BIOENERGY SYSTEMS IN CANADA: TOWARDS ENERGY SECURITY AND CLIMATE CHANGE SOLUTIONS

by

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Abstract

The energy security and climate change risks of fossil fuel consumption have stimulated interest in developing renewable energy sources. Canada's vast biomass potential is an attractive local resource but high transportation costs are a barrier to implementation. This study assesses how transformative systems can enable large-scale bioenergy production through integration with existing transportation corridors and fossil fuel infrastructure. Potential bioenergy corridors include the network of natural gas pipelines and the Great Lakes St. Lawrence Seaway (GLSLS).

Sustainable lignocellulosic biomass production integrated with traditional food and fibre production was assumed to occur on 196 Mha of land within 100 km of pipelines. Conservative (81 Mt of dry biomass per year) and aggressive (209 Mt) scenarios were investigated for converting biomass to synthetic natural gas (SNG) via gasification, methanation, and upgrading, yielding enough pipeline-quality gas to meet 20% to 60% of Canada's current needs. A systems analysis approach was used to calculate bioSNG life-cycle emissions of 15 to 18 kgCO_2e GJ^{-1}, compared to 68 or 87 for conventional or liquefied natural gas, respectively. Production costs ranged from \$16 to \$20 GJ^{-1}, which were high compared to regional gas prices (\$5 to \$10 GJ^{-1}).

The biomass potential on 125 Mha of land area within 100 km of the Canadian portion of the GLSLS and railway lines ranged from 36 to 80 Mt(dry) per year, which was enough to displace coal-fired power in Ontario plus produce 1.6 to 11 billion L of green diesel that could offset 14% to 96% of fossil diesel in GLSLS provinces. Life-cycle emissions ranged from 110 to 130 gCO_2e kWh^{-1} for biopower (compared to 1030 for coal) and 20 to 22 kgCO_2e GJ^{-1} for green diesel (compared to 84 for conventional diesel). Cost estimates ranged from \$130 MWh^{-1} for biopower (compared to an average market power price of \$54 MWh^{-1}) and \$28 to \$36 GJ^{-1} for green diesel (compared to \$16 to \$24 GJ^{-1} for diesel). The auxiliary benefits (energy security, climate change, air quality, and rural development) were seen as justification for supportive bioenergy policies.

Co-Authorship

Chapters 3 and 4 are separate manuscripts to be published in peer-reviewed academic journals with Drs. D.B. Layzell and P.J. McLellan as co-authors. Dr. Layzell conceived of the concepts discussed in the manuscripts while both Dr. Layzell and Dr. McLellan provided guidance and assistance in the preparation of the manuscripts.

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List of Abbreviations

AAC	Annual allowable cut
bbl	Barrel of oil
BEV	Battery electric vehicle
BTL	Biomass-to-liquid
CCS	Carbon capture and storage
CFS	Canadian Forest Service
CGA	Canadian Gas Association
CH_4	Methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
CSP	Concentrating solar power
EC	Environment Canada
EIA	Energy Information Administration
EJ	Exajoule (10^{18} J)
EROI	Energy return on investment
FAO	Food and Agriculture Organization of the United Nations
FT	Fischer-Tropsch
g	Gram
GHG	Greenhouse gas
GJ	Gigajoule (10^{9} J)
GLSLS	Great Lakes St. Lawrence Seaway
ha	Hectare
HHV	Higher heating value
IEA	International Energy Agency
IGCC	Integrated gasification and combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt hour
L	Litre

LHV	Lower heating value
LNG	Liquefied natural gas
M	Million
m^3	Cubic metre
Mbpd	Million barrels per day
MJ	Megajoule (10^6 J)
MW	Megawatt
MWh	Megawatt hour
N_2O	Nitrous oxide
NAFTA	North American Free Trade Agreement
NEB	National Energy Board
NEP	National Energy Program
NOP	National Oil Policy
NO_x	Nitrogen oxides
NRCan	Natural Resources Canada
NRTEE	National Round Table on the Environment and the Economy
OEE	Office of Energy Efficiency
OPA	Ontario Power Authority
OPEC	Organization of Petroleum Exporting Countries
OPET	Organization for the Promotion of Energy Technologies
OPG	Ontario Power Generation
ORNL	Oak Ridge National Laboratory
PJ	Petajoule (10^{15} J)
ppmv	Parts per million by volume
PV	Photovoltaic
SNG	Synthetic natural gas
SO_x	Sulphur oxides
t	Tonne
t(dry)	Tonne of dry biomass
TWh	Terawatt hour (10^{12} Wh)
WCSB	Western Canadian Sedimentary Basin
WNA	World Nuclear Association

Chapter 1
Introduction

Modern civilizations are dependent on energy to generate wealth and improve quality of life (Bauen, 2006). The complex global economic infrastructure is fuelled by non-renewable hydrocarbons that were formed millions of years ago (Heinberg, 2007a). However, the synergistic effects of two global energy-related issues are colliding in a perfect storm that could threaten environmental, economic, and social sustainability.

Access to adequate, affordable, and reliable energy is threatened by rising global energy demand and supply constraints. Rapid industrialization of the developing world is driving up fossil fuel consumption (IEA, 2007). Surging demand for petroleum-based transportation fuels – the lifeblood of globalization – is putting enormous pressure on oil supplies. Unfortunately, many oil-producing nations are experiencing declining production and resources are increasingly concentrated in geopolitically unstable regions or areas with high extraction and production costs (Heinberg, 2007b). Furthermore, the maturing North American natural gas industry raises the likelihood of reliance on both foreign oil and gas (Darley, 2007). Global competition for the remaining fossil fuel resources could be a destabilizing factor that leads to shortages, price volatility, acts of terrorism, and increased militarization of energy supplies. Consequently, the world is faced with immediate energy security concerns.

Anthropogenic emissions of climate-warming gases are responsible for an enhanced greenhouse effect that is raising the planet's average surface temperature and accelerating rates of climate change (IPCC, 2007). Deep cuts in greenhouse gas emissions are essential to limit warming to a maximum of 2.4°C above pre-industrial levels (IEA, 2007). Otherwise, global warming could have irreversible effects, which would destabilize the global climate system with unpredictable consequences.

The twin threats of energy security and climate change are two of the world's greatest challenges. Fortunately, there are many existing technologies that can supply clean and secure energy (IEA, 2006). One possibility is to use renewable, domestic biological resources for heat, power, and transportation. Canada has a vast supply of forest and agricultural biomass that could potentially meet all of its energy needs (Layzell et al., 2006). Energy security and climate change are strong drivers of bioenergy production, which also offers air quality and rural economic development benefits.

Large-scale systems will be required for bioenergy to make a substantial contribution to Canada's energy supply. Since biomass is a distributed resource low in energy density, small-scale systems for local markets are more traditional (IEA, 2006). The cost and logistics of biomass transportation from the field to energy conversion facilities and then to markets pose the most significant technical and economic barriers (Wyman, 2003). Transformative energy systems that integrate large-scale bioenergy production with existing transportation corridors will enable biomass to be efficiently moved from the field to energy markets. Two such corridors in Canada are the network of natural gas pipelines and the Great Lakes St. Lawrence Seaway.

This manuscript-style thesis is organized as follows. The Introduction (Chapter 1) is a brief summary of the motivation for this work and introduces the topics of the manuscripts. The Literature Review (Chapter 2) provides a comprehensive analysis of the drivers, alternative solutions, an overview of bioenergy production, and proposes a national bioenergy target. Chapters 3 and 4 are manuscripts that investigate two transformative energy systems in Canada. The Discussion (Chapter 5) then links the research in the previous chapters and develops a strategic national energy policy with a focus on bioenergy systems. The Conclusion (Chapter 6) then summarizes the recommendations put forth in the Discussion and their relation to energy security and climate change.

Chapter 2
Literature Review

2.1 Energy outlook

2.1.1 Global energy trends

2.1.1.1 Primary energy demand

Secondary fuels such as electricity and gasoline are derived from three categories of primary energy – fossil fuels, nuclear, and renewable energy (Evans, 2007). Population and economic growth drive a society's primary and secondary energy demand. The International Energy Agency's (IEA) 2007 World Energy Outlook predicts that population will grow 32% from 6.2 to 8.2 billion people over 2005-2030. Most of this growth is expected to occur in the fast-growing economies of the developing world. The most populated countries (China and India) are expected to experience the most economic growth over 2005-2030.

Industrialization generally requires huge inputs of energy to build infrastructure and upgrade the standard of living (Vanderburg, 2000). The industrialization of developing countries is largely responsible for the anticipated 55% increase in primary energy demand from 480 to 740 EJ over 2005-2030 (IEA, 2007), which will intensify competition for global energy resources. The corresponding increase in primary energy supplies is expected to require an investment of $22 trillion in energy-supply infrastructure (IEA, 2007).

2.1.1.2 Primary energy supply

Fossil fuels such as oil, coal, and natural gas supply most of the world's energy. The global energy supply mix in 2005 was 81% fossil fuels while the rest was biomass and waste, nuclear, hydro, and other renewables (Table 2-1).

Table 2-1: Global energy supply mix 1980-2030 according to the reference scenario of World Energy Outlook 2007 (IEA, 2007).

Primary energy source	**Fraction of supply mix**			**Overall average annual growth rate (2005-2030)**
	1980	2005	2030	
Oil	43%	35%	32%	1.3%
Coal	25%	25%	28%	2.2%
Natural gas	17%	21%	22%	2.1%
Biomass and waste	10%	10%	9.1%	0.7%
Nuclear	2.6%	6.3%	4.8%	2.0%
Hydro	2.0%	2.3%	2.3%	1.4%
Other renewables	0.2%	0.5%	1.7%	6.7%
Total	**100%**	**100%**	**100%**	**-**

Consumption of all energy sources is expected to increase over the period to 2030, especially coal for power generation. The Energy Information Administration's (EIA) 2008 International Energy Outlook indicates that the US, China, and India have large domestic deposits and are expected to turn to coal-fired power in lieu of more expensive fuels. Global coal production is expected to increase 73% from 4,154 to 7,173 Mt over 2005-2030 to supply power to developing economies (IEA, 2007).

The petroleum industry produces the majority of the world's transportation fuels and chemical products. Crude oil production is expected to increase 37% from 84.6 to 116.3 million barrels per day (Mbpd) over 2006-2030 to meet growing demand in developing countries (IEA, 2007). Global reserves are increasingly concentrated in a small group of countries; for example, the Organization of Petroleum Exporting Countries' (OPEC) market share of oil supply is predicted to jump from 42% to 52% over 2006-2030 (IEA, 2007).

The real (inflation-adjusted) price of petroleum has steadily increased since 1997 as supplies have stretched to meet demand (Fig. 2-1). Discovery of conventional oil fields, which contain high quality, light petroleum that easily flows from underground reservoirs (Hirsch et al., 2005), peaked in 1964 (Darley, 2007) and one barrel is currently discovered for every five extracted

(Heinberg, 2007b). As the petroleum industry matures, the net energy extracted from conventional wells (energy content of oil versus energy used in extraction, processing, and transport) has declined from 100:1 to less than 20:1 (Santa-Barbara, 2007). The decline in net energy coupled with growing demand and fewer discoveries has been a major contributor to escalating prices.

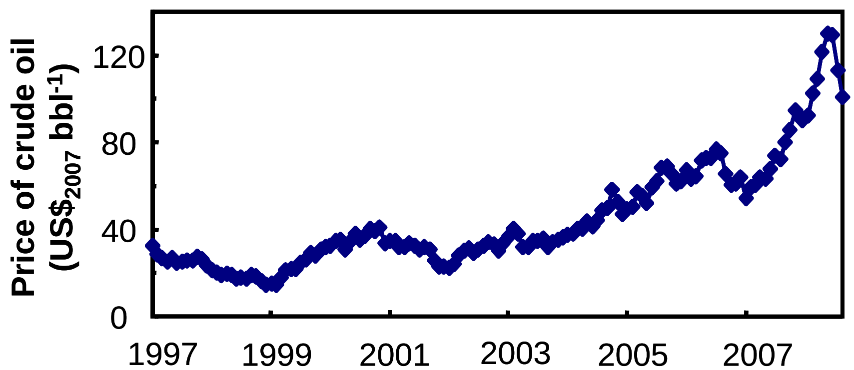

Figure 2-1: Real price of West Texas Intermediate crude oil from January 1997 to September 2008 (source: EIA, 2008d).

The rate of change of crude oil prices was approximately constant from 2002 to late 2006. After a brief decline, the rate of change increased sharply and real prices rose 140% from \$55 to \$130 bbl^{-1} over January 2007 to June 2008.

Natural gas continues to be in high demand primarily for high-efficiency combined cycle power generation. Gas production is expected to increase 67% from 7,847 to 13,093 Mm^3 day^{-1} over 2005-2030 even though many regions will experience declining production (IEA, 2007). The commercialization of liquefied natural gas (LNG) has made intercontinental transport possible and grants producers access to world markets.

Other primary energy sources such as nuclear, hydro, and biomass and waste are predicted to increase modestly by 2030. Strong growth in renewable energy for power generation is anticipated although its share of total primary energy supply will remain low (IEA, 2007). Fossil fuels are expected to continue their domination of global fuel supplies by 2030.

2.1.1.3 Global peak oil

Growing demand for petroleum-based transportation fuels is expected to put enormous pressure on global oil supplies (IEA, 2006). Unfortunately, more than 60% of major petroleum-producing countries are experiencing declining production from aging conventional fields (Heinberg, 2007b) and diminishing net energy returns (Santa-Barbara, 2007). Approximately 98% of petroleum supplies in 2006 were from conventional sources while unconventional oil (heavy, tar-like petroleum that is not readily recovered (Hirsch et al., 2005)) only contributed 2% (IEA, 2007). Although unconventional oil production from the Canadian oil sands is expected to substantially increase, conventional sources are still predicted to supply 93% of the world's petroleum. The IEA projects that a supply-side crunch that would raise petroleum prices could occur by 2015 unless substantial investments in oil-supply infrastructure are made.

A deeper analysis of conventional oil supplies presents a pessimistic scenario. An IEA assessment of the top 400 oil fields revealed that depletion rates were higher than expected and global production would barely reach 100 Mbpd (King and Fritsch, 2008). Moreover, an estimated $5.4 trillion investment in oil-supply infrastructure is required to maximize production (IEA, 2007); whereas historically under-investment has prevailed in petroleum industries dominated by national oil companies (Worldwatch Institute, 2006). Since OPEC and national oil companies' market share of oil supply is expected to increase compared to the rest of the world, output may not rise much higher than current production rates (84.6 Mbpd).

There are geological limits to oil extraction rates and at some point production will have to decline (Heinberg, 2007b). The issue is not the magnitude of petroleum resources, but the rate at which they can be extracted. For example, Canada's proven oil reserves (178.8 billion barrels) are second only to Saudi Arabia (264.3 billion barrels) (Warnock, 2007) but the investment and infrastructure requirements of extracting synthetic crude oil from oil sands as well as process complexity makes it hard to ramp up production. Furthermore, declining production rates at existing oil fields coupled with strong petroleum demand growth indicate that 64 Mbpd of additional capacity (approximately six Saudi Arabias) must be in place by 2030 (IEA, 2008). Otherwise, global production could peak and subsequently decline. Countries that reach peak oil experience declining domestic production and a growing reliance on imports. Unfortunately, a global peak in production cannot be addressed by increasing imports, while replacement of petroleum-based transportation fuels would be a major short-term challenge (Darley, 2007). Declining production in many oil-producing nations, lower discovery rates, and potential under-investment in oil-supply infrastructure are all contributing factors to global peak oil.

2.1.1.4 Energy security

Energy security refers to access to adequate, affordable, and reliable energy supplies (IEA, 2007). The world's complex economic infrastructure is built to run on abundant and inexpensive fossil fuels (Heinberg, 2007a), which makes energy insecurity a global issue that has the potential to disrupt every economy (Hirsch et al., 2005). Rising global energy demand, peak oil production, and a lack of geographical supply diversity all pose real threats to energy security.

Developing countries with expanding rates of energy consumption are becoming more reliant on energy imports, specifically oil and natural gas. In addition, Canada's National Energy Board (NEB) reports that the geographic supply diversity of oil and gas is increasingly limited to the Middle East and Russia (NEB, 2007). This heightens the risk of short-term supply disruptions due to a heavy reliance on a few supply routes in politically unstable regions. Furthermore, the concentration of resources in a small group of countries means that sabotage, political intervention, strikes, technical failures, accidents, or natural disasters could threaten access to energy and lead to shortages and high prices (IEA, 2007).

Peak oil poses a long-term threat to energy security since demand is predicted to rise to 116.3 Mbpd (IEA, 2007) whereas production is barely expected to reach 100 Mbpd (King and Fritsch, 2008). The supply gap will put upward pressure on prices and those that cannot afford to pay will face shortages (Hirsch et al., 2005). Supply interruptions will continually increase as global production declines possibly leading to economic chaos, geopolitical tensions, terrorism, and famine (Heinberg, 2007b). There are demand- and supply-side mitigation options but these must be implemented well before the peak to have maximum effect (Hirsch et al., 2005). Some experts believe that a near-term peak is inevitable (Heinberg, 2007b) whereas the IEA projects that peak oil can be averted until 2030 as long as the necessary investments are made (IEA, 2008).

2.1.2 North American energy outlook

2.1.2.1 Demand and supply

North America's population and economy are predicted to expand, leading to a 25% increase in primary energy demand from 120 to 150 EJ over 2005-2030 (IEA, 2007). Rising demand is expected to boost US coal consumption, where coal-fired power plants could supplant gas-fired stations as the preferred choice for new generating capacity (EIA, 2008b).

The shift to coal appears puzzling at first since gas-fired generation is cleaner, more efficient, and has lower investment costs (IEA, 2007). However, North American natural gas production fell from 2,107 to 2,036 $Mm^3\ day^{-1}$ over 2000-2005 (IEA, 2007) due to declining output from mature conventional gas fields (EIA, 2008b; NEB, 2007). Increased production from unconventional natural gas sources could expand supply to 2,299 $Mm^3\ day^{-1}$ by 2030 but this would still not be enough to meet demand, which is expected to grow 30% from 2,096 to 2,723

Mm^3 day^{-1} over 2005-2030 (IEA, 2007). North American self sufficiency could decrease from 97% at current domestic production rates to 92% by 2015 and 84% by 2030, leading to an increased reliance on LNG imports.

North America has an integrated natural gas market with a network of pipelines that physically connects production basins and consumers (CGA, 2003). The end-use price of gas is made up of the wellhead price (deregulated) and transmission and distribution costs (regulated). The real wellhead price has gradually increased since 1997 with occasional periods of volatility (Fig. 2-2). Prices jumped 60% from \$6.7 to \$10.7 GJ^{-1} from August to October 2005, when Hurricane Katrina shut down gas production in the Gulf of Mexico (Worldwatch Institute, 2006).

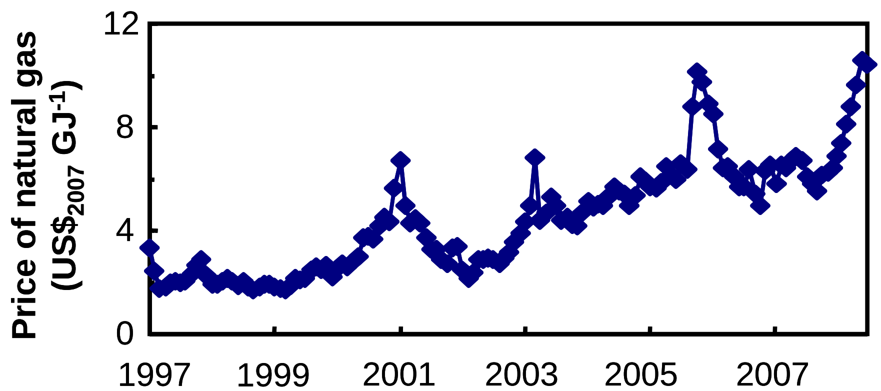

Figure 2-2: Real wellhead price of North American natural gas from January 1997 to July 2008 (source: EIA, 2008c).

Substitutability between natural gas and certain refined petroleum products links wellhead prices to global crude oil prices (CGA, 2003). Historically, North American gas prices have been approximately 84% of the energy-equivalent price of crude oil (NEB, 2007). Wellhead prices increased 61% from \$6.4 to \$10.3 GJ^{-1} from December 2007 to June 2008 while oil prices were steeply climbing. Consequently, sustained high petroleum prices due to strong global demand and peak oil would also increase regional natural gas prices.

Petroleum demand is projected to increase 20% from 24.9 to 30.0 Mbpd over 2006-2030 (IEA, 2007). Over the same period, North American output is predicted to rise 9% from 13.9 to 15.2 Mbpd, despite declining production from conventional oil fields (IEA, 2007; NEB, 2007). Overall, North American dependence on foreign oil is set to rise.

2.1.2.2 Energy security

North America's continuing reliance on foreign oil and gas presents energy security risks such as supply interruptions and higher prices, as witnessed during the 1973 OPEC oil embargo and the 1979 Iranian oil cut-off (Hirsch et al., 2005). Peak oil endangers long-term energy security with the threat of prolonged supply interruptions and sustained high prices.

Energy security concerns associated with foreign oil imports may soon extend to natural gas as well. Gas consumption already exceeds regional supplies and the trend is expected to worsen. North America will then become dependent on LNG imports, which entails its own risks. The long-term availability of LNG is uncertain since world natural gas discovery peaked in 1970 (Darley, 2007) and resources are concentrated in Russia and the Middle East (NEB, 2007). The high cost of building LNG-supply infrastructure could be prohibitive and a supply gap is expected to slowly emerge (Honoré and Stern, 2007). Countries reliant on gas imports would then face shortages and high prices. Methane hydrate deposits under Arctic permafrost and the ocean floor are estimated to be an abundant source of methane – the principal component of natural gas (US Department of Energy, 2008). However, there are technical issues to resolve such as production at commercial volumes and extraction methods that mitigate the escape of methane gas into the atmosphere, which would have tremendous climate change and safety implications.

Another energy security issue related to LNG imports is supply interruptions from geopolitical tensions. The geographic supply diversity is limited to politically unstable regions, where technical failures or acts of terrorism could cause short-term supply disruptions (NEB, 2007). A fear of terrorism or accidents on pressurized LNG tankers (Santa-Barbara, 2007) has delayed construction of receiving terminals in North America (Hirsch et al., 2005). On the supply-side, Russia is the world's largest gas producer (1,751 Mm^3 day^{-1} or 22% of 2005 global output (IEA, 2007)) and has already demonstrated a willingness to use its resources as a political hammer. Russia cut gas supplies to Ukraine in January 2006 in retaliation for attempting to break away from Russian political influence (Honoré and Stern, 2007). Unreliability of Russian suppliers coupled with potential under-investments in supply infrastructure by state-controlled gas industries adds considerable risk to a dependence on LNG imports.

2.1.3 Canadian perspective

Canada's population and economy are predicted to expand, leading to a 39% increase in primary energy demand from 12 to 17 EJ over 2004-2030 (NEB, 2007). Most of the demand growth is anticipated to be met by increased consumption of oil and natural gas.

Crude oil demand is predicted to increase 62% from 2.1 to 3.4 Mbpd over 2004-2030 while production is projected to increase 88% from 2.5 to 4.7 Mbpd (NEB, 2007). Total petroleum production will substantially increase despite declining output from mature conventional oil fields in the Western Canadian Sedimentary Basin (WCSB) and east coast offshore deposits due to tremendous growth (315%) in unconventional oil production (1.0 to 4.2 Mbpd over 2004-2030) (NEB, 2007). About 90% of total petroleum supply will be unconventional extra heavy oil (or bitumen) by 2030.

Natural gas demand in Canada is predicted to increase 34% from 270 to 360 Mm^3 day^{-1} over 2004-2030 while production is projected to decrease 38% from 480 to 300 Mm^3 day^{-1} (NEB, 2007). Domestic gas production peaked in 2002 then gradually declined as output from mature fields in the WCSB waned. Strong domestic demand coupled with declining production will force Canada to reduce its gas exports to the US and become a net importer of natural gas between

2025 and 2030 (NEB, 2007). Canada would then have to assume the aforementioned risks associated with a reliance on LNG imports.

The boom in oil sands development is a major driver of natural gas demand. The industry uses gas as a means of generating steam to extract and upgrade bitumen to synthetic crude oil. Oil recovery by surface mining and upgrading requires less natural gas (21 m^3 bbl^{-1}) than in situ production (42 m^3 bbl^{-1}) but is only possible for 7% of the deposits (Pembina Institute, 2005). Assuming production of 1.0 Mbpd, gas demand could range from 21 to 42 Mm^3 day^{-1}. If production were to increase to 5.0 Mbpd, demand would range from 105 to 210 Mm^3 day^{-1} or 30% to 60% of total gas production. The oil sands are on pace to become an even larger gas consumer and accelerate national reliance on LNG.

In addition to petroleum and natural gas, Canada's primary energy supply mix consists of coal, hydro, nuclear, and biomass and renewable sources (Table 2-2).

Table 2-2: Canadian energy supply mix 2004-2030 based on the continuing trends scenario of the NEB Canada's Energy Future report (source: NEB, 2007).

Primary energy source	**Fraction of supply mix**		**Overall average annual growth rate (2004-2030)**
	2004	2030	
Crude oil	38%	44%	1.9%
Natural gas	28%	27%	1.1%
Coal	11%	4.8%	-1.7%
Hydro	10%	8.9%	0.8%
Nuclear	8.1%	8.1%	1.3%
Biomass and renewables	5.4%	6.8%	2.1%
Total	**100%**	**100%**	**-**

Coal demand is expected to decrease 36% over 2004-2030 primarily due to the eventual closure of Ontario's coal-fired power plants, which is the reverse trend compared to the US and the rest of the world. Hydroelectric power generation is anticipated to only increase 24% as the best sites for generating hydroelectricity have already been developed. Nuclear power is predicted to grow at the same rate as primary energy demand while biofuels and emerging energy are expected to deliver the most growth but still only account for 6.8% (1.2 EJ) of total primary energy demand by 2030 (17 EJ).

2.2 Climate change

2.2.1 Global trends

The Intergovernmental Panel on Climate Change (IPCC) has concluded that anthropogenic emissions of long-lived greenhouse gases (GHGs) are responsible for an enhanced greenhouse effect that is raising the planet's average surface temperature and accelerating rates of climate change (IPCC, 2007). The primary GHGs – carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) – differ in their global warming potential due to distinct radiative properties and atmospheric residence times. Consequently, GHG emissions and atmospheric concentrations are expressed in terms of CO_2-equivalents (CO_2e), which is the amount of CO_2 that would be needed to cause the same radiative forcing over a given time period (IPCC, 2007). Global consumption of fossil fuels is expected to increase 57% from 390 to 610 EJ, which will cause a 58% rise in energy-related emissions from 26.6 to 41.9 $GtCO_2e$ over 2005-2030 (Fig. 2-3) (IEA, 2007).

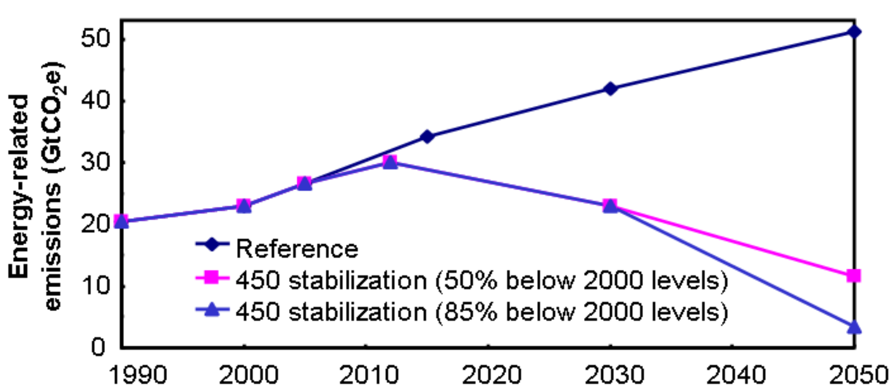

Figure 2-3: Global energy-related GHG emissions over 1990-2005 and projections to 2050 (source: IEA, 2007).

The concentration of CO_2 in the atmosphere rose from a pre-industrial level of 280 to 379 ppmv (parts per million by volume) by 2005 (IEA, 2007). Climate models predict that global warming could be limited to 2.0 to 2.4°C above pre-industrial levels by stabilizing atmospheric CO_2e concentration at 450 ppmv (IEA, 2007). A larger average rise in global surface temperatures is almost certain to cause significant disruptions such as flooding of densely populated coastal areas, more extreme weather events, more species extinction, and higher risks of disease and water shortages (Bramley, 2005; IPCC, 2007). Global energy-related GHG emissions would then have to peak and decline to 23 GtCO_2e by 2030 (Fig. 2-3) and drop to 50% to 85% below 2000 levels by 2050 (12 to 3.5 GtCO_2e) (IEA, 2007). The business-as-usual projection is consistent with stabilization at 855-1130 ppmv, which could warm the planet 6.1°C above pre-industrial levels and lead to unpredictable consequences.

In the past 25 years energy-related emissions grew more slowly than primary energy demand as the use of nuclear power and natural gas expanded (IEA, 2007). The rise in the use of coal in developing countries is projected to reverse this trend and recarbonize global fuel supplies even though decarbonization is needed to mitigate GHG emissions (Homer-Dixon, 2008).

2.2.2 Canadian perspective

Climate change would disproportionately affect polar countries like Canada, where warming will occur twice as fast compared to the global average because of positive feedbacks (Homer-Dixon, 2008). The albedo of snow and ice is high since it reflects more solar radiation than terrestrial land or water. However, higher rates of warming will increase melting in polar regions, which will further accelerate climate change by lowering surface albedo and increasing the amount of solar radiation absorbed. Despite the positive feedbacks that accelerate warming in Canada, fossil fuel demand is expected to increase 38% from 9.4 to 13 EJ while total GHG emissions are predicted to rise 36% from 746 to 1012 $MtCO_2e$, which would be 42% higher than 2000 levels (NEB, 2007).

The Canadian federal government has committed to medium- and long-term GHG emission reductions. The National Round Table on the Environment and Economy (NRTEE) report on a low-emission future identified the targets as 20% below 2006 levels by 2020 and 60% to 70% below by 2050 (NRTEE, 2007). According to Environment Canada's (EC) 2006 National Inventory Report, energy-related emissions in 2006 were 583 $MtCO_2e$ (EC, 2008), which makes the target 470 and 200 $MtCO_2e$ by 2020 and 2050, respectively.

The IPCC estimates that world GHG emissions need to be reduced 50% to 85% below 2000 levels by 2050 to stabilize atmospheric CO_2e concentration at 450 ppmv (IEA, 2007). Based on equity principles, industrialized countries must reduce their emissions by a greater amount (80% below 1990 levels by 2050) (Bramley, 2005). Canada's 1990 energy-related emissions were 470 $MtCO_2e$ (EC, 2008), which means that 2050 emissions should not exceed 94 $MtCO_2e$ (Fig. 2-4).

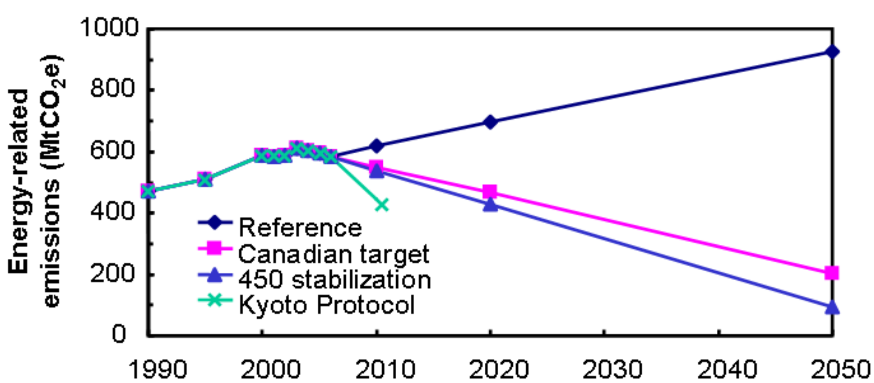

Figure 2-4: Canada's energy-related GHG emissions over 1990-2006 and projections to 2050 (sources: Bramley, 2005; EC, 2008; NEB, 2007).

The revised target, which is based on limiting global warming to a maximum of 2.4°C, is 54% lower than the federal government's 2050 target. Moreover, the federal 2020 target (470 $MtCO_2e$) is equal to 1990 levels whereas Canada's commitment under the Kyoto Protocol was to reduce GHG emissions 6% below 1990 levels by 2008-2012. The weakness of Canada's 2020 target is as much a concern as the 2050 target because policies implemented today will bear more heavily on the medium-term commitments (Bramley, 2008).

2.2.3 Summary

The world is not headed towards a sustainable energy future. Growing consumption of oil and natural gas threatens the world's energy stability while the resurgence of coal is raising the carbon intensity of the global economy. Alternative approaches that mitigate energy security and climate change risks are needed.

2.3 Energy technology options

There are three ways to reduce imported fossil fuel dependence whilst building a cleaner, more secure energy supply: energy conservation and efficiency, carbon capture and storage, and decarbonized energy sources (Bauen, 2006).

2.3.1 Energy conservation and efficiency

Demand management can reduce the burden on energy supplies to meet growing global energy needs (Bauen, 2006; IEA, 2006). Energy conservation is a reduction in energy consumption through behavioural changes (Bauen, 2006). The transportation sector offers great potential for conservation as 67% of personal automobile and 50% of air travel are estimated to be discretionary (Hirsch et al., 2005). Transit-oriented development that promotes high-density living around public transportation corridors could also reduce transportation needs (Vanderburg, 2000). Households can reduce energy consumption by adjusting thermostats, using energy-intensive major appliances such as dishwashers, washing machines, and clothes dryers at full loads, or turning off unnecessary lights. An alternative that may encounter fierce public opposition (especially in Canada) would be to forego the use of secondary "beer fridges", which are in most cases older, inefficient models (Young, 2008).

Energy efficiency allows the same amount of useful work to be extracted from an energy conversion process with less energy input. Technological efficiency improvements can occur anywhere along the supply chain from production to end-use. For example, more advanced steam turbine technologies can increase the overall thermal efficiency of coal-fired power generation from 30% to 45% (IEA, 2007). Combined heat and power plants could improve the overall fuel utilization ratio compared to electricity- or heat-only plants (Bauen, 2006). Decentralized distributed generation using microturbines or fuel cells eliminates transmission and distribution network power losses (Massardo et al., 2002).

The energy efficiency of buildings can be increased by an estimated 70% (IEA, 2006). Space heating and cooling can be reduced by insulating windows and the building envelope (Worldwatch Institute, 2006). More advanced major appliances, lighting, motors, and pumps can raise electrical end-use efficiency, which saves at least twice as much primary energy after accounting for power supply chain conversion losses (Bauen, 2006). Large efficiency gains in the transportation sector are also achievable by adapting hybrid technology, lighter materials, and keeping tires inflated to the correct pressure (IEA, 2006).

Although conservation practices can be immediately implemented, end-use efficiency depends on the stock of energy-using equipment. For example, improving overall fuel economy in the transportation sector under normal replacement rates is estimated to take decades (Hirsch et al., 2005). Policies that promote energy efficiency are essential; otherwise the economy gets locked in with inexpensive, low-efficiency capital (NRTEE, 2007).

A number of energy economists have challenged the view that improving efficiency reduces total energy consumption. The paradox is that technological efficiency gains at the microeconomic level have direct and indirect rebound effects that increase consumption at the macroeconomic level (Brookes, 2000; Herring, 2006). The direct rebound effect is greater energy consumption through lower implicit prices while the indirect effect is that more money is available to spend on other goods and services, which increases economic growth and total energy consumption (Herring, 2006). However, it has also been argued that the total rebound effect is less than the energy saved (Schipper and Grubb, 2000). A recent study estimated a 26% total rebound effect (i.e., actual energy savings are 74% of the theoretical amount) using an energy-environment-economy model (Barker et al., 2007). The energy efficiency paradox is still unresolved and must be considered when formulating energy policy.

2.3.2 Carbon capture and storage

Carbon capture and storage (CCS) is a technology anticipated to prolong the use of coal and bridge the transition to a carbon-free economy. CO_2 is separated from a product stream, compressed, and sequestered into one of four possible storage sites: depleted oil or gas reservoirs, unminable coal beds, deep saline aquifers, or the deep ocean (Evans, 2007). It is most often associated with coal-fired power generation although CCS is applied to natural gas produced at the Sleipner and In Salah fields in Norway and Algeria, respectively (IEA, 2007).

Clean coal technologies produce power or liquid fuels from coal with subsequent CCS. Conventional coal power stations employ the Rankine cycle, where the heat of combustion boils water into steam, which then drives a turbine that generates electricity (IEA, 2007). The overall thermal efficiency ranges from 30% to 45% for more advanced technologies (Evans, 2007). The exhaust flue gas is mostly nitrogen and about 15% CO_2 by volume and also contains air contaminants like nitrogen oxides (NO_x), sulphur oxides (SO_x), and particulate matter (Evans, 2007). Clean coal power is more commonly associated with oxygen-blown, integrated gasification and combined cycle (IGCC) power plants with minimal nitrogen dilution of CO_2

streams. An IGCC power plant would have a thermal efficiency of 55% (Bauen, 2006) and CCS could offset more than 85% of CO_2 emissions (IEA, 2007). However, the energy requirements of CCS would reduce net thermal efficiency of IGCC to 40% (Bauen, 2006). Similarly, CCS can be applied to coal-to-liquid plants that produce liquid transportation fuels via coal gasification and catalytic synthesis (Evans, 2007). However, the carbon emitted from the vehicle's internal combustion engine cannot be sequestered. Consequently, the life-cycle GHG emissions of coal-to-liquid fuels are most likely higher than petroleum-based fuels whether or not CCS is employed.

There is no financial incentive to install CCS unless carbon is priced. The capital cost of a coal power plant is estimated to be 50% higher when affixed with CCS equipment ($1900 to $2300 kW^{-1}) and the cost of electricity is predicted to range from $50 to $100 MWh^{-1} (Table 2-4, page 25). On the other hand, clean coal has lower estimated life-cycle GHG emissions compared to traditional power stations. The feasibility of large-scale CCS and infrastructure requirements are the primary barriers to implementation (Schiermeier et al., 2008).

2.3.3 Nuclear power

Nuclear fission of uranium-235 (U-235) sparks a chain reaction in the core of a nuclear reactor that generates heat (WNA, 2008). The thermal energy evolved is used in a Rankine cycle to generate power. A by-product of fission is radioactive nuclear waste that is either reprocessed or disposed of.

The popularity of nuclear power blossomed in the 1970s after the oil crises thrust energy security into the political spotlight. Natural uranium was seen as a secure energy source since more than half of global production is in Canada and Australia (WNA, 2008). Its popularity declined by the late 1980s due to falling global energy prices, cost and schedule overruns of nuclear plants, failure to make progress on radioactive waste management, and public concerns from accidents at Three Mile Island (1979) and Chernobyl, Ukraine (1986) (Grimston, 2007). France was the lone exception and gradually increased nuclear power capacity, driven by a lack of domestic energy resources and security concerns (Grimston, 2007).

Nuclear power has a high capacity factor and life-cycle GHG emissions are estimated to range from 10 to 20 gCO_2e kWh^{-1} (Miller, 2007), which is comparable to hydro and wind (Table 2-4, page 25). Earlier designs faced economic challenges because they were capital-intensive with long construction times (Grimston, 2007). Capital costs were predicted to decline from \$2000 to \$1600 kW^{-1} for modularized, next generation reactors (Evans, 2007) but labour shortages, rising material costs, and new technology inexperience have led to construction delays and higher costs (\$5000 to \$8000 kW^{-1}) (Hamilton, 2008).

There are other unresolved issues with nuclear power. The dominant isotope in natural uranium is U-238 (99.3%) whereas the fissile isotope U-235 is only present in small quantities (0.7%) (WNA, 2008). Current technology is based on once-through operation and although some reprocessing of spent fuel is performed most of the uranium is discarded as radioactive waste. Based on proven reserves of natural uranium, a 50- to 80-year supply is estimated for existing nuclear plants (Evans, 2007; Schiermeier et al., 2008). Breeder reactors can use a higher percentage of the uranium fuel but simultaneously produce plutonium, which raises nuclear weapons proliferation concerns (Schiermeier et al., 2008). Advanced processes based on fuel recycling or alternative feedstocks (i.e., thorium) must first prove to be commercial and gain public acceptance before they can be seriously considered.

2.3.4 Renewable energy

2.3.4.1 Hydropower

The potential of hydro resources to produce power was recognized a long time ago (IEA, 2006). Hydroelectricity is a low-cost, mature technology, and the world's largest source of renewable power (IEA, 2007). Canada's extensive hydro resources contribute more than 50% to domestic electricity supplies (NEB, 2007). Unlike most renewable energy sources, hydro technology can be developed at large scales through the use of hydraulic turbines up to 700 MW in size (Evans, 2007). Although the investment costs of hydroelectric power plants are high (\$1000 to \$3000 kW^{-1}), they enjoy longer life expectancies and no fuel costs (Evans, 2007). Hydropower is very affordable at \$30 to \$40 MWh^{-1} for large plants and \$20 to \$90 MWh^{-1} for small projects (IEA, 2006). They also exhibit high capacity factors and low life-cycle GHG emissions (Table 2-4, page 25). Most low-cost hydro resources have already been developed and the remaining large-scale potential is in Africa, Asia, and Latin America (IEA, 2006). Small hydropower projects can still be exploited in the developed world but have limited potential.

2.3.4.2 Wind energy

The potential to generate power from wind has made tremendous strides due to technological advances and the high cost of fossil fuels. From 2001 to 2003, Germany increased its world-leading installed wind capacity by 67% while 20% of Denmark's electricity supply is from wind sources (Evans, 2007). The largest wind turbines now have a peak capacity of 4.5 MW with units up to 5 MW in development (Evans, 2007). Wind farms that take advantage of economies of scale have been constructed on both onshore and offshore sites. The capital cost of onshore wind farms ranges from \$1000 to \$1500 kW^{-1} installed, while offshore installations range from \$2000 to \$2500 kW^{-1} due to higher construction costs (Table 2-4, page 25) (IEA, 2006). The range of electricity production costs is \$30 to \$200 MWh^{-1} while life-cycle emissions are only 20 to 36

$gCO_2e\ kWh^{-1}$ (Evans, 2007; IEA, 2006; Samson et al., 2008). Unfortunately, the windiest places that could offer the lowest production costs are more remote locations and require investments in electricity-supply infrastructure (Schiermeier et al., 2008).

Wind intermittency can be prohibitive with current electrical grid systems. A wind turbine designed for a peak capacity of 4.5 MW will only operate at that level about 25% of the time (Evans, 2007). Utilities should be able to handle up to 20% wind power without much difficulty (Schiermeier et al., 2008). In Denmark's case, back-up electrical ties to neighbouring countries provides insulation from wind variability (Evans, 2007). Intermittency could be solved by more sophisticated grid management and electricity storage systems (i.e., batteries, hydrogen) (Bauen, 2006; IEA, 2006).

2.3.4.3 Solar energy

Solar technologies use solar radiation to produce heat or power. Solar thermal technologies use the sun's thermal energy to provide heat or electricity using a conventional Rankine power cycle whereas photovoltaic (PV) cells convert sunlight directly into electricity (Evans, 2007).

Solar thermal energy systems can provide heating in buildings. Passive solar techniques such as enlarged south-facing windows and black-painted concrete walls can perform natural space heating (Evans, 2007). Solar collectors mounted on rooftops can heat water, which can be circulated to provide active solar heating or used as a source of hot water (Evans, 2007).

Solar thermal technologies can also produce power through Concentrating Solar Power (CSP) systems that operate like thermal power stations. Solar radiation is captured by reflecting mirrors and beamed onto a focal point that heats up a working fluid, which then drives a turbine that produces electricity (Evans, 2007; Schiermeier et al., 2008). The system can have a high capacity factor (up to 60%) when using thermal energy storage to continue producing power when sunlight is unavailable (Evans, 2007). Investment costs range from \$2000 to \$4000 kW^{-1} and the cost of electricity ranges from \$120 to \$200 MWh^{-1} (Table 2-4, page 25) (IEA, 2003; Neuhoff, 2007). Large CSP installations would most likely be in desert or other remote locations that would require investments in electricity-supply infrastructure (Schiermeier et al., 2008).

Solar PV is a modular technology that can convert up to 20% of sunlight directly into electricity (IEA, 2006; Schiermeier et al., 2008). The life-cycle GHG emissions range from 100 to 150 $gCO_2e\ kWh^{-1}$ but it is an intermittent technology with a capacity factor of about 15%, which is even lower than wind power (Table 2-4, page 25) (Evans, 2007; Schiermeier et al., 2008). Investment costs range from \$4000 to \$6000 kW^{-1} and the cost of electricity ranges from \$200 to \$450 MWh^{-1} (IEA, 2003; Neuhoff, 2007). Although the potential of PV power is tremendous, considerable investments and a technological breakthrough are required before it can be commercialized (IEA, 2006; Schiermeier et al., 2008).

2.3.4.4 Geothermal energy

Geothermal energy uses high temperature heat from Earth's interior to provide heating or power generation (Evans, 2007). However, the rate at which heat flows from the Earth's core makes it hard to produce electricity from geothermal sources except in places with hot springs (Schiermeier et al., 2008). Geothermal electricity produced via the conventional Rankine cycle from superior sites was estimated to cost \$30 to \$80 MWh^{-1} (Table 2-4, page 25) (Schiermeier et al., 2008) with life-cycle emissions of 75 to 100 $gCO_2e\ kWh^{-1}$ (Samson et al., 2008). Geothermal power generation from lower temperature sources is more expensive to produce but higher energy prices could expand production (Evans, 2007). Lower temperature resources in certain parts of the world hold promise as a source of domestic heating or cooling via ground-source heat pumps (IEA, 2006).

2.3.4.5 Hydrogen fuel-cell and battery electric vehicles

Hydrogen and electricity from low-carbon sources are attractive energy carriers to displace petroleum-based transportation fuels. A fuel cell is an electrochemical device that converts the chemical energy in hydrogen into electricity at about 50% efficiency with water as the only by-product (Evans, 2007). Stationary fuel cells have been used to produce electrical power on space ships or for large-scale power generation applications (Evans, 2007). However, hydrogen from low-carbon sources used in fuel-cell vehicles could decarbonize the transport sector in the long-term (IEA, 2006). The onboard fuel storage system is critical because hydrogen would require pressurized or cryogenic fuel tanks that add weight and volume to the vehicle (MacLean and Lave, 2003). Moreover, huge infrastructure investments would be required to develop hydrogen production and distribution systems (IEA, 2006).

An all-electric vehicle using a high-efficiency battery might be more feasible than a fuel-cell vehicle (Evans, 2007). An onboard battery that powers an electric motor that turns the wheels could be directly charged with grid electricity (MacLean and Lave, 2003). The process of getting electricity from the "well" to the "tank" is much more efficient for battery-powered vehicles assuming a readily available source of power (Table 2-3).

Table 2-3: Energy conversion chain and overall well-to-tank efficiency for a hydrogen fuel cell or battery assuming a readily available source of power (source: Evans, 2007).

Fuel cell		**Battery**	
Electrolysis	75%	Battery charging	90%
Compression	90%	-	-
Fuel cell	50%	-	-
Overall well-to-tank efficiency	**34%**	**Overall well-to-tank efficiency**	**90%**

Battery electric vehicles would be pollution-free and decarbonized provided the electricity was produced from low-carbon sources. A major challenge is the limited driving range available between recharges (Bauen, 2006). Lithium-ion batteries are expected to engineer the transition to electric vehicles due to their large electrochemical storage capacity (Daniel, 2008). However, more progress still needs to be made in lithium-ion technology and vehicle performance before commercialization is possible (Evans, 2007; MacLean and Lave, 2003).

2.3.5 Summary

A number of energy technology options that reduce fossil fuel dependence and GHG emissions have been presented. Past assessments of future energy systems acknowledge that there is no silver bullet and a suite of technologies are needed to meet energy security and climate change objectives (Bauen, 2006; Hoffert et al., 2002; NRTEE, 2006; Pacala and Socolow, 2004). A summary of the power generation options is given in Table 2-4.

Table 2-4: Characteristics of various power generation technologies (sources: Bauen, 2006; Evans, 2007; IEA, 2003; Miller, 2007; Neuhoff, 2007; Overend, 2003; Samson et al., 2008; Schiermeier et al., 2008).

Power source	Capacity factor	Investment ($ kW^{-1})	Cost of electricity ($ MWh^{-1})	Life-cycle emissions ($gCO_2e\ kWh^{-1}$)
Coal	90%	1300 – 1500	35 – 45	980 – 1100
Coal + CCS	90%	1900 – 2300	50 – 100	150 – 160
Natural gas	90%	500 – 700	35 – 70	450 – 600
Nuclear	90%	1600 – 5000	45 – 70	10 – 20
Hydro	90%	1000 – 3000	30 – 90	10 – 25
Wind (onshore)	25%	1000 – 1500	30 – 120	20 – 36
Wind (offshore)	25%	2000 – 2500	50 – 200	20 – 36
CSP	60%	2000 – 4000	120 – 200	N/A
Solar PV	15%	4000 – 6000	200 – 450	100 – 150
Geothermal	75%	1000 – 3000	30 – 80	75 – 100
Biomass	85%	1500 – 2000	50 – 150	100 – 160

It is evident that there are a number of sources available for generating decarbonized power at reasonable costs. Substitution of heating and transportation fuels is more challenging although the long-term prospect of battery electric or hydrogen fuel-cell vehicles is tempting.

Biomass power generation was included in Table 2-4 but has not yet been discussed. The next section will investigate bioenergy production in more detail.

2.4 Bioenergy

2.4.1 Fundamentals

Biomass is photosynthetic matter, in which sunlight energy is stored in the chemical bonds of carbohydrates. Growth and decay is renewable since oxidation emits CO_2 and water, which then becomes available for photosynthesis of new biomass (McKendry, 2002a). Traditionally, biomass is used for food, feed, and fibre (Klass, 1998) as well as cooking and space heating in developing countries (Faaij, 2006). Woody and herbaceous biomass such as hybrid poplar and switchgrass are lignocellulosic substances composed of cellulose, hemicellulose, and lignin (Klass, 1998). Cereal crops such as corn and wheat are composed of starch (complex carbohydrate) as well as fat and protein, whereas sugar cane is mostly simple carbohydrates. Commercial energy farming of biomass crops is driven by energy security, climate change, and rural economic development. High-yield, low-cost perennial crops that have minimal energy and nutrient requirements offer the most environmental, economic, and social benefits (McKendry, 2002a).

The higher heating value (HHV) represents the maximum amount of energy attainable from combustion as it includes recovery of water's latent heat of vaporization through condensation. The lower heating value (LHV) on a wet basis discounts the energy required to evaporate water and is affected by hydrogen and moisture content (Table 2-5, column 5) (van Loo and Koppejan, 2003). The LHV on a dry basis (Table 2-5, column 6) is based on dry biomass with no moisture.

Table 2-5: Physical characteristics and energy content of biomass.

Type of biomass	HHV (GJ $t(dry)^{-1}$)[a]	Moisture[a]	Hydrogen (dry weight basis)[b]	LHV (GJ $t(wet)^{-1}$)[c]	LHV (GJ $t(dry)^{-1}$)[c]
Woody	20.0	45%	6.0%	9.20	18.7
Herbaceous	18.5	25%	5.5%	12.4	17.3

[a] From Klass, 1998.
[b] From van Loo and Koppejan, 2003.
[c] Equations in Appendix A.

The CO_2 emitted during biomass oxidation is equivalent to the uptake from the atmosphere during photosynthesis. Consequently, biomass can be a negative- (if CCS is applied) to low-carbon source of renewable energy as long as replanting occurs after harvest (Evans, 2007). A basic bioenergy supply chain involves biomass production, harvesting, pre-processing, transportation, and energy conversion (Fig. 2-5). In addition to sunlight, CO_2, and water, which drive photosynthesis, production requires fertilizers, pesticides, and diesel inputs (Turhollow and Perlack, 1991). Consumption of diesel and other petroleum-based inputs emits CO_2 while application of synthetic nitrogen fertilizer to agricultural soils leads to N_2O emissions, which has a global warming potential 310 times that of CO_2 (IPCC, 2000). Trees are then felled, skidded to the side of the road, and chipped. Herbaceous crops are harvested, baled, and stored at the side of the farm. Wood chips or straw bales are then loaded onto a truck, transported to an energy conversion facility, unloaded, and put into storage.

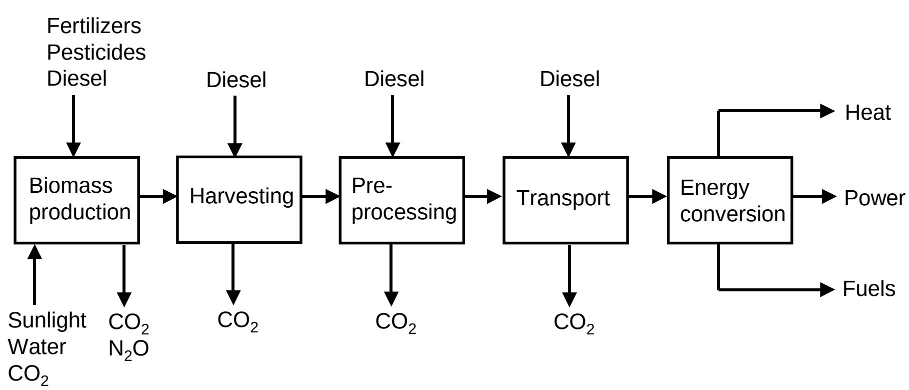

Figure 2-5: Typical bioenergy supply chain.

2.4.2 Biomass for heat, power, and transportation fuels

Biomass is a flexible resource that can produce heat, power, or transportation fuels through a variety of conversion routes. Processes are classified as thermochemical, biochemical, or extraction depending on the pathway (Table 2-6).

Combustion of lignocellulosic biomass can be a source of heat and power. Utilization of biomass for domestic space heating and hot water has expanded in Europe as a large number of household gas- and oil-fired boilers have been substituted with wood pellet boilers and stoves (Duffy and Conroy, 2007). Biomass combustion can also feed district heating systems from centralized heat-only or cogeneration plants (IEA, 2006). Cogeneration applies a conventional Rankine cycle to generate power and uses the exhaust flue gas for district heating. The combined system improves the fuel utilization ratio from around 35% for electricity-only plants to 90% (Faaij, 2006). Another possibility is co-firing with coal, which can be done with small modifications up to 15% biomass (Gjernes et al., 2007).

Table 2-6: Conversion options for producing heat, power, or transportation fuels from biomass (sources: Faaij, 2006; McKendry, 2002b).

Conversion option	Final product	Examples
Thermochemical		
Combustion	Heat Power	Domestic and district heating, cogeneration, co-firing
Gasification	Heat Power	Gas turbine combined cycle, hydrogen fuel cell
	Transportation fuels	Methanol, ethanol, Fischer-Tropsch liquids, dimethyl ether, hydrogen, synthetic natural gas
Pyrolysis	Heat Power	Gas turbine combined cycle
	Transportation fuels	Diesel
Biochemical		
Digestion	Heat Power	Synthetic natural gas, gas engine, gas turbine
	Transportation fuels	Compressed natural gas
Fermentation	Transportation fuels	Ethanol
Extraction		
Esterification	Transportation fuels	Biodiesel

The Alholmens Kraft plant in Pietersaari, Finland, is the world's largest biomass power plant (OPET Finland, 2002). It is a wood-fired combined heat and power plant that produces 240 MW of electricity, 100 MW of process steam, and 60 MW of district heating. The Williams Lake

Generating Station in British Columbia has North America's largest biomass-fired boiler, with a capacity of 60 MW of electricity (Wiltsee, 2000).

Biomass gasification is a high-temperature (800-900°C) process that converts biomass into a solid-gas mixture in an oxygen-limited environment (McKendry, 2002c). Dry feedstock is directly or indirectly heated to devolatilize the volatile components of biomass leaving behind a solid char residue (Bridgwater, 2003). Direct heating is exothermic partial oxidation of the feedstock in either air or pure oxygen (McKendry, 2002c) while indirect heating is when the solid char fraction is combusted in a separate vessel and the heat is recirculated to the gasifier (Rauch, 2005). Steam is then injected into the gasifier, which drives endothermic gasification reactions that produces a syngas rich in carbon monoxide and hydrogen (Bridgwater, 2003). The overall energy efficiency of gasification is estimated to range from 75% to 80% (McKendry, 2002c). There are different gasification techniques that have unique impacts on syngas quality, scale-up potential, and cost (Tijmensen et al., 2002). A summary of the various methods are presented in Table 2-7.

Table 2-7: Advantages and disadvantages of various gasification methods (Bridgwater, 2003; McKendry, 2002c; Tijmensen et al., 2002).

Gasifier	Advantages	Disadvantages
Atmospheric	Lower costs at small scale	Larger downstream equipment; Less scale-up potential
Pressurized	Smaller downstream equipment; Good scale-up potential	Higher costs at small scale
Directly heated	Less tars produced; Good scale-up potential	Syngas may be diluted with nitrogen (i.e. air-blown directly heated gasifiers)
Indirectly heated	Nitrogen-free syngas without an air separation unit	More tar issues; Complex design impedes scale-up potential
Air-blown	Lower costs	Syngas diluted with nitrogen; Less scale-up potential; Larger downstream equipment
Oxygen-blown	No nitrogen dilution of syngas (smaller equipment); Good scale-up potential	Capital and operating costs of air separation unit

The optimal gasification method depends on the scale of operation and the desired energy product. Small-scale applications to produce heat and power should employ direct or indirect, air-blown, atmospheric systems to minimize investment costs. Large-scale applications to produce heat, power, or fuels should invest in capital-intensive pressurized, directly heated (better scale-up potential), oxygen-blown systems to reduce the size of downstream equipment and minimize nitrogen separation requirements during fuel synthesis.

The syngas must then be cleaned of impurities that could foul downstream equipment or catalysts (Tijmensen et al., 2002). The extent of cleaning required depends on the gas end-use (McKendry, 2002c). For example, catalytic processes require cleaner syngas than heat and power generation. Tar contamination of the syngas is the most significant technical barrier (Bridgwater, 2003). Clean syngas could be used in a gas turbine combined cycle process (McKendry, 2002b) or in a water-gas shift reactor that converts carbon monoxide and water into hydrogen and CO_2 (Hamelinck et al., 2002).

The extent of the water-gas shift reaction depends on the desired fuel. Methanol, dimethyl ether, and Fischer-Tropsch (FT) liquids require a hydrogen to carbon monoxide ratio of 2:1 (Hamelinck et al., 2002; Hu et al., 2005; Tijmensen et al., 2002) whereas synthetic natural gas (SNG) production by methanation requires a 3:1 ratio (Duret et al., 2005). Biological conversion of syngas to ethanol does not require a set ratio (van Kasteren et al., 2005) while hydrogen production requires as much of the carbon monoxide to be reacted as possible. A hydrogen stream can be used to generate high-efficiency power in a gas turbine combined cycle or stationary fuel cell or as an alternative transportation fuel in fuel-cell vehicles (McKendry, 2002b). The CO_2 stream can be released to the atmosphere or sequestered using CCS technology. This could result in carbon-negative power albeit at significant economic costs.

An 8 MW thermal input cogeneration plant in Güssing, Austria, uses an indirect gasifier fuelled by wood chips to produce heat and power in a gas engine (Rauch, 2005). The plant produces 2 MW of electricity and 4.5 MW of heat, which gives a fuel utilization ratio of 81%. The Kymijarvi generating station in Lahti, Finland, is a coal-fired power plant equipped with a 45 MW thermal input biomass gasifier (Wiltsee, 2000). The gasifier runs on a recycled fuel mixture that consists of wood, paper, cardboard, and some plastic. The McNeil Generating Station in Burlington, Vermont, is testing and operating an indirect biomass gasifier developed by Battelle Columbus Laboratories (Wiltsee, 2000). Biomass gasification and fuel synthesis is not yet commercial, where the primary technological challenge is sufficient gas cleaning to protect downstream catalytic gas processing equipment (Faaij, 2006).

There are coal- and gas-based FT-synthesis plants in South Africa, Qatar, and Nigeria that have commercialized their technology and have similar processes as biomass-to-liquid (BTL) fuel synthesis plants (Boerrigter, 2006; Dry, 2001). Coal- and biomass-based processes are complex and more expensive than gas-to-liquid processes (Boerrigter, 2006). Furthermore, biomass-based plants are likely to cost more than coal plants due to higher feedstock costs, tar contamination of syngas, and technology learning. An advantage of BTL fuels is that their feedstock is renewable and low in GHG intensity whereas coal-based fuels are non-renewable and have a larger carbon footprint.

Pyrolysis at around 500°C converts the organic components of biomass in the absence of oxygen into a liquid bio-oil, gaseous, and solid fractions (Klass, 1998). Predominantly bio-oil can be produced if fast pyrolysis (high heating rates) is used (McKendry, 2002b). Pyrolysis products can technically be used as a source of heat and power while bio-oil can be converted into diesel fuel but the processes are not commercially viable (Faaij, 2006). For example, a flash pyrolysis pilot plant built by Dynamotive Energy Systems at West Lorne, Ontario, was heavily subsidized but failed to achieve large-scale bio-oil production (Struck, 2007). Pyrolysis is predicted to have potential as a pre-treatment option to increase the energy density of biomass prior to long-distance transport (Faaij, 2006).

Anaerobic digestion of organic waste produces biogas, which is an approximately 50:50 mixture of methane and CO_2 (Faaij, 2006). Biogas contains 20% to 40% of the feedstock energy content and can be used in an engine or turbine to produce heat and power (McKendry, 2002b). Biogas can also be upgraded to SNG by CO_2 removal and pressurized to yield compressed natural gas (CNG), which is an alternative transportation fuel (Faaij, 2006). Western European countries like Denmark and Germany use advanced digestion systems to process wet, industrial waste streams while landfill gas utilization is widely adopted in the EU and North America (Faaij, 2006).

Ethanol can be produced via direct fermentation of sugar-based feedstocks or hydrolysis and fermentation of starch-based crops (McKendry, 2002b). Cellulosic ethanol synthesis, which requires pre-treatment and hydrolysis steps, is more complex. Ethanol blended with gasoline at low percentages does not require engine modifications (Faaij, 2006) although it is less energy dense, which reduces vehicle range (Samson et al., 2008). Sugar-based ethanol in Brazil is a mature technology competitive with gasoline (Faaij, 2006). In North America, grain-based ethanol requires extensive government subsidies and has few environmental benefits (Samson et al., 2008). Grain-based biofuels also negatively impact food security by competing with poor countries for grain on the international market (Brown and Funk, 2008). Cellulosic ethanol has more long-term potential, with lower cost feedstocks that are widely available and can be grown on abandoned agricultural land unsuitable for food production (Solomon et al., 2007). There are many pilot, demonstration, and near-term commercial cellulosic ethanol facilities. Ottawa-based

Iogen launched the first pilot (1985) and demonstration (2004) plants that use cellulosic feedstocks in ethanol production (Solomon et al., 2007).

Oilseeds can be mechanically extracted and converted to biodiesel through transesterification processes (Faaij, 2006; McKendry, 2002b). It is a direct substitute for fossil diesel and does not require engine modifications. Although production and distribution of biodiesel is established technology in Europe, it still requires subsidies partly because of the cost of oilseeds production (Faaij, 2006). Waste vegetable oil and animal fat are a low-cost but limited alternative source of feedstock (van Gerpen, 2005).

2.4.3 Benefits of bioenergy

Bioenergy could make important contributions to energy security since it can be used for heat, power, or transportation via different pathways (Faaij, 2006). The ability to substitute for any number of fuels makes bioenergy a flexible option for energy planners. Current security risks revolve around petroleum-based transportation fuels (Hirsch et al., 2005), which can be replaced by ethanol, biodiesel, and FT-liquids. Similarly, the anticipated regional natural gas supply gap could be addressed by producing SNG from biomass as opposed to importing LNG.

Bioenergy can help meet GHG emission reduction targets by substituting fossil fuels with low-carbon alternatives. The life-cycle GHG emissions of bio-based heat, power, and transportation fuels are generally lower than their fossil fuel counterparts (Table 2-8).

Table 2-8: Life-cycle GHG emissions of primary and secondary energy sources (Börjesson, 1996; Jaramillo et al., 2007; Samaras and Meisterling, 2008; Samson et al., 2008).

Fuel	Heat ($kgCO_2e\ GJ^{-1}$)	Power ($gCO_2e\ kWh^{-1}$)	Fuel	Transportation ($kgCO_2e\ GJ^{-1}$)
Straw pellets	9.2	100	**Canola biodiesel (ON)**	41
Wood pellets	13	130	**Soybean biodiesel (ON)**	49
Natural gas	68	530	**Corn ethanol (CAN)**	78
Oil	84	860	**Diesel**	84
LNG	87	680	**Gasoline**	93
Coal	95	1030	**Corn ethanol (US)**	100

The GHG intensity of heat and power from lignocellulosic biomass is substantially lower than natural gas, which is the cleanest burning fossil fuel. The life-cycle emissions of grain-based transportation fuels depend on the feedstock and carbon-content of electricity. For example, canola is converted into biodiesel more efficiently than soybean while electricity used to manufacture corn-based ethanol has a higher carbon-content in the US than in Canada (Samson et al., 2008). Planting perennial biomass crops such as hybrid poplar and switchgrass sequesters carbon in soil and provides another method of reducing GHG emissions. On the other hand, converting existing peatlands or grasslands to produce annual energy crops releases GHG emissions and incurs a carbon debt that could take years to pay back (Fargione et al., 2008).

Fossil fuels are a major source of air pollution. Coal power plants emit mercury as well as NO_x and SO_x, which cause smog and acid rain, respectively (Senior et al., 2000) while consumption of petroleum-based fuels in internal combustion engines is a primary source of urban air pollution (Ogden et al., 2004). Utilizing biomass for power or transportation can reduce pollution and improve air quality. Biomass contains trace amounts of mercury and sulphur compared to coal while NO_x formation during power generation can be minimized by careful control of the operating parameters (Klass, 1998). Petroleum-based fuels blended with ethanol have fewer dust and NO_x emissions (Faaij, 2006) while biodiesel releases less carbon monoxide, unburned hydrocarbons, and particulates but slightly more NO_x than fossil diesel (van Gerpen, 2005). Similarly, FT-liquids are clean-burning, free of sulphur and nitrogen, and produce significantly lower exhaust emissions than standard fuels (Dry, 2001). Substituting fossil fuels with bioenergy alternatives would improve air quality.

A bioeconomy would also promote rural economic development in parts of Canada where natural resources have been unable to sustain jobs (Duchesne and Wetzel, 2003). Biomass could provide a new source of revenue for farmers through the sale of high-cellulose agricultural residues and purposely-grown energy crops on abandoned farmland (Worldwatch Institute, 2006). The forestry sector could be revived by retrofitting uneconomical pulp and paper mills into forest biorefineries that produce non-timber forest products such as transportation fuels and chemicals (Leidl, 2008; Ragauskas et al., 2006).

Global and North American bioenergy potential is estimated to be considerable. The current global contribution of bioenergy is 40 to 55 EJ per year (Faaij, 2006) but could increase to more than 400 EJ by 2050 (Berndes et al., 2003; Hoogwijk et al., 2003), which is similar to current primary energy demand. The US plan is to produce 1200 Mt(dry) (or 19 EJ) per year to replace 30% of petroleum by 2030 (ORNL, 2005). However, this can only meet 18% of current US energy consumption (103 EJ) (ORNL, 2005). Canada's biomass potential is estimated to range from 5 to 16 EJ (or 300 to 1000 Mt(dry)) per year (Layzell et al., 2006), which could meet 40% to 130% of current primary energy demand (12 EJ). Canada's biomass resources could meet a much higher share of primary energy demand.

Energy security and climate change are major drivers towards a bioeconomy. There are also strong economic incentives such as a hedge against future energy prices and the creation of a competitive bioproducts industry (Duchesne and Wetzel, 2003). Hence, the bioeconomy could serve as a transition from a hydrocarbon economy to a post-carbon society. Since biomass is a carbohydrate, the existing energy-supply infrastructure can more easily accommodate increased flows of bioenergy unlike hydrogen, which would need its own infrastructure (Ogden, 1999). For example, biomass can be used in existing coal-fired power plants to provide continuous, non-intermittent baseload power. Fuels such as FT-liquids and biodiesel can be blended with conventional fuels and utilize the same product distribution systems.

2.4.4 Barriers to bioenergy

The primary barrier faced by bioenergy systems is cost (IEA, 2006). In general, the delivered cost of biomass is more expensive than coal, comparable to natural gas, and less than crude oil (Table 2-9). Energy conversion facilities have high investment costs but benefit from the economy of scale (Boerrigter, 2006). Consequently, the cost of converting biomass into more usable energy carriers can be reduced by increasing the scale of operation. However, biomass is a distributed resource low in energy density, which limits the potential to collect sufficient amounts for large-scale systems without substantially increasing transportation costs (Bibeau et al., 2005; IEA, 2006). The issue then becomes whether higher transportation costs will outweigh the projected economies of scale (Wyman, 2003).

Table 2-9: Price and LHV of primary fuels (delivered cost of biomass in square brackets).

Fuel	LHV (GJ t^{-1})	Price (\$ GJ^{-1})
Woody biomass	9.2[a]	2.7 – 3.2 [4.2 – 4.7][b]
Herbaceous biomass	12.4[a]	3.8 – 4.2 [5.3 – 5.7][b]
Coal	15 – 30[c]	2 – 3[d]
Natural gas	47 – 50[e]	5 – 10[f]
Crude oil	44[g]	12 – 20[h]

[a] See Table 2-5.
[b] See text for details.
[c] Bituminous (27-30 GJ t^{-1}) and lignite (15-19 GJ t^{-1}) coal, respectively (ORNL, 2008).
[d] Average delivered cost to coal power plants in Ontario (Samson et al., 2008).
[e] Based on a natural gas LHV of 34-36 MJ m^{-3} (ORNL, 2008) and density of 0.71-0.73 kg m^{-3}.
[f] Range of wellhead natural gas prices over the last few years (EIA, 2008c).
[g] Based on a crude oil LHV of 6.1 GJ bbl^{-1} and density of 7.2 bbl t^{-1} (ORNL, 2008).
[h] Based on a range of crude oil prices from \$75 to \$125 bbl^{-1}.

The price of chipped, 45% moisture woody biomass was estimated to range from \$45 to \$54 $t(dry)^{-1}$ (2005 US\$) for forest residues and whole trees, respectively (Kumar et al., 2008). Prices were estimated to range from \$2.7 to \$3.2 GJ^{-1} based on an LHV of 9.2 GJ $t(wet)^{-1}$ for woody biomass. The price of baled, 25% moisture herbaceous biomass was estimated to range from \$62 to \$70 t(dry)$^{-1}$ for agricultural residues and biomass crops, respectively (Samson et al., 2008). Prices were estimated to range from \$3.8 to \$4.2 GJ^{-1} based on an LHV of 12.4 GJ t(wet)$^{-1}$ for herbaceous biomass.

The delivered cost of biomass includes loading, truck transportation, and unloading at the plant. Transportation costs were assumed to be \$1.5 GJ^{-1} (Table 2-9) but are very site-specific and can be much higher for larger catchment areas. The graph in Fig. 2-6 is based on an initial price of \$66 t(dry)$^{-1}$ or \$4.1 GJ^{-1} (including loading/unloading costs) and estimates the change in delivered costs as the scale of operation increases.

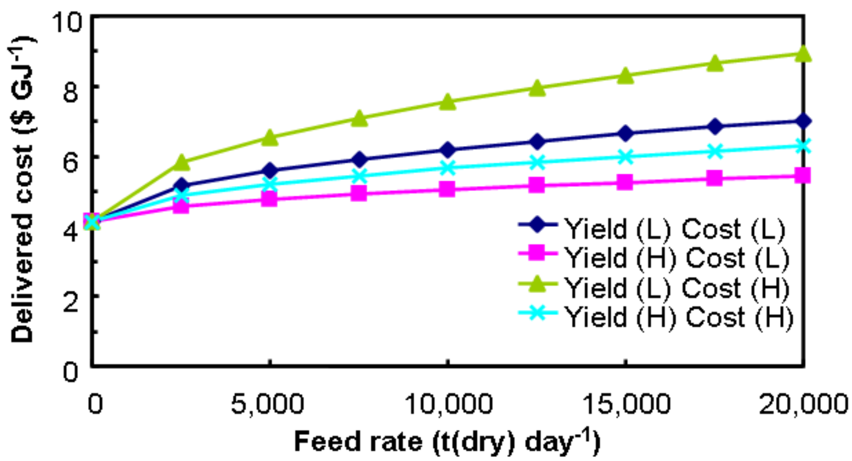

Figure 2-6: Delivered cost of biomass at different feed rates for low (L) and high (H) estimates of biomass yield and truck transportation cost. Yield estimated to range from 2.2 to 11 t(dry) ha^{-1} and cost estimated to range from \$0.072 to \$0.12 t(wet)$^{-1}$ km^{-1} (Searcy et al., 2007). Road tortuosity and land accessibility were assumed to be 1.5 (unitless) and 10%, respectively.

The challenge of building large-scale bioenergy production systems is clearly illustrated in Fig. 2-6. The delivered cost of feedstock increases slightly or significantly depending on the assumptions made for biomass yield, accessible land area, and cost of transportation. A bioenergy plant that processes 5000 t(dry) day^{-1} would be comparable in size to a large pulp and paper mill (Stuart, 2008) whereas 20,000 t(dry) day^{-1} is similar to conventional power stations and petroleum refineries. The optimum plant size is strongly dependent on biomass production and transportation assumptions as well as estimated cost reductions at larger scales.

Another challenge associated with bioenergy systems is the distance to market. Canada is a large country where sites of biomass production are located far from energy end users. An energy conversion facility built near forest or agricultural resources would be in close proximity to a large supply of feedstock but would most likely be far from heat, power, or transportation fuel consumers. The investment cost of building bioenergy-supply infrastructure or the cost of long-distance transportation of liquid fuels would form another barrier to large-scale systems.

2.4.5 Canadian bioenergy targets

Energy security, climate change, air quality, and rural economic development benefits in addition to Canada's vast biomass potential is ample justification to include bioenergy as an integral part of Canada's energy future. Biomass and other sources only contributed 0.70 EJ (6.0%) to primary energy demand in 2003 (12 EJ), most of which was used for industrial heating (NRCan, 2006b). An ambitious target of 20% of total primary energy demand from now until 2030 would be large enough for bioenergy to have a significant impact. Primary demand is predicted to increase from 12 EJ in 2003 to 15 and 17 EJ by 2015 and 2030, respectively (NEB, 2007). The bioenergy target would then rise from 2.4 EJ in 2003 to 3.0 and 3.4 EJ by 2015 and 2030. If biomass is estimated to have an average LHV of 16 GJ per dry tonne (Layzell et al., 2006), about 150, 180, and 210 Mt(dry) would be required to meet 20% of primary demand in 2003, 2015 and 2030, respectively. To put this into perspective, Canada's forestry and agriculture production is about 165 Mt(dry) per year (Layzell, 2008).

Production and distribution of more than 150 Mt(dry) or 2.4 EJ of biomass per year is not feasible without large-scale systems of similar orders of magnitude as fossil energy systems. The major barrier then becomes the logistics and cost of transportation from the biomass production site to the energy conversion facility, and the distance to market. Transformative systems that integrate large-scale bioenergy production with existing transportation corridors and fossil fuel infrastructure are essential to enable biomass to be efficiently moved from the field to energy markets. These energy systems would allow biomass to be produced at a magnitude that contributes to energy security and climate change objectives while benefiting from economies of scale.

2.4.6 Summary

Bioenergy can make a substantial contribution to Canada's primary energy supply but the cost of biomass transportation in large-scale systems is prohibitive. Bioenergy needs to be integrated with existing transportation corridors and fossil fuel infrastructure to enable large-scale production systems that efficiently move biomass from the field, to energy conversion facilities, and to markets. Two such transportation corridors in Canada are the network of natural gas pipelines and the Great Lakes St. Lawrence Seaway system. The rest of this thesis will focus on how large-scale bioenergy systems can be built around these transportation corridors.

Chapter 3
Production of Bio-Synthetic Natural Gas in Canada

3.1 Introduction

In North America, the demand for natural gas is expected to continue to rise as a result of a growing population and fuel shifting linked to high prices for crude oil (EIA, 2008a; NEB, 2007; CGA, 2003). However, Canadian production of natural gas is expected to peak by 2011 and then slowly decline thereafter (NRCan, 2006a), significantly impacting the North American gas supply. The shortfall will probably be made up by increasing the use of coal (EIA, 2008a) and by importing liquefied natural gas (LNG).

Increased reliance on LNG extends to natural gas the energy security concerns around reliance on unstable parts of the world for supplies of oil to North America. This issue, coupled with the higher life-cycle greenhouse gas (GHG) emissions associated with LNG (about 30% greater than domestic natural gas (Jaramillo et al., 2007)) and coal use, compared to domestic natural gas, has led to a strong interest in finding alternative sources of natural gas.

Renewable natural gas production from either anaerobic digestion or gasification of biomass has attracted attention because it can be produced from a wide range of feedstocks and it generates a low carbon footprint (Felder et al., 2007; Schulz et al., 2007; Zwart and Boerrigter, 2005). Compared with anaerobic digestion to a methane-rich biogas, the gasification of lignocellulosic biomass and subsequent methanation has much higher energy conversion efficiency and is better suited to the large-scale production of biomethane needed to make a significant contribution to North American energy systems.

This study assesses the technical and economic feasibility for the large-scale gasification of sustainably-produced biomass to bio-synthetic natural gas (bio-SNG) that can be distributed through the extensive network of natural gas pipelines in Canada. A systems approach was used to assess the bioSNG production potential of lands adjacent to Canada's natural gas pipelines and then track the flows of mass and energy throughout the process while assessing parasitic energy (external energy inputs) use, GHG intensity, and unit cost using a range of assumptions.

3.2 Methodology

The analysis began with an assessment of the sustainable bioenergy production capacity of the land adjacent to the existing network of natural gas pipelines in Canada. The biomass was assumed to be brought to processing sites along the pipeline where it was first gasified into a syngas (predominantly carbon monoxide and hydrogen), then converted to methane, upgraded to natural gas quality, and compressed into the pipeline. The analyses determined mass and energy flows for a number of different scales of operation from which parasitic energy use, greenhouse gas emissions, and economic costs could be evaluated. Gasification plants were assumed to be spaced at regular intervals along the pipeline. Greater spacing required larger gasification plants as well as longer biomass transportation distances.

An assessment of the range of the bioenergy potential for each scenario was obtained by making either conservative or aggressive assumptions for parameters such as land area available, biomass productivity, and conversion efficiency. Throughout the paper, conservative assumptions and calculated values will be presented in the flow of the text, whereas aggressive values will be shown in parentheses (i.e., {…}) if they differ from the conservative numbers.

3.2.1 Land area

In Canada, most natural gas pipelines originate in western Canada (northern British Columbia, Alberta, and Saskatchewan) and extend to population and industrial centres across the country. A scaled map of Canada's natural gas pipelines (Fig. 3-1) and a reference map with updated information were used to calculate Canadian land area located within 50 {100} km of one or more pipelines (Table 3-1). The map was first tested to ensure it had an equal-area projection by comparing the estimated land area of provinces to actual values. Land area measurements adjacent to gas pipelines were then traced onto mylar paper and cut out into shapes. The weight of the traced area was then compared to the weight of mylar paper having a known surface area to determine the total area of the cut out shapes. The map scale was then used to calculate the geographical area. Land areas were assigned to one of three categories: forest, good agriculture, or marginal based on current land use practices, soil types, and water availability (NRCan, 1988; NRCan, 1980).

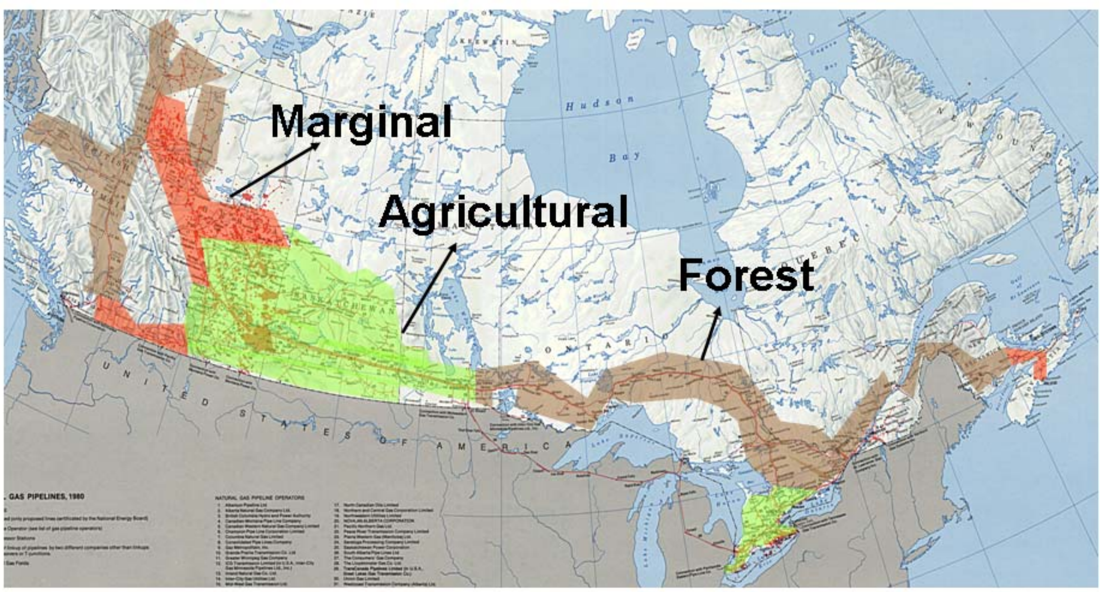

Figure 3-1: Map of Canada's network of natural gas pipelines and the forest, agricultural, and marginal land area within 100 km of the pipeline (source: NRCan, 1984a).

Table 3-1: Assumed parameters and results for the conservative (A) or aggressive (B) estimate of land area and biomass production within 50 or 100 km of natural gas pipelines for forest (FOR), good agriculture (GA), and marginal (MAR) land.

Land type	Total land area (Mha)[a]	Biomass type	Accessible land area (% $year^{-1}$)	Yield (t(dry) ha^{-1})	Available land area (Mha $year^{-1}$)[m]	Biomass (Mt(dry) $year^{-1}$)[n]
		A. Conservative				
FOR	68	Residues	0.48[b]	32[c]	0.33	10
		Whole tree harvest	0.30[d]	130[e]	0.20	26
GA	34	Residues	50[f]	0.50[g]	17	8.5
		Biomass crops	7.5[h]	7.0[i]	2.6	18
MAR	34	Biomass crops	15[j]	3.5[k]	5.1	18
Total	**136**				**25**	**81**
		B. Aggressive				
FOR	98	Residues	0.64[b]	38[c]	0.63	24
		Whole tree harvest	0.40[d]	140[e]	0.39	53
GA	49	Residues	50[f]	0.75[g]	25	18
		Biomass crops	13[h]	9.6[i]	6.1	59
MAR	49	Biomass crops	20[j]	5.6[k]	9.8	55
Total	**196**				**41**	**209**

Note: Values in footnotes refer to conservative {aggressive} assumptions.
[a] Estimated land area within 50 {100} km of natural gas pipelines in Canada.
[b] Calculated as 80% {80%} of land area as forest management x 0.6% {0.8%} of area harvested per year.
[c] Calculated as 140 {140} t(dry) ha^{-1} x 30% {30%} forest biomass residue fraction x 75% {90%} removal of forest residues.
[d] Assumed whole tree harvest from an additional 0.3% {0.4%} of forested land area per year.
[e] Calculated as 140 {140} t(dry) ha^{-1} x 93% {97%} fraction removed.
[f] Assumed 50% {50%} of good agricultural land was reserved for food crop production each year.
[g] Calculated as 1 {1.5} t(dry) ha^{-1} x 50% {50%} removal of food crop residues.
[h] Calculated as 50% {50%} of cropland per year x 5% {5%} of cropland replaced by biomass crops + 5% {10%} of good agricultural land diverted to biomass crop production.
[I] Calculated as 10 {12} t(dry) ha^{-1} x 70% {80%} fraction removed.
[j] Assumed 15% {20%} of marginal land could support biomass crop production each year.
[k] Calculated as 5 {7} t(dry) ha^{-1} x 70% {80%} fraction removed.
[m] Obtained by multiplying "Total land area" by "Accessible land area".
[n] Obtained by multiplying "Available land area" by "Yield".

3.2.2 Forest biomass production

Forest biomass for energy was assumed to be derived from two major sources: forest residues associated with conventional forest harvest and whole tree harvesting. To calculate forest residue availability from existing fibre production, 80% of the forest land area was assumed to be managed and harvested by clear-cutting at a rate of 0.6% {0.8%} of the managed land area per year. The conservative assumption (0.6%) was based on current forest harvest rates (CFS, 2006), whereas the aggressive assumption {0.8%} predicted more intensive forest management practices that enhanced productivity and reduced tree rotation length. On the harvested land, total production was 140 t(dry) ha^{-1} where 30% of the total harvested biomass was forest residue (David Suzuki Foundation, 2004) of which 75% {90%} could be removed as an energy resource.

The biomass potential of whole tree harvesting was estimated based on harvesting the unused Annual Allowable Cut (AAC), trees killed by fire, pests, and disease, and replanting with fast-growing species. Some of this biomass came from diverting biomass resources from traditional pulp and paper production systems, which have declined due to changing global markets (Towers et al., 2007). Another possibility was to make more of Canada's forests available for harvesting since only half of potentially harvestable forests were subject to management practices (CFS, 2006). Additional forest biomass resources were procured by harvesting the unused portion of the AAC (approximately 20% (CFS, 2006)) or by replanting harvested areas with fast-growing woody crops such as poplar and willow (McKendry, 2002a). Overall, it was calculated that an additional 0.3% {0.4%} of forested land area was harvested each year at a production rate of 140 t(dry) ha^{-1} where 93% {97%} of the aboveground biomass could be sustainably removed.

3.2.3 Agricultural biomass production

Agricultural biomass for energy was assumed to come from food crop residues and purposely-grown biomass crops on good agricultural and marginal land. To calculate agricultural residue availability, 50% of good agricultural land area was assumed to be reserved for food crop production each year, which produced 1.0 {1.5} t(dry) ha^{-1} of straw (Statistics Canada, 2007b; Statistics Canada 2007c). Approximately half the straw from these fields was sustainably removed as an energy resource.

The biomass potential of energy crops grown on good agricultural land was estimated based on diverting a percentage of cropland and partially-used agricultural land. It was assumed that 5% of agricultural land currently in food/feed production systems was diverted to biomass crops, and another 5% {10%} of the total good agricultural land area (possibly through conversion of pasture lands or unused agriculture lands) were replanted with purposely-grown energy crops. These crops yielded 10 {12} t(dry) ha^{-1} (Kumar and Sokhansanj, 2007) where 70% {80%} of the aboveground biomass was sustainably removed.

The biomass potential of energy crops grown on unused marginal land was estimated by assuming that 15% {20%} of marginal land area could support biomass crops at a yield of 5 {7} t(dry) ha^{-1} each year where 70% {80%} of the aboveground biomass was sustainably removed.

3.2.4 Mass, energy, and GHG emissions

Forest and agricultural biomass production required fossil fuel energy inputs. Natural gas, diesel fuel, and electricity were used in fertilizer production, harvesting operations, and pre-processing of forest and agricultural biomass. The energy inputs in biomass production were estimated from studies found in the literature (Turhollow and Perlack, 1991) and GHG emissions were determined from life-cycle emission factors for diesel fuel, natural gas, and electricity (Börjesson, 1996; Jaramillo et al., 2007; OEE, 2006).

Nitrogen use in agricultural soils leads to GHG emissions of nitrous oxide (N_2O) through the microbial processes of nitrification (conversion of ammonia to nitrate) and denitrification (conversion of nitrate to N_2O). Intergovernmental Panel on Climate Change (IPCC) guidelines were used to calculate direct and indirect N_2O emissions from applications of synthetic fertilizer nitrogen and decomposition of nitrogen-containing crop residues (IPCC, 2000). Conservative or aggressive assumptions were made with respect to the soil's nitrogen-use efficiency as described in the Results section. The global warming potential of N_2O, which is 310 times that of CO_2 on a mass basis, was used to convert N_2O emissions into CO_2 equivalents (CO_2e).

Mass and energy flows for bioSNG conversion were based on one dry tonne of forest biomass and one dry tonne of agricultural biomass as summarized in Fig. 3-2. The lower heating value (LHV) of biomass was determined from its chemical composition and moisture content (Domalski et al., 1987; van den Broek et al., 1995). An LHV of 15.8 and 16.3 GJ t(dry)$^{-1}$ was calculated for agricultural and forest biomass at moisture contents of 25% and 45%, respectively.

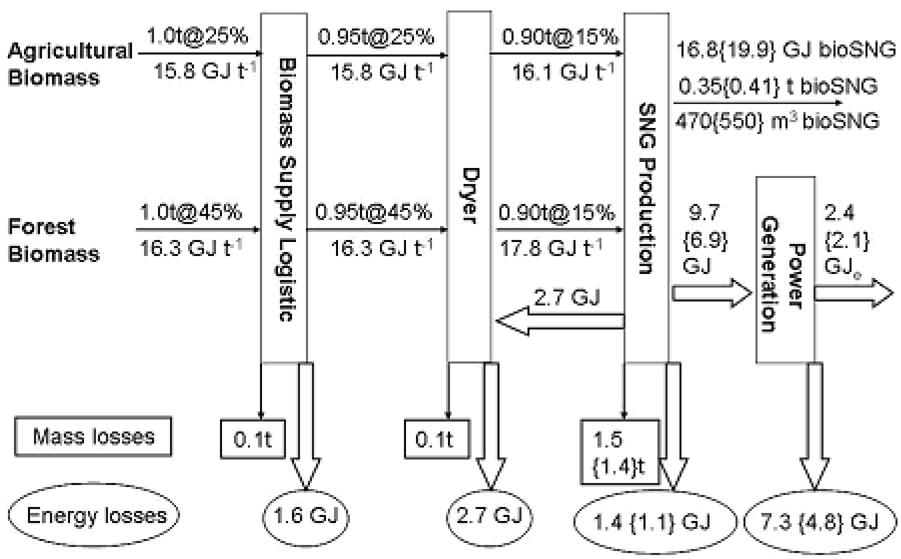

Figure 3-2: Conservative {aggressive} estimates of mass and energy flow in the bioSNG production process assuming inputs of 1 t agricultural biomass plus 1 t forest biomass. All weights are dry tonnes.

Dry matter losses of 5% were associated with harvesting, baling/chipping, and transporting biomass (Kumar and Sokhansanj, 2007; Wihersaari, 2005).

Since thermochemical conversion processes operated more efficiently with low-moisture feedstocks, all biomass was dried to 15% moisture content (McKendry, 2002c), a process that resulted in an additional 5% loss of dry matter when combined with losses associated with storage. Altogether, dry matter losses prior to gasification were 10% (Hamelinck et al., 2005). However, drying also increased the LHV of biomass to 16.1 and 17.8 GJ t(dry)$^{-1}$ for agricultural and forest biomass, respectively (Domalski et al., 1987; van den Broek et al., 1995).

Dry biomass was converted to bioSNG through gasification and subsequent methanation (production of methane) of the syngas. We assumed the use of a pressurized, oxygen-blown gasifier (Tijmensen et al., 2002), followed by a methanation system based on adiabatic (no heat gains/losses) reactors and intermediate cooling (Zwart et al., 2006), and then removal of the CO_2 to create pipeline-quality biomethane. Conservative {aggressive} estimates of the energy conversion efficiency of biomass to pipeline-quality gas were estimated to be 55% {65%} (Duret et al., 2005; Zwart and Boerrigter, 2005).

As summarized in Fig. 3-2, these assumptions meant that 2 dry tonnes of biomass (half forest, half agricultural) yielded about 16.8 {19.9} GJ of bioSNG which occupied 470 {550} m^3 and weighed 0.35 {0.41} t, based on a natural gas LHV of 36 MJ m^{-3} and a final gas composition of 98 vol% CH_4 and 2 vol% CO_2 (TransCanada, 2008).

A large amount of exothermic heat was generated during bioSNG production. It was assumed that 90% of the heat was used in the dryer and a power generation cycle while 10% was lost to the surroundings. The heat demand of the dryer was determined based on the amount of water that had to be removed from the incoming agricultural and woody biomass at 80% efficiency. The remaining useful heat was used in a power generation cycle at an electrical conversion efficiency of 25% {30%} (OEE, 2006), which produced 2.4 {2.1} GJ of electricity.

3.2.5 Economics

BioSNG production costs were the sum of delivered feedstock costs plus capital and operating costs. The delivered cost of biomass was broken down into the cost of producing wood chips or bales at roadside and the cost of truck transportation to the storage facility adjacent to a bioSNG production plant. To estimate the overall total investment and annual operating costs, we drew on previous studies that analyzed the conversion of biomass into methanol and hydrogen (Hamelinck and Faaij, 2002) or Fischer-Tropsch liquids (fuels produced through Fischer-Tropsch synthesis) and power (Tijmensen et al., 2002) via biomass gasification. However, instead of estimating the equipment costs for Fischer-Tropsch and methanol synthesis, an estimate was used to assess the equipment costs for a methanation system (Zwart et al., 2006).

Economies of scale decreased unit equipment costs at larger plant sizes. Scale factors from the above studies were used to calculate capital costs at a number of different plant scales. Overall total investment costs were then amortized over a 20-year project lifetime and added to annual delivered biomass and bioSNG production plant operating costs to determine total production costs. Unless otherwise stated, all costs were calculated as 2005 US$.

A summary of the parameters used to calculate parasitic energy use, GHG emissions, and cost of bioSNG production are presented in Table B-1 of Appendix B.

3.3 Results and discussion

3.3.1 Canadian biomass potential adjacent to natural gas pipelines

Within 50 {100} km of Canada's natural gas pipelines, the land area was estimated to be 136 {196} Mha (Table 3-1), equivalent to about 14% {20%} of Canada's total land area (980 Mha) (CFS, 2006). However, virtually all of this land was in southern Canada, where the nation's biological resources were most abundant. About 50% of the adjacent land was assessed to be forest, 25% agricultural, and 25% marginal land.

Residues from Existing Forest and Agricultural Production. Using the assumptions identified in the footnotes to Table 3-1, forest and agricultural residues were estimated to contribute 10 {24} and 8.5 {18} Mt(dry) yr^{-1} of bioenergy potential, respectively.

To put these values into perspective, residues from traditional forest harvesting were estimated from 2004 values for the Canadian harvest of industrial roundwood production (206 Mm^3 or 90 Mt(dry), (CFS, 2006)). Assuming roundwood represented 70% of the total harvest, with 30% as forest residue, the residue fraction was about 40 Mt(dry). Therefore, the sustainable residues in the forest land area adjacent to Canada's natural gas pipelines were about 25% {60%} of total forest residue production in the country.

In contrast, the annual residue production from food crops from 2003 to 2007 was estimated to be about 55 Mt(dry) (Statistics Canada, 2007b). Therefore, the sustainable residues in the agricultural land area adjacent to Canada's natural gas pipelines were 15% {35%} of the total agricultural residue production in the country.

Whole Forest Harvest for Energy. Given the assumptions in the footnotes of Table 3-1, we estimated that 0.20 {0.39} Mha of forest land per year was harvested for energy production, thereby providing 26 {53} Mt(dry) yr^{-1} of biomass. The primary source of whole forest harvest were trees having little commercial value such as dead trees, trees in unmanaged forests, and trees unused by the forestry sector. To put this into perspective, these values were equivalent to 22% {43%} of the annual forest harvest (0.9 Mha yr^{-1}) and 29% {59%} of the 2004 roundwood harvest in Canada (90 Mt(dry)) (CFS, 2006).

Biomass Crops. The production potential for biomass crops was calculated from estimates of total good agricultural and marginal land area adjacent to natural gas pipelines as well as assumptions regarding accessible land area and biomass yields on the different land types. A total of 2.6 {6.1} Mha of good agricultural land (equivalent to 4% {9%} of the estimated 68 Mha of farmland in Canada (Statistics Canada, 2006)) was calculated to be available to produce 7 {9.6} t(dry) ha^{-1} when 30% {20%} of the crop was left on the field, yielding 18 {59} Mt(dry) biomass per year. In comparison, 5.1 {9.8} Mha of marginal land (equivalent to 30% {58%} of the estimated 17 Mha of unused marginal land suitable for biomass crops in Canada (Samson et al., 1999)) was calculated to be available to produce 3.5 {5.6} t(dry) ha^{-1} when 30% {20%} of the crop was left on the field, yielding 18 {55} Mt(dry) biomass per year.

The biomass potential from residues, whole tree harvesting, and biomass crops within 50 {100} km of natural gas pipelines was combined to generate an estimate for total annual harvest of 81 {209} Mt(dry) yr^{-1}. Based on an LHV of 16 GJ t(dry)$^{-1}$, Canada's sustainable biomass production potential adjacent to natural gas pipelines was estimated at 1296 {3344} PJ yr^{-1} of thermal energy, a value equivalent to 11% {28%} of Canada's total primary energy use in 2003 (12 EJ) (NRCan, 2006b).

3.3.2 Canadian bioSNG potential

Based on known efficiencies for mass and energy flow for biomass to SNG (Fig. 3-2), each tonne of dry biomass (50% straw, 50% wood) was estimated to yield 235 {275} m^3 of bioSNG. Given the calculated potential for sustainable biomass production in the corridor around natural gas pipelines (Table 3-1), total bioSNG production was estimated at 19,000 {57,500} Mm^3 per year. Since Canada's natural gas consumption was about 96,700 Mm^3 in 2005 (EIA, 2007), bioSNG production could fulfill about 20% {60%} of current domestic natural gas demand.

3.3.3 Scale effects

The effects of the scale of biomass transportation and processing on parasitic energy, GHG intensity, and production cost were calculated for plant operations ranging from 500 to 5000 t(dry) biomass harvested per day. The parasitic energy ratio (Fig 3-2A) was calculated as a proportion of the amount of bioSNG produced. Larger plant sizes were predicted to have slightly higher parasitic energy ratios because of extra diesel use over longer biomass transportation distances. These calculations anticipated that the conversion efficiency of biomass to product was independent of scale for the type of gasifier considered (Dornburg and Faaij, 2001).

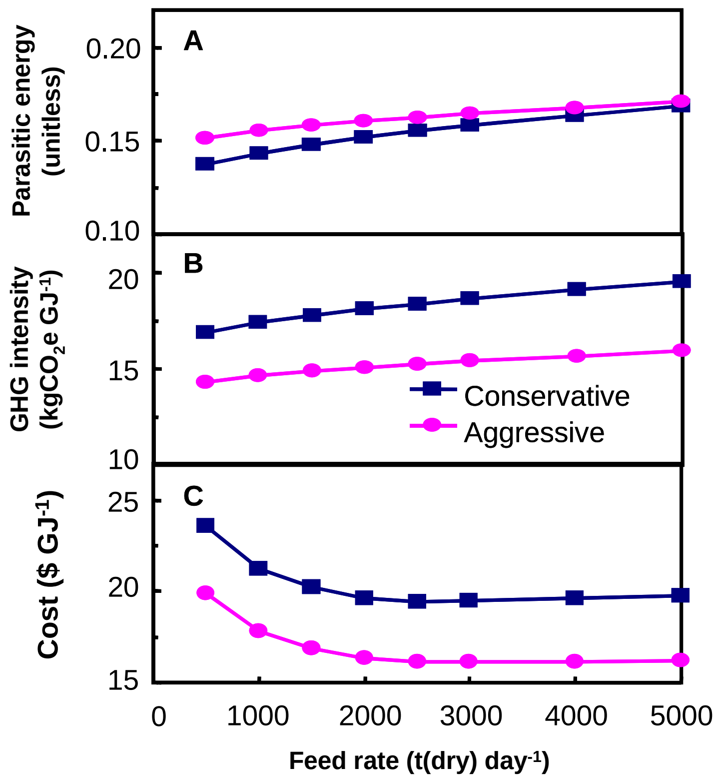

Figure 3-3: Conservative and aggressive estimates of parasitic energy use (A), GHG intensity (B), and production cost (C) at different scales of operation.

The aggressive estimate of parasitic energy ratio (0.15 to 0.17; unitless) was slightly higher than the conservative estimate (0.14 to 0.17) because the aggressive conversion efficiency to bioSNG produced less net exothermic heat for power generation, which meant a portion of electricity had to be supplied externally. The inverse of the parasitic energy ratio was the energy return on investment (EROI), which ranged with scale from 5.9 to 7.3 in the conservative scenario and 5.9 to 6.6 in the aggressive. The EROI for bioSNG decreased with scale due to increased diesel fuel consumption associated with longer biomass transportation distances. As a comparison, the EROI for corn-based ethanol and synthetic crude oil from tar sands (excludes energy involved in mining and transporting the raw tar sands) was 0.8: to 1.6:1 (Farrell et al., 2006) and 5:1 (Homer-Dixon, 2006), respectively.

Process GHG intensity (Fig. 3-3B) also increased slightly with scale due to increased emissions from biomass transportation. Although the aggressive estimate of parasitic energy use was higher its GHG intensity (14 to 16 $kgCO_2e\ GJ^{-1}$) was slightly less than the conservative estimate (17 to 20 $kgCO_2e\ GJ^{-1}$) because the aggressive scenario assumed that perennial crops had an enhanced nitrogen use efficiency, which was predicted to reduce N_2O emissions from synthetic nitrogen fertilizers.

Scale factor calculations indicated that the rate of reduction of capital costs was most pronounced at small scales (Fig. 3-3C). A study by Tijmensen et al. used an overall scale factor of 0.74 for biofuel plants as large as 400 MW_{th} and a factor of 0.91 for larger plant sizes. Production costs for the conservative estimate (\$19 to \$24 GJ^{-1}) were 20% higher than the aggressive estimate (\$16 to \$20 GJ^{-1}). Costs were minimized when the scale of biomass production ranged from 2500 to 3000 t(dry) day^{-1}, which corresponded to thermal inputs of 440 to 530 MW_{th}.

3.3.4 System components

An analysis was also carried out to determine how various stages in the production of bioSNG in a 400 MW_{th} industrial plant impacted the energy content of the product stream, parasitic energy use, GHG intensity, and production costs (Fig. 3-4).

In contrast, most of the parasitic energy and GHG emissions were calculated to be linked to biomass production and transportation (Figs. 3-3B and 3-3C). Emissions were associated with fertilizer production from natural gas, N_2O emissions from soil nitrogen pools, and diesel fuel use in harvesting. Together, this was estimated to be responsible for 86% {82%} of the total GHG emissions. Expressed per GJ bioSNG, total life-cycle emissions were calculated to be 18 {15} $kgCO_2e$ (Fig. 3-4C).

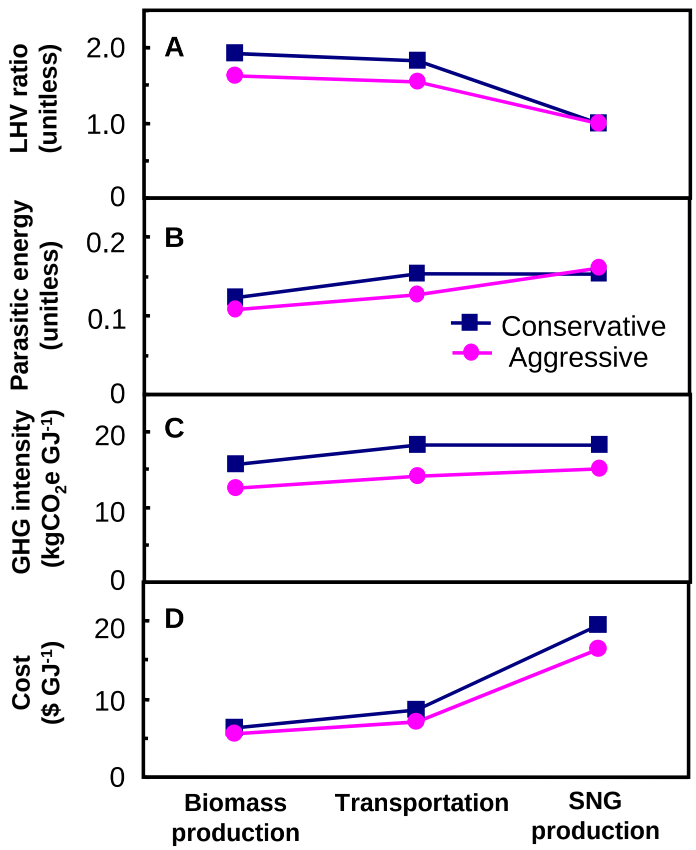

Figure 3-4: Conservative and aggressive estimates for changes in biomass production, transportation, and ultimate conversion to bioSNG in terms of LHV (A), parasitic energy (B), GHG intensity (C), and cost (D) based on a 400 MW_{th} (2270 t(dry) day^{-1}) plant.

The major cost associated with producing bioSNG was calculated to be the capital cost investments for the thermochemical conversion of biomass into bioSNG (Fig. 3-4D). Amortized capital costs and annual operating costs contributed 55% {57%} to total production costs whereas biomass production was responsible for an additional 32% {34%} of the total cost. Although a 400 MW_{th} bioSNG plant was smaller than the plant size predicted to minimize production costs (Fig. 3-3C), total production costs at this scale were very close to the minimum. Overall, the production cost per GJ bioSNG was calculated to be $20 {$16}.

3.3.5 Sensitivity analysis

A sensitivity analysis was performed to ascertain the impact of key parameters on calculated values for parasitic energy use, GHG intensity, and production cost (Fig. 3.5). The analysis was performed by independently varying assumed parameters such as the energy conversion efficiency of biomass to SNG, energy and cost efficiency of truck transportation, and the auxiliary power efficiency for a 400 MW_{th} bioSNG plant under conservative assumptions.

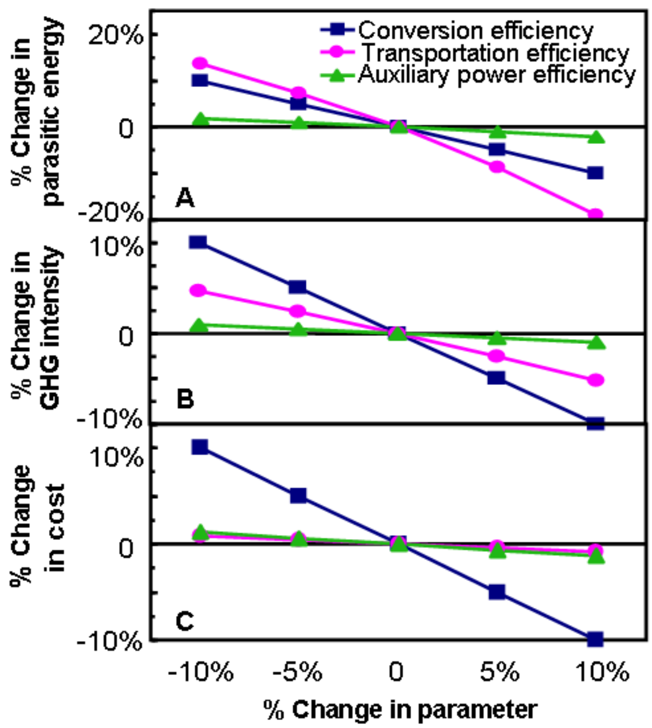

Figure 3-5: Sensitivity of parasitic energy use (A), GHG intensity (B), and cost of bioSNG production (C) with respect to conversion efficiency, electricity production, and transportation efficiency for a 400 MW_{th} plant in the conservative scenario.

Changing the amount of electricity consumed or produced in the bioSNG production process had the strongest effect on parasitic energy (Fig. 3-5A). A 10% increase in the amount of power generated decreased parasitic energy use by 19%; however, the corresponding reduction in GHG emissions was only 5.2% (Fig. 3-5B) because the GHG intensity of the Canadian electricity sector was only 224 $gCO_2e\ kWh^{-1}$ (OEE, 2006). The effect of a 10% increase in power generation was even less pronounced for production costs, which decreased only 0.8% (Fig. 3-5C). Changes to the biomass to SNG conversion efficiency had a direct proportional impact on parasitic energy, GHG intensity, and production costs. For example, a 10% improvement in conversion efficiency decreased parasitic energy, GHG intensity, and production costs by 10%. On the other hand, the model's sensitivity to changes in transportation parameters was minor in all cases.

3.3.6 Comparison to fossil fuels

Life-cycle GHG emissions for domestic natural gas and LNG were estimated to be 68 and 87 $kgCO_2e\ GJ^{-1}$, respectively (Jaramillo et al., 2007). On the other hand, the present study estimated emissions of 18 {15} $kgCO_2e\ GJ^{-1}$ for bioSNG. Therefore, per unit of energy, bioSNG produced 17% to 26% of the GHG emissions associated with natural gas or LNG. However, production costs were estimated to be \$20 {\$16} GJ^{-1}, which were significantly higher than recent prices for natural gas in North America (\$6 to \$12 GJ^{-1}) (EIA, 2008c).

Historically, North American natural gas prices were approximately 84% of the energy-equivalent price of crude oil (NEB, 2007). If this relationship was maintained in the future, a natural gas price of over \$20 GJ^{-1} would be achieved when oil reached \$150 per barrel (\$24.6 GJ^{-1}) (Fig. 3-6). This is an oil price that is in the range predicted by many for the next few years.

Even without natural gas prices in the range of \$16 to \$20 GJ^{-1}, bioSNG could be cost competitive by placing a value on the GHG benefits relative to domestic natural gas or LNG. Fig. 3-6 shows how the value placed on carbon (units of \$ tCO_2e^{-1}) affected the cost of bioSNG (Fig. 3-6, left axis) and the price of domestic natural gas and by extension petroleum (Fig. 3-6, right axis) needed to make bioSNG cost competitive. At a value of \$50 tCO_2e^{-1}, bioSNG production costs (\$17 {\$12} GJ^{-1}) are in the range of recent North American gas prices.

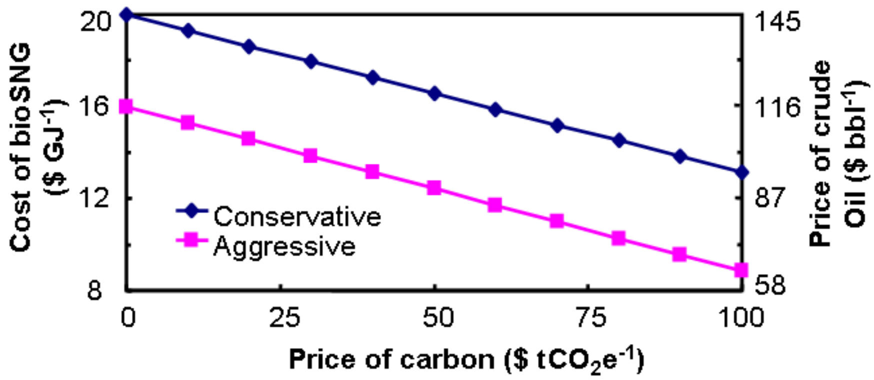

Figure 3-6: The cost of bioSNG when replacing LNG and the associated price of crude oil that makes bioSNG cost-equivalent with domestic natural gas as a function of the price of carbon.

There are additional benefits associated with a national bioSNG production strategy that were harder to account for but important from a public policy perspective. For example, the industry would have a direct impact on rural economies in need of an economic stimulus. Based on a national annual bioSNG potential of 19,000 {57,500} Mm^3 and 400 MW_{th} plants that produced 220 {260} MW of bioSNG, it was estimated that 99 {252} such plants would be required. The overall total investment cost for a 400 MW_{th} bioSNG plant was estimated to be $500M (Hamelinck and Faaij, 2002; Tijmensen et al., 2002; Zwart et al., 2006), leading to a total investment of $49 {$126} billion over a 20-year period. The bioenergy sector produced about 10 jobs for every $1M invested (The Institute for America's Future, 2004), which could promote rural economic development through the creation of 490,000 {1,300,000} new jobs. Furthermore, the industry would serve as a domestic solution to North America's future declining rates of conventional natural gas production and reduce the likelihood of developing a dependence on gas imports from unstable regions of the world.

3.4 Conclusions

The potential contribution of bioSNG to Canada's gas and energy supply is substantial. BioSNG could be manufactured from sustainably-produced biomass and transported long distances via the existing network of natural gas pipelines. The replacement of LNG imports by bioSNG would decrease GHG emissions and improve North American energy security whilst promoting rural economic development. It may also allow for an enhanced use of natural gas (including bioSNG) as an alternative to coal or crude oil, which have greater GHG emissions per GJ.

Conditions that would make bioSNG production economical without government subsidies included high energy prices and GHG emission reduction credits. Nevertheless, other biofuels with minor GHG benefits such as corn-based ethanol and biodiesel receive government subsidies due to their effect on energy security and rural economic development. Creating the policy environment, including initial subsidies for bioSNG production may be a very effective policy to deliver on priorities for energy security, climate change, and rural economic development

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Chapter 4
Feasibility Study of the Great Lakes Bioenergy System

4.1 Introduction

Energy security and access to reliable and affordable sources of oil and natural gas are a growing concern in North America (Hirsch et al., 2005; IEA, 2007). The anticipated global peak in conventional oil and gas production could cause supply disruptions and escalate energy prices, endangering the security of our economy and society (Darley, 2007; Heinberg 2003). Scarcity of conventional sources is likely to shift future North American energy supplies to fuels with high life-cycle greenhouse gas (GHG) emissions such as coal, synthetic crude oil from tar sands, and liquefied natural gas (EIA, 2008a; NEB, 2007). Combustion of these fuels for power generation or transportation negatively impacts air quality (Ogden et al., 2004; Senior et al., 2000) and accelerates climate change (Homer-Dixon, 2008).

Rising fossil fuel prices have spurred economic growth in energy-rich parts of Canada while the industrial heartland in the Great Lakes region has experienced a steady decline. Manufacturing job losses have mounted since 2001 in part due to increased global competition and high energy prices (Campaign 2000, 2008) while rural economies have been negatively affected by mill closures in the pulp and paper sector (Towers et al., 2007). Transformative changes are needed to strengthen the Great Lakes economy and improve its environmental, economic, and social sustainability.

A bioeconomy that uses local biological resources to meet material and energy needs could improve energy security, reduce GHG emissions, and promote rural economic development (Duchesne and Wetzel, 2003). Although the bioenergy potential in the Great Lakes region (assumed in this study as the provinces of Ontario, Quebec, New Brunswick, and Nova Scotia) is significant (Wood and Layzell, 2003), large-scale systems suffer from high transportation costs since biomass is a distributed resource low in energy density. Transportation is further exacerbated in Canada since energy end users are often far from sites of biomass production.

This study assessed the feasibility of an energy system built around the Great Lakes St. Lawrence Seaway (GLSLS) transportation corridor (Fig. 4-1) that delivers lignocellulosic biomass to large-scale power generation and biomass-to-liquid (BTL) fuel synthesis plants. In this system, biomass was integrated with existing fossil fuel infrastructure (coal-fired power plants and petroleum refineries) on the GLSLS. A systems analysis approach was used to assess the sustainable biomass potential in the region and then track the flows of mass and energy throughout the process while assessing parasitic energy use (external energy inputs), GHG emissions, and production costs using a range of assumptions.

Figure 4-1: Map of the Canadian portion of the Great Lakes St. Lawrence Seaway system and the railway transportation network (source: NRCan, 1984b).

4.2 Methodology

The analysis began by developing the layout of the GLSLS bioenergy system. An assessment of the sustainable biomass production capacity in the GLSLS region was then performed. The analyses then determined mass and energy flows for a number of different scales of operation from which parasitic energy use, GHG emissions, and economic costs could be evaluated.

An assessment of the range of the bioenergy potential for each scenario was obtained by making either conservative or aggressive assumptions for parameters such as land area available, biomass productivity, dry matter losses, and biomass conversion efficiencies. Throughout the paper, conservative assumptions and calculated values will be presented in the flow of the text, whereas aggressive assumptions and calculated values will be shown in parentheses (i.e., {…}) if they differ from the conservative numbers.

4.2.1 System outline

The GLSLS bioenergy system consisted of forest and agricultural biomass production sites, pellet mills, transportation corridors (truck, rail, and ship), and energy conversion facilities. A graphical illustration of the supply chain that connects areas of biomass production to energy conversion facilities via transportation corridors is presented in Fig. 4-2.

Biomass densification plants or pellet mills were modelled adjacent to the GLSLS or railway lines. Mills were supplied with biomass in the form of wood chips or straw bales from production sites within a 100 km radius. Major unit operations such as drying, size reduction, and densification converted biomass into stable pellets of uniform particle size (Mani et al., 2006). Pellets were viewed as an ideal intermediate form of biomass for long-distance shipping due to low moisture content and physical properties that reduced handling and transportation costs (Samson and Duxbury, 2000). Heat treating of pellets reduced the risk of disease transfer to other biological materials (Swaan, 2008), although off-gassing of carbon monoxide in confined spaces was still a safety hazard (Svedberg et al., 2008).

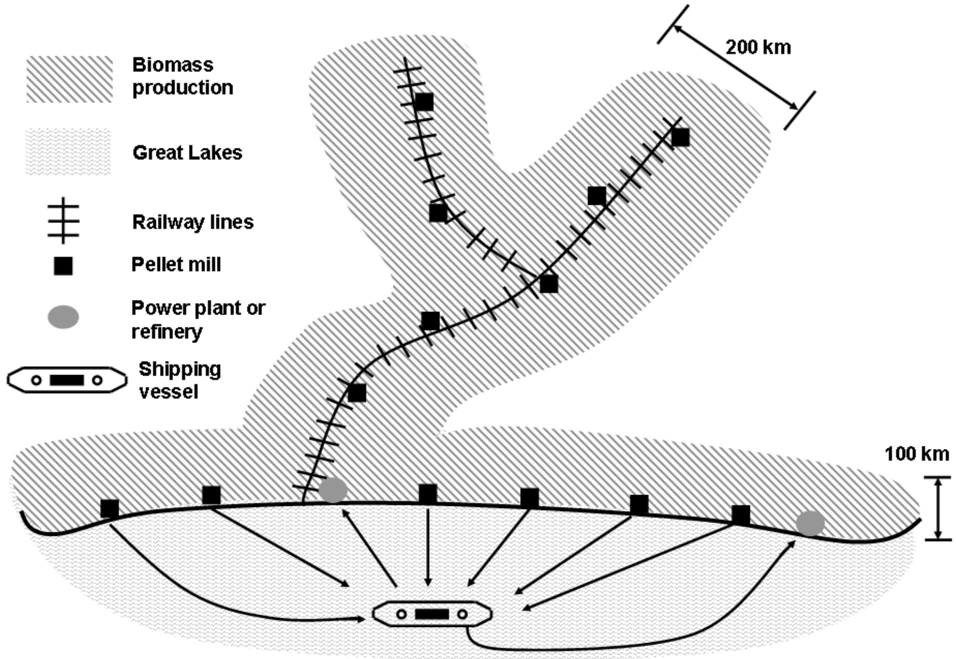

Figure 4-2: An illustration of the GLSLS bioenergy supply chain that connects areas of biomass production to pellet mills and energy conversion facilities via rail and water-borne transportation corridors.

Long-distance transport of pellets occurred by rail, ship, or a combination of both. Shipping in the GLSLS is often part of a greater intermodal network, where major ports on the system are linked to road and rail transportation offering shippers greater flexibility and cost savings (Transport Canada et al., 2007). Pellets transported by rail from several mills were concentrated at major ports and loaded on to lake freighters with a cargo capacity of 10,000 to 55,000 tonnes (Robertson, 2008). Conversely, individual mills adjacent to the GLSLS employed smaller vessels such as barges pushed by tugboats that carried approximately 1500 tonnes of cargo.

In one simulation, pellets were delivered to Ontario coal-fired power plants to replace coal with biomass. Nanticoke, Lambton, and Thunder Bay are current coal-fired generating stations sited on the shores of the GLSLS whereas Atikokan is a 215 MW station located away from the

Great Lakes (OPG, 2008) and more likely to be supplied with biomass by truck and/or rail. Existing large-scale boilers can co-fire up to 15% biomass with small modifications or utilize 100% with retrofitting (Gjernes et al., 2007). Modifying an existing coal plant was attractive because pellets were handled and burned using similar equipment, which resulted in lower investment costs and greater fuel flexibility (Gjernes et al., 2007). Pellet storage capacity was necessary since the lower Great Lakes (Erie and Ontario) and the St. Lawrence Seaway were only available for commercial navigation about 280 days per year due to ice and weather conditions (The St. Lawrence Seaway Management Corporation et al., 2008). On the other hand, the upper Great Lakes (Superior, Michigan, and Huron) operated at least a month longer (Robertson, 2008).

In a second simulation, pellets were delivered to BTL plants that produced substitute liquid transportation fuels. Biomass gasification followed by gas cleaning and conditioning was assumed to produce a clean syngas rich in carbon monoxide and hydrogen (Tijmensen et al., 2002; Zwart and Boerrigter, 2005). Syngas was then catalytically reformed to synthetic *green diesel* via high-pressure Fischer-Tropsch (FT) synthesis. FT-liquids are clean-burning fuels free of sulphur and nitrogen and can be blended with petroleum diesel (Dry, 2001). Implementation of a biomass-based liquid transportation fuel strategy was enabled by integrating biomass conversion and fuel distribution operations with the existing fossil energy infrastructure. Co-locating BTL plants adjacent to petroleum refineries would allow green and fossil diesel to share product distribution systems, steam production, utilities, and local expertise.

An alternative approach not investigated in this study was to convert uneconomical pulp and paper mills into forest biorefineries that produced transportation fuels and chemical products (Ragauskas et al., 2006). Mills offer competitive advantages such as proximity to feedstock and biomass processing infrastructure (Stuart, 2006) but lack the benefits associated with integration into the petrochemical industry. On the other hand, such retrofitting would enable aging mills to diversify their revenue streams and keep forestry alive in rural communities (Leidl, 2008).

4.2.2 Land area

The GLSLS system is a natural transportation route that extends from inner North America into the Atlantic Ocean via the St. Lawrence River. It consists of locks, shipping channels, ports, and bridges that make the entire system navigable (Transport Canada et al., 2007). A scaled map was used to calculate Canadian land area located within 100 km of the GLSLS and within 100 km of railway lines (NRCan, 1984b). The provinces of New Brunswick and Nova Scotia were also included in the estimate along with Ontario and Quebec since they lie within a reasonable proximity to the GLSLS. Land area measurements were traced onto mylar paper and then cut out into shapes. The weight of the traced area was then compared to the weight of mylar paper having a known surface area to determine the total land area represented by the cut out shapes.

Land areas were assigned to one of three categories (Table 4-1): forest, good agriculture, or marginal based on current land use practices, soil types, and water availability (NRCan, 1980; NRCan, 1988). Table 4-1 summarizes the hectares of land area estimated from the conservative or aggressive assumptions.

4.2.3 Forest biomass production

Forest biomass for energy was assumed to be derived from two major sources: residues associated with conventional forest harvest and whole tree harvesting. To calculate residue availability from existing fibre production, 70% of the forest land area was assumed to be managed and harvested by clear-cutting at a rate of 0.60% {0.48%} of the managed land area per year. The conservative assumption (0.60%) was based on current forest harvest rates (CFS, 2006) whereas the aggressive assumption (0.48%) predicted a 20% decrease due to mill closures in the

Table 4-1: Assumed parameters and results for the conservative (A) and aggressive (B) estimate of land area and biomass production on forest (FOR), good agriculture (GA), or marginal (MAR) land.

Land type	Total land area (Mha)[a]	Biomass type	Accessible land area (% year^{-1})	Yield (t(dry) ha^{-1})	Available land area (Mha)[m]	Biomass (Mt(dry) year^{-1})[n]
			A. Conservative			
FOR	105	Residues	0.42[b]	19[c]	0.44	8.3
		Whole tree harvest	0.12[d]	82[e]	0.13	11
GA	10	Residues	53[f]	0.23[g]	5.3	1.2
		Biomass crops	3.9[h]	8.0[i]	0.39	3.1
MAR	10	Biomass crops	20[j]	6.4[k]	2.0	13
Total	**125**				**8.3**	**36**
			B. Aggressive			
FOR	105	Residues	0.34[b]	24[c]	0.35	8.5
		Whole tree harvest	0.41[d]	94[e]	0.43	41
GA	10	Residues	52[f]	0.35[g]	5.2	1.8
		Biomass crops	6.1[h]	12[i]	0.61	7.3
MAR	10	Biomass crops	25[j]	8.5[k]	2.5	21
Total	**125**				**9.1**	**80**

Note: Values in footnotes refer to conservative {aggressive} assumptions.
[a] Estimated land area within 100 km of GLSLS and railway lines.
[b] Calculated as 70% {70%} of land area subject to forest management x 0.6% {0.48%} of area harvested per year for traditional forest products.
[c] Calculated as 90 {100} t(dry) ha^{-1} x 30% {30%} forest residue fraction x 70% {80%} removal of residues.
[d] Calculated as 0.42%{0.34%} harvest rate x 25%{56%} additional area available (from 20% unused AAC and 0%{20%} diverted from pulp and paper) + 100,000{150,000} ha yr^{-1} of disturbed forests x 20%{25%} accessible / 105 Mha yr^{-1} + 0.11%{0.19%} additional harvest x 0%{100%} increase in productivity.
[e] Calculated as 90 {100} t(dry) ha^{-1} x 91% {94%} fraction removed.
[f] Assumed 55%{55%} of agriculture used for food/forage crops x 97%{95%} not diverted to biomass.
[g] Calculated as 1 {1.5} t(dry) ha^{-1} x 23% {23%} removal of food crop residues for bioenergy production.
[h] Calculated as 55%{55%} of cropland per year x 3%{5%} diverted to biomass crops + 11%{11%} of total agricultural land reserved for natural and tame pasture x 20%{30%} of pasture land diverted to biomass.
[i] Calculated as 10 {14} t(dry) ha^{-1} x 80% {85%} fraction removed.
[j] Assumed 20% {25%} of marginal land diverted to biomass production.
[k] Calculated as 8 {10} t(dry) ha^{-1} x 80% {85%} fraction removed.
[m] Obtained by multiplying "Total land area" by "Accessible land area".
[n] Obtained by multiplying "Available land area" by "Yield".

pulp and paper sector. Mill closures reduced the amount of residues available from conventional forest harvesting but expanded the resource base for bioenergy applications. On the harvested land, total production was 90 {100} t(dry) ha^{-1} (CFS, 2006) where 30% of the total harvested biomass was forest residue (David Suzuki Foundation, 2004) of which 70% {80%} could be sustainably removed as an energy resource. Previous estimates vary widely for the amount of residues that need to be left at the harvest site to provide cover for wildlife, prevent erosion, maintain soil carbon stocks, protect emerging tree seedlings, and minimize moisture loss from the forest floor (Wood and Layzell, 2003). This study assumed that, on average, 70% {80%} of forest residues could be sustainably removed but the actual amount depends on local site characteristics.

The biomass potential of whole tree harvesting was estimated based on harvesting the unused Annual Allowable Cut (AAC), trees killed by fire, pests, and disease, and more intensive forest management practices that enhanced productivity and reduced the time needed for tree rotation. The unused portion of the AAC was typically 20% (conservative) (CFS, 2006) but increased to 36% (aggressive) when 20% of biomass resources were assumed to be diverted from traditional pulp and paper production systems. Consequently, whole trees from the unused AAC contributed 0.11% {0.19%} of the 105 Mha of forest land area to biomass potential. Forest disturbances (fire, pests, and disease) were estimated to be 100,000 {150,000} ha yr^{-1} of which 20% {25%} were accessible for harvesting, which contributed 0.02% {0.04%} of land area to biomass potential. Lastly, silvicultural practices such as pre-commercial thinning and replanting after harvest (Layzell et al., 2006) were predicted to double forest productivity in the aggressive scenario. Hence, an additional 0% {0.19%} of land area was predicted to be available. Overall, it was assumed that 0.12% {0.41%} of the 105 Mha of forest land area was harvested each year at a production rate of 90 {100} t(dry) ha^{-1}, where 91% {94%} of total forest harvest biomass (roundwood plus residues) was sustainably removed.

4.2.4 Agricultural biomass production

Agricultural biomass for energy was assumed to come from food/forage crop residues and dedicated biomass crops. The 5.5 Mha of good agricultural land reserved for food/feed production in Ontario and Quebec (Statistics Canada, 2006) was estimated to produce 1.0 {1.5} t(dry) ha^{-1} of straw residues (Statistics Canada, 2007b; Statistics Canada, 2007c). Only 23% of this crop residue was predicted to be available because of demand from existing markets and soil requirements (Layzell et al., 2006; Wood and Layzell, 2003).

Dedicated biomass crops were assumed to be grown on 20% {25%} of the 10 Mha of unused marginal land (Samson et al., 1999) at a production rate of 8 {10} t(dry) ha^{-1} (Kumar and Sokhansanj, 2007). These crops were also grown on diverted pasture and feed crop production land since it was assumed that domestic ruminant production would decline given concerns about the GHG footprint of meat production (FAO, 2006) and the effect of biomass markets on land values and animal feed costs. Biomass production was calculated on 20% {30%} of the 1.1 Mha of pasture land and 3% {5%} of the 5.5 Mha of cropland at a crop productivity of 10 {14} t(dry) ha^{-1} (Khanna et al., 2008). Of the dedicated biomass production, 80% {85%} of the aboveground biomass was assumed to be available for energy use.

4.2.5 Mass, energy, and GHG emissions

The material and energy flow for the GLSLS bioenergy system (Fig. 4-3) was based on 1 dry tonne each of forest and agricultural biomass while dry matter losses were estimated from the literature (Hamelinck et al., 2005). Lower heating values (LHVs) of 9.2 and 12.4 GJ $t(wet)^{-1}$ were determined based on higher heating values (HHVs) of 20.0 and 18.5 GJ $t(dry)^{-1}$ (Klass, 1998), hydrogen contents of 6.0% and 5.5% (dry basis) (van Loo and Koppejan, 2003), and moisture contents of 45% and 25% for woody and herbaceous biomass, respectively.

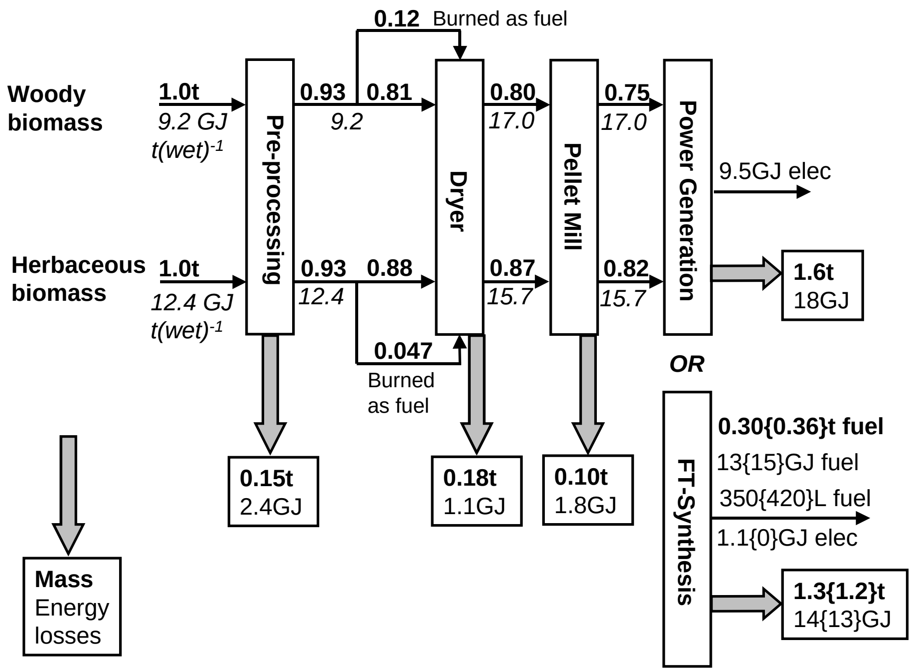

Figure 4-3: Conservative {aggressive} estimates of mass and energy flow for the GLSLS bioenergy system assuming inputs of 1 tonne woody biomass plus 1 tonne herbaceous biomass. All weights in bold are dry tonnes while biomass LHV values are in *italics*.

Biomass production required fossil energy inputs of diesel, natural gas, and electricity for fertilizer production, harvesting operations, and pre-processing into wood chips or straw bales. External energy inputs were estimated from the literature (Turhollow and Perlack, 1991) and the associated GHG emissions were determined from fuel life-cycle emission factors (Börjesson, 1996; Jaramillo et al., 2007; OEE, 2006). Improved production technology reduced external energy inputs by 20% in the aggressive scenario (Turhollow and Perlack, 1991).

Production of herbaceous biomass crops required application of synthetic nitrogen fertilizer. Nitrogen use in agricultural soils lead to GHG emissions of nitrous oxide (N_2O) through the microbial processes of nitrification (conversion of ammonia to nitrate) and denitrification (conversion of nitrate to N_2O) (IPCC, 2000). Literature estimates of N_2O emissions from fertilizer use in switchgrass production were used (Samson et al., 2008). The global warming potential of

N_2O, which is 310 times that of CO_2 on a mass basis, was used to convert N_2O emissions into CO_2 equivalents (CO_2e).

Pre-processed biomass was then transported by truck to a pellet mill, where it was dried to 8% moisture. Dryer heat demand was met by combusting 13.0% and 5.1% of the forest and agricultural biomass, respectively. The dried biomass was then forwarded to size reduction and densification units powered by electricity (Raymer, 2006). After pelleting, the LHV of woody and herbaceous biomass increased from 9.2 and 12.4 to 17.0 and 15.7 GJ $t(wet)^{-1}$, respectively.

The rail transportation distance from a pellet mill to a GLSLS port was estimated to be 500 km, whereas lake shipping to an energy conversion facility was estimated to be 1000 km. Great Lake vessels were assumed to be powered by diesel engines although steamships driven by turbines and heavy fuel oil are still in operation (Robertson, 2008). Diesel fuel requirements for various modes of transportation were estimated from the literature (Börjesson, 1996).

Pellets were delivered to large-scale generating stations or BTL plants. The conversion of biomass to electricity was 39% efficient on an LHV basis and internal power consumption required 10% of the electricity produced (Kumar et al., 2008). Synthetic green diesel produced by FT-synthesis was predicted to have an LHV efficiency of 46% {55%} and net power production of 4% {0%} (Boerrigter, 2006; Tijmensen et al., 2002; Zwart and Boerrigter, 2005).

4.2.6 Economics

Production costs were determined by estimating the costs associated with biomass production, transportation, pelleting, and energy conversion. Unless otherwise stated, all costs were calculated as 2005 US$.

Prices for wood chips or straw bales at the roadside from residues, whole trees, or herbaceous biomass crops were estimated from the literature (Kumar et al., 2008; Samson et al., 2008).

Transportation costs were calculated using distance fixed and variable costs (Searcy et al., 2007). Biomass production and transportation did not benefit from economies of scale.

Biomass densification techniques were more cost efficient at larger scales (Hamelinck et al., 2005). Pellet production followed the economy of scale, where scale factors of 0.75 {0.60} were used to calculate cost reductions at larger plant sizes (Mani et al., 2006). Total annual pellet production costs were the sum of amortized capital, operating, and delivered feedstock costs. A 20% profit margin was used to calculate the wholesale price of pellets based on production costs.

The cost of biopower was the sum of delivered biomass, amortized investment, and operating costs. The cost of retrofitting a coal plant (Layzell et al., 2006) was amortized over a project lifetime of 20 years and an interest rate of 10% to yield the annual investment cost. Annual investment costs were then added to operating and feedstock costs to determine total annual production costs. Annual production costs were then divided by the net power generated to yield the cost of electricity.

Fuel synthesis plants had high investment costs but large-scale facilities benefit from the economy of scale (Boerrigter, 2006). Scale factors of 0.90 {0.70} were used to predict overall total investment costs of BTL plants at various capacities (Boerrigter, 2006; Tijmensen et al., 2002). The production cost of green diesel was then calculated by dividing the sum of delivered feedstock, amortized investment, and operating costs by the amount of fuel manufactured. A 20% profit margin was then used to calculate the wholesale price of green diesel.

A summary of the parameters used to calculate parasitic energy use, GHG emissions, and production cost are presented in Table B-2 of Appendix B. The Energy Return on Investment (EROI), GHG intensity, and price of intermediate and final products are shown in Table B-3.

4.3 Results and discussion

4.3.1 Biomass potential in the GLSLS region

Within 100 km of the GLSLS and railway lines, the land area was estimated to be 125 Mha (Table 4-1), equivalent to about 13% of Canada's total land area (980 Mha) (CFS, 2006). About 84% of the land was assessed to be forest, 8% agriculture, and 8% marginal.

Residues from Existing Forest and Agricultural Production. Using the assumptions identified in the footnotes to Table 4-1, forest and agricultural residues were estimated to contribute 8.3 {8.5} and 1.2 {1.8} Mt(dry) yr^{-1} of bioenergy potential, respectively.

To put these values into perspective, the harvest of industrial roundwood in Ontario, Quebec, New Brunswick, and Nova Scotia was 87 Mm^3 (39 Mt(dry)) in 2004 (CFS, 2006). Since roundwood represented 70% of the total harvest, with 30% as forest residue, the residue fraction was about 17 Mt(dry), of which 49% {50%} was removed as an energy resource.

Agricultural residues for all of Canada were estimated to be 55 Mt(dry) in 2007 (Statistics Canada, 2007b). Since 15% of Canada's cropland was in Ontario and Quebec (Wood and Layzell, 2003), food/forage crop residues in the GLSLS region were calculated to be 8.3 Mt(dry), of which 14% {22%} were removed as an energy resource.

Whole Forest Harvest for Energy. Given the assumptions in the footnotes of Table 4-1, we estimated that 0.13 {0.43} Mha yr^{-1} of forest land could be harvested for energy production, thereby providing 11 {41} Mt(dry) yr^{-1} of biomass. These values were equivalent to 20% {65%} of the annual forest harvest (0.66 Mha) and 28% {105%} of the 2004 roundwood harvest in the GLSLS region (CFS, 2006). The aggressive estimate of forest bioenergy potential was greater than the conventional forestry roundwood harvest due to silvicultural improvements that increased tree productivity and reduced the time needed for tree rotation.

Biomass Crops. The potential for biomass crops was calculated from estimates of total good agricultural and marginal land area in the GLSLS region as well as assumptions regarding accessible land area and biomass yields. A total of 0.39 {0.61} Mha yr^{-1} of good agricultural land was calculated to be available, which was equivalent to 4.4% {6.9%} of the estimated 8.9 Mha of farmland in Ontario and Quebec (Statistics Canada, 2006). The land offered a net yield of 8.0 {12} t(dry) ha^{-1}, which produced a total of 3.1 {7.3} Mt(dry) yr^{-1}. In comparison, 2.0 {2.5} Mha yr^{-1} of marginal land was calculated to be available, which was equivalent to 69% {86%} of the estimated 2.9 Mha of unused marginal land suitable for biomass crops in Ontario, Quebec, and New Brunswick (Samson et al., 1999). The land offered a net yield of 6.4 {8.5} t(dry) ha^{-1}, which produced a total of 13 {21} Mt(dry) yr^{-1}.

The biomass potential from residues, whole trees, and biomass crops in the GLSLS region was combined to generate an estimated total harvest of 36 {80} Mt(dry) yr^{-1}. The sustainable bioenergy production potential was projected to be 600 {1300} PJ yr^{-1} of thermal energy, equivalent to 8.8% {19%} of total primary energy use in Ontario, Quebec, New Brunswick, and Nova Scotia in 2004 (6.8 EJ) (NEB, 2007). Total pellet production was calculated to be 32 {70} Mt yr^{-1}. The GLSLS moved an average of 261 Mt yr^{-1} of cargo between 1995 and 2003, which was estimated to be half of its potential capacity (Transport Canada et al., 2007). Therefore, an additional 12% {27%} of traffic through the GLSLS could be accommodated.

4.3.2 Biopower and green diesel potential in the GLSLS region

Based on known efficiencies for mass and energy flow (Fig. 4-3), each tonne of dry biomass (50% wood, 50% straw) was estimated to yield 4.9 GJ (1400 kWh) of biopower or 6.4 {7.6} GJ (180 {210} L) of green diesel as well as 0.56 {0} GJ (150 {0} kWh) of auxiliary electricity.

Coal-fired generation annually contributed 36.4 billion kWh to Ontario’s power supply (OPG, 2008). Based on a biomass to power conversion rate of 1400 kWh $t(dry)^{-1}$, 27 Mt(dry) yr^{-1}

was required to offset coal power. Given the calculated potential for sustainable biomass production (Table 4-1), the potential for BTL production was 9.3 {53} Mt(dry) yr^{-1} after meeting coal requirements. Based on a BTL conversion rate of 180 {210} L $t(dry)^{-1}$, 1.6 {11} billion L of synthetic green diesel was annually produced, equivalent to 14% {96%} of fossil diesel use in the GLSLS provinces in 2005 (11.6 billion L) (OEE, 2008).

4.3.3 Scale effects

An increase in the size of a pellet mill proportionally increased its biomass catchment area, which led to higher truck transportation costs. However, overall production costs decreased with size due to economies of scale (Fig. 4-4). The biomass input capacity ranged from 124 to 744 t(dry) day^{-1}, which was small compared to traditional pulp and paper mills that process more than 3000 t(dry) day^{-1} (Stuart, 2008). Scale factor calculations predicted a decrease in the wholesale price from \$123 {\$123} to \$115 {\$110} t^{-1} even though the average delivered price of feedstock increased from \$69 {\$68} to \$75 {\$72} $t(dry)^{-1}$ when the mill size increased from 124 to 744 t(dry) day^{-1}. The absolute effect of larger biomass production sites and longer transportation distances on parasitic energy use and GHG emissions was negligible (data not shown).

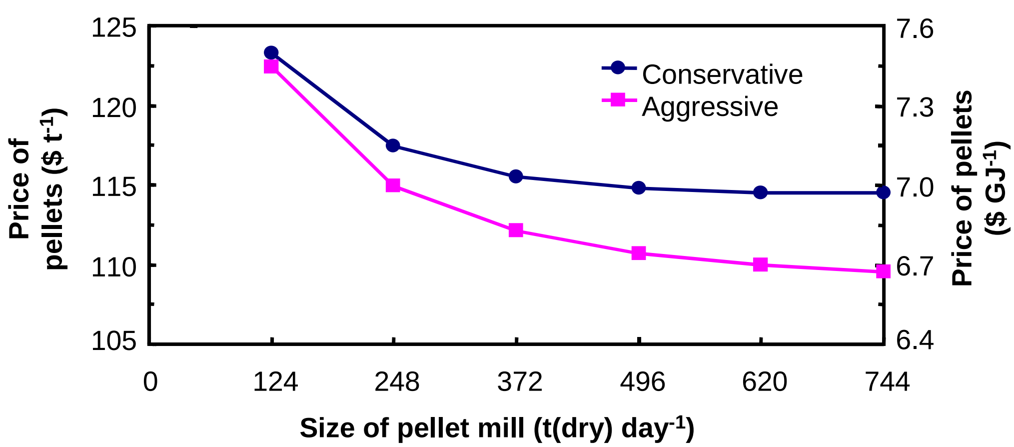

Figure 4-4: Conservative and aggressive estimates of the wholesale price of biomass pellets prior to long-distance transport at different pellet mill sizes.

Scale factor calculations for fuel synthesis plants predicted a decrease in the wholesale price of green diesel from \$38 {\$33} to \$35 {\$27} GJ^{-1} when plant size increased from 2100 to 26,000 t(pellet) day^{-1} (400 to 5000 MW_{th}) as shown in Fig. 4-5. To calculate the energy-equivalent price of crude oil (Fig. 4-5, right axis), fossil diesel was assumed to cost 25% more than the energy-equivalent price of petroleum (EIA, 2008d). Hence, the wholesale price of green diesel was estimated to be equivalent to crude oil prices of \$130 to \$190 bbl^{-1}.

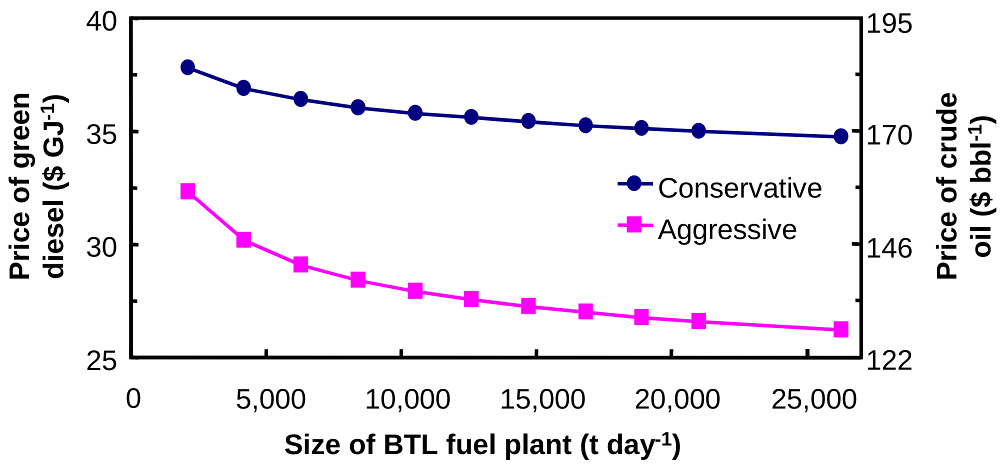

Figure 4-5: Conservative and aggressive estimates of the wholesale price of green diesel as a function of the size of the BTL fuel plant. Secondary y-axis indicates the estimated comparable wholesale price of crude oil.

Larger BTL plants were not subject to higher delivered biomass costs because feedstock was imported from several small production sites. For the GLSLS bioenergy system, the radius of supply for biomass production sites was calculated to range from 10 to 60 km. On the other hand, a 26,000 t day^{-1} BTL plant would require a single production site to have a radius of 150 to 400 km. In reality, larger plants would have to import biomass from more distant production sites but the availability of low-cost rail and water transportation corridors would minimize those additional costs.

The practical scale of a BTL plant was limited because of logistical and investment challenges (Wyman, 2003). Although the GLSLS transportation corridor granted bioenergy plants efficient access to a substantial supply of resources, logistical problems associated with handling, transporting, and processing could arise. Secondly, the investment cost required to build a large-scale BTL plant could be prohibitive. A 2100 t day^{-1} plant was estimated to have an overall total investment cost of $382M (Tijmensen et al., 2002) whereas a 26,000 t day^{-1} facility was estimated to require $3700M {$2200M}. Although production costs were lower at larger plant sizes securing the initial financing would be a challenge.

4.3.4 System components

The GLSLS bioenergy system was made up of a number of stages to transform biomass into power or green diesel (Fig. 4-6). The EROI (a measure of thermal energy content relative to parasitic energy use) of biomass before transporting or pelleting was 16 {18} (unitless) and decreased by more than 80% to 2.1 {2.2} for biopower or 3.0 {3.5} for green diesel (Fig. 4-6A). A steep decline in EROI occurred during pelleting because of process electricity demand and utilization of biomass for drying.

The GHG intensity of bioenergy products had the reverse trend of EROI (Fig. 4-6B). Life-cycle GHG emissions increased from 6.0 {5.0} $kgCO_2e\ GJ^{-1}$ for newly harvested biomass to 35 {31} $kgCO_2e\ GJ^{-1}$ (130 {110} $gCO_2e\ kWh^{-1}$) for biopower or 22 {20} $kgCO_2e\ GJ^{-1}$ for green diesel. The spike in GHG intensity occurred at energy conversion, when 65% of thermal energy was lost during power generation or 54% {45%} during FT-synthesis. Net co-production of power and FT-liquids in the conservative scenario ensured that the GHG intensity was not much higher than the aggressive estimate. A more substantial increase in GHG intensity was not observed during pelleting because Canadian electricity had a low emission factor of 224 $gCO_2e\ kWh^{-1}$ (OEE, 2006).

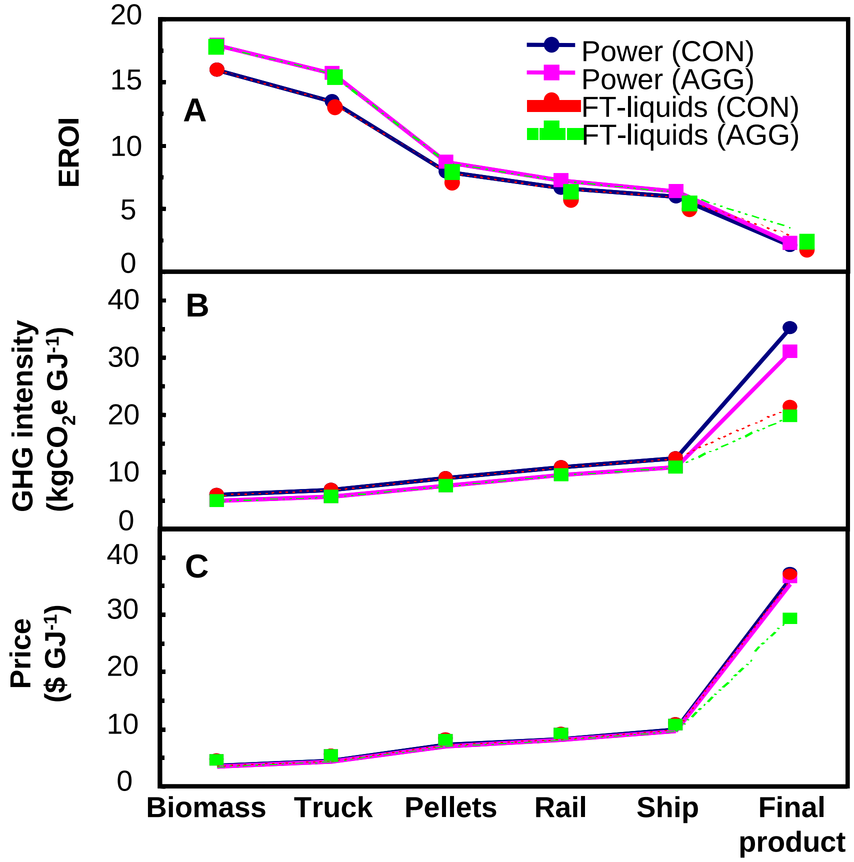

Figure 4-6: Conservative (CON) and aggressive (AGG) estimates of EROI (A), GHG intensity (B), and price (C) at different stages in biopower and green diesel production.

Bioenergy production costs increased as biomass was converted into more useful forms of energy (Fig. 4-6C). Average prices increased by eight to ten times from \$3.6 {\$3.6} GJ^{-1} for raw biomass to \$36 {\$35} GJ^{-1} (\$130 {\$130} MWh^{-1}) for biopower or \$36 {\$28} GJ^{-1} for green diesel. Pelleting increased costs by \$3.0 {\$2.8} GJ^{-1} and long-distance transportation added \$2.6 GJ^{-1}. The most expensive cost component was energy conversion, which required substantial investments and incurred significant thermal energy losses.

4.3.5 Sensitivity analysis

A sensitivity analysis on the conservative scenario was performed by independently varying assumed parameters suspected to have a significant impact on calculated values for EROI, GHG intensity, and cost (Table 4-2). Fig. 4-6A indicated that pellet mill power consumption had a strong impact on the overall EROI. A 50% reduction in pellet mill power requirements had the most tangible effect on EROI, which increased 17% over the base case. The corresponding decrease in GHG intensity was not as pronounced because of the GHG footprint of Canada's electricity sector.

Table 4-2: Sensitivity of EROI, GHG intensity, and cost/price of biopower or green diesel to system parameters.

Parameter	Biopower			Green diesel		
	EROI	GHG (gCO_2e kWh^{-1})	Cost ($ MWh^{-1})	EROI	GHG ($kgCO_2e$ GJ^{-1})	Price ($ GJ^{-1})
Conservative base case	2.1	130	130	3.0	22	36
50% increase in truck efficiency	3.2%	-3.4%	-2.2%	3.2%	-4.3%	-2.1%
50% decrease in pellet mill electricity needs	17%	-6.7%	-1.9%	17%	-8.4%	-1.7%
50% decrease in rail transportation	7.1%	-7.6%	-2.2%	7.1%	-9.5%	-2.0%
No rail transportation	15%	-15%	-7.2%	15%	-19%	-6.7%
50% decrease in shipping	4.4%	-4.9%	-2.5%	4.4%	-6.1%	-2.3%
No shipping	9.3%	-9.8%	-11%	9.3%	-12%	-10%
18% increase in diesel GHG emissions	0%	12%	0%	0%	15%	0%

Rail transportation was observed to have a strong impact on EROI and GHG intensity. A reduction in average rail transportation distance from 500 to 250 km increased EROI 7.1% and decreased GHG intensity 7.6% to 9.5%. Moreover, when biomass was harvested and pelletized adjacent to a water transportation corridor, which eliminated the need for rail shipping, EROI increased 15% and GHG intensity decreased 15% to 19%.

Water-borne shipping had the strongest impact on production costs. A reduction in average shipping distance from 1000 to 500 km only decreased costs by about 2.4% mainly because cargo still had to be loaded and unloaded. However, when only long-distance rail transportation was required, the distance fixed costs of waterborne shipping (\$11.5 $t(wet)^{-1}$) were eliminated and overall costs decreased 10%. Unlike rail or ship, improvements in the energy and cost efficiency of truck transportation had minimal effect in this supply chain.

The impact of consuming a greater proportion of fuels from unconventional oil sources was also investigated. Heavy oil production in Canada was estimated to increase the average GHG intensity of domestic diesel to 99 $kgCO_2e\ GJ^{-1}$ (Samson et al., 2008), which was 18% higher than diesel from conventional sources (Börjesson, 1996). The impact was that the overall GHG intensity of biopower and green diesel increased 12% to 15%. Similar gains in the life-cycle emissions of domestic natural gas and electricity had insignificant effects (data not shown).

4.3.6 Comparison to fossil fuels

Life-cycle GHG emissions of coal-fired power and diesel fuel were 286 (1030 $gCO_2e\ kWh^{-1}$) (Jaramillo et al., 2007) and 84 (Börjesson, 1996) $kgCO_2e\ GJ^{-1}$, respectively. The calculated GHG intensities of biopower and green diesel were 85% and 75% lower than coal power and fossil diesel, respectively. On the other hand, the cost of biopower was about 2.5 times the market power price in Ontario (\$54 MWh^{-1}) (Samson et al., 2008) and the wholesale price of green diesel was higher than the range of diesel prices in the last two years (\$13 to \$28 GJ^{-1}; EIA, 2008d).

Biomass-fired power was more cost competitive when GHG emission reductions had economic value. Biopower replacing coal was calculated to cost less than the market power price at a GHG credit of \$90 tCO_2e^{-1} and less than the premium price (\$110 MWh^{-1}) available through Ontario's Renewable Energy Standard Offer Program (OPA, 2008) at a GHG credit of \$30 tCO_2e^{-1} (Fig. 4-7A). However, the subsidy was only offered for power generation less than 10 MW, which was much smaller than the proposed scales of operation and would limit the benefits afforded by economies of scale.

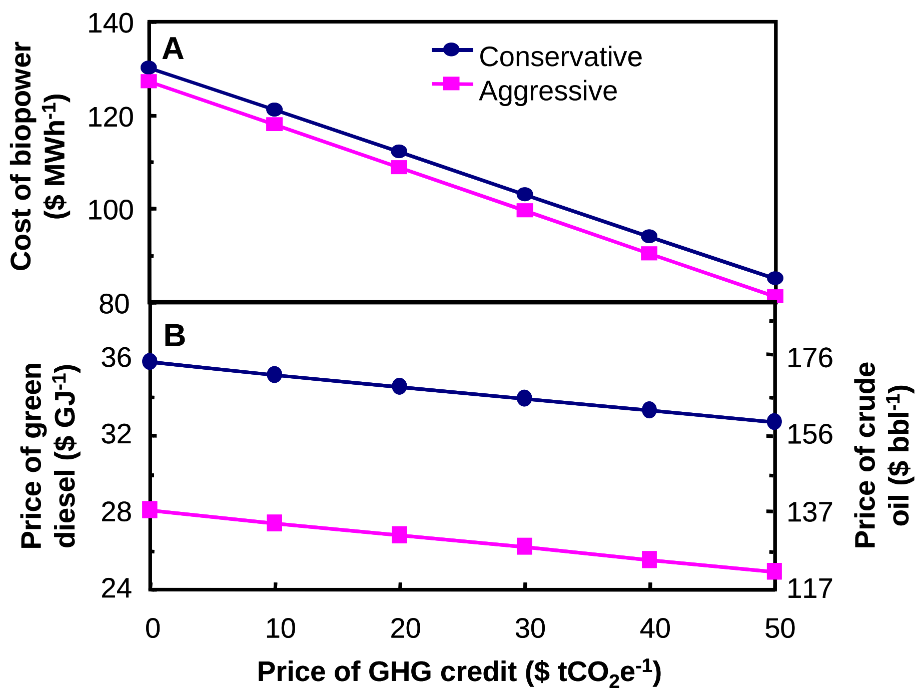

Figure 4-7: Conservative and aggressive estimates of the cost of biopower (A) and the wholesale price of green diesel (B) as a function of GHG credit values.

The wholesale price of green diesel and its break-even crude oil price were calculated to decrease at higher GHG credit values (Fig. 4-7B). Green diesel price decreased to \$33 {\$25} GJ^{-1} when replacing conventional diesel at a GHG credit of \$50 tCO_2e^{-1}. The break-even crude oil price was then calculated to be \$161 {\$122} bbl^{-1}, which is in the range predicted by many for the next few years.

There were additional benefits associated with a GLSLS bioenergy system that were more difficult to account for but important from a public policy perspective. For example, the industry would have a direct impact on rural economies in need of an economic stimulus. If 36.4 billion kWh of coal-fired power in Ontario was substituted with biomass at an investment cost of \$10 MWh^{-1} (Layzell et al., 2006), a total investment of \$360M over a 20-year period would be required. Similarly, it was estimated that 1.6 {11} billion L of green diesel was annually produced, which was equivalent to 59 {400} PJ. About 11 {64} 400 MW_{th} BTL plants at an overall total investment cost of \$382M per plant would then be required, leading to a total investment of \$4.3 {\$24} billion. Since the bioenergy sector produced 10 jobs for every \$1 million invested (The Institute for America's Future, 2004), 46,000 {250,000} new jobs would be created. Furthermore, bioenergy would improve air quality by mitigating fossil-related air pollution and improve energy security by reducing foreign oil dependence.

4.4 Conclusions

The potential to use the GLSLS as a means of diversifying Canada's energy supply mix is substantial. Biopower and synthetic green diesel were manufactured from sustainably-produced biomass and transported long distances as pellets via an intermodal network of rail and water shipping. Substitution of coal-based power and petroleum-based diesel could decrease GHG emissions, stimulate rural economies, improve air quality, and boost energy security.

Conditions that would make production economical without government subsidies include high energy prices and GHG emission reduction credits. Nevertheless, other biofuels with minor GHG benefits such as corn-based ethanol and biodiesel receive government subsidies due to their effect on energy security and rural economic development. Creating the policy environment, including initial subsidies for biopower or green diesel production, may be a very effective policy to deliver on priorities for energy security, climate change, clean air, and rural economic development.

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Chapter 5
Discussion

5.1 Summary of the transformative energy systems

Chapters 3 and 4 illustrated how transformative systems could enable large-scale bioenergy production through integration with existing transportation corridors and fossil fuel infrastructure. The biomass potential adjacent to Canada's network of natural gas pipelines and the GLSLS region was estimated to range from 81 to 209 Mt(dry) and 36 to 80 Mt(dry) per year, respectively. These estimates were comparable to the national bioenergy targets developed earlier (150 to 210 Mt(dry) per year up to 2030). Although the two models were not mutually exclusive, there was some land area overlap especially east of the Manitoba-Ontario border.

Each concept had unique advantages and disadvantages. The network of natural gas pipelines links biomass resources in remote parts of Canada to energy end users thousands of kilometres away. However, the size of an SNG production plant adjacent to the pipeline and economy of scale benefits were limited because biomass was assumed to come from local sources. A plant located adjacent to a pipeline and a railway line that delivered biomass by train could potentially be built at larger scales. On the other hand, the GLSLS system enabled fuel synthesis plants to be built at very large scales because rail and water-borne transportation corridors granted access to biomass production sites throughout the region. The drawback was a lengthy supply chain that required biomass to first be converted into pellets, and then transported by rail and ship before final conversion. Efficiency losses associated with each step in the supply chain reduced bioenergy EROI and increased production costs. In terms of implementation, biopower generation is an established technology whereas biomass gasification essential for synthetic natural gas (SNG) and biomass-to-liquid (BTL) fuels has not yet been commercialized.

Cost of bioenergy was estimated to decrease with scale but not to the point where costs were competitive with fossil fuels. Governments often subsidize renewable energy sources, ostensibly to reduce atmospheric GHGs linked to climate change. Different renewable energy technologies can be compared based on their respective cost of reducing GHG emissions (Table 5-1).

Table 5-1: The subsidy required and cost of GHG emission reductions for renewable energy carriers. Rows shaded in light grey were based on results from Chapters 3 and 4 for large-scale (LS), medium-scale (MS), and small-scale (SS) systems.

Renewable energy carrier	Fossil fuel replaced	Subsidy ($ GJ^{-1})	Offset ($kgCO_2e\ GJ^{-1}$)	Cost of emission reductions ($ tCO_2e^{-1})[c]
Heating				
BioSNG (LS)	**LNG**	8[a]	71[b]	110
BioSNG (MS)		13[a]	71[b]	180
BioSNG (SS)		18[a]	71[b]	260
Electricity				
Wind power	**Coal**	13[d]	280[f]	45
Solar PV power		84[d]	250[f]	330
Biopower		20[e]	250[f]	79
Transportation				
Corn ethanol	**Gasoline**	6.6[g]	14[i]	460
Soybean biodiesel	**Diesel**	4.7[g]	35[j]	130
Canola biodiesel		4.6[g]	43[j]	110
Green diesel (LS)		5[h]	64[j]	78
Green diesel (MS)		10[h]	64[j]	160
Green diesel (SS)		15[h]	64[j]	230

[a] Based on an LNG price of $12 GJ^{-1}, bioSNG production costs of $16, $20, and $25 GJ^{-1}, and a 20% profit margin (wholesale price is $20, $25, and $30 GJ^{-1}) for LS, MS and SS systems, respectively.
[b] Based on emissions of 87 (Table 2-8) and 16 $kgCO_2e\ GJ^{-1}$ for LNG and bioSNG, respectively.
[c] Obtained by dividing "Subsidy" by "Net offset" then multiplying by 1000 kg t^{-1}.
[d] Based on a CA$55 and CA$365 MWh^{-1} total subsidy for wind and solar power <10 MW in Ontario, respectively (Samson et al., 2008) and a 2005 exchange rate of 1.21 CA$/US$.
[e] Based on a market power price of CA$65 MWh^{-1} or $54 MWh^{-1} ($15 GJ^{-1}) in Ontario (Samson et al., 2008) and a biopower cost of $35 GJ^{-1} ($126 MWh^{-1}) (GLSLS bioenergy system).
[f] Based on life-cycle emissions of 1030, 25, 125, and 120 $gCO_2e\ kWh^{-1}$ for coal, wind, solar PV, and biopower, respectively (Miller, 2007; Samson et al., 2008).
[g] Based on total subsidies of CA$0.17, CA$0.20, and CA$0.20 L^{-1} ($0.14, 0.17, and $0.17 L^{-1}) and energy densities of 21.0, 35.2, and 35.7 MJ L^{-1} for corn-based ethanol, soybean, and canola biodiesel in Ontario, respectively (Samson et al., 2008).
[h] Based on a diesel price of $20 GJ^{-1} and a green diesel price of $25, $30, and $35 GJ^{-1} for LS, MS, and SS systems, respectively (GLSLS bioenergy system).
[i] Based on life-cycle emissions of 92.8 and 78.4 (Table 2-8) $kgCO_2e\ GJ^{-1}$ for gasoline and corn-based ethanol produced in Canada, respectively.
[j] Based on life-cycle emissions of 84, 48.8, 41.0 (Table 2-8), and 20 $kgCO_2e\ GJ^{-1}$ for fossil diesel, soybean and canola biodiesel produced in Canada, and green diesel, respectively.

Table 5-1 illustrates the impact of scale on the economics of bioenergy production. The subsidy required by bioSNG or green diesel decreased at larger plant sizes due to the economy of scale, which then reduced emission reduction costs since net GHG offsets were assumed to be independent of scale.

The cost of GHG emission reductions varied for different types of bioenergy. BioSNG to replace LNG required carbon credits greater than \$100 tCO_2e^{-1}. Lower bioSNG production costs could reduce carbon costs whereas an LNG price less than \$12 GJ^{-1} would have the opposite effect. Coal replacement for power generation was estimated to cost \$79 tCO_2e^{-1}, which was higher than wind but lower than solar PV power. The cost of green diesel produced in large-scale BTL plants (\$78 tCO_2e^{-1}) was estimated to be lower than biodiesel due to a higher net GHG offset. The trend was reversed for smaller BTL plants with lower economies of scale. Bioenergy offers additional benefits that were not internalized in the economic analysis such as security of supply, better air quality, and rural economic development.

The remainder of this thesis is a more personal perspective on how Canada can strategically use its domestic resources to build a more secure energy system with a lower carbon footprint.

5.2 Energy policy

5.2.1 A history of energy policy in Canada

The most significant Canadian energy policies prior to the North American Free Trade Agreement (NAFTA) were the National Oil Policy (NOP) and the National Energy Program (NEP). The NOP (1961) guaranteed a market for high-cost Canadian oil by granting producers exclusive rights to energy markets west of the Ottawa Valley while refineries in Montreal and Atlantic Canada continued to be supplied by cheap imported oil (Laxer, 2007). The NOP expanded the market for Canadian oil and led to American transnational corporations taking over domestic oil and gas companies.

International oil crises in the 1970s led to the development of energy policies that emphasized energy independence. The NEP was adopted in 1981 by Pierre Trudeau's Liberal government to insulate Canadians from high prices (Laxer, 2007). The program tried to Canadianize the petroleum industry by expanding federally-owned PetroCanada to challenge transnationals for control. The government's actions were opposed by US oil companies and Alberta, which felt that Canada was intruding on its jurisdiction over natural resources (Wonder, 1982). The program failed when global petroleum prices crashed in 1982 and was abolished by the subsequent Conservative government. The adoption of NAFTA and the proportionality clause, which forces Canada to export a percentage of energy production to the US, relinquished control of the petroleum industry to transnationals (Laxer, 2007). Foreign ownership of domestic resources and NAFTA export obligations impede the development of a national energy policy that could improve energy security and reduce GHG emissions.

5.2.2 The Pickens plan

The Pickens Plan is an energy strategy marketed by oil tycoon T. Boone Pickens to reduce US foreign oil dependence. The proposal is to build wind farms along the Great Plains region to supply 20% of electricity, which would liberate domestic natural gas for use as a transportation fuel (Pickens, 2008). The strategy would require investments in electricity-supply infrastructure, compressed natural gas (CNG) fuelling stations, and vehicle engine modifications. Although current natural gas demand is met mostly by regional supplies, long-term availability in North America is uncertain as the conventional resource base depletes (EIA, 2008a). However, commercialization of biomass gasification technologies and large-scale bioSNG production could augment domestic gas supplies and support a CNG-fuelled vehicle fleet.

5.3 A strategic Canadian energy policy

There are a number of different technology options that deliver energy services (i.e. heat, power, or transportation). Strategic use of domestic renewable and non-renewable resources can reduce fossil fuel consumption and improve the environmental, economic, and social sustainability of Canada's energy systems. Biomass is anticipated to play a major role because it is an abundant, renewable source of heat, power, and transportation fuels.

5.3.1 Heating

Residential, commercial, and industrial heating contributed 4.9 EJ (41%) to primary energy demand in 2003 (NRCan, 2006b). Natural gas delivered directly to consumers through transmission and distribution networks contributed 3.0 EJ (61%) to total heat demand. The following recommendations could improve the security and carbon footprint of the heating sector:

- Implement stronger building codes that minimize heat loss.
- Promote solar thermal technologies to reduce the strain on gas supplies.
- Explore ways of reducing natural gas use in the oil sands.
- Use bioSNG instead of LNG imports to augment gas supply.

These measures are to ensure that Canada has sufficient natural gas for domestic heating and other uses (i.e. alternative transportation fuel) in the long-term and does not have to rely on LNG imports.

5.3.2 Power

Power generation contributed 3.7 EJ (31%) to primary energy demand in 2003 although only 2.0 EJ of electricity was actually consumed by end users due to system energy losses (i.e. inefficient thermal power stations and transmission lines) (NRCan, 2006b). Canada has extensive renewable hydro resources that make up more than 50% of supply but the best sites have already been exploited. Fortunately, there are a variety of technologies such as CCS, nuclear, wind, solar, and biomass that can provide decarbonized electricity from domestic resources. The following recommendations could improve the security and carbon footprint of the electricity sector:

- Retrofit coal-fired power plants with CCS equipment and/or co-fire with biomass.
- Slowly phase out gas-fired power plants and divert gas resources to the transportation sector.
- Construct large-scale wind farms to provide decarbonized, central power generation.
- Promote decentralized solar PV power (i.e. rooftop solar panels) as a source of distributed generation.
- Use biomass as a source of baseload power in future electricity systems that expands into the transportation sector (explained below).
- Improve electrical end-use efficiency of household appliances, lights, pumps, and motors.
- Promote conservation to reduce pressure on renewable energy supplies.

These measures are to ensure the security of Canada's electricity supply by diversifying generation and relying on domestic resources. They also reduce GHG emissions and air pollution.

5.3.3 Transportation

Transportation contributed 2.4 EJ (20%) to primary energy demand in 2003 although only 0.47 EJ was converted into mechanical power (NRCan, 2006b) due to inefficient internal combustion engines. The following recommendations could improve the security and carbon footprint of the transportation sector:

- Produce BTL fuels in the short-term to reduce foreign oil dependence, GHG emissions, and urban smog-causing air pollutants.

- Shift biomass resources from liquid fuel production to electricity that powers battery electric vehicles (BEVs).
- Improve fuel economy and avoid offsetting efficiency gains with larger, more powerful vehicles.
- Promote alternative forms of transportation through financial incentives (cheaper public transportation fares) and public education programs.

These measures are a hedge against peak oil repercussions such as price volatility and supply interruptions. Fuel switching to BTL fuels or electricity can also reduce GHG emissions and urban air pollution.

5.3.4 Bioenergy strategy

Large-scale bioenergy production should be central to future Canadian energy policies. The bioenergy target is 20% of primary energy demand from now until 2030 and can be implemented in the following stages:

1. Replace coal-fired generation with biopower.
2. Offset a percentage of petroleum-based fuels with BTL fuels.
3. Expand biopower generation to support electrification of transport.
4. Offset LNG imports with bioSNG.

The 2003 bioenergy target (2.4 EJ) was based on a primary energy demand of 12 EJ (Table 5-2). The first objective was to offset 105 TWh of coal-fired electricity (OEE, 2006), which was estimated to require 1.2 EJ of biomass. In the second stage, the remaining 1.2 EJ of biomass was converted to 15 billion L of green diesel, which was enough to offset 79% of diesel consumption in 2003.

Table 5-2: Outline of bioenergy strategy to displace coal, LNG, diesel, and gasoline over 2003-2030.

Fuel type	2003	2015	2030
Primary energy demand (EJ)[a]	12	15	17
Bioenergy target (EJ)[b]	2.4	3.0	3.4
Bioenergy target (Mt(dry))[c]	150	180	210
Coal replaced by biopower			
Coal power (TWh)[a]	105	66.6	59.3
Fraction replaced	100%	100%	100%
Biomass required (EJ)[d]	1.2	0.76	0.68
Biomass required (Mt(dry))[c]	75	48	42
LNG replaced by bioSNG			
LNG imports (Mm^3 day^{-1})[a]	-	-	81
Fraction replaced	-	-	100%
Biomass required (EJ)[e]	-	-	2.0
Biomass required (Mt(dry))[c]	-	-	120
Fossil diesel replaced by green diesel			
Diesel consumption (billion L)[f]	19.2	25.0	30.4
Biomass available (EJ)[g]	1.2	1.1	-
Biomass available (Mt(dry))[c]	76	69	-
Green diesel produced (billion L)[h]	15	14	-
Fraction replaced	79%	54%	-
Gasoline replaced by biopower-fuelled electric vehicles			
Gasoline consumption (billion L)[i]	42.3	50.2	57.6
Biomass available (EJ)[j]	-	1.1	0.80
Biomass available (Mt(dry))[c]	-	69	49
Biopower at the tank (EJ)[k]	-	0.29	0.20
Fuel equivalents (billion L)[m]	-	36	26
Fraction replaced	-	71%	44%

[a] From NEB, 2007.
[b] Bioenergy target is 20% of primary energy demand.
[c] Based on a biomass heating value of 16 GJ per dry tonne.
[d] Based on energy efficiencies of 90% and 35% for biomass production and transportation and net power conversion, respectively (Table 5-3).
[e] Based on efficiencies of 90% and 60% for production and SNG conversion, respectively (Table 5-3).
[f] Diesel (LHV = 36 MJ L^{-1}) consumption in 2003 was 697.5 PJ (OEE, 2006) while demand was projected to grow 2.2% and 1.3% per year over 2003-2015 and 2015-2030, respectively (NEB, 2007).
[g] Calculated as 2.4 EJ (bioenergy target) minus 1.2 EJ (coal requirements) for 2003. Calculated as (3.0-0.76) x 50% for 2015, since half the biomass available was used for BTL fuel production.
[h] Based on efficiencies of 90% and 50% for production and FT-synthesis, respectively (Table 5-3).
[i] Gasoline (LHV = 32 MJ L^{-1}) consumption in 2003 was 1,355 PJ (OEE, 2006), while demand was projected to grow 1.4% and 0.9% per year over 2003-2015 and 2015-2030, respectively (NEB, 2007).
[j] Calculated as (3.0-0.76) x 50% for 2015, since half the biomass available was used for BEV biopower. Calculated as 3.4 EJ minus 0.68 EJ (coal requirements) minus 2.0 EJ (LNG requirements) for 2030.
[k] Based on energy efficiencies of 90%, 35%, 92%, and 90% for biomass production and transportation, net power conversion, distribution, and battery charging, respectively (Table 5-3).
[m] Biopower was converted to gasoline equivalents by multiplying by 4 since BEV powertrains were four times more efficient (72%) than gasoline engines (18%) (Table 5-3).

The third stage of the strategy diverted biomass from BTL fuels to power generation in support of the electrification of transport. Electric vehicles were assumed to be commercialized by 2015 and the need for extra generating capacity could come from biomass resources. The 2015 bioenergy target (3.0 EJ) was based on a primary energy demand of 15 EJ (Table 5-2). The biomass available after the replacement of 66.6 TWh of coal power was assumed to be divided equally between BTL and biopower production (1.1 EJ each). The overall conversion efficiency to wheel power varied between internal combustion engine and electric vehicles (Table 5-3).

Table 5-3: A comparison of the energy efficiency and GHG emissions associated with different transportation options.

Conversion step	Gasoline	Diesel	BTL	BioSNG	Bio-BEV
Extraction and transportation	94%	94%	90%[b]	90%[b]	90%[b]
Fuel production	88%	95%	50%[c]	60%[c]	35%[c]
Distribution	99%	99%	99%[a]	97%[a]	92%[a]
Gas compression or battery charging	-	-	-	93%[a]	90%[d]
Powertrain	18%	22%	22%[a]	19%[a]	72%[a]
Overall well-to-wheel efficiency	**15%**[a]	**18%**[a]	**10%**	**9.2%**	**19%**
Fuel GHG intensity (kgCO_2e GJ^{-1})	94[e]	85[e]	21[f]	19[g]	40[h]
Vehicle emissions (gCO_2e km^{-1})[i]	210	160	40	41	23
Cost of emission reductions ($ tCO_2e^{-1})	-	-	78 to 230[j]	29 to 170[k]	66[m]

[a] From Hekkert et al., 2005.
[b] Energy efficiency of biomass production and transportation (Hamelinck et al., 2005).
[c] Net conversion efficiency of biomass to green diesel, SNG, or power.
[d] From Evans, 2007.
[e] Based on life-cycle emissions of 93 (Samaras and Meisterling, 2003) and 84 (Börjesson, 1996) kgCO_2e GJ^{-1} and 99% distribution efficiency for conventional gasoline and diesel, respectively.
[f] Based on 21 kgCO_2e GJ^{-1} for green diesel (GLSLS system) and 99% distribution efficiency.
[g] Based on 17 kgCO_2e GJ^{-1} for bioSNG, 97% distribution efficiency, and 93% compression efficiency.
[h] Based on life-cycle emissions of 33 kgCO_2e GJ^{-1} (120 gCO_2e kWh^{-1}) for biopower (GLSLS system), 92% distribution efficiency, and 90% battery charging efficiency.
[i] Calculated as "Fuel GHG intensity" (gCO_2e MJ^{-1}) multiplied by 0.41 MJ km^{-1} (theoretical wheel power, Hekkert et al., 2005) and divided by "Powertrain".
[j] See Table 5-1.
[k] BioSNG price of \$20-30GJ^{-1} (Table 5-1) and CNG price of \$22-33GJ^{-1} after accounting for distribution and compression. Subsidy calculated to range from \$2-13GJ^{-1} based on gasoline price of \$20GJ^{-1}, net offset determined to be 173gCO_2e km^{-1}, and range calculated to be 463kmGJ^{-1} (1000MJ GJ^{-1} x 0.19MJ(wheel)MJ^{-1} / 0.41 MJ(wheel) km^{-1}). Cost of carbon calculated as \$2 to \$13 GJ^{-1}/ 463km GJ^{-1}/ 173x10^{-6} tCO_2e km^{-1}.
[m] Biopower cost of \$35GJ^{-1} (Table 5-1) and \$42GJ^{-1} after accounting for distribution and battery charging. Subsidy calculated as \$22GJ^{-1} based on a gasoline price of \$20GJ^{-1}, net offset determined to be 191gCO_2e km^{-1}, and range calculated to be 1756km GJ^{-1} (1000MJ GJ^{-1} x 0.72MJ(wheel) MJ^{-1} / 0.41MJ(wheel) km^{-1}). Cost of carbon calculated as \$22GJ^{-1} / 1756 kmGJ^{-1} / 191 x 10^{-6} tCO_2e km^{-1}.

The primary difference between the supply chains was the energy efficiency of fuel production and the powertrain. Crude oil refining to gasoline or diesel is a mature, energy efficient technology whereas production of BTL fuels, bioSNG, or biopower are inherently inefficient processes. The powertrain for internal combustion engines only converted 18% to 22% of fuel energy to mechanical power whereas batteries delivered 72% of electrochemical energy to the wheels. Consequently, 1.1 EJ of biomass yielded 14 billion L of green diesel or 36 billion L of gasoline equivalents for BEVs, which was equal to 54% and 71% of projected diesel and gasoline consumption in 2015, respectively.

Vehicle life-cycle emissions were the lowest for biopower-fuelled BEVs because of the high overall well-to-wheel efficiency. However, the cost of GHG emission reductions was lowest for bioSNG-fuelled vehicles that replaced gasoline-powered vehicles. The price range of bioSNG in the vehicle fuel tank (\$22 to \$33 GJ^{-1}) was less than green diesel (\$25 to \$35 GJ^{-1}) and biopower (\$42 GJ^{-1}) (Table 5-3, footnotes "k" and "m").

The final stage of the strategy was a complete shift from BTL production to bioSNG and power generation. The 2030 bioenergy target (3.4 EJ) was based on a primary energy demand of 17 EJ (Table 5-2), when coal power was expected to decline to 59.3 TWh and gas imports were anticipated to average 81 Mm^3 day^{-1}. Complete offset of coal and LNG was estimated to require 0.68 and 2.0 EJ of biomass to be converted to power and SNG, respectively. The remaining 0.8 EJ of biomass could be converted to 26 billion L of gasoline equivalents for BEVs, which was equal to 44% of projected gasoline consumption in 2030.

To summarize, an ambitious bioenergy target could offset substantial amounts of coal, petroleum-based fuels, and LNG. Bioenergy production would boost energy security by reducing reliance on foreign oil and gas and mitigate GHG emissions by mitigating fossil fuel consumption. The anticipated GHG emission savings as a result of replacing fossil fuels with bioenergy alternatives is presented in Table 5-4.

Table 5-4: Anticipated GHG emissions and savings ($MtCO_2e$) over 2003-2030 based on the proposed bioenergy strategy.

Source of GHG emissions	2003	2015	2030
Coal replaced with biopower			
Actual coal-fired power GHG emissions[a]	110	69	61
GHG savings[b]	95	61	54
GHG offset ($tCO_2e\ t(dry)^{-1}$)[c]	1.3	1.3	1.3
Cost of emission reductions (\$ tCO_2e^{-1})[d]		79	
LNG replaced with bioSNG			
Actual LNG GHG emissions[a]	-	-	93
GHG savings[b]	-	-	75
GHG offset ($tCO_2e\ t(dry)^{-1}$)[c]	-	-	0.60
Cost of emission reductions (\$ tCO_2e^{-1})[d]		110-260	
Fossil diesel replaced with green diesel			
Actual diesel GHG emissions[a]	59	76	93
GHG savings[b]	37	36	-
GHG offset ($tCO_2e\ t(dry)^{-1}$)[c]	0.49	0.52	-
Cost of emission reductions (\$ tCO_2e^{-1})[d]		78-230	
Gasoline replaced with biopower-fuelled electric vehicles			
Actual gasoline GHG emissions[a]	130	150	170
GHG savings[b]	-	98	72
GHG offset ($tCO_2e\ t(dry)^{-1}$)[c]	-	1.4	1.5
Cost of emission reductions (\$ tCO_2e^{-1})[d]		66	
Totals			
Total energy-related GHG emissions[e]	610	730	850
Total GHG savings[f]	130	190	200
Net emissions[g]	480	540	650
Reduction below actual levels	22%	27%	24%
Increase above 1990 levels[e]	1.4%	14%	37%

[a] Based on Table 5-2 and life-cycle GHG emission factors of 1030 $gCO_2e\ kWh^{-1}$ for coal-fired power and 87, 84, and 93 $kgCO_2e\ GJ^{-1}$ for LNG, diesel, and gasoline, respectively.
[b] Calculated as the difference between actual and bioenergy emissions, then multiplied by the fraction replaced (Table 5-2). Bioenergy emissions were estimated using factors of 120 $gCO_2e\ kWh^{-1}$ for biopower and 17 and 21 $kgCO_2e\ GJ^{-1}$ for bioSNG and green diesel, respectively.
[c] Calculated as biomass input (units of Mt(dry)) (Table 5-2) divided by "GHG savings".
[d] Table 5-1.
[e] Canada's energy-related GHG emissions in 1990 and 2003 were 470 and 610 $MtCO_2e$, respectively (EC, 2008). Emissions were projected to grow 1.5% and 1.0% per year over 2003-2015 and 2015-2030, respectively (NEB, 2007).
[f] Sum of individual "GHG savings".
[g] Calculated as "Total energy-related GHG emissions" minus "Total GHG savings".

The bioenergy strategy reduced GHG emissions 130, 190, and 200 MtCO_2e but total energy-related emissions still rose 1.4%, 14%, and 37% above 1990 levels in 2003, 2015, and 2030, respectively. Canada's target to stabilize atmospheric CO_2e concentration at 450 ppmv was 80% below 1990 levels by 2050.

Bioenergy substitution can reduce GHG emissions even further by shifting biomass allocation. The "GHG offset" rows in Table 5-4 show that more CO_2e was displaced when gasoline or coal was substituted by bio-BEVs or biopower, respectively. One dry tonne of biomass offset 1.3 to 1.5 tCO_2e when replacing gasoline or coal as opposed to 0.49 to 0.60 tCO_2e when replacing LNG and diesel with bioSNG and green diesel. Thus, GHG emissions were only reduced by an additional 10 MtCO_2e per year between 2015 and 2030 because most of the available biomass was used to replace low-offset LNG imports as opposed to high-offset gasoline vehicles. The differences in offset arose because 1) the overall well-to-wheel efficiency of bio-BEVs was high and 2) coal had the highest carbon to energy ratio of all energy sources. Allocating biomass to high-offset areas would have reduced GHG emissions more substantially.

The cost of GHG emission reductions was similar for biopower and large-scale green diesel production (\$66 to \$79 tCO_2e^{-1}) (Table 5-4). Carbon costs were higher for medium- to small-scale FT-synthesis and LNG replacement (>\$100 tCO_2e^{-1}). The lowest emission reduction costs (\$29 to \$170 tCO_2e^{-1}) were observed for bioSNG-fuelled vehicles (Table 5-3). Although investment costs for engine modifications and fuelling infrastructure would be required, bioSNG deserves strong consideration as an alternative transportation fuel in addition to a mitigator of LNG imports.

Bioenergy production was estimated to reduce GHG emissions by approximately 22% to 27% at costs of around \$100 tCO_2e^{-1}. However, bioenergy on its own was not enough to lower emissions 80% below 1990 levels by 2050. Other renewable energy technologies must also be employed and growth in energy demand and GHG emissions must be curtailed.

A slightly different approach to the bioenergy strategy outlined above involves making use of some of the concepts put forth by the Pickens Plan. In this revised approach, biomass could be used to offset gas-fired power generation as opposed to producing BTL fuels, which would liberate natural gas for use in the transportation sector. This strategy would also be more immediately implementable because biomass power generation and CNG-fuelled vehicles are both commercialized technologies more developed than BTL or SNG synthesis. The future use of BTL fuels or biopower-based BEVs in the transportation sector could depend on how the respective technologies develop and their rates of commercialization. Overall, steps 2 and 3 of the bioenergy strategy in particular will likely be revisited while step 4 takes a long-term perspective that could change depending on the future needs of Canadian society.

5.4 Policy implementation

The international oil crises gave rise to energy policies dominated by security of supply concerns. These policies were abandoned after global petroleum prices crashed and market-based energy policies that promoted privatization, liberalization, and competition were instituted (Helm, 2007). However, current energy security and climate change issues are sufficient in magnitude to require a fundamental shift in energy policy. The new energy paradigm must go beyond standard market approaches to achieve policy objectives.

A strategic Canadian energy policy with supply security and climate change at its core was developed. The proposal is a policy paradigm shift that reflects the need for transformative changes to energy systems. A set of policy instruments to implement the plan was also required. Market-based instruments were attractive to correct energy security and climate change market failures (Helm, 2007) but complementary regulatory approaches were also necessary (NRTEE, 2007). The following action plan and set of policy instruments is one possible way of implementing the energy strategy:

1. Level the playing field.
2. Promote renewable energy.
3. Elevate expectations.
4. Start the paradigm shift.

5.4.1 Level the playing field

The structure of the current energy market favours fossil fuels such that alternatives will have a hard time gaining market share. The fossil fuel industry is supported by government subsidies while the environmental and social costs are borne by the public (Worldwatch Institute, 2006). Some of the externalities associated with fossil fuels are energy insecurity, GHG emissions, air pollution, and militarization (i.e. the need to protect foreign oil supplies) (Klare, 2006; Worldwatch Institute, 2006). Since these impacts are not internalized the market price of energy is offered below the total social costs (Neuhoff, 2007). Environmental and social costs need to be internalized and fossil fuel subsidies eliminated to level the playing field with alternatives. For example, mass transit would be more appealing if the costs of urban air pollution were incorporated in the price of transportation fuels. Foreign oil dependence has many negative factors such as the destabilizing effect of peak oil, wealth transfers to foreign nations, and military protection of key supply routes that are not reflected in the market price of petroleum. Air pollution from coal-fired power plants causes respiratory problems and acid rain, factors that are not accounted for in the price of electricity.

A carbon tax is widely considered to be one of the most effective policy instruments to reduce fossil fuel consumption and correct climate change market failures. The tax would act as a financial disincentive on GHG-intensive commodities and improve the competitiveness of low-carbon alternatives. The tax can be offset through a reduction in income taxes making it revenue neutral. A long-term carbon price signal was deemed necessary to guide investment decisions in renewable technologies and energy productivity (NRTEE, 2007). Tables 5-1 and 5-3 showed that bioenergy and other renewable technologies were cost competitive with conventional fuels at carbon prices as low as \$29 tCO_2e^{-1} or greater than \$100 tCO_2e^{-1}. These prices do not include security of supply, improved air quality, and rural economic development benefits.

5.4.2 Promote renewable energy

Renewable energy technologies offer advantages such as reduced GHG emissions, better air quality, and energy security compared to fossil fuels. Consequently, renewables should be subsidized to benefit from unpriced advantages (Neuhoff, 2007). In many cases the cost of new technologies are reduced with increasing market experience. Mass deployment of non-commercial technologies supported by the government can accelerate technology learning and even prove to be a wise long-term investment (IEA, 2006). Denmark spent \$1.4 billion in wind subsidies over 1993-2001 and by 2001 annual wind energy revenues were \$2.7 billion, most of which came from technology exports (Neuhoff, 2007). Sugar-based ethanol in Brazil competes openly with gasoline and no longer requires government subsidies (Faaij, 2006). Moreover, wind and ethanol industries have created thousands of domestic jobs. Renewable energy can also provide a hedge against future energy prices or environmental regulations (Worldwatch Institute, 2006) while diversifying the supply mix. Public investments in research and development and infrastructure such as electricity transmission lines and grid modernization are necessary to support emerging technologies that will eventually become cost competitive, diversify the energy supply mix, create jobs, and reduce GHG emissions.

5.4.3 Elevate expectations

Although renewable energy technologies hold significant promise they have realistic limits (Schiermeier et al., 2008) and may not be able to fully substitute the conventional energy system

(Glover, 2006). The strain on renewable energy supplies to meet demand has to be reduced by demand-side management. The government needs to enact legislation that elevates accepted standards for energy productivity because technological efficiency improvements are viewed as the fastest and most cost effective way of reducing fossil fuel consumption (IEA, 2006). Stronger building codes should demand that new buildings meet net-zero energy standards (Gonick and Haley, 2007). The government should also mandate that gains in vehicle energy efficiency be used to reduce fuel consumption rather than improve other attributes such as power (Bandivadekar et al., 2008). Finally, major appliances should have to meet advanced efficiency standards before they can go on the market (Worldwatch Institute, 2006). Strategic deployment of renewable technologies coupled with aggressive reductions in energy consumption has a much better chance of dethroning fossil fuels.

5.4.4 Start the paradigm shift

Replacing fossil fuels with renewable energy involves more planning and investments but does not require behavioural changes (Heinberg, 2007a). Technological efficiency improvements also have very little impact on lifestyle. However, conserving energy by simply doing without is an essential behavioural change. Western society has grown accustomed to abundant supplies of heat, power, and transportation fuels to feed ever-expanding demand, albeit at significant environmental costs. Even higher energy productivity, which intuitively should reduce demand, has rebound effects that may increase consumption on a macro-level. Future energy systems that rely on renewable as opposed to conventional technologies will have to manage demand and conserve energy much more effectively. Energy self-sufficiency and deep cuts in GHG emissions are not possible without a complementary paradigm shift that fosters behavioural changes in individuals. Communities have to want renewable, decarbonized energy sources to assist mass deployment of emerging technologies. Similarly, new taxation policies such as a carbon tax will face political hurdles without an appreciation for the new energy paradigm. Moreover, the rebound effect from energy productivity gains can be much less if individuals understand the overall societal impacts of energy production.

Public education programs are instrumental in making the paradigm shift. The message that needs to get out is that fossil fuel dependence can disrupt our economy, security, and planet. The public needs to understand that current patterns of energy use are unsustainable and weaning the world off of non-renewable, climate change inducing forms of energy is one of the greatest challenges of the 21st century. A new energy paradigm would compel individuals to rethink travel, housing, diet, and all other aspects of their lives. A paradigm shift, where citizens demand renewable energy and make concerted efforts to reduce consumption, would offer society a better chance to overcome the perils of fossil fuels and choose a more sustainable energy future.

Chapter 6

Summary and Conclusions

A strategic Canadian energy policy with security and climate change at its core was proposed. The policy focused on deployment of renewable energy technologies and demand-side management to reduce fossil fuel consumption for heat, power, and transportation fuels. Market-based and regulatory instruments were proposed to implement the strategy. An action plan using subsidies, carbon taxes, new legislation, and a paradigm shift was put forward.

Bioenergy was proposed to play a central role in future energy policy because of Canada's vast biomass potential and its flexibility as a renewable energy source. Large-scale production systems were deemed necessary to meet ambitious bioenergy targets. However, those systems suffered from high biomass transportation costs from the field to energy conversion facilities, and to markets. Transformative energy systems were proposed to enable large-scale bioenergy production through integration with existing transportation corridors and fossil fuel infrastructure. Canada's network of natural gas pipelines and the Great Lakes St. Lawrence Seaway were explored as potential bioenergy transportation corridors. The bioenergy strategy suggested that biomass be used to 1) replace coal-fired power generation, 2) produce liquid transportation fuels, 3) generate more power to fuel battery electric vehicles, and 4) offset liquefied natural gas imports with bio-synthetic natural gas.

Several alternative technologies including bioenergy were proposed to reduce fossil fuel dependence. Despite the many services fossil fuels have provided over the years, the time has come to exit the hydrocarbon economy and enter a post-carbon society. Reorganizing our lives and economies according to the new energy paradigm will be a huge undertaking but the twin threats of energy security and climate change should be able to provide the necessary motivation.

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Appendix A
Model Equations

A.1 Biomass production

The lower heating value of biomass (LHV_{WB}) was a function of its higher heating value (HHV_{DB}), intrinsic moisture (MC), and hydrogen content (HC). The scale of operation (M_H ; an independent variable), biomass yield (*Yield*), and land area accessible (LAA) directly affected the size of the harvest area (A_H). Production sites were modelled as circles with an even distribution of biomass and a central gathering point at the origin, where bioSNG or pellet production facilities were located.

The parasitic energy use of biomass production (PE_{BP}) was based on energy inputs (EI) of diesel, natural gas, and electricity. The associated greenhouse gas (GHG) emissions (GHG_{BP} and GHG_{Fert}) were estimated using life-cycle emission factors ($LCEF$) and a nitrous oxide emission factor (N_2O_{EF}). The cost of biomass production ($Cost_{BP}$) was based on the price of biomass ($Price_B$) and the amount transported (M_{Truck}).

Table A 1: A summary of the variables used to model biomass production.

Symbol	Definition	Value	Units	Reference
A_H	Area of harvest		ha	
Can ElecEff	Overall efficiency of Canadian electricity sector	53%		OEE, 2006
CF	Capacity factor	8000	hr year^{-1}	
$Cost_{BP}$	Cost of biomass production		\$ year^{-1}	
DML_{BP}	Dry matter losses in biomass production	5%		Hamelinck et al., 2005
EC_H	Energy content of harvested biomass		GJ year^{-1}	
ECF	Energy conversion factor	1000	MJ GJ^{-1}	
$EI_{X,BP}$	Energy inputs (diesel, natural gas, or electricity)		GJ t(dry)$^{-1}$	Turhollow and Perlack, 1991
GHG_{Fert}	GHG emissions from fertilizer application		kgCO_2e year^{-1}	

$GHG_{X,BP}$	GHG emissions from parasitic energy use		$kgCO_2e\ year^{-1}$	
GWP_{N2O}	Global warming potential of nitrous oxide	310	$kgCO_2e\ kgN_2O^{-1}$	Samson et al., 2008
$\Delta H_{V,15}$	Latent heat of vapourization of water (15°C)	2.447	$GJ\ tH_2O^{-1}$	van Loo and Koppejan, 2003
HC	Hydrogen content on a dry basis (woody biomass)	6.0%		van Loo and Koppejan, 2003
HC	Hydrogen content on a dry basis (herbaceous biomass)	5.5%		van Loo and Koppejan, 2003
HHV_{DB}	Higher heating value on a dry basis (woody biomass)	20.0	$GJ\ t(dry)^{-1}$	Klass, 1998
HHV_{DB}	Higher heating value on a dry basis (herbaceous biomass)	18.5	$GJ\ t(dry)^{-1}$	Klass, 1998
HPD	Hours per day	24	$hr\ day^{-1}$	
LAA	Land area accessible		%	
$LCEF_D$	Life-cycle emission factor (diesel)	84	$kgCO_2e\ GJ^{-1}$	Börjesson, 1996
$LCEF_{Elec}$	Life-cycle emission factor (Canadian electricity)	224	$gCO_2e\ kWh^{-1}$	OEE, 2006
$LCEF_{NG}$	Life-cycle emission factor (natural gas)	68	$kgCO_2e\ GJ^{-1}$	Jaramillo et al., 2007
LHV_{WB}	Lower heating value of biomass on a wet basis		$GJ\ t(wet)^{-1}$	
M_H	Size of biomass harvest		$t(dry)\ day^{-1}$	
M_{Truck}	Amount of biomass transported by truck		$t(dry)\ day^{-1}$	
MC	Moisture content (woody biomass)	45%		Klass, 1998
MC	Moisture content (herbaceous biomass)	25%		Klass, 1998
N_2O_{EF}	Nitrous oxide emission factor (switchgrass)	0.5	$kgN_2O\text{-}N\ ha^{-1}\ year^{-1}$	Samson et al., 2008
NCF	Nitrogen conversion factor	1.57	$kgN_2O\ kgN_2O\text{-}N^{-1}$	Samson et al., 2008
PCF	Power conversion factor	3.6	$MJ\ kWh^{-1}$	
PE_{BP}	Parasitic energy use		$GJ\ year^{-1}$	
$Price_B$	Price (woody biomass)	45-54	$US\$(2005)\ t(dry)^{-1}$	Kumar et al., 2008
$Price_B$	Price (herbaceous biomass)	62-70	$\$\ t(dry)^{-1}$	Samson et al., 2008
W_{H2}	Water created per unit hydrogen during combustion	9.01	$kgH_2O\ kgH_2^{-1}$	van Loo and Koppejan, 2003
$Yield$	Yield of biomass		$t(dry)\ ha^{-1}\ year^{-1}$	

Mass and energy

$$LHV_{WB} = HHV_{DB} * (1 - MC) - \Delta H_{V,15} * \left[MC + W_{H2} * HC * (1 - MC)\right]$$ [GJ t(wet)$^{-1}$]

$$LHV_{DB} = \frac{LHV_{WB} + \Delta H_{V,15} * MC}{1 - MC}$$ [GJ t(dry)$^{-1}$]

$$EC_{H} = \frac{M_{H}}{1 - MC} * LHV_{WB} * \frac{CF}{HPD}$$ [GJ year^{-1}]

$$EC_{H} = \left(M_{H} * LHV_{DB} - \Delta H_{V,15} * \frac{M_{H} * MC}{1 - MC} \right) * \frac{CF}{HPD}$$ [GJ year^{-1}]

$$M_{Truck} = M_{H} * (1 - DML_{BP})$$ [t(dry) day^{-1}]

$$A_{H} = \frac{M_{H}}{Yield * LAA} * \frac{CF}{HPD}$$ [ha]

$$PE_{D,BP} = M_{H} * EI_{D,BP} * \frac{CF}{HPD}$$ [GJ year^{-1}]

$$PE_{NG,BP} = M_{H} * EI_{NG,BP} * \frac{CF}{HPD}$$ [GJ year^{-1}]

$$PE_{Elec,BP} = M_{H} * EI_{Elec,BP} * \frac{CF}{HPD} * \frac{ECF}{PCF}$$ [kWh year^{-1}]

$$PE_{BP} = PE_{D,BP} + PE_{NG,BP} + \frac{PE_{Elec,BP}}{CanElecEff} * \frac{PCF}{ECF}$$ [GJ year^{-1}]

<u>GHG emissions</u>

$$GHG_{D,BP} = PE_{D,BP} * LCEF_{D}$$ [kgCO$_2$e year^{-1}]

$$GHG_{NG,BP} = PE_{NG,BP} * LCEF_{NG}$$ [kgCO$_2$e year^{-1}]

$$GHG_{Elec,BP} = \frac{PE_{Elec,BP} * LCEF_{Elec}}{MCF}$$ [kgCO$_2$e year^{-1}]

$$GHG_{BP} = GHG_{D,BP} + GHG_{NG,BP} + GHG_{ELEC,BP}$$ [kgCO$_2$e year^{-1}]

$$GHG_{Fert} = N_{2}O_{EF} * NCF * GWP_{N2O} * \frac{M_{H}}{Yield} * \frac{CF}{HPD}$$ [kgCO$_2$e year^{-1}]

<u>Cost</u>

$$Cost_{BP} = Price_{B} * M_{Truck} * \frac{CF}{HPD}$$ [\$ year^{-1}]

A.2 Truck transportation

The average truck transportation distance (*R_{Truck}*) was based on the average radius of the harvest area and a road tortuosity factor (*RoadTort*). Parasitic energy use and GHG emissions were calculated on the basis that trucks hauled a full load of biomass to the central plant and returned empty. The cost of transportation was determined from distance fixed costs (*DFC_{Truck}*) such as loading and unloading cargo and distance variable costs (*DVC_{Truck}*) such as fuel, wages, and maintenance.

Table A 2: A summary of the variables used to model truck transportation.

Symbol	Definition	Value	Units	Reference
ACF	Area conversion factor	100	ha km^2	
Avg Radius	Average radius of a circle	2/3	unitless	
CC_{Truck}	Truck cargo capacity	25	tonnes	Marrison and Larson, 1995
$Cost_{Truck}$	Cost of truck transportation		\$ $year^{-1}$	
DFC_{Truck}	Distance fixed cost of truck transportation (wood chips)	3.1	US\$(2005) $t(wet)^{-1}$	Searcy et al., 2007
DFC_{Truck}	Distance fixed cost of truck transportation (straw bales)	4.5	\$ $t(wet)^{-1}$	Searcy et al., 2007
DVC_{Truck}	Distance variable cost (wood chips)	0.072	\$ $t(wet)^{-1}$ km^{-1}	Searcy et al., 2007
DVC_{Truck}	Distance variable cost (straw bales)	0.12	\$ $t(wet)^{-1}$ km^{-1}	Searcy et al., 2007
EI_{Truck}	Energy inputs (diesel)	0.85	MJ $t(wet)^{-1}$ km^{-1}	Statistics Canada, 2007a
GHG_{Truck}	GHG emissions		kgCO_2e $year^{-1}$	
$Mass_{Truck}$	Mass of a truck	15	tonnes	Marrison and Larson, 1995
N_{Trucks}	Number of trucks required to transport biomass		trucks $year^{-1}$	
PE_{Truck}	Parasitic energy		GJ $year^{-1}$	
R_{Truck}	Average truck transportation distance		km	
RoadTort	Road tortuosity (forest)	2	unitless	
RoadTort	Road tortuosity (agriculture)	1.5	unitless	

<u>Mass and energy</u>

$$R_{Truck} = \sqrt{\frac{A_H}{\pi * ACF}} * AvgRadius * RoadTort \qquad \text{[km]}$$

$$N_{Trucks} = \frac{M_{Truck}}{1 - MC} * \frac{CF}{HPD} * \frac{1}{CC_{Truck}} \qquad \text{[trucks year}^{-1}\text{]}$$

$$PE_{Truck} = \frac{N_{Trucks} * EI_{Truck} * R_{Truck} * \left(2Mass_{Truck} + CC_{Truck}\right)}{ECF} \qquad \text{[GJ year}^{-1}\text{]}$$

<u>GHG emissions</u>

$$GHG_{Truck} = PE_{Truck} * LCEF_D \qquad \text{[kgCO}_2\text{e year}^{-1}\text{]}$$

<u>Cost</u>

$$Cost_{Truck} = \left(DFC_{Truck} + DVC_{Truck} * R_{Truck}\right) * \frac{M_{Truck}}{1 - MC} * \frac{CF}{HPD} \qquad \text{[\$ year}^{-1}\text{]}$$

A.3 Synthetic natural gas production

Biomass was delivered to central facilities that produced synthetic natural gas (SNG) via gasification and methanation processes. The overall energy conversion efficiency of dry biomass to SNG (Eff_{BioSNG}) was used to calculate the amount of bioSNG produced (EC_{BioSNG}). The heat demand of the biomass dryer ($Heat_{Dryer}$) was met by exothermic heat produced during gasification and methanation ($Heat_{Recovery}$). Excess heat was then used in a heat recovery steam generator and steam turbine to produced auxiliary power ($AuxPower_{BioSNG}$) to offset internal electricity requirements ($IntPower_{BioSNG}$). The energy return on investment (*EROI*) and $LCEF_{BioSNG}$ were calculated based on the energy content of bioSNG and upstream parasitic energy use or GHG emissions.

The scale of the plant ($PlantScale_{BioSNG}$) was directly related to M_H. Scale factor (*SF,BioSNG*) calculations estimated investment costs at different plant sizes ($CapitalCost_{BioSNG}$) by using the capital cost of a 400 MW_{th} plant as a reference. Capital costs were amortized using a capital recovery factor (*CRF*) and overall production costs ($ProdCost_{BioSNG}$) were estimated from annual capital, operating, and feedstock costs.

Table A 3: A summary of the variables used to model SNG production.

Symbol	Definition	Value	Units	Reference
$AuxPower_{BioSNG}$	Auxiliary power generated by waste heat		kWh $year^{-1}$	
C_P	Heat capacity (wood)	2.26	MJ $t(wet)^{-1}$ K^{-1}	
C_P	Heat capacity (straw)	1.34	MJ $t(wet)^{-1}$ K^{-1}	
$CapitalCost_{BioSNG}$	Capital cost at any scale		$	
$CapitalCost_{BioSNG,400MW}$	Capital cost of a 400 MW_{th} SNG production plant	500 x 10^6	US$(2005)	Tijmensen et al., 2002; Zwart et al., 2006
$Cost_{Capital,BioSNG}$	Annualized capital cost		$ $year^{-1}$	
$Cost_{Elec,BioSNG}$	Cost/Revenue of power consumption/production		$ $year^{-1}$	
$Cost_{O\&M,BioSNG}$	Annual operating and maintenance costs		$ $year^{-1}$	
CRF	Capital recovery factor		unitless	Fraser et al., 2000
$DML_{Storage\&Drying}$	Dry matter loss in storage and drying	5%		
EC_{Dry}	Energy content of dried biomass		GJ $year^{-1}$	
Eff_{BioSNG}	Energy conversion efficiency of biomass to SNG	55%-65%		Duret et al., 2005; Zwart and Boerrigter, 2005
Eff_{Dryer}	Energy efficiency of biomass dryer	80%		
$Eff_{WasteHeat\ Power}$	Efficiency of waste heat to power	25%-30%		
$EROI$	Energy return on investment		unitless	
$Frac_{Recovery}$	Fraction of exothermic heat recovered	90%		
$Fraction_{O\&M,BioSNG}$	Fraction of capital cost invested in operation and maintenance each year	4%		Hamelinck et al., 2002
$GHG_{Elec,BioSNG}$	GHG emissions of electricity consumption/production		$kgCO_2e$ $year^{-1}$	
$\Delta H_{V,100}$	Latent heat of vapourization (100°C)	2257	MJ tH_2O^{-1}	van Loo and Koppejan, 2003
$Heat_{Dryer}$	Heat demand of the dryer		GJ $year^{-1}$	
$Heat_{Recovery}$	Exothermic heat production		GJ $year^{-1}$	
$Heat_{for\ Power}$	Heat available to generate power		GJ $year^{-1}$	
i	Interest rate	10%		

IntPower BioSNG	Internal power requirements	7.7% input		Mozaffarian and Zwart, 2003
$LCEF_{BioSNG}$	Life-cycle emission factor of bioSNG		$kgCO_2e\ GJ^{-1}$	
$LHV_{WB,Dry}$	Lower heating value of dried biomass		GJ t(wet)$^{-1}$	
M_{BioSNG}	Amount of biomass to be converted to SNG		t(dry) day^{-1}	
M_W	Mass of water evaporated during drying		tH_2O day^{-1}	
MC_{Dry}	Moisture content after drying	15%		
n	Plant lifetime	20	years	
$Plant\ Scale_{BioSNG}$	Thermal biomass input to SNG production		MW_{th}	
$Price_{Elec}$	Market power price	0.054	\$ kWh^{-1}	Samson et al., 2008
ProdCost BioSNG	Production costs of bioSNG		\$ GJ^{-1}	
SF,BioSNG	Scale factor for SNG production plants	0.75-0.91	unitless	Tijmensen et al., 2002
SPH	Seconds per hour	3600	s hr^{-1}	
T_{In}	Temperature of biomass entering the dryer	15	°C	
T_{Out}	Temperature of biomass leaving the dryer	100	°C	

<u>Mass and energy</u>

$$M_{BioSNG} = M_{Truck} * \left(1 - DML_{Storage\&Drying}\right) \qquad [\text{t(dry) day}^{-1}]$$

$$LHV_{WB,Dry} = HHV_{DB} * \left(1 - MC_{Dry}\right) - \Delta H_{V,15} * \left[MC_{Dry} + W_{H2} * HC * \left(1 - MC_{Dry}\right)\right] \qquad [\text{GJ t(wet)}^{-1}]$$

$$EC_{Dry} = \frac{M_{BioSNG}}{1 - MC_{Dry}} * LHV_{WB,Dry} * \frac{CF}{HPD} \qquad [\text{GJ year}^{-1}]$$

$$EC_{BioSNG} = EC_{Dry} * Eff_{BioSNG} \qquad [\text{GJ year}^{-1}]$$

$$Heat_{Recovery} = EC_{Dry} * \left(1 - Eff_{BioSNG}\right) * Frac_{Recovery} \qquad [\text{GJ year}^{-1}]$$

$$M_W = \frac{M_{Truck} * MC}{1 - MC} - \frac{M_{Truck} * MC_{Dry}}{1 - MC_{Dry}} \qquad [\text{tH}_2\text{O day}^{-1}]$$

$$Heat_{Dryer} = \frac{\left[\frac{M_{Truck}}{1-MC} * C_P * (T_{Out} - T_{In}) + M_W * \Delta H_{V,100}\right] * \frac{CF}{HPD * ECF}}{Eff_{Dryer}}$$ [GJ year^{-1}]

$$HeatforPower = Heat_{Recovery} - Heat_{Dryer}$$ [GJ year^{-1}]

$$AuxPower_{BioSNG} = HeatforPower * Eff_{WasteHeatPower} * \frac{ECF}{PCF}$$ [kWh year^{-1}]

$$Power_{Required,BioSNG} = EC_{Dry} * IntPower_{BioSNG} * \frac{ECF}{PCF}$$ [kWh year^{-1}]

$$PE_{Elec,BioSNG} = Power_{Required,BioSNG} - AuxPower_{BioSNG}$$ [kWh year^{-1}]

$$EROI_{BioSNG} = \frac{EC_{BioSNG}}{PE_{BP} + PE_{Truck} + \frac{PE_{Elec,BioSNG}}{CanElecEff} * \frac{PCF}{ECF}}$$ [unitless]

<u>GHG emissions</u>

$$GHG_{Elec,BioSNG} = \frac{PE_{Elec,BioSNG} * LCEF_{Elec}}{MCF}$$ [kgCO_2e year^{-1}]

$$LCEF_{BioSNG} = \frac{GHG_{BP} + GHG_{Fert} + GHG_{Truck} + GHG_{Elec,BioSNG}}{EC_{BioSNG}}$$ [kgCO_2e GJ^{-1}]

<u>Cost</u>

$$PlantScale_{BioSNG} = \frac{M_{Truck}}{1-MC} * LHV_{WB} * \frac{ECF}{HPD * SPH}$$ [MW_{th}]

$$CapitalCost_{BioSNG} = CapitalCost_{BioSNG,400MW} * \left(\frac{PlantScale}{400}\right)^{SF,BioSNG}$$ [$]

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$ [unitless]

$$Cost_{Capital,BioSNG} = CapitalCost_{BioSNG} * CRF$$ [$ year^{-1}]

$$Cost_{O\&M,BioSNG} = CapitalCost_{BioSNG} * Fraction_{O\&M,BioSNG}$$ [$ year^{-1}]

$$Cost_{Elec,BioSNG} = PE_{Elec,BioSNG} * Price_{Elec}$$ [$ year^{-1}]

$$ProdCosts_{BioSNG} = \frac{Cost_{BP} + Cost_{Truck} + Cost_{Capital,BioSNG} + Cost_{O\&M,BioSNG} + Cost_{Elec,BioSNG}}{EC_{BioSNG}} \quad [\$ \ GJ^{-1}]$$

A.4 Pellet production

An alternative to bioSNG production was to manufacture biomass pellets. The heat demand of the dryer ($Heat_{PelletDryer}$) was met by combusting a portion of the biomass feedstock ($Frac_{Fuel}$). Parasitic energy use and GHG emissions of pelleting were based on internal power requirements ($EI_{Elec,Pellets}$).

The size of the pellet mill (*MillScale*) was also directly related to M_H. Scale factor (*SF*,*PelletMill*) calculations estimated investment costs at different mill sizes ($CapitalCost_{PelletMill}$) by using the capital cost of a 6 tonne per hour (TPH) mill as a reference. The cost of pelleting ($Cost_{Pelleting}$) was calculated from annualized capital, operating, and power costs whereas the price of biomass pellets ($Price_{Pellets}$) included upstream costs as well as a profit margin.

Table A 4: A summary of the variables used to model pellet production.

Symbol	Definition	Value	Units	Reference
$CapitalCost_{PelletMill}$	Capital cost of a pellet mill at any scale		$	
$Cost_{6TPH}$	Capital cost of a 6 t hr^{-1} pellet mill	3.1×10^6	US$(2005)	Mani et al., 2006
$Cost_{Pellting}$	Pelleting costs (excludes feedstock and delivery)		$ $year^{-1}$	
DML_{Drying}	Dry matter loss during drying	1%		
$DML_{Storage}$	Dry matter loss in storage	2%		Hamelinck et al., 2005
$EI_{Elec,Pellets}$	Electricity requirements for pelleting	113	kWh $t(pellet)^{-1}$	Raymer, 2006
$Frac_{Fuel}$	Fraction of biomass to be used as a dryer fuel (woody)	13%		
$Frac_{Fuel}$	Fraction of biomass to be used as a dryer fuel (herbaceous)	5.1%		
$Fraction_{O\&M,PelletMill}$	Fraction of capital costs that need to be invested in operation and maintenance	See Mani et al, 2006		

$Heat_{PelletDryer}$	Heat demand of the dryer		GJ year^{-1}	
$MC_{Pellets}$	Moisture content of pellets	8%		
$M_{Pre\text{-}Dryer}$	Mass of biomass before drying		t(dry) day^{-1}	
$M_{W,PelletDryer}$	Mass of water to be evaporated		tH_2O year^{-1}	
MillScale	Size of pellet mill		t(pellet) hr^{-1}	
$Price_{Pellets}$	Wholesale price of pellets		\$ GJ^{-1}	
$ProdCost_{Pellets}$	Total pellet production costs		\$ GJ^{-1}	
ProfitMargin	Amount of profit added to total pellet production costs	20%		Mani et al., 2006
SF,PelletMill	Scale factor for pellet mills	0.60-0.75		Mani et al., 2006

<u>Mass and energy</u>

$$M_{Pre-Dryer} = M_{Truck} * \left(1 - DML_{Storage}\right) \qquad \text{[t(dry) day}^{-1}\text{]}$$

$$Heat_{PelletDryer} = \frac{M_{Pre-Dryer}}{1 - MC} * Frac_{Fuel} * LHV_{WB} * \frac{CF}{HPD} \qquad \text{[GJ year}^{-1}\text{]}$$

$$M_{W,PelletDryer} = \frac{M_{Pre-Dryer} * \left(1 - Frac_{Fuel}\right) * MC}{1 - MC} - \frac{M_{Pre-Dryer} * \left(1 - Frac_{Fuel}\right) * MC_{Pellets}}{1 - MC_{Pellets}} \qquad \text{[tH}_2\text{O day}^{-1}\text{]}$$

$$Heat_{PelletDryer} = \frac{\left[\frac{M_{Pre-Dryer}}{1 - MC} * \left(1 - Frac_{Fuel}\right) * C_P * \left(T_{Out} - T_{In}\right) + M_{W,Pellet} * \Delta H_{V,100}\right] * \frac{CF}{HPD}}{Eff_{Dryer}} \qquad \text{[GJ year}^{-1}\text{]}$$

$$M_{Pellets} = M_{Pre-Dryer} * \left(1 - Frac_{Fuel}\right) * \left(1 - DML_{Drying}\right) \qquad \text{[t(dry) day}^{-1}\text{]}$$

$$LHV_{WB,Pellets} = HHV_{DB} * \left(1 - MC_{Pellets}\right) - \Delta H_{V,15} * \left[MC_{Pellets} + W_{H2} * HC * \left(1 - MC_{Pellets}\right)\right] \qquad \text{[GJ t(wet)}^{-1}\text{]}$$

$$EC_{Pellets} = \frac{M_{Pellets}}{1 - MC_{Pellets}} * LHV_{WB,Pellets} * \frac{CF}{HPD} \qquad \text{[GJ year}^{-1}\text{]}$$

$$PE_{Elec,Pellets} = \frac{M_{Pellets}}{1 - MC_{Pellets}} * EI_{Elec,Pellets} * \frac{CF}{HPD} \qquad \text{[kWh year}^{-1}\text{]}$$

$$PE_{Pellets} = \frac{PE_{Elec,Pellets}}{CanElecEff} * \frac{PCF}{ECF} \qquad \text{[GJ}_{th}\text{ year}^{-1}\text{]}$$

<u>GHG emissions</u>

$$GHG_{Pellets} = \frac{PE_{Elec,Pellets} * LCEF_{Elec}}{MCF} \qquad \text{[kgCO}_2\text{e year}^{-1}\text{]}$$

<u>Cost</u>

$$MillScale = \frac{M_{Pellets}}{1 - MC_{Pellets}} * \frac{1}{HPD} \qquad \text{[t(pellets) hr}^{-1}\text{]}$$

$$CapitalCost_{PelletMill} = Cost_{6TPH} * \left(\frac{MillScale}{6}\right)^{SF,PelletMill} \qquad \text{[\$]}$$

$$Cost_{Capital,PelletMill} = CapitalCost_{PelletMill} * CRF \qquad \text{[\$ year}^{-1}\text{]}$$

$$Cost_{O\&M,PelletMill} = CapitalCost_{PelletMill} * Fraction_{O\&M,PelletMill} \qquad \text{[\$ year}^{-1}\text{]}$$

$$Cost_{Elec,PelletMill} = PE_{Elec,Pellets} * Price_{Elec} \qquad \text{[\$ year}^{-1}\text{]}$$

$$Cost_{Pelleting} = Cost_{Capital,PelletMill} + Cost_{O\&M,PelletMill} + Cost_{Elec,PelletMill} \qquad \text{[\$ year}^{-1}\text{]}$$

$$ProdCost_{Pellets} = \frac{\begin{array}{c} Cost_{BP} + Cost_{Truck} + Cost_{Capital,PelletMill} \\ + Cost_{O\&M,PelletMill} + Cost_{Elec,PelletMill} \end{array}}{EC_{Pellets}} \qquad \text{[\$ GJ}^{-1}\text{]}$$

$$Price_{Pellets} = ProdCost_{Pellets} * (1 + ProfitMargin) \qquad \text{[\$ GJ}^{-1}\text{]}$$

A.5 Rail transportation

In certain areas of the Great Lakes St. Lawrence Seaway (GLSLS) region, pellets were transported by rail to a port or an energy conversion facility. Storage at the mill resulted in dry matter losses. Parasitic energy, GHG emissions, and cost of rail transportation were based on empirical factors from the literature and the assumed average transportation distance.

Table A 5: A summary of the variables used to model rail transportation.

Symbol	Definition	Value	Units	Reference
$AvgDist_{Train}$	Average rail transportation distance	500	km	
DFC_{Train}	Distance fixed cost of rail transportation	5.6	US$(2005) $t(wet)^{-1}$	Searcy et al., 2007
DVC_{Train}	Distance variable cost of rail transportation	0.018	$ $t(wet)^{-1}$ km^{-1}	Searcy et al., 2007
EI_{Train}	Energy inputs (diesel) in rail transportation	0.70	MJ $t(wet)^{-1}$ km^{-1}	Börjesson, 1996
M_{Train}	Biomass delivered by rail		$t(dry)\ day^{-1}$	

<u>Mass and energy</u>

$$M_{Train} = M_{Pellets} * (1 - DML_{Storage}) \qquad [t(dry)\ day^{-1}]$$

$$PE_{Train} = \frac{M_{Train}}{1 - MC_{Pellets}} * EI_{Train} * AvgDist_{Train} * \frac{CF}{HPD * ECF} \qquad [GJ\ year^{-1}]$$

<u>GHG emissions</u>

$$GHG_{Train} = PE_{Train} * LCEF_D \qquad [kgCO_2e\ year^{-1}]$$

<u>Cost</u>

$$Cost_{Train} = (DFC_{Train} + DVC_{Train} * AvgDist_{Train}) * \frac{M_{Train}}{1 - MC_{Pellets}} * \frac{CF}{HPD} \qquad [\$\ year^{-1}]$$

A.6 Ship transportation

Water-borne shipping was also part of the GLSLS supply chain. Storage at the port and shipping resulted in dry matter losses. Parasitic energy, GHG emissions, and cost of shipping were based on empirical factors from the literature and the assumed average transportation distance.

Table A 6: A summary of the variables used to model ship transportation.

Symbol	Definition	Value	Units	Reference
$AvgDist_{Ship}$	Average shipping distance	1000	km	
DFC_{Ship}	Distance fixed cost of water-borne shipping	11.5	US$(2005) $t(wet)^{-1}$	Searcy et al., 2007
$DML_{Shipping}$	Dry matter loss during water-borne shipping	0.3%		Hamelinck et al., 2005

DVC_{Ship}	Distance variable cost of shipping	0.01	\$ t(wet)$^{-1}$ km^{-1}	Searcy et al., 2007
EI_{Ship}	Energy inputs (diesel) in water-borne shipping	0.23	MJ t(wet)$^{-1}$ km^{-1}	Börjesson, 1996
M_{Ship}	Biomass delivered by ship		t(dry) day^{-1}	

<u>Mass and energy</u>

$$M_{Ship} = M_{Train} * (1 - DML_{Storage}) * (1 - DML_{Shipping}) \qquad \text{[t(dry) day}^{-1}\text{]}$$

$$PE_{Ship} = \frac{M_{Ship}}{1 - MC_{Pellets}} * EI_{Ship} * AvgDist_{Ship} * \frac{CF}{HPD * ECF} \qquad \text{[GJ year}^{-1}\text{]}$$

<u>GHG emissions</u>

$$GHG_{Ship} = PE_{Ship} * LCEF_{D} \qquad \text{[kgCO}_2\text{e year}^{-1}\text{]}$$

<u>Cost</u>

$$Cost_{Ship} = (DFC_{Ship} + DVC_{Ship} * AvgDist_{Ship}) * \frac{M_{Ship}}{1 - MC_{Pellets}} * \frac{CF}{HPD} \qquad \text{[\$ year}^{-1}\text{]}$$

A.7 Biopower production

Biomass pellets were delivered to retrofitted coal-fired power plants that operate on 100% biomass feedstock. The amount of biopower produced ($EC_{Biopower}$) was assumed to be equal to the amount of coal power replaced.

The size of the biopower plant was independent of M_H because the GLSLS system delivered biomass from many production sites. Therefore, upstream parasitic energy use, GHG emissions, and cost were calculated using the ratio of biomass required ($M_{Biopower}$) to biomass delivered (M_{Ship}). For example, if the amount of biomass needed to replace coal was twice the amount of biomass harvested from a single site, than two sites would be required and upstream parasitic energy use, emissions, and cost would double. Biopower production costs ($ProdCost_{Biopower}$) were based on retrofit, operating, and upstream costs.

Table A 7: A summary of the variables used to model biopower production.

Symbol	Definition	Value	Units	Reference
CoalPower	Coal power to be replaced		kWh $year^{-1}$	
$Cost_{Capital,Biopower}$	Annual investment costs to retrofit a coal plant		\$ $year^{-1}$	
$CostFactor_{O\&M}$	Operating and maintenance costs of a biomass power plant	16	\$ MWh^{-1}	Layzell et al., 2006
$CostFactor_{Retrofit}$	Cost to retrofit a coal plant to accept 100% biomass feedstock	10	\$ MWh^{-1}	Layzell et al., 2006
$EC_{BiomassforPower}$	Thermal bioenergy required to replace coal		GJ $year^{-1}$	
$Eff_{Biopower}$	Net conversion efficiency of biomass to power	35%		Kumar et al., 2008
$EROI_{Biopower}$	Energy return on investment of biopower		unitless	
$LCEF_{Biopower}$	Life-cycle emission factor of biopower		gCO_2e kWh^{-1}	
$M_{Biopower}$	Biomass required to replace coal		t(dry) day^{-1}	
$ProdCost_{Biopower}$	Cost of electricity from biomass		\$ kWh^{-1}	

<u>Mass and energy</u>

$$EC_{Biopower} = CoalPower \qquad [\text{kWh year}^{-1}]$$

$$EC_{BiomassforPower} = \frac{EC_{Biopower}}{Eff_{Biopower}} * \frac{PCF}{ECF} \qquad [\text{GJ year}^{-1}]$$

$$M_{Biopower} = \frac{EC_{BiomassforPower}}{LHV_{WB,Pellets}} * \left(1 - MC_{Pellets}\right) * \frac{HPD}{CF} \qquad [\text{t(dry) day}^{-1}]$$

$$EROI_{Biopower} = \frac{EC_{Biopower} * \frac{PCF}{ECF}}{\frac{M_{Biopower}}{M_{Ship}} * \left(PE_{BP} + PE_{Truck} + PE_{Pellets} + PE_{Train} + PE_{Ship}\right)} \qquad [\text{unitless}]$$

<u>GHG emissions</u>

$$LCEF_{Biopower} = \frac{M_{Biopower}}{M_{Ship}} * \left(\frac{GHG_{BP} + GHG_{Fert} + GHG_{Truck} + GHG_{Pellets} + GHG_{Train} + GHG_{Ship}}{EC_{Biopower}} \right) * MCF \qquad [\text{gCO}_2\text{e kWh}^{-1}]$$

Cost

$$Cost_{Capital,Biopower} = CostFactor_{Retrofit} * \frac{EC_{Biopower}}{ECF}$$ [$ year^{-1}$]

$$Cost_{O\&M,Biopower} = CostFactor_{O\&M} * \frac{EC_{Biopower}}{ECF}$$ [$ year^{-1}$]

$$ProdCost_{Biopower} = \frac{\frac{M_{Biopower}}{M_{Ship}} * \begin{pmatrix} Cost_{BP} + Cost_{Truck} + \\ Cost_{Pelleting} + Cost_{Train} + Cost_{Ship} \end{pmatrix} + Cost_{Capital,Biopower} + Cost_{O\&M,Biopower}}{EC_{Biopower}}$$ [$ kWh^{-1}$]

A.8 Biomass-to-liquid production via Fischer-Tropsch synthesis

Pellets were also delivered to biomass-to-liquid (BTL) fuel production plants that employ Fischer-Tropsch (FT) synthesis to convert biomass to synthetic green diesel. The scale of the plant ($PlantScale_{BTL}$) was independent of M_H since it was sited on the GLSLS. The overall energy conversion efficiency (Eff_{FT}) was used to calculate the amount of BTL fuels produced (EC_{BTL}) and the electricity conversion factor ($ElecEff_{FT}$) was used to estimate net co-production of auxiliary power. The *EROI* and *LCEF* were determined from upstream parasitic energy and GHG emissions minus the thermal energy content of auxiliary power and its associated GHG emission reductions.

Scale factor (*SF,BTL*) calculations estimated investment costs at different plant sizes ($CapitalCost_{BTL}$) by using the capital cost of a 400 MW_{th} plant as a reference. Total production costs ($ProdCost_{BTL}$) were estimated from annual capital, operating, and feedstock costs minus the revenue from the sale of auxiliary power. The wholesale price of BTL fuels ($Price_{BTL}$) was determined from total production costs and a profit margin.

Table A 8: A summary of the variables used to model Fischer-Tropsch synthesis.

Symbol	Definition	Value	Units	Reference
$AuxPower_{BTL}$	Auxiliary power produced		kWh $year^{-1}$	
$CapitalCost_{BTL}$	Capital cost of BTL plants at any size		$	
$CapitalCost_{BTL,400MW}$	Capital cost of a 400 MW_{th} biomass input BTL fuel synthesis plant	382 x 10^6	US$(2005)	Tijmensen et al., 2002
$Density_{BTL}$	Energy density of green diesel	36	MJ L^{-1}	Boerrigter, 2006
EC_{BTL}	Energy content of BTL fuels		GJ $year^{-1}$	
Eff_{FT}	Energy conversion efficiency from biomass to FT-liquids	46%-55%		Tijmensen et al., 2002; Boerrigter, 2006
$ElecEff_{FT}$	Fraction of thermal input converted to net power	0%-4%		Tijmensen et al., 2002; Boerrigter, 2006
$EROI_{BTL}$	Energy return on investment of BTL fuels		unitless	
$Fraction_{O\&M,BTL}$	Fraction of capital costs invested in operation and maintenance	4%		Tijmensen et al., 2002
GHG_{BTL}	GHG emissions/savings from auxiliary power		$kgCO_2e$ $year^{-1}$	
$LCEF_{BTL}$	Life-cycle emission factor of BTL fuels		$kgCO_2e$ GJ^{-1}	
M_{BTL}	Biomass pellets to be converted to BTL fuels		t(dry) day^{-1}	
$PlantScale_{BTL}$	Size of BTL fuel synthesis plant (biomass thermal input)		MW_{th}	
$Price_{BTL}$	Sale price of BTL fuels		$ GJ^{-1}	
$ProdCost_{BTL}$	BTL production costs		$ GJ^{-1}	
$Revenue_{Elec,BTL}$	Revenue from the sale of auxiliary power		$ $year^{-1}$	
SF,BTL	Scale factor of BTL plants	0.7-0.9	unitless	Tijmensen et al., 2002; Boerrigter, 2006

Mass and energy

$$M_{BTL} = \frac{PlantScale_{BTL} * \frac{SPH * HPD}{ECF}}{LHV_{WB,Pellets}} * (1 - MC_{Pellets}) \qquad [\text{t(dry) day}^{-1}]$$

$$EC_{BTL} = \frac{M_{BTL}}{1 - MC_{Pellets}} * LHV_{WB,Pellets} * Eff_{FT} * \frac{CF}{HPD}$$ [GJ $year^{-1}$]

$$AuxPower_{BTL} = \frac{M_{BTL}}{1 - MC_{Pellets}} * LHV_{WB,Pellets} * ElecEff_{FT} * \frac{CF}{HPD} * \frac{ECF}{PCF}$$ [kWh $year^{-1}$]

$$EROI_{BTL} = \frac{EC_{BTL}}{\frac{M_{BTL}}{M_{Ship}} * \begin{pmatrix} PE_{BP} + PE_{Truck} + \\ PE_{Pellets} + PE_{Train} + PE_{Ship} \end{pmatrix} - \frac{AuxPower_{BTL}}{CanElecEff} * \frac{PCF}{ECF}}$$ [unitless]

<u>GHG emissions</u>

$$GHG_{BTL} = \frac{AuxPower_{BTL} * LCEF_{Elec}}{MCF}$$ [kgCO_2e $year^{-1}$]

$$LCEF_{BTL} = \frac{\frac{M_{BTL}}{M_{Ship}} * \begin{pmatrix} GHG_{BP} + GHG_{Fert} + GHG_{Truck} + \\ GHG_{Pellets} + GHG_{Train} + GHG_{Ship} \end{pmatrix} - GHG_{BTL}}{EC_{BTL}}$$ [kgCO_2e GJ^{-1}]

<u>Cost</u>

$$CapitalCost_{BTL} = CapitalCost_{BTL,400MW} * \left(\frac{PlantScale_{BTL}}{400} \right)^{SF,BTL}$$ [$]

$$Cost_{Capital,BTL} = CapitalCost_{BTL} * CRF$$ [$ $year^{-1}$]

$$Cost_{O\&M,BTL} = CapitalCost_{BTL} * Fraction_{O\&M,BTL}$$ [$ $year^{-1}$]

$$Revenue_{Elec,BTL} = AuxPower_{BTL} * Price_{Elec}$$ [$ $year^{-1}$]

$$ProdCost_{BTL} = \frac{\frac{M_{BTL}}{M_{Ship}} * \begin{pmatrix} Cost_{BP} + Cost_{Truck} + \\ Cost_{Pelleting} + Cost_{Train} + Cost_{Ship} \end{pmatrix} + Cost_{Capital,BTL} + Cost_{O\&M,BTL} - Revenue_{Elec,BTL}}{EC_{BTL}}$$ [$ GJ^{-1}]

$$Price_{BTL} = ProdCost_{BTL} * (1 + ProfitMargin)$$ [$ GJ^{-1}]

$$Price_{BTL} = ProdCost_{BTL} * (1 + ProfitMargin) * Density_{BTL}$$ [$ L^{-1}]

Appendix B

Data Tables

B.1 BioSNG production

Table B 1: Conservative {aggressive} estimates of parasitic energy use, GHG emissions, and cost per dry tonne of harvested forest (FOR), good agricultural (GA), or marginal (MAR) biomass at different stages in the bioSNG production process.

	Parasitic energy (GJ $t(dry)^{-1}$)			**GHG emissions ($kgCO_2e$ $t(dry)^{-1}$)**			**Cost (\$ $t(dry)^{-1}$)**	
Land type	FOR	GA	MAR	FOR	GA	MAR	FOR	AGR
Biomass production	0.91[a] {0.90}	1.0[b] {1.1}	1.2[c]	72[d] {72}	79{82} + 76{54}[e]	92[e] + 112{71}	39[f]	62[g]
Transport (per 100 km)	0.38[h]	0.28[h]		32[i]	24[i]		26[j]	
SNG production	2.2[k]			74[m]			$A*\left(\frac{B}{C}\right)^{SF}*\frac{D+E}{F}+G$ [n]	
Total	**3.5 {3.5}**	**3.5 {3.6}**	**3.7**	**178 {178}**	**253 {234}**	**302 {261}**		

[a] Hybrid poplar production, where diesel, natural gas, and electricity contributed 77%, 21%, and 2%, respectively (Turhollow and Perlack, 1991). For forest residues, only parasitic energy in harvesting was included.
[b] Switchgrass production, where diesel, natural gas, and electricity contributed 65% {63%}, 29% {31%}, and 6% {6%}, respectively (Turhollow and Perlack, 1991). For food crop residues, only parasitic energy in harvesting was included.
[c] Switchgrass production, where diesel, natural gas, and electricity contributed 57%, 36%, and 7%, respectively (Turhollow and Perlack, 1991).
[d] Calculated from forest parasitic energy and life-cycle CO_2 emission factors ($kgCO_2e$ GJ_{th}^{-1}) for diesel (84) (Börjesson, 1996), natural gas (68) (Jaramillo et al., 2007), and electricity (33) (OEE,2006).
[e] GHG emissions from parasitic energy (79 {82} $kgCO_2e$ $t(dry)^{-1}$ for good agricultural land; 92 $kgCO_2e$ $t(dry)^{-1}$ for marginal) were calculated as in footnote "d" and N_2O emissions from fertilizer use (76 {54} $kgCO_2e$ $t(dry)^{-1}$ for good agricultural land; 112 {71} $kgCO_2e$ $t(dry)^{-1}$ for marginal) were calculated from (IPCC, 2000). Assumptions were 30% {15%} of applied fertilizer was leached and 70% {80%} of aboveground biomass was harvested.
[f] Cost of producing 45% moisture wood chips (\$33 $t(dry)^{-1}$) and loading/unloading on to a truck (\$6.1 $t(dry)^{-1}$) (Marrison and Larson, 1995).
[g] Farm gate price of 25% moisture baled agricultural biomass (CA\$70 $t(dry)^{-1}$ or \$58 $t(dry)^{-1}$) and loading/unloading on to a truck (\$4.5 $t(dry)^{-1}$) (Marrison and Larson, 1995).
[h] Assumed a fuel efficiency of 0.35 L km^{-1} for trucks 15 tonnes or heavier (Statistics Canada, 2007a), diesel energy density of 39 MJ L^{-1} (Turhollow and Perlack, 1991), truck load limit of 23 tonnes (Marrison and Larson, 1995), and an empty return trip.
[i] Calculated similarly to footnote "d" using diesel fuel.

[j] Assumed trucking costs of $0.26 t(dry)$^{-1}$ km^{-1} (Marrison and Larson, 1995).
[k] Estimated that a 100 MW_{th} bioSNG plant, which is equivalent to a biomass harvest of 570 t(dry) day^{-1}, would require 7.7 MW of electricity (Mozaffarian and Zwart, 2003). On average Canadian power plants were able to convert 53% of primary energy into electricity (OEE, 2006).
[m] Calculated similarly to footnote "d" using electricity.
[n] *A* ($500M) is the estimated capital cost of a 400 MW_{th} bioSNG plant (Hamelinck and Faaij, 2002; Tijmensen et al., 2002; Zwart et al., 2006). *B* (MW_{th}) is the variable scale of the bioSNG plant and *C* (400 MW_{th}) is the reference scale. *SF* (unitless) is the plant scale factor, which is 0.74 when B<400 MW_{th} or 0.91 when B>400 MW_{th} (Tijmensen et al., 2002). *D* (11.8% year^{-1}) is the capital recovery factor for an internal rate of return of 10% over a plant lifetime of 20 years (Fraser et al., 2000). *E* (3% year^{-1}) is the percentage of capital costs that need to be invested in annual maintenance operations (Tijmensen et al., 2002). *F* (830,000 t(dry) year^{-1}) is the estimated amount of biomass required to sustain a 400 MW_{th} plant. *G* ($15 t(dry)$^{-1}$) is the estimated cost of external electricity inputs at 330 kWh t(dry)$^{-1}$ and a price of CA$0.065 kWh^{-1} ($0.054 kWh^{-1}).

B.2 Great Lakes St. Lawrence Seaway bioenergy system

Table B 2: Conservative {aggressive} estimates of parasitic energy use, GHG emissions, and cost/price per tonne of biomass pellet produced from forest (FOR), good agriculture (GA), or marginal (MAR) land.

	Parasitic energy ($GJ\ t^{-1}$)			**GHG emissions ($kgCO_2e\ t^{-1}$)**			**Price/Cost ($\$\ t^{-1}$)**		
Land type	FOR	GA	MAR	FOR	GA	MAR	FOR	GA	MAR
Biomass production	1.1 {1.0}[a]	1.2 {1.1}[b]	1.4 {1.2}[c]	84 {78}[d]	120 {99}[d]	150 {120}[d]	58 {61}[e]	72 {73}[f]	75[f]
Truck transport	0.27[g] {0.17}	0.08[g] {0.06}	0.05[g] {0.04}	23[h] {14}	7.1[h] {5.0}	4.1[h] {3.2}	18[i] {14}	13[j] {11}	10[j] {10}
Pelleting	0.82[k]			27[m]			43 {42}[n]	45 {44}[n]	45 {44}[n]
Train	0.37[p]			31[h]			15[q]		
Shipping	0.23[r]			20[h]			22[s]		
Total	**2.7 {2.6}**	**2.7 {2.5}**	**2.9 {2.6}**	**180 {170}**	**200 {180}**	**230 {200}**	**160 {150}**	**170 {160}**	**170 {160}**
Weighted average	2.8 {2.6}[t]			200 {180}[t]			160 {160}[t]		

[a] Hybrid poplar production, where diesel, natural gas, and electricity contributed 81% {75%}, 17% {23%}, and 2% {3%}, respectively (Turhollow and Perlack, 1991). For residues, only parasitic energy inputs in harvesting were included.
[b] Switchgrass production, where diesel, natural gas, and electricity contributed 64% {62%}, 30% {32%}, and 6% {7%}, respectively (Turhollow and Perlack, 1991). For residues, only parasitic energy inputs in harvesting were included.
[c] Switchgrass production, where diesel, natural gas, and electricity contributed 57%, 36%, and 7%, respectively (Turhollow and Perlack, 1991).
[d] Calculated from parasitic energy and life-cycle CO_2 emission factors ($kgCO_2e\ GJ^{-1}$) of diesel (84) (Börjesson, 1996), natural gas (68) (Jaramillo et al., 2007), and electricity (33) (OEE, 2006). Estimated N_2O emissions were 0.5 kgN_2O-N ha^{-1} or 0.79 kgN_2O ha^{-1} or 245 $kgCO_2e$ ha^{-1} (Samson et al., 2008).

[e] Assumed a price of CA$55 and CA$64 t(dry)$^{-1}$ for chipped forest residues and whole trees (Kumar et al., 2008), respectively, and a 2005 Canada-US exchange rate of 1.21.
[f] Assumed a farm gate price of CA$75 and CA$85 t(dry)$^{-1}$ for crop residues and herbaceous biomass crops, respectively (Samson et al., 2008).
[g] Estimated from a fuel efficiency of 0.35 L km^{-1} for trucks 15 tonnes or heavier (Statistics Canada, 2007a), diesel LHV of 36.3 MJ L^{-1} (Boerrigter, 2006), load limit of 25 tonnes, and an empty return trip.
[h] Calculated similarly to footnote "d" using diesel fuel.
[i] Wood chip transportation costs of $3.1 t(wet)$^{-1}$ plus $0.072 t(wet)$^{-1}$ km^{-1} (Searcy et al., 2007).
[j] Straw bale transportation costs of $4.5 t(wet)$^{-1}$ plus $0.12 t(wet)$^{-1}$ km^{-1} (Searcy et al., 2007).
[k] Power requirements estimated to be 113 kWh t(pellet)$^{-1}$ (Raymer, 2006) and an average 56% electrical conversion efficiency in Canada (OEE, 2006).
[m] Calculated similarly to footnote "d" using electricity.
[n] Calculated as the average pellet production cost based on maximum mill sizes of 5, 10, 15, 20, 25, and 30 t hr^{-1}. The investment cost of a 6 t hr^{-1} plant was estimated to be $3.1M while maintenance and personnel costs were estimated from the literature (Mani et al., 2006; Hoque et al., 2006). A scale factor of 0.75 {0.60} was used to estimate investment costs at different plant sizes and a 20% profit margin was included to estimate the wholesale price of pellets (Mani et al., 2006).
[p] Energy cost of 0.70 MJ t(wet)$^{-1}$ km^{-1} for rail transportation (Börjesson, 1996) and a distance of 500 km.
[q] Rail transportation costs of $5.6 t(wet)$^{-1}$ plus $0.018 t(wet)$^{-1}$ km^{-1} (Searcy et al., 2007).
[r] Energy cost of 0.23 MJ t(wet)$^{-1}$ km^{-1} for ship transportation (Börjesson, 1996) and a distance of 1000 km.
[s] Assumed ship transportation costs of $11.5 t(wet)$^{-1}$ plus $0.01 t(wet)$^{-1}$ km^{-1} (Searcy et al., 2007).
[t] Based on a forest, agricultural, and marginal biomass distribution of 53% {62%}, 12% {11%}, and 35% {27%}, respectively (Table 4-1).

Table B 3: Conservative (CON) and aggressive (AGG) estimate of energy return on investment (EROI), GHG intensity, and price/cost of biomass pellets, biopower, and green diesel.

	EROI		GHG intensity ($kgCO_2e\ GJ^{-1}$)		Price/Cost ($ GJ^{-1})	
	CON	AGG	CON	AGG	CON	AGG
Biomass pellets	5.9[a]	6.4[a]	12[b]	11[b]	10[c]	10[c]
Biopower	2.1[d]	2.2[d]	35[e]	31[e]	36[f]	35[f]
Green diesel	3.0[g]	3.5[g]	22[h]	20[h]	36[i]	28[i]

[a] Based on a parasitic energy consumption of 2.8 {2.6} GJ t(pellet)$^{-1}$ (Table B-2) and a weighted average LHV of 16.5 GJ t(pellet)$^{-1}$.
[b] Based on a GHG intensity of 200 {180} $kgCO_2e$ t(pellet)$^{-1}$ (Table B-2) and an LHV of 16.5 GJ t(pellet)$^{-1}$.
[c] Based on a delivered price of $160 {$160} t(pellet)$^{-1}$ (Table B-2) and an LHV of 16.5 GJ t(pellet)$^{-1}$.
[d] Based on a delivered pellet EROI of 5.9 {6.4} and a net electrical efficiency of 35% (Kumar et al., 2008).
[e] Calculated as 12 {11} $kgCO_2e$ GJ^{-1} divided by 35% conversion efficiency.
[f] Cost of electricity was estimated by assuming a delivered feedstock cost of $10 {$10} GJ^{-1}, $10 MWh^{-1} investment to retrofit a coal-fired power plant to accept 100% biomass feedstock and operating costs of $16 MWh^{-1} (Layzell et al., 2006).
[g] Based on a delivered pellet EROI of 5.9 {6.4} and a 46% {55%} LHV conversion efficiency to green diesel as well as 4% {0%} production of auxiliary power (Tijmensen et al., 2002; Boerrigter, 2006).
[h] Based on the feedstock GHG intensity 12 {11} $kgCO_2e$ GJ^{-1}, conversion efficiency, and GHG savings from auxiliary power production.

[i] Wholesale price of green diesel based on cost of pellet feedstock, capital and operating costs, and a 20% profit margin. Overall total investment cost for a 400 MW_{th} plant were estimated to be \$382M (Tijmensen et al., 2002) and annual operating and maintenance costs were assumed to be 4% of the initial investment. A scale factor of 0.90 {0.70} was used to estimate overall total investment costs at various plant sizes (Tijmensen et al., 2002; Boerrigter, 2006), which were amortized over a 20-year period at a 10% interest rate. A market power price of CA\$65 MWh^{-1} (Samson et al., 2008) was used to estimate revenue from the sale of auxiliary power. Listed price of green diesel is the average price based on plant sizes from 400 to 5000 MW_{th}.