The Potential of Distributed Cogeneration in Commercial Sites in the Greater Vancouver Regional District

By

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ABSTRACT

The Canadian government is evaluating options to reduce CO_2 emissions in order to honor commitments under the Kyoto Protocol, an international agreement to reduce greenhouse gas emissions. Significant technological advances in small-scale, electricity generation technologies and a worldwide trend toward competition and deregulation in the electricity sector may lead to new market opportunities for systems that cogenerate useful heat and electricity. This form of distributed generation (production of electricity at the point of use) may reduce CO_2 emissions relative to the most likely alternative system, that being one combustion technology to produce heat within buildings (a standard, on-site, heating boiler) and another combustion technology to produce electricity (an off-site, combined cycle gas turbine - CCGT).

This study examines one possibility from these recent trends in technological development and electricity market reform: the economic potential and environmental implications of on-site, cogeneration systems in commercial buildings in greater Vancouverd3 on-

the cogeneration technologies) ranged from $7-117 t. CO_2 for the selected cogeneration units.

Sensitivity analysis tested differences in amortization periods, capital cost estimates, capacity factors and heat rates, finding that under certain assumptions smaller scale cogeneration systems may be competitive. Cogeneration units may also defer the need for some transmission and distribution investments, and the sensitivity analysis included a critical value assessment to determine at what value of T&D savings the cogeneration units would become economic.

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1. INTRODUCTION

The British Columbia (BC) government is currently evaluating technologies to reduce CO_2 emissions in order to honor commitments under the Kyoto Protocol.[1] Adoption of distributed cogeneration, to provide heat and power in Greater Vancouver Regional District (GVRD) commercial buildings, could reduce net CO_2 production and may cost less than other supply options. Cogeneration is the combined production of heat and power. With this technology, heat from electrical generation is used for various thermal applications including space heating, water heating, and cooling. It is not economical to transport heat over long distances. Therefore, cogeneration units need to be located close to thermal users and would be distributed throughout the electrical grid in or near commercial buildings.

When heat and power are produced separately (which is the norm), heat from electrical generation is vented off and wasted. Technological evolution has lead to greater efficiency in small-scale electrical generators, such as those that could be employed in cogeneration applications in commercial buildings. Consequently, cogeneration is likely more fuel-efficient and less CO_2 polluting than separate heat and power systems.

Because cogeneration is more fuel-efficient, it may ultimately cost less than other technologies that will likely be considered as new electrical generation supply options. In North America, electricity markets are transforming from utility based monopolies into competitive markets where numerous generators sell into an organized marketplace or power pool. The advent of unrestricted competition will force utilities and independent power producers to adopt least cost technologies to generate new supply. Competitive markets will nonetheless be subject to environmental regulation and quite possibly some form of CO_2

natural gas-fired combined cycle gas turbines[2] (CCGT's) to be the most likely option to provide incremental increases in electrical generation to electricity markets. However, small-scale, natural gas-fired cogeneration can produce even less CO_2 than CCGT's, and this may be particularly economical in serving commercial buildings in urban centres like the GVRD.

1.1. Study Objectives

The purpose of this study is to assess the market competitiveness and greenhouse gas reduction potential of distributed cogeneration of heat and power in the commercial building sector in the GVRD in a competitive electricity market structure. The primary objectives of this study are to determine:

1. if small-scale natural gas cogeneration in commercial buildings in the GVRD is a cost-effective technology under competitive market conditions, and

2. if adoption of these cogeneration systems, in lieu of investment in a new, large scale, combined cycle generating station, will reduce atmospheric emissions and help to attain provincial GHG emission reduction targets.

1.2. Report Structure

Chapter One provides background information on changes in the electricity sector and describes cogeneration technology and its potential role in meeting GHG emission commitments as electricity markets evolve. Chapter Two describes the methodology used to conduct a market assessment of cogeneration and to estimate potential CO_2 emission reduction for commercial buildings in the GVRD. Chapter Three identifies the inputs required for the study and provides intermediate calculations. Chapter Four presents the results in order to evaluate the viability of cogeneration as a low CO_2 emission technology in a competitive electricity market. Finally, Chapter Five summarizes the study and makes suggestions for further research.

[2] Typically, in a combined cycle power plant the exhaust from a gas combustion turbine is routed through a heat recovery steam generator. Steam from the steam generator is then used to turn a steam turbine. Both the steam and gas turbines generate electricity. Using previously wasted heat to fire the steam turbine increases overall fuel efficiency.

1.3. GHG Emission Reduction

The greenhouse effect is a natural process whereby GHG's such as carbon dioxide (CO_2), methane, water vapour, and nitrous oxide (NO_x) trap solar energy within the atmosphere, warming the planet and making life possible. However, dramatic increases of emissions of GHGs from human activities since the Industrial Revolution have increased atmospheric concentrations of these gases. The Intergovernmental Panel on Climate Change[3] predicts that unabated, continued emissions will cause global warming and climate change with potentially catastrophic consequences. To limit GHG emissions, it is conceivable that in the near future GHG emitters will be subject to some form of emission charges, such as tradable emission permits, taxes, or stricter regulations. To limit costs associated with emission charges or taxes, building owners with a natural gas infrastructure will likely seek affordable technologies that conserve energy (and reduce emissions) without compromising the supply of energy for end use services. Cogeneration is one such technology. This study will help determine if cogeneration is an affordable and suitable technology for application in commercial buildings in the GVRD.

1.4. Cogeneration

Cogeneration is the production of electricity and useable heat from a single fuel source. Cogeneration is currently more fuel efficient than generating electricity and heat separately, due to the waste heat produced in electrical generation. Fuel savings associated with implementing cogeneration could potentially reduce GHG emissions and help Canada meet international CO_2

Efficiency levels for cogeneration are up to 60% higher than conventional generating technologies (single cycle gas or steam turbines) and range from 65-93% depending on fuel

Falling capital costs and increased efficiency were the cause of falling economies of scale. At the same time, the natural gas market was deregulated, increasing availability of this low cost, clean fuel. The result is an improved economic climate for micro generators and an erosion of the monopoly rationale now that large-scale, centralized power plants are no longer the most fuel efficient or cost effective. In 1978, the United States (US) Congress passed the Public Utility Regulatory Policy Act (PURPA), legislating the inclusion of independent power production within utilities' power mixes (Pfiefenberger et al, 1997). Several states, particularly California, have progressed further in restructuring the power industry by dismantling monopoly control and developing competitive markets for the sale

1.4.3. Role of Distributed Power Generation

Greater investment in cogeneration and other distributed generation resources is expected as electricity markets in North America become more competitive. Initially, distributed resources may serve only niche markets, but as constraints on existing transmission and distribution networks become increasingly costly to electricity consumers, distributed resources may comprise a larger component of generation capacity.

The predominance of central power stations in the electricity sector is based on several assumptions. It is generally accepted that large centralized stations have benefited from scale economies with respect to systems control, operations, and maintenance. Large plants have also benefited from economies in plant development such as siting, permit acquisition, and fuel contract negotiations (Pfiefenberger et al., 1997). With the emergence of large energy service corporations, with sufficient financial clout to negotiate on behalf of a wide customer base, cheap fuel may no longer be restricted to utilities and their large facilities. The economies of scale once exclusive to mega-generating stations may shift to mega-manufacture of many micro and mid-sized natural gas turbines and reciprocating engines, thereby greatly reducing the capital cost of highly efficient on-site technology (Flavin and Lenssen, 1994). Also, due to environmental and other public concerns, siting large-scale energy projects has become increasingly difficult, even outside urban areas. Numerous smaller, distributed facilities may be more palatable to the public and environmental regulators. Also, by siting energy generation at or near the point of consumption, cogeneration limits expensive long-term investment in the transmission and distribution infrastructure often required with utility mega-power projects.

Modular design and short lead times associated with distributed resources can make them more attractive.c72.06(ban)1mc(i)2(v)t leae(t)-8(i(v) m)-7(e)-1,(larg)-12()(1 e6(desig)a)]TJ T* 7(ed) (k
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Despite the apparent advantages of cogeneration and other distributed resources, existing distribution systems were not designed for widespread deployment of micro-generators. Because of high impedance in the distribution system, connection between customers and the transmission system can cause high line losses. Therefore, higher voltage or lower impedence interconnections may be required. Also, control frameworks for system stability are not as extensive as in the transmission system. Some form of centralized coordination is required to ensure that individual distributed generators conform to standards that reinforce system synchronicity. Individual generators would be required to carefully monitor generator controls and their settings, operating within system control designs (Cardell and Tabors, 1997).

2. METHODOLOGY

Cogeneration is more fuel efficient than CCGT's because waste heat is captured and used for thermal applications such as space heating and cooling, in such a manner as to consume less fuel than providing heat and electricity separately. Consequently, less CO_2 is emitted. However, cogeneration may cost more than CCGT's. This study was undertaken to determine the cost of distributed cogeneration and how much CO_2 it emits relative to CCGT's.

First, I estimated the technical potential for cogeneration. To do this, I developed an estimate of current and future baseload thermal demands among commercial buildings in the GVRD. Then, I selected representative commercial generators for different thermal load size categories. I used data from manufacturers on operating characteristics such as electrical to thermal output to determine the optimum size of cogeneration units to serve baseload thermal demand and to determine the associated electrical output of each size class.

I then computed the levelized unit cost of electrical output from these units, using capital and operating costs for each type of generator from manufacturers. In calculating levelized costs, I deducted credits for the value of heat, avoided back-up generation, non-fuel operating and capital costs for avoided heating boilers. To compute the levelized unit costs I used a weighted average cost of capital representing typical debt:equity ratios for private generation and representative costs of debt and equity.

2.1. Typical Building Type Energy Use Profiles

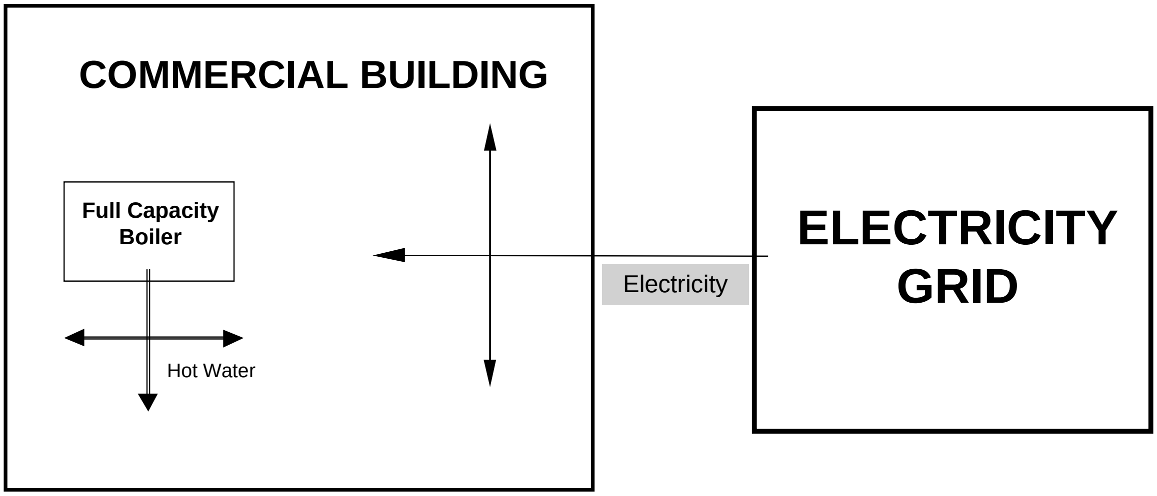
In order to determine the appropriate generator for different sized buildings, typical energy use profiles for different building types were required. Characteristic energy use profiles for each building type were taken from the Commercial Base Building Reports (CBBR) (ERG International, 1993). Both electricity and thermal demand were reported in kW/square foot. Normally, kW is a measurement of electrical capacity, however, for the purposes of this study it is also used to report thermal demand. I have distinguished between the two with the common designators of kW_e for electricity and kW_t for thermal energy.

The most economical configuration for commercial building scale cogeneration would be one that supplies baseload thermal demand (Figure 2) (Willis, 1997). A peaking boiler in each building would make up for shortfalls in thermal energy. Cogeneration would work in concert with the existing electrical grid. In general, cogeneration would supply baseload electrical loads. The grid would supply peak and emergency electricity. Buildings generating excess electricity would export power to the grid at the wholesale/spot price.

Figure 2: Distributed Cogeneration for a Commercial Building

In the conventional electricity system, the grid supplies all electricity demand (Figure 3). In the event of a black out, on-site generators are sized to supply only essential needs. All thermal energy in commerguished be.008-1-6(he 90(mmener).i)-7(he 90(mmener).i)-(o)10(f)-i7(nat)-8(i8

Figure 3: Conventional Heat and Power Supply for Commercial Buildings



To estimate thermal baseload, I used an industry rule of thumb for the Vancouver area (Willis, 1997) which suggests that half of annual space heating, refrigeration, and cooling and all of annual hot water energy demand should be considered when calculating thermal baseload.[9] Cogeneration units, and specifically the generators, can be sized based on the thermal load. The CBBR's differentiate between energy demand in existing buildings and both ASHRAE (Association of Heating, Refrigeration, and Air Conditioning Engineers) and non-ASHRAE approved future buildings. For the purposes of this study, I assumed that all future buildings would be built to ASHRAE standards, as this is the standing policy for the City of Vancouver according to building bylaws. For existing buildings, calculation of baseload thermal demand was based just on space heating and hot water heating with the assumption that retrofit to absorption chillers[10] would not be economical, whereas installation of absorption chillers in future buildings would be. Cooling and refrigeration energy use in CBBR is based on electrical end use technologies. Absorption chillers use twice as much energy as electrical chillers; therefore, CBBR figures for cooling and refrigeration were doubled to more accurately reflect energy demand from a thermal source.

[9]Because thermal demand is relatively constant throughout the year in food stores and refrigerated warehouses, generator size was based on 100% of thermal loads.
[10] Absorption chillers provide space cooling and are well suited for cogeneration systems as they can be powered by heat from the generator.

2.2. Technical Feasibility

For the purposes of this economic analysis, the principal factor governing the technical feasibility of cogeneration installation in different buildings is the size of the thermal load and whether it is sufficient to warrant purchase of cost effective generation technology. A detailed feasibility study to determine the suitability of cogeneration for a specific building would contain a more thorough analysis to evaluate compatibility with existing building features or new building architectural design. Early discussions with industry experts[11] indicated that large cogeneration installations are more cost effective than small projects and the smallest cost effective cogeneration package is the 75 kW_e Allied Signal microturbine. I initially estimated that no cogeneration plant in GVRD commercial buildings would exceed 50 MW. Therefore, cogeneration packages for this study range in size from 75 kW_e to 50 MW_e. For buildings to qualify for cogeneration they had to have at least sufficient thermal baseload to warrant a microturbine. Therefore, buildings with an electrical demand of at least 56 kW_e (75 kW_t) were included in the study. To determine what the minimum building size is for each building type, I simply divided 75 kW_t by each building type's baseload thermal demand (in kW_t /square foot). To simplify calculations, thermal demand was measured in the kW_t equivalent to GJ.

2.2.1. Building Stock

A database of GVRD commercial building stock, identifying the number of buildings in different size (square feet) classes, was required for this study. With the exception of warehouses and food stores (R. A. Malatest and Associates Ltd., 1997) this information was not readily available; therefore, for most building types I contacted building owners, managers, or engineers directly. A comprehensive list of residential complexes and apartment buildings does not exist. As a result, potential installations in these building types are not represented in this study.

In downtown Vancouver, a district heating network run by Central Heat Ltd. already supplies steam to most buildings. Buildings currently connected to this central district heating steam network are not individually assessed for cogeneration as I assumed that cogeneration for these downtown hotels, office buildings, and schools could be amalgamated into a larger

[11] Howard Bell, Mercury Electric Corporation, Calgary, AB; Paul Willis, Willis Energy Services Ltd., Vancouver, BC; Roy Hewitt, Pamco Enerflex Ltd., Calgary, AB; Paul Gauguin, Alberta Power, Edmonton, AB; Doug Cullen, International Energy Systems Ltd.,

(and more cost effective) central district heating and power plant. Similarly, several hospitals and other medical and research facilities, as well as an RCMP administrative building on the West Side of Vancouver are linked together as they are linked by a steam grid which is not currently being used. For this study, I collectively refer to these amalgamated buildings as the Shaughnessy Steam Grid. I have grouped this potential cogeneration site in the hospital building designation (Business in Vancouver, 1997a).

Other building types represented in this study include: hotels (Tourism Vancouver - The Greater Vancouver Convention & Visitor's Bureau , 1997), offices (Building Owners and Managers Association, 1997), high schools (Vancouver Public School Board, 1998), shopping malls (Business in Vancouver, 1997b), colleges (Business in Vancouver, 1998), universities, food stores, and refrigerated warehouses (Malatest and Associates Ltd., 1997). Most hotels were unwilling to discuss the size of their buildings, so I estimated squarefootage based on the number of rooms. Similarly, squarefootage for some shopping malls was unavailable and I estimated total size from gross leasable area. Data for food stores and refrigerated warehouses were obtained from the Malatest report (Malatest and Associates Ltd., 1997). Because data from the Malatest report were grouped into size categories and not separated into individual buildings like other building types, I took the median square footage in each size category to calculate generator sizes and to estimate the number of buildings in each category.

2.2.2. Generator Sizing

Thermal baseload for each building type (kW_t /sqft) was then multiplied by square footage of each building to determine total thermal capacity. Depending on the generator required to meet baseload thermal demand, different electrical:thermal ratios were used to determine the size of the electrical generator. To ensure that thermal baseload estimates from annual thermal demand were in fact baseloads, I graphed monthly baseload thermal demand with thermal output from the cogeneration unit to ensure that heat is not produced beyond the requirements of the building and to check if any building types could use more heat because of the nature of their baseload thermal demand profile. Baseload thermal demand for food stores and refrigerated warehouses is approximately 100% of total thermal demand.

Delta, BC; David Fernandez, Cummins-Wartsila, Maple Ridge, BC; Mark Axford, Stewart and Stevenson International, Inc., Houston, TX.

2.3. Cogeneration Costs

I calculated the total levelized[12] unit costs for cogeneration using capital and operating costs for each type of generator (Equation 1). In calculating levelized costs I also deducted credits for the value of the heat, avoided backup generation, and non-fuel operating and maintenance (O+M) and capital costs for avoided heating boiler capacity).

Equation 1: Levelized Cogeneration Unit Cost

Levelized Cogeneration Unit Cost ($/kWh$_e$) =

Levelized Unit(Capital + non-fuel O+M + Fuel + Grid backup) Costs –

Levelized Unit (Heat/Steam + avoided Boiler O+M + avoided Boiler Capital + avoided Back up Generator) Credits

The design of some locations may not be well suited to cogeneration retrofit, and adapting a new technology to fit an old building may add substantially to costs.

To calculate the levelized costs ($/kWh$_e$) for each cogeneration package I used a real discount rate based on the weighted average cost of capital (Equation 2):

Equation 2: Weighted Average Cost of Capital

Weighted Average Cost of Capital =

% debt financing * real cost of debt + % equity financing * real pre-tax rate of return on equity.

2.3.1. Capital Cost

Levelized capital cost represents the installed cost of a new cogeneration plant and is a function of the cost of fixed system components ($/kW$_e$) divided by the present value of the energy (total lifetime operating hours). Capital cost represents installed cost and includes extra costs associated with advanced grid inter-connection equipment (approximately $50/ kW$_e$), enabling the cogeneration system to run in parallel with the grid.

[12] Levelizing involves the conversion of non-uniform cost and energy streams into a present value equivalent uniform unit cost series. In other words, it is a way of obtaining an average unit cost while incorporating the rental value of the resource.

2.3.2. Operating and Maintenance Cost

Levelized O+M costs equal annual O+M costs ($/yr) divided by annual electricity generation (kWh_e /yr).

2.3.3. Fuel Cost

Levelized fuel cost is a function of the fuel price, fuel consumption, and plant capacity (kW_e).

A fuel conversion from lower heating value (LHV) to higher heating value (HHV) is necessary as generator performance is measured with LHV, whereas fuel requirements are measured with HHV. HHV measures total heat given off by a fuel, but some fuel bound hydrogen forms water in combustion. Therefore, to determine natural gas consumption from generator heat rate, fuel consumption must be increased by 11% (Equation 3) (Waukesha

2.3.4. Standby Fee for Peak and Backup Requirements

Cogeneration facilities will pay a standby fee for grid hook-up for peak and emergency backup electricity requirements. However, provided that T+D capacity is sufficient it would probably not be a substantial cost. For the purposes of this study, electricity produced by cogeneration will approximate baseload requirements under normal operating conditions. The grid provides excess demand for peak and shoulder requirements. However, under emergency conditions full electrical load would be taken from the grid. Existing buildings have sufficient T+D capacity to provide full electrical load. Full T+D capacity for new buildings would also be required in the event of an emergency. However, distributed resources like cogeneration would probably not all fail simultaneously. Consequently, individual T+D capacity requirements to deliver baseload power under backup situations would be incidental. Nevertheless, there is currently no explicit backup or standby tariff for small generators. Instead of estimating the standby fee in this study, I conduct a critical value analysis later which gives an indication of how high a standby fee could be without affecting the profitability of cogeneration. To prevent too many distributed generators from simultaneously drawing on backup power, a central system power pool operator would have to schedule routine downtime between generators.

2.3.5. Absorption Chilling Cost in New Buildings

The cost of absorption chilling in a cogeneration system is essentially equivalent to the cost of an electrical chilling system, the most likely technology used in conjunction with grid supplied electricity. Therefore, I assumed that addition of absorption chilling to cogeneration systems in new buildings would add no net cost.

2.3.6. Steam / Heat Credit

Steam or heat is a byproduct of cogenerated electricity. The steam (or heat) credit represents the cost to produce an equivalent amount of steam or hot water in a conventional system with a boiler, thereby giving a dollar value to cogenerated thermal energy. The levelized steam credit is equivalent to the unit value for replaced fuel, the amount of fuel necessary to produce an equivalent amount of heat or steam in a conventional boiler.

2.3.7. Operating and Maintenance and Boiler Credits

O+M and boiler credits represent the incremental difference in costs associated with a conventional full load boiler normally used to heat a building and a smaller, peaking boiler used in conjunction with cogeneration. Therefore, I have applied a credit to the over all cogeneration cost representative of the decreased capital cost of purchasing a smaller boiler and maintaining it. A retrofit is undertaken when the boiler is due for retirement, consequently both greenfield and retrofit installations require cogeneration equipment and peaking boilers. Unit cost for the O+M credit equals the annual cost divided by the annual electricity production. Levelized unit cost for the boiler credit equals the differential cost between full load and peaking boilers divided by the present worth of energy (kWh_e) over the lifetime of the plant.

2.3.8. Backup Generator Credit

The levelized credit for the backup generator is based on the present value of the cost of an inexpensive generator estimated to last as long as the cogeneration package which is

average market price, or alternatively, combined cycle gas turbine cost. Transmission line losses (estimated at 5%) are included in CCGT and electricity market rates. Some cogeneration installations are large enough to power a district heat network. Heat losses for these systems are reflected in total levelized costs.

2.5. CO_2 Emission Difference Between Cogeneration and CCGT

Relative to a heat and power system in which a centralized CCGT plant generates electricity for buildings which get their heat from gas fired boilers, a distributed cogeneration system may emit less CO_2. Cogeneration uses less natural gas to produce heat and electricity because heat from power generation is used as thermal energy, not wasted. In the cogeneration system, heat and power are produced from the same source. In the CCGT system, buildings receive electricity from the grid and generate thermal energy internally with boilers, both producing CO_2 (Figure 4).

Figure 4: CO_2 Sources from Buildings using Cogeneration and CCGT's

Combustion of 0.0497 GJ of natural gas produces one tonne of CO_2

been retired by 2010. Specifically, I assumed that half of the boiler stock is retired in 1998 and the other half in 2004. Greenfield installations are based on the expected building stock growth for each building type. Mostly because of gains in energy efficiency, thermal demand generally decreases for new buildings relative to existing stock. Future thermal energy demand (kW_t /sq.ft.), in conjunction with the current stock of buildings, was used to calculate a capacity average for each generator type in new buildings. When growth in the building stock reached the appropriate level, another suite of average capacity cogeneration plants was constructed. CO_2 reduction and cost differences between cogeneration and CCGT's were identified by generator size for each building type.

I assumed that half the boiler stock is retired in 1998 and the rest is retired 6 years later. To determine potential CO_2 reduction to 2010 for retrofits, I incorporated this assumption into the model by taking half the annual CO_2 reduction for 12 years plus the other half for 6 years for each generator size in each building type. Total cost/benefit for cogeneration retrofit potential amounts to the present value of 12 years of the first half of retrofits plus 6 years (from 2004-2010) of the second half of the retrofits. For greenfield installations, the total emission reduction to 2010 is the annual CO_2 reduction corresponding to new plants multiplied by the number of years they are in operation between now and 2010. Total cost/benefit for greenfield installations for this period is calculated by taking the present value for each year that a plant is running.

Totals for CO_2 reduction and cost differences for retrofit and greenfield installations were calculated independently. Then, CO_2 and cost differences were combined to calculate totals for each generator size in each building type. These totals were then summed for all buildings.

Specific fuel consumption and thermal efficiency values for the microturbine had yet to be determined by the manufacturer. For this study, I used a high thermal efficiency and low fuel consumption estimate provided by the manufacturer. If the microturbine proves to have lower thermal efficiency and higher fuel consumption it will be a net CO_2 producer relative to CCGT's and of no value as a CO_2 reduction technology in the scope of this study.

Combined retrofit and greenfield capacity by the end of year 2010 was determined to calculate the annual cost difference and CO_2 reductions for cogeneration relative to CCGT's at 2010 for each generator in each building type. Finally, the sum total for both cost and CO_2

differentials was calculated for all generators in all building types to estimate the potential annual reduction in CO_2 and the corresponding annual costs or savings.

2.8. Sensitivity Analyses

I conducted three sensitivity analyses. In the first two, I tested the sensitivity of the CCGT-cogeneration cost difference to ranges in key variables including: capacity factor, capital costs, fuel prices, heat rate, amortization period, and components of the weighted average cost of capital, specifically: % debt financing, real cost of debt, and pre-tax rate of return on

3. INPUTS AND INTERMEDIATE CALCULATIONS

3.1. Building Archetype Baseload Thermal Demand

Based on the calculations discussed in the Methodology section, the baseload thermal demands for each building type are listed in Table 1 for both existing and future buildings. Food stores and refrigerated warehouses do not have sufficient thermal demand without absorption chilling to warrant cogeneration installation and retrofit to absorption chilling is not economical. Therefore, only future building installations were calculated for this building type. Advances in energy conservation have generally led to decreased thermal demand in future building types, but future offices and hotels exhibit an increase due to greater energy intensification in these commercial activities. As the Vancouver downtown core is primarily composed of office buildings, I have also used the office energy demand profile for the central district heat and power system. Energy savings in future high schools are significant enough that there will no longer be sufficient baseload thermal demand to justify cogeneration. Baseload thermal demand is used to calculate the appropriate generator size for each building. In turn, generator sizing allows a minimum size standard to be set for each building type.

Table 1: Building Archetype Baseload Thermal Demand

	Existing	Future

3.2. Technical Feasibility

3.2.1. Generators

I have selected generator sizes for cogeneration units ranging from 75 kW_e to 50 MW_e. In an

67%, producing the equivalent of 863 kW_t of thermal energy. Buildings with the equivalent of 500-1500 kW_t of baseload thermal demand have been allocated this generator.

Buildings requiring the equivalent of 1500-6000 kW_t of thermal power have been allotted the Recip 2000 cogeneration package for which I chose the Wartsila Nohab 25 Diesel (Wartsila Diesel Power News Customer Journal, 1997). This engine generates 2100 kW_e of electricity and 2045 kW_t of thermal power with an electrical:thermal efficiency ratio of 38:37 and an overall efficiency of 75%.

To represent the 10 MW turbine, I selected the Allied Signal ASE120 (Gas Turbine World 1997 Handbook, 1997, pp. 133). This turbine generates 9580 kW_e of electricity and 14 370 kW_t of thermal power. The 25 MW turbine is represented by the General Electric LM 2500+ (Gas Turbine World 1996 Handbook, 1996, pp. 5-12), generating 26 350 kW_e of electricity and 39 525 kW_t of thermal power. The Rolls Royce / Westinghouse Trent (Gas Turbine World 1996 Handbook, 1996, pp. 5-16) generates 49 602 kW_e of electricity and 74 403 kW_t of thermal power, representing the 50 MW turbine. All turbines have an electrical:thermal efficiency ratio of 30:45 and an overall efficiency of 75%.

These generators are all designed to run at high capacity factors, important for this application of meeting baseload thermal demand. In this study, all generators are assumed to run for 7446 hours per year (85% capacity factor), although the impact of higher and lower capacity factors on cogeneration prices were assessed in the Sensitivity Analysis. The industry standard is 85% which leaves sufficient down time for regular maintenance. The turbines are assumed to have a lifetime of 20 years, the reciprocating engines 12 years, and the microturbine 10 years. The expected lifetime of some turbines may be longer, but for accounting purposes, 20 years appears to be the standard.

3.2.2. Minimum Building Size

As noted earlier buildings have to have at least sufficient baseload thermal demand to warrant purchase of a 75 kW

Table 3: Minimum Building Size

3.3. Building Type Stock

3.5.2.3 Fuel Cost

Table 7: Steam/Heat Credits

3.5.3.2 Boiler Operating and Maintenance Credit

The O+M credits for the different cogeneration packages were as follows: \$0.0013/ kWh_e for the microturbine (Table 8

3.5.3.4 Backup Generator Credit

I asssumed a unit cost of \$200/ kW_e for backup generators for all cogeneration plants (Table 10). This is a typical cost for an inexpensive generator which is used occasionally on an intermittent basis. Levelized costs for the backup generator credit are \$0.0046/ kWh_e for the microturbine, \$0.0042 for the Recip 500 and Recip 2000, and \$0.0038 for the turbines.

Table10: Backup Generator Credits

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Capital Cost of Backup Generator($/kW)	200	200	200	200	200	200
PV of Energy (h)	43622	48056	48056	53176	53176	53176
Levelized Cost ($/kWh$_e$)						

3.6. Greenfield Installations

New cogeneration installations were estimated from projected building stock growth and average generator capacity. Growth in building stock ranged from 1.01% in food stores and warehouses to 1.03% in offices and malls (R. A. Malatest and Associates Ltd., 1997) (Table 11). In this study simulation, for simplicity, when stock (and consequently capacity) in each building type increased sufficiently to match average capacity (from existing building stock), a ‘suite’ of new cogeneration units was installed. Depending on the building type, a ‘suite’ can consist of one, two, or several generators and is based on the average size of generators used in the existing building stock and future baseload thermal demand. Cumulative installations of new suites are also displayed in Table 11. Building types with a high growth rate and a significant number of units, such as shopping malls, will consequently have more suites.

Table 11: Estimated Greenfield Cogeneration

	Food Store	Hotel	Shop Mall	Hospital	College	Ref. Warehse	Office	Uni-versity	Central Heat	High School
Growth (%)	1.01	1.02	1.03	1.02	1.02	1.01	1.03	1.02	1.03	n/a
1999	0	0	0	0	0	0	0	0	0	n/a
2000	0	0	0	0	0	0	0	0	0	n/a
2001	0	0	0	0	0	0	0	0	0	n/a
2002	0	1	1	0	0	0	0	0	0	n/a
2003	1	0	0	0	0	0	0	0	0	n/a
2004	0	1	1	0	0	1	0	0	0	n/a
2005	1	1	1	1	0	0	0	0	0	n/a
2006	1	1	2	0	1	1	0	0	0	n/a
2007	1	2	2	1	0	0	1	0	0	n/a
2008	1	2	2	0	1	1	0	0	0	n/a
2009	2	2	2	1	0	1	0	0	0	n/a
2010	2	3	3	1	1	1	1	1	1	n/a

4. RESULTS

The purpose of this study is to determine the economic viability and GHG (specifically CO_2) reduction potential of distributed cogeneration of heat and power in the GVRD commercial building sector. This chapter is a discussion of the results of a simulation of cogeneration costs and CO_2 emissions to the year 2010.

Section 4.1 estimates the potential number of installations and associated electrical capacity for retrofit and greenfield cogeneration. Also, in this section the methodology for sizing cogeneration units for individual buildings is assessed. Section 4.2 estimates potential CO_2 reduction associated with cogeneration. Section 4.3 provides a breakdown of costs and credits for the cogeneration units used in this study. Section 4.4 identifies the costs and potential capacity associated with different cogeneration units on a cogeneration supply curve. Section 4.5 assesses cogeneration economic competitiveness from a social perspective and that of a private investor. Section 4.6 estimates cogeneration CO_2 reduction

4.1.1. Retrofit Installations

For the study period 1998–2010, there are 93 potential commercial building sites suited for cogeneration retrofit (Table 12): 34 hotels, 12 shopping malls, 16 hospitals, 14 colleges, 2 universities, 1 central district heat and power system, and 12 high schools.

Table 13: Retrofit Capacity (kW_e)

Sites	Hotel	Shop Mall	Hosp.	College	Office	University	Central Heat	High School	Totals
Microturbine	4073	2154	1720	1420	315			1021	10703
Recip 500	1336		1466	1511					4312
Recip 2000			6015	2112		2503			10630
10MW Turbine						10903			10903
25MW Turbine							25000		25000
	5408	2154	9201	5043	315	13405	25000	1021	61548

4.1.2. Greenfield Installations

By 2010, cogeneration would be installed at 95 greenfield sites (Table 14). Some building types, such as food stores, have a range of building sizes requiring different generators and consequently have more overall new installations. Most potential greenfield installations exist in the food stores (27) and hotels (26). There are also a sizable number of potential installations for new shopping malls (14) and hospitals (12), fewer for colleges (6) and refrigerated warehouses (5), and very few for offices (2), universities (2), and a central district heat and power system (1).

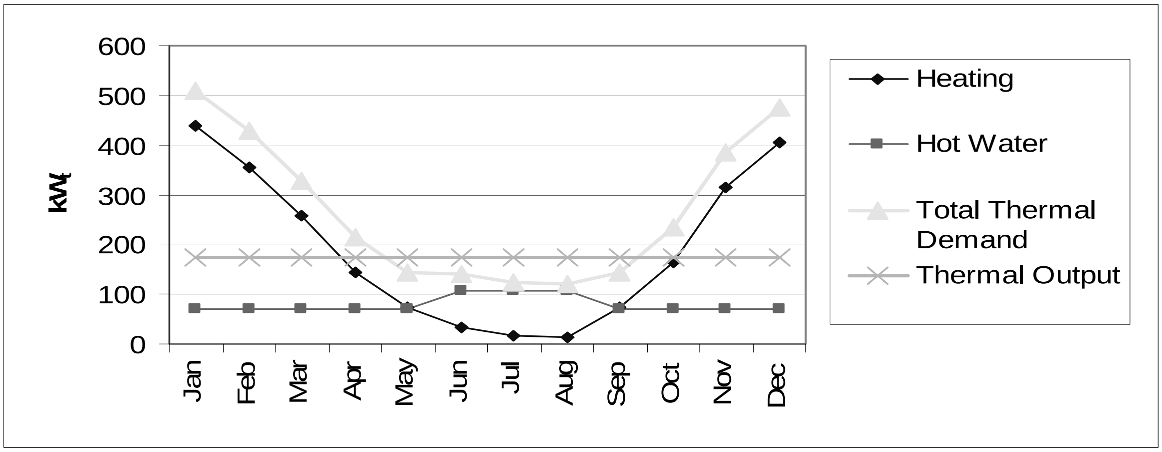
Table 14: Greenfield Installations (at 2010)

Sites	Food Store	Hotel	Shop Mall	Hosp.	College	Ref. Warehse	Office	University	Central Heat	Totals
Microturbine	9	13	14	4	3	5	2			50
Recip 500	9	13		4	3					29
Recip 2000	9			4				1		14
10MW Turbine								1		1
25MW Turbine									1	1
	27	26	14	12	6	5	2	2	1	95

Because of the sheer size of universities and a central district heat and power system, growth in thermal demand for these two building types would not result in new installations until the last year of the simulation, 2010. Given expected energy conservation measures, future high schools will no longer have sufficient baseload thermal demand to warrant distributed cogeneration. Most potential installations would be in smaller generator size classes. I have forecasted 50 microturbine installations, 29 Recip 500's, 14 Recip 2000's, 1 10MW turbine, and 1 25MW turbine.

baseload thermal demand for microturbine installations varies from a low of 121 kW_t in August to a high of 509 kW_t in January.

Figure 7: Existing Hotel (Microturbine) Thermal Load (kW_t)



For optimal sizing, cogeneration would be set to the lowest monthly baseload. Buildings with high seasonal variability may have a high annual thermal demand, but cogeneration could efficiently only provide a limited portion of the total demand. Greenfield installations typically have more stable thermal load profiles, as the addition of absorption chilling for cooling and refrigeration somewhat offsets low summer space heating demand (Figure 8). In the case of microturbine installations in future hotels, absorption chilling for summertime cooling and refrigeration would increase demand sufficiently to use up all thermal output from a baseload facility.

Figure 8: Future Hotel (Microturbine) Thermal Load (kW_t)

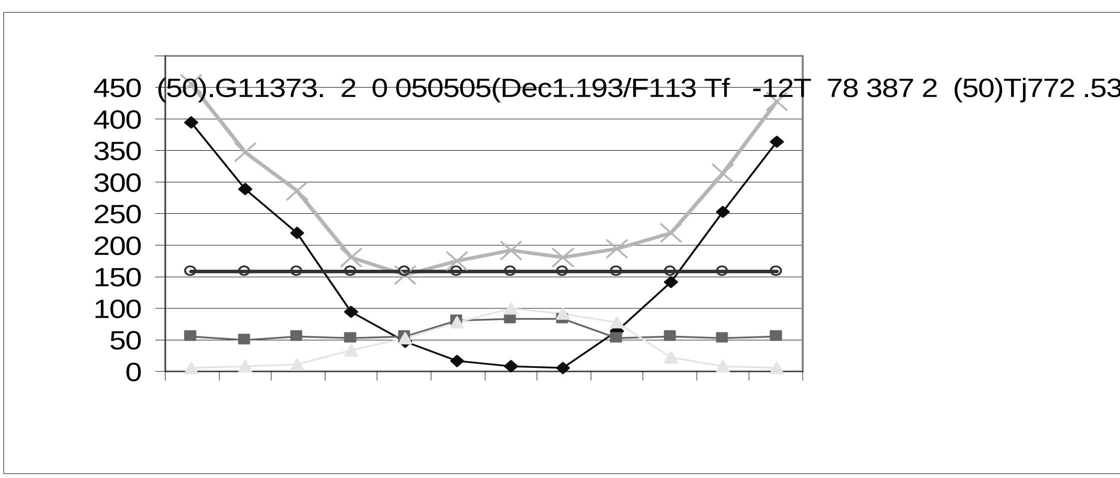


Figure 10: **CO_2 Reduction with Adoption of Cogeneration (Relative to CCGT's and Boilers) in 2010**

4.3. Cogeneration Costs and Credits

Table 16 displays total cogeneration unit costs (including credits). Total cost decreases with generator size and varies from \$0.0432/ kWh_e for the microturbine to \$0.0292/ kWh_e for the 50MW turbine, showing a pattern of declining cost with increased generator size.

Table 16: Total Cogeneration Costs (\$/kWh_e)

At first glance (Figure 11) fuel would appear to be the most significant component of total

Figure 11: Breakdown of Cogeneration Costs and Credits

4.4. Cogeneration Supply Curve

I created a supply curve illustrating the unit cost and technical potential for cogeneration in commercial buildings in the GVRD. Combined retrofit and greenfield cogeneration capacity in the year 2010 is 144.9 MW (Figure 12) with 25MW and Recip 2000 installations comprising the bulk of new capacity, 35% and 27%, respectively. The remaining 38% of

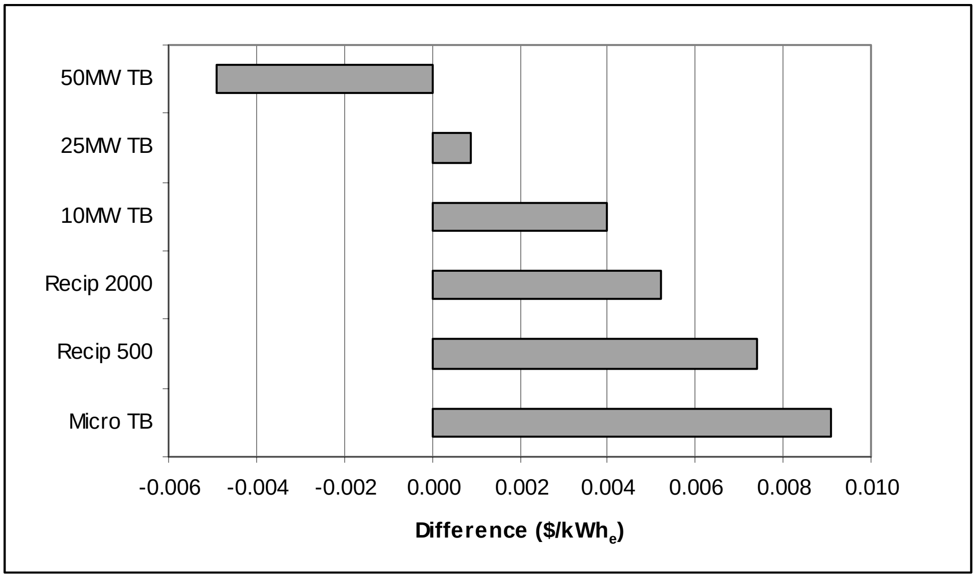
Figure 14: Critical Value Assessment: CCGT and Cogeneration Cost Differences

4.5.2. Private Perspective

The predicted average electricity price (plus an allowance for grid line losses of 5%) in a competitive market in BC is \$0.0341/kWh$_e$ (Berry, 1997). Similar to the cost comparison with CCGT's, only the 50MW cogeneration unit is less expensive than the average price of electricity in a competitive market (Figure 15).

Critical value analysis indicates that for cogeneration to be competitive with CCGT's, the CCGT T+D cost would have to be greater than grid backup costs by the following amounts: microturbine - \$0.009/ kWh$_e$, Recip 500 - \$0.007/ kWh$_e$, Recip 2000 - \$0.005/ kWh$_e$, 10MW turbine - \$0.004/ kWh$_e$, and the 25MW turbine - \$0.001/ kWh$_e$. It is not unusual that the CCGT cost and the average market price is similar. In a competitive and efficient market, price would generally fluctuate around the long-term cost of new supply. As demand for new

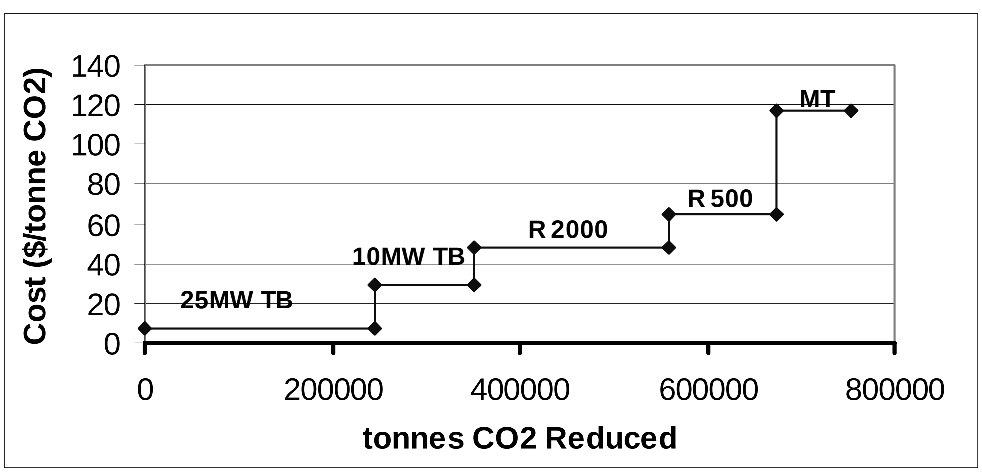
Figure 15: **Critical Value Analysis: Difference Between Cogeneration Cost and Avg. Electricity Price**



4.6. CO_2 Reduction Costs

Overall, adoption of distributed cogeneration by the commercial building sector in the GVRD would reduce cumulative CO_2 emissions by more than 750 000 t over the study period (1998-2010) relative to the separate incremental generation of electricity by CCGT's combined with regular boilers to meet thermal needs (Figure 16). 25MW turbines would diminish emissions by about 250 000t, 10MW turbines by about 110 000t, Recip 2000 engines by about 210 000t, Recip 500 engines by about 115 000t, and microturbines by about 80 000t.

Figure 16: Cost Curve for Potential CO_2 Reductions with Cogeneration



The cost of reducing a tonne of CO_2 emissions is a good measure to compare different emission reduction strategies and technologies or to indicate an appropriate CO_2 taxation or credit rate. The cost for reducing a tonne of CO_2 varies for the different cogeneration systems. Before including a CCGT T+D cost or a cogeneration grid backup fee into the analysis, all the cogeneration systems represented in this study have a net CO_2 reduction cost relative to CCGT's. The 25MW installation is the least costly at $7/t CO_2, followed by the 10MW turbine ($29/t), Recip 2000 ($48/t), Recip 500 ($65/t), and microturbine ($117/t). In order to determine the relative merit of cogeneration as a CO_2 reduction tool, these CO_2 reduction costs should be compared to other options currently being examined by governments in various provincial (GHG Forum) and national (National Climate Change Initiative) processes.

Research conducted by Taylor (1999) suggests an increasing taxation rate of $7/t CO_2 to $22.5/t CO_2 from the year 2000 to 2010 for a tentative approach to CO_2 taxation and an increasing rate of $13.75/t CO_2 to $41.25/t CO_2 for the same period for an ambitious approach. With the tentative CO_2 taxation approach only the 25MW turbine would be competitive with CCGT. With the ambitious approach, the 25MW and 10MW turbines would be competitive.

4.7. Cogeneration Implementation Costs

To illustrate the potential impact of different cogeneration systems I have listed annual CO_2 reduction, and cost of CO_2 in the year 2010 before accounting for a CCGT T+D cost or a cogeneration grid backup fee (Table 17). Of all the generators, the 25MW turbine has the greatest potential capacity (50.0 MW) and CO_2 reduction (54 375 t CO_2/yr) with both a retrofit and greenfield installation at a central district heat and power site. However, it is slightly more expensive ($0.001/ kWh_e on average) than CCGT's and would ultimately cost about $400 000/yr more.

Without accounting for a CCGT T+D cost or a cogeneration grid backup fee no cogeneration installations are economical relative to CCGT's. Total cogeneration capacity of 145MW would reduce CO_2 emissions by 134 528 t /yr at a cost $4.7 million per year.

Table 17: Cogeneration Potential at 2010

		Capacity (kW_e)	CO2 Reduced (t CO2/yr)	Cost ($/yr)
Hotel	Recip 500	2886	5926	384706
Hotel	Microturbine	9505	3329	388782
Office	Microturbine	786	419	48975
High School	Microturbine	1021	605	70604
Mall	Microturbine	4502	2666	148975
College	Recip 2000	2112	1785	84977
College	Recip 500	4274	3742	242909
College	Microturbine	1903	1127	131603
University	10MW turbine	18226	19691	568179
University	Recip 2000	4184	3535	168308
Hospital	Recip 2000	17605	14876	708270
Hospital	Recip 500	2937	2572	166967
Hospital	Microturbine	2432	1440	168183
Central Heat	25MW turbine	50000	54375	398690
Food Store	Recip 2000	15434	13041	620924
Food Store	Recip 500	4266	3735	242494
Food Store	Microturbine	2174	1287	150305
Fridge Warehouse	Microturbine	636	377	43986
TOTAL:		144884	134528	4737837
TOTAL (without Microturbines):		121924	123278	3586424

Because the microturbine is still in the prototype stage, a specific thermal efficiency has not yet been determined. The manufacturer estimated a range of 30 - 40%. A thermal efficiency as low as 30% would produce the same CO_2/ kWh_e as CCGT's. I used a thermal efficiency of 40% to calculate the microturbine's optimum potential. If the thermal efficiency of the microturbine proves to be 30% or less, then it would have little value as a CO_2 reduction tool in the commercial building sector. Total cogeneration capacity at 2010 without microturbines would be about 122MW with an estimated CO2 reduction of 123 278 t/yr at a cost of about $3.5 million per year, relative to CCGT's.

4.8. Sensitivity Analysis

4.8.1. Key Cost Variables

To test the sensitivity of the CCGT-cogeneration cost difference I chose a low, base, and high value for each of eight key cogeneration cost variables (Table 18) and individually tested the range of each cogeneration cost value while keeping the other values at base levels. Initially, I assumed that the CCGT cost would only be affected by changes in % debt financing and fuel price, and I varied these CCGT values accordingly. All other CCGT values were held constant at base values.

Table 18: Variable Range

	Low	Base	High
% debt financing	40%	50%	60%
real cost of debt	4%	5.25%	8%
ROE	15%	17%	19%
capacity factor	75%	85%	90%
capital cost	0.9	1	1.1
fuel price	0.9	1	1.1
heat rate	0.9	1	1.1
amortization	0.66	1	1.33

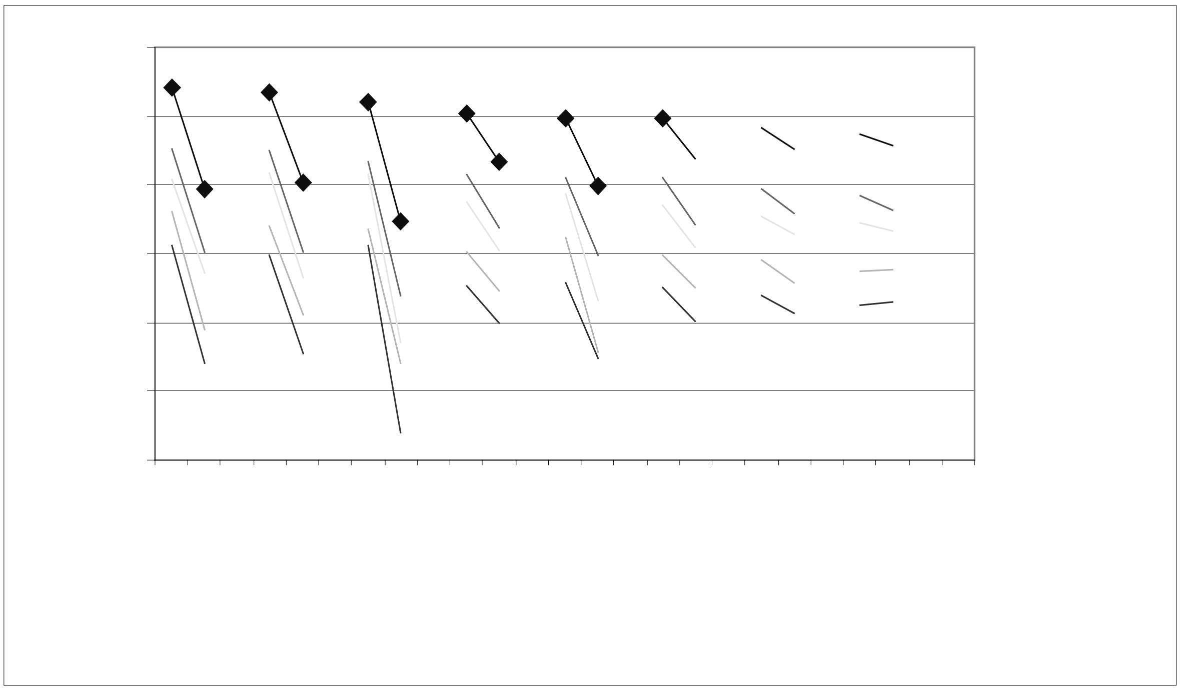
For the second sensitivity analysis, I again tested each cogeneration cost value individually while holding the other values at base levels. However, this time I also varied all corresponding CCGT cost values, not just % debt financing and fuel price. The range in CCGT values is listed in Table 19 and is proportional to that of cogeneration. For example, CCGT heat rate ranges from 6390 – 7810 Btu/kWh, from a factor of 0.9 to 1.1 of the base value, 7100 Btu/kWh.

Table 19: CCGT Variable Range

	Low	Base	High
% debt financing	40%	50%	60%
real cost of debt	4%	5.25%	8%
ROE	15%	17%	19%
capacity factor	75%	85%	90%
capital cost ($US/kW)	464	515	567
fuel price ($US/mmBtu)	1.18	1.31	1.44
heat rate (Btu/kWh)	6390	7100	7810
amortization (years)	10	15	20

The first sensitivity analysis assessed the cost relationship between CCGT's and cogeneration by testing assumptions about cogeneration cost (Figure 17), and reveals that CCGT cost exceeds or is equal to the 25MW turbine cost under several cogeneration variable assumptions (low heat rate, low capital cost, high amortization period, high debt financing, high capacity factor, and low expected return on equity). The cost of the 25MW turbine is greater than CCGT cost for the remaining variable assumptions (high and low fuel price, high and low real cost of debt, base values, high heat rate, high capital cost, low amortization period, low debt financing, low capacity factor, and high expected return on equity). CCGT cost is less than the other cogeneration units' costs for all variable ranges explored in this study. In other words, the CCGT is less expensive than all cogeneration units under all variable ranges, except the 25MW turbine under some assumptions.

Figure 17: % Difference: CCGT Cost vs. Cogeneration Cost (CCGT Base Values)



Of the range of variables explored in this analysis, the % difference in cost is most sensitive to variability in length of amortization periods, heat rate, capital cost and capacity factor, in that order. Capital cost is a significant variable because it is the largest component of total cogeneration cost. Consequently, variability in this value will have a proportionally greater impact on the cogeneration-CCGT cost difference than other cost components such as fuel and non-fuel O+M costs. Capital is also a fixed cost. When the amortization period is longer, more energy is produced with the same fixed costs. Therefore, as Figure 17 illustrates, increasing the lifetime of a cogeneration unit will have a considerable impact on total cogeneration cost, and, as a result, the cost difference. Variability in amortization periods is greatest with respect to the microturbine because it has the shortest lifetime of all the selected generators and the highest $/kWh$_e$ cost. Consequently, change in amortization

Figure 18: % Difference: CCGT Cost vs. Cogeneration Cost (CCGT Variable Values)

Consequently, if CCGT's keep pace with cogeneration technological improvements and optimum maintenance, there would be limited opportunities for improving cogeneration competitiveness. Overall industry increase in amortization periods by 33% or capacity factors by 5% would improve microturbine, Recip 500, and Recip 2000 competitiveness by about 10%. In general, most financial or technical changes that would reduce cogeneration costs, would also reduce CCGT costs, although, to a slightly lesser degree. In order for cogeneration to improve its market competitiveness, it must distinguish itself by outperforming its main competitor, CCGT, in technological improvements, enhanced maintenance systems, and capital cost reduction.

The other way to make up for the shortfall between CCGT and cogeneration costs would be to introduce a carbon credit system for CO_2

4.8.2. Weighted Average Cost of Capital

As shown in the above analyses, relative to other cogeneration and CCGT cost values, components of the weighted average cost capital calculation, such as debt financing, real cost of debt, and expected return on equity (ROE), do not have a great impact on cogeneration cost or the cogeneration-CCGT cost difference. As Figure 19 shows, cogeneration and CCGT costs are similarly affected by changes in the weighted average cost of capital, but are not highly sensitive to them. For example, an increase in the interest rate from 10% to 12% increases the cost of a 25MW cogeneration system by $0.002/ kWh_e. Costs for CCGT's and other cogeneration systems also display similar sensitivity to the weighted average cost of capital, although microturbine and Recip 500 costs are slightly less sensitive to changes in the weighted average cost of capital.

Figure 19: Sensitivity of Cogeneration and CCGT Costs to Weighted Average Cost of Capital

From a social perspective, all electricity investments should have the same the weighted average cost of capital. Nevertheless, because the government absorbs much of the risk for public projects, cost of capital is essentially subsidized. Consequently, private investment is often subject to higher the weighted average cost of capital because the rate includes a risk premium. Ig269(er)-icludes aapitare market str-7(u)1-(c)-(t)-8(u)-7(e)10( )-8(plo)12(e)-1(i)-7(sublic pcs

4.9. Barriers to Implementation

4.9.1. Existing Market Structure

Independently financed generation can not currently compete with the low BC Hydro electricity tariff. Much of BC Hydro's generating capacity comes from low cost hydro power. Investment in new capacity costs more than the tariffs, in part because a considerable amount of the debt from the development of earlier hydro projects has been amortized. BC Hydro supports its own new supply by averaging it with the low costs of existing assets. The new average price is still less than what private investors require to finance independent power projects. Thus, under the current market and tariff structure, it is unlikely that distributed cogeneration will be adopted unless it is by BC Hydro.

In a competitive market, electricity prices would likely oscillate around the long run cost of new supply (probably CCGT's). Even if there were a competitive market for electricity, cogeneration would need some type of help, such as CO_2 emission credits or a carbon tax, to make up for its higher cost relative to CCGT. Only the 25MW and 10MW turbines, and possibly the Recip 2000, with favourable value assumptions (high amortization period and capacity factor and low cost of capital and heat rate), would be competitive with CCGT's. Simply put, high capital costs could price many cogeneration systems out of consideration.

A perfect match between cogeneration electricity and thermal output and building demands are highly unlikely. A cogeneration system can be matched to a building's thermal demand; however, either too much or too little electricity will be produced. Therefore, in order for cogeneration to benefit economically from its higher fuel efficiency, small generators, like cogeneration must be able to import and export electricity to and from the grid. The current electricity market structure does permit IPP's to wheel electricity[18]; however, they are required to pay high fixed costs for transmission under the current tariff and they may have to find a purchaser outside the province. Also, there is currently no explicit backup or standby tariff for small generators. Without regulatory protection for independent operators, these economic barriers could limit investment in cogeneration, even if electricity market rates were higher. Although some independent power production is contracted for by BC

[18] To use the grid to supply power to a third party.

Hydro in the current monopoly market, IPP's often face higher costs of capital than BC Hydro. Ultimately, high capital cost, financing, bureaucratic hurdles, and cheaper investments like CCGT's discourage IPP's from considering distributed cogeneration.

4.9.2. Technical

From a technical perspective, some buildings are not well suited to cogeneration. Modifications required to retrofit cogeneration into existing sites may, in some cases, prove prohibitively expensive. Also, buildings with low or highly variable thermal demand are not good candidates for the baseload cogeneration options examined in this paper. With grid connection for import and export of electricity shortfalls or excesses, electricity to thermal demand does not have to be perfectly matched. However, if cogeneration units are less dependent on the grid, then future T+D investment will more likely be deferred, ultimately reducing net cogeneration costs relative to larger scale investments such as CCGT's.

5. CONCLUSIONS

The first objective of this study was to determine if small-scale cogeneration would be a cost competitive technology under competitive market conditions. CCGT is generally considered the marginal resource for new investment in electrical generation technology, so I used CCGT cost as a proxy for electricity price in a competitive market. If cogeneration proved to be less expensive than CCGT's then it would be cost competitive. However, there is not a straightforward answer. At first blush, the answer is no. The 25 MW turbine is almost competitive, only \$0.0011/kWh_e more expensive than CCGT. Cost difference for the remainder of the cogeneration systems varies from \$0.0042/kWh_e for the 10MW turbine to \$0.0093/kWh_e for the microturbine. The main driver for the cost difference between these technologies and CCGT is cogeneration capital cost. Capital is the largest component of total cogeneration cost, and on a unit cost basis, it is high relative to other potentially competitive generation technologies.

Nevertheless, sensitivity analysis indicates that the 25MW turbine is competitive under many value assumptions (high amortization period and capacity factor and low capital cost and heat rate). Also, costs for all cogeneration units are highly variable when subject to a range of amortization period, capacity factor, capital cost, and heat rate values. Consequently, cogeneration competitiveness would be enhanced by factors that improve technical performance (heat rate) and length of operation (capacity factor and amortization period), such as optimal maintenance and improved engineering.

Further, CCGT T+D cost and cogeneration grid backup costs were not directly considered in the analysis. If distributed cogeneration installations throughout the grid lead to significant deferral of future T+D investments and grid backup costs prove to be low, cogeneration competitiveness would also be enhanced. Critical value assessment indicated that cogeneration would be competitive if CCGT T+D cost exceeds grid backup costs by \$0.001/ kWh_e for the 25MW turbine, \$0.004/ kWh_e for the10MW turbine, \$0.005/ kWh_e for the Recip 2000, \$0.008/ kWh_e for the Recip 500, and \$0.009/ kWh_e for the microturbine.

The second study objective was to determine if adoption of selected cogeneration systems, in lieu of investment in a CCGT powered generating station would reduce CO_2 emissions. From an environmental perspective, cogeneration is a more attractive technology than

CCGT's, for it produces less CO_2 on a per kW_e basis. Reductions in the order of 135 000 t/yr in CO_2 emissions are possible in 2010 with about 145MW capacity of retrofit and greenfield distributed cogeneration in the GVRD commercial building sector. Cogeneration could be an important CO_2 reduction tool, but convincing private investors that it is an economically viable technology may require financial incentives like CO_2 reduction credits, or penalties in the form of a carbon tax.

Without including T+D costs and grid back-up costs, cogeneration would cost about $4.7 million more annually in the year 2010 relative to CCGT's. This cost is equivalent to $7/t - $117/t of CO_2 reduced, depending on the size of the cogeneration system. With a tentative CO_2 tax the 25MW turbine would be competitive with CCGT's. With an ambitious tax, the 25MW and 10MW turbines, and possibly the Recip 2000 would be competitive. Combining an ambitious CO_2 tax with a high T+D cost and/or technological improvements in amortization period, capacity factor, and heat rate might also make the smaller cogeneration units economically viable generation technologies in a competitive market.

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7. APPENDIX A - Existing Building Stock And