High Efficiency Combined Heat and Power Facilities - Benefits and Barriers

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Summary

There are important linkages between the economy, energy production, the environment and our health. Where thermal energy is needed, distributed Combined Heat and Power facilities, using gas turbines, reciprocating engines and future fuel cells can provide significant improvements to our long term mix of energy production. Local generation can also have benefits in security of energy supply and economic savings.

This paper is intended to discuss the relevant air pollution and greenhouse gas emissions from modern CHP plants, the emission prevention and reduction methods available, and their operating experience and cost-effectiveness. Mention is made of recently constructed industrial and commercial plants, and institutional barriers to further development.

Solutions described for these barriers include the need for more awareness of opportunities, improved access to the electricity grid, the proper design balance between thermal and electric for CHP systems rather than large combined cycles, improved corporate taxation incentives, and the assessment of all environmental and economic benefits when considering such cleaner sources in a restructured energy market.

High Efficiency Combined Heat and Power Facilities - Benefits and Barriers

Most of our air emissions of acid gases, toxics and greenhouse gases come from energy use and production. Energy conservation, and cleaner energy systems, will be needed for our children to benefit from cleaner air for healthy lungs, and to minimize the effects of climatic changes. Since one cannot often produce air pollution without making CO_2, it is practical to prevent both types of emissions at the same time.

Much of Canada's population lives in areas with a wide annual temperature range, from - 30°C to + 30°C. This then requires both heating and cooling systems in many areas, at the same time that electrical demands are increasing, and industrialized provinces such as Alberta and Ontario are beginning to implement electricity restructuring and privatization, with some environmental constraints. Opportunities abound for establishing Combined Heat and Power (CHP) energy systems, including industrial, commercial and municipal cogeneration projects, some with district energy.

Most places in Canada use a fuel to make only heat; 30 percent of our fuel is used in this way. In addition, one-fifth of our electricity is made from fuel in a high emissions steam power plant, usually rejecting most of its available energy to the atmosphere or to water. These two individual energy production methods can represent a substantial waste of energy.

1.0 Benefits of CHP Systems

After energy conservation in our normal daily lives, one important way for towns and cities to improve the overall energy picture is to embrace the concept of combining heat/cooling with electrical power production. If cleaner fuels such as natural gas and hydrogen, or waste fuels such as biomass or landfill gas are used, the energy conservation and pollution prevention potential can be enormous.

Benefits of CHP Systems

- Energy Conservation and Security
- Maintaining Energy $$ in Communities
- Energy Diversity and Reliability
- Reduces Transmission Losses
- More Building Space Available
- Lower GHGs, Air Pollution, CFCs

Figure 1.

The basic benefit of the CHP system is the energy saving from obtaining two forms of energy from the same input fuel, resulting in a total 30-40 percent fuel saving. Greater use of cogeneration coupled with clean fuels and waste heat recovery for district heating offers a number of benefits, including decreased emissions of air pollution and greenhouse gases, as shown in the simple emissions comparisons below, as well as mercury and other trace elements. Retirement of aging coal fired plants can provide the opportunity to move the generation back to the local community (as it was originally in the 1880's).

All buildings, factories and communities need electricity and some form of heat. In most cases where a fuel is burned to produce heat or power, then the other "product" should be cogenerated, with a variety of types of fuels and equipment (reciprocating engines, gas turbines, fuel cells, or boilers for difficult fuels).

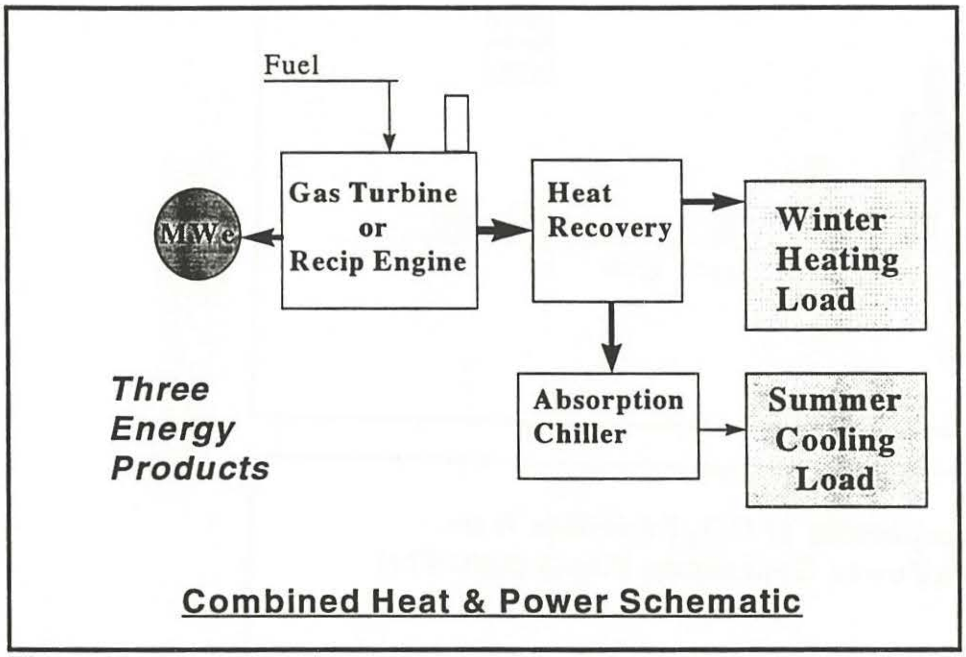


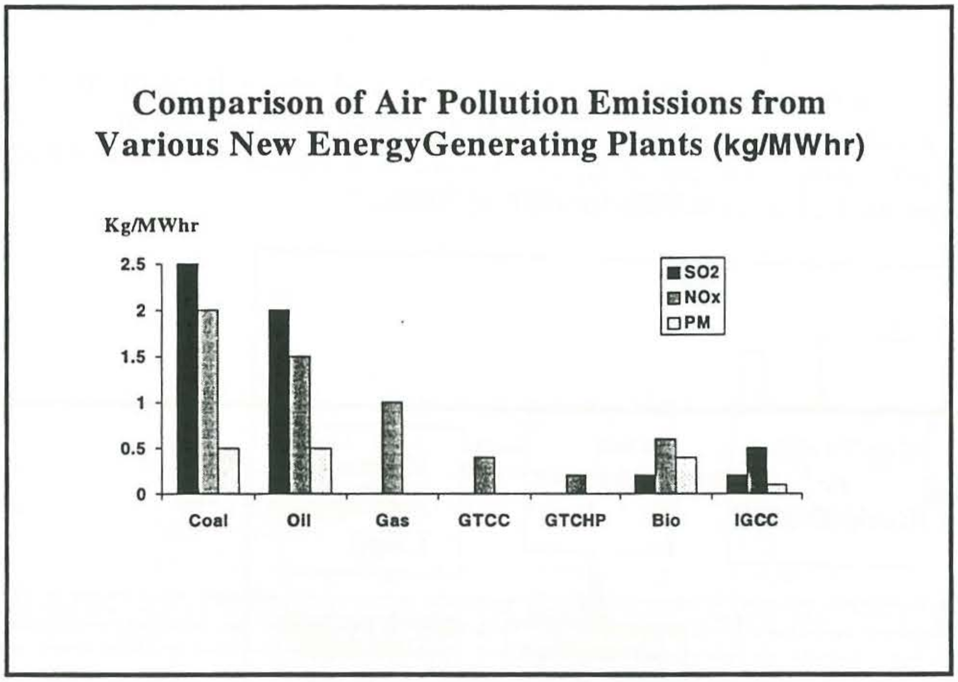
Figure 2.

Waste heat can be used to make cooling during summer, and thus reduce CFCs and electricity use, and local generation reduces transmission losses. CHP systems also make a lot of sense in areas which have hydroelectricity, because existing large hydro has a major risk of insufficient water levels arising out of climate change impacts. This makes hydropower a scarce resource, and coupled with major land use issues, something to be conserved for the best electrical applications.

Combined Heat and Power systems are not new, as they date back to the 19th century in Europe and North America. The development of large centralized electricity plants, and the regulated electric utility systems, forced many of the facilities away from load centers. The first Canadian gas turbine cogen plants were built along the DEW line in the Arctic in the early 1960's. Over the last 30 years, about 150 large and small plants have been built, or are in the works, across Canada for various applications.

2.0 Environmental Air Emissions

The graphs of Figures 1 and 2 compare approximate air pollution and CO_2 emissions from various fuel-based energy sources, such as coal, oil and gas steam plants, gas combined cycles and CHP, sustainable biomass boilers, and coal gasification. The large, multiple pollution prevention benefits of cogeneration are evident.



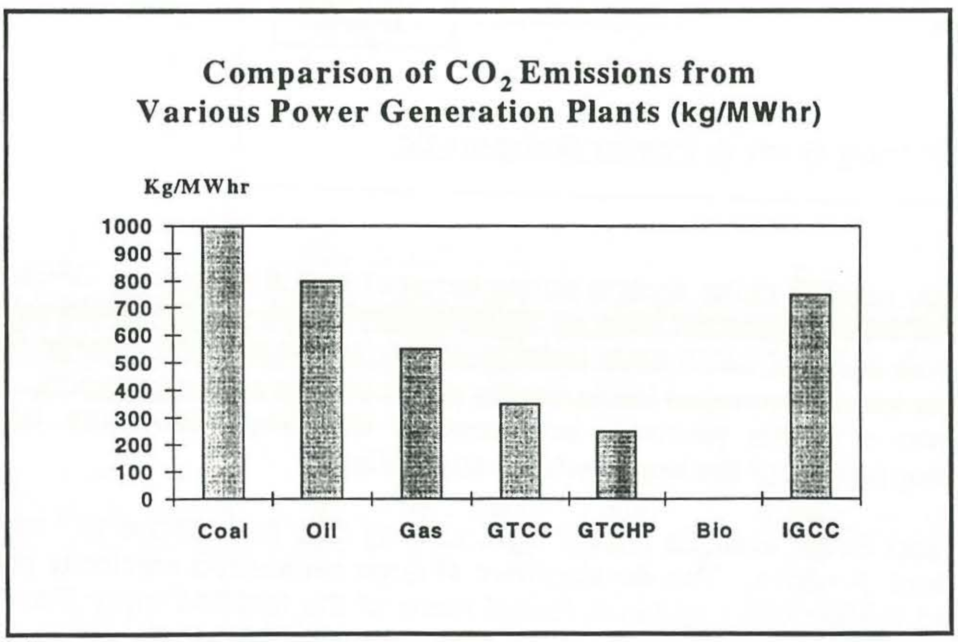


Figure 3.

Coal, Oil and Gas Boiler Rankine Cycles
GTCC - Gas Turbine Combined Cycle
GTCHP - Gas Turbine Cogen & CHP

Bio - Woodwaste Biomass
IGCC- Coal Gasification Combined Cycle

2.1 Air Pollution Emissions Reductions

A major improvement in the viability of distributed on-site generation is the emergence of cleaner burning systems which prevent much of the NOx emissions, a precursor to smog (of course, most natural gas fueled systems have little or no SO_2, particulate or toxic emissions). With steam or water injection, gas turbine CHP plants have emission rates in the 0.5 to 1 kg/MWhr range, a 60-80 percent reduction from uncontrolled levels, with an associated plant efficiency penalty. Steam injection can increase engine power, however it may also detract from overall plant efficiency since high pressure steam is a valuable CHP commodity.

More effective are the new Dry Low NOx combustion systems now widely available, producing about half of the NOx levels of steam/water injection. They employ lean premix combustion, air and fuel staging, to reduce peak flame temperatures to prevent NOx formation without efficiency loss. These new commercial DLE systems are now very common in many industrial gas turbines, and some aero-derivative engines.

Reciprocating gas engines also have combustion based on the same approach, with emissions in the 1 to 3 kg/MWhr range. These types of cleaner systems allow plants to be located near the thermal loads in city commercial districts, public buildings and industrial parks. Fuel cell systems would have no NOx emissions.

2.2 Greenhouse Gases

Low carbon fuels, used in high efficiency applications, are the best way to reduce GHG emissions from thermal energy systems. Using the factors below, one can easily estimate the CO_2 emission rate of various fossil fueled plants (Figure 3), once the overall heat rate or efficiency (GJ/MWhr) has been determined. (Although the factor for wood and woodwaste is quite variable, and higher than coal, the CO_2 recycling nature of woodwaste results in a low number depending upon assumptions.)

<u>CO_2 Factors (kg/GJ):</u>

Coal	85-95	Oil	73-74	Natural Gas	50

A more difficult calculation is the net plant heat rate for high and low grade heat, especially on an annual basis when cooling is included. The CHP industry will need to establish some reasonable guidelines for this, possibly modeled on the "Fuel chargeable to Power" method employed in Class 43.1 Capital Cost Allowance calculations. Another challenge is how to characterize GHG credit reductions - from what baseline scenario?

3.0 <u>Electricity Industry</u>

Almost 2/3 of the 550 TWhrs Canadian electricity production is sourced from large and small hydroelectric power, mostly in the provinces of British Columbia, Manitoba, Quebec and Newfoundland. Ontario and New Brunswick rely on a combination of hydro, nuclear and thermal plants, and Alberta, Saskatchewan and Nova Scotia are primarily powered by coal burning plants. Natural gas is being increasingly used in many provinces, with new discoveries coming on line in Atlantic and northern Canada.

The hydropower-based provinces have a potential for more east-west and north-south trade of a valuable, low emission commodity. It will thus be essential to recognize the local conservation, and environmental/health, benefits from combining industrial and commercial thermal energy with additional electricity production. This is especially true when regional concerns over hydro flooding, and nuclear energy issues, may tend to restrict these important low emissions, high capital cost choices. With recent growth since 1970, cogeneration has only developed to provide about 4 percent of present electricity production.

3.1 Industrial and Commercial Energy

The same places that need large amounts of electricity, will also need to burn a lot of high cost natural gas fuel to provide process heating and cooling. By providing several major energy products at the same time, 30-40% savings can be realized. In assessing this concept, the **quality** of energy is important, as the maximum benefit can be obtained from the same fuel by cascading energy output in a descending order from high quality electricity to low grade space heat.

1. Electricity & Shaft Power High
2. Industrial Process Heat
3. Cooling
4. High Pressure Steam
5. Hot Water
6. Space Heating Low

So when fuels are burned, these opportunities to make several related energy products at once should be seriously considered. One of the challenges of the cogeneration industry is to be able to quantify the energy equivalence of these products, especially the low grade energy usually wasted.

Fig 4. Approx. Annual Stationary Energy Profile, Canada, 1997

Energy	Electricity (TWhrs)	Industrial Heat (PJ)	Commercial Heat (PJ)
Hydro	345		
Nuclear	77		
Coal / Oil	105	1070	150
Natural Gas	20	1200	500
Other	9	630	-
Total	556	2900	650

With a total of over 5000 PJ of stationary heat energy required in Canada by 2020, and 2000 PJ of thermal fueled electricity, there is a major potential for establishing new CHP systems in cities and communities near industries. (Note that this is about 70% of

Canada's total secondary end use energy demand estimates of ~ 10 000 PJ/yr in 2010, from NEB, 1999).
Combined Heat and Power systems are not new in Canada. Since the mid-1900s, the pulp and paper industry has traditionally made use of boiler-based backpressure steam systems, and is now moving towards gas turbine systems. Since the late 1960's the petrochemicals and gas processing industries have been the next largest users of CHP. There are an estimated 4000 large boilers (> 10 GJ/hr) in industry today, many of which are older types needing life extension upgrades and pollution controls over the next decade.

Similarly, there are 3000 medium sized commercial boilers, and about half a million small commercial boilers in Canadian buildings. The eventual replacement (or relegation to standby status) of some of these units can be managed economically as gas and electricity prices rise, when CFC chillers need replacement, and as energy restructuring proceeds. A variety of large and small gas turbines, reciprocating engines, fuel cells, absorption chillers, and renewable energy systems can then contribute to significant air pollution and GHG emission reductions, and savings in avoided capital cost.

3.2 Estimating CHP Potential

In a very simple way, one can estimate CHP potential for each PJ of industrial heat, as outlined in Appendix A. Typically for many industries, one PJ of heat energy can match about 20-25 MWe of electricity in a thermally balanced 70% efficient system. If some capacity has a Combined Cycle component with a steam turbine, a larger plant producing over twice that amount of power (50-60 MWe/PJ) can be expected (most Canadian cogen plants are like this). This means that a 1000 PJ/yr of thermal energy growth, plus replacement, would translate into up to 40 000 MWe of matching power capacity, only a portion of which is connectable.

Although this is somewhat difficult to pin down, it is quite conceivable that Canada could by 2020 increase its electricity share from all types of CHP systems from today's 4% level to somewhere near 15%. That would mean that about 100 TWhrs of power, involving 20 - 25 000 MWe of capacity, could come from cogeneration and district energy, and provide ~ 500 PJ of heat and cooling energy to buildings and factories in communities.

4.0 Barriers and Solutions to Greater CHP Implementation

Some of the suggested barriers to be resolved by government initiatives are described below. Most of these appear to be institutional barriers rather than technical ones.

4.1 Public Outreach

One of the most apparent barriers to developing better CHP infrastructure is that most people do not know that various qualities of energy, in the form of electricity, heating and summer cooling, can often be produced from the same fuel source, in various technology choices. Many are still designing on the basis of separate thermal and mechanical energy production, and basing a plant location and size on electricity instead of local thermal needs. This represents one of the major non-technical "mindset" barrier issues. Others are;

- the measurement of macro-energy use in Petajoules of annual fuel input, without regard to efficiency or quality of energy,
- the need for balanced assessment of cleaner energy options, and related comprehensive environmental impacts (ie; all emissions at once),
- treating energy infrastructure as a system, rather than several individual distinct units,
- the perception that training and site visits are a cost, rather than a necessary investment,
- the focus on short term economic goals (payback period) instead of medium/long term investment for our children.

There is a push on now to again re-establish energy and environmental courses in secondary and university education, and to assist in cross-Canada technical workshops to raise public and private sector awareness of important energy topics. Learning never ends, and training initiatives can have several side benefits in matching up people with complimentary needs.

4.2 Corporate Taxation Incentives

Since the 1970's there has been an energy efficiency incentive in terms of Accelerated Capital Cost Allowance, or fast depreciation, to encourage capital investment by deferring some tax payments into the future. This now provides a writeoff at 30% on a declining balance basis, if the qualifying energy plant (cogen, waste heat, landfill gas, flare gas, some renewables) maintains an annual heat rate of less than 6.3 GJ/MWhr (6000 BTU/kWhr). At this point, district energy system (DES) piping for commercial heat is not eligible. More recent tax changes have now increased the normal depreciation rate for new power and heat facilities from 4% to 8% to stimulate investment, in recognition of shorter perceived economic lives in a restructured energy market.

Additional improvements may be evaluated to promote effective investments in better CHP systems, such as the re-inclusion of DES piping, and a two-tiered CCA/performance threshold to allow some lesser tax benefits to reasonably efficient systems which cannot always achieve the annual performance threshold.

There has also been a recent federal Green Municipal Funding assistance program for communities, made available to the Federation of Canadian Municipalities to assist in developing sustainable projects. Some other direct public assistance to non-taxpaying entities may also assist in recovery of previously rejected energy in communities.

4.3 Electricity Restructuring Initiatives

Electricity Restructuring and a decentralized electricity system demand will new rules to be developed by provincial and federal governments. An energy system approach would adopt uniform interconnection standards for decentralized power plants (this is one of the significant technical issues). The ability of small on-site power producers to sell excess electricity to their utilities must be enhanced and promoted. One way to do this is location based pricing, where transmission is avoided, and thermal efficiency for on-site generation is given a credit. Implementation of net billing mechanisms will help. High gas prices can be a hindrance (price of fuel) or a stimulus (need for more efficiency), as many thermal customers already have gas contracts but make no electricity. We should make sure we are getting the maximum amount of useful work from each GJ of natural gas. As long as the "spark spread" or difference between gas ($/GJ) and power (c/kWhr) is not high enough, CHP will continue to have difficulty. Electricity should be allowed to achieve the proper market price level to maximize all opportunities.

4.4 Full Financial Quantification of all Benefits

Any analysis of cost must also properly consider the probable range of benefits, so that projects can be ranked appropriately. Economic feasibility often dismisses several of the tangible benefits of distributed CHP, including;

1. avoided costs of replacing aging utility, industrial, and commercial boilers, and long power transmission lines
2. the impending phaseout costs of CFC chillers,
3. the energy security provided by district energy loops,
4. process reliability of on-site generation with two or more units.
5. the prevention of <u>all</u> air emissions, and cooling water impacts,

On the last point, it may be common to quantify the monetary impact on GHGs, without also adding the common reductions in regional acid rain, smog and air toxic emissions, plus less cooling water usage. Certainly, clean-fueled CHP can provide all of those benefits, and portions of capital and operating costs should be allocated to each emission reduction to show multi-pollutant $/tonne cost-effectiveness. For example, if a cleaner energy system such as a 10 MWe, 70% efficient gas fired CHP plant costs an additional $1 million/yr, it may well be that it can reduce or prevent a range of air emissions, reasonably allocated to;

- Acid gases (NOx, SO2, PM) $500 per tonne
- Greenhouse gases $5 per tonne
- Air Toxics and CFC prevention $?

Such allocations can be used for planning purposes, but are sensitive to assumptions around what energy mix is being replaced.

Our 1998 eastern Canadian ice storm resulted in millions without power and heat for several days or weeks, yet those with access to CHP at least did not lose heating – this is an important benefit of well designed CHP. What would it be worth for an industry or a community?

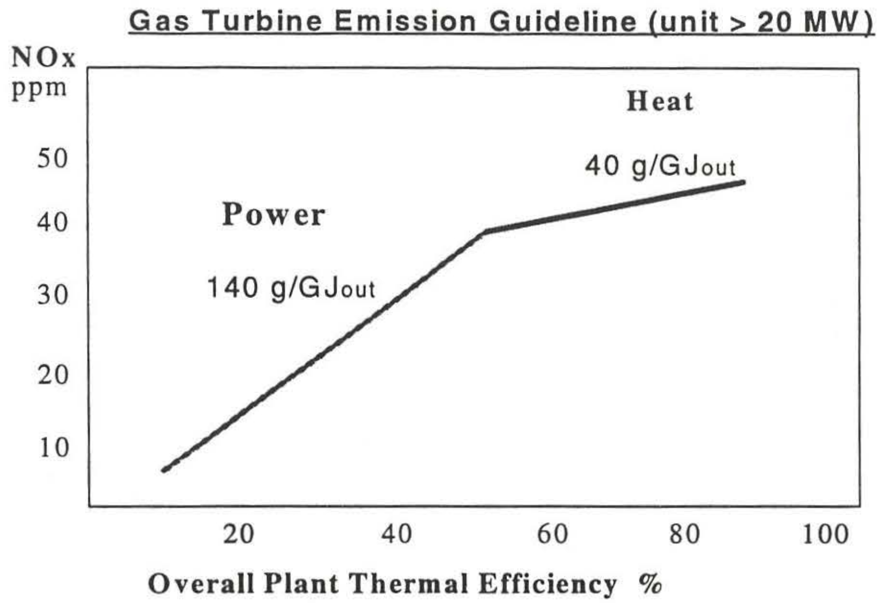
Another possible "barrier" for many organizations is that the management of the capital budget is done by a <u>different group</u> of people than those who do operating (fuel) budgeting. Thus certain projects which have a long term benefit with high efficiency and lower total costs, can be discouraged by those who tend to want to minimize capital expenditures and debt.

4.5 Air Emissions Regulations

Many environmental rules are still based on pollution control, using a variety of single pollutant, backend control methods, each of which has other drawbacks. Also still common is the concentration based (ppmv or mg/m^3) or the fuel input based standard (g/GJin). Neither of these methods promotes energy efficiency nor pollution prevention of a multitude of pollutants, concepts which will become critical in dealing with sustainable development and climate change. In fact, overly stringent local stack emission concentration limits can lead to lost opportunities in required efficiency, air pollution prevention and GHG reductions.

Environment Canada and a multi-stakeholder working group developed a 1992 NO_x National Emission Guideline for stationary gas turbine plants, using a "mass flow per energy output" methodology. It provides for a Power Output Allowance, and a Heat Recovery Allowance, with NO_x limits expressed in $grams_{NOx}$ per output GigaJoule, or Megawatt. Energy efficiency to minimise CO_2 emissions was deemed to be important, as well as considerations of pollution prevention, operational reliability and cost-effectiveness. The Guideline was developed to promote cogeneration applications, without the need for ultra-low NO_x levels requiring back-end SCR cleanup and ammonia problems.

Gas turbine cogeneration plants are one of the cleanest types of fossil fueled equipment available for energy production (Fig 1). Gas turbines have high exhaust temperatures across a wide range of sizes (20 kW to 200 000 kW) and are therefore well suited to steam applications. They produce no sulphur dioxide, PM or heavy metals. Significant strides have been made in reducing NO_x emissions by 85 percent down to the 0.3 kg_{NOx}/MWhr level (~25 ppm) for large simple cycle units, translating to 0.2 kg_{NOx}/MWhr and less for CHP plants, on a combined heat and power basis. Reciprocating engines in smaller sizes are better for low grade heat, usually hot water district energy. These have now much lower NOx emission as well, in the 1-3 kg/MWhr range, a 70% reduction
from uncontrolled levels.



4.6 CHP Terminology

The characterization or sizing of a CHP plant in terms of Megawatts, electric (MWe) leads to common problems of lack of thermal balance, and too much combined cycle capacity on large plants. (The electricity restructuring regulatory system tends to exacerbate this issue in not properly promoting thermal opportunities.) The author believes that cogeneration should be rated both on thermal and electrical load at the design point, so that both are treated as important. Some method, such as a MWth & MWe rating system, should be developed. In Europe, the industry is developing the concept of "good quality CHP" , and the United Kingdom has issued a guidance document setting out their proposed requrements.

Many large "cogeneration" plants are mostly combined cycle, which without low grade heat recovery, are not necessarily environmentally sound. They tend to reject large amounts of otherwise usable low grade heat to lake or air condensers. Typically a 300 MWe combined cycle will reject 200 MWth into the air or water, causing an environmental impact in its own right from condenser thermal pollution or large vapour plumes. As large office buildings may use about 1 MWth in heat load, this means that the whole commercial sector thermal needs of a city are being wasted by baseload condensing. Large combined cycles should be more applicable to repowering of existing coal/oil power sites which do not have thermal hosts.

5.0 Summary of Cogeneration and District Energy in Canada

Apart from steam in the pulp, paper and chemical sectors, the first Canadian gas turbine cogen plants were built for radar sites in the Arctic in the early 1960's. Over the last 30 years, about 150 large and small CHP plants have been built, or are in the works, across Canada for industrial and commercial applications.

Figure 6 below shows an estimate of the variety of gas turbine and recip engine CHP facilities completed or being planned across Canada. In addition, there are several straight combined cycles and utility repowering projects being proposed, which could potentially involve heat recovery.

There is over 5500 MWe of natural gas and woodwaste cogen plant installed mostly since 1990, with a similar amount being installed or planned for 2002-2005. Environment Canada an other federal departments are studying the inventories of all types of industrial thermal plants to better understand potential opportunities. Many older boiler based steam systems may have to be upgraded or replaced based on economic or environmental factors. Based on Canada's industrial/commercial fuel consumption of Figure 3, there is a potential for another 20-25 000 MWe of gas and biomass cogen for Canada for 2020 (although "MWe size" is not the best measure of CHP potential).

Fig 6. Summary of Sectoral CHP Projects

	Completed/Construction		Planned	
Sector	# plants	MWe	# plants	MWe
Chemicals	7	1070	4	570
Oil Industry	8	1340	3	580
Pulp & Paper	12	750	6	720
Gas Processing	3	190	2	200
Food Processing	7	300	-	-
Steel, Metals,Mining	2	115	3	600
Manufacturing	8	190	6	50
Hospitals	6	95	2	10
Unversities	8	28	3	15
Municipal Service	12	55	5	40
Utility Repowering	1	200	5	1800
Total	**75**	**4333**	**39**	**4585**

Commercial Energy Systems

Most large cities have some central heating and cooling district energy system in sizes of about 50 to 300 MWth, although few of these generate electricity. Since 1993, small Ontario cities such as Cornwall, Sudbury, Markham and Windsor have established gas CHP / DES systems at about 3-5 MWe each. Typically these are providing about 1 MW thermal for every MW of electrical capacity using reciprocating gas engines.

Systems in Ottawa and London, Ont also have small gas turbine plants with higher thermal outputs. Fort MacPherson, NWT is a small northern community with a diesel fueled 1.8 MWe recip engine plant. There are a few microturbine CHP units for buildings (in addition to their now common use for power in oil and gas flaring). Future fuel cell systems with appropriate thermal exhaust design will provide opportunities for a total energy package in buildings, possibly in combination with renewable or earth energy systems.

Several universities and hospitals in Ontario and Alberta have installed small gas turbines or recips, depending on steam or hot water based system design. The world's first 68 MWe GE LM6000 based plant, built by TransAlta Energy in 1992, provides heat and cooling services at a major Ottawa hospital. The federal government has three units at National Defence and National Research Council facilities. In future, CHP also has the ability to provide for urban transportation using electricity for rail based systems.

Industrial Plants

As shown in Fig. 6, most Canadian cogeneration and CHP is installed in industrial applications. A summary of some of the larger systems is included in Appendix B. The degree of actual "good quality" cogen from a thermal balance perspective varies, since many of these plants often have a large combined cycle component as an electricity exporter. Several food processing and paper plants using process steam also have small gas turbine based facilities in Ontario, which are primarily for on-site generation. Some larger utility repowering projects, designed as combined cycles, have the potential to provide a large amount of thermal energy to nearby cities. A sampling of major industrial gas turbine cogen plants across Canada includes;

		MWe	GT units
Cascades Paper	Kingsey F.,Que	25	2 LM1600
Magnola Metallurgy	Asbestos, Que	20	2 Solar Mars
CASCO Foods	Cardinal, Ont	156	W501D
ADM Salt	Windsor, Ont	102	ABB 11N
GLP/ St. Marys Paper	Sault St. Marie, Ont	95	2 LM6000
Celanese Chemicals	Kingston, Ont	110	GE Frame 6FA
TransAlta / Boeing	Mississauga, Ont	110	2 LM6000
Abitibi Paper	Iroquois Falls, Ont	115	2 LM6000
Atlantic Packaging	Whitby, Ont	50	RR Trent
NOVA Chemicals	Red Deer, Alta	416	2 W501F
Pan Canadian	Calgary, Alta	106	2 LM6000
Amoco Heavy Oil	Primrose, Alta	84	Frame 7EA
SUNCOR Oilsands	Ft McMurray, Alta	360	2 Alstom GT11N
PetroCan Offshore	Newfoundland	80	2 Frame 6
Fletcher Pulp	Campbell R, BC	250	Alstom GT24
Husky Heavy Oil	Lloydminster, SK	225	2 Frame 7EA

6.0 Conclusions

There is a significant Canadian CHP potential in many applications across Canada, using all types of equipment and clean burning fuels. These types of facilities could potentially supply over 20 percent of our electricity and thermal needs, while resulting in major reductions in air pollution and GHGs as older systems are replaced. Increasing energy costs may provide opportunities for energy conservation through such systems. There are still some remaining non-technical barriers to be addressed such as;

- awareness of opportunities,
- proper financial incentives,
- recognition in market restructuring
- thermal balance sizing,
- government policy recognition,
- cross sectoral cooperation.

The public sector will need to work together with the private sector, and with post secondary education, in overcoming these barriers. We need the ability to carry out design and financial analyses that are robust in the long term, taking into account energy supply and environmental factors. Improved societal infrastructure must be viewed not only as a cost, but as an investment for the health and security of our children and theirs.

Estimating Canadian CHP Potential — Appendix A

Some rough numbers to estimate total industrial/commercial potential, based on PJ of heat production in NRCan and NEB Energy forecasts. This will grow from about 4000 PJ now to up to ~ 5000 PJ by 2020. It would be about 80% industrial.

Today, the 5500 MWe of operating plants are making about 30 TWhrs of power, and about 100 PJ of heat.

Below are some estimates of power that can match thermal load, based on an annual average CHP efficiency of 70%. The approximations are based on the electrical power that can match a certain amount of hourly thermal load, in proportion to 100 GJ/hr, and fuel input based on engine Heat Rate (HR). It seems that most plants around 20-25 MWe of size match the thermal load of a 1 PJ/yr fueled boiler plant. Plants with a Combined Cycle component are about twice that size.

Assume;

One PJ/yr of fuel makes on average about 0.7 PJ of usable heat.
These 700 000 GJ over 300 days is roughly **100 GJ/hr** of thermal load.

Simple small gas turbine cogen (HR = 12 GJ/MWhr)

1 MWe uses 12 GJ/hr of fuel, making ~ 5 GJ/hr of heat.
Thus 1 PJ matches ~ 20 MWe of capacity.

Simple large gas turbine cogen (HR = 10 GJ/MWhr)

10 MWe uses 100 GJ/hr of fuel, making ~ 40 GJ/hr of heat.
Thus 1 PJ matches ~ 25 MWe of capacity.

Combined Cycle Cogen, 20 MW GT plus 10 MW steam turbine (HR = 7 GJ/MWhr)

30 MW plant uses 210 GJ/hr of fuel, making 50 GJ/hr of residual heat.
1 PJ matches ~ 60 MWe plant.

Recip Engine (HR = 9 GJ/MWhr)

5 MWe plant uses 45 GJ/hr, making 20 GJ/hr of low grade heat.
1 PJ matches ~ 25 MWe recip capacity.

Possibly 1/5 of national total energy could be available from CHP of some sort by 2020, and that would be 800 PJ of industrial, and 200 PJ of commercial/municipal energy. With an improved thermal design in future, these 1000 PJ of load may match ~ 40 000 MWe of plant capacity, using a variety of equipment/fuels/sizes. This could represent 200 TWhrs, especially if some coal based units are replaced/avoided by gas/biomass CHP. Only a portion of CHP potential would actually be achievable and connectable.

Examples of Canadian Gas Turbine Cogeneration Projects — Appendix B

DOW SARNIA COGERNERATION COMPLEX

As a result of increasing energy costs associated with the existing four large industrial boilers providing 60 MW of on-site power, Canada's first large scale cogeneration facility was completed in 1972 at the Dow Chemical manufacturing complex in Sarnia, Ontario.

The new gas turbine plant consisted of a pair of GE Frame 7B gas turbines, exhausting into two dual-pressure (1450/45 psi) heat recovery steam generators capable of supplementary firing. These units supplied the HP steam to the existing steam turbines to produce about 50 MW of power, and about 1 million lb/hr of 475/185/45 psi steam is extracted for chemical plant processes. In 1977, additional power was installed when a 73 MW ABB 11 gas turbine was added. With a total capacity of about 240 MW, it was until 1999 the largest cogeneration facility in Canada.

In 1995, a new Agreement was reached among NOVA, Dow and Bayer to form a partnership for sharing of steam, condensate and electricity. Some power was sold to Ontario Hydro. In 1999, TransAlta has announced a proposal to add units to increase the total cogeneration capacity to over 600 MWe to supply seven major petrochemical companies. A total of four gas turbines and one steam turbine will result from integration of the existing plant with new units in 2003.

FORT FRANCES COGENERATION PLANT

Ontario's first large gas-fired combined cycle at a pulp and paper mill was built in 1991 at the Boise Cascade facility near Fort Frances in Western Ontario. The 98 MWe plant provides steam to the paper mill and electricity under a 15 year contract to Ontario Hydro.

The gas turbine is a Westinghouse 48 MW W251 unit, with a single pressure heat recovery unit and full duct firing to provide 400 000 lb/hr of 875 psi/825oF steam from the turbine exhaust, or up to 300 000 lb/hr from duct firing without the gas turbine. This steam is sent to the Westinghouse steam turbine, and is also supplemented with 300 000 lb/hr from the chemical recovery boiler. The extraction/condensing steam turbine produces up to 45 MW of electricity, while 175 and 70 psi steam is extracted for process purposes at the paper mill.

WESTCOAST McMAHON PLANT

Westcoast Power, owned by British Columbia's major gas utility Westcoast Energy, formed a partnership with CU Power International (now ATCO). The joint venture constructed a 110 MW cogeneration facility near the town of Taylor in northern B.C. The plant was completed in September 1993 at a cost of about $100 million. It provides process steam to Westcoast's McMahon gas processing plant for the treatment of raw, sour natural gas. The plant sells about 105 MW of electric power to B.C. Hydro.

Two Westinghouse CW251-B12 gas turbines, each normally rated at 48 MW, can provide up to 58 MW with steam injection. They each drive a Brush water cooled generator. Two Deltak waste heat boilers use duct burners to produce up to 250 000 lb/hr of steam. Steam at 425 psi and 50 psi is directed to the gas plant, and some HP steam is injected into the gas turbine for NOx control to 25 ppmv. Three 450 kW compressors are required to boost the natural gas fuel pressure. Some existing power boilers have been shut down.

OTTAWA HEALTH SCIENCES CENTER

TransAlta Energy owns and operates this 68 MW plant built in Ottawa, Ontario to supply electricity to the local grid, and low pressure steam and hot water to five institutions at the Ottawa General Hospital site. Chilled water produced by absorption chillers is also provided. The $70 million plant was completed in September 1992, and was the world's first commercial application of GE's new LM6000 aeroderivative gas turbine.

The 42 MW LM6000, normally provides exhaust heat to a triple pressure (900/70/15 psi) Foster Wheeler heat recovery steam generator to produce an additional 13 MW of power from an ABB VAX condensing, extraction-admission steam turbine. A Coen duct burner, designed specifically for the LM6000 low exhaust oxygen content, can provide more thermal energy to fully load the steam turbine to a 30 MW peak output. Both the 42 MW and 30 MW generators were supplied by Brush Electrical Machines, the latter a double-end drive unit. Condensation cooling is done by a hybrid wet surface/air cooled system. Gas turbine power is maintained at a constant level through air inlet heating with a glycol mixture, or by cooling using energy from one of two 800 tonne Carrier absorption chillers fed by 15 psi steam.

CARDINAL COGENERATION PLANT

Cardinal Power is a joint venture between the developer, Sithe Energies of New York, and the gas supplier, Husky Oil of Calgary. This is a 156 MW project at the town of Cardinal, near Kingston, Ontario. It is located adjacent to a Canadian Starch Company facility which processes corn into corn starch and animal feed. Hot water from the facility is circulated to a local school.

This is the first Canadian application of the large 110 MWe Westinghouse W501D5 gas turbine. The Zurn vertical single pressure HRSG can supply 340 000 lb/hr of 1050 psi steam to a Westinghouse condensing/extraction steam turbine, and 100 000 lb/hr of 70 psi steam to the CASCO processing plant.

CASCADES COGENERATION

Cascades Inc, a major pulp and paper corporation (now Boralex), installed a cogeneration system in 1990 at the Kingsey Falls plant south of Quebec City. This facility provided electricity for its own needs and for the local utility, and steam for paper drying at seven nearby locations. However the low fuel efficiency of these first generation engines did not result in economical operation, and it was decided in 1992 to retrofit with newer engines. Two GE LM1600 engines, rated at 13 MW each, were packaged and supplied by Nuovo Pignone of Italy. Previously these new high-efficiency aeroderivative engines were popular in mid-size Canadian pipeline applications, and this installation marked their first use in cogeneration.

LAKE SUPERIOR POWER PROJECT

A consortium of Great Lakes Power Ltd. and Union Energy completed construction of this cogeneration plant in Sault Ste. Marie, Ontario in late 1993 at an estimated cost of $120 million. The 95 MW of electricity is sold by Lake Superior Power to the local utility, Great Lakes Power, and the steam to the St. Mary's Paper mill, and potentially to Algoma Steel in future.

The plant incorporates two General Electric LM6000 gas turbines rated at 42 MW each. The two Deltak 150 000 lb/hr HRSG's produce 900 psi steam for the GE condensing/extraction steam turbine, and 175 psi steam for the paper mill process requirements. The steam turbine can provide up to 25 MW of electricity depending on the amount of process steam production. Water is returned to the steam cycle after being condensed in a once-through cooling water system.

NATIONAL RESEARCH COUNCIL

This is a load displacement project constructed in 1993 at the Montreal Road laboratory facilities of the National Research Council in Ottawa. The installation is the first 4 MW Ruston/EGT Typhoon industrial gas turbine in Canada. The $7 MM plant was sized on the base thermal needs of the complex, using the existing steam distribution system.

The Typhoon gas turbine, with a thermal efficiency of 32 percent was placed into the existing coal storage area of the main heating plant. The Ideal electric generator is driven off the cold end of the engine. An unfired exhaust gas boiler supplied by ERI/Nebraska provides 22 000 lb/hr of 100 psi steam, and is located on a heavy steel structure above the gas turbine. Fuel gas to the engine is boosted to 265 psi by a 150 kW rotary screw gas compressor. There is provision for fuel oil backup.

KIRKLAND LAKE GENERATING STATION

This was the first large combined cycle cogeneration facility to be completed in Northern Ontario to address the regional power needs of Ontario Hydro. Northland Power developed the 102 MW project and completed construction in less than one year in 1989/90. This integrated generation facility burns natural gas in three gas turbine units, and uses wood waste from local sawmills in biomass boilers.

The three gas turbines are GE LM2500 units rated at about 23 MW, each exhausting into a waste heat boiler. The engine exhaust heat produces 60 000 lb/hr of saturated steam from each genset. Wood waste is fed into three wood boilers to produce 180 000 lb/hr of steam, and this combined steam production is superheated to drive two 18 MW steam turbine generators. Additional energy is utilised from the gas turbine exhaust to dry the fuel for the wood boilers.

BAYSIDE COGENERATION PROJECT

New Brunswick Power operates the Courtney Bay oil-fired utility boiler plant in St. John, which consists of 2-100 MW units, a 50 MW unit, and a 12 MW backpressure unit. With utility restructuring, and the pending arrival of Sable Island natural gas, NB Power accepted Westcoast Power's bid to repower Unit #3 to provide electricity to the grid for domestic and export use, and to provide steam to the Irving Paper mill nearby. That boiler and the 12 MW unit will be shut down.

The project completed in 2001 consists of a new 180 MW ABB GT24 gas turbine and a new Heat Recovery Steam Generator, two auxiliary boilers, a fuel gas compressor, along with the necessary gas delivery infrastructure from Enbridge Consumers Gas. The existing steam turbine's output will be in the 70 MW range. Much of the existing condensing system will be used. One of the main drivers for the project is the local environmental benefit from reducing acid gases (with DLN combustion) as compared to the heavy fuel oil, as well as low CO_2 emissions.

ISLAND COGENERATION PROJECT

In response to a 1994-96 bidding process for new electricity in British Columbia, Fletcher Challenge Energy and Westcoast Power announced a 250 MW in late 1996 for Vancouver Island. The project would provide electricity to BC Hydro, steam to the Fletcher Elk Falls pulp and paper mill in Campbell River, and is being considered around the principle of the "utility Island" for supplying energy to other nearby industries.

This applies for the first time in Canada a new 180 MW ABB GT24 reheat gas turbine, and an associated steam turbine. The project will use about 42 MMcfd of natural gas from an upgraded Westcoast Energy gas pipeline crossing project, with Centra Gas BC as the distributor. About 25 full time personnel will run the plant. It is scheduled for completion by late 2000, and will allow two old wood fueled power boilers to be shut down.

Terra Nova "Floating Production, Storage, Offloading Vessel" (FPSO)

This vessel will be used by PetroCanada in the oil producing Terra Nova fields, in offshore Newfoundland on the Grand Banks southeast of St. John's. The portable 290 m long platform, which can move to avoid icebegs, will have two 39 MW GE Frame 6B gas turbines to produce electricity with two Brush generator/gearbox combinations. The electricity provides propulsion power for six thrusters, pumping power for waterflood injection for oil production, and gas compression for re-injection.

The gas turbines are dual fuel machines supplied by Thomassen in the Netherlands, and are backed up by two 6 MW diesel engines. A special 3-point skid mounted package serves to isolate the generator packages from ship vertical and lateral movements.
The design is also unique in Canada in that two 30 MWth ABB waste heat recovery boilers will be used for heating the over 100 000 barrels/day crude oil from 110°C to 140°C, thus being Canada's first major floating cogeneration plant.

NOVA Chemicals Joffre Plant

This new cogeneration facility is included in the $1.8 billion expansion of NOVA Chemical's Joffre petrochemicals complex near Red Deer, Alberta. The existing ethylene and polyethylene plants will receive a third ethylene plant (NOVA and Union Carbide), a new polyethylene plant, and an Amoco olefins facility. CU Power (now ATCO) and NOVA have built the $320 million 400 MW cogen installation .

This is the largest plant of this type in Canada, using two Westinghouse W501F gas turbines manufactured in Hamilton, Ontario. The 180 MW W501F units exhaust into two HRSGs and provide HP steam to an 80 MW Toshiba steam turbine. On average, the cogen units will produce 416 MWe for the Joffre site and the Alberta Interconnected System (about 3/4 to the grid, marketed by CUPIL and EPCor). Process requirements are about 140 MWth for 600 psi steam , and a small amount of 1000 psi steam.

SUNCOR Millenium

Suncor Energy proposes to double its heavy oil production, near Fort McMurray, Alberta, with a $2 billion investment in their Millenium project This includes a partnership with TransAlta to operate a $315 mllion gas fired cogen plant for an in-service date of 2001, using two 110 MW ABB Alstom GT11N units. The existing steam energy plant, producing a total of up to 1.6 million kg/hr of steam for bitumen extraction, consists of three coke and one gas fired boilers producing 425 and 790 psi steam and about 60 MW of electricity from two steam turbines, and four smaller gas boilers generating 150 and 10 psi steam. Large quantities of compressed air are also used.

The gas fired boilers will be replaced with the addition of the two duct fired HRSGs, and ABB 65 MW and 70 MW steam turbines. The bitumen extraction processes will be integrated into the energy plant, including condensing with the process water recycle system. The total new generation will be about 360 MWe and 2.3 million kg/hr of steam. Half of the electricity would be sold to the grid.

MERIDIEN Cogeneration Project

TransAlta and Husky have constructed a 225 MW cogen plant in Lloydminster on the Alberta - Saskatchewan border. This $160 million facility serves the heat load of the Husky heavy oil upgrader, and most electricity is sold to SaskPower as its first major independent power project. Two GE Frame 7EA units, provide an average of about 170 MW of electricity, and exhaust into two Nooter-Eriksen HRSGs operating at 700 psi and 50 psi. Max steaming capacity of 165 000 kg/hr can be doubled by duct firing for additional electrical output. This thermal energy supplies one 55 MW Mitsubishi condensing steam turbine generator, and up to 190 000 kg/hr to the Husky operation. Low pressure steam is also used for building heating through heat exchangers, and and heating of gas fuel and water systems. A four cell BAC wet surface air cooled condenser cools the exhaust steam for boiler feedwater.