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Montpelier District Energy CHP Feasibility Study

Prepared for:
The City of Montpelier

October 15, 2008

MONTPELIER DISTRICT ENERGY CHP FEASIBILITY STUDY

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For:
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EXECUTIVE SUMMARY

The purpose of this report and the work that informs it was to build on previous development work to provide a more detailed study of the combined heat and power (CHP) potential for a wood-fired district energy system that might be built in Montpelier, Vermont. The system under study would link a central heat and power plant to a network of buried heat distribution pipes connected to all the larger buildings in and around Montpelier's downtown. Under district heating, individual building owners buy their heat from the system instead of operating their own boilers and furnaces. An operating principle of this study was that the district energy system would be separate from the existing central plant owned and operated by the State of Vermont to heat the Capital District complex of state buildings.

The first of two report sections looks at general issues having to do with the overall concepts of district energy, including comparison of fuels that might be employed and the types of systems and technologies that would create power and distribute heat to users. The preferred medium for distributing heat to user buildings is hot water. While near-commercial technologies were considered in this report, the focus was on mature, commercial steam-cycle technology for CHP. The smallest district energy size for which this CHP technology would be economically justified, with full utilization of both the heat and power output, is 200 KW in electrical capacity and with the capacity to heat 300,000 square feet of space. System economic feasibility gets better as the size increases above this level.

Based on guidance from the Montpelier Planning Department and the Montpelier District Energy Committee, three sites were identified: one centrally located in the state Capital District (the current site of the State of Vermont central heating plant); one on the west edge of town; and one on the east side. Of these, the Barre Street site on the east side offers the best potential.

The study also considered "distributed" district energy potential – meaning that instead of one large central boiler plant multiple small plants might serve smaller groupings of buildings. These small mini-grids for heat could be built first and later consolidated into a larger centralized heat grid, or they could be built in areas where the main distribution grid did not reach. The study identified a few sites where such plants could be built. However, the distributed approach did not appear to offer a compelling advantage over the central plant and grid approach.

Woodchips and wood pellets were considered as central boiler plant fuels. While both fuels would work very well at this scale, economics strongly favor woodchips, which cost less than half as much as wood pellets. While the smallest feasible wood CHP system would only use 3,000 tons of woodchips annually, a previous study showed that the whole downtown area (excluding state buildings and National Life of Vermont) would require about 9,000 tons of woodchips. This earlier study estimated that all the larger heat loads in Montpelier (including state, National Life and other outlying buildings) would require 18,000 tons of chips annually. The current study determined that the five surrounding counties of Vermont have 750,000 acres of managed timberland within 25 miles of Montpelier and have far more wood available on a sustainable basis than would be required by this system.

The study found that the most likely way to market and distribute the electrical power produced by a Montpelier CHP plant would be through "group net metering" – assuming that the City of Montpelier would own the plant and would allocate the electricity to its own buildings and facilities elsewhere in the city. It appears that selling the power to the grid is less likely to be cost effective because the power will probably not qualify for Renewable Energy Credits (RECs) from the two states that currently define the New England REC market, Massachusetts and Connecticut.

The second section of the report lays out and studies a path to construction of what would be the first stage of a long-term project of system establishment and growth. To model and define this "first stage" scenario, we selected the Barre Street site as the most attractive plant location. We further defined a geographic grouping of larger buildings that could readily be served from this plant location, including Vermont College, municipal buildings on Barre Street, and the east side of the downtown. The 25 million Btu per hour wood boiler capacity would be sufficient to heat approximately 550,000 sq. ft. of building space. The projected sale of heat would be 34,500 million Btus, displacing the equivalent of 360,000 gallons of fuel oil annually. On the electric side, the CHP system would have a capacity of 400 KW and produce 1.25 million KWH each year. We estimated the project cost for building the plant (with two woodchip boilers and two backup oil boilers) and the heat distribution system to serve the identified buildings at $11 million.

A simplified "year 1" business pro-forma was developed to identify key factors that would determine system profitability. This first-cut analysis looked at how system costs would translate to a sale price for heat to customers under different assumptions. It was found that, if all the plant and distribution costs were allocated to heat sales in the "first stage" of system development, in the first year it would be possible to sell heat at a cost significantly less than building owners are now paying if the project got a $1 million grant subsidy. A more detailed analysis, based on an assumed schedule for system expansion into other parts of the city, would be needed to give a more precise analysis of the point at which the system would be profitable, sell heat energy at a cost less than building owners now pay, and create power valued at market rates.

This study demonstrates that a central wood-fired CHP plant linked to a downtown district heating network is likely to be cost-effective at today's fuel prices, with modest or no non-debt subsidy. The planned next step in project development is for the City of Montpelier to select an experienced development partner to do more detailed design and budget estimation, and to help the city determine the most attractive business model for the CHP district energy system.

This report was written at a time of great volatility in fuel oil pricing, when oil prices could easily go up or down 10-20 percent within a few months. The results of the analysis are sensitive to the price of oil. As the system is further developed it will be important to provide sensitivity analysis to assure an economically viable system under a variety of realistic future fuel price

INTRODUCTION

This report and the work that informs it were carried out by the Biomass Energy Resource Center (BERC) under contract to the City of Montpelier, with funding from the Vermont Clean Energy Development Fund (CEDF). In the course of this work BERC collaborated closely with the Montpelier Planning and Development Department and the volunteer Montpelier District Energy Committee.

BERC's broad charge was to study the potential for supplying heat and power from sustainably produced biomass fuel through district energy in Montpelier. The study was intended to be a preliminary look at combined heat and power (CHP) as it might be incorporated into a district heating plan for the city. The scope of work included, specifically: studying an optimized CHP system that would provide the highest utilization of both heat and power produced; studying, mapping and quantifying heat loads of groupings of buildings that might be served by district heating; studying the use and sale of electrical power produced; developing an economic plan to model the costs and benefits of a biomass CHP system, both to system customers and to the owner/operator of the system; and assessing the available, sustainable supply of both woodchips and wood pellets within a reasonable transport distance of Montpelier.

Under the terms of BERC's contract and Montpelier's grant from CEDF, the following items characterize the boundaries and constraints of the study:

- The conversion technology must be for biomass power or CHP.
- The project concepts studied must have a direct path to near-term renewable energy power production.
- The study scope will be for a "Montpelier only" system, not predicated on the use or modernization of the existing State of Vermont central heating plant at 120 State Street.
- Consideration will be given both to single central plant systems and "distributed" systems with multiple smaller biomass plants.
- Consideration will be given to the appropriate use of both woodchip and wood pellet fuels.

This report is divided in two sections. The first looks at general issues having to do with the overall concepts of district energy, including comparison of fuels that might be employed and the types of systems and technologies that would create power and distribute heat to users. The second section lays out and studies a path to construction of what would be the first stage of a long-term project of system establishment and growth.

I. GENERAL ISSUES IN CITY-WIDE DISTRICT ENERGY DEVELOPMENT

1. Project History

The Montpelier Community Energy System was first conceived in the early 1990s as a wood-fueled district heating system based on the successful model of Charlottetown, provincial capital of Prince Edward Island in eastern Canada. Initial discussions about the project were held at Montpelier City Council meetings at this time.

Phase I of project development started in the late 1990s when Community Renewable Energy (CORE), a collaboration between the Chittenden County Regional Planning Commission, the Central Vermont Regional Planning Commission and others, advanced the concept of wood-fired district energy for Vermont. CORE worked with Montpelier to fund a preliminary study that was carried out in 2000/2001 by Natural Resources Canada's CANMET division, (*District Energy in Montpelier, Vermont – Concepts & Review*) based on building survey work in Montpelier by CORE staff and GIS mapping by the Montpelier Planning Office. Also in 2000 the Montpelier City/State Commission completed the Capital District Master Plan, of which District Energy was one of the ten key elements.

Phase II of developing the Montpelier Community Energy System took place from 2002 to 2004. In this phase the key partnerships between the City of Montpelier (including the City Council and the Planning and Public Works Departments, as well as the Montpelier School District) and the Vermont Department of Buildings & General Services (BGS), the Department of Public Service (DPS) and the Department of Environmental Conservation's Air Pollution Control Division, supported by the City/State Commission. Joining these public entities were National Life of Vermont and a number of the city's largest building owners. Three studies were carried out, all with primary funding from the USDA Forest Service and the US Department of Energy, through grants received by BERC, with additional funding from the partners.

Phase III – consolidating the project and moving to implementation – consists of three stages. In the <u>first</u> of these stages BGS carried two engineering studies in 2005 and 2006, with $150,000 in funding from the Vermont Legislature. The first study looked at the capacity of the existing state heating plant and the second did preliminary engineering design and budget cost estimation for modernizing and expanding the plant. In this stage BERC, using US DOE funds, also updated the building survey from 2000.

The current report by BERC represents the <u>second</u> stage of Phase III, in which the City of Montpelier used a $25,000 CEDF grant to update the previous Natural Resources Canada CANMET study and reconfigure the project for CHP, without any assumption of connection between a "Montpelier only" system and whatever changes the State of Vermont might make to its existing system. During this stage, the City of Montpelier also put out a Solicitation of Interest (SOI) to identify and gauge the interest of district energy developers and other entities which might enter into a public/private partnership with the City in developing the Montpelier project. Respondents to the SOI are listed in the Appendix. To complete this phase of project development and move to implementation, Montpelier will select a partner through an RFP process, to do more detailed design and budget estimation, serving as the basis for decision-making on the scope and scale of the initial construction project for building the district energy system.

Phase IV – is the future implementation phase, which follows on and integrates with the system development work described above. The City of Montpelier will work with its development partner to secure final project construction funds and build the project. The City's $250,000 bond funds, already committed, will be used for part of the cost of the piping infrastructure to provide heat to community and downtown buildings.

2. CHP Technology for District Energy

BERC surveyed commercially mature and near-commercial technologies that could be used to provide hot water heat and electricity from both woodchips and wood pellets, across a range of scales and system outputs. The study looked at nearly-commercial and commercial CHP technologies for woodchip and pellet fuel, and also looked at district heating technology to distribute thermal energy to system customers throughout the city.

As part of the study, BERC developed a spreadsheet-based analytic tool that predicts the amount of heat and power produced by a steam-cycle CHP system sized to the square footage of heated space being addressed. This tool allowed us to look at different scales of implementation, from a central system that could heat the entire downtown of Montpelier to small neighborhood systems that might serve only a few buildings. The analytic tool also allowed us to consider the economic impacts of using either woodchips or pellets to displace no. 2 fuel oil, the primary fuel in use in Montpelier today. The tool also predicts the volume of woodchip or pellet fuel required to provide heat and produce power through CHP operation for any level of penetration of district heating in the city. Another key output of the tool is the ratio of thermal to electrical output from the central CHP plant.

Note that the analytic tool and its outputs are intended as a rough guide to address broad areas of feasibility in general and wood-fired CHP in specific. The tool and the process are intended to be used for comparison of options. The tool is not intended to provide precise determinations of heat load within the Montpelier downtown area, to size a system that might be built, to provide accurate quantification of the amount of wood fuel that might be required, or to provide budget-ready cost estimates.

Commercial Wood-fired CHP Technology

Our study of technology availability showed that there is only one commercially mature technology for producing both heat and power from woodchip or pellet fuel. It is ***conventional steam-cycle CHP technology***, in which wood (either chips or pellets) is burned in a high-pressure steam boiler, with the output steam introduced to a steam turbine. As the steam passes through the turbine a large part of its energy is used to drive a generator to produce electricity. The low-pressure steam from the turbine exhaust can then be used as a source of thermal energy. In this case the low-pressure steam would be run through a steam-to-hot-water heat exchanger, so that hot water could be pumped to supply heat to the buildings of the community through a buried pipe network.

Steam boiler and turbine technology is not widely available at scales less than 5 million Btu/hour (MMBH) thermal output, the size required to heat about 100,000 sq. ft. of building space (Montpelier High School is about 80,000 sq. ft.). The electrical power capacity at this scale of steam CHP is 65 KW.

At this scale, the net efficiency of wood-fired steam-cycle CHP is about 72%. On a BTU basis, the thermal output is 15 times greater than the electrical output. For every 1000 tons of woodchips burned (valued at $50,000), 6900 MMBTU of useful heat (with an oil displacement value of $240,000) and 220,000 KWH of electricity are produced (valued at $27,000).

Near-Commercial Wood-fired CHP Technology

BERC identified two near-commercial technologies that might be used for wood-fired CHP in Montpelier in the future. Neither is at a state of commercial development that would assure daily 24/7 reliable operation today, a key requirement for district energy.

The first is ***gasifier CHP technology*** in which wood fuel is introduced into a starved-oxygen reactor, driving off volatile gases. After cleaning and cooling, these gases can be used to power a gas engine, which would in turn run a generator for electricity. Heat from the engine coolant and exhaust, and from gas cooling, would be available for fuel drying and district heating. Our research found two companies with gasifier CHP on the near-term path to commercialization. One is Community Power Corporation located in Colorado, the developer of the BioMax gasifier, now available in pre-commercial status up to 50-75 KW in power output. The other is the Ankur gasifier from Ankur Scientific in India, available from 15 KW to 500 KW. Ankur gasifiers are commercial technology in India, but require modification to meet US environmental standards. A number of US companies are modifying Ankur gasifiers for use in this country. Gasifier technology is thermodynamically more efficient than steam-cycle technology and cleaner than boiler combustion technology.

The second pre-commercial technology is ***biomass gas turbine technology*** that uses wood fuel to produce electricity and steam (or hot water) employing a hot gas turbine (not to be confused with a gas combustion turbine).The system, developed by Zilkha Biomass, a Texas company, consists of a pressurized combustor, which generates hot, high-pressure gases that in turn pass through a cyclonic separator into a gas turbine, transforming biomass into electricity and process heat. Ambient air is pressurized in the gas turbine compressor section to provide air for combustion. Small dry particles of biomass are fed into a hopper and mixed with the compressed air. The combustor burns the mixture of biomass and compressed air and produces hot gases. The combustion gases are cleaned using a cyclonic filter before they are ducted to the gas turbine, which drives the generator to produce electricity. The system can be designed in different configurations to produce from 1 to 10 megawatts of electrical power. Turbine exhaust is used to provide thermal energy. The first such system in the US has been installed in a commercial facility in southern New Hampshire and is currently undergoing testing and technology refinement.

District Heat Distribution Technology

District energy is the production of thermal (heating and/or cooling) and electrical energy from one or more plants serving the thermal loads of multiple buildings. Those systems that produce only heating or only cooling are referred to as district heating or district cooling systems, respectively. Systems that also produce electricity from the same equipment at the central plant are called district CHP systems. District energy systems distribute thermal energy to customer buildings via pumped networks of insulated piping, usually buried. In this way district heating or cooling systems are a form of municipal infrastructure, similar to public water systems or sewage systems. Like these systems the product being supplied, in this case hot water, is metered at the user site and billing is according to consumption.

This study is predicated on the use of modern, European-style district heating equipment. The medium that transfers heat from the central plant or plants to the users is "low temperature" hot water (approximately 176-230 deg. F). Older district heating systems in US cities typically used steam as the heat transfer medium. Hot water distribution is more efficient, partly because the heat loss from piping is greatly decreased compared to steam.

The heat distribution piping is typically thin-wall welded steel with integral foam insulation and plastic jacketing, designed to be direct-buried at a depth of about 3 feet. Pipes are placed in pairs with supply pipes for the hot water from the plant and return pipes for the lower-temperature water being returned to the plant. Each customer building is served by a pair of lateral pipes from the supply and return mains. Generally these pipes enter the basement to connect to the heating system of the building. The central plant uses variable speed pump controls to minimize the amount of electricity used in pumping.

Inside each connected building, there is an "energy transfer station." For a building with hot water heat (serving baseboard, radiators, unit heaters or fan coil units for individual room heat), the energy transfer station includes one water-to-water heat exchanger for space heat and a smaller one for domestic hot water (DHW) supply. The larger heat exchanger replaces the building's boiler and the smaller one replaces the water heater. For most buildings in Montpelier, these heat exchangers will be compact and can be wall-mounted. The energy transfer station also includes a heat meter, which measures how much heat is taken out of the system water and transferred to the building. These meters are usually read monthly, like water or electric meters, with billing according to consumption. Usually when buildings are connected to district heating, the existing boiler is kept in place for one or two years while the customer gets used to the new service. After that, it is common to remove the building's boiler and water heater to free up space for other uses.

For buildings with hot water heat it is usually very simple to connect the supply and return laterals from the system mains to each building's own system supply and return pipes. For buildings with warm air furnaces, steam boilers, electric heat or propane space heaters, it is more difficult and costly to retrofit these systems to make them compatible with hot water heat coming from the district heating system. Electric heat needs to be removed and the building needs to be piped for hot water heating. Steam pipes and radiators need to be replaced with hot water distribution.

Warm air furnaces need to have water-to-air coils installed in the main heating ducts. Propane space heaters need to be removed and replaced with baseboard hot water for room heating.

3. CHP System Size

Unlike hot water boilers, high-pressure steam boilers at the central plant require full-time supervision by trained boiler operators. The staffing cost for such a plant would be about $150,000 annually, a significant operating cost. Because of this staffing cost, a 5 MMBH system run on woodchips would not be cost-effective. Woodchip-fired steam CHP systems start to be cost-effective at around 16 MMBH boiler capacity (14 MMBH thermal output and 200 KW power output capacity), when compared to oil-fired CHP systems. This size is necessary for the fuel cost savings to overcome the cost of labor for boiler supervision. At this capacity (16 MMBH thermal), the heat output would be able to supply heating to 300,000 sq. ft. of building space, about one and a half times the size of Montpelier's three schools combined. In addition to providing heat, the CHP system would produce about 700,000 KWH of electricity.

A plant of with a CHP capacity of 16 MMBH boiler output capacity (and 200 KW power output) would require, for a woodchip system, about three-quarters the space taken up by the State Capital Complex plant at 120 State Street, and about half the size for a pellet system. Thus, for a "Montpelier-only" district CHP system large enough to be cost effective, the plant space requirements will severely limit the available plant location options. With currently-available biomass-fired CHP technology, any cost-effective system would be far larger than neighborhood size. Earlier work suggests that there may only be five or six possible sites at this scale in the city.

4. Plant Siting

The Montpelier District Energy Committee has identified three promising sites in the city:
- ***East side*** – Barre Street (between river and railroad tracks)
- ***Central*** – State of Vermont Capital District Plant (120 State Street)
- ***West side*** – Green Mountain Drive (State Liquor Control warehouse area)

These sites are shown on the map on page ten of this report. Of these, two involve state-owned property and therefore would require cooperative development between the City of Montpelier and the State of Vermont. The east side site on Barre Street is on private property. There is also the possibility that a west side site might be developed on private property near Liquor Control.

The most promising site, in light of the City's interest in a "Montpelier only" system, is the Barre Street site on the east side of town.

Other sites might be useable for smaller satellite plants or for a large plant (such as a new industrial development outside the city, which could be co-located with a district heating plant and operate as a cogeneration facility).

Potential remote large industrial cogeneration system sites are:

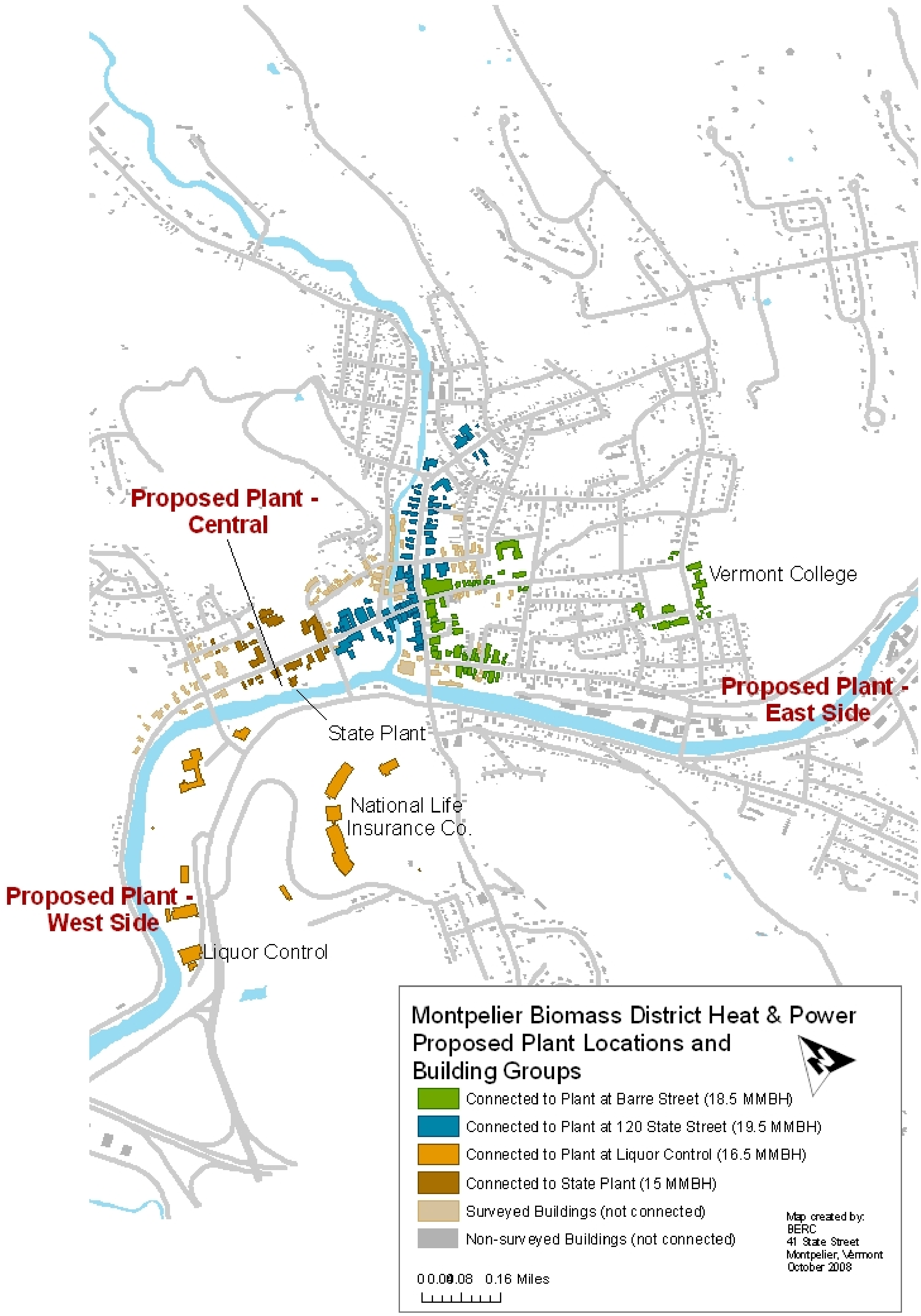
- National Life Annex site – near the train station, west of Montpelier
- Grossman's site – junction of US 2 and US 302, east of Montpelier

The satellite plant locations are:

- West side – north side of Barre Street (Sabin's Pasture site, behind Vermont College)
- National Life – the "stump dump" site on the access road to the National Life campus

These large industrial and satellite sites are shown on two maps in the Appendix (showing eastern and western Montpelier). In an earlier study of how air emissions impacts would determine the best central wood system sites, a number of sites were modeled. One of the outputs of this study was a determination of the likely stack height required for adequate dispersion of stack gases at each site. A map showing these sites is in the Appendix section, "Potential Sites For Boiler Facility" of the Capitol Complex Long-Term Thermal Energy Needs Study.

In addition, it might be possible to locate small pellet-burning satellite plants in a number of locations – such as the Montpelier School District building on Barre Street, recently taken over by the City – to serve very small clusters of buildings. These satellite clusters might be later incorporated into a central system as it expands over time.


Proposed Plant - Central
Vermont College
Proposed Plant - East Side
State Plant
National Life Insurance Co.
Proposed Plant - West Side
Liquor Control
Montpelier Biomass District Heat & Power Proposed Plant Locations and Building Groups
Connected to Plant at Barre Street (18.5 MMBH)
Connected to Plant at 120 State Street (19.5 MMBH)
Connected to Plant at Liquor Control (16.5 MMBH)
Connected to State Plant (15 MMBH)
Surveyed Buildings (not connected)
Non-surveyed Buildings (not connected)
Map created by: BERC 41 State Street Montpelier, Vermont October 2008
0 0.04 0.08 0.16 Miles

5. Types of Biomass Fuel

This study considers two types of woody biomass fuel, woodchips and wood pellets.

Woodchips come from two sources. They are a byproduct from sawmill activity, with wood that cannot be made into lumber (slabs, edges and off-cuttings) chipped at the mill and sold into a variety of markets – principally as feedstock for wood power plants and pulp mills. Woodchips are also produced in the woods, using large mobile chippers, taking low-grade cull wood and turning it into a saleable product. Woodchips are a high-moisture, green fuel, with moisture contents in the 28-45% range (wet basis) at the point of combustion.

Three primary markets utilize low-grade harvested wood from the forests – pulp, firewood, and biomass fuel. Pulp and firewood markets extract low-grade roundwood (logs) harvested primarily from tree trunks while biomass fuel chips are produced from a mixture of low-grade wood that can come from all parts of the tree except, in most cases, foliage.

Commercial harvesting of pulpwood (for paper products) and sawlogs (high-quality roundwood suitable for milling into lumber or making veneer) removes the main stem or high-value *bole* of the tree from the woods and leaves the tops and limbs either scattered in the woods near the stump or in a pile at the log landing. *Whole-tree harvesting*, where entire trees are dragged or skidded from the stump to the log landing instead of just the log, requires the tops and limbs be removed and piled at the log landing. This leftover wood can be chipped into biomass fuel commonly known as *whole-tree chips*. In some cases entire trees, not just the tops and limbs, are fed to the chipper to also produce whole-tree chips. *Bole chips* are produced from low grade or pulpwood. The difference between whole-tree chips and bole chips is that bole chips do not include the branches, tops or foliage. When the trees are harvested for bole wood the limbs are removed and the slash is left on the ground in the woods or at the log landing (depending whether the tree was de-limbed where it fell or at the landing).

Biomass fuel harvesting is common on larger commercial harvests using whole tree harvesting techniques. Whole-trees and tops and limbs cut from logs are chipped into fuel.

Wood pellets are typically made from sawdust, woodchips and other wood residues. The feedstock wood is ground up and forced through a die to produce a product that looks like and has the same particle size as feed grain. The heat of the process uses the natural lignin in the wood to bond the pellets and make them stable. No other binder or additive is used. In the U.S. most wood pellets are bagged and sold as residential stove fuel. New bulk-delivery markets are being developed now. Wood pellets are a dense, dry fuel, requiring less storage volume than woodchips, with a moisture content in the 5-10% range (wet basis).

6. The Amount of Biomass Fuel Required for District Energy CHP

The minimum size biomass CHP system for a Montpelier stand-alone district system would offset 200,000 gallons of fuel oil and require either 3,100 tons of woodchips or 1,800 tons of wood pellets. A previous study (CANMET, 2001) of district heating potential in Montpelier concluded that the diversified heat load of all existing large buildings in the downtown area (excluding the State Capital Complex and including National Life) would be about 46 MMBH. At this scale, 8,900 tons of woodchips or 5,100 tons of wood pellets would be required, and would offset 650,000 gallons of fuel oil for space heating. In addition to the heat output, 2 million KWH of electricity would be produced. An earlier study estimated that a city-wide woodchip district heating system would require 15,700-18,100 tons annually to heat both Montpelier and the State complex and also provide heat for future building growth.

7. Available, Sustainable Wood Fuel Supply for District Energy

Montpelier is surrounded by an estimated 3/4 million acres of managed timberland within an approximate 25 mile radius. The forests have ample stocking and annual growth of low-grade wood suitable for chip fuel. Current demand and harvesting for low-grade wood in Vermont is less than half of the amount actually grown annually. While the forest products industry in Vermont has experienced a gradual decline in harvesting and processing, much of the necessary infrastructure (foresters, loggers, chippers, sawmills, truckers, etc.) are in place and have the capacity to supply the required volume of chip fuel. Demand for wood fuels for biomass electric generation, home firewood heating, commercial and institutional heating, and pellet fuel production will likely continue to grow in the future. Forest sustainability safeguards such as harvesting standards, logger certification and third party "green" certification of the wood fuel should be explored in effort to make sure forest resources are responsibly managed in the face of increased demand for energy.

For district energy systems in Vermont, hardwood bole chips should be the primary fuel source and whole-tree chips should be sourced as needed. This mixture will provide an optimum balance of price, reliability and sustainability. The central energy plant should be designed and sited to allow for both receiving chipped fuel and delivery of roundwood fuel for on-site chipping.
The relatively small amount of approximately 5,000 – 20,000 green tons of annual woodchip demand from the Montpelier District Energy System would not over burden the region's forests. The acreage required to supply this wood is in the range of 7,000 acres for an initial system (as modeled later in this report) up to about 25,000 acres for the full build-out of district energy in Montpelier.

Given the location for the project in Montpelier and the locations of the other large volume consumers of low grade wood in the region, competition for the low grade wood resource is not as great as it would be if the project was located closer to large wood consumers like the pulpmills and biomass power plants.

A detailed study of woodchip fuel supply for district energy in Montpelier is in the Appendix.

Wood pellets are less likely as a fuel source for district energy because pellets, as a manufactured product, are significantly more expensive than woodchips (as quantified in the next section of this report). Pellets might be used in small, in-town satellite district heating plants where there is limited space for fuel storage and limited access for tractor trailer truck delivery.

A typical wood pellet plant has an output up to 150,000 tons of pellets annually. New England Wood Pellet in Jaffrey, New Hampshire, is the closest pellet manufacturing plant to Montpelier. Its production capacity is 80,000 tons per year. Other wood pellet plants are under construction or in planning in northern New England at this time. The demand for pellets from a Montpelier city-wide district CHP system fired with pellets would not tax the available or near-term future supply of pellets.

8. Wood Fuel Price Comparison

The cost per million Btu of wood fuel for CHP is calculated from the BTU content of dry wood (which is the same for woodchips and pellets), the moisture content of the wood fuel, the delivered price of the fuel, and the seasonal combustion efficiency of a large steam boiler burning that fuel. The cost per million BTU of fuel oil is calculated the same way, except that there is no water content. This analysis is relevant for boilers producing heat only, and does not apply directly to CHP systems.

The calculation output of the table below (right-hand column) represents the fuel cost of heat leaving the boiler (after combustion), comparing wood fuels to oil at a large, central boiler facility. Fuel prices assume bulk delivery to a central plant and efficiencies are for central-plant operation by a full-time, professional staff. Note that the efficiency and fuel price assumptions are not valid for residential scale fuel purchases. Based on the assumptions above, the fuel cost of heat from wood pellets is 50 percent less than the cost of oil and the cost of woodchip heat is 80 percent less than the cost of oil heat.

Fuel Type	Unit	Cost per Unit	BTU per Unit (dry)	Moisture Content	Average Seasonal Efficiency	Delivered MMBTU per Unit	Cost per MMBtu After Combustion
Oil	gallon	$4.00	138,000	0%	85%	0.104	**$34.10**
Wood Pellets	ton	$225	16,800,000	5%	82%	13.087	**$17.19**
Woodchips	ton	$50	16,800,000	40%	75%	7.560	**$6.61**

9. Cost to Produce Heat and Electricity with Biomass

When power and heat are produced at a central plant for sale to customers, the energy production cost is the sum of the fuel cost, the operating and maintenance costs, and the cost of capital for the equipment. For a 16 MMBH boiler plant producing 14 MMBH of thermal energy and 200 KW of electricity (the minimum plant size for CHP), a preliminary first-cut analysis to compare central plant fuels gives the following cost estimates:

FUEL:	Oil	Woodchips	Wood Pellets
Heat production cost per MMBtu	$45.72	$24.03	$30.17
Power production cost per KWH	15.6¢	8.2¢	10.5¢

Based on the cost to produce power with wood-fired, steam-cycle CHP at this scale, it can be seen that woodchips are the most economical fuel to use in a central plant, when fuel cost, system capital cost and O&M costs are all included. Using oil in a central district energy CHP plant would require the system to charge building owners to pay much more for heat than they do with their individual building heating systems, and the cost to produce electricity would be significantly higher than the cost of electricity on the market today. From this analysis, it appears that a wood-fired central CHP plant (chips or pellets) could produce power at a rate similar to market rates of 8-12¢/KWH. As discussed below, the best value of electricity produced at the CHP plant would be determined by whether the power was used by the City of Montpelier for municipal buildings through group net metering, or sold into the grid through a power purchase contract with the local electric utility.

It is important to note that the production cost estimates for heat production, shown above, do not represent the cost of heat sold to district heating customers because the cost of the buried pipe infrastructure to distribute the heat to buildings in the community and the cost of building connections are not included at this point (these costs will be treated in another section of this report).

It is also important to note that the analysis of this section is only for the purpose of comparing oil, woodchips and wood pellets as fuels for a CHP system. The second section of this report provides a much more detailed analysis of the central woodchip system potential when looked at from the perspective of a specific, first stage district energy project.

10. Use and Sale of Power

As explained in a detailed report in the Appendix, there are two ways that electricity generated by a CHP plant can be utilized. It can be self-used by the owner of the CHP plant through net metering, or it can be sold, most likely to the local electric utility, for distribution to the power grid.

It is not possible to direct the power produced by a city-owned plant to the use or direct benefit of community members, whether residential or commercial.

Under ***net metering***, the owner of the generating equipment can use the power produced to meet its own electric needs with any excess power going onto the grid. When the plant owner requires more power than it is producing at the time, it gets the needed power from its utility. The electric meter records power coming from the grid and power being fed back to the grid, which is netted out each month. At the end of the year, any excess power produced by the CHP system, beyond its own use for the year, would revert to the utility. Net metering is a way for a small power producer to get the best value for the power produced by offsetting its own retail-rate purchases from the utility. Net metering is particularly attractive for variable power production, such as a district CHP plant which generates according to the seasonal need for heat by its customers, since there will be times when power production is low and others when it is high. Without net metering, the small-scale producer would need to sell its power production to the utility at low wholesale rates.

Net metering is not very useful to producers who do not also require a lot of electricity. If a CHP plant owner only needs enough electricity to serve its plant needs, net metering would not be an effective tool for optimizing the value of the much larger amount of generated power.

Group net metering allows the generator who also owns other buildings or facilities with separate electric meters to direct, effectively, the power produced from its own plant to its other metered facilities. By aggregating the various metered accounts it owns, the power producer is able to displace expensive retail purchases of electricity with its own self-generated power. For example, if the City of Montpelier owned the district CHP plant, it would be able to include, under group net metering, electric use at the CHP plant, City Hall, the fire station, the police station, the Recreation Center, the sewage treatment plant and possibly the city's three schools in a group. The objective would be to use all the produced power in city accounts so that none would revert to the utility and the grid (on a net basis annually).

One feature of net metering and group net metering is that the producer of power cannot produce or sell any green credits, such as renewable energy credits (RECs). Green credits, also called *green tags*, are positive environmental attributes of produced power that may have market value separate from the value of the electricity itself. Carbon credits are one class of green energy credits. Renewable power producers will naturally want to get an additional revenue stream by selling green tags at the best price they can get, to supplement the revenue from selling electricity itself.

Sale to grid: The other option for getting financial benefit from power produced at a small-scale CHP plant is to sell the power to the utility for general grid use. If the power has no positive environmental attributes (such as being renewable or decreasing CO_2 emissions), the utility will only be willing to pay low wholesale rates for the purchased power. If the power from the CHP plant does have positive environmental attributes, then the utility would be willing to pay more as long as it has some economic or marketing use for owning the green tags associated with the power.

There is a relatively new REC market in New England because both Massachusetts and Connecticut have Renewable Portfolio Standards (RPSs). These standards require electric utilities that sell power in the state to certify that a certain percentage of the power in their generating mix is renewable according to strict state-set definitions, or to purchase RECs from other generators. This has bolstered the market for renewable power by producing an additional revenue stream for renewable power producers. In addition there is a voluntary market in green tags for businesses or individuals who want to buy green power to meet marketing or environmental objectives.

It appears that, using conventional biomass CHP combustion technology, key emissions components–particulate matter (PM) and NOx–will not meet the REC requirements of Massachusetts (for PM) or Connecticut (for NOx).

This non-qualification for RECS will limit the interest of Green Mountain Power, or other power purchasers, to buy electricity from the Montpelier CHP plant at premium prices. There may be interest on the part of Green Mountain Power, Central Vermont Public Service (CVPS), Washington Electric Co-op or other utilities to purchase power produced by a biomass CHP plant in Montpelier for use in voluntary green power programs, such as the CVPS "Cow Power" initiative.

Another option for the City of Montpelier would be to market the green tags from biomass power production itself, into the voluntary green tag market, selling to individuals or businesses who want to be "green" and support renewable energy broadly or support the city's efforts in green energy production.

At any rate, it is not clear that the green attributes of power from the Montpelier District Energy System would have enough value to make power produced at a cost of more than 8-10¢/KWH worth the additional capital and operating costs of a CHP plant, compared to a heat-only thermal district energy plant. One option to explore in more detail, as explained in the Appendix, is a yet-untested hybrid approach where a certain amount of power produced would be group net metered, with the balance being sold to the utility as green power.

11. District Heat Layout

The part of a district energy system devoted to distributing heat to buildings is called the district heat distribution system. The simplest district heating (DH) systems use a single heating plant with radial pipe mains (paired supply and return pipes) which carry the heat in multiple directions to the customer buildings. For larger systems, the distribution mains are interconnected into a network or grid of pipes so that there is more than one route for heat to get from the plant to any particular customer building. In urban settings these grids grow to include multiple heat sources: other boiler plants, backup plants, power plants, and industries with waste heat that can be sold into the system. It becomes in effect a heat grid with multiple sources injecting heat into the grid in different locations, and with many heat users extracting the heat they need.

District heating systems always have multiple boilers, usually with more than one fuel source, and often with more than one heat plant. In this way there are multiple redundancies in the system. If one boiler needs to be shut down for servicing, another takes its place. If one fuel becomes too expensive, an alternate fuel is used. If there should be a shutdown of a whole plant, a backup location takes over. If pipe fails or needs to be replaced in one area, the hot water is diverted to another route to reach the customers.

12. Distributed Community Energy Systems

In the dialogue of the Montpelier District Energy Committee, it has been suggested that an alternate system design might be to employ multiple, small boiler sites, each serving a number of buildings in close proximity, with no network of pipe connecting the different mini-DH systems. This *distributed community energy system* model would be well-suited for pellet systems since they are most cost-effective at a neighborhood scale too small for woodchip systems. In BERC's view this idea is not a viable alternative to a central-plant system because the distributed system and the customers would not have access to the least expensive wood fuel, woodchips. There are further difficulties in that the multiple pellet boiler plants would need to be under central ownership and control, raising issues about site location, land purchase or lease, and stack emissions at this small scale. Also, at this scale it would be impossible to do CHP, absent a technology breakthrough for very small-scale pellet CHP. Instead, we believe that the role for small pellet-fired boiler plants is as satellite plants in areas where the central distribution pipe network has not reached. Over time, as the central distribution system grows, these small plants would be connected to the main grid and would serve as backup plants that could feed the heat grid when needed.

13. Potential Users and Heat Load

A 1997 survey of buildings in Montpelier by Community Renewable Energy (CORE) identified 177 buildings that were deemed of an appropriate size for connection to a city-wide district heating system. The smallest buildings identified can be characterized as apartment buildings with five housing units, or small commercial buildings of approximately 3,000 square feet of heated space. CORE did site visits to a sampling of these buildings, inspecting heating plants and collecting heating fuel usage data. CORE worked with the Montpelier Planning Department to create a GIS map of these buildings.

The 2001 CANMET report used the CORE building identification as the basis for characterizing the potential heat load of all buildings that would be connected to a city-wide district heating system, including the Capital District of state office buildings (500,000 sq. ft.), the National Life complex of buildings (500,000 sq. ft.), the Montpelier School Department's three schools, the Vermont College Campus and other public and private buildings. CANMET applied a "heat loss factor" of 25.4 Btu/hour/sq. ft. to the heated space of buildings, and a "diversification factor" of 85 percent to arrive at an estimate of 72.7 million Btu/hour (72.7 MMBH) of connected load or 64.0 MMBH of diversified peak city-wide heat demand for the system, including an estimated 6.0 MMBH of demand from anticipated new state construction.

CANMET divided the city into three areas for the purpose of preliminary heat distribution layout and analysis, as shown below.

Area 1 North of the Winooski River, west of the North Branch of the Winooski
(including the Capital Complex of state office buildings)
24.9 MMBH

Area 2 North of the Winooski, east of the North Branch
(including most of Montpelier's downtown and two public schools)
24.4 MMBH

Area 3 South of the Winooski
(including National Life and Montpelier High School)
14.7 MMBH

There has been no analytic work since the 2001 CANMET study to provide more detailed estimates of potential heat loads for buildings in Montpelier.

BERC funded and carried out a survey of potential district heat customers in 2006, collecting data on heating system type, fuel and age. Working with the Montpelier Planning Department's GIS office, this data was used to create three color-coded GIS maps of potential customers, included in the Appendix.

14. Potential Plant Locations and Service Areas

For this report, which assumes a "Montpelier only" district heating system with no consideration of state loads, BERC looked at the three primary CHP plant locations identified by the Montpelier District Energy Committee:

Barre Street (***east side***, south of street, opposite "Sabin's Pasture")
120 State Street (***central***, current state plant site)
Liquor Control (***west side***, Green Mountain Drive, GMP or state property)

BERC used the previously created GIS map and CANMET's building load estimations to identify three geographic areas that might be served by heating plants located at each of these three sites, as shown in the three GIS maps in the Appendix. These maps also shows the state Capital Complex of buildings.

Using CANMET's building heat load estimates, BERC identified the larger buildings in areas that could be served from a plant at each of the three plant sites and summed the connected (un-diversified) loads for each plant:

Barre Street Plant (***east side***)	18.5 MMBH
120 State Street Plant (***central***)	19.5 MMBH
Liquor Control Plant (***west side***)	16.5 MMBH

The loads listed above do not include state buildings that are included in the existing Capital District heating system. The maps also show surveyed buildings that are not included in the heat load estimates above.

Note that the building clusters that might be served from the Barre Street and 120 State Street plant locations (east side and central areas) overlap to some extent in the downtown area near the intersection of Main and State Streets. Also note that the buildings that might be served by a plant at the Liquor Control site (west side) match CANMET's Area 3.

Because 120 State Street and Liquor Control are state properties, BERC believes that the most promising site for a "Montpelier only" CHP plant is the proposed plant location on Barre Street (shown on the GIS map "Proposed Plant Location and Building Group – Barre Street.") We envision this as the best site to locate a plant that would first serve Vermont College, Barre Street, the east side of Main Street, Union Elementary School and other larger buildings on the east side of Montpelier's downtown. A plant located here might expand over time to serve all of Montpelier, with the possible exceptions of National Life and the state's Capital Complex campus of buildings.

15. Building Connections

The district heat network will use hot water as the heat distribution medium. Any building in Montpelier with hot water heating (baseboard or other) and one or more boilers in a single boiler room can be easily connected to a central heating network using hot water. The connection between the network and the individual building heating system is described above in the "District Heat Distribution Technology" section. The interface equipment (heat exchangers for space heat and domestic hot water, energy meter, etc.) is called the "energy transfer station."

Buildings with steam heat, electric heat or propane space heaters will require significant retrofit before they can be connected to the central hot water network.

To minimize the up-front cost for customers of connecting to the heat network, we recommend that connection costs be provided as part of the district heat service, at no direct cost to the users. The cost of the building connections and the energy transfer stations would then be recovered through the cost of the metered heating service, on a "dollars per million Btu used" basis. For the purposes of cost estimation (below) we updated CANMET's 2001 cost estimates.

II. SPECIFIC DISTRICT ENERGY SYSTEM DEFINITION AND DEVELOPMENT

1. District Energy Financial Feasibility

The 2001 CANMET study modeled a full build-out scenario, for a district heat distribution system that would serve all of Montpelier, including National Life and the state Capital Complex. It found that the district system would be able to sell heat energy to customers at a cost marginally lower than they were paying for heating their buildings with their own heating systems. The economic analysis was based on the system's central plant being a modernization of the State's Capital Complex plant at 120 State Street.

BERC has used the core analysis of the CANMET study to update that report by applying new assumptions of fuel price and capital cost inflation. Since the CANMET study was completed seven years ago, fuel oil prices paid by building owners have risen from $1.45 per gallon to over $4.00, an increase of nearly 200 percent. At the same time, wood fuel price has risen from $30 per ton to $50 per ton, an increase of 67 percent. Increases in the cost of steel and concrete have dramatically inflated the cost of constructing a boiler plant and piped heat distribution network over the last seven years.

BERC's update of the CANMET study findings is included in the Appendix.

2. First Stage District Energy System and Pro-Forma Development

The current work was intended to move beyond a "whole system" analysis of the long-term potential of building a community system that would serve all buildings in Montpelier, to a more specific path towards implementation. This was done by first identifying the most likely and available plant location not on state-owned property, close to downtown Montpelier but not in the downtown. Then we modeled the heat load–geographic area and individual buildings–that might be served by such a plant. We then developed a "pro-forma" that included a budget for the initial CHP construction project and all the costs and revenues of a district energy company that would be established to run the system. This allowed us to project the amount of heating energy that would be produced (as well as electricity produced), and to compare the per-million-Btu price of heat from the central plant to that being paid currently by building owners for operating their own heating systems.

The "best" plant location, by these criteria, is the Barre Street Plant site on the east side of Montpelier, on the south side of Barre Street, between the railroad tracks and the Winooski River.

We preliminarily sized the wood boilers for the plant with a peak output capacity of 25 MMBH, using a 20 MMBH main wood boiler and a 5 MMBH summer wood boiler. There would also be two oil boilers, also of 20 MMBH and 5 MMBH capacities, to give complete redundancy and security. The total plant boiler capacity would then be 50 MMBH. The boilers would produce high-pressure steam for CHP operation. The plant would also include 400 KW of turbine-genset power generating capacity (to match the 25 MMBH of wood-fired heating capacity on an optimized basis).

The wood boiler capacity would be sufficient to heat approximately 550,000 sq. ft. of building space. The projected sale of heat would be 34,500 million Btus, displacing the equivalent of 360,000 gallons of fuel oil.

The proposed project for the first phase of construction would then be able to heat all of the buildings shown in the map titled "Proposed Plant Location and Building Group – Barre Street" with wood fuel, with approximately 35 percent extra plant capacity to extend to more buildings downtown in the future. This plant capacity would match the building loads of CANMET's Area 2.

The budget estimate for the described project (at approximately ± 25% accuracy) is given below, in 2009 dollars. Keep in mind that this is the budget for the proposed first stage of system construction, not for the full system build-out.

Budget Summary	
Plant	$3,900,000
Heat distribution	$2,500,000
Customer connections	$2,100,000
Total Construction	$8,500,000
Land	$200,000
Design & other project costs	$2,300,000
Total Project Cost	**$11,000,000**

The pro-forma developed for this analysis is presented in the next section below.

3. Results and Sale Price for Heat

The simplified pro-forma for a district energy business based on the assumptions above is given on the next page. It shows the budget for the first implementation stage and how that would translate to a Year 1 operating cost assuming a certain level of grant funding available to the project. It assumes a plant staffing level necessary for 24/7 coverage of the steam boilers and generating equipment. It assumes that all customers (shown on the Barre Street Plant map in the Appendix) will be connected to the system in Year 1 and will buy all their heating energy from the system.

On the revenue side, the pro-forma assumes that the system will be run in "heat priority" mode, with electric production as a byproduct. It assumes a differential sale rate for heat between "public" buildings (City of Montpelier and Montpelier School District properties) and all other or "private" buildings.

Sale rates for heat were set at levels that would provide savings to heat customers while also providing enough revenue to customer system costs.

Simplified Year 1 Pro-Forma for 25 MMBH System					
Expense					
System capital cost					$11,000,000
Grants [1]					$1,000,000
Cost to be financed					$10,000,000
Annualized system capital [2]					$795,000
Annual fuel					$280,000
Annual labor [3]					$145,000
Non-Fuel non-labor O&M					$120,000
Total Annual Expense					$1,340,000
Revenue					
Heat energy sold (annual) [4]			34,585	MMBtu	
	Private	Public			
	90%	10%			
Rate/MMBtu	$35.00	$42.00			$1,235,000
Electricity sold (annual)			1,237,632	KWH	
Sale price of electricity			$0.105	/KWH	
Electric revenue					$130,000
Total Annual Revenue					$1,365,000
Revenue in Excess of Expense					$25,000

Notes:

[1] The amount of grant funding was arbitrarily set at a level to make the system economically viable in the first year. Higher grant funding would allow the accumulation of an operating and expansion fund.

[2] It was assumed that the capital cost was provided by borrowing at 7.5% over 20 years.

[3] High-pressure steam boilers required for CHP operation must have three-shift coverage by trained operators.

[4] It was assumed that 10% of the heat energy sold by the system would go to buildings owned by the City and the Montpelier School District, at a lower rate than that paid by other building owners. The rates/MMBtu are explained below.

Using the assumptions stated above, with no grant funding available to the project, expenses would exceed revenues. The assumption of $1million grant funding produces a modest net revenue gain over expenses.

4. Sale Rates for Heating Energy

For any heating plant, whether it is a district energy plant or a plant owned and operated by a building owner, the value of heat can be quantified by adding up all costs of running the plant for a year. The most obvious of these costs is the amount paid for heating fuel. However, there are other costs, including those of repairs, replacement of major components from time to time, and (for larger plants) the cost of operator time.

The cost of the heating equipment and the space that houses it is also an operating cost. This "capital cost" component is generally accounted for in large plants but is often disregarded by smaller building owners, since they tend to looked at this as a part of the original construction cost of the building, not as an annualized operating cost.

When all costs associated with heat for a year are combined and divided by the heating requirement of the building (in million Btu per year), the result is the cost of heating the building on a "per-million-Btu-per-year" basis. Below are shown the cost of heat currently being paid by two classes of building owners in Montpelier: public schools and private commercial buildings (such as those in the downtown on State and Main Streets).

Current Cost per Million Btu of Oil Heat in Montpelier		
	Public Building (School)	Private Building
Fuel	$31.80	$46.40
O&M	$ 2.20	$ 1.70
Capital	$ 9.80	$11.80
Total	**$43.80**	**$59.90**

The reason why fuel costs are lower for public schools than for private buildings is that schools have large-volume oil storage tanks and can bid competitively for the lowest cost, bulk-delivered fuel oil. Private buildings generally have small oil tanks in their basements and pay a price for oil much closer to that of residential oil customers. This study assumes that the central plant will pay $50 per delivered ton for woodchip fuel, and that the price for oil will be $3.50 for large users (schools) and $4.50 for smaller commercial users. At this point in time oil pricing is extremely volatile, with significant changes, up or down, seen within a few months. No one knows what prices will be a year from now.

The challenge for a district heating company (whether public or private) is to be able to sell thermal energy (metered and measured on a Btu basis) at a price lower than that paid by potential customers for heat produced by their own heating systems. The pro-forma analysis performed for a Montpelier district energy system using wood fuel to produce heat (and electricity) demonstrates that heat can be produced at a cost of about $29 per million Btu (assuming that about 20 percent of all expenses can be attributed to power production).

It will therefore be difficult for the system to produce and sell heat to the public schools at a cost that can beat the schools' current fuel costs ($31.80 per million Btu). However, if the system sells heat to schools at $35 then the schools will come out ahead in the long run because their O&M and capital costs will be reduced to zero (building space now allocated to heating equipment can be converted to other uses and current heating equipment will not require replacement or repairs in the future).

For private building owners, and other non-city public building owners, it will be important to set the sale price of thermal energy below what they are currently paying in fuel price alone, since they will tend to look at fuel cost as their principal or only annual operating costs. Private building owners are unlikely to value the capital cost of their existing heating equipment and the space that houses it as annual costs that contribute directly to their costs of heating. For this reason, we have preliminarily set the sale price of district heat to non-city users at $42 per million Btu. This will represent a 10 percent savings on fuel bills for these building owners. Lower heating cost plus stability in heating costs over time should be compelling arguments for these building owners to connect to the system. As time goes on and oil prices rise, the system will become more attractive to potential customers because of the higher heating savings.

5. Need for Subsidies

Given the assumptions of this preliminary analysis, it appears that a modest one-time grant subsidy may be needed to make the system viable in the early years. It is important that system revenues be significantly greater than energy sales so that a fund can be established and built up to cover cash flow and to capitalize system expansion in the future. However, the analysis of this report is not significantly detailed, particularly in its budget estimation, to say definitively at this time whether or not a grant subsidy will be needed.

6. Summary of Pro-Forma Analysis

As can be seen by the discussion above, predicting the financial performance of a complex district energy system that creates and sells both power and heat through a piped distribution network, and which grows and expands over time, is not a simple matter. There are many budget and other assumptions that must be made and which are critical in predicting the expenses and revenues of the system. A $25,000 study can provide a general indication of likely system financial performance, but to get a more accurate assessment, much more detailed engineering design and budget estimation must be carried out.

This analysis looked at a first year snapshot of system financial performance. A more detailed and informative study would project growth of the system, in capacity and in energy sales, on a yearly basis over 20 years. A more detailed study would include the establishment of an operating fund to cover cash flow variations over the course of a year and from early years (when the system may run in the red) to later years (when most potential heat customers have been connected to the system and when revenues significantly exceed operating expenses). A more detailed study would also look at fuel price volatility (wood fuel price to the central plant and oil price to the individual building owner), to test in more detail the fuel prices at which the system is financially viable.

7. Next Steps

This study demonstrates that a wood-fired central energy plant linked to a downtown district heating network is likely to be cost-effective at today's fuel prices, with modest or no non-debt subsidy. For a central CHP plant, the heat side economics are more robust than on the power side. The City of Montpelier has charted a course that will move the project to construction on a relatively fast track. That course involves partnering with a private-sector firm with deep experience in district energy system design, finance, construction and operation. By sharing both the risks and benefits associated with creating a new energy infrastructure for the city, it is hoped that a system can be built that will provide heating cost savings and cost stability to building owners throughout the city, while also producing green power – all under a business structure that will be financially secure and capable of expanding the system over time.

The next steps in development of the project are to develop an RFP that will be used to select the best development partner. The selected development partner will immediately refine the analysis of this study, creating a more definitive project budget and pro-forma for the district energy company that will be formed to run the system. The development partner will also, working with the City, apply for a certificate of public good for the sale of renewable power for the plant and refine the power side of the CHP system design concepts. The form of the district energy company that will be created will be decided. Options include: a private company (possibly the development partner); an existing power utility; a cooperative; a non-profit; or a department of city government.

APPENDIX

A. GIS Maps

Proposed Plant Locations and Building Groups
- Plant at Barre Street
- Plant at 120 State Street
- Plant at Liquor Control

Large Industrial and Satellite Plant Sites – Eastern Montpelier
Large Industrial and Satellite Plant Sites – Western Montpelier
2006 Survey Data Maps
- Downtown Buildings & Heat Type
- Downtown Buildings & Heat Fuel Type
- Downtown Buildings – Year Heat Systems Installed

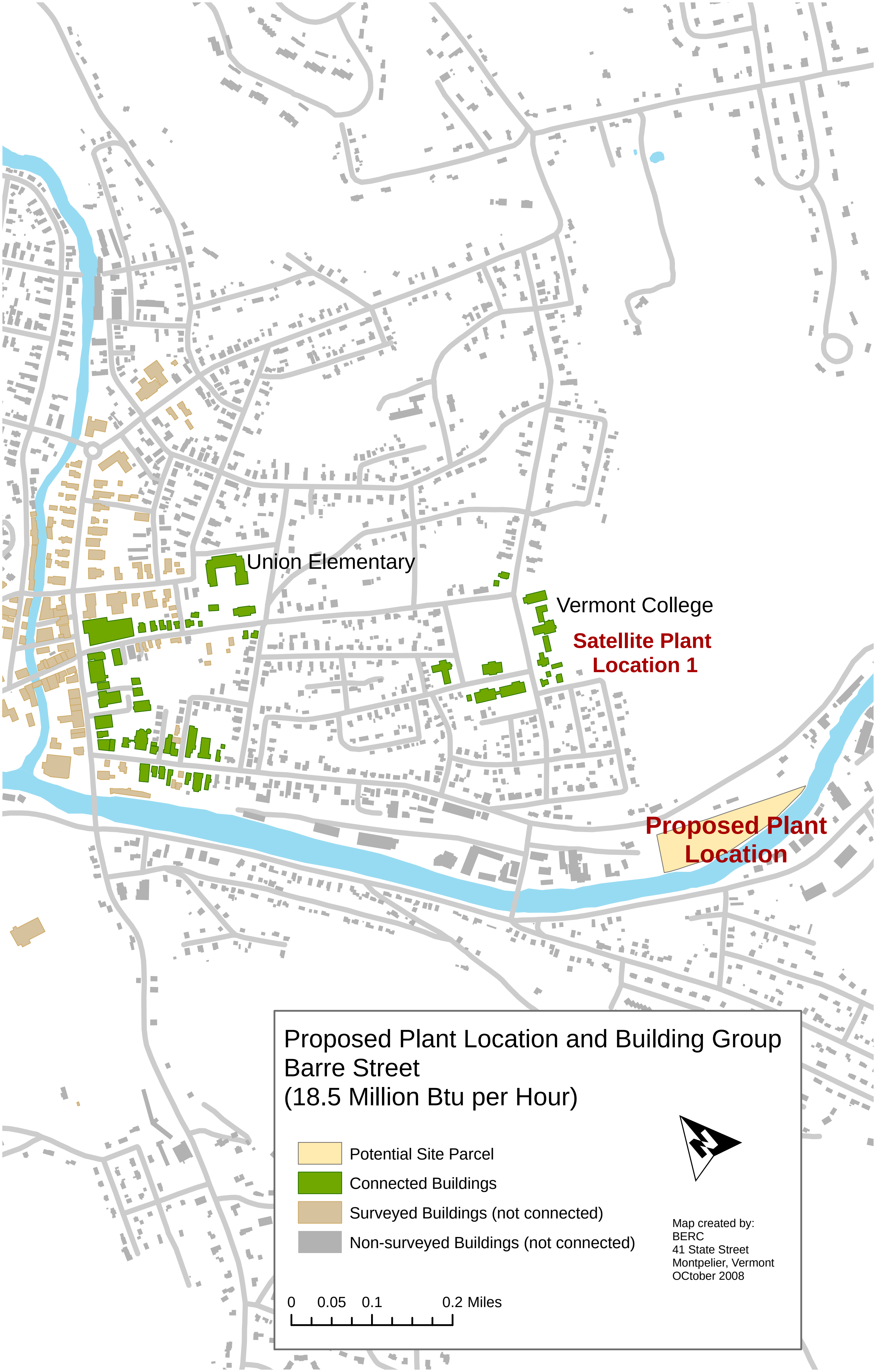
B. CANMET Study Update

C. Capitol Complex Long-Term Thermal Energy Needs Study, "Potential Sites for Boiler Facility"

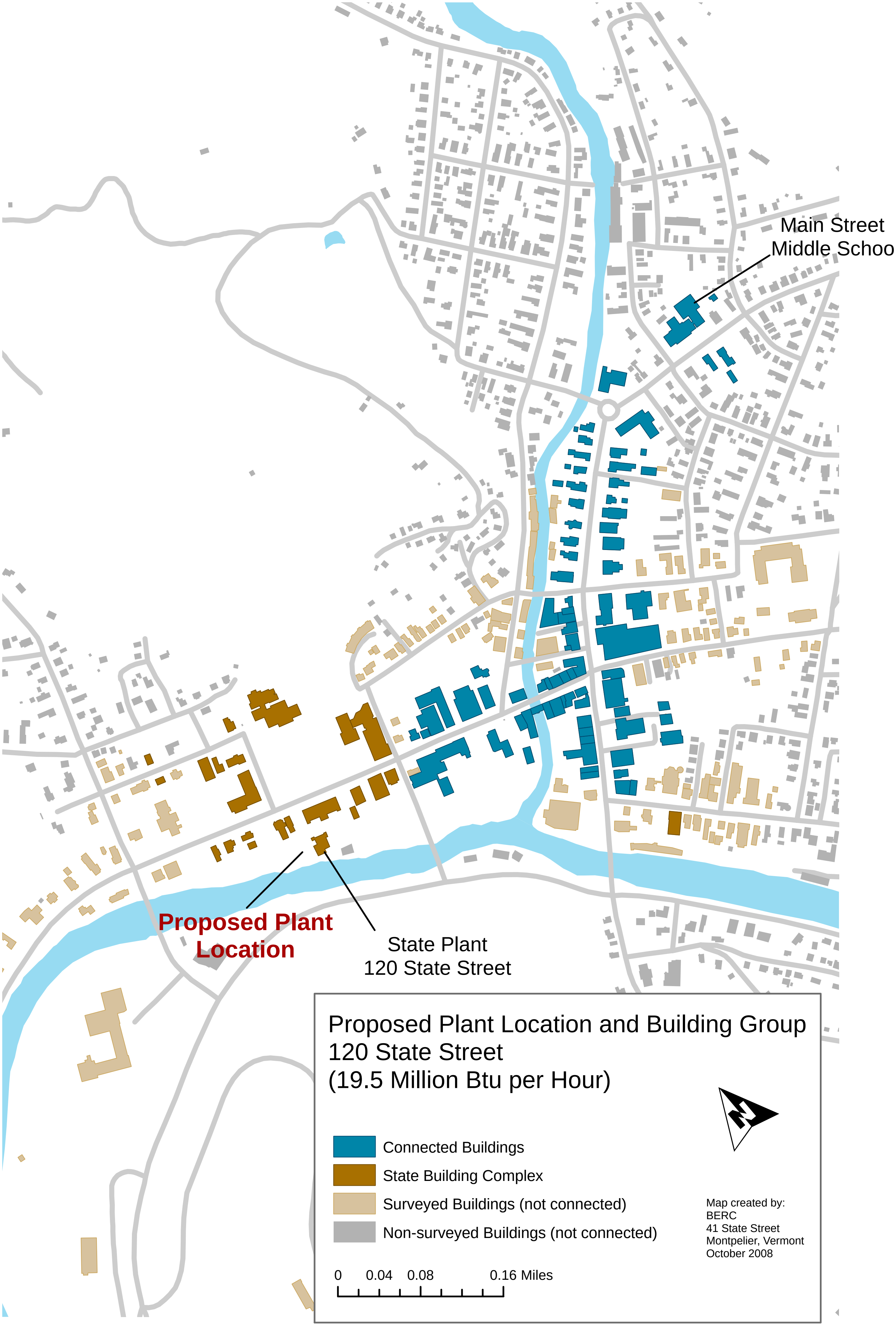
D. Solicitation of Interest Respondents

E. Research Reports

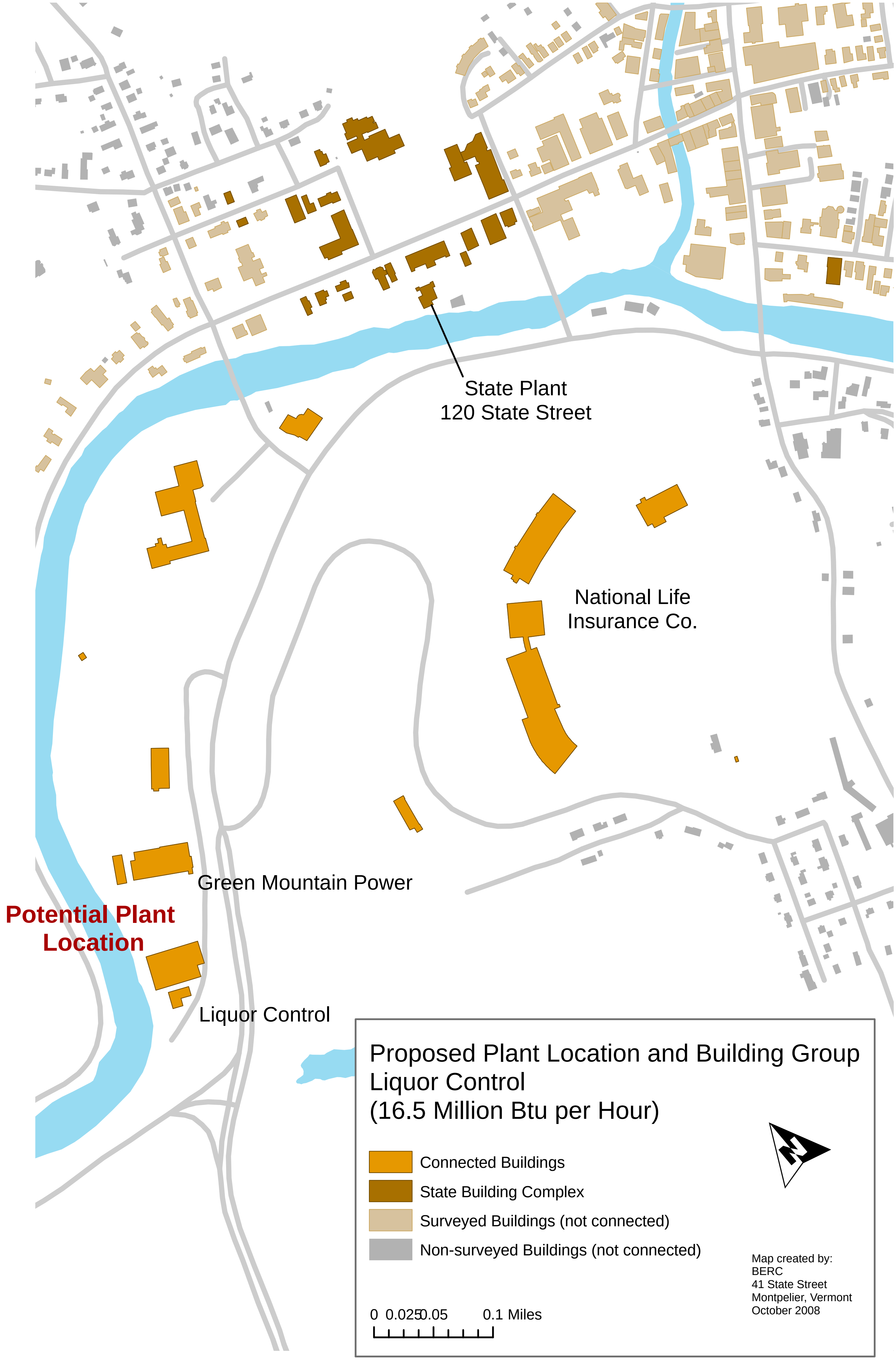
Assessment of Available, Sustainable Wood Fuel Supply
Assessment of Income Potential from Montpelier CHP System Power Sales
Survey of Renewable Energy Credit Requirements in the Northeastern States

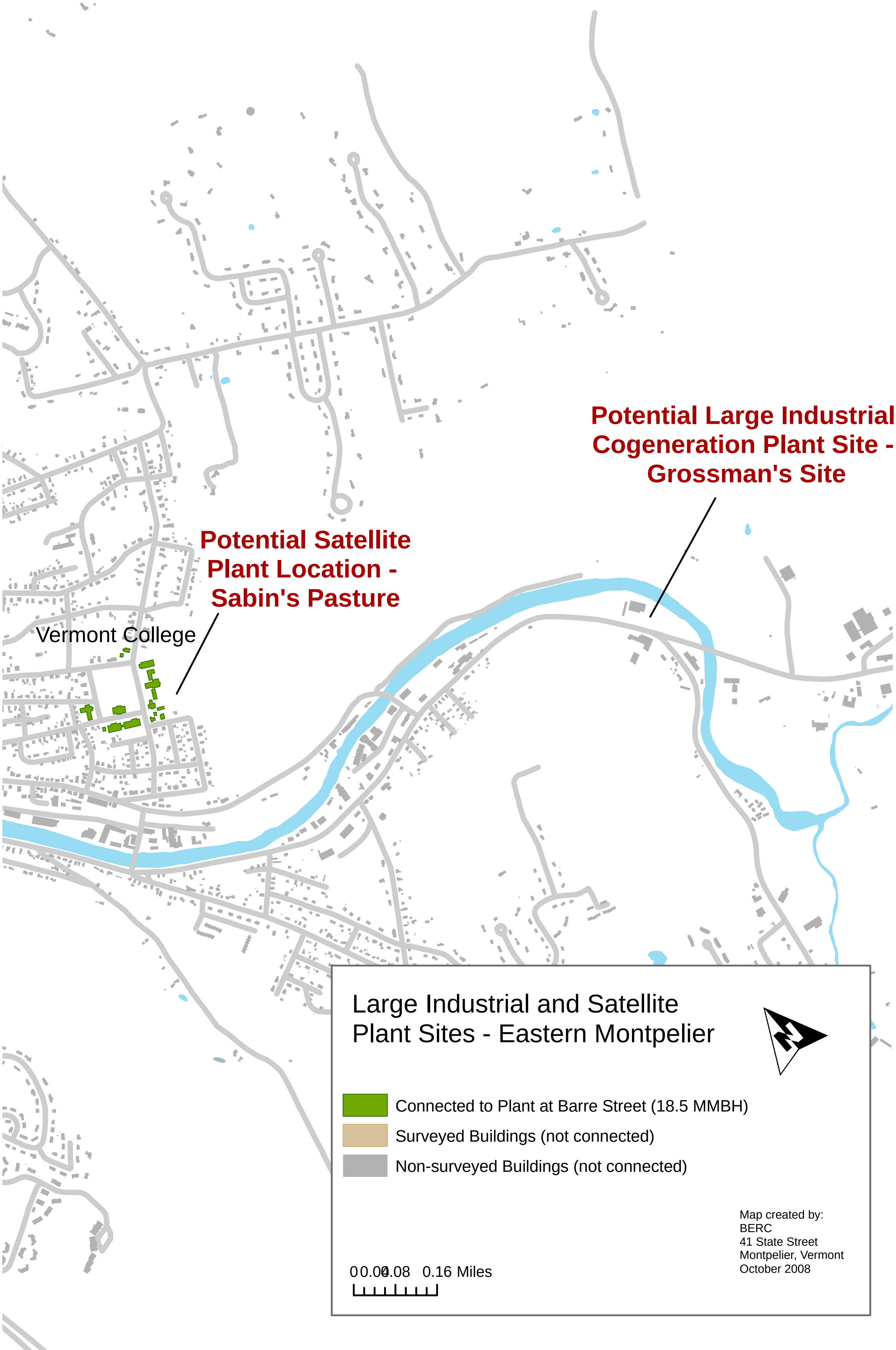


Union Elementary
Vermont College
Satellite Plant Location 1
Proposed Plant Location
Proposed Plant Location and Building Group
Barre Street
(18.5 Million Btu per Hour)
Potential Site Parcel
Connected Buildings
Surveyed Buildings (not connected)
Non-surveyed Buildings (not connected)
Map created by:
BERC
41 State Street
Montpelier, Vermont
OCtober 2008
0 0.05 0.1 0.2 Miles

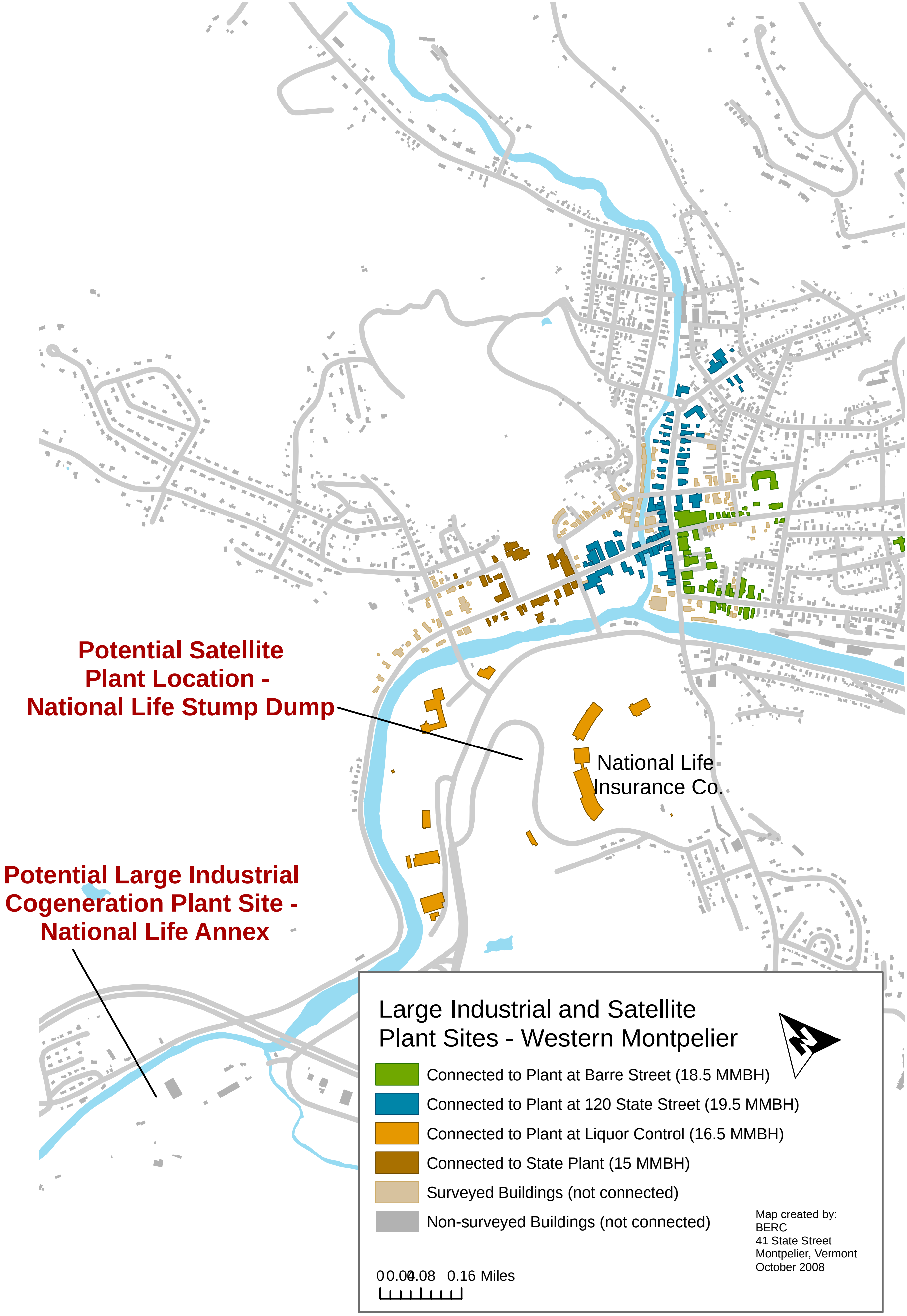


Main Street
Middle School
Proposed Plant
Location
State Plant
120 State Street
Proposed Plant Location and Building Group
120 State Street
(19.5 Million Btu per Hour)
Connected Buildings
State Building Complex
Surveyed Buildings (not connected)
Non-surveyed Buildings (not connected)
Map created by:
BERC
41 State Street
Montpelier, Vermont
October 2008
0
0.04
0.08
0.16 Miles


State Plant
120 State Street
National Life
Insurance Co.
Green Mountain Power
Potential Plant
Location
Liquor Control
Proposed Plant Location and Building Group
Liquor Control
(16.5 Million Btu per Hour)
Connected Buildings
State Building Complex
Surveyed Buildings (not connected)
Non-surveyed Buildings (not connected)
0 0.025 0.05 0.1 Miles
Map created by:
BERC
41 State Street
Montpelier, Vermont
October 2008



Potential Large Industrial Cogeneration Plant Site - Grossman's Site
Potential Satellite Plant Location - Sabin's Pasture
Vermont College
Large Industrial and Satellite Plant Sites - Eastern Montpelier
Connected to Plant at Barre Street (18.5 MMBH)
Surveyed Buildings (not connected)
Non-surveyed Buildings (not connected)
0 0.04 0.08 0.16 Miles
Map created by:
BERC
41 State Street
Montpelier, Vermont
October 2008



Potential Satellite Plant Location - National Life Stump Dump
Potential Large Industrial Cogeneration Plant Site - National Life Annex
National Life Insurance Co.
Large Industrial and Satellite Plant Sites - Western Montpelier
Connected to Plant at Barre Street (18.5 MMBH)
Connected to Plant at 120 State Street (19.5 MMBH)
Connected to Plant at Liquor Control (16.5 MMBH)
Connected to State Plant (15 MMBH)
Surveyed Buildings (not connected)
Non-surveyed Buildings (not connected)
Map created by:
BERC
41 State Street
Montpelier, Vermont
October 2008
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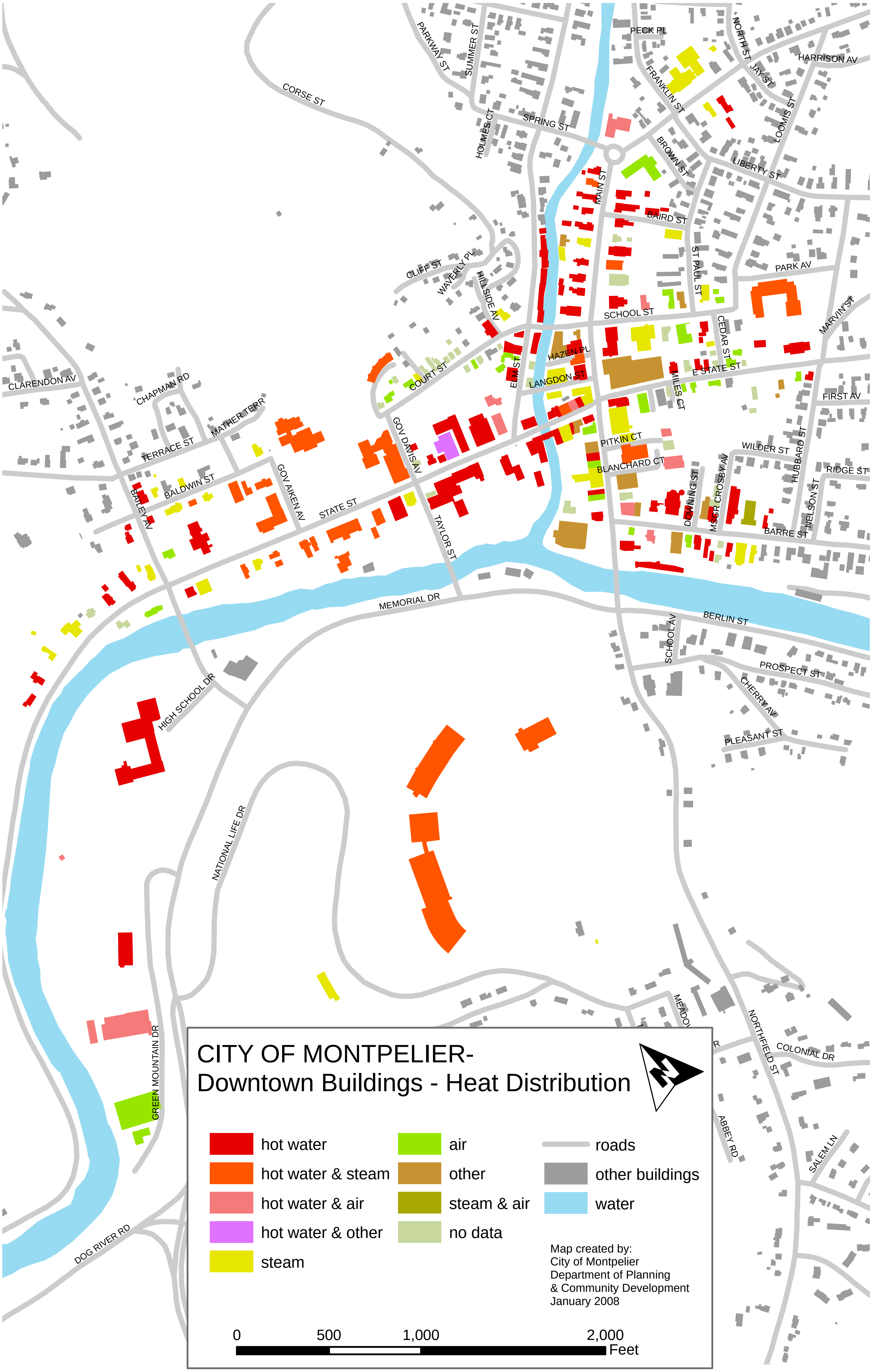
CITY OF MONTPELIER-
Downtown Buildings - Heat Distribution
hot water
hot water & steam
hot water & air
hot water & other
steam
air
other
steam & air
no data
roads
other buildings
water
Map created by:
City of Montpelier
Department of Planning
& Community Development
January 2008
0
500
1,000
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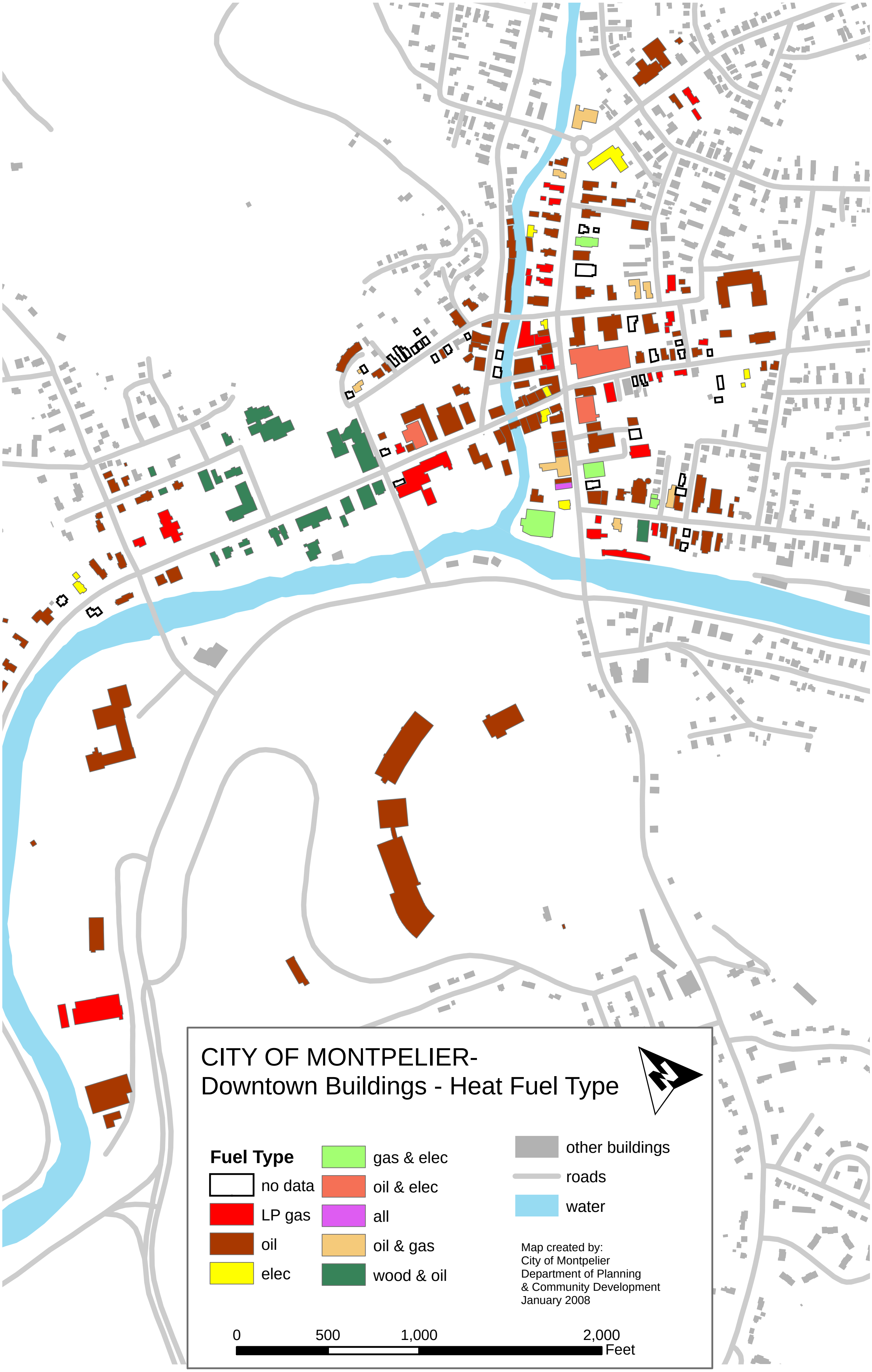
Feet
CORSE ST
PARKWAY ST
SUMMER ST
HOLMES CT
SPRING ST
PECK PL
FRANKLIN ST
NORTH ST
JAY ST
HARRISON AV
LOOMIS ST
BROWN ST
LIBERTY ST
MAIN ST
BAIRD ST
ST PAUL ST
PARK AV
CLIFF ST
WAVERLY PL
HILLSIDE AV
SCHOOL ST
CEDAR ST
MARVIN ST
HAZEN PL
ELM ST
LANGDON ST
E STATE ST
MILES CT
FIRST AV
COURT ST
CLARENDON AV
CHAPMAN RD
MATHER TERR
TERRACE ST
BALDWIN ST
BAILEY AV
GOV AIKEN AV
GOV DAVIS AV
STATE ST
PITKIN CT
BLANCHARD CT
WILDER ST
HUBBARD ST
RIDGE ST
DOWNING ST
MSGR CROSBY AV
NELSON ST
BARRE ST
TAYLOR ST
MEMORIAL DR
BERLIN ST
SCHOOL AV
PROSPECT ST
CHERRY AV
PLEASANT ST
HIGH SCHOOL DR
NATIONAL LIFE DR
GREEN MOUNTAIN DR
DOG RIVER RD
NORTHFIELD ST
COLONIAL DR
ABBEY RD
SALEM LN


CITY OF MONTPELIER-
Downtown Buildings - Heat Fuel Type
Fuel Type
no data
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oil
elec
gas & elec
oil & elec
all
oil & gas
wood & oil
other buildings
roads
water
Map created by:
City of Montpelier
Department of Planning
& Community Development
January 2008
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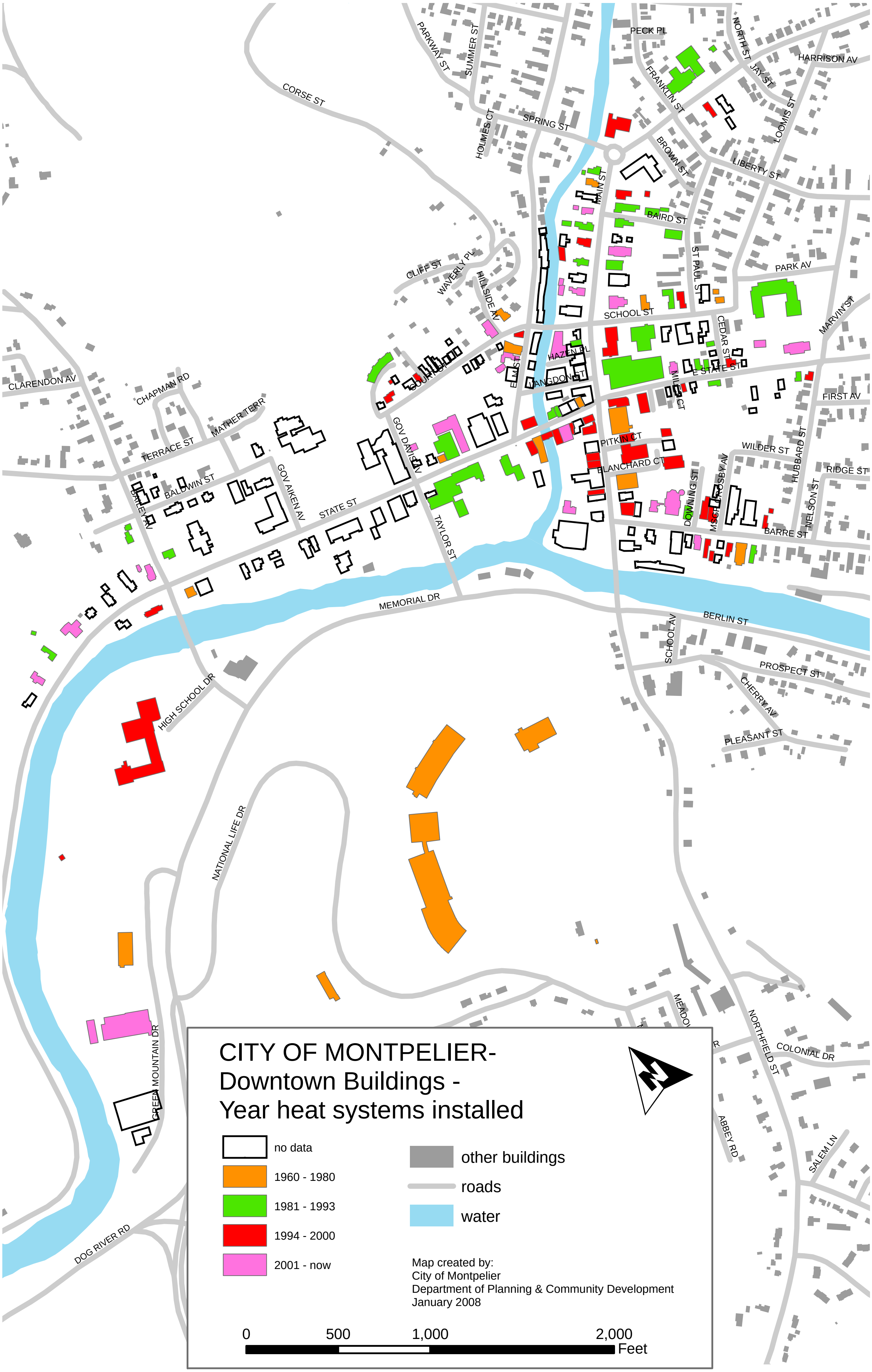
Feet


CITY OF MONTPELIER-
Downtown Buildings -
Year heat systems installed
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1994 - 2000
2001 - now
other buildings
roads
water
Map created by:
City of Montpelier
Department of Planning & Community Development
January 2008
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Feet
PECK PL
PARKWAY ST
SUMMER ST
CORSE ST
HOLMES CT
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NORTH ST
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TERRACE ST
BALDWIN ST
GOV AIKEN AV
GOV DAVIS AV
PITKIN CT
WILDER ST
BLANCHARD CT
HUBBARD ST
RIDGE ST
DOWNING ST
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BARRE ST
STATE ST
TAYLOR ST
MEMORIAL DR
BERLIN ST
SCHOOL AV
PROSPECT ST
CHERRY AV
PLEASANT ST
HIGH SCHOOL DR
NATIONAL LIFE DR
NORTHFIELD ST
COLONIAL DR
ABBEY RD
SALEM LN
GREEN MOUNTAIN DR
DOG RIVER RD

Appendix B

CANMET STUDY UPDATE

The Community Energy Systems Group, Natural Resources Canada (CANMET) prepared a report titled "District Energy in Montpelier – Vermont Concepts & Review" in March 2001. The table below shows the revised snapshot analysis given on page 22 of the original 2001 CANMET report. For this revised analysis, the total project cost was escalated based on increases in the chemical engineering plant cost index, and the O&M pumping cost was escalated using standard assumptions for inflation of 3.25 % per year (for 7 years) since the original report. Fuel costs were increased to $50 per ton for woodchips (from $30 per ton) and to $4.50 per gallon for fuel oil (from $1.45/gallon) based on the prevailing market rates in Montpelier, VT.

Option	Total Project (million)	Annualized Capital (million)	O&M and Pumping Cost (million)	Fuel Cost (million)	Total Annual Cost (million)	Unit Energy Cost Per MMBTU
Status Quo	$2.5 -3.7					$48.02
Option 1	$16.37	$1.526	$0.452	$1.04	$3.02	$22.28
Option 2	$14.49	$1.351	$0.413	$1.50	$3.26	$24.05
Option 3	$16.12	$1.503	$0.439	$1.04	$2.98	$21.99
Option 4	$15.16	$1.414	$0.426	$1.50	$3.34	$24.64

The updated cost estimates show that, compared to the earlier analysis, project costs will now be about 25 percent higher. However, the analysis is most impacted by the rapid increase in oil price compared to wood price. The updated analysis shows that state costs for district heating using oil at a modernized plant would be significantly higher than the costs of providing community-wide district heating from a wood system. The previous study indicated that the cost of oil heat from a central plant would only be 10 percent higher than the wood district heat cost whereas now it is almost double the wood heat cost.

Appendix C

EXCERPT FROM CAPITOL COMPLEX LONG-TERM THERMAL ENERGY NEEDS STUDY

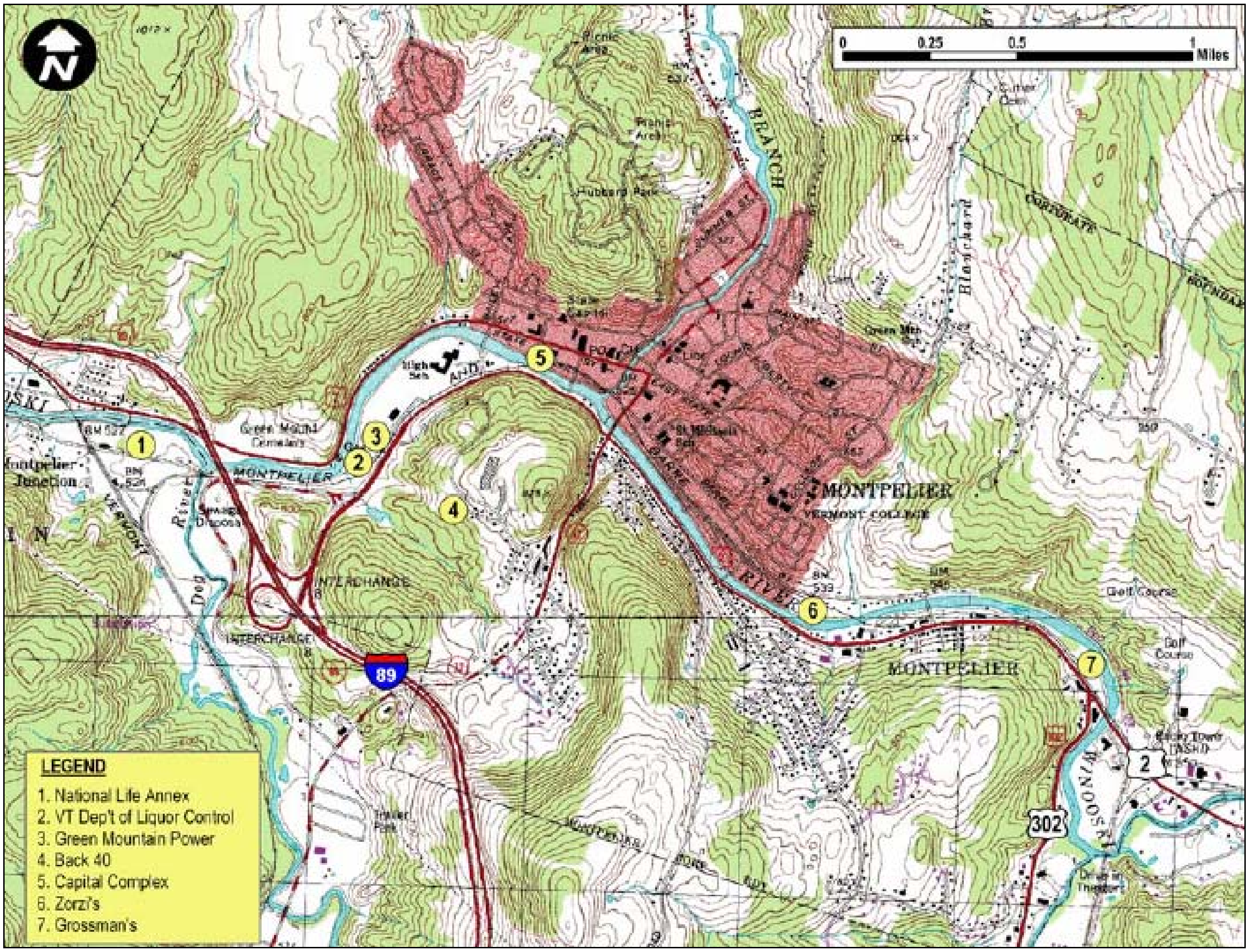
Section III: Potential Sites for Boiler Facility

Resource Systems Group (RSG) was engaged by BERC to conduct an air quality feasibility study for a hypothetical district heating plant, using both wood and oil to generate a maximum heat output of 85 MMBtu/hr. (See Appendix B for Executive Summary[1].) The RFS study also examined alternate sites for a facility that could meet the State's needs.

The Montpelier District Heating Steering Committee identified nine potential sites for analysis. Seven of the sites offered proximity to downtown Montpelier, rail and/or truck access and locations on (or adjacent to) properties owned by the State or National Life. Two additional sites were selected to assess the potential of a generating facility located to the east of downtown. Of the nine sites, two sites on the National Life property were eliminated due to the expectation that their stack heights would need to exceed 200 feet. Six of the remaining seven potential sites are located along the Winooski River Valley and one is located above the valley, near the National Life campus. The specific locations are shown on the map and described below:

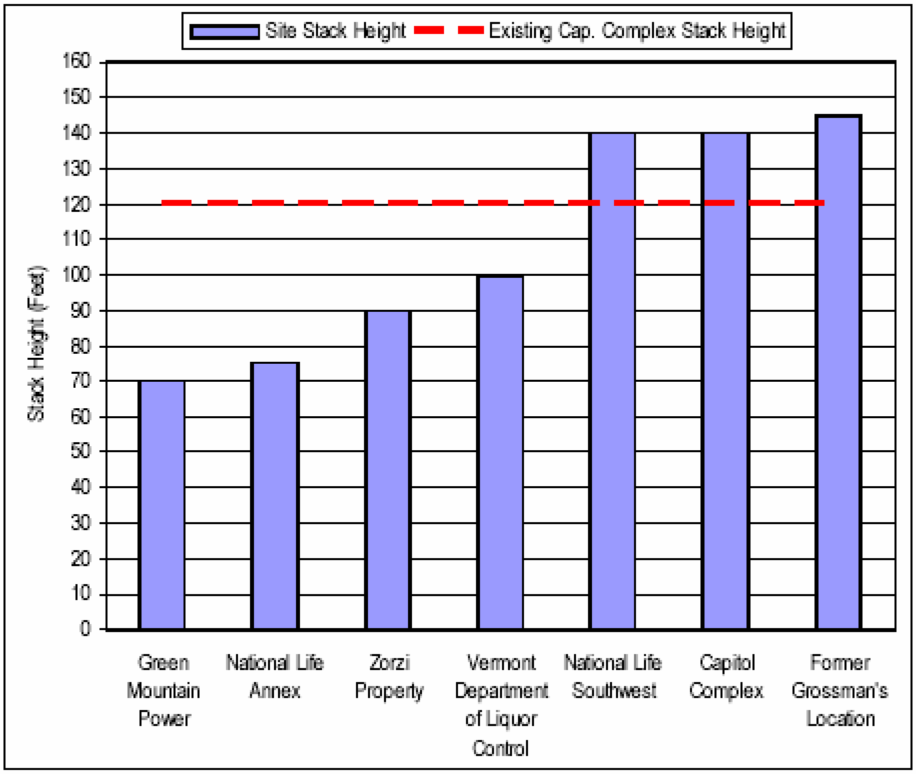
1. *National Life Annex*, Three Mile Bridge/Junction Road area;
2. *Vermont Department of Liquor Control*, 15 Green Mountain Drive;
3. *Green Mountain Power*, 7 Green Mountain Drive;
4. *National Life Southwest*, 1 National Life Drive (Southwest of Nat'l Life Main Building);
5. *Capitol Complex Central Heating Plant* (existing site), 122 State Street;
6. *The Zorzi Property*, 367 Barre Street; and
7. *Former Grossman's Location*, 260 River Street.

[1] A copy of the complete *Montpelier District Heating Air Quality Feasibility Study* as prepared by Resource Systems Group, Inc. is available upon request from either the Commissioner of Buildings and General Services or the Biomass Energy Resource Center.



A number of methods were used to assess the feasibility of the seven sites from an air quality perspective. The primary indicator of feasibility was whether or not the hypothetical facility was in compliance with relevant air quality standards as determined by using air pollutant dispersion modeling. This modeling incorporates boiler configuration, emission rates, historic meteorological data, land use, terrain, stack exhaust parameters, and building geometry. The 85MMBtu/hr facility was assumed to have 50 MMBtu/hr generated by wood-fired boilers, with the remaining 35 MMBtu/hr from oil-fired boilers. Total annual heat generation considered was 195,000 MMBtu's. All study calculations were based on peak demand. ISC3-Prime, a U.S. Environmental Protection Agency (EPA) air dispersion model, was used to estimate ground level concentrations of relevant pollutants.

Modeling results indicate the potential to meet all air quality standards at all sites, with stack heights ranging from 70 to 145 feet. The minimum stack height, 70 feet, occurred at the Green Mountain Power site. The maximum stack height, 145 feet, occurred at the former Grossman's location. The following chart indicates comparative stack heights:



Additional Site Considerations

Additional findings from the RSG analysis regarding site selection include the following:

- Excess heat generation capacity exists and can be expanded at the National Life Main Building heating plant.
- The proximity of each site to population should be considered, with greater priority assigned to sites which are further removed from population centers.
- It may be necessary to exhaust oil-fired and wood-fired boilers through two separate stacks.
- A fuel oil sulfur content of 0.3% may be necessary to meet the particulate matter emissions standard.
- If implemented, a community-wide district heating system could eliminate emissions from state, municipal, commercial, and residential buildings which join the district heating system and deactivate their own heating systems. This could result in a net improvement in air quality near those buildings, as the district heating system would emit less air pollution per unit of energy generated and have greater dispersion ability than the heating systems in those buildings.

Appendix D

SOLICITATION OF INTEREST RESPONDENTS

	Bonhag	Constellation	Dalkia	Ever-Green	Noresco	RDA Engineering	Veolia
Fuel	Wood chip biomass	Biomass	Wood chips or pellets	Biomass	Biomass	Biomass	Local wood.
System	CHP. One central plant or three satellite systems.	Steam CHP or heat	Cogeneration/CHP	CHP or thermal only.	CHP or thermal.	District heating.	CHP and cooling. Sizing is flexible.
Scope	No preference.	No preference.	No preference.	No preference.	No preference.	No preference.	Customer commitments.
Technical Risk	40 year equipment life. N-1 assurance. Open to different technologies.	They absorb all repair and replacement risk.	They manage technical risk and share financial risk.	Use and integrate proven technologies.	Coordinate OEM support for plant equipment.	No preference.	Velioa assumes equipment risk.
Location	No preference.	No preference.	Distributed sites.	No preference.	No preference.	No preference	No preference.
Power	CHP with power sales, RECs, carbon credits, hedges.	Steam CHP.	Cogeneration/CHP.	CHP or thermal only.	CHP.	Thermal only.	Power production desirable.
Build Out	Need evaluation.	No preference. Possible to expand.	Additional plants are possible.	Expandable.	No preference.	No preference.	Phased approach.
Cost/Benefits Share	No preference.	Possible. 20 year finance with buy out at end.	Several options – they can own and operate or share responsibility	No preference.	Several options – they are open to equity interest.	No preference.	Prefer to own and operate.
Ownership	N/A	Provide capital, design/build, operations and maintenance, and reliability guarantees	They prefer to have long term management and ownership.	Experience with public-private partnerships, but not owners.	Qualified operating leases or operating entity.	Engineers, not owners.	Can build, own, and operate under right conditions. Can also just maintain and operate.
Operation	N/A	Provide operations and maintenance.	Provide operations and maintenance.	Manage infrastructure development and billing.	Prefer to manage and operate plant.	Not operators.	Operation is a requirement.
Heat Utility	N/A	Fixed and variable charges.	Standing and unitary charges, several metering options.	Experience with variety of rate structures.	Meters and consumption billing.	No preference.	Capacity charge plus energy usage. Currently bill 1,100 customers.
Efficiency	Optimized.	No answer.	Recommend LEED	Rate based, workshops.	$2.5 billion over 24 years	No answer.	Encourages efficiency.
Cogeneration	N/A	No answer.	Feasible.	Possible.	No answer.	No answer.	No answer.
Similar Projects	Engineering consultants, completed studies on 150 CHP projects.	Heinz Field, Pittsburgh. $4.6 m Nashville District Energy. $46 m Canton Crossing, Baltimore. $18 m Fashion Show Mall, Las Vegas. $9.8 m Aberdeen Proving Ground, MD. $18 m	Thermal North America $800 m Cambridge, MA 83 MW $14 m Montreal, Canada, 50% share CCUM. 120 MW heating 9 MW cooling. Villnius District Heat. $28 m.	District Energy St. Paul District Cooling St. Paul St. Paul Cogeneration Energy Park – St. Paul Port Authority.	Plymouth State University Humberton Center Lawrence Convention Center	Studies and engineering at a lot of different places.	Manages over 680 district energy networks. 11 million lbs/hr of steam and hot water production. 1,109 MW electric power. 165,225 tons chilled water. Philadelphia Grays Ferry won 1998 EPA award.
Key Personnel	Wayne Bonhag, PE	Jim Olcott, Marc Romanczyk	Jacques Guertin, eng.	Anders Rydaker, CEO	John Kauppinen, Mark Millins, Alan Davis	David Wade, P.E.	Brett Jacobson

Appendix E

ASSESSMENT OF AVAILABLE AND SUSTAINABLE WOOD FUEL SUPPLY

Introduction

Biomass comes in all shapes and sizes. This section focuses on woodchips as a fuel for the Montpelier district energy system and discusses the various types and grades of woodchips, their overall quality as a boiler fuel, the availability and pricing from different sources, and general recommendations for securing the necessary volumes. For this assessment of wood fuel supply several scenarios were explored:

1. Full district energy system build-out (requiring 20,000 green tons of woodchips annually)
2. A robust first phase of district system build out targeting larger facilities (requiring approximately 10,000 green tons of woodchips annually)
3. A small first district system to connect municipal buildings (requiring 2,000 – 5,000 green tons of woodchips annually)
4. The minimum sized district energy system that could effectively produce electricity in addition to heat (requiring 5,000 green tons annually)

Determining the Wood Fuel Procurement Area

Woodchips are likely to be sourced directly from periodic forest harvesting to supply the Montpelier district energy system from within a cost-effective transport radius to the proposed district energy plant. To gain a better sense of this forestland area from which woodchips could be sourced for the Montpelier energy system, circles were drawn using 25-, 50- and 75-mile radii. The resulting land area was divided by county into the three procurements areas shown in the table below. These zones and counties served as the framework for further analysis of the availability and sustainability of woodchip supply for this project. .

TABLE 1 – WOOD FUEL PROCUREMENT AREA		
Zone 1(within 25 miles)	**Zone 2 (25 - 50 miles)**	**Zone 3 (50 - 75 miles)**
Washington, VT	Addison, VT	Clinton, NY
Lamoille, VT	Rutland, VT	Essex, NY
Orange, VT	Windsor, VT	Warren, NY
Chittenden, VT	Grafton, NH	Washington, NY
Caledonia, VT	Essex, VT	Sullivan, NH
	Orleans, VT	Merrimack, NH
	Franklin, VT	Carroll, NH
		Coos, NH

Wood Fuel Availability

Vermont has a relatively mature wood energy market with over 20 years of using woodchips for heat and power production. Historically, there has been sufficient supply of wood by-products such as sawdust, chips, and bark generated by the forest products industry to meet the wood energy demand and regional pellet production. Over recent years the demand for chips has grown dramatically while the by-product supply has decreased due to general downturn in the forest products industry. Woodchip and sawdust supply from sawmills is extremely tight in Vermont today and sawmills are unlikely to respond to increased demand by producing more by-product. Despite the downturn in by-product supply of woodchips, logging contractors have encouragingly responded to the recent surge in demand for wood fuels produced as a primary product. Low-grade logs or pulpwood that would historically have gone to regional pulpmills now is a major source for chip and pellet production. While some wood fuel sourced for the Montpelier CHP system may be a by-product, a majority of the supply will come directly from harvesting.

Wood is renewable but its supply is not infinite – our forests have a finite capacity for supplying wood fuel sustainably. If close attention is not paid to the question of how much, we run the risk of growing our wood fuel demand beyond the capacity of our forests to supply.

In effort to better understand the potential capacity of the region's forests to provide increased amounts of wood fuel for community-scale biomass energy systems several steps must be taken:

- First, the forestland area must be identified and examined.
- Second, the inventory or amount of wood on the forested land must be reviewed.
- Third, the rate of forest growth building upon existing inventory must be understood.

Forested Land Area

While examining forestland area is important, it is too broad a category because it includes forest preserves and unproductive forest areas like forested wetlands. For the purpose of this project, a more specific subset of forestland area, called timberland, was examined. Timberland is defined by the USDA Forest Service as "forestland capable of producing 20 cubic feet of industrial wood per acre per year and not withdrawn from timber utilization."

TABLE 2 –TIMBERLAND AREA (ACRES)		
Zone	**Total Timberland Area**	**Estimated Accessible Managed Timberland**
Zone 1	1,517,561	758,781
Zone 2	3,034,238	1,517,119
Zone 3	3,925,021	1,962,511
GRAND TOTAL	8,476,820	4,238,410
Source: Forest Inventory and Analysis (FIA) Program of the U.S. Department of Agriculture (USDA) Forest Service		

Northern Vermont and the surrounding counties of New York and New Hampshire are heavily forested areas. At over 8.4 million acres, the combined timberland area within Zones 1, 2 and 3 counties is significant. It is important to note that while 8.4 million acres is a vast amount of forestland that not all forestland is actively managed and periodically harvested. There is a significant amount of this land area that is not accessible due to physical reasons such as slope, elevation, wilderness designation, steam and wetland buffer areas, and key wildlife habitat such as deer yards. If theses physical constraints are accounted for, as is the portion of the forest land area that is typically actively managed and periodically harvested, the land area is effectively reduced by 50%.

Inventory and Composition of Forests

The next step is examining the current amount or inventory of live trees on the timberland footprint. Since it is impossible to count every tree, the USDA Forest Service Forest Inventory and Analysis (FIA) Program uses a statistically designed sampling method. First, aerial photographs of the forest are interpreted. Next, a grid of thousands of points is overlaid on the aerial photos. If forested, each point is classified according to land use and tree size. Using this information, a sample of hundreds of plots is selected for measurement by FIA field crews. The sample includes plots that were established during previous forest inventories. The re-measurements yield valuable information on how individual trees grow. Field crews also collect data on the number, size, and species of trees, and the related forest attributes. All this information is used to generate reliable estimates of the condition and health of the forest resource, and how it is changing over time.

TABLE 3 – FOREST INVENTORY (GREEN TONS)			
Zone	**Bole Wood**	**Top & Limb Wood**	**Total**
Zone 1	136,738,000	19,206,000	155,944,000
Zone 2	289,680,000	40,272,000	329,952,000
Zone 3	371,614,000	52,114,000	423,728,000
Grand Total	798,032,000	111,592,000	909,624,000

With nearly a billion green tons of combined above-ground biomass inventory, the region has ample forest inventory. When the above-ground biomass inventory is examined on a per-acre basis the average inventory is approximately 107 green tons per acre.

Forest Growth and Sustained Yield Capacity

While it is very important to understand the amount of standing wood (or inventory) and its composition, it does not tell us how much wood can be sustainably removed year-in and year-out. We must now explore how much the forests are growing and what level of harvested wood can be sustained over time.

As trees grow each year, they add weight and volume. The actual growth rates vary according to a wide range of factors, including soils, species, stand age, how crowded the trees are, etc. When forests are examined from the 30,000 foot perspective, wood inventory can be compared to money invested in a bank account that earns interest annually. The total *annual growth* of trees in a forest is analogous to the interest earned on capital invested. A wise financial investor strives to only spend the annual interest earned each year and not dip into the principal. Forests are the same: sound forest management policy within a state or region allows only harvesting up to the amount of annual growth.

For the purpose of this project, the net annual growth[1] of new amounts of wood was chosen as the indicator of how much wood the forests of these counties can provide on a sustained-

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[1] FIA defines forest *net annual growth* as "the change, resulting from natural causes, in growing-stock volume during the period between surveys (divided by the number of growing seasons to produce average annual net growth). The simplified FIA formula for net growth is: In-growth[1] + Accretion[1] – Mortality[1] = Net growth

yield basis. In addition to accounting for the forestland area that is not physically accessible and the forestland area that is not managed and periodically harvested, it would be inappropriate to include high quality wood otherwise capable of yielding merchantable wood for sawlog production. For these reasons, a series of assumptions were used in our analysis to target a more appropriate amount of wood that could be available for various low-grade wood markets including community-scale biomass energy like the Montpelier district energy system.

Using a series of reasonable assumptions, the amount of low-grade wood grown each year on available timberland in the region was estimated.

TABLE 4 – ESTIMATED NET ANNUAL GROWTH OF LOW-GRADE WOOD ON ACCESSIBLE AND MANAGED TIMBERLAND (GREEN TONS)			
Zone	**Bole Wood**	**Top & Limb Wood**	**Total**
Zone 1	833,011	60,499	893,510
Zone 2	1,721,563	126,857	1,848,420
Zone 3	2,154,076	164,159	2,318,235
TOTAL	4,708,650	351,515	5,060,165

While nearly a million green tons sounds like an extremely large amount of wood that can be harvested on a sustained-yield basis, it should be noted that there is significant existing demand for low-grade wood within this region.

Forestland Area Necessary to Supply the Montpelier District Energy System

It is common for decision makers to ask the question: "How much actively managed forest land would it take to supply our project?" While the wood fuel will likely come from all over the given wood basket area in a given year (depending on where the harvesting happens to be taking place at the time), it is useful to calculate the theoretic forestland area needed to sustainably supply the on-going fuel needs of the system.

Typical Vermont Forest Stocking	100 green tons/acre
Average Net Annual Growth Rate	2.25%
Sustained -Yield	2.25 green tons/acre/year

Assuming two thirds of the annual growth is higher quality material suitable for lumber production, there is approximately 0.75 green tons of wood grown per acre per year suitable for use as woodchip fuel. The following table shows the acres of forestland conceptually required to sustainably supply the system over time.

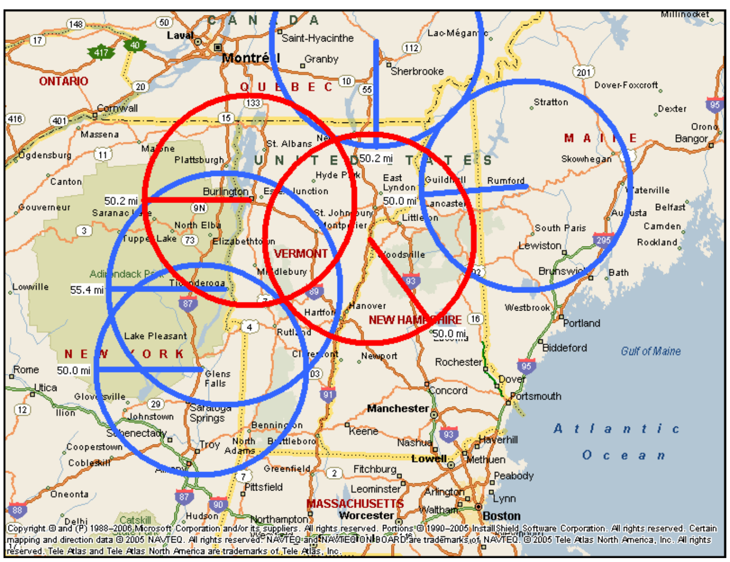
TABLE 5 – FORESTLAND REQUIREMENTS	
Montpelier District Energy System Scenario	**Forestland Required (Acres)**
Full build-out (20,000 tons/yr)	26,666
Robust first phase (10,000 tons/yr)	13,333
Small system connecting Municipal Buildings (5,000 tons/yr)	6,666

It is important to note that the numbers above are purely conceptual and are not meant to reflect the amount of harvesting actually happening. The approach above can be compared to a slightly different basic method of calculating the required forestland area as presented below:

> 20,000 green tons of fuel needed per year
> <u>Divided by 100 tons of forest inventory per acre of forestland</u>
> Equals 200 acres of harvested forestland per year
> <u>Multiplied by 125-year harvest rotation</u>
> Equals 25,000 acres of forestland needed to supply 20,000 tons of wood fuel

For the full-system build out scenario of 20,000 tons per year, both methods of calculating forestland area yield similar results—approximately 25,000 – 27,000 acres.

Current Market Demand for Low-grade Wood



Three primary markets utilize low-grade harvested wood – pulp, firewood, and biomass fuel (whole-tree chips). Pulp and firewood markets extract low-grade roundwood harvested primarily from tree bole inventory while biomass chips are produced from a mixture of low-grade bole and top & limb wood.

Pulpwood demand and harvesting in Vermont has gradually declined over the past decade, although there are still several large pulpmills in Eastern New York, Southern Quebec and Northwestern Maine which still draw upon Vermont for their wood supply. Although pulp volumes have declined, current prices paid by the pulpmills have increased dramatically in the past 12 months.

Residential firewood accounts for a large majority of low-grade wood demand in the region. Given the current high cost of heating oil, Vermont has seen a dramatic increase in demand for cordwood for home heating. With this recent surge in demand, firewood prices have also increased significantly in the past 12 months.

Whole trees and tops & limbs cut from logs are chipped into fuel. Both of Vermont's wood-fired power plants, McNeil Station in Burlington and Ryegate Power in Ryegate, consume large amounts of harvested wood in the form of whole-tree chips. International Paper and Finch Paper also consume whole-tree chips as boiler fuel in addition to the pulpwood and pulp chips they consume for making paper.

When the pulp, firewood, and biomass chip market demands are added up and compared to the estimated amount of annual growth of low-grade wood on available timberland, there is an annual surplus capacity of over ¼ million green tons within a 25 mile radius of Montpelier.

TABLE 6 – ESTIMATED NET ANNUAL GROWTH OF LOW-GRADE WOOD ON ACCESSIBLE AND MANAGED TIMBERLAND (GREEN TONS)			
Zone	**Estimated Low-grade growth**	**Estimated current low-grade wood harvest**	**Net available**
Zone 1	833,011	550,000	283,011
Zone 2	1,721,563	770,000	951,563
Zone 3	2,154,076	1,200,000	954,076
TOTAL	4,708,650	2,520,000	2,188,650

The relatively small amount of approximately 5,000 – 20,000 green tons of annual demand from the Montpelier district energy system would not burden the region's forests. Even if 100% of the fuel were sourced exclusively from within Zone 1 (rather than spreading the demand over 2 or 3 zones), the net available growth of low grade wood would only be reduced by less than 10%.

Given the location for the project in Montpelier in relation to other large volume consumers of low-grade wood in the region, competition for the low-grade wood resource is not as great as it would be were the Montpelier project located closer to large wood consumers like the pulpmills and biomass power plants.

Woodchip Sources

Woodchips have historically been a by-product of timber harvesting in the woods, lumber production at sawmills, and clean wood waste recycling efforts from communities. In recent years increased market demand for chips as fuel and decreased sawmill activity has prompted a gradual shift toward woodchips sourced as a commodity wood fuel harvested directly from the forest rather than a by-product produced from higher value wood harvesting and processing.

Logging and Land-Clearing Residue

Commercial harvesting of sawlogs and pulpwood removes the main stem or bole of the tree from the woods and leaves the tops and limbs either scattered in the woods near the stump or in a pile at the log landing. Whole-tree harvesting, where entire trees are dragged or skidded from the stump to the log landing instead of just the log, requires the tops and limbs be removed and piled at the log landing. This leftover wood can be chipped into biomass fuel commonly known as whole-tree chips. In some cases entire trees, not just the tops and limbs, are fed to the chipper to also produce whole-tree chips. It is common practice for the wood to be chipped in the woods at the log landing directly into box trailers which are transported directly to large plants like biomass power plants and pulpmills that are equipped with trailer tippers to unload the chips from the box trailers.

Sawmills
The business of sawing round logs into dimensional lumber produces a significant amount of wasted wood. The slabs and off-cuts from lumber production at larger sawmills is typically chipped and shipped to regional pulpmills, biomass power plants or woodchip heated institutions. These "mill" or "paper" chips are the best suited for use as fuel in biomass heating systems. Mill chips tend to be the highest quality chips available for chip fueled heating systems. Because logs are debarked before sawing the chips, mill chips are very clean and have relatively low ash content. Mill chips are also commonly screened to remove over-sized stringers and fines. Wasted wood from sawmills is commonly chipped on a continual basis as logs are sawn and chips are blown directly into dedicated box trailers. When the trailers are full they are shipped to the various markets and an empty trailer is set in its place.

Bole Chips
Bole chips are produced from low grade or pulpwood. The difference between whole-tree chips and bole chips is that bole chips do not include the branches or foliage. When the trees are harvested the limbs are removed and the slash is left on the ground in the woods or at the log landing (depending on where the tree is de-limbed). While bole chips can make for higher quality fuel and help forest soil health by returning a portion of the biomass and nutrients to the soil, they are significantly more expensive than sawmill chips and whole-tree chips which are both by-products. In the past, sawlog prices were high enough that low-grade wood could be extracted at the same time as sawlogs and still be profitable for the logger and pay the landowner stumpage. With recent drops in the sawlog market, however, low-grade wood like pulp, chips and firewood can no longer rely on subsidized costs—this low-grade wood must pay its own way out of the woods.

Woodchip Fuel Pricing

The price of woodchips is affected by numerous factors, but the primary factors which influence chip pricing are:

- Wood source and production costs (varies widely depending on whether the wood is a by-product of some more lucrative activity);
- Regional balance of supply and demand for low-grade wood; and
- Trucking distance from point of generation to end market.

Hardwood "paper-grade" woodchips from sawmills are the preferred type of chip fuel for seasonal heating systems because they are a high quality and consistent chip and they are relatively low in price. However, the availability of these chips is extremely tight and is very unlikely to be a part of the wood fuel mix for the Montpelier project.

Whole-tree chips are an excellent and cost-effective fuel for larger systems–like the one proposed for Montpelier–which are designed to handle oversized chips. Whole-tree chips in Vermont and New York also range widely in price but are most commonly available within the range of $34-$48/green ton. At 2008 pricing, whole-tree chips delivered to a district energy plant in Montpelier in live-bottom trailers could be expected to cost $42 per green ton.

Bole chips are commonly produced in Vermont and are a viable option for biomass systems. Bole chips are typically available to the seasonal heating market in Vermont for $50 - $65 per green ton. With recent losses of pulpwood markets in Northern New Hampshire "bole" fuel chips could prove to be a helpful local market for low-grade wood which would otherwise need to be trucked out of state. The benefit of bole chips is that more chips can be produced as energy market demand increases as opposed to chips from sawmills.

Forest Sustainability Safeguards

If the Montpelier district energy system produces electricity and requires a certificate of public good from the Vermont Public Service Board, it is possible that conditions would be placed on the procurement and harvesting of wood as part of the Act 248 permit similar to the requirements that McNeil and Ryegate are required to meet.

Beyond any requires for sustainably placed upon the wood fuel procurement by the Vermont Public Service Board, there are numerous voluntary options for ensuring wood fuel is sourced from well managed forests. These options can include third party green certification, logger training and accreditation programs, and the requirement of professional foresters to oversee the harvesting jobs that would supply wood fuel to the Montpelier district energy plant. These voluntary options can be phased in to increase the assurances of sustainability overtime or set in place from the outset.

Conclusions

Montpelier is surrounded by an estimated 3/4 million acres of managed timberland within an approximate 25-mile radius. The forests have ample stocking and annual growth of low-grade wood suitable for chip fuel. Current demand and harvesting for low-grade wood in Vermont is less than half of the amount actually grown annually. While the forest products industry in Vermont has experienced a gradual decline in harvesting and processing, much of the necessary infrastructure (foresters, loggers, chippers, sawmills, truckers, etc.) are in place and have the capacity to supply the required volume of chip fuel. Demand for wood fuels for biomass electric generation, home firewood heating, commercial and institutional heating, and pellet fuel production will likely continue to grow in the future. Forest sustainability safeguards such as harvesting standards, logger certification and third party "green" certification of the wood fuel should be explored in effort to make sure forest resources are responsibly managed in the face of increased demand for energy.

Hardwood bole chips should be the primary fuel source and whole-tree chips should be sourced as needed. This mixture will provide an optimum balance of price, reliability and sustainability. The central energy plant should be designed and sited to allow for both delivery of roundwood fuel for on-site chipping or receiving chipped fuel.

Appendix E

ASSESSMENT OF INCOME POTENTIAL FROM MONTPELIER CHP SYSTEM POWER SALES

There are three possible structures for the power production portion of the Montpelier CHP project:
1. Generated electricity is net metered to supply the district energy plant's electrical requirements;
2. Generated electricity is group net metered to supply a collection of municipal buildings and facilities within downtown Montpelier; or
3. 100% of the electricity generated is sold via a power purchase agreement to the local utility.

These three scenarios were examined at 250, 500 and 750 kWh energy system capacities.

Net Metered Electric Generation at District Energy Plant

Vermont's original net metering legislation was enacted in 1998, and the law has been expanded several times since. Prior to net metering, self-generators had to install expensive battery banks to store the power they needed or go through lengthy negotiations with their utilities to have them buy any extra power generated. Net metering allows customers to generate and use power simultaneously. With net metering, the meter will measure electricity flowing in both directions, unifying a customer's power usage into one system. Once the net metering system is interconnected, power generated by that system can be fed into the utility grid. If a net metering customer uses more electricity than is generated, the customer will pay the utility only for the difference. If the system generates more electricity than the customer used that month, the utility records a credit for the excess kilowatt hours towards the customer's next bill. Net metered customers still must pay the same customer service charges and other monthly fees required of other consumers.

It is important to note that if the customer still has a credit on the bill at the end of the year, that credit reverts to the utility. For this reason a net metered system should be sized as close to but not exceeding average electrical usage.

From homes with small photovoltaics and wind turbines to dairy farms with manure digestion systems, net metering can be an effective power production arrangement for those producing less than or close to the amount of power they consume. The economics of net metered systems are based on the avoided retail costs of purchasing electricity from the utility at retail rates of $0.12/kWh (assuming it costs less to produce your own). No renewable energy certificates (RECs) can be sold under a net metering arrangement.

Any electric customer in Vermont may net meter after obtaining a Certificate of Public Good from the Vermont Public Service Board (PSB). The Vermont Department of Public Service (DPS) power production rules allow for systems up to 250 kWh to be net metered as long as they are from renewable energy sources[1]. Wood fuel such as woodchips or pellets would meet the DPS definition of "renewable energy." Utilities must allow net metered systems on a first-come, first-served basis to all customers until the cumulative generating capacity of all the net metering systems on its lines equals two percent of the company's peak demand[2].

A steam plant the size of the proposed Montpelier district energy system would require an estimated 200,000 kWh annually. A turbine sized to efficiently match the estimated thermal load would likely range between 250 and 750kWh—generating 1.1 to 3.5 million kWh per year[3]. Under the net metering rules all the monthly surplus credits would revert to the utility without compensation. Given the likely sizing of a steam turbine based on the various thermal load scenarios and the relatively small likely electrical requirements for a large wood-fired boiler plant, net metering only the district energy plant is not a logical option for the Montpelier district energy project. The net metering option would be the same whether the district energy plant was city owned and operated or privately owned.

Group Net Metered Electric Generation for Multiple Municipal Buildings

Another option for electric generation at the Montpelier district energy system is to net meter the power production from the plant with a group of multiple municipal buildings with separate electric meters. Net metering laws in Vermont were recently expanded to include "group" net metering which allows for multiple meters to be grouped together and function as one meter, thereby tracking the combined net import and export of electricity to and from the grid. The new rules allow for net metering of:
1. Farm group systems (main barn, milk house, main residence, farm hand residence(s), maintenance shop/garage, etc.);
2. Non-municipal group systems within the same electric utility service territory and located on property contiguous to the property on which the generation facility is located; and
3. Municipal group systems on property owned by a municipality that is located within the same municipality and electric utility service territory as the associated net metering system.

Like the net metering rules, group net metering systems are capped at 250 kWh. However, group net metered systems larger than 250 kWh can be installed but only if the net-metered amount does not exceed 250 kWh, the customer/generator signs a contract with its utility specifying the specific amount to be net metered, and only the net metered amount is assigned to the utility's cumulative capacity limit. If the Montpelier district energy system is owned and operated by the City of Montpelier, a municipal group system could be formed. If the plant were to be private third party owned and operated the effective group net metering would be limited to fewer meters.

Without detailed analysis of the combined electric consumption of city owned facilities, it is difficult to accurately assess whether a group net system of city owned facilities would be a viable option. However, between the numerous city owned facilities for administration,

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[1] Based on the recent revisions to the net metering law 30 V.S.A. § 219a (amended by S.B. 209) on March 19th 2008
[2] The utility's current peak demand or its 1996 peak demand, whichever is greater
[3] Based on basic assumptions of operational run time and average steam load

education, public safety, and water treatment, it seems very plausible that enough meters could be aggregated to closely match the output capacity of the district energy plant.

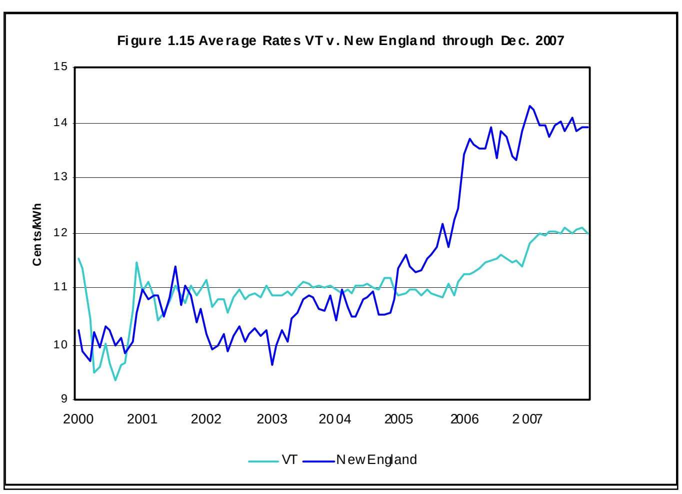
It is important to note that because the expansion of the Vermont net metering law allowing group net metering was so recent, there still are no existing systems in Vermont that are group net metered. Without clear examples there is an added risk of being potentially the first to pursue this option.

Similar to the net metering option, group net metering shares the same economic driver—avoided retail electric purchase. Depending on the size and number of municipal meters that are tied together into a group and the size of the steam turbine installed at the district energy plant, the avoided cost of electric purchase could result in significant savings to the City of Montpelier. At current electric retail prices of $0.12/kWh, the breakeven point for the incremental costs of electricity production from the district energy plant would need to be $0.10/kWh or less to make this option viable. Again, no renewable energy certificates (RECs) can be sold under a group net metering arrangement.

Power Purchase by Utility

The third option for consideration is a traditional power purchase agreement between the owners of the district energy plant and the local utility. Green Mountain Power (GMP) is the electric utility for Montpelier and for that reason is the most likely purchaser of the power produced. However it is possible to sell the power to another utility but this would require paying a transmission fee to Green Mountain Power and would be an expensive option for this relatively small project.

There are three main revenue steams possible for the production and sale of power to a utility—the energy itself, capacity credits, and renewable energy certificates (RECs). These three revenue streams can be rolled together and sold directly to the utility or sold separately. Each can be sold on the spot market or under more secure long term fixed or viable price contracts. Given the overall price volatility of energy markets and the uncertainty of future REC values, the long term market values tend to be significantly lower because the utilities must hedge this risk.



The energy market in Vermont is somewhat unique as compared to the rest of New England. Long-term power supply contracts with Vermont Yankee and Hydro Quebec have helped keep electric rates lower than the average seen in the rest of New England[4]. When the current Vermont Yankee and Hydro Quebec are due to expire in 2010, higher electric prices are anticipated and are

[4] Based on data provide within report by Vermont Public Service Department

projected to track closer to the rest of New England which has seen on average prices 10 percent higher than Vermont. Higher electric wholesale prices in the near future could help improve the economic viability of the Montpelier district energy system if a power purchase agreement with GMP is pursued and the system owner is paid more for the electricity produced. On the other hand, higher electricity retail costs in the near future could make the net metering option more attractive.

The second potential revenue stream are the capacity credits, however capacity credits are often rolled into the purchase price of the power. For larger power generation projects the project would go through a process to be evaluated for its capacity rating and based on the rating the capacity credits would be auctioned (annually) to determine the value of the capacity credits. For smaller power generation like the potential output of 250 – 750 kWh for the Montpelier district energy system it is simpler for the capacity credit to be negotiated and packaged with the power purchase agreement.

Renewable energy certificates (RECs) are the third possible revenue stream for power produced by the district energy plant. RECs can be sold together with the power directly to the local electric utility or can be sold separately to a third party. Current markets for renewable energy credits in the Northeastern US are mostly driven by the renewable energy portfolio standards in Massachusetts and in Connecticut. These states have set high enough goals for their renewable energy mix that the resulting credits are currently worth approximately $50 per MWh or $0.05 per kWh. But these prices are subject to change over time with revisions to the goals set in the Renewable Portfolio Standard (RPS) and with changes in the supply of renewable energy in the region. For additional information on RECs please refer to *Appendix E: Survey of Renewable Energy Credit Requirements in the Northeastern States.*

If the Montpelier district energy system were to sell electricity to GMP, the current estimated value is $0.08 - $0.085 for the energy and the capacity credits combined and they could offer $0.02 - $0.025 for the RECs in a long-term agreement[5]. While $0.02 -$0.025 per kWh is approximately half the current market value for Massachusetts and Connecticut credits, it is somewhat difficult to predict the future market value of these credits and so a long-term agreement would need to significantly undervalue the current market value as a hedge against the future risk.

As gauge for GMP's overall interest in purchasing renewable energy generated in-state, we can look to a pending deal between GMP and PPL Renewable Energy LLC to purchase power, capacity credits and RECs from a bio-gas fueled generating station to be installed at the Moretown Landfill which is owned and operated by Interstate Waste Services Inc. (IWS). While the full details of the deal have not been disclosed it is reportedly a 15 year fixed price contract. The reportedly favorable contract terms that were negotiated for this project indicate GMP's current interest in including biomass projects in their energy portfolio.

So, for a total income of $0.10 - $0.11 per kWh paid by GMP, the option of a direct power purchase agreement is less attractive an option than the group net metering option where

[5] Based on initial conversations with Green Mountain Power representatives

$0.12 are avoided. If a long-term contract for a price at or slightly higher than the cost of retail electricity could be negotiated with GMP, a direct power purchase agreement could prove to be a better option.

TABLE 1 – REVENUE POTENTIAL FOR ELECTRICITY SALES FROM MONTPELIER DISTRICT ENERGY SYSTEM			
Steam Turbine Capacity Size	**Estimated Annual Power Generation**	**Long-term Contract Price[6]**	**Potential Annual Power Sales**
250kW	1.155 million kWh	$0.105	$121,275
500kW	2.31 million kWh	$0.105	$242,550
750kW	3.465 million kWh	$0.105	$363,825

Another option to consider is a combination of group net metering (up to the 250 kWh limit) and negotiating a power purchase agreement with GMP for capacity beyond the group net metered amount. While this option is technically allowed under the new net metering rules (yet to be finalized), it has never been done and would likely prove very complicated to permit with the Public Service Board, negotiate with the utility, and to track the net metered power, the exported power and the imported power. This net metering/power sale hybrid would theoretically be the best of both worlds but in reality would be a very complicated project to develop.

Conclusions

Group net metering rules are still in the process of being finalized by the Public Service Board and Public Service Department and somewhat untested as a group net metering project has never been evaluated or approved thus far in Vermont. Critical details regarding the "group" of municipal electric meters that can be aggregated into one group need further clarification from the Public Service Department.

The attractiveness of selling the energy directly to GMP is based on simplicity and long-term revenue security. However, whether this is the best option for the Montpelier project will depend on the price for power and RECs that can be negotiated and whether these combined prices meet or exceed the retail price paid by the City for its power use at facilities through Montpelier.

The best options for producing and using or selling electricity depend largely on the Montpelier district energy system's thermal load demand and the resulting electrical generation capacity design. The table below frames the various strategies recommended based on how the system is designed and where the energy markets are at the time when the decision is made to move forward.

[6] Based on long-term fixed price contract which would include power, capacity and RECs

TABLE 2 – RECOMMENDED STRATEGIES		
System Capacity Scenario	**Wholesale Power Purchase Market Prices Scenario**	**Recommended Electric Strategy**
250 kWh	Lower than retail	Group net meter as many city meters to match 250 kW capacity
	Higher than retail	Secure long-term, fixed-price purchase agreement for bundled power, capacity credit and RECs with GMP
500 kWh	Lower than retail	Further explore hybrid option of group net metering up to 250kWh cap and sell surplus to GMP
	Higher than retail	Secure long-term, fixed-price purchase agreement for bundled power, capacity credit and RECs with GMP
750 kWh	Lower than retail	Further explore hybrid option of group net metering up to 250kWh cap and sell surplus to GMP
	Higher than retail	Secure long-term, fixed-price purchase agreement for bundled power, capacity credit and RECs with GMP

We cannot predict how the wholesale and retail electricity markets will change in Vermont when the current Vermont Yankee and Hydro Quebec contracts expire in 2010. It is fairly safe to assume that both wholesale and retail rates will increase but whether they will increase in lock step is not known. Given the current electric, capacity and REC markets, it is recommended that group net metering be pursued if the thermal load is relatively small and the CHP power capacity is less than 250 kW. It is recommended that for larger systems such as those with 500-750 kW power capacity, a power purchase agreement be pursued.

Appendix E

SURVEY OF RENEWABLE ENERGY CREDIT REQUIREMENTS IN THE NORTHEASTERN STATES

Renewable energy certificates or credits (RECs) are the valuation of the environmental attributes of a unit of electricity —typically one megawatt-hour—generated from renewable sources. RECs are an important innovation in green power marketing from the perspective of both producers and consumers of renewable energy. For producers, selling RECs generates a second revenue stream in addition to the income earned from selling commodity electricity at market rates. This extra revenue helps to make renewable energy cost-competitive with conventional electric power and stimulates the development of new renewable energy projects. RECs allow producers to sell their power output where it can be easily delivered to the grid and its renewable attributes in other markets where they may bring higher value. For consumers, RECs make it possible to support renewable energy generated from many types of fuels in favorable locations (for example, solar power produced in Arizona or biomass energy generated from agricultural waste in farm states), and to separate investments in renewable energy from their electric power purchases, thus avoiding the need to switch power providers.

RECs are transacted in two arenas: voluntary markets and regulatory compliance markets. Voluntary purchasers - companies, government agencies, nonprofit institutions, or households - buy RECs from sources of their choice for purposes such as supporting renewable energy development, meeting corporate environmental performance pledges, or stimulating local economic development (if the credit comes from a nearby energy source). The CVPS "Cow Power" program in Vermont is a good example of a voluntary REC market.

Several states in the northeastern US have adopted energy policies known as renewable portfolio standards (RPS) which call for increased generation of electricity from renewable sources such as wind, solar and biomass. Regulatory compliance markets exist in states that have adopted renewable portfolio standards (RPS) requiring that certain percentages of the electricity delivered in-state must be generated from renewable energy by specified dates. Renewable energy producers that meet the standards earn RECs for the electricity they produce. In addition to the electricity generated, these credits can then be sold to power supply companies.

Because RECs represent all of the given attributes of renewable energy generation, the credits cannot be sold more than once. For any given project the credits, should they qualify, may be sold to either a buyer who uses them to meet compliance with the targets set by a state RPS or a buyer who sells the credits into a voluntary market, but not both.

Northeastern US REC Market

A number of states in the northeastern US are developing RPS that set targets for the amount of renewable energy in their energy mix. Until now Massachusetts and Connecticut have been the only states with RPS that have tradable RECs with market value. New RPS systems have recently come to market in Maine, Rhode Island and New Hampshire. As these states RPS programs become mature, new REC market opportunities will result.

Massachusetts
Massachusetts created the outlines for a RPS as part of its 1997 electric utility restructuring legislation. In April 2002, the Massachusetts Division of Energy Resources (DOER) adopted RPS regulations mandating all utilities in Massachusetts to utilize new, renewable-energy sources for at least 1% of their power supply in 2003, increasing to 4% by 2009. These regulations have been revised and updated several times since then.

Eligible new renewables include solar, wind, tidal, fuel cells using renewable fuels, landfill gas, and low-emission, advanced-technology biomass. To qualify as a new renewable resource, systems must have been installed after December 31, 1997. Systems that meet all qualifications but were installed before December 31, 1997, may qualify as a new renewable generation unit under a special provision. Under the "vintage waiver" provision, older biomass plants may create tradable RECs for power output above their historical levels.

The following schedule of target renewables was established to increase the amount of renewable energy generated and supplied in Massachusetts:

1.0% by 2003
1.5% by 2004
2.0% by 2005
2.5% by 2006
3.0% by 2007
3.5% by 2008
4.0% by 2009

An additional 1.0% will be required each year beyond 2009. These mandates for increased percentages of renewable energy not only increase the amount of renewable energy in the state's energy mix, but they also help balance the supply and demand of RECs, thereby stabilizing market prices. If more renewable energy capacity comes on-line in a given year but the target percentage does not increase, the market value for the RECs could drop dramatically as happened several years ago in the Connecticut REC market.

Massachusetts rules do not include a minimum system size requirement for eligibility for RECs. There are however three general criteria that biomass systems must meet. The system must:
1. burn an eligible biomass fuel,
2. meet low emissions criteria, and
3. employ "advanced" technology.

Wood from harvesting and clean wood by-product from sawmills (unpainted, stained, or treated) are considered eligible biomass fuels. To be eligible for RECs, a biomass system would need to meet or exceed the emissions limits shown below for nitrous oxides (NOx) and particulate matter (PM).

TABLE 1 – MASSACHUSETTS RPS MONTHLY AVERAGE EMISSION LIMITS FOR WOOD-FIRED AND OTHER SOLID-FUELED STEAM BOILERS		
Facility Capacity	**NOx**	**PM**
< 1 MW	0.30 lbs/MMBtu	0.012 lbs /MMBtu
1-10 MW	0.15 lbs/MMBtu	0.012 lbs/MMBtu
Source: http://www.mass.gov/eoeea/docs/doer/rps/guideline-low-emission.pdf		

Using wood boiler and emissions control technology on the market in the U.S. today, it is unlikely that particulate emissions limits of the Massachusetts REC standard could be met, while the NOx standard probably could be met.

The definition of "advanced technology" is not as clearly defined as the first two requirements for REC eligibility. Various combustion technologies will qualify as long as a compelling case is made that they are "advanced" in some manner. This requirement applies to the combustion equipment, the generator technology, etc. It is very likely that the Montpelier district energy system could meet this "advanced" technology requirement.

In summary, the PM requirement for eligibility for Massachusetts RECs will be the most difficult for a Montpelier district energy plant to meet. NOx, "eligible fuels" and "advanced technology" should not be a problem.

Connecticut

Connecticut first established a RPS in 1998. Connecticut's RPS initially required each electric supplier in the state to supply no less than 5% of its total output by qualifying renewable-energy resources by January 1, 2006. This requirement has more recently been increased to 23% by January 1, 2020. An interesting element to Connecticut's RPS is that it also requires that 4% be derived from combined heat and power (CHP) systems and energy efficiency improvements by 2010.

The Connecticut RPS increases annually to the target percentage of power supplied, similarly to Massachusetts.

- 2006: 2.0% Class I + 3% Class I or II
- 2007: 3.5% Class I + 3% Class I or II + 1% Class III
- 2008: 5.0% Class I + 3% Class I or II + 2% Class III
- 2009: 6.0% Class I + 3% Class I or II + 3% Class III
- 2010: 7.0% Class I + 3% Class I or II + 4% Class III
- 2011: 8.0% Class I + 3% Class I or II + 4% Class III
- 2012: 9.0% Class I + 3% Class I or II + 4% Class III
- 2013: 10.0% Class I + 3% Class I or II + 4% Class III
- 2014: 11.0% Class I + 3% Class I or II + 4% Class III
- 2015: 12.5% Class I + 3% Class I or II + 4% Class III
- 2016: 14.0% Class I + 3% Class I or II + 4% Class III
- 2017: 15.5% Class I + 3% Class I or II + 4% Class III
- 2018: 17.0% Class I + 3% Class I or II + 4% Class III
- 2019: 18.5% Class I + 3% Class I or II + 4% Class III

- 2020: 20.0% Class I + 3% Class I or II + 4% Class III

There are several tiers to Connecticut's RPS as separate portfolio standards exist for various energy resources. There are three classes of renewable energy sources. Class I sources include solar, wind, new sustainable biomass, landfill gas, fuel cells (using renewable or non-renewable fuels), tidal power, and hydropower facilities. Class II sources include trash-to-energy facilities, biomass facilities not included in Class I, and some hydro-power facilities. Class III sources can include existing energy projects that install heat recovery systems to become CHP systems, certain energy efficiency projects and new CHP projects with operating efficiency over 50% installed at commercial or industrial facilities.

Class I biomass facilities include those utilizing land clearing debris, tree stumps as fuel and also includes facilities using biomass fuel harvested and cultivated in a sustainable manner (that regenerates or its use will not result in resource depletion). Class I biomass facilities must also meet an average emission rate equal to or less than .075 pounds of NO_x per million Btu. The Class I RECs are the most valuable of the three classes and have a current market value comparable to the Massachusetts RECs.

Using existing technology common for the size of the anticipated Montpelier plant, which would be in the Class I category, it is unlikely that the plant would be able to meet the Connecticut NO_x standard.