists of tub grinding for initial size reduction and hammermilling for further size reduction required for pelleting. Tub grinding specific energy was measured to be 34 kWh/Mg DM during field operations in 2009, which is within the range presented for rice straw (Arthur et al., 1982), while hammermill specific energy is 27 kWh/Mg DM (Mani et al., 2004). Biomass energy content for all calculations within the analysis is assumed to be 18.6 MJ/Mg DM (8000 BTU/lb). The drum dryer is assumed to consume 5.13 MJ/kg water removed.

All electricity emissions are assumed to accrue from the consumption of electricity produced in the Northeastern US using EPA's online tool, eGRID.[4] Fuel cycle emissions are calculated by a weighted average of the fraction of coal, oil and natural gas generation within each subregion. The resulting emissions factor for the Northeast regional grid is 691 kg CO_2e/MWh.

Production Costs

Crop Production

Switchgrass production costs consist of two distinct operations, establishment and biomass production. Establishment costs will vary depending on the prior land-use of the acreage being cultivated. We assume that establishment takes place on marginal lands and thus requires the use of conventional tillage to prepare the seedbed. Our estimate is provided by Calvin Ernst of Ernst Conservation Seeds (ECS, Meadville, PA). His estimate of $534.21/ha with an additional $98.80/ha ($40/ac) for land rent[5] brings total, annualized establishment costs to $86.01/ha. Costs are amortized over a ten year period at 6% interest to reflect the assumed ten year stand lifetime and the rate of return that could be expected by investing this capital otherwise.

Biomass production costs are taken from ECS's database. Detailed costs are included for all associated harvesting operations, including mowing, raking, round baling, and collection and delivery to a satellite storage location. A summary of switchgrass production costs is presented (Table A-3).

[4] NE region assumed to consist of eGRID subregions RFCE, NYUP, and NEWE.
[5] $40/ac is low compared to other estimates in the literature; however, this is a typical marginal land rental rate in the rural NE US.

Table A-3 – Farm gate costs for baled switchgrass

Item	annual costs ($/ha)	annual costs ($/Mg)
Establishment[1]	$86	$8.71
biomass harvest[2]	$430	$47.98
annual maintenance[3]	$79	$8.05
land rent	$99	$11.00
total farm gate cost		$75.73

[1] – (Calvin Ernst, Personal communication)
[2] – Developed from ECS database
[3] – Cost of anhydrous ammonia plus application

Observed yield in the producer database was 3.1 Mg DM/ha. This value is below optimal biomass production in the harvested stands for two reasons. First, many of the observed fields are recently established and have not reached full yield potential. Second, ECS manages stands for seed production and not biomass. In order to align production costs with the 8.98 Mg DM/ha yield assumed in the life cycle assessment, costs are adjusted. Since costs are expressed per Mg DM, we assume that only mowing costs will change with yield. Mowing cost/Mg DM will change with yield since mower speed will not change. Modern discbines are capable of high speeds in fields with heavy yields, and are assumed to cover the same amount of acreage regardless of yield. Therefore, mowing costs per hectare are not changed with yield; this has the effect of adjusting mowing costs per Mg DM directly with yield. Raking costs are not expected to change, since one pass will be required regardless of yield. In the low yield case, raking is required to combine windrows to keep the baler at capacity. For higher yields, one pass is necessary to facilitate field drying. Baling costs are not expected to change, since raking is conducted to keep the baler at capacity and ground speed can be adjusted depending on yield. Collection costs are assumed to be the same. We investigate the impact of these assumptions via sensitivity analysis (Figure B-2).

Transportation Costs

Transportation costs are evaluated at each step of the analysis. Transport costs are assumed to be \$3/loaded mi for round bales, \$10/Mg DM for transport to thermal applications, and \$15/Mg DM for transport to electric generation facilities. Round bale transport is assumed to be limited by dimensional constraints to 13.6 Mg DM/trailer.

Densification

Densification costs are developed from ECS's business plan for a pellet plant currently under construction. Plant infrastructure is assumed to be the same for pellet, briquette and cube plants. Changes to plant design for the larger densified products include the capital and maintenance costs associated with the densification mill itself, the elimination of the additional size reduction equipment (only a tub grinder is required), the reduction in energy requirement for both, and the elimination of the need for packaging equipment and materials (Table A-4).

Table A-4 – Densification plant costs[1]

item	pellets		briquettes		cubes	
	annual cost ($/y)	operating cost ($/Mg)	annual cost ($/y)	operating cost ($/Mg)	annual cost ($/y)	operating cost ($/Mg)
Fixed Costs						
annualized capital[2]	$216,546	$7.94	$262,759	$8.03	$216,943	$6.63
management	$57,800	$2.12	$57,800	$1.77	$57,800	$1.77
operators	$464,535	$17.03	$309,845	$9.47	$309,845	$9.47
secretarial	$15,000	$0.55	$15,000	$0.46	$15,000	$0.46
Insurance	$28,776	$1.06	$28,776	$0.88	$28,776	$0.88
accounting and misc.	$4,000	$0.15	$4,000	$0.12	$4,000	$0.12
plant maintenance	$57,841	$2.12	$57,841	$1.77	$57,841	$1.77
Variable Costs						
feedstock	$2,646,181	$88.21	$3,175,417	$88.21	$3,175,417	$88.21
electric	$474,692	$17.41	$355,720	$9.88	$315,835	$8.77
dryer fuel	$187,879	$6.26	$222,279	$6.17	$214,336	$6.17
diesel fuel	$31,200	$1.14	$37,309	$1.14	$37,309	$1.14
pellet packaging	$720,000	$26.40	-	-	-	-
die costs	$113,700	$4.17	$36,000	$1.10	$48,960	$1.50
product testing	$75,000	$2.75	$75,000	$2.29	$75,000	$2.29
Total operating cost	**$4,876,604**	**$177.30**	**$4,637,746**	**$131.28**	**$4,557,063**	**$129.17**

[1] - All costs developed from ECS business plan for pellet plant currently under construction

[2] – All plant capital costs are amortized over the assumed 25-year plant lifetime at 6% interest

Also, the elimination of the packaging step dictates the need for fewer operators. Operator requirements are assumed to be three per shift for the pellet plant and only two per shift for the briquette and cube plants.

Thermal Energy

Thermal energy system costs are estimated based on installed capital and fuel costs (Table A-5). Installed capital costs are based on vendor quotes for commercial systems and list price plus 50% for installation of residential systems. Residential capital costs are amortized over the assumed 15 y lifetime of the systems at an interest rate of 8%. Commercial systems are annualized over the assumed 20 y system lifetime at an interest rate of 6%.

Electric Power

Electric generation costs are developed from estimates of installed capital costs, fixed and nonfuel variable O&M, and fuel costs (Table A-6). All capital and fixed and nonfuel variable O&M costs are taken from EIA (2009) data for fossil systems. Fossil fuel prices are also derived from EIA data (EIA, 2010a). Biomass repower capital costs are based on FirstEnergy estimates for the retrofit of the RE Burger Generation facility (Energy Business Review, 2009). Biomass O&M costs are taken from existing literature (Zhang et al., 2010). Biomass retrofit and operating costs will vary widely depending on the particular application. The impact of the assumed biomass electric generation costs is investigated via sensitivity analysis.

Table A-5 – Thermal energy system costs

item	installed cost	annualized capital cost[1]	fuel price[2] ($/unit)	unit	annual fuel usage (GJ)	normalized fuel cost ($/GJ)	annual fuel cost ($/y)	system cost ($/GJ)
Residential								
0.25 mmBtu/h natural gas boiler	$3,546	$414	$10.31	mcf	50	$9.41	$470	$17.69
0.20 mmBtu/h fuel oil boiler	$4,775	$558	$2.93	gal	50	$19.98	$999	$31.14
0.09 mmBtu/h pellet stove	$4,499	$526	$187	ton	40	$11.10	$538	$21.27
Commercial								
4 mmBtu/h natural gas boiler	$176,000	$12,488	$10.31	mcf	8,000	$9.41	$75,246	$10.97
4 mmBtu/h fuel oil boiler	$176,000	$12,488	$2.93	gal	8,000	$19.98	$159,842	$21.54
3.0 mmBtu/h biomass cubes	$895,000	$63,502	$139	ton	6,400	$8.24	$58,786	$15.29
3.0 mmBtu/h biomass briquettes	$895,000	$63,502	$141	ton	6,400	$8.37	$59,587	$15.39

[1] – Capital costs amortized at 6% interest over assumed plant lifetime of 20 years
[2] – Fossil fuel costs are taken from EIA data (10)

Table A-6 – Electric generation production costs[1]

item	capital cost ($/kW)	fixed O&M ($/kW)	variable O&M ($/MWh)	fuel price ($/GJ)	plant size (MW)	capacity factor	heat rate	production cost ($/MWh)
coal baseline	sunk	$27.53	$4.59	$2.09	1000	80	10128	$30.90
conventional natural gas turbine	$634	$10.53	$3.17	$4.63	500	60	9751	$61.31
natural gas advanced combined cycle	$948	$11.70	$2.00	$4.63	500	60	6994	$51.15
biomass repower[2,3] cubes	$640	$54.50	$4.90	$8.54	100	70	12321	$142.19
biomass repower briquettes	$640	$54.50	$4.90	$8.67	100	70	12321	$143.82

[1] – All electric production costs taken from EIA Electricity Market Module (6) unless otherwise stated.
[2] –Fixed and variable O&M estimates taken from Zhang et al. (9).
[2] –Capital estimate taken from FirstEnergy estimate for RE Burger Generating facility retrofit (8).

Appendix B

Sensitivity of Results

Sensitivity of Results

Life Cycle Inventory

Emissions associated with the production of densified switchgrass and its utilization in energy applications accrue from four distinct operations: crop production, densification, combustion, and transportation at each step. A sensitivity analysis is conducted to evaluate the impact of varying highly uncertain and/or large sources of emissions.

By far the largest source of emissions in the crop production module is nitrous oxide emissions. IPCC (IPCC, 2006) identifies the global warming potential of N_2O relative to CO_2 to be 298 +/- 35%. In the densification step, two large sources of uncertainty are identified. First is the energy consumption of the densification mill itself. Since emissions are estimated based on throughput and horsepower rating, and horsepower rating will not change with throughput, we alter the reported throughput rate by +/- 1 Mg DM/h from manufacturer reported values. The other large source of uncertainty is the drying requirement of the incoming feedstock; initial moisture content is varied +/- 10% MC from the assumed intake value of 30% MC. The impact of these sources of uncertainty is evaluated (Figure B-1). Of the larger densified products, only the uncertainty surrounding cubes is presented given the similarity of values for the two processes.

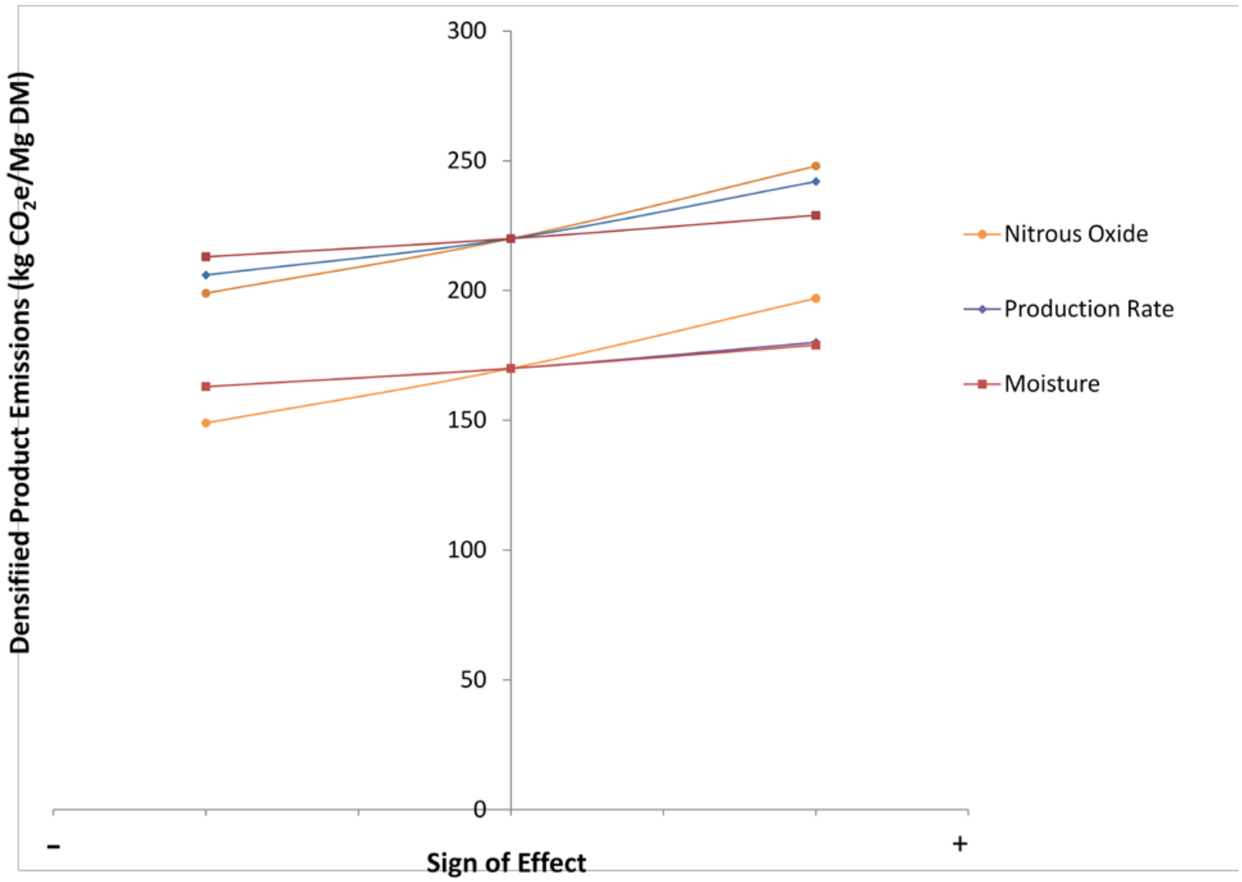

Figure B-1 – Sensitivity analysis of LCI through densification

For both pellets and cubes, the analysis is most sensitive to uncertainty surrounding the GWP of nitrous oxide. The 35% uncertainty surrounding the GWP of N_2O results in a low value of 199 kg CO_2e/Mg DM and a high value of 248 kg CO_2e/Mg DM for pellets and a range of 149 – 197 kg CO_2e/Mg DM for cubed switchgrass. The effect of these two parameters is considered in the sensitivity analysis of abatement costs.

Production Costs

Several sources of uncertainty are identified within the production cost analysis. First, since observed yields are lower than those assumed over time, we investigate the impact of changing biomass costs at the farm gate. Low and high values for production costs are taken from the only other known analysis that incorporates actual farm production data (Perrin et al., 2008). The average of the five lowest and highest cost sites reported is $55.91 and $88.25, respectively. In the densification step, the largest source of uncertainty accrues from the reported throughput rates of the densification mill. Densification mill throughput is varied +/- 1 Mg DM/h to determine the impact of this parameter on the cost analysis. The impact of varying these parameters on densification production costs is investigated (Figure B-2).

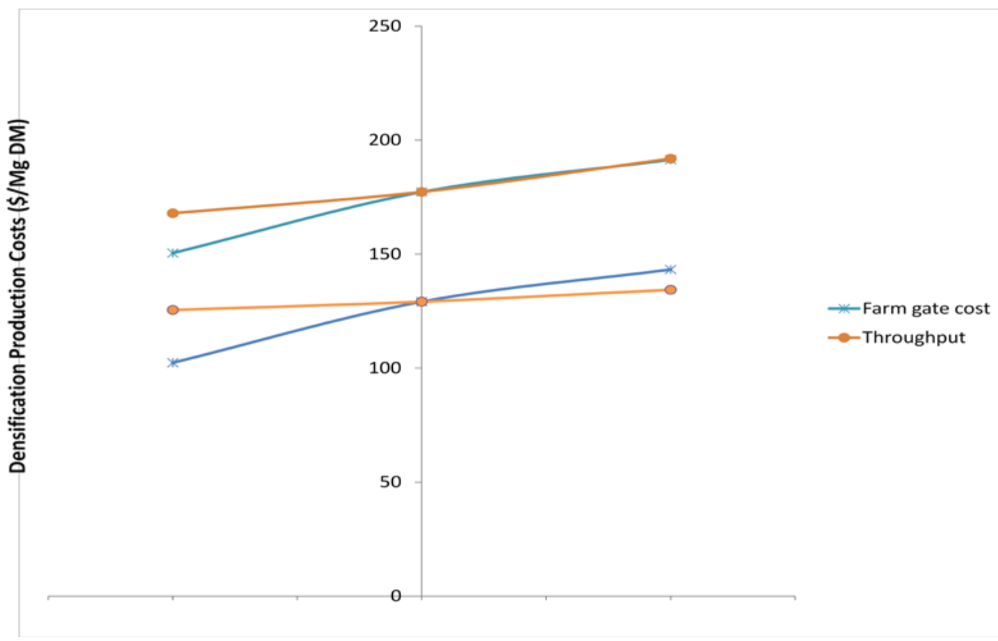

Figure B-2 - Sensitivity analysis of production costs through densification

For both types of densified products considered, variation in farm gate costs has the largest impact on densified product cost. The effect compared to throughput is more pronounced for cubes since feedstock costs play a larger role in total product costs than for pellets.

Beyond densification costs, biomass retrofit and operations and maintenance costs for electricity generation are the remaining large sources of uncertainty within the analysis. These costs will vary widely depending on the particular application, thus it is difficult to develop realistic values between which to investigate sensitivity. Therefore, capital and all nonfuel O&M costs are varied +/- 50% from their baseline values to determine their impact (Figure B-3).

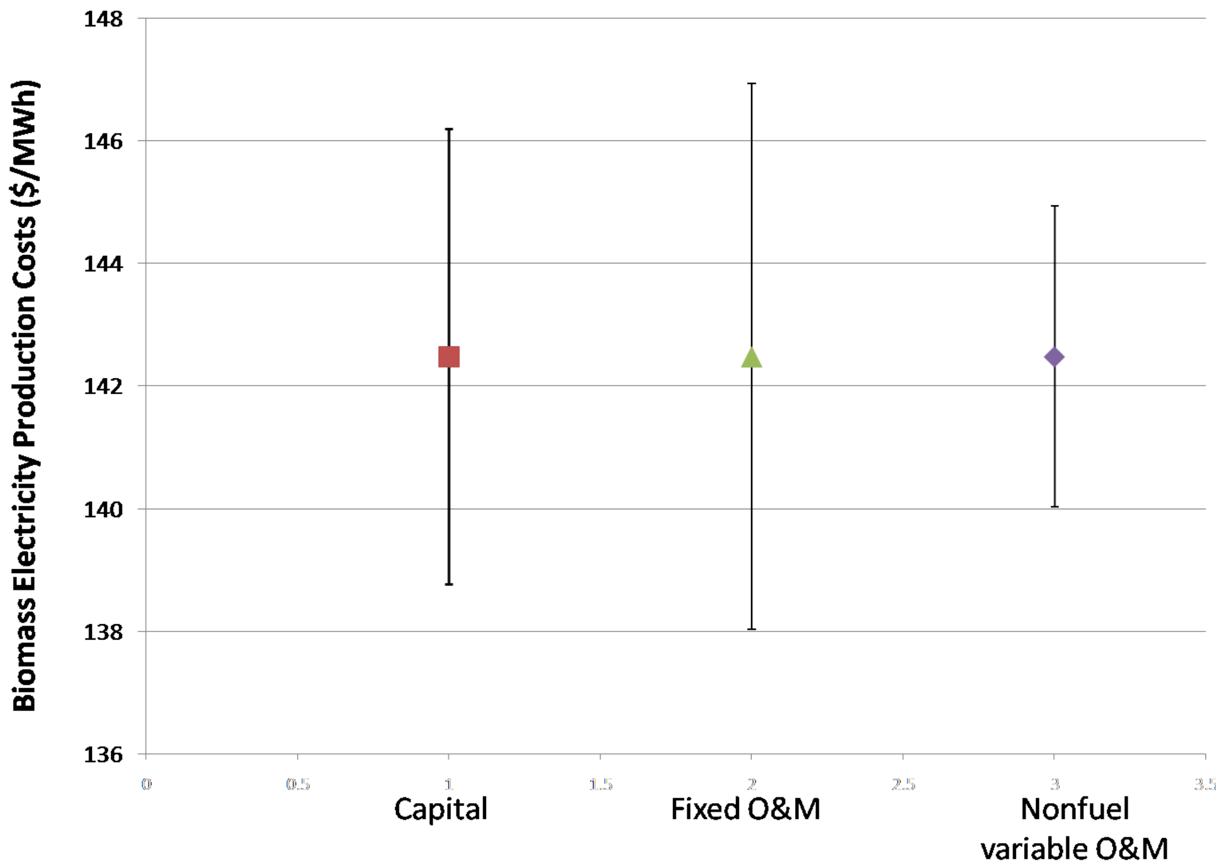

Figure B-3 – Sensitivity analysis of biomass electricity production costs (+/- 50% of baseline)

Of nonfuel costs, biomass generation cost is the most sensitive to the fixed operations and maintenance parameter.

Abatement Costs

Thermal Energy

Based on the sensitivity analyses of the life cycle inventory and production costs associated with the production and combustion of densified switchgrass for heat and power, nitrous oxide emissions, densification mill productivity, biomass farm-gate costs, and fixed operations and maintenance costs are identified as the parameters to which the analysis is most sensitive. Each of these parameters is considered in evaluating the sensitivity of GHG abatement costs associated with the replacement of fossil fuels with biomass (Figure B-4).

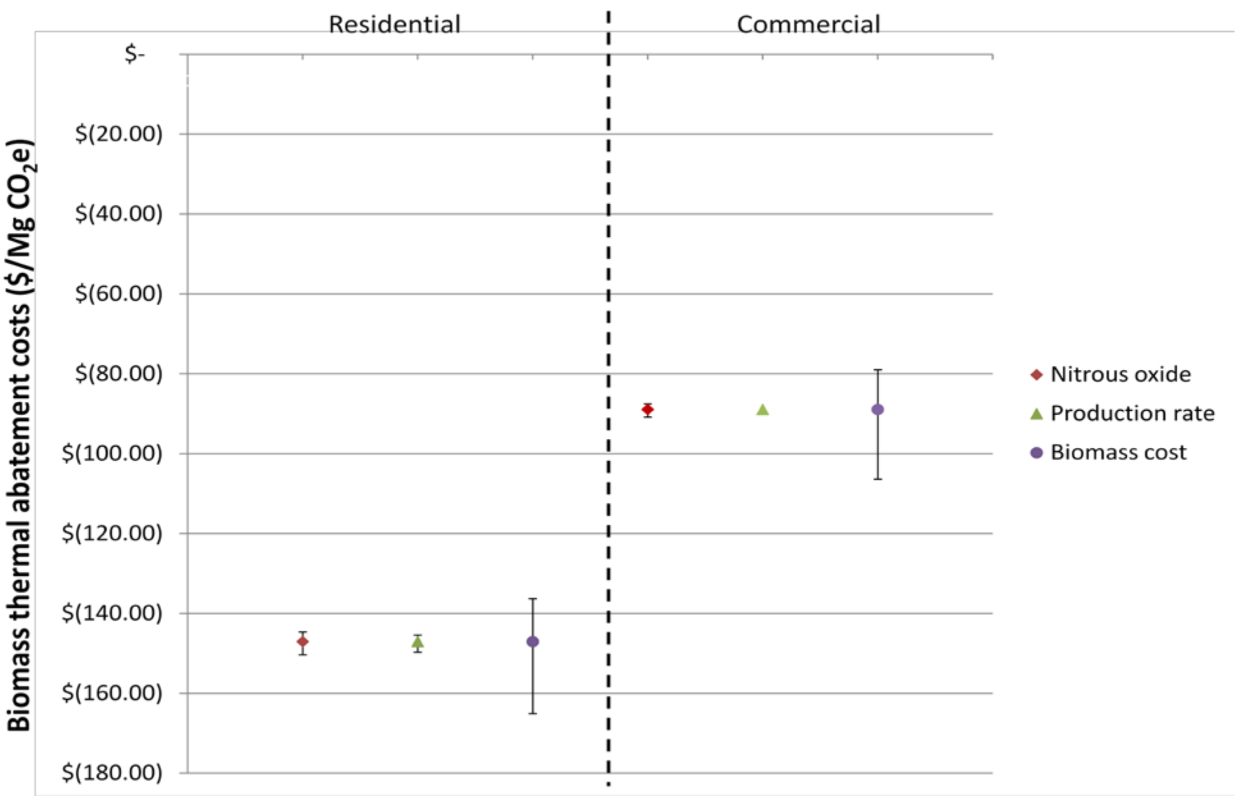

Figure B-4 – Sensitivity analysis of biomass thermal abatement costs

For both pellets and cubes, biomass cost is by far the largest source of uncertainty. Regardless, varying switchgrass production cost within the range of plausible values yields substantial negative abatement costs. Abatement costs for cubes used in thermal applications range from (-$83) – (-$111)/Mg CO_2e reduced; the same variation in switchgrass production costs for pellets in residential applications results in a high of (-$136) to a low abatement cost of (-$165)/Mg CO_2e.

Biomass Electric

The same sensitivity analysis that was conducted for biomass thermal parameters is conducted for the biomass to electric pathway (Figure B-5). In addition to uncertainty surrounding nitrous oxide, densification productivity and switchgrass production costs, we investigate the impact of variation in fixed O&M costs.

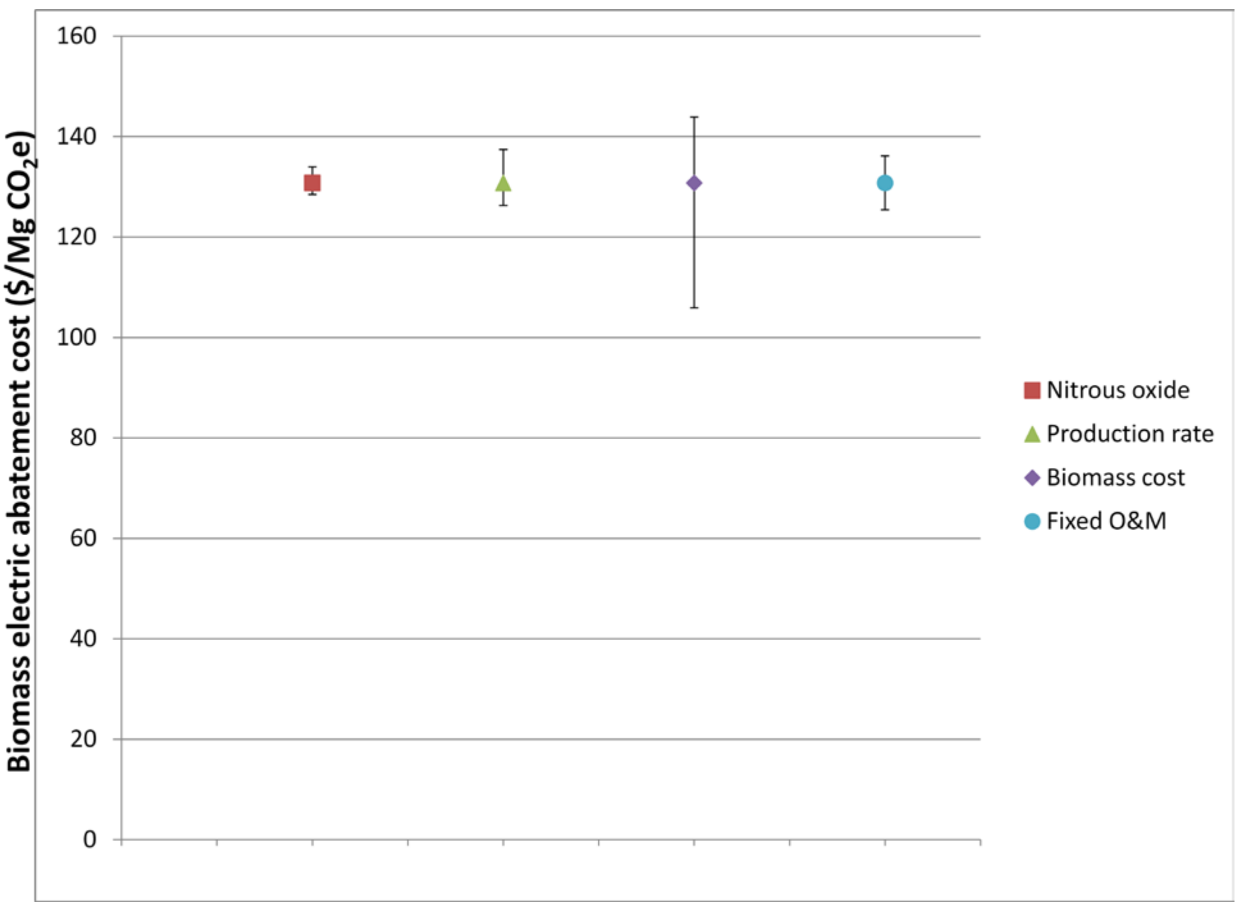

Figure B-5 – Sensitivity analysis of biomass electric abatement costs

Again, results are most sensitive to switchgrass production costs, since these costs most directly influence the cost of energy. Over the range of plausible values (52-88 $/Mg DM), abatement costs vary from a low of $105 to a high of $143/Mg CO_2e.

Land Costs

One component of production costs is the assumed rental rate of land. The baseline assumption of land value in the analysis is $99/ha ($40/ac), which accurately reflects current land rental rates for marginal land (land currently not in production) in Northwestern Pennsylvania, the region in which production costs were evaluated. However, this value is highly regionally dependent. In order to determine how much the major result, that the replacement of fuel oil with biomass results in negative abatement costs, is dependent on land value, land rental rate is adjusted upward until savings from biomass are eliminated. At the commercial scale, increasing land rent to $1150/ha ($470/ac) eliminates savings associated with switching from fuel oil to biomass. At the residential scale, land rent must increase to more than $1175/ha ($710/ac) before savings are eliminated. In both cases, assumed land rental rate must increase by more than an order of magnitude to change the fundamental result of the analysis.

Fuel Price Sensitivity

In addition to the parameters internal to the analysis that drive the major result, fossil fuel prices play a large role as well, specifically fuel oil and natural gas prices. In order to establish the point at which negative GHG abatement costs for the replacement of fuel oil with biomass no longer exist, fuel oil prices are adjusted downward until savings are eliminated. At a fuel oil price of $1.48/gal, all savings for residential customers are eliminated. For commercial and institutional customers, this value is $2.00/gal. These values are, respectively, approximately half and two-thirds of the EIA reported price of $2.93/gal for April 2010 delivery employed in the analysis.

While natural gas heat is relatively less costly than biomass and fuel oil at both the commercial and residential scales, natural gas pipelines do not exist in many locations. Even though the fuel is less costly, the large capital costs associated with pipeline installation often make the installation of natural gas systems financially impractical. To determine the cost of pipeline installation that a consumer would be willing to pay to burn the less expensive fuel, natural gas costs are adjusted upward until they are equal to the biomass option at both the residential and commercial scales. This value is slightly greater than $15/mcf delivered natural gas at both scales. Subtracting values of $10.31/mcf and $8.83/mcf extracted from EIA data for residential and commercial customers, the residential consumer is willing to pay approximately $5/mcf in capital costs for the assumed lifetime of the project, whereas the commercial customer's willingness to pay for natural gas pipeline installation is an estimated $6.50/mcf amortized over the project lifetime. So, for large consumers that are relatively close to a pipeline, the capital costs may be justified. However, in theory, the difference between the price of heating oil (or propane, for that matter) already reflects this cost.