MSc Program

Renewable Energy in Central and Eastern Europe

Increasing Renewable Energy in a Community in Ontario with Biomass – Technical, Economic and Regulatory Evaluation

A Master Thesis submitted for the degree of

"Master of Science"

supervised by

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Vienna May 2009

Affidavit

I, Pamela Hay, hereby declare

1. that I am the sole author of the present Master Thesis " Increasing Renewable Energy in a Community in Ontario with Biomass – Technical, Economic and Regulatory Evaluation", 92 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and

2. that I have not prior to this date submitted this Master Thesis as an examination paper in any form in Austria or abroad.

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Abstract

The core objective of this work is to determine whether a renewable energy option based on biomass could replace some of the current energy mix in the community of Kingston, Ontario, Canada and be economically, technically and socially feasible within the existing regulatory framework. Four different options are examined: 1) a 40 MW wood-chip CHP combustion plant generating 10 MW electric and no heat; 2) a 40 MW wood chip CHP combustion plant generating 4 MW electric and 30 MW heat; 3) a 40 MW wood-chip CHP gasification plant generating 10 MW electric and 24 MW heat; and a 2 MW biogas plant generating 2 MW electric and 2 MW heat. All four options make use of existing feedstock in and around Kingston, namely wood, crop residue and animal waste from farming. In all 4 cases the projects are economically, technically and socially feasible. To determine the degree to which Kingston can reduce its annual greenhouse gases as a result of implementing 2 of the options, statistics for Kingston's green house gases for 2006 are used, and Kingston's own target for reducing its CO_2 emissions by 16% below 2006 by 2020 are compared.

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1. Introduction and Background

Transforming urban centres in Canada from fossil fuel dependant to partly renewable is viable. Given the urgent need for domestic and global greenhouse gas reductions, it is not only a sensible but an inevitable approach. This thesis examines how a typical Canadian city can significantly increase its renewable energy mix and decrease its annual greenhouse gas emissions. Kingston, Ontario, a city with a population of 117,000 inhabitants, has been chosen as a case study for Canada. It is proposed that Kingston achieve an increase in renewable energy use and a corresponding decrease in GHG emissions primarily by instituting measures to increase the use of biomass and biogas and switch some of the current demand for fossil energy with these renewable sources. This would make Kingston a model for other urban centres in Canada.

This thesis examines biomass as an alternative fuel which Kingston could add to its energy mix and hypothesizes that Kingston could substitute over 20% of its current non-renewable power to renewable energy sources using solid biomass and biogas, and reduce its GHG emissions by 1/4, while maximizing the regulatory, technological, economic and social frameworks influencing the uptake of bioenergy in Ontario.

1.1 International Political Framework in Support of Renewable Energy

The Kyoto Protocol is a United Nations (UN) led international agreement reached in 1997 in Kyoto, Japan to address the problems of global warming and to reduce the human induced greenhouse gas emissions that contribute to this problem. The Kyoto Protocol went into force in 2005 and committed 38 industrialized countries, including Canada, to cut their greenhouse gas emissions by an average of 5% below 1990 levels over the first commitment period of 2008-2012.

The reason such measures are required stem from the findings over the last decade of a group of over 100 scientists from around the world as part of the

Intergovernmental Panel of Climate Change (IPCC). Scientific evidence demonstrates that the world's climate is being altered at a steady rate by anthropogenic causes, as mankind emits high concentrations of greenhouse gases (GHGs) into the air annually. This is leading to warming air and sea temperatures which have damaging effects such as decreasing snow cover worldwide, drought, proliferation of pests and disease, stronger wind storms, tidal waves, forest fires and habitat destruction. According to the World Meteorological Organization (WMO), the top 11 warmest years on record have all been in the last 13 years. The IPCC have confirmed in numerous studies throughout the period of 2004-7 that these climactic changes are the result of anthropogenic influences due to the high concentrations of greenhouse gases that mankind emits into the air annually. Three quarters of all GHGs come from CO_2. (IPCC, 2007)

Studies conducted by the International Energy Agency (IEA) indicate that the world's total energy demand is growing steadily and will continue this trend in the foreseeable future. This is due to several key factors: the growing world population, increasing demand for electricity due to innovation, and the rapidly rising living standard of certain developing countries in the world like China and India. The Intergovernmental Panel on Climate Change reported that CO_2 emissions rose even faster than the worse case scenario it forecast during 2000-2004 and that greenhouse gases will rise 25-90% over 2000 levels by 2030 without new government action. The Netherlands Environmental Assessment Agency has applied data from the U.S Geological Survey and the IEA and has determined that China surpassed the United States in carbon emissions in 2006 by 8%. China already consumes over 2 billion tons of coal a year and may produce 4 billion tons annually by 2016. (Chikkatur, 2008)

Switching from conventional fossil fuels to renewable fuel sources reduces $C0_2$ emissions. Renewable energy is normally clean and non-polluting, and protects the environment while strengthening the economy.

All developed countries, including soon the USA, have committed to a GHG reduction target. The EU 27 also approved in December 2008 a plan to reduce its collective GHG emissions 20% by 2020, and increase its renewable energy use to 20% of its total energy requirement by 2020.

One measure to reduce CO_2-emissions is fuel switching. Fig. 1 shows the possible reduction of CO_2-emissions by switching from coal to oil, oil to gas, and finally to renewables. The largest effect can be obtained by switching from coal (highest CO_2-emissions) to renewables (zero CO_2-emissions).

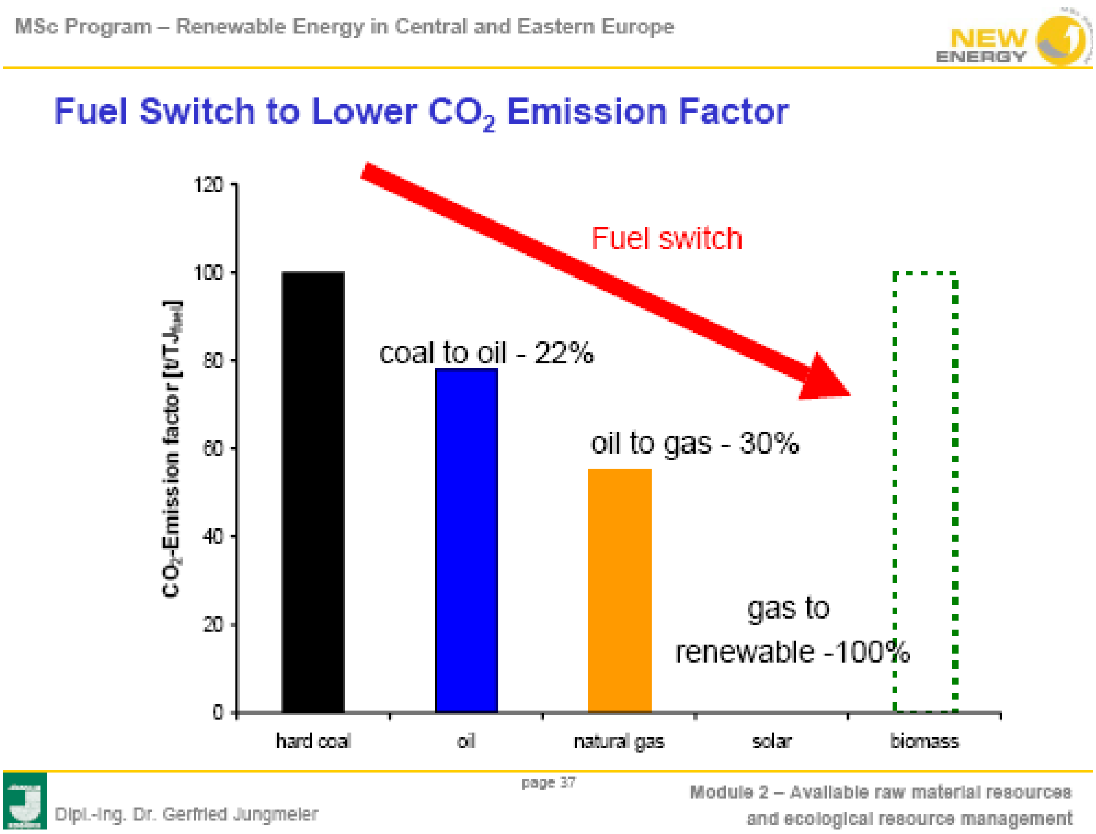


Figure 1: Fuel Switch to Lower CO_2 Emission Factor, (Source: Jungmeier, 2008)

1.2 The Status of Canada's Greenhouse Gas Emissions

It is within the interests of Canada to adopt measures to support initiatives that foster increased production and use of energy from renewable sources. Canada is a signatory to the Kyoto Protocol on the reduction of global greenhouse gases. The Canadian government ratified the Kyoto Protocol in December 2002, and committed to a target of reducing GHG emissions to 6% below their 1990 levels by 2012. The Conservative government elected in early 2006 has since decreed that Canada's target is unattainable and has developed an alternative to the Kyoto Protocol called the "made-in-Canada" solution which commits Canada to a target of 50% reduction of GHGs from 2006 levels by 2050. This target, however, amounts to slowing the growth in emissions since 1990 as opposed to cutting back emissions from these levels.

Even with a reduced GHG emissions reduction target, Canada is far from reaching its modified goal. In fact, emissions have increased significantly since 1990. The long-term trend indicates that emissions in 2006 were about 22% above the 1990 total of 592 Mt. This trend shows a level 29.1% above Canada's Kyoto target of 558.4 Mt. It is clear that in order to achieve its target, Canada must undertake some vigorous measures in energy efficiency and lessen its reliance on fossil fuel sources of energy. (Source: Environment Canada, 2009).

Canada has 1/10th of the world's forests. Per capita, Canada has access to more biomass resources than any other country in the world. According to an inventory of existing forest biomass, Canadian forest biomass resources in 1993 amounted to more than 26 billion dry tons, the equivalent of 82 billion barrels of oil, or enough to meet Canada's oil needs for 151 years (at 1993 consumption rates). Currently Canada uses biomass to meet approximately 6 percent of the national demand for primary energy. (Source: Industry Canada, 2008). Canada's only large scale biomass plant is Williams Lake, located in British Columbia. It is a 60 MW el plant requiring 768,000 tons of wood per year. It has come close to zero fuel cost as it is located very close to five large sawmills (Source: National Renewable Energy Laboratory, 2000).

For reasons of supply security alone, it is extremely important that Canada make better use of its natural resources to harness new sources of energy. According to the Polaris Institute, Canada has less than 13 years of conventional oil reserves and only 8.9 years of natural gas supplies available at current rates of production (Source: Polaris Institute, 2009).

The transportation sector in Canada represented approximately 23.3% of Canada's total GHG emission inventory in 2005 or 174 Mt CO_2e (excluding aviation transportation); while electricity and heat generation produced an estimated 129 Mt CO_2e (17.2%) and commercial and residential heating produced 78.8 Mt CO_2e, or roughly 10.5% (Environment Canada, 2007). Collectively, these areas represented 51% of Canada's GHG emissions. This represents a sizable market for solid, liquid and gaseous biofuels (Source: BIOCAP, 2008).

Figure 2 shows greenhouse gas (GHG) emissions in kgCO_2e / GJ (CO_2 equivalent) for different sectors (transportation, electric power, heating) and different fuels. Again, from this Figure it can be seen that coal leads to the highest and natural gas to the lowest fossil fuel GHG emissions (see Fig. 1). Furthermore, electrical power production with coal and oil shows more than double values compared to all the other applications. Therefore, substituting electric power production with coal and oil with power production from renewables (e.g. biomass) gives the largest CO_2-reduction effect.

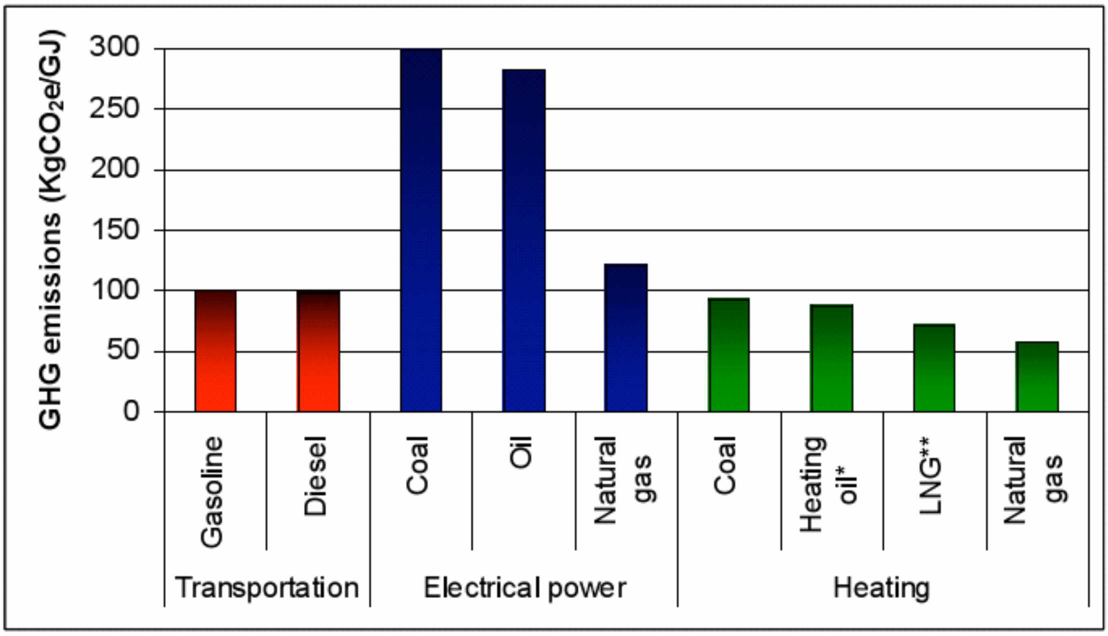


Figure 2: Life Cycle Greenhouse Gas Emissions of Fossil Fuels in Canada by Sector (Source: BIOCAP, 2008)

* Petroleum value provided here represents typical oil mix in Canada (48% domestic production and 52% international sources)

** Estimate based on studies of Russian gas imports into Europe (Source: Uherek, 2005) and Australian LNG imports into the US (Sources: Heede, 2006; Jaramillo et al., 2007)

A main trend in GHG emissions from domestically produced fuels is increasing emissions from petroleum based fuels, as conventional oil production is declining while heavy oil production is increasing in Canada. Heavy oil has higher emissions because natural gas is used in the tar sands extraction process and oil sands materials located on site are gasified to provide the processing energy for heavy oil production. The GHG emissions in Canada from new-generation oil production now have GHG emissions approaching those of coal. As a result, for heat applications, heating oil use is now comparable to coal in terms of its GHG footprint. A significant new energy source for Canada is liquefied natural gas (LNG), with projects planned already for the 3 Canadian provinces of Quebec, New Brunswick and British Columbia. These LNG imports are planned to be sourced primarily from Russia. Unfortunately there has been limited discussion within Canada to date about the GHG emissions associated with such imports. Germany's gas pipeline imports from Russia have been recently studied by a joint Russian/German team and identified to be 73.8 Kg CO_2e/GJ (Source: Uherek, 2005) or 18% below the reference value for oil. In the study, 68% of the indirect emissions were found to come from CO_2 released from the gas turbines of compressor units providing the energy to move the gas along the pipelines. Upstream emissions with LNG imports are quite large. LNG imports will significantly increase the carbon footprint of natural gas use in North America due to increased emissions associated with longer distance gas transport in pipelines, LNG liquification, ocean transport and heating during re-gasification. This report uses a value of 73.7 kg CO_2e/GJ, providing a GHG loading value 28% greater than the emissions of natural gas from North America (Source: BIOCAP 2008).

Canada relies on nuclear energy to meet a portion of its electricity demand. One option available for meeting the growing electricity demand would be to build additional nuclear capacity. Substituting fossil fuels with nuclear power is, however, a highly controversial strategy. There are significant environmental and safety issues associated with the production of nuclear power since the radiation and chemical contaminants produced are deadly for humans and animals, as well as damaging to the environment. Not surprisingly, social acceptance for existing and planned nuclear power facilities in their communities is extremely low Nuclear waste cannot be disposed of without the threat of leakages or human error, and spent fuel rods retain dangerous levels of toxicity for thousands of years. This also makes nuclear power plants very vulnerable to the threat of terrorist attacks. Plutonium and highly enriched uranium are the materials required for making nuclear bombs (Source: Earth Institute, 2009).

1.3 Energy Supply and Demand in the Province of Ontario

A provincial taskforce recently found that, if nothing is done to satisfy the growing demand in Ontario for energy, by 2020 the province will have a peak demand of more than 30,000 MW (megawatts) of power, but will have only 10,000 MW (megawatts) of generating capacity.

Presently, Ontario is largely powered by coal-fired power plants and aging nuclear plants, dating back to the 1980's. Coal plants contribute to southern Ontario's poor air quality and summer smog, while nuclear plants are plagued with unresolved safety issues, chronic under-performance problems, massive cost overruns and unresolved toxic waste problems. Ontarians' concerns about air pollution resulted in a promise by the Ontario government to close down 5 coal-fired power plants by 2007. This scenario will improve Ontario air quality but will leave a supply-demand imbalance of 7,500 MW. Yet the Smart Generation report of Canada's world renowned environmentalist David Suzuki, estimates that Ontario could generate more than *2,450 MW* of power using a variety of biomass sources by 2020, and create 1,470 to 6,174 jobs.

Ontario's forest resources cover 690,000 square kilometres, representing 17% of Canadian forests and 2% of the world's forests. Despite the wealth of this resource however, there does not yet exist any commercial scale production of energy in Ontario from wood-fired boilers (Source: Suzuki, 2004).

Figure 3 shows the shares of primary energy for electricity production in the year 2006. 54 % of the current Ontario electricity generation mix comes from nuclear power. This form of energy production does not generate carbon dioxide emissions during operation, however there are significant environmental and health risks associated with nuclear power production that may drive future political decisions to turn instead towards renewable energy options.

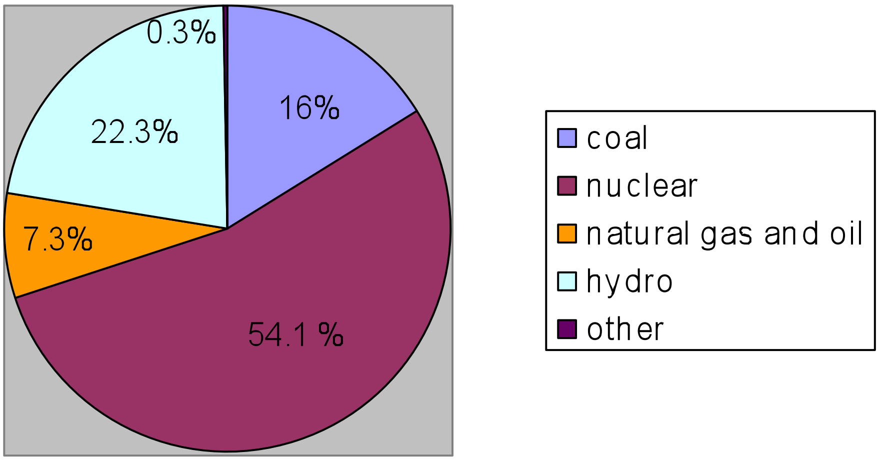


Figure 3: Percentage of RE in Kingston in 2006 (Source: Hsu, 2007)

Another consideration in the fuel option discussion is that, given difficult price fluctuations, it is becoming increasingly uneconomical to use electricity, natural gas, heating oil and propane for home heating. Currently Ontario uses about 57 PJ (petajoules) of electricity in the residential sector for space and hot water heating. (Source: Suzuki, 2004). Although energy self-sufficiency would be optimal, Canada still imports a portion of its oil from OPEC countries, with Ontario importing about 36% of its oil requirements (Source: Russell, 2009).

All of this points towards the need for serious investment in renewable energy sources, to take advantage of the vast natural resources available in Canada. The door seems to be wide open for new technologies. The government of Ontario has set for itself the modest goal of 2,700 MW of renewable energy generation by 2010, representing about 10% of all of its total installed capacity. Since currently only about 1% of the province's energy supply (150-160 MW) derives from low-impact renewable sources, there is definitely an opportunity for using biomass to produce energy.

1.4 Kingston's Greenhouse Gas Targets

Kingston, Ontario is a city situated on Lake Ontario with a population of just over 117,000 inhabitants. Its current sources of energy are nuclear, coal, hydropower, natural gas, and oil. Kingston was selected for this thesis as it is hypothesized that increasing its use of renewable energy is viable from a social, environmental, technical and economic perspective.

Substituting existing fossil fuel use for renewable energy would have the following advantages:

- reduce the concern about dwindling, finite fossil fuel energy supplies
- reduce the concern about rising fossil fuel energy prices
- contribute to domestic goals for reducing provincial and national greenhouse gas emissions
- become a North American leader in innovative energy technology
- stimulate new employment and economic growth in renewable energy development and production
- stimulate eco-tourism to Kingston
- stimulate renewable energy programs at the city's prestigious Queen's University
- stimulate R & D exchange programs with other nations
- make better use of existing natural resources in the province of Ontario

From a social and community perspective, it is probable that the construction of a CHP plant based on wood and a biogas plant in 2 areas of Kingston would be accepted given that this city of 117,000 residents has already shown a willingness to undertake environmental initiatives. In 2005, Kingston set itself apart from the rest of Canada by being one of a small collection of communities in the country to participate in a federal initiative called the One Tonne Challenge program. This obliged citizens of Kingston to account for their own environmental GHG footprint and take measures to reduce it.

Kingston is also one of a few cities in Canada to set greenhouse gas targets. It has established for itself the goal of reducing its greenhouse gas emissions to 10%

below year 2000 levels by 2014. This goal was stimulated by the Federation of Canadian Municipalities program *Partners for Climate Protection* which Kingston City Council opted to join in 2001.

Kingston has an alternative energy cluster called SWITCH which assists local residents and industries to adopt green measures offered under the government of Ontario's Standard Offer Program for Renewable Energy or the rebate program of Kingston Electricity Distribution Limited. These programs support those who wish to produce and sell renewable energy to the grid. One such project was that of a Kingston homeowner in 2007 who began to produce and sell solar power from his home.

From an environmental perspective, it should be viable to switch to biomass within the current energy mix, as the availability of biomass within a 150 km radius of Kingston is abundant and accessible. This is because Kingston is situated within the Eastern Ontario Model Forest (EOMF), which encompasses 1.5 million hectares of mixed forest, urban and agricultural land in eastern Ontario, and 90 percent of the land is privately owned. It is located in the Great Lakes-St. Lawrence forest region between the St. Lawrence and Ottawa Rivers. The forest's dominant tree species include basswood, beech, red maple, sugar maple, white ash, white spruce and yellow birch. The Eastern Ontario Model Forest certifies private woodlots, and promotes urban forestry and landowner education. The Canadian Model Forest Network (CMFN) includes Canada's 14 Model Forests and has as partners private citizens, forest companies, parks, Aboriginal communities, provincial governments and universities. One of the Network's key partner organizations, Natural Resources Canada's Canadian Forest Service, provides primary funding for the CMFN through the Forest Communities Program (Source: Canadian Model Forest Network, 2009).

From a technological perspective, Queen's University in Kingston has set up a Bioenergy Centre within their Innovation Centre to support the technological development of green energy technologies in Canada. Queen's University purchased 50 acres of land in 2008 specifically zoned for industrial use, including research and experimental activities. The development of these green field lands adjacent to the multi-tenant facility will be guided by LEED (Leadership in Energy and Environmental Design) standards. The master planning process with the City of Kingston is still underway. Queen's University could therefore be an excellent partner in the kind of biomass and biogas project suggested by this paper. It could even conceivably make several acres of land available for a pilot project, thereby reducing the upfront investment costs for a biomass project. This land is within access of Utilities Kingston. Utilities Kingston is responsible for supplying, distributing and metering electricity and natural gas in the City Central.

From an economic perspective, there are existing incentive programs in Ontario to support the uptake of renewable energy generation. These include the Ontario Standard Offer Program, the OMAFRA Biogas Financial Assistance Program and Advanced Manufacturing Investment Strategy. In addition, Queen's University Innovation Centre may have some funding to support this project By making a portion of its innovation centre land available for a pilot renewable energy project, this also reduces the cost of a biomass CHP plant and a pellet production plant.

1.5 Austria as a Model for Biomass Utilization

Austria has already reached 22.5% renewable energy within its overall mix, close to its EU commitment of 25% by 2012, as established on 9 March 2007 by the Council of the European Union in their Energy Policy for Europe 2007. However, Austria has set for itself an ambitious goal beyond its EU target to achieve 45% renewable energy within its overall energy mix by 2020. In order to reach this goal, the government supports initiatives for heat and power generation that are renewable.

One third of Austria's annual greenhouse gas emissions comes from the residential housing sector. Of its total electricity production, about 66-70% is from renewable energy, mostly hydro power followed by biomass. This is one of the highest shares in Europe. The EU average is 6%.

Austria's experience with biomass heating is excellent. While the overall degree of biomass utilization in the EU is at 3-4 % rather low, Austria's share of biomass utilization is 11%.

Figure 4 gives an overview of the distribution of different renewable energy sources of the overall renewable usage in Austria.

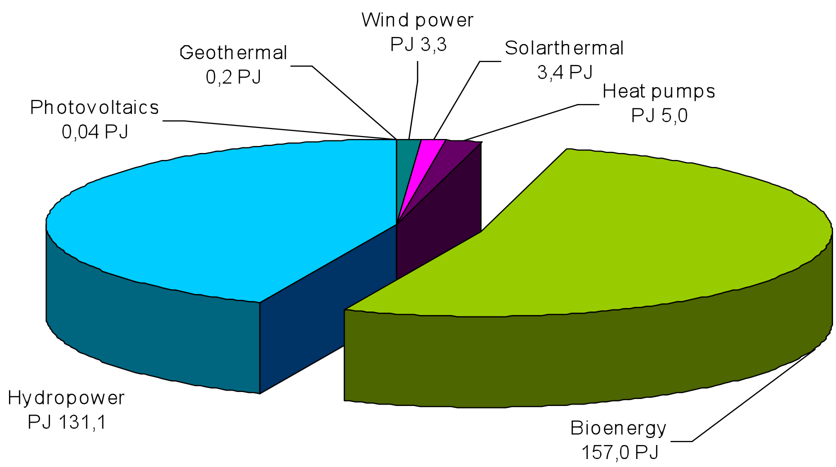


Figure 4: Austria's Use of Renewables by Type (Source: Hofbauer, 2008)

Biomass-fired district heating networks have been developed and built in rural areas of Austria since the mid 1980's. Small stations with an output between a few 100 kW and 5 MW produce heat by burning wood chips from forestry or sawmill residues. Approximately 50 new installations have been built per year in recent years, and as many as 694 plants have become operational since 2001, with a total capacity of 822 MW $_{th}$ (capacity range: 100 KW $_{th}$ to 20 MW $_{th}$) (Source: Austrian Energy Agency 2004).

Figure 5 shows a map of Austria together with the location of all biomass combustion plants. The size of the circle gives an impression of the capacity of the respective plants.

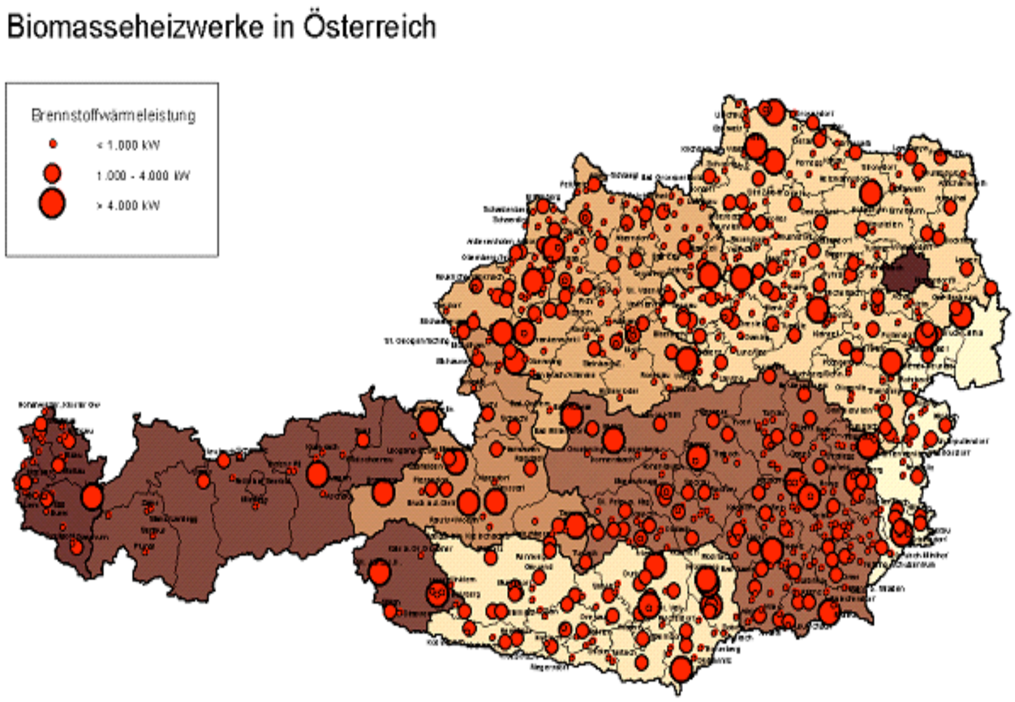


Figure 5: Biomass Fired Plants in Austria

(Source: The Austrian Energy Agency, 2004)

It is for this reason that biomass systems modeled after existing Austrian technology will be recommended for Kingston, Ontario.

1.6 A Community Gone Renewable - the Model of Güssing, Austria

Güssing is the first community in the European Union to produce its entire energy demand, ie electricity, heating, cooling, and fuels from renewable sources of energy from within the region. This investment in renewable energy transformed its economy. Güssing was, in 1988, one of the poorest and least developed areas of Austria, located in its most depressed region Burgenland on the Hungarian border. Many of its residents commuted to Vienna or deserted the city for better prospects elsewhere. Güssing decided in 1990 to free itself of its dependence on fossil fuels. It realized that substantial capital outflow from the region was due to the town's energy being bought from outside sources. This included oil, power and fuels, while existing resources e.g. 45% forest land, remained largely unused. Thus, some "reformers" proposed to start producing and then selling energy to the citizens themselves. With national and EU funding support of approximately € 6 million, it invested in bio-diesel and biomass district heating plants and cut public use of energy by 50%. One thousand jobs were created, many new eco-tourists per year were attracted to its eco-friendliness (Güssing recorded 30,000 tourists total in 2007), and the city cut down its CO_2 emissions by 92%. Additionally, it took a new sustainable approach to managing its surrounding forests.

The Vienna University of Technology decided to build a pilot project in Güssing. The initial decision was to require that all public buildings in the town stop using fossil fuels. As result of the energetic optimization of buildings in the town, expenditure on energy was reduced by almost 50%. The next step was the construction of a wood burning plant that provided heating for 27 houses. Then, a facility was constructed which turned rapeseed into car fuel. In 1998, Koch and Vadasz saw a presentation by a Viennese scientist, Hermann Hofbauer, about a technology he had developed to make an alternative fuel from wood. They asked Hofbauer and Vienna's University of Technology, how wood chips are gasified under high temperature conditions. Wood gas fuels a Jenbacher engine that produces electricity and the "by-product" heat is used to produce warm water for district heating system. The plant efficiency is about 82-85%.

Significant power plants in Güssing include a 2 MW electric power 4.5 MW thermal wood gas generator power plant and, in nearby Strem, a biogas plant with 0.5 MW electric power and 0.5 MW thermal power using green silage re-growing raw materials like grass, clover, mains, sunflower. The town hosts today a number of innovative technologies, solutions, and patents, with now 27 different decentralized heat and partly power plants within the Güssing area. Güssing today has an "energy" turnover of about € 14 million per year. Part of the profit is invested back into renewable energy projects.

The result has been stable energy prices (not linked to oil and gas), guaranteed long-term (10-15 years) promotion of the establishment of local enterprises, and the attraction of 50 new enterprises with more than 1,000 direct and indirect jobs in the city. Güssing has since developed into an important location for industries with high energy consumption, such as parquetry production or hardwood drying. This helped make Güssing the second largest producer of parquet flooring in Austria. Recently a photovoltaic production facility was built in Güssing (Source: Wikipedia, 2009).

1.7 Social Considerations for the Increase of Bioenergy

Projects that make use of biomass can be sustainable and profitable because they rely on biological and renewable feed stocks and can be designed to produce heat as well as electricity. In addition, bio-energy offers a potential solution to the disposal of municipal solid waste by converting solid waste to energy. It serves as a new source of income for the province's forestry and agricultural sectors; especially for farmers in rural areas where they can grow switch grass for fuel and use animal manure in anaerobic digesters to generate heat and power.

The production and transportation of solid bio-fuels at the necessary scale could also provide significant economic stimulation to the rural economy in sectors of Canada where unemployment is already a concern. By the 2004 estimate of the Suzuki Foundation of Canada, Ontario could have added at least $9 billion to its economy and created 25,000 new jobs by 2010 if the province had begun to use renewable energy to power its electricity system.

Biomass CHP plants should be well accepted by the public in Ontario as it offers a clean alternative to coal-fired plants. As previously mentioned, Ontarian's concerns about air pollution resulted in a promise by the Ontario government to close down 5 coal-fired power plants operated by Ontario Power Generation by 2007. This initiative improved Ontario air quality but resulted in a supply-demand imbalance of 7,500 MW (Source: Suzuki, 2004).

Bio-energy generally offers a net social benefit, as it can satisfy a region's demand for heat and power but, compared to fossil fuels generates lower air emissions and, relative to nuclear energy does not carry the same safety risks. State of the art biomass production plants have minimal environmental impact and decrease dependence on imported fuel, such as coal or liquified natural gas imports in Ontario's case.

Almost all forms of energy production produce a resistance by inhabitants in the vicinity of the proposed site, but some forms generate more resistance than others. The environmental impact of a biomass cogeneration plant involves a comparatively low amount of smell and noise and is influenced by the size of its turbines which generate the power. This impact is, however, significantly smaller than that of a coal fired plant which generates the same amount of power and which necessitates coal mining and significant emissions of carbon dioxide and pollutants.

As for biogas generation, anaerobic digestion of manure produces an end product called digestate that in many cases has at least a 97% reduction in pathogen and odour levels and therefore has a positive social impact. While there is little volume or nutrient reduction in anaerobic digestion systems, a higher percentage of the nutrients in the digestate are in an inorganic form, similar to conventional fertilizer. Typically, the digestate is land-applied in a manner similar to liquid manure for use with conventional field crops.

Digestate can be passed through a solid separator system that produces a high-quality solid material. This material can be used in other settings such as horticultural applications. This may assist the nutrient management plan for a farm by transporting nutrients off the farm. In addition, this separated solid material works effectively as a livestock bedding material.

An effective biogas plant optimizes many biological and mechanical processes. The biogas slurry is applied to fields, where it is used as an organic fertiliser. The application of biogas slurry has 2 different ecological effects. The nutrient content of the slurry leads to a reduced consumption of artificial fertilizer, made from high energy processes. The emissions from the biogas slurry contribute to acidification/eutrophication and produce some greenhouse gases. However, these negative effects, especially the acidification from gaseous NH_3 emissions, contribute to around 25% of the total ecological effects. This threat to the environment can be reduced through application and incorporation methods in keeping with good agricultural practice resulting in low emission levels of the applied biogas slurry. Moreover, these emissions levels are below the emissions from manure, which is used as input to the plant, and would alternatively spread to the fields, where it would cause emissions (Source: Hartmann, 2006).

The feedstock for the wood-chip fired biomass plant and the agricultural residue based biogas plant being proposed in this paper would help the city of Kingston use its existing natural resources and rely less on imported fossil fuels. The 2 MW biogas plant would provide a solution for the disposal of farm and agricultural waste, potentially also capturing otherwise fugitive emissions of methane, while realizing an annual profit . The wood requirement for the 40 MW CHP plant would provide a source of revenue for wood lot owners in the 1.5 million hectares of Eastern Ontario Model Forest who have excess capacity.

2. Thermal Conversion of Biomass

2.1 The Technology Framework for Bioenergy in Kingston

Kingston has the natural resources to permit it to increase its share of renewable energy production through biomass because it is surrounded by forest and farmland. It falls within the territory of the Eastern Ontario Model Forest, spanning 500 km from the Ottawa Valley south to Toronto, containing 1.5 million hectares of forest (3.7 million acres). Approximately 35% of this land is forested with a mixed hardwood forest of 40 different tree species, of which 80% is privately owned. The maple, ash and other tree varieties are suitable for wood chips that would be used in a biomass plant. It would be very feasible therefore to enter into fixed long-term supply contracts with wood lot owners. In addition to this forest land in the EOMF, there is Renfrew County within which is 250,000 ha of Crown forest land and 250,000 ha of privately owned forest land. Added to this is wood that comes out of Algonquin park, having an available forested land base of 500,000 ha, not all of which goes to mills east of the park. In 2005/6, about 600,000 cubic meters of wood logs were cut in the park.

Up until 3 years ago, the major customer for the wood supply within the EOMF was Domtar, a specialty fine paper plant in Cornwall, Ontario. Since Domtar closed their plant, this has released 500,000 cubic metres or approximately 357,000 tons of pulp wood into the market. There is currently little market for this wood! (Source: Lawn, 2009)

At present, there is no large scale energy production from biomass in Ontario. This could change with the introduction of a wood-chip based 40 MW biomass CHP combustion or gasification plant in Kingston and a 2 MWel biogas plant using farm waste.

The Ontario government is likely to invest the required funding into any upgrades to the electricity grid that might be required in order for increased decentralized generation from renewable energy sources such as biomass plants. The US Obama administration plans to invest $11 billion USD into US electricity grid upgrades. If Canada were to collaborate with the US on a North American energy agreement involving renewable energy production and trade, it would require Canada to also rapidly make a similar investment to the electricity grid.

The Kingston Economic Development Corporation projected in 2004 that Kingston's growth rate was 0.8% per year. The Canadian census results, however, listing Kingston's growth rate at 1.19% in 2006, showed that the actual growth rate projections are more accurately 0.5% per year. With this rate of growth over 14 years from the 2000 baseline year, Kingston would actually need to reduce its greenhouse gases by *16% below year 2014* in order to reach its greenhouse gas target. In a business case as usual scenario, this is not possible. However, with a substitution of over 30% percent of the current non-renewable power supply with bio-energy, this could be achieved.

Data from Kingston's energy emissions between 2000-2006 reveals that Kingston's primary source of greenhouse gases stems from its consumption of electricity, heat and transport fuels. Kingston was responsible for emitting about 1.4 million tons of CO_2 in 2000 (Source: Hsu, 2007).

The City of Kingston Community Emissions Inventory calculated that the year 2003 baseline inventory of GHGs is shown in Table 1 for the year 2003. The values are given in kt CO_2 per year. As it can be clearly seen the largest amounts are originating from electricity, gasoline, natural gas, and diesel. A distribution of GHG emission (in terms of percentage) for the year 2000 can be seen in Fig. 6.

Table 1: Kingston's GHG Inventory by Source in 2003

(Sources: City of Kingston, 2003 and Hsu, 2007)

Source	Emissions (kt CO_2)
Electricity	430
Natural Gas	237
Fuel Oil	39
Propane	31
Gasoline	427
Diesel	194
Waste in Landfills	25
Totals	**1385**

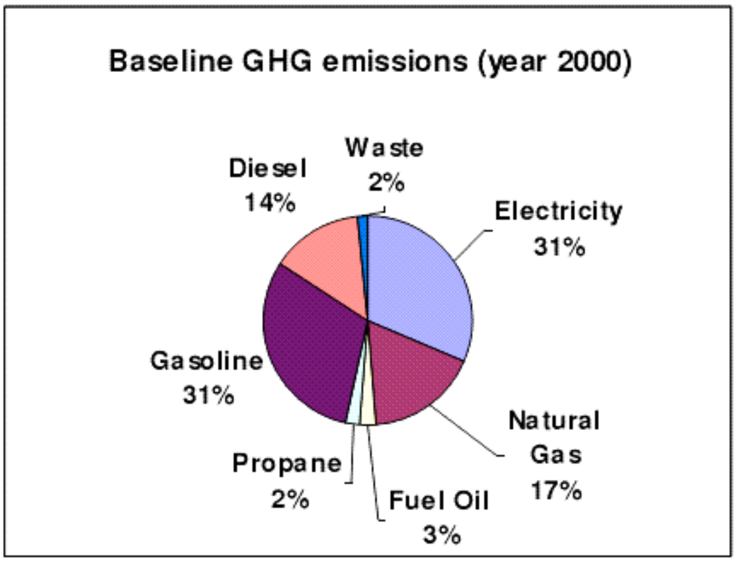


Figure 6: Baseline GHG Emissions in Kingston in 2006

(Source: City of Kingston, 2003 and Hsu, 2007)

Electricity Generation

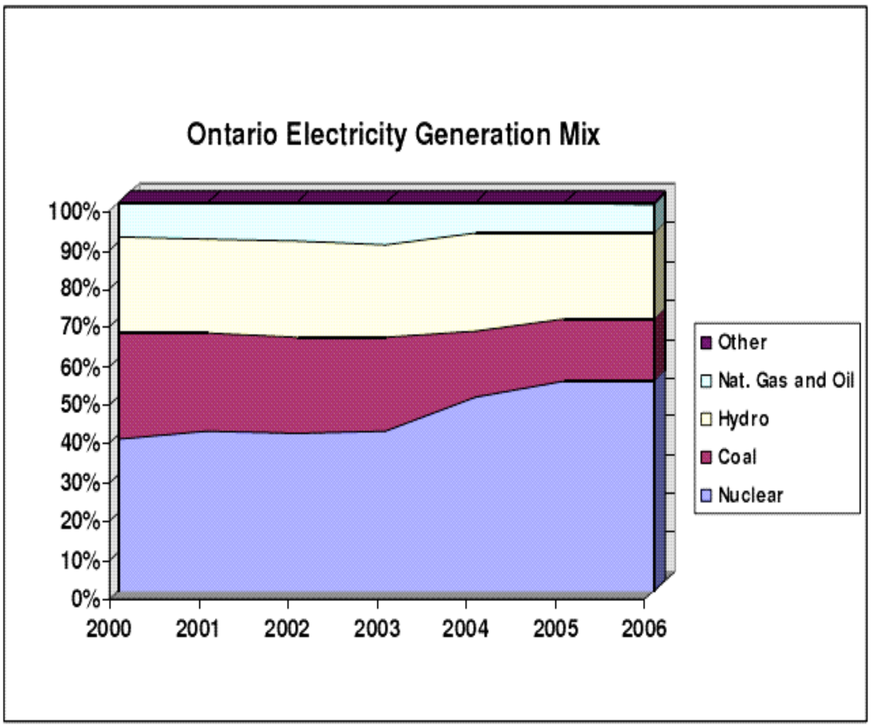
Just over half of Ontario's electricity came from provincial nuclear power in 2006. Another 22.3% came from provincially sourced hydro power (Table 2). Since 2003, the use of coal has decreased in Ontario and the use of nuclear power has increased. By 2006, 23.6% of Ontario's electricity generation mix was derived from fossil fuel sources.

If fossil fuels are used to generate the electrical power requirement of a community, it affects the number of GHG emissions attributable to the consumption of electricity. The relevant quantity is the carbon intensity of electricity and has units of tons of CO_2 emitted per MWh. For example, a coal plant emits 0.9 tCO_2/MWh while a hydro plant emits about 0 tCO_2/MWh. Table 2 and Figure 7 show the electricity mix in Ontario.

Table 2: Ontario Electricity Generation Mix
(Source: Hsu, 2007)

YEAR	Nuclear	Coal	Hydro	Natural Gas + Oil	Other
2000	39.0%	27.3%	24.7%	9.0%	0.0%
2001	41.3%	25.3%	24.3%	9.1%	0.0%
2002	40.8%	24.6%	24.9%	9.7%	0.0%
2003	41.3%	23.9%	24.0%	10.8%	0.0%
2004	50.0%	17.0%	25.0%	8.0%	0.0%
2005	54.0%	16.0%	22.0%	8.0%	0.0%
2006	54.1%	16.0%	22.3%	7.3%	0.3%

Figure 2



Data source: Ontario Energy Board and Independent Electricity System Operators

Figure 7: Ontario Electricity Generation Mix (Source: Hsu 2007)

Figure 7 shows shares of the Ontario electricity generation mix from 2000 until 2006. From this Figure it can be seen that nuclear power production has increased steadily.

Electricity consumption in Kingston in 2006 was 1324 GWh and GHG emissions were 297 kt of CO_2 (Table 3). Electricity use increased by 4% over the 6 year period from 2000, however its related CO_2 emissions decreased by about 24% because of the fact that Ontario Power Generation decreased its use of coal and increased its use of nuclear power to generate electricity (Source: Hsu, 2007).

Table 3: Kingston Annual Electricity Consumption (Source: Hsu, 2007)

Year	Utilities Kingston (GWh)	Hydro One Networks (GWh)	Total (GWh)
2000 baseline			1370
2000	728	**542**	**1270**
2001	728	**561**	**1289**
2002	743	**581**	**1324**
2003	751	601	1352
2004	749	567	1316
2005	757	601	1358
2006	734	590	1324

Highlighted numbers in Table 3 = extrapolated estimate

As seen in year 2000, total electricity consumption from Hydro One + Utilities Kingston was less than the amount claimed in the 2000 baseline study (when actual data from Hydro One was available but the breakdown by company and the methodology were no longer available). As a result, the study did not overestimate growth and likely underestimated how much Kingston needs to cut its emissions in order to achieve the City Council target (Source: Hsu, 2007).

Table 4 shows estimates of electricity consumption and GHG emissions from Kingston Between 2000 – 2006.

Table 4: Combined Estimates of Electricity Consumption and the Carbon Intensity of Grid Electricity to Produce an Estimate of the Time Variation of GHG Emissions from Kingston's Electricity Consumption (Source: Hsu, 2007).

Year	Electricity Usage (GWh)	Emission Factor (tCO_2/MWh)	GHG emissions (kt CO_2)
2000 baseline	1370	0.313	430
2000	1270	0.307	390
2001	1289	0.291	376
2002	1324	0.279	369
2003	1352	0.304	411
2004	1316	0.255	335
2005	1358	0.218	296
2006	1324	0.224	297

Natural Gas

Because of a warming trend in recent winters, GHG emissions from natural gas usage have gone down by about 85%.

Natural gas supply in Kingston is broken up very much like electricity with Utilities Kingston serving the pre-amalgamation City of Kingston and Union Gas serving the old townships. Just as for electricity, consumption can change depending on the weather (on heating degree days in this case). The study extrapolated Union Gas consumption data from 2003 back to 2000 in order to fill in unavailable data, using

12 month moving averages of monthly natural gas consumption data from Utilities Kingston in order to cancel out seasonal effects. Variations in residential use of natural gas ended up correlating very well with heating degree days (HDD, see Table 5).

Table 5: Natural Gas Consumption in Kingston
(source: Hsu, 2007)

YEAR	Utilities Kingston (million m^3)	Annual Variation	Annual HDD	Annual Variation	Union Gas small customers (million m^3)	Annual Variation	Union Gas large customers (million m^3)
2000	82.0		4131		**50.8**		**67.5**
2001	72.3	-11.8%	3640	-11.9%	**46.2**	**-9.1%**	**67.5**
2002	76.5	5.7%	3806	4.6%	**50.3**	**8.9%**	**67.5**
2003	82.7	8.1%	4285	12.6%	56.0	**11.3%**	67.5
2004	79.5	-3.8%	4068	-5.0%	54.4	-2.8%	67.4
2005	77.8	-2.2%	3919	-3.7%	56.7	4.3%	60.3
2006	71.0	-8.8%	3494	-10.9%	52.5	-7.5%	60.9

Highlighted figures in the above Table are extrapolations.

The Hsu report suggests that natural gas consumption in Kingston in 2006 was 184 million m^3, which amounted to *347 kt of CO_2 (or 347,000 t of CO_2)*. The development of natural gas consumption from 2000 until 2006 is shown in Table 6.

Table 6: Total Natural Gas Consumed in Kingston
(Source: Hsu, 2007)

Year	Natural Gas (million m^3)	GHG emissions (kt CO_2)
2000 baseline	126	237
2000	200	377
2001	186	349
2002	194	364
2003	207	388
2004	202	379
2005	195	367
2006	184	347

The same conversion factor used for the year 2000 baseline was used here. (1.88 kt/million m^3). Some of this growth is attributable to the conversion to natural gas and not by new homes (Source: Environment Canada, National Inventory Report 1990-2004).

There is a substantial difference in natural gas usage between the 2000 baseline study and the year 2000 value of this study. However, data from Union Gas was not available for the 2000 baseline study. Instead natural gas usage was estimated from electricity consumption by Hydro One customers and some assumptions about the relative consumption of electricity and natural gas. That estimate may have missed the large "contract" customers (Source: City of Kingston, 2003).

Heating Oil

According to Hsu's Report, heating oil consumption in Kingston in 2006 was 12 Ml, amounting to 33.8 kt of CO_2 (Table 7). Heating oil has decreased by 12 – 16% from 2000 due to the lower number of heating degree days, ie warmer weather. To determine the greenhouse gas emissions, the conversion factor is 2.83 kg CO_2 per litre of oil burned (Environment Canada National Inventory Report, 1990-2004).

Table 7: Heating Oil Consumption and GHG Emissions

Year	Consumption (million l)	GHG emissions (kt CO_2)
2000 baseline	13.8	39.0
2000	13.8	39.0
2001	12.1	34.2
2002	12.8	36.1
2003	14.0	39.5
2004	13.5	38.0
2005	13.1	37.1
2006	12.0	33.8

Motor Fuel

The Hsu report indicates that Kingston's annual consumption of motor fuel in 2006 was 144 million l of gasoline and 21.7 million l of diesel. Gasoline can be converted to CO_2 using the factor 2.36 kt/million l, and diesel can be converted to CO_2 using the factor 2.73 kt/million l (Source: Environment Canada, National Inventory Report 1990-2004). Therefore, the total GHG emissions attributable to Kingston's consumption of motor fuel in 2006 was 400 kt CO_2.

Table 8: Kingston's Annual Consumption of Motor Fuel and Resulting GHG Emissions (Source: Hsu, 2007)

Year	Gasoline (million l)	Diesel (million l)	Gas (kt CO_2)	Diesel (kt CO_2)	Total ($ktCO_2$)
2000 baseline	181	71	427	194	621
2000	139	20.8	328	57	385
2001	139	20.8	328	57	385
2002	144	21.6	339	59	398
2003	149	22.3	351	61	412
2004	144	21.6	339	59	398
2005	138	20.8	327	57	383
2006	144	21.7	341	59	400

General Conversion Factors

1m^3 natural gas = 10 kWh

1l heating oil, motor fuel = 11.6 kWh

1 m^3 propane = 25.8 kWh (or 1 kg propane = 13.9 kWh)

1kWh = 3.6 MJ

1GWh = 3600 GJ

Therefore, overall energy demand in Kingston in 2006 was electricity 1324 GWh, natural gas 184 million m^3 = 1840 GWh, heating oil 12 million l = 139 GWh, motor fuel 165.7 = 1922 GWh million l, propane 20.5 million l = 237.8 GWh *for a total of*

5179 GWh.

Figure 8 shows the GHG emissions in kt in Kingston for the year 2006. The greenhouse gas emissions in 2006 amounted to 297 kt (electricity) plus 347 kt (natural gas), plus 400 kt (motor oil) plus 33.8 kt (heating oil) = *1077.80 kt.*

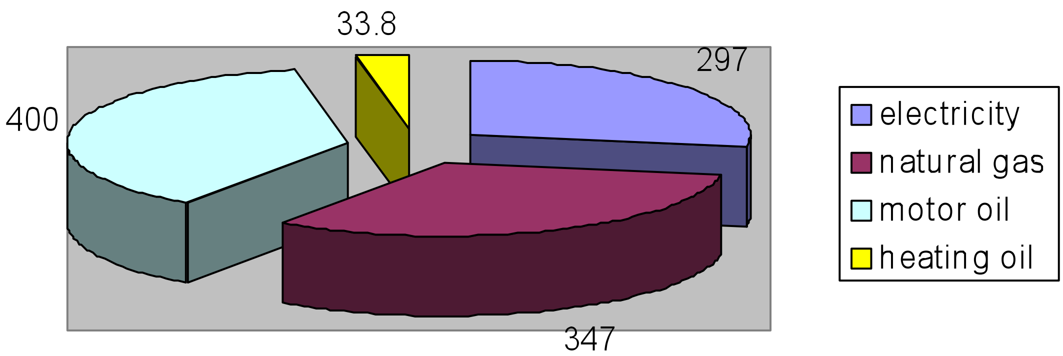


Figure 8: Greenhouse Gas Emissions in Kingston in 2006; (Source: Hsu, 2007)

2.2 Technological Principles of Solid Biomass Conversion

2.2.1 Characterization of Solid Biomass

Biomass is defined as organic matter available on a renewable basis that was directly or indirectly derived not too long ago from contemporary photosynthesis reactions, such as vegetal matter and its derivatives, eg wood and wood waste, fast-growing plants and trees (both aquatic and on land), agricultural crops and waste, livestock operation residues, animals and animal waste, and municipal and industrial waste (Source: Hofbauer, 2008).

It is estimated that the energy stored in the world's total supply of biomass makes up twice the world's current energy demand. Moreover, the thermo-chemical process of converting this stored energy to heat, power and transport fuels is considered renewable and clean. This is because the carbon released into the atmosphere when it is burned is equal to the amount of carbon absorbed by the tree or plant during its growth cycle.

Biomass consists of a large number of chemical elements, the main ones being carbon (C), oxygen (O), hydrogen (H), nitrogen (N), potassium (K), phospohorus (P), calcium (Ca), magnesium (Mg), sulphur (S), and chlorine (Cl). Woody biomass has a carbon content of about 47 - 50 wt -% in the dry matter (dm). Other non-woody biomass contains typically a carbon content of about 45 wt-%. The oxygen content lies between 40 - 45 wt-% and the hydrogen content between 5-7 wt-%. From this composition a mean molar composition of $CH_{1,44}O_{0,66}$ can be calculated (Source: Hofbauer, 2008).

Wood has a high carbon content and a net calorific value that is about 10% higher than straw or grass. Its supply is more reliable as well, making it the optimal solid fuel for a CHP plant for Kingston.

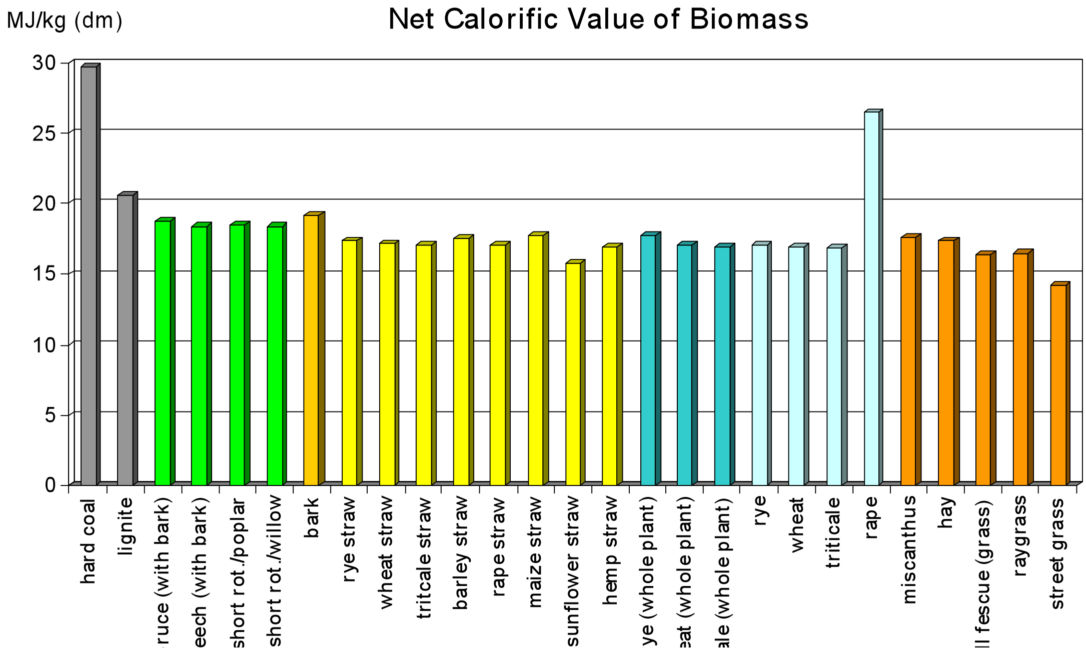


Figure 9: Net Calorific Value of Biomass (Source: Hofbauer, 2008)

The net calorific value (NCV) of a biofuel is much more influenced by its water content than by the type of fuel. This is the reason why the calorific values of the biofuels are given for the dry substance in order to get a comparable basis.

The net calorific value for biomass referred to the dry substance *Hu* ranges between 15.8 (straw) and 26.5 (rape) MJ/kg (Figure 9). For wood fuels the net calorific value is between 18-19 MJ/kg. The energy in 2.5 kg air dried wood is equivalent to the energy of 1 litre of heating oil (10 kWh = 36 MJ).

Fresh wood from the forest or wood from short rotation forests have a water content that can be as high as 50% or more, giving it very low net calorific value. Therefore, for thermal conversion, bio-fuels should be as dry as possible (Source: Hofbauer, 2008). The influence of the water content on the net calorific value is shown in Fig. 10.

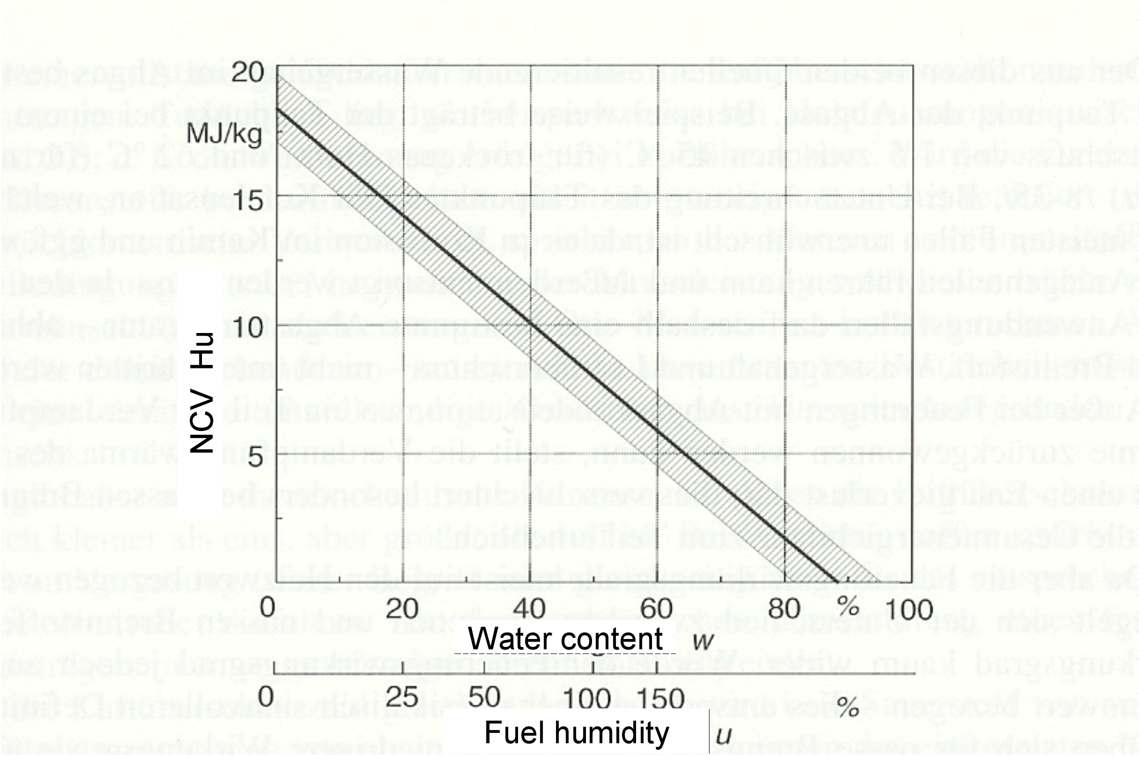


Figure 10: Influence of Water Content on the Net Calorific Value for Wood Fuels (Source: Hofbauer, 2008)

The ash content also influences the net calorific value (NCV). The higher the ash content the lower the combustible organic substance. Ash content must be factored into the design of the thermal conversion plant as the higher the ash content the higher the amount of dust in the flue gas. This then requires more efforts to separate, store and transport the separated ash. Of all of the biomass fuels, wood fuels, including bark, show the lowest ash content (mostly <0.5 wt-%). Higher ash contents (up to 2 wt-%) can be observed for short rotation forests (ie poplar, willow) as the ratio of bark to wood is higher than for conventional forest products. The ash contents for bark are typically between 2.5 to 5 wt-%. The highest ash contents were analyzed for straw and grass (Source: Hofbauer, 2008). This is another factor favouring wood as the biomass type for firing a boiler in Kingston.

The ash melting temperature is another factor influencing combustion performance. For biofuels with low ash melting temperatures, the danger of slagging in the combustion chamber and the formation of deposits at the grate or heat transfer surfaces is high. Such deposits can lead to disturbances and to a change of the air supply and also favour high temperature corrosion problems. Measures, such as suitable design or feeding of additives must be taken for these fuels.

For wood and bark fuels, melting starts between 1200 – 1400 degrees C which is normally no problem for combustion systems. The temperature range for ash melting of straw from cereals, grasses or grains is much lower than for wood fuels. Typical temperatures for the deformation temperature are at about 800-950 degrees C (Fig. 11) (Source: Hofbauer, 2008).

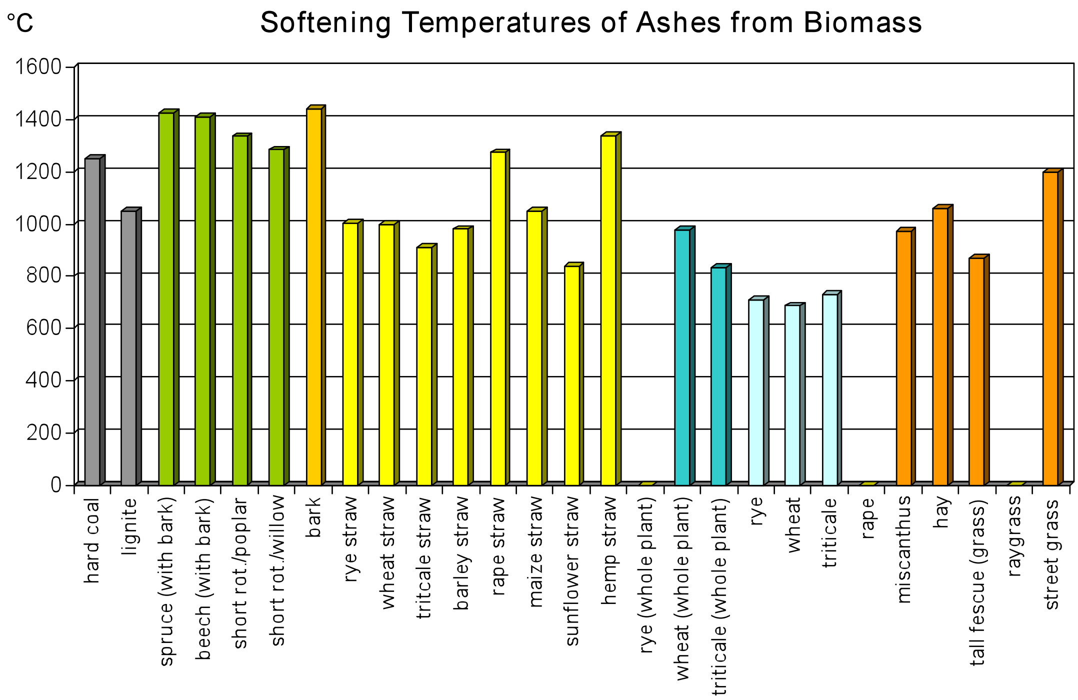


Figure 11: Ash Softening Temperatures for Biofuels (Source: Hofbauer, 2008)

The nitrogen and chlorine content in biofuels is sometimes very different depending on the kind of biofuels and fertilizing. The nitrogen und chlorine content in wood fuels is the lowest of all bio-fuels. Therefore, the emissions on NOx and HCl are low and also there is no danger for corrosion.

Energy density is another parameter which gives a value for the energy per volume or energy per mass. The calculation is based on the net calorific value (NCV) and a water content of about 15%.

The material density is important for the thermal conversion as the rate of conversion and the heat conductivity are directly dependant on this parameter. Furthermore, the above discussed bulk density is also directly influenced by the material density.

Considering each of the above factors, it is clear that either wood chips or wood pellets would make the most suitable renewable fuel for a large scale CHP plant.

Wood Chips

The size and distribution of wood chips is one important quality criteria having also an effect on the price. The storage and transport devices have to be designed according to the size and distribution of the wood chips. Wood chunks that are too large can block and even damage the transport and distribution systems. Wood chips are e.g. transported with a screw feeder into the combustion chamber (Source: Hofbauer, 2008).

Tables 9 and Table 10 contain quality criteria for wood chips according to the Austrian standards.

Table 9: Size Classes for Standardized Wood Chips (Source: ÖNORM M7133)

A) Size and size distribution	Mass portion and specific range for particle sizes (Sieve analysis)				Allowable extreme values for single particles	
	max. 20 %	60-100 %	max. 20 %	max 4%	max. cross-section	max. length
G 30	> 16 mm	16-2,8 mm	2,8-1 mm	< 1mm	3 cm²	8,5 cm
G 50	> 31,5 mm	31,5-5,6 mm	5,6-1 mm	< 1mm	5 cm²	12 cm
G 100	> 63 mm	63-11,2 mm	11,2-1 mm	< 1mm	10 cm²	25 cm

Table 10: Quality Criteria for Standardized Wood Chips (Source: ÖNORM M7133)

	Description	Class limits	Explanation
B) Water content	W 20 W 30 W 35 W 40 W 50	< 20 % 20-30 % 30-35 % 35-40 % 40-50 %	„air-dried“ "suitable for storage" "conditional suitable for storage" "moist" "fresh from harvesting"
C) Bulk density (referred to dm)	S 160 S 200 S 250	< 160 kg/m³ 160-250 kg/m³ > 250 kg/m³	"low bulk density" "medium bulk density" "high bulk density"
D) Ash content (referred to dm)	A 1 A 2	< 1 % 1-5 %	"low ash content" "high ash content"

A major advantage of wood chips over wood pellets is the cost. Wood chips currently sell on the Canadian market for *$30 - 100/ dry ton*.

<u>Wood Pellets</u>

Wood pellets are a high quality fuel, containing constant size, constant low water content, a higher energy density, and constant high quality. The demand for wood pellets is growing annually e.g. in Austria. With such a well defined fuel the combustion can be optimized easily to very low emissions even for small appliances. Furthermore, storage is not a problem, due to the low water content. One disadvantage is the low attrition of fine particles and dust which can cause problems in transport systems. Another disadvantage is the higher cost of pellets over wood chips. Several quality criteria for wood pellets are shown in Table 11.

The current Canadian price *is $280/dry ton*.

Large scale CHP plants are operated mainly with wood chips whereas for small scale pellets are the preferable fuel. For reasons of efficiency and economics, it is recommended in this thesis that Kingston adopt a similar approach using Austrian biomass CHP boiler technology based on wood chips.

Table 11: Quality Criteria for Wood Pellets (Source: ÖNORM M7133)

Criteria	Unit	Wood pellets
Diameter *D*	mm	$4 \le D < 10$
Length	mm	$\le 5 \times D$ [1])
Raw density	kg/dm³	≥ 1,12
Water content	%	≤ 10,0
Ash content[2])	%	≤ 0,50
Net calorific value[2])	MJ/kg	≥ 18,0
Sulphur content[2])	%	≤ 0,04
Nitrogen content[2])	%	≤ 0,30
Chlorine content[2])	%	≤ 0,02
Attrition	%	≤ 2,3
Press additive	%	≤ 2
[1]) max. 20 % of the mass of the pellets are allowed to have a length of 7,5 x *D* [2]) for dry matter		

2.2.2 Thermal Conversion Processes

There are 3 options for thermal conversion of biomass to generate thermal energy using wood chips or wood pellets. These include *combustion, pyrolysis and gasification*. With combustion, the conversion takes place at a high temperature such as 800+ degrees C and the product is primarily a flue gas consisting of carbon dioxide and water for heat utilization. Pyrolysis by contrast, is the thermal conversion of organics in the absence of oxygen. The conversion takes place at lower temperatures, such as 400-600 degrees C and the primary product is a liquid. The gasification option involves thermal conversion of the wood biomass at temperatures under 800 degrees C and the desired product is a usable synthesis gas (Source: Hofbauer, 2008).

Biomass combustion is carried out at high temperatures (8–0 - 1200 degrees C). The aim of combustion is the production of heat which can be used for different applications, such as residential or industrial heat, power production etc. Chemical energy is stored in the fuel which is expressed by the heating (calorific) value: lower heating value LHV and higher heating value HHV, MJ/kg. By oxidation of the organic matter the chemical energy is set free and heats up the flue gas. From there heat is exchanged to a heat carrier such as hot water, steam, or oil.

Biomass Combustion

Biomass pieces are introduced into a hot combustion chamber and heated up. First drying is performed and the weight loss corresponds to the water content. Afterwards devolatilization (pyrolysis) takes place. This is the case since at low temperatures combustion reactions are very slow and practically zero. The weight loss in this stage is about 75-85 %. If the particle has reached a sufficient high temperature, gasification and combustion reactions take place (Biomass Technology Report, 2008).

Grate Combustion Systems

There are several different types of grate firing, fixed and moving grates. They have the advantage over underfeed stokers that they can accommodate fuels with high moisture and ash content as well as with varying fuel sizes. It is very important that fuel is spread evenly over the grate surface in order to ensure that air is distributed uniformly throughout the fuel and thus combustion is kept homogenous and stable. There are a number of different types of grate firing including fixed grates, moving grates, rotating grates and travelling grates.

Moving grate furnaces usually have an inclined grate consisting of fixed and moveable rows of grate bars. The alternating forward and backward movements transport the fuel along the grate, mixing burned and unburned fuel particles and thereby evenly distributing the fuel over the grate surface.

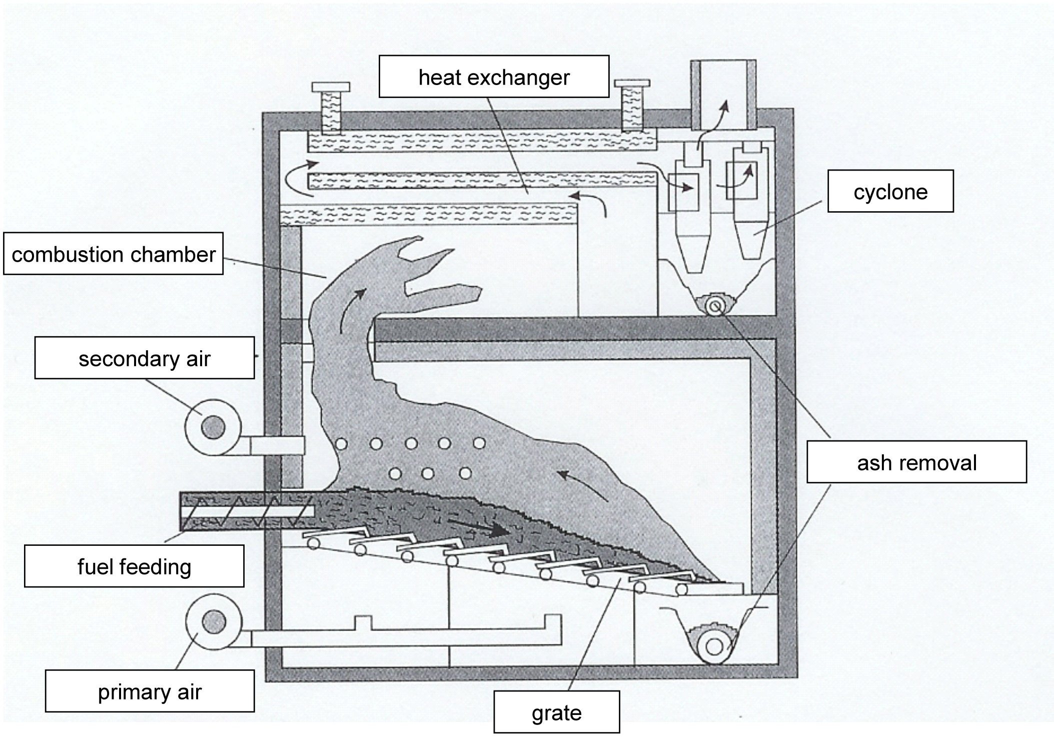


Figure 12: Inclined Moving Grate Combustion System (Source: Hofbauer, 2008)

In moving grate furnaces, a wide variety of bio-fuels can be burned. As one example, an inclined moving grate is shown in Figure 12. Air-cooled moving grate furnaces use primary air for cooling the grate and are suitable for wet bark, sawdust and wood chips. For dry bio-fuels or those with low ash sintering temperatures, the water-cooled moving grate systems are recommended (Source: Hofbauer, 2008).

Fluidized Bed Combustion Systems

There are 2 types of boilers, bubbling fluidized bed boilers (BFB) and circulating fluidized beds (CFB).

With the effective mixing of the woody materials, fluidized bed combustion plants can work with different fuel mixtures. However, there can be problems associated with the fuel particle size and impurities contained in the fuel. Usually a particle size below 40 mm is recommended for CFB units and below 80 mm for BFB units. Moreover, partial load operation of FB combustion plants is limited due to the need for bed fluidization. The low excess air quantities necessary increase combustion efficiency and reduce the flue gas volume flow. This makes FB combustion plants especially interesting for large-scale operations. One disadvantage of FB combustion plants is posed by the high dust loads entrained in the flue gas, which makes dust precipitators and boiler cleaning systems necessary. Another problem can occur during combustion of biomass with low ash melting temperatures. As the normal operation temperatures of fluidized bed combustors are about 850 °C the ash softening temperature of the fuel has to be well above which is the case for woody fuels.

Bubbling fluidized bed combustion (BFB)

In bubbling fluidized bed furnaces, the fluidized bed is located in the bottom section of the furnace. The primary air is supplied over a nozzle distributor plate and fluidizes the bed. The bed material is usually silica sand. The advantage of BFB furnaces is their flexibility concerning particle size and moisture content of the biomass fuels. Furthermore, it is also possible to use mixtures of different kinds of biomass or to co-fire them with other fuels (bark, sludge, coal in Figure 13). One big disadvantage of BFB furnaces, the difficulties they have at partial load operation, is solved in modern furnaces by splitting or staging the bed. BFB furnaces are typically used for nominal outputs between 5-50 MW_{th}.

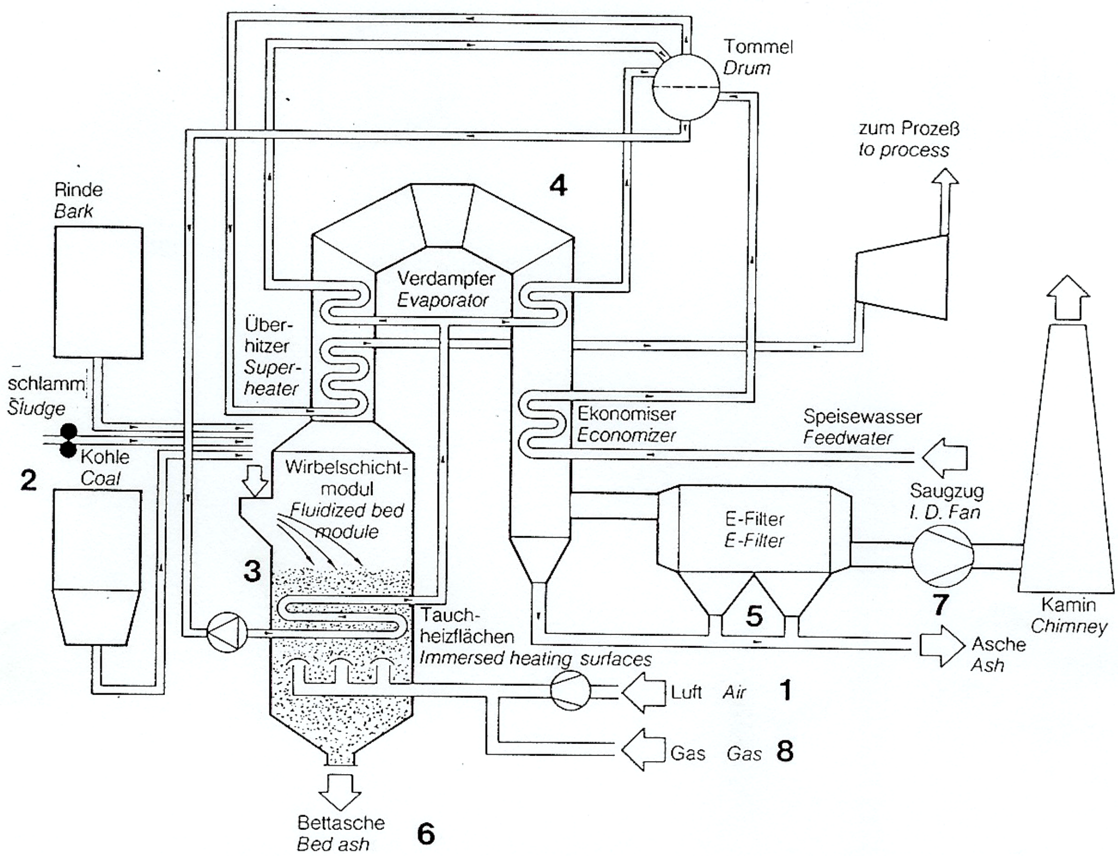


Figure 13: Stationary Fluidized Bed Combustion System (source: Hofbauer, 2008)

Circulating Fluidized Bed (CFB) Combustion

By increasing the fluidizing velocity to 5 to 10 m/s and using smaller sand particles a CFB system is achieved. The sand particles will be carried with the flue gas, separated in a hot cyclone or a U-beam separator, and fed back into the combustion chamber (see Figure 13). The higher turbulence in CFB furnaces leads to a better heat transfer and a very homogeneous temperature distribution in the bed. The disadvantages of CFB furnaces are their larger size and therefore higher price, the even greater dust load in the flue gas leaving the sand particle separator than in the BFB system, the higher loss of bed material in the ash, and the small fuel particle size required (between 0.1 and 40 mm in diameter). This often causes higher investments in fuel pre-treatment. Moreover, their operation at partial load is problematic. CFB furnaces are usually applied in a power range of more than 30 MW_{th} (Source: Hofbauer, 2008).

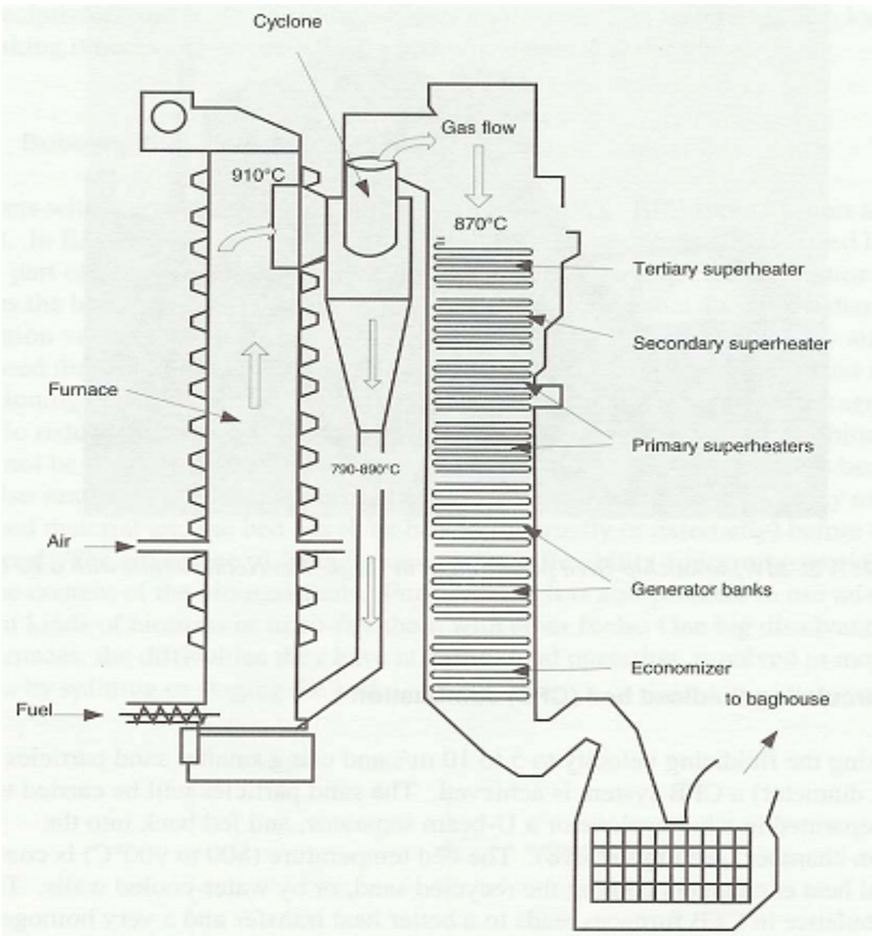


Figure 14: Circulating Fluidized Bed Boiler (Source: Hofbauer, 2008)

For Kingston, a BFB combustion system would be recommendable.

For larger biomass plants, it is recommended to use fluidized bed gasification or electric turbines. For smaller biomass projects, it is recommended to use fixed-bed gasification or Organic Rankine Cycle process or steam engines. Generally speaking, the larger the plant, the lower the electricity production costs (Source:

Hofbauer, 2008).

Biomass Gasification

Gasification is a thermal conversion process for biomass with the aim of producing a gaseous product which can be used in various applications. For this conversion process a gasification agent is necessary which normally contains oxygen (air, O_2, steam, CO_2). Different reactor designs are used for biomass gasification mainly dependent on the application and dependent on different power scales. For the small scale range fixed bed gasifiers are frequently used. For a larger scale, fluidized bed gasifiers can be found in different applications.

Biomass as a renewable but limited energy source has to be used in a very efficient way. This means that besides electricity a high amount of heat should also be used which is generated during electricity production. The way to achieve this is combined heat and power production. The route via gasification allows high electrical efficiency and high total efficiencies at the same time. Electrical efficiencies are possible in the range of 25 – 30 %. Furthermore, heat can be used simultaneously up to an overall efficiency of about 80 % which is an advantage of steam processes in connection with combustion. As a result, numerous developments of this technology are currently under way. All of these have the same basic configuration. The gas is produced with a gasifier, cleaned (tar and particle separation), and fed into a gas engine or gas turbine.

Fixed Bed Gasifiers (small scale)

The gasification of biomass takes place in a gasification chamber where dry biomass is moving from the top to the bottom due to gravity and the ongoing gasification reactions. There are two different options for the flow direction of the gasification agent (usually air). In case of updraft gasifiers the gasification agent in introduced at the bottom and the product gas leaves the gasifier at the top (countercurrent to biomass). If the gasification agent is introduced above the bottom and the producer gas is withdrawn at the bottom a co-current flow is created. This fixed bed gasifier is called also downdraft gasifier.

Fixed bed gasifiers are used for small scale gasification in the range of 0,5 – 5 MWth. Therefore, this type of gasifier is not suitable for a CHP plant with 40 MW fuel input.

Fluidized Bed Gasification (large scale)

Fluidized bed gasifiers use a bed material which can be inert with respect to the gasification reactions (e.g. quartz) or catalytically active (e.g. dolomite, olivine). The gasification agent (air, steam, or oxygen/steam mixtures) is blown into the fluidized bed at the bottom and the producer gas is withdrawn at the top.

The gas velocity distinguishes between bubbling fluidized bed (velocity 1-2 m/s) from circulating fluidized bed gasifier (4-8 m/s) similar to fluidized bed combustion. Typical temperatures for fluidized bed gasifiers are between 850 to 950 °C. Particle size (<5 cm) and water content of the biomass are not as restricted as in the case of fixed bed gasifiers.

As an example, the most successful project for combined heat and power production shall be presented here. This is the Güssing plant built by AE/Repotec in Austria. The plant was erected between September 2000 and October 2001 and went into operation at the beginning of 2002. The plant has a capacity of 8 MW_{th} (fuel) and is able to produce 2 MW_{el} and 4,5 MW heat (Fig. 15).

Wood chips are transported from a daily hopper to a metering bin and fed into the fluidised bed reactor via a rotary valve system and a screw feeder system. The fluidised bed gasifier consists of two zones, a gasification zone and a combustion zone. The gasification zone is fluidised with steam which is generated by waste heat from the process to produce a nitrogen free producer gas. The combustion zone is fluidised with air and delivers the heat for the gasification process via the circulating bed material.

The producer gas is cooled and cleaned by a two stage cleaning system. A water cooled heat exchanger reduces the temperature from 850 –C - 900 °C to about 160 –C - 180 °C. The first stage of the cleaning system is a fabric filter to separate the particles and some of the tar from the producer gas. These particles are returned back into combustion zone of the gasifier. In a second stage the gas is liberated from tar by a scrubber.

Spent scrubber liquid saturated with tar and condensate is vaporized and introduced into the combustion zone of the gasifier. The scrubber is used to reduce the temperature of the clean producer gas to about 40 °C which is necessary for the gas engine. The clean gas is finally fed into a gas engine to produce electricity and heat.

If the gas engine is not in operation the whole amount of producer gas can be burned in a boiler to produce heat. The flue gas of the gas engine is catalytically oxidised to reduce the CO emissions. The heat of the engine´s flue gas is used to produce district heat.

The sensible heat of the flue gas from the combustion zone is used for preheating of the air, superheating the steam and also to deliver heat to the district heating system. A gas filter separates the particles before the flue gas is released via a stack to the environment.

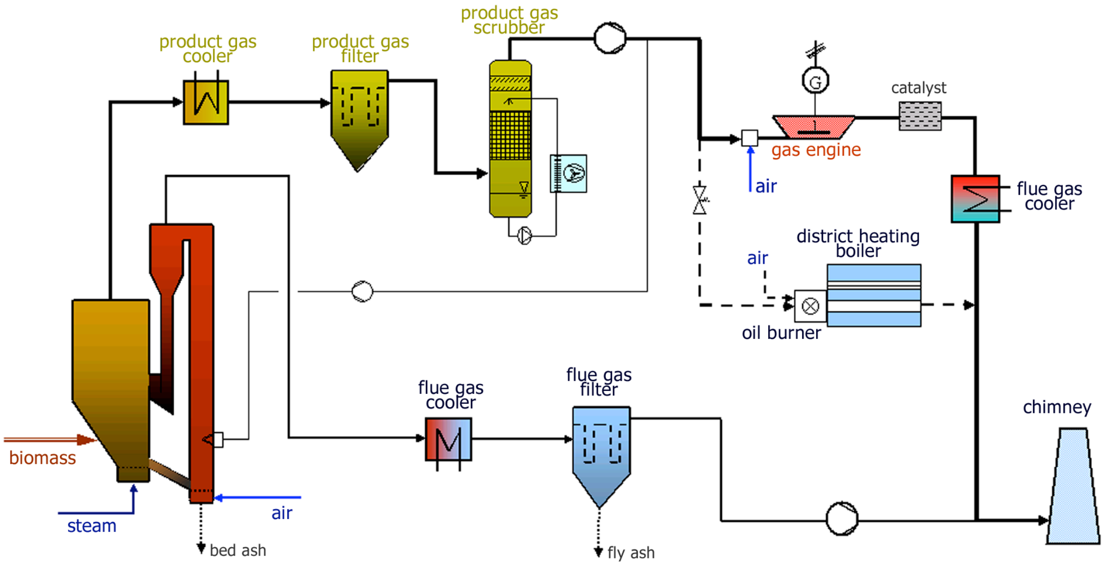


Figure 15: Flow Sheet of the Güssing Combined Heat and Power Plant (Source: Hofbauer, 2008)

Another plant using this technology went into operation in Oberwart, Austria in 2008. The electrical efficiency could be increased above 30 % by integrating an Organic Rankine Cycle (ORC) process in addition to the gas engine converting heat to electrical energy. Wood chips are used as fuel and the capacity of the plant is about 10 MWfuel.

2.3 Solid Biomass Energy for Kingston

The state of the art of thermal conversion of biomass was shortly presented in the previous chapter. Combustion technologies are common on market since many decades whereas for gasification technologies the first demonstration plants are successfully set into operation. Pyrolysis methods are still experimental and not yet commercially viable. Therefore, the proposed system for Kingston would be a combustion based CHP boiler and as alternative a CHP fluidized bed gasification plant.

2.3.1 Combustion Based CHP Boiler

A 40 MW wood chip fired CHP combustion plant with 10 MW_{el} electricity would serve 20,000 households in Kingston. As technology a stationary fluidized bed combustion with steam process is chosen. Steam is produced and used in a back pressure steam turbine. The design data are summarized in Table 12.

Table 12: Design data (combustor)

Fuel capacity	40 MW
Wood chip water content	30 – 35 %
Net calorific value	12 MJ/kg
Wood chip requirement	96,000 tons/yr (as received)
Expected operating time	8000 h for 20 years
Operation case 1	
Electrical output / Thermal output	10 MW_{el} / 0 MW_{th}
Operation case 2	
Electrical output / Thermal output	4 MW_{el} / 30 MW_{th}

Calculations:

Operation case 1: 10 MW_{el} / 0 MW_{th}

Electricity: 10 MW_{el} x 8000 h = 80,000 MWh = 80 GWh
Heat: 0 MW_{th}

1324 GWh – 80 GWh = 1244 GWh

Therefore, an input of 80 GWh of electrical current from green sources into the grid generated from a wood chip CHP plant would reduce some of Kingston's annual demand for fossil electricity of *1324 GWh to 1244 GWh*.

This would also reduce Kingston's production of 297 kt of CO_2 in 2006 (or 297,000 t) by approximately *56,000 tons of CO_2 per year* as compared to coal, leaving it with an annual CO_2 production of 241,000 tons.

As a point of reference for comparative purposes, the Simmering plant in Vienna is 24.5 MWel and saves 144,000 tons of CO_2 compared to an oil-fired plant.

Operation case 2: 4 MW_{el} / 30 MW_{th}

Electricity: 4 MW_{el} x 8000 h = 32,000 MWh = 32 GWh
Heat: 30 MW_{th} x 8000 h = 240 GWh

If district heating lines are installed, or a heat customer next door is created, ie a pellet production plant, the production of 240 GWh of heat from the CHP plant would reduce Kingston's annual demand of 1980 GWh to 1740 GWh based on its annual (2006) demand of 184 million m^3 of natural gas, 12 million l of heating oil and 20.5 million l of propane.

Calculations:

Gas:
184 million m^3 x 10kWh = 1840 M kWh = 1840 GWh

Oil:
12 million l x 11,6 = 139 GWh

Propane:
20.5 million l
20,500 m^3 x 25,8 kWh = 528,900 kWh = 0.53 GWh

Total: 1980 GWh – 240 GWh produced by the plant = 1740 GWh

2.3.2 Fluidized Bed Gasification CHP (Güssing Type)

In this case a dual fluidized bed gasifier coupled with 5 gas engines (2 MW_{el}) is applied. Producer gas is produced and used in 5 gas engines each 2 MW_{el}. The design data are summarized in Table 13.

Table 13: Design data (gasifier)

Fuel capacity	40 MW
Wood chips as received	30 – 35 %
Dry wood chip (drying with waste heat)	20 %
Net calorific value	14 MJ/kg
Wood chip requirement	82,000 tons/yr
Electrical output	10 MW_{el}
Heat output	24 MW_{th}
Expected operating time	8000 h for 20 years

Calculations

Electricity: 10 MW_{el} x 8000 h = 80,000 MWh = 80 GWh
Heat: 24 MW_{th} x 8000 h = 192,000 MWh = 192 GWh

Therefore, an input of 80 GWh of electrical current from green sources into the grid generated from a wood chip gasification CHP plant would reduce some of Kingston's annual demand for fossil electricity of 1324 GWh to *1244 GWh*.

If district heating lines are installed, or a heat customer next door is created, ie a pellet production plant, the production of 192 GWh of heat from the gasification CHP plant would reduce Kingston's annual demand for fossil heat of 1980 GWh to *1788 GWh*.

2.4 Economic Considerations for Solid Biomass Energy in Kingston

Any energy strategy should maximize the possible economic, environmental and social benefits while minimizing the negative economic, environment and social impacts.

A high priority for biomass plants is a very low fuel cost. In Ontario, however, as heating oil and natural gas prices continue to rise, coal is increasingly becoming the most cost-effective commercial heating source on a per GJ basis. This is due to the fact that in Ontario large scale solid biofuels do not currently get a direct provincial or federal incentive. With respect to coal, however, because of the rise in 2008 of the Canadian dollar, more imports of low-cost US coal are reaching heating markets in applications such as greenhouses in Ontario. Further, residential heating oil and natural gas were expected to have a delivered cost of approximately $19.38/GJ and $12.54/GJ, respectively for winter heating in 2007/8, but heating oil surpassed this price due to the spike in 2008 of oil prices to over $80/barrel. Small to medium size commercial natural gas and coal users are expected to pay an estimated $9.73/GJ and $6.88/GJ, respectively for delivered fuel. For large industrial users such as power generators, and cement and steel manufacturers, the price of coal is even lower. For power generation at the utilities in Ontario, its delivered fuel cost is in the range of $1.83 to $3.09 per GJ. (Source: BIOCAP, 2008)

It is clearly not in Ontario or Canada's long term interests from an environmental, health and safety perspective for coal to be the country's most cost-effective commercial heating source on a per GJ basis which draws the market to this source of energy. To increase the use of renewables in Ontario, there would need to be a subsidy for renewables to make them competitive with coal. There is not, however, any existing subsidy for solid biofuels. Resource Efficient Agricultural Production (REAP) of Canada did an analysis in 2008 and drew the conclusion that wood or straw pellets have the potential to replace coal, and that solid biofuels would be able to compete with coal in the current marketplace for the production of industrial heat and power if the government were to provide a subsidy of $4 per gigajoule (Source: BIOCAP, 2008).

Implementing such a measure should be financially viable for Canada as the

Federal government announced in its 2009 Budget that it would invest up to $2.4 billion in new measures to support a cleaner and more sustainable environment, and to help meet Canada's climate change objectives (Source: Department of Finance, 2009).

To calculate what level of direct provincial or federal incentive would be needed for solid biomass to compete with coal, the following factors were considered:

In 2005-6 about 500,000 tons of BC wood pellets were sold to Europe for power generation at a 'freight on Board' price of $6-7/GJ thermal (Source: Swaan, 2009). The feedstock costs would be greater in Ontario than in BC, probably by $30-40/tonne, bringing total cost to $7.50 - $9.00/GJ.

Delivered coal prices in Ontario are typically $3-4 per GJ (thermal), creating a gap of about $4 -5 per GJ. This is why the BIOCAP report recommends a provincial incentive for biomass at $4/GJ.

A ton of oil has a heating value of 9.8 MWh/kg. A ton of wood with 10% water content has a heating value of about 4.6 MWh/kg (16,5 MJ/kg). Fresh cut wood with 50% water content has a heating value of about 2 MWh/kg (7,2 MJ/kg) (see also Fig. 10).

Wood chips are assumed to have a density of 0.25 t per m^3.

Heating oil costs $1,000 per ton
Wood pellets cost $280 per ton.
Wood chips cost $ 0 -100 per ton.

1 ton of oil = 2 tons of wood bone dry (energy equivalent)
1 ton of oil = 2.5 tons of wood with 20% water content (energy equivalent)
1 ton of oil = 4.5 tons of wood with 50% water content (enrgy equivalent)

An estimate of wood prices is broken down as follows:

- $5/ton to the landowner, presuming it is part of a bigger cut with better quality logs giving a higher return (this is important to note)
- $30/ton to get the wood out of the bush and taken to a chipper
- $5/ton for chipping at 45% to 50% moisture content
- $10/ton to dry to 35% moisture content
- $15/ton to truck from Renfrew County to Kingston (less to Port of Prescott, east of Prescott on the Seaway)

Total - $65/(dry)ton. If trucking from sources closer to Kingston, the price might get closer to $50/ton (Source: Lawn, 2009).

Ontario Standard Offer Program

Ontario has a Standard Offer Program for Biomass Energy which offers the following data for the current case:

Standard Offer Price: 11.0 cents/KWh

On-peak rate: additional 3.52 cent/KWh (must be 80%)

Inflation index: 20% of the price increase by CPI

Capital Cost (est): $2,400 - $6,200 per kW_{el} installed

There is no minimum production capacity to participate, however the maximum project size is 10 MW_{el}.

Table 14 shows the existing incentives for small scale electricity production from different renewable alternatives according to the Ontario Standard Offer Program.

Table: 14 Existing Incentives for Small Scale Electrical Power (< 10 MW_{el})

(Source: BIOCAP, 2008)

Renewable Energy Alternative	Incentives ON Standard Offer		Traditional Fossil Fuel Replaced	Net Offset ($KgCO_2e/GJ_{el}$)	Cost to offset one ton ($/ton CO_2e)
	($/kWh)	($/$GJ_{el}$)			
Wind Power	0.055	15.28	Coal	293.31	52.09
Small Biopower	0.055	15.28		270.48	56.56
Solar PV Power	0.365	101.40		271.09	374.03

Therefore, it was estimated that an incentive of about $4/$GJ_{th}$ would be sufficient to make biomass cost-competitive compared to coal. As the government has done with liquid biofuels, Ontario could implement a solid biofuel standard (eg 10%) for coal users in the province.

Given this level of government incentive, possibly coupled to a solid biofuel standard, biomass pellets replacing coal would have a CO_2 abatement cost of about $48.26 per ton CO_2e, about half the cost of bio-diesel and $1/8^{th}$ the cost of CO_2e abatement using corn ethanol. Therefore, solid bio-fuels targeted at replacing coal offer a significant advantage for reducing greenhouse gas emissions.

Table 15 contains a proposal for necessary incentive for solid biofuels to make them competitive.

Table 15: Proposed Incentive for Solid Biofuels
(Source: BIOCAP, 2008)

Renewable Energy Alternative	Proposed Incentive ($\$/GJ_{th}$)	Traditional Fossil Fuel Replaced	Net Offset ($kgCO_2e/GJ_{th}$)	Cost to offset 1 ton of CO_2e ($\$/tonCO_2e$)
Biomass pellets	$4.00	Coal	82.94	48.26
		Oil	77.73	51.50
		LNG	61.79	64.80
		Natural Gas	47.40	84.56

Revenue from a Solid Biomass 40 MW CHP Plant

Capacity installed: 10 MW_{el}

Current price for electricity under Ontario Standard Offer Program:

- base load 11.00 cents/kWh
- peak load 14.52 cents/kWh
- average 12.00 cents/kWh

Tables 16-20 calculate the basic boiler data, capital costs, annual costs and energy revenue stemming from a combustion CHP plant under a scenario of maximum electrical output and no heat production, and combined electrical and heat production.

Table 16: Basic Boiler Data for a Combustion CHP Plant

Expected operation time	8000 hrs/a for 20 years
Wood chip water content	30 - 35%
Wood chip requirement	96,000 ton/yr (as received)
Operation case 1	
Electric output	10 MW_{el}
Heat output	0 MW_{th}
Operation case 2	
Electric output	4 MW_{el}
Heat output	30 MW_{th}

Table 17: Capital Costs for Combustion CHP

CHP plant for 40 MW	$40 million
Chipper plant	$2 million
Pellet plant 100,000 t/yr	$15 million
Total	**$57 million**

Table 18: Energy Revenue from Combustion CHP Operation Case 1

Energy Sales	Feed-in tariff	Amount of Revenue
80,000 MWh_{el} (10 MW_{el})	$0.12/kWh	$9.6 million
Heat (0 MW_{th})	Gas price $30/MWh	$0
Total		**$9.6 million**

Table 19: Energy Revenue from Combustion CHP Operation Case 2

Energy Sales	**Feed-in Tariff**	**Amount of Revenue**
32,000 MWh_{el} (4 MW_{el})	\$0.12/kWh = 120 MWh x 20yrs	\$3.8 million
*100,000 MW_{th} for pellet plant	Gas price \$30/MWh	\$3.0 million
140,000 MW_{th} for other heat user	Gas price \$30/MWh	\$4.2 million
Total		**\$11 million**

* Although the plant could produce 240,000 MW th ,for a total revenue of \$7.2 million, it is only guaranteed to sell the 100,000 MW to the pellet plant but a customer for the remaining 140,000 MW_{th} must be found.

Table 20 : Annual Costs for Combustion CHP Plant

Interest on capital loan @ 4% of \$40 mill	\$1.6 million/yr
Chipper plant	\$0.1 million/yr
Wood storage	none required if chipped at plant
96,000 ton of wood chips @ \$60/t	\$5.76 million/yr
Land rental	\$0.01 million/yr
Operating costs	\$0.01 million/yr
Inspection costs	\$0.01 million/yr
Total	**\$7.57 million/yr**

Therefore it can be seen that after annual costs of \$7.57 million/yr, this combustion CHP plant would realize an annual profit of approximately \$2 million in Case 1 and \$3.4 million in Case 2. Therefore, this project is economically feasible!

The profitability would increase greatly if the BIOCAP report recommended subsidy *of $4.00/GJ* were to be implemented.

A gasification plant (Tables 21-24) could be an alternative scenario, as in this case 10 MW_{el} electricity and 24 MW_{th} heat at the same time is possible (overall efficiency 80 %).

Table 21: Basic Data for Gasification CHP Plant

Expected operation time	8000 hrs/a for 20 years
Wood chip water content	20 %
Wood chip requirement	82,000 ton/yr (as received)
Electric output	10 MW_{el}
Heat output	24 MW_{th}

Table 22: Capital Costs for Gasification CHP Plant

CHP gasification plant for 40 MW	$45 million
Chipper plant	$2 million
Pellet plant 100,000 t/yr	$15 million
Total	**$62 million**

Table 23: Annual Costs for Gasification CHP Plant

Interest on capital loan @ 4% of $45 mill	$1.8 million
Chipper plant	$0.1 million
Wood storage	None if chipped at plant
82,000 ton/yr of wood chips	$4.9 million
Land rental	$0.01 million
Operating costs	$0.01 million
Inspection costs	$0.01 million
Total	**$6.8 million**

Table 24: Annual Revenues from Gasification CHP Plant

Energy Sales	**Feed-in Tariff**	**Amount**
80,000 MWh_{el} (10 MW_{el})	$0.12/kWh	$9.6 million
24 MW_{th}	Gas price $30/MWh	$5.8 million
Total		**$15.4 million**

(Calculation: 24 MW_{th} x 8000 h = 192,000 MWh x $30/MWh = $5.8 million)

This scenario assumes that there will be a customer for the full amount of heat produced, beyond the 100,000 MW $_{th}$ required by the pellet plant.

Therefore, it can be seen that after annual costs of $6.8 million, the annual profit would be $ 8.6 million. This project is economically feasible! The technology is currently under demonstration and the first three commercial plants are already sold abroad and under construction.

3. Biological Conversion of Biomass and SNG Production

3.1 Technology Framework for Biogas/SNG in Ontario/Kingston

Kingston could invest in the production of biogas plants and engines to produce electricity, heat and in biogas for the natural gas grid, utilizing biomass from waste sources of the local agricultural and restaurant industry.

Food-based inputs for biogas systems include food processing by-products, off-specification or out-of-date food products, 'plate food waste' (from homes, institutions, restaurants), and other similar materials. None of these remove crops from the food chain. Based on a number of methodologies used in the study for assessing availability of food-based inputs, there are between 1.2 and 9.8 million wet tons per year of suitable food-based inputs that are produced in Ontario. The study estimates that roughly 50% of this material could be available for use in biogas systems.

The consistency of the supply of materials, reliability of biogas systems as a destination, cost of transportation of materials, and avoided costs normally associated with materials are key factors affecting a company's decision-making process about where to send materials. Wastewater and wet residues may readily find their way into biogas systems, while dry residues may have a number of other competitive end uses.

Materials such as fruit and vegetable processing by-products that are only available during harvest season may not be suitable as the primary or sole input for biogas systems because of the resulting biogas system downtime (when those inputs are not available). Residues and waste are typically managed in a "least-cost" fashion, meaning that if biogas systems represent an economical and low-effort management solution, they can be a desirable destination for these types of materials. The study shows that the bulk of estimated energy available from food and beverage processing materials is from the meat processing, rendering, and grains and oilseeds sectors. Post-consumer plate food wastes also account for a significant share of the estimate of overall energy potential.

If the estimated 50% of available food-based inputs in Ontario are used in biogas systems, the study predicts the following energy production potential: Electrical production in a conventional 30% efficient co-generation unit would produce from 53 to 697 GWh/yr of electrical production. This is equivalent to 6.1 to 80 MW of continuous electrical capacity, or 27 to 350 MW of peak power production.

Using the 2008 Renewable Energy Standard Offer Program electricity value of 11¢/kWh, the Biogas Study for Ontario estimates that electrical production could result in between \$5.8 million to \$77 million in electricity sales per year. If the biogas produced was converted to natural gas, between 0.64 to 8.4 million GJ/yr of energy could be captured. Using a conservative estimate for the value of natural gas (\$7/GJ) the total value of natural gas replacement from the biogas would be between \$4.5 million to \$59 million per year.

Other materials besides by-products from food and beverages could also be used in biogas systems, such as manure and energy crops. A reasonable estimate developed by OMAFRA predicts that 33,000 tons/day of manure could be directed to biogas systems under good circumstances, producing approximately 54 MW of continuous electrical power. Thus, the estimates of total energy from manure and from food-based inputs available in Ontario are of approximately the same magnitude. With respect to energy crops, when the economics of using energy crops like corn silage became viable in Germany, total biogas production quickly doubled from the baseline biogas production level (Source: Final Report for the Study of Food-Based Inputs for Biogas Systems in Ontario, 2008).

Energy crops such as corn silage can also be used in the digester. European numbers indicate that almost 16,000 kWh of electricity (plus equal heat) can be produced from corn silage produced from 1 ha (yield of 45 wet tonnes). Since there are additional costs related to growing and harvesting energy crops, one must conduct a detailed economic analysis to ensure the process is economically viable before building a biogas system. Producers must ensure the material does not contain components that may inhibit the biological process or eventually cause the process to stop. For example, antibiotics or high levels of nitrogen in the material may inhibit the biological process. Sand in the material will also affect the capacity of the digester when it settles to the bottom (Source: OMAFRA, 2008).

The study indicates that tipping fees for receiving food-based inputs can provide additional revenue for biogas system operators. Using general approximations, the study estimates that approximately $233 million per year in tipping fees could be collected at biogas systems.

Alternatively, if competition for inputs drives down tipping fees, sending materials to biogas systems could represent a savings to the food and beverage processing sector of an equivalent amount (i.e. approximately $233 million). While tipping fees will usually be associated with the materials received at biogas facilities, in some cases, high-quality inputs might be purchased for use as inputs at biogas systems. This already occurs with some high-quality materials in Ontario.

Figure 16 shows a basic flow sheet for a biogas plant with the feedstocks and the valuable products. Besides the products (biogas, fertilizer) also the GHG reduction is an important benefit from this technology.

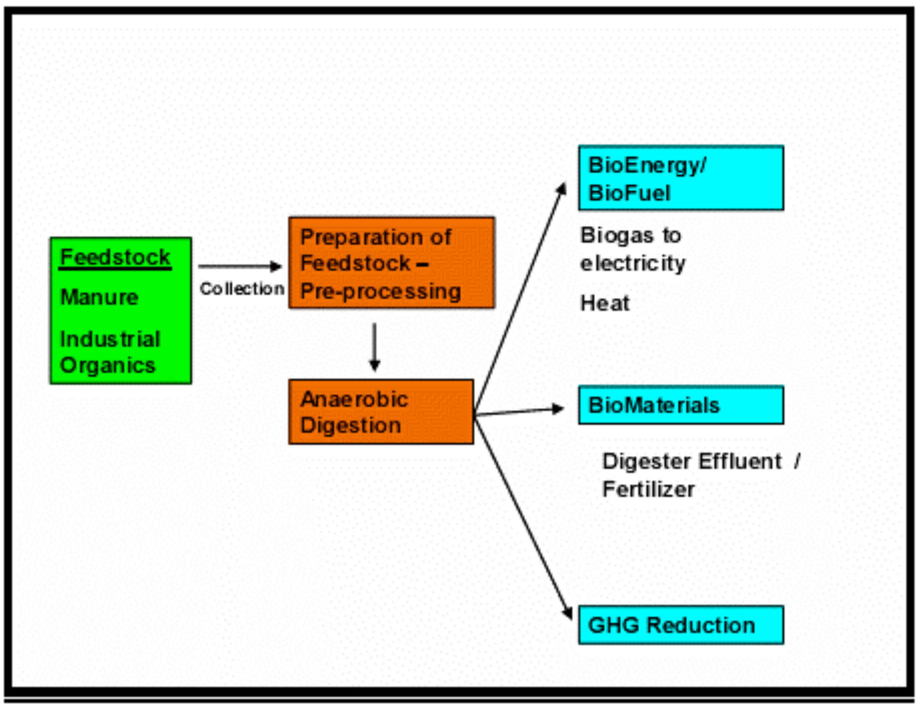


Figure 16: Understanding Commercial Opportunities in the Biogas Sector in Canada (Source: Goodfellow Agricola Consultants Inc, 2006)

Another opportunity besides electricity and heat production is the upgrade of biogas to natural gas quality and feed into existing gas networks. Hydro One Networks indicates that they are committed to working with all generation proponents to ensure assessments of their proposals and integration of projects into the existing gas distribution system are done in a timely, consistent and fair manner.

This implies plenty of feedstock available to feed a biogas engine from animal husbandry (manure) and crop waste (organic remains). It would not be difficult for these farmers to supply 10,000 tons of organic material annually to a biogas engine.

3.2 Technological Principles of Biogas Generation and SNG Production

In previous sections of this thesis it has been demonstrated that Kingston could increase its renewable energy mix through solid biomass. A wood-fired cogeneration combustion system could produce electricity and heat profitably and provide electricity to 20,000 homes in Kingston while providing process heat to commercial facilities with a heat requirement.

It would be possible for Kingston to additionally make use of the waste organic materials coming from its agriculture and restaurant industries to further increase its renewable energy mix. Biogas can be used to produce electricity, heat and biogas for the natural gas grid or biofuel for vehicles.

3.2.1 Biogas Production by Anaerobic Fermentation

Biogas systems use anaerobic digestion to produce primarily methane. Methane can be used in a boiler to produce heat or in an engine connected to a generator to produce electricity. As explained already above, anaerobic digestion treats manure and other organic materials such as agricultural residues, food-based organic materials and energy crops to produce biogas and reduce pathogens and odours. The Canadian Nutrient Management Act has been amended to facilitate the use of off-farm organic materials in biogas systems. Biogas systems can produce clean, renewable energy that reduces greenhouse gas emissions. Biogas systems produce a new revenue stream for farm and food processing operations. Co-digestion of animal manure and other types of suitable organic waste in biogas plants is an integrated process with the following benefits:

1) Savings for farmers
2) Improved fertilization efficiency
3) Less greenhouse gas emissions
4) Cheap and environmentally sound waste recycling
5) Reduced nuisance from odours and flies
6) Possibilities of pathogen reduction through sanitation connected to renewable energy production.

Biogas primarily contains methane (50%-70%), carbon dioxide (30%-50%) and water vapour and also some minor parts of sulphur (e.g. H_2S) and nitrogen (e.g. NH_3) compounds. Natural gas contains over 99% methane, meaning biogas is essentially diluted natural gas. Biogas produces electricity when used as a fuel in an engine that drives a generator. Often in agricultural systems, a standard diesel or spark engine is modified to burn the biogas to turn a generator to produce electricity. Between 25% and 40% of the energy in the biogas is converted to electricity. The remaining available energy is converted to heat that is used to heat the materials in the anaerobic digester and for other purposes, such as heating a home, shop or greenhouse. Most biogas plants produce surplus heat. There is potential to improve the economics and efficiency by using this heat to replace conventional heat sources.

A digester requires volatile organic material to produce biogas. Historically, manure has been the primary source of material that is digested. Manure can be provided daily and contains material readily broken down by anaerobic bacteria. Farm-based materials, including straw (used in bedding), waste feed, grain cleanings and horticultural by-products, can also be digested. In addition to farm-based materials, it has been shown recently that other food or plant-based materials can be digested successfully. Laboratory tests can determine the biogas production potential of different materials.

In Figure 17 a typical process sequence of biogas production can be seen.

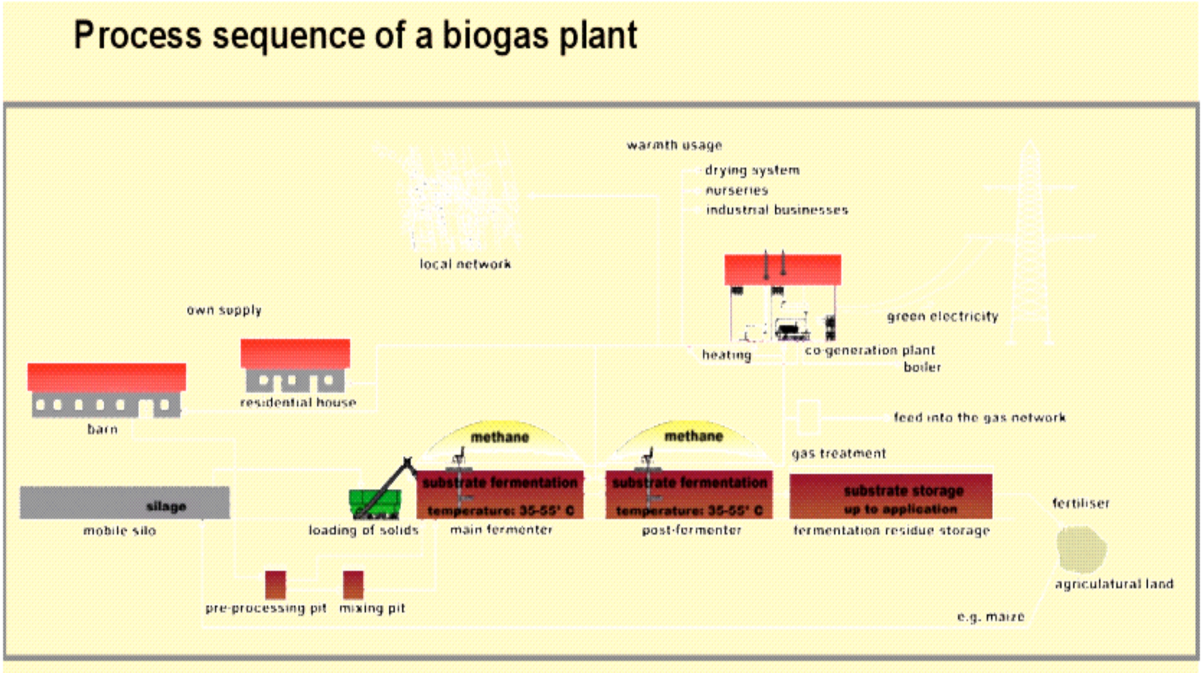


Figure 17: Process Sequence of a Biogas Plant (Source: Richard Agrinz, 2008)

3.2.2 Biogas Upgrading for Feed into the Natural Gas Grid

In order to upgrade biogas to a purity level that allows it to be used in the natural gas grid, it needs to be cleaned. As biogas has a methane content of between 50 – 70% and a CO_2 content of 30-50%, it needs to be cleaned using an upgrading device to reach a methane content of > 97%.
For CO_2 separation different technologies are used e.g. absorption and membrane processes. Such processes are currently under demonstration (Source: Harasek, 2009).

3.2.3 SNG-Production via Syngas

Wood biomass could also be used to produce biogas (methane) that can be upgraded to the point of being suitable for injection into the natural gas grid system or for use as a fuel for vehicles. This is done using a thermochemical conversion technology which gasifies the wood at high temperatures to produce synthetic natural gas (SNG).

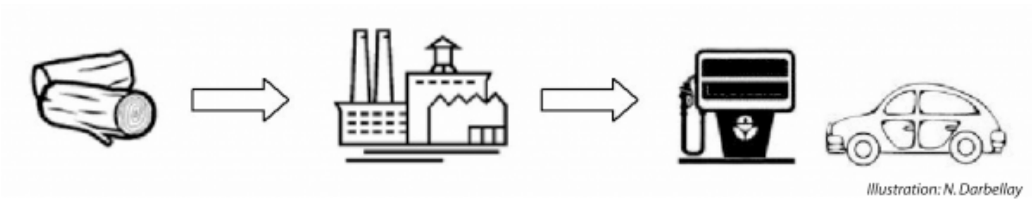


Figure 18: BioSNG Production and Use for Transportation

The advantage of this using this conversion technology is that there are adequate and reliable supplies of wood feedstock available to the City of Kingston, as discussed earlier. The process itself is energy efficient (efficiency about 65 %).

The thermochemical process of converting wood to SNG consists of wood gasification (endothermic), followed by methane synthesis (exothermic) and then gas purification. Representing wood as a typical molecule and using the carbon atom as reference, the overall conversion is exothermic and can be expressed as:

$CH_{1.35}O_{0.63} + 0.3475\ H_2O \rightarrow 0.51125\ CH_4 + 0.48875\ CO_2 \qquad DH^0 = -10.5 kJ/(mol_{wood})$

The process steps are shown in Fig. 19. The recommendable feedstock is wood chips. Due to the high moisture content in wood chips, a drying stage prior to gasification is necessary. Secondly, the gas produced through gasification needs to be cleaned from impurities to prevent catalyst damage during methane synthesis. As the calorific value of the obtained gas is low, an upgrading consisting of CO_2 removal and SNG compression prior to injection into the national gas grid, which is operating at around 50 bar, is necessary to meet the condition of a Wobbe index between 13.3 and 15.7 kWh/Nm^3.

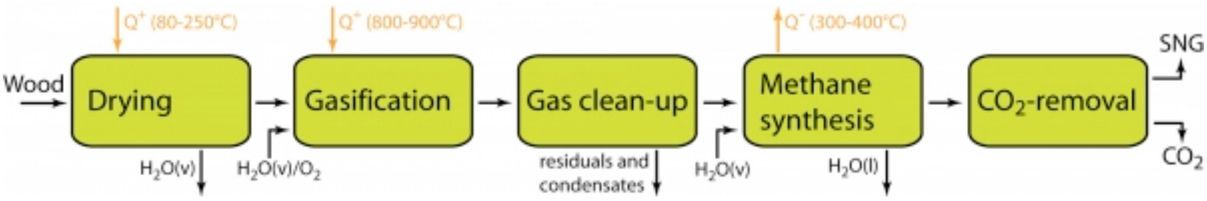


Figure 19: Process Steps for BioSNG Production (Source: LENI, 2004)

The thermochemical conversion technology for wood is currently under demonstration in Austria, however, and rather complex as compared to the fermentation process of converting biological biomass to biogas (methane) via fermentation using an anaerobic digester. This fermentation technology is mature and reliable. The usual feedstock is organic waste from the agricultural or waste food processes. For this reason, this paper will focus on the potential for Kingston of using biogas from biological sources to produce electricity, heat and fuel, although it would be possible in future for Kingston to also consider more closely the options for suing woody biomass.

3.3 Example of a Farm Community Biogas Project - Margarethen am Moos, Austria - A Model for Electricity, Thermal Heat, and Gas for Cars.

There are one hundred bio-gas plants with a total output of 30 MW_{el} operating in the province of Lower Austria. Lower Austria has a population of 1.5 million people.

The guaranteed feed-in-tariff for a plant of 500 kW_{el} electric power is € 0.145 ($ CAD 0.22) over 13 years. Currently 24 farmers cooperate in this biogas project at Margarethen am Moos. Official support for this project was provided by the Lower Austrian Investment Fund "Agrar Plus".

The plant operates on the liquid fermentation process without oxygen at 38-55°C and uses all biogenic materials except wood (due to lignin). It produces approximately half methane and half CO_2. The material left after the process is used as fertilizer.

One ton of dry matter produces approximately 1 MWh of electricity and 1 MWh of heat. The annual intake in the St. Margarethen plant is 10,000 tons of wet grass, maize, rye, agricultural waste. The dry matter is 40%.

The electric output is 4,000 MWh/a (0.5 MW x 8000 hrs), good for approximately 1,000 households. The plant will be upgraded to produce 620 kW_{el} electricity.

The thermal output is 4,000 MWh/a (almost 1,000 MWh are used for the process) good for approximately 200 households. 3 km of district heating pipes had to be placed.

Table 25: Overview of the Investment Costs of the Biogas Plant in Magarethen

Concrete, asphalt	€ 250,000
silo	€ 250,000
Mixers, pumps	€ 170,000
Electric control system	€ 300,000
Gas engine	€ 320,000
Piping	€ 80,000
Engine operating house	€ 150,000
Gas storage	€ 200,000
Other expenses	€ 280,000
Total	**€ 2 million**

Considering all costs it is profitable to use bio-methane in Austria!

Biogas can be used untreated in gas engines to produce electricity and heat and it is calculated at € 0.3/m³ to be able to compete with other energy suppliers. For automotive use it still has to be cleaned. The methane gas station for cars, which started operations in late 2007, has a capacity of 25 kg/hr (34 std m³) or 150 000 kg/yr. This provides fuel for 200 cars, each 15,000 km/yr. If one were to upgrade the biogas as was done in Maragethen am Moos, there would be the extra cost:

For biogas upgrading to natural gas grid using membrane technology the following additional investment costs have to be taken into account:

Gas cleaning & compressing	€ 280,000
Petrol station	€ 150,000
Total costs	**€ 430,000**

When extracting CO_2 from bio-gas to obtain 96% of methane only half the quantity is left and therefore the price will be EUR 0.6/m³ plus processing costs (CH_4 has a weight of 0.7kg/m³). Methane gas is selling for € 0.89/kg, petrol with 95 octane sells for €0.9/litre, three months ago (end of 2008) the price climbed up to €1.30/litre. 1 kg gas equals approximately 1.5 litre petrol. There is no tax burden imposed on biogas.

Austrian producers of biogas systems are among the world's leading manufacturers of gas engines and generator sets which can burn not only on natural gas, but also a variety of biogases and special gases from agriculture, industry and waste treatment.

Figure 20 shows the biogas plant in Magarethen am Moos together with the key data. The substrate is corn silage, grass, and liquid manure and amounts 9,980 t/a. From these inputs 3,7 million kWh of electrical current per year is fed into the public grid of the utility EVN. Year round heating for households in Margarethen am Moos via district heating grid. With this plant a reduction of 2,200 t/yr of CO_2 through substitution of heating oil can be obtained.

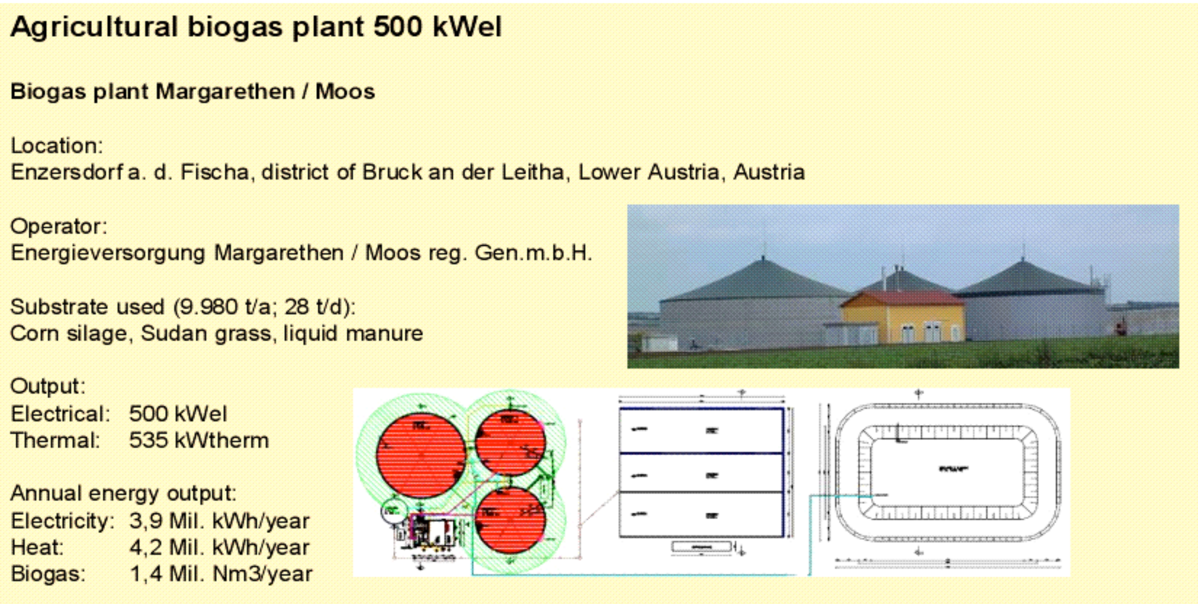


Figure 20: Agricultural Biogas Plant 500 kW_{el}
(Source: Margarethen am Moos, 2008)

3.4 Biogas Generation Potential for Kingston

Canada is the world’s second largest country by landmass, with an enormous agricultural infrastructure. This makes Canada the world’s 4th largest agri-food exporter. Ontario is Canada's second largest province in size. The biogas industry has the potential to thrive in Ontario because the agricultural and food and beverage processing sectors could create substantial amounts of biogas from waste.

Approximately 180,000 Ontarians live on farms. Biogas can be derived from a wide variety of crops, manure from livestock operations, residuals from the food industry like cereal husks, and leftovers and 'spoils' from the beverage and bakery industry.

The food and beverage processing sector in Ontario is a $32.5 billion industry, providing the link between agricultural commodities and the food consumer. As in any industrial sector, the production of food and beverage products results in a number of residuals, by-products and wastes. A study commissioned in 2008 by the Ontario Ministry of Agriculture, Food and Rural Affairs determined that using food-based inputs in biogas systems can provide new options for waste management for the food and beverage processing sector, while also contributing to Ontario’s renewable energy generation objectives.

There is adequate organic biomass feedstock for the provision of 40,000 tons to a biogas engine in the City of Kingston. Waste from livestock, produce farming and food waste stemming from the restaurants in Kingston would deliver the required organic matter.

There are 200 farms that are currently active within the City of Kingston, having an average size of 218 acres per farm for a total of 43,600 acres of farmed land within the City. Year 2001 statistics showed that the most significant product is corn, having a total of 1,148 acres, and hay, having 9,191 acres. Vegetable farming covered on average 36 acres of land in Kingston in 2001, and besides some small scale fruit tree farming, the rest was used for beef and poultry farming. (Source: City of Kingston Agricultural Study Report, 2007).

This thesis assumes that manure and organic waste would be available from at least one half of the 200 farms and would produce the required tonnage. Accordingly, 2 MW_{el} electricity and 2 MW_{th} heat shall be produced. This means that the plant has 4 times the capacity of Magarethen am Moos, the biogas project in Austria discussed in section 3.3. The electricity and heat will be produced with 4 gas engines with 0,5 MW_{el} each. Table 26 gives the technical data for the biogas based CHP plant in Kingston.

Table 26: Technical Parameters for 2 MW_{el} Biogas CHP Plant in Kingston

Substrate used (agricultural waste, manure)	16 million to (dry substance)/yr
Dry matter moisture of substrate	40%
Wet substrate used	40 million to (wet)/yr
Electricity produced	16 million kWh/yr
Heat produced	16 million kWh/yr

Therefore, a further input of *16 GWh/yr* of electric current into the grid from biogas would further reduce Kingston's annual demand for electricity from fossil fuel of 1244 GWh (calculated after installation of the CHP plant) to *1224 GWh.*

3.5 Economic Considerations for Biogas Energy in Kingston

Many factors affect the viability of a farm-based or food processing-based anaerobic digestion system. These factors include the system's capital and operating costs, the value of the Renewable Energy Standard Offer Program and the rate of efficiency with which the system converts biogas to a usable form such as electricity.

Ontario offers a fixed price for biogas of *11 Canadian cents per kWh for a fixed period of 20 years*. The Ontario Renewable Energy Standard Offer Program (RESOP) will provide some incentive to farmers and others to consider when developing biogas systems. It will give generators of electrical power meeting the criteria for renewable energy a price of *11cents/kWh* for the electricity put on the Ontario grid. This price is available for wind, biomass (including biogas) and small hydro developments. There is no minimum production capacity to participate, however the maximum project size is 10 MW_{el}.

There is an additional rate of 3.52/kWh for power produced during peak times. The peak power price boost is only available to generators able to reliably generate during 80% of peak hours. *Most biogas systems achieve this requirement.*

Designing a system to operate only some of the time (e.g. during peak hours) adds additional costs due to the increased size of generator system and associated line connection, the cost of additional biogas storage, and the requirement to use engine or biogas treatment systems that function properly with daily shutdowns. Within this zone, the OPA will only issue RESOP contracts to the following types of new projects: Micro projects that have a capacity of ≤10 kW and farm-based bio-energy projects that have a capacity of ≤250 kW. The aggregate capacity of all the RESOP projects in the zone cannot exceed 10,000 kW (10 MW).

A farm-based bio-energy project is defined in the RESOP as a project that forms part of an Ontario-situated farming business (as defined in the Farm Registration and Farm Organization Funding Act, 1993 (Ontario)) operated by the applicant or a person not at arm's length to the applicant, that generates electricity from renewable biomass, biogas or bio-fuel.

A 250-kW_{el} farm-based project running 8,000 hr per year would require manure from

3,000 head of beef feeder cattle if manure were the sole input. If energy crops were the sole input, approximately 125 ha of corn silage would be required to feed this size digester. Connections with these pipelines permit gas to enter the Ontario, Quebec, New England and New York markets (Source: Canadian Energy Research Institute, 2009).

The Ontario Ministry of Agriculture, Food and Rural Affairs has a program to support biogas development called the Ontario Biogas Systems Financial Assistance Program (OBSFAP). The OBSFAP is an $11.2-million investment that helps farmers and agri-food businesses develop and build generating systems that produce clean energy, reduce electricity costs and contribute to local economies. There are two phases to the program:

- Phase 1 funding will cover up to 70 per cent of the eligible costs of carrying out a feasibility study, to a maximum of $35,000.

- Phase 2 funding will cover up *to 40%* of eligible construction and implementation costs. The maximum total feasibility and construction cost funding is *$400,000* for each anaerobic digester system, as outlined in Table 27.

Table 27: Ontario Provincial Incentives

Incentive RESOP	Rate	Value
Construction and implementation cost support	40% of capital cost (up to $400,000)	$400,000
Feed in tariff x 20 yrs	12 cent/kWh (11 cent non-peak/14.52 peak)	$1.5 million/yr

Table 28 shows the capital costs for the construction of a 2 MW_{el} biogas plant.

Table 28: Investment Costs for 2 MW_{el} Biogas Plant

Building for gas engine and control room	$281,250
Concrete, asphalt	$468,750
Silo	$468,750
Mixers, pumps	$318,750
Electric control system	$562,500
Gas engine	$600,000
Piping	$150,000
Gas storage	$375,000
Other expenses	$525,000
Total	**$3.75 million (- $400,000 Ont incentive)** **=$3.35 million**

Table 29 shows the revenue stemming from the sale of energy in this 2 MW_{el} plant

Table 29: Revenues for 2 MW_{el} plant

Energy Sales	**Rate**	**Revenue**
Electricity 16 million kWh/yr	$0.12/kWh	$1.92 million
Heat 16 million kWh/yr	$30/MWh	$480,000
Total		**$2.4 million**

Table 30 shows the profit from the 2 MW el plant after costs.

Table 30: Annual Profits for 2 MW_{el} Plant

Servicing capital loan @ 4% of $3.4 mill	-$136,000
Revenue from biogas	$2.4 million
Profit	**$2.3 million**

Therefore, this project is economically viable and realizes an annual profit of $2.3 million!

4. Results

Electricity consumption in Kingston in 2006 was 1324 GWh and GHG emissions were 297,000 t of CO_2. By installing a 40 MW wood-chip fired CHP biomass plant (10 MW_{el}) or a 40 MW wood-chip fired CHP gasification plant, together with a 2 MW_{el} biogas plant with gas engine, the City of Kingston could generate up to 12 MW_{el} of green electricity. This would be enough to power half the homes in Kingston, given that it would produce enough electricity for 24,000 households and the average number of homes (based on a family size of 2.5 people per household) would be 46,800. Further, the wood chip CHP and biogas plants together would realize for Kingston an annual profit of up to $ 10.9 million and reduce its CO_2 emissions by 68,000 tons per year. As Kingston's goal is to reduce its annual GHG emissions by 10% below 2000 levels by 2014, and it's GHG emissions were 1.4 tons of CO_2 in 2000, these 2 biomass projects alone would allow Kingston to come half way towards meeting its target.

Table 31: Summary of Proposed Technologies: Energy, Emissions and Profit

Technology proposed	Electricity (# homes)	Heat (# homes)	GHG reduced (tons CO_2)	Profit (million CAD $)
Combustion CHP 10MW_{el}/0 $_{th}$	20,000	0	56,000	2.0
Combustion CHP 4MW_{el}/30 MW_{th}	8,000	12,000	22,400	3.4
Gasification CHP 10MW_{el}/24 MW_{th}	20,000	9,6000	56,000	8.6
Biogas plant 2MW_{el}/2MW_{th}	4,000	800	11,200	2.3

Case 1

The production of *80 GWh* of electricity generated from a 10 MW_{el}/ 0 MW_{th} wood chip combustion CHP plant would reduce some of Kingston's annual demand for fossil electricity of 1324 GWh to *1244 GWh.* This would also reduce Kingston's annual (2006) production of 297 kt of CO_2 by approximately *56,000 tons of CO_2 per year as compared to coal, leaving it with an annual CO_2 production of 241,000 tons. This would provide renewable electricity for 20,000 households. The annual profit under this scenario would be $2 million.*

Case 2

The production of *32 GWh* of electricity generated from a 4 MW_{el}/30 MW_{th} CHP combustion plant would reduce some of Kingston's annual demand for fossil electricity of 1324 GWh to *1292 GWh*. This would also reduce Kingston's annual (2006) production of 297 kt of CO_2 by *22,400 tons of CO_2 per year*. The production of *240 GWh* of heat from the CHP plant would reduce Kingston's annual fossil heat demand of 1980 GWh to *1740 GWh* (based on its annual 2006 demand of 184 million m^3 of natural gas, 12 million l of heating oil and 20.5 million l of propane). *This would provide renewable electricity for 8000 households and renewable heat for 12,000 households. The annual profit under this scenario would be $3.4 million.*

Case 3

The production of *80 GWh* of electricity generated from a 10 MW_{el}/24 MW_{th} wood chip gasification CHP plant would reduce some of Kingston's annual demand for fossil electricity of 1324 GWh to *1244 GWh.* This would also reduce Kingston's annual (2006) production of 297 kt of CO_2 by approximately *56,000 tons of CO_2 per year* as compared to coal, leaving it with *an annual CO_2 production of 241,000 tons*. The production of *192 GWh* of renewable heat from the CHP plant would reduce Kingston's annual fossil heat demand of 1980 GWh to *1788 GWh. This would provide renewable electricity for 20,000 households and renewable heat for 9,600 households. The annual profit under this scenario would be $ 8.6 million.*

Case 4

The production of *16 GWh* of electricity generated from a 2 MW_{el}/2 MW_{th} biogas plant would reduce some of Kingston's annual demand for fossil electricity of 1324 GWh to *1308 GWh.* This would also reduce Kingston's annual (2006) production of 297 kt of CO_2 by approximately *11,200 tons of CO_2 per year* as compared to coal, leaving it with *an annual CO_2 production of 285,800 tons*. The production of *16 GWh* of heat from the biogas CHP plant would reduce Kingston's annual fossil heat demand of 1980 GWh to *1964 GWh. This would provide renewable electricity for 4000 households and renewable heat for 800 households. The annual profit under* *this scenario would be $ 2.3 million.*

Cases 2, 3 and 4 assume that there will be a customer in Kingston for the additional heat produced beyond the requirement of 100,000 MW $_{th}$ needed to run the pellet plant. Under this scenario Kingston would also produce pellets from its new pellet production facility to service the demand of the residents of Kingston if they decided to switch to pellet home heating systems and thereby further reduce GHG emissions. If the province of Ontario was to follow the BIOCAP report recommendations to offer a 4.00 /$GJ_{th,}$ subsidy for biomass, it would be very cost competitive compared to coal.

If the government of Ontario participates in a future North American cap and trade program that imposes an indirect carbon tax on carbon emissions from coal, production of power, heat and fuel from biomass will be in all likelihood cheaper than coal.

The Obama Administration has announced plans to create such a scheme in the USA, capping some 80% of energy use in the USA. This is likely to result in an emissions trading scheme similar to the European Emissions Trading System (EU-ETS). The four Canadian provinces of Ontario, Quebec, Manitoba and BC are part of the California-led "Western Climate Initiative" which has also been gearing up for an emissions cap and trade system. If this system were to be adopted by Ontario, then several thousands of dollars in additional revenue could be generated with each renewable energy project that offsets CO_2, and the price of renewable energy options might become more competitive relative to high carbon emitting fossil fuel options.

Ontario announced in March 2009 plans for a proposed Green Energy Act. If it passes, it will offer a feed-in tariff of 12.2 cents/kWh for biomass projects (of any size) and 14.7 cents/kWh for biogas projects <5 MW. (Source: OPA, 2009) As this thesis has calculated revenues for the biomass and biogas projects at 12 cents/kWh, it can be seen that these energy projects could be significantly more profitable in the future under the new regulatory environment.

5. Conclusions

1. The production of power and heat from biomass, both woody biomass and biogas in Kingston is technical viable, economically profitable from the very first year and is compatible with Kingston's social and regulatory environment.

2. For maximum electricity production and maximum annual profit, Kingston should construct a 40 MW CHP gasification plant (10MW_{el}/24 MW_{th}), a wood pellet production facility nearby utilizing the produced heat from the gasification plant, and a 2 MW biogas plant.

3. Under this scenario, Kingston could provide "green" power to 50% of the homes in Kingston, substitute 21% of its non RE power (excluding nuclear) with RE, reduce its GHGs by just over 22%, and move 50% towards its goal of reducing 10% of its GHG emissions from 2000 levels by 2014.

4. In addition, Kingston could produce enough heat to meet the heat demand of 10,400 homes, or up to 12,800 homes if it used the technology of a 40 MW CHP (4 MW_{el}/30 $MW_{th)}$ combustion plant.

5. The annual profit that Kingston would realize from the CHP gasification, pellet, and biogas plants would be $10.9 million, or higher with the proposed "Green Plan" tariffs.

5. The feedstock needed for the 40 MW CHP plant and the 2 MW biogas plant would help the city use its existing natural resources and rely less on imported fossil fuels. The biogas plant would provide a solution for the disposal of farm and agricultural waste, capture fugitive emissions of methane, and realize an annual profit of $2.3 million. The wood requirement for the CHP gasification plant would provide a source of revenue for wood lot owners in the 1.5 million hectares of EOMF forest.

6. Ontario should implement a provincial government subsidy of $4.00 /$GJ_{th}$ for biomass to make it cost competitive with coal. Delivered coal prices in Ontario are $3-4 per GJ (thermal), creating a gap of about $4 -5 per GJ compared to biomass.

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