FINAL REPORT

Bio-energy Opportunities for New Brunswick Communities and Woodlot Owners

Three Case Studies Examining Potential Opportunities for Biomass Usage

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Foreward

The Bio-energy Opportunities for New Brunswick Communities and Woodlot Owners project was a combined effort of Stantec Consulting and AGFOR Inc. The case study report detailed herein by Stantec is intended to accompany the *Regional Biomass Profiles Report* prepared by AGFOR. AGFOR's report provides details on the feedstock consumed in these case studies.

Executive Summary

The New Brunswick Federation of Woodlot Owners (NBFWO), in collaboration with Fundy Model Forest Network, the New Brunswick Department of Energy, as well as other groups represented on a steering committee, desired an independent analysis on the feasibility of small-scale thermal and combined heat and power plants (CHP) for the production of energy utilizing biomass as a feedstock. The study is centered on three case studies representing the three opportunities the steering committee felt may be viable and wished to pursue. As such, three high level scoping studies were carried out on the following cases:

- Use a sawmill as a site of a new condensing turbine power plant installation with a steam extraction to serve the mill process steam requirements.
- Locate a district heating facility near an industrial park and other potential institutional buildings (hospital and schools) to determine the feasibility of heating multiple buildings from a central location.
- Examine the seasonal heating of a single commercial building using a new biomass boiler, including converting the existing heating infrastructure as required.

Each case was initially examined to assess the potential size of the boiler installations. The condensing turbine at the sawmill was sized to suit the existing mill steam requirements and maximize the electrical generation, according to the current NB Power Embedded Generation program limit of 3 MW. The district heating and seasonal commercial building heating cases were sized to service the heat loads as required. It was determined that the selected district heating system could be serviced by a 400 boiler horsepower (3,924 kW_{th}) biomass boiler, similar in design to the sawmill case. The seasonal heating boiler could vary between 200 and 400 kW_{th} depending on which of the buildings included in the assessment were considered.

For the purposes of this screening study, information obtained from AGFOR on biomass sourcing and pricing, along with design data from Stantec was entered into the RETScreen Clean Energy Project Analysis Software. This software is used to evaluate the energy production and savings, capital cost opinions, emission reductions, financial viability and risk for various types of Renewable-energy and Energy-efficient Technologies (RETs). Stantec has developed a Biomass Combined Heat & Power Project Analysis Tool (BioCHP) in response to the needs of this study to develop business cases based on RETScreen.

Based on the assessments detailed in the report, each of the three cases do not appear to be viable. Each case suffers from the effects of economies of scale which is the typical barrier to the success of small-scale biomass installations. When considering capital costs, the initial cost of the installation of the boiler and selected auxiliaries are the most significant. Whether the unit is small or large, the owner must still purchase and prepare the land, install fuel handling equipment, install the boiler and auxiliaries as well as associated infrastructure, hire operators, etc. Increasing the capacity of the unit has a lower incremental cost on the overall capital cost. It is for these reasons, utility power stations are large capacity units, benefiting from economies of scale, and usually house multiple boilers in the same location to benefit from existing infrastructure.

A breakdown cost summary for each case is presented below:

1. **Sawmill Condensing Turbine Power Plant**

Opinion of Probable Capital Cost	$ 22,715,000
Opinion of Probable Operating Cost	$ 3,426,000
Opinion of Probable Revenue	$ 2,770,000

2. **District Heating (Thermal) Plant**

Opinion of Probable Capital Cost	$ 3,984,000
Opinion of Probable Operating Cost	$ 1,089,400
Opinion of Probable Revenue	$ 225,689

3. **Commercial Seasonal Heating (Thermal) Plant**

Opinion of Probable Capital Cost	$ 451,000
Opinion of Probable Operating Cost	$ 17,900
Opinion of Probable Revenue	$ 13,000

It is apparent from the summary data that for each case study, the probable revenues are below the probable operating costs. Operating costs take into account standard items such as personnel salaries, regular and preventative maintenance and materials, and insurance. Also included are fuel costs and debt servicing payments. For each case, as expected, the operating costs for fuel consumption alone would drop the operating costs below the revenue, as biomass is a more affordable fuel source. It is the operating and maintenance costs, coupled with the capital expenditure payback that renders the cases unviable.

Based on the case study results, a number of options to improve viability are presented within the case discussions. The main options for further study include:

- Seek out high capacity heat loads with non-seasonal fluctuations, such as industrial processes. Season loads make payback difficult as the facility is shutdown for half the year, generating no revenue. In addition, the boiler still has to be sized for the maximum peak load, resulting in poor boiler capacity utilization when below peak demand (district heating cases average heat demand is one-tenth the peak demand).

- Power production can only be economical in higher capacity ranges. NB Power should extend its limitation on embedded generation capacity beyond the 3 MW threshold to improve the viability of small scale >10 MW biomass power plants.

- Although condensing steam turbines represent the best avenue to generate power independently of heating load, they are inefficient in terms of thermal efficiency when compared to a back pressure turbine cogeneration plant (20% compared to 66% net thermal efficiency, respectively). The drawback of having the electrical production of the back pressure turbine dependant on the heat load can be mitigated by finding less seasonal, higher capacity, constant heating requirement.

- District heating suffers from season heating loads, but opportunities still exist by increasing the number of users and user density. By having high capacity heating requirements close together, distribution capital costs can be reduced significantly for the same operating cost. Clusters of high density users should be sought out for further study.

- Conversion costs are very high for existing buildings, particularly those currently using electrical baseboards or heating coils. Replacing installations that currently employ hot water heating using an oil furnace/boiler are more easily retrofitted. This impacts the potential revenues for a heating plant, as the cost of steam heating must be less than the existing system to facilitate conversion payback, yet high enough to payback the capital cost of the facility.

- For the smaller single building units, heating capacity is also an issue based on economies of scale. Due to the air conditioning volumes of the commercial buildings case study, their heating requirements are lower than expected, affecting the feasibility of an installation. The buildings examined in the district heating study, such as the Middle/High School, would have been more suitable for assessment given the school's larger heating requirements and existing hot water infrastructure to lower conversion costs.

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1.0 Introduction

The New Brunswick Federation of Woodlot Owners (NBFWO), in collaboration with Fundy Model Forest Network, the New Brunswick Department of Energy, and other groups represented on a steering committee, desired an independent analysis on the feasibility of small-scale thermal and combined heat and power plants (CHP) for the production of energy utilizing wood products. This project has two main objectives:

- To identify opportunities for the building of small-scale biomass facilities for the production of energy; and to identify opportunities for the use of forest biomass resources as a potential fuel in thermal and CHP plants throughout the province of New Brunswick.
- To analyze the financial feasibility of constructing and operating small-scale biomass facilities and identifying policy or systemic barriers to their construction and operation.

Based on the project objectives, several brainstorming sessions, and consideration of the budget available, the steering committee decided to proceed with a series of case studies to highlight potential opportunities. Three (3) case studies were selected to highlight energy production options and help illustrate expected: installation, harvesting, capital cost, performance, capacity, and operational issues as well as the implementation gaps that need to be considered. Due to budget limitations, the case studies could only be completed as screening exercises - using high level costing data to provide indicative costing, coupled with sensitivity analyses to showcase varying opportunities that may exist. The three case studies undertaken are provided in Table 1.0

Table 1.0 - Three (3) Case Studies Selected by the Steering Committee

Case Studies	Application
Case 1	Cogeneration (Heat and Power)
Case 2	District Heating (Heat Only – Large Scale)
Case 3	Facility Seasonal Heating (Heat Only – Small Scale)

For each case study, the following data was examined:

- An analysis of feedstock costs including: options for a range of feedstock (mill residue, harvest residue, round wood etc.) and the risk associated with increasing or volatile costs. Covered in AGFOR’s Regional Biomass Profiles Report.
- Details of operating the facility including staffing complement, regular and scheduled maintenance and operation of the feedstock storage facility.

- A sensitivity analysis assessing the feasibility of the facilities based on a range of costs of oil and/or electricity in addition to biomass feedstocks.
- Opinion of Probable Costs for the design, procurement, construction, and commissioning of the facility. Order of magnitude opinion to determine whether there is incentive to pursue a more detailed analysis/study.
- The cost differentials between the existing heating method and the proposed biomass facility.
- Energy outputs for the specific facility.
- Impact of operation schedules and the impacts of facility shutdown (due to regular maintenance, seasonal shutdowns).
- Provide an indication of greenhouse gas impacts.
- Building conversion costs, to switch to biomass from the existing system.

Each case study is presented in its own section in the following report.

The case studies are preceded in the following sub-sections with background information as requested by the steering committee. This background information is intended to provide data on the energy conversion methods used and other pertinent information for the cases.

1.1 FUNDAMENTAL TECHNOLOGY DESCRIPTIONS

During the project scope development, a number of items needed to be dropped in favour of others in order to meet budget constraints. One aspect that could not be funded was a detailed review and analysis of current small scale biomass conversion technologies. Therefore, the case studies are based on commercially available and proven boiler and steam turbine technologies. The boiler is used to convert biomass into steam, which is used as a heat source or to drive a steam turbine to turn the steam into electricity. The following three sub-sections describe the three fundamental arrangements used in the assessments of the case studies.

1.1.1 Thermal (Heating) Plant

The thermal plant represents the most basic use of biomass in this study. It is simply the conversion of solid fuel biomass into heat for use in a process or for space heating. Figure 1.0 is a graphical representation of the process along with an indication of thermal efficiency (how efficiently the heat that is generated is consumed). The following descriptions are based on biomass fuel (percentages will vary by fuel type and boiler efficiency) and are approximate values for discussion purposes.

Biomass fuel enters Figure 1.0 from the left hand side and represents 100% of the heat input. During the process of combustion, steam generation, and cleanup of the exhaust gas (flue gas), an approximate 5% heat loss can be expected (as shown leaving the bottom of the figure as

Misc Losses). Further to the 'internal' losses, approximately 25% of the heat can be expected to be discharged out the stack/chimney. Therefore, 70% of the heat remains and can be transferred to the process by the steam. This is considered the **gross** thermal efficiency of the system. Taking into account the electrical requirements for pumps and miscellaneous equipment (considered here at 3%), a **net** thermal efficiency of 67% can be expected.

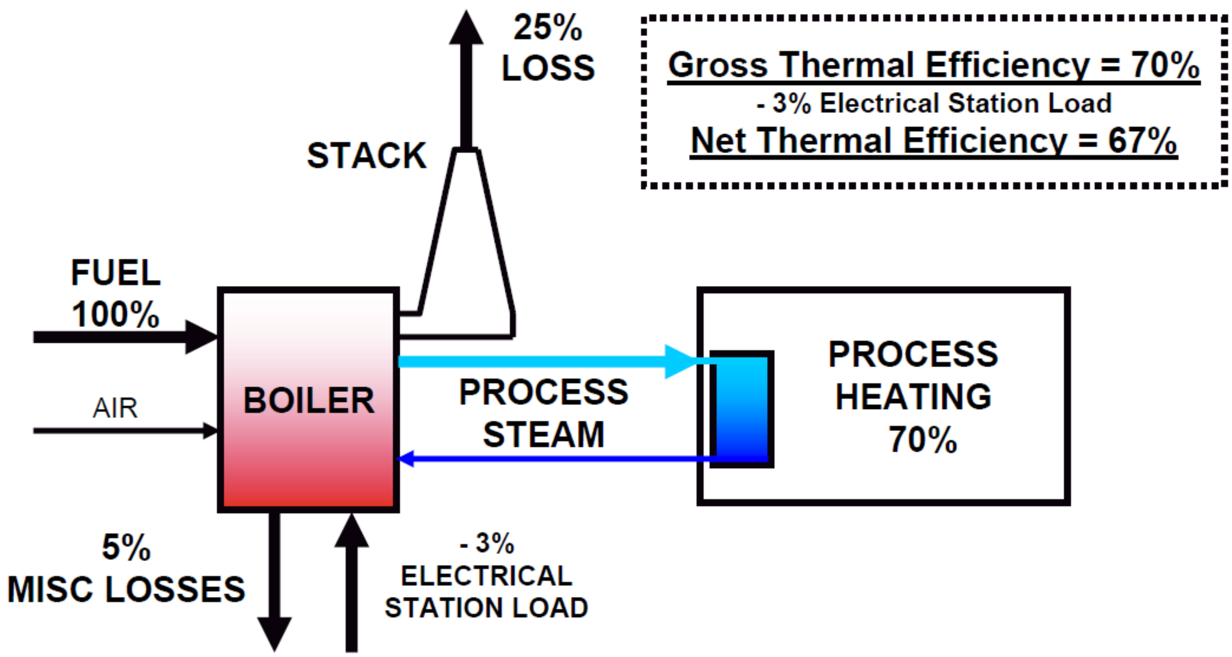


Figure 1.0 – Thermal Plant with Heat Generated by a Steam Boiler for Process Heating

1.1.2 Cogeneration – Combined Heat and Power (CHP)

The cogeneration plant is the addition of power generation to the thermal plant. There are two types of turbines used to generate power from steam, and Figure 1.1 outlines one of the two options covered in the case study. It makes use of a steam turbine called a reducing or back pressure turbine.

Similar to the arrangement of the thermal plant boiler, with 100% heat input from the fuel, approximately 5% of the heat is lost in the process and 25% of the heat is lost up the stack. The major difference is in the opportunity to generate power. For this arrangement, the back-pressure turbine is placed between the boiler and the process heating load. As well, the boiler will now need to deliver high pressure/high temperature steam (greater than 600 psig at 750 ºF) to the new back-pressure turbine. The turbine will discharge the steam at the low pressure conditions the process required in Figure 1.0 (the process sees no change in operation). The expansion of the high quality steam from high to low pressure in the turbine drives the turbine blades and generator rotor to generate electricity. For the example, 7% of the heat is consumed by the turbine, leaving 63% for the process. By using this arrangement, the boiler will need to be larger than that used in Figure 1.0, as it must accept additional fuel (11% more) to have sufficient heat to drive the turbine while still servicing the same process load.

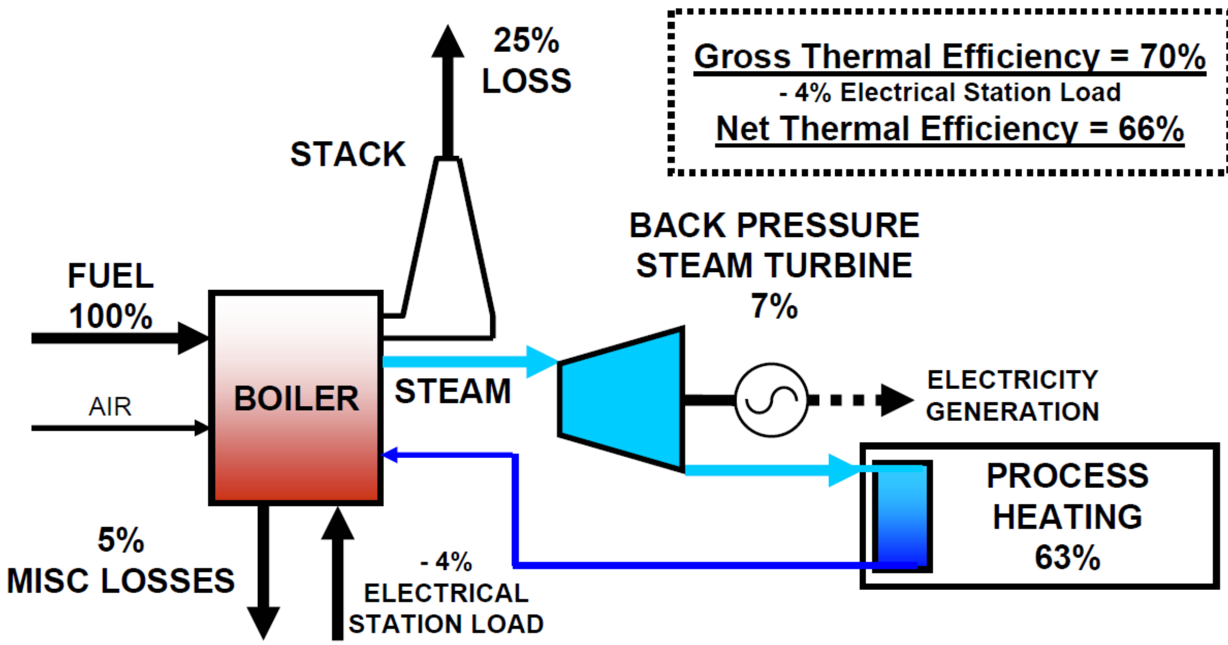


Figure 1.1 – Cogeneration Plant Using a Back-Pressure Turbine

Based on the use of heat in this manner, the gross thermal efficiency of this option is equivalent to the thermal at approximately 70% (with 7% for the turbine and 63% for the process). There is a slight increase in electrical station load which drops the net efficiency to 66% (due to the additional equipment associated with the turbine). The use of a back-pressure turbine is considered the perfect cogeneration system, as all the heat is still used by the system (both the turbine and process). The only detractor in its implementation is that electrical power generation is directly tied to the process heating load. The boiler is simply 'piggy-backing' additional heat onto the steam flow going to the process to generate power. Therefore at design, the capacity of the turbine is determined based on the maximum process load expected. Hence the larger the process heating load available, the larger the turbine can be, and the greater the potential of generating power. Although sized for the maximum heating load, once it is in operation, if the process is running at low loads or is shutdown completely, power generation and electrical revenues are directly impacted.

1.1.3 Power Generation with Steam Extraction

In order to avoid the loss of electrical generation during drops in, or loss of, process heating demands, a condensing steam turbine with extraction can be used. As with the back-pressure unit, the condensing turbine needs to receive high pressure/high temperature steam from the boiler which then expands through the turbine. At a selected pressure, some steam can be extracted for process heating as shown in Figure 1.2. The remaining steam continues to expand through the turbine, until it is exhausted into a condenser. The condenser is a large heat exchanger, operating under vacuum pressure, which is used to condense all the remaining steam into water to be returned to the boiler. In order to perform this operation, the condenser is supplied with cold water from a cooling tower to cool and condense the hot steam.

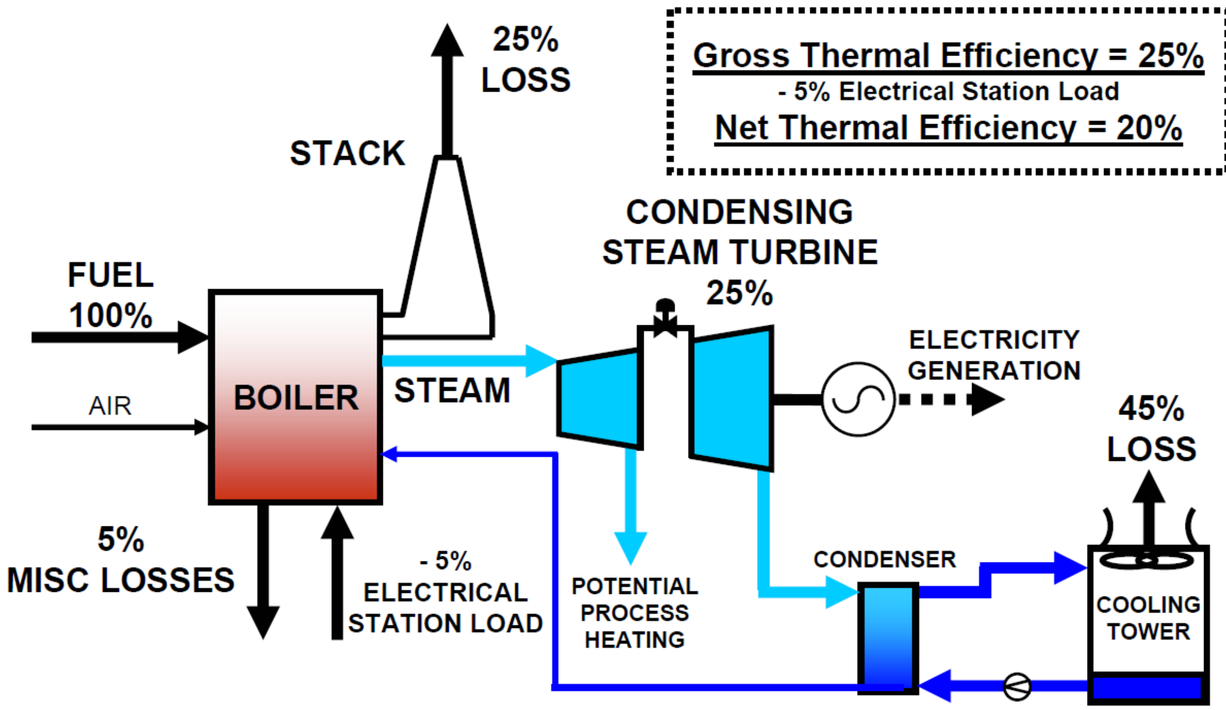


Figure 1.2 – Power Plant Using a Condensing Turbine with Extraction for Process Heating

The condensing turbine tries to extract as much energy as possible from the steam before condensing. Maximum power generation occurs when there is no process heating, and all the steam is sent to the condenser. As shown in Figure 1.2, this option has similar boiler side characteristics with internal and stack losses of 5 and 25% respectively, delivering the remaining 70% of the heat generated to power production. By extracting steam off the turbine as required, allows the condensing turbine to benefit from being independent of the process heating demands. This advantage makes it capable of generating power as a stand alone unit, unlike the back pressure turbine.

The significant drawback for the condensing turbine is that in order to function, it must reject the heat of the condensing steam through the condenser and cooling tower. For a typical operation, this can amount to approximately 45% of the total heat input being rejected as low quality heat (not suitable for process heating). Therefore, only the remaining 25% can be used for power generation, resulting in a poor gross and net thermal efficiency. From a cost standpoint, the owner must now pay to reject the low grade heat of the condenser in order for the turbine to operate. With the back-pressure unit, the power was essentially a by-product of the value added service of providing heat to the process.

This may raise the question of why the condensing turbines are used extensively for power production throughout the world, on coal and oil fired units. The answer is that its poor efficiency is usually offset by economies of scale in building very large capacity units (i.e., utility power generating stations). Utility generation is not usually tied to a process, and if it could be, the process heating requirements would have to be extremely large to match the electrical generation required. This is also the driver that limits small scale installations throughout Canada, as economies of scale work against the plant, making them cost prohibitive.

1.2 ELECTRICITY GENERATION INCENTIVES

1.2.1 Federal Government Programs

Class 43.2

Through the federal government, an Accelerated Capital Cost Allowance for Efficient and Renewable Energy Generation Equipment (Class 43.2) program exists. According to Natural Resources Canada, the objective of the program is to provide an accelerated rate of depreciation (Class 43.2: 50% per year, subject to half (25%) in the first year) for investments that produce heat for use in an industrial process or electricity using renewable energy sources or waste fuel (biomass). Refer to Schedule II of the Income Tax Regulations for more details.

The purpose of Class 43.2 is to “assist such investments by allowing businesses to write-off the capital cost of these assets at a rate faster than would be the case if the costs were written-off over the useful life of the assets, thus improving the after-tax rate of return on these investments”. [http://oee.nrcan.gc.ca]

The current Class 43.2 program is in effect until 2020, at which point it will be up for renewal.

Canadian Renewable and Conservation Expenses (CRCE)

As described above, Class 43.2 is an incentive provided to improve the viability of projects based on assets purchased. Leading up to and during construction, there are other start-up expenses such as: pre-feasibility and feasibility studies, regulatory approval expenses, detailed engineering and design, etc. that will be incurred. A large portion of these expenses are covered under the Canadian Renewable and Conservation Expenses (CRCE) category allowing for eligible expenses to be 100% deducible in the year they are incurred, carried forward, or transferred to investors. Some expenses, such as project management, are not covered.

Program details for the CRCE, Class 43.1 (fossil fuels), and Class 43.2 (biomass) can be found in a free guide provided by Natural Resources Canada, Office of Energy Efficiency, Class 43.1/43.2 Secretariat at http://oee.nrcan.gc.ca/industrial/financial-assistance/tax-incentives.cfm?attr=24

ecoEnergy for Renewable Power Program

A second program provided by the federal government is the ecoEnergy for Renewable Power program. The program provides an incentive of 1¢/kWh of generation for up to 10 years. For a biomass installation, the unit must be EcoLogo[M] certified through TerraChoice Environmental Marketing Inc., under the Environment Canada's Environmental Choice[M] Program, and all eligible installations have to be commissioned between 01 April 07 and 31 March 2011. The criteria certification document (CCD-003) is available through the TerraChoice website at http://www.terrachoice-certified.com/en/

1.2.2 Provincial Legislation

The New Brunswick *Electricity Act* was enacted on October 1st, 2004, and opened up competition in the electricity generating sector of New Brunswick. There was a large scale restructuring that resulted in NB Power breaking into separate subsidiary corporations, to look after generation (hydro and thermal units, and nuclear), transmission, distribution, and operations. Furthermore, the *Electricity Act* required NB Power to purchased electricity from independent power producers (IPPs). This resulted in the creation of the Embedded Generation program described in detail in the next sub-section.

In 2006, a requirement was established in the *Electricity from Renewable Resources Regulation – Electricity Act (2006-274, Reg. 2006-58)*, for NB Power to generate or purchase 10% of its electrical requirements from renewable or alternative-use sources by 2016. Such generation would have to be EcoLogo certified. At present, the major thrust for renewable energy is from wind farms located in the province. As per NB Power's 2007/08 Annual Report, a total of 309 MW of embedded generation should be online by 2009, with NB Power anticipating achieving the 10% electrical requirement by 2010 rather than 2016 by using new wind installations.

Renewable energy in the electrical generating sector was also targeted in the New Brunswick Climate Change Action Plan 2007 – 2012, as the province attempts to reduce greenhouse gas (GHG) emissions to 1990 levels by 2012, and a further reduction to 10% below 1990 levels by 2020. One of the main steps identified in the Action Plan is the *Electricity from Renewable Resources Regulation* identified above.

In the definition of a 'generator', under the *Electricity Act*, there are three main activities in which an independent power producer can be active in the New Brunswick electricity sector, these include:

- Open Access Transmission: The first of these activities is to operate a large-scale generation facility that is connected directly to the transmission system. This type of enterprise is permitted to sell the electricity it generates to NB Power Distribution and Customer Service Corporation ("Disco"), large industrial users connected directly to the transmission system, the three existing municipal distribution utilities, or to out of province customers (e.g., in a US State). The contract price is negotiated between generators and customers, with a tariff being paid by the generator for use of the transmission system.
- Embedded Generation: The second permitted activity is "embedded generation", whereby a generator connects its electricity into the local distribution system and sells its electrical output to Disco, which buys it at the displaced cost of the electricity, which is typically lower than the market rate.
- Net Metering: The third activity (permitted by NB Power policy) is "net metering". It allows end users of electricity to displace some or all of the electricity that they would otherwise purchase from Disco by generating electricity for their own use up to 100 kW. The price received is the full retail value of the electricity, as the amount generated is "netted" against the amount consumed by the customer, with the customer paying any difference.

1.2.3 New Brunswick Power Embedded Generation

As mentioned previously, NB Power has implemented the Embedded Generation program. This program enables generators producing power from renewable resources (i.e. Biomass, wind, tidal, etc.) to connect to the distribution system and sell electricity to NB Power. The program was initially established in 2004 when the *Electricity Act* was proclaimed, but saw little implementation with respect to biomass, and required negotiation to determine rate structures for power sales. To improve the application process, and eliminate the need for negotiations, a preset feed-in tariff was established, providing a fixed price for IPPs with a long term contract. Effective on April 1, 2009, the feed-in tariff was set at 9.445 ¢/kWh. The set price was established based on the avoided cost to NB Power, value of the environmental attributes, among other valuations. Note that under an Embedded Generation contract, NB Power is purchasing the renewable energy and environmental attributes, such that an IPP would not be able to apply for the EcoLogo financial incentive, yet must remain EcoLogo certified.

There is a capacity range limitation associated with the program of 100 kW to 3,000 kW (or 3 MW).

1.3 RETSCREEN

For the purposes of this screening study, information obtained from AGFOR and the design data from Stantec was entered into the RETScreen Clean Energy Project Analysis Software. This software is used to evaluate the energy production and savings, capital cost opinions, emission reductions, financial viability and risk for various types of Renewable-energy and Energy-efficient Technologies (RETs). Stantec has developed a Biomass Combined Heat & Power Project Analysis Tool (BioCHP) in response to the needs of this study to develop business cases based on RETScreen.

RETScreen is an international clean energy project analysis spreadsheet tool developed by Natural Resources Canada using Microsoft Excel as a platform. Stantec's version of the analysis tool facilitates the analysis of biomass combined heat and power cogeneration projects for use as a screening tool to assess the validity of a potential project on a high level. Projects determined to be potentially or border line viable should be selected for more in-depth pre-feasibility or feasibility level studies.

2.0 Case 1: Sawmill Power / Cogeneration Plant

A sawmill was selected as the site for the analysis of a cogeneration plant servicing a process heat load, while generating power. To enhance the mill's operations, the owners are interested in the possibility of installing a new power or cogeneration plant to allow the site to generate electrical power as well as process steam from wood waste.

NB Power will allow small generators onto the grid, and subsidize their generation from non-fossil fuel sources by buying the power at a premium above the local market value. This is limited to a maximum of 3 MW. With this limitation in mind, the following study has been completed to determine the feasibility of using the sawmill site to generate electricity and to incorporate the new boiler and steam turbine-generator into the existing process.

The existing sawmill houses a sawdust biomass boiler capable of generating approximately 10,500 lb/hr of 125 psig saturated steam to service the onsite steam kilns, and building heating requirements. Using biomass in this method is an efficient means by which to transfer heat from the fuel to the process using steam, as described in Section 1.1.1, and is representative of a typical sawmill steam plant (fuel feedstocks can varying from biomass to fossil fuels, as well, thermal oil can be used in place of steam).

The purpose of this case study is to replace the existing sawdust heating system with a new biomass boiler (using bark or hogged fuel), coupled with a turbine for electrical generation. The base case for design of the system is assumed to be a condensing turbine power plant capable of generating 3 MW of electricity year round while servicing the mill's steam load. The 3 MW capacity allows the sawmill to maximize its application to NB Power under the embedded generation program. A condensing turbine power plant is used instead of a strict cogeneration plant, as the mill's steam load is insufficient to generate 3 MW with a back pressure turbine (maximum generation of ~0.5 MW with 10,500 lb/hr of steam).

2.1 PROCESS DESCRIPTION

The following describes aspects of the process for the new condensing turbine power plant. Note that the capacity of the condensing turbine sets the size of all the other equipment from a process point of view.

Additional capacity of storage piles and bins is determined by the expected delays in the process due to such things as truck delivery schedules or unplanned interruptions in the process flow. Stantec has assumed the size of these storage piles and bins based on our understanding of the local process needs and our experience with similar material handling projects. The existing sawmill facilities will be incorporated into the new process where it is practical to do so. However, power generation is a continuous 24 hour per day operation while the sawmill has a variable schedule. The power plant must be able to stand alone from an operations point of view.

The process begins with the input of fuel to the sawmill complex. Fuel can come from various sources. Internally, the mill will produce bark, sawdust, shavings and chips. Some of this will be sold outside the mill for better income potential while the rest will be placed on the fuel pile by a front-end loader for use at the boiler. Bark from outside the mill will be brought to the mill by transport truck. These trucks will be unloaded by a truck dumper. The dumped material will be placed on the outside storage pile for later processing. The pile will have one week's storage capacity or approx. 120,000 cubic feet.

Fuel will be fed into a hopper conveyor that feeds a hogger. The conveyor will have a belt magnet and metal detector to protect the hogger and boiler equipment from damage due to metal contamination. The hogged bark will then be sent to a boiler feed storage bin. The bin will be sized to hold up to 24 hours of fuel at the maximum firing rate of the boiler.

From the fuel storage bin, a live bottom conveyor will feed fuel from the bin into the boiler furnace by way of a feeding/distribution conveyor system. The fuel will be fed into the boiler as determined by the steam production demand. The boiler furnace will burn the fuel on a live grate that will take the ash out of the boiler while the fuel continues to burn. This can be done in a variety of ways depending on the boiler vendor design. Ash is removed and conveyed to an outside bin for disposal. The ash will go to a disposal facility outside the mill complex.

Steam can be produced in the boiler at 600 to 900 psig and superheated to 750 to 900 ºF at a flow rate of up to 42,000 lbs/hr. The steam will be sent to the turbo generator where up to 3 MW of electrical power will be extracted from the steam. Some steam will be extracted from the turbo generator at the mill pressure, with the remainder sent to the condenser. Heat from the condenser will be extracted by circulating cooling water from the condenser to a cooling tower. Evaporation of water from the cooling tower into the atmosphere will release the condenser heat into the air. The cooled water will then be circulated to the condenser to pick up more waste heat.

Electricity generated by the turbo generator is sent to a new switch yard and metering station that connects to the NB Power grid. This system will be separate from the existing incoming power system for the mill.

Fresh water for the boiler make-up and cooling tower make-up will be supplied from existing wells on site. The water will need to be treated to remove dissolved solids and softened for use in the boiler and turbo generator. Turbo generators are particularly sensitive to hardness build-up and scaling of the turbine blades. Any build-up can cause rotor unbalance and require shutdown to prevent damage. A water treatment facility and storage tank will need to be built to address this concern.

2.2 OPINION OF PROBABLE COSTS AND PAYBACK

As described in Section 1.3, Stantec has developed a Biomass Combined Heat & Power Project Analysis Tool (BioCHP) to evaluate the case studies. This facilitates the use of budget costing and interpolation from data gathered during other similar studies. The numbers represent an order of magnitude cost that can be used to screen out unviable projects more quickly and before a more costly detailed study is undertaken.

2.2.1 Major Equipment

For the sawmill, the following major pieces of equipment are considered:

- Truck Dumper
- Fuel Storage Pile Paving 80 x 100 ft
- 400 HP Hogger and Conveyor System
- 24 Hr Fuel Surge Bin
- 43,000 lb/hr Boiler and Auxiliaries
- Boiler / TG Building
- Water Treatment
- Condensing Steam Turbine-Generator
- Condenser
- Cooling Tower
- Electrical Equipment
- Instrumentation and Controls
- Electrical Switch Yard and Metering Station
- Steam and Water Piping to Existing Facilities
- Project and Construction Management and Engineering

2.2.2 Capital Opinion of Probable Capital Cost

Using the BioCHP program, coupled with biomass sourcing data from AGFOR and design data from Stantec, the opinion of probable capital cost is presented in Table 2.0.

Table 2.0 - Opinion of Probable Costs for Sawmill Power Plant

Opinion of Probable Capital Cost – Sawmill	
Biomass Boiler Package	$ 6,600,000
Condensing Steam Turbine	$ 3,500,000
Cooling Tower	$ 200,000
Condenser	$ 250,000
Sub-Total – Major Equipment	**$10,550,000**
Civil	$ 2,500,000
Electrical, Instrumentation and Controls	$ 1,800,000
Mechanical	$ 3,000,000
Sub-Total – Direct Costs	**$17,850,000**
Freight, Overheads, Admin, Owners Costs, and Commissioning	$ 1,100,000
Detailed Engineering and Project Management	$ 1,700,000
Sub-Total Project Costs	**$20,650,000**
Contingency	$ 2,065,000
Total Project Costs	**$22,715,000**

The power plant at this capacity is designed to maintain 3 MW of generation throughout the range of varying mill steam loads. If the boiler is fired at its maximum capacity, and all the steam is condensed in the turbine, the power plant is capable of generating approximately 4.8 MW of power. With an opinion of probable capital cost of $ 22.7 million, this generates a unit cost of $4.7 million per MW. The larger the plant capacity, the lower the unit cost becomes due to economies of scale. For example, increasing the capacity to 10 – 25 MW of electrical generation can lower the unit cost to approximately $4.0 million per MW.

2.2.3 Opinion of Probable Annual Operating Costs

As a bare minimum, a 24-hour two personnel crew is required to operate the plant. Fuel handling, storage, and in-feed can likely be handled by mill personnel based on previous operations. In order to operate the steam plant, a steam plant engineer with a Class 2 ticket will be required on-site at all times based on New Brunswick boiler codes. Day-to-day operations will be carried out by this staffing complement, although larger or more technical repairs/maintenance will require outside assistance. Maintenance and Material allowances need to be made for regular scheduled maintenance, an annual shut-down (typically two (2) weeks per year), and general usage. Miscellaneous costs for insurance, taxes, chemicals, ash disposal, phone lines, etc. are assumed.

Table 2.1 represents a breakdown of the annual operating and maintenance (O&M) opinion of probable costs developed in BioCHP. These costs should be considered a minimum threshold to check for project validity. Numerous O&M costs need to be validated once more in-depth engineering can be completed.

Fuel consumption is the second major part of operating the plant and is predicted to cost approximately $1 million annually based on sourcing and costing information inputted into BioCHP by AGFOR. On top of all operating and maintenance cost, the debt servicing payment must be added to determine viability. For the purposes of this assessment, the opinion of probable capital cost is amortized over 15 years with a 7% interest rate.

Table 2.1 – Sawmill Opinion of Probable Annual Operating Costs

Opinion of Probable Annual Operating Costs	
Operating Personnel	$ 400,000
Maintenance and Materials	$ 200,000
Insurance, Taxes, Misc.	$ 49,000
Sub-Total Annual O&M (w/o Fuel)	**$ 649,000**
Fuel Consumption Hogged Fuel (43% MC), $16.3/GMT	65,873 GMT $1,030,000
Total Annual O&M Cost	**$1,679,000**
Debt Servicing Annual Debt Payments, 15 yr am., 7% interest	$1,747,000
Total Annual Costs	**$3,426,000**

2.2.4 Revenue and Payback

To determine if the project is viable, annual revenues must exceed annual costs. To determine annual revenues, one must look at the displaced fuel cost of the existing boiler, and the revenue from electricity sales. Table 2.2 outlines these two revenue streams to determine the total expected revenue for the project at only $2.77 million.

Table 2.2 – Sawmill Opinion of Probable Annual Revenue

Opinion of Annual Probable Revenue	
Displaced Fuel Cost	$ 370,000
Electrical Sales Embedded Generation, 9.445 ¢/kWh	$2,400,000 (25,200 MWh / yr)
Total Annual Revenue	**$2,770,000**

Based on this screening assessment, it is possible to see that the annual costs of operating the facility are in excess of the expected revenues for this installation. Given the magnitude of the disconnect, a unit of this capacity, based on this technology, should not be pursued further.

2.3 CASE 1 DISCUSSION

The following sub-sections outline specific areas for discussion or additional information as requested by the steering committee in the initial scope of work, or during case presentations. Items covered include sensitivity analyses, greenhouse gas intensities, risks, and options to improve viability/alter policy.

2.3.1 Sensitivity Analyses

Based on the presentation of Case 1 to the steering committee, and a new understanding of why an installation of this capacity was not feasible, Stantec was requested to supply a sensitivity analysis on increased capacity of the power plant. Representative plant sizes were chosen at 6 and 10 MW for this purpose. These plant sizes were carried forward for the sensitivity analyses requested based on variations of electricity export rate and biomass fuel pricing, as presented in the following figures. For the purposes of the assessment all electricity is sold at the Embedded Generation rate of 9.445 ¢/kWh even beyond the 3 MW limit.

Figure 2.0 showcases the sensitivity analysis for variations in electrical export price, indicating as proven in the report, that the 3 MW plant examined for Case 1 has a payback greater than 20 years (and is not economically viable). Increasing the plant capacity to the 6 and 10 MW thresholds results in slightly more attractive financials, with the units having a payback of 10 and 6.2 years, respectively (assuming the current Embedded Generation program rate). As capacity increases, economies of scale provide a better return on investment, but the upfront capital investment is increasing accordingly. Furthermore, a five to eight year payback is not typically an attractive investment for most in industry investments, particularly in the forest sector. Two to three, possibly four years is more typical on a capital expenditure of this magnitude.

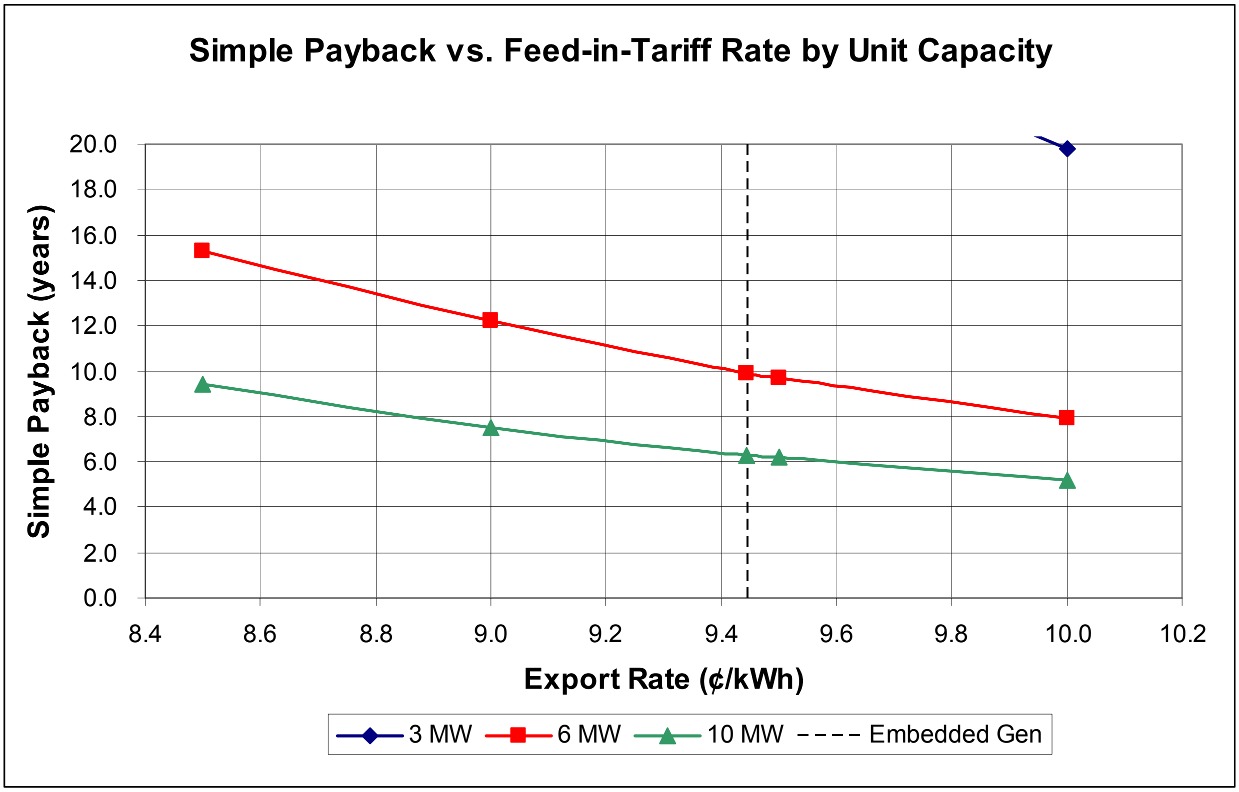


Figure 2.0 – Equity Payback vs Electricity Export Rate by Unit Capacity

Figure 2.0 also provides an indication on the reduction in payback with increasing feed-in-tariff. The curves start off at 8.5¢/kWh which is a lower price for electricity than it is currently purchased for by most small industrial sites like the current sawmill. As the feed-in-tariff increases to the current NB Power Embedded generation price of 9.445¢/kWh, the payback is improved by over five years for the 6 MW unit, from an approximate 15.3 year payback to just under 10 years. Further increases in feed-in-tariff improve the payback on the larger capacity units, but have no improvement on the 3 MW unit until 10¢/kWh.

Any further work in the area of power generation at or below 3 MW would need to focus on a different technology as the conventional biomass Rankine cycle plant is not economical.

Please note that the sensitivity analysis in Figure 2.0 is based on the predicted fuel price of $33 / GMT, and held constant throughout the payback period. Fuel at the sawmill will be at a lower cost than that available to outside users (assuming it's the byproduct of its operation), and will fluctuate with market conditions.

A secondary sensitivity analysis was performed on the payback vs. biomass fuel price. As one would expect, increased fuel prices greatly extends the payback period for the units as depicted in Figure 2.1. The Case 1, 3 MW capacity unit is again sitting in the +20 year payback range, with more attractive results for the higher capacity units. For the more attractive payback of the 10 MW unit, a $15/GMT increase in price results in +3 year extension in the unit's payback.

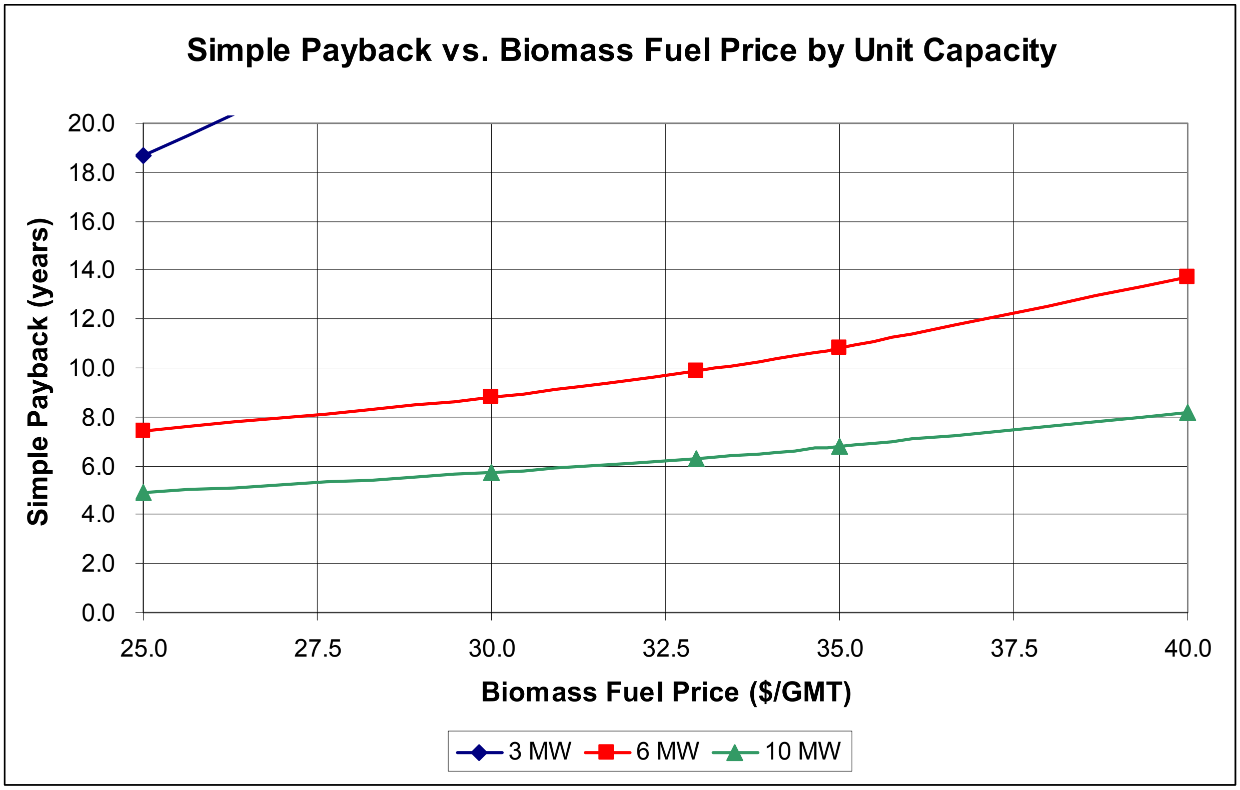


Figure 2.1 – Equity Payback vs Biomass Fuel Price by Unit Capacity

2.3.2 Greenhouse Gas Intensity

An additional request made during the Case 1 presentation was for an assessment of greenhouse gas (GHG) intensity or reductions expected based on the new installation. For this purpose, Stantec has calculated a range of potential GHG emission reduction associated with the displacement of electricity in the context of the New Brunswick electricity GHG intensity mix. The displacement of fossil fuels for creating process steam, or for other uses for the steam in co-generation, could be considered as potential sources for generating GHG reductions. In the case of the sawmill power plant, there would not be reductions as a result of the use of the steam generated, due to the fact that biomass is the existing fuel for process steam and other uses for the steam are not contemplated.

The GHG intensity for New Brunswick's electricity on a monthly basis can range from 0.34 to 0.62 tonnes of CO_2 equivalent (CO_{2e}) per megawatt-hour (MWh) generated depending on the mix of generation employed. The intensity also changes seasonally as the generation mix changes to compensate for winter peak loads. From October 2008-'09 the average annual intensity was 0.522 tonnes CO_{2e} / MWh of electricity produced. An average intensity is used because the CHP plant is considered to be operational year-round and thus would be displacing an average mix of electricity on the New Brunswick system.

GHG reductions from the production of steam and electricity could potentially result in the creation of carbon offset credits that could be monetized and represent a source of revenue for these types of projects. Environment Canada is currently developing a system of GHG offsets involving protocols and certification, and it is expected that biomass projects will be able to generate offset credits. However, for the purposes of this study, these potential revenues are not included in the business model as there is no way to predict how the offset system will develop and what value can be expected from the generation of offset credits.

On average, a 3 MW facility could be expected to create 13,154 tonnes of GHG reductions per year. Similarly a 6 MW and 10 MW size CHP plant could be expected to create 26,309 and 43,848 tonnes of GHG reductions per year respectively. Table 2.3 shows an opinion of annual electricity production for the different capacities and their respective potential to reduce GHGs from offsetting electricity in New Brunswick.

Table 2.3 – Electrical Generation and Potential GHG Offset per MWh

Unit Capacity (MW)	Annual	
	Electrical Generation (MWh)	GHG Reduction (tonnes CO2e)
3.0	25,200	13,154
6.0	50,400	26,309
10.0	84,000	43,848

2.3.3 Risks

A number of risks were identified during the course of the Case 1 evaluation. These risks were not fully explored due to time and budget constraints but should be evaluated should the project proceed:

- Water Supply – A continuous source of water is required and well sources may not be suitable. Running the mill's and neighboring wells dry is a serious risk (more significant with increasing unit capacity).

- Soil Conditions for Foundations – Current site layouts are based on an installation near the existing biomass fuel piles. This is a mostly land filled area and may not be suitable for the new installation, but is representative of the area require for a plant of this nature. Soil condition will determine siting of the plant and if spread footings or piles will be required.
- Ash Disposal – The avenue used for ash disposal of the existing boiler need further investigation to determine disposal cost and available capacity.
- NB Power – Several items that will require NB Power's involvement including locating the closest power line for connect, right of ways for connect, system assessment fees and timelines, sizing for transformer, switch gear, metering and protection, is the existing sawmill infrastructure capable of handling the additional load of the power plant, etc.
- Embedded Generation – The current program has not enticed a new biomass installation, and as such is an unknown with respect to long term price contract negotiations and terms. It is perceived to limit payback to the IPP should oil prices rise, as well, all biomass fuel is subject to market price variations and could rise. These are just two issues that should be tied to the contract for electricity sales. NB Power also receives all 'green' credits under the program such as existing ecoEnergy incentives, US subsidies for renewable fuels (if exported), any other subsidies, as well as any future implications with respect to carbon credits/trading etc.

2.3.4 Options to Improve Viability

Although the opportunity for a small scale installation is not viable in its current state and market conditions, several items could be investigated further to improve the payback:

- Embedded Generation – A first step would be to extend or remove the NB Power Embedded Generation capacity limit of 3 MW. Other potential installations in the province have requested the limit be removed as they believe that power generation at the embedded rate is attractive in higher capacity units. Ontario currently offers 11¢/kWh.
- Condensing Turbine – If a condensing turbine continues to be pursued for power generation, the capacity will need to increase to make it viable. The initial capital costs to install the system are simply too great for small capacity units to be viable unless under specific circumstances.
- Third Party Ownership – Have NB Power underwrite the capital cost of the unit and accept the longer payback period to the installation. NB Power could offset coal/oil generation by having multiple biomass power/cogen plants in the province (along with other IPPs) with the capital for the biomass units coming from avoided cost of coal/oil generation and capital replacement/new installation costs for these units.
- Switch to Cogeneration – As outlined in Section 1.1.2, a cogeneration system is a far more thermally efficient unit than a condensing turbine. That said, because of its dependency on the heat sink, the steering committee is advised to seek out high heat sink applications and partner with industrial users with high heat demands. The current

mill heat load is not sufficient to make an attractive case for a cogeneration unit, as its economies of scale are hindered by the small capacity variation in mill loads.

- Process Steam Sales – Should a desirable heat load be located, there is the potential to sell steam if the switch to cogeneration is made. In this case, the price of steam would need to be priced to be competitive with the alternative heating source, be it electricity, propane, oil, or natural gas. Generating an attractive business case would depend on a number of site specific conditions including, but not limited to: the cost of the alternative fuel, operating and maintenance requirements, the cost of biomass steam, conversion costs that would require an attractive payback, additional infrastructure requirements, and contractual agreements. Table 2.4 highlights energy costs from highest to lowest.

Table 2.4 – Energy Cost Comparison (including assumed boiler efficiencies)

Fuel / Boiler Efficiency	Approximate Fuel Cost and Heating Value	Equivalent Energy Cost (incl. boiler efficiencies)
Propane (83% Eff.)	95¢/L (25,000 Btu/L)	$ 45.8 /mmBtu
Electricity (100% Eff.)	10¢/kWh	$ 29.3/mmBtu
No 2. Oil (84% Eff.)	80¢/L (37,000 Btu/L)	$ 25.7/mmBtu
Natural Gas (81% Eff.)	$20/scf (1000 Btu/scf)	$ 24.7/mmBtu
No 6. Oil (84% Eff.)	65¢/L (38,500 Btu/L)	$ 20.1/mmBtu
Biomass – 50% M (66% Eff.)	$25/GMT (4,250 Btu/lb)	$ 4.0 / mmBtu

3.0 Case 2: District Heating Plant – (Industrial/Institutional)

A preliminary look at installing a power plant at the sawmill site concluded that the operation would not be feasible. The two main obstacles preventing a payback for investors were the installation capital cost and the low overall efficiency due to using a condensing turbine (having to pay to reject waste heat to operate). This case study is based on a scenario whereby the condensing load is converted to a saleable heating load in the form of a district heating network for an industrial park and institutional area. This is representative of a thermal plant delivering heat to a process with high thermal efficiency. For a sensitivity analysis, this case will also have the option to use a back-pressure turbine to generate electricity for sale to the NB Power grid, replacing the thermal plant with a cogeneration plant.

3.1 OPPORTUNITY DESCRIPTION

Stantec was requested to pursue a district heating plant (thermal plant) in rural setting, considering medium industrial and institution clients. The preliminary design for the plant was to include one manufacturing facility and a number of institutional installations (hospital and schools). Profiles for the participants in this case study, that will form the basis for the district heating analysis, are provided below from in-house assumptions and other sources:

Industrial Client - Manufacturing – For the purposes of the study, a 100,000 square foot, heated, manufacturing facility was developed. Based on a set of high level assumptions, a portion of the total electrical consumption of the facility was allocated to heating requirements.

The results of the facility assumptions are showcased in Figure 3.0. A base line was established and assumed to account for running of equipment, lighting, etc., and makes up approximately 31% of the total electrical consumption for the facility. A production factor was developed to account for a potential increase in production during the winter months to generate a more conservative estimate of heating loads. The assumed factor increased the equipment electrical consumption, consuming an additional 18% of the annual electrical requirement. The remaining 50.9% of the annual electrical consumption was assumed to be heating requirements that could be serviced by the district heating system, equating to approximately 2,352 mmBtu annually. The resulting annual electrical consumption profile is presented in Figure 3.0. Electrical peak demand information had to be assumed. Based on other electrical heating installations, and the magnitude of the peak consumptions in the winter month, and assumed peak demand of 2.3 mmBtu/hr was assumed (peak demands will determine the sizing for the boiler/system).

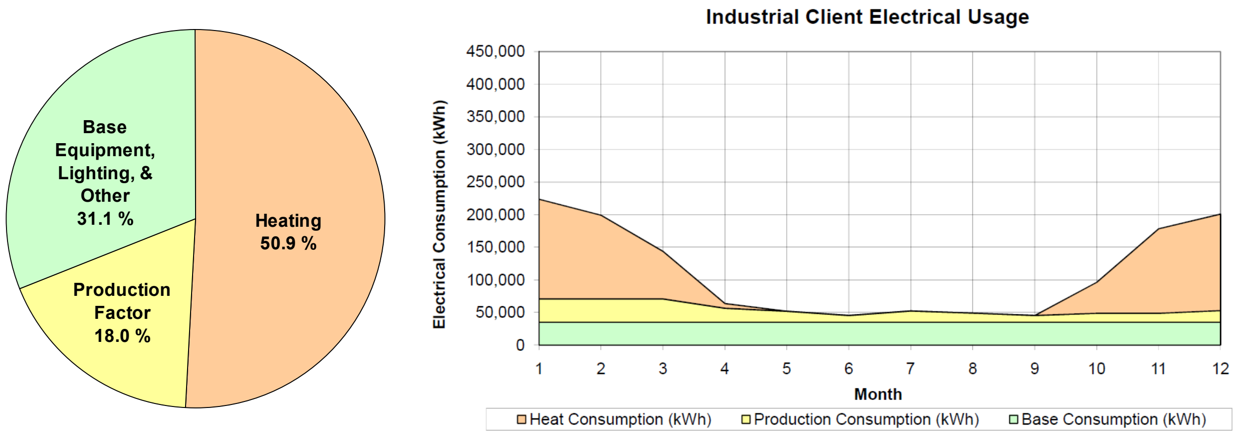


Figure 3.0 – Industrial Client Assumed Breakdown and Profile of Electrical Consumption

Institutional Client - Hospital – A smaller, rural hospital was assumed for the study. The hospital is assumed to be 100,000 square feet in size, and utilizes heating from ventilation (rooftop) heating coils in conjunction with internal electric baseboard heaters and reheat coils. On top of heating requirements, the hospital is assumed to have a large demand for hot water, both for use and laundry facilities. Based on assumed information, regarding annual electrical consumptions, an assessment was completed to determine the opportunity from district heating.

In similar fashion to the industrial client, a base load was established to account for hospital's equipment, computers, lighting, etc., and the potential air conditioning requirements. For the hospital, the base equipment is believed to account for 78.6% of the annual electrical consumption, as shown in the breakdown of Figure 3.1. A second base load consumption was established to represent the hot water requirements of daily operations, consuming an additional 11.4%. The remaining 10% is assumed to be the potential heating requirements that can be offset by the district heating system. As shown in the profile plot of Figure 3.1, heating is only accounting for the winter peaks of the hospitals electrical requirements. Unlike space heating, the hot water service presents an opportunity to operate the district heating facility during the summer months to meet demand. Overall the hospital represents a heating potential of 1,547 mmBtu annually, with an expected peak heating demand of 2.54 mmBtu/hr.

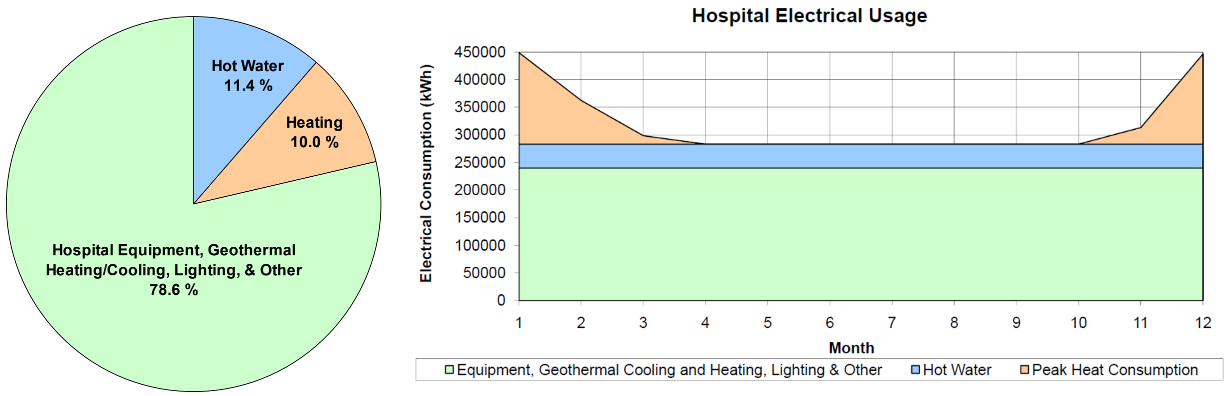


Figure 3.1 – Institutional Client – Hospital - Assumed Breakdown and Profile of Electrical Consumption

Institutional Client – Primary or Middle School – A primary or middle school is the first of two schools considered to be in the area for district heating. It is not uncommon in the Maritimes to have education facilities close together. The school will house approximately 500 students and staff members during the school season, and is closed to students during the summer months of July and August. This school is considered to be heated solely by electricity through electric wall heaters and overhead ventilation with reheating coils. The school would also have a demand for hot water, although considerably less than the hospital and not year round due to the off period in the summer.

The electrical consumption data was assumed and analyzed with the breakdown and profile presented in Figure 3.2. The assumed baseline equipment, lighting, and other consumption accounts for 48% of the annual usage, with a dip in consumption over the summer months. Hot water only represents an assumed 3% of the yearly consumption, with heating requirements making up the balance at 48.8%. The annual profile in Figure 3.2 showcase the general heating trend, and result in an annual consumption of approximately 2,069 mmBtu for the district heating system. Peak demand over the winter is expected in the range of 1.85 mmBtu/hr.

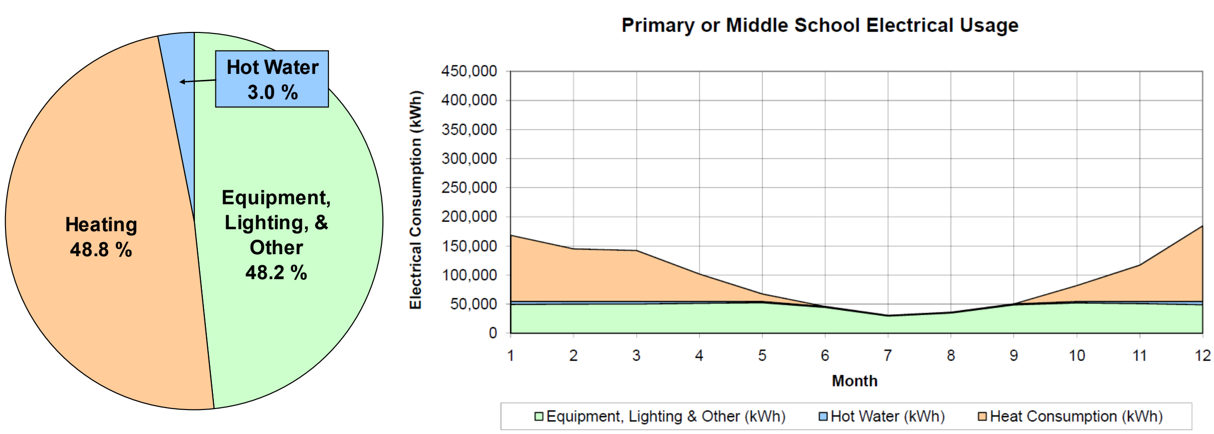


Figure 3.2 – Institutional Client – Primary or Middle School – Assumed Breakdown and Profile of Electrical Consumption

Institutional Client – Middle or High School – The final candidate considered for the district heating study is a middle or high school. This school is assumed to be located in relatively close proximity to the primary/middle school as well as the industrial client and hospital facilitating a potential connection to the district heating system. The school is assumed to be largest participant in the study with approximately 150,000 square feet of heated space, serving around 1000 students and staff members. Of course, similar to the other school, it will be closed to student for the months of July and August. Unlike the rest of the participants, this school is assumed to be heated by an oil boiler, supplemented with electrical heating coils in the ventilation system. The hot water oil boiler would service hot water baseboard heaters.

Figure 3.3 provides the breakdown of the electrical usage at the second school, with the base load including school equipment, lighting, miscellaneous usage and the supplementary electric heating. The electrical heating was not included in the study as it is minor compared to the oil heating, and would be more costly to convert the ventilation units than supplementing the oil boiler. Therefore the heating (63.7%) and hot water (3.3%) duty to be serviced by the district heating system, comprising of 67% of the total annual energy consumption, is a conservative estimate.

The usage profile depicted in Figure 3.3 is similar to that of the first school but scaled up in capacity to the larger square foot area. The high school would also contain larger volumes of space heating requirements (i.e., auditoriums, gymnasiums) than would be potentially present in the smaller school. On an annual basis, by supplementing the oil heating requirements of the oil boiler, the district heating system can expect an additional annual load of 5,325 mmBtu. This will be the largest load on the system, and also the highest peak demand, estimated at 3.93 mmBtu/hr.

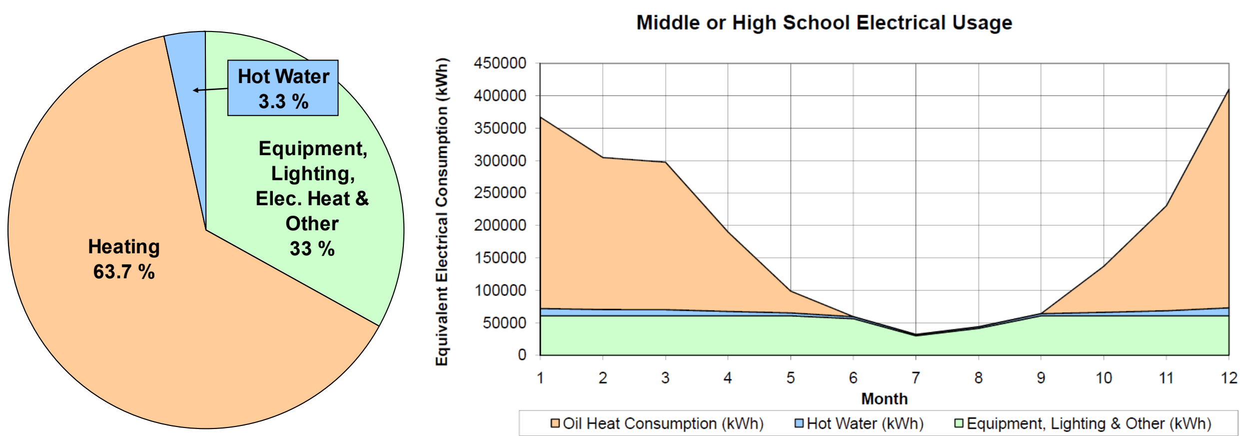


Figure 3.3 – Institutional Client – Middle or High School – Assumed Breakdown and Profile of Electrical Consumption

Taking the assumed four participating buildings into account, the annual expected district heating load profile is presented in Figure 3.4. Based on the expected loads, it can be assumed that the district heating facility will be shutdown during the summer months to avoid operating costs during the time over low loads, and the system users will rely on electric heating for any ‘off season’ requirements. During operation, the system will deliver approximately 11,284 mmBtu of heat to its users annual. The highest loading will occur during the winter months of December and January, into February.

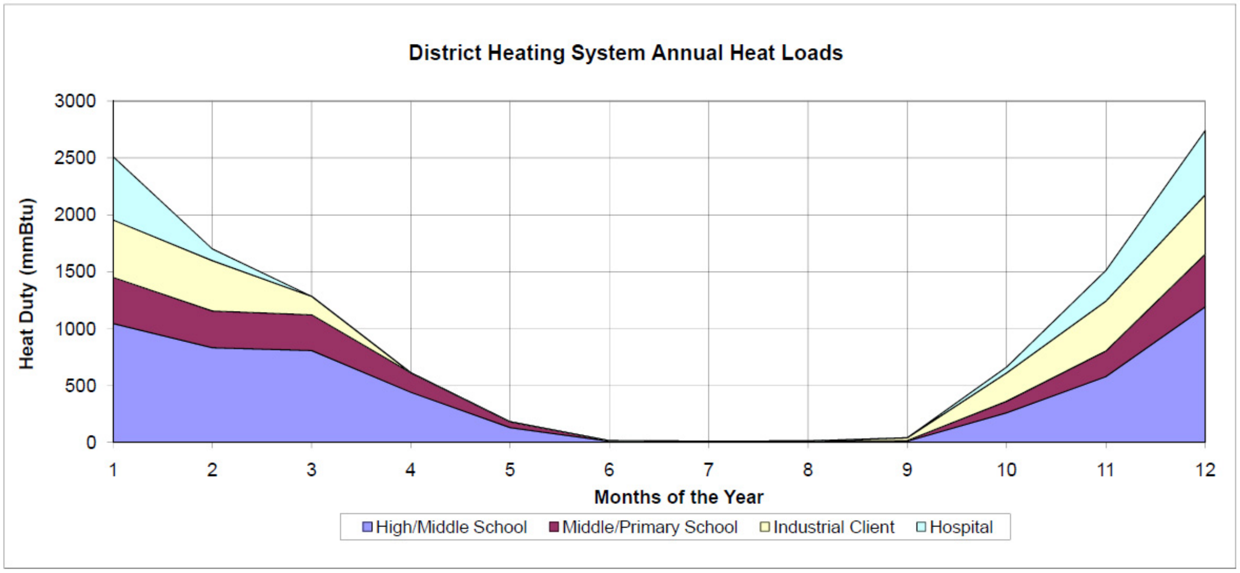


Figure 3.4 – Assumed Annual District Heating Load

In order to size the district heating facility, the peak loading requirements will dictate the boiler size. For this case, based the assumed profile presented previously, the peak demand is expected to be approximately 10.6 mmBtu/hr. Monthly average demands are well below this threshold, as peak demands occur in the early morning hours when buildings ramp up their heat ahead of being occupied for the day after a cold night.

3.2 PROCESS DESCRIPTION

The following describes aspects of the process for the new district heating (thermal) plant. The capacity of the boiler, and the optional case to turn the plant into a cogeneration plant with a back pressure turbine, is based on the peak demand presented in Figure 3.5 and dictates the majority of the design considerations.

The seasonal nature of the load, and the normal variance of the heating, swings from day-to-day and month-to-month. This results in the boiler being over sized on average but is necessary for seasonal and daily peaks in temperature requirements.

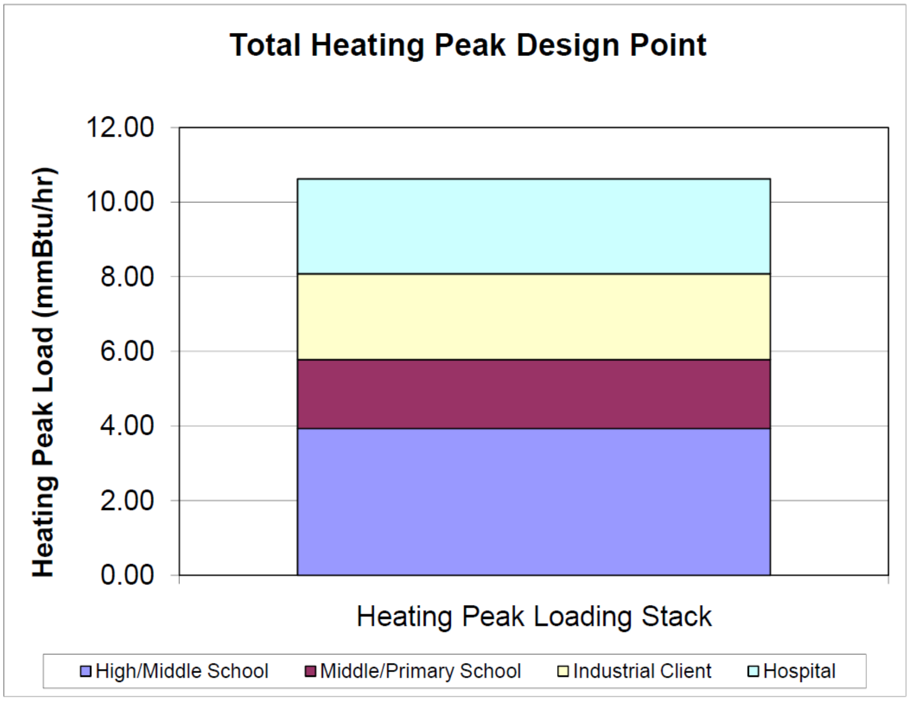


Figure 3.5 – Assumed District Peak Load

The district heating system is made up of two main components. The first is the boiler plant where the steam is generated, and second is the piping system required to deliver the heat to the users. The biomass conversion process would be similar to the sawmill scenario. Trucks would deliver biomass to a truck dumper and seven day storage pile area on a new site located near the industrial users. The biomass fuel is then fed to a boiler fuel bin with a live bottom floor and onto the boiler where it is burned in the furnace. Steam is then produced at a medium pressure (assumed 125 psig) and medium temperature (with sufficient superheat to reduce condensation in the steam lines). The steam is directed into the district heating steam distribution network and supplied to the attached users. The users will condense the steam and extract the heat energy for use in building space heating, hot water heating, or other miscellaneous process heating requirements. This functions in the same fashion as the condenser in the power plant, except the heat from condensation is not rejected to the atmosphere, but recovered and used to offset electrical or oil consumption. The condensate will then be pumped back to the boiler for reuse.

The district heating distribution system is made up of steam supply lines, and condensate (water) return lines. The steam and condensate lines will be buried underground in concrete tunnels that are interconnecting. The tunnels are necessary to provide access to make repairs and maintain the piping system. Smaller distances, or attaching additional users to the system could be accomplished using buried underground lines. The main line can be buried as well at a reduced cost, but tunnels are considered at this stage as they represent an infrastructure investment in the area and may be used for other purposes. An aboveground system could be an alternative but does not have any advantage in cost. The pipelines would need to be raised onto tower supports in order to permit traffic flow. A hot water system could also be used, but the disadvantage is that the piping would need to be much larger in order to carry the amount of energy required by the end users. In general, the higher the steam pressure, the smaller the line can be to carry the same amount energy. Most of the energy contained in steam/condensate is contained in the change of state from steam to water.

An option to generate addition revenue is to turn the district heating plant into a cogeneration plant (or combined heat and power plant). This is accomplished by upgrading the boiler to a high pressure / high temperature unit, and placing a back pressure turbine in service between the boiler and the steam supply to the distribution system. The turbine will then generate power based on the expansion of the steam before it is condensed by the users. This case is considered for the interest of the steering committee.

3.3 OPINION OF PROBABLE COST

As with the sawmill mill, Stantec has developed a Biomass Combined Heat & Power Project Analysis Tool (BioCHP) to evaluate the case studies. This facilitates the use of budget costing and interpolation from data gathered during other similar studies. The numbers represent an order of magnitude cost that can be used to screen out unviable projects more quickly and before a more costly detailed study is undertaken.

3.3.1 Major Equipment

For the district heating plant, the following major pieces of equipment are considered:

- Truck Dumper / Front End Loader
- Fuel Storage Pile Paving
- Fuel Surge Bin
- 400 BHP Boiler and Auxiliaries
- Boiler and Potential Turbine Building
- Water Treatment
- Potential Back Pressure Steam Turbine-Generator
- Electrical Equipment
- Instrumentation and Controls
- Steam and Condensate Distribution System

- Project and Construction Management and Engineering

3.3.2 Opinion of Probable Capital Cost

Using the BioCHP program, coupled with biomass sourcing data from AGFOR and design data from Stantec, the opinion of probable capital cost is presented in Table 3.0. The table has two columns, one for the district heating option (medium pressure steam straight to users) and the second is the potential combined heat and power plant with a back pressure turbine and upgraded boiler.

Table 3.0 – Opinion of Probable Capital Costs for the District Heating and CHP Plants

Opinion of Probable Capital Cost		
	District Heating (DH)	Combined H & P
Biomass Boiler Package	$1,650,000	$2,184,000
Back Pressure Steam Turbine	$ -	$ 676,000
Sub-Total – Major Equipment	**$1,650,000**	**$2,860,000**
Civil	$ 575,000	$ 679,000
Electrical, Instrumentation and Controls	$ 375,000	$ 429,000
Mechanical	$ 700,000	$ 824,000
Sub-Total – Direct Costs	**$2,960,000**	**$4,792,000**
Freight, Overheads, Admin, Owners Costs, and Commissioning	$ 237,000	$ 287,000
Detailed Engineering and Project Management	$ 425,000	$ 480,000
Sub-Total Project Costs	**$3,622,000**	**$5,559,000**
Contingency	$ 362,000	$ 555,900
Total Project Costs	**$3,984,000**	**$6,114,900**

Both options represent costs significantly below that of the sawmill, but will need to be paid back based on revenues that are directly tied to the magnitude and demand of the users. The combined heat and power plant can benefit from the additional electrical generation, but has 50% additional capital to pay down. Having the plants shutdown over the summer months is an additional shortcoming, which leaves capital investments of these magnitudes sitting idle.

The underground tunnel and piping system is estimated to be in the range of $1300/foot. This system is made of concrete prefabricated sections that can be lowered into trenches and covered. The steam and condensate lines would be installed inside the tunnel. Enough room for maintenance personnel to walk along side the piping system is allowed. The steam and condensate piping will be insulated for personnel protection. Tunnel lighting is also included. Based on the proposed distribution system layout, the total length of tunnelling required is approximately 11,500 feet or 3500 meters. At $1300/foot the total capital cost would be approximately $15,000,000.

3.3.3 Opinion of Probable Annual Operating Costs

As with the sawmill, a 24-hour, two personnel crew is required to operate the plant. Fuel handling, storage, and in-feed will require the purchase/lease of a new front end loader for one for the crew. In order to operate the steam plant, a steam plant engineer with a Class 2 ticket will be required on-site at all times based on New Brunswick boiler codes. Day-to-day operations will be carried out by this staffing complement, although larger or more technical repairs/maintenance will require outside assistance. Maintenance and Material allowances need to be made for regular scheduled maintenance and general usage. Miscellaneous costs for insurance, taxes, chemicals, ash disposal, phone lines, etc. are assumed. The district heating plant will be able to accommodate the annual shutdown during the off-season. Depending on the ownership arrangement, additional administrative personnel may be required for customer service, sales, accounting, etc. Administrative and associated staff has not been accounted for in this study.

Table 3.1 represents a breakdown of the annual operating and maintenance (O&M) opinion of probable costs developed in BioCHP. Again, these costs should be considered a minimum threshold to check for project validity. Numerous O&M costs need to be validated once more in-depth engineering can be completed. The O&M costs are higher with the addition of the turbine, as it will represent increased maintenance and routine overall costs in its lifetime.

Table 3.1 – Opinion of Probable Annual Operating Costs for the District Heating and CHP Plants

Opinion of Probable Annual Operating Costs		
	District Heating (DH)	Combined H & P
Operating Personnel	$ 400,000	$ 400,000
Maintenance and Materials	$ 100,000	$ 150,000
Insurance, Taxes, Misc.	$ 50,000	$ 50,000
Sub-Total Annual O&M (w/o Fuel)	**$ 550,000**	**$ 600,000**
Fuel Consumption Hogged Fuel (50% MC), $60/GMT	1,874 GMT $ 112,400	2,194 GMT $ 131,600
Total Annual O&M Cost	**$ 662,400**	**$ 721,600**
Debt Servicing (without Tunnels) Annual Debt Payments, 15 yr am., 7% interest	$ 427,000	$ 655,500
Total Annual Costs	**$1,089,400**	**$1,377,100**

Fuel consumption is the second major part of operating the plant and is predicted to cost approximately $112,000 to 132,000 annually depending on the type of plant. The added fuel for the CHP plant is the additional heat required to generate electricity in the turbine. On top of all operating and maintenance cost, the debt servicing payment must be added to determine viability. For the purposes of this assessment, the opinion of probable capital cost is amortized over 15 years with a 7% interest rate.

3.3.4 Revenue and Payback

To determine if the project is viable, annual revenues must at least exceed annual costs. For the district heating system, it's only source of revenue is the sale of heat to its users. The sale of steam will need to be attractive enough for the user to convert (i.e., lower than their current heating bill), but high enough to provide a payback on the plant itself. Electricity is more expensive than oil, $29.3/mmBtu and $25.7/mmBtu respectively, yet the cost for conversion of a building equipped with electric baseboard heaters and reheat ventilation coils far exceeds that of replacing/bypassing a hot water oil furnace. Therefore the steam pricing must reflect these barriers with competitive pricing. For the purposes of this study, a rate of $20/mmBtu is considered for all users. In a more detailed assessment this value can be varied for different users and contractually would likely be tied to the market price for oil and electricity (i.e., displaced cost to user). For the CHP plant, electricity sale would fall under NB Power's embedded generation program.

Table 3.2 outlines the two revenue streams for each plant to determine the total expected revenue for the options at $225,700 and $264,300 annually.

Table 3.2 – Opinion of Probable Annual Revenue for the District Heating and CHP Plants

Opinion of Probable Annual Revenue		
	District Heating (DH)	Combined H & P
Steam Sales $20/mm Btu of heat sold	$ 225,700	$ 225,700
Electrical Sales Embedded Generation, 9.445 ¢/kWh	$ -	$ 38,600
Total Annual Revenue	**$ 225,689**	**$ 264,300**

Based on this screening assessment, it is possible to see that the annual costs of operating the facility are in excess of the expected revenues for this installation. This exercise does not take into account the outstanding cost for the tunnel and/or distribution system. Given the magnitude of the disconnect, a unit of this capacity, based on this technology, should not be pursued further.

3.4 CASE 2 DISCUSSION

The following sub-sections outline specific areas for discussion or additional information as requested by the steering committee in the initial scope of work, or during case presentations. Items covered include sensitivity analyses, greenhouse gas intensities, and a general discussion with options to improve viability/alter policy.

3.4.1 Sensitivity Analyses

Stantec was requested to supply a sensitivity analysis for substitute/biomass fuel costs. This analysis is based on the data presented in the discussion section of Case 1 in Table 2.4 regarding a comparison of fuel energy costs (refer to Table 2.4 for additional details). Table 3.3 re-iterates the previous energy costs determined by fuel type, and provides additional information on potential for biomass substitution. For each fuel the energy cost per million Btu is provided, and an assumed sale price for replacing the fuel with biomass heat supply is made at three discount levels of 10%, 20%, and 30% reductions in fuel cost to provide incentive to switch fuels and to payback potential conversion costs.

Table 3.3 – Substitute Biomass Fuel Costs

Fuel	Equivalent Energy Cost ($/mmBtu)	Biomass Replacement Price ($/mmBtu)		
		10% Discount	20% Discount	30% Discount
Propane	$ 45.8	$41.2	$36.6	$32.0
Electricity	$ 29.3	$26.4	$23.4	$20.5
No 2. Oil	$ 25.7	$23.2	$20.6	$18.0
Natural Gas	$ 24.7	$22.2	$19.8	$17.3
No 6. Oil	$ 20.1	$18.1	$16.1	$14.1
Biomass	$ 9.7	-	-	-

Applying the fuel discounts above to Case 2 (replacing buildings currently operating on electricity and No. 2 oil) would present variations in potential revenue as shown in Table 3.4. Overall there is a significant difference in the potential reduction in fuel cost when comparing any alternative fuel to biomass. The significant difference that makes the application of biomass district heating unattractive lies in the capital cost for required infrastructure (both the boiler plant and distribution), increased operating and maintenance requirement, and staffing requirements for operation and fuel handling.

Table 3.4 – Analysis of Substitute Biomass Fuel Costs

Fuel and Approximate Annual Consumption	Annual Existing Fuel Cost	Biomass Replacement Price and Potential Revenue		
		10% Discount	20% Discount	30% Discount
Electricity (6,484 mmBtu/yr)	$ 190,000 / yr	$ 171,000 / yr	$ 152,000 / yr	$ 133,000 / yr
No 2. Oil (4,800 mmBtu/yr)	$ 123,600 / yr	$ 111,200 / yr	$ 98,800 / yr	$ 86,500 / yr
Biomass (11,284 mmBtu/yr)	-	$ -46,600 / yr	$ -46,600 / yr	$ -46,600 / yr
Potential Revenue	**-**	**$ 235,600 / yr**	**$ 204,300 / yr**	**$ 173,000 / yr**

3.4.2 Greenhouse Gas Intensity

Similar to Case 1, an assessment of greenhouse gas (GHG) intensity or reductions for Case 2 is presented in Table 3.5. For the purposes of the district heating plant, the potential GHG emission reduction needs to be associated with the displacement of both electricity and oil currently in use. For electricity, the reduction needs to be placed in the context of the New Brunswick electricity GHG intensity during the winter months, not the yearly average, as the bulk of the heating is done during this period. The GHG intensity for New Brunswick's electricity during the winter months is approximately 0.5665 tonnes of CO_2 equivalent (CO_{2e}) per megawatt-hour (MWh), or 0.1660 tonnes CO_{2e} per mmBtu (depending on the mix of generation). For oil heating, the New Brunswick Department of Energy provided a factor current employed in evaluations for the NB Climate Action Fund, rating No 2 oil for buildings at 2,839.7 tonnes CO_{2e} per litre, or approximately 0.0767 tonnes CO_{2e} per mmBtu.

Table 3.5 – Potential GHG for the District Heating System

Fuel and Approximate Annual Consumption	Annual	
	GHG Factor Provided by NBDOE	Annual GHG Reduction (tonnes CO_{2e})
Electricity (6,484 mmBtu/yr)	0.1660 tonnes CO_{2e}/mmBtu	1076
No 2. Oil (4,800 mmBtu/yr)	0.0775 tonnes CO_{2e}/mmBtu	372

3.4.3 General Discussion

The overall conclusion is that the distributed heating system will not be economically viable for a system of this size. The large capital investment of the boiler and distribution system required to sell the heating energy to the four users makes the distribution system unviable. There are three factors that must be considered in order to change the economics in order for the system to be economically viable. They are:

- User density - Number of, and distance between users
- Cost of conversion for the end user
- Cost of users current energy source

The first problem for our economic return-on-investment is that the density of users is too low. Although the survey had trouble gaining a large number of participants, the remaining buildings in the area would be considered lower intensity users (small commercial and industrial sites) that could tie into the system if the larger users justified its installation. Their lack of participation and relative heat load, would not improve the economics surrounding this installation. In order for a distribution system to work economically the users must be close together. Examples of viable clusters would be large numbers of high rise housing buildings, large institutional buildings within a city block, etc. By keeping the distance short between users, the cost of capital for the distribution system is spread over many users and results in a smaller cost for each user. This is important when calculating the payback for switching from the users current heat supply system.

For the purposes of this case study, the cost associated with the distribution network (tunnels) was not accounted for in the economics. This served a dual purpose, the first being that it would give a conservative indication if the heating plant and operational side of the installation was feasible and economical. The second was the assumption that the infrastructure for such a system may be covered financially in whole or in part by municipal or government bodies. The installation of such infrastructure in an industrial park or heavy commercial/institutional area may present opportunities to bury additional municipal services such as phone/network, power, and/or water, along with representing a potential attraction for future investment in the area. If a heating plant were to prove successful at another site, these and other benefits could be explored to help offset the significant cost of distribution. As mentioned in the case study, there is also the opportunity to bury the lines without the use of tunnel infrastructure, which could be explored in order to further reduce distribution costs.

The cost of conversion is the second potential roadblock for users to switch from their current heat source to a new one. If large capital is needed to switch, then a larger fuel cost gap needs to exist in order to have an attractive payback. Some investigation into the type of existing heating systems within the buildings would be necessary. If the building has an existing central heating system (i.e., boiler room) then conversion would be relatively low compared to a building with electric heating in each room. The added capital cost of converting to a central heating system may not be attractive to the user and make payback impractical.

The third consideration is the relative cost of the existing fuel source for the user's process/ building heat. Price and supply volatility may also be a factor as to whether or not a longer payback is a risk they are willing to take. Electrical energy pricing has traditionally been very predictable. Oil and natural gas have been more volatile but have returned to low pricing for extended periods. These long low price periods will delay any savings that could off set conversion costs. The cost of biomass for the boiler is also more volatile and is linked to the price of oil. As the price of oil increases, the market will turn to alternative fuels such as biomass, which in turn puts upward pressure on biomass pricing.

Overall a distributed heating system using biomass as the fuel source is not economically viable unless the end users are very close to the biomass boiler and have high demands for heat. Electrical generation is a potential add-on to the heating system but difficult to become economically viable in low capacity cases. Seasonal variations in load and the low heating requirements are the main drivers diminishing the return on investment and lengthen the payback period for the project.

4.0 Case 3: Single Building Heating/Cooling – Commercial

The third case study for scoping potential opportunities for biomass utilization is a standalone biomass unit dedicated to a single commercial installation. In consultation with the steering committee, two commercial building were assumed to makeup the case study. Both are assumed to use electric heating by way of ventilation coils and baseboard heaters. The first building will be slightly small at approximately 20,000 square feet, while the other will be slightly larger at 40,000 square feet but have a substantially larger air conditioning load. The first building, denoted at B1, will only focus on a heating system retrofit, while the second building (B2) will investigate the potential in servicing the building cooling load as well.

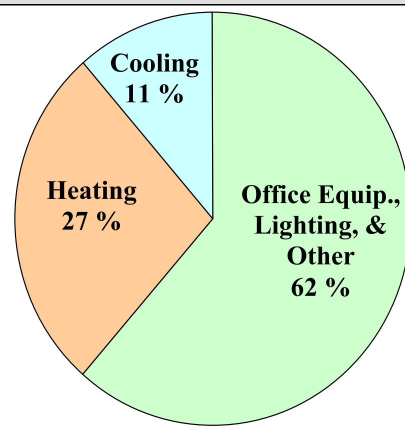
As in previous cases, an assumed electrical consumption and profile will be generated to suit both buildings and facilitate the analysis.

4.1 OPPORTUNITY DESCRIPTION

The two office buildings will be strictly dependent on electricity for all their heating, cooling, lighting, and office operational needs. Heating is typically accomplished by electric baseboards, and electric heating coils in ducting, with rooftop air handling units (cooling takes place in this unit as well). Like many office environments, apart from heating and cooling, they would also use computers, copiers, lunch room appliances, and lighting make-up the bulk of electrical consumption. These machines and the individuals that use them, release heat that is actually used to offset building heating requirement in office areas. Conversely, if the occupants are more focused on data processing or IT operations, then the amount of computer processing and electrical equipment in the building may require supplemental cooling even in the winter months.

The total heating energy requirements for the year were developed by assuming a baseline for the year and producing potential cooling and heating loads in their respective seasons. The yearly total for building heating becomes approximately 170,000 kWh, with 70,000 kWh for cooling. As outlined in Table 4.0, the heating and cooling loads only account for approximately 40% of the annual electrical consumption, with more than 60% being consumed by office operations. The exact division of electrical consumption for any given office building would require additional analysis should any work proceed as these are only approximations.

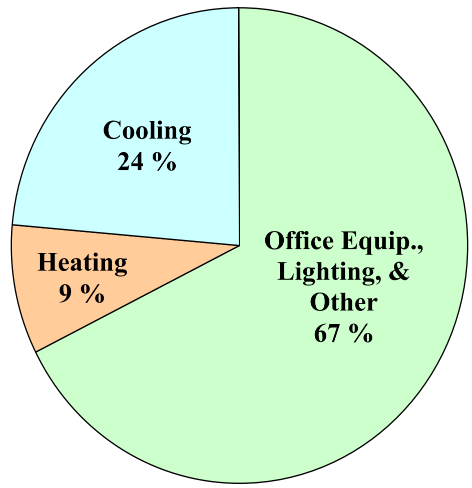
Table 4.0 – Break-Out Comparison of Electricity Use in the B1 Office Building

Use	kWh /Year	% of Annual kWh
Computers, Copy Machines, Lighting, Appliances, & Other	384,000	
Heating	170,000	
Cooling	70,000	
Total	**622,000**	

As mentioned earlier, it is interesting to note that some of the heating load is supplied by the heat given off from the office equipment (and personnel). Since this heat supply is integral to the office operation, it cannot be displaced by other forms of fuel such as oil or biomass. In this case, the energy must be supplied as electricity which is used in the office equipment and the heat by-product is then used to off-set the heating requirement for the building.

Along the same lines, the air conditioning require in B2 will further decrease the heating requirements. A typical ventilation system in an office building is setup to supply cold air to specified room to accommodate the heat load generated. Warm air is returned from these office spaces and re-circulated in the ventilation unit to reduce the need for heating. At the level of detail of this study, it is difficult to determine the exact impact on heating requirements, but the amount would drop from those presented in Table 4.0 for B1 (assuming it was the same size and had the same office functions). As such, Table 4.1 below presents an opinion of the probable breakdown for electrical consumption in B2. B2 is considered to be double in size, with more significant requirement for air conditioning due to an increased heat load due to occupants, laboratories, server rooms, etc.

Table 4.1 – Break-Out Comparison of Electricity Use in the B2 Office Building

Use	kWh /Year	% of Annual kWh
Computers, Copy Machines, Lighting, Appliances, & Other	1,110,000	
Heating	144,000	
Cooling	388,000	
Total	**1,642,000**	

Note commercial buildings typically have humidity control as well that would account for additional electrical consumption. The impacts of humidity control have not been considered at this high level assessment and require further analysis.

Given the assumed breakdowns for the two buildings, as presented in Table 4.1 and 4.2 for B1 and B2 respectively, Figure 4.0 outlines the assumed annual electrical profiles for the two buildings. These profiles and assumed demand curves will be employed to predict the requirements for a new biomass unit.

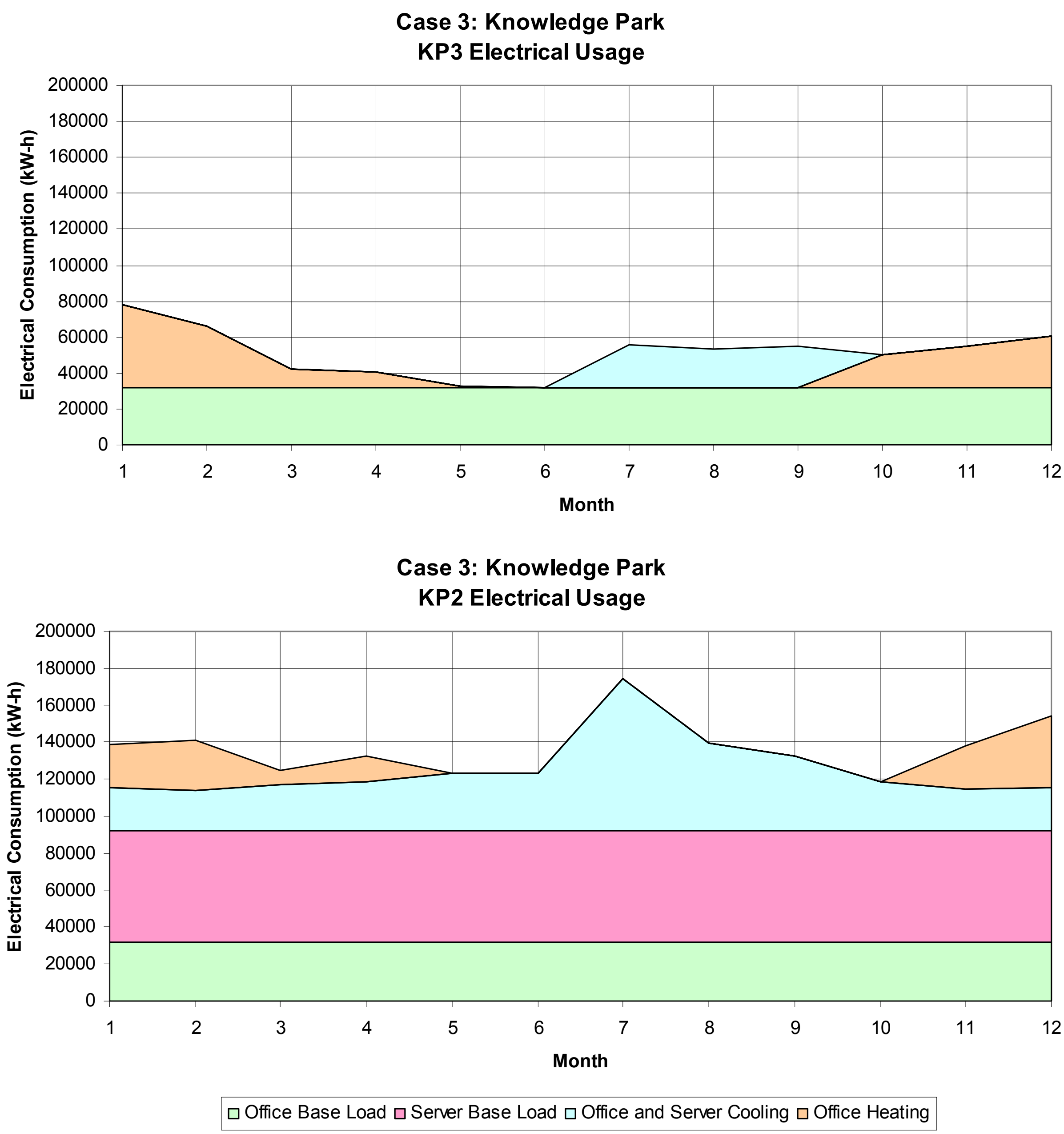


Figure 4.0 – B1 and B2 Assumed Electrical Usage Profiles for Base Loads, Cooling and Heating

The size of the biomass boiler is determined by the highest loading the unit may experience. For the purposes of this case study, B1 is set up to only service the heating portion of the electrical demand. B2 will be set up to service both the heating and cooling components to benefit from economies of scale as it presents the highest cooling load possible. Therefore, the highest heating loading B1 will experience is in the winter months, and based on the assumed demand curve for the winter, the capacity of B1 boiler will need be approximately 760,000 Btu/hr. The B2 boiler must account for the loading required due to cooling and heating. The peak demand for the B2 system is expected to occur in the summer peak of the cooling load, and based on the efficiency of the cooling technology discussed later, is expected to be 1,380,000 Btu/hr. .

4.2 HEATING AND COOLING TECHNOLOGIES/CONVERSION

This case study is based on determining the opportunity to use biomass to reduce the assumed commercial buildings' dependency on electric heating and cooling. The method employed to accomplish each aspect is outlined below with a description on the technology for heating or cooling and the retrofit requirements on the assumed buildings.

4.2.1 Heating

Offsetting the electrical heating requirements of a building requires a method to convert the raw solid fuel into heat, and a method to disperse the heat through the building. Converting the biomass supply into heat is accomplished in the same method as the other case studies by way of a boiler, in this case a hot water boiler. The reduced capacity of a boiler dedicated to a single building in turn reduces the overall capital cost of the installation, fuel storage requirements, and being able to switch from steam to hot water reduces the operation supervision and maintenance, compared with a steam district heating system.

There are a number of biomass boiler manufacturers for a range of heating capacities. Given the capacity range for B1 and B2, a KOB Pyrot Rotation Heating System is considered for the boiler. Headquartered in Austria, the KOB boiler is an efficient small capacity boiler capable for firing wood chips, pellets, and briquettes. Figure 4.1 provides photos of a typical Pyrot design, with a cutaway photo on the right. Fuel is fed in using the fuel auger into the furnace where it is ignited and gasified on the boiler grate. Ash is automatically discharged to an ash bin (not shown) while the combustion gases run over the horizontal tube heat exchanger used to generate the hot water. The flue gas exhaust is either vented out the stack/chimney, or recirculated for further combustion.

Figure 4.1 – KOB Pyrot Biomass Boiler Exterior (Left) and System Overview (Right) [www.kob.cc]

Once the hot water is generated, it must be piped to a distribution system to service the building. Two possible conversions of the heating system in the assumed buildings are considered. The first is a total system conversion, and the other is a partial conversion. The existing heating for the assumed buildings relies on electric heat provided by the rooftop generation unit, multiple small duct heating coils, and electric base board heaters. A total building conversion would require removal/demolition of the majority of the existing heating systems and replacing them with equivalent hot water systems. A partial conversion deals solely with the rooftop unit, avoiding the need to affect the interior of the building. The following are general overviews of both approaches.

A total system conversion would cover the following scope of work:

- Demolition of the existing electric baseboard heaters.
- Demolition of electric reheat coils in ducts.
- Demolition of electric air handler coil in rooftop unit.
- Removal/Replacement of acoustic ceiling tiles.
- Installation of new hot water baseboard heaters complete with associated piping.
- Installation of new hot water reheat coils in ducts complete with associated piping.
- Installation of new glycol air handler coil in rooftop complete with associated piping.
- Installation of new hot water to glycol heat exchanger with associated pumps.

For freeze protection, the hot water would have to be used in a heat exchanger with a glycol fluid which would in turn service the outdoor unit.

A partial conversion would cover the following scope of work:

- Installation of new glycol air handler coil in rooftop complete with associated piping.
- Installation of new hot water to glycol heat exchanger with associated pumps. For freeze protection, the hot water would have to be used in a heat exchanger with a glycol fluid which would in turn service the outdoor unit.

The partial conversion is based on the possibility to only retrofit the rooftop unit with heat from the hot water system. The existing electrical heating infrastructure in the interior of the building would remain and be used to trim the heating requirements. A good portion of the heating would still be serviced by the hot water system, but the peaks would be controlled using the existing electrical systems. This option requires further detailed study to determine the possibility of retrofitting the rooftop unit and the magnitude of the heating that can be displaced by the hot water system.

4.2.2 Cooling

The possibility of offsetting the cooling requirements of B1 using biomass is a challenging task, as it is fundamentally based on trying to cool using a heat source. Although contradictory, equipment has been developed to accomplish this task, and for the purposes of this study, a hot water absorption chiller will be employed, depicted in Figure 4.2. The chiller generates chilled/cold water that can be piped through a distribution system, similar to hot water, and used for cooling. In order to function, the chiller requires the use of hot water from the boiler, cooling water from a new cooling tower, and circulating pumps.

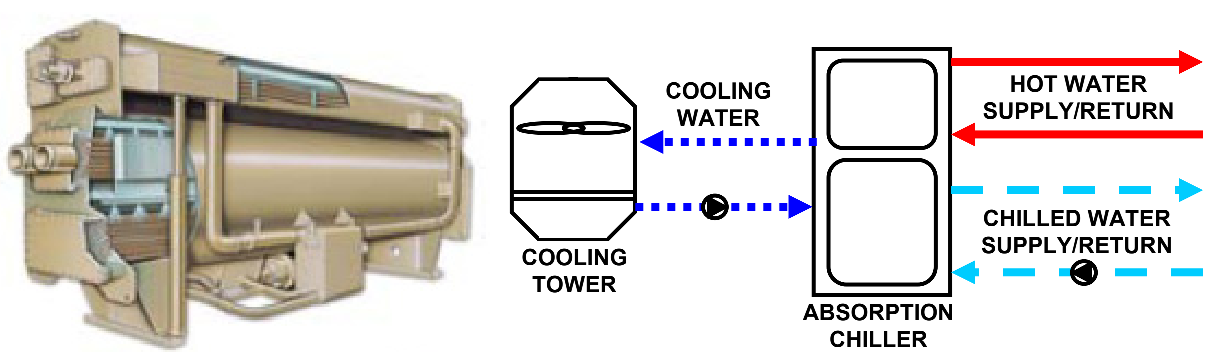


Figure 4.2 – Trane Absorption Chiller (Left) and System Overview (Right) [www.trane.com]

4.3 OPINION OF PROBABLE CAPITAL COST AND PAYBACK

Based on the electrical data provided, a high level assessment of probable heating and cooling load, and the equipment selected, opinions of probable cost for the two buildings were generated. The costs are broken down by major equipment and assumed miscellaneous direct and indirect costs. Conversion costs are added separately for discussion purposes. Table 4.2 outlines the opinions of probable cost for B1 Full Conversion (heating only), B1 Partial Conversion (heating only), B2 Conversion (heating and cooling).

Table 4.2 – Opinion of Probable Capital Costs for B1 and B2

<table>
<tr><th colspan="5">Opinion of Probable Capital Cost</th></tr>
<tr><td></td><td>B1 Full</td><td>B1 Partial</td><td></td><td>B2</td></tr>
<tr><td rowspan="2">Biomass Boiler Pyrot 220</td><td rowspan="2">$156,000</td><td rowspan="2">$156,000</td><td>Biomass Boiler Pyrot 400</td><td>$ 165,000</td></tr>
<tr><td>Absorption Chiller and Auxiliaries</td><td>$ 200,000</td></tr>
<tr><td>Civil</td><td>$ 50,000</td><td>$ 50,000</td><td>Civil</td><td>$ 90,000</td></tr>
<tr><td>Electrical</td><td>$ 35,000</td><td>$ 35,000</td><td>Electrical</td><td>$ 55,000</td></tr>
<tr><td>Mechanical</td><td>$ 60,000</td><td>$ 60,000</td><td>Mechanical</td><td>$ 140,000</td></tr>
<tr><td>Indirects:
Admin, Owner Costs, Engineering, Commissioning</td><td>$100,000</td><td>$100,000</td><td>Indirects:
Admin, Owner Costs, Engineering, Commissioning</td><td>$ 160,000</td></tr>
<tr><td>Boiler System Total</td><td>$401,000</td><td>$401,000</td><td>Boiler System Total</td><td><b>$ 810,000</td></tr>
<tr><td>Conversion Costs</td><td>$300,000</td><td>$ 50,000</td><td>Conversion Costs</td><td>$ 400,000</td></tr>
<tr><td>Project Total</td><td>$701,000</td><td>$451,000</td><td>Project Total</td><td>$1,210,000</td></tr>
</table>

The biomass boilers are quoted Pyrot systems including fuel storage, furnace, ash removal, tube cleaning, freight, and start-up. The absorption chiller and auxiliaries is also vendor quoted. Civil, electrical, and mechanical costs encompass: foundation, structures/buildings, insulation, instrumentation, electrical wiring, piping, painting, and other miscellaneous costs. Project in-directs cover administration, owners costs, engineering and commissioning. These costs require further analysis in detailed design. In detailed design an option to be explored is a ‘containerized’ Pyrot, in which the boiler is shipped and contained in a shipping container which may reduce some installation costs (although may be less aesthetically pleasing).

Conversion costs for heating alone are expected to be between $50,000 and $300,000 depending on the level of conversion inside the buildings. Completing demolition and replacement work on the interior is very expensive due to the time, materials, and labour requirements. Avoiding entering the building, and retrofitting the outside equipment, is a possibility but is not likely to reduce the capacity of the boiler required. As well, the smaller the boiler becomes, the more challenging the economics become as it is the boiler supply and installation that drive the bulk of the cost, differential costs for capacity increases are minor in comparison (i.e., the Pyrot 400 has twice the heating capacity of the Pyrot 220, yet only requires a 20% increase in equipment cost). Conversion costs on B1 require the complete replacement of the rooftop unit and an additional heat exchanger along with the interior replacements making it substantially more expensive. If the hot water heating piping system for B2 was to have been installed during its initial construction, a new system would cost approximately $250,000 (not including boiler costs).

Once installed, there are costs associated with operating the new units as outlined in Table 4.3. A unit of this size does not require hourly or daily attention. For this scenario it is assumed that the operator will only be needed on a part time basis to ensure fuel hopper is filled, ash is removed, there are no operation problems such as plugging of fuel feed system, and general inspections of the equipment. For the purposes of this exercise we have assumed a weekly commitment of approximately four hours per week. The B2 installation is more complex with additional equipment and checks required; hence it has a high annual cost.

Maintenance and material cost are a fact of the units operation and represent an average over the life of the unit. Maintenance and material will have a lower cost in the initial years of operation until system degradation starts. An allotment is indicated for insurance, taxes, and other miscellaneous cost of operating the unit and its structure.

The final significant operation cost is the fuel. The Pyrot units are designed to accept a variety of fuels but perform at their highest efficiency on wood pellets, or chips with a moisture content less than 30%. Due to the limited quantities required for the boilers, prices will be higher than for a large industrial user. Prices for chips ($125/GMT) and pellets ($330/GMT) round out the assumed operation costs, as presented in Table 4.3.

Table 4.3 – Opinion of Probable Annual Operating Costs for B1 and B2

Opinion of Probable Annual Operating Costs			
	B1 Full	B1 Partial	B2
Operating Personnel	$ 4,000	$ 4,000	$ 10,000
Maintenance and Materials	$ 7,500	$ 7,500	$ 16,000
Insurance, Taxes, Misc.	$ 1,500	$ 1,500	$ 4,000
Annual O&M	**$ 13,000**	**$ 13,000**	**$ 24,000**
Fuel Consumption Chips, 30% MC, $125/GMT	52 GMT $ 6,500	39 GMT $ 4,900	326 GMT $ 40,800
Fuel Consumption Pellets, 8% MC, $330/GMT	40 GMT $ 13,200	30 GMT $ 9,900	248 GMT $ 81,900
Total Annual Cost (Chips)	**$ 19,500**	**$ 17,900**	**$ 64,800**
Total Annual Cost (Pellets)	**$ 26,200**	**$ 22,900**	**$105,900**

In order to justify the conversion from the existing electrical heating/cooling systems to biomass, there must be a great enough savings. As outlined in Table 3.5, the reduction in annual electrical consumption would generate an annual costs savings between $13,000 and $17,000 per year for heating only (B1), and $53,000 per year for replacing the heating and cooling for B2. The revenue presented in Table 4.4 doesn't account for the electricity required to run the boiler and auxiliary equipment, therefore should be considered a maximum in order to screen for economic viability. Based on these figures, and the annual operating costs outlined in Table 4.4 on the following page, it does not appear economically viable to pursue converting the buildings of this nature over to biomass as the cost savings do not outweigh the new operating cost. This does not even consider paying down the capital investment.

Table 4.4 – Opinion of Probable Annual Cost Savings for B1 and B2

Opinion of Probable Annual Cost Savings			
	B1 Full	B1 Partial	B2
Reduction in Annual Electrical Consumption (kWh)	169,520	127,140	531,504
Annual Off-Set Electrical Cost ($0.10 kWh)	**$ 17,000**	**$ 13,000**	**$ 53,000**

4.4 CASE 3 DISCUSSION

The following sub-sections outline specific areas for discussion or additional information as requested by the steering committee in the initial scope of work, or during case presentations. Items covered include sensitivity analyses, greenhouse gas intensities, and a general discussion with options to improve viability/alter policy.

4.4.1 Sensitivity Analyses

Based on the results of this case, the steering committee, in consultation with Stantec and AGFOR, has proposed to conduct a feasibility study on a more suitable site. Of interest is a site with a higher heat load, existing hot water infrastructure, and located in a more rural setting (similar to the assumed middle/high school in Case 2). This approach is currently under review.

4.4.2 Greenhouse Gas Intensity

An assessment of greenhouse gas (GHG) intensity or reductions for Case 3 is presented in Table 4.5. For the purposes of the point source heating system, the potential GHG emission reduction are only associated with electricity for this site. As with Case 2, the electricity reduction needs to be placed in the context of the New Brunswick electricity GHG intensity during the winter months and is approximately 0.5665 tonnes of CO_2 equivalent (CO_{2e}) per megawatt-hour (MWh). As mentioned, the electrical saving presented here is a maximum and does not account for electrical consumption of the boiler or auxiliary equipment which would lower these potentials.

Table 4.5 – Potential GHG for the B1 and B2 Full Installation

Building	Fuel and Approximate Annual Consumption	Annual	
		GHG Factor Provided by NBDOE	Annual GHG Reduction (tonnes CO_{2e})
B1 Full	Electricity (169,520 kWh)	0.5665 tonnes CO_{2e}/MWh	96
B1 Partial	Electricity (127,140 kWh)		72
B2	Electricity (531,504 kWh)		301

4.4.3 General Discussion

The unexpected low heating demand for such large buildings is explained by the nature of the activities within the building. A high use of electricity for computers, lighting and other business machines results in waste heat being generated and dispersed into the building ventilation system. This lowers the demand for make up heat from the building heating system. This may change over time as more efficient lighting and computing equipment become available. With a biomass heating system there would be more incentive to upgrade electrical equipment based on efficiency since displacing heat generated by electrical equipment would lower cooling costs during the year.

Based on the heating and cooling requirements of the B1 and B2 buildings, and the appropriate biomass equipment, there appears marginal opportunities for implementation. The greatest challenges are operation costs, fuel cost, and scale. Operations costs presented here cover very limited operator time per week on the system. In detailed engineering or prefeasibility study, a number of the current KOB installations should be contacted and visited to gain a more in-depth understanding of expected costs/requirements.

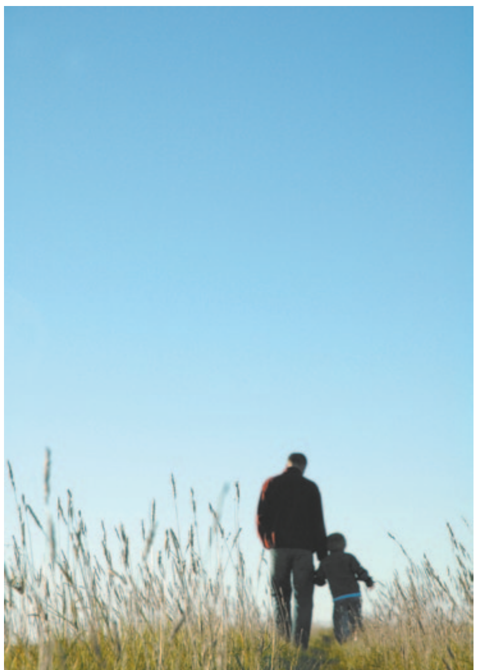
Fuel for the units was considered as low moisture content chips or pellets. There are variations in the expected costs of either fuel, as the capacities of the boiler units are relatively small for bulk fuel purchasing. Therefore the pellets costs are better than a residential rate for pellets, yet not approaching an industrial rate for a higher volume consumer. Chips are considered in a similar fashion where industrial users will be paying $50 - $80/GMT and there will be a premium for additional processing and delivery to a small capacity, remote user. As biomass installations increase, there maybe an opportunity to make a business case for receiving, processing, and delivering lower moisture content fuels to multiple point source locations. Benefiting form bulk purchasing and distribution, this may further reduce the expected operating costs. This service could also be tied to potential boiler operating and services agreements.

Beyond the fuel impact, the scale of these units also impacts the payback. Having point source heating in this case (i.e., one biomass boiler for each building), does not appear practical or economical. Servicing a number of similar buildings very close in proximity (concentrated district heating application) off a single boiler complex would reduce the capital cost by a significant amount, and reduces the operating cost and maintenance costs. This is the advantage of district heating over point source heating when the heating and cooling requirements are in close proximity.

If the operational costs could be lowered to make an attractive business case, a second scenario to consider for operation would be for the fuel supplier to provide the capital investment of the retrofit (conversion and boiler) and to then supply the building owner with a monthly charge for energy that would be slightly lower than the price of electricity. In this scenario the supplier has more control of biomass pricing versus capital repayment on the heating system. The supplier would also get any benefit from the increases in electricity cost inflation. The building owner would not have to invest capital or operating costs and therefore should expect a much lower saving benefit. There may also be other compelling factors for the building owner to switch fuels such as carbon footprint mitigation or “green policies” within their company business values.

There may also be government initiatives to switch from fossil fuels to carbon neutral ones such as biomass that could help lower the payback period for the retrofitting of existing heating systems. The greatest benefit of the incentive would be to cover the costs of conversion or the new biomass equipment which even is greater. Retrofitting a building that has a natural gas or oil furnace may be less extensive for the building conversion, in comparison with all electric, but would have the similar equipment cost as considered in Case 3, all things being equal.

Because of the budgetary accuracy of the costing and the sensitivity to capital costs for payback calculations it is recommended that a more detailed cost analysis be done. This would include looking for lower cost boiler systems and detailed routing of the piping and heat exchanger installation for the actual building. By getting a detailed design and more case specific contractor pricing, a more accurate estimate can be used to determine the viability of converting a building. From the case study, further analysis should only be considered for B2, and possibly B1, on a heating basis only. For B2 the conversion to biomass burning would not be a good investment due to the inefficiencies of biomass absorption cooling, and the lower season heating requirements.



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