University of Alberta

Biomass Usage for Power and Liquid Fuels

by

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DEDICATION

To my parents Tulsi and Sheo Shankar

for

their continuous support and encouragement.

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List of Abbreviations

AAC	Annual Allowable Cut
BCL	Battelle Columbus Laboratory
BETs	Biomass Energy Technologies
BIG/GT	Biomass Integrated Gasifier/Gas Turbine
BIGCC	Biomass Integrated Gasification Combined Cycle
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
DCF	Discounted Cash Flow
DVC	Distance Variable Cost
ENFOR	Energy From Forest
FMA	Forest Management Agreement
FERIC	Forest Engineering Research Institute of Canada
GHG	Greenhouse Gas
HHV	High Heating Value
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IGT	Institute of Gas Technology
IPCC	Intergovernmental Panel on Climate Change
Km	Kilometer

List of Abbreviations (cont'd)

KWh	Kilowatt Hour
LHV	Low Heating Value
M	Million
MJ	Mega Joule
MW	Megawatt
MWh	Megawatt Hour
NREL	National Renewable Energy Laboratory
Odt	Oven Dried Tonnes
ORNL	Oak Ridge National Laboratory
PMH	Productive Machine Hour
SMH	Scheduled Machine Hour
STS	Simultaneous Transportation and Saccharification
TPS	Termiska Processor Sweden

Chapter 1

Introduction

1.1 Background

Climate change is one of the important environmental issues facing the world today. It is caused by the greenhouse gas (GHG) effect. The GHG effect is the heating of the earth's atmosphere due to the resistance to heat release to the outer atmosphere. Indiscriminate use of fossil fuels results in release of GHGs (e.g., carbon dioxide, methane, nitrous oxide etc.). Research has shown that carbon dioxide is the main contributor to the GHG effect among all the different GHGs. According to a study done by Intergovernmental Panel on Climate Change (IPCC), global mean temperature is expected to change 2.0 to 4.5 °C in the time period of 1900 to 2100 (IPCC, 2001). This rise in global temperature could have adverse effect on the climate. This could have an adverse affect on biodiversity and weather pattern resulting in floods, droughts, high precipitation etc. Hence global warming is a major challenge for our society today.

As the world economy grows, energy consumption increases. Energy consumption is expected to increase at the rate of 2.3% per year from 1995 to 2020 (Energy Information Administration, 1998). In 2001, 79.5% of energy was provided by fossil fuels (coal, natural gas and oil) (International Energy Agency, 2003). In order to reduce the emission of carbon dioxide from fossil fuel use, clean energy sources need to be explored. Nuclear energy and renewable energy are two main viable options.

Among the different renewable energy sources, biomass is one of the most promising options for substituting the fossil fuels. Biomass is a renewable (regrowable) fuel derived from a currently living organism or the by-product of a currently living organism. Biomass provides a unique opportunity as an energy source. It could be used in different forms. It is a solid fuel; liquid and gaseous fuels can be derived from it. Today biomass contributes to fourteen percent of the world's energy use and ranks fourth as an energy source. Thirty five percent of energy produced in developing countries is from biomass (Bain et al., 1998). Bioenergy is used in rural areas where it is accessible and easily available. Biomass usage, specifically capturing energy from biomass that would otherwise decay, is one of many options available to mitigate the impact of the buildup of GHG emissions from fossil fuel utilization. Biomass is considered carbon neutral because the amount of CO_2 released during its combustion is essentially the same as absorbed by the plants during their growth.

In Canada, the primary energy contribution from the fossil fuels (coal, gas and oil) was about 75% and from biomass was less 10% in 2001 (International Energy Agency, 2004). This clearly shows that biomass usage for energy purposes in Canada is minimal, although the potential is large. The total installed electricity generation capacity in Alberta, as of 2003, was 11,513 MW. The electricity production in the province, based on different energy sources in 2003, was: coal – 48%, natural gas – 42.2%, and renewable energy sources (consisting of hydro, wind and biomass) – 9.8% (Government of Alberta, 2003). Biomass contribution to electricity generation was very small. GHG emissions from fossil fuel use are very significant in Alberta. Alternate energy resources would need to be used in the province to reduce the GHG emissions.

1.2 Statement of the problem

Alberta has large biomass resource potential for energy purposes. Most of the biomass power plants in Alberta are small scale and use mill residues. In some locations, including western Canada, good data on the cost of using biomass is not available, and this leads to a high degree of uncertainty in the cost of GHG credits that would be required to support such a facility. Western Canada, in particular the Province of Alberta, is a particularly relevant place to evaluate the economics of generating power from biomass for three reasons. First, Alberta has a growing power demand and is an area of active development of new coal based power plants, with one project of a single 450 MW unit under construction and a second project of two 450 MW units approved. Second, the region has abundant forest biomass resources. Third, the region has a large oil and gas resource that is being exploited for industrial, domestic and transportation fuels, and continued development of this resource may well depend on developing effective GHG offsets. The combination of these three factors makes western Canada an ideal location for implementing power from biomass at a full commercial scale.

Power from biomass is not economic today in western Canada, where power is generated from a large base of hydroelectric, gas fired, and base-load mine-mouth coal fired plants. Hence, one key measure of the cost of biomass is the carbon credit (as $ /tonne CO_2 abated) required to equalize the cost of power from a biomass plant with current alternatives. In effect, this is the "premium" associated with the mitigation of GHG. Because coal based power projects are under active development and represent the current marginal power plant fuel of choice, GHG credits are calculated in comparison to a new coal based power plant using conventional combustion supercritical boiler technology.

This study applies the general methodology to western Canada. Good regional data is available on the cost of harvest and transport of biomass, including costs of loading and unloading that have not always been considered in previous studies. Western Canada is also the site of both recent and current major energy projects, and good data is available on construction costs for both developed and remote locations. Hence, this study draws on actual data to determine the cost difference for substituting biomass for coal at an optimum plant size in a region of active coal power development.

Biomass usage on large-scale for energy purposes would need a detailed evaluation of each element contributing to the energy production process. Biomass transportation is a major component of biomass power cost. In almost all the places where biomass is used for energy or liquid fuel production, it is transported by truck. Truck transportation is expensive and on larger scale truck congestion issues arise. To overcome this problem alternate biomass transportation mode needs to be investigated. None of the large fossil fuel based plants depend on truck delivery of fuel; it is transported by pipeline, rail or ships. This study evaluates pipeline transport of biomass in detail. Pipeline transport of biomass has a significant effect on the end-use of the biomass. This conclusion has prompted the evaluation of pipeline transport of biomass for liquid fuel production.

Today most of the biomass utilization facilities are on small scale. At this scale, these facilities are less efficient and do not have the advantage of economy of scale. Detailed study on the techno-economic issues of large-scale biomass facilities is required. This study focuses on these issues of a large-scale biomass facility producing power and liquid fuels.

1.3 Objective of the study

The purpose of this research is to estimate the cost and evaluate the cost sensitivities for major biomass utilization projects located in the Province of Alberta. This research has focused on two major biomass resources located within western Canada that are available in significant quantities for future energy purposes: forest biomass from harvesting of the whole forest, and the residues from harvesting forests for lumber and pulp. Each of these sources is discussed in more detail in subsequent chapters.

The study evaluates the biomass usage for power generation on a large-scale based on two fuels mentioned above. Different cost elements of biomass power generation have been evaluated. Optimum sizes of the biomass power plants based on direct combustion and gasification have been evaluated. The greenhouse gas credit required for biomass-based power to be competitive with fossil fuel-based power has also been evaluated.

In order to reduce the harvesting cost of biomass, an integrated harvesting operation for forest harvest residue is evaluated.

Biomass transportation is a major cost component. Pipeline transport of biomass for power and biofuel production is evaluated in detail. Implications of pipeline transport of biomass on its properties have been evaluated. The opportunity of using pipeline transport for other biomass fuels (e.g. corn stover) for ethanol production is explored. The study evaluates large-scale ethanol production through pipeline delivery of biomass.

Specific objectives of each part of the study are discussed in the respective chapters.

1.4 Scope and limitations of the study

In this study biomass power generation is based on two fuels:

- Whole forest biomass – wood chips of whole tree.

- Forest harvest residues – wood chips from slash (limbs, tops and branches), left after pulp and lumber operations.

Biomass power generation technologies are limited to:

- Direct combustion of biomass (no combined heat and power).
- Biomass integrated gasification combined cycle (BIGCC).

The cost of biomass power generation has been estimated for a western Canadian setting. The results could be used at other places with suitable modification for local cost factors.

Pipeline transport of biomass has been evaluated for wood chips and corn stover. Cost figures generated could be generalized to other places with modification for local cost factors.

1.5 Organization of the thesis

The report is divided in ten chapters. This thesis is in the format of a consolidation of papers and each chapter is intended to be read independently. As a result some tables and concepts are repeated. The current chapter gives the introduction and objective of this study. The second chapter presents forest biomass resource potential sources in western Canada and their yields. The third chapter gives the baseline biomass power cost and optimum size based on direct combustion of biomass. It discusses in detail the methodology used for the estimation of the power cost. The fourth chapter gives the cost of biomass power using advanced biomass conversion technology – BIGCC. This chapter also gives the comparison of biomass power cost based on direct combustion and gasification. The fifth chapter gives the greenhouse gas mitigation potential of a biomass power plant over its life cycle and calculates the carbon credit required for making biomass power competitive with fossil fuel based power in Alberta. The sixth chapter evaluates the pipeline transport of biomass. It gives in detail the different cost elements and the cost of transporting biomass through a pipeline. The inherent economics of truck and pipeline transport have been discussed. The seventh chapter gives the methodology and results of the experiments done for the determination of carrier fluid uptake by wood chips. It also discusses the implications of carrier fluid uptake for bioenergy applications. The eighth chapter discusses the application of pipeline for transportation of corn stover for ethanol production. It also explores the potential of simultaneous saccharification in the pipeline. Limitations of simultaneous saccharification in the pipeline have also been discussed. The ninth chapter explores the possibility of large-scale ethanol production through pipeline delivery of biomass. Cost of large-scale ethanol production using pipeline transport of corn stover and wood chips is estimated. Finally, chapter ten gives the conclusions and provides recommendations for future research. An appendix has been provided, which contains the input data and some related calculations.

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Chapter 2

Forest Biomass Resource Potential in Western Canada

2.1 Overview

The boreal forest is like a green scarf across the shoulders of North America. In Canada, it occupies 33% of the total land area and 77% of the northern hemisphere forestland. The boreal forest extends from the Yukon Territory as a band 1000 kilometers wide sweeping southeast to Newfoundland. To its north is the tree line and beyond that the tundra of the artic. To its south, the boreal forest is bordered by the subalpine and montane forests of British Columbia, the grasslands of the Prairie Provinces, and the Great lakes – St. Lawrence forests of Ontario and Quebec. The Boreal Forest Region is one of the nine forest regions of Canada. These regions are differentiated from each other based on differences in terrain, soil and climate. The boreal forest occupies by far the largest percent of Canada's forested area.

Globally, boreal forests comprise almost 25% of the world's closed canopy forest as well as vast expanses of open traditional forest. It is dominated by a small number of needle-leaved coniferous tree species of *Picea mariana* (spruce), *Abies balsamea* (fir), *Larix laricina* (tamarack) and *Pinus* (pine). There are also several cold-hardy broadleaved tree and shrub species, in particular *Populus balsamifera* (poplar), *Salix* (willow) and *Sorbus decora* (mountain ash). Even though all these species and the associated shrubs, herbs, mosses, lichens and fungi range widely through the boreal forest, there is, nevertheless, a considerable regional diversity in boreal forest makeup from south to north and from east to west.

The boreal forest is divided into two great transcontinental belts of approximately equal size: the sub arctic open lichen woodland and the closed crown forest. This major horizontal sectioning of the two areas reflects the steady decline in temperature from south to north. The more northern sub arctic lichen woodland is a handsome landscape mostly unknown to Canadians because of its few settlements and roads. Northern stands of scattered *Picea* (spruce) and *Pinus banksiana* (jack pine), accompanied by *Abies balsamea* (fir) in Quebec, form attractive open-canopied areas carpeted with yellow, green and light grey lichens. Recently burned areas are covered with *Betula* (birch), *Vaccinium corymbosum* (blueberries) and other small evergreen shrubs. Larch is common in low marshy areas while shallow-rooted *Picea mariana* (black spruce) populates the surface of frozen and uplifted bogs known as peat plateaus. The southern belt of closed crown forest occupies a milder climatic zone where the trees grow taller and closer together to form closed-canopies beneath which plentiful mosses, herbs and shrubs thrive. This is the commercial forest that feeds the sawmills and pulp mills. In the western part of the closed crown forest area (the northern part of British Columbia and the Rocky Mountain Foothills of Alberta) prominent tree species include *Picea glauca* (white spruce), *Picea mariana* (black spruce), *Betula* (birch), *Populus tremuloides* (trembling aspen) and *Populus balsamifera* (balsam poplar). Further east in the Precambrian area of Ontario and Quebec, the predominant tree species are *Pinus banksiana* (jack pine) and *Picea mariana* (black spruce). There are also large flatter areas of particularly productive forests of *Picea* (spruce), *Abies balsamea* (fir) and *Pinus* (pine). On the southern border of the closed crown forest, fertile soil supports a richer combination of trees including *Picea glauca* (white spruce) and *Populus balsamifera* (poplar). Further to the east there are *Acer saccharum* (sugar maple), *Betula alleghaniensis* (yellow birch), *Pinus resinosa* (red pine) and *Pinus strobes* (white pine). These bands or areas of mixed woods show the affect of the increase in precipitation as one moves from west to east. This not only allows for greater numbers of tree species but also the greater prominence of balsam fir, a most important member of the forest from Lake Superior to Newfoundland (Natural Resources Canada, 2003; Natural Forestry Database Program, 1991a; Farr, 2003).

Table 2.1 shows the annual allowable cut (AAC) and the percentage of different types of species in Alberta. The AAC represents a specified level of harvest to be achieved annually over a specified number of years. The method of determining AACs is complex and varies significantly across Canada. AACs depend on the extent of the forest land base, the growth rate of trees, losses due to fire, insects, and disease, accessibility, economics conditions, environmental considerations, silvicultural investment and management objectives. AACs are revised periodically to reflect the changing conditions and improvements in data and knowledge. Most of the provinces in Canada recalculate AACs every 5 to 10 years. AACs are affected by the license agreements allocated to the forestry companies (Natural Forestry Database Program, 1991b).

Table 2.1: Annual allowable cut and percentage contribution of different species in Alberta in 2002

Type of species	Contribution
Hardwood	33%
Mixedwood	23%
Softwood	44%
Annual allowable cut (million m^3)	27.4

Source: Natural Resources Canada, 2003

2.2 Whole forest biomass

The forest industry in Alberta has grown over the last three decades. Revenue to the Government of Alberta, in the form of timber royalties and fees, was US$ 47.9 million for the fiscal year 2001, offset by government expenditures on forest management and protection (Schindler, 1999). There are mainly three types of tenure system in Alberta: timber permits, timber quotas, and Forest Management Agreements (FMAs). Timber permits are for small-scale users and community use. Timber quotas are for small to medium scale users with long-term secure wood supply. Forest management planning for quota holders is the responsibility of the government. Instead of a fixed land base they are allocated a specific volume of timber. FMAs are for large-scale users. These are long-term contractual agreement between the province and a company to establish, grow and harvest timber on a defined land area. FMA holders are responsible for developing and following a forest management plan approved by the government.

The FMA holders are responsible for their own inventory studies and road development, and forest regeneration (Alberta Centre for Boreal Studies, 2001). The five largest companies in Alberta in 2000 were: Alpac, size of FMA 58,000 km^2; Tolko, size of FMA 39,400 km^2; Weyerhaeuser, size of FMA 29,648 km^2; Daishowa-Marubeni, size of FMA 29,000; and International Paper, size of FMA 16,949 km^2 (Forest Watch Alberta, 2001).

Current government forestry policy is based on a provincially developed conservation strategy. The basic principle of conservation strategy is that benefits from the forest can be received on a sustainable basis only if forest ecosystem health is maintained. The government of Alberta is developing a policy which would be flexible for the forestry companies. According to this policy the companies would have the freedom to implement ecosystem-based management at their own pace (Schindler, 1999). Some salient features of existing FMAs are (McCougall, 1986):

- Harvest levels must be based on a forest management plan which projects harvest levels for the entire rotation.
- Forest management planning must be based on a completed inventory which accurately measures the volume and area of each age class in the forest. Oldest timber is cut first, since leaving the younger stand has positive effect on average growth rate.
- All FMAs require complete reforestation of the cut areas to provincial standards, with no cost to the Province.

- At present there are five FMA areas in Alberta covering 10% of the provincial forest lands.

The first source of biomass in this study is whole forest biomass from a dedicated forest plot, with the power plant located centrally within the plot. Note that in the Province of Alberta the majority of forested areas are owned and controlled by provincial government, and these in turn have been committed to existing forestry operations (pulp and lumber) under long term management agreements (Shelly, 2000). Hence, in theory there is no available uncommitted forest area that could be specifically harvested for biomass. However, the alignment of forest processing plants (e.g. pulp mills and lumber operations) and forest reserves is inexact, and it is likely that some excess forest capacity will emerge particularly if faster growing hybrid species are replanted after harvesting (note however that current regulations in Alberta disallow this).

Northern forests in Alberta are boreal; two types of sub-region are the most common: mixed hardwood and spruce. Biomass yields for different species of boreal forest reported by different authors were studied (e.g. MacLeod and Blyth, 1955; Singh, 1982a; Singh 1982b; Lieffers and Campbell, 1984; Campbell et al., 1985; Singh, 1986; Corns, 1988; Peterson et al., 1987; Man and Lieffers, 1999). The basis of the whole forest biomass case is a medium yield site (Alberta Energy and Natural Resources, 1985). Our assumption is that good yield site would be reserved for timber and pulp operations; however sensitivity cases for both good and fair yield site are included. Table 2.2 gives the biomass yields from mature stands of good, medium and fair yield for a mix of mixed hardwood and spruce. Biomass yields for medium site are 94 and 74 dry tonnes per hectare respectively (Alberta Energy and Natural Resources, 1985), and these have been blended in this study to an assumed forest biomass yield of 84 dry tonnes of biomass per hectare. The yields are at an age of 80 years for hardwood and 90 to 120 years for conifers. Large contiguous areas of mixed hardwood and spruce are available in Alberta, and could support a large power plant for a 30+ year life without having to harvest or leap over major low yield bog areas, hence an aggregated biomass yield based on the two sub-regions is warranted. The study is based on clear-cut logging throughout the dedicated forest plot, resulting in a constant transportation distance to the power plant over the life of the plant. Whole forest harvesting includes chipping of branches and limbs, i.e. the entire tree is chipped, but does not include stump removal, which although starting to be practiced in some areas of the world is not part of forest management practices in western Canada.

A dedicated whole forest plot supporting a power plant is not sustainable in a long term perspective, since at the end of the power plant life, assumed to be 30 years in this study and 30 to 40 years based on actual power plant experience, the dedicated forest plot would not have re-grown to maturity. However, if an area of land equivalent to approximately three times that used in this study is reserved, then long term sustainability is realized, in that at the end of the first power plant's useful life a second is built, and later a third, after which the original dedicated forest block that supported the first power plant is ready for re-harvesting. Note that whether a block to support one or three power plants is reserved does not affect the economic analysis of the first power plant.

Nutrients are not restored in most existing Alberta forest operations, most of which are occurring in areas of first cutting. Branches and tops are left in the forest in current harvesting, however the distribution of these is usually not uniform. About 80% of harvest operations in Alberta skid whole trees to roadside, where they are delimbed and topped (Shelly, 2000; Christiansen, 2000). The leaves/needles in this trimmed material contain a large portion of the nutrients, especially nitrogen. The limb and top residue is piled by the side of the logging road, and typically burned at the end of the harvest, which results in a loss of the nitrogen to atmosphere.

Table 2.2: Biomass yield from good, medium and fair site in Alberta

Site	Yield (dry tonnes/ha)
Good	124
Medium	84
Fair	53

Source: Alberta Energy and Natural Resources, 1985

2.3 Forest harvest residues

Given that forest resources have a value as fiber in pulp or lumber, an alternative is to recover harvest residues. In theory, one could harvest brush and deadfall as well as limbs and tops, but in practice this would require a major modification of forest harvesting, since as noted above, the current predominant practice is to cut and skid trees to roadside where they are delimbed and topped, whereas brush and deadfall are left in place in the forest. Hence, the basis of this study is the recovery of limbs and tops from the side of logging roads; as with the whole forest, stump removal is not considered due to current forest management practices in western Canada. These residues range from 15 to 25% of the total biomass in the forest. In lumber based operations there is a growing emphasis on "cut to fit" in the field, i.e. trimming logs to the economic length in the field so as to avoid transporting waste material to the mill. This practice pushes harvest residues to the 25% range, whereas in some pulp operations it is as low as 15% (Shelly, 2000; Lieffers, 2000). 20% residue from a good yield site has been used as the basis of this study, since current lumber and pulp harvesting draws from such sites. This is equivalent to a blended yield of 24.7 dry tonnes of residue per net harvested hectare (Alberta Energy and Natural Resources, 1985). However, the forest in Alberta is harvested on a planned average rotation of 80 to 120 years, due to poor soil conditions and a northern climate. In this study, a rotation of 100 years is assumed, giving a long-term sustainable yield of forest harvest residues of 0.247 dry tonnes of residue per gross hectare.

2.4 Mill Residues

The annual allowable cut for the Province of Alberta is twenty seven million cubic meters (Natural Resources Canada, 2003). This is mostly used for pulp and lumber purposes. At the mills sawdust and other residues are generated. These residues are a source of biomass fuel. Over 50% of these residues are used today.

Mill residues from processing of lumber and pulp (for example, bark and sawdust) were not evaluated, because these are widely utilized today and recent volatility in the cost of natural gas has led to intensive development of additional projects based on this resource.

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Chapter 3

Baseline Forest Biomass Power Cost and Optimum Size in Western Canada

3.1 Overview

Biomass power plants exist in different parts of the world. These plants are based on different types of biomass fuels (e.g. wood chips, straw, peat etc.). Most of these plants are on small-scale (1-50 MW). Most of these plants are operated in combined heat and power (CHP) mode or co-firing mode. In Europe most of the biomass power plants operate in combined heat and power mode. Scandinavian countries are leading biomass power producers in Europe. The world's largest biomass power plant, which has a capacity of 250 MW, is in Finland (Timperi and Martin, 2002). In North America most of the biomass-fired plants are in the USA and their size ranges from 1-80 MW (Wiltsee, 2000). In the USA about 7500 MW of biopower is generated (Bain et al., 1998). About seventy percent of this power is co-generated with process heat and eighty eight percent of these systems are based on wood chips, the rest on agricultural residues, landfill gas and anaerobic digesters. In Canada, biomass power is generated mostly in pulp and paper mills. The main biomass feedstock used is mill residues. These plants are on a small-scale of 1-25 MW and their contribution is negligible to the total generation of electrical power.

Biomass power cost is specific to a location. This is because of differences in the local environment, infrastructure and economic conditions. The economics of biomass-based power is affected by the local power price, taxes on the carbon emission and subsidies for green power.

In Canada, small-scale biomass based power was studied in the 1980s by Natural Resources Canada under the program called Energy From Forest (ENFOR). These preliminary studies included both upstream and downstream processes of biomass usage (e.g., Edwards et al., 1983a; Goater et al., 1983a; Wong et al., 1983; Edwards et al., 1983b; Edwards et al., 1983c; Edwards et al., 1983d; Goater, 1983b; Routhier, 1982).

Biomass power cost and optimum size of a large-scale commercial power plant has not been estimated in Canada. This chapter gives the detailed estimation of the biomass power cost for western Canada and estimates optimum size of the biomass power plants.

3.2 Methodology for estimation of biomass power cost

3.2.1 Estimation of biomass power cost

This section details the general methodology that has been used to determine the biomass power cost in this study. One can conceptually break down biomass utilization into three component costs:

A. Field harvest of biomass.

B. Transportation from the field to the biomass processing site.

C. Cost of processing/conversion.

Cost of field harvest of biomass includes harvesting, collection, road construction and silviculture operations. Cost of processing and conversion of biomass includes capital cost of the plant, operating cost, maintenance cost, power transmission cost and ash disposal cost.

Estimation of biomass power cost involved different sets of data. The cost components and operating parameters have been estimated based on the published literature, in consultation with industries, and after discussions with leading researchers. Some new parameters have been introduced which will be discussed in detail further in the chapter. In this study a discounted cash flow model (DCF) was used to estimate the power cost of biomass. Using this model biomass power cost was developed in dollars per unit of biomass power produced ($/MWh). Costs were converted to 2000 US$ using an inflation index (http://www.jsc.nasa.gov/bu2/inflateGDP.html). Canadian dollars were converted to US dollars at the rate of 1 US$ = $1.52 Canadian.

Note that for both the biomass source in this study, the reported yields or weights are on dry weight basis, except as noted, i.e. actual wet yields are adjusted to zero moisture content (the forestry industry refers to "bone dry wood", which the study treats as identical to a dried tonne). Estimated actual moisture content is 50% for whole forest chips, and 45% for forest harvest residue chips. These estimated actual moisture levels were used in calculating transportation costs and net heat yields from combustion. The heat of combustion of biomass per dried tonne varies with species; in this study a blended value for each biomass fuel is used.

The model used in this study, while comprehensively addressing cost elements, does not address all current forest management regulations in the Province of Alberta. If use of the forest as an energy source rather than for pulp and lumber emerges in western Canada it will lead to some changes in forest management practice, one example being an FMA selected to support either one or three power plants if the whole forest is the source of biomass. The forest management practices envisioned in this study are consistent with the general objective of long term sustainability and forest ecosystem health.

3.2.2 Estimation of optimum size of biomass power plant

Optimum size of a biomass power plant is a tradeoff between per unit capital cost of the plant and transportation cost of biomass. Per unit capital cost of the biomass power plant decreases with the increase in size of plant. Transportation cost of the plant increases with the increase in size of plant, as the draw area for biomass collection increases. Hence, at a particular size of the biomass power plant, the total cost of biomass power is minimum and this size gives optimum size of the plant. Previous studies have assessed biomass economics from the perspective of general models (Jenkins, 1997; Nguyen and Prince, 1996; Overend 1982; Larson and Marrison, 1997; McIlveen-Wright et al., 2001). Dornburg and Faiij (2001) have developed a detailed study of small to medium scale biomass plants in a Dutch setting. In this study the general models are applied to western Canada using highly detailed cost inputs; optimum size of the plant has been estimated using the DCF model developed in Microsoft Excel.

3.3 Components of biomass power plant cost

3.3.1 Field purchase cost of biomass

Whole forest biomass cost in this study is based on full recovery of all costs associated with harvesting and chipping, including capital recovery, but without nutrient replacement. An additional market premium of $4 /dry tonne is placed on the biomass, but note that this market premium is at the low end of the range of royalty payments (stumpage fees) realized from the sale of timber cutting rights. Hence, traditional pulp and lumber operations could, in most market conditions, compete for access to the forest biomass. As a region rich in forest and fossil fuel resources that will likely require GHG offsets, interesting tradeoffs arise: is the forest worth more as a low royalty fuel supply that enables parallel development of high royalty fossil fuel projects, as compared to its value for pulp and lumber? Note that for the whole forest case, security of fuel supply is readily addressed by the granting of cutting rights, which are controlled in western Canada by the Provincial Governments that have retained ownership of the forests.

Forest harvest residue cost in this study is also based on full recovery of all costs associated with harvesting and chipping, including capital recovery, but without nutrient replacement. An additional market premium of $4 /dry tonne is placed on the biomass, which would result in a direct gain by the company that held the timber cutting rights. In theory a government could require long term access to forest harvest residues without a premium as a condition of granting cutting rights, thereby reducing the cost of forest harvest residues and addressing long term security of supply.

3.3.2 Harvesting cost of biomass

Harvesting cost of biomass has been estimated based on the current forestry operations used in Canada.

3.3.2.1 *Whole forest biomass*

In whole forest case, harvesting cost included felling, skidding and chipping costs. This study draws on regionally specific detailed studies of the costs of recovering forest biomass performed by the Canadian Government, by the Forest Engineering Research Institute of Canada, from other literature, and from personal discussions with researchers and equipment suppliers (Puttock, 1995; Hudson and Mitchell, 1992; Hankin et al., 1995; Hudson, 1995; Perlack et al., 1996; Zundel and Lebel, 1992; Hall et al., 2001; LeDoux and Huyler, 2001; McKendry, 2002; Zundel et al., 1996; Silversides and Moodie, 1985; Zundel, 1986; Mellgren, 1990). In addition to these sources, a detailed model of chipping costs for both forest cases has been built in this study. For the whole forest case, whole trees are cut and skidded to a 50/48 Morbark chipper, which prepares chips suitable for direct combustion that are loaded into a waiting chip van. The large-scale chipper is assumed to operate 5000 hours per year, and is fed by a dedicated grapple. Based on this specific case, a whole forest chipping cost of $2.40 /dry tonne is calculated. Table A3 in the appendix A gives the detailed cost calculation for whole tree chipping. This is considerably lower than other reported values in the literature, which range from $8.23 to $14.54 /dry tonne. The lower value in this study arises from the large-scale of the chipper (100 green tonnes/hour) and the high number of operating hours per year compared to chippers in (Desrochers, 2002; Kowallic, 2002; Wiksten and Prins, 1980; Folkema, 1989; Bowater Newfoundland Ltd., 1983; Favreau, 1992; Spinelli and Hartsough, 2001; Asikainen and Pulkkinen, 1998). In pulp operations the transport of whole trees is an alternative, but in the case of using forest biomass for power generation the limbs and tops (that are left at roadside in pulp or lumber harvesting) are also recovered, requiring the transport of chipped material.

Costs for construction of logging roads, and silviculture costs (replanting) are included for harvesting the whole forest; these are a significant component of overall cost. Table 3.1 shows the different components of harvesting cost.

Table 3.1: Harvesting cost in whole forest case

Cost Components	Value	Source/Comments
Whole forest harvest cost including skidding to roadside ($\$/m^3$) • Felling • Skidding	 $0.9177V^{-0.5963}$ $0.9936V^{-0.3676}$	In the formula V stands for mean merchantable volume of per stem. Average merchantable volume is assumed to be 90% of the gross volume per stem. Skidding distance is assumed to be 150 m. Value of V is assumed to be 0.26 m^3 per stem based on the yields of the hardwood and spruce in the boreal forest (Favreau, 1992).
Chip loading, unloading and transport cost ($\$/m^3$)	0.7585*(2.30 + 0.0257D)	D is the round-trip road distance from the forest to the receiving plant (Favreau, 1992). In this study the cost has been converted to green metric tonnes. The transport cost for the chips in the whole forest case and forest residue case is the same.
Road construction and infrastructure cost ($\$/m^3$)	0.7585 + (379.24/VT)	VT is the mean merchantable volume per hectare, where T is the mean number of merchantable stems per hectare. Value of VT has been assumed to be 185.4 m^3/ha for the boreal forest. The construction cost of roads is \$379.24 /ha represents the tertiary road network used only during the year of the harvest. Infrastructure cost of \$0.7585 /m^3 depends on the amount of labor and machine, and possibly the merchantable volume per hectare (Favreau, 1992).
Silviculture cost (\$/ha)	151.69	Many Canadian provinces require that silviculture treatments be performed

Cost Components	Value	Source/Comments
		shortly after harvesting, so that cut areas are returned to a productive state (Favreau, 1992).
Chipping cost for whole tree ($/dry tonne)	2.40	Based on detailed study of Morbark 50/48 whole tree chipper.

3.3.2.2 *Forest harvest residues*

Residue material is piled (consolidated from small roadside piles into larger piles), chipped in the field and transported to the power plant by chip van truck. Chipping of branches and tops is less efficient than chipping whole trees, and requires different equipment. As with the whole forest case, the literature reports a wide range of chipping costs for residues, from $2.00 to $28.78 per dry tonne (Desrochers, 2002; Kowallic, 2002; Wilksten and Prins, 1980; Desrochers et al., 1993a; Desrochers et al., 1993b; Desrochers et al., 1995; Hunt, 1994; Richardson, 1986). For forest residues a specific case using pilers, loaders and high capacity Nicholson WFP3A chippers with a capacity of 48 green tonnes/hour operating at 5000 hours per year gives a total cost of $9.42 /dry tonne to recover residues left by the sides of logging roads. Table A4 in appendix A gives the detailed cost calculation for piling, forwarding and chipping of forest residues. Note that for forest residues the limit to throughput is the ability to feed the material into the chipper, and for this reason a smaller capacity chipper is used.

Costs for construction of logging roads and silviculture are not attributed to the cost of power from forest harvest residues, since the roads and silviculture costs are required regardless of the disposition of the residues. Table 3.2 shows the different components of harvesting cost.

Table 3.2: Harvesting cost of forest harvest residues

Cost Components	Value	Source/Comments
Chip loading, unloading and transport cost ($\$/m^3$)	0.7585*(2.30 + 0.0257D)	D is the round-trip road distance from the forest to the receiving plant (Favreau, 1992). In this study the cost has been converted to green metric tonnes. The transport cost for the chips in the whole forest case and forest residue case is the same.
Chipping cost of forest residues ($/dry tonne)	9.42	The cost of chipping for forest residues includes forwarding and piling.

3.3.3 Transportation cost of biomass

Transportation cost of biomass consists of two components: loading and unloading cost and the variable transportation cost. Transportation cost of biomass is an important component of biomass power cost. Increased size of the biomass power plant results in an increase of transportation cost. Transportation cost also depends on the yield of the fuel. In case of whole forest, yield is higher and so the transportation distance is small. In case of forest harvest residues, biomass is collected over large area, as the density of the fuel is low. This results in transportation of biomass over long distance. Note that access to forestry roads to recover forest harvest residues is assumed to be at no cost other than the field cost of biomass. The chips are transported to the plant in a chip van truck. Table

3.1 and 3.2 gives the cost for long term hauling of whole forest chips and forest harvest residue chips. For short term contractor hauling the transportation is higher and it will be discussed in subsequent chapters.

3.3.4 Capital cost and unit size of biomass power plant

3.3.4.1 *Scale factor*

The base case unit scale factor used in this study was 0.75, where scale factor is an exponent for adjusting the cost of a power generation unit from one capacity to another (i.e. $Cost_2 = Cost_1 \times (Capacity_2 / Capacity_1)^{Scale\ factor}$). Scale factors for single boiler biomass power plants from the literature range from 0.7 to 0.8 (Bain et al., 1996; DOE, 1997; Marrison and Larson, 1995); similar values are reported for coal (Williams, 2002; Silsbe, 2002). Actual cost data is available for a number of straw based plants, although comparison is difficult because the plants use the steam for heat and power, and the relative mix of these varies from plant to plant (Larsen, 1999; Caddet, 1988a; Caddet, 1988b; Caddet, 1998c). After manipulating the data to adjust for scope, the scale factor is estimated at 0.8, but this reflects plants built in a variety of locations that are always "new" to that location and that are small and built as demonstration units. For that reason, it has been assumed that in a mature large-scale facility the scale factor would be lower. Previous studies have shown some disagreement on appropriate range of scale factors; Jenkins (1997), has explored a wide range, from zero to 1.0, while Dornburg and Faaij (2001), argue for a narrower range. Based on discussions with firms that have built major energy facilities, the study explores the impact of scale factor in the range of 0.6 to 0.9 for a single unit up to 450 MW size. Over 450 MW, a step change in scale factor occurs: the cost of an additional identical unit is assumed to be 95% (Silsbe, 2002) of the first unit cost, i.e. the cost of building an incremental identical unit saves 5% on the incremental unit only. This is close to Jenkins' assumption that scale factors approach unity, as project sizes get very large.

3.3.4.2 *Maximum unit size*

The study assumed that the maximum unit size for a biomass fired boiler is 450 MW_e. For any capacity over 450 MW, two or more identical sized units are built, e.g., at 500 MW two units of 250 MW would be built. This assumption reflects two qualitative factors: a judgment regarding comfort in scale up of existing biomass combustion units, and the maximum unit size that is acceptable in relation to the size of the electrical power market. It is important to note that the three coal fired units being built in the Province of Alberta are all sized at 450 MW, although larger coal fired units have been built in other locations, e.g. (http://www.few.com/power/products/). The assumption of maximum unit size is critical for whole forest case in this study, where the optimum plant size is found to be one or more of the maximum sized units. This is discussed further below.

3.3.4.3 *Capital cost*

Data were drawn from a variety of actual plant costs and literature sources, and show a wide variability (Larsen, 1999; Caddet, 1988a; Caddet, 1988b; Caddet, 1998c; Wiltsee, 2000; Williams and Larson, 1996; Broek et al., 1995). Actual data for straw fired units, built for a mix of heat and power, appeared after manipulation for scope and size to be about 20% higher than wood based biomass units. The value used in this study is $1184 /kW for wood and forest residues at a size of 450 MW; comparable values for new coal-fired plants in Alberta are $850 /kW. Two points are important here. First, many biomass plants built to date have been demonstration units, for which higher capital costs would be expected than would be realized with a mature technology. Second, boiler/power plant cost for wood is 40% higher than comparable capital costs for large coal fired boiler/power plants in western Canada (which has low sulfur coal that does not required sulfur removal from flue gas). Several factors contribute to a higher cost for burning biomass, including higher mass flow rate of solid fuel, lower flame temperature (and hence larger convective to radiant heat transfer ratio in the boiler) and a more corrosive ash (Miles et al., 1996), but these factors do not readily equate to such a large difference in cost as compared to coal. The author is not able to justify the large premium in capital cost compared to coal, and hence the biomass capital cost values may be conservative (high). Capital cost of the boiler and power plant is thus a source of uncertainty; sensitivities have been run on capital cost to explore the impact of this uncertainty.

3.3.5 Operating cost of biomass power plant

For the forest harvest residue plants, assumed to be located in an existing small urban setting, power plant staff compensation is estimated at $27 /hour to cover salary plus benefits. For the remote whole forest case, a premium of 20% on all labor is applied.

3.3.5.1 *Direct operating labor cost*

A single boiler unit requires eight operators per shift, and each additional unit requires an additional four operators (Broek et al., 1995; Matvinchuk, 2002). These levels are slightly higher than comparable coal plants, and reflect expected difficulties in the receipt and processing of biomass fuel.

3.3.5.2 *Administration costs*

The biomass power plant is assumed to be a stand-alone company, and an administration staffing level of 26 is assumed for each case. In the whole forest case, these staff is sited at the remote location. If a larger firm owned and operated the biomass power plant, savings in administration costs would be possible. However, these are not a significant cost factor in the overall price of power.

3.3.5.3 *Maintenance cost*

Maintenance is a major source of uncertainty in evaluating biomass plant operating cost. Existing power plants in Alberta that pulverize and fire high ash coal have maintenance costs in the range of \$1.25 to \$1.75 /MWh. Various studies of biomass units show values that are 7 to 10 times higher (Bain et al., 1996; Broek et al., 1995). After some manipulation of actual data from a small demonstration straw fired power plant, maintenance costs were estimated at about \$13 /MWh (Caddet, 1997). The author cannot explain this wide range in terms of difficulty of processing fuel or expected problems in the boiler, and it has been attributed in part to the startup and demonstration nature of existing plants. In this study annual maintenance costs (parts plus labor) have been assumed to be 3% of the initial capital cost of the plant, which gives a maintenance cost in the range of \$4.93 to \$6.20 /MWh. A similar value for a pulverized coal fired plant is 1.5% to 2.5% of capital cost. Actual maintenance costs in large-scale biomass facilities are a critical issue for future study in overall economics of biomass usage.

3.3.6 Ash disposal cost

Evidence from two Canadian plants is that once a biomass power plant starts up, a demand develops for ash, in that farmers and foresters will remove ash from the plant at zero cost, and spread it on fields (Matvinchuk, 2002). However, since this takes some time to develop, in this study a more conservative approach has been taken: ash is hauled to fields at an assumed average haul distance of 50 km, and spread, all at full cost to the power plant. For this scenario, spreading cost is 74% of total ash disposal cost. Ash content varies for the two fuels, affected in part by the dirt content of the fuel.

3.3.7 Site reclamation cost

A site recovery and reclamation cost of 20% of original capital cost, escalated, is assumed in this study, spent in the 30th year of the project. Because the charge occurs only in the last year, it is an insignificant factor in the cost of power.

3.3.8 Other critical cost factors

3.3.8.1 *Location of plant*

Alberta has a cold winter, but also has a workforce and construction industry well used to working productively in cold weather. Hence, no capital cost penalty was applied for climactic conditions. However, in both cases the plants are sufficiently remote from major population centers that construction labor would be housed in a camp, and a provision of $13 million was provided for the camp and for workforce transportation costs at a 450 MW capacity, and adjusted for scale (Williams, 2002). The whole forest power plant is built in a remote location away from existing infrastructure, and would have additional costs during construction such as access roads, higher freight costs, higher contractor mobilization and demobilization costs, and a longer construction staff cycle (for example, two weeks in and one week out rather than the traditional five day work week). To account for this, capital costs are escalated by 10% for this case (Williams, 2002).

3.3.8.2 *Plant reliability and startup profile*

Biomass plants have operating outages that are often associated with solids handling problems. In this study, a plant operating availability of 0.85 is assumed, which is less than levels of 0.90 to 0.95 routinely achieved in coal-fired plants. Startup of solids based power generation is rarely smooth, and this is accounted for by assuming a plant availability of 0.70 in year 1 and 0.80 in year 2. In year three and beyond the availability goes to 0.85 (Wiltsee, 2000). The plants are assumed to be base loaded, which is a reasonable assumption in Alberta where plants with a higher net marginal cost (fired by natural gas) provide non-base load power.

3.2.8.3 *Connection of the power plant to the existing transmission grid*

- In the case of forest harvest residues, the collection areas for biomass are large, and there is some flexibility in the location of the power plant, which is assumed in this study to be at or very near to an existing community and to an existing transmission line. In Alberta, the likely location of a forest harvest residue power generation plant is also in a power load consuming area, so that there would likely be no transmission penalty assessed. Hence, no net transmission cost is assigned to the generation facility.

- For the whole forest biomass case, the basis of the study is a remote forest plot located 300 km from existing transmission lines, which requires a dedicated transmission line to connect to the existing grid. This transmission line is assumed to have 3% line loss (Xu, 2001). The cost of the line is recovered as a transmission charge; at the optimum sized whole forest biomass plant, the charge to recover the cost of the transmission line is $1.52 /MWh. The scale factor for the remote transmission line is 0.5 rather than the 0.75 figure used for power generation equipment; the 0.5 factor is based on actual estimates for transmission lines at various scales, and reflects that clearing of the right of way is required regardless of line capacity.

3.3.8.4 *General factors*

- Gathering of biomass in the field: Capital costs for harvesting equipment are not estimated in this study but rather treated as an operating cost that includes capital recovery. This is equivalent to assuming that the power plant operator contracts out harvesting.

  For whole forest biomass, it is assumed that contract harvesting rates cover cutting, skidding, and field chipping of whole trees. For forest harvest residues, it is assumed that limbs and tops are stacked and chipped. As noted above, chipping of limbs and tops is less efficient than chipping whole trees, and a higher chipping cost is factored into the forest harvest residues case.

- Nutrient replacement: Nutrient replacement is not included in the base case for forest biomass. For whole forest, the cost of nutrient replacement is assessed in later section, in which the cost of applying the fertilizer is included.

- Transport of biomass to the power plant site: For forest harvest residues, transport is over existing forest roads from pulp and lumber operations that generate the residues. For whole forest biomass, the cost of road building is charged to the project since there is no existing road infrastructure. As noted biomass projects have a transportation cost that varies with plant capacity. This arises because the area from which biomass is drawn is proportional to plant capacity, and the haul distance is proportional to the square root of area. Biomass economics are thus sensitive to biomass yield: higher yields per unit area reduce the area required to sustain a given project size. This effect is explored in a sensitivity.

- Processing of biomass at the plant site: A small reserve of biomass is stored on site (equivalent to about two weeks operation) to sustain the power plant when roads are impassible.
- Combustion of the biomass in a boiler, with use of the steam solely for power generation: Full capital costs are calculated for power generation, and are adjusted for capacity by a scale factor. Note that co-generation, the use of low-pressure steam exhausted from turbo generators for heating, is not considered in this study.

- Return: Power price is calculated to give a pre-tax return of 10%. The impact of rate of return is assessed in a sensitivity case. This value is consistent with a plant with a publicly guaranteed return on investment. An alternate case is run at 12%.

Table 3.3 gives the power plant characteristics, Table 3.4 gives the fuel properties and Table 3.5 gives general assumptions.

3.4 Results and discussion

Biomass power cost and optimum size of the biomass power plant have been calculated. The area required to sustain biomass power plants based on two fuels have also been estimated. Sensitivity analysis of different parameters on optimum size and power cost has been carried out to study the impact of different parameters on power cost.

3.4.1 Economic optimum size of power plant

For the two sources of biomass, the economic optimum size of power plant, the power cost and the geographical "footprint" from which biomass is drawn are shown in Table 3.6.

As expected, the economic optimum size of power plant based on biomass fuel increases with increasing biomass yield per unit area. Figure 3.1 shows the power cost as a function of plant capacity for the two cases.

Table 3.3: Power plant characteristics

Factor	Value	Source/comments
Plant life (years)	30	
Net plant efficiency (LHV) (%)	34	Internal plant use of power is assumed at 10% of gross (Broek et al., 1995; DOE, 1997; Wiltsee, 2000).
Plant operating factor:		
• Year 1	0.70	
• Year 2	0.80	
• Year 3 onwards	0.85	
Operating staffing excluding maintenance staff:		Staffing levels are derived from the literature (Broek et al., 1995;Williams and Larson, 1996; Wiltsee, 2000), and discussions with personnel in the power generation industry. For a plant up to 450 MW, operators per shift are fuel receiver (1), fuel handlers (2), control room (2), ash handling plant (1), and other power plant tasks (2). For each additional unit we add one fuel handler, one ash handler, and two staff for other power plant tasks. The assumed staffing is five shifts (10,400 hours per shift position per year), which allows for vacation coverage and training.
• 450 MW or below	8	
• Above 450 MW, for each additional unit	4	
Power Generation Capital Cost ($/kW at 450MW)		This is for a 450 MW direct combustion biomass power plant determined from the literature (Bain et al., 1996; Broek et al., 1995) and existing wood plants (DOE, 1997). Note that this figure is more than 40% higher than comparable figures for coal based power generation; the source of this discrepancy is not obvious and the cost for biomass power generation is considered conservative, i.e. high.
• Wood plants	1,184	
Average annual labor cost including benefits ($/hr)		
• Operators	27.00	
• Administration staff	27.00	

Factor	Value	Source/comments
Ash disposal cost		Hauling distance for the ash is assumed to be 50 kms for the two cases
• Ash hauling cost ($/dry tonne/ km)	0.114	(Zundel et al., 1996)
• Ash disposal cost ($/dry tonne/ ha)	15.90	(Zundel et al., 1996)
• Amount of ash disposal (dry tonnes/ha)	1	(Zundel et al., 1996)
Transmission charge for remote location ($/MWh)	2.16	The transmission charge for the whole forest case has been calculated assuming 300 km of dedicated lines carrying 900 MW at a total capital cost of $97 million at 10% capital recovery plus an operating cost of $408,000 excluding line loss. The cost is for the power plant running at full load at a capacity factor of 0.85.
• Capital cost	2.08	
• Operating cost	0.08	
Spread of costs during construction (%)		Plant startup is at end of year 3 of construction.
• Year 1	20	
• Year 2	35	
• Year 3	45	

Table 3.4: Fuel properties

Characteristics	Whole forest	Forest residues
Moisture content (%)	50	45
Heating values (MJ/dry kg, HHV)	20[a]	20[a]
Fuel density during transport (dry kg/m^3)	350[b]	350[b]
Ash (%)	1[c]	3[d]

a – (REAP, 2000), b – (Desrochers, 2002), c - (EM Database, 1995), d – (Broek et al., 1995).

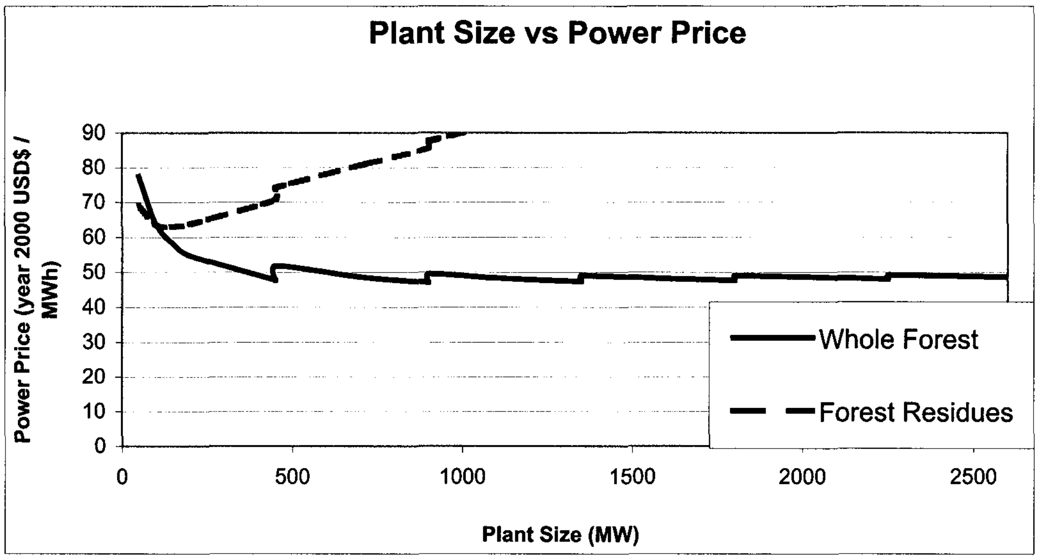

Figure 3.1: Power cost as a function of capacity for two biomass fuels.

The curve for forest harvest residue shows a sharp minimum relative to the whole forest curve. The optimum size is reached at smaller scale as the transportation cost increases rapidly with size.

Table 3.5: General assumptions

Factor	Value	Source / Comments
Scale factor		
• Total power plant capacity 20 to 450 MW.	0.75	(Bain et al., 1996; DOE, 1997)
• Transmission line capital cost.	0.49	0.49 is based on fitting a curve to estimates of 300 km transmission lines through remote boreal forest at various capacities. This value is an exponent. 0.5 is an exponent for operating costs and is an estimate based on consultation with the electrical industry.
• Transmission line operating cost.	0.50	
Cost of an additional equal sized power plant unit relative to the first.	0.95	0.95 is based on conversations with Engineering Procurement Construction (EPC) contractors. This value is not an exponent. It states that additional identical power plant units only cost 95% as much as the first unit (Silsbe, 2002).
Factor to reflect capital cost impact for remote location.	1.10	1.1 is based on discussions with EPC contractors regarding construction of a power plant in a remote location (Williams, 2002).
Transmission loss for remote location.	3% of generated power	The value has been estimated based on consultation with the electrical industry for a base load 300 km line.
Annual maintenance cost.	3% of initial capital cost per year	The value has been assumed based on blending data from existing coal-fired units and from studies of biomass power plants (Bain et al., 1996; Broek et al., 1995; Caddet, 1997).
Labor surcharge for remote location.	1.20	

Factor	Value	Source / Comments
Aggregate pre-tax return on investment (blend of debt plus equity).	10 %	
Site recovery and reclamation costs.	20% of initial capital cost	The reclamation cost is escalated and is assumed to be in the 30^{th} year of operation.

Table 3.6: Economic optimum size of power plant for Alberta based biomass

Biomass source	Biomass yield (dry tonnes per gross hectare)	Optimum size (MW)	Project area from which biomass is drawn (km^2)	Power price ($/MWh)
Whole Forest Biomass	84	900	19,000	47.16
Forest Residues	0.247	137	764,000	63.00

The whole forest curve has two characteristics worth noting:

- The profile of power cost vs. capacity is flat: In biomass projects, two cost factors compete: fuel transportation costs rise in approximate proportion to the square root of capacity, while capital costs per unit capacity decrease. Because the variable component of fuel transportation cost becomes a significant cost factor as biomass yields drop, the result is a very flat profile of cost vs. capacity. This result is consistent with previous studies of optimum size (Jenkins, 1997; Nguyen and Prince, 1996; Larson and Marrison, 1997; McIlveen-Wright et al., 2001). The flatness of cost vs. capacity for biomass is different than coal projects, where "bigger is better", and the size of a unit is often determined by either the largest available capacity or the largest increment of power generation that the power market can accommodate. The result is that biomass to power projects can be built over a wide range of capacities without a significant cost penalty. For example, the economic optimum sized biomass plant for whole forest is 900 MW (two maximum sized units), but the range of capacity for which the power price is within 10% of the optimum value is 450 MW to more than 3150 MW. While the calculated optimum size for a forest biomass plant is 900 MW, in practice significant road congestion would occur at this scale, and the far more likely plant size would be one 450 MW unit.

- The assumption of maximum unit size drives the determination of the optimum size: The assumption that the largest single biomass unit that can be built is 450 MW puts a discontinuity in power cost at any multiple of that size, as is seen in Figure 3.1. This occurs because at 451 MW, two identical 225.5 MW units are built rather than a single unit. For the whole forest cases, the optimum size is found to be a multiple of the maximum size of a single boiler. However, as noted above, the flatness of the curve suggests that whole forest based power plants could be built in any scale from 450 MW to 3150 MW with an output power price predicted to be within 10% of the optimum value.

3.4.2 Composition of power cost from biomass

Table 3.7 shows the makeup of power cost per MWh for the two biomass cases at optimum size. Note that costs are for the first year of operation at full capacity (year 3), but are deflated back to the base year 2000.

- <u>Whole forest biomass:</u> Harvesting the whole forest for power generation has the higher biomass yield per gross hectare and the lower power cost. The variable transportation cost is low, due to the high biomass yield per hectare. Construction of roads is a major cost factor for power from biomass; the forest harvest residue case, utilize existing roads. This cost would disappear for a second-generation power plant based on harvesting replanted forest. The remoteness of the assumed location for this plant is also a significant penalty, giving a higher construction and operating cost and adding both transmission cost and line loss. If the whole forest plant were in a non-remote location, the cost of power would drop to $43.29 /MWh.

* <u>Forest harvest residues:</u> Forest harvest residues give the more expensive power. The major cost penalty is the high cost of biomass transportation, which exceeds the cost of capital recovery. The slow growth of the Northern Alberta forest leads to a long rotation period, which in turn gives a very low yield of residues per gross hectare. Areas that have shorter rotation periods would have more favorable economics for these residues.

* <u>Ash removal:</u> Ash removal cost is based on the conservative assumption of no credit for the nutrient value of the ash; as noted above, there is evidence that once a biomass plant starts operation that a demand for the ash emerges and that growers will haul it away at no charge to the plant. This is evaluated in a sensitivity case.

Table 3.7. Cost of power from biomass, year 2000 US$/MWh, at full capacity (year 3) and optimum size

Cost element	Whole forest	Forest harvest residue
Capital Recovery	16.97	20.72
Transportation	6.74	23.93
Harvesting	6.74	5.41
Maintenance	5.09	6.20
Operating	0.59	2.50
Administration	0.24	1.30
Field Cost of Biomass	2.45	2.30
Silviculture	1.39	-
Road Construction	5.19	-
Transmission	1.52	-
Ash disposal	0.25	0.64
Total	**47.16**	**63.00**

3.4.3 Sensitivity analysis

Some key sensitivities were evaluated to determine their impact on optimum size of the biomass power plant and power cost. Table 3.8 shows key sensitivities.

3.4.3.1 *Capital cost of biomass power plants*

A 10% decrease in the capital cost results in an overall power price decrease of 4.7% for whole forest and 4.5% for forest harvest residues. As noted above, the capital cost of biomass power plant is 40% higher than a coal power plant. If this gap is reduced, the cost of power could come down significantly. This would also have a significant impact on optimum size of the biomass power plant.

3.4.3.2 *Transportation cost of biomass power plant*

Transportation is an important component of the biomass power cost. Optimum size is dependent on the transportation cost as stated earlier. This study assumed that biomass would be transported by truck. One of the important issues is truck congestion. At a power plant size of 450 MW, 17 trucks would be required per hour. In order to overcome this problem, a large-scale biomass power plant would benefit from an alternate transportation mode. This could be pipeline transport or rail transport. Pipeline transport of biomass has been studied in detail and is discussed in Chapter 7.

Table 3.8: Key sensitivities for power from biomass

Factor	Power Price (\$/MWh)	Price Impact (%)	Optimum Size Impact (MW)
Capital cost of power plant is 10% lower			
• Whole forest	44.96	- 4.7	No Change
• Forest residues	60.30	- 4.3	128
Pretax return on capital is 12% rather than 10%			
• Whole forest	50.70	+ 7.5	No Change
• Forest residues	67.27	+ 6.8	151
Efficiency increased from 34% to 35% (LHV)			
• Whole forest	46.46	- 1.5	No Change
• Forest residues	61.77	- 2.0	142
Whole forest biomass location is not remote	43.29	- 8.2	450
Scale factor is 0.6 rather than 0.75			
• Whole forest	41.14	- 12.8	No Change
• Forest residues	59.20	- 6.0	168
Scale factor is 0.9 rather than 0.75			
• Whole forest	55.52	+ 17.7	No Change
• Forest residues	66.47	+ 5.5	95
Biomass yield is 25% higher per gross hectare			
• Forest residues	60.71	- 3.6	152
Whole forest biomass from			
• Good Site (124 dry tonnes/gross hectare)	43.50	- 7.8	No change
• Fair Site (53 dry tonnes/gross hectare)	53.33	+ 13.1	No change
Biomass harvesting cost is 25% lower			
• Whole forest	45.47	- 3.6	No Change
• Forest residues	61.64	- 2.2	No Change
Staffing cost reduced by 25%			
• Whole forest	46.95	- 0.4	No Change
• Forest residues	61.98	- 1.6	124
Ash disposal at zero cost			
• Whole forest	46.90	- 0.6	No Change
• Forest residues	62.35	- 1.0	No Change

3.5 Opportunities for improvement

3.5.1 Integration of harvesting operations

A detailed analysis of delivered cost of biomass is shown below. Table 3.9 gives the breakdown of the delivered cost of two biomass fuels at their optimum size with existing practice. Table 3.10 shows the elements of the harvesting costs for each of the two fuels.

It can be seen from Table 3.9 that for forest harvest residues transportation cost and harvesting cost are 76% and 17% of the total delivered cost of biomass. The same figures for whole forest are 30% and 59% respectively. This section looks at the options of harvesting cost reduction. Alternate transportation is discussed in subsequent chapters. Table 3.10 shows that piling and forwarding is 50% of the field cost of forest harvest residues. This section concentrates on reducing piling and forwarding cost for forest harvest residues. Some elements of harvesting are mature and well optimized; for example silviculture, nutrient replacement and road construction have been optimized by long practice. However improved harvesting methods when a biomass residue is to be recovered are an opportunity for cost reductions since at present forest harvest residues in western Canada are not recovered at all.

Table 3.9: Biomass power from direct combustion with existing harvesting methods

	Forest Residues	Whole Forest
Optimum size (MW)	137	900
Delivered cost of fuel		
Biomass purchase ($/dry tonne)	4.00	4.00
Harvesting cost ($/dry tonne)	9.42	21.74
Transportation cost ($/dry tonne)	41.63	11.00
Total delivered cost of fuel		
($/dry tonne)	55.05	36.74
($/MWh)	31.64	22.51
Cost of power ($/MWh)	63.00	47.16

Table 3.10: Cost elements of biomass fuel harvesting ($/dry tonne)

Forest residues harvesting cost elements	$/dry tonne	Whole forest harvesting cost elements	$/dry tonne
Piling and forwarding	4.72	Cutting and skidding	8.60
Chipping	4.70	Chipping	2.40
		Road construction	8.47
		Silviculture	2.27
Total	9.42	Total	21.74

Forest residues harvesting and collection

A study was done to investigate integration of delimbing and chipping to eliminate forwarding and recovery of the limbs and tops from the ground. The conceptual process places a hopper underneath the delimber that directly feeds the chipper so that the limbs and tops never come into contact with the ground. Hence:

- Forwarding and piling are eliminated, saving labor, fuel, and capital recovery on the machinery. This saving is $4.72 /tonne or $2.94 /MWh.
- The residues contain less rocks and dirt.

Detailed study revealed a limitation with this approach due to a mismatch in machine capacities. Delimber capacity is 4.5 tonnes per productive machine hour (PMH) (Folkema and Levesque, 1982; Folkema, 1982; Richardson et al., 1991), which is set by the constraint of processing one tree at a time. The typical capacity of a large-scale chipper is 28 tonnes/PMH (Desrochers et al., 1993b). Shrinking a chipper to match the delimber would cause a diseconomy of scale.

Based on discussions with industry specialists the capital cost of an integrated chipper of smaller size would be little different than a stand-alone delimber and chipper (Desrochers, 2001) and net operating costs would increase from $8 /MWh by $23 /MWh because poor utilization of the chipper increases capital and operating costs per unit of biomass processed. Table A5 in appendix A gives the detail of calculation. Since this cost penalty is higher than the cost of piling and forwarding, integrated delimbing and chipping does not reduce overall biomass costs. This is similar to a finding of Hall et al., (2001), in their evaluation of integrated forwarding and chipping. Integration of delimbing and chipping operations for forest harvest residues is not economic because of a mismatch between delimber and chipper capacities.

Whole forest harvesting and collection

If the whole forest were to be used as a fuel source trees would be skidded to the roadside and chipped whole, and hence there is a single crop and no opportunity to integrate residue recovery.

3.5.2 Improvement of energy conversion efficiency

Improvement in the efficiency of energy conversion can be achieved by using advanced power generation technologies. In this study biomass integrated gasification combined cycle is investigated in detail. This is discussed in chapter 4.

3.6 Sustainability issues in a large-scale biomass power generation

Large-scale biomass power would be possible only if there is sustainable recovery of fuel. Sustainability issues mainly include impact on nutrient cycles and impact on biodiversity.

3.6.1 Whole forest biomass

Since the current forestry practice in Alberta, based on first cut, is not to replace nutrients, in this study the base case does not include a provision for nutrient replacement. However, this is evaluated as a sensitivity case since it is a key cost factor if included. For the nutrient replacement sensitivity case, nitrogen, phosphorous and potassium are replaced. Calcium is not replaced since it is abundant in boreal forest soils in western Canada since they originate from glacial till (Lieffers, 2001). Ultimately, as long-term forest management in European countries has demonstrated, nutrient replacement is necessary regardless of the end use of the forest biomass. First cut operations take advantage of the initial bounty of nutrients in the soil, but this is eventually depleted with sustained harvesting.

In case of utilization of whole forest biomass it has been assumed that the forest management practices would be same as that used by forestry companies today in Alberta for pulp and lumber. Table 3.11 gives the nutrient content in the tree. The data given is for white spruce-subalpine fir forest in Canada. It has been generalized for the boreal forest. Table 3.12 gives the cost of nutrients. The nutrient costs are given in cost per unit of fertilizer. To determine the cost of nutrient replacement one must multiply by the amount of nutrient per unit of fertilizer. K_2O is 83% potassium and P_2O_5 is 44% Phosphorus.

Table 3.11: Nutrient content of whole tree

Nutrients	Content (weight %)
Nitrogen	0.31
Phosphorus	0.05
Potassium	0.15

Source: Kimmins, 1987

Table 3.12: Nutrient cost

Nutrients	Cost ($/kg)
Nitrogen	0.62
P_2O_5	0.41
K_2O	0.22

Source: Hartman, 1999; Hursh, 2001.

With nutrient replacement, the power from the whole forest costs $51.58 per MWh. This results in a price increase of 9.4% as compared to the base case. There is no impact on the optimum size of the power plant.

3.6.2 Forest harvest residues

For most operations in western Canada, forest harvest residues are piled on the roadside and burnt to prevent forest fires in Alberta. Return of phosphorous, potassium and other trace nutrients in the ash is very limited at best, since ash distribution is rare. In most existing forestry operations in Alberta, nutrients are not replaced, and the nutrients from harvest residues end up being concentrated at roadside or dispersed in the atmosphere and hence are not available to fertilize regrowth. Hence for most forest harvesting where trees are delimbed at roadside virtually all nutrients in the forest biomass are lost, and are not replaced. In this study the nutrient replacement for forest harvest residues have not been considered.

3.7 Discussion

This study is based on production of electrical power from the direct combustion of biomass. Other technologies warrant comment and further assessment:

- Use of low pressure steam for heating purposes helps the economics of any thermal power plant project, i.e. biomass, fossil fuel or nuclear. However, the potential for developing such a co-generation application is higher for the forest harvest residues (where the plant has such a large draw area that it might be economically located near a pulp or lumber operation). For a remote whole forest biomass, such a co-gen application is less likely.
- In all cases of use of biomass fuel, water content of the fuel reduces efficiency. This study does not include an assessment of field drying of wood chips or the use of very low quality heat, such as flue gas, for drying of fuel.
- For forest residues, a major cost is the forwarding (consolidation) and piling of residues prior to chipping. If forest residue power projects were

implemented on a large-scale, a major effort would develop to reduce these costs.

- This study assumes that biomass fuel is sold at a premium over cost of $4 /dry tonne. An alternative for each of the fuels in this study is to require their availability at cost (as a condition of access to Provincially owned timber in the case of forest harvest residue biomass). Such an approach would presumably reflect a growing social concern re the need to mitigate GHG. It would also address a critical issue for the power plant operator, security of fuel supply. Failure to address reliability of fuel supply would leave the power plant operator hostage to biomass price increases once the plant is built. This kind of concern in the power industry is normally addressed by long-term fuel supply contracts, which might work for forest biomass. The author believes that some social intervention will be necessary to address security of fuel supply. For whole forest biomass, a key question is the value of the wood as fuel vs. the value of the wood as fiber (lumber or pulp).
- This study assumes truck delivery of fuel. The author notes that no other power generation facility of significant size relies on highway truck delivery of fuel. Alternate transport mechanisms include rail and pipeline, from hubs within the area from which biomass is drawn.
- Direct combustion of biomass has a lower efficiency and lower heat rate than other technologies, notably gasification. Gasification of wood can be achieved at significantly lower temperatures than for coal.

3.8 Conclusion

Power from biomass in western Canada is not economic in its own right, but may become so if a system of trading GHG credits emerges. Whole forest biomass can generate power for \$47 /MWh at its optimum size. Forest biomass likely requires a remote location with dedicated transmission, but has low transportation cost due to the high biomass yield per gross hectare. Forest harvest residues have a very low yield per gross hectare because of the long rotation and low cutting density in the boreal forest; transportation costs are of the same scale as capital recovery in this case, and the cost of power is \$63 /MWh and optimum plant size is the smallest, at 137 MW. Nutrient replacement was not factored into the forest biomass cases since first cut operations in Alberta do not practice nutrient replacement. However, repeated forest harvesting ultimately requires nutrient replacement, and this is a significant cost factor for the whole forest case (\$4.42 /MWh).

The whole forest biomass case shows a region of flat profile of power cost vs. plant capacity, which occurs because the reduction in capital cost per unit capacity with increasing capacity is offset by increasing fuel transportation cost as the area from which biomass is drawn increases. This means that smaller than optimum plants can be built with only a minor cost penalty. The forest harvest residues case has a sharp optimum.

Biomass yield per gross hectare is a major factor in the cost of power from biomass, and forest harvest residue usage would be more economic in areas with shorter rotations. The assumption of maximum unit size for a biomass boiler drives the optimum capacity for the whole forest case, but the flatness of the cost vs. capacity curve means this is not a critical factor.

Integration of delimbing and chipping operations for forest harvest residues is not economic because of a mismatch between delimber and chipper capacities.

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Chapter 4

Advanced Technology for Biomass Power Generation

4.1 Overview

A promising alternative to the steam-turbine cycle for biomass power generation is the use of a biomass integrated gasifier/gas turbine combined cycle (BIGCC). This process involves marrying combined power generating or co-generating cycles, which have already been developed for natural gas and clean liquid fuel applications, to closely coupled biomass gasifiers. The gasifiers can be based to a large extent on designs already developed for similar applications using coal in gas turbine power cycles (Williams and Larson, 1996). Electricity produced with BIGCC power systems not only offers higher efficiency but also might be competitive with electricity produced from fossil fuels and nuclear energy under a wide range of circumstances (Williams and Larson, 1993).

There are two general classes of gas turbines which can be used for power generation: heavy duty industrial turbines designed specifically for power generation, and lightweight, compact, aero-derivative gas turbines. Advantages of aero-derivative turbines are their compact size and high efficiency (Williams and Larson, 1996).

Integrating gasifiers with aero-derivative gas turbine in particular makes it possible to achieve high efficiencies and moderate capital costs in modest-scale biomass power generating facilities. The high peak cycle temperature of modern gas turbines facilitates the achievement of high thermodynamic efficiencies; compared to about 540 °C in steam turbines, a temperature of the order of 1269 °C can be achieved in gas turbines. The hot exhaust gas from gas turbine still carries a high thermal energy, which can be used in a heat recovery steam generator (HRSG) to produce steam for industrial applications or for further power generation. The steam recovered in the HRSG is used for power generation. This system uses a simple Brayton gas cycle and is essentially a combined cycle in which the products of gasification are burnt in a combustor to drive a gas turbine and the heat in the exhaust flue gases is recovered in an HRSG that in turn drives a steam turbine. The combined cycle is the most efficient power generating cycle on the market (Williams and Larson, 1993; Williams and Larson, 1996). Typically, with heavy-duty industrial turbines, the steam turbine bottoming cycle provides about one-third of the total output of the combined cycle. In this case heavy-duty industrial gas turbines have better performance compared to aero-derivative gas turbines due to their ability to withstand higher pressures.

BIGCC plants are currently at an early stage of commercialization. The following section gives a brief description of different current BIGCC technologies.

4.2 Biomass power generation using different gasification technologies

Atmospheric pressure directly heated gasification combined cycle

Biomass can be gasified in a atmospheric pressure gasifier to produce fuel gas. One variant of this type of gasifier has been developed by Termiska Processor Sweden (TPS). The gasifier is an air-blown circulating fluidized bed (CFB) type. It operates at about 850-900 ^{o}C and produces a gas of 4-7 MJ/Nm^3 (Rensfelt, 1997; Consonni and Larson, 1996). The atmospheric-pressure BIGCC technology consists of fuel preparation and drying (if required), air-blown gasification in an atmospheric pressure circulating fluidized bed (CFB) reactor, tar cracking using dolomite catalyst in a secondary CFB reactor, product cooling and cleaning in a conventional filter/scrubber unit (to remove particulates, chloride (as $CaCl_2$), tar, alkali, ammonia, moisture and so on from the fuel gas as required), fuel gas compression in a multiple-stage compressor, fuel gas combustion and expansion in a gas-turbine generator, and gas turbine exhaust gas heat recovery by employing a HRSG and steam turbine generator. Fouling of the gas coolers is minimized as the tar produced in the gasifier is cracked. A wet scrubbing system is provided for cleaning alkalis and ammonia from the fuel gas.

This technology is most suitable in the range of 1-100 MW range. A number of power plants based on this technology are under different stages of demonstration. Some of these include:

- Chianti, Greve, Italy – Plant capacity will be 6.7 MW_e and is based on refuse derived fuel (RDF) (Rensfelt, 1997).

- Arbre, Yorkshire, UK – Plant capacity will be 9 MW_e and is based on wood from short rotation coppice (SRC) fuel (Rensfelt and Everand, 1998; Pitcher et al., 1998).
- Bahia, Brazil – This plant will have a capacity of 30 MW_e and is based on eucalyptus as fuel (Waldheim and Carpentieri, 1998; Carpentieri and Silva, 1998).

Pressurized gasification combined cycle

Pressurized gasification combined cycle has been demonstrated successfully on small scale. There are two configuration of pressurized gasification. These include systems with bubbling fluidized bed and circulating fluidized bed for gasification of biomass. The Institute of Gas Technology (IGT) has developed pressurized bubbling fluidized bed gasification technology. The gasifier operates at a pressure of 15-25 bar and a temperature of 850-1000 °C. The gas produced is about 4.3 MJ/Nm^3 (Craig and Mann, 1997; Consonni and Larson, 1996). The system consists of hot gas cleaning systems to remove alkalis and particulates (Engstrom, 1998). Tar is not a major problem because its production is very small.

The first BIGCC plant based on pressurized gasification was established at Varnamo, Sweden. This plant was based on wood fuel. It had a total capacity 15 MW; the plant produced 6 MW of electricity and 9 MW of thermal energy from a total energy input of 18 MW (LHV) (Stahl and Neergaard, 1998). This has been demonstrated successfully. Another project based on this technology is in progress in Hawaii, USA (Lau, 1998; Knight, 2000). This plant will be based on bagasse. Other plants based on this technology are also in different stages of demonstration in Europe.

Low pressure indirectly heated gasification combined cycle

The Battelle Columbus Laboratory (BCL) has developed an indirectly heated gasifier combined cycle. The BCL design is an atmospheric–pressure twin, short-residence-time fluidized-bed, in which a combustor unit provides heat to a separate gasification unit via circulating sand. Residual char from the gasifier provides fuel for the combustor. Product gas is re-circulated as the fluidizing agent, along with some steam. The operating temperature of the gasifier is about 850 °C. The gas produced is about 13.2 MJ/Nm^3 (Craig and Mann, 1997). The process also consists of a gas cleaning unit. This process is based on pyrolysis and occurs in the absence of air in the gasifier.

In Vermont, USA, a BIGCC plant based on this technology, is under demonstration. The capacity of the plant will be 60 MW_e (Paisley and Anson, 1998; Paisley et al., 1999). This is one of the first of its kind, which uses the indirect gasification technology. The fuel used is wood.

4.3 Performance and cost of BIGCC

The main advantage of the BIGCC plants is their high efficiency as compared to direct combustion plants. The size of a BIGCC plant is determined by the gas turbine selected. The number of suitable gas turbines is rather limited today. BIGCC has the potential for significant reduction in capital cost per kW of generation capacity. Efficiency improvements are expected to result from design improvements, use of higher firing temperature gas turbines, and other technology enhancements such as hot-gas cleanup. Other expected contributors to reduced capital costs are: economies of scale, reduced engineering costs and improvements resulting from operating experience.

The capital cost of first generation commercial BIGCC plants will be high. The cost of BIGCC plants has been extensively reported in the literature. Table 4.1 gives the summary of the capacity, cost and efficiency of BIGCC plants reported in different studies.

Mann and Spath (1997) of National Renewable Energy Laboratory (NREL, USA) carried out the life cycle assessment of BIGCC systems. The study covered the upstream and downstream processes of BIGCC. Craig and Mann (1997) evaluated different gasifiers. These include: an indirectly heated atmospheric pressure gasifier, a directly heated atmospheric pressure gasifier and a pressurized gasifier. These gasifiers were studied in different configuration with an aero-derivative turbine and industrial turbine. The characteristics and cost of BIGCC of different capacities, as reported by Craig and Mann (1997) are shown in Table 4.2.

Table 4.1 Performance and cost of BIGCC plants

Capacity (MW_e)	Efficiency (LHV, %)	Cost (\$/kW)[a]	Comments	Reference
25-30	45	1455-1680	Atmospheric-pressure directly heated gasifier	Consonni and Larson, 1996
60-70	40-50[b]	1685-2247	Commercial plant, Bioflow technology, European conditions	
146	46	1237	Pressurized RENUGAS	van den Broek et al., 1996
29	45	2139-2821	Pressurized Bioflow	
51	54	1800	Scaled-up nth plant cost	Faaij and van Ree, 1998
110	55	1440		
215	59	1028		
30	-	2812	First plant	Rensfelt, 1997
55	47	1458	Nth plant Atmospheric-pressure gasifier	

a – Cost in year 2000 US dollars, b – 40-45% electricity production for cogeneration operation; 45-50% efficiency for power generation only.

Table 4.2: Characteristics of BIGCC plants based on a NREL study

Type	Capacity (MW)	Capital Investment (\$/kW)	Efficiency (HHV, %)
High pressure gasifier, aeroderivative, gas turbine	56	1588	36.01
High pressure gasifier, greenfield plant	56	1696	36.01
High pressure gasifier, advanced utility gas turbine	132	1371	39.70
Low pressure indirectly heated gasifier, utility gas turbine	122	1108	35.40
Low pressure air blown gasifier, utility gas turbine	105	1350	37.90

4.4 Optimum size and power cost of a BIGCC plant in western Canada

Optimum size of a BIGCC plant is a tradeoff between the capital cost of the plant and transportation cost of biomass. Optimum size and power cost for BIGCC based on whole forest biomass and forest harvest residues have been evaluated in this study.

4.4.1 Methodology and assumptions

Biomass yield for the whole forest and forest harvest residues have been assumed to be the same as for direct combustion plants (Chapter 3). Biomass collection and transportation costs were based on the formulae given in Table 3.1 and 3.2. Plant characteristics apart from capital cost and efficiency have been taken from Table 3.3 and 3.4 (the same as that of a direct combustion plant). In this study, the optimum size has been evaluated based on the capital cost and efficiency reported by Craig and Mann (1997). After considering different types of gasifiers, it was concluded that for large-scale BIGCC plants pressurized gasifiers would be economical (Rensfelt, 1997; Consonni and Larson, 1996; Blackadder et al., 1994). In this study, a high pressure gasifier coupled with advanced utility gas turbine was considered. A unit size of 130 MW was assumed. The overall efficiency of power generation was assumed to be 36.5% (HHV) and 45% (LHV).

4.4.2 Results and discussion

Table 4.3 shows the cost of biomass power cost for biomass gasification. In the case of forest harvest residues, power cost decreases significantly because the savings arising from the increase in efficiency of plant is more dominant than the increase in capital cost. For whole forest the result is the opposite, i.e., the increment in capital cost is more dominant than the saving from the increased efficiency of the plant, and the result is a higher power price for gasification compared to the direct combustion case. Figure 4.1 shows the percentage change in the power price in case of biomass gasification as compared to direct combustion. The power price for whole forest increases by 7.9%, while for forest harvest residues, it decreases by 13.7% at their optimum size. This shows that BIGCC is only economical for high cost fuel (forest harvest residues) and direct combustion is economical for low cost fuel. Table 4.4 gives the optimum size of the BIGCC plant in western Canada and the power cost.

Table 4.3: Cost of power from biomass using BIGCC technology, year 2000 US$/MWh, at full capacity (year 3) and optimum size

Cost element	**Whole forest**	**Forest harvest residue**
Capital Recovery	23.65	21.85
Transportation	4.91	15.66
Harvesting	5.09	4.09
Maintenance	7.11	6.55
Operating	1.52	2.62
Administration	0.21	1.37
Field Cost of Biomass	1.85	1.74
Silviculture	1.05	
Road Construction	3.92	
Transmission	1.41	
Ash disposal	0.19	0.48
Total	**50.91**	**54.37**

The primary factor in these different results is the delivered cost of fuel. Gasification, which spends capital dollars to improve efficiency, is beneficial for fuels which have high delivered cost, but is detrimental for a low cost fuel. The results are specific both to the delivered cost of biomass fuel and the capital cost increment for gasification. While the cost of power from forest harvest residues is reduced by gasification, the impact is not large enough to make it competitive with direct combustion of whole forest.

Table 4.4: Power cost and optimum size for a biomass integrated gasification combined cycle power plant

Biomass fuel	Optimum size of the power plant (MW)	Power cost at the optimum size ($/MWh)
Whole forest	1040	50.91
Forest harvest residues	130	54.37

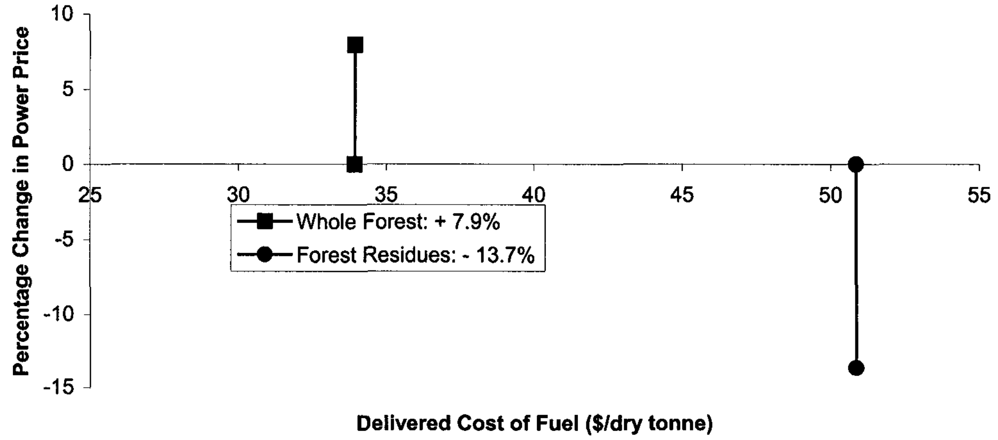

Figure 4.1: Effect of gasification on power price as compared to direct combustion of biomass.

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Chapter 5

Greenhouse Gas Abatement Cost

5.1 Overview

The greenhouse gas (GHG) emission mitigation potential of a biomass energy system depends on the characteristics of the conversion technology and the energy potential of biomass fuels to be used. The competitiveness of the biomass energy technologies to fossil fuel power plant depends on carbon credits required. Accurate estimation of carbon credit requires estimation of GHG emissions over the life cycle of the power plant.

It is desirable to take an approach when comparing different technologies which accounts for emissions of all greenhouse gases i.e., not only CO_2, inherently associated with all uses of energy carriers and materials for activities upstream and downstream of the conversion step and for the conversion step itself. The usual approach of considering only the conversion step of primary to secondary energy, viz. GHGs from combustion of fossil fuels in power plants, is inadequate for climate benign energy planning. The emissions that take place in the upstream and the downstream processes contribute significantly to the greenhouse gas pool in the atmosphere.

The concept of life-cycle assessment is to evaluate the environmental effects associated with any given activity from the initial gathering of raw material from the earth until the point at which all residuals are returned to the earth. In this study, a "cradle-to-grave" approach has been adopted. Emission factors over the life cycle of the biomass power plant have been estimated.

5.2 Estimation of the life cycle emission factors for biomass energy technologies and fossil fuel based power plants

In this study, the system boundary for biomass energy plants includes biomass production, transportation, construction and decommission of plant, and energy conversion. For fossil fuel power plants, system boundary includes mining and extraction, transportation, construction of plant and energy conversion.

When an ecosystem is disturbed one occurrence is that carbon levels in soil decline due to oxidation and/or leaching; see, for example, Marland and Schlamadinger (1997) re loss of soil carbon after forest harvesting. One key assumption in this study is that soil carbon is fully restored over the period of regrowth of the forest, approximately 100 years. Hence, the initial increase and subsequent decrease in atmospheric carbon due to harvesting has not been factored into the life cycle analysis in this study.

Emission factors, except for transportation and energy conversion, for both biomass energy plants and fossil fuel power plants have been taken from the literature and some existing computer models. Emission factors for biomass production, construction and decommissioning of biomass power plants are based on the study done by Mann and Spath (1999). These emission factors have been assumed to be same for both forest harvest residues and whole forest biomass. Emission factors for construction and decommissioning of a coal power plant has been estimated, based on study by Spath et al. (1999). An emission factor for transportation has been calculated separately for forest harvest residues and whole forest biomass as the distance of biomass transportation in two cases are different. An emission factor for coal mining has been estimated based on the study done by Hollingshead (1990) for the Genessee, Alberta coalfield. Table 5.1 gives the different emission factors considered in this study.

Table 5.1: Life cycle emissions (g of equivalent CO_2 equivalent/kWh) from the power plants

	Production	**Transp.**	**Construction and Decommissioning**	**Energy Conversion**	**Total Emissions**
Forest Residues	28.0[a]	35.5[b]	12.0[a]	0	75.5
Whole Forest	28.0[a]	6.4[b]	12.0[a]	0	46.4
Coal	11.6[d]	0[b]	5.0[e]	968.0[c]	984.6

a – Mann and Spath (1999), b – Estimated, c- calculated, d – Hollingshead (1990), e – Spath et al. (1999).

Notes on Table 5.1:

- The emission factor for transportation is based on truck transportation distances of 329 and 52 kms for forest residues and whole forest respectively, assuming the energy input of 1.3 MJ/tonne/km by truck and a release of 3 gC/GJ/km (Borjesson, 1996). Most of the coal power plants in western Canada are at a mine, so the transportation distance is very small. The emission during transportation would be negligible as compared to the other components. Hence it has been neglected in this case.

- The emission factor for energy conversion of coal is calculated based on characteristics of Alberta coal and the new 450 MW coal power plant. The emission factor for energy conversion of biomass has been considered zero because biomass is considered to be carbon neutral. This means that the amount of CO_2 released during combustion of biomass is same as that taken-up by plants during their growth.
- The emission factor for coal mining has been calculated for the Genesee; Alberta coalfield. It includes the contribution from methane emission and also the emission of the mining of coal.

5.3 GHG abatement cost of biomass energy technologies

As noted in Chapter 3, power from a forest biomass plant is more expensive than from existing coal fired power plants in Alberta and new plants in development or construction. Many forms of support of projects that mitigate greenhouse gas emissions are possible, including GHG or carbon credits, green certificates, the establishment of mandatory renewable portfolio standards for power companies, and sulfur and nitrogen credits that would incrementally favor biomass. In this study the GHG credit has been selected as a means of measuring the relative amount of financial support that would be required to make alternative forest biomass power projects competitive in western Canada.

GHG credit (\$/tonne CO_2 equivalent) required for biomass power to be competitive with fossil coal power has been estimated for forest harvest residues and whole forest biomass. Biomass power is compared to coal, as over half of the power generated in Alberta comes from coal and a base loaded biomass power plant would displace a future coal fired plant. Biomass power cost used for calculation is based on the optimum size of the plants based on the two fuels (discussed in Chapter 3).

The specific greenhouse gas abatement cost can be calculated from the difference of the specific cost of energy from biomass energy system and specific cost of energy from relevant fossil fuel system being replaced, divided by the greenhouse gas abatement achieved by replacing the fossil fuel system by the bioenergy system.

Specific greenhouse gas abatement cost

= (Specific cost of energy delivered from biomass – Specific cost of energy delivered from fossil fuel system replaced) / Specific GHG emission mitigation potential

5.4 GHG credits required for direct combustion based biomass power in western Canada

None of the biomass cases are directly competitive with coal based power in western Canada, which has a power cost (including return on capital) in the range of \$30 per MWh. Hence, in the absence of an emission credit biomass power will not be developed. A carbon credit of \$18.30 /tonne of CO_2 and \$36.20 /tonne of CO_2 would be required to equalize against an incremental coal plant for each of whole forest biomass and forest harvest residue. Note that carbon credit values are high compared to a "cap" on carbon credits announced by the Federal government of Canada of \$10 per tonne of CO_2. However, this cap has a limited duration, and is not a long term estimate of the cost of carbon credits in Canada. The same figures for \$40 average pool price of power are \$7.63 and \$25.30 respectively.

The Alberta power market was fully deregulated in 2000, and since that time monthly average power price has ranged from less than \$16 /MWh to more than \$165 /MWh. Figure 5.1 shows the carbon credit that would be required to make the biomass cases economic in Alberta as a function of power price. These values could be used to calculate a variable incentive for a publicly supported biomass power plant. Such an incentive would be tied to actual power price rather than the cost of power from a displaced fossil fuel plant i.e., by a new coal fired plant.

The GHG credit that would have been required to make biomass power competitive over the last three years (based on monthly average power pool price in Alberta) ranges from \$0 per tonne of CO_2 to \$47 per tonne of CO_2. Figures 5.2 and 5.3 show the greenhouse gas credits that would have been required to make the biomass power competitive in Alberta. A negative value for a credit means that had a forest biomass power plant been operating during that period, the owner would have realized a return in excess of that specified in the DCF model, and no supplemental carbon credit payment would have been required in that month. Note that there are many arrangements under which a biomass power plant might proceed, ranging from a publicly guaranteed rate of return with regulated power price to a fully competitive plant based on the sale of carbon credits. Under some arrangements, a negative carbon credit would be available to the guarantor of the project.

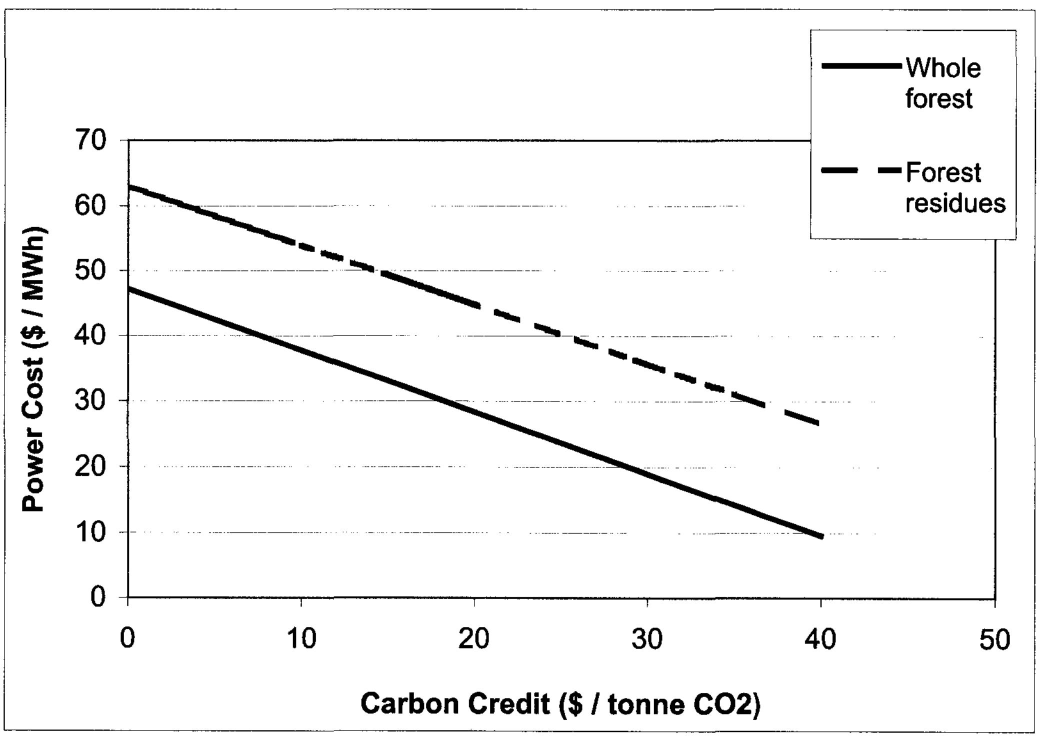

Figure 5.1: Carbon credit required to make biomass power economic in western Canada as a function of average power price.

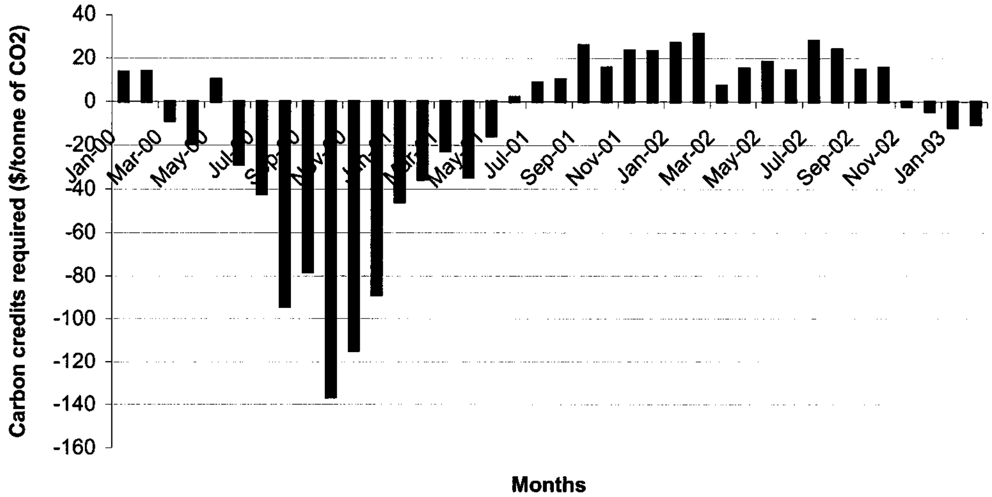

Figure 5.2: Carbon credits that would have been required for whole forest based power to be competitive.

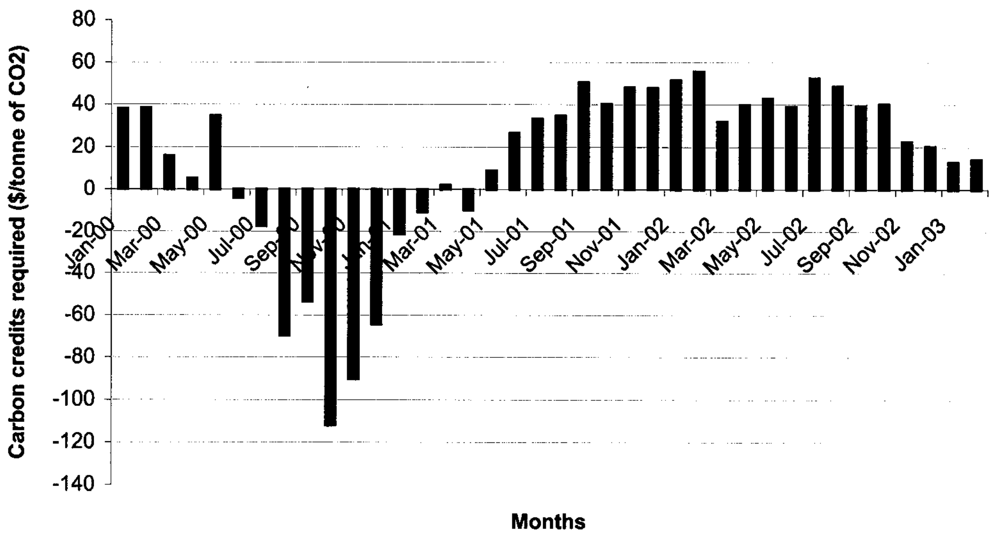

Figure 5.3: Carbon credits that would have been required for forest harvest residues based power to be competitive.

While the net credit over the 38 months period shown in Figures 5.2 and 5.3 are negative, this likely reflects an unusual period of high power prices that arose with the long delays in development of new power generation during the initial uncertainty prior to the onset of deregulation of power price in Alberta. A power price of $30 to $40 is a more reasonable planning basis for evaluating the potential support required through carbon credits for biomass power in Alberta.

5.5 GHG credits required for biomass integrated gas turbine combined cycle (BIGCC) based power in western Canada

Power cost from BIGCC plant using whole forest biomass and forest harvest residues are $50.91 /MWh and $54.37 /MWh (calculated in Chapter 4), respectively. Table 5.2 gives the carbon credits required for biomass based power to be competitive with fossil fuel power for direct combustion and gasification. Carbon credits have been calculated at fossil fuel based power cost of $30 /MWh and $40 /MWh. Power cost for biomass plants, considered here, are at their optimum size.

As compared to direct combustion, BIGCC based on forest harvest residues requires lower GHG credit for it to be competitive with fossil fuel power. At a power cost of $30 /MWh and $40 /MWh, BIGCC based on whole forest biomass results in an increase of carbon credit by 21.7% and 52.3% respectively, as compared to direct combustion. Similar figures for forest harvest residues are – 26.4% and – 37.9%, respectively.

Table 5.2: Comparison of GHG credits (\$/tonne of CO_2) required for biomass power (direct combustion and BIGCC) to be competitive with fossil fuel based power

Fuels	**Direct Combustion**		**BIGCC**	
	At power cost \$30 /MWh	At power cost \$40 /MWh	At power cost \$30 /MWh	At power cost \$40 /MWh
Whole forest	18.30	7.63	22.28	11.62
Forest harvest residues	36.20	25.30	26.65	15.71

5.6 Conclusion

None of the biomass based power plants in western Canada are economic today. Biomass power could become competitive to fossil fuel power with carbon credits. A power plant based on whole forest biomass using direct combustion technology, would need a carbon credit of \$18.30 per tonne of CO_2 at a power cost of \$30 /MWh. At the same power cost and same technology, a plant based on forest harvest residues would need a carbon credit of \$28.10 per tonne of CO_2. Use of advanced energy conversion technology is advantageous for forest harvest residues, as it decreases the value of carbon credit required to make it competitive with fossil fuels. BIGCC doesn't help in reducing power cost from whole forest biomass. The carbon credit value increases as compared to direct combustion case.

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Chapter 6

Pipeline Transport of Biomass

6.1 Overview

Carbon based power generation facilities do not typically rely on delivery of fuel by highway truck. Oil and gas fired plants rely on pipelines, and coal based facilities typically are either located at mine mouth or rely on rail or ship for fuel delivery. The reason for this is the high cost and high congestion that would be associated with delivery of large tonnages of fuel to modern large sized power plants.

Numerous biomass power plants are small and utilize truck delivery of fuel. However, in Chapter 3, it was estimated that optimum size for wood based biomass power plants in a western Canadian setting was greater than 450 MW for wood from harvesting the whole forest, and that cost of power increased sharply at sizes below about 200 MW. For forest harvest residues (limbs and tops), which are more widely dispersed, the optimum size was 137 MW.

A 450 MW biomass power plant burning 2.1 M dry tonnes per year of wood chips would require 17 truck deliveries per hour at 20 tonne per truck capacity. Highway transportation of fuel is a significant cost element, contributing, at optimum power plant size, 14 and 38% of the total cost of power generation from direct combustion of wood from harvesting the whole forest, and forest harvest residues, respectively. This work evaluates pipeline delivery of biomass to a power generation plant, to avoid road congestion (and likely resistance by nearby residents), and to reduce overall fuel transportation cost.

Pipeline transport of wood chips was studied in the 1960's. Brebner (1964), Elliott (1960), and Wasp et al. (1967) looked at solids carrying capacity and pressure losses, and Wasp et al. (1967) did a cost analysis for a 160 km pipeline with one-way transport, i.e., no water return. These studies were focused on the supply of wood chips to pulp mills, and hence water uptake by chips did not have a downstream processing impact. More recently Hunt (1976) did an extensive analysis of friction factors in wood chip slurries in water; the work presented here utilizes his formula for the friction factor. Appendix B gives the formula for friction loss in a wood slurry pipeline. More recently Liu et al. (1995) completed an analysis of two phase pipelining of coal logs (compressed coal cylinders) by pipeline. In this chapter, the estimate has been drawn on the work of Wasp et al. (1967), Liu et al. (1995), and discussions with a Canadian engineering contractor (Williams, 2003) to develop pipeline cost estimates for transporting water slurries of wood chips.

Two carrier mediums are considered for biomass: water and oil. The study reviews the inherent economics of truck vs. pipeline transport, and then evaluates a case of field delivery of biomass by short haul truck to a pipeline terminal. The prospects for pipeline transport of biomass are discussed.

6.2 The inherent economics of truck transport of biomass

Truck delivery of material has a fixed cost associated with the time required to load and unload the truck, and a variable cost that is related to the time the truck is being driven and/or the distance driven. For most biomass delivery applications, truck speed is relatively constant over the route; thus, for example, a truck picking up straw would average about 80 km/hr on rural and district roads, and a truck picking up wood chips in a forest would average about 50 km/hr on logging roads. Only if the wood chips had a significant drive over highways would there be a second higher speed portion of the trip; this effect is ignored here. Figure 6.1 shows cost data per km for truck transport of wood chips in a typical western Canadian setting (Favreau, 1992; Evashiak, 2003) the intercept of the lines is the fixed cost of loading and unloading, and the slope is the incremental variable cost per km. Figure 6.1 is adjusted to dry tonnes of biomass to make comparison with pipeline costs easier; pipeline costs are discussed later in the chapter. Typical field moisture levels for wood in western Canada is 50%. The range of costs for truck transport of wood chips comes from two different types of estimate: the lower bound is from a Forest Engineering Research Institute of Canada (FERIC) study of chip transport costs from a long term dedicated fleet, while the upper bound is based on current short term contract hauling rates. The FERIC data is more representative of steady biomass supply to a long-term end use such as a power plant. Note that there is no change of cost with scale for any biomass application of interest, i.e., the amount of biomass moved fully utilizes multiple trucks and no savings occur with larger throughput.

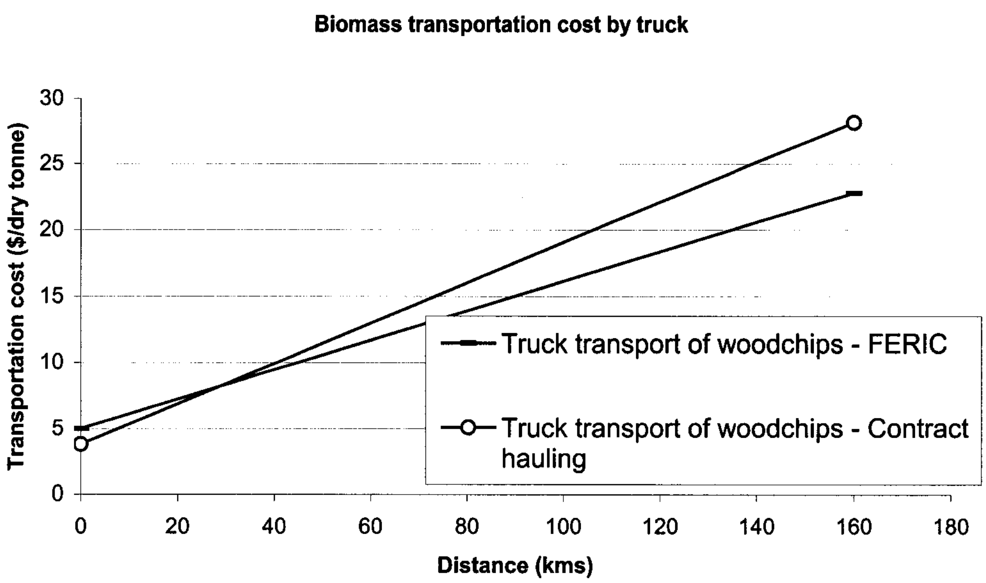

Figure 6.1: Truck transportation cost for wood chips.

6.3 Methodology for estimation of pipeline transport cost of biomass

The estimation of pipeline transport cost involved collection and calculation of different cost components. The cost components and operating parameters have been estimated based on the published literature, in consultation with industries, and after discussions with the leading researchers. Wherever operating parameters were not available, it was estimated based on the existing practice. Some new parameters have been introduced which will be discussed in detail further in the chapter. Total investment in the pipeline transport was estimated and converted to a yearly capital recovery cost. In addition to capital cost, operating and maintenance costs were also estimated. Final cost of transportation of wood chips was estimated as $/dry tonne of biomass transported. Transportation cost of wood chips has been estimated at a particular concentration and at different throughput capacity of the pipeline. For longer distance of transport booster stations costs were added to the total cost. Wherever necessary costs were converted to 2000 US$ using inflation index (http://www.jsc.nasa.gov/bu2/inflateGDP.html). The Canadian dollar was converted to US dollars at the rate of 1 US$ = $1.52 Canadian.

In this analysis some potential issues have not been addressed. Earlier studies of pipelining of woodchips for pulping noted that there was no degradation in the quality of the chips (Elliott and de Montmorency, 1963) for pulping. Pipelining of wood chips to an energy application would, however, require further research on the impact of leaching on both carrier fluid and wood chip quality, and of the potential for bacterial or fungal attack of the biomass. The extent to which both alkali halides and soluble organic compounds would leach during pipelining is not known, and no cost provision has been made in this study for treatment of any discharge water beyond simple retention in a pond prior to discharge. Note that in two way pipelining, discussed below, a bleed stream from the circulating carrier fluid would be required to control the buildup of soluble compounds. In addition, no allowance has been made for any degradation in the energy content of the wood chip from the loss of soluble organic compounds or from bacterial or fungal action. Note also that leaching of alkali halides from wood chips would have the potential to reduce the capital and maintenance cost of a boiler due to lower corrosion during combustion (Jenkins et al., 1996); again, any potential impact is not assessed in this study. These potential issues would have to be assessed before pipelining of biomass was commercialized.

6.4 Cost components of pipeline transport of biomass

6.4.1 Fixed and distance variable cost of pipeline transport

The fixed cost in pipeline transport of biomass is associated with the investment in the material receiving and slurrying equipment at the pipeline inlet, and the separation and material transport equipment at the terminus. The slope of the curve comes from the operating cost of pumping, and the recovery of the incremental capital investment in the pipeline and booster pumping stations plus associated infrastructure such as power and road access, all of which increase linearly with distance. Technically, pipeline costs would have a slight "sawtooth" shape, with a slight discrete increase in overall cost occurring when an additional pumping station is required. Practically, most of the incremental capital cost is in the pipeline rather than pumping stations, and the sawtooth effect can be ignored. (In this analysis the pipeline component of the total capital cost is 85% at 50 km, and 94% at 500 km.)

One key element in the pipeline scope and estimate is whether a return line for the carrier fluid is provided. This would be required in virtually all circumstances if the carrier fluid were a hydrocarbon, e.g., oil, and would be required for water if upstream sources were not available, as might occur in a forest cut area, or if downstream discharge of separated water was prohibited. Table 6.1 shows the scope and cost estimate included in a two-way pipeline, i.e., one with return of the carrier fluid. Table 6.2 shows the operating and maintenance cost for pipeline transport. Table 6.3 shows the general assumptions for cost calculations and operations. Key elements at the upstream end are materials receiving from trucks, dead and live storage, slurrying, and pipeline initial pumps. Key elements along the pipeline are the slurry and return pipeline and booster pumping stations. Key elements at the discharge end are slurry separation and drainage of the wood chips, and material transport to the biomass processing facility. As noted above, pressure drops, pumping requirements, and the overall estimate are based on water as the carrier fluid.

Table 6.1: Capital costs for inlet, outlet and booster station facilities (two-way pipeline, 819 mm slurry, 606 mm water, 2 M dry tonnes/year, 104 kms)

Item	Cost ($ 1000)	Remark
Inlet facilities		
Land for inlet facility	19.7	Estimated
Access roads	39.9	RS Means Company Inc., 2000
Conveyor belt	245.3	Peters and Timmerhaus, 1991
Mixing tank (water and chips)	61.3	Peters and Timmerhaus, 1991
Piping	405.1	Liu et al., 1995
Foundation for pump area	100.0	Estimated
Storage tank for water	769.3	Peters and Timmerhaus, 1991
Auxiliary pump (with one redundant pump)	137.1	Liu et al., 1995
Power supply line and sub station	400.0	Estimated
Communication lines	40.0	Estimated
Building	236.8	Estimated
Road along the pipeline	266.0	RS Means Company Inc., 2000
Fire suppression system	65.8	Estimated
Mobile stacker for dead storage	100.0	Estimated
Main pump for wood chips and water	2,678.8	Liu et al., 1995

Item	Cost ($ 1000)	Remark
mixture transport		
Pipeline for wood chips transport to plant	58,863.9	Liu et al., 1995
Total capital cost at inlet	**64,389.2**	
Outlet facilities		
Building	236.8	Estimated
HVAC system to blow air	48.6	Peters and Timmerhaus, 1991
Conveyor belt	490.6	Peters and Timmerhaus, 1991
Filtration tank	3.4	Peters and Timmerhaus, 1991
Water intake tank	769.3	Peters and Timmerhaus, 1991
Water supply lines from a water source	42.6	Liu et al., 1995
Auxiliary pump (with one redundant pump)	137.1	Liu et al., 1995
Main pump for water return	2,262.3	Liu et al., 1995
Return water pipeline	41,897.2	Liu et al., 1995
Total capital cost at outlet	**45,887.9**	
Booster station facilities		
Substation	400.0	Estimated
Booster pump for mixture	1,283.0	Liu et al., 1995
Booster pump for water	1,017.5	Liu et al., 1995
Building	19.7	Estimated
Access roads	4.0	RS Means Company Inc., 2000
Land	0.7	Estimated
Foundation for pump area	100.0	Estimated
Total capital cost at booster station	**2824.9**	

Table 6.2: O/M cost for inlet, outlet and booster station facilities (two-way pipeline, 819 mm slurry, 606 mm water, 2 M dry tonnes/year, 104 kms)

Item	Cost ($ 1000)	Remark
Inlet facilities		
Electricity	1,775.9	
Maintenance cost	423.0	
Salary and wages	1,080.0	*4 per shift*
Total O/M at inlet	**3,278.9**	
Outlet facilities		
Electricity	1,448.0	
Maintenance cost	331.1	
Salary and wages	540.0	*2 per shift*
Total O/M at inlet	**2,319.1**	
Booster station		
Electricity	2,627.7	
Maintenance cost	38.5	
Total O/M at inlet	**2,666.2**	

Table 6.3: General economic and technical parameters

Item	Values
Life of pipeline	30 years
Contingency in cost	20% of total cost
Engineering cost	10% of total capital cost
Discount rate	10%
Operating factor	0.85
Power cost	$50 per MWh
Velocity of the slurry	1.5 m/s
Velocity of water in the water return pipeline	2.0 m/s
Maximum pressure	4100 kPa
Pump efficiency	80%
Scale factor applied to inlet, outlet and booster station facilities excluding pumps	0.75

6.5 Pipeline transport cost of biomass

Figure 6.2 and 6.3 show the pipeline transport cost at 27% concentration of wood chips for one-way and two-way pipelines respectively. Pipeline transport curves are similar to the truck transport cost. Figures 6.2 and 6.3 shows that the pipeline transport cost decreases with the increase in the throughput of the pipeline. Another point to note is that two-way pipeline is more expensive than the one-way pipeline mainly because of the additional cost of the water return pipeline. Note that unlike truck transport there is an economy of scale in slurry transport of materials, since larger throughputs benefit from an economy of scale in construction of the pipeline and associated equipment, and in lower friction losses in larger pipelines. Table 6.4 gives the cost formulae for pipeline transport of biomass and the distance between the booster stations required at different throughput capacity.

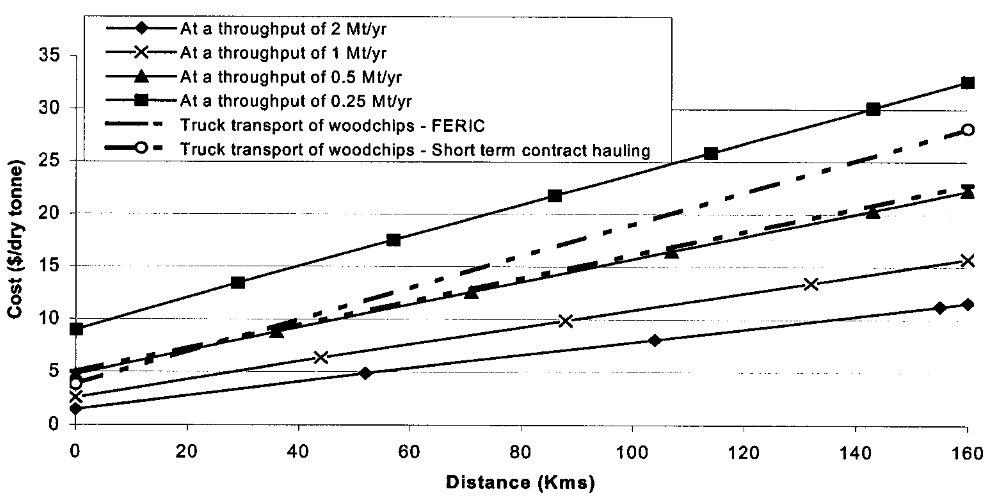

Figure 6.2: Pipeline transport cost of wood chips without carrier fluid return pipeline.

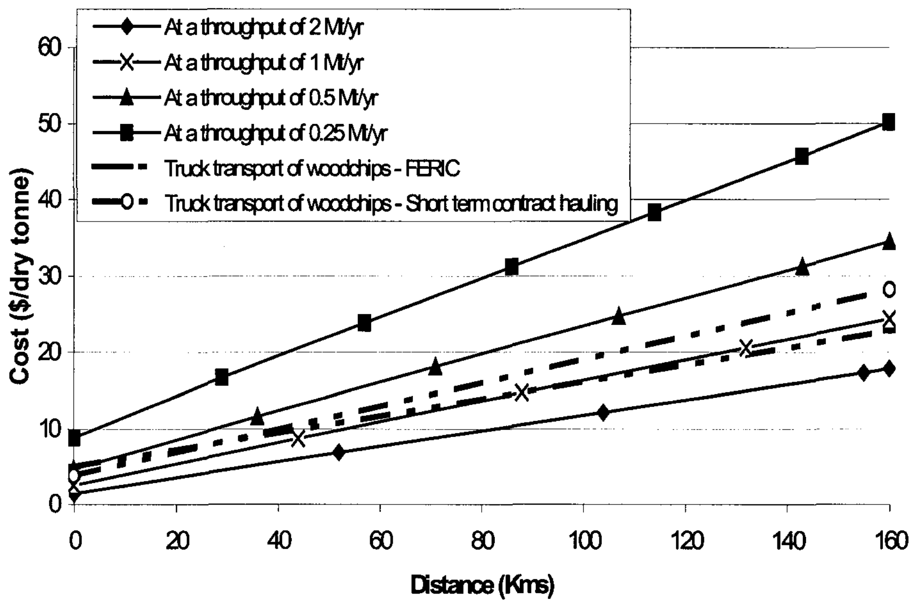

Figure 6.3: Pipeline transport cost of wood chips with carrier fluid return pipeline.

Figure 6.4 compares the total transport costs of wood chips by truck and by pipeline, in $ /dry tonne/km, for an arbitrary fixed distance of 160 km. The basis of the cost estimate is a wood chip concentration of 27% by volume at the inlet end and 30% by volume at the outlet end. The close agreement between the estimating formulae of Liu et al. (1995) and the results of Wasp et al. (1967) for a one-way pipeline is evident. The one-way pipeline cost estimates were cross checked against a recent estimate of two short large diameter liquid pipelines in western Canada (Williams, 2003) with good agreement. Figure 6.4 shows the impact of scale on pipeline costs, as compared to the cost of truck transport, which is independent of scale. (The formulae of Liu et al. (1995) and the data from Bantrel (Williams, 2003) suggest a capital cost scale factor for pipelines of

0.59 to 0.62; the data of Wasp et al. (1967) is not specific enough to calculate a comparable figure.) Appendix B gives the cost formulae used for pipeline and pump capital cost used in this study. Figure 6.4 also shows the significantly higher cost for a two-way pipeline that returns carrier liquid to the inlet end.

Table 6.4 Formulae for truck and pipeline costs as a function of distance

Cases	Cost, \$/dry tonne (d is distance in km)	Distance between slurry pumping stations, km
Two-way pipeline transport cost of a water wood chip slurry		
• At 2 Mt/yr capacity	0.1023d + 1.47	51
• At 1 Mt/yr capacity	0.1355d + 2.65	44
• At 0.5 Mt/yr capacity	0.1858d + 4.80	36
• At 0.25 Mt/yr capacity	0.2571d + 9.05	29
One-way pipeline transport cost of a water wood chip slurry		
• At 2 Mt/yr capacity	0.0630d + 1.50	51
• At 1 Mt/yr capacity	0.0819d + 2.63	44
• At 0.5 Mt/yr capacity	0.1088d + 4.80	36
• At 0.25 Mt/yr capacity	0.1473d + 9.07	29
Truck transport cost of wood chips (50% moisture)		
• FERIC (long term hauling) (Favreau, 1992)	0.1114d + 4.98	-
• Short term contract hauling (Evashiak, 2003)	0.1542d + 3.81	-

From Figures 6.1- 6.4 it is clear that the marginal cost of transporting biomass by pipeline at a concentration of 30% is higher than truck transport at capacities less than 0.5 M dry tonnes per year (one way pipeline) and 1.25 M dry tonnes per year (two way pipeline) at a distance of 160 km. The implications of this are discussed in the next section.

6.6 Practical application: integrated truck / pipeline transport of biomass

Any real application of pipeline transport of biomass from a field location (as opposed to mill residue) will normally require an initial truck haul to get the biomass to the pipeline inlet. This means that the fixed costs associated with both truck and pipeline transport are incurred. Thus, for example, truck hauling of 2 M dry tonnes per year of biomass to a pipeline inlet at an average haul distance of 35 km, as might occur in a whole forest harvest operation, with further transport of biomass by one or two way pipeline, would have cost curves as shown in Figure 6.5. The alternative of transport by truck alone is shown by the dashed line.

Since by inspection, Figure 6.2 and 6.3 show that all pipelines with a capacity of less than 0.5 M dry tonnes per year (one way) or 1.25 M dry tonnes per year (two-way) have a higher incremental cost (slope) per km than the alternative of hauling by truck, it is clear that pipelines below this capacity cannot compete with the alternative of leaving the biomass on the truck for the extra distance. In the example illustrated in Figure 6.5, at 2 M dry tonnes per year the minimum pipeline distance to recover the fixed costs of the pipeline as compared to truck haul are 75 km for a one way pipeline (in addition to the initial 35 km truck haul to the pipeline inlet), and 470 km for a two way pipeline (again in addition to the initial truck haul); pipeline distances lower than this are less economic than continued hauling by truck. Hence, pipelining of truck delivered biomass at a concentration of 30% can only make sense at both large capacity and medium to long distances.

6.7 Carrier fluids for wood chips transport by pipeline

In this analysis, cost for pipeline transport of wood chips has been estimated using water as the carrier fluid. Petroleum derived oil could also be used as the carrier fluid for pipeline transport of wood chips. A series of tests were conducted to estimate the carrier fluid uptake by wood chips and this will be discussed in chapter 7. Implications of uptake of carrier fluid by wood chips will also be discussed in next chapter.

The choice of an oil carrier requires a tradeoff between the viscosity of the carrier, which drops with lower boiling range of the oil fraction, and the value of the carrier, which increases with lower boiling range. At one extreme, a diesel fraction would have low viscosity but has such a high value as a transportation fuel that its use as a thermal fuel would be cost prohibitive. At the other extreme, a residuum fraction would have low value but such a high viscosity that transport of the slurry would likely be prohibitive in operating (pumping) cost. In this study, a heavy gas oil has been selected arbitrarily as the balance between these competing considerations.

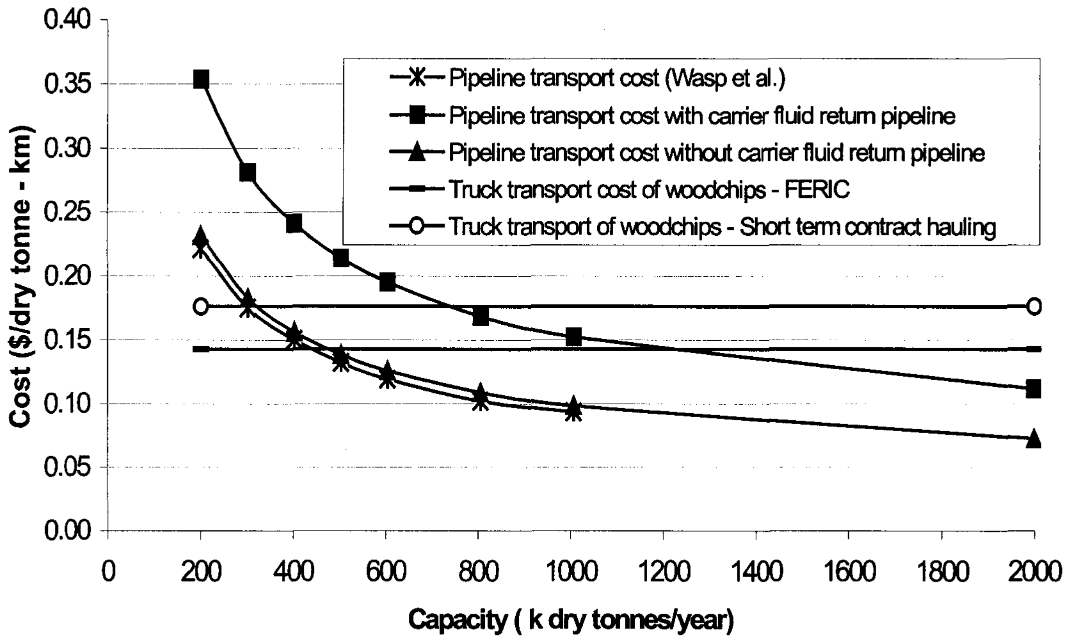

Figure 6.4: Pipeline and truck transport cost of wood chips at a fixed distance of 160 kms.

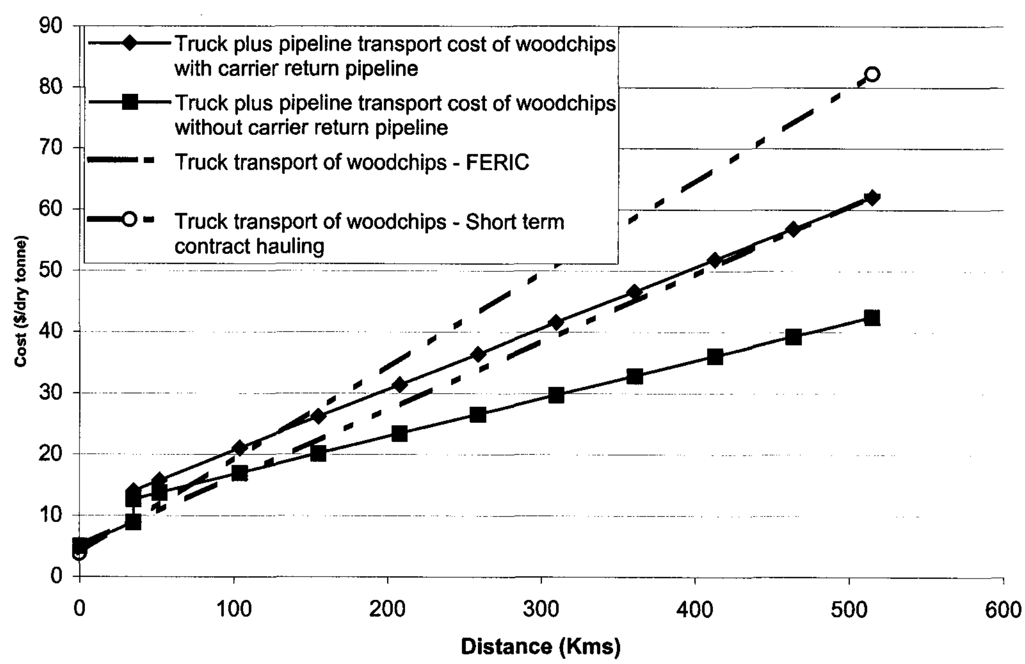

Figure 6.5: Comparison of integrated pipeline/truck transport versus truck only transport of wood chips at 2 M dry tonnes/year capacity.

Bio-oil is the name given to the liquid product of fast pyrolysis of biomass such as wood (Grassi and Bridgewater, 1993). As produced, it is a highly oxygenated oil with a high phenol content and a low pH. It could be used as a carrier fluid for wood chips if produced at the upstream end of the pipeline. One can envision a process in which wood chips at the pipeline inlet are partially converted to bio-oil to slurry the remaining wood chips to a power plant; waste heat from the pyrolysis process could be used to dry wood chips, increasing their lower heating value. However, fast pyrolysis of wood is not a commercially available technology, and the metallurgical issues for transport of bio-oil would need to be assessed to complete a pipeline design. For these reasons, this alternative is mentioned but not evaluated.

6.8 Discussion

Pipeline transport of oil and natural gas is clearly far more economic than truck transport, even in relatively small pipelines. Three factors combine to make the transport of energy in the form of biomass far less economic:

- The density of energy in the pipeline is far lower for biomass than for oil. This work is based on 30% biomass by volume in a carrier liquid. Wasp et al. (1967) based their work on 22% biomass. Brebner (1964) and Elliott (1960) indicated that at about 47% concentration by volume a slurry of wood chips and water cannot flow. Given the low heat content of wood per unit volume relative to oil and the low concentration of wood chips in water, the energy density in a 30% wood chip slurry is about 8%

compared to oil, even based on HHV, and hence far larger pipelines are required to transport the same amount of energy.

- The pressure drop in the pipeline is high for suspended solids in a carrier fluid. For example, Wasp et al. (1967) indicates that at 30% concentration of wood and a velocity of 1.4 m/s, a wood chip slurry in a 214 mm diameter pipeline has a pressure drop that is 3 times larger than for water alone.
- Recycle of the carrier fluid will often be required in biomass transport by pipeline, both because large quantities of water will not be available at the inlet end and discharge of water that has carried the biomass will, in some jurisdictions, be prohibited. This requires that a second pipeline and set of pumping stations be constructed.

In addition to these cost elements, transport of biomass for a direct combustion application by water creates a prohibitive drop in the LHV of the fuel because of absorbed water. This is discussed in next chapter.

6.9 Conclusion

It can be concluded from this section of the study that:

- Pipeline transport of truck delivered wood chips is only economic at large capacities and medium to long distances. For a one way pipeline, the minimum economic capacity is >0.5 M dry tonnes per year. For a two way pipeline, the minimum economic capacity is >1.25 M dry tonnes per year.

- At 2 M dry tonnes per year, the minimum economic distance for a one way pipeline without carrier fluid return is 75 km, and for a two way pipeline with carrier fluid return is 470 km.

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Chapter 7

Uptake of Carrier Fluids by Boreal Wood Chips: Implications for Bioenergy

7.1 Overview

The need to reduce fossil fuel carbon emissions has increased the interest in bioenergy applications. Woodchips have been evaluated for combustion (see, for example, Bain et al., 1998; Broek et al., 1996; Brammer and Bridgwater, 2002) and fermentation to ethanol (Gregg et al., 1998; Sivers and Zacchi, 1995; Alkasrawi et al., 2003; Iranmahboob et al., 2002). Virtually all field-harvested biomass is initially transported from the field by truck, but as noted above truck delivery to energy processing facilities limits the size of plants due to truck congestion at the delivery point (Atchison and Hettenhaus, 2003). Pipeline delivery of biomass to a bioenergy facility is an alternative transport means that permits larger scale plants, with the potential benefit of improved economy of scale in the processing plant.

The previous chapter has evaluated the cost of pipeline delivery of wood by pipeline and compared it to the cost of truck delivery. Carrier fluids for biomass could include water or oil, and carrier fluid could be recovered and returned to the pipeline inlet by a separate return pipeline, or discharged or used at the terminating end of the pipeline. Oil would likely be recirculated; water would be recirculated normally only if water supply was scarce at the upstream end of the pipeline.

One critical impact on downstream processing is the uptake of carrier fluid by the biomass. For example, high water uptake will reduce the lower heating value (LHV) of the biomass, which is the amount of energy released in any combustion process that discharges water contained in the fuel as a vapor. High oil uptake would reduce the biomass percentage of a fuel that was combusted.

The uptake of oil and water by boreal forest woodchips over a time period typical of pipelining was measured. Typical woodchip slurry pipeline velocities are 1.5 m/s, and typical distances for fuel transport would be 500 km or less, so in a typical pipeline application woodchip immersion times would be 100 hours or less. Since in an industrial application wood chips might dry somewhat in storage before being pipelined, the impact of initial moisture content on the uptake of carrier fluid was also measured. Since in an industrial application wood chips might sit at the discharge end prior to usage, the impact of drain time on fluid uptake was also assessed.

7.2 Materials and methods

Separate samples of boreal hardwood (aspen and poplar) and softwood (mixed white and black spruce) chips from fresh cut green logs were obtained from Millar Western's Whitecourt Alberta Canada pulp operation. Chips were obtained in the winter and sealed in a container immediately after chipping, to minimize moisture loss. Chips were stored in their sealed containers in cool temperatures (< 3 °C) prior to blending. Chip sizes varied from 2 to 5 cm in length and had a thickness of 0.3 to 0.5 cm. Two blended samples, one softwood and one hardwood, were prepared by sampling the original chip container from three locations (top, middle and bottom) and blending. Individual test samples were then prepared of five chips randomly drawn from the blended sample. (This procedure was developed in consultation with Pak Chow, a technician in the University of Alberta Renewable Resources Department.) Nine samples were run at room temperature at each immersion time or condition, to assess variability in measured uptake. The initial moisture level of the woodchips was 45% for the hardwood chips and 53% for the softwood chips.

Moisture level in wood chips was determined by weight. Chips were placed in paper bags in a 68 °C oven (a standard procedure used for moisture determination in wood samples) and repeatedly weighed until no further loss in weight occurred. Samples typically took seven days or less to dry; typical dry weight measurements were recorded after more than ten days, to ensure full oven dryness was achieved. Chips immersed in water were weighed immediately after removal, without draining; the impact of this on measured moisture level is discussed below.

The oil used was a heavy gas oil fraction obtained from Syncrude Canada Ltd., with a nominal boiling range of 325 to 550 °C and a viscosity of 1.3 Pas at 20 °C. This oil is typical of a furnace oil and is negligibly volatile at room temperature.

Oil level in wood chips was determined by weight; wood chips were removed from immersion and allowed to stand for one hour in a covered container so that surface oil would drain. Oil content is expressed as a mass % of the final oil wet chip.

Draining experiments were conducted to test the impact of draining time on carrier fluid uptake. Chips were allowed to stand on a screen in sealed containers for periods of one to eight hours, and the weight determinations were then performed as above. Experiments were also conducted on chip samples, which were partially, or totally oven dried before immersion. Initial moisture content for these chips was determined by weight.

7.3 Results

7.3.1 Result of immersion in water and oil

Figures 7.1 and 7.2 show the uptake of water and oil by softwood and hardwood chips as a function of immersion time. The height of the vertical bars indicates one standard deviation of the variability in the results. The dimensions of the bar are one standard deviation above and below the average.

For water, there is a period of rapid initial uptake, and both hardwood and softwood chips quickly reach a moisture level in excess of 60%. This is followed by a period of very slow but ongoing slight uptake of water. In the case of the hardwood chips, moisture level clearly increases between 50 and 100 hours; in the case of the softwood chips, it likely occurs, but the apparent increase between 50 and 100 hours is within one standard deviation and may be random. For oil, uptake is more gradual over the immersion period, and there is no evidence of an initial rapid uptake mechanism as with the water. Over typical pipeline immersion times, oil content reaches more than 30%.

7.3.2 Impact of draining after immersion in water and oil

Figures 7.3 show measured moisture and oil levels as a function of drainage time after immersion for 18 hours. About 6% of water and 10% of oil drain away within the first hour; longer drain times do not further reduce fluid uptake.

7.3.3 Result of immersion of dried wood chips in water and oil

Figure 7.4 shows the fluid uptake after 18 hours of immersion as a function of the initial moisture content of the partially and totally dried wood chips. Note that samples immersed in oil were drained for one hour, while those immersed in water were not. Water uptake in 18 hours is unaffected by the initial moisture content of the chips, while oil uptake is significantly higher for dry chips.

7.4 Discussion

Within the time frame that a wood chip would remain in a biomass pipeline, uptake of both water and oil by both hardwoods and softwoods is significant.

The pattern of uptake of water suggests a possible two step process, in which some water is quickly absorbed within three hours or less, and a much slower process continues to draw water into the chip. The initial uptake of water is so rapid that even for short pipelines the produced chips will have a moisture level of more than 60%. This ultimate moisture level is consistent with the findings of Wasp et al. (1967), Brebner (1964), and Elliott et al. (1963), who evaluated water slurry pipelining of wood chips for pulp applications.

Absorption of water has serious implications for any process such as direct combustion that converts absorbed liquid water in the fuel to emitted water vapor in the flue gas, in that it reduces the LHV of the biomass and requires more biomass per unit of heat released by combustion, an effect also noted by Yoshida et al. (2003). Figure 7.5 shows the loss in LHV and the corresponding increase in biomass that must be delivered to a direct combustion based biomass operation; at 67% moisture level Werther et al. (2000) note some other problems with increasing moisture in the direct combustion of biomass: reduced combustion temperature, delay of release of volatiles, poor ignition, and higher volumes of flue gas. These secondary impacts on efficiency and operability of a direct combustion unit are not considered in Figure 7.5.

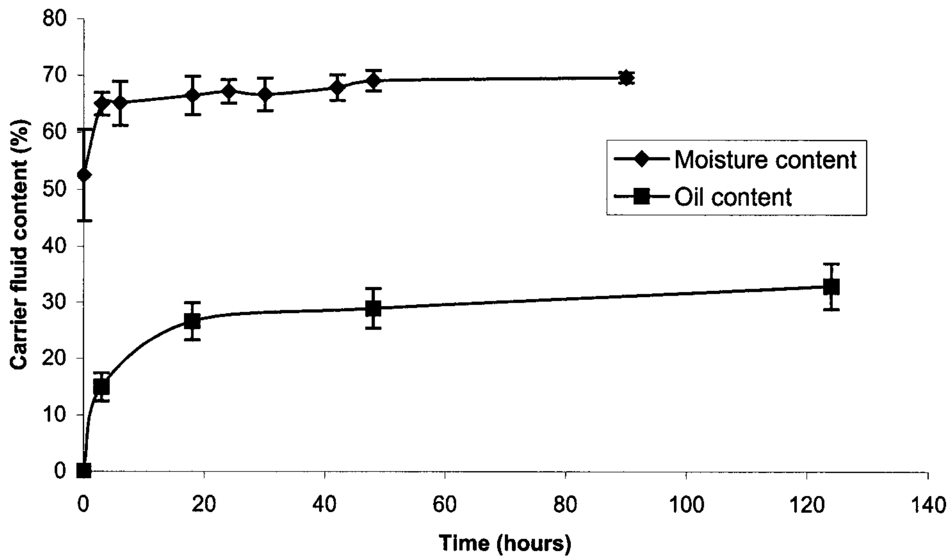

Figure 7.1: Carrier fluid content of softwood (mixed spruce) wood chips after different hours of immersion in carrier fluid.

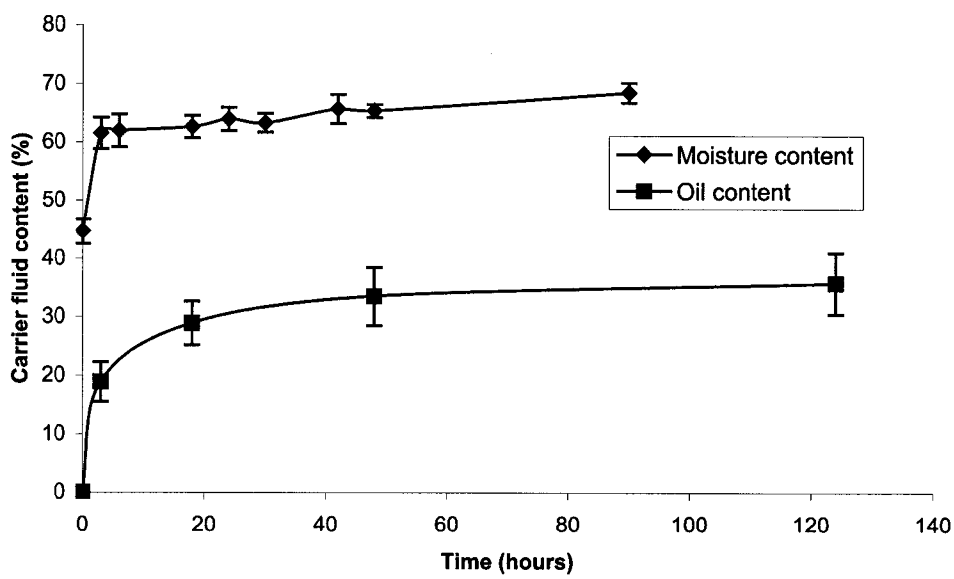

Figure 7.2: Carrier fluid content of hardwood (aspen) wood chips after different hours of immersion in carrier fluid.

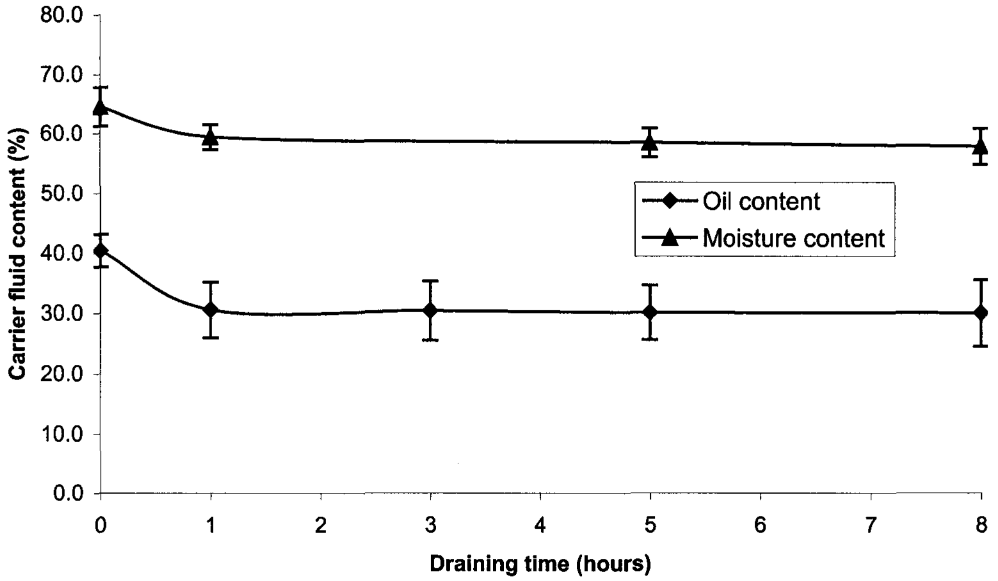

Figure 7.3: Impact of different hours of draining on the content of carrier fluid in wood chips.

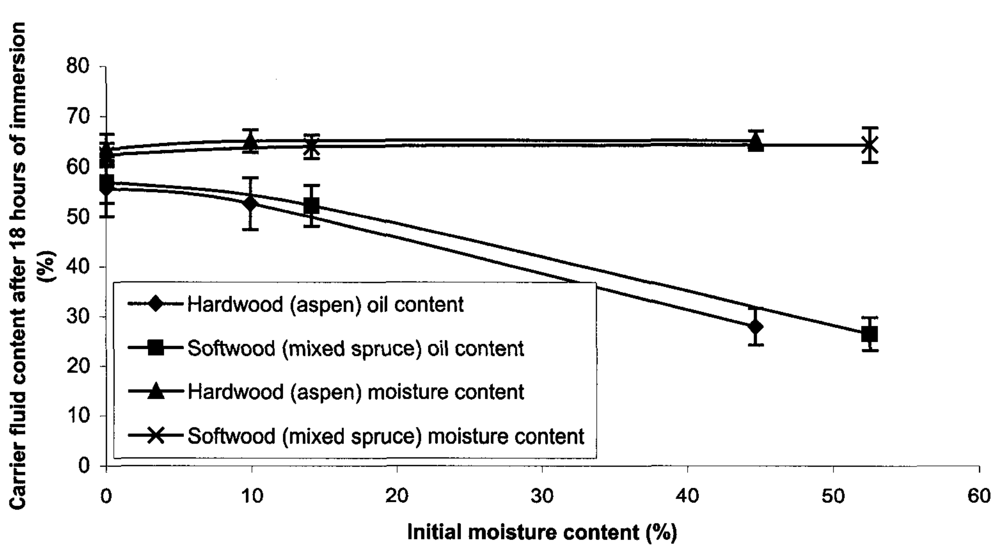

Figure 7.4: Carrier fluid absorption by wood chips after 18 hours of immersion with different initial moisture level.

As discussed in Chapter 3, one can conceptually break down biomass utilization into three component costs:

D. Field harvest of biomass.

E. Transportation from the field to the biomass processing site.

F. Cost of processing / conversion.

For direct combustion of truck transported biomass from harvesting of the whole forest in western Canada at or near optimum scale, the percentage and cost per MWh for category A is: 33.4%, 15.77 \$/MWh; B: 14.3%, 6.74 \$/MWh; and C: 52.3%, 24.65 \$/MWh. Since, from Figure 7.5, changing the moisture level of wood chips from 50% to 67% increases the requirement for field biomass in direct combustion by 78% for a given output of heat and power, it is evident that water based pipelining of wood chips cannot be economical for direct combustion, since the increase in field harvest cost associated with the higher biomass requirement is larger than any possible transportation cost saving.

This impact is not true for a fuel process such as supercritical water gasification of biomass (Antal et al., 2000; Matsumura et al., 1997a; Matsumura et al., 1997b) that does not produce water vapor from absorbed water, since the higher heating value (HHV) value of the biomass is effectively realized by countercurrent exchange of heat between products and feed that results in condensation of produced water. The impact of absorbed water is also not an issue for fermentation of biomass, since this is a water based process. Pipelining of biomass to fermentation processes offers the promise of larger scale more economic processing of ethanol, chemicals, and byproducts such as lignin. However, the pipeline design would require more detailed assessment since saccharification in the pipeline would be a logical processing alternative, and this would require temperature control in during pipeline transport. More detailed assessment is discussed in chapter 8.

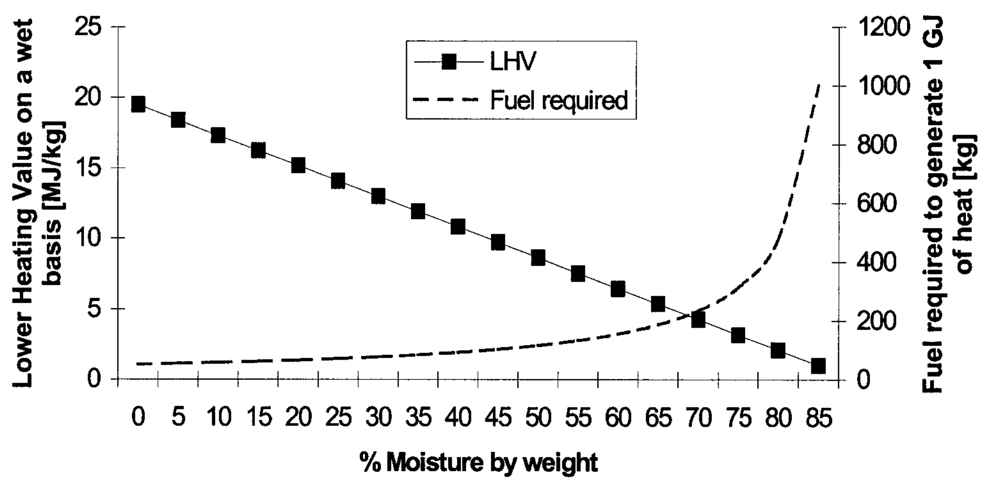

Fig. 7.5. Moisture content vs. LHV and fuel requirement of wood chips.

The pattern of uptake of oil suggests a single step process in which oil gradually penetrates the woodchip over a long period of time. By 20 hours of immersion time, the produced chips are more than 25% oil. Since oil has a significantly higher heating content than wood (LHV of 37 MJ/kg for a typical heavy gas oil vs. 8.2 MJ/kg for mixed wood chips with an average moisture level of 50%), the produced fuel, if used in a combustion plant, would be more than 60% oil on a thermal basis. In effect, transporting wood chips in oil produces a fuel that is more fossil than biomass in origin, eliminating much of the potential environmental gain. In addition, in most of the world oil has such a high value as a transportation fuel, directly or after processing, that its use as a combustion fuel is prohibitively costly. Very low value residual fuels have such high viscosity that these cannot economically be transported for long distances in pipelines. In the opinion of the author, the only potential application that might arise for oil transported wood chips is pyrolysis to form light transportation fuels or their precursors.

These issues limit the application of pipeline transport of biomass to large applications that:

- Use oil as a carrier medium, or
- Supply a process for which the heat content of the fuel is not degraded by the requirement to remove absorbed water as vapor, e.g., a supercritical water gasification process.

Allowing wood chips to drain for a period longer than one hour does not change the amount of carrier fluid uptake; however, for periods up to one hour there is some loss of carrier fluid. In Figures 7.1 and 7.2, oil uptake is based on measurements taken after one hour of drain time, and represents the oil content that would occur in a typical industrial application where chips would stand in a surge pile before being used. However, water uptake is based on measurements taken immediately after removal from water immersion, and hence in an industrial application one might expect that chips would lose about 6% of contained water by drainage.

Dry or partially dry woodchips, when immersed in water, reach the same level of moisture content as the received green chips would; hence drying has no impact on ultimate moisture level in pipelining. This is not true for oil; dry or partially dry chips take up a significantly larger amount of oil than green chips.

7.5 Conclusion

Boreal woodchips absorb water quickly when immersed and reach a moisture level in excess of 60%. The absorbed water reduces the LHV of the woodchip, which in turn means that pipeline transport of woodchips is not suitable for energy applications that exhaust water contained in the fuel as a vapor, such as combustion or gasification applications. Pipeline transport with a water carrier would be suitable for fermentation applications and processes such as supercritical water gasification that exhaust water as liquid. Uptake of a heavy gas oil fraction by woodchips is slower than water, but nevertheless oil content in the woodchip exceeds 25% in less than 20 hours of immersion. At this level of absorbed oil, more than 50% of the available LHV in the chip comes from the oil, limiting the environmental benefit achieved from combustion of biomass. Oil is not likely a suitable carrier fluid for pipeline transport of woodchips for bioenergy applications, with the possible exception of pyrolysis of woodchips to form light transportation fuels. Drain times in excess of one hour do not reduce the measured uptake of carrier fluid. Dry or partially dry chips return quickly to the same ultimate moisture level when re-immersed in water; dry or partially dry chips absorb significantly more oil when immersed.

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Chapter 8

Pipeline Transport and Simultaneous Saccharification of Corn Stover for Ethanol Production

8.1 Overview

Fossil fuel based plants do not generally depend on highway truck delivery of fuel. Plants using oil or gas typically receive fuel by pipeline, and coal based facilities are usually either located at the mine mouth or rely on rail or ship for fuel delivery. A large-scale facility cannot depend on truck delivery of fuel because of high cost and the problem of high truck congestion.

Biomass utilization requires the transport of a fuel with a lower energy density than fossil fuels, and problems of truck delivery to large-scale facilities would be even greater than for a fossil fuel plant (Atchison and Hettenhaus, 2003). The desire for low transport distances and low congestion has favored smaller biomass processing plants, while traditional issues of economy of scale have favored larger scale facilities.

The production of ethanol from corn stover exemplifies the problems. A plant using 2 M dry tonnes of corn stover per year to produce up to 960 M liters/year at full theoretical yield (Kadam and McMillian, 2003; Sokhansanj et al., 2002) would require approximately 15 highway trucks (20 tonne capacity) per hour. However, this size of ethanol plant is very small compared to a typical modern oil refinery. At this scale significant diseconomies of scale occur, for example in the utilization of byproducts such as lignin (Wallace et al., 2003) and in the distillation of the ethanol.

Larger ethanol plants would increase truck congestion and transportation cost. Several studies have indicated that transportation cost is between 20 and 45% of the delivered cost of corn stover at plant capacities of less than 1 M dry tonnes/year (Aden et al., 2002; Perlack and Turhollow, 2002) and hauling distances of 50 to 80 km (Glassner et al., 1998).

The initial stage of transport of biomass from the field is always by truck. One possible means of shifting the balance between truck congestion/transport cost vs. larger plant size is the use of multiple pipelines to feed a large ethanol processing complex. Trucks would deliver biomass to many local pipeline inlet stations, which would then transport the biomass as a slurry to a processing plant. This approach has limitations for any biomass application involving combustion, due to uptake of the carrier fluid by the biomass (Kumar et al., 2004). However, there is no processing penalty for water transport of biomass for ethanol production via fermentation since the process itself is aqueous. Pipeline transport of corn stover to an ethanol plant can be thought of as relocating the initial processing steps (washing, shredding, slurrying, and possibly pretreatment) from the plant to the pipeline inlet.

This work estimates the pipeline transportation cost for corn stover using one way (without carrier fluid return) and two way (with carrier fluid return) pipelines, with water as the carrier fluid. Pipeline capacity, distance and solids loading are key determinants of cost. Pipeline transport costs are compared to estimates of truck transport cost, which show a high degree of variability. Pipeline transport costs have a high economy of scale, while truck transport costs have a negligible economy of scale. Hence, the study determines the capacity above which pipeline costs less than trucking of corn stover, which depends on the solids loading in the pipeline.

Issues of leaching from biomass and bacterial or fungal attack of biomass impact any pipeline application. In delivery to an aqueous process, leaching issues are less significant, in that soluble compounds would enter the aqueous process whether delivered by pipeline or truck. However, as noted above in Section 6.3 these issues would require more detailed assessment prior to commercial development of a biomass pipeline.

A major processing step in an ethanol plant is enzymatic saccharification of cellulose to sugars through treatment by enzymes; this step requires lengthy processing and normally follows a short term pretreatment step. The study evaluates the potential for simultaneous transport and saccharification (STS) within the pipeline.

All costs in this chapter are in Year 2000 US dollars.

8.2 Truck transport of corn stover

Truck transport cost of biomass consists of a fixed cost and a variable cost relative to distance, which the author refers to hereafter as distance variable cost. Note that the distance variable cost includes the depreciation and return on investment in capital assets. For trucking, the fixed cost is based on the time required for loading and unloading; the distance variable cost depends on the driving time, which is linearly related to the distance since haul speeds are nearly constant. Hence truck transport cost as a function of distance is linear, with the intercept representing the fixed costs independent of distance and the slope representing the distance variable costs per km of transport.

The literature shows a wide range in estimates of North American truck transportation costs, as shown in Table 8.1 (Figures from other geographical regions are available, for example wood chips in Brazil (Marrison and Larson, 1995) and Sweden (Hankin et al., 1995) and mixed agricultural and forest residues in Thailand (Junginger et al., 2001). However, these costs are not included in Table 8.1 because differences in fuel taxation have the potential to create a geographical variation in transportation cost. The range in North American costs is so high that it significantly impacts any conclusion about the relative costs of truck vs. pipeline transport. In this work, the author identified four representative estimates of truck haul costs for corn stover like material: a very high estimate, based on the work of Marrison and Larson (1995) on switchgrass bales, a high range based on the work of Jenkins et al. (2000) and Kumar et al. (2003) on straw bales, a mid estimate based on an actual corn stover bale collection project in Harlan, Iowa, USA, reported by Glassner et al. (1998) of the US National Renewable Energy Laboratory (NREL), and a low estimate based on a theoretical study by Perlack and Turhollow (2002) of the US Oak Ridge National Laboratory (ORNL) on corn stover. The distance variable cost component for the four estimates adjusted to dry tonnes is \$0.1984, \$0.1328, \$0.1167, and \$0.0527 /dry tonne/km. Note that the high and mid estimates are close, and the very high and low estimate are significantly above and below these. The ORNL study assumes a much higher load size of corn stover per truck than the other studies, which are based on current practice.

8.3 Pipeline transport of corn stover

Pipeline transport of wood chips was studied in the 1960's by Brebner (1964), Elliot (1960) and Wasp et al. (1967). Hunt (1976) carried out a detailed analysis of friction loss during the transportation of wood chips. Liu et al. (1995) developed a detailed cost estimate of transportation of coal logs (compressed coal cylinders). Recently Kumar et al. (2004) carried out a detailed cost estimate of pipeline transportation of wood chips. In this study, the work of Kumar et al. (2004) has been extended to corn stover. In this work Hunt's formula for friction losses have been utilized, originally developed for wood chips.

Slurry pipelines sometimes provide for the return of all or a portion of the carrier fluid from the outlet to the inlet end; this is accomplished by installing two parallel pipelines. The author refers to such pipelines as two way pipelines; a one way pipeline would discharge or use the carrier fluid at the downstream end. In the case of transport of corn stover, for example in the US Midwest, it is likely that one way pipelines would be chosen, since there are sufficient rivers to be sources of water, the water is used in the ethanol plant for processing, and a large ethanol plant would have water treatment capability that would likely enable discharge of water after processing. However, two way pipeline costs are calculated in this study, and would apply in cases where either water was not available in sufficient quantities at the upstream end of the pipeline or discharge of treated process water from the ethanol plant was not permitted.

Cost of delivery of material by pipeline in which the material is drained at the receiving end (for example, for a combustion application) has a similar shape to the truck transportation curve. The cost of facilities at the inlet and outlet end of the pipeline represent fixed costs independent of distance, while both the capital recovery charge (depreciation and return) for the pipeline and pump stations and the ongoing operating and maintenance cost are distance variable costs that increase linearly with distance for all but very short pipelines. Fixed costs of inlet and outlet facilities are typically low compared to the pipeline cost; at a distance of 50 km, investment in inlet and outlet facilities is less than 15% of total investment (Kumar et al., 2004). The operating cost of a pipeline mainly arises from electrical power to operate the pumps.

Table 8.1: Distance variable and fixed cost of biomass transportation by truck in North America

Biomass	**Moisture content (%)**	**Distance Variable Cost ($/dry tonne/km)**	**Fixed Cost ($/dry tonne)**
Straw (Jenkins et al., 2000)	11	0.1348	4.43
Straw (Kumar et al., 2003)	16	0.1309	4.76
Wood chips – long term supply (Kumar et al., 2004)	50	0.1114	4.98
Wood chips – short term supply (Kumar et al., 2004)	50	0.1524	3.81
Corn stover (Aden et al, 2002; Glassner et al., 1998)	-	0.1167	6.76
Corn stover (Jose and Brown, 2001)	-	0.1045	0
Corn stover (Perlack and Turhollow, 2002)	-		
• Round bales		0.0527	5.91
• Rectangular bales		0.0596	5.84
Switch grass (Marrison and Larson, 1995)	-	0.1984	3.31

In the case of pipelining biomass to a fermentation process, most of the costs at the inlet end of the pipeline displace costs that would otherwise be incurred at the plant if the biomass were delivered to the plant site, e.g., the cost of washing, sizing and slurrying. If the biomass is transported in the pipeline at about the same concentration as the processing stage, the material leaving the pipeline would flow directly into the fermentation process. Hence, for pipeline transport of corn stover to an ethanol plant the transport cost can be modeled as only the distance variable cost component.

All biomass starts its trip from the field on a truck, and the key question is whether it is economical to remove the material from the truck at some intermediate gathering point and move it by pipeline to a processing plant. Hence for corn stover being transported to an ethanol plant, pipelining will cost less when the distance variable cost of pipelining is less than the distance variable cost of trucking. Table 8.2 shows the distance variable cost of pipelining corn stover at various solids concentrations and capacities. Table 8.3, 8.4 and 8.5 show details used in developing the cost estimates. Note that at 2 M dry tonnes/yr and a concentration of 20% (stalk material such as corn stover absorbs water quickly and achieves a moisture level of 80%, so a 20% slurry of wet corn stover would be 4% dry matter and 96% water), 67% of the distance variable cost of pipelining is recovery of invested capital, and 33% is operating cost, of which the overwhelming largest component is electrical power for pumping. Figures 8.1A and 8.1B compare the pipeline distance variable transportation cost of corn stover for one way and two way pipelines at 20% solids concentration to the distance variable cost of truck transport. Technically the pipeline transport curve would have a slightly "sawtooth" shape, with a slight increase in overall cost occurring when an additional pumping station is required. In practice, the cost impact of an incremental pumping station is negligible compared to the overall pipeline cost, and the sawtooth effect can be ignored (Kumar et al, 2004). From Figures 8.1A and 8.1B, it is clear that pipeline transport costs less than trucking at some higher capacity; the capacity at which this occurs depends on the distance variable cost of trucking.

Table 8.2: Distance variable cost for one way and two way pipeline transport cost for corn stover at different solids concentration

Solids concentration (%)	Capacity (M dry tonnes/yr)	Diameter of pipeline (m)	Distance variable cost, d is distance in km ($/dry tonne/km)		Distance between slurry pumping stations (km)
			One way	Two way	
30					
	2	1.028	0.0892d	0.1370d	48
	1	0.727	0.1140d	0.1801d	42
	0.5	0.514	0.1486d	0.2411d	35
	0.25	0.363	0.1978d	0.3294d	29
25					
	2	1.126	0.0946d	0.1491d	59
	1	0.796	0.1212d	0.1964d	51
	0.5	0.563	0.1583d	0.2633d	43
	0.25	0.398	0.2112d	0.3600d	35
20					
	2	1.259	0.1018d	0.1653d	75
	1	0.890	0.1312d	0.2186d	64
	0.5	0.629	0.1724d	0.2937d	54
	0.25	0.445	0.2298d	0.4013d	44
15					
	2	1.453	0.1140d	0.1906d	101
	1	1.028	0.1480d	0.2527d	85
	0.5	0.727	0.1942d	0.3394d	70
	0.25	0.514	0.2595d	0.4622d	56

Table 8.3: Capital costs for inlet and booster station facilities (one way pipeline, 1259 mm slurry, 2 M dry tonnes/year, 150 kms, 20% solids concentration)

Item	Cost ($ 1000)	Remark
Inlet facilities		
Main pump for wood chips and water slurry transport	5223.7	Liu et al., 1995
Pipeline for wood chips transport to plant	139,613.8	Liu et al., 1995; Williams, 2003
Total capital cost at inlet	144,837.5	
Booster station facilities		
Substation	400.0	Estimated
Booster pump for mixture	2,592.7	Liu et al., 1995
Building	19.7	Estimated
Access roads	4.0	RS Means Company Inc., 2000
Land	0.7	Estimated
Foundation for pump area	100.0	Estimated
Total capital cost at booster station	**3,117.1**	

Table 8.4: O/M cost for inlet and booster station facilities (one way pipeline, 1259 mm slurry, 2 M dry tonnes/year, 150 kms, 20% solids concentration)

Item	Cost ($ 1000)
Inlet facilities	
Electricity	3,608.5
Maintenance cost	966.4
Salary and wages	100.0
Total O/M at inlet	**4,674.9**
Booster station	
Electricity	3,611.4
Maintenance cost	77.8
Total O/M at inlet	**3,689.2**

Table 8.5: General economic and technical parameters

Item	Values
Life of pipeline	30 years
Contingency in cost	20% of total cost
Engineering cost	10% of total capital cost
Discount rate	10%
Operating factor	0.85
Power cost	$50 /MWh
Velocity of the slurry	1.5 m/s
Velocity of water in the water return pipeline	2.0 m/s
Maximum pressure	4100 kPa
Pump efficiency	80%
Scale factor applied to inlet, outlet and booster station facilities excluding pumps, saccharification tank	0.75
Capital cost of saccharification tank and related accessories at a plant capacity of 2000 dry tonnes of stover per day	$ 3,000,000

8.4 Cost crossover for pipeline vs. truck transport of corn stover

Truck transport of biomass is effectively independent of scale; more biomass requires more trucks, and the relationship is linear. Pipelines have an economy of scale that arises from both the equipment and the construction cost. Previous work calculated a scale factor of 0.59 to 0.62 for a biomass pipeline (Kumar et al., 2004). Figures 8.2A and 8.2B show the distance variable cost of transport by truck and pipeline (one way and two way) as a function of capacity and solids concentration; note the different capacity scale on Figure 8.2B. Pipeline transport cost decreases with increasing solids concentration and capacity. The point at which pipelining becomes less costly than trucking depends strongly on the distance variable cost of trucking. Figure 8.3A shows the cost crossover at which the cost of using a one way pipeline is less than trucking as a function of solids concentration for the four ranges of truck distance variable cost. Note, however, that the comparison between pipelining and trucking is based on transportation costs only, and does not factor in any savings in the ethanol fermentation plant that might arise from economies of scale from a facility served by multiple pipelines. Economics of pipelining would require an analysis in a specific project to factor in any cost savings from increased fermentation plant size.

Figure 8.3B shows the comparable cost crossover between pipelining and trucking for a two way pipeline. Note the difference in scale between Figures 8.3A and 8.3B. Only in the case of the very high estimate of trucking cost is a two way pipeline lower cost than trucking capacities less than 2 M dry tonnes/yr. Given the likelihood of 2 M dry tonnes/yr being a congestion limit on field receipt of biomass, the study focuses on one way pipelines in subsequent discussion of results.

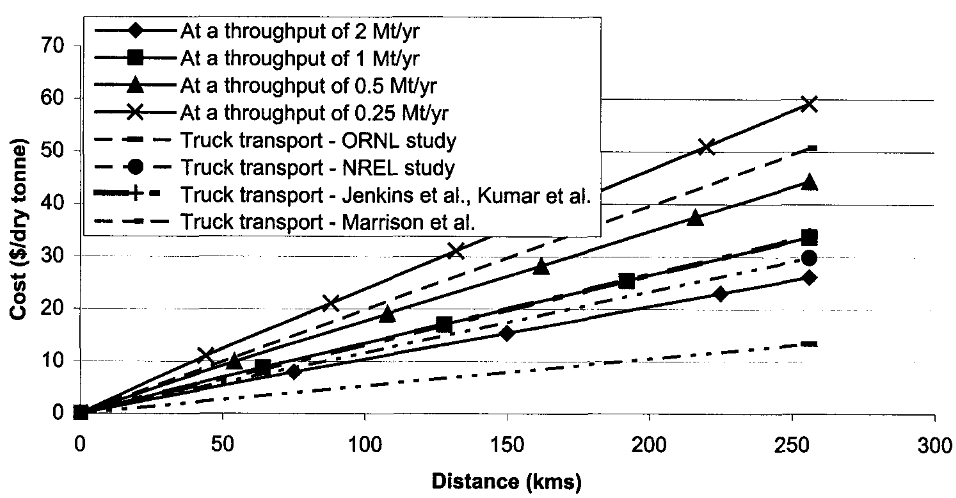

Figure 8.1A: One way (without water return pipeline) distance variable pipeline transport cost of corn stover at 20% solids concentration compared to truck distance variable cost.

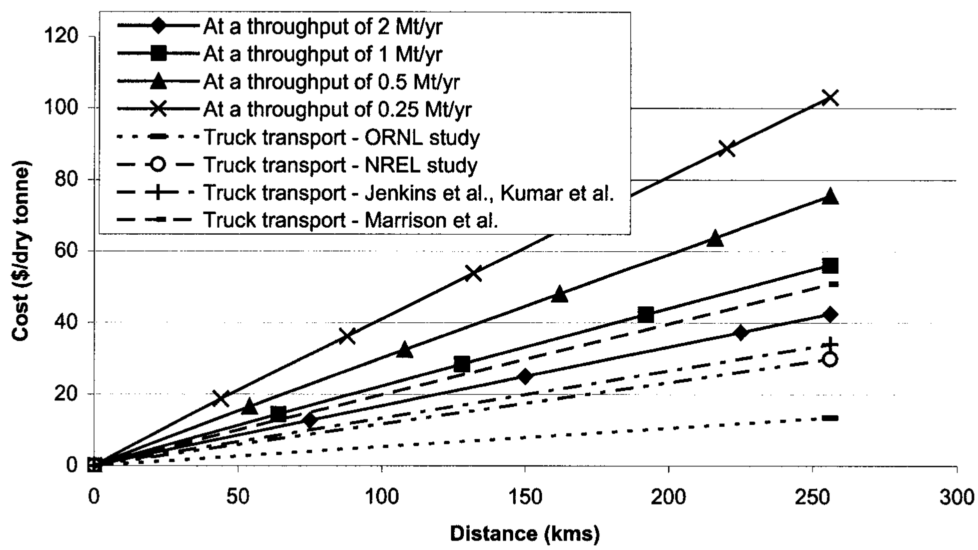

Figure 8.1B: Two way (with water return pipeline) distance variable pipeline transport cost of corn stover at 20% solids concentration compared to truck distance variable cost.

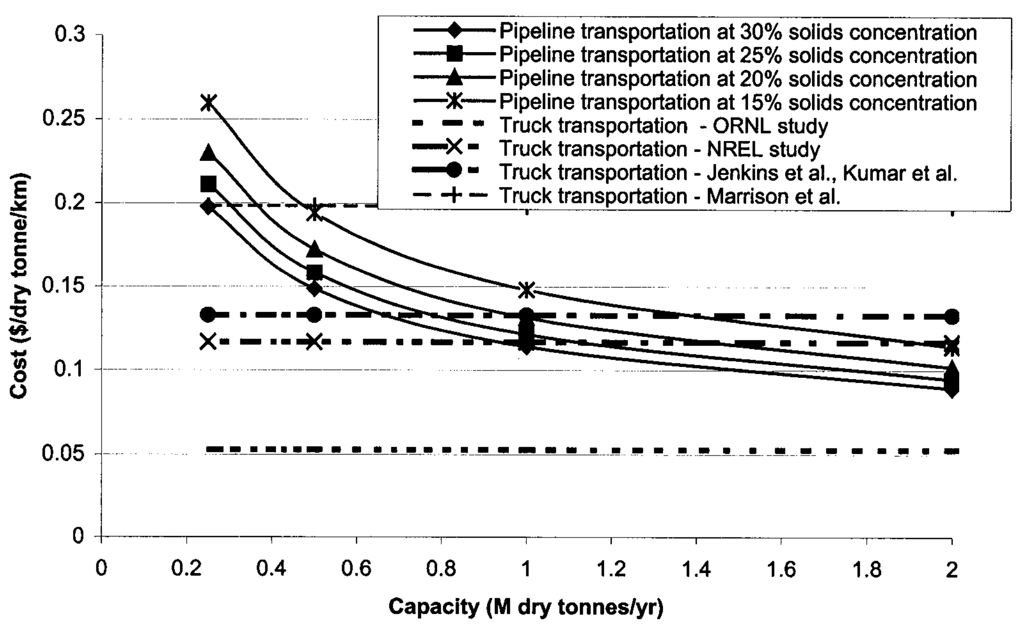

Figure 8.2A: One way pipeline and truck distance variable cost of corn stover at different concentrations.

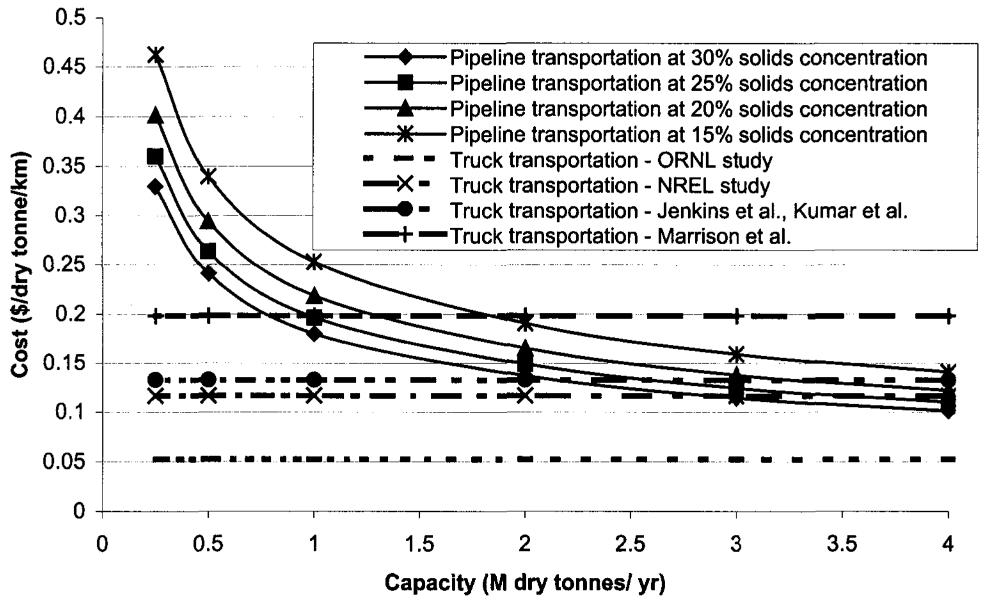

Figure 8.2B: Two way pipeline and truck distance variable transport cost of corn stover at different concentrations.

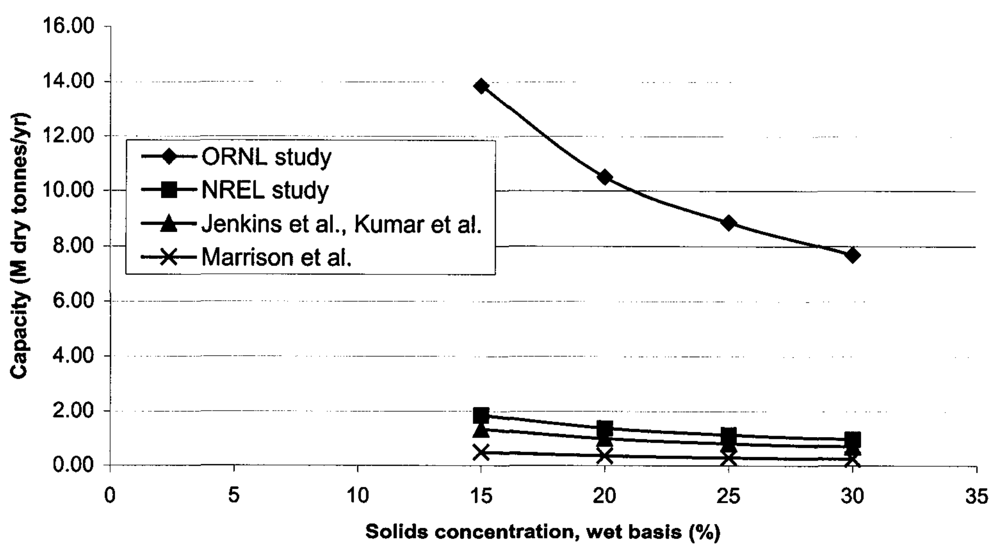

Figure 8.3A: Cost crossover above which one way pipelining has a lower distance variable cost than trucking (no credit for economies of scale in the fermentation plant).

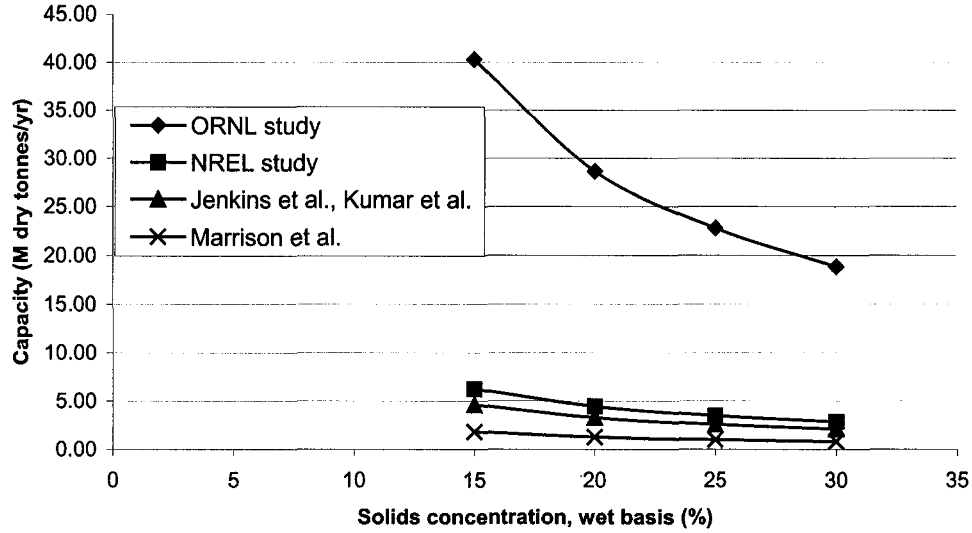

Figure 8.3B: Cost crossover above which two way pipelining has a lower distance variable cost than trucking (no credit for economies of scale in the fermentation plant).

These results make clear that an accurate estimate of trucking distance variable cost is critical to an assessment of the capacity of a biomass pipeline at which cost of transport is less than trucking. The high and mid range estimates of truck transport cost from Glassner et al. (1998), Jenkins et al. (2000) and Kumar et al. (2003) are close, and based on these estimates, one way pipelining of biomass at a scale of 1 to 2 M dry tonnes/year costs less than trucking. The ORNL study (Perlack and Turhollow, 2002) estimates a far lower truck variable transportation cost, and based on this estimate one way pipelines at 20% solids, for example, are more costly than truck transport at capacities below 10.5 M dry tonnes/year. The ORNL study is based on a theoretical analysis, with truck loadings that have not been implemented in any trial to date. However, a commitment to a long term biomass processing facility would no doubt stimulate the trucking industry to try to achieve lower costs. At the other extreme, Marrison and Larson's (1995) estimate of the distance variable cost of hauling switchgrass bales is significantly higher than trucking costs from actual current operations, but if their estimate proves to be realistic then pipelining is highly competitive with trucking even if two way pipelines are required. Accurate identification of distance variable truck costs for corn stover will be critical to any future assessment of transportation modes.

8.5 Simultaneous saccharification of corn stover in a pipeline

Saccharification or hydrolysis is the process of conversion of starch into sugars, normally in the presence of enzymes. Production of ethanol from corn stover uses saccharification of cellulose to glucose using the cellulase enzyme (Aden et al., 2002). In a conventional process of production of ethanol from corn stover, saccharification is carried out in a tank and glucose produced during saccharification is fermented to produce ethanol in a separate fermentation tank. More recently research is being done on simultaneous saccharification and fermentation (SSF) (see for example (Aden et al., 2002; Varga et al., 2003)).

Pipeline transport of biomass gives the potential to perform the saccharification step in the pipeline by simultaneous transportation and saccharification (STS). (Any required treatment before saccharification, such as acidification, would be conducted at the pipeline inlet facilities.) Note that there are two significant barriers to saccharification in the pipeline, including the need for an enzyme that does not require the low pH (between 4 and 5) currently required. The NREL design for ethanol fermentation (Aden et al., 2002) specifies stainless steel for the saccharification tank; a stainless steel pipeline would be prohibitively expensive both due to materials cost and difficulty of construction. In this study a preliminary cost estimate is developed based on an assumption that enzyme development will lead to cellulases that can provide high yield at pH levels that enable carbon steel. If this does not occur, there is low potential for pipeline saccharification. A second issue is the need to maintain a sterile environment within the pipeline, since a warm sugar rich environment would promote rapid degradation if not sterile. One implication of this is that all pipeline commissioning and ongoing maintenance would have to include procedures that ensured a sterile pipeline, for example, flushing with sterilants such as hydrogen peroxide or bleach. Saccharification would reduce the viscosity of the biomass slurry over the length of the pipeline; this has not been factored into pumping power calculations in this study.

Contact time and temperature are critical factors in saccharification. For example, Varga et al. (2003) notes that a temperature drop from 50 to 40 °C increases the reaction time for saccharification from 24 to 72 hours. Work from NREL suggests a saccharification temperature of 65 °C at a contact time of 36 hr (Aden et al., 2002). In a corn stover slurry pipeline velocity would be about 1.5 m/s or 5.4 km/hr; distances of 200 to 400 km correspond to residence times of 36 to 72 hr, typically required for adequate saccharification. Temperature is more critical for two reasons:

- A significant cost impact arises if the slurry is heated from ambient temperature to a net 40 to 65 °C in the pipeline. Note that in the NREL process (Aden et al., 2002) corn stover is heated to above 150 °C and then cooled. Typical fermentation plants that include product distillation are highly heat integrated, and a portion of heating is done with waste heat from the process. In the case of pipeline delivery of corn stover, unless waste heat is available near the pipeline inlet (say from a gas pipeline compression station or a thermal electric power plant), the fuel cost for heating the slurry would be significant. The study estimates that the fuel cost for heating slurry water by 40 °C using natural gas at $5/GJ would cost more than 5 cents/liter of produced ethanol even at maximum theoretical yield of ethanol. This cost impact assumes that heating above this temperature could be achieved by feed/effluent exchange.
- Elevated temperatures might require insulated pipelines, depending on pipeline size and soil type. For larger capacity pipelines in typical clay prairie soils, this is not the case. The estimated temperature drop over 400 km in a 1.26 m buried pipeline carrying 2 M dry tonnes/yr of corn stover through clay soil with a thermal conductivity of 0.85 W/m/K is about 5 °C for a slurry inlet temperature of 50 °C and a soil temperature of 10 °C (Stewart, 2003). However, smaller capacity pipelines buried in soils with higher thermal

conductivity might require insulation to sustain temperature, adding cost to the pipeline. The study estimates that insulating a 1.09 m pipeline carrying 1.5 M dry tonnes/yr with 1 inch of foam insulation would increase the installed cost of the pipeline by 15%, and would increase the distance variable cost of pipeline transport of corn stover by 10%.

Whether insulation is required in a specific pipeline would require more detailed modeling of both the reaction kinetics and the heat loss from the specific pipeline geometry and routing.

Three approaches could aid in reducing the cost of saccharification in pipelines:

- Co-location of a biomass pipeline inlet with a source of low quality heat, such as a power plant. Using once through untreated cooling water from a power plant as a source of pipeline slurry water would eliminate the cost of raising the temperature of the slurry and save investment in cooling facilities at the power plant.
- The development of enzymes that are active at typical pipeline temperatures of 0 to 25 °C. This is not a trivial problem, and there is no indication today that this goal is achievable.
- Higher enzyme loading. Note, however, that enzymes are a significant cost factor; an NREL study estimates that even after significant development the cellulase cost will be about 10% of the total cost of ethanol (Aden et al., 2002); hence increased enzyme loading will be very expensive.

In STS of corn stover, since saccharification takes place in the pipeline a separate saccharification tank, agitator and other related accessories in the plant are not required. This results in a capital savings in the plant; this savings is scale dependent. Figure 9.4 shows the calculated credit for eliminating saccharification equipment from the fermentation plant, drawing on the work of Aden et al. (2002) of NREL.

8.6 Discussion

The incentive for pipelining of corn stover is that it enables the development of a much larger biomass refinery for the production of ethanol fuels. In the absence of pipelining of corn stover, plant size will likely be limited to 1 to 2 M dry tonnes/yr due to truck congestion; it is hard to imagine community acceptance of a plant that required more than 15 truck deliveries/hour. NREL (Aden et al., 2002) base their detailed cost estimates on 0.7 M dry tonnes/yr. At this capacity, much of the equipment in the ethanol facility is significantly below optimum size. A typical modern oil refinery has a liquid product capacity of more than 25 GL/yr, more than 50 times the fuel output from an ethanol plant processing 1 M dry tonnes/yr of corn stover. Wallace et al. (2003) noted in particular the cost penalty of burning lignin to produce power and heat at this small-scale, but similar diseconomies would occur in other processing steps such as distillation.

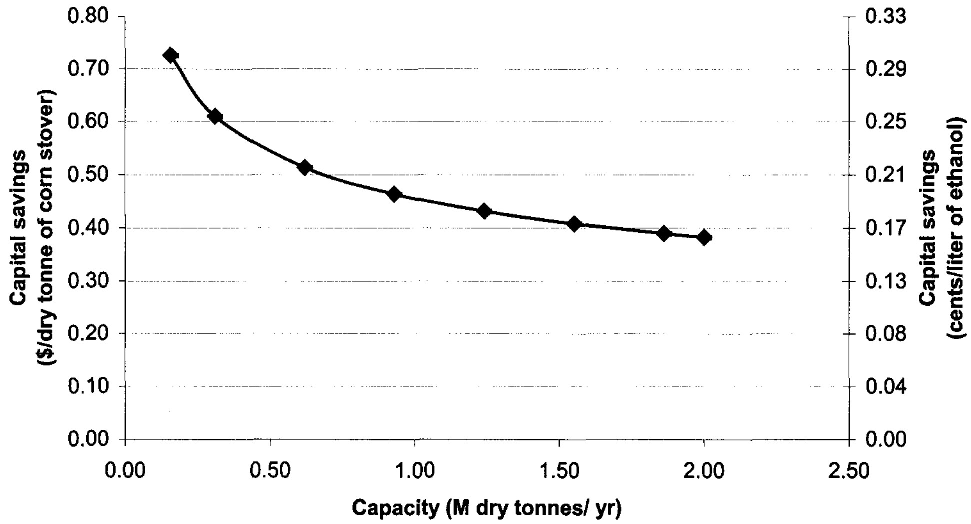

Figure 8.4: Capital credit from eliminating the saccharification step from an ethanol processing plant due to simultaneous transportation and saccharification (STS) of corn stover.

Pipelining of biomass to an ethanol refinery would overcome the feedstock delivery issues associated with a much larger facility. For example, one could locate 10 or more local corn stover receiving facilities with a capacity of 1 to 2 M dry tonnes/yr throughout a corn growing region, and use a one way pipeline from each of these facilities to a central ethanol refinery. The corn stover slurry could enter the ethanol processing facility directly, i.e., no adjustment would be required in solids water ratio at the plant. At a scale of 10 to 40 M dry tonnes/yr, ethanol fermentation and distillation and lignin processing economics would be substantially enhanced, and the recovery of significant quantities of higher value byproducts could also be considered. Produced ethanol could also be transported by a liquid pipeline of economic scale to non-corn growing regions for addition to the gasoline pool.

One critical issue in evaluating the economics of pipeline vs. truck delivery of biomass is an accurate value for the cost of truck transport. As noted above, there is a very wide range of estimates of truck delivery of corn stover. If current costs, as reflected in the studies by Glassner et al. (1998), Jenkins et al. (2000), and Kumar et al. (2003) are realistic, then pipelining is directly cost competitive with trucking at reasonable scales even without consideration of the improved economic efficiency of the fermentation plant. If the cost forecast of Perlack and Turhollow (2002) of ORNL is achievable, then pipelining of corn stover cannot directly compete with trucking at reasonable scales, although full cycle analysis of the cost of the transport and processing might still confirm that pipelining is in aggregate more economic than trucking due to economies of scale achieved in the fermentation plant. The distance variable cost estimated by Marrison and Larson (1995) seems very high in comparison to actual current costs for trucking baled agricultural residues.

Two way transport of biomass by pipelines that return carrier fluid to the inlet of the pipeline is significantly less economic than one way transport. Only if the cost estimates of Marrison and Larson (1995) are realistic would two way pipelining be cost competitive against trucking at scales compatible with field receipt of truck delivered biomass.

The location requirement for a pipeline inlet is access to significant amounts of water to slurry the corn stover; the water requirement per dry tonne of corn stover is 24 m^3. As noted above, if simultaneous transport and saccharification is contemplated, an ideal location would have access to warm water or a source of low quality waste heat; in addition there is a major technical challenge of identifying a cellulase that has high activity at a pH that is compatible with carbon steel. The location requirement for a large-scale ethanol processing plant is the same as for smaller plants: a watercourse to accept discharged treated water. In many jurisdictions, transfer of water from one watershed to another is problematic, hence an ideal configuration would draw and discharge water in the same major drainage basin.

This work has applied a friction factor calculation derived for wood chips to corn stover, since experimental data for corn stover slurries is not available. This study tests the sensitivity of this assumption in the range of friction factors that are 50% lower to 100% higher than calculated using the model of Hunt (1976). In this range, the distance variable cost of pipelining corn stover in a one way pipeline is 16% lower to 31% higher. This sensitivity does not invalidate the conclusions of this study, but precise determination of the friction factor of corn stover slurry would be a valuable contribution to the future evaluation of pipelining of corn stover.

Pipelining of fossil fuels is commonly practiced at scales far smaller than those identified as cost competitive in this study. Reasons for the difference include a higher friction factor for pipelining slurries and a far lower energy density for slurried biomass. Crude oil, for example, has an energy density of 35.65 GJ/m^3, while a 20% slurry of wet corn stover has an energy density of 0.732 GJ/m^3 (HHV basis), about 2% that of oil.

8.7 Conclusions

The study concludes that:

- Traffic congestion is a factor limiting the size of ethanol plants processing corn stover delivered by truck. A plant processing 2 M dry tonnes/yr would require a truck delivery every four to eight minutes; capacities larger than this are likely above community acceptance levels.
- The capacity at which pipelining biomass costs less than trucking depends on slurry concentration and on the cost of trucking of corn stover. There is a very wide variation of reported and forecast trucking costs for corn stover.
- One way pipeline transportation of corn stover at 20% solids loading costs less than trucking at a capacity of 1.4 M dry tonnes/yr when compared to a mid range of variable trucking cost of $0.1167 /dry tonne/km. Note that savings in the ethanol processing plant due to economies of scale are not factored into this calculation.
- Two way pipeline transportation costs less than trucking only at higher capacities and higher solids concentration. At 20% solids concentration, it is economical (again, without consideration of potential savings in the ethanol fermentation plant) only at capacities greater than 4.4 M dry tonnes/year when compared to a mid range of variable trucking cost of $0.1167 /dry tonne/km.

As noted, this capacity is likely larger than the ability of a single receiving facility to accept corn stover delivered by truck from the field.

- Pipelines could be used as a reactor for carrying out simultaneous transport and saccharification (STS) if cellulases with high activity at a pH compatible with carbon steel can be identified. At 2 M dry tonnes/year capacity, STS result in a capital credit of 38 cents per dry tonne of corn stover or 0.2 cents/liter of ethanol due to reduced costs in the ethanol plant.
- One key issue with STS is the need to maintain elevated temperature in the slurry during pipelining. Heating of the slurry, which in a normal ethanol plant occurs from waste heat, by 40 °C by firing natural gas would cost more than 5 cents/liter of produced ethanol. One alternative is to locate a pipeline inlet near a source of low quality waste heat; the use of once through cooling water from a power plant, for example, would be an ideal slurry medium for corn stover. Insulation is not likely required for large diameter pipelines in typical clay soils of the prairies: a 1.26 m pipeline carrying 2 M dry tonnes/yr would experience a temperature drop about 5 °C over a distance of 400 km with a temperature drop (pipeline inlet to soil) of 40 °C. Smaller pipelines or soil of high thermal conductivity might require insulation of the pipeline. Adding insulation to a 1.09 m pipeline carrying 1.5 M dry tonnes/yr of corn stover would increase the installed cost of the pipeline by 15% and increase the cost of pipelining of corn stover by 10%.

- Transport of corn stover through multiple pipelines to a large ethanol plant offers the potential to overcome problems of economy of scale in the production of ethanol.

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Chapter 9

Large-scale Ethanol Fermentation Through Pipeline Delivery of Biomass

9.1 Overview

Biomass projects have unique economics relative to other energy projects: there is an optimum size of plant. This arises because there are competing cost drivers: increasing scale achieves improved capital efficiency through economies of scale, but also increases the average distance that biomass must be transported to the facility. Because transportation of biomass is a major component of overall delivered fuel cost, ultimately a size is reached where further increases are not economic (see, for example, Jenkins, 1997; Larson and Marrison (1997); Nguyen and Prince (1996); McIlveen-Wright et al., 2001; Kumar et al., 2003).

However, most biomass projects are built well below optimum size either because of biomass availability or transportation constraints. Field produced biomass (as opposed to mill residues) starts its trip to a processing facility on a truck, and usually highway truck transport is the selected mode for transport all the way from field to plant. Since truck carrying capacity is limited to 20 to 40 tonnes, economically sized biomass plants require a high frequency of delivery (Atchison and Hettenhaus, 2003; Kumar et al., 2004b). Community resistance and/or road congestion can hence become a limiting factor before the economic optimum size of biomass processing plant is achieved. For example, Kumar et al. (2003)

calculated that the optimum size of a power plant processing wood chips from harvesting the whole forest is 900 MW. This size of plant would require 4.3 M dry tonnes per year of fuel, or one 36 tonne chip van delivery every 4 minutes. It is difficult to imagine a community or a local road system that could accept this traffic density. For similar reasons, much of the analysis of ethanol fermentation from corn stover completed by the United States National Renewable Energy Laboratory (NREL) in Colorado has focused on ethanol processing plants that are very small compared to a typical oil refinery. Many NREL studies have used a base case feed rate of 0.73 M dry tonnes per year (2000 dry tonnes per day) because of transportation constraints (see, for example, Aden et al., 2002; Wooley et al., 1999).

A slurry pipeline is an alternative means of delivering biomass to processing plants. Kumar et al. (2004a) evaluated pipeline delivery of wood chips to a power plant. Transportation costs are lower for one way pipeline (without carrier fluid return) than truck at delivery rates above 0.5 M dry tonnes per year. However, absorption of water reduces the lower heating value (LHV) of the wood chips, which is the available energy in a combustion process, by more than 40%, which more than offsets the reduction in transportation cost.

Uptake of carrier fluid by biomass is not an issue in processes such as fermentation that are water based. In a subsequent study Kumar et al. (2004b) showed that transport of corn stover to an ethanol fermentation plant had a lower transportation cost than truck at delivery rates in excess of 0.75 M dry tonnes per year. They noted that multiple pipelines delivering to a larger ethanol processing facility could also potentially gain from economies of scale in the processing plant as well. In addition to economy of scale, the ability to convert byproducts such as lignin into useful products (power or chemicals) would also be enhanced by a larger scale plant. For example, Wallace et al. (2003) notes combustion of lignin in small-scale ethanol plants as a particular source of diseconomy.

The purpose of this chapter is to screen two alternatives for processing of biomass to ethanol. The first is processing of truck delivered corn stover or wood chips in smaller processing plants, with a capacity of 2 M dry tonnes per year. The second is truck delivery of biomass to pipeline inlets, each with a capacity of 2 M dry tonnes per year, which then transport the biomass as a water slurry to a central large ethanol processing plant. Total transport distance for biomass in the second alternative is higher; the key question is whether higher economy of scale in the fermentation plant more than offsets the higher transportation cost. Note that 2 M dry tonnes of biomass per year equates to one truck delivery every 5 to 10 minutes, and in this study it is assumed as a limit of community acceptance. This assumption is arbitrary; in specific cases limits might be higher if a delivery site is adjacent to a major highway, and lower if the site is near or requires transport through a community.

This study draws on previous design work by NREL of an ethanol plant processing 0.73 M dry tonnes per year of corn stover (Aden et al., 2002), and on two previous studies of pipelining biomass (Kumar et al., 2004a and 2004b). The NREL study includes a specific analysis of scale factors by equipment type, which allows an assessment of the impact of scale for portions of the ethanol plant. This screening study assumes identical investment in the fermentation plant for both corn stover and wood chips; future study could be based on a more detailed assessment of wood chip fermentation capital costs. Note that all cost figures in this study, even when cited from literature, have been adjusted for inflation to a common year 2000 US dollar basis. Costs include a capital recovery factor based on a return of 10%.

9.2 Optimum size for truck delivery of corn stover and wood chips to a fermentation plant in the absence of constraints

Table 9.1 shows the range of the distance variable cost (DVC) component of truck transport of biomass reported in the literature, in dollars per dry tonne per km. Estimates of the truck DVC of low density biomass such as straw and corn stover vary widely. The low value of 5.3 cents is from a United States Oak Ridge National Laboratory (ORNL) theoretical study (Perlack and Turhollow, 2002). The high value of 19.8 cents is from a study by Marrison and Larson (1995). Values by Jenkins et al. (2000), Kumar et al. (2003), and a study by NREL (Aden et al., 2002) are each based on an analysis of actual transportation costs. For wood chips, rates depend on length of contract. The wide range in estimates of DVC for trucking is discussed in more depth in Kumar et al. (2004b)

Correct estimation of DVC is critical to any analysis not only of pipeline vs. truck transport but also of optimum biomass plant size, since the critical increasing cost element that has an impact on optimum size is only the distance variable component of transportation cost. In the balance of this work a DVC of 12.75 cents per dry tonne per km for corn stover, which is a blended average of the actual transportation costs for baled agricultural residues cited by Jenkins et al. (2000), Kumar et al. (2003), and the NREL study (Aden et al., 2002) has been used. The distance fixed cost (DFC) for truck transport of corn stover is estimated at $5.32 per dry tonne (Kumar et al., 2004b). Comparable figures for wood chips are a DVC of 11.14 cents per dry tonne per km and a DFC of $4.98 per dry tonne. Note that all fixed costs of biomass, including acquisition or harvesting cost, do not affect the calculation of the optimum size of processing plant (Cameron et al., 2004).

Figure 9.1 shows the estimated cost of production of ethanol from corn stover and wood chips in a fermentation plant supplied by highway trucks. Ethanol yield per dry tonne of biomass is drawn from Aden et al. (2002) for corn stover, and Wooley et al. (1999) for woodchips. Note that the dashed portions of the curves are not practically achievable due to assumed transportation constraints of community acceptance and road congestion, as discussed above. Hence, the theoretical minimum cost of 23.3 cents per liter of ethanol from truck delivered wood chips is not attainable; the cost at 0.73 and 2.0 M dry tonnes of corn stover per year is 29.7 and 27.3 cents per liter, respectively, and for wood chips is 31.1 and 26.6. Note that even if traffic congestion constraint were not a limiting factor, the optimum size of ethanol plant for corn stover would still be about 2 M dry tonnes per year, because the low biomass yield per gross hectare is low and transportation costs that are rising with increasing plant size overwhelm capital savings. Appendix C gives the cost details of ethanol production.

Table 9.1: Distance variable cost of transportation of biomass

Biomass	Distance Variable Cost ($/dry tonne/km)
Straw (Jenkins et al., 2000)	0.1348
Straw (Kumar et al., 2003)	0.1309
Wood chips – long term supply (Kumar et al., 2004a)	0.1114
Wood chips – short term supply (Kumar et al., 2004a)	0.1524
Corn stover (Aden et al, 2002; Glassner et al., 1998)	0.1167
Corn stover (Jose and Brown, 2001)	0.1045
Corn stover (Perlack and Turhollow, 2002)	
• Round bales	0.0527
• Rectangular bales	0.0596
Switch grass (Marrison and Larson, 1995)	0.1984

9.3 Pipelining of biomass

Figures 9.2A and 9.2B show the cost of one way pipelining (no return of carrier fluid) of corn stover and wood chips as a function of the capacity of the pipeline. See Kumar et al. (2004a) for details of the cost estimates for pipelining. Note that the concentrations of biomass in water in Figures 2A & 2B are based on water saturated material. Stalk material such as corn stover or straw absorbs water quickly and achieves a moisture level of 80% (Hettenhaus, 2003; Jenkins et al., 1996 and Kumar et al., 2004a), so a 50% slurry of wet corn stover would be 10% dry matter and 90% water. Uptake of water by wood chips is slower, but would reach a level of about 65% water within the typical residence time for pipeline transport (Kumar et al., 2004a). A pipeline inlet processing biomass delivered by trucks into a water based slurry would face the same congestion constraint as an ethanol processing plant, so in Figures 2A & 2B the pipeline is limited to a maximum capacity of 2 M dry tonnes per year.

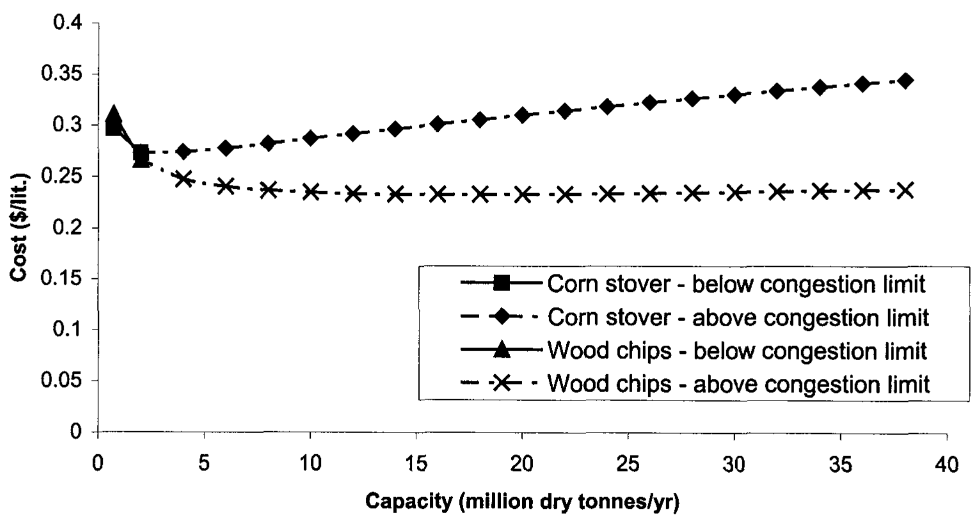

Figure 9.1: Cost of ethanol from a fermentation plant supplied by truck delivery.

Figures 9.2A and 9.2B also show the variable cost of truck transportation of biomass for comparison. Since the biomass is already on a truck when it arrives at the pipeline inlet, the fixed costs of truck transportation, associated with loading and unloading of the truck, have already been incurred. In comparing pipeline transportation costs to truck transportation cost, the critical question is whether the cost of pipelining is less than the incremental (distance variable) cost of further truck transport.

Figure 9.2A and 9.2B illustrate why an accurate assessment of DVC for truck transport of biomass is so critical. If the value of DVC for trucking from the ORNL study is realistic, then pipelining of corn stover will never be economic at any practical scale. If, on the other hand, the values of Jenkins et al. (2000), Kumar et al. (2004a), and the NREL study (Aden et al., 2002) are realistic, then pipelining can compete with incremental trucking at capacities above 0.5 and 0.75 M dry tonnes per year for wood chips and corn stover, respectively. If the values of Marrison and Larson (1995) are realistic, then pipelining is competitive even at very small capacities.

9.4 Configuration of an ethanol fermentation plant supplied by pipeline

Figure 9.3 illustrates a configuration used for comparing the cost of ethanol from smaller plants supplied by trucks vs. a larger plant using 38 M dry tonnes per year of biomass supplied by a combination of truck plus pipeline. Key transportation distances are contained in Table 9.2. (Truck hauling from the interstitial areas has been ignored in this screening study.) Note that in the innermost circle biomass would be supplied by truck only to the processing plant, whereas in each other circle biomass is delivered by truck to a pipeline inlet. Circle diameter is a function of gross biomass density, i.e. biomass yield per total hectare, and hence is different for wood chips, for which this study assumes a boreal forest density (Kumar et al., 2003) and corn stover, for which the study uses data from ORNL (Perlack and Turhollow, 2002). Also note that for an annual crop such as corn, the stover is harvested from the entire area each year, while for a multi-year crop such as trees only $1/20^{th}$ of the area is harvested each year, based on an assumed fermentation plant life of 20 years. One can use the distance data in Table 9.2 to estimate the transportation cost for any plant size between 2 and 38 dry tonnes per year of biomass feed. Seven, 13 and 19 circle configurations will have a "close packed" configuration relative to other plant sizes.

Note that a 38 M dry tonne per year ethanol plant would produce at theoretical maximum yield about 300,000 barrels per day (18 billion liters per year) of ethanol. This scale is comparable to the production of transportation fuel from modern large-scale oil refineries. The scale of solids handling would be large in comparison to power generation (a 3 GW coal fired power plant processes 10 to 15 M tonnes per year of coal), but small in comparison to other energy projects (an oil sands plants in Canada producing 250,000 barrels per day of synthetic crude oil processes about 180 M tonnes per year of bituminous sands).

Two cases were evaluated for treatment at the pipeline inlet. In the low treatment case, biomass is shredded (stover only), washed (to remove rock) and passed over a magnetic separator to remove iron, then slurried and pipelined at low temperature to the central ethanol plant. In the high treatment case, biomass is treated as above, then pretreated with sulfuric acid and neutralized, after which enzymes are added to enable saccharification to take place in the pipeline. This processing sequence is drawn from an NREL design case (Aden et al., 2002); note, however, that this case assumes the development of cellulases that have high activity at a pH compatible with a carbon steel pipeline, as discussed in Section 8.5.

Early analysis indicated that the low treatment case was more economic than the high treatment case. In the high treatment case, the cost penalty from many small pretreatment facilities, i.e. one per pipeline inlet, is greater than the benefit realized from saccharification in the pipeline. This is the case even if it has been assumed that saccharification proceeded to completion within the pipeline, which would eliminate the need for a saccharification tank for all pipelined biomass. In addition, today's enzymatic processes to break down cellulose into glucose require elevated temperature, around 50 °C. The cost of heating the slurry going into the pipeline would be prohibitive unless waste heat were available at the pipeline inlet, for example, from a power plant (Kumar et al., 2004b); note that in an ethanol plant low quality steam and hot water from the distillation process are available to heat the biomass slurry. Higher activity enzymes that could catalyze cellulose saccharification at temperatures near 0 to 20 °C would also eliminate the need for heating of the slurry.

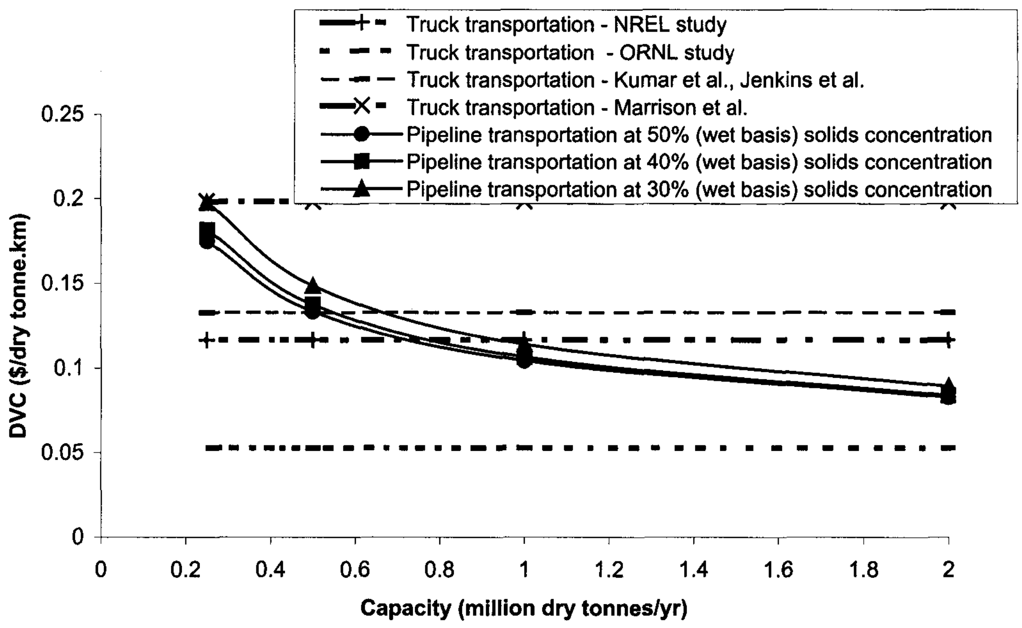

Figure 9.2A: Distance variable cost (DVC) of transporting corn stover by pipeline.

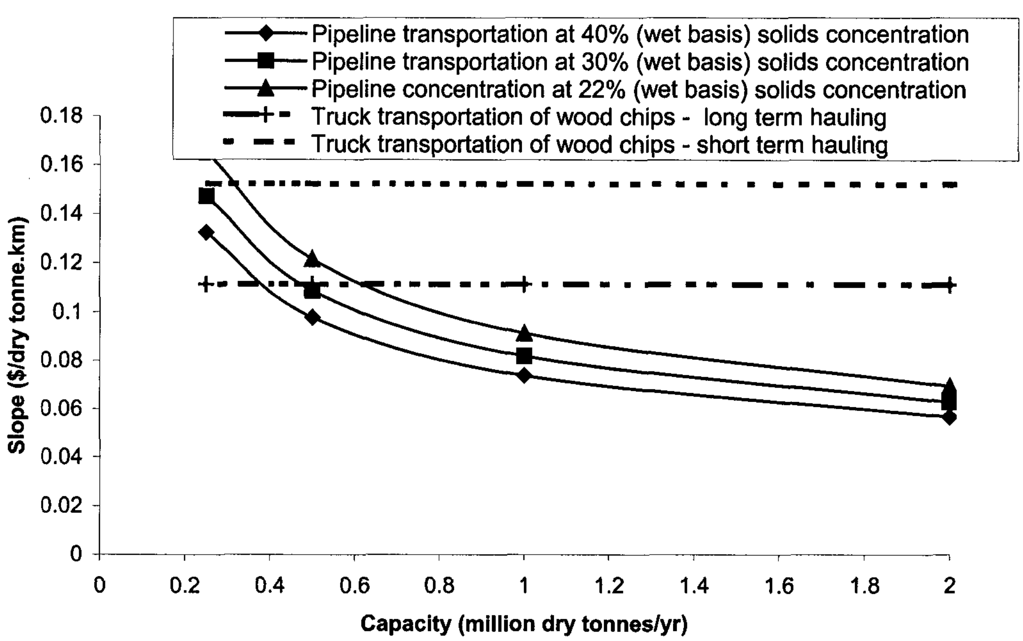

Figure 9.2B: Distance variable cost (DVC) of transporting wood chips by pipeline.

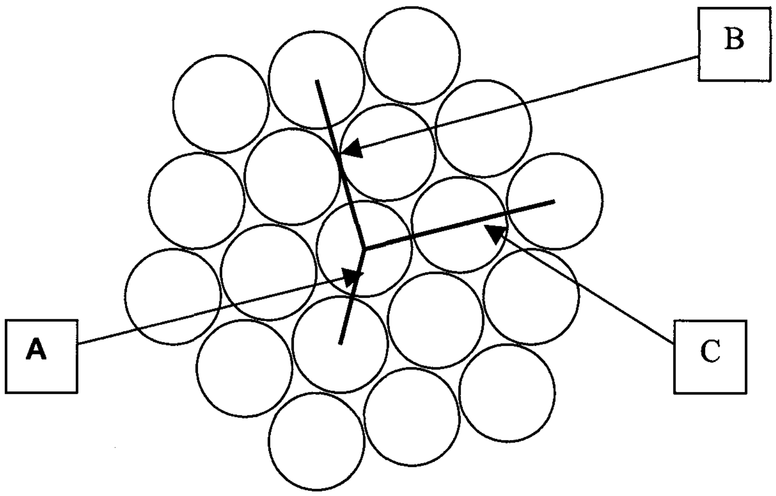

Figure 9.3: Sample configuration for 19 truck based ethanol plants vs. one larger facility supplied by truck plus 18 pipelines.

Table 9.2: Biomass yield and truck and pipeline distances for corn stover and wood chips

	Corn Stover	**Wood Chips**
Available biomass gross yield (dry tonne/ha)[a]	2.47[b]	84[c]
Radius of circle containing 2 M dry tonne/yr biomass (km)	146	39
Average truck haul length per circle (km)	103	28
• A – pipeline length (km)	292	78
• Residence time in pipeline A (hr)[d]	54	15
• B – pipeline length (km)	506	135
• Residence time in pipeline B (hr)[d]	94	25
• C – pipeline length (km)	584	156
• Residence time in pipeline C (hr)[d]	108	29

a – Biomass yield per gross hectare including allowance for roads, communities, and other non-biomass land use.
b – Perlack and Turhollow, 2002.
c – Kumar et al., 2003.
d – Pipeline slurry velocity is 1.5 m/s (Kumar et al., 2004a and 2004b).

9.5 Cost of ethanol from large-scale fermentation

Figure 9.4A and 9.4B compare the calculated cost of ethanol from a large-scale fermentation plant supplied by a combination of truck and pipeline over the range of 4 to 38 M dry tonnes per year of biomass to the cost from a truck supplied plant in the range of 0.73 to 2 M dry tonnes per year. Deflections at 14 and 26 M dry tonnes per year arise from the "close packing" effect. For corn stover, all plant sizes larger than 2 M dry tonnes per year supplied by a combination of truck plus pipeline are less economic than the cost of ethanol from truck delivered plants alone. For wood chips, the cost savings from economy of scale in the processing plant more than offset the rising cost of transportation at a scale of 4 to 38 M dry tonnes per year, although the net reduction in ethanol cost with increasing scale is slight above 14 M dry tonnes per year. Appendix C gives the low treatment and high treatment cost of ethanol production at different capacities.

Pipelining of wood chips benefits from two cost factors compared to corn stover: pipeline lengths are shorter due to a higher biomass density (yield of biomass per gross hectare), and the pipeline is a smaller diameter (and pumping costs are lower) because the concentration of biomass in the pipeline is higher. The study assumes a corn stover concentration of 10% dry matter, which is equivalent to 50% free water since the stover itself reaches a water content of 80%. For wood chips, the concentration is 13% dry matter (40% concentration of wood chips with a moisture content of 65% water). In order to assess the relative impact of these two factors, the author evaluated one case with a biomass yield of 50% of the base case and a second case with a pipeline concentration of 50% of the base case. The impact of a change in biomass yield on a change in ethanol cost is more than 5 times greater than the impact of a change in pipeline concentration. Pipeline length is a greater cost driver than pipeline diameter.

9.6 Discussion

Figure 9.4 suggests that for diffuse sources of biomass with low gross yield, such as corn stover, transportation cost overwhelms processing savings as scale increases. For corn stover, the most economic approach to the large-scale production of ethanol would appear to be numerous small plants, with perhaps the only economy of scale being the savings from repeated design and construction of similar facilities. One problem with numerous small processing facilities is that any secondary processing of byproducts would be difficult to conduct at small-scale; for instance, chemicals or even energy from lignin is more costly and less efficient in small-scale plants (Wallace et al., 2003).

For higher density sources of biomass, as illustrated by wood chips, this study indicates that process savings from larger plants more than offset transportation costs, although the incremental impact is relatively small above 14 M dry tonnes per year. At 14 M dry tonnes per year, the cost of ethanol is 22.8 cents per liter, compared to 26.6 cents per liter for a 2 M dry tonne per year plant supplied by truck only, a savings of 13%. If a value added use of a byproduct such as lignin emerges, then the economics would be even more favorable for a larger scale plant. It is hard to conceive of a significant processing of chemicals from biomass to arise in numerous distributed small plants, whereas aggregation of biomass in large plants could enable this.

Note, however, that large contiguous areas of high density biomass are rare in temperate zones, and occur primarily in the boreal and tropical forests. Unless large areas of arable land were planted to hybrid tree species, a lower biomass gross density would be more typical of temperate agricultural areas. Also note that in any forested area, energy use of biomass would have to compete with alternate uses of wood fiber for lumber and paper.

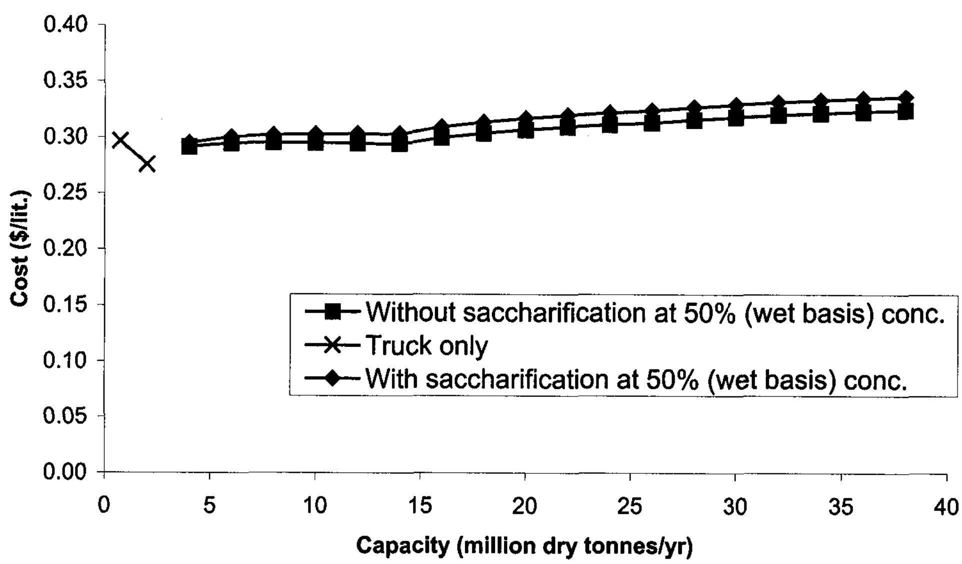

Figure 9.4A: Cost of ethanol from a fermentation plant supplied by truck only vs. pipeline plus truck.

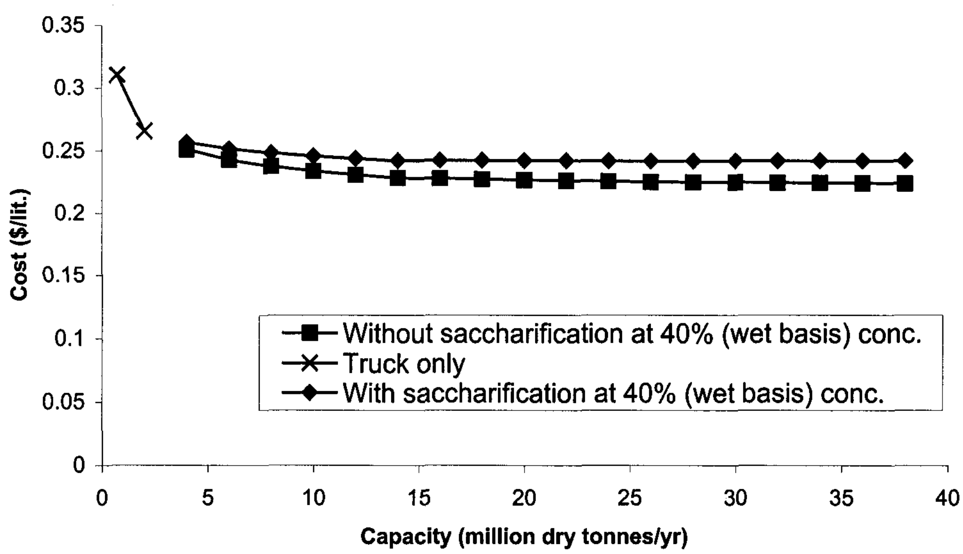

Figure 9.4B: Cost of ethanol from a wood chip fermentation plant supplied by truck only vs. pipeline plus truck.

A number of simplifying assumptions occur in this study that could be explored in more detail in further analysis. One simplifying assumption is that the plant capital and operating cost of fermenting ethanol from biomass does not significantly differ between wood chips and corn stover. If processing of wood chips to ethanol requires more capital than corn stover, then the benefit from larger plants will be even greater. A second simplifying assumption is that transport of biomass in cold water by pipeline without pretreatment does not result in a significant loss of sugar to the carrier fluid (since carrier fluid at the processing plant would be in excess of that needed for fermentation and would presumably be discharged). A third simplifying assumption was to model biomass source areas as simple circles, as shown in Figure 9.3. Note that the impact of scale on ethanol distribution has not been factored into this study; widespread use of ethanol as a transportation fuel will require a comprehensive distribution system between fermentation plant and fuel retail outlet. One critical issue in comparing pipeline based larger biomass fermentation plants to distributed smaller plants relying on truck delivery is an accurate identification of the distance variable cost of trucking. The literature contains a four fold range of this number, from 5 to nearly 20 cents per dry tonne km. Three studies for straw and stover based on actual current trucking costs report values near 12.75 cents, while a theoretical study from ORNL cites 5 cents. If the ORNL value is attainable, pipelining of biomass will never be economic.

In this and a previous study, the author has used experimental data from wood chip slurries to estimate viscosity and pressure drop in a corn stover pipeline. One critical element of any further study of pipeline delivery of corn stover is a more accurate assessment of viscosity. Keller et al. (2003) note that treatment of corn stover with phanerochaete results in a major reduction of viscosity. Garcia et al. (1998) notes that sugars in the carrier fluid reduce the viscosity of banana pulp. Hence future research may identify pretreatment options that can reduce the pumping cost for corn stover.

9.7 Conclusion

Truck delivery of biomass to multiple pipeline inlets that deliver biomass as a slurry to a central ethanol fermentation plant offers a means to achieve large plant size while avoiding excessive truck congestion.

For biomass types with a low gross yield per hectare, such as corn stover, the increase in transportation cost is larger than the savings in economy of scale of the fermentation plant. It is more economic to process corn stover in small distributed fermentation plants supplied by truck. In this case, the sole benefit of economy of scale is the benefit that arises from building numerous identical processing plants.

For biomass types with a higher gross yield per hectare, such as wood chips from the boreal forest, the increase in transportation cost is less than the savings in economy of scale of the fermentation plant and a reduction in the cost of ethanol of more than 10% can be achieved. In addition, a larger fermentation plant would increase the likelihood of processing of higher value products, such as chemicals from lignin.

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Chapter 10

Conclusions and Future Research

10.1 Conclusions

The power cost and optimum plant size for power plants using two biomass fuels in western Canada were determined. The two fuels are biomass from whole boreal forest, and forest harvest residues from existing lumber and pulp operations (limbs and tops). Forest harvest residues have the smallest economic size, 137 MW, and the highest power cost, \$63.00 /MWh (Year 2000 US \$). Whole forest harvesting has an optimum size of 900 MW (two maximum sized units), and a power cost of \$47.16 /MWh without nutrient replacement. However, power cost vs. size from whole forest is essentially flat from 450 MW (\$47.76 /MWh) to 3150 MW (\$48.86 /MWh), so the optimum size is better thought of as a wide range. None of these projects are economic today, but could become so with a greenhouse gas credit. Whole forest biomass case shows flatness in the profile of power cost vs. plant capacity. This occurs because the reduction in capital cost per unit capacity with increasing capacity is offset by increasing biomass transportation cost as the area from which biomass is drawn increases. This in turn means that smaller than optimum plants can be built with only a minor cost penalty. Both the yield of biomass per unit area and the location of the biomass have an impact on power cost and optimum size. Forest harvest residues is transported over existing road networks, whereas the whole forest harvest requires new roads and has a location remote from existing transmission lines.

Biomass integrated gasification combined cycle (BIGCC) is good for high cost fuel. In this study forest harvest residue has high delivered cost as compared to whole forest biomass. Hence, cost of power from BIGCC for forest harvest residues is 11.6% lower than power cost from direct combustion. In case of whole forest, the power cost increases by 4.8%. The reason is, in case of forest residues, the increase in capital cost is less dominant than the benefits from increased efficiency. BIGCC plants are still under demonstration stage and further research would help in decreasing the cost and increasing the efficiency. A decision to invest in large-scale BIGCC plant would depend on the cost of the fuel available at the site and the successful demonstration of the technology.

Biomass power in western Canada would need carbon credits to be competitive with fossil fuel based power. Direct combustion plants based on forest harvest residues and whole forest biomass would need carbon credits of \$36.20 per tonne of CO_2 and \$18.30 per tonne of CO_2 at a power cost of \$30 /MWh, respectively. BIGCC helps in reducing the carbon credit for forest harvest residues by 22.4% as compared to direct combustion. For whole forest biomass it increases the value of carbon credit by 13%.

Large-scale biomass processing facility cannot depend on truck delivery of fuel. At large plant size, truck transportation of biomass reaches a congestion limit. Pipeline transport of biomass could be an alternative to truck transport. The cost of transporting wood chips by truck and by pipeline as a water slurry is determined. In a practical application of field delivery of biomass by truck to a pipeline inlet, the pipeline will only be economical at large capacity (>0.5 M dry tonnes per year for a one way pipeline, and >1.25 M dry tonnes per year for a two way pipeline that returns the carrier fluid to the pipeline inlet), and at medium to long distances (>75 km (one way) and >470 km (two way) at a capacity of 2 M dry tonnes per year).

As part of a long-term study of pipeline transport of woodchips for bioenergy applications, the uptake of two fluids by hardwood and softwood chips from the boreal forest was determined. Water or oil would be the likely carrier fluids in pipelining woodchips for ultimate use as bioenergy (e.g., any of combustion, gasification, pyrolysis to form bio-oil, or fermentation to ethanol). Bio-oil is a potential future carrier, but there is insufficient data available today to develop an economic assessment. Uptake of water and a heavy gas oil by spruce and aspen and poplar woodchips has been measured as a function of immersion time. One unit (mass) of spruce wood chips with an initial moisture level of 53% (all percentages expressed as mass %) immersed in water for 48 hours absorbs an additional 0.52 units of water to reach a moisture level of 69%, initial water uptake is rapid, with a subsequent very slow increase with time; equilibrium does not appear to have been reached. One unit of spruce chips immersed in heavy gas oil for 48 hours absorbs 0.41 units of heavy gas oil to reach an oil content of 29%; uptake of oil is slower than water, and has not reached an equilibrium. Similar figures for aspen and poplar are an initial moisture level of 45%, an uptake of an additional 0.57 units of water to reach a moisture level of 65%, and an uptake of 0.51 units of oil to reach an oil content of 34%. For both oil and water, draining in excess of one hour does not reduce the measured uptake of water or oil. The moisture level in wood chips after immersion is not affected by the initial moisture level in the chip; lost water due to drying is quickly reabsorbed. Oil uptake is significantly higher in wood chips that have a lower initial moisture content. Mixed hardwood and softwood chips in western Canada rise in moisture level from about 50% to 67% when transported in water; the loss in LHV would preclude the use of water slurry pipelines for direct combustion applications. The same chips, when transported in a heavy gas oil, take up as much as 50% oil by weight and result in a fuel that is over 30% oil on mass basis and is about 2/3 oil on a thermal basis. Pipeline delivered biomass could be used in processes that do not produce contained water as a vapor, e.g., fermentation or supercritical water gasification.

Pipeline transport of corn stover delivered by truck from the field is evaluated against a range of truck transport costs. Corn stover transported by pipeline at 20% solids concentration or higher could directly enter an ethanol fermentation plant, and hence the investment in the pipeline inlet end processing facilities displaces comparable investment in the plant. At 20% solids, pipeline transport of corn stover costs less than trucking at capacities in excess of 1.4 M dry tonnes/yr when compared to a mid range of truck transport cost (excluding any credit for economies of scale achieved in the ethanol fermentation plant from larger scale due to multiple pipelines). Pipelining of corn stover gives the opportunity to conduct simultaneous transport and saccharification (STS) if cellulases can be developed that have high activity at a pH compatible with carbon steel; the pipeline would have to be maintained as a sterile environment to prevent degradation of produced sugars. Current enzyme activity levels would require heating of the slurry. Heating of the slurry for STS, which in a fermentation plant is achieved from waste heat, is a significant cost element (more than 5 cents/liter of ethanol) if done at the pipeline inlet unless waste heat is available, for example from an electric power plant located adjacent to the pipeline inlet. Heat loss in a 1.26 m pipeline carrying 2 M dry tonnes/yr is about 5 °C at a distance of 400 km in typical prairie clay soils, and would not likely require insulation; smaller pipelines or different soil conditions might require insulation for STS. Saccharification in the pipeline would reduce the need for investment in the fermentation plant, saving about 0.2 cents/liter of ethanol. Transport of corn stover in multiple pipelines offers the opportunity to develop a large ethanol fermentation plant, avoiding some of the diseconomies of scale that arise from smaller plants whose capacities are limited by issues of truck congestion.

Issues of traffic congestion and community acceptance limit the size of biomass processing plants based on truck delivery to about 2 M dry tonnes per year or less. In this study the cost of ethanol from a 2 M dry tonne per year ethanol fermentation plant supplied by truck is compared to larger plants in the range of 4 to 38 M dry tonnes per year supplied by a combination of trucks plus pipelines.

For corn stover, a biomass source with a low yield per gross hectare, the cost of ethanol from larger plants is always higher. For wood chips from the boreal forest, a biomass source with a relatively high yield per gross hectare, a plant processing 14 to 38 M dry tonnes per year produces ethanol at a 13% reduction compared to a 2 M dry tonne per year plant supplied by truck. Processing of value added products, such as chemicals from lignin, would be enabled by larger scale plants.

10.2 Overview of environmental issues

Biomass power cost and optimum size of the plant have been estimated based on current forestry practice. Current forestry practice is based on first cut and does not replace nutrients lost in the harvest. In the long-term nutrient replacement is necessary regardless of the end use of the forest biomass. The study estimates a nutrient replacement cost of $4.42 /MWh for nitrogen, phosphorus and potassium. Calcium has not been considered, as it is abundant in boreal forest soils in western Canada. Nutrient replacement increases the power cost. Ash produced during combustion could be used as fertilizer and would help in reducing the nutrient replacement cost.

Technically a single power plant with a 30 year life in a forest with an 80 to 100 year rotation is not sustainable; however, reservation of forest for two additional power plants to be built in the future will address this issue, since after the third power plant reaches its useful life the original forest plot would be again available for harvesting.

Life cycle analysis of carbon equivalent emissions from a forest biomass power plant is based on the assumption that carbon lost from the soil after harvesting of trees would be fully restored during the regrowth of the trees on 80 to 100 years rotation. If soil carbon is not fully restored in this time period, the GHG benefit from use of the forest for energy would be less than that estimated in this study.

Pipeline transport of biomass using water as a carrier fluid could result in discharge water quality issues associated with leaching of minerals and soluble organic compounds. The results in this study show that pipeline transport of biomass is not economic for combustion purposes. Pipeline transport of biomass is economic for aqueous process, i.e., for production of ethanol; however, in this case it is questionable whether leaching during pipelining creates any incremental impact compared to truck delivery of biomass, since leaching will occur in any event in the subsequent aqueous based process. When a one way pipeline is used for transportation of biomass, it has been assumed that water would be used in the process. Two way pipelines are not economic for transportation of corn stover for ethanol production, and are only economic for long distance transport of wood chips (breakeven distance is approximately 500 km). Hence, two way pipelining is unlikely to be commercially applied. However, any use of a two way pipeline for transportation of wood chips would require the removal of a bleed stream;

depending on leaching extent some water treatment other than ponding prior to release may be required. This cost factor has not be taken into account in this study. A further potential water quality issue from pipelining of biomass could arise from bacterial or fungal activity in the pipeline. The assumption in this study is that most places (for example - corn belt in US, boreal forest in western Canada etc.) would have water sources available for pipeline transport of biomass and plants would use one way pipeline transport of biomass.

10.3 Recommendations for future research

- Cost of direct combustion based biomass power plants needs further investigation. Today the estimated capital cost of biomass power plants is 40% higher than coal fired power plants. Tracking of actual cost of biomass power plants would help in reducing the uncertainty in cost of power from biomass and value of carbon credit required for biomass power to be competitive with fossil fuel based power.

- Maintenance cost of biomass power plants should also be further investigated to reduce the uncertainty in biopower cost. Reported maintenance costs from demonstration plants are very high compared to coal plants, which may be caused by their novelty. Tracking maintenance costs in larger plants over time will give a better estimate of reasonable figures.

- Advanced biomass conversion technology (e.g., BIGCC) has been studied extensively. Resolving the technical issues regarding hot gas cleaning of producer gas before it is used in a gas turbine will reduce the cost of utilization.

- A key assumption in this study is that soil carbon in harvested forests is restored as the forest reaches mature growth. This assumption can be confirmed over time for western Canada's boreal forest.

- Biomass processing plants suffer from high transportation cost. Truck transport of biomass is constrained by logistics and congestion. Alternative transport methods need to be developed. Pipeline transport gives an opportunity for large-scale transport of biomass without road congestion. In this study, pipeline transport cost of corn stover has been estimated based on the friction loss reported for a wood chip slurry. Measurement of the friction factor of a corn stover slurry should be done before deciding on any project on pipeline transport of corn stover. Note also that any economic comparison of trucking vs. pipeline transport of biomass requires an accurate assessment of trucking costs; literature values vary widely.

- The extent to which alkali halides and soluble organic compounds would leach from biomass during pipeline transport is unknown, and hence it is also unknown whether discharge water might be negatively affected. Prior to any commercial application of pipelining this aspect would need to be fully developed. In addition, the impact of potential degradation of biomass due to bacterial or fungal action will need to be assessed.

- Saccharification of biomass in a pipeline has high potential provided enzymes are developed which are active at lower temperature and pH compatible with a carbon steel pipeline. Enzyme development for carrying out saccharification in a pipeline is recommended.

- Large-scale ethanol production plant based on pipeline transport is economical for high density fuels like wood chips. Large-scale transport of biomass by rail should be studied in detail. Train transport is being used in some countries for biomass transportation. Economics of rail transport of biomass should be evaluated for western Canada.

- Biomass power is not economic in western Canada. Carbon credits would be required for it to be competitive with fossil fuel based power in Alberta. The prospect of biomass power raises some policy issues that will have an impact on the rate at which it develops. Because of the large capital investment required to build a power plant, security of fuel supply is a critical factor in developing any new power project. Biomass power, particularly a project that uses forest residues, raises important questions about how to secure a long term fuel supply, and government can, if it chooses to play a role. A study of the policy issues, which could make biomass power competitive, is recommended.

- Biomass could be used for the production of power, liquid fuels and specialty chemicals. A detailed techno-economic study to rank the different biomass utilization options should be carried for Canada.

- This study analyzes a hydrocarbon based carrier fluid for pipeline transport of wood chips and concluded that it would be impractical, as major portion of energy would come from fossil component. Bio-oil produced by fast pyrolysis of biomass is a potential carrier for solid biomass; better definition of a process for field production of bio-oil, and an understanding of bio-oil properties and their impact on pipeline materials, is required before such a case can be evaluated.

Appendix A

Table A1: Summary of discounted cash flow for wood chips based power plant in western Canada at an optimum size of 900 MW

Cost items ($'000)/Year	-2	-1	0	1	2	3	4
Capital cost	234065	409613	526646	0	0	0	0
Operating cost	0	0	0	4043.5	4124.4	4206.9	4291.0
Maintenance cost	0	0	0	35109.7	35811.9	36528.2	37258.7
Administration cost	0	0	0	1684.8	1718.5	1752.9	1787.9
Harvesting cost	0	0	0	39041.3	45511.0	48355.4	49322.5
Transportation cost	0	0	0	38291.4	44636.8	48375.1	49342.6
Roads and Infrastructure cost	0	0	0	30661.1	35041.3	37231.4	37976.0
Silviculture cost	0	0	0	8052.2	9386.6	9973.3	10172.7
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	0	0	0	14196.8	16549.4	17583.8	17935.5
Transmission charge	0	0	0	10671.7	10885.2	10885.2	11102.9
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	0	0	0	1713.6	1747.8	1782.8	1818.4
Total cost	234065	409613	526646	183466.2	205412.9	216674.8	221008.3
PV of total cost at 10%	283218.4	450574.7	526645.8	166787.4	169762.8	162791.0	150951.7
MWh sold	0	0	0	5353235.6	6117983.6	6500357.5	6500357.5
Price required for 10% return				50.04	51.04	52.06	53.11
Revenue required for 10% return				267896.5	312290.8	338445.1	345214.0
PV of revenue at 10%				243542.29	258091.6	254278.8	235785.8

Table A1 cont'd

Cost items ($'000)/Year	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Capital cost	0	0	0	0	0	0	0
Operating cost	4376.8	4464.4	4553.7	4644.7	4737.6	4832.4	4929.0
Maintenance cost	38003.9	38764.0	39539.2	40330.0	41136.6	41959.8	42798.6
Administration cost	1823.7	1860.2	1897.4	1935.3	1974.0	2013.5	2053.8
Harvesting cost	50309.0	51315.2	52341.5	53388.3	54456.0	55545.2	56656.1
Transportation cost	50329.5	51336.1	52362.8	53410.1	54478.3	55567.8	56679.2
Roads and Infrastructure cost	38735.5	39510.2	40300.4	41106.5	41928.6	42767.2	43622.5
Silviculture cost	10376.2	10583.7	10795.4	11011.3	11231.5	11456.2	11685.3
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	18294.2	18660.1	19033.3	19413.9	19802.2	20198.2	20602.2
Transmission charge	11324.9	11551.4	11782.4	12018.1	12258.5	12503.6	12753.7
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	1854.8	1891.9	1929.7	1968.3	2007.7	2047.5	2088.8
Total cost	225428.5	229937.1	234535.8	239226.5	244011.1	248891.3	253869.1
PV of total cost at 10%	139973.4	129793.5	120354.0	111600.9	103484.5	95958.4	88979.6
MWh sold	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5
Price required for 10% return	54.17	55.25	56.36	57.48	58.63	59.81	61.00
Revenue required for 10% return	352118.3	359160.7	366343.9	373670.8	381144.2	388767.1	396542.4
PV of revenue at 10%	218637.8	202736.8	187992.3	174320.2	161642.3	149886.5	138985.7

Table A1 cont'd

Cost items ($'000)/Year	12	13	14	15	16	17	18
Capital cost	0	0	0	0	0	0	0
Operating cost	5027.6	5128.2	5230.7	5335.3	5442.0	5550.9	5661.9
Maintenance cost	43654.5	44527.6	45418.2	46326.5	47253.1	48198.1	49162.1
Administration cost	2094.8	2136.7	2179.5	2223.1	2267.5	2312.9	2359.1
Harvesting cost	57789.2	58945.0	60123.9	61326.4	62552.9	63803.9	65080.0
Transportation cost	57812.6	58969.0	60148.4	61351.4	62578.4	63830.0	65106.6
Roads and Infrastructure cost	44494.9	45384.8	46292.5	47218.4	48162.8	49126.0	50108.5
Silviculture cost	11919.0	12157.4	12400.5	12648.5	12901.5	13159.5	13422.7
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	21014.3	21434.5	21863.2	22300.5	22746.5	23201.4	23665.5
Transmission charge	13008.8	13268.9	13534.3	13805.0	14081.1	14362.7	14650.0
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	2130.6	2173.2	2216.7	2261.0	2306.2	2352.3	2399.4
Total cost	258946.5	264125.4	269407.9	274796.1	280292.0	285897.9	291615.8
PV of total cost at 10%	82508.3	76507.7	70943.5	65784.0	60999.7	56563.4	52449.7
MWh sold	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5
Price required for 10% return	62.22	63.47	64.74	66.03	67.35	68.70	70.07
Revenue required for 10% return	404473.3	412562.7	420814	429230.3	437814.9	446571.2	455502.6
PV of revenue at 10%	128877.6	119504.7	110813.5	102754.3	95281.3	88351.7	81926.1

Table A1 cont'd

Cost items ($'000)/Year	19	20	21	22	23	24	25
Capital cost	0	0	0	0	0	0	0
Operating cost	5775.1	5890.6	6008.5	6128.6	6251.2	6376.2	6503.7
Maintenance cost	50145.3	51148.2	52171.2	53214.6	54278.9	55364.5	56471.8
Administration cost	2406.3	2454.4	2503.5	2553.6	2604.7	2656.8	2709.9
Harvesting cost	66381.6	67709.3	69063.4	70444.7	71853.6	73290.7	74756.5
Transportation cost	66408.7	67736.9	69091.6	70473.5	71882.9	73320.6	74787.0
Roads and Infrastructure cost	51110.7	52132.9	53175.6	54239.1	55323.9	56430.4	57559.0
Silviculture cost	13691.2	13965.0	14244.3	14529.2	14819.8	15116.2	15418.5
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	24138.8	24621.5	25114.0	25616.3	26128.6	26651.2	27184.2
Transmission charge	14943.0	15241.9	15546.7	15857.6	16174.8	16498.3	16828.2
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	2447.4	2496.3	2546.2	2597.2	2649.1	2702.1	2756.1
Total cost	297448.1	303397.1	309465.0	315654.3	321967.4	328406.8	334974.9
PV of total cost at 10%	48635.1	45098.0	41818.2	38776.9	35956.7	33341.7	30916.8
MWh sold	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5
Price required for 10% return	71.47	72.90	74.36	75.85	77.37	78.91	80.49
Revenue required for 10% return	464612.7	473904.9	483383.0	493050.7	502911.7	512969.9	523229.3
PV of revenue at 10%	75967.9	70442.9	65319.8	60569.3	56164.2	52079.6	48291.9

Table A1 cont'd

Cost items ($'000)/Year	26	27	28	29	30
Capital cost	0	0	0	0	0
Operating cost	6633.6	6766.5	6901.8	7039.9	7180.7
Maintenance cost	57601.2	58753.2	59928.3	61126.9	62349.4
Administration cost	2764.1	2819.4	2875.8	2933.3	2991.9
Harvesting cost	76251.6	77776.6	79332.2	80918.8	82537.2
Transportation cost	76282.7	77808.4	79364.6	80951.8	82570.9
Roads and Infrastructure cost	58710.1	59884.3	61082.0	62303.7	63549.7
Silviculture cost	15726.8	16041.4	16362.2	16689.5	17023.2
Nutrient replacement cost	0	0	0	0	0
Premium to fuel owner	27727.9	28282.4	28848.1	29425.0	30013.5
Transmission charge	17164.8	17508.1	17858.3	18215.4	18579.7
Site recovery and reclamation cost	0	0	0	0	0
Salvage value	0	0	0	0	0
Ash disposal	2811.3	2867.5	2924.8	2983.3	3043.0
Total cost	341674.4	348507.9	355478.0	362587.6	557091.2
PV of total cost at 10%	28668.3	26583.4	24650.0	22857.3	31926.1
MWh sold	6500357.5	6500357.5	6500357.5	6500357.5	6500357.5
Price required for 10% return	82.10	83.74	85.42	87.13	88.87
Revenue required for 10% return	533693.9	544367.8	555255.1	566360.2	577687.4
PV of revenue at 10%	44779.8	41523.1	38503.2	35703.0	33106.4

Table A2: Summary of discounted cash flow for forest harvest residues based power plant in western Canada at an optimum size of 137 MW

Cost items ($'000)/Year	-2	-1	0	1	2	3	4
Capital cost	44611.0	78069.3	100375	0	0	0	0
Operating cost	0	0	0	2695.7	2749.6	2804.6	2860.7
Maintenance cost	0	0	0	6691.7	6825.5	6962.0	7101.2
Administration cost	0	0	0	1404.0	1432.1	1460.7	1489.9
Piling, forwarding and chipping cost	0	0	0	4906.1	5719.1	6076.5	6198.1
Transportation cost	0	0	0	21684.5	25277.9	26857.8	27394.9
Roads and Infrastructure cost	0	0	0	0	0	0	0
Silviculture cost	0	0	0	0	0	0	0
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	0	0	0	2083.7	2429.0	2580.8	2632.4
Transmission charge	0	0	0	0	0	0	0
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	0	0	0	685.9	699.6	713.6	727.9
Total cost	44611.0	78069.3	100374.8	40151.5	45132.7	47456.0	48405.1
PV of total cost at 10%	53979.3	85876.2	100374.8	36501.3	37299.8	35654.4	33061.3
MWh sold	0	0	0	837257.8	956866.1	1016670.2	1016670.2
Price required for 10% return				66.85	68.19	69.55	70.95
Revenue required for 10% return				55974.1	65249.8	70714.5	72128.8
PV of revenue at 10%				50885.5	53925.4	53128.8	49264.9

Table A2 cont'd

Cost items ($'000)/Year	5	6	7	8	9	10	11
Capital cost	0	0	0	0	0	0	0
Operating cost	2917.9	2976.2	3035.8	3096.5	3158.4	3221.6	3286.0
Maintenance cost	7243.3	7388.1	7535.9	7686.6	7840.3	7997.1	8157.1
Administration cost	1519.7	1550.1	1581.1	1612.8	1645.0	1677.9	1711.5
Piling, forwarding and chipping cost	6322.0	6448.5	6577.4	6709.0	6709.0	6843.2	6980.0
Transportation cost	27942.8	28501.7	29071.7	29653.1	30246.2	30851.1	31468.1
Roads and Infrastructure cost	0	0	0	0	0	0	0
Silviculture cost	0	0	0	0	0	0	0
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	2685.0	2738.7	2793.5	2849.4	2906.4	2964.5	3023.8
Transmission charge	0	0	0	0	0	0	0
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	742.4	757.3	772.4	787.9	803.6	819.7	836.1
Total cost	49373.2	50360.7	51367.9	52395.2	53443.1	54512.0	55602.2
PV of total cost at 10%	30656.9	28427.3	26359.8	24442.8	22665.1	21016.7	19488.2
MWh sold	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2
Price required for 10% return	72.36	73.81	75.29	76.79	78.33	79.89	81.49
Revenue required for 10% return	73571.3	75042.8	76543.6	78074.5	79635.9	81228.7	82853.3
PV of revenue at 10%	45682.0	42359.7	39278.9	36422.3	33773.4	31317.2	29039.6

Table A2 cont'd

Cost items ($'000)/Year	12	13	14	15	16	17	18
Capital cost	0	0	0	0	0	0	0
Operating cost	3351.7	3418.8	3487.1	3556.9	3628.0	3700.6	3774.6
Maintenance cost	8320.2	8486.6	8656.4	8829.5	9006.1	9186.2	9369.9
Administration cost	1745.7	1780.6	1816.2	1852.5	1889.6	1927.4	1965.9
Piling, forwarding and chipping cost	7262.0	7407.3	7555.4	7706.5	7860.7	8017.9	8178.2
Transportation cost	32097.5	32739.5	33394.2	34062.1	34743.4	35438.2	36147.0
Roads and Infrastructure cost	0	0	0	0	0	0	0
Silviculture cost	0	0	0	0	0	0	0
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	3084.3	3145.9	3208.9	3273.0	3338.5	3405.3	3473.4
Transmission charge	0	0	0	0	0	0	0
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	852.8	869.9	887.3	905.0	923.1	941.6	960.4
Total cost	56714.3	57848.6	59005.6	60185.7	61389.4	62617.2	63869.5
PV of total cost at 10%	18070.9	16756.7	15538.0	14408.0	13360.1	12388.5	11487.5
MWh sold	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2
Price required for 10% return	83.12	84.79	86.48	88.21	89.97	91.77	93.61
Revenue required for 10% return	84510.3	86200.5	87924.6	89683.0	91476.7	93306.2	95172.4
PV of revenue at 10%	26927.6	24969.2	23153.3	21469.4	19907.9	18460.1	17117.6

Table A2 cont'd

Cost items ($'000)/Year	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Capital cost	0	0	0	0	0	0	0
Operating cost	3850.1	3927.1	4005.6	4085.8	4167.5	4250.8	4335.8
Maintenance cost	9557.3	9748.5	9943.4	10142.3	10345.2	10552.1	10763.1
Administration cost	2005.3	2045.4	2086.3	2128.0	2170.6	2214.0	2258.2
Piling, forwarding and chipping cost	8341.8	8508.6	8678.8	8852.4	9029.4	9210.0	9394.2
Transportation cost	36869.9	37607.3	38359.5	39126.7	39909.2	40707.4	41521.5
Roads and Infrastructure cost	0	0	0	0	0	0	0
Silviculture cost	0	0	0	0	0	0	0
Nutrient replacement cost	0	0	0	0	0	0	0
Premium to fuel owner	3542.8	3613.7	3686.0	3759.7	3834.9	3911.6	3989.8
Transmission charge	0	0	0	0	0	0	0
Site recovery and reclamation cost	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0
Ash disposal	979.6	999.2	1019.2	1039.6	1060.4	1081.6	1103.2
Total cost	65146.9	66449.8	6778.8	69134.4	70517.1	71927.4	73366.0
PV of total cost at 10%	10652.0	9877.3	9159.0	8492.9	7875.2	7302.5	6771.4
MWh sold	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2
Price required for 10% return	95.48	97.39	99.34	101.32	103.35	105.42	107.53
Revenue required for 10% return	97075.8	99017.3	100997.7	103017.6	105077.9	107179.6	109323.1
PV of revenue at 10%	15872.7	14718.3	13647.9	12655.3	11734.9	10881.5	10090.1

Table A2 cont'd

Cost items ($'000)/Year	26	27	28	29	30
Capital cost	0	0	0	0	0
Operating cost	4422.5	4511.0	4601.2	4693.2	4787.1
Maintenance cost	10978.4	11197.9	11421.9	11650.3	11883.3
Administration cost	2303.4	2349.5	2396.5	2444.4	2493.3
Piling, forwarding and chipping cost	9582.1	9773.7	9969.2	10168.6	10372.0
Transportation cost	42352.0	43199.0	44063.0	44944.2	45843.1
Roads and Infrastructure cost	0	0	0	0	0
Silviculture cost	0	0	0	0	0
Nutrient replacement cost	0	0	0	0	0
Premium to fuel owner	4069.6	4151.0	4234.0	4318.7	4405.1
Transmission charge	0	0	0	0	0
Site recovery and reclamation cost	0	0	0	0	0
Salvage value	0	0	0	0	0
Ash disposal	1125.3	1147.8	1170.8	1194.2	1218.1
Total cost	74833.3	76330.0	77856.6	79413.7	116690.8
PV of total cost at 10%	6278.9	5822.3	5398.8	5006.2	6687.4
MWh sold	1016670.2	1016670.2	1016670.2	1016670.2	1016670.2
Price required for 10% return	109.68	111.87	114.11	116.39	118.72
Revenue required for 10% return	111509.6	113739.8	116014.6	118334.9	120701.6
PV of revenue at 10%	9356.3	8675.8	8044.9	7459.8	6917.2

Table A3: Cost calculations whole tree chipping

Items	Whole Tree Chipping, Morbark Chipper 50/48 All Costs are in 2000 US$
Working Assumptions	
Working shifts per day	2
Hours per shift	10
Working days per year	250
Scheduled machine hours per year	5000
Cost Assumptions	
Estimated machine life (years)	3.3
Purchase Price ($)	380000
Salvage Value ($)	63540.75
Insurance Cost ($/yr)	4180
Interest rate (%)	11
Utilization (%)	80
Lifetime repair & maintenance costs ($)	290499.43
Fuel consumption (lit./PMH) @ 20gallon/hr	75.7
Fuel price ($/lit.) @ $1.5/gallon	0.4
Oil and lubrication ($/PMH)	3.73
Operator wages ($/SMH)	25
Fixed Costs	
Annual capital recovery factor	0.3776
Annual capital cost	126471.14
Yearly other costs	4180
Yearly total	130651.14
Costs per PMH	32.66
Costs per SMH	26.13
Variable Costs	
Yearly costs	224070.13
Costs per PMH	56.02
Costs per SMH	44.81
Labour Costs	
Cost per year	125000.00
Costs per PMH	31.25
Costs per SMH	25.00
All Costs	
Grand total per year	479721.27
Grand total per PMH	119.93
Grand total per SMH	95.94
Productivity	
odt/PMH avg.	50
Costs	
$/odt avg.	2.40
Total cost pile & chip ($/odt)	**2.40**

Table A4: Cost calculations forest harvest residues piling, forwarding and chipping

Items	Forest Residues (All costs are in Canadian $1991)		
	Nicholson Chipper	Loader	Off-road piler
Working Assumptions			
Working shifts per day	2	2	2
Hours per shift	10	10	10
Working days per year	250	250	250
Scheduled machine hours per year	5000	5000	5000
Cost Assumptions			
Estimated machine life (years)	3.3	3.3	2.5
Purchase Price ($)	660000	160000	180000
Salvage Value ($)	99000	24000	27000
License Cost ($/yr)	0	2000	0
Insurance Cost ($/yr)	19800	4800	5400
Interest rate (%)	11	11	11
Utilization (%)	80	80	80
Lifetime repair & maintenance costs ($)	990000	128000	144000
Fuel consumption (lit./PMH) @ 20gallon/hr	85.3	13.2	18
Fuel price ($/lit.) @ $1.5/gallon	0.45	0.45	0.45
Oil and lubrication ($/PMH)	3.84	0.59	0.81
Operator wages ($/SMH)	16.5	16.5	16.5
Fixed Costs			
Annual capital recovery factor	0.3776	0.3776	0.4790
Annual capital cost	222699.93	53987.86	76257.96
Yearly other costs	19800	6800	5400
Yearly total	242499.93	60787.86	81657.96
Costs per PMH	60.62	15.20	20.41
Costs per SMH	48.50	12.16	16.33
Variable Costs			
Yearly costs	468900.00	64907.88	93240.00
Costs per PMH	117.23	16.23	23.31
Costs per SMH	93.78	12.98	18.65
Labour Costs			
Cost per year	82500.00	82500.00	82500.00
Costs per PMH	20.63	20.63	20.63
Costs per SMH	16.50	16.50	16.50
All Costs			
Grand total per year	793899.93	208195.74	257397.96
Grand total per PMH	198.47	52.05	64.35
Grand total per SMH	158.78	41.64	51.48
Productivity			
odt/PMH avg.	28.18	28.18	28.18
odt/PMH low	20.18	20.18	20.18

Table A4 cont'd

Items	Forest Residues (All costs are in Canadian $1991)		
	Nicholson Chipper	Loader	Off-road piler
odt/PMH high	35.29	35.29	35.29
Costs			
$/odt avg.	7.04	1.85	2.28
$/odt low	9.84	2.58	3.19
$/odt high	5.62	1.47	1.82
Total cost pile & chip in US$ 2000			
$/odt avg.	9.42		
$/odt high	13.16		
$/odt low	7.53		

Table A5: Cost calculations for integrated chipping and delimbing for forest harvest residues

Items	Nicholson chipper
Scheduled machine hour (SMH)	1980
Productive machine hour (PMH)	1188
Utilization	0.6
Total cost of chipping per year ($/yr)	261273.16
Total cost of loading per year ($/yr)	70358.87
Total cost of piling per year ($/yr)	87562.77
Total cost of chipping per year ($/PMH)	219.93
Total cost of loading per year ($/yr)	59.22
Total cost of piling per year ($/yr)	73.71
Productivity of the chipper in normal operation (odt/PMH)	28.18
Productivity of the chipper when integrated with delimber (odt/PMH)	4.5
Cost of chipping in normal operation ($/odt)	7.80
Cost of loading in normal operation ($/odt)	2.10
Cost of piling in normal operation ($/odt)	2.62
Total cost of chipped fuel in normal operation ($/odt)	12.52
Cost of chipping in integrated operation ($/odt)	48.87

Appendix B

1. Formula for calculating the friction factor in wood chip water slurry pipeline (Hunt, 1976):

$$\mathbf{(F_m/F) - 1 = 197\left(\frac{D^{0.970} * g^{1.312} * \upsilon^{0.342}}{V_m^{2.964}}\right)[C/(1-C)]^{[0.838 + \{0.930 * \ln(1-k)\}]}}$$

F_m – Darcy-Weisbach friction factor for mixtures of wood chips and water, dimensionless
F – Darcy-Weisbach friction factor, dimensionless
D – internal diameter of pipe, m
g - gravitational acceleration, 9.81 m/s^2
υ – kinematic viscosity of carrier water, m^2/sec
V_m – mean velocity of mixture flow, m/sec
C – concentration of solids in mixture (decimal fraction), dimensionless
k – ratio of characteristic chip dimension to pipe diameter, d_c/D, dimensionless

2. Formula for calculating the friction factor in water pipeline

Colebrook equation:

$$\mathbf{f = a + b * Re^{-c}, \text{ if } Re > 10^4 \text{ and } 10^{-5} < k < 0.04}$$

$a = 0.094 * k^{0.225}$

$b = 88 * k^{0.44}$

$c = 1.62 * k^{0.134}$

$Re = d*g*D/\mu$

$k = e/D$

f – Darcy – Weisbach friction factor, dimensionless
Re – Reynolds number, dimensionless
d – density of fluid, kg/m^3
D – internal diameter of pipe, m
g - gravitational acceleration, 9.81 m/s^2
μ – viscosity, Pa.S
e – Roughness of pipe, m

3. Formula for calculating the head loss

Darcy – Weisbach equation:

$$h_f = f * L * V^2 / (2 * g * D)$$

h_f - head loss, m
f - Darcy-Weisbach friction factor
L – length of the pipe, m
V – velocity of fluid, m/s
g - gravitational acceleration, 9.81 m/s^2

4. Formula for pipeline cost (Liu et al., 1995)

$$C = 132 * D^{1.34} + 104 * D^{0.87} + 24 * D + 20$$

C – capital cost for constructed pipeline capital cost ($1000) per mile, which include steel pipe, construction (excavation, welding and insulation), coating, wrapping, valves and the right of way (cost in $1994)
D – nominal pipe diameter in feet

5. Formula for pump cost (Liu et al., 1995)

$$C = 1.15 * (H_p)^{0.8056}$$

C – cost for pump ($1000), cost in 1994 dollars
H_p – pump power in horsepower

Appendix C

Table C1: Ethanol production cost from corn stover using pipeline transport for a 2 million dry tonnes per year plant

Items	Units	Values
Capacity of plant	dry tonnes per day	5,480
Capacity of plant	dry tonnes per year	2,000,000
Ethanol Yield		
Yield	liters/dry tonne	384
Ethanol production	liters/year	768,076,800
	gal/year	202,926,499
Capital costs		
Total capital at given capacity	$	225,795,009
Added cost (Warehouse (1.5%), site development (5.2%), Field and prorateable expenses, Home office & construction fee, Project contingency, Other costs (startup, permits etc.))	% of total installed capital cost	73.6
Added cost	$	391,980,136
Life of plant	years	20
Return	%	10
Capital recovery factor		0.1175
Feedstock		
Losses in storage and handling	%	10
Actual amount of corn stover for plant	dry tonnes per year	2,222,444
Density of corn acreage	%	30
Farmer selling stover	%	50
Inaccessible fields	%	10
Stover yield	dry tonnes/acre	1.1
	dry tonnes/km^2	247
Collection area	km^2	66,762
Feedstock cost		
Baling and staging	$/dry tonne	29
Premium to farmers	$/dry tonne	11
Fertilizer cost (N, K and P)	$/dry tonne	8
Transportation cost		
Distance transported by truck	km	103
No. of inner circles		0
No. of outer circles		0
No. of outer most circles		0

Table C1 cont'd

Items	Units	Values
Length of pipeline for inner circles	km	292
Length of pipeline for outer circles	km	505
Length of pipeline for outermost circles	km	584
Truck transportation fixed cost	$/dry tonne	5.32
Truck transportation variable cost	$/dry tonne/km	0.1275
Pipeline transportation variable cost	$/dry tonne/km	0.0829
Fixed costs		
Total salaries	$	2,150,000
General overhead	% of total salary	60
Maintenance cost	% of installed equipment cost	2
Insurance taxes	% of total installed cost	1.5
Plant operating cost		
Feedstock	$/year	132,918,291
CSL	$/year	5,206,000
Cellulase	$/year	19,180,000
Other raw materials	$/year	10,412,000
Waste disposal	$/year	5,480,000
Fixed costs	$/year	11,569,377
Electricity	$/year	-18,969,569
Capital cost	$/year	46,041,840
Total cost of ethanol	**$/liter**	**0.2758**

Table C2: Ethanol production cost from corn stover using pipeline transport for a 38 million dry tonnes per year plant (without saccharification in pipeline)

Items	Units	Values
Capacity of plant	dry tonnes per day	104,110
Capacity of plant	dry tonnes per year	38,000,150
Ethanol Yield		
Yield	liters/dry tonne	384
Ethanol production	liters/year	14,592,057,600
	gal/year	3,855,233,184
Capital costs		
Total capital at given capacity	$	1,672,500,644
Added cost (Warehouse (1.5%), site development(5.2%), Field and prorateable expenses, Home office & construction fee, Project contingency, Other costs (startup, permits etc.))	% of total installed capital cost	73.6
Added cost	$	2,903,461,117
Life of plant	years	20
Return	%	10
Capital recovery factor		0.1175
Feedstock		
Losses in storage and handling	%	10
Actual amount of corn stover for plant	dry tonnes per year	42,222,389
Density of corn acreage	%	30
Farmer selling stover	%	50
Inaccessible fields	%	10
Stover yield	dry tonnes/acre	1.1
	dry tonnes/km^2	247
Collection area	km^2	1,268,362
Feedstock cost		
Baling and staging	$/dry tonne	29
Premium to farmers	$/dry tonne	11
Fertilizer cost (N, K and P)	$/dry tonne	8
Transportation cost		
Distance transported by truck	km	103
No. of inner circles		6
No. of outer circles		6
No. of outer most circles		6

Table C2 cont'd

Items	Units	Values
Length of pipeline for inner circles	km	292
Length of pipeline for outer circles	km	506
Length of pipeline for outermost circles	km	584
Truck transportation fixed cost	\$/dry tonne	5.32
Truck transportation variable cost	\$/dry tonne/km	0.1275
Pipeline transportation variable cost	\$/dry tonne/km	0.0829
Fixed costs		
Total salaries	\$	5,329,990
General overhead	% of total salary	60
Maintenance cost	% of installed equipment cost	2
Insurance taxes	% of total installed cost	1.5
Plant operating cost		
Feedstock	\$/year	3,900,018,568
CSL	\$/year	98,904,500
Cellulase	\$/year	364,385,000
Other raw materials	\$/year	197,809,000
Waste disposal	\$/year	104,110,000
Fixed costs	\$/year	68,743,610
Electricity	\$/year	-360,387,198
Capital cost	\$/year	341,039,453
Total cost of ethanol	**\$/liter**	**0.3231**

Table C3: Ethanol production cost from corn stover using pipeline transport for a 38 million dry tonnes per year plant (with saccharification in pipeline)

Items	**Units**	**Values**
Capacity of plant	dry tonnes per day	104,110
Capacity of plant	dry tonnes per year	38,000,150
Ethanol Yield		
Yield	liters/dry tonne	384
Ethanol production	liters/year	14,592,057,600
	gal/year	3,855,233,184
Capital costs		
Capital cost of equipment at a scale of 2 Mt/yr upto pretreatment process	$	65,007,791
Capital cost of equipment after pretreatment process at given capacity	$	1,214,080,631
Total capital at given capacity	$	2,449,233,529
Added cost (Warehouse (1.5%), site development(5.2%), Field and prorateable expenses, Home office & construction fee, Project contingency, Other costs (startup, permits etc.))	% of total installed capital cost	73.6
Added cost	$	4,251,869,407
Life of plant	years	20
Return	%	10
Capital recovery factor		0.1175
Feedstock		
Losses in storage and handling	%	10
Actual amount of corn stover for plant	dry tonnes per year	42,222,389
Density of corn acreage	%	30
Farmer selling stover	%	50
Inaccessible fields	%	10
Stover yield	dry tonnes/acre	1.1
	dry tonnes/km^2	247
Collection area	km^2	1,268,362
Feedstock cost		
Baling and staging	$/dry tonne	29
Premium to farmers	$/dry tonne	11
Fertilizer cost (N, K and P)	$/dry tonne	8

Table C3 cont'd

Items	Units	Values
Transportation cost		
Distance transported by truck	km	103
No. of inner circles		6
No. of outer circles		6
No. of outer most circles		6
Length of pipeline for inner circles	km	292
Length of pipeline for outer circles	km	506
Length of pipeline for outermost circles	km	584
Truck transportation fixed cost	$/dry tonne	5.32
Truck transportation variable cost	$/dry tonne/km	0.1275
Pipeline transportation variable cost	$/dry tonne/km	0.0829
Fixed costs		
Total salaries	$	5,329,990
General overhead	% of total salary	60
Maintenance cost	% of installed equipment cost	2
Insurance taxes	% of total installed cost	1.5
Plant operating cost		
Feedstock	$/year	3,900,018,568
CSL	$/year	98,904,500
Cellulase	$/year	364,385,000
Other raw materials	$/year	197,809,000
Waste disposal	$/year	104,110,000
Fixed costs	$/year	96708,596
Electricity	$/year	-360,387,198
Capital cost	$/year	499,422,985
Total cost of ethanol	**$/liter**	**0.3258**

Table C4: Ethanol production cost from wood chips using pipeline transport for a 2 million dry tonnes per year plant

Items	Units	Values
Capacity of plant	dry tonnes per day	5,480
Capacity of plant	dry tonnes per year	2,000,000
Ethanol Yield		
Yield	liters/dry tonne	270
Ethanol production	liters/year	768,076,800
	gal/year	202,926,499
Capital costs		
Total capital at given capacity	$	225,795,009
Added cost (Warehouse (1.5%), site development(5.2%), Field and prorateable expenses, Home office & construction fee, Project contingency, Other costs (startup, permits etc.))	% of total installed capital cost	73.6
Added cost	$	391,980,136
Life of plant	years	20
Return	%	10
Capital recovery factor		0.1175
Feedstock cost		
Harvesting cost	$/dry tonne	21.4
Transportation cost		
Distance transported by truck	km	28
No. of inner circles		0
No. of outer circles		0
No. of outer most circles		0
Length of pipeline for inner circles	km	78
Length of pipeline for outer circles	km	135
Length of pipeline for outermost circles	km	156
Truck transportation fixed cost	$/dry tonne	4.98
Truck transportation variable cost	$/dry tonne/km	0.1114
Pipeline transportation variable cost	$/dry tonne/km	0.0829
Fixed costs		
Total salaries	$	2,150,000
General overhead	% of total salary	60
Maintenance cost	% of installed equipment cost	2
Insurance taxes	% of total installed cost	1.5

Table C4 cont'd

Items	Units	Values
Plant operating cost		
Feedstock cost	$/year	59,004,300
CSL	$/year	5,206,000
Cellulase	$/year	19,180,000
Other raw materials cost	$/year	10,412,000
Waste disposal	$/year	5,480,000
Fixed costs	$/year	11,569,377
Electricity	$/year	-13,337,978
Capital cost	$/year	46,041,840
Total cost of ethanol	**$/liter**	**0.2658**

Table C5: Ethanol production cost from wood chips using pipeline transport for a 38 million dry tonnes per year plant (without saccharification in pipeline)

Items	Units	Values
Capacity of plant	dry tonnes per day	104,110
Capacity of plant	dry tonnes per year	38,000,150
Ethanol Yield		
Yield	liters/dry tonne	270
Ethanol production	liters/year	10,260,040,500
	gal/year	2,710,710,832
Capital costs		
Total capital at given capacity	$	1,672,500,644
Added cost (Warehouse (1.5%), site development(5.2%), Field and prorateable expenses, Home office & construction fee, Project contingency, Other costs (startup, permits etc.))	% of total installed capital cost	73.6
Added cost	$	2,903,461,117
Life of plant	years	20
Return	%	10
Capital recovery factor		0.1175
Feedstock cost		
Harvesting cost	$/dry tonne	21.4
Transportation cost		
Distance transported by truck	km	28
No. of inner circles		6
No. of outer circles		6
No. of outer most circles		6
Length of pipeline for inner circles	km	78
Length of pipeline for outer circles	km	135
Length of pipeline for outermost circles	km	156
Truck transportation fixed cost	$/dry tonne	4.98
Truck transportation variable cost	$/dry tonne/km	0.1114
Pipeline transportation variable cost	$/dry tonne/km	0.0569
Fixed costs		
Total salaries	$	5,329,990
General overhead	% of total salary	60
Maintenance cost	% of installed equipment cost	2
Insurance taxes	% of total installed cost	1.5

Table C5 cont'd

Items	Units	Values
Plant operating cost		
Feedstock cost	$/year	1,372,927,225
CSL	$/year	98,904,500
Cellulase	$/year	364,385,000
Other raw materials cost	$/year	197,809,000
Waste disposal	$/year	104,110,000
Fixed costs	$/year	68,743,610
Electricity	$/year	-253,397,249
Capital cost	$/year	341,039,453
Total cost of ethanol	**$/liter**	**0.2236**

Table C6: Ethanol production cost from wood chips using pipeline transport for a 38 million dry tonnes per year plant (with saccharification in pipeline)

Items	Units	Values
Capacity of plant	dry tonnes per day	104,110
Capacity of plant	dry tonnes per year	38,000,150
Ethanol Yield		
Yield	liters/dry tonne	270
Ethanol production	liters/year	10,260,040,500
	gal/year	2,710,710,832
Capital costs		
Capital cost of equipment at a scale of 2 Mt/yr upto pretreatment process	$	65,007,791
Capital cost of equipment after pretreatment process at given capacity	$	1,214,080,631
Total capital at given capacity	$	2,449,233,529
Added cost (Warehouse (1.5%), site development(5.2%), Field and prorateable expenses, Home office & construction fee, Project contingency, Other costs (startup, permits etc.))	% of total installed capital cost	73.6
Added cost	$	4,251,869,407
Life of plant	years	20
Return	%	10
Capital recovery factor		0.1175
Feedstock cost		
Harvesting cost	$/dry tonne	21.4
Transportation cost		
Distance transported by truck	km	28
No. of inner circles		6
No. of outer circles		6
No. of outer most circles		6
Length of pipeline for inner circles	km	78
Length of pipeline for outer circles	km	135
Length of pipeline for outermost circles	km	156
Truck transportation fixed cost	$/dry tonne	4.98
Truck transportation variable cost	$/dry tonne/km	0.1114
Pipeline transportation variable cost	$/dry tonne/km	0.0569
Fixed costs		
Total salaries	$	5,329,990
General overhead	% of total salary	60

Table C5 cont'd

Items	Units	Values
Maintenance cost	% of installed equipment cost	2
Insurance taxes	% of total installed cost	1.5
Plant operating cost		
Feedstock cost	$/year	1,372,927,225
CSL	$/year	98,904,500
Cellulase	$/year	364,385,000
Other raw materials cost	$/year	197,809,000
Waste disposal	$/year	104,110,000
Fixed costs	$/year	96,708,596
Electricity	$/year	-253,397,249
Capital cost	$/year	499,422,985
Total cost of ethanol	**$/liter**	**0.2418**