COMBINED HEAT AND POWER GENERATION FOR HIGHRISE CONDOMINIUMS IN TORONTO

A LOOK AT OPPORTUNITIES FOR MARKET-BASED DEMAND MANAGEMENT STRATEGIES USING DISTRIBUTED GENERATION TECHNOLOGIES IN THE MULTI-UNIT RESIDENTIAL BUILDING SECTOR

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SECTION 1: BACKGROUND AND OVERVIEW OF TECHNOLOGIES

What is Cogeneration?

Cogeneration is the simultaneous generation of heat and power, both of which are utilized. It encompasses a range of technologies, but will always include an electricity generator and a heat recovery system. Cogeneration is also known as `combined heat and power' (CHP).

The principle behind cogeneration is simple. Conventional fuel source power `generation on average is only 35% efficient, meaning up to 65% of the energy potential is released as waste heat. More recent combined cycle generation can improve this to 55% - 60%, excluding losses for the transmission and distribution of electricity. Cogeneration is a means of reducing this loss by using the waste heat for process heating as well as space heating and cooling.

In conventional electricity generation, further losses of around 15% to 20% are associated with the transmission and distribution of electricity from relatively remote power stations via the electricity grid. These losses are greatest when electricity is delivered to the smaller or more rural consumers.

Through the utilization of the heat, the efficiency of a cogeneration plant can reach 80% to 90%. In addition, the electricity generated by the cogeneration plant is typically used locally; therefore, transmission and distribution losses are negligible. Hence, cogeneration offers energy savings ranging between 15% and 40% when compared to the independent supply of electricity and heat from conventional power stations and boilers.

Because transporting electricity over long distances is easier and cheaper than transporting heat, cogeneration installations are usually sited as near as possible to the place where the heat is consumed and, ideally, are sized to meet the heat demand.

Since it is impractical to run a fuel source generator to produce only electrical energy, it is essential that waste heat utilization is maintained at a high percentage through the life cycle of the system.

HOW DOES COGENERATION WORK?

Cogeneration uses a single process to generate both electricity and usable heat suitable for space heating, domestic hot water or space cooling. The proportions of heat and power needed (heat:power ratio) vary from site to site, so the type of plant must be selected carefully and an appropriate operating regime must be established to match demands as closely as possible. The plant may therefore be designed to supply part or all of the site heat and electricity loads, or an excess of either may be exported if a suitable customer is available.

A typical cogeneration plant consists of four basic elements:

- a prime mover (engine);
- an electricity generator;
- a heat recovery system;
- a control system.

Depending on site requirements, the prime mover may be a reciprocating engine, steam turbine, gas turbine or micro turbines and fuel cells. The prime mover drives the electricity generator and usable heat is recovered.

Cogeneration plants are available to provide outputs from 30 KW to 500 MW. For larger scale applications (greater than 1 MW) there is no "standard" cogeneration kit: equipment is specified to maximize cost-effectiveness for each individual site. For small-scale cogeneration applications, equipment is normally available in pre-packaged units, helping to simplify installations.

Cogeneration is an established technology. Its ability to provide a reliable and cost-effective supply of energy has been proven. Indeed cogeneration has been used since the start of the 20th century, and properly designed systems can operate for at least 20+ years. Cogeneration is currently used on thousands of sites throughout the world.

In the last 10-15 years, significant technological progress has been made to enable engine and turbine technology to be widely implemented and promote more decentralized forms of cogeneration and power generation. Cost-effectiveness and decreasing emissions have also resulted from recent technological advances. There are an increasing number of varied applications in commercial and residential areas and which can be used in heating and cooling applications.

APPLICATIONS SUITED TO COGENERATION

Cogeneration has a long history of use in many types of industry, particularly in the paper and bulk chemicals industries, which have large concurrent heat and power demands. In recent years the greater availability and wider choice of suitable technology has meant that cogeneration has become an attractive and practical proposition for a wide range of applications. These include the process industries, commercial and public sector buildings and district heating schemes, all of which have considerable heat demand. These applications are summarized in the table below.

Possible opportunities for application of cogeneration

Facilities

- District heating
- Hotels
- Hospitals
- Leisure centres and swimming pools
- College campuses and schools
- Airports
- Prison and detention facilities
- Office buildings
- Highrise residential buildings

Industrial

- Pharmaceuticals and fine chemicals
- Paper and board manufacture
- Brewing, distilling and malting
- Ceramics
- Brick
- Cement
- Food processing
- Textile processing
- Minerals processing
- Oil refineries
- Iron and steel
- Motor industry
- Horticulture and glasshouses
- Timber processing

THE BENEFITS OF COGENERATION

Provided the cogeneration is optimized in the way described above (i.e. sized according to the heat demand), the following benefits arise:

- Lower emissions to the environment, in particular CO_2 and NO_x
- Reduced burden on existing limited fossil fuel supplies and positive stabilization of future fuel supply.
- Significant operating cost savings, while providing additional competitiveness for industrial and commercial users, and offering affordable heat for domestic users.
- Capability to implement energy conserving management schemes such as peak shaving, demand limiting and peak demand reduction during market peaks.
- An opportunity to move towards more decentralized forms of electricity generation, where plant is designed to meet the needs of local consumers, providing high efficiency and avoiding transmission losses.
- Improved local and general security of supply – local generation, through cogeneration, can reduce the risk that consumers are left without supplies of electricity and/or heating.
- Cogeneration provides one of the most important vehicles for promoting liberalization and competition in energy markets.
- In some cases, where there are biomass fuels and waste byproducts such as refinery gases, process or agricultural waste (either anaerobically digested or gasified), these substances can be used as fuels for cogeneration schemes, thus increasing the cost-effectiveness and reducing the need for waste disposal;

<u>Energy and cost savings</u>

A well-designed and operated cogeneration scheme will always provide superior energy efficiency than conventional generating plants leading to both energy and cost savings. A single fuel is used to generate heat and electricity, so cost savings are dependent on the price-differential between the primary energy fuel and the purchased electricity that the scheme displaces (the so-called "spark spread"). However, although the profitability of cogeneration generally results from its cheap electricity, its success depends on using recovered heat productively, so the prime criterion is a suitable heat requirement. As a rough guide, cogeneration is likely to be suitable where there is a fairly constant demand for heat for at least 2900 – 3000 hours per year.

The timing of the site's electricity demand is important since the cogeneration installation will be most cost effective when it operates during periods of high electricity charges typically found in the afternoon and early evening.

Based on current fuel prices and electricity costs, and allowing for installation and life-cycle maintenance costs, payback periods of four to five years can be achieved on many cogeneration installations.

Environmental savings

By displacing older inefficient poor quality combustion plants such as coal-fired facilities, cogeneration yields significant environmental benefits by using fossil fuels more efficiently. In particular, it is a highly effective means of reducing carbon dioxide (CO_2), sulphur dioxide (SO_2), and oxides of nitrogen (NOx). This is particularly the case in Ontario, where coal is a significant fuel.

Savings in carbon dioxide (the main greenhouse gas) can vary from 100 kg per MWh to more than 1000 kg MWh, depending on the type of electricity generation and age of facility.

If we assume that most new cogeneration will be gas-fired at least for the next 10 years, then a gas-fired reciprocating engine with waste-heat-boiler will produce the following savings.

CO_2 Savings[*]

Gas turbine with waste heat boiler	
Heat to power ratio	1.6
Efficiency	80%
Emissions of CO_2 per unit of fuel	225 g/kWh
Emissions of CO_2 per kWh of electricity	581 g/kWh

If it is assumed that cogeneration displaces electricity from a mix of fuels and heat from a boiler with a mixed type of fuels, then the savings per kWh will be 615 g/kWh.

NOx and SO_2 savings

To calculate NOx and SO_2 savings, the same principles apply. It is necessary to look at what type of facility is being displaced. For instance, the following savings can be achieved by a gas reciprocating engine with a waste heat boiler.

Boiler replaced	**NOx**	**SO_2**
Coal boiler	2.9 g/kWh	23.2 g/kWh
HFO boiler	2.9 g/kWh	23.4 g/kWh

[*] These values are further refined in the report provided by ICF International which is cited in the condominium pilot study and appended to the end of this document.

THE ECONOMICS OF COGENERATION

In areas where a de-regulated electricity market reflects significant price fluctuations during peak demand periods, cogeneration can usually be developed more feasibly than in markets where regulated ratios are set. In 2003, many of the barriers to further development of cogeneration were removed. However, subsidized or artificially suppressed market pricing continues to hinder progress in promotion of this technology. This includes:

- Low peak ratios for surplus cogenerated electricity sold to the grid;
- Potentially severe charges for standby power and, in particular, back-up power supply;
- Regulatory restrictions to exporting power (third party access) or, when allowed, too expensive to consider;
- Cogeneration schemes need to fulfill certain technical and safety requirements for proper operation and approval by regulatory bodies. Sometimes the procedures take too long and are not transparent enough.

Environmental costs are almost never included in the regulated energy market pricing, but impose significant cost on private distributed energy.

In a liberalized market, these traditional barriers will not exist and cogenerators are free to sell to any customer. Provided the market is properly structured, cogeneration can provide the most cost-effective option for producing electricity when the savings from heat utilization are taken into account.

Due to the long term commitment required of the need to take a relatively medium term view (cogeneration is a relatively expensive capital investment), volatility and uncertainty in energy markets, prices may deter potential investors. The economics of cogeneration are sensitive to, and dependant upon, the level of energy prices, and the difference between the price of the fuel used by the prime mover, and the value of the electricity and heat that is generated. Evaluating the impact of price changes requires clear and transparent policies in the regulation and operation of energy markets, ultimately leading to relative stability and predictability of energy prices.

In the long term, provided policy makers make the necessary fine tuning to correct the market where needed, the problems mentioned above should be solved, and cogeneration will have a good future.

COGENERATION TECHNOLOGIES

Cogeneration has long been deployed in energy intensive industries that have large concurrent heat and power demands. The most commonly used system for these applications was traditionally the steam power generating cycle, using steam turbines which allowed exhaust steam to be used for process heating.

Intensive developments over the past two decades have made a wide variety of equipment available, enabling cogeneration packages to be matched accurately to site requirements. This has broadened the market to include a wider variety of facilities and applications.

Small-scale cogeneration schemes, usually designed to meet space and water heating requirements in buildings, based on spark or compression ignition reciprocating engines, are best suited to residential, commercial and light industrial applications.

Large-scale cogeneration schemes, usually associated with steam raising in industrial and very large building applications, are usually based on compression ignition reciprocating engines, steam turbines or gas turbines.

Cogeneration units are generally classified by the type of prime mover (i.e. drive system), generator and fuel used. The following sections examine the main types of cogeneration unit and the factors affecting their use and application.

For purposes of this study, we will focus on the reciprocating engine technologies and application.

The reciprocating engines used in cogeneration are internal combustion engines operating on the same principles as their gasoline and diesel engine automotive counterparts. Although conceptually the system differs very little from that of gas turbines, there are important differences. Reciprocating engines give a higher electrical efficiency, but it is more difficult to use the thermal energy they produce, since it is generally at lower temperatures and is dispersed between exhaust gases and engine cooling systems.

There are two types of engine, classified by their method of ignition:

<u>Spark-ignition engines</u> are derivatives of their diesel engine equivalents and have provided 90ºC cooling water as a heat source typically. They can also use exhaust gases for heat recovery purposes, thus plants can be built with hot water or low grade steam output.

Traditionally, shaft efficiency is lower that for compression ignition engines, at between 27% and 35%, and the output range is limited to a maximum of around 5 MW. The output of a spark-ignition engine is little smaller, typically 80% of the diesel engines, because of the possibility of knocking.

They are suited to smaller, simpler cogeneration installations, often with cooling and exhaust heat recovery cascaded together with a waste heat boiler providing medium or low temperature hot water to site.

Spark-ignition engines operate on clean gaseous fuels, natural gas being the most popular. Biogas and similar recovered gases are also used but, because of their lower calorific value, output is reduced for a given engine size. Spark-ignition engines give up less heat to the exhaust gases (and correspondingly more to the cooling system) than diesel engines.

The following are among the most common applications for the thermal energy produced by reciprocating engines:

- production of up to 15 bar steam utilizing the heat of exhaust gases; and separate production of hot water at 85-90ºC from the cooling system of the engine;

- production of hot water up to 100ºC, supplementing the temperature of cooling system water with heat from gases;

- generation of hot air. All the residual energies from the engine can be used, through the installation of suitable exchange devices, for the generation of hot air.

Reciprocating machines by their nature have more moving parts, some of which wear more rapidly than those in purely rotating machines. Shutdown maintenance is usually provided by the manufacturer at much shorter intervals. Nevertheless, typical availability is about 90-96% - according to the Statistics from the North American Electric Reliability Council 1999. Average availability is above 94-96%, when machines are run at slower speeds since they require less frequent maintenance. However, there is a penalty since the overall size and weight of the engines are greater for a given rating.

The comparative maintenance costs of gas turbines and reciprocating engines are much debated. There is unlikely to be a consensus until a larger body of cogeneration operating experience enables a truly realistic assessment of lifetime running costs to be obtained.

In the absence of the emissions legislation, reciprocating engines have generally been tuned to maximize power and efficiency. The operating regime occurs with a slightly over stoichiometric air/fuel ratio and produces relatively high NO_x emissions.

NO_x emissions can be reduced markedly by operating with a large excess of combustion air (lean-burn). However, this has an adverse effect upon the engine's power output and ultimately, at higher excess air levels, leads to increase CO and unburned hydrocarbons, combustion instability and misfire. Power output is typically compensated by use of turbocharging.

As with gas turbines, SCR is used for highly special applications where ultra low NO_x emissions are required. This technology can be used in conjunction with particulate filters to produce relatively clean emissions even in diesel gensets.

Compression-ignition (`diesel') engines for large-scale cogeneration are predominantly four-stroke direct-injection machines fitted with turbochargers and intercoolers. These engines will accept diesel, natural gas and a mixture of both diesel and natural gas in the case of a bi-fuel unit. Shaft efficiencies are 35 to 45%, and output range is up to 15MW. Cooling systems are more complex than spark-ignition engines and temperatures are often lower, typically 85ºC maximum, thereby limiting the scope for heat recovery. Compression-ignition engines run at speeds of between 500 and 1800.

Modern engines use delayed ignition timing and increased compression ratios to limit NO_x formation while maintaining high levels of power output and efficiency. This requires sophisticated fuel injection and engine management system.

Although gas engines can be designed to achieve relatively low emissions through primary reduction methods (i.e. limiting NO_x formation within the engine) larger compression ignition engines are often fuelled by heavy fuel oil. De- NO_x treatment of the exhaust gases is then required to reduce emissions to acceptable levels. This is normally achieved by use of SCR (Selective Catalytic Reduction) using either ammonia or urea as reaction agent.

Microturbines

Manufacturers are developing smaller and smaller microturbine systems with packaged units as small as 25 KW. In general, microturbines can generate anywhere from 25 KW to 200 KW of electricity. Microturbines are small high-speed generator power plants that include the turbine, compressor, generator, all of which are on a single shaft as well as the power electronics to deliver the power to the grid. Microturbines have only one moving part, use air bearings and do not need lubricating oil. They are primarily fuelled with natural gas, but they can also operate with diesel, gasoline or other similar high-energy fossil fuels including bio-gas.

Microturbines are smaller than conventional reciprocating engines, and capital and maintenance costs are lower. There are environmental advantages, including low NO_x emissions of 10-25 ppm (O_2 – 15% equivalent) or lower.

Microturbines can be used as a distributed generation resource for power producers and consumers, including industrial, commercial and residential users of electricity. Significant opportunities exist in five key applications:

- Traditional cogeneration,
- Generation using waste and biofuels,
- Backup power,
- Remote power for those with "Black Start" capability,
- Peak Shaving.

Fuel cells offer a combination of performance and environmental advantages for on-site cogeneration:

- Their high efficiency is not compromised by small size and they operate high efficiency at low load;

- They have few moving parts and are not susceptible to wear-and-tear arising from the need to convert explosive combustion into mechanical energy;

- This provides reliable operation combined with infrequent servicing intervals, reducing maintenance costs and interrupted poser supply associated with conventional plant,

- Siting flexibility allows by-product heat to be used, doubling energy efficiency.

A number of different types of fuel cells are being developed. The characteristics of each type are very different: operating temperature, available heat, tolerance to thermal cycling, power density, tolerance to fuel impurities etc. They are also in very different stage of development and some of them have not emerged from the laboratory. Some are approaching commercial breakthrough, however, the capital costs will be prohibitive until wide-spread use becomes more common.

Waste Heat Recovery Units

The heat recovery boiler is an essential component of the cogeneration installation. It recovers the heat from the exhaust gases of gas turbines or reciprocating engines. The simplest one is a heat exchanger through which the exhaust gases pass and the heat is transferred to the boiler feedwater to produce hot water or steam. The cooled gases then pass on the exhaust pipe or chimney and are discharged into the atmosphere. In this case, the composition or constituents of the exhaust gases from the prime mover are not changed.

The exhaust gases contain significant quantities of heat, but not all can be recovered in a boiler. Several factors prevent this:

- For effective heat transfer the temperature of the exhaust gases must remain above the temperature of the fluid to be heated. A minimum practical temperature difference of 30ºC is typical;

- The exhaust gases must not be cooled to a temperature at which their buoyancy prevents them from rising from their point of discharge into the surrounding atmosphere, thereby ensuring proper dispersion of the gases under all weather conditions.

- The exhaust gases must not be cooled to a temperature at which acid condensation could occur. This risk is associated particularly with the combustion of oil fuels that contain some sulphur, as this can be condensed into sulphuric acid below certain temperatures.

- The latent heat of the water vapour in the exhaust gases can only be recovered by reducing the exhaust gas temperature to below 100ºC, at which point the water vapour will condense into liquid form and release its latent heat. Boilers designed to do this are more efficient, but the three previous constraints still apply, limiting the applications for this technique.

One typical feature of the exhaust heat boiler (or waste heat recovery unit) is that the typical size is bigger than a conventional fuel-burning unit. This is for two main reasons:

- The lower exhaust gas temperatures require a greater heat transfer area in the boiler;
- There are practical limitations on the flow restriction. Excessive flow resistance in the exhaust gas stream must be avoided as this can adversely affect operation of the turbine or engine.

Exhaust heat boilers are not, therefore, `off-the-shelf' items: they need to be designed for the particular exhaust conditions of the specified turbine or engine. The usual procedure is to provide the boiler supplier with details of the exhaust gas flow from which the heat is to be recovered, and with the temperature and pressure conditions of the required heat output. The boiler supplier will then be able to advise on the quantity of heat that can be recovered, and the temperature at which the exhaust gas will be discharged from the boiler.

A method commonly used to maximize heat recovery in an open-cycle system is to install an economizer as a heat exchanger in the flue gas stream leaving the boiler. The relatively cool boiler feedwater is passed through tubes within the economizer, recovering heat whilst cooling exhaust gases to 120ºC or less. Economizers are also used with high-pressure boilers installed for steam cycle cogeneration. Where hot water is required, say at 60ºC, the economizer may be replaced or followed by a condensing economizer (another heat exchanger) to heat the water while cooling flue gases to 80ºC. This may only be used on systems using natural gas, as there is no sulphur present in the fuel, so the risk of acid corrosion is minimized.

<u>Generators</u>

Generators convert the mechanical energy in the rotating engine shaft into electricity. They can be either synchronous or asynchronous.

A synchronous generator can operate in isolation from other generating plants and the grid. This type of generator can continue to supply power during grid failure and so can act as a standby generator.

An asynchronous generator can only operate in parallel with other generators, usually the grid. The unit will cease to operate if it is disconnected from the mains or if the mains fail, so they cannot be operated as standby units. However, connection and interface to the grid is simple.

Synchronous generators with outputs below 200 KW are usually more expensive than asynchronous units. This is because of the additional control, starting and interfacing equipment that is required. In general, above 200 KW output the cost advantages of asynchronous over synchronous types disappear. There is a trend however, to use synchronous generators even on cogeneration units with low power output.

ADVANTAGES AND DISADVANTAGES OF EACH SYSTEM

This section simply lists the main advantages of each of the prime mover options for cogeneration.

	Advantages	***Disadvantages***
Reciprocating Engines	• High power efficiency, achievable over a wide load range. • Relatively low investment cost per KW electrical output. • Wide range of unit sizes from 5 KW upward. • Part-load operation flexibility from 30% to 100% with high efficiency. • Can be used in island mode, good load following capability. • Fast start-up time of 15 second to full load (gas turbine needs 0.5 – 2 hours). • Real multi-fuel capability can also use HFO as fuel. • Can be overhauled on site with normal operators. • Low investment cost in small sizes. • Can operate with low-pressure gas (down to 1 bar).	• Must be cooled, even if the heat recovered is not reusable. • Low power:weight ratio and out-of-balance forces requiring substantial foundations and vibration isolation. • High levels of low frequency noise. • High maintenance costs.
Gas Turbines	• High reliability which permits – long term unattended operation. • High grade heat available. • Constant high speed enabling – close frequency control of electrical output. • High power:weight ratio. • No cooling water required. • Relatively low investment cost per KW electrical output. • Wide fuel range capability (diesel, LPG, naphtha, associated gas, landfill sewage). • Multi fuel capability. • Low emissions.	• Limited number of unit sizes within the output range. • Lower mechanical efficiency than reciprocating engines. • If gas fired, requires high pressure supply or in-house boosters. • High noise levels (of high frequency can be easily alternated). • Poor efficiency at low loading (but they can operate continuously at low loads). • Can operate on premium fuels but need to be clean and dry. • Output fails as ambient

	Advantages	***Disadvantages***
		temperature rises due to thermal constraints within the turbine. • May need long overhaul periods.
Micro Turbines	• High reliability due too small number of moving parts. • Simplified installation. • Low maintenance requirement. • Compact size. • Light weight. • Acceptable noise levels. • Fuelled by domestic natural gas resource with expanded fuel flexibility. • Competitive costs when built in quantity. • Low emissions. • High temperature exhaust for heat recovery. • Acceptable power quality.	• Costs, lack of qualified service personnel. • Extended downtime potential.
Fuel Cells	• Low emissions and low noise. • High efficiency over load range. • Modular design, siting flexibility, short construction time. • Automated operation, quick load changes, low maintenance. • Many fuels, but require processing unless pure hydrogen. • Flexible heat to power ratio. • Low or high-grade heat, depending on design and fuel cell type.	• Costs, durability, power density, start-up time, degradation. • Poor part load characteristics. • Long re-start times. • Long downtimes.

INSTALLATION CONSIDERATIONS

Heat : Power Ratio

The ratio of heat to power required by a site will vary during different times of the day or seasons of the year. Importing power from the grid will supplement the shortfall in electrical output from the co-generation unit, while gas-fired boilers will typically supplement the thermal output during peak demand periods.

Proper sizing and sequencing operation of the co-generation plant is somewhat complex since it is affected by many conditions that must be simultaneously met. Among this criterion is the following:

- The spot market price for electricity.
- The thermal load in the facility.
- The variety of heat synes available at any given time.
- The market price of the fuel source, i.e.: natural gas.
- Environmental restrictions – emissions and noise.

All of the above factors influence the heat to power ratio and effective utilization rate of the cogeneration plant. Since many of these factors are variable in nature, it is essential that advanced controls be utilized in order to track the fluctuations and calculate optional start/stop of the system in order to maximize the net return on investment.

Operating strategies

For cogeneration plant there are three main operating regimes:

- The unit is operated to provide base load electricity and thermal output; any shortfall is supplemented with electricity from the public supply, and heat from stand-by boilers.

- The unit is operated to provide electricity in excess of the site's requirements, for export, whilst all the thermal output is used on site.

- The unit is operated to provide electricity for site, with or without export, and the heat produced is used on site with the surplus being exported to off-site customers.

One further option exists in which the cogeneration unit is operated primarily to provide electricity either for site use or for export, in conjunction with thermal trimming. Under these circumstances, excess thermal output is dumped (i.e. rejected to atmosphere via heat exchangers). However, the proportion of heat dumped reduces the overall efficiency of the plant. This type of scheme is a sub-optimal solution generally applicable only when electricity prices are extremely high.

Connection to the Public Supply

Cogeneration systems are most often designed to operate in parallel mode, i.e. with the generator connected alongside the public supply network. This enables the import of power to supplement that generated on site and the export of power surplus to site needs. Both the public system and the cogeneration plant need to be protected against disturbance of supply caused by the parallel system. There are mandatory requirements for the provision of protective controls and procedures.

It is vitally important that the installed power plant is able to remain stable, i.e. to maintain synchronism when disturbed by load changes and system faults. A detailed evaluation of site electrical loads is an essential part of the initial design study. This will include analysis of switchgear and transformers, operational sequences, load flows and fault levels (i.e. the maximum current that can flow under a 3-phase short circuit condition).

It may be advantageous for some systems to be able to operate in island mode, that is, entirely independently of the public supply system. In particular, island mode enables the system to continue operating during times of public supply failure (a parallel-only installation shuts down with the grid). The proportion of the site capable of operating under island mode depends on installed capacity and its characteristics. The practicalities of this mode of operation need to be carefully considered, as it may require load-shedding controls that will add to the cost of the installation.

Standby Power and Cogeneration

Cogeneration plant can be integrated with standby electrical plant but this is a complex issue and again requires careful thought and detailed understanding of the plant or process being supplied. In many cases integration may not be cost-effective option, especially for small-scale applications. However, the use of cogeneration plant as full or partial standby can be significant advantage and, for some sites, has been one of the deciding factors in choosing cogeneration.

In cases where cogeneration alone is to provide the standby requirement, sufficient plant capacity must be provided to ensure security of life safety within the facility.

SITE APPRAISAL

To properly identify potentially viable projects, it is necessary to pre-screen candidate sites in stages to avoid incurring substantial posts prior to qualification.

This should begin with an initial appraisal to determine whether it is worth committing the resources necessary to undertake a detailed feasibility study.

If the initial appraisal shows that, in principle, cogeneration is a viable option for the site, then a second stage detailed technical appraisal should be undertaken. The study should be based on careful analysis of site energy usage and demand to enable appropriate, cost effective designs and specifications. It should also examine the effects of plant optimization, export of electricity and integration or displacement of existing standby plants. At this stage, it is worth contacting the relevant regulatory agencies to determine any restrictions or possible hindrances due to environmental or safety related issues.

Prior to implementation, several important factors should be taken into consideration.

1) Is there a simultaneous base load requirement for electricity and heat which will allow sufficient hours of operation to justify the capital expenditure?

2) Is there suitable access and space for a cogeneration unit and is the location suitable with respect to other site functions (e.g. noise and exhaust)?

3) Is there a suitable fuel supply?

4) Are there any site changes/developments or expansions planned that could have possible effects on the cogeneration sizing/economics?

5) Is there a requirement to upgrade any part of the existing heating system, electrical distribution or control system as a result of the cogeneration installation?

6) Is the proposed heat sync and/or electrical distribution system near to the proposed cogeneration location?

7) Have all other energy saving measures been identified and either implemented or taken into consideration?

8) Is there adequate space available for ventilation and venting?

Site Energy Profiles

If the initial assessment suggests that it is worth proceeding further, then detailed investigatory work will have to be undertaken and resources allocated. Whether this work is undertaken in consultation with equipment suppliers, consultants or ESCOs is a matter of choice depending on financial and human resource availability.

The starting point for all detailed cogeneration feasibility studies is to gain an accurate assessment of the electrical and thermal load profiles.

Electrical load profiles can be relatively easy to determine using existing utility bills and hourly load modeling. If more detailed or equipment specific information is required, data loggers can be installed.

Thermal loads are more difficult to measure accurately. However, the importance of gaining an accurate understanding of the thermal load cannot be over-stated. A number of existing cogeneration systems have not achieved their anticipated savings because the plant was inaccurately modeled, sometimes on the basis of existing installed boiler capacity. For the correct specification of cogeneration, the peak thermal demand of the site is of much less importance than the base load profile. Cogeneration is generally only cost effective if a sufficiently large heating or cooling requirement exists for most of the running hours.

In addition to load profiling, it is essential to identify coincidental electrical market pricing in order to establish an accurate and usable operating scheme. Operating a cogeneration plant in the middle of the night simply because there is a thermal demand is impractical and irresponsible.

Correct sizing of the cogeneration unit is essential to the viability of the installation. Furthermore, the correct sizing and choice of the prime mover is only possible if the heat and electricity demands are clearly defined, and threshold values are established for automated operation based on a combination of energy rates and thermal usage.

One final important point, cogeneration should not be sized based on grossly inefficient use of energy on the site. During the evaluation phase opportunities for reducing the site energy demand should be identified. Those that are cost-effective should be implemented.

Capital Cost

This is the expenditure required for the establishment of an operational cogeneration plant on the site, and is comprised of the following:

- Engineering design; compliance with planning and building regulations, environmental requirements, fire prevention and protection etc., and external professional services engaged to handle these matters;

- Cogeneration unit(s) and associated plant, installed, tested and commissioned;
- Fuel supply, storage and handling;
- All associated mechanical and electrical services, installed and commissioned;
- Any new buildings, modification to existing buildings, foundations and support structures;
- Commissioning, maintenance and service costs including spare parts;
- Interconnection with electrical distribution, safety controls and automation systems.

Prices are obtained from the appropriate manufacturers, suppliers, contractors and engineering consultants and added together to arrive at a “first cut” capital cost. Avoided costs, i.e. those for plant and services which would have been replaced in any case, should be identified so that the marginal cost of cogeneration can be derived.

Capital costs typically vary from $1,000 per kW for larger systems to more than $1,800 per kW for small plants depending on the choice of cogeneration plant and auxiliaries required.

For gas turbine and large reciprocating engine cogeneration plant, the prime mover/generator package and associated equipment (auxiliary systems, gas compressor and back-up distillate fuel storage) frequently represent 50 – 65% of the total installed cost. The heat recovery equipment (heat recovery boiler and heat exchangers) and associated equipment (water treatment plant, boiler pumps) can account for a further 15% to 25% of the costs. Electrical switchgear and protection equipment amounts to 10% to 20% and the balance is attributable to design, project management and installation (including piping, civil and building works).

Small-scale cogeneration plants based on spark ignition gas engines and dual-fuel diesel engines tend to be marketed as complete packages including baseframe, generator, heat exchangers and control equipment, accounting for 50% to 60% of the total installed costs.

<u>Operating Costs</u>

Costs of operating a cogeneration plant includes:

- Fuel for the prime mover, and for supplementary and auxiliary firing if applicable;
- Labour for operating and servicing the plant;

- Maintenance materials and labour, including scheduled maintenance carried out by the manufacturers. As some scheduled component replacements are often at long intervals, maintenance costs should preferably be averaged over five years;

- Consumables, e.g. lubricating oil, water treatment chemicals

- Possible standby charges

- Fuel consumption costs will vary greatly depending on the type of equipment and the size of the plant. Larger systems will typically be more efficient with operating costs ranging between \$0.12 and \$0.14/kWH. Smaller systems such as microturbines or automotive derivatives will cost approximately \$0.13 - \$0.15/kWH.

Typical maintenance costs are approximately \$0.008 - \$0.012/kWH for reciprocating engine cogeneration, and \$0.012 - \$0.015/kWH for microturbine systems.

<u>Savings</u>

Savings are obviously site specific and influenced by many factors. Maximizing the savings requires effective engineering and design in addition to cost control measures during construction and finally, an optimized operating strategy that can take full advantage of peak operating conditions.

This will ensure the system operates as many hours as possible throughout the year, and will provide the highest positive net cashflow, which will in turn produce the best rate of return on investment.

Also, proper maintenance and monitoring of the system will ensure the cogeneration plant always operates at peak efficiency while producing the lowest emissions.

<u>Overall Economics of Cogeneration Projects</u>

Under favorable circumstances cogeneration projects can result in simple payback periods of 5 – 7 years. The economics of cogeneration projects are much more sensitive to changes in electricity price than to changes in fuel price; for example a 10% increase in electricity prices might reduce the payback period by 15% whereas a 10% reduction in fuel price would reduce the payback period by only 6%.

Factors favouring short payback periods include:

- low investment cost;
- low fuel price;
- high electricity price;
- high annual operating hours;
- high overall thermal efficiency.

FINANCING COGENERATION

Although cogeneration is a long-term investment, with equipment lifetimes of up to forty years, in most cases it has to compete with other potential energy projects that can yield more returns. In addition, since cogeneration is not considered to be a core energy plant, it receives a lower priority. These factors may fall outside a company's investment criteria for a utility plant or alternative methods of financing often need to be investigated if cogeneration is to be implemented.

The source of finance, ownership and degree of risk are the main factors to be taken into account. If financed by direct capital injection using equity funds, debt or a combination of both, the purchaser takes on full ownership and risk. The risk will normally be offset by the terms of contract negotiated with all relevant parties.

OWNERSHIP, OPERATON & MANAGEMENT

The complexities associated with the timing and integration of cogeneration systems suggests that such systems may be beyond the administrative capabilities of Condominium Corporations. Instead, in order to ensure timely responses to price signals in the Provincial energy network, and to be sure that equipment is properly maintained, an optimal ownership structure would involve a third party entity. If such an entity is able to aggregate multiple assets across different sites, then economies of scale – in terms of operations and maintenance, as well as financing – could significantly improve the business case and individual project economics.

Under a Design-Build-Own-Operate (B-O-O) structure, a third party energy management company would work with a property developer at the earliest stages of project design to offer value added infrastructure and services. Negotiations with the developer should include re-allocation of sunk capital costs that would need to be spent on equipment that will be replaced by the cogeneration system. For instance, in order for the economics to work, the developer should be prepared to make capital contributions to the cogen project based on the avoided costs of equipment such as emergency back-up generator(s) and reduced boiler plants. Bilateral negotiations between district utility companies and developers are not uncommon, as evidenced by Tridel's successful negotiations with Markham District Energy and Enwave in downtown Toronto.

SECTION II: COGEN OPPORTUNITIES IN THE CONDOMINIUM MARKET

In late 2005, The Conservation Bureau of the Ontario Power Authority and the Toronto Atmospheric Fund provided support to the Toronto and Region Conservation Authority (TRCA) to evaluate the feasibility of incorporating cogeneration into new condominium construction in Toronto. The Tridel Group, a Toronto-based condominium developer, managed the project and provided a pilot project opportunity. Provident Energy Management provided data on a representative sample of existing condominiums.

The Study contained two parts. Part I examined a sample size of highrise condominiums built by Tridel within the last decade. Part II involved costing, designing and modeling a full-scale integration of a cogeneration system in a new highrise construction project.

The rational for splitting the study into two components is twofold: 1) The review of empirical data concerning power and hot water consumption in existing buildings can reveal patterns that are important for understanding the costs, benefits and operating cycles of a new installation; and 2) The number of existing condominium towers in the City of Toronto offers potentially significant cogeneration retrofit opportunities.

Rationale for focusing on the highrise multi-unit residential (MURB) sector

According to data collected by CMHC, highrise residential buildings use the most energy per square meter (see chart) when compared to other housing types. Several structural and practical reasons explain this:

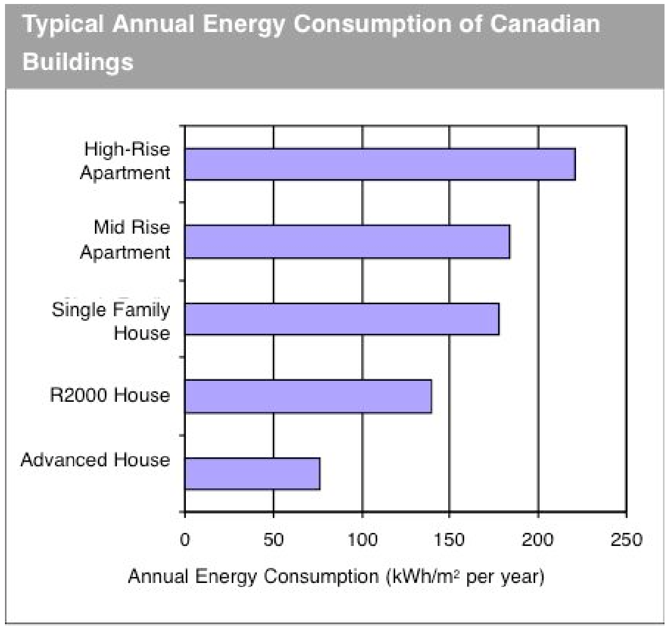
- MURBs illuminate corridors between dwellings; whereas municipal streetlights illuminate distances between single family dwellings.

- MURBs have very high ventilation requirements to provide conditioned fresh air and make-up air for exhaust fans and appliances. While it is possible to control these systems, it is neither practical – nor allowable – to turn them off, as a homeowner could do when the dwelling is not occupied.

- MURB residents must rely on elevators for conveyance.

- Most major building systems (particularly common area lighting and HVAC) operate 24 hours per day, 7 days per week; whereas most single-family homeowners are able to turn their lights off and adjust their thermostats during the day.

TABLE 1: Energy Consumption in Residential Buildings



Source: CMHC The Healthy High-Rise

Many of the services that provide comfort and convenience in the highrise residential setting can be improved through more efficient design. Appropriate controls (variable speed drives and thermostats) can regulate energy consumption of equipment while it is in use. However, for safety and code related reasons, it is simply not practical to turn such equipment off during periods of lower occupancy periods.

These characteristics of highrise dwellings practically guarantee a significant amount of electricity will be consumed around-the-clock, a particularly high demand will occur during the late afternoons in summer when air conditioning loads are greatest.

The reality of large base electricity loads, including predictable loads during peak periods, creates an advantage for on-site electricity production and offers benefits to the key constituencies: condominium residents and the Province. The residents can benefit from predictable pricing, and the Province benefits from offsetting critical loads.

Multi-unit residential buildings have consistent and predictable Domestic Hot Water loads. However, as this study revealed, peak periods of electricity use are not entirely coincident with high demand for hot water (especially in the morning). By offering a repository for waste heat and a service that would require natural gas consumption, combined heat and power plants in or near a highrise residential building creates a second-tier of benefits for this sector. It also improves the economics significantly.

Condominiums represent a rapidly growing share of the homeowner market

An important justification for exploring peak demand reduction strategies in the highrise condominium context lies in the fact that highrise condos have become a dominant form of housing in the Greater Toronto Area, Ontario's most rapidly expanding population centre. The area will be home to over 1 million new residents over the course of the next ten years, placing additional demands on the energy sector.

At the same time, one of the best ways to influence Ontario residents when it comes to energy use is to reach them where they live. Electricity costs have a direct impact on homeowners – as opposed to office workers who are not responsible for paying the bills on their energy consumption. Condo owners in particular are concerned about rising utility costs. Energy costs represent approximately 40% of the monthly Common Element Assessments that are levied against each condo dwelling on a pro rata basis.

PART I: Review of Existing Buildings

Cogeneration Technology

Following a brief review of the various technologies available, we settled on the reciprocating gas engine as the best approach for this application. This conclusion was largely based on the robustness and reliability of the technology, but also on price and scale. Smaller scale applications could do well with microturbines, provided they factor in the need to provide high pressure gas.

Building Selection

Provident Energy Management identified six buildings constructed in the last decade and provided gas and electricity data to Energy Profiles Limited for analysis. The six buildings had properties characteristic of Tridel's typical construction. For the most part, the buildings contained:

- Over two hundred suites
- In-suite fan coils connected to central boilers and chillers
- Recreation facilities and common areas

One important difference between these sample buildings and new Tridel projects concerns the energy efficiency of their design and construction. As of 2005, Tridel's new projects will all be at least 25% more efficient than the Model National Energy Code for Buildings. This translates into higher performance equipment in the new buildings. The difference in the efficiency ratings of equipment (and possibly envelope) will have an adverse impact on the economics of on-site power generation. Comparing buildings with low efficiency gas boilers, for example, and buildings with high efficiency gas boilers reduces the net savings available.

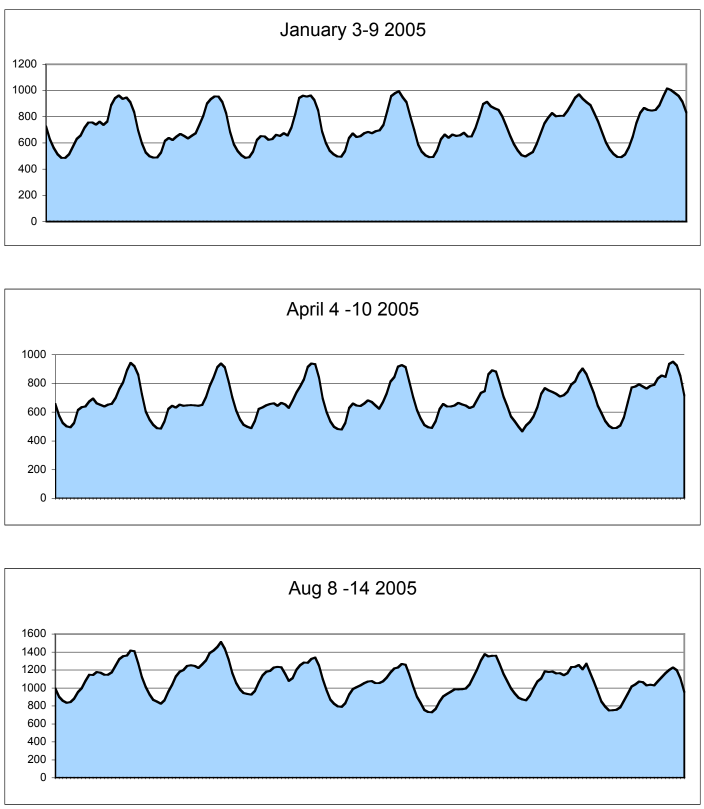
Nonetheless, the patterns of gas and electricity consumption – the underlying building behavior – will not necessarily be affected (except to the extent that more efficient buildings also employ more controls to cycle equipment on and off).

Electricity Analysis

The analysis of the hourly electricity profiles of the six subject buildings revealed remarkable consistency. Diurnal demand peaks and valleys corresponded with typical occupancy patterns. Following overnight lulls, morning demand picks up when occupants are turning on lights and appliances and using the elevators to exit the building. Afternoon demand tapers off just slightly, except in the summer, when there is heavy reliance on electrically powered cooling. Early evenings, when occupants are returning from work to cook, watch television, run their home appliances and computers, etc, is the period of peak demand in condominiums.

Unlike office buildings that have a characteristic 'business day' profile, condominiums have a consistent 7 day weekly profile, with slightly higher usage occurring on weekends.

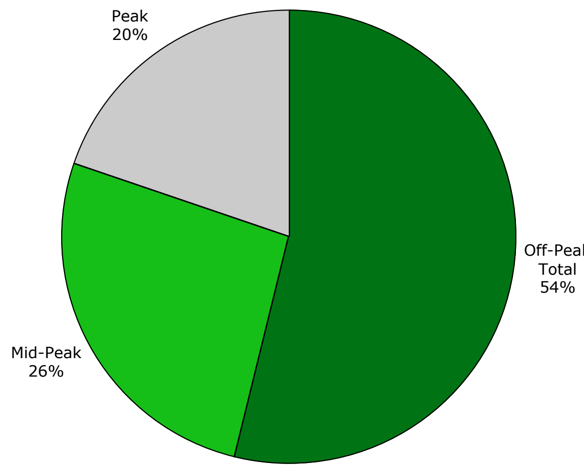
Table 2: Typical Weekly Condominium Electrical Profile



Correlating these consumption patterns to the Regulated Price Plan's Time of Use electricity rates helps to model their impact on the electricity costs for the buildings. Table 3 summarizes the average percentage of each building's energy consumption in each of the three price periods (off peak, mid-peak and peak).

Table 3: Electricity Time of Use in Six Condominium Towers

Summer (5 Months)	Off-Peak	28.6%
	Mid-Peak	15.3%
	Peak	9.7%
	Total	53.6%
Winter (7 Months)	Off-Peak	25.3%
	Mid-Peak	11.1%
	Peak	10.0%
	Total	46.4%



This data helps to frame an understanding of the potential economic model for operating a CHP system. Discounted off-peak rates are typically too low to justify generating power using natural gas. Power generated during off-peak periods is also cleaner from an emissions point of view, as the fuel mix contains much higher percentages of hydro and nuclear. Burning natural gas for electricity at this point is therefore less economical and less beneficial from an environmental perspective.

Peak periods, on the other hand, correspond to the highest electricity rates when more fossil fuel plants are brought into service to supply the grid. So from the point of view of the Cogen operator, the number of peak hours of consumption is critical. The more peak hours, the better the business case will be. Altogether, the six buildings average 20% peak power.

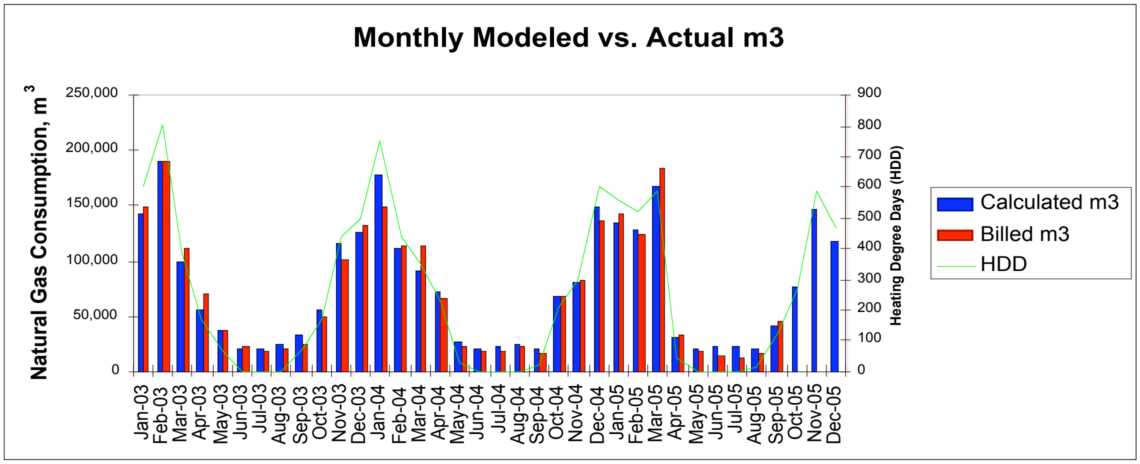
Gas Analysis

Gas consumption in highrises in heating dominated climates like Ontario is used for boilers to provide domestic hot water and space heating. In addition to building scale, occupant demographics and the average size of common areas and dwelling units, the volume of gas consumed for a given building is dependent on a number of tangible factors as well:

- Weather
- The efficiency of the installed boilers
- The thermal insulation of the building envelope (especially with regard to the performance of the windows and the overall window-to-wall ratio)
- Hot water consumption in kitchens, washrooms and washing machines

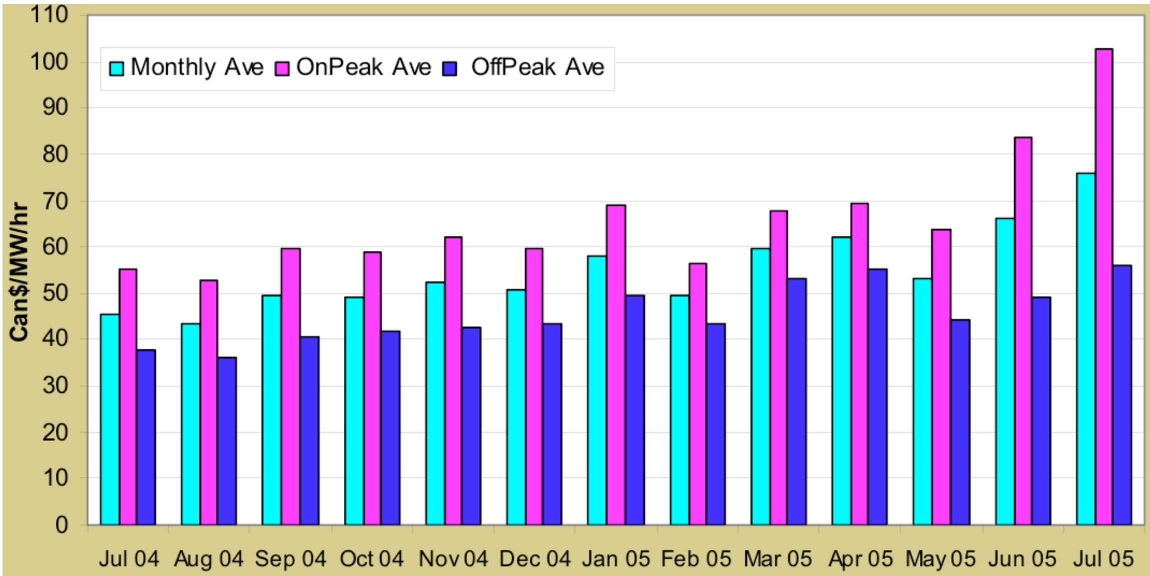
For this analysis, Energy Profiles Limited made predictions about energy use based on heating degree days and the size and features of the individual buildings. Then, they compared these predictions with observed gas consumption data provided by the six Condominium Corporations. Over a 36-month period, the correlations between predicted gas consumption and actual consumption were very strong. And the patterns revealed by the analysis were very consistent with expectations. Namely, heavy volume consumption in the winters and minimal consumption in the summer months. Summer gas consumption is solely for the purposes of domestic hot water production for washrooms, kitchens and laundry.

TABLE 4: Calculated vs Actual Gas Consumption in Six Condominium Towers



Reduced hot water demand in the summer is the central limiting factor in sizing and deploying CHP in the condominium context. This characteristic of residential building behavior precludes taking advantage of sustained cogen operation during peak electricity demand and limits the value of avoided utility costs. As the IESO chart below shows, hot summers generate high peak demand prices. Unfortunately for the cogen operator, supplying additional power at this time would result in "dumping" a lot of hot water down the drain, significantly reducing the system's overall efficiency.

TABLE 5: HOEP Monthly Prices



Modeling a CHP Retrofit

The next step involved taking the data from the existing buildings to model the thermal, electrical and economic impacts of variously sized cogeneration systems. Based on the results presented by the previous baseline analysis and the limitations associated with summer thermal demands, the best way to optimize system design would be to combine two buildings. This decision was partly influenced by the fact that Tridel's proposed pilot project is located on a site that will support two towers. Furthermore, since a robust cogen plant potentially replaces emergency back-up generators, servicing two buildings avoids the costs of two appliances, rather than just one.

Modeling Scenarios

An important consideration for site selection is the ability to share services. There were two pairs of buildings in the sample group that were close enough for a single generator. One such pair was selected. Peak load for the two buildings varied from 500 kW to 1500 kW.

Three different scenarios were modeled:

- 335 kW “Small” system
- 540 kW “Robust” system
- 1078 kW “Large” system

Energy Profiles Limited built a model to determine the costs and benefits of alternative operating scenarios for each of the systems listed above. The following three operating scenarios were applied at each scale:

- Full-time operation (24x7)
- Part-time operation to coincide with the higher utility rates associated with Mid-Peak and Peak hours as dictated by the Time of Use Regulated Price Plan (RPP)
- Part-time operation to coincide with the RPP Peak hours only.

In any modeling exercise, the underlying assumptions are critical to understanding the confidence level of your predictions. Therefore, it is worth providing some background to the assumptions on which Energy Profiles' models are based. Each of the following assumptions have been applied to the operating scenarios of the different sized systems:

<u>Boiler efficiency</u> The efficiency with which a boiler converts natural gas to useable thermal energy (in the form of domestic hot water and space heating) will have a significant impact on the amount of gas displaced. Inefficient boilers, which are more typical of buildings requiring a retrofit, use more gas than efficient ones. Therefore, associated avoided costs will be greater. For this exercise, we are applying an efficiency factor of 55%, which is on the low end, but is assuming that the boilers are older, typical atmospheric boilers with low seasonal efficiency ratings. Newer buildings may have high efficiency boilers, which will impact the economics of a cogen system.

<u>Generator electrical and thermal efficiency</u> In this case we applied the values supplied by GE for their Jenbacher combined heat and power generator. The larger systems have 35.3% electrical and 50.6% thermal efficiency; while the smaller system has 35.8% and 49.3%, respectively. Overall efficiency, therefore, is substantially higher than typical electricity plus thermal energy (nearly 86%). This overall efficiency factor is very important to bear in mind, as the volume of natural gas consumed in a cogen system is slightly greater overall than in the reference building. However, in this case the natural gas is providing two services (heat and power) as opposed to just one. (This relationship is explored further in the emissions profile.)

<u>Cost of Gas</u> Assigning a cost of gas and annual escalation factor is a highly theoretical exercise – and all important. High gas prices and low electricity prices negatively impact the business case. We applied $0.45/m3 of gas, a price that includes both distribution and commodity charges. We did not apply an escalation factor.

<u>RPP Time of Use Rates</u> These rates apply to residential customers with Smart Meters and are divided into three periods of the day, each with its own rate: Off-peak ($.035/kWh), mid-peak ($.075/kWh), and peak ($.105/kWh). In addition, we applied an avoided wholesale operations charge of $0.0062/kwh and a percentage of the avoided Provincial debt retirement or $.007/1.0376 per kWh.

<u>Incremental Demand (or Peak Demand) Rate</u> _This charge is assessed based on a building's monthly peak demand, regardless of when the peak occurs. The full potential avoided cost is $9.36 per kW of demand. In the case of a cogen application, the avoided cost is equal to the rate multiplied by the size of the system (eg either 335 kW, 540 kW, or 1078 kW) as this power production reduces the building's peak demand. However, for reasons that will be

discussed later, the model does not apply the full $9.36 per kW, except under the full-time (24/7) operating scenario, because a monthly peak that occurs on weekends or off-peak periods will still be used to calculate the building's monthly demand charge. For this exercise, we ran a cost benefit scenario both with the avoided demand charge and without.

Summary of cogen retrofit modeling

For the retrofit study, we only looked at operating costs and savings. We did not include the capital outlays required to acquire and install the equipment and related conveyance infrastructure, storage, controls and design. Hence, the results from the modeling do not predict payback schedules, cash flow or net present value of investment. In general, it is assumed that a retrofit application will cost more than a new project. Fortunately, the operating cost savings are expected to be greater due to the fact that the baseline building performance is much lower. Recognizing that the installation costs would not vary greatly between one system and the other (the essential difference being the cost of the generator), the objective was to establish the comparative advantage of the different scales and run times, measuring operating costs and savings.

1. The Small Cogen system provides the best savings under full-time operation, with a potential 40% additional value if the full cost of the Peak Demand Charge ($9.36 per kW) is applied.

2. The Mid-Cogen system (540 kW) provides the best savings under Mid-Peak and Peak operation (unless the avoided Peak Demand Rate is applied under the full-time operating scenario.

3. The Large Cogen system (1078 kW) effectively displaces the majority of the electrical LDC load. However, the model did not demonstrate a substantial benefit when compared with Mid system.

PART II: NEW CONDOMINIUM PROJECT

The assessment of the operating benefits of cogeneration in existing buildings provides the underlying justification for considering cogeneration for new buildings (with the co-benefit of providing background analysis for potential retrofit applications). The overall objective of this study is to determine the feasibility of integrating this technology into *new* condominiums.

The second phase of the study provides the design and system analysis for a new Tridel development in the North York district of Toronto, Ontario.

Site Selection

Identifying the appropriate pilot project site was challenging. Tridel had several projects at various stages of development, and there was a strong desire to incorporate a cogeneration system as early as possible. However, there are legal and logistical constraints with adding a new heating and power source after a building is already on the market. For one thing, the developer did not want to be faced with a "material change" that would require an amendment to signed Purchase and Sale Agreements with the condo buyers. This would create an unwarranted business risk. At the same time, there are additional costs associated with changing a design and/or finding enough space or an appropriate location on a site.

The best approach, therefore, was to find a new development that was in the design phase prior to going on the market.

The criteria used for site selection included: A) sufficient space, either on the roof, on grade or in the parking garage; and B) Two buildings within close proximity. Tridel's Northtown development in North York best suited these criteria when compared to the other possible candidates. Two new buildings are planned as the last of a large master planned community that has been under development for the past decade. Grand Triomphe II is a highrise condominium building with over 30 storeys and more than 300 units. Just south of the tower will be a mid-rise rental building for senior assisted living, owned and operated by Delmanor, a Tridel Group company.

Design And Sizing

The optimal location of the plant is below grade in the garage. This allows the distribution network to run along the ceiling of the first level from the plant to the storage tanks of both buildings. A schematic of the design is provided in the Appendix.

If the system were servicing a single building, then it would be possible to consider placing the unit on the roof in a sound proof penthouse and with special attention paid to attenuating the vibrations. This approach simplifies issues related to exhausting the appliance but creates additional complexity from the point of view of cutting off the gas supply in the case of a fire or other emergency where total gas shut-off is required.

Placing the plant below grade reduces compartmentalization and access challenges, which may offset the lost revenue from the sale of parking spaces.

Engineering

The study's engineer, Novatrend Engineering, had already been selected as the mechanical and electrical engineer for both Grand Triomph II and Delmanor developments and has extensive experience with cogeneration applications in the commercial building sector. In order to avoid delays or conflicts with the critical path of development, Novatrend was commissioned to provide two sets of designs for the development: one *with* cogeneration (funded by The Conservation Bureau and the Toronto Atmospheric Fund) and one *without* cogeneration (part of the developer's expense). This redundancy was necessary as the developer could not assess the merits of integrating the system without fully understanding the economic, design and logistical impacts.

Novatrend's scope of work covered:

- Equipment sizing and selection
- Daily operating schedules
- Design and integration (including siting the plant)
- Costing analysis
- Preliminary economic analysis

Run Times

Modeling of the building hourly gas and electricity consumption revealed a pattern similar to the one presented by the existing building analysis. The condominiums will consume most of their gas in the mornings and evenings, with substantially higher consumption in winter. Summer gas loads are entirely related to domestic hot water demand.

Peak and Mid-Peak LDC rates do not entirely overlap with the buildings' thermal load. Since the business case depends on being able to offset the highest electricity rates, the cogeneration system would have to follow the rates, and not the thermal load (which would have been optimal). This resulted in a decision to install substantial hot water storage capacity in the garage of the building, a factor that adds start-up capital costs. However, it permits the production of hot water when electricity rates are highest and ensures a reliable hot water supply for morning showers.

Due to the low off-peak rates and the resulting spark spread with natural gas costs, the system will not operate at night nor on weekends year-round. Due to the low thermal demand in Summer, the system will only run On-Peak. For the seven heating months (October through April), when there is substantial demand for hot water for space heating, the system will run On-Peak and Mid-Peak.

Table 6 plots the run times of the system, which will be in operation for a total of 2,793 hours, or nearly one-third of the time.

TABLE 6: Hours of CHP Operation in New Condo Development

Rate-Following Cogeneration Operating Schedule

(Shaded areas indicate Winter heating season)

Month	On Peak Operation	Mid Peak Ioperation	Total Operation	Operating Days per Month	Total Run Time
	hours/day	*hours/day*	*hours/day*	*days*	*hours*
JAN	6	9	15	23	345
FEB	6	9	15	20	300
MAR	6	9	15	23	345
APR	6	4	10	22	220
MAY	6	-	6	23	138
JUNE	6	-	6	22	132
JULY	6	-	6	23	138
AUG	6	-	6	23	138
SEPT	6	-	6	22	132
OCT	6	4	10	23	230
NOV	6	9	15	22	330
DEC	6	9	15	23	345
ANNUAL					2,793

The system will generate 1.5 mWh of power and 2.2 mWh(thermal) of heat annually. Table 7 plots the electricity produced by the modeled schedule using the selected equipment.

TABLE 7: Heat and Power Produced by Cogeneration for New Condo Project

	Electricity Generation			Domestic Hot Water		Space Heating			Total Energy Produced
	Electricity	Electricity Generated		Dom	Domestic Hot Water	Heat	Heat	Space Heating	Total
	kwh	*kwh/day*	*kwh/mon*	*kwh/day*	*kwh/mon*	*kwh*	*kwh/day*	*kwh/mon*	*kwh/day*
JAN	540	8,100	186,300	4,395	116,248	772	7,185	165,255	19,680
FEB	540	8,100	162,000	4,395	101,085	772	7,185	143,700	19,680
MAR	540	8,100	186,300	4,395	111,194	772	7,185	165,255	19,680
APR	540	5,400	118,800	4,395	101,525	772	3,325	73,150	13,120
MAY	540	3,240	74,520	4,395	101,085	772	237	5,451	7,872
JUNE	540	3,240	71,280	4,395	96,690	-	-	-	7,635
JULY	540	3,240	74,520	4,395	101,085	-	-	-	7,635
AUG	540	3,240	74,520	4,395	101,085	-	-	-	7,635
SEPT	540	3,240	71,280	4,395	96,690	772	237	5,214	7,872
OCT	540	5,400	124,200	4,395	106,139	772	3,325	76,475	13,120
NOV	540	8,100	178,200	4,395	106,359	772	7,185	158,070	19,680
DEC	540	8,100	186,300	4,395	116,248	772	7,185	165,255	19,680
ANNUAL			1,508,220		1,255,432			957,825	3,721,477

Emissions*

There are three possible scenarios for optimizing the performance of the system, depending on the operator's objectives:

A) *Thermal load following* to utilize the waste heat as the demand occurs;

B) *Rate following* to maximize avoided utility costs and thereby maximize potential revenue; and

C) *Emissions following* to ensure that system is offsetting electricity generated by the most polluting fuel sources.

We determined that the only way to operate the system economically at this point is to follow the highest rates, which are not necessarily consistent with the highest thermal loads. If we could optimize the system to follow the worst-case fuel mix in the Province of Ontario, then we would be able to maximize the environmental benefits of the system. Since the worst-case fuel mix involves coal, which the Province is committed to eliminating from power generation, then this would also have a beneficial policy impact. Currently, however, the rate structure does not allow us to provide the best emissions reduction portfolio.

Nonetheless, there are still measurable – and potentially substantial – emissions reductions benefits from operating cogeneration at the point of use. Running an emissions profile for the system, however, is complicated by lack of understanding of the actual fuel mix during the proposed run times.

The project hired a third party consultant to endeavor to understand this critically important component. ICF International compared the emissions from the baseline building case (eg buildings without cogeneration) to the emissions from a cogeneration system operating during Peak (and Mid-Peak) periods only. The comparison quantifies emissions from natural gas consumption for producing the equivalent domestic hot water and space heating hot water from a baseline high efficiency boiler with no cogeneration. Added to that are the estimated GHGs associated with an equivalent amount of power (based on the proposed cogeneration schedule) provided by the Ontario grid.

The results demonstrate that even though adding cogeneration to a building increases the overall volume of Natural Gas consumed by approximately 70%, overall emissions from the system as a whole are reduced.

The emissions reduction comparisons used two classes of emissions reductions factors: one based on time of use, the other on a monthly average. The monthly average is probably overly conservative, as the cogeneration plant, being a rate-following system, will not operate when rates are their lowest (during off peak) and when the fuel supply for power generation is the cleanest. By utilizing more time sensitive emissions factors (for peak power, for instance), we see a more realistic impact.

* *The full ICF International report on emissions reduction potential is included in an attachment to this document.*

The two scenarios also provide maximum and a minimum ranges. Each range also has two sets of results depending on whether or not the line losses from transmission of power across the grid to the end user are taken into account. For the purposes of this exercise, we applied a high loss value of 14%, recognizing that this could be lower depending on the location of the building in question (as low as 4% from anecdotal reports). Line and transmission losses from on-site power generation are treated effectively as zero.

An additional factor that is not included in ICFI's results, because it is more anecdotal and less verifiable, would lend further support to the conclusion that cogeneration results in a net reduction of emissions. The model only takes into account domestic sources of power. Imported power, from Michigan, for example, is not included. However, it is safe to assume, that an even higher percentage of imported power is generated by coal. Emissions reductions projections are probably on the conservative.

Table 8: Summary of Emissions Reductions Potential from Cogeneration

Maximum Emission Reductions	Emissions with Transmission	Emissions without Transmission
	tonnes CO2e/year	tonnes CO2e/year
Baseline	1,234	1,138
Project	768	768
Emission Reduction	466	370

Minimum Emission Reductions	Emissions with Transmission	Emissions without Transmission
	tonnes CO2e/year	tonnes CO2e/year
Baseline	833	786
Project	768	768
Emission Reduction	66	19

Further study of the final operating schedule and its impacts on the emissions profile is required in order to verify potential GHG credits, but it is possible to conclude from this preliminary review that overall, cogeneration not only helps to offset peak demand, it is also a worthwhile strategy that can contribute to Canada's efforts to address climate change.

Costs

The challenge of completing a full cost accounting for the system and it's integration into the building relates to the re-allocation of avoided costs to the cogeneration budget. The avoided costs are those expenses that a developer would pay irrespective of a cogeneration system. For instance, if the project requires fewer boilers, then that is a direct savings that should be discounted from the cost of the new system. Ancillary equipment, piping and connections also need to be factored.

The most significant avoided cost, however, and the one that makes cogeneration in this context potentially feasible, concerns the avoided cost of emergency back-up generators. All buildings are required to contain an emergency back-up generator and a multi-hour back-up fuel supply in order to provide life support systems in the event of a major emergency in the building.

Until recently, natural gas generators were not allowed to provide this service due to the inability to store a sufficient amount of fuel. Now that an amendment has been filed with the code officials and the CSA standard governing back up power, cogeneration obviates the need for either two generators, or one large one servicing both properties in the present study.

The total cost of the system is estimated to be $888,000, including the lost revenue (approximately $30,000) from the underground parking stalls, as well as permits. After applying a 5% contingency, 4% design fee, and 8% project management costs, the total comes to a little over $1.1 million. This is equal to $2,050 per kW of capacity. The soft costs are also very conservative, as developers may be able to capture efficiencies by overlapping with other design and management costs on the project.

For our economic analysis we then deducted the cost of a back up generator and two avoided boilers for a combined discount of $310,000. An expected (but not confirmed) incentive from the LDC of $160/kW, or $86,000, raises the total discount to just under $400,000.

Total *incremental* costs, therefore, are expected to be in the range of $711,000, or $1,317 per kW of capacity. This is the figure that has been applied in the following economic analysis.

<u>Economic Analysis</u>

Understanding the economics of the cogeneration system requires an understanding of the run times, cost of gas, maintenance, and electricity rates. The cost of gas is a variable that is very difficult to predict, so we chose a realistic price based on today's commodity rates, plus ancillary distribution charges. Since these rates can be locked in for multiple years, we are not including an escalation factor. This could mean that the spark spread (cost of gas vs cost of electricity) may be conservative in our estimates.

As with the retrofit analysis, we concluded that the most appropriate rates to apply would be the RPP Time of Use Rates (for one thing, without time of use, there is no way to run a cogeneration system affordably). The rates are the same as those applied in the retrofit analysis, where we applied a percentage of the stranded debt and transmission charges. Hence Peak Rates are calculated as $0.11795 per kWh and the Mid-Peak Rate is $0.08795 per kWh.

Table 8 below represents a conservative economic profile based on the operating profile presented above.

TABLE 9: Preliminary Economic Profile of Condo CHP System

	Displaced Utility Costs				**System Operating Costs**	**Net Savings**
	Hydro $/mon	DHW $/mon	Space Heating $/mon	Total (w/ GST) $/mon	(includes GST) $/mon	Net Savings $/mon
JAN	$ 19,846	$ 5,580	$ 7,932	$ 33,358	($24,668)	$ 8,690
FEB	$ 17,417	$ 4,852	$ 6,898	$ 29,167	($21,450)	$ 7,717
MAR	$ 19,846	$ 5,337	$ 7,932	$ 33,115	($24,668)	$ 8,448
APR	$ 13,812	$ 4,873	$ 3,511	$ 22,197	($15,730)	$ 6,467
MAY	$ 8,789	$ 4,852	$ 262	$ 13,903	($9,867)	$ 4,036
JUNE	$ 8,407	$ 4,641	$ -	$ 13,048	($9,438)	$ 3,610
JULY	$ 8,789	$ 4,852	$ -	$ 13,641	($9,867)	$ 3,774
AUG	$ 8,789	$ 4,852	$ -	$ 13,641	($9,867)	$ 3,774
SEPT	$ 8,407	$ 4,641	$ 250	$ 13,299	($9,438)	$ 3,861
OCT	$ 14,384	$ 5,095	$ 3,671	$ 23,150	($16,445)	$ 6,705
NOV	$ 19,036	$ 5,105	$ 7,587	$ 31,729	($23,595)	$ 8,134
DEC	$ 19,846	$ 5,580	$ 7,932	$ 33,358	($24,668)	$ 8,690
ANNUAL	$ 167,370	$ 60,261	$ 45,976	$ 291,506	($212,764)	$ 78,742
					R.O.I	**11.08%**
					Simple Payback (years)	**9.03**

In order to understand the calculations, it is necessary to review the underlying assumptions. In this case, they are similar to the assumptions applied in the retrofit analysis. The avoided cost of gas delivered to the building is calculated at $0.45 per cubic meter; maintenance costs are $6.50 per hour of run-time (based on $0.0012 per kWh, as specified by the manufacturer). The other important variable, again, is the Peak Demand Charge. The *potential* avoided peak demand charge is $9.87 per kW. Since our system shaves 540 kW when operating, the *total potential* avoided Peak Demand Charge could be over $5,000 per month. However, for this exercise, we have only applied a savings of $2.27 per kW, as these reductions are the only ones assured (largely because of the reduced run-time in Summer). The economic profile improves significantly if the full Peak Demand Charge can be avoided (see *Discussion* below).

The 9-year payback and 11% ROI suggests that integrating cogeneration in condominiums is approaching feasibility. However, in order to attract private equity and create a robust business model, it will be necessary to improve the outcome. The current analysis does not include the cost of capital, and it is unlikely that an investor will cover the full capital cost without financing.

DISCUSSION

Cogeneration for condominiums presents a number of opportunities to assist the Province in managing peak electricity demand and reducing reliance on coal-fired power plants. The Province could also benefit from the participation of multiple private sector stakeholders in the development and management of distributed assets that could generate a healthy business return while helping the Province reduce the overall amount of capital required to invest in new central generating plants. At the very least, the distributed generation model helps obviate the need to oversize central plants and equipment to generate the incremental capacity required to compensate for transmission losses. Putting a dollar value on that redundancy in capacity is beyond the scope of this study, but it would be a worthwhile exercise, as that surplus capital could be used to support the distributed generation model.

There are some additional instruments to improve the business case, such as the Province's RFPs for conservation, demand management and new generation. However, there are barriers constraining a micro-cogen operator's participation. For one thing, the overall size required for eligibility is too large and the "bundling" of distributed assets is not permitted. This is unfortunate, as there are plentiful opportunities in the new construction and retrofit market to foster an immediate uptake of new generation capacity in highrises. And there are substantial benefits to consumers as well. Instead of having to waste money testing and maintaining inactive back-up generators that only supply six hours worth of emergency capacity, Condominium Corporations could have a cost-free service that insulates them from future price escalation *and* future black or brown outs.

Demand Response Programs

We briefly explored the opportunity under existing Demand Response Programs, but found that they are not particularly well suited to the application in question and have only a limited demonstrable risk mitigation benefit at this time.

The basic approach of these programs involves having a dispatchable system that can be called into service by the LDC. One program allows participants to specify a price above which the generator would be called upon to provide power. However, the program is designed to respond to high prices and relies on an operational baseline that the operator has to be able to justify. In our case, our business model would be dependent on the program, which is counter to the current program's structure.

Other IESO programs, like the Transitional Demand Response Program and the Emergency Demand Response Program offer promise, as they set prices well above the offset RPP rates that were used in modeling the present case study. For instance, according to discussions with Toronto Hydro, rates for dispatched power from the cogen would be approximately $0.30/kWh, which is significantly higher than the grid displaced peak rates. Furthermore, program operators are offered a standby rate which exceeds the current Standard Offer for renewables. This rate is applied for each hour that the system is prepared to be called into service (at which point the higher rates would be applied).

Credit for standby time would certainly help to mitigate risk. However, it is unclear if the system would be allowed to operate for normal business purposes while in standby mode, or if it actually would need to be off and ready for dispatch. This creates an unintended consequence. Cogen operators would be paid more not to run their systems than to run them, and if this coincides with peak periods (which it would), then the benefit of the system overall is diminished. And if the system is running anyway, then a standby payment is redundant.

While these demand response programs offer some assurance that there are programs available to improve the economics of the cogen system, they are not consistent or predictable enough to mitigate the risk between the fuel rates and the electricity rates. Until a cogen operator is able to quantify the number of hours when these higher rates would apply, they are not dependable enough to build a business case around. Additional risk mitigation is required.

Proposed Approaches for Improving Cogen Economics

What is the best approach to improve Cogen's outlook in the condominium context in Ontario, and specifically in Toronto?

First of all, a Cogen operator should lock in a medium-to-long-term contract for natural gas (at least 5 years) in order to eliminate volatility on the fuel price side of the equation and mitigate one side of the spark spread risk. Consistent fuel pricing allows for multi-year projections on which to base customer contracts.

Second, and in order to validate the rates applied in this study, it is necessary for the LDC to create rate structures that allow cogen operators to take advantage of differential Time Of Use rates. This is critical. It provides consistent price points for scheduling operating scenarios.

Third, in some respects, simply aligning a rate structure that is consistent with the Province's objectives would go a long way. Our analysis revealed a fundamental weakness in the current Peak Demand Rate structure. If the objective of the Province is to improve the mix of fuels in active use and to reduce the overall amount of imported – or high priced – electricity – then shifting peak demand from the middle of the week to the weekends should be viewed as a positive development. Our condominium project would do just that. By firing the generator during weekdays, and shutting it down at night and on weekends, we are able to move the building's peak demand to off-peak periods.

However, the current Peak Demand Rate is not sensitive to this shift. All that happens is that the peak has shifted from Weekdays to Weekends, so much of the Peak Demand Rate will still be charged back to the customers by the LDC. Hence, we cannot apply the full discount ($9.87 per kW of reduced capacity). A simple change discounting weekend peak demand would take the model to a 15% ROI and a 6.5 year payback.

A further alignment of the LDC's peak rates and the Province's overall peak demand profile could also be beneficial. If our system could reduce the cost of expensive hot water storage, we could operate the system more optimally by following the thermal load (rather than the current rates). The ideal run-times would be 6:00 am – 9:00 am and 4:00 pm to 7:00 pm (more or less). However, an operating sequence like this does not currently capture the highest rates.

Finally, either in lieu of the above or in addition to it, the Province could provide a Standard Offer (S.O.) rate, similar to the Standard Offer applied to renewables, however with a different logic. The logic of the present Standard Offer is to stimulate the marketplace for renewables, a laudable goal. However, it will not be as effective – either in terms of cost or practicality - in eliminating coal on the margins as an infrastructure that supports multiple distributed generation assets running on “clean” fuels.

A systematic approach would provide a S.O. limited to Mid-Peak and Peak hours only. The fuel mix off peak is relatively clean by comparison, and there is plenty of it. A S.O. intended to offset coal power would be an effective instrument if it could apply to micro-utilities, like cogen, in the 300 kW to 750 kW range.

For example, a Standard Offer rate of $0.145 per kWh during Peak and Mid-Peak only for natural gas (or biogas) power cogen would improve ROI in our model to 17.5%.

If you combine the Standard Offer and the full Peak Demand Reduction, the ROI on our model exceeds 19% and provides a 5 year payback. At this point, the Province would see considerable activity in this area – and most likely very quickly.

Capital Incentives

Recognizing that these policy instruments may be complicated and require adjusting programs for a small sector of the overall marketplace, it is also possible to implement incentives that would provide a capital cost benefit for the investor. Our model already includes an incentive from the LDC. If the LDC and the Province together were to contribute to discounting the installation cost, then they could demand an agreement to make the equipment dispatchable, similar to the Demand Response Program. The scale of the incentive should be based on the kW capacity of the equipment being installed and needs to be evaluated in a sensitivity analysis. Our analysis suggests that the contribution would have to be on the order of $450 to $500 per kW of capacity to make a viable business case. This is a steep incentive and could be pared down with a combination of the other factors described above.

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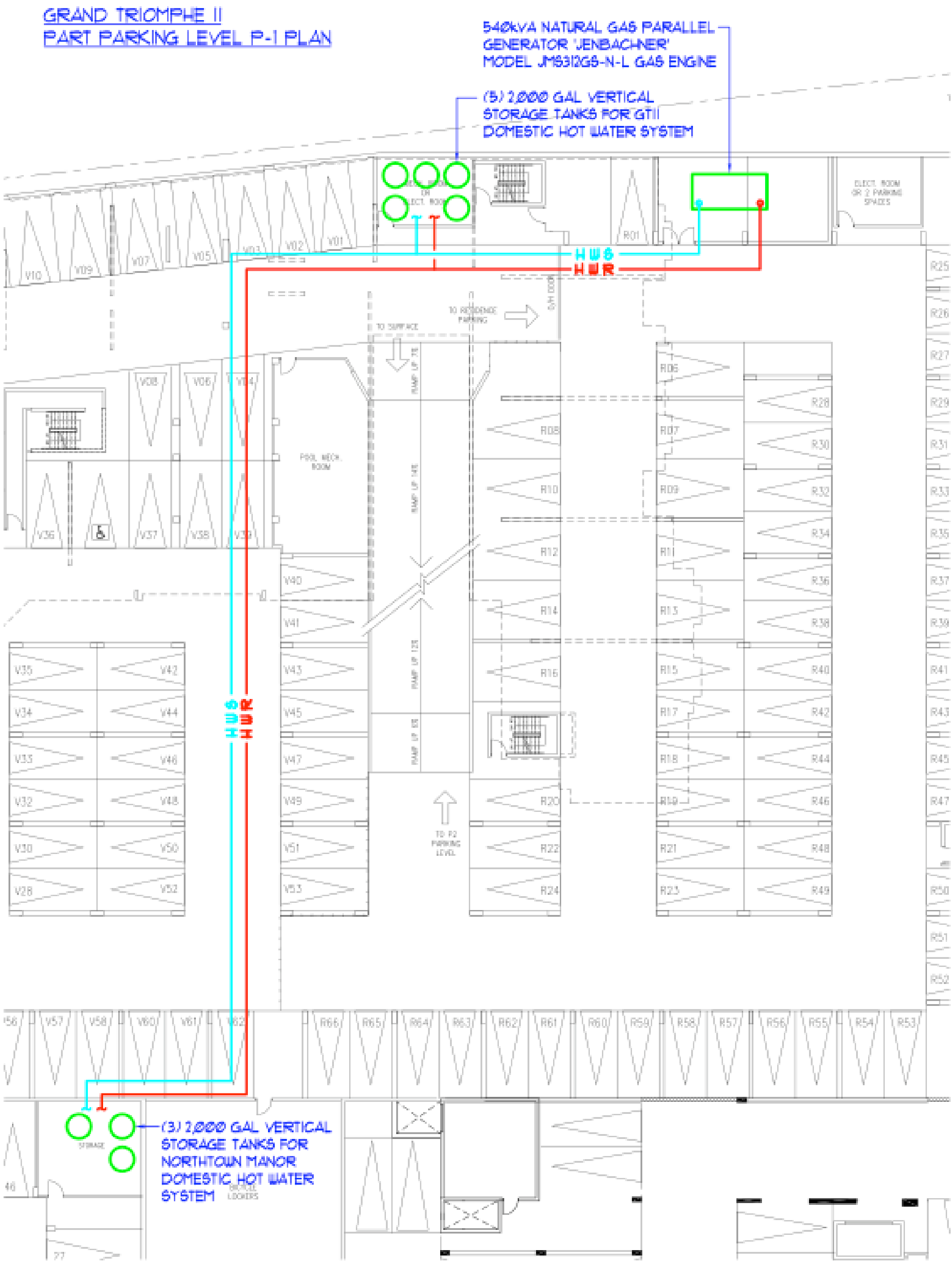
APPENDIX 1
DRAWINGS FOR CHP INSTALLATION
TWO BUILDINGS IN NORTH YORK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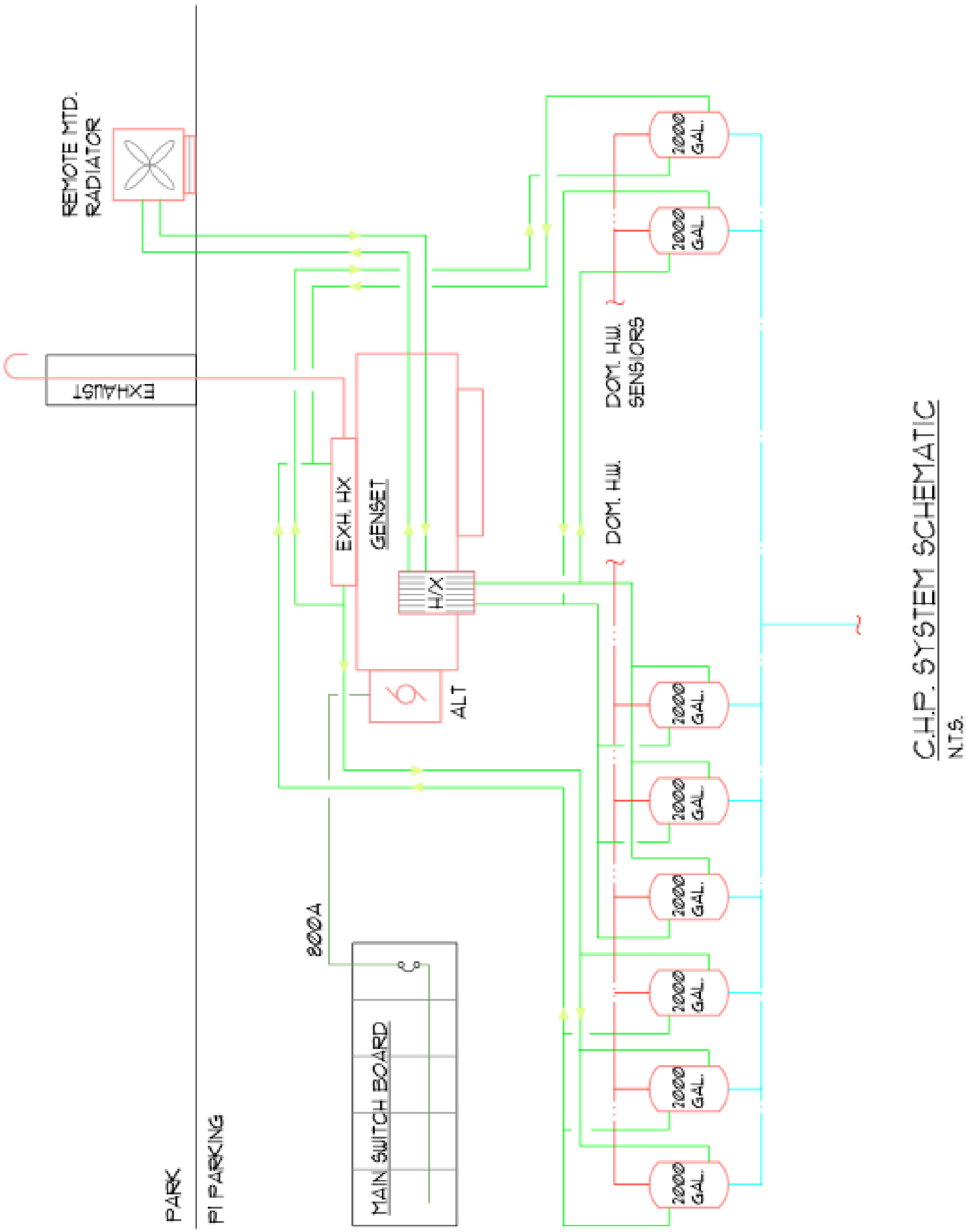
PART PARKING LEVEL P-1 PLAN
540kVA NATURAL GAS PARALLEL GENERATOR 'JENBACHER' MODEL JMS312GS-N-L GAS ENGINE
(5) 2,000 GAL VERTICAL STORAGE TANKS FOR GTII DOMESTIC HOT WATER SYSTEM
HWS
HWR
(3) 2,000 GAL VERTICAL STORAGE TANKS FOR NORTHTOWN MANOR DOMESTIC HOT WATER SYSTEM


REMOTE MTD. RADIATOR
EXHAUST
EXH. HX
GENSET
H/X
ALT
DOM. H.W. SENSORS
DOM. H.W.
2000 GAL.
800A
MAIN SWITCH BOARD
PARK
P1 PARKING
C.H.P. SYSTEM SCHEMATIC
N.T.S.

APPENDIX 2
ICF INTERNATIONAL REVIEW OF GHG EMISSION REDUCTIONS FROM COGENERATION

APPENDIX 3
APRIL 27TH POWERPOINT PRESENTATION TO OPA AND TAF WITH SUMMARY FINDINGS