Natural Resources Canada Ressources naturelles Canada

ALTERNATIVE ENERGY SOURCES FOR POTENTIAL COMMUNITY USE

CLEAN ENERGY TECHNOLOGIES

Canada

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TABLE OF CONTENTS

INTRODUCTION 4
Chapter 1: Biomass Combustion 5
Biomass Combustion 5
Forestry and Agricultural Residues 9
Biomass Pellets 14
Peat 20
MSW Combustion 25

Chapter 2: Biomass Derived 29
Landfill Gas 29
Anaerobic Digestion 34
Bio-oil 39
Ethanol 45
Biodiesel 52

Chapter 3: Ocean/Hydro 59
Tidal Current 59
Wave 62
Small Hydro 65

Chapter 4: Solar 69
Photovoltaics (pv) 69
Solar Thermal 74

Chapter 5: Wind 81
Wind 81

Chapter 6: Thermal/Other 86
Earth Energy – thermal storage 86
Hydrogen – remote community use 91
Snow Cooling 97

INTRODUCTION

This portfolio of 'briefing notes' comprises information on a range of alternative or renewable energy sources, each of which has some potential for meeting present and future energy requirements in Canada. This information has been drawn from interviews and correspondence with NRCan energy specialists and researchers, and from contacts in other federal departments, academic institutions and private sector firms. An Internet literature search was also undertaken to review and include material from relevant papers. In order to minimize the length of this document, information is presented concisely in bullet form.

These briefing notes have been written to update the reader on technical developments in the field of renewable energy, especially from the standpoint of future community energy use, and can be seen as part of the effort towards sustainability and local economic development. In this context the 'community' is assumed to be more rural than urban.

Information which is likely most relevant to future local energy development is summarized on a separate sheet ('Community Energy Supply Potential') at the end of the briefing note. A reference chart is also included (overleaf) which indicates those renewable energy options, which are most likely relevant and cost-effective for communities with a variety of land-use and geographical characteristics.

Chapter 1: Biomass Combustion
Biomass Combustion

- *Biomass in Canada*
- *Small-scale Biomass Cogeneration*
- *Micro-scale Biomass Cogeneration*
- *Fluidized Bed Gasification*
- *Tools*

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Biomass in Canada

- Biomass is increasingly seen as a competitive and sustainable energy source, due to its greenhouse gas-neutral characteristics. Almost 6% of Canadian primary energy demand is presently supplied by biomass, the majority of this being used by the pulp and paper industries, which burn their own residues to produce steam and electricity. The remainder is mostly cordwood, used for residential heating.
- In Canada, most biomass combustion R&D is now concentrated on small-scale cogeneration systems to utilize industrial waste, of around 1 MW output.
- Various recent studies have confirmed that extensive biomass resources remain under-utilized across Canada. This includes over 5 million bone-dry tonnes of sawmill and lumber plant residues, which are currently being landfilled or incinerated without heat recovery. About 38% of this amount is produced in BC, with Quebec (30%), Alberta (17%) and Ontario (8%) making up most of the balance.
- High transportation and handling costs and high moisture content have long outweighed the low price of biomass feedstocks. Moisture-laden fuels are hard to burn properly, since they require large or specialized furnaces, and heat release is slow and difficult to control. Fuel upgrading options, such as pelletization and drying make biomass more economically attractive, especially under a carbon trading regime.
- The inherently low SO_2, NOx, and metals emissions from biomass fuels, and their CO_2 neutral status can also make them useful in blending and co-firing applications with coal.

Small-Scale Biomass Cogeneration

- Recognising the significant potential for utilisation of unused sawmill waste and other biomass feedstocks, several Canadian companies are currently developing small-scale biomass-fired cogeneration systems. There are likely over 100 mill-based applications across Canada for such systems under 5 MW, as well as extensive overseas markets where biomass residuals presently go to waste. The first such systems will likely be 1 MW in output. The list of system developers includes KMW Systems (working with CANMET at BCC), Etho Power (BC), Entropic Energy, Noram and SNC Lavalin.
- Canadian developers of small-scale biomass cogeneration units are constrained by federal labour laws, which stipulate that all installed systems utilizing steam at pressures > 15psi for electricity generation are subject to 24-hr surveillance by (at least) a licenced 3rd class stationary engineer. This requirement drives operating costs out of the economic range for equipment of this size and capital cost, and to date has curtailed the development of commercial biomass systems of 1-5 MW. Each of the companies currently engaged in R&D in this area is working to get around these laws, for example by using a binary fluid system based on a refrigeration-type cycle.
- European manufacturers have not been constrained by such system supervision laws, and several Finnish companies, for example, have developed automated biomass cogenerator systems (utilizing steam) in the 1-5 MW range. These are not legal in Canada.
- CETC researchers at Bells Corners have modified an existing KMW 1 MW moving-grate combustor, and built a custom heat exchanger, which will route combustion gases through a gas turbine. The unit is due to be tested in summer 2003.
- The manufacturers listed above are aiming at an installed capital cost of CAD$3000/kW (i.e. $3 million/MW), and NRCan expects most of these companies to put a product on the market by 2005/6. At present, due to the intensive design effort required, capital costs are much higher than this (around $5000/kW).
- Commercial units will be 2-stage combustion gasifiers, using gas turbines to generate electricity. The units will be designed to handle a wide range of biomass feedstocks with moisture content in the 30%-60% range. This can include previously un-utilized feedstocks such as bark shavings, chicken litter and forest floor residuals. Depending on moisture content, projected electrical efficiencies in the range 15% - 20% of input feedstock can be expected, with heat recovery pushing this beyond 50% overall. A 1MW unit would require a biomass feed rate of approximately 0.5 – 0.75 tonnes/hr.
- Together with the steam pressure issue, the major technical challenge for manufacturers is heat exchanger design. To achieve the desired efficiency, the heat exchanger in a system of this kind must be able to operate at temperatures around 1100°C, so specialized alloys are required.
- Feedstock drying remains a key issue, and there are no efficient biomass drying systems yet on the market, although three are said to be under development in

Canada (one of which – built by Mabarex Inc. - has been awarded funding under Sustainable Technology Development Canada).

- Further R&D is also required for emissions reduction, especially for fine particulates (i.e. PM_{10}) that, as Environment Canada has warned, cause significant damage to lung tissue. Nevertheless, levels of fine particulates (ash, unburned hydrocarbons and condensable aerosol mists) are difficult to measure and evaluate.
- In 2001 VTT Energy, Finland's state-funded energy research centre, published a comprehensive study of biomass cogeneration technologies, which includes economic analyses of energy production and plant costs from existing Finnish facilities utilizing wood chips, peat, straw and forest residues (Title: '*Biomass CHP Technologies – Future Cogeneration*'; E.Alakangas, M.Flyktmann; VTT Energy Reports 7/2001).

Micro-Scale Biomass Cogeneration

Micro-scale biomass-fired power units (up to 50 kW in output) are starting to enter the commercial market, and can ultimately be expected to provide widespread potential for distributed and remote applications, both in Canada and in developing countries, where electric power may be unavailable. Canada has not been active in developing systems of this size, but the US DOE has funded several prototypes, in which a dry agricultural residue such as coconut fibre or nut casings is used to power a reciprocating engine with heat recovery. Such units require a dry, low-ash, uniform feedstock, however, and off-the-shelf commercial units are not yet available. DOE-funded leaders in this field include:

- Community Power Corporation, of Colorado, which builds 15 kW 'BioMax' cogeneration systems, using augered dry fuel, for community or agricultural use.
- External Power Inc. of Indianapolis, Ohio, which is developing residential and commercial scale systems fired by wood pellets or cordwood, using a Stirling engine to generate electricity. Prototypes have been built down to 1 kW in size, although larger models will have capacities in the 20kW range. The company is focusing on markets in N.Europe and Scandinavia, and has formed a partnership with Energidalen, a prominent Swedish biomass research facility.

Fluidized Bed Gasification

- There are presently 11 large-scale biomass combustors in Canada; all use fluidized beds to burn hog fuel at pulp and paper mills. Due to the high moisture content of the fuel, efficiencies are low, and typical unit size is 30 – 70 MW electrical, plus process steam. The number of these installations is expected to grow with the pulp and paper industry (today and historically the largest recipient of federal biomass combustion R&D funding).
- Co-firing of biomass with coal is common in Finland and Sweden, but there are no Canadian installations at present. Nova Scotia Power operates one fluidized bed combustor for pulverized coal, but without green credits of some kind there is

presently no commercial incentive to displace coal with biomass, either in Nova Scotia or elsewhere in Canada. The US is investigating co-firing of biomass with coal at several test facilities, using dry agricultural residues.

- When used in fluidized bed combustors the high mineral content of biomass fuels can cause technical problems, therefore when designing an installation it is essential to examine fuel characteristics, as well as the phase diagram for the combustion process. Much research remains to be undertaken in this area.
- An example of a mis-matched fuel and reactor occurred in August 2002 when an 8 MW biomass-fired power plant was commissioned in Eggborough, Yorkshire (UK). The reactor was forced to shut down after just 8 days because the fluidized bed had "gummed up". The most likely cause was high potassium content in the chipped willow fuel, which combined with the silicon sand bed material to form 'eutectics' (clumps). According to NRCan researchers, the solution to this problem may be as simple as changing the sand in the reactor to olivine, a non-silicon rock.
- According to researchers, some biomass fuels are "extremely difficult" to burn effectively for energy. Corn, for example has high ash and potassium content, producing significant clinker buildup in small-scale combustors.

Tools

Information and articles on combustion developments in Canada can be found at:

http://www.combustion-net.com

Forestry and Agricultural Residues

- *Lumber Mill Residues*
- *Short Rotation Energy Cropping*
- *Harvesting Forest Floor Residues*
- *Straw-fired Neighbour Heating*

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Lumber Mill Residues

- Potential sources of residual energy from the Canadian forestry sector include mill residues, harvesting residues and short rotation forest plantations. Of these, only mill residues have to date been utilized in Canada for energy.
- In western Canada around 78% of a sawlog is used directly in wood products: 40% as sawn lumber and 38% as wood chips for pulp and paper. The remaining 22%, comprising bark, sawdust and shavings, is wood residue or hog fuel.
- Reduced harvest levels, increased utilization of hog fuel and a growing demand for engineered wood products have reduced Canada's surplus wood residue volumes by 50% over the past decade. Recent analyses[1] found that in 1999 mills across the country were producing 17.7 million bone-dry tonnes of residue annually, of which 70% (12.3 mbdt) was utilized for energy or other wood products, leaving a surplus of 5.4 million bdt.
- These 5.4 million bdt of un-utilized millwood residue are distributed amongst the lumber production regions of the country. Around 38% of the total is produced in BC, with Quebec (30%), Alberta (17%) and Ontario (8%) making up most of the balance. The proportion of bark and whitewood components in surplus wood residue varies regionally. In BC and Alberta the proportion of bark and whitewood is approximately the same, while Quebec and the Maritimes report that most of their surplus is bark.
- Although un-utilized mill residues are presently landfilled or burned in beehive burners with no energy recovery, the competition for (and the price of) this biomass is expected to rise, with fibreboard, plywood, OSB, wood pellet and particle board mills all potentially competing with cogeneration options for the raw material. Utilization of these wastes will move forward on a mill-by-mill

[1] Inventory of Biomass Feedstocks Potentially Available for Fuel Ethanol Production, Levelton Engineering, for OEE, NRCan, Nov. 2002 ;

basis according to local considerations, but it is rapidly becoming uneconomic simply to dispose of whitewood mill residues even at the most remote mills.

Short Rotation Energy Cropping

- The REAP Canada research program (Resource Efficient Agricultural Production) has operated since the mid-1990s, with the goal of developing short rotation biomass energy crops. Under this program optimal yield crops are selected and tested based on their growth characteristics, tolerance to pests and disease and suitability for various soil types. In addition, data is being collected on silviculture, cloning, establishment, planting and tending.
- Willow, poplar and switchgrass varieties have the most potential for energy cropping. Willow can be coppiced, and is normally grown and harvested on a 2- 4 year cycle, when the fast-growing stems reach a diameter of about 1 inch. Poplar is harvested on a 10 - 15 year cycle, with a trunk diameter of about 6 inches. Switchgrass is harvested by mowing annually, with plants remaining in the ground for 10 years or so, before being ploughed up and replaced.
- Silvicultural site preparation includes ploughing, harrowing and application of herbicide and fertilizer, before dormant cuttings of 20-25cm are planted, either by machine or by hand.
- Harvested stems are often chipped on-site, and then transported to the combustion plant. Operational yields in the northern hemisphere approach 10-15 tonnes/Ha annually, so a plantation of 11,250 Ha could in theory produce enough biomass for a 30 MW power station, or enough to supply a medium-sized community.
- Sustainability issues surrounding energy cropping are widely acknowledged to need more research, particularly in the areas of soil nutrient depletion and soil-carbon interaction from ongoing cropping cycles. Other issues requiring more study in this context include conservation of biological diversity and maintenance of forest ecosystem vitality.
- Energy cropping systems are not yet widely proven. For example *New Scientist* magazine reported in November 2002 that a 8 new MW biomass-fired power plant in Eggborough, England had been forced to close down after 8 days combustion of local willow crops, which were grown specifically as fuel. The technical problems faced by the plant included alkaline contaminants in the biomass fuel, which combined with the sand in the fluidized bed gasification unit, gumming it up. This situation highlights the need for careful evaluation of all biomass fueled combustion systems.

Harvesting Forest-Floor Residues

- Scandinavian countries have moved towards utilization of forest floor residuals from timber harvesting. Until recently the cost of collecting and transporting this bulky material outweighed its energy value as hog fuel. However, at least one manufacturer of lumber equipment (Timberjack – a subsidiary of John Deere) has devised a tractor-mounted bundler for collecting forest residuals.

- In the bundling method, the forest residual (or slash) left behind by a harvester, is collected and fed into the bundler, which produces compact "slash logs." Typical slash logs are 3 metres in length and 60-80 cm in diameter. The Timberjack company claims that each bundle can contain 1 MWh of energy when combusted. A felling area one hectare in size can yield 150 such bundles.
- Slash logs are transported from the forest to the roadside using standard forwarders. They can be stored temporarily in the forest or trucked directly to a power plant, where they are either stored or chipped at the terminal inventory. The bundles can be dried in stacks, making them available for use throughout the year.
- The Timberjack slash bundler has been used successfully in Scandinavia, and the company plans to ship a unit to Canada for demonstration purposes in 2003. The base machine is typically a standard forwarder, modified to accommodate the bundler.
- The 2002 NRCan/Levelton Engineering report includes assessments of 'forest residuals' from accessible lumber production areas in all Canadian provinces. On average, the foliage of lumber-producing trees contains about 4% of the tree's biomass, the branches 11% and the top 7%. These slash components, totaling 22% of the average tree's biomass, are typically left on the forest floor during logging operations.
- Given that Canada's forest industry logged an area of 1.08 million hectares in 1998 (80% of which was clearcut), and assuming an average biomass density of 75 tonnes per hectare, 22% of this harvested amount indicates a national annual forest floor residual (branches, top and foliage) of :

  $75 \times (1.08 \times 10^6) \times .22 = 16.5$ million tonnes.

- An updated national inventory of forest residues from lumber operations is being prepared under the direction of Mark Gillis of the National Forest Inventory, CFS Victoria. This database is expected to be online by 2005, and will contain a far more accurate component breakdown of all national forests than is currently available (e.g. biomass per tree component by area and forest type, per province).

- The website for Canada's National Forest Inventory contains authoritative data on the distribution and structure of Canada's forests. This site can be found at:

  http://www.pfc.cfs.nrcan.gc.ca/monitoring/inventory

Straw-fired Neighbour Heating

In Denmark the market for district heating plants is "almost saturated", according to the country's DH industry association, but a widespread market is emerging for smaller-scale 'neighbour heating' systems, whereby farmers invest in a larger straw-fired heating plant than they need and sell the excess heat to the local community. Such systems have been found to be viable for up to 100 separate buildings or residences, wherever the housing density allows at least one residential connection per 30m of main pipe. Favourable economics are reported for any system which can distribute 600 MWh/km of main pipe, and depending on the distribution of heat, such systems can be built for as little as "half the cost of conventional district heating systems"[2]. Typical costs for a straw-fired heating plant are reported by the Danish District Heating journal as:

Plant Size		***Price per Component ($ CAD)***		
	Boiler Plant (incl. building)	*Straw Storage Facility*	*Main Pipeline*	*Service Pipeline*
400 kW	104,000	220/m2	250/m	2400 per household
800 kW	217,000	220/m2	250/m	2400 per household

Case Study

In 1998 a crop farmer in the western Danish village of Sdr.Nissum installed a straw-fired plant, which now provides heat to 70 households, a school and a sports hall, all of which were formerly heated by individual oil-fired boilers.

Capital costs for the entire system, including heating plant, fuel storage/loading facility, backup oil boiler and heat distribution network were CAD$1.17 million, of which 24% was covered by a grant from the Danish Energy Agency. The remaining costs were financed through a 10-year loan from a local bank.

The straw-fired heating system uses 600-700 large bales of straw each winter, all produced on the 430 hectare farm. Before the decision was taken to build a heating plant the farmer had difficulty selling his straw profitably, and much of it was left in the field. During the heating season the system's only labour input is one person-hour (or less) each day, loading bales onto an automatic conveyer system.

The project has been profitable for all participants, with householders saving an average of CAD$300 per season on the cost of oil heating. Price stability is also a significant factor in the decision of many residents to sign heating agreements.

Further information on this and on similar projects is available from the Danish Centre for Biomass Technology at:

http://www.videncenter.dk

[2] Quote from Lars Nikolaisen of the Danish Centre for Biomass Technology, Arhus

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**FOREST AND AGRICULTURAL RESIDUES**	
Technology	**Forest floor residues**	**Straw**
Energy Form Produced	- heat / electricity	- heat / electricity
Energy Applications	- biomass combustion Systems (cogen)	- small-scale district heat
Local Economic ***Development Potential***	- moderate/high	-high (displaced fuel, employment)
Estim. Cost of Energy	- low	- low/moderate
Level of Investment	- moderate (collection, processing)	- moderate/ high (storage, handling, combustion)
Critical Requirements	- lumber producing areas - biomass combustion plant nearby - specialized slash log equipment	- excess straw - DH systems – population density
Level of Expertise?		
-Design/install	- moderate	- high
-O&M	- low	- low
Existing Installations	- many in Finland; none in Canada	- many DH systems in Denmark
Benefits	- utilizes waste which was left in forest - equipment forms 10m slash logs from forest floor waste, these can be transported, dried cost-effectively	- utilizes farm waste - can be viable where full sized DH systems are not
Limitations & Issues	- requires proximity of lumber site operations and biomass-fired plant	- no systems available off the shelf in Canada

Biomass Pellets

- *Wood Pellets*
- *Switchgrass Pellets*
- *Pellet Stove Issues and Barriers*
- *Tools*

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Wood Pellets

- Wood pellets can be made from a variety of feedstocks, but generally in Canada white wood waste is used (i.e. sawdust, chip and planer fines). This material is separated from bark in sawmills and dried to approximately 6% moisture in a biomass-fired dryer. The material then passes through a screen and hammer mill before being transferred to the pellet mill, where it is steam-conditioned for extrusion through dies to form wood pellets. The hot pellets are then cooled to reset the lignin and form a hard, stable product. In all areas of handling, dust is recovered and used as fuel in the dryers. In Canada the fuel is sold in 18 kg sacks.
- The US-based Pellet Fuels Institute has established national standards for pellet fuels, which define a range of characteristics including minimum fuel density, dimensions, % fines (to prevent fuel clogging), % chlorides (to prevent combustor rusting) and inorganic ash content. Two fuel grades have been established, and the ash content determines whether a pellet is considered premium (< 1% ash content) or standard (< 3% ash content).
- Several European countries (e.g. Austria, Sweden) have made the political decision to develop a wood pellet industry and infrastructure, which allows maintenance-free stove operation for users. High-grade (i.e. white wood) fuel is delivered by pneumatic truck to a hopper at the home or business, and all stoves are fitted with automatic ignition systems and thermostat controls. In Canada the wood pellet industry has not received government support, and no such infrastructure exists.
- The world's first Pellet conference was held in Stockholm in Sept. 2002. The Swedish pellet industry reports that Sweden now has 800 wood pellet burner installations in the 25 – 300 kW range, including many district and community systems. Participants at this conference toured several wood pellet production and combustion facilities, including the Fortnum power station, Stockholm's first

cogeneration plant, which is connected to one of the city's district heating networks and which operates 3 x 100 MW pellet-fired boilers.

- The Swedish wood pellet industry predicts a European market of around 5 million tonnes for their product by 2007.
- Canada produces approximately 500,000 tonnes of wood pellets annually, over 80% of which is exported to the US and Europe. However, feedstock availability from Canadian mills is decreasing in all parts of the country: NRCan noted a 50% decline in surplus wood residues between 1990 and 1998 at Canadian mills, and the manufacturing capacity of existing wood pellet plants is now double the available fuel supply. The Canadian wood pellet industry seems to be in transition, with pellet manufacturers facing increased competition for raw material from a variety of building board plants and others.

Switchgrass Pellets

The adoption of switchgrass pellets for fuel has been promoted over the past decade by Resource Efficient Agricultural Production (REAP), a non-profit organization working with farmers, scientists, NGOs and industry to promote sustainable farming. REAP, in collaboration with NRCan and Energy Probe, has analyzed full-fuel cycles for a range of biomass crops, and has shown that pellets made from perennial hardy grasses have significant potential for providing low-grade heat, promoting rural economic development and reducing GHG emissions. REAP's technical and economic analysis of this fuel source is summarized in an extensive market study prepared for the Ontario government[3], available online (www.reap-canada.com). This analysis shows:

- Switchgrass is a native perennial of the tallgrass prairies. It is a hardy, drought-resistant, resource-efficient plant, and cropping permits low-cost marginal farmland to be utilized, requiring minimal fossil fuel input for planting, harvesting, and fertilizing. Switchgrass is suitable for pelletization with minimal upgrading, drying and processing.
- In most agricultural regions switchgrass can be grown with little risk at a cost of US$2–3/GJ. Using existing production equipment and techniques this translates to an agricultural energy output of 100-250 GJ/Ha. REAP's analysis shows that switchgrass pellets typically produce 13 GJ of energy per GJ input into the fuel production cycle, whereas corn ethanol produces just 2 GJ.
- While alfalfa has been grown as a pellet fuel for years in N.Alberta and Saskatchewan, it is less attractive than switchgrass as an energy crop since it needs to be cut several times per year, and it has a high nitrogen requirement and fuel content, producing significant NOx emissions when burned.
- Several Canadian manufacturers are now marketing efficient pellet stoves, which can burn moderately high-ash agricultural fuels such as grass pellets. For example in 2001 CETC's combustion lab tested a residential-sized pellet stove

[3] 'Switchgrass Fuel Pellet Production in Eastern Ontario: A Market Study', by Jannnasch et al, 2002.

manufactured by DellPoint to a measured efficiency of 82% on switchgrass pellets. This performance is comparable in combustion efficiency and particulate emissions to that of a new residential oil furnace. Clinker production is likely the most important issue when burning this fuel (see below).

- Switchgrass energy cropping has the potential to cut GHG production significantly at a local level. Fuel pellet manufacturing is a simple mechanical procedure, which can be undertaken by farm-sized operations without specialized labour, at a low capital cost compared with other energy sources. The industry has significant potential for community energy development, in comparison to industrial-scale, capital-intensive biomass alternatives such as corn- or cellulose-derived ethanol. This fuel can be produced on a farm and used as a source of low-grade agricultural heat in greenhouses, livestock barns and other commercial and residential applications.
- Switchgrass can be produced cost-effectively where land rents are $60/acre per year or less. Average yield is 9 tonnes/ha, but new strains are increasing yields.
- In Canada it is generally assumed that a newly constructed pellet plant requires an annual processing capacity of 50,000 tonnes to be commercially viable. Data from the US-based Pellet Fuels Institute suggests that a 7–8 tonne/hr facility can be built at a cost of CAD$2.1 million, while a new 3-4 tonne/hr facility costs CAD$1.4 million.
- REAP's market survey indicated that farmers supported the idea of mobile pelleting systems, which would move from farm to farm to process grasses as required. Several such systems are available, for example those manufactured by the Italian firm 'Ecotre', which cost between US$100-250k and which can process 1 - 3 tonnes/hr.
- The biofuel pellet industry has received no government support to date, so significant improvements in fuelstock pelletization efficiencies are likely achievable with modest resource input.
- According to REAP, the farming community looks positively on the potential for development of a switchgrass fuel industry, but recognizes that this is a new crop. Established crops and industries have well-funded support infrastructure and lobbying ability; the US corn ethanol industry, for example, has been politically active at the highest level for decades. A switchgrass fuel industry will likely not develop in Canada without significant policy support at least at the provincial or regional level.
- Agricultural commodity prices have been declining in real dollars, while wood pellets have been rising in price due to ongoing improvement in mill residue utilization and increased competition for the product. Both these trends are likely to continue, and could provide switchgrass consumers with lower and more stable heating costs. REAP's analysis suggests that the annual fuel cost of heating an average home in Ontario could be halved using switchgrass pellets.
- Switchgrass plants can be left intact in the field for 10 years or more, with the stalks harvested annually. However, growing stock can be re-seeded every 3 or 4

years to improve strains and productivity, an option which is not available for longer-cycle energy crops such as willow and poplar. The switchgrass plant requires 20% or less of the nitrogen fertilizer input of other biomass-to-energy crops such as corn.

- Although straw is now combusted directly, or used as an ethanol fermentation feedstock, its high silicon content may make it more suitable for use in fibre applications, such as compressed fibreboard.

Pellet Stove Issues and Barriers

- Pellet appliances are controlled combustion units with automatic fuel delivery, where a thermostat setting controls an auger to deliver fuel from a storage hopper to the fire. The dry, processed fuel and constant feed rate both promote high levels of combustion efficiency (80 – 85%), and these appliances can be side-vented through an exterior wall without the need for a conventional chimney. Pellet stoves typically produce only 10% of the emissions from a wood stove.
- The primary technical problem with burning pellet fuels made from non-white wood residues (including switchgrass, bark and corn) is clinker buildup in the combustor. In the case of switchgrass this is due to the high potassium content of the fuel. Over a period of hours potassium, which has a low melting point, builds up in clumps and must be mechanically separated or removed to preserve combustion efficiency. NRCan researchers feel this issue need not be a limiting factor in the uptake of alternative pellet fuels, but some resources will have to be invested into automating the mechanical separation of clinker buildup inside the combustor if such alternative fuels are to be used in the residential and commercial markets.
- Clinker buildup in the European small-scale pellet stove market is avoided by legislation allowing only high-grade (i.e. white wood-derived) fuel to be used in residential stoves. Lower grade and alternative pellet fuels such as bark are used exclusively in industrial applications, where large volumes allow such technical issues to be addressed with relative ease.
- The relatively high cost of a high quality domestic pellet appliance (e.g. DellPoint's latest stove, priced at CAD$3100) can act as a market barrier, but this initial cost is offset in new installations by savings from wall venting over the cost of a full chimney.
- Pellet stoves rely on a 12v supply of auger-fed fuel and fan-induced combustion air, and are therefore vulnerable to electricity supply disruptions. Some manufacturers are addressing this issue by supplying their units with backup batteries, which will provide at least 1 day's electrical requirements.

Tools:
More information on pellet fuels can be found at the following websites:

http://www.pelletheat.org	(Pellet Fuels Institute, Arlington, Vermont)
http://www.pellet.org	(BC Pellet Fuel Manufacturers Association)

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**BIOMASS PELLETS**
Technology	**Switchgrass pellets**
Energy Form Produced	- space heat
Energy Applications	- space heat – residential, commercial, agricultural
Local Economic ***Development Potential***	- high (local pellet sales and employment)
Estim. Cost of Energy	- low ($3-4 /GJ estimated)
Level of Investment	- low
Critical Requirements	- policy support at regional/national level, including fuel standards, infrastructure, risk insurance for farmers and producers - further R&D on small-scale combustion stoves to solve clinker issue - annual rent of $60/acre or less for agricultural production land
Level of Expertise	
-Design/install	- low
-O&M	- low
Existing Installations	- None yet. REAP Canada conducted a successful pilot for local switchgrass production in Quebec (1999). A 2001 market potential study for E.Ontario found "significant potential" for a switchgrass pellet industry
Benefits	- Reduced heating costs for homes and businesses (40 - 50%) - Significant GHG emissions reduction potential from renewable local fuel production, unlike some biomass-derived fuel such as corn ethanol - Rural economic development via increased farm income and employment - Increased local self-sufficiency from fuel production and use - Fuel ideal for heating greenhouses, barns, commercial buildings - Switchgrass is a native prairie tallgrass, drought and heat resistant, requiring little fertilizer, adapts well to marginal, poor quality farmland
Limitations & Issues	- Clinker buildup from high potassium content in switchgrass needs to be addressed by further stove R&D to incorporate a mechanical means of mixing clinker with the ash. This would not require much funding. - Switchgrass could play an important role in energy diversification and supply security, especially at the rural level. Federal or provincial policy support will be needed to initiate a viable industry.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **BIOMASS PELLETS**

Technology **Wood pellets**

Energy Form Produced - space heat, cogeneration electricity

Energy Applications - space/process heat, grid electricity

Local Economic - moderate

Development Potential
Estim. Cost of Energy - low

Level of Investment - moderate

Critical Requirements - significant and stable supply of white wood mill residues

- policy support at regional/national level, including fuel standards, distribution infrastructure, tax incentives etc

Level of Expertise
-Design/install - moderate
-O&M - low

Existing Installations - Sweden has > 800 wood pellet installations in the 25-300 kW range, including many district heat and cogen facilities, also major power plants up to 300 MW. In Canada wood pellets are sold only by the sack**,** for small scale residential/commercial use.

Benefits
- Wood pellets are clean-burning, suitable for any combustion equipment including residential-scale stoves
- The pelletizing process resolves biomass combustion problems arising from high moisture content and non-uniformity of fuel
- Combustion efficiency >80% is achieved even by small pellet stoves
- North American standards/grades have been established for pellet fuels

Limitations & Issues
- 60% of Canadian wood pellet production is exported to US and Europe
- availability of wood residues from Canadian lumber mills has declined by 50%+ since 1990, as wood pellet manufacturers face increasing competition for raw material from building board plants and others
- The pellet industry has received no support at the federal or provincial policy level, unlike some European countries which have developed an extensive pellet fuel delivery infrastructure over the past decade (Austria, Sweden), making this fuel as convenient as oil for customers.

Peat

- *Characteristics*
- *Peat Harvesting & Production*
- *Sustainability and GHG Issues*
- *Peat Energy in Newfoundland*
- *Peat Use in Europe*

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Characteristics

- Peat is composed of organic residues from the Sphagnum plant. It originates via the incomplete decomposition of plant constituents under water-saturated, anaerobic conditions. Sphagnum is a non-vascular (no roots) plant, which sheds cellulosic material as it grows, and it is this material, which accumulates underwater to form ‘peat moss’. Five Sphagnum species dominate Canadian bogs.
- More than 90% of natural peat mass is water, but the calorific content of dry peat is high: 20 - 22 MJ/kg, depending on ash content.
- There are four classes of peatland, namely bogs, fens, swamps and marshes, and these are characterized by the height and flow of the water table. For land to be classified as peatland, the depth of the peat layer, exclusive of surface vegetation, must be 20cm on drained and 30cm on undrained land.
- Canada has substantially more pristine peatland than any other country. Here peatlands are most extensive in poorly drained areas such as the Hudson Bay lowlands, depressions in the Canadian Shield and Northern Alberta and Manitoba. Most peatlands (93%) occur in boreal and subarctic ecoclimatic zones.
- Ontario (312,000 km^2) is the province with the largest peatland area, followed by Manitoba (191,000), NWT/Nunavut (168,000), Quebec (111,000), Alberta (99,000) and Newfoundland (54,000). The Canadian peat industry currently harvests on just 16,000 hectares.
- During the 1970s and 1980s several Canadian studies were undertaken to examine the use of peat as a source of combustion energy, with most interest shown in Newfoundland. Every study concluded that peat was not competitive as a fuel source, owing to the availability of cheap oil, coal and natural gas. Now, as then, virtually no peat is burned in Canada. However, this country is now one of the world’s leading producers and exporters of peat and peat moss for horticultural use.

Peat Harvesting and Production

Although Canadian peat production experience pertains to the horticultural product, all commercial peat development depends on certain common factors:

- An average peat deposit depth of 2m is generally considered the minimum – largely to permit adequate drainage channels to be cut. The local topography must also show good potential for drainage, and there should be no tree cover.
- Proximity to infrastructure and resources is important for commercial peat production, particularly roads, electrical power and labour.
- The local climate must be suitable for drying peat during harvesting periods (generally June to September in Canada). This condition has long been a major restriction for the implementation of peat energy projects in Newfoundland.
- Once a peatland has been selected for development, it is surveyed and a gravity-flow drainage plan is developed. A perimeter ditch is dug to a depth of about 2m, together with a row of parallel ditches spaced 20 or 30m apart across the site. This allows the surface to dry sufficiently to bear the weight of peat harvesting equipment.
- After ditching the field is left to dry for 4 – 6 years. During this period the moisture content of the field falls from 95% to around 80%, and surface drying is greatly enhanced.
- During harvesting a tractor-drawn plough is used to harrow the top layer, which loosens the peat and breaks capillary action. After several days further drying in sunny conditions vacuum harvesters (large tractors fitted with vacuum collectors) collect the surface peat.
- Once drained and put into production, a peat bog can be harvested for horticultural production for 15 – 30 years, since only the top layer is removed each season. Far greater volumes of peat are extracted for energy use.

Sustainability and GHG Issues

- Peat is presently classified as a fossil fuel by the IPCC, and burning it would therefore increase Canadian GHG emissions. However, this definition may change, with some regarding peat as a "slowly renewable natural resource". The European Parliament added peat to its list of renewable resources in Nov 2000.
- Peat bogs are major sources of methane, due to the anaerobic (underwater) decomposition of plant material. The contribution of peatland methane to Canada's GHG emissions is significant. On an annual basis most peat bog methane is released during the growing season, and in a 2002 paper Finnish researchers reported total annual CH_4 measurements of 21 g/m^2 for typical boreal peat bogs in northern Finland[4].

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[4] This rate of release represents 1 tonne of methane per square kilometer per year.

- Draining peat bogs for agricultural or energy use does reduce methane production, but greatly increases CO_2 production from the same land, so there may be little GHG benefit overall. In addition, the loss of habitat for many bird and insect species when peat bogs are drained can be dramatic. In Canada, a recent model estimating peatland sensitivity to climate change showed that 60% of all Canadian peatlands, containing 53% of the carbon found in organic soils in this country (154 Gt), is expected to be "severely" or "extremely severely" affected by projected climate change.
- Since peat thrives in cold, nutrient-poor environments which are almost entirely dependent on atmospheric inputs, peat bogs regenerate very slowly after harvesting, taking as much as 30 years to fully recover. In recent years research has been undertaken in Canada into improving the regeneration characteristics of harvested bogs, for example by re-establishing the original hydrological conditions and by re-seeding the depleted sphagnum surface. Some of this work has been carried out by the peat moss industry, in the interests of determining sustainability characteristics.

Peat Energy in Newfoundland

Newfoundland has been the most active Canadian province in assessing its peat resources. Historically, a few residents adjacent to peat deposits have used the fuel to heat their houses, but to date there has been no commercial development of peat for energy purposes on the island. Landmarks include:

- In the late 1970s the provincial government contracted a detailed peat inventory for Newfoundland. This report was completed in 1983.
- In 1990 Newfoundland Power commissioned a pre-feasibility study for a projected 50 MW peat-fired power plant on the Burin Peninsula.
- In 1991/2 Abitibi Price and partners conducted a feasibility study for a 40-80 MW peat-fired plant utililizing existing boilers at the Stephensville newsprint mill.
- In 1993 an international conference took place in Corner Brook, which examined all aspects of the peat industry, including supply and demand, peat resource development and the Newfoundland experience in harvesting and production.
- In 1994 Northland Associates and Acres International, submitted a development strategy for the province's peat resources to the Newfoundland & Labrador Peat Association.
- In 2000 Abitibi revisited the 1991 work with a view to replacing the old boilers with a peat fueled 70 MW cogeneration facility. This effort has not moved forward due to lack of funding and inconclusive assessment of the available peat resource.
- Various provincial and federal departments in the past have supported studies of the use of peat for industrial and commercial energy use. They have also sponsored a feasibility study on production of peat firelogs, and research was also conducted on developing a liquid fuel from peat.
- In its 1999 energy policy review, the provincial government declared that peat-generated power was potentially cost-effective on the Island, but that, due to

weather-related drying issues, the harvest would be uncertain from year to year. No decision to support the peat industry was made at that time.

Peat Use in Europe

- Finland leads the world in peat combustion, generating 6% of its primary energy demand from this resource. Peat-fired CHP plants are used for district heating in over 200 municipalities, with most of these being dual fuel systems utilizing local forestry products such as wood chips and mill residues. Burning peat together with wood (or coal) helps to control the combustion process and reduce corrosion in superheater tubes.
- Finland has invested heavily in biomass combustion RD&D since the early 1980s, and has developed a wide range of efficient and environmentally sensitive methods for harvesting and utilizing peat while minimizing the ecological impact of the industry.
- In 2001 VTT, Finland's primary institution for energy research, published an analysis of existing and future biomass cogeneration technologies[5], which includes economic and investment data taken from existing and planned Finnish power facilities. For example, peat-fired cogen plants were built for district heating in 1999 at a cost of CAD$2000 - $3000 /kW.
- Peat production for energy in Europe in 1999 totalled 21.5 million tonnes of air-dried product; the major producers were Finland (7.5 million tonnes), Russia (3.5), Belarus, Sweden and Estonia. Used as a local biomass fuel, peat meets most of the demands for European energy policy: it is produced in remote areas where there is a lack of jobs, and the powerful tractors used in peat harvesting can be used outside the production season for agriculture, road maintenance and wood transportation.
- In Finland, where most harvested peat is burned for energy, it is cut and collected from the fields in sods, which are further dried and stacked by front-end loaders in triangular piles 5m high and 50 - 100m in length.
- Despite the 1990s closure of several older peat-fired power stations, Ireland is maintaining its long tradition of peat combustion, and dried briquettes or 'turf' sods are still burned in open fireplaces in many homes. In 2002 Ireland announced the construction of two new peat-fired power stations, which will have capacities of 150 MW and 100 MW. Both are expected to be in commercial operation by 2005.

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[5] 'Biomass CHP Technologies – Future Cogeneration'; E.Alakangas, M.Flyktmann; VTT Energy Reports 7/2001

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **PEAT**

Technology **Combustion - gasification**

Energy Form Produced - heat and electricity from cogeneration

Energy Applications - space/process heat, grid electricity

Local Economic - moderate/high

Development Potential

Estim. Cost of Energy - moderate

Level of Investment - high (costs include site drainage, harvesting, transport, combustion plant)
- Finnish cogen plants typically cost $2-3K / kW installed (although Finnish equipment cannot be used in Canada due to labour law issues over steam)

Critical Requirements
- peat deposits > 2m in depth to allow ditching, drainage
- long-term development policy and industry investment
- suitable summer climate for drying

Level of Expertise

-Design/install - high

-O&M - low

Existing Installations - Canada is the world's primary exporter of horticultural peat, but does not presently use any peat for energy. Finland generates 6% of its primary energy from peat, mostly in co-firing applications with wood chips.

Benefits
- Canada has significantly more peat resources than any other country
- Peat offers rural economic development opportunities from displaced conventional fuels; also harvesting, drying, processing and transporting are relatively labour-intensive, providing rural employment opportunities.
- Co-burning with wood improves combustion characteristics, reduces corrosion in superheater tubes.

Limitations & Issues
- A long-term development strategy and investment plan is needed to effectively utilize this resource (e.g. Finland has invested heavily in peat combustion / production R&D since 1984).
- Drainage of peat production fields typically takes 4 – 6 years.
- Burning peat would add to national GHG emissions
- Suitable weather is required for drying during harvesting (e.g. summer in Newfoundland has long proved a barrier to peat energy development)

MSW Combustion

- *MSW in Canada*
- *MSW in Europe*
- *MSW Incineration*

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MSW in Canada

- Canada's MSW production in 1996 was 7.03 million tonnes. This is the last year for which precise data is available, since Statistics Canada discontinued the dissemination of MSW statistics in that year. NRCan predicts that MSW production will track population growth, and therefore expects national production to reach 8.1 million tonnes by 2010.
- In 1992 the composition of MSW included: Organics – 49.5%, Paper – 21.9%, Plastics – 9%, Glass – 5.8%, Metal – 3.4%.
- Of the total 1996 Canadian MSW production, 13.9% was recycled, 4.9% incinerated with energy recovery and the rest (81.2%) landfilled. Given that several provinces have bans on new incinerator construction, and since recycling, composting and source reduction infrastructure are expanding rapidly (e.g. Nova Scotia and Edmonton – see below), the waste-to-energy incineration option is presently seen to be non-viable in most parts of the country.
- There are currently 12 MSW incineration facilities in Canada, which together burn over 120,000 tonnes of waste per year. Four of these operate energy recovery systems - Sydney NS, Burnaby BC, Quebec City and Leavis, QC.
- In some regions, including parts of Newfoundland and the North, landfilling is may not be feasible due to the lack of topsoil. In these areas cheap incineration has in the past been considered the only viable alternative for waste disposal. The usual method is to burn waste in beehive units with no controls or energy recovery.
- In 1995 Nova Scotia (pop. 940,000) set itself a target to divert 50% of all solid waste from landfill within 5 years. The province also decided to cut the number of waste disposal sites from 40 in 1995 to less than 10 in 2005. As a short-term measure Nova Scotia banned disposal of drinks containers, corrugated cardboard, newsprint, lead-acid batteries, tyres, used oil and leaf and yard waste, and over the longer term this list was expanded to include waste paint, antifreeze, some plastics, steel/tin and glass food containers and compostable material from industrial, commercial, institutional and residential sources. The Nova Scotia program has succeeded in meeting its 50% reduction goal.

- Edmonton, Alberta (pop. 938,000) now diverts 70% of its residential waste from landfill. In 1999 the city was sending 86% of its residential solid waste to landfill, but by 2001 this had been reduced to 30%, with a further 15% being recycled and 55% composted. In two years Edmonton cut the landfilled proportion of its waste by two-thirds, without building new incinerators. This was achieved by building North America's largest composting facility outside the city to sort residential garbage, mix the organic component with sewage sludge, and then compost the mix for a month. The resulting product is sold as garden compost. Recycling participation is 90% in Edmonton, one of the highest rates in the world. However, the system costs over $120 for each tonne processed, compared to the conventional system employed in Toronto, for example, where waste processing costs the city $72/tonne but only 32% of waste is diverted from landfill.

MSW in Europe

- In Europe and Japan MSW incineration continues to be viewed as a more desirable waste disposal method than landfill. The Netherlands, for example, incinerates 42% of its residential waste with energy recovery, about the same quantity as it diverts though recycling and composting. This leaves only 16% of the total waste stream to be landfilled. In Germany 25% of the waste stream is incinerated with energy recovery in 59 facilities, but a further 18 plants are under construction or planned. In Japan over 75% of MSW is incinerated.
- Further waste reduction initiatives are planned in many European countries. In Germany it is proposed to ban combustible waste from entering landfills by 2005. In Sweden the 1994 level of residential waste landfilling will be cut 70% by 2005 through recycling, incineration and composting, and after that year organic waste will not be accepted at landfills. Finland has set a goal of 70% MSW reduction by 2005, and aims to close around 300 of its 350 landfills by then.

MSW Incineration

- Emissions problems are usually due to trace contaminants in the waste stream, combined with poor combustion efficiency. Many of the most problematic emissions from incinerators are caused by pollutant precursors in the waste - chlorine, sulphur, heavy metals, organics and nitrogen - which combine during combustion to form a wide variety of toxics.
- Stack emissions can include: particulates (including heavy metals such as cadmium and lead), acid gases (e.g. sulphuric, hydrochloric acid), mercury, nitrogen oxides (which contribute to acid rain and ground level ozone) and products of incomplete combustion such as dioxins and furans (and their precursors – chlorobenzenes and chlorophenols).
- Emission control devices employ a wide range of physical and chemical techniques to clean the combustion airstream, including absorbtion, adsorption, condensation, pH neutralization, filtration and electrostatic precipitation. Various reagents are used, such as water, lime, ammonia and urea, which can be injected

into the combustion gas stream to increase efficacy. Combustion, emissions control and monitoring technologies have improved rapidly over the past 15 years.

- Together with source separation and waste screening, the most effective way of preventing high emissions is by optimizing combustion via optimal feed rates, adequate temperatures, optimal combustion air and complete mixing.
- Effective source separation is common in Europe, where magnets are used to extract iron and steel. Waste material is further sorted by weight, as it passes across a grid with an upward airstream. Material, which floats, is taken off and assumed to be combustible.
- NRCan believes that MSW incineration with heat recovery can be a viable, environmentally acceptable and cost-effective alternative to landfill in Canada if a gasification process is used at existing clean combustion facilities. This means installing a fluidized bed gasifier at a coal-fired generating plant. By using existing combustion facilities there is no investment requirement for expensive flue gas cleaning technology, since it is already in place.
- Using a fluidized bed gasifier it is possible to burn virtually any kind of MSW, since this technology can accommodate a non-uniform fuel. The gasification process produces combustible H, CO and other volatiles, which can then be fed into a coal furnace as part of the fuel mix. If gasified MSW is co-fired with coal at up to 15% of the mix, then the overall combustion efficiency is reduced only by one or two percent, and this is due to the lower energy density of the MSW.
- In Lahti, Finland, a 170 MW coal-fired power plant was retrofitted with a biomass/MSW gasifier at a capital cost of US $11 million. This system uses a 15% MSW mix, which has been shown to reduce the overall plant efficiency only marginally.
- Based on the above argument, Canada's coal burning provinces are the only candidate regions for MSW co-firing gasification: Alberta, Saskatchewan, Ontario and Nova Scotia have coal-fired generation facilities which could be adapted to this technology.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**MSW COMBUSTION**
Technology	- MSW gasification/combustion at existing coal-fired power plant
Energy Form Produced	- heat and electricity from cogeneration
Energy Applications	- grid electricity
Local Economic	- low
Development Potential	
Estim. Cost of Energy	- moderate
Level of Investment	- high (e.g. Lahti, Finland: US$11 M for MSW gasifier retrofit at existing 170 MW coal-fired generating plant)
Critical Requirements	- coal fired power plant fitted with advanced flue gas treatment technology
Level of Expertise	
-Design/install	- high
-O&M	- high
Existing Installations	- none in Canada: several in Europe
Benefits	- Diverts significant volumes of waste from landfill - Existing 'clean coal' flue treatment technology can largely eliminate toxic emissions from waste incineration
Limitations & Issues	- capital costs for this technology are high, landfill costs in Canada are low - limited to locations with existing coal-fired power plants - needs fluidized bed gasifier and optimum combustion conditions - highly successful waste reduction initiatives have been initiated in various Canadian jurisdictions (e.g. Nova Scotia, Edmonton), which can greatly increase landfill lifespan at lower capital and environmental cost.

Chapter 2: Biomass Derived **Landfill Gas**

- *Tools*
- *Landfill Gas Production and Use*
- *Capital Costs*
- *Bioreactors*

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Tools

- The most comprehensive study of landfill sites and landfill gas (LFG) utilization potential in Canada was conducted in 1999 for Environment Canada. This report was commissioned to examine all potential landfill gas development sites in the country. It is not available online:

  'Identification of Potential Landfill Sites for Additional Gas Recovery and Utilisation in Canada' ; July 1999. Environment Canada/PERD
  Prepared by Conestoga-Rovers and Associates (CRA).

- Further relevant information was prepared in a December 1999 Options Paper by the Municipalities Table of Canada's National Climate Change Implementation process, by the Landfill Gas Sub-committee. The group's primary objective is to encourage municipalities to undertake a sustained effort to reduce GHG emissions, with a 20 percent reduction as the ultimate goal. This paper examines municipal options for program design and delivery. It looks at LFG capture for GHG reduction purposes alone, and examines the economics, benefits and barriers of LFG capture strategies at the local level. This document can be viewed at:

http://www.nccp.ca/nationalprocess/issues/municipalities_e.html

Landfill Gas Production and Use

Landfill gas is the only energy stream directly under the control of municipal authorities in Canada. Information on potential development of landfill gas projects is taken from the above Environment Canada report and from an interview with Alain David (Nov 29, 2002):

- Currently there are around 5000 municipalities in the country, most of which operate or have operated at least one landfill site. The EC report has developed a full inventory and assessed every major landfill in Canada to determine which sites are good candidates for LFG recovery and utilization. Sites are assessed in terms of size, age (incl. date of closure) and waste input.
- Currently, 41 landfills collect LFG, and 16 burn it for energy – 8 for electricity generation and 8 for industrial processes or boilers. The other 25 LFG collectors flare the gas as a GHG mitigation procedure.
- Many sites have favourable economics for electricity generation or other productive use of the gas (e.g. Trail Rd, Nepean) but they may also lack a "champion" to move the process forward.
- Site screening criteria for the EC report specify a minimum size at closure of 1 million tonnes of waste for active landfills, and higher sizes for inactive, closed sites (e.g. > 2 million tonnes for sites closed between 1985 and 1990). Smaller sites and sites closed before 1980 are not considered to be economic for LFG production.
- The EC report identifies and ranks the 'next 84' landfills in Canada which are most likely to produce economic quantities of LFG. There are currently many landfills, which are abandoned or forgotten – Statistics Canada identified 767 landfills nationally in their most recent waste management survey.
- The major barrier to LFG capture and utilization projects is capital cost. The cost of LFG utilization depends on the degree of gas processing required: at the minimal level, condensate is removed to form low grade fuel suitable for space and process heat; for medium grade fuel (suitable for fueling a wider range of boilers or kilns, or fueling gas turbines for electrical generation) there must be further treatment to remove moisture and contaminants. To produce high grade fuel as a pipeline gas for electricity generation, the methane and CO_2 must be separated, and trace contaminants removed.
- Due to the minimal gas treatment required, favourable economics are often obtained by projects that can use the LFG directly, by burning it for process heat without generating electricity. The ideal direct user of LFG would have a consistent (24 hours, 7 days) fuel demand and would be located not more than a few kilometers from the landfill site.
- The EC study found that under existing electricity and natural gas market pricing (1999) nine major landfill sites could be developed to produce electricity cost-effectively, most of these being located in Ontario. If GHG credits from emissions trading were included in the economic analysis, at \$1.68/tonne CO_2e, then LFG recovery was found by this study to be economic at 23 sites across Canada. *However, this study used an assumed electrical power price of*

3 cents/kWh, which has risen in all parts of the country at the time of writing, making more landfill site projects potentially viable.

- Production of LFG from a conventional landfill may continue for 50 years after site closure, and can result in total yields of 125 – 310 m^3 methane per tonne of waste (waste density is assumed to be 0.8 tonnes/m^3).
- Future trends in landfill management will see integration of waste management between municipalities and eventual changes in the way waste is viewed – i.e. more as a resource than as a liability.
- A key variable in the equation of economic viability for any landfill is the lengthy lifespan of conventional sites – LFG is released in moderate quantities over a period of between 50 and 100 years. New design and research initiatives have led to the concept of 'bioreactors', namely engineered waste management sites in which the decomposition process is both speeded up and highly controlled. These bioreactors are designed to produce high rates of LFG flow upon commissioning, and therefore greatly increase the economic viability of landfill gas production. Bioreactors will be the landfills of the future, and they will be designed to produce all their gas within 10 - 15 years (see below).
- Environment Canada has initiated a study of the bioreactor concept and of reactor performance, which is due to be completed in April 2003.

Capital Costs

Capital costs for LFG recovery systems vary widely, according to site location, site configuration and gas production rate. The Environment Canada report cited above lists the following capital costs for LFG capture and flaring only (1999 $):

Item Description	**Landfill Site Size (million tonnes)**		
	Small *(< 2.5)*	*Medium* *(2.5 – 5)*	*Large* *(>5)*
Capital Cost ($/tonne waste)			
- system w/vertical wells	$1.05 - $3.10	$0.8 – $1.25	$0.55 - $0.90
- system w/trenches	$1.15 - $3.70	$0.8 – $1.35	$0.50 - $0.90
Monitoring (x 1000 per year)	$25 – 50	$40 - $100	$60 - $120
Operations & Maintenance (x 1000 per year)	$60 – $110	$90 - $250	$160 - $275

This study also incorporates cost estimates for LFG utilization technology. The figures used were as follows (1999 $):

Utilization Technology	*Typical Site Size (million tonnes)*	*Capital Costs ($/kW generated)*	*Annual O&M Costs ($/kW generated)*
Boilers/steam turbines	> 6	$830 - $1,200	$45 - $75
Reciprocating engine	1 – 8	$1,200 - $1,700	$150 - $180
Gas Turbine	3 – 12	$1,100 - $1,300	$90 - $120
Combined Cycle Engine	> 10	$900 - $1,300	$50 - $85

Bioreactors

- A bioreactor landfill is designed to rapidly transform and degrade organic waste. The increase in waste degradation and stabilization rate is accomplished through the addition of liquid and air to enhance microbial processes. This bioreactor concept differs from the traditional "dry tomb" municipal landfill approach.
- The Solid Waste Association of North America (SWANA) has defined a bioreactor landfill as "any permitted Subtitle D landfill or landfill cell where liquid or air is injected in a controlled fashion into the waste mass in order to accelerate or enhance biostabilization of the waste."

There are three general types of bioreactor landfill configuration:

- **Aerobic** - In an aerobic bioreactor landfill, leachate is removed from the bottom layer, piped to liquid storage tanks and re-circulated into the landfill in a controlled manner. Air is injected into the waste mass, using vertical or horizontal wells, to promote aerobic activity and accelerate waste stabilization.
- **Anaerobic** - In an anaerobic bioreactor moisture is added to the waste mass in the form of re-circulated leachate and other sources, to achieve optimal moisture levels. Biodegradation occurs in the absence of oxygen (i.e. anaerobically) and the process generates landfill gas, primarily methane, which can be captured to minimize greenhouse gas emissions and burned for energy.
- **Hybrid** (Aerobic-Anaerobic) - The hybrid bioreactor landfill accelerates waste degradation by employing a sequential aerobic-anaerobic treatment to rapidly degrade organics in the upper sections of the landfill and collect gas from lower sections. Operation as a hybrid results in the earliest onset of methanogenesis compared to aerobic landfills.
- Further information on bioreactors can be found at the US Government's EPA website: http://www.epa.gov/epaoswer/non-hw/muncpl/landfill/bioreactors

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **LANDFILL GAS (LFG)**

Technology **- Gas recovery and combustion**

Energy Form Produced - methane

Energy Applications - combustion fuel for process heat or turbine-generated electricity

Local Economic - low

Development Potential
Estim. Cost of Energy - moderate (> 3 cents /kWh gas energy content)

Level of Investment - moderate/high ($0.50-$3.70 per tonne of waste + O&M)

Critical Requirements - landfill size > 1 million tonnes; site still operating or recently closed

Level of Expertise
-Design/install - moderate
-O&M - low

Existing Installations - 41 landfills in Canada now collect LFG, 16 burn it for energy

Benefits
- Only source of energy under direct local (municipal) control
- gas capture can significantly reduce local GHG emissions
- ideal user is adjacent industrial process with constant heat demand
- LFG is a largely untapped source of energy in Canada
- several successful microturbine installations now running (e.g. Calgary)

Limitations & Issues
- capital costs are high for LFG recovery systems
- gas must be dried and cleaned if used in a turbine for electricity
- sites < 1 M tonnes in size or closed before 1985 likely uneconomic
- gas production can last 50 years – avg. yield is 125-310 m^3/tonne waste
- new landfill type - 'bioreactors' - designed for much faster decomposition
- bioreactors circulate moisture/air to speed decomposition to < 10 - 15 yrs

Anaerobic Digestion

- *Technology*
- *Manure Production in Canada*
- *System Cost and Performance*
- *Tools*

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Technology

- Anaerobic digestion (AD) is a naturally occurring biological process that can be used to treat a wide variety of waste material, including agricultural manure, organic wastes from the food and beverage industry and municipal sewage. Unlike most other waste treatment processes, AD is a net energy producer, since the biogas produced contains 60-70 percent methane. Biogas is typically used in boilers and in engine generator sets to produce electricity and heat. Facilities can use the electricity on-site or export it to the power grid. Other options for treating manure include aerobic composting.
- AD is commonly used in Canada for the treatment of industrial wastes and municipal wastewater, but the treatment of MSW and manure is still in the demonstration phase. Environment Canada has commissioned a 2003 report on the potential for the uptake of AD technology in Canada, which will update work done in the 1980s.
- Many different AD technologies are available, and new approaches in anaerobic treatment are evolving. Technologies vary in their waste treatment time and temperature, as well as in the size, configuration and complexity of the reaction vessels. Many technologies are readily available from European distributors, but may need to be modified to operate in Canada, primarily due to feedstock and climate differences.
- In general, per-animal costs for building and operating anaerobic treatment systems decrease for larger-sized operations. The economics of biogas production from livestock waste could be improved in intensive production areas by constructing centralized treatment facilities and by accepting a variety of organic wastes from slaughterhouses and the food industry, yet it is likely un-economic to transport manure, due to the high water content (manure is washed out from stalls daily). In addition, the risk of disease contamination by incoming and outgoing farm trucks (e.g. Foot and Mouth disease) mitigates against this approach becoming widespread.

- Anaerobic digesters are 'living systems' which require care in their day-to-day use. For example, adding antibiotics to pig feed can easily kill off the bacteria in a farm's digester. Digesters rely on at least one of three types of bacteria – cyclophilic (20^{o}C), mesophilic (35^{o}C), and thermophilic (55^{o}C), with most systems using the two higher-temperature types. Maintenance of suitable temperature regimes and pH levels is therefore critical to the AD process. Residence time for a plug-flow AD unit is around 30 – 40 days.
- The AD process does not lead to a reduction in waste volume, so this type of manure management will not affect the cost and effort required to spread residuals on agricultural land. However, the ammonia/nitrogen content of the digested waste is more stable, with lower odours, and is more readily available for plant uptake. The methane produced from AD is typically corrosive, due to its high sulphur content.
- In the US, AD is more common on farms than in Canada, especially in southern states with moderate climates, where there is a minimal heat requirement for the digestion process, allowing farms to operate lagoons economically.

Manure Production in Canada

- In 2000 the Canadian Agricultural Marketing Council (CAMC) called for Canada to increase its share of the world agricultural export market from 2 to 4 per cent by 2010. Interim figures suggest that this figure may be met. Agriculture Canada calculates that under this scenario cow and hog populations will increase by 16% over this period. If agriculture is to contribute its share to Canada's Kyoto target, GHG intensity and emissions from this sector will need to be reduced. One way of doing this is through changes in manure management, to reduce methane and NOx emissions.
- In the 1980s, NRCan helped fund 28 AD farm demonstration projects in Canada, none of which is still operating. Funding was stopped in the early '90s because projects could not compete economically. More recently, NRCan's focus has been on landfill gas and biogas from the pulp and paper industry (e.g. Tembec).
- Farm intensification has been a visible trend in Canada's livestock industry, and presents a need for pollution control, as well as an opportunity to generate energy, while retaining the nutrient value of manure.
- NRCan estimates the amount of recoverable manure from the major livestock sectors in eastern Canada at 46,000 tonnes/day in Ontario, 43,000 in Quebec and 7,000 in the Atlantic Provinces. Potential gross energy production from the AD of livestock waste was estimated at 16 million GJ/year.
- NRCan is working to define typical current engineering parameters and economic performance for various digester types, and to provide data of use to individual farms and communities on minimum feasible digester size, economics, gas production, GHG reduction etc.
- NRCan believes that increased use of AD on Canadian farms will be driven primarily by legislated environmental rules (as in Europe), not energy/GHG concerns. The Walkerton, Ontario crisis was allegedly caused by runoff from a livestock farm, and now water quality concerns are forcing restrictions on the

expansion of some farms. AD may help to ease these restrictions, although this has yet to be proven in Canada. While it is difficult to put a value on the environmental benefits of waste treatment, in cases where treatment is deemed necessary energy production from anaerobic systems can mitigate the cost of system establishment and operation.

- Agriculture Canada is developing a unique low-temperature anaerobic treatment system for the treatment of liquid animal manures, and is in the demonstration phase with industrial partners (2002 - 2004).
- The Canada Composting Inc. plant in Newmarket, Ontario is the largest AD facility for MSW in North America. It uses German technology (BTA Process) to produce biogas and generate electricity for purchase by Ontario Power Generation.
- Currently, there are several Government programs that can support AD projects, including the TEAM program, which provides support under the Climate Change Action Fund for the demonstration and deployment of technology to reduce GHG emissions.

System Cost and Performance

Since there are presently no full-scale operating AD systems on Canadian farms, accurate cost information is difficult to obtain. However, five units are scheduled to be installed in 2003.

Methane recovery systems represent a significant capital investment: for an average 300 – 500 cow dairy farm, capital costs can range from $100 – 500k, depending on components[6], which include holding tanks, pumps, covers, mixers and fuel burning equipment and generator. In a 2003 conference presentation a US-based consultancy specializing in the design and installation of AD systems presented the following data on electricity production potential from farm-based systems:

Stock	***kWh/head (Per day)***	***Electricity in Excess?***	***Population needed for 40 kW generator***
Cow	2.5 – 3.7	usually	400
Sow	0.2 – 0.3	seldom	3,200
Nursery	0.06 – 0.09	seldom	11,000
Finisher	0.15 – 0.22	usually	4,400

Examples of recent farm-based AD installations outside Canada include:

[6] 'Farm Methane Recovery in Vermont – Outline of Barriers', Richmond Energy Assoc., July 2000

- Matlink Dairy (NY) installed a 'complete mix' AD system in 2001 sized for 2,000 cows at a cost of US$325/cow ($650,000 total). The digester runs a 135 kW generator, which has operated at 98% capacity factor.
- Koetsier Dairy (CA) installed a plug flow digester in 2002 , sized for 1,500 cows, at a cost of $200/cow ($300,000). The system operates a 99 kW generator.
- A UK mixed farm installed an AD system in 2002 for an annual manure production of 3000 tonnes (150 cows, 160 pigs). The digester size was 335 m3 (temp range 35 - 37 C) and the cogenerator output was 35 kW electrical plus 57 kW thermal. The system had a capital cost of Euros 213,000 (CAD$340,000), while the electrical and thermal outputs are valued at Euros 31,500. Simple payback time is therefore 6.7 years.

The successful installation and operation of an electricity-generating AD system requires the co-operation of the local electricity utility. Other required permits can include: zoning, air, water, building and environmental.

Tools

Agriculture and Agri-Food Canada has maintained its 'ManureNet' website since 1998, which acts both as a national information resource and as a coordination centre for manure and nutrient management issues. ManureNet has over 7,000 links on the site, and an online
Oracle database of 4,500 articles covering a wide range of related categories, including selection of digester systems, co-generation power sources and European/U.S. programs, projects, technology providers and contacts. The site is located at:

http://res2.agr.ca/initiatives/manurenet

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **ANAEROBIC DIGESTION**

Technology **- farm-based digester system with methane recovery**

Energy Form Produced - methane: heat and electricity from cogeneration

Energy Applications - digester process heat and electricity; grid electricity

Local Economic - moderate
Development Potential

Estim. Cost of Energy - moderate (paybacks typically 5 – 9 years)

Level of Investment - moderate (farm systems typically $200-$400/cow)

Critical Requirements - size of farm (e.g. 400 cows required to generate sufficient methane for 40 kW electrical generator)

Level of Expertise
-Design/install - moderate
-O&M - moderate

Existing Installations - no farm-based systems in Canada, but 5 scheduled for installation in 2003
- over 1000 systems operating in Europe

Benefits
- waste treatment system which doesn't require expensive drying
- per-animal costs for farm systems decrease with system size
- AD is also used to process municipal sewage and industrial food waste
- for farm systems AD stabilizes ammonia and nitrogen content of waste making it more suitable for field fertilizer

Limitations & Issues
- 28 farm AD units were funded in 1980s, none then viable economically
- AD installations likely driven by environmental issues, not energy
- central AD facilities likely non-viable due to high manure transport costs and risk of spreading disease.
- local electrical utility cooperation essential for large systems

Bio-oil

- *Notes*
- *Gas Turbine Applications*
- *Diesel Applications*
- *Bio-Refining*
- *Canadian Bio-oil Companies*

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Notes

'Bio-oil' is a free-flowing dark brown liquid with a pungent, smoky odour containing several hundred chemicals. It is produced by heating a biomass feedstock to 450 – 500°C for less than two seconds in a fluidized bed reactor, which decomposes the material into a combination of solid char, gas, vapours and aerosols. Rapid quenching and condensation prevents chemical cracking of the components, and produces bio-oil, of which:

- Constituents are water (20-25%), pyrolitic lignin (25-30%), organic acids (5-12%), hydrocarbons (5-10%), anhydrosugars (5-10%) and other oxygenated compounds (10-25%).
- Any biomass feedstock can be used – wood or bark, straw or bagasse. Preparation typically includes pre-drying the feedstock to < 10% m.c. to minimize water content in the product.
- When wood-derived feedstocks are used, the process generally yields 70% bio-oil on a mass basis, with 15% char and 15% non-condensable, "medium-calorific" gas. If bagasse is used, the yield of bio-oil is around 62%.
- On a volumetric basis, bio-oil has 55% of the energy content of diesel oil. The pyrolysis conversion process consumes around 5% of the calorific content of the biomass feedstock.
- The most immediate commercial applications for bio-oil are as a replacement for natural gas and diesel in boilers, gas turbines and diesel engines. There are two bio-oil industry leaders, and both are Canadian: Ensyn Engineering Ltd (based in Ottawa)

and DynaMotive Power Corp. (Vancouver), are actively seeking to expand their commercial production facilities in Canada, the US and beyond (see below).

- Since bio-oil has only 55% of the energy density of diesel oil, flowrates must be doubled to maintain the same combustor energy output. This, combined with the poor ignition characteristics of the fuel, has led CETC's combustion researchers to collaborate with DynaMotive in developing an innovative burner nozzle that improves the atomization and spray characteristics of the fuel, promoting more complete combustion. A bio-oil fuel system, as used to power a gas turbine, will deliver a high-pressure flow of pre-heated fuel.
- Polymerization is the growing of molecular chains within a stored fluid, which increases its viscosity. This is an important issue with bio-oil, and since the process is time and temperature dependent (increasing with increasing temperature), fuel storage must address potential problems. To quote Finnish researchers "the challenge of today is to attain a 12 month storage time for bio-oil without changes in homogeneity…".
- Since bio-oil is strongly acidic (e.g. pH = 2.3 from pine feedstock), material selection is important for all elements coming into direct contact. Generally this does not require the use of exotic materials, but metals used to contain or process bio-oil should be 300 series stainless steel. HDPE is suitable as a polymer for hoses etc.
- bio-oil has some favourable emissions characteristics when compared to diesel oil or other fossil fuels. It can be CO_2-neutral, and since biomass contains no sulphur, produces no SOx emissions. The water content in bio-oil has some advantages, firstly in reducing viscosity and secondly in reducing NOx emissions, which are generally less than half those produced by diesel oil. On first generation gas turbine combustion systems, CO and particulate emissions have been found to be higher on bio-oil than with diesel.

Gas Turbine Applications

- The most common biomass conversion technology in present use is a stoker-fed grate or a fluidized bed combustor connected to a boiler, which produces electric power from steam using the Rankine cycle. By adopting a combined cycle system using a gas turbine engine coupled to a heat recovery steam generator and steam turbine, the conversion efficiency can be increased by 40% over present systems.
- Although a gas turbine can be run directly on powdered or gasified biofuel, the bio-oil option allows far more flexibility in plant operation, since the fuel can be produced elsewhere and stored for later use. Transportation costs are greatly reduced over other biomass systems, since the liquid bio-oil has a relatively high energy density. In addition, the fuel can be mixed as required before combustion, which helps to eliminate the non-homogeneity issues commonly associated with biomass.
- Economic analysis of a gas turbine system powered by bio-oil has shown promise. DynaMotive claims that near-future life-cycle electricity generation costs could be in the 6c/kWh range, for a 30 MW combined cycle installation and a biomass feedstock cost of $5-6/tonne.

Diesel Applications

Finnish bioenergy researchers see “huge potential” for using bio-oil in future retrofits to existing oil and diesel-fired boilers and power plants in the 0.1 – 10 MW range. In their view, the primary technical issue to be overcome is polymerization of stored fuel, but variability in fuel, depending on feedstock, also needs to be addressed, they say, to produce fuels with standard combustion characteristics.

Bio-Refining

Similar to oil refining, ‘bio-refining’ is the chemical separation of individual constituents from a biomass feedstock into a variety of products. bio-oil comprises several hundred constituent chemicals, and if individual components can be separated, they can be sold off as value-added products. This industry is still at the developmental stage, with many procedural steps still being researched. The attached biomass processing chart produced by the Canadian Green Chemistry Network outlines the variety and complexity of potential options for the treatment of feedstocks.

Although the bio-oil refining industry is in its infancy, a number of chemical constituents have been identified and successfully removed from the bulk product, including:

- Non-toxic resins, which can be used in place of formaldehyde in the manufacturing of wood products such as oriented strand board and plywood.
- Additives for concrete.
- Pharmaceuticals
- Food additives e.g. smoke flavourings.
- Activated carbon for water filters.

The combustion characteristics of bio-oil can be improved by refining out these and other chemical constituents.

Industry Canada sees bio-refining as a promising vehicle in the development of diverse and sustainable rural industries, with strong potential for economic growth, and is actively promoting the concept.

Canadian Companies

- Ensyn Technologies Inc. is an Ottawa-based RD&D company with a proprietary ‘Rapid Thermal Processing’ pyrolysis system for the commercial production of bio-oil. This system has been under development since the mid-1980s, and Ensyn currently operates four commercial scale plants in Canada and the US, with a combined annual production capacity of 19 million litres.
- Ensyn is a bio-refining pioneer, and is positioning itself both as a producer and a refiner of bio-oil. Ensyn expects that the extraction of value-added products will

be a significant driver in the development of a viable international bio-oil industry. The company is reportedly close to finalizing a major development project in Renfrew, Ontario[7], for the manufacture and refining of commercial quantities of bio-oil from wood residuals produced by two local furniture/flooring plants.

- Dynamotive Power Corp. of Vancouver has been promoting their own proprietary bio-oil production technology for several years. The company has been set back by a 2002 bioenergy crop project failure in the UK, in which a fast-growing willow crop was found to be uneconomic for bio-oil manufacture. In March 2003 the company's stock was trading at a 52-week low.
- In February 2003 Dynamotive secured an option on 500,000 tonnes of wood residue in Saskatchewan, with a bio-oil production potential of 2,140,000 Barrels. In the same month DynaMotive and UBC announced a the initiation of a joint Lime Kiln Program for producing bio-oil in the pulp and paper industry
- A third Canadian company promoting a promising bio-oil conversion technology is Renewable Oil International, based in Ottawa, Ont. This company estimates that their pyrolysis process can currently produce bio-oil economically from a 25 tonnes/day plant. The company's president estimates the capital cost for plant this size at about CAD$700,000 and a 100 tpd plant at CAD$2,000,000.

[7] The company's CFO expects a public announcement initiating this project in Spring 2003

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**BIO-OIL PRODUCTION / REFINING**
Technology	**Pyrolysis of biomass feedstock**
Energy Form Produced	- bio-oil
Energy Applications	- combustion in diesel generators or gas turbines
Local Economic ***Development Potential***	- moderate/high (fuel from biomass, employment, residual products)
Estim. Cost of Energy	- moderate
Level of Investment	- high (new commercialization of technology)
Critical Requirements	- source of low cost biomass with low moisture content - pyrolysis plant located near biomass source - policy support at regional/national level, including fuel standards
Level of Expertise	
-Design/install	- high
-O&M	- moderate
Existing Installations	- 3 – 5 small-scale production plants for bio-oil in Canada, US, Europe - First large commercial scale development planned for 2003 (Ensyn)
Benefits	- Significant market opportunity for waste biomass e.g. wood offcuts - Refining yields a range of value added products e.g. food, concrete additives - Significant GHG emissions reduction potential from renewable local fuel production - Bio-oil can be transported cost-effectively, compared to other forms of biomass, due to its higher energy density and ease of handling - Rural economic development via product income and employment - Increased local self-sufficiency from fuel production and use - Researchers expect to isolate many more value added products in future
Limitations & Issues	- Polymerization (i.e. solidifying of stored product over time) needs to be addressed by future R&D - Bio-oil could play an important role in energy diversification, rural economic development and energy supply security

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**BIO-OIL COMBUSTION**
Technology	**Combustion in gas turbine or retrofit diesel plants**
Energy Form Produced	- heat/electricity from cogeneration
Energy Applications	- combustion in diesel generators or gas turbines
Local Economic ***Development Potential***	- moderate/high
Estim. Cost of Energy	- low/moderate (future projections as low as 5 cents/kWh)
Level of Investment	- high (new technology)
Critical Requirements	- further R&D on improving combustion characteristics of bio-oil via moisture removal, fuel preheating, better nozzle design etc.
Level of Expertise?	
-Design/install	- high
-O&M	- moderate
Existing Installations	- First large commercial scale development planned for 2003 (Ensyn)
Benefits	- Bio-oil can be transported cost-effectively, compared to other biomass - Significant GHG emissions reduction potential from renewable local fuel production - Finnish researchers see "huge potential" for future burning of bio-oil in retrofitted oil or diesel boilers, power plants etc.
Limitations & Issues	- Polymerization (i.e. solidifying of stored product over time) needs to be addressed by future R&D - Bio-oil could play an important role in energy diversification, rural economic development and security of energy supply - Bio-oil has 55% of the energy density of diesel, so flowrates must double for the same calorific output. - Combustion characteristics for the fuel are poor, requiring special nozzles to be used - Bio-oil is strongly acidic, requiring stainless steel and other high quality materials to be used at all times

Ethanol

- *History*
- *Chemistry*
- *Industrial Ethanol Production*
- *Vehicle Emissions*
- *Energy Balance of Ethanol Production*
- *Climate Change Impact*
- *Future Ethanol Production*
- *Iogen*

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History

- Henry Ford originally designed his 1908 Model T to run on corn-derived ethanol, and from 1920 to 1924 Standard Oil included 25% ethanol in gasoline sold in parts of the US. During the 1930s more than 2,000 Midwest service stations sold 'gasohol' (ethanol made from fermented corn), but low petroleum prices ended this business in the 1940s. Oil supply disruptions in 1979 led to the re-introduction of ethanol blends in North America and the resumption of ethanol-related R&D in the US and elsewhere.
- Since the 1980s demand has grown for ethanol-based fuels (mainly E85), particularly in urban areas with air quality problems attributable in part to high CO levels. Ethanol acts as an oxygenate when blended with gasoline, reducing the amount of unburned hydrocarbons and volatile organics (VOCs) emitted in the tailpipe, and therefore decreasing the formation of ground level ozone and reducing the incidence of urban smog.
- E10 (10% ethanol blend) is now the most common formulation, and was originally introduced in place of lead additives to increase octane value (a measure of the fuel's ability to reduce engine knocking). Blending 10% ethanol increases gasoline's octane rating by 2.5 points. Vehicle performance and fuel consumption on E10 blends is almost identical to gasoline.
- Ford, GM and Daimler-Chrysler each manufacture and market a range of flexible fuel vehicles (FFVs) at no added cost from standard models. These can run on any ethanol blend from E85 down, or on pure gasoline. All gasoline motor vehicles manufactured since 1990 are warranted to run on E10.

- The Alternative Fuels Act became law in Canada in 1995, and requires that all federal government departments and agencies use alternative fuels where they are cost effective. The Act also requires that 75% of new vehicle procurements after f.y. 2000 are 'alternative fuel' vehicles.

Chemistry:

- The feasibility and complexity of ethanol production from biomass depends on the feedstock used. Simple sugars are most straightforward feedstock, followed - in increasing complexity - by starches, cellulose and hemicellulose. The range of accessibility of fermentable sugar in biomass feedstocks is reflected in the history of ethanol production. In the 1930s industrial grade ethanol was made from sugarcane and sugarbeet-derived molasses, which can be fermented directly to produce ethanol, but these feedstocks have too many other potential uses, making them prohibitively costly. Corn, a starch-based feedstock, is currently used to produce 99% of all ethanol in North America, with wheat grain making up the balance (note: sugar crops such as sugarbeet and Jerusalem artichoke are not suited to ethanol production in Canada since they are frost-susceptible, have high water contents and cannot be stored for year-round use in a production facility).
- Starches are chemically linked sugars: starch consists of strings of glucose molecules held together by glycosidic links. If an enzyme breaks these links, the glucose becomes available for fermentation. The ability to commercially produce sugars from starch was one of the earliest examples of modern industrial enzyme technology. Researchers have long hoped to emulate the success of this process in converting cellulosic biomass.
- Non-starch or sugar-based biomass material, such as wood, leaves and straw, has three primary components: cellulose (40-60% dry weight), hemicellulose (20-40%) and lignin (10-25%). Lignin remains as a residual material after the sugars in biomass have been fermented to ethanol. It can be burned or used as a feedstock, but, while versatile, lignin is a notoriously un-economic material.
- Cellulose is the most common form of carbon in biomass, and is also a bipolymer of glucose, but the chemical linkages between molecules are much more stable and resistant to attack than those in starch, and it has a crystalline structure making it highly insoluble. At least four methods of converting cellulose are being investigated; enzyme procedures (e.g. Iogen), weak acid hydrolysis, concentrated acid hydrolysis and the organosolv method.
- Hemicellulose consists of short, highly branched chains of sugars; it is more accessible to fermentation in hardwoods than in softwoods, due to the type of sugars present.

Industrial Ethanol Production

- The US currently produces 6 billion litres of ethanol annually, with most of this production coming from the Midwest states, using corn feedstocks. US production is growing rapidly, and at present is divided evenly between wet and dry mill procedures. The wet mill process soaks corn kernels until the components can be separated mechanically, while the dry mill process grinds all parts of the corn cob to a flour, putting the entire product through the fermentation procedure.

- Wet mills are typically large operations that make ethanol along with many food industry products, such as corn oil, corn syrup, starch and animal feed. These plants (7 in 2001) can be thought of as bio-refineries which process all parts of the feedstock. US growth in the ethanol industry is centred in the Midwest (Iowa, Minnesota, S.Dakota), where corn prices are attractive to the industry.
- The ethanol industry is moving towards ever-larger plants, rather than small scale, community operated facilities. A typical new installation will likely be sized to produce 200 million litres/yr.
- In Canada, annual fuel ethanol production is over 240 million l/yr, using corn feedstocks in Ontario/Quebec and grain in the western provinces. The federal government supports ethanol production by exempting excise tax on the ethanol portion of gasoline (i.e. 10 cents/litre for E10). Ethanol-producing provinces (Quebec, Ontario and the Prairies) also subsidise ethanol by exempting the fuel from provincial tax.

Vehicle Emissions (CO, VOC and NOx)

Despite the ethanol industry's promotion of its product as a clean, green fuel, tailpipe test data varies widely, depending on the age and type of vehicle, and solid evidence for significantly improved emissions performance can be difficult to find:

- A January 2000 AgCan study analyzed the effect of ethanol-blended fuel on emissions of CO and VOCs for the Canadian vehicle fleet. This study predicted an average 10% decrease in CO emissions, and a 9% decrease in VOCs, using an E10 ethanol blend. The study also noted that CO emissions from advanced low emission vehicles (e.g. Toyota Prius) can actually increase with the addition of an oxidant to gasoline.
- Tailpipe emissions of NOx can fall, if ethanol is used to replace other high octane components such as olefins and benzene, yet NOx emissions can also rise if ethanol is 'splash blended' (i.e. where ethanol is blended with gasoline during truck loading, rather than at a refinery, to prevent contamination with water. The E10 blend has a higher rate of evaporation than either component).
- Due to the high rate of evaporation, many studies have concluded that ethanol blends contribute to urban ozone and smog formation, especially in hot weather.
- Ethanol production in the US is expanding rapidly to accommodate the banning in many jurisdictions of the gasoline oxygenate MTBE, which has contaminated groundwater via leaking underground fuel tanks in many parts of the country. Currently California uses 3.8 billion gallons of MTBE annually, almost as much as the rest of the US, all of which is due to be replaced by ethanol. Consequently, the state faces severe logistical problems in importing sufficient ethanol to displace it. Due to ethanol's affinity for absorbing water, ethanol-blended gasoline cannot be transported via pipeline. Proposed solutions include shipping ethanol from the Midwest by train and by coastal barges.

Energy Balance of Ethanol Production

Ethanol's potential contribution to climate change emissions reduction is complex and can be politically contentious. Federal subsidies for corn-based ethanol production in the US have come under fire from all parts of the political spectrum, with one Cornell University study characterizing the industry in 2001 as "unsustainable, subsidized food burning". The current US federal subsidy, at 54 c/gallon, makes it possible for ethanol to compete as a gasoline additive. Critics of corn-based ethanol production have noted that:

- The net energy balance of ethanol production can approach zero. Typically the process uses fossil fuels for fertilizers, irrigation, drying, tilling, harvesting, seeding, transportation, milling, fermenting, distilling and cleaning. Notably, corn ethanol plants do not use ethanol for power – it is too expensive.
- Subsidizing corn producers results in higher corn prices and therefore higher prices for milk, eggs and meat, since 70% of US corn is used as feed. These price rises are passed on to consumers.
- Most corn ethanol plants are located in the Midwest, where coal-fired electricity is used during the ethanol production process - a greenhouse gas-intensive form of power generation.
- The environmental impact of corn harvesting due to topsoil and nutrient loss and groundwater depletion from irrigation is not factored into the bottom line of ethanol production, and the sustainability of this form of production is therefore highly questionable.

Ethanol's Impact on Climate Change

- In 1999 the US-based Argonne National Laboratory examined the fuel cycle for corn ethanol production and use, and estimated that an average vehicle fueled with corn-derived E10 would achieve a 2% reduction in CO_2 production per mile traveled, compared with pure gasoline. If the vehicle used E85 that figure was predicted to rise to 25% . This study showed that cellulose-derived ethanol could achieve far higher greenhouse gas impacts, namely an 8 – 10% reduction on E10, or a 68% reduction using E85.
- In Canada, AgCan's climate change impact study (January 2000) found that using ethanol produced from corn in Ontario in an E10 blend could reduce overall greenhouse gas emissions from an average vehicle in the Canadian fleet by 3.9%. This figure assumes economies of scale and modern production facilities (i.e. that the ethanol is produced in a 150 million litre/yr plant),
- The AgCan study calculated current 'full fuel cycle' efficiency for corn ethanol production in Ontario at 31% (i.e. the equivalent of 59% of the fuel energy in a litre of ethanol is used upstream during the growing and manufacturing process). In comparison, the full fuel cycle efficiency for gasoline (including production, refining and transportation) was quoted at 76%.
- The federal Action Plan 2000 on Climate Change has targeted an E10 blend for 35% of all gasoline sold in Canada by 2010. Given the present national gasoline consumption of 38.8 billion litres, converting this amount to E10 would presently

require 1.36 billion litres of ethanol. To put this target in perspective, if we assume a plant size of 200 million litres/yr, Canada would need a further 5 such plants to be operational within 7 years, at a capital cost of around $300 M each. Given a rate of feedstock conversion of 300 – 325 litres ethanol/tonne, the annual feedstock requirements for each plant of this size approach 700,000 tonnes[8]. NRCan anticipates that the national ethanol production target will need to be reached using starch-based feedstocks, due to the developmental nature of cellulose-to-ethanol technology.

Future Ethanol Production

In spite of producing a wide range of value-added co-products, the high cost and sustainability issues surrounding starch-based ethanol production from corn and grain have led many to question whether fuel ethanol will ever be competitive with gasoline without subsidies (although these subsidies are small in comparison to current and historical subsidies for the petroleum industry). As the above figures reveal, the use of starch-based ethanol in an E10 blend suitable for the entire vehicle fleet makes inherently little impact on greenhouse gas production (< 5%), therefore if a major expansion of ethanol use in Canada is to be climate change-driven, cellulose-derived ethanol will have to play a more significant role.

In 2002 NRCan commissioned a national inventory of fuel ethanol biomass feedstocks[9]. This study did not estimate potential ethanol production from energy cropping of willow or native grasses, but it did analyze the amounts of non-utilized starch crops, straw, corn stover and wood waste produced by each province. Discounting the huge quantities of forest floor residuals potentially available in lumber-producing regions, the amount of non-utilized biomass potentially available nationwide each year was as follows:

Starch-based crops	4.97 M tonnes (mainly Alberta & Saskatchewan)
Straw	11.89 M tonnes (mainly prairies)
Corn Stover	0.92 M tonnes (Ontario & Quebec)
Mill Woodwaste	5.38 M tonnes (BC, Quebec)
Total	23.16 M tonnes

Assuming an ethanol production rate of 300 litres/tonne this quantity of waste biomass could, in theory, generate $(23.16 \times 10^6) \times 300 = 6.95$ billion litres of ethanol. This represents around 20% by volume of the country's present gasoline consumption, or over 5 times the current 2010 target.

[8] At an annual agricultural production of 10 tonnes per hectare, this represents 70,000 Ha of starch crop, or a fully utilized area approx. 27 km square.

[9] Inventory of Biomass Feedstocks Potentially Available for Fuel Ethanol Production; Levelton Engineering Ltd, for the Office of Energy Efficiency, Natural Resources Canada, Nov. 2002

Iogen

- Iogen Corp. is the world leader in the production of ethanol from cellulose. Following 20 years of related R&D, the company has patented an integrated process, which includes pre-treatment of feedstock and the use of proprietary enzymes. Iogen sees itself primarily as an industrial enzyme and process developer, rather than an ethanol manufacturer; the company plans to license ethanol operations worldwide using its technology.
- The company opened its Ottawa ethanol pilot plant in 1999, where it currently produces around 12,000 litres/day from wheat straw feedstock. The pilot plant was funded by Iogen and Petro-Canada, and received financial assistance from Technology Partnerships Canada.
- In 2002 Iogen signed a development agreement with Royal Dutch Shell, under which the oil company will invest CDN $46 million; negotiations are underway in Saskatchewan, Manitoba and Alberta to determine the site of the company's – and the world's - first commercial-scale cellulose-to-ethanol plant. According to Iogen, the new facility will need to be located within 80-100km of its feedstock sources, to minimize trucking costs. Feedstock will be either wheat straw or corn stover, of which 700,000 tonnes will be required, to produce 220 million litres of ethanol. This first commercial plant is expected to be operational by 2007. The siting of a plant depends on an optimal combination of many factors, including feedstock production and storage facilities, road and rail infrastructure, water availability and local support.
- Iogen is currently negotiating future commercial ethanol facilities in three other countries – the US (probably Nebraska or Idaho), the UK (Humber region) and Germany.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**ETHANOL**	
Technology	**Corn or grain-derived**	**Cellulose-derived**
Energy Form Produced	- ethanol	- ethanol
Energy Applications	- vehicle fuel	- vehicle fuel
Local Economic ***Development Potential***	- low	- moderate
Estim. Cost of Energy	- high	- moderate in future
Level of Investment	- very high ($300M for major plant)	- very high
Critical Requirements	- low-cost energy input (electricity, fertilizers)	- large quantities of low-cost biomass feedstock near plant (straw, wood chips)
Level of Expertise		
-Design/install	- high	- high
-O&M	- high	- high
Existing Installations	- 6 major plants in Canada	- first commercial facility planned 2005/6 W.Canada (Iogen)
Benefits	- increased income for farmers	- various feedstocks can be used - can significantly reduce GHGs - potential source of rural income
Limitations & Issues	- energy balance is questionable - corn requires significant irrigation - E10 blend has little impact on GHGs - production and distribution can contribute to ground level ozone - vehicle emissions not necessarily improved - major investment needed for industrial plant	- Iogen enzyme process is only present technology ready for -

Biodiesel

- *Biodiesel Production*
- *The BIOX Process*

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Biodiesel Production

- The diesel engine was originally intended to burn biofuels – the first diesel engine was exhibited by Dr. Rudoph Diesel in 1900, and it ran on peanut oil.
- Biodiesel is made by reacting any natural oils or fats with methanol to produce fatty acid alkyl esters (a.k.a. biodiesel). Europe is the leading producer and consumer of this fuel, at 700,000 tonnes annually. The European industry has benefited since the 1980s from extensive agricultural subsidies granted to non-food crops - canola oil is used for 84% of European biodiesel production, sunflower oil 14%. France and Germany are the primary producers and users.
- Biodiesel delivers similar torque, horsepower and kilometres per litre performance characteristics when compared to petroleum-based diesels. It mixes readily with petroleum diesel and can be used straight or as a blend (e.g. 20% or B20). The product can normally be used without diesel engine modifications. In France biodiesel is used mainly in B50 diesel engine blends, and as a heating oil.
- Biodiesel is an oxygenated fuel, so it provides a more complete fuel burn and a greatly improved emissions profile (e.g. B20 typically reduces CO by 13%, particulates by 18%, SOx by 11%). Emissions of NOx, however, increase slightly using this product. Biodiesel is biodegradable and non-toxic, making it ideal for mass transit, marine, mines and other environmentally sensitive applications.
- More than a hundred cities worldwide have run biodiesel transit demonstrations to date, involving some 1000 buses over a combined distance of more than 5 million kilometres. Biodiesel does not require new refueling stations or new parts inventories.

- Currently there is no commercial use of biodiesel in Canada, and its uptake has been restricted by high production costs. The product has, until recently, been unable to compete without subsidies, but this situation is expected to change rapidly because:

1. A Canadian researcher has discovered a way of producing biodiesel from waste fats that is at least 50% cheaper than conventional methods (the BIOX Process: see below).
2. The federal government's Kyoto response, Action Plan 2000, calls for a national biodiesel production/use target of 500 million litres by 2010. Currently the fuel is used only by various federal and municipal fleets, including the Toronto Hydro fleet of 400 vehicles.

- In June 2002 the Ontario Government dropped their 14.3c/litre tax on biodiesel, in part to encourage the use of cleaner fuels in urban environments. Other provinces are expected to follow suit.
- A new ASTM standard for biodiesel (D6751) has been implemented in the US. This will allow producers and distributors to standardize the quality of biodiesel, and allow vehicle manufacturers to include the fuel under their engine warranties, all of which will enhance the use and credibility of the product.

The BIOX Process

- The BIOX process represents a Canadian breakthrough in the production of cost-competitive biodiesel fuel. All companies currently producing biodiesel worldwide use a high pressure, high temperature process which is energy intensive and costly.
- The BIOX process was discovered in 1995 by David Boocock, a professor at the University of Toronto. He found a way to eliminate one of the chemical steps traditionally needed to create biodiesel. By using an inert, cheap, recyclable co-solvent the reaction becomes single-phase rather than two-phase. This cuts the reaction time to minutes, rather than hours, and allows it to take place at ambient temperature and pressure.
- The BIOX process can use a wide variety of waste or low-cost feedstocks, including recycled vegetable oils, agricultural seed oils or animal fat. This can include lower quality canola or other oils from frost-damaged or overheated seed, which are currently unusable for food production.
- Commercial rights to this process are now held in a joint venture by the U of T and BIOX Corporation of Toronto, who have built a 1 million litre/year pilot plant in Oakville, Ont., funded through TEAM. (Total budget for the Oakville pilot - $1.2 million, $464,000 covered by TEAM (repayable) and $138,000 covered by NRCan and NRC).
- BIOX Corp. expects to open a 60-million litre capacity biodiesel plant in Southern Ontario by late 2003 to start commercial-scale production. According to the company, the cost of a facility this size will be $15 million plus the cost of the site, site preparation and tank farm.
- The BIOX process takes 40 minutes from start to finish. The company claims that a European competitor turns a litre of (virgin) vegetable oil into biodiesel for

about 25 cents, but their process can produce that litre from used oils for 7 cents ($CAD). The production equipment does not require specialized technicians or chemists. Transport trucks will be able to dock at a plant and pipe in the raw material (used oil), then truck it away as biodiesel after processing.

- The BIOX business plan involves setting up global franchises that would lease the equipment to a variety of organizations ranging from oil companies to rendering plants. There is potential for community energy development in Canada and elsewhere, using the BIOX process. From the company's website:

  "Our goal is to produce ASTM D6751 grade biodiesel from any feedstock, vegetable oils, agricultural seed oils, recycled cooking oils/greases or waste animal fats/greases at a cost of 5 - 7 cents CAD per litre, plus the cost of capital and feedstock, thereby making biodiesel cost competitive with petroleum diesel".

- This process is expected to provide significant new markets both for the agricultural sector (e.g. soybean, canola producers) and for the animal fat rendering industry, which has experienced a steep decline in demand for its products following mad cow disease outbreaks in Europe.
- According to Tim Haig, the company's president, BIOX Corp. is actively negotiating the startup of four plants in Canada, and a further 24 worldwide. He claims that the 0.5 billion litre goal set in Canada for 2010 will not be difficult to reach, and that the BIOX process will provide most of that fuel. The Rothsay, Ont. animal fat rendering operation (Canada's largest) could, he claims, produce sufficient raw material to operate 3 x 60 million litre biodiesel plants and 3 x 30 million litre plants (total capacity 270 million litres, or half the 2010 goal).
- Large quantities of waste canola and soy oil currently remain untapped in Canada, according to BIOX (for example frost damaged crops unsuitable for food).
- NRCan and Environment Canada officers successfully pushed for the 4c/litre federal sales tax on biodiesel to be eliminated in the February 2003 budget. All other provinces are now showing interest in following Ontario by abolishing their 14.3 c/l provincial biodiesel tax.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**BIODIESEL**
Technology	**- BIOX Process**
Energy Form Produced	- Biodiesel from waste oils
Energy Applications	- Vehicle fuel
Local Economic ***Development Potential***	- moderate
Estim. Cost of Energy	- low (future goal 5 – 7 cents / litre)
Level of Investment	- high ($15M for a 60 million litre/yr plant)
Critical Requirements	- significant source of waste vegetable or animal oils (e.g. animal rendering industry, sub-grade oilseed) - the process is patented by BIOX Corp, which plans to sell franchise licenses to investors around the world
Level of Expertise?	
-Design/install	- high
-O&M	- moderate/ low
Existing Installations	- pilot plant has operated 2 years - first commercial scale plant due to open in Fall 2003, S.Ontario
Benefits	- Biodiesel offers comparable performance to conventional diesel, but significantly improved emissions, making it ideal for mass transit, marine and other environmentally sensitive applications - more than 100 cities have run successful biodiesel transit programs - the BIOX process is a Canadian technology which can produce biodiesel at half the price of conventional methods. - an ASTM standard now exists for biodiesel, which blends readily with conventional diesel and can be used in any diesel engine. - The federal and Ontario governments have both dropped their excise tax on biodiesel fuel. - the company claims there are significant sources of waste oil from animal rendering plants and spoiled oilseed in many parts of the country
Limitations & Issues	- requires significant and stable source of feedstock oils - high initial investment

Super Cetane

- *Notes*

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Notes

- CETC has developed a diesel fuel blending stock nominally called Super Cetane (previously called Cetane Enhancer). This product can be derived from a variety of feedstocks, including vegetable oil, animal fat and waste grease.
- CETC's Super Cetane has a high cetane value and low sulphur content, with characteristics similar to premium diesel (the cetane number is a measure of the ignition quality of diesel fuel). It is a higher quality product than biodiesel, and its production is more complex, requiring a supply of hydrogen for hydrocracking and hydrotreating, plus a conventional catalyst. NRCan's researchers expect that any commercial scale production of this product would take place adjacent to existing oil refineries where sufficient quantities of hydrogen are readily available. Commercial production would also require access to significant sources of vegetable or other oils (e.g. soybean, canola, tallow).
- Yields of between 75 – 80%, based on feedstock input volume, have been achieved. The process has been successfully scaled up in a one barrel/day hydrotreating pilot reactor at CETC, using depitched tall oil as the feedstock. Unlike conventional biodiesel, this product does not use methanol in the manufacturing process, and it is biodegradable. Emissions tests have shown that using Super Cetane as a diesel additive can reduce NOx production.
- Higher cetane number is normally achieved through the use of non-renewable nitrate additives. Unlike these products, Super Cetane has a linear impact on the cetane value of diesel fuel, directly proportional to its concentration in the blend.
- Demonstration projects are being undertaken using CE-blended fuel in Montreal (155 transit buses running for one year out of a dedicated garage) and in Saskatchewan.

- This product also improves fuel economy. For example, a Canada Post test program in Vancouver achieved 8% fuel savings over a 6 month period using a CE-blended diesel fuel.
- CETC commissioned a feasibility study for the construction and operation of a commercial Super Cetane plant, converting biomass-derived feedstock oils. It was found that a plant producing 400 barrels (80,000 litres) per day would have a capital cost of approx. CDN$8.4 million and an estimated payback time of 4.6 years, assuming an oil feedstock cost of 6 cents/kg. For a plant with double this capacity, the payback time was calculated at 2.7 years.
- NRCan sees Super Cetane is a complementary fuel to biodiesel, rather than a competitor. For example, its chemical structure is close to that of conventional diesel, making it easier to blend, and reducing or eliminating technical risk to refinery systems and diesel engines.
- Ongoing test programs are assessing the performance and emissions characteristics of diesel vehicles using Super Cetane blended with B20 diesel (a 20% biodiesel blend). Another possible use for the product is as an enhancer of low grade oil sands fuel.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**SUPER CETANE**
Technology	**Hydrotreating of waste oils**
Energy Form Produced	- Diesel fuel blending stock
Energy Applications	- combustion engine vehicle fuel
Local Economic	- low
Development Potential	
Estim. Cost of Energy	- plant payback < 5 years (@ feedstock cost of 6 cents/kg)
Level of Investment	- high (e.g. CAD$8M+ for 25M litre/yr plant)
Critical Requirements	- source of bulk hydrogen (petrochemical refinery), source of waste oils
Level of Expertise	
-Design/install	- very high
-O&M	- high
Existing Installations	- none (demonstration phase now ending)
Benefits	- can use a range of waste oils, including tallow, tall oil, canola etc - blends with petroleum diesel more readily than biodiesel - improves NOx and other emissions and fuel economy - can be used to enhance low grade oil sands fuel - complementary to biodiesel
Limitations & Issues	- production realistically restricted to existing petrochemical facilities - needs significant source of low-grade oils, and will ultimately be competing with biodiesel for this feedstock.

Chapter 3: Ocean/Hydro
Tidal Current

- *Notes*
- *BC Hydro*
- *Tools*

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Notes

- Tidal current energy is derived from the flow of coastal ocean waters in response to the tides. Large tidal currents do not necessarily require a large tidal range, since they are influenced by tide phasing (location and timing of high and low tides in different locations along a coastline) combined with various physical coastal features, particularly the presence of narrow passages between inlands or inlets. Tidal current resources must therefore be evaluated on a site-specific basis, since they are affected by many variables.
- Tidal energy is extracted directly as kinetic energy from a moving stream, whereby seawater is 'partially impounded' in its flow through a channel. Local effects on the tidal regime are considered low or negligible, depending on the technology used to extract energy.
- Tidal current energy is predictable and regular, and will be unaffected by global climate change. Nevertheless the technology for exploiting this resource is still in its infancy, and there are, as yet, no commercial installations anywhere in the world. Tidal current power development is estimated to be 1- 3 years behind ocean wave energy and 5 – 8 years behind wind energy.
- Like windspeed, tidal current speed (U) is critical to the economic feasibility of an installation, since power varies by U^3.

BC Hydro

- In 2001, as part of their Green Energy Study, BC Hydro commissioned a detailed engineering assessment of tidal current resources along the coasts of British Columbia. Over 100 prospective sites were analyzed. With a minimum tidal current speed of 2 m/s selected as the economic threshold, the best 55 sites have a theoretical power output of 2200 MW. Of these, the most promising 12 sites at which existing technology can be used have a theoretical power output of 300 MW, or 2700 GWh/y, with half of this amount available at Discovery Passage, off the east coast of Vancouver Island.
- BC Hydro's analysis of capital, operating and decommissioning costs for an 800MW tidal current power plant at Discovery Passage showed energy costs of around 11 cents/kWh over the 30 year lifetime of the facility. Smaller facilities using available technology were found to be less cost effective.
- Assuming that robust R&D continues in this field, and that maximum currents greater than 3.5 m/s can ultimately be exploited, BC Hydro is projecting future tidal energy costs of 5 – 7 cents/kWh ($CAD).
- Most tidal current technology manufacturers are located in Europe or North America. In preparing their analysis of recoverable tidal current power and cost, BC Hydro's consultants reviewed technologies from the following companies:

Blue Energy Canada	- Vancouver, BC
Clean Current	- Vancouver, BC
Marine Current Turbines	- London, UK
UEK Corp.	- Annapolis, MD, USA
RV Co	- London, UK / CA, USA

- These companies produce a wide variety of tidal current devices, ranging from large scale 'tidal fence' installations to 'farms' of individual free stream units. At the time of the BC Hydro report (2001), only UEK had a device in the water.
- Blue Energy base their system on extensive tests done at the NRC during the 1980s. This company has proposed an ambitious multi-billion dollar combined tidal fence / vehicle bridge installation in the Philippines.

Tools

Further information on tidal current energy is available through BC Hydro's website:

http://www.bchydro.bc.ca/environment/greenpower/greenpower1767

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**OCEAN ENERGY – TIDAL CURRENT**
Technology	**- anchored tidal generators or tidal fence installations**
Energy Form Produced	- electricity
Energy Applications	- grid electrical
Local Economic	- low
Development Potential	
Estim. Cost of Energy	- moderate: >11 cents/kWh (future projection 5 – 7 cents/kWh)
Level of Investment	- high (new technology)
Critical Requirements	- tidal flowrates > 2 m/s, suitable development site
Level of Expertise	
-Design/install	- high
-O&M	- low
Existing Installations	- none anywhere in the world, but several at the planning stage
Benefits	- large untapped energy potential in some coastal areas - BC Hydro has defined 300 MW of readily accessible power off Vancouver Island - no GHG emissions other than those from equipment manufacture - predictable, reliable power source unaffected by climate change
Limitations & Issues	- high capital costs, no proven systems yet in the water - limited application even in coastal areas, since tidal currents result from tide phasing at different points along the same coastline - best power production sites usually remote from population, so storage or transmission required

Wave

- *Notes*
- *BC Hydro*
- *Tools*

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Notes

- Waves are caused by the transfer of energy from wind to water via friction. The rate of transfer depends on wind speed and the distance over which it interacts with the water surface (the fetch). This energy transfer has a potential energy component (mass displaced from mean sea level) and a kinetic component (velocity of water mass). Waves are characterized by their height, wavelength and frequency.
- Wave power is usually stated in kW/m, representing the rate at which energy is transferred across a line of 1m length parallel to the wave front. The best wave sites on the coasts of BC or Nova Scotia have power densities in the range 30 – 50 kW/m, but in other locations (particularly Atlantic or Pacific islands) the power density can be over 100 kW/m.
- Prime wave sites generally occur at high latitudes (40 – 60 degrees N or S) and on the west sides of continents, against the prevailing westerly global wind direction. Wave density therefore tends to be more powerful on the Canadian west coast than the east, although there are some high density wave sites in Newfoundland and Nova Scotia.
- Ocean wave technology extracts kinetic energy from the up-and-down motion of waves, using it to generate electricity. Inventors have taken out hundreds of patents for wave energy devices over the years, but concentrated effort in this direction dates from the 1970s oil crisis.
- The first two (govt. funded) wave power plants were installed near Bergen, Norway, in 1984, with a combined capacity of 850 kW. The first commercial wave energy plant was brought online off the island of Islay, Scotland, in November 2000. Japan, India, Indonesia, Australia, and countries of the European Union have undertaken numerous government-supported projects.

BC Hydro

- BC Hydro has committed to implementing 3 – 4 MW of ocean wave generating capacity as part of the Vancouver Island Green Energy Demonstration project. Two wave energy developers have been selected: Energetech, an Australian company, and Ocean Power Delivery, who are based in the UK. BC Hydro is funding 50% of the cost of installation for two plants – one operated by each of these companies. Neither installation will be a pilot: Ocean Power has an installation running in Scotland, while Energetech is currently installing a 500 kW plant in New South Wales. Further funding (e.g. TEAM) is being actively sought by Energetech and BC Hydro.
- The Energetech project will be built near Ucluelet, which has one of the highest wave energy densities on the Vancouver Island coast. Their design uses an oscillating water column: just offshore a concrete parabolic structure with 40m wide opening is constructed, which concentrates incoming waves into a 10m wide vertical column. The rising water column forces air through an opening and drives a turbine, generating electricity on the upward and downward strokes. The company has devised a turbine with blades that adjust (i.e. optimize) their angle throughout the stroke, depending on the velocity of airflow. This is therefore more a wind project than a hydro project. NRCan is presently evaluating the design to determine its suitability for funding under TEAM. Energetech claims that discounted electricity generation costs could approach 5c/kWh over time.
- The Ocean Power 'Pelamis' approach uses a 'wave farm' of floating generators, which looks like a string of sausages, each about 1m in diameter. Wave action causes the sections to move in relation to each other, which pumps oil from the joints through motors, generating electricity. Ocean Power has installed a pair of 375kW generators off Islay, Scotland. BC Hydro has commissioned a 2 MW system.
- In order to develop wave power towards its potential, extensive data collection is needed to pinpoint prime sites. Further research is also needed to assess the impact of heavy storms on installed equipment.

Tools

More information on wave energy, including interactive models of the two wave energy systems that BC Hydro is investing in can be found on their website;

http://www.bchydro.bc.ca/environment/greenpower/greenpower1767.html

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**OCEAN ENERGY – WAVE**
Technology	**- shore-mounted or floating generators**
Energy Form Produced	- electricity
Energy Applications	- grid electrical
Local Economic	- low/moderate
Development Potential	
Estiated Cost of Energy	- moderate: >15 cents/kWh (future projection: 5 cents/kWh)
Level of Investment	- high (new technology)
Critical Requirements	- significant, measured wave power resource (> 30 kW/m)
Level of Expertise	
-Design/install	- high
-O&M	- low
Existing Installations	- few: 1-2 in Scotland (375 kW floating type), 1x 500kW shore unit under construction in SE Australia.
Benefits	- large untapped energy potential in some coastal areas - BC Hydro has signed agreements to install 3- 4 MW by 2006 - no GHG emissions other than those from equipment manufacture
Limitations & Issues	- high capital costs - no long term results yet from systems in the water - limited application even in coastal areas, since high energy sites are needed for economic installations - best generation sites are typically far from population centres, requiring expensive electrical transmission or storage

Small Hydro

- *Notes*
- *System Costs*
- *Recommended Procedures*
- *Tools*

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Notes

- There is no international consensus on the definition of small hydropower. In Canada 'small' can refer to upper limit capacities of 20 - 25 MW, while in the United States it can mean 30MW. However, a value of up to 10 MW total capacity is becoming generally accepted. Small hydro can be further subdivided into mini hydro (usually defined as < 500KW) and micro hydro (< 100kW).
- In general, small-scale hydro requires that a suitable head be obtained without building a substantive water containment dam. Small hydroelectric plants can therefore be developed in rugged topography by constructing relatively simple diversion structures which divert flows at the top of a waterfall or steeply falling watercourse. The water is channeled through a penstock and down to power a turbine. Hydropower station efficiencies of over 90% are achievable.
- The Canadian small hydro industry comprises over 20 equipment manufacturers and some 70 engineering firms, and employs 2,000 people nationally. Domestic sales have reached approximately $150M per year.
- Canadian companies, challenged by low domestic energy prices, have become market leaders in the cost-effective manufacture and installation of low-head (< 30m) turbines, microprocessor control systems and GIS-based databases.

System Costs

Many factors impact the cost of small hydro installations, and it is therefore difficult to define a reasonable range. Cost-effectiveness relates directly to displaced energy, so hydro systems, which would be un-economic in many parts of Canada, become far more attractive in remote regions where imported diesel is displaced.

According to NRCan's Small Hydro team, the average cost of a small- or micro hydro system is in the range $1500-3000/kW, and systems with costs at the lower end of this scale tend to have far more chance of being implemented.

Recommended Procedure

NRCan recommends the following procedure to any community or organization interested in assessing undeveloped local hydro resources:

1. Download NRCan's pre-feasibility study software, RETScreen, which includes a small-hydro module. This software and its supporting literature is available free at:

   www.retscreen.net

2. To obtain a wide range of general information on small hydro, visit the www.small-hydro.com website, following up links as required.

3. Work through a preliminary RETScreen analysis; this should be done by a trained user, although the software is designed for general, not necessarily professional use. The model requires defining and inputting a range of site-specific data, including hydrology, equipment and economic information, but RETScreen is being updated regularly, and now includes direct links to weather, streamflow, equipment specifications and on-line help.

4. If the RETScreen analysis shows economic promise at a potential small hydro site, the next step is normally to commission a full feasibility study. This would be carried out by an engineering consultant using more detailed data and software, such as the 'IMP' package designed by UBC and now available through NRCan (upgrade Version 5 pending).

Tools

- A wealth of information is available online to proponents of small or micro hydro projects. Geographic Information Systems (GIS) are a powerful map-based tool, ideal for reviewing the feasibility of hydro installations, because they can demarcate watersheds, contours, hydrologic data and the proximity (and therefore transmissions costs) of communities. Canada's entire land mass has been analyzed for potential hydropower capacity at some level of detail, using existing GIS data. This information has been made available and is maintained by NRCan's Renewables group via the IEA sponsored website:

  www.small-hydro.com

This website contains:

- An Atlas of stream flow data and preliminary analyses of hydropower potential for watercourses in all parts of Canada, and for 30 other participating countries. The Atlas can provide a listing of potential hydro development sites for a river, including estimates of head, streamflow and power availability.
- A database of organisations, contacts, and literature related to small hydro in Canada and internationally.
- A review of small-hydro resource assessment tools and methodologies;
- Guidelines for planning, constructing, operating and financing a small-hydro project, including a bibliography of technical documents and assessments.

Using the same GIS database tools NRCan has also developed a method for systematically screening and identifying small hydro sites that could potentially supply power and energy economically to remote communities. This process is now known as the Remote Small Hydro Reconnaissance Methodology. In collaboration with an Ottawa-based engineering firm the entire land area of Northern Ontario has been mapped and analyzed using this method, and economic hydro sites have been evaluated for each existing remote community, assuming that potential small hydro plants offset the full cost of diesel power. The methodology allows input data to be changed, including transmission line and substation costs, discount rates and amortization periods, diesel costs, small hydro operating and maintenance costs, etc. This methodology can greatly simplify the preliminary evaluation of remote community hydro potential in all regions of Canada, because it is done from a desktop, with no need for site visits.

BC Hydro has made their 2002 *Handbook for Developing Micro Hydro* available at their website (www.bchydro.com) , which contains much practical information on planning, developing and constructing a hydropower installation.

NRCan is currently finishing a *Buyer's Guide to Micro Hydro Systems,* which is expected to be available in print form by Fall 2003.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **SMALL/ MICRO HYDRO**

Technology **Hydro Turbine**

Energy Form Produced - electricity

Energy Applications - grid or off-grid power

Local Economic - moderate

Development Potential
Estim. Cost of Energy - moderate – depends heavily on site characteristics

Level of Investment - moderate/high (typically $1500 - $3000 / kW for systems > 100 kW)

Critical Requirements
- significant hydro head and/or flowrate
- site proximity to energy-using population or facility

Level of Expertise
-Design/install - moderate
-O&M - low

Existing Installations - many worldwide

Benefits
- can be economic form of power generation, especially in remote areas
- low maintenance requirements
- GIS analysis can provide rough estimate of potential without site visits

Limitations & Issues
- each installation is unique, and most have to be custom designed
- streamflow can be highly seasonal; a good site and good data is essential
- capital costs for civil containment works and transmission are high

Chapter 4: Solar **Photovoltaics (pv)**

- *Solar PV Technology*
- *PV in Canada*
- *Building-Integrated Photovoltaics (BIPV)*
- *Tools*

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Solar PV Technology

- PV cells convert sunlight directly into electricity via the photovoltaic effect using specially treated semiconductor materials. Over the past 30 years crystalline silicon has been the material of choice in PV panels – this technology uses 200 – 300 µm thick wafers, similar to those used in integrated circuits, to generate power. In spite of its high module conversion efficiency (11 - 16%) crystalline silicon is rapidly being displaced in the PV market by a range of thin film technologies, which have far greater potential for low-cost mass production. Thin films have lower conversion efficiencies but use far less semiconductor material, since they are only 1% as thick as crystalline wafers. They can be deposited on a variety of inexpensive substrate materials, such as glass, stainless steel and plastic, and scribed with a laser to form cells, without the need for costly, labour-intensive wiring between each cell.
- Thin film PV semiconductor materials and typical module conversion efficiencies are: amorphous silicon (6 - 9%), cadmium telluride (CdTe)(6 – 9%) and copper indium diselenide (> 11%). Amorphous silicon now makes up 13% of world PV sales, but cadmium telluride is considered the most probable technology for widespread future breakthroughs in PV manufacturing and deployment.

PV in Canada

- Solar PV systems represent a $42 M industry in Canada, with sales increasing, on average, more than 20% annually over the past decade. In 2000, 1.5 MW of modules were sold in Canada, with 98% of this total being used in off-grid or remote applications, and 2% grid-tied.

- Based on annual 20% growth rates, the production price of electricity from photovoltaics in Canada can be expected to drop below that of conventional thermal sources by 2020. The US DOE has forecast a PV electricity cost of (US$) 14 cents/kWh by 2010, and 8 cents/kWh by 2020.

- Each installed kW of PV power has the potential to offset 1.6 tonnes of CO_2/yr when replacing coal-generated electricity, 1.3 tonnes/yr when replacing oil and 0.7 tonnes/yr when replacing natural gas.

- In 2001 CANMET's PV team analyzed the Maryland state residential solar rooftop program (a strong participant in the US 'million solar roof' initiative) to determine its replication potential in Canada. This analysis considered costs and benefits of residential PV installations in Toronto and Edmonton, where greenhouse gas emissions from electricity production are high, and where deregulated power markets support alternative generation options. The analysis showed:
  - over the period 2005 – 2019, over 51,000 PV systems could be installed in the two cities with a total incentive cost of $8.5 million and private investment of $108 million ($CDN). Total power would be 36.5 MW.
  - These installed PV systems would displace 0.46 MT of CO_2 over their lifetimes, representing an 'emissions credit' of $6.90/tonne CO_2 for Edmonton and $28 in Toronto. The program could create 800 jobs in the service and manufacturing industries.

- Following consultations with the Canadian PV industry, CANMET has made a series of recommendations for increased PV adoption in this country[10]. These include:
  - Seeking federal R&D funding to accelerate Canadian PV product development.
  - Fostering collaboration amongst architects, developers, builders and industry to establish Canadian capacity and experience. Also educating Canadians on the benefits of PV through demonstration projects.
  - Removing barriers to PV adoption, such as technical barriers to the direct connection of systems to the electricity grid.

Building-Integrated Photovoltaics (BIPV)

- By using PV modules as building components, BIPV offsets some of the high initial costs of PV technology. BIPV can be incorporated into roofing, glazing and wall components, providing benefits other than electricity generation, including weatherproofing, aesthetic appearance, daylighting, shading and thermal or acoustic insulation.

[10] 'Photovoltaics for Buildings: Opportunities for Canada', CANMET Varennes, 2001.

- Since it provides other values beyond energy, BIPV can be seen as a stepping-stone for accelerated solar industry development. The use of BIPV can reflect aesthetic, social and environmental values, so decisions to incorporate PV can now move beyond the simple economics of payback time.
- BIPV can be incorporated into a building shell as tiles or metal sheet roofing, or as semi-tranparent glazing for atriums, sunspaces or greenhouses. Curtain wall systems for high-rise buildings represent another large potential market for BIPV applications, given both the surface areas involved and the visual/public exposure potential available to a company or organization in demonstrating environmental or social values.
- The uptake of BIPV depends heavily on complementary programs. Foremost among these is net metering, which allows consumers to tie their system into the grid and use it as a battery, both buying and selling power from the utility as needed. This eliminates the need for battery storage, typically 20% of stand-alone system cost (in addition the elimination of storage losses gives BIPV a 20% gain in efficiency over stand-alone systems). Also important are certification of equipment and of design/installation personnel, as well as education and marketing, to promote the non-financial aspects of BIPV.
- With net metering, a single, conventional meter keeps track of electricity being drawn from or fed to the grid. Customers pay for their net consumption, and implementation and administration costs are minimized. Under net *billing*, two meters are used, and power sold back to the utility is credited only at the marginal cost of generation i.e. at a lower price than bundled retail rates.

- Typical BIPV component costs currently range from \$450-600 /m^2 for roofing panels to \$600-750 /m^2 for shingles. Glazing elements range in price from \$400 - 1000 /m^2 and grid tie inverters are priced at \$1000-3000 /kW (\$ CDN).
- These component prices typically add up to an installed BIPV system cost of \$10,000 /kW_{peak} in Canada (BC Hydro, 2002). Over a 20 year lifetime, annual electricity production costs are currently estimated at \$CAD 30 – 90 cents/kWh[11], depending on location, yet, as stated above, these costs are expected to decrease to under 20 cents/kWh by 2010, and to halve again in the following decade.

- The embodied energy costs for BIPV (i.e. the total energy used in manufacturing the units) are lower than for stand-alone PV panels, in large part because aluminum mounting frames are not required.

Tools

- A technical and economic evaluation of BIPV[12], together with a listing of manufacturers and contacts can be found on BC Hydro's website at:

[11] Source: 'Photovoltaics in Buildings: Opportunities for Canada', NRCan, 2002
[12] Green Energy Study for British Columbia, Phase 2: Building Integrated Photovoltaic Solar and Small Scale Wind, October 2002, prepared by Eric Smiley, BCIT Technology Centre

http://www.bchydro.bc.ca/environment/greenpower

- 1n 2001 CANMET – Varennes published an extensive report on PV potential for buildings in Canada "*Photovoltaics for Buildings: Opportunities for Canada*". CES has a copy, and others are available via the NRCan website. The report includes manufacturers' specifications for a range of PV products.

- A RETScreen module is available free online for pre-feasibility studies of photovoltaic systems. The site is located at:

  http://www.retscreen.net

- Environment Canada offers various data products for solar resource assessment in Canada, including *Solar Radiation Data Analysis for Canada*, "a 6 volume set of reports providing detailed analysis (means, frequency of occurrence) of solar radiation on a horizontal and tilted surfaces for 143 Canadian locations". More solar insolation information and data is available at:

  http://www.msc-smc.ec.gc.ca/climate

  To access the number of hours sunshine at a given location, it is necessary to access the archived climate normals (1961- 1990), available on the first page of this site. Then perform a custom search for solar data using the advanced search feature for the station required.

- The Canadian Solar Energy Society (SESCI) provides general information on PV systems at its website:

  http://www.solarenergysociety.ca

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**SOLAR PHOTOVOLTAIC (PV)**	
Technology	**Building Integrated (BIPV)**	**Stand-alone system**
Energy Form Produced	- grid-connected electricity	- electricity w/storage
Energy Applications	- non-heating applications	- non-heating applications
Local Economic	- low	- low
Development Potential *Estim. Cost of Energy*	- 30 – 90 cents/kWh	
Level of Investment	- high ($10,000/kWpeak)	- high
Critical Requirements	- new construction or need to replace roofing or cladding - net metering allowed by utility	- can be economic in remote locations
Level of Expertise		
-Design/install	- high	- high
-O&M	- none	- moderate
Existing Installations	- 100s in Europe - very few in Canada	- many remote units in Canada
Benefits	- no storage needed - forms part of building shell - can be used as aesthetic element - very low maintenance - 20% more efficient than PV systems requiring storage	- panels can be retrofitted
Limitations & Issues	- high initial cost: new technology - needs co-operation of hydro utility - should be included in initial building design	- battery storage increases cost by 20% over BIPV - demands efficient appliances, to be cost-effective

Solar Thermal

- *Solar Air Heating*
- *Solar Water Heating*
- *Solar District Heating in Europe*
- *Solar Thermal Electricity Generation*

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Solar Air Heating

- The Solarwall system, developed by Conserval Engineering (Downsview, Ont.) is Canada's most prominent commercial solar thermal heating system. The Solarwall is a perforated dark-coloured metal cladding, which is installed on south facing walls to form an airspace between it and the building surface. The system is designed to pre-heat ventilation air, which is drawn in through small holes across the metal surface and warmed inside the plenum as it rises to a ventilation intake duct near the roof.
- A Solarwall can pre-heat air by 17- 30^{o}C, cutting down on delivered heat from the primary heating system. The plenum also captures heat escaping through the building's south wall.
- The Solarwall's efficiency improves slightly at colder temperatures, because less of the collected heat is radiated away, and adjacent snow also improves performance by reflecting radiant energy onto the wall. In summer there is considerable potential to recover heat from the plenum for other uses, e.g. via a hot water heat exchanger, but such refinements are not yet part of the commercial package. The system is now being used in crop drying applications in the Far East.
- NRCan statistics show that 20 Solarwall systems were installed in Canada in 2001, with a total wall area of 4,000 m^2. In 2002 the installed area was 7,000 m^2. Payback times reflect incremental costs of individual installations, and whether or not the avoided cost of another cladding system can be deducted from the Solarwall cost (i.e. for new buildings or those in need of new cladding). Accordingly, NRCan quotes typical payback times for monitored installations of between 3 and 7 years (with REDI incentive).
- The Solarwall system is supported by a Federal REDI subsidy of 25% for commercial or industrial applications. NRCan recommends that the SWIFT

modeling program be used for full feasibility studies. SWIFT was developed for NRCan and is available free at the CANREN website (www.canren.ca).

- Solarwall installations are becoming more diverse, and range from major manufacturing facilities (e.g. Ford, Canadair plants) to livestock-rearing barns in the Eastern Townships, to apartment/condominium complexes in Toronto. REDI funding for qualifying systems is guaranteed through 2004.
- Solarwall is supported by a RETScreen module, available free online, which allows simple pre-feasibility analysis of an installation at any location in Canada. (RETScreen is available at www.retscreen.net)

Solar Water Heating

- A solar water heating industry flourished in Florida and other Southern states during the 1930s without government intervention or support, with systems being installed in 60,000 residences. The industry shut down during the 1950s and 60s due to low oil and gas prices, and did not reappear until the 1970s oil crisis. There are around 1.5 million residential solar water heating installations in the US, the majority of which are simple swimming pool heaters that circulate water directly between a collector panel and the pool. These are seasonal units that do not require freeze protection.
- Although water heating is the second-largest energy end use in most residences, solar water heating has never been widely adopted in Canada, due to the difficulties of designing appropriate freeze-protected systems, and due to historic low energy prices. Here, as in the US, unglazed pool heaters dominate the market, with sales of around 25,000 units in both 2000 and 2001. In contrast, sales of glazed collectors for residential hot water systems averaged only 800 units nationally for each year. Pool heaters can be sized using ENERPOOL, a software package developed by NRCan and available free online at the CanRen website (www.canren.ca).
- The current solar hot water industry leader in Canada is Thermodynamics Inc, of Nova Scotia. Their system uses a closed glycol loop for heat exchange between the collector and an existing electric or gas water heater, and fluid circulation is PV-driven. System performance (i.e. displaced primary heating fuel) for any solar system is dependent on use characteristics, but monitoring has shown the ‘solar fraction’ varying between 30% in winter and 70% in summer, with a seasonal average of around 50% for most southern Canadian locations. Payback time is typically 7 – 10 years.
- Enerworks Inc, a London, Ontario based manufacturer, is presently undertaking a major effort to cut the cost and therefore increase market penetration of residential solar hot water systems in Canada (and the US). The company has designed their flat-plate collector system as a production item, and is aiming at an installed cost of $2000 (in Canada) for 2003.

- Active-system water heaters need to be designed, sized and installed properly to avoid a wide range of potential problems, some of which have set back the industry for years. Problems can include improper freeze or overheat protection (and glycol breakdown), valve and seal failures, entrained air, pump failure, loss of fluid, insulation breakdown and roof penetration leakage.

Solar District Heating in Europe

- The European Community reports that 10 million m^2 of glazed solar panels had been installed in all EEC countries by 2001, 99% of this in small-scale residential or commercial water heating systems.
- Between 1998 – 2002 the EEC contributed funding to nine solar district heating systems in five member countries[13]. Each of these systems was designed to provide heat from a central storage facility to multiple dwellings. The project was designed to investigate whether higher solar fractions and lower unit costs were achievable through medium-term (1 - 2 weeks) and seasonal heat storage.
- Administrators reported no serious technical difficulties with any of the nine custom projects, and average solar fractions of 40% (water and space heating) were measured over the year. The largest installation, at Neckarsulm in Germany, provides space heat and hot water to 231 dwellings via 5,924 m^2 of collector panels and 63,000 m^3 of water storage. It now achieves a 50% solar fraction.
- Comparative characteristics of small and large European systems:

	Short Term ***Storage***	Week-Long ***Storage***	Long-Term ***Storage***
Solar Energy Use	DHW only	DHW + space	DHW + space
Solar Fraction	10 – 20%	30 – 40%	40 – 70%
Collector area / dwelling unit (m^2)	2 – 4	4 – 10	10 - 40
Storage vol./collector area (l/m^2)	50 – 70	200 – 400	2000 - 4000
Investment cost (Euros/m^2 heated)	20 – 25	30 – 50	90 - 150

- The EEC project has demonstrated that community solar heating systems are technically feasible, if expensive. Nevertheless, the high installation costs are offset by high fuel costs in Europe. For example, residential electricity prices in most EEC countries vary between Euros 0.1 – 0.2 / kWh (CAD $0.15 – 0.31/ kWh), while the Neckarsulm installation in Germany reports a discounted solar

[13] Renewable Energy World magazine, Nov/Dec 2002.

heating cost of Euros 172/ MWh[14]. At current exchange rates this represents CAD $0.27/kWh, which is just above the household electricity cost in Germany. Due to its large size, the Neckarsulm project was the most cost-effective in the group.

- In Denmark, seven 'first generation' solar district heating systems were operating by 2002. These ranged in size from a 3000 m2 system in Ry (no thermal storage) to an 8,000 m2 system in Marstal, with 2,100 m3 of thermal storage. The Marstal system collects solar radiation from large collectors (8 m in width) installed in back-to-back arrays in a field close to the centre of the community. Marstal is presently expanding its system to 19,000 m2 of collectors and has excavated an insulated in-ground thermal storage pit to house 10,000 m3 of warmed water. The expanded system is expected to meet 30% of the annual community heating load.
- The Marstal solar DH system and several others were built by Arcon Solvarme, a Danish manufacturer that claims to be Europe's leader for large-scale solar plants. According to the company, the successful performance of its solar DH systems is dependent on: large panel size (minimizing manufacturing labour, transport and installation cost); effective insulation of all units; rapid installation procedures through simple design and layout; efficient heat storage. More information is available at the company's website (www.arcon.dk)
- A 2001 economic analysis of large vs. small scale Danish solar heating installations compared respective performance, and found that a large central system delivered heat energy at around one quarter of the price attained by individual house-mounted units. This study was performed on behalf of the Danish District Heating Board and published in their 'Energy and Environment' Journal, 2002. Summary information is as follows:

Unit	Annual Cost of Production (MWh)	Panel Size (m2)	Storage Size (m3)	Investment per Household ($ Canadian)	Investment per Energy (cents / kWh)
Small	3	4.8	0.28	7200	21.4
Large	3500	8000	2000	2100	5.3

- In 1999 the community of Anneberg, Sweden, built a subdivision of 50 new houses utilizing solar thermal storage in rock boreholes. This is the first solar DH plant utilizing such an approach. The system provides some 70% of the total heat and hot water demand for these houses. Due to the experimental nature of the project, the payback time is long, but the installation is considered a success and energy costs have been estimated by the design team at around CAD$ 0.17/kWh.

[14] Dr.Muller-Steinhagen, Univ. of Stuttgart Institute for Thermodynamics,

Solar Thermal Electricity Generation

- Thermal solar energy can be used to generate steam, by using mirrored collectors to concentrate sunlight onto a receiver. The steam produced can be used to drive a turbine. The receiver can be a high tower, a dish or a trough.
- The world's first solar electric plant used mirrored troughs. Luz International, the pioneering solar electric company completed its first solar power plant in 1985 in California's Mojave Desert. By 1991 Luz had brought 354 megawatts of solar electricity on line at nine different sites. Although the company went out of business in 1992, its plants continue to produce electricity. During Luz's existence, the cost of solar electricity was cut from 25 cents/kWh to less than 8 cents. Luz's Solar Energy Generating Station failed economically because gas prices and electricity costs did not rise as expected, operating and maintenance costs for the station did not decline as rapidly as expected, and tax incentives were expiring or uncertain.
- The southern Prairie provinces of Saskatchewan, Alberta and Manitoba have the highest average annual solar radiation rates in Canada, at 17 – 18 MJ/m^2 per day (inclined plane at angle of latitude). Over the year Swift Current, Saskatchewan (for example) receives 2375 hours of sunshine, which is around 55% more than St.Johns, Newfoundland, or 16% more than Ottawa.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **SOLAR THERMAL**

Technology	**Solarwall**	**Water heating**
Energy Form Produced	- warm air	- hot water
Energy Applications	- preheat ventilation air	- domestic/commercial hot water
Local Economic	- low/moderate	- low
Development Potential		
Estim. Cost of Energy	- payback 3 – 8 years	- payback > 7 years residential (less for high-use commercial)
Level of Investment	- moderate ($200-250/m2)	- low ($2 – 4 k/ household)
Critical Requirements	- large S-facing wall, unglazed	- higher water demand better
Level of Expertise		
-Design/install	- low	- moderate
-O&M	- none	- low
Existing Installations	- over 70 in Canada - e.g. Montreal, Oshawa, Toronto	- approx. 800 units/yr in Canada
Benefits	- wide range in applications incl. farm, industrial, sports - good performance/payback in remote Northern locations	- cuts peak power demand - low cost systems coming 2003/4
Limitations & Issues	- economics favour new buildings - also retrofits where cladding needs replacing	- systems must withstand temperature extremes

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**SOLAR THERMAL**
Technology	**Solar District Heating Systems**
Energy Form Produced	- hot water
Energy Applications	- space and hot water heating
Local Economic	- moderate - high (mainly displaced conventional heating fuels)
Development Potential	
Estim. Cost of Energy	- 5 – 25+ cents/kWh
Level of Investment	- moderate/high (e.g. large Danish installation $2100+/ household)
Critical Requirements	- high building density, high solar radiation, large (custom) solar panels
Level of Expertise	
-Design/install	- high
-O&M	- low
Existing Installations	- 10 in Denmark, 20 in Sweden, Germany and the rest of Europe - none yet in Canada
Benefits	- sufficient heat storage allows full utilization of panels and summer heat
Limitations & Issues	- First generation systems are all custom designs - Second generation systems now appearing in Denmark - Underground thermal storage can be central pit or boreholes - No North American manufacturer yet for large (field-mounted) panels

Chapter 5: Wind
Wind

- *Wind Power*
- *Global Wind Industry*
- *Wind Energy in Canada*
- *Energy Storage*
- *Tools*

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Wind Power

- The energy content of wind, like any fluid, varies with the cube of velocity, so doubling wind speed increases available energy by a factor of 8, and tripling the wind speed yields 27 times more available energy.
- The amount of energy available from a rotor depends on its swept area. Doubling the rotor length increases the area by $2^2 = 4$ times, and since windspeed increases with distance above ground, ever-larger turbines mounted on ever-higher towers can access far more wind energy, dramatically improving their economics. A typical 1 MW wind turbine has a rotor diameter of 50-55 m.

Global Wind Power Industry

- With sustained growth rates of over 30% per year, wind is the world's fastest-growing energy source. In January 2002, installed world capacity exceeded 24,000 MW, of which 205 MW (or 0.85% of world capacity) was located in Canada.
- Over the past decade the cost of wind energy has fallen from 30 cents/kWh to around 8 c/kWh at sites with average windspeed of 8 m/s, and down to 12 c/kWh at sites with average 6 m/s windspeeds. In major policy reviews the US DOE and the British government have predicted future wind energy costs of between 3.4 - 5.5 c/kWh by 2020[15] ($US).
- The world wind turbine industry is led by European manufacturers, particularly those of Denmark, who maintained their 50%+ global market share in 2001. If foreign joint ventures are included then Denmark's share of the world wind

[15] Windpower Monthly, January 2002

industry approaches 65%. Over the past 5 years the biggest markets for wind turbines have been Germany, the US, Spain and Denmark, with Germany and the US now having installed capacities of over 6,000 MW, more than twice that of any other country.
- Wind turbines are getting larger. From 1998 to 2001 the size of the average wind turbine sold on the world market increased from 701 to 944 kW[16].
- Wind is becoming an increasingly capital-intensive industry, with the (world) cost of wind turbines presently averaging CAD$1.5 million per megawatt installed.

Wind Energy in Canada

- Canada has wind farms in Alberta, Saskatchewan, PEI and Quebec, and utility-scale generators in Ontario and the Yukon. The largest wind plant in the country is Le Nordais, located on the Gaspé peninsula, which currently has 133 turbines at 2 sites, each 750 kW, for a total plant output of 100 MW. The largest individual turbine in Canada is the 1.8 MW Vestas unit located next to the Pickering nuclear plant in Ontario.
- In 2002 the Canadian Wind Energy Association (CanWEA) stated that Canada has the industrial capacity to manufacture utility-scale wind turbine components, such as blades, towers and nacelles, but not generators, gearboxes and control systems, and there are as yet no comprehensive wind turbine manufacturing facilities in Canada. In 2001 CanWEA launched its 'Wind Vision for Canada' plan, calling for the installation of 10,000 MW by 2010, to provide 5% of the country's electricity needs.
- Wind energy development in any jurisdiction is necessarily constrained by electrical grid layout and capacity. A small country like Denmark, for example (population 5.3 million), can contemplate supplying 50% of its electrical needs with wind and other renewables by 2030 because it is connected to the German, Swedish and other grids, which can be used essentially as storage batteries, given existing and planned power trading agreements between these countries.
- The federal government is supporting wind energy development in Canada through the Wind Power Production Incentive (WPPI), a 15-year, $260-million program to support the installation of 1000 MW of wind energy capacity from 2001- 2006, with funding extending over an additional 10 years to 2016. Project administration is expected to cost $5 million, with the balance available as a direct incentive to producers. None of the WPPI funding has been allocated to domestic R&D support, for example to fund research into turbine modifications for cold weather and ice-affected installations. The decision not to support Canadian R&D has been heavily criticized by the domestic wind industry.
- Under WPPI, the wind incentive averages 1 cent / kWh for installations commissioned during the period 2002 – 2007, falling to 0.8 c/kWh for the next 10 years to 2016.

[16] Danish Windpower Association website, 2003

- CANMET has predicted a wind market potential of 985 MW in Canada to 2010, mainly in Quebec (725 MW), Newfoundland (122 MW), Ontario (61 MW) and Nova Scotia (42 MW).
- According to NRCan's wind team, investment costs for small wind energy systems are $2-$5K/kW installed – a wide range reflecting differences in windspeed, site conditions and transmission costs. Very small systems (under 10 kW) would fall in the high end of that range (say, $3-5k/kW), while the medium size units (20-300 kW) would fall in the $2-$3k/kW range.

Energy Storage

- The availability and type of storage dramatically affects the economics of wind-generated electricity. A regional or national grid acts as a storage medium whereby demand loads can be managed according to available supply.
- Various energy storage options are available to off-grid or remote sites or communities, including: lead acid or nickel cadmium batteries, flywheels, pumped hydro and hydrogen (via electrolysis).
- Storage needs and costs reflect the storage time required. Short term needs (up to one hour) for small systems are still met most economically by batteries. For example a 1998 NREL study of wind-diesel hybrid power systems for remote communities found that a 30-minute storage capacity could halve the annual run-time for the diesel generator, when compared to the zero-storage case.
- Hydrogen offers the most promise for future energy storage in larger applications such as remote communities. In a 2001 conference paper[17] officers of Stuart Energy (a Canadian leader in hydrogen system deployment) presented an economic analysis of a future 1 MW wind/hydrogen system to meet all community electricity needs in Cambridge Bay, Nunavut, by 2010. In this community electrical demand averages 780 kW, and diesel-generated power currently costs 45 cents/kWh. The Stuart Energy analysis for 2010 indicated:

Component / unit cost	Total Cost
Wind turbines – 8 MW @ $800 / kW	$6.4 million
Electrolyzer - 4 MW @ $600 / kW	$2.4 million
Storage – 10 days with no wind	$3.0 million
Fuel cell – 1.4 MW @ $1400 / kW	$2.0 million
Total	$13.8 million

Given the present community electrical revenue of $3 million/yr, this analysis appears to indicate significant future potential for hybrid wind/hydrogen systems, although the authors caution that costs are projected, not current.

[17] Hydrogen and Wind/Solar Electricity: Partners in Sustainable Energy Supply'; P.Scott, M.Fairlie, Stuart Energy Systems, 2001, submitted to Hy Forum.

- Grid limitations in Canada (capacity and distribution) significantly affect the feasibility of wind energy development, with many potential wind sites being un-economically distant from potential electricity markets. Saskatchewan, for example, has the potential to develop 2-3 GW of wind power, but would need to link any such generation system with existing hydroelectric storage stations in, for example, Manitoba, in order to balance supply and demand. Future development of this resource will therefore require interprovincial co-operation, such as a comprehensive power sharing strategy with Manitoba Hydro.

Tools

- A wealth of information on wind energy is available online. By far the most comprehensive site is that of the Danish wind industry association, which has a wide range of technical, economic and background information. The site is at:

  www.windpower.org

- A RETScreen module has been developed for pre-feasibility studies of wind energy sites. It is available free online at:

  www.retscreen.net

- The RETScreen Wind Energy Project Model can be used to evaluate energy production, life-cycle costs and GHG emissions reduction for central-grid and isolated-grid wind energy projects, from large scale multi-turbine wind farms to small scale single-turbine wind-diesel hybrid systems. The latest version includes updated turbine equipment worksheets based on manufacturer-specific power curve data for different wind distributions.

- Wind data for locations across Canada is available at Environment Canada's website:

  http://www.msc-smc.ec.gc.ca/climate/climate_normals_1990/index_e.cfm

- A map of average windspeed in Canada can be found at Environment Canada's website. This is useful as a 'first-cut' in determining regions of promising wind resources. Any area that falls outside the 20 km/h average speed contour will likely not contain economically viable wind sites.

  http://www.cmc.ec.gc.ca/rpn/modcom/eole/CanadianAtlas0.html#anchor368403

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **WIND**

Technology	**Grid-connected**	**Off-Grid**
Energy Form Produced	- electricity	- electricity
Energy Applications	- all	- non-heating applications
Local Economic	- low/moderate	- moderate
Development Potential		
Estim. Cost of Energy	- > 10 cents/kWh	- > 12 cents/kWh
Level of Investment	- small $2–5K /kW installed - large systems $1.5 million /MW	- $4 – 5 K/ kW installed
Critical Requirements	- windspeed > 5 m/s minimum	- windspeed > 5 m/s
Level of Expertise		
-Design/install	- high	- high
-O&M	- moderate	- moderate
Existing Installations	- 205 MW in Canada - e.g. Gaspe, Alberta, Sask.	- some larger systems e.g. Whitehorse, Yukon
Benefits	- equipment costs decreasing rapidly	- good potential in N
locations		
	due to expanding world market - cold air has more density, power	with high electricity rates
Limitations & Issues	- industry moving to larger turbines for better economics - avg. new wind installation 944 kW - grid limitations limit wind dev't in best regions - proper site selection is critical. - need minimum 1 year of detailed site wind data to assess potential	- battery storage still cheapest for smaller installations - hydrogen storage in future - generally much smaller systems than grid-connected, due storage issues.

Chapter 6: Thermal/Other
Earth Energy – thermal storage

- *Technology*
- *Earth Energy Systems in Canada*
- *Energy Costs*
- *Geothermal Energy in BC*
- *Tools*

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Technology

- Earth energy (EE) systems use soil or groundwater as a 'heat battery' to provide space conditioning to buildings. Most systems are designed to provide both heating and cooling, with heat being deposited in summer and withdrawn in winter. Closed-loop systems pump a dilute heat transfer fluid around a continuous poly loop, extracting and upgrading heat using a heat pump, while open loop systems pump water from a body of water (well, lake, aquifer) and return it after extracting or adding heat. Larger systems designed for multiple buildings are likely open loop.
- Closed-loop units can circulate any approved fluid inside the pipe, depending on the performance characteristics desired. Each manufacturer must specify which fluids are acceptable to a unit, with the most common being denatured ethanol or methanol[18]. Due to fears of groundwater contamination methanol is not approved for use in Ontario.
- Higher system efficiencies are obtained by lower Δt values between source and sink (i.e. temperature lift). Minimum practical temperatures for soil or groundwater when used as a heat source are 4 – 10°C. Systems must be designed for balanced annual use (i.e. heat out = heat in).
- Groundwater-based systems generally have the best economic performance, especially if aquifers of relatively warm water can be accessed, such as disused flooded mineshafts. For example in Springhill, NS, 12 commercial buildings and warehouses extract/sink heat from 18°C water pumped from flooded coal mines.

[18] Source: Earth Energy Society of Canada website

- Heat pump COPs reflect the performance of all system components, including compressors, heat exchangers and pumps. In Canada heat pumps are rated according to a CSA standard and must comply with the Energy Efficiency Act, which specifies a minimum efficiency in heating mode of COP = 3.0 for ground source heat pumps and 2.5 for air source units.
- Using current technology, ground source heat pump systems have a maximum COP of around 4.0, but far higher efficiencies are achievable in 'direct connect' systems, which do not use a refrigerant cycle (i.e. water provides a direct heat source or sink).
- For promising sites (e.g. economically attractive results from a RETScreen pre-feasibility study) hydrogeological surveys are required for any larger commercial installation. This can include test drilling and use of ground penetrating radar.
- Environmental concerns can limit the feasibility of open loop groundwater-based systems, due to aquifer depletion or water contamination. Improperly installed wells can provide a path for surface water runoff, carrying pesticides, fertilizers and other contaminants to enter aquifers or lakes. Re-injection wells can be drilled to allow the replenishment of aquifers, but these usually perform at a reduced rate than they would yield water (typically 50 - 75%). Aquifer re-injection wells may also experience mineral encrustation or overflow, therefore it is standard practice to consult a professional hydrogeologist.

Earth Energy Systems in Canada

- The Earth Energy Society of Canada reports that more than 40,000 earth energy (EE) systems have been installed to date in Canada, and over 400,000 units in the U.S. This is a proven technology, with little potential for significant technological breakthroughs.
- NRCan supports the installation of EE systems through the REDI program (market support only) and by providing software and associated support services, such as RETScreen. NRCan's Commercial Building Incentive Program also provides funding for energy efficiency initiatives, including EE systems.
- Some provincial electric utilities offer support e.g. Manitoba offers long term homeowner loans of up to $15,000 for EE system installations, payable on monthly electricity bills.
- FCM administers a $50 million feasibility study fund as part of its Green Municipal Enabling Fund, as well as $200 million in its Green Municipal Investment Fund, to support environmentally sound projects, including EE systems.
- The Canadian Standards Association recently approved new standards for the design and installation of underground thermal energy systems (C448), which are available for online purchase at the CSA website.
- The City of Toronto is installing a lakewater cooling system for downtown commercial buildings. The Deep Lake Water Cooling project, administered by Enwave (a private corporation, 50% owned by the City) will extract water from the bottom of Lake Ontario, where the year-round temperature is 4^{o}C. This project will replace existing electric chillers and is expected to reduce peak summer

demand by 250 MW. The first phase of this project has operated since 1997 (Simcoe Street Cooling Plant) while full implementation is expected by 2005.

System and Energy Costs

- The feasibility and economics of EE systems vary significantly from site to site, and are strongly influenced by local geology, water table and climate. In general, higher the tonnage, the lower the cost/ton. Costs for the ground loop are in the $1000/ton range for horizontal loops and $1500-1700/ton for vertical loops. A consultant's report prepared for NRCan on the cost of EE system heat pumps quotes:

  "water loop heat pumps used in GSHP applications are available in sizes from 1.5 to 300 kW (0.5 to 60 tons). Costs range from $800 to $1,000/ton for common size ranges"

- The EE system at Springhill, N.S. is likely representative of the most economic installations. It had a simple payback time of less than 2 years. Many other EE systems in Canada have demonstrated simple paybacks of 2 – 5 years, including federal facilities, hockey rinks and groups of community-owned buildings.

Geothermal Energy in BC

- Geothermal energy resources are associated with geologically active crustal rift zones, and BC is the only part of Canada that is situated on a tectonic plate (the west edge of the North American Plate runs north-to-south through western BC while the plate's eastern edge forms part of the mid-Atlantic Ridge).
- BC Hydro examined geothermal energy potential as part of its 2001 Green Energy Study, and identified 16 sites in the province at which energy could economically be extracted, based on existing information. The most promising 6 sites were located near Pemberton (2), Terrace, Squamish, Mt.Edziza and Lillooet.
- These geothermal sites would use drilled production wells to produce superheated steam (260 – 170^{o}C) or water (100 – 170^{o}C) from geothermal reservoirs. BC Hydro estimates the resource potential of these sites at up to 1070 MW, with an electricity generation capacity factor of 100%, and an energy production potential of up to 9,000 GWh /yr, at a levelized cost of 5 – 9 cents / kWh. Their analysis considers a range of plant sizes between 10 - 55 MW.
- The upper level of geothermal potential, if realized, would represent 15 - 20% of BC Hydro's current annual electricity generation capacity of 43 - 54,000 GWh. However, each of these sites requires costly exploration and drilling to confirm the resource potential. The current provincial requirement to undergo a competitive bidding process for geothermal leases creates a problem at this stage of development, since significant financial risk is involved for participants.

Tools

- The Earth Energy Society of Canada's website is an extensive online resource, maintained on behalf of the earth energy industry. It contains many links to case studies, technology descriptions, FAQs and lists of earth energy system contractors by province. The site is at: www.earthenergy.ca
  Additional case studies are available at
  www.canren.gc.ca and www.ghpc.org

- A RETScreen module is available free online (www.retscreen.net) for technical and economic pre-feasibility analysis of earth energy systems. The software provides links to a variety of data sources, allowing users to quickly access weather data, ground temperatures and equipment suppliers.

- In 2002 NRCan published '*Commercial Earth Energy Systems – A Buyer's Guide*', as a general and technical reference on this heating/cooling option. It is available through NRCan's website (www.nrcan.gc.ca)

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source **EARTH ENERGY**

Technology **- heat pump heating and cooling systems using soil or groundwater**

Energy Form Produced - upgraded warm/cool water

Energy Applications - heating / cooling for buildings

Local Economic - low/moderate

Development Potential
Estim. Cost of Energy - moderate

Level of Investment - moderate (most paybacks are in the range 2 - 7 years, since systems provide both heating and cooling)

Critical Requirements - larger multi-building open loop systems must have good hydrological conditions (i.e. suitable aquifer and flowrates)

Level of Expertise
-Design/install - moderate
-O&M - low

Existing Installations - 40,000 EE systems in Canada (most are single residential size)

Benefits - proven technology with good industry support, some incentive progams
- load shaving electrical demand from utility perspective (year round)
- highly cost effective where aquifers of relatively warm water accessible
- CSA standard now available
- single technology can provide all heating and cooling needs for buildings

Limitations & Issues
- relatively high capital costs
- larger systems need hydrogeologic survey, expensive test wells etc
- improperly installed aquifer-based systems can cause groundwater contamination

Hydrogen – remote community use

- *Potential*
- *Hydrogen in Iceland*
- Hydrogen-fuelled Internal Combustion Engine
- *Hydrogen Storage*
- *Future Off-grid Community Hydrogen Use in Canada*
- *Hydrogen from Biomass*
- *Tools*

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Potential

- Optimistic forecasts of a hydrogen-based economy are still set decades into the future. Senior NRCan staff involved in automotive fuel cell RD&D expect it will be "20 to 50 years, perhaps longer" for the fuel cell to be adopted in mass-market vehicles, despite the publicity given to recent demonstrations by major auto manufacturers. Nevertheless, there is immediate potential in Canada to develop community-based projects utilizing local renewable energy sources to produce hydrogen, which can be stored and used as a community fuel in a variety of non-fuel-cell applications, including vehicles. Low-pressure hydrogen storage is a safe, proven and commercially available option.
- Steam reforming of methane presently accounts for almost all the 50 million tonnes of hydrogen used world-wide for ammonia-based fertilizers and oil product enhancement. However electrolysis is also a mature technology, and is used mainly for the production of high purity oxygen and hydrogen.

Hydrogen in Iceland

- Germany and Japan lead current research efforts into a future hydrogen-based economy, but Iceland (pop. 287,000) is the political leader: in 1999 the Icelandic government formally announced its intention to adopt hydrogen as its future fuel of choice, and to work towards eliminating fossil fuel use on the island entirely. Iceland presently uses hydroelectric and geothermal sources to meet 70% of its primary energy needs (including most space heating) but its vehicle and fishing fleets run on imported oil.
- In its effort to build the world's first hydrogen economy Iceland has set itself a 30-year agenda, starting with experimental use of compressed hydrogen fuel in its bus fleet. The first transit experiment will run from summer 2003 for two years, testing the performance of fuel cell buses as well as a hydrogen production and storage infrastructure. Hydrogen will be produced by electrolysis at a single station (using grid hydroelectric power), and the station will serve as the refueling point for buses, as well as the gas compression and storage facility. Compressed hydrogen will be stored on the bus roof, at a pressure of 350 bars, and the vehicle range will be a standard 200-300 km. Partners in this transit pilot include Shell Iceland and DaimlerChrysler.
- By 2010 Iceland also plans to build and test prototype hydrogen-fueled fishing trawlers, develop its fuel production infrastructure and test stationary fuel cell power generators. Due to the space limitations for compressed gas storage, the future Icelandic private vehicle fleet and the fishing fleets are expected to run on methanol, from which hydrogen is released on heating.

Hydrogen-fuelled Internal Combustion Engine (ICE)

- Hydrogen can be used as a motor vehicle fuel in a converted internal combustion engine, which is now available at a fraction of the current price of mobile fuel cell technology. Many companies are currently developing hydrogen-powered combustion engines, including Ford, DaimlerChrysler, Nissan and Mazda. In all cases the converted ICE is coupled to a conventional transmission and drive system. Daimler and BMW both started research into liquid hydrogen-fuelled vehicles in the 1970s. Both companies originally planned to use hydrogen imported to Germany from Quebec hydro sources.
- Ford introduced its hydrogen powered P2000 2-litre sedan at the 2002 Detroit Motor Show. This "low-cost, low-emissions" ICE vehicle has been developed as a driver for the hydrogen fuel infrastructure ultimately required for fuel cell vehicles. Test reports for this car indicate negligible tailpipe CO_2 emissions (i.e. 0.4% of those produced by a comparable gasoline-powered vehicle), NOx emissions of 0.23-0.46 g/km and acceptable general levels of road performance. Compressed hydrogen fuel is stored in tanks in the vehicle trunk.

Hydrogen Storage – Technology Options

- **Compressed gaseous storage** is the most common method of storing the fuel for vehicle use, with tanks pressurized to 5,000 – 10,000 psi in order to get an acceptable range within the storage space available. For stationary applications, hydrogen can be stored at much lower pressures (e.g. 150 psi).
- **Liquid hydrogen** has the advantage of greatly increased fuel density, but it must be kept at –253°C (its boiling point), making it highly unlikely as a suitable fuel for vehicles. Nevertheless, several German car manufacturers have conducted decades-long experiments with this fuel.
- **Metal halide storage** deposits hydrogen in metal alloys at low pressure. The disadvantage is that, depending on the type of alloy, more or less elevated temperatures are needed to liberate the hydrogen. Research continues in Quebec and Japan.
- **Methanol** storage has the advantage of high fuel density and easy infrastructure handling, but it must be reformed into hydrogen at an energy loss before use.
- **Graphite nano-fibre storage** probably represents the future for mobile and stationary hydrogen technologies. Researchers at Northeastern University in Boston have experimented with graphite formations and found that, due to their extraordinarily high surface areas, some graphite materials are capable of absorbing and retaining up to 30 liters of gaseous molecular hydrogen per gram of carbon at room temperature and moderate pressure. Research indicates that a future vehicle tank with a volume of 25 litres and a mass of 15 kg could provide a potential operating range of 1500 km for a fuel cell-driven subcompact car.

Future Off-grid Community Hydrogen Use in Canada

- The most suitable participants in a Canadian community hydrogen pilot project would likely be off-grid or remote communities that presently use diesel to generate electrical power, especially communities with under-utilized renewable resources, such as wind or hydro. In communities where hydro power plants were originally installed to provide power to mills or mines, hydrogen could provide storage for excess or undeveloped capacity. To date, no Canada-wide feasibility studies seem to have been carried out to examine the potential for remote hydrogen generation coupled with community use.
- In a June 2000 conference paper[19] officers of Stuart Energy (a Canadian leader in hydrogen system deployment) presented an economic analysis of a future 1 MW wind/hydrogen system to meet all community electricity needs in Cambridge Bay, Nunavut, by 2010. In this community electrical demand averages 780 kW, and diesel-generated power currently costs 45 cents/kWh. The Stuart Energy analysis for 2010 estimated the following costs:

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[19] Hydrogen and Wind/Solar Electricity: Partners in Sustainable Energy Supply'; P.Scott, M.Fairlie, Stuart Energy Systems, submitted to Hy Forum 2000.

Component / unit cost	Total Cost
Wind turbines – 8 MW @ $800 / kW	$6.4 million
Electrolyzer - 4 MW @ $600 / kW	$2.4 million
Storage – 10 days with no wind	$3.0 million
Fuel cell – 1.4 MW @ $1400 / kW	$2.0 million
Total	$13.8 million

These figures represent an installed system unit cost of CAD$10/$\text{Watt}_{peak}$. Given the community's present electrical revenue of $3 million/yr, the analysis appears to indicate significant future potential for hybrid wind/hydrogen systems, although the authors caution that costs are projected, not current.

- This study also examines the economics of a smaller wind/hydrogen system installed at a site with similar wind data to Cambridge Bay's, using current technology and prices. For a 10 kW peak load and 6 kW average load the cost of energy was calculated at CAD$0.91 /kWh.
- The Stuart Energy paper cites work by Rambach examining the feasibility and economics of wind/hydrogen systems for villages in Alaska[20]. This study estimated near-term system costs of US$9 - $22/ Watt_{peak}, and long-term costs of US$3 – 16. These figures are comparable to those for the Cambridge Bay analysis.
- German researchers have analyzed the technical and economic potential for hybrid offshore wind-hydrogen systems ranging in size from 1 kW to 5 MW. They found that medium-to-large (100 kW – 5 MW) systems would be most cost effective, with near term capital costs expected to range upwards from CAD$10/ Watt_{peak}, including the wind turbine (the largest individual component cost).
- If a variable power source such as wind or hydro (or PV) is used for electrolytic hydrogen production then a custom 'load following' electrolyzer must be used, in order to optimize fuel production.
- Many technologies which could be deployed in a renewables-powered community hydrogen pilot are already available:

    1. commercial electrolyzer systems are now sold worldwide by Stuart Energy of Mississauga (a Canadian-owned world leader in the development and deployment of hydrogen electrolysis systems).
    2. Prototype hydrogen combustion engine vehicles are now being produced by Ford and others.
    3. Prototype catalytic hydrogen heating systems (e.g. for space heat) are being developed in which a mixture of fuel and air is fed through a porous fibre structure, whose surface is coated with a catalyst. The fuel reacts directly (without a flame) and gives off reaction heat.
    4. Standard natural gas/propane cookstoves can be converted to run on hydrogen by simple modifications to burner orifice size.

[20] 'Integrated Hydrogen Utility Systems for Remote Northern Communities', G.Rambach, 10th Canadian Hydrogen Conference, 2000.

5. Stationary hydrogen-fueled fuel cells are already being deployed for distributed power generation.

Hydrogen from Biomass

- In 2001 researchers at NREL in Colorado examined the economic and technical feasibility of producing hydrogen from biomass via two thermochemical processes: gasification and fast pyrolysis. Three hydrogen production rates were studied, from 22.7 to 113.7 tonnes/day. Results for these six options showed a delivered energy cost of CAD$0.05 – 0.15 /kWh, including storage (fuel energy content only). The study concluded that hydrogen can be produced economically from biomass, and that feedstock pyrolysis (to bio-oil which is then reformed) has the most favourable economics, especially when compared to other renewables-based production options[21].

- In a September 2001 paper entitled 'Future Prospects for Production of Methanol and Hydrogen from Biomass' Dutch researchers at the University of Utrecht evaluated evolving gasification technologies and concluded that "biomass-derived methanol and hydrogen are likely to become competitive fuels tomorrow". They base this statement on estimated production costs of 5 – 7 cents ($CAD) /kWh for biomass-derived fuel (i.e. methanol or hydrogen fuel energy content, not delivered energy). The technology used is assumed to be advanced gasification in large scale (2000 MW) plants, with or without reforming. Biomass feedstock cost is assumed to be CAD$3/GJ.

Tools

The German hydrogen website 'HyWeb' contains links to a range of technically sound articles on hydrogen issues and fuel cells, including conference papers from (predominantly German) academics and researchers. The site is at:

www.hyweb.org

[21] 'Technoeconomic analysis of options for producing hydrogen from Biomass', P.Spath, J.Lane, M.Mann, NREL, Golden, Colorado, 2001.

COMMUNITY ENERGY SUPPLY POTENTIAL

Energy Source	**HYDROGEN**	
Technology	**from Wind**	**from Biomass gasification**
Energy Form Produced	- electricity to hydrogen	- bio-oil/biogas to hydrogen
Energy Applications	- combustion fuel for engines or fuel cells	- combustion fuel for engines or fuel cells
Local Economic	- high (displaced conventional fuels)	- high
Development Potential		
Estim. Cost of Energy	- high (> 75 cents/kWh) (delivered electricity cost)	- moderate (5 – 15 cents/kWh?) (delivered hydrogen cost)
Level of Investment	- high (system $10,000/kWpeak)	- high
Critical Requirements	- good wind resource (> 6 m/s) - high cost of electrical power (i.e. remote community)	- low-cost biomass feedstock - more R&D needed
Level of Expertise		
-Design/install	- high	- high
-O&M	- moderate	- moderate
Existing Installations	- small demonstration systems only (e.g. Toronto)	- none
Benefits	- benign emissions from combustion	- various feedstocks can be used - gasification or pyrolysis used
Limitations & Issues	- high initial cost of custom systems - hydrogen storage is expensive and the fuel has a poor reputation for safety - more R&D required	- not proven commercially - feedstocks require drying

Snow Cooling

- *Technology*
- *Sunsdvall Hospital, Sweden*
- *System Performance*

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Technology

- Snow storage offers the potential for low-cost summer cooling of a building or group of buildings. The principle is simply to store freely available cooling energy during winter until it is required later in the year.
- Various means can be employed to store cooling energy, yet the idea of snow storage has seen little practical application since the days of ice houses. Several federally sponsored studies examined the potential for snow cooling in Canada during the early 1980s, but concluded at the time that it was not a cost-effective option.
- If snow is used as a cold storage medium, one of the simplest and most effective way of extracting cooling energy is to pass meltwater through a heat exchanger. The rate of melting of snow or ice is reduced by a top layer of thermal insulation.

Sunsdvall Hospital, Sweden

- The regional hospital of Sundsvall in central Sweden requires 1000 MWh of summer cooling, with a peak cooling load of 1500 kW. Faced with a need to replace its outdated conventional chillers the hospital board decided to install a snow cooling system to meet the bulk of this load. An engineering consultant (VVB/VIAK) was hired together with staff at Lulea Technical University, and a design was approved for a watertight asphalt-paved snow storage area adjacent to the hospital, with sloped edges and pumping station. The asphalt layer was laid on 1.2m of compacted sand and gravel, with 0.1m rigid foam insulation.
- The snow storage area was oversized to permit future expansions to the hospital's cooling load. It can hold 60,000 m^3 of snow (around 40,000 tonnes), with a theoretical cooling potential of 1800 MWh. The 'snow field' is covered with a 0.2m thick layer of wood chips for insulation, and meltwater is collected at a

pumphouse, situated as close as possible to the hospital. The meltwater is passed through a heat exchanger connected to the hospital's hydronic cooling system.
- The snowfield has no covering but wood chips, yet the rate of melting (and therefore the quantity of meltwater and the rate of cooling) is increased by recirculating warmed meltwater from the heat exchanger onto the field surface.
- The wood chips form a cheap source of insulation, but they may not be the ideal solution for Sundsvall. They facilitate cooling of the snow pile by absorbing moisture that is then evaporated, but they only last for 2 seasons and they are implicated in extensive algal growth on the heat exchanger, reducing its efficiency during the cooling season. The old chips are burned in a nearby cogeneration plant or used as ground cover.
- The Sundsvall system became operational in June 2000, and has performed according to expectations for three full seasons, during which it has met 77 – 93% of the hospital's total annual cooling load. The system is still being monitored and adjusted to improve performance.
- Summer air temperatures in Sundsvall frequently reach 25 – 30^{o}C.
- Cold is extracted from the meltwater after being cleaned by a coarse filter, oil filter and automatically rinsed fine filters. It is pumped through two heat exchangers (1 and 2 MW) at a rate of approximately 0.08m^3/s.

System Performance

- The Sundsvall snow cooling system is, to date, a unique installation. Its performance has improved over each of its three seasons of operation. Results include the following (COP figures include discounted energy used in plant construction)

	2000	**2001**	**2002**
Snow volume (m^3)	18,800	27,400	40,700
Snow cooling energy (MWh)	607.9	897.2	1126
Max. snow cooling power (kW)	1366	1100	1873
$COP_{total\ snow}$	10.7	13.6	19.4

- The technical staff supervising this system estimate the simple payback for a snow storage unit of this type at around three years, or less for a larger system.