Sizing of a CHP plant

A case study for

Dublin City University

By

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Declaration

I hereby certify that the material, which I now submit for assessment on the programme of study leading to the award of Degree of Master of Engineering is entirely my own work and has not been taken from the work of others save and to the extent that such work has been cited and acknowledged within the text of my work.

Signed:--

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Abstract

Dublin City University (DCU) occupies an 85 acre campus that includes the main academic and administrative buildings as well as residence accommodation. The university has a low-pressure hot water (LPHW) heating system fed from a central boiler house and electrical power provided by the ESB. DCU's electrical and thermal power consumption has sharply increased in the last few years due to rapid expansion, which has lead the university to focus on the high cost of its heating and power bills. An overview of the current technology of the field of combined heat and power is given in this thesis. A review of recent energy bills for the campus and an analysis of trends in heat and power for the past three years is presented. A detailed examination of the energy requirements of the DCU campus, with particular references to the possible role of combined heat and power in supplying these requirements efficiently and cheaply is given. Suggestions are also made for the size of plant suitable for the campus and recommendations given from current market suppliers of CHP equipment.

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Nomenclature

CHP_C	CHP fuel price (€)
CHP_f	CHP fuel cost (€)
E_C	Electricity shortfall/surplus cost (€)
E_{IN}	Energy cost without CHP (€)
E_S	Engine electricity shortfall/surplus unit price (€)
FES	Fuel energy saving
F_C	CHP fuel consumption (kw)
H	Heat from the boiler (kw)
H_C	Heat shortfall/surplus cost (€)
H_e	Heat recovered by CHP (kwh)
H_f	Fuel price (€)
H_{fc}	Fuel power of the cogeneration system
H_{fs}	Total fuel power for separate production
E_h	Exhaust heat recoverable (kw)
H_p	CHP plant working hours
H_S	Heat shortfall/surplus (kw)
HPR	Heat to Power Ratio
L	Line
Mfg	Manufacture
O&M	Operating and maintenance
Q	Grid electricity
Q_a	Engine electric output (kw)
Q_B	Boiler thermal energy output
Q_e	Electricity produced by CHP plant (kwh)
QI	Fuel in put
Q_O	Useful heat
Q_S	Electricity shortfall/surplus (kwh)
Q_U	Engine useful heat output
W	prime mover work
W_e	Engine electrical output
η_e	Electrical efficiency
η_f	Efficiency of fuel conversion
η_G	Generator efficiency
η_m	Prime mover efficiency
η_Q	Boiler efficiency
η_T	Total efficiency
η_{th}	Engine thermal efficiency
η_V	Engine availability
η_w	Power plant efficiency

Since there are two or more usable energy outputs from a CHP system, defining overall system efficiency is more complex than with a simple system, the power system (which is usually some type of boiler). The efficiency of the overall system results from an interaction between individual efficiencies of the power and heat recovery systems. The most efficient CHP systems (exceeding 80 percent overall efficiency) are those that satisfy a large thermal demand. As the required temperature of the recovered energy increases, the ratio of heat to power output will decrease. The decreased output of electricity is important to the economic of CHP because moving excess electricity to market is technically easier than in the case with excess thermal energy. However, there currently are barriers to distributing excess power to market in Ireland [7].

CHP can boost competitiveness by increasing the efficiency and productivity of our use of fuels, and human recourses. Euros saved on energy are available to spend on other goods and services. Past research by the Irish Energy Centre has shown that savings are retained in the local economy and generate greater economic benefit than the Euros spent on energy [7-12].

1.1 Method of approach

To achieve this study objective, the following method of approach was adopted. The proposed method based its calculations upon twelve months measured electrical load profile, twelve months of gas and electricity bills, and the operating times of the existing boiler plant, while calculating the savings made for each month of the year.

1.2 Aims of the study

Dublin City University occupies an area of 85 acres campus includes of the main academic and administrative buildings as well as the residence accommodation. The university has low-pressure hot water (LPHW), heating system fed from a central boiler house and electrical power provided by ESB.

Dublin City University electrical and thermal power has sharply increased in the last few years due to the new expansion that Dublin City University has made, which led the university to focus on the high cost of energy. An examination of the energy requirements of the Dublin City University campus was carried out with particular references to the possible role of combined heat and power in supplying these requirements efficiently and cheaply. As a result of this analysis, it is believed that the installation of combined heat and power plant represent the optimal solution for Dublin City University which will be shown at the end of this theses. Energy bills will be substantially reduced and security of supply will be enhanced.

The fundamental strategy of CHP is to reduce the host building's energy expense. In return, this will minimise repayment time for the cost of plant installation. Another major benefit of CHP is the reduction in the level of polluting exhaust emission compared to a large power station and gas fired boiler for the equivalent energy supply. The reduction in CO_2 levels is typically 60 % per unit of energy for coal and 75 % per unit for fuel oil [3].

The objectives of this study can be summarise as follows:

- Analysis of purchased power used at Dublin city university site becomes for the years 2000 – 2003.
- Analysis of power cost during this period.
- Out line a method for assessing the feasibility of installation a CHP unit into Dublin City University
- Sizing a CHP plant for Dublin City University according to the year 2003 energy data.
- Calculating the power cost, saving and the payback period.
- Thermodynamic analysis of the chosen CHP plants.

1.3 Lay out of thesis

This thesis is divided into six chapters. Following this introductory chapter, chapter two investigates different types of CHP systems and their uses in public and commercial sectors.

Chapter three is an analysis of the electrical and heat consumption for Dublin City University for the period (2000 – 2003), while chapter four outline the feasibly study of CHP at Dublin City University & shows the method used by the author to calculate the energy output of the system and its cost.

Chapter five gives a thermodynamic analysis for three proposed CHP systems and compares the results. Finally, chapter six conclusions with a summary of the present work.

2 Chapter two

2.1 Literature Survey

The principle behind Combined Heat and Power (CHP) is simple. Conventional power generation, on average, is only 35 % efficient, with up to 65 % of the energy potential released as waste heat (figure 1). More recent combined cycle generation can improve this to 55 %, excluding power for the transmission and distribution of electricity. Cogeneration reduces this loss by using the heat for industry, commerce and home heating/cooling [12-13].

Cogeneration is the simultaneous generation of heat and power from a single fuel source and has made the concept of self-power generation even more attractive. Cogeneration is well known technology for energy conservation in industry and in commercial buildings.

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)'[5-6].

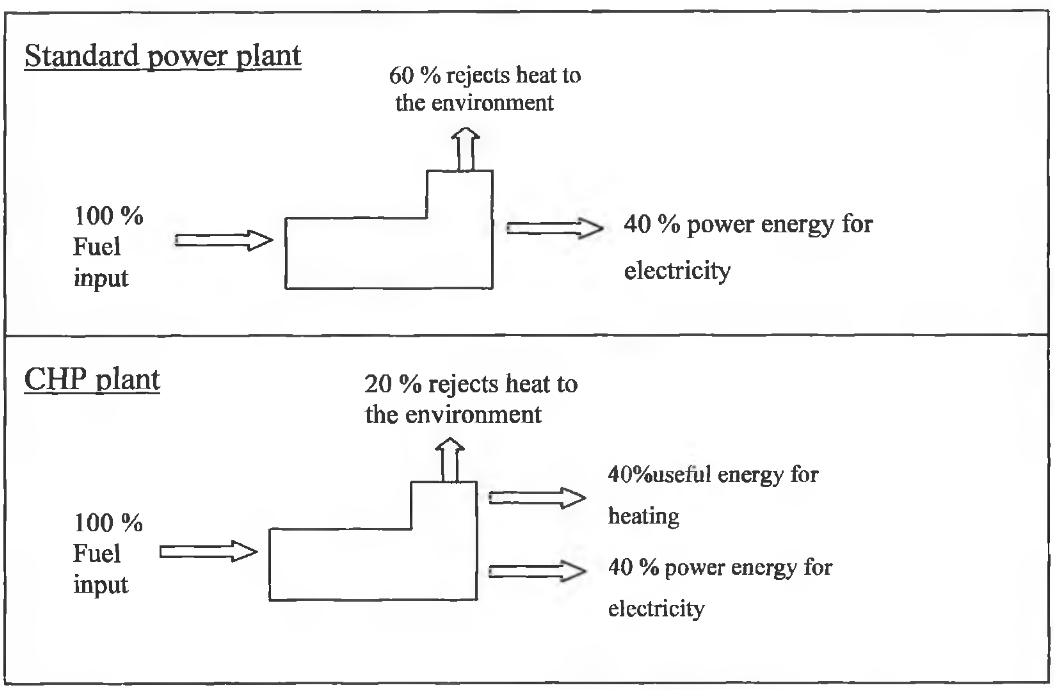

Figure 1 CHP versus separate power generation and heat production

In conventional electricity generation, further losses of around 5-10% are associated with the transmission and distribution of electricity from relatively remote power stations to the electricity grid. These losses are greatest when electricity is delivered to the smallest consumers.

Through the utilisation of the heat, the efficiency of cogeneration plant can reach 90% [6,12]. In addition, the electricity generated by the cogeneration plant is normally used locally, and then transmission and distribution losses will be negligible. Cogeneration therefore offer energy saving ranging between 15-40 % when compared with the supply of electricity and heat from conventional power stations and boilers.

Because transportation of electricity over long distance is easier and cheaper than transporting heat, cogeneration installation as usually sited as near as possible to the place where the heat is consumed and, ideally, are built to a size to meet electricity and heat demand. An additional boiler would be necessary some times, and the environmental advantages will be partly hindered. This is the central and most fundamental principle of cogeneration.

When less electricity is generated than needed, it will be necessary to buy in extra capacity. However, when the scheme is sized according to the heat demand, normally more electricity than needed is generated. The surplus electricity can be sold to the grid or supplied to another customer via the distribution system.

Typically, naturally gas is used, but there are installation in operation that use wood, agricultural waste, peat moss and a wide Variety of other fuels, depending on local availability. Most engines convert 35% of the fuels available energy into shaft power. The remaining chemical energy becomes heat [11]. A more efficient approach is to utilize CHP systems, which recover the majority of the rejected heat so that it is suitable for space heating in buildings or for industrial process. Typically, an overall efficiency of 80 % is achievable with CHP [14].

Combined heat and power systems require that a power generation turbine or an engine be installed on a site to produce the majority of the energy required for a site. The CHP system allows the site to generate its own electric power and takes advantages of the rejected heat from the prime mover to heat up water or run an absorption chiller for the cooling loads. These systems have an advantage over other types of cooling equipment in that they use waste heat as a source of power and do not rely on primary energy, except for small auxiliary equipment [15]. Until recently, this option has been limited to sites requiring large amount of energy, 1MW or greater.

A CHP facility consists of equipment that uses energy to produce both electrical energy and forms of useful thermal energy (such as heat or steam) for industrial or commercial, heating or cooling purposes. CHP facilities are designed as either bottoming cycle or topping cycle facilities.

In bottoming cycle facilities, energy is first used to satisfy the thermal demand of a high temperature process, and the reject heat is then later used to produce electric power. In contrast, topping cycle facilities first transform the fuel into useful electric power output. The reject heat from power production is then used to provide useful thermal energy. Either of these cycles can apply thermal energy to meet process heating, ventilation and air conditioning. Topping cycle units, though, offer more opportunity than bottoming cycles for energy saving because of the availability of appropriate technologies and because low temperature process account for the majority of total thermal demands [3-5].

There are four key factors that have renewed interest in cogeneration systems in general, and specifically with CHP systems. The first was during the later half of the 70s and the early 80s. The main factors that attribute to this phenomenon are the two oil shocks, which led to spiralling energy prices and the availability of efficient, and small-scale cogeneration systems, which became cost effective and competed well with the conventional large-scale electricity generation units. Another reason for the revived interest of cogeneration was the rapidly increasing demand for electricity and constraints faced by the national authorities to finance additional power generation capacity.

The second key factor was the growing concern to limit the environmental emission and pollution associated. The third factor was the developments made in more efficient heat retrieval technology. The final factor has been and continues to be, the uncertainties in electric utility industry and its future. The increased costs of building a centralised power plant, transmission lines, payback of the investment, and now deregulation of the industry all contribute to the utility industries' dilemma.

2.2 Principle of cogeneration

Cogeneration is defined as the sequential generation of two different forms of useful energy from a single primary energy source, typically mechanical energy and thermal energy. Mechanical energy may be used either to drive an alternator for producing electricity, or rotating equipment such as motor, compressor, pump or fan for delivering various service. Thermal energy can be used either for direct process applications or for indirectly producing steam, hot water, and hot air for drying or chilled water for process cooling.

Cogeneration makes sense from both macro and economic perspectives. At the macro level, it allows a part of the financial burden of the national power utility to be shared by the private sector; in addition, indigenous energy sources are preserved or the fuel import bill is reduced.

The overall energy bill of the users can be reduced, particularly when there is a simultaneous need for both power and heat at the site.

In some countries, it is not unusual to come across the situation of grid power supply interruption either due to technical failure of the system or because the consumer demand during a given time period exceeds the utility supply capacity. Industrial and commercial building normally adopt stand-by power generation for talking care of their essential loads during these period. It is essential to assure continuity of some activities to minimize production losses or guarantee supply to clients. The stand-by generators have limited use in the year; moreover, these devices require investment and incur operation and maintenance cost while contributing practically nothing to reduce the overall energy bill of the site.

Since these generators serve the main purpose of assuring emergency power to priority areas of the site, no financial analysis is carried out to assess their economic viability. However, these generators offer the possibility of continuous power generation so that the monthly power bill of the site can be reduced. Such benefits accrued can well justify the need for higher investment that is associated with prime movers which are designed to operate continuously and at higher efficiencies.

In a gas turbine or reciprocating engine, typically a third of the primary fuel supplied is converted into power while the rest is discharged as waste heat at relatively high temperature, ranging between 300 and 500 °C. At sites having a need for thermal energy in one form or the other this waste heat can be recovered to match the quantity and level of requirements. For instance, steam may be needed at low or medium pressure for processes applications. Any heat recovered from the exhaust gases of the prime movers will help to save the primary energy that would have been otherwise required by the on-site conversion facility such as boilers or dryers.

An ideal site for cogeneration has the following characteristics:

- a high power requirement
- relatively steady electrical and thermal demand
- high electricity and thermal energy demand
- long operating hours in the year
- inaccessibility to the grid or high price of grid electricity and gas

Typical cogeneration application may be in three distinct areas:

a) Utility cogeneration: caters to district heating and /or cooling. The Cogeneration facility may be located in industrial estates or city centres.

b) Industrial cogeneration: applicable mainly to two types of industries, Some requiring thermal energy at high temperature (refineries, fertilizer plants, steel, cement, ceramic and glass industries), and other low temperature (pulp and paper factories, textile mills, food and beverage plants, etc);

c) Commercials/ institutional cogeneration: specifically applicable to establishments having round-the-clock operation, such as hotels, hospitals and universities campuses.

2.3 The benefit of cogeneration

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

- Increase efficiency of energy conversion and use;
- Lower emission to the environmental, in particular of CO_2, the main greenhouse gas;
- Large cost saving, providing additional competitiveness for industrial and commercial users, and offering affordable heat for domestic users;
- An opportunity to move towards more decentralised forms of electricity generation, where plant is designed to meet the needs of local consumers, providing high efficiency, avoiding transmission losses and increasing flexibility in system use. This will particularly be the case if natural gas is the energy carrier;
- In some cases, where there are biomass fuels and some waste material such as refinery gases, process or agricultural waste, these substances can be used as fuels for cogeneration schemes, thus increasing the cost-effectiveness and reducing the need for waste disposal;
- 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. In addition, the reduced fuel need which cogeneration provides reduces the import dependency- a key challenge for Europe's energy future;

- An opportunity to increase the diversity of cogeneration plant, and provide competition in generation. Cogeneration provides one of the most important vehicles for promoting liberalisation in energy markets;

2.4 Possible opportunity for application of cogeneration

Opportunity exists in the following areas for the application of cogeneration facilities.

Industrial	Buildings
• Pharmaceuticals & fine chemicals • Paper and board manufacture • Brewing, distilling & malting • Ceramics • Brick • Cement • Food processing • Textile processing • Minerals processing • Oil refineries • Iron and steel • Motor industry • Horticulture and glasshouses • Timber processing	• District heating • Hotels • Hospitals • Leisure centre & swimming pools • College campuses • Airports • Supermarkets & large stores • Office buildings • Individual houses

2.5 Cogeneration systems

Cogeneration produces both electricity and useful thermal energy. The thermal energy can be used in heating and cooling application. Heating application include generation of steam or hot water. Cooling application require the use of absorption chillers that convert heat to cooling. A range of technologies can be used to achieve cogeneration, but the system must always include an electricity generator and a heat recovery system. The heat-to-power ratio, overall efficiency and the characteristic of the heat output are key attributes of cogeneration systems.

The heat-to-power ratio is the ratio of the amount of useful thermal energy available to the amount of the electricity generated usually expressed in terms of kW of heat per kw of electricity (kW_e). Heat-to-power ratio varies depending on the type of prime mover.

Overall efficiency is the percent of the fuel converted to electricity plus the percent of fuel converted to useful thermal energy. Typically, cogeneration systems have overall efficiency of between 65 and 85%.

Heat output varies greatly depending on the system type. The output can range from high pressure, high temperature (500 to 600 °C) steam to low temperature low-pressure hot water (90 °C). High pressure, high temperature steam is considered high quality thermal output because it can meet most industrial process needs. Hot water is considered a low quality thermal output because it can only be used for a limited number of thermal applications.

One classification of cogeneration systems is by the type of prime mover used to drive the electrical generator. The four main types currently in use include gas turbines, steam turbine, and reciprocating engines and combined cycle gas turbines. New systems currently under development are fuel cells and micro-turbines.

2.5.1 Gas Turbine Cogeneration Systems

The gas turbine act as the common prime mover in large cogeneration systems built recently. They range in electricity output from 250 kw_e to 200 MW_e. Gas turbine systems produce more electricity per unit of fuel than steam turbines and have an

average heat-to-power ratio of 2:1. Supplemental heating through secondary firing of the exhaust gases can increases this ratio to 5:1. Steam injection, which increase the volumetric flow trough the turbine, can increases the electrical output by 15%.
Gas turbine systems produce high temperature, high pressure gases in a combustion chamber.

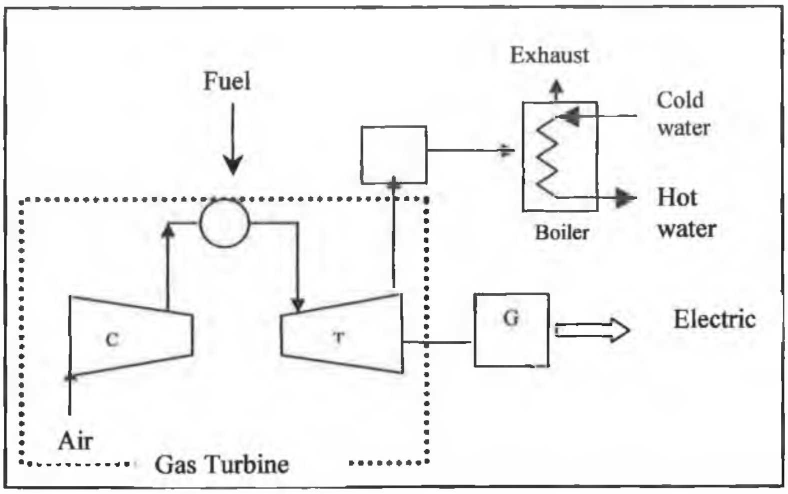

Figure 2 Schematic diagram of gas turbine cogeneration system

The gases exit the turbine at a temperature of between 450-550 °C and are used to meet the thermal requirement of the site. They can be used directly for drying, or indirectly to produce high, medium or low pressure steam or hot water.

Gas turbines generators have experienced rapid development in recent years due to the greater availability of natural gas, rapid progress in the technology, significant reduction in installation costs, and better environmental performance. Furthermore, the gestation period for developing a project is shorter and the equipment can be delivered in a modular manner. Gas has a short start-up time and provides the flexibility of intermittent operation. Though it has a low heat to power conversion efficiency, more heat can be recovered at higher temperature. If the heat output is less than that required by the user, it is possible to have supplementary natural gas firing by mixing additional fuel to the oxygen-rich exhaust gas to boost the thermal output efficiency [16-20].

On the other hand, if more power is required at the site. It is possible to adopt a combined cycle that is a combination of gas turbine and steam turbine cogeneration. Steam generated from the exhaust gas of the gas turbine is passed through a backpressure or an extraction-condensing steam turbine to generate additional power. The exhaust or the extracted steam from the steam turbine provides the required thermal energy.

2.5.2 Steam turbine cogeneration systems

Steam turbines are the most common cogeneration systems used in industrial applications [2]. They range in size from a 500Kw to 80Mw. The smaller sized systems may not be economical unless the fuel used has no alternative commercial value. Steam turbine cogeneration systems usually produce significantly more heat than electricity per unit of fuel consumed and therefore have high heat-to-power ratios. The ratios vary from site to site and range from 3:1 to 10:1. The thermal needs of the site typically determine this ratio. The lower the quality of heat required (i.e., the lower the temperature and pressure), the greater the amount of electricity generated per unit of fuel.

Steam turbine cogeneration systems generate steam in a high-pressure steam boiler. The steam expands through a turbine to produce mechanical energy. This mechanical energy drives an electrical generator. The output heat service process applications such as drying wood, pulp or paper.

Steam turbines come in two types, condensing turbines exhaust steam at a pressure lower than atmosphere (i.e., vacuum) and therefore required a condenser. Condensing turbines produce more electricity per unit of fuel than backpressure turbines because the turbine makes less energy available for thermal applications and extracts more of the energy contained in the steam.

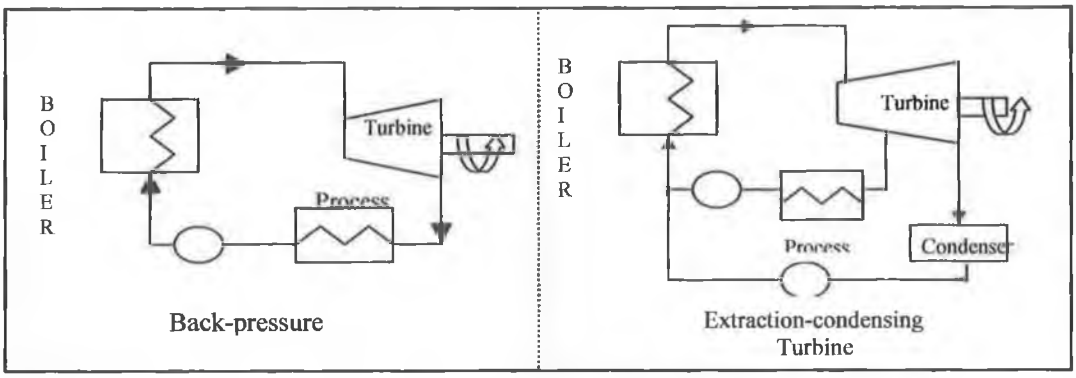

Figure 3 Schematic diagram of steam turbine cogeneration system

2.5.3 Reciprocating engine cogeneration systems

Also known as internal combustion (I.C.) engines, these cogeneration systems have high power generation efficiencies in comparison with other prime movers.
Systems range in size from 20 kW_e to 50 MW_e. The heat to power ratio ranges from 0.5:1 to 2.5:1. As with gas turbines, supplemental firing can be used to increase the thermal output [21-25].

One the thermal output from the reciprocating engine comes from two sources, the exhaust gas and engine cooling systems. The exhaust gases provide heat up to 400 ^{o}C but the cooling systems generate only low-grade heat (below 90 ^{o}C). Often one cascades the two heat sources to produce hot water. These systems are more popular with smaller energy consumer facilities, particularly those having a greater need for electricity than thermal energy and where the quality of heat required is not high, e.g. low-pressure steam or hot water.

Though diesel has been the most common fuel in the past, the prime movers can also operate with heavy fuel oil or natural gas. In urban areas where natural gas distribution network is in place, gas engines are finding wider application due to the ease of fuel handling and cleaner emission from the engine exhaust.

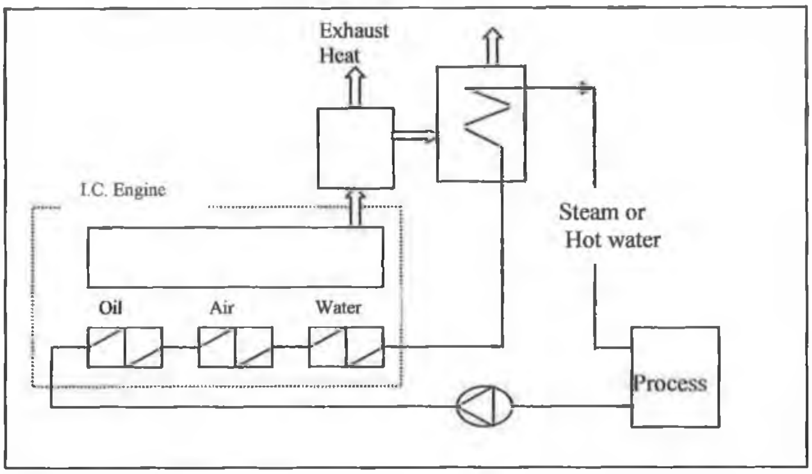

Figure 4 schematic diagram of reciprocating engine cogeneration

These machines are ideal for intermittent operation and their performance is not as sensitive to the changes in ambient temperature as gas turbines.

Though the initial investment on these machines can be low, their operating and maintenance costs are high due to high wear and tear, although this is very much dependent on the type of the engine selected. Diesel engines tend to be expensive to install and maintain while gas turbines are relatively inexpensive.

There are other more complex and integrated CHP designs that combined these prime movers with other plant and technologies [26-29]. While these may ultimately prove to be the right option for a site, the initial feasibility study should confine itself to reviewing the three main options and to working on the basis that power and heat produced by the CHP plant can be used on site.

2.6 Advantages and disadvantages of each system

Table 1 :Advantages and disadvantages of CHP systems [1-5].

	Advantages	Disadvantages
Gas Turbine	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; relatively low investment cost per kw_e electrical output Wide fuel range capability (diesel, LPG, naphtha, associated gas, landfill sewage); Multi fuel capability; low emission.	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 fuel but need to be clean of dry; output falls as ambient temperature rises due thermal constraints within the turbine; may need long overhaul period.
Steam Turbine	High overall efficiency; any type of fuel may be used; heat to power ratio can be varied through flexible operation; ability to meet more than one site heat grade requirement; wide range of sizes available; long working life.	High heat: power ratio high cost; slow start up.
Reciprocating engine	High power efficiency, achievable over a wide load range; relatively low investment cost per kw_e electrical output; wide range of unit sizes from $3kw_e$; can used in island mode; first start up time of 15 sec to full load (gas turbine needs 0.5-2hr); real multi fuel capability, can also use HFO as fuel; can be overhaul 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; high levels of low frequency noise; high maintenance cost.
Fuel Cell	Low emission and low noise; high efficiency over load range; modular design, siting flexibility, short construction time; automated operation, quick load changes, low maintenance; many fuel but require processing unless pure hydrogen. Fixable heat to power ratio; low or high-grade heat, depending on design and low fuel cell type	Costs, durability, power density, start-up time, degradation; corrosion for liquid electrolytes, sulphur.
Micro Turbines	High reliability due to small number of moving parts; simplified installation; low maintenance requirement; compact size; light weight; acceptable noise level; fuelled by demotic natural gas; resource with expand fuel flexibility; competitive cost when built in quantity; low emissions; high temperature exhaust for heat recovery; acceptable power quality.	Costs

2.7 Classification of cogeneration systems

Cogeneration systems can be classified according to the operating scheme whose choice is very much site-specific and depends on several factors [21-24], as described below:

2.7.1 Base electrical load matching

In this configuration, the cogeneration plant is sized to meet the minimum electricity demand of the site based on the historical demand curve. The reminder of the requested power is purchased from the utility grid. The thermal energy requirement of the site could be met by the cogeneration system alone or by additional boilers. If the thermal energy generated with the base electrical load exceeds the site's demand, excess thermal energy can be dumped.

2.7.2 Base thermal load matching

Here, the cogeneration system is sized to supply the minimum thermal energy requirement of the site. Stand-by boilers or burners are operated during periods when the demand for heat is higher. The prime mover installed operates at full load at all times. If the electricity demand of the site exceeds that which can be provided by the prime mover, then the remaining amount can be purchased from the grid. Likewise, if local laws permit, the excess electricity can be sold to the power utility.

2.7.3 Electrical load matching

In this operating scheme, the facility is totally independent of the power utility grid. All the power requirements of the site, including the reserve needed during scheduled and unscheduled maintenance, are to be taken into account while sizing the system. This is also referred to as a "stand-alone" system. If the thermal energy demand of the site is higher than that generated by the cogeneration system, auxiliary boilers are used. On the other hand, when the thermal energy demand is low, some thermal energy is wasted.

2.7.4 Thermal load matching

The cogeneration system is designed to meet the thermal energy requirement of the site at any time. The prime movers are operated following the thermal demand. During the period when the electricity demand exceeds the generation capacity, the deficit can be compensated by power purchased from the grid. Similarly, if the local legislation permits, electricity produced in excess at any time may be sold to the grid.

2.8 Important technical parameters for cogeneration

While selecting cogeneration system, it is necessary to consider some important technical parameters that assist in defining the type and operating scheme of different alternative cogeneration systems to be selected [7].

2.8.1 Heat-to-Power Ratio

Heat-to-power ratio is one of the most important technical parameters influencing the selection of the type of cogeneration system. The heat-to-power ratio of a facility should match with the characteristics of the cogeneration system to be installed.
It is defined as the ratio of thermal energy to electricity required by the energy consuming facility. Though it can be expressed in different units such as Btu/kWh, kcal/kWh, lb/hr/kW, etc., here it is presented on the basis of the same energy unit (kW).

Basic heat-to-power ratios of the different cogeneration systems are shown in table 2 along with some technical parameters [4-5]. The steam turbine cogeneration system can offer a large range of heat-to-power ratios.

Table 2: heat to power ratio for each CHP type

Cogeneration system	Heat-to-power ratio	Power output (As per cent of fuel input)	Overall efficiency (Per cent)
Back-pressure steam turbine	4.0-14.3	14-28	84-92
Extraction-condensing steam turbine	2.0-10.0	22-40	60-80
Gas turbine	2.0-5.0	24-35	70-85
Combined cycle	1.0-1.7	34-40	69-83
Reciprocating engine	0.5-2.5	33-53	75-85

2.8.2 Quality of thermal energy needed

The quality of thermal energy required (temperature and pressure) also determines the type of cogeneration system.

For a system requiring a thermal energy at about 120 °C, a topping cycle cogeneration system can meet the heat demand. On the other hand, for a cogeneration system can meet both high quality thermal energy and electricity.

2.8.3 Load patterns

The heat and power demand patterns of the user affect the selection (type and size) of the cogeneration system. For instance, the load pattern of two energy consuming facilities would lead to two different sizes, possibly types also, cogeneration depending on the availability of fuels, some potential cogeneration systems may have to be rejected. The availability of cheap fuels or waste products that can be used as fuels at a site is one of the major factors in the technical consideration of which system to choose.

2.8.4 Fuels availability

Depending on the availability of fuels, some potential cogeneration systems may have to be rejected. The availability of cheap fuels or waste products that can be used as fuels at a site is one of the major factors in the technical consideration because it determines the competitiveness of the cogeneration systems.

2.8.5 System reliability

Some energy consumption facilities require very reliable power and/or heat, for instance a pulp and paper industry cannot operate with a prolonged unavailability of process steam. In such instances, the cogeneration system to be installed must be modular. i.e. it should consist of more than one unit so that shut down of a specific unit cannot seriously affect the energy supply.

2.8.6 Grid dependent system versus independent system

A grid-dependent system has access to the grid to buy or sell electricity. The grid independent system is also known as a "stand-alone" system that meets all the energy demand of the site. It is obvious that for the energy consuming facility, the technical configuration of the cogeneration system designed as a grid dependent system would be different from that of a stand–alone system.

2.8.7 Retrofit versus new installation

If the cogeneration system is installed as a retrofit, the system must be designed so that the existing energy conversion systems, such as boilers, can still be used. In such a circumstance, the option for cogeneration system would depend on whether the system is a retrofit or a new installation.

2.8.8 Electricity buy-back

The technical consideration of cogeneration system must take into account whether the local regulation permit electricity utilities to buy electricity from the co generators or not. The size and type of cogeneration system could be significantly different if were to allowed the export of electricity to the grid.

3 Chapter three

3.1 Energy profiles for Dublin City University

The collection and analysis of Dublin City University data requirements and the cost of energy is an integral part of this cogeneration development process. Both electrical and thermal energy requirements has been quantified, as the economic availability of most cogeneration systems is a function of the amount of purchased power that can be displaced and the amount of fuel that can be displaced by recovered heat or, alternatively, the amount of cogenerated power that can be sold to Electricity Supply Board (ESB). Most cogeneration power is used to displace purchases from an electric utility. Therefore, this chapter will focus on the analysis of purchased power use and cost.

The energy consumption in Dublin City University can be subdivided into two utilities, electricity and gas.

At the initial stages of site evaluation, where the objective is simply one of determining whether a more detailed alternative is justified, monthly energy use data is acceptable [30-33].

During this thesis it was decided to perform an energy audit to comprehensively analyse the energy flows within the university. Investigations were carried out to analyse typical profiles of electrical energy demand and heating load demand of Dublin City University, which is required to evaluate its feasibility of cogeneration. Audit and surveys are the backbone of energy management with any other subsequent information reinforcing knowledge of the environment.

3.2 Source of information

The information on Dublin City University historic site electricity consumption data in the preparation of this project has been provided by the ESB. In addition, information relating to the particular circumstances has been provided by the university's finance office. In cases where definite information is not readily available, conservative assumptions based on industrial practice have been made.

3.3 Analysis of bills

The bills have been computerised to provide an insight into the case history of the energy consumption at Dublin City University. Billing data for electricity and gas supply have been studied from January 2000 to December 2003, with detailed analysis carried out on the billing data. This involved the compilation of Dublin City University's energy consumption profile over the previous few years, against which the current consumption can be compared. Computer analysis of the utilities invoices allows a visual means of comparing previous consumption data on a month-to-month basis. This graphical representation enables a preliminary assessment of performance to be made, irregularities, trends and seasonal patterns.

3.4 Energy consumption profile

In the energy consumption profile at Dublin City University from the year 2000 to 2003 (figures 5,19) there is a seasonal component to both electricity and gas consumption.

The consumption of the primary heating fuels is expected to have a large seasonal components in a weather compensated heating system although it is not expected to find a real seasonal components in the electricity consumption.

The seasonal component in the electricity consumption although slight is present. When the scale is altered to directly overlay the electricity and gas consumption graphs, the components coincide with each other, corresponding closely to the heating season where the temperature is low. The seasonal component in electricity consumption therefore hints at increased usage during the heating season.

There are a number of possible reasons for this increased electricity consumption, firstly there are a number of electrical heaters used in the winter months to boost the temperature, secondly there is an increasing lighting demand due to the generally lower levels of day lights and the shorter days.

In other studies of energy consumption in commercial/public sectors seasonal variation was apparent in the electricity consumption profile [23].

3.4.1 DCU's historic Electricity consumption (2000-2003)

Demand and/or load management techniques to study the electrical energy demand profile of a site require continuous data for the whole year. Such a method was employed in this analysis.

The actual electric of load for Dublin City University varies substantially over the course of the year and from month to month. In general, it is useful to review three to five years of historic billing or monthly electricity use to identify long-term trends and to asses whether or not the most recent data, which are generally the basis of cogeneration system modelling, are typical.

Figure 5 illustrates the monthly electricity consumption for Dublin City University for four years. The monthly consumption trends are similar, more electricity is needed in winter times and less in summer. Monthly electricity consumption during these years is between 550000 kWh for summer consumption to 1146000 kWh for winter.

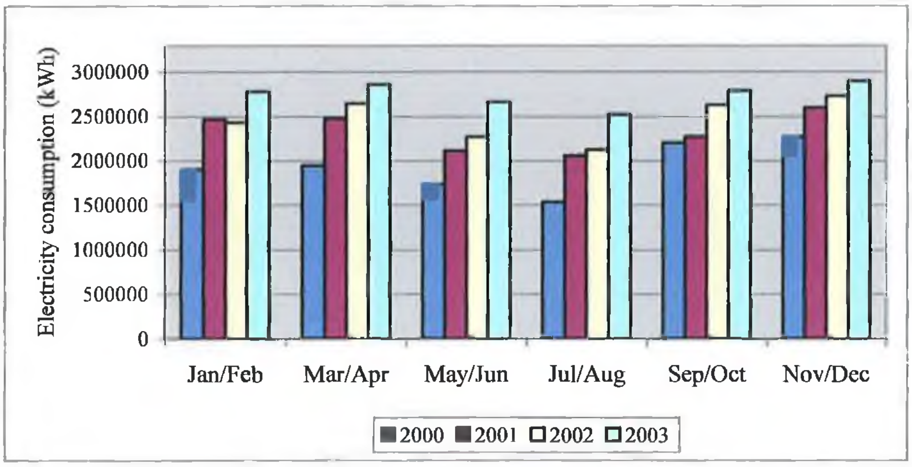

Figure 5 DCU's electricity consumption for several years

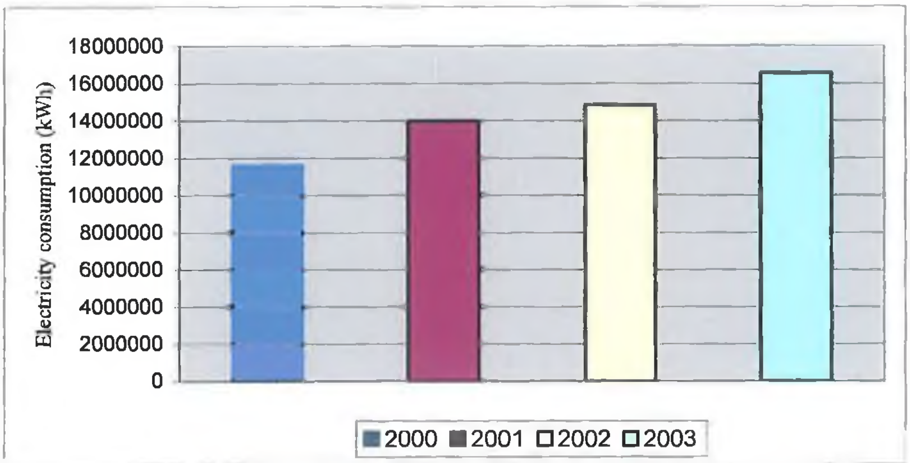

Figure 6 DCU's yearly electricity growth

The yearly electricity consumption profile for Dublin City University from January 2000 to December 2003 is shown if figure 6. There is a considerable upwards trend shown during this time period in the electricity consumption, with demand increasing on a year basis.

Figure (6) shows the growth in electrical demand from January 2000 to December 2003 rose from 11.606 GWh to more than 16.534 GWh, respectively. This 30 % growth is due to the considerable building expansions in Dublin City University that happened over this period. This expansion included the school of Nursing, the new Engineering/Research facilities and the Helix arts centre.

Dublin City University's electrical data shows the electrical requirement for each month, and different seasons. The figures (7-9) illustrate monthly data for Dublin City University & its cost for twelve months for the year 2000.

In general, electrical loads for Dublin City University begin to steadily increase, reaching a high between January, to March, and Sep, to Nov. Outside this time the load begins to drop steadily, until it reaches the lowest demand, which usually occurs in summer season, around July and August. Off peak hours are from 10 pm – 7 am, and on peak hours 7 am – 10 pm.

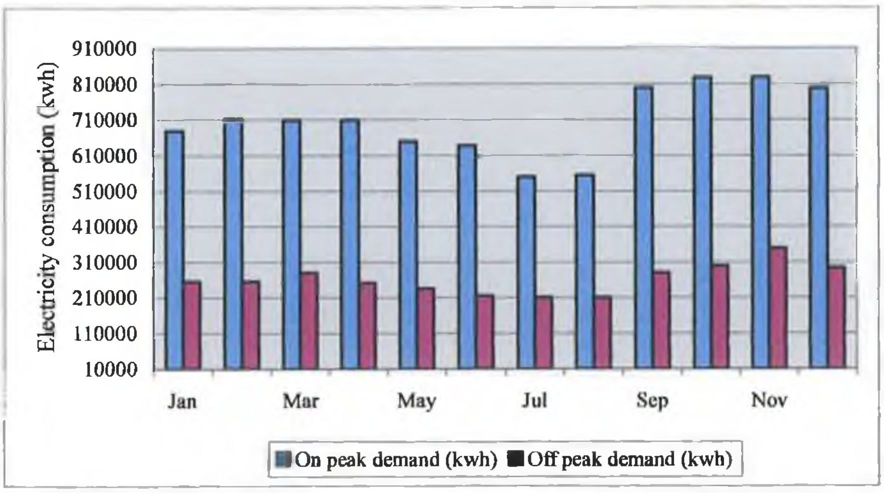

Figure 7 DCU electricity demand (2000)

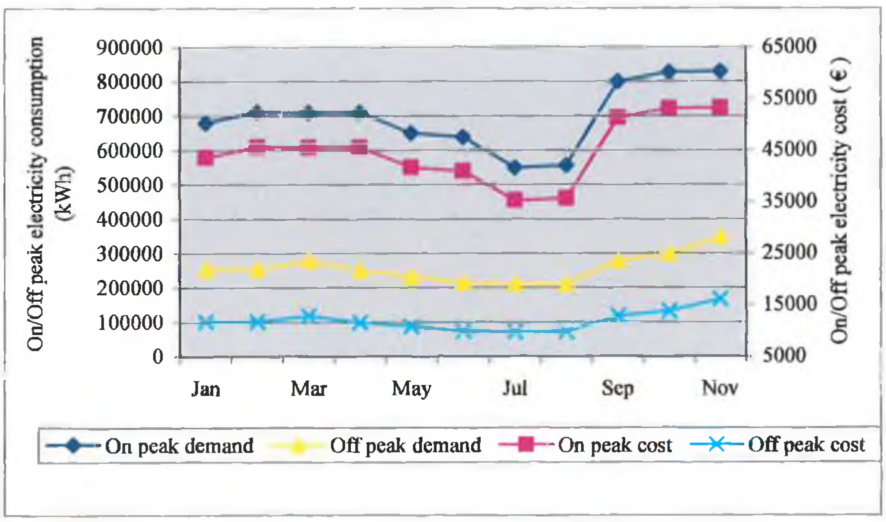

Figure 8 On/Off peak energy consumption & cost (2000)

Figures (7,8) show the on/off peak electricity consumption & cost from Jan to December 2000. We can see from figure 7 the variation in electricity demand due to changes in weather. The total electricity consumption for that year was around 11.606 Gwh. This amount of electricity consumption would cost Dublin City University around €687,884. On peak electricity consumption at the same period was about 8.462 Gwh, which accounts to € 543,260.

Due to the higher electrical consumption in the previous years the energy bills were higher. A monthly increase in electricity consumption of 15 % in 2001 caused a yearly increase in electricity bills by 17 %. Figures 9,10 show the electricity consumption & cost for the year 2001.

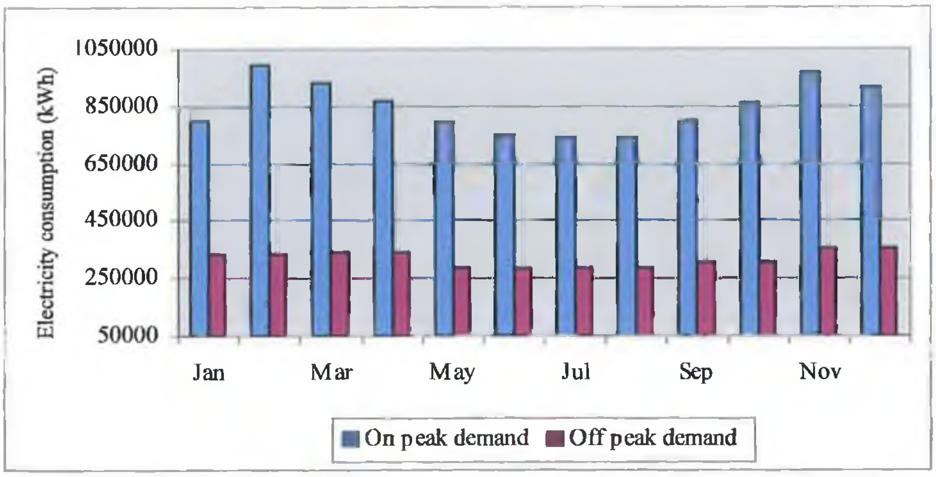

Figure 9 DCU electricity demands (2001)

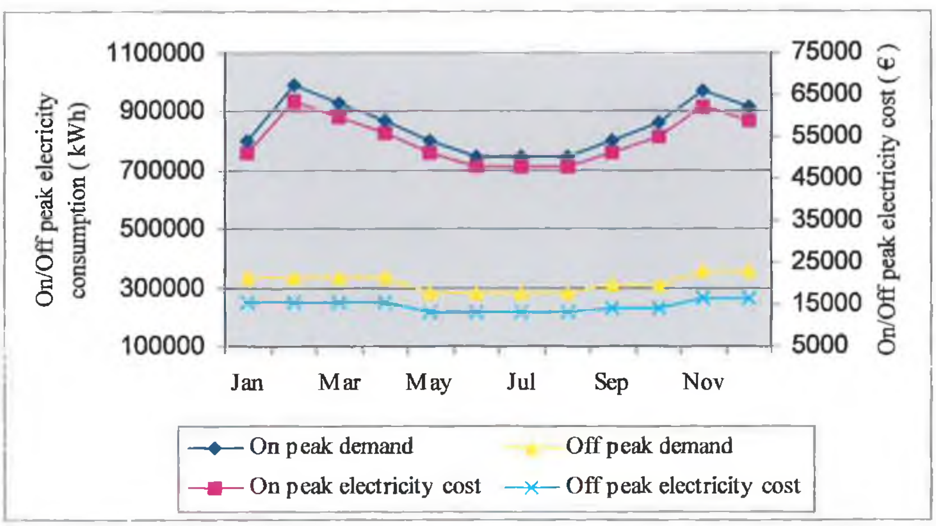

Figure 10 On/Off peak energy demand & cost (2001)

On peak electricity forms 74 % from the yearly electricity consumption in 2002. Figures 11,12 show an increase in electricity consumption by 42 % to the year of 2000 and 31 % to the previous year. On peak electricity cost forms 77 % of the yearly electricity cost of 2002. Electricity consumption in 2002 was around 14 Gwh, on peak accounts for 74% of that. The yearly cost of electricity was €882,442.

Figures 11,12 illustrate the electricity cost at on/off peak and the monthly electricity consumption for the whole year (2002).

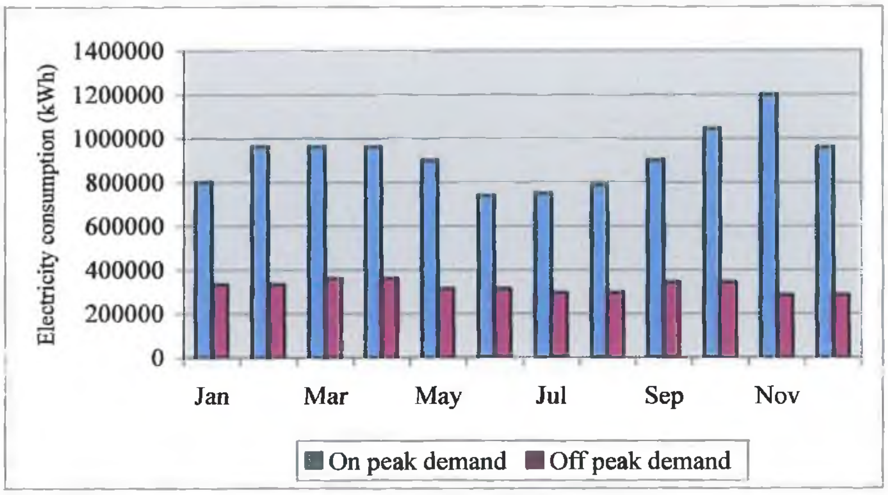

Figure 11 DCU electricity demands (2002)

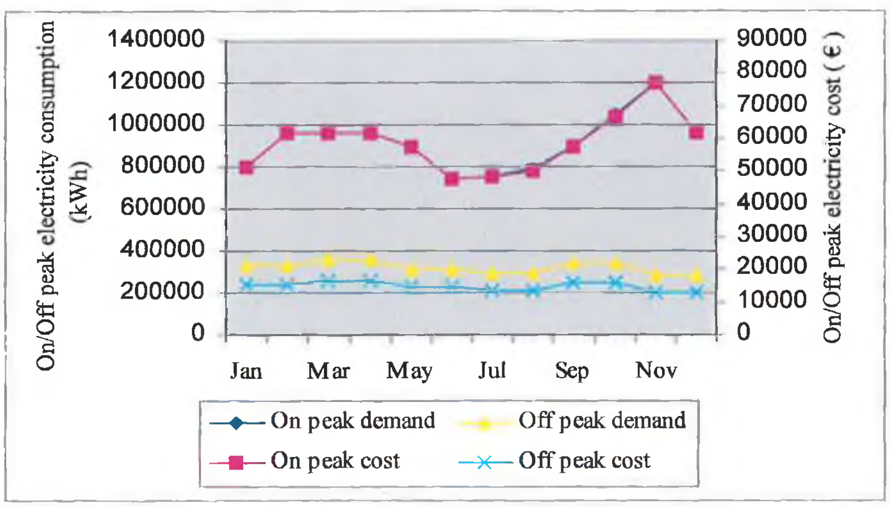

Figure 12 On/Off peak energy consumption & cost (2002)

It is noted that the electricity consumption has shown a gradual upward trend in both usage and maximum demand. The year to December 2003 saw an increase of over 18 % over the previous year, with a total usage of 16.534 Gwh. Maximum demand to date occurred in the November billing period of 2003. This was an increase of 34.8 % over the same period in 2002.

Figure 13 shows the on/off peak electricity consumption during the year 2003 was 12.09 Gwh, which was an increase by 9.3 % over the same period in 2002 that would lead to increasing the electricity bills by the same percentage. Off peak electricity consumption was increased by 12.7 to the previous year.

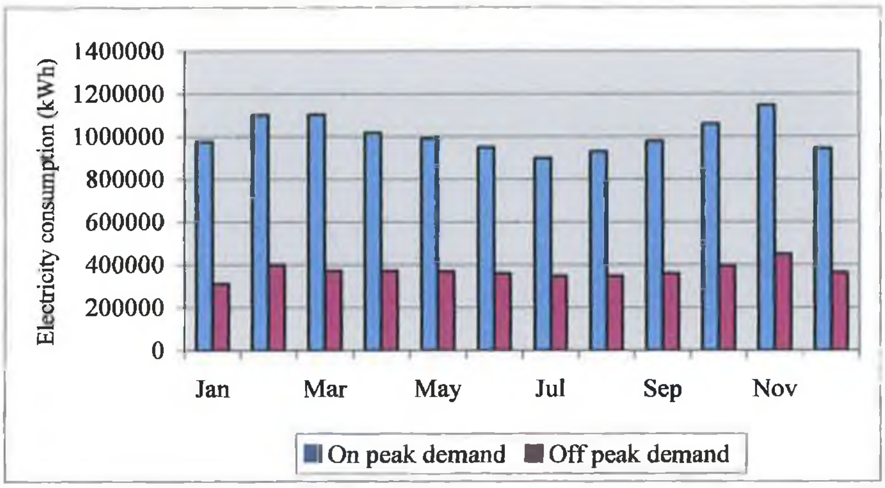

Figure 13 DCU On/Off peak electricity consumption (2003)

It can be seen clearly from figure16 the differences in monthly demand due to the season time. The majority of the electricity load is due to lighting requirements and laboratory demand.

This supports the idea that seasonal increases are at least partially due to extra heat and light requirements. These increases would be expected during certain months. A typical demand profile of peak electrical energy for the whole year is shown in fig. 16. It is observed that electrical energy demand increases slightly during wintertime and decreases a little during summer time.

The electricity for the site is being provided by the ESB Company on a tariff of 0.0642 €/kWh time-of-day rates services, during peak hours from 7 am to 10 pm, and during off-peak hours, from 10 pm to 7 am is 0.046 €/kWh.

Table 3 DCU's Monthly average electrical consumption for 2003

Months	Electrical Consumptions (Gwh)	On Peak demand %	On peak Monthly bill (€)
Jan/Feb	2.784	71	133,278
Mar/Apr	2.864	72.5	136,101
May/Jun	2.668	73	124,548
July/Aug	2.524	71.7	117,357
Sep/Oct	2.792	72.9	130,710
Nov/Dec	2.902	72.5	134,177

A slight seasonal variation is noted in the electricity consumption, but in general usage does not deviate greatly from an average of 1931 kW (Jul) in any billing period.

On an annual basis Dublin City University consumed up to 12.09 GWh of electricity on peak time during the year 2003, which costs Dublin City University €776,178 per annum (figure 16). These bills increased by 9.3 % to the previous year and 30 % over the year 2000.

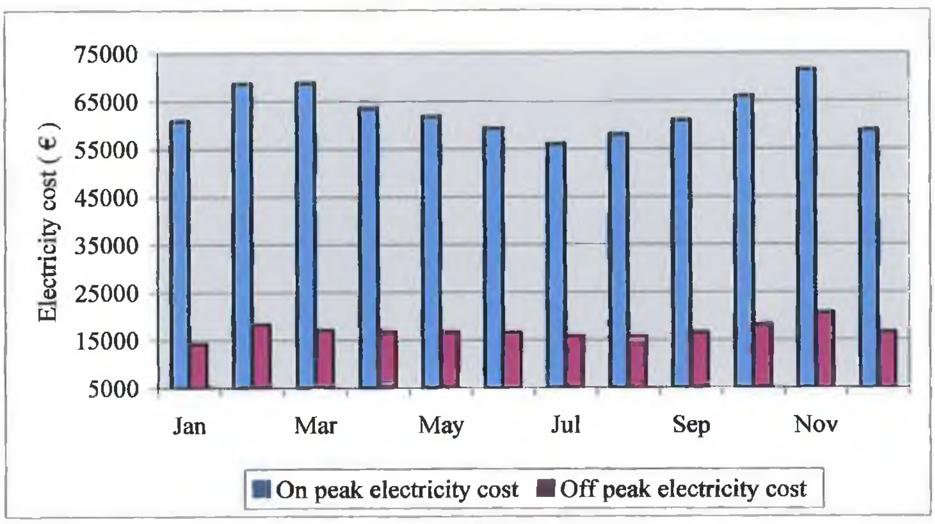

Figure 14 On/Off peak electricity cost (2003)

Electrical energy consumption of Dublin City University was determined from the recorder meter by the ESB office and annual electricity bills. Monthly energy consumption and average demand are summarised in table 4.

Table 4 Monthly power consumption & cost (2003)

Months	On Peak electricity consumption (kWh)	Off Peak electricity consumption (kWh)	On peak heat-to-power ratio	On peak average electrical consumption (MWH)	On peak Monthly bill (€)
January	975,720	310,000	1.1296	2.098	60,885
February	1,002,280	398,000	0.858	2.619	68,657
March	1,102,400	372,000	0.678	2.371	68.789
April	1,017,600	372,000	0.595	2.261	63,498
May	990,000	368,000	0.578	2.129	61,776
Jun	950,000	366,000	0.555	2.111	59,280
July	898,000	348,000	0.222	1.931	56,035
August	930,000	348,000	0.190	2	58,032
September	977,280	360,000	0.387	2.171	60,982
October	1,058,720	396,000	0.666	2.276	66,064
November	1,146,100	450,000	0.829	2.546	71,516
December	943,900	362,000	0.590	2.029	58,899
Total	12,090,000	4,444,000			776,178

Analysis of the monthly electricity consumption of Dublin City University in 2003 shows the following:

- Maximum Monthly Electricity Consumption (November): 1,146 MWh
- Minimum Monthly Electricity Consumption (July): 898 MWh
- Peak Power Demand (February): 2,6 kW
- Base Power Demand (July): 1931 kW
- Total Electricity Consumption in 2003: 16,543 MWh

Dublin City University used 16,534MWh of electricity during this case study year of January 2003 to December 2003, at a cost of €776,178. During this period electricity accounted for 79% of the cost of energy consumption and as shown in fig. 14, electricity is therefore an expensive commodity, and measures to reduce or optimise its use could provide considerable cost savings.

3.4.2 DCU's historic gas consumption (2000-2003)

Domestic space heating is an important contributor to final energy use in most countries. The objective of domestic space heating is to keep a building at a certain temperature level above the ambient temperature.

Heating energy is a very important issue for Ireland's public and private sectors (hospitals, hotels, university, leisure, and houses), and commercial firms due to its cold weather in certain seasons [34-36].

Figure 15 shows the gas consumption profile for Dublin City University from January 2000 to December 2003. There is a general upwards trend of 64 % during this time period in gas consumption.

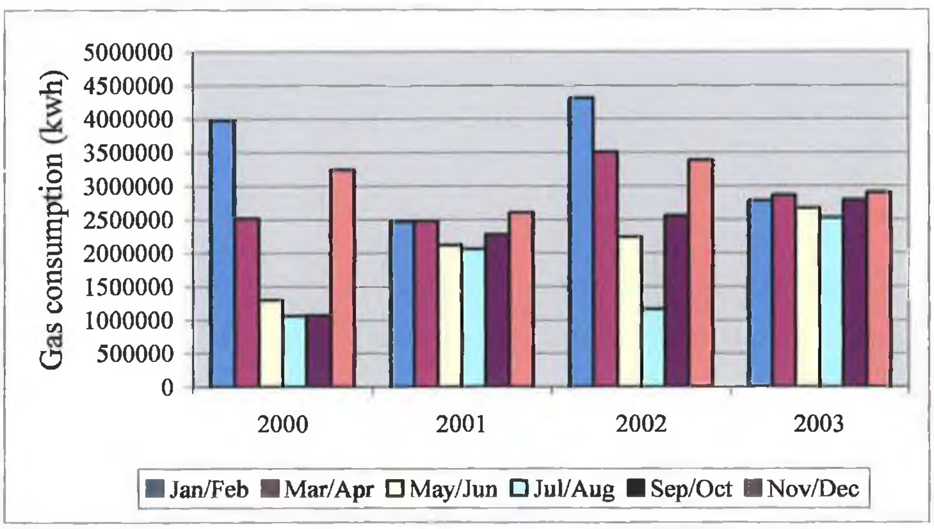

Figure 15 DCU gas consumption form 2000-2003

Although there is a single price for gas, the monthly usage divided into two sections daily and nightly consumption. This allows a direct comparison with the electrical power demand during this period.

The major heat demand for Dublin City University consist of space heating, and domestic hot water. The monthly heat demand varies through the year due to weather changes. Figure 15 show the monthly gas consumption for four years (2000-2003).

Figures (16,17) show the on/off peak gas consumption & cost for Dublin City University during the year 2000. The obvious variation is due to the change in monthly demand. The highest consumption was during winter from Nov to Mar. Gas consumption for the year 2000 was around 9460 MWH and 3700 MWH, on/off peak, respectively. Gas demand had 53 % of the whole year energy consumption, where electricity consumption was 47 %. The 53 % was made up of 72 % day consumption and 28 % night consumption.

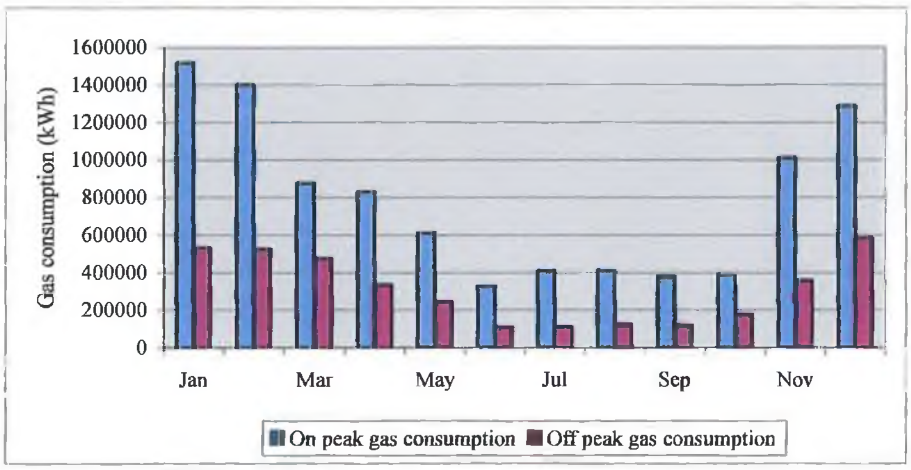

Figure 16 On/Off peak gas consumption (2000)

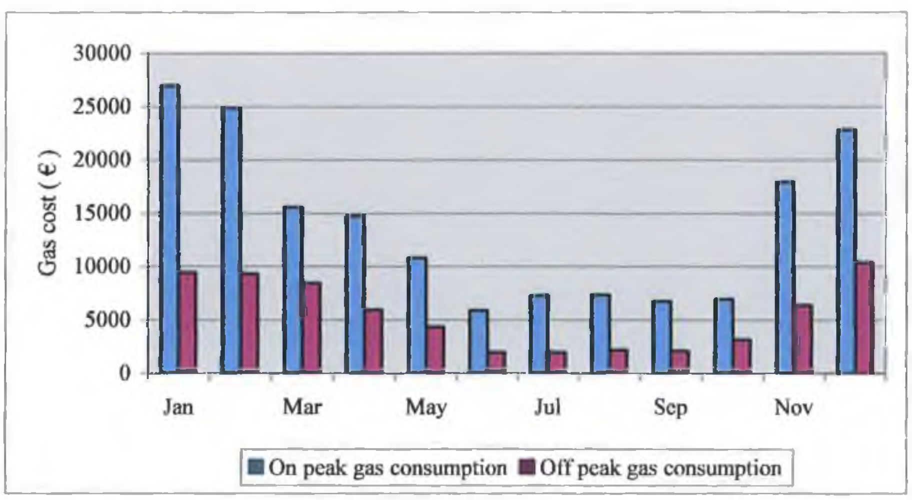

Figure 17 On/Off peak gas cost (2000)

Figures (20,21) show on/off peak gas consumption for Dublin City University for 2001. Dublin City University consumed 14.026 Gwh in 2001. On peak consumption was 9.818 Gwh at cost of €174,286. 49 % of the energy demand was gas (fig.21).

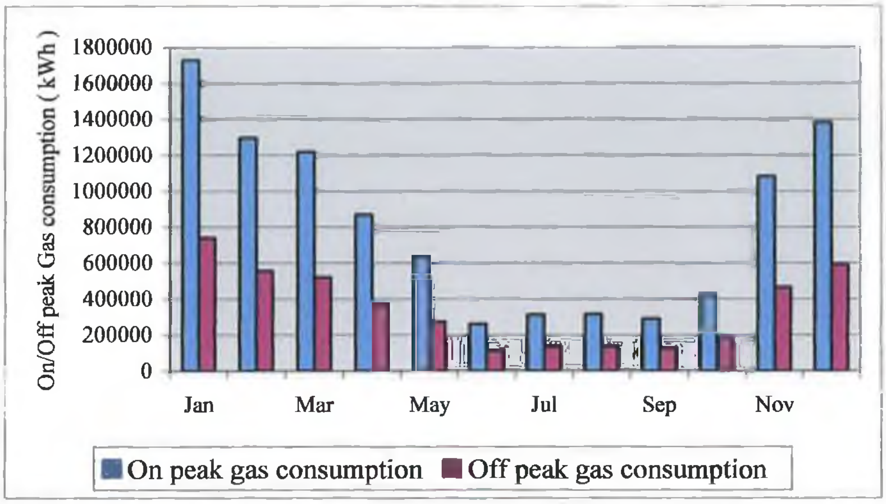

Figure 18 On/Off peak gas consumption (2001)

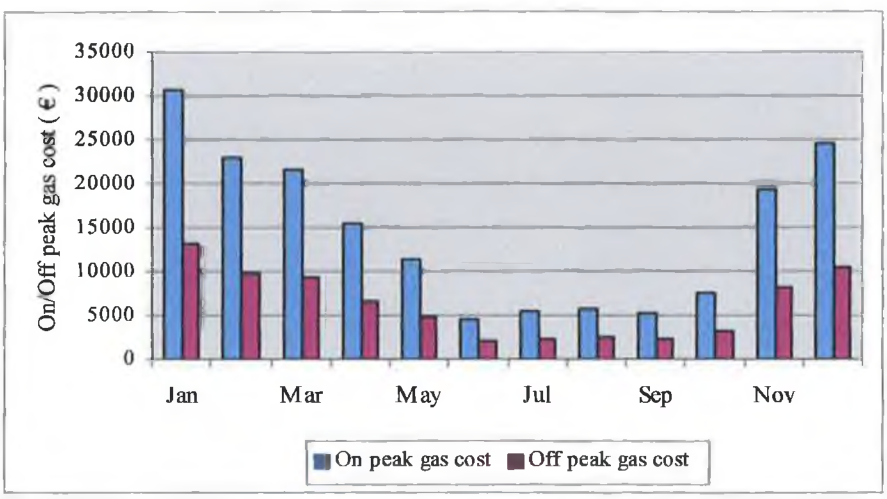

Figure 19 On/Off peak gas cost (2001)

On peak gas consumption during 2002 was 12.017 Gwh at a cost of €213,316. This is 55 % of energy consumption but only 23 % of the total cost of the energy. It should be noted that at present gas consumption in Dublin City University is increasing, gas consumption increased by 7.9 % in the period from 2000 to 2003.

During the financial year 2002 an increase by 21% in gas cost over the year 2000 was recorded.

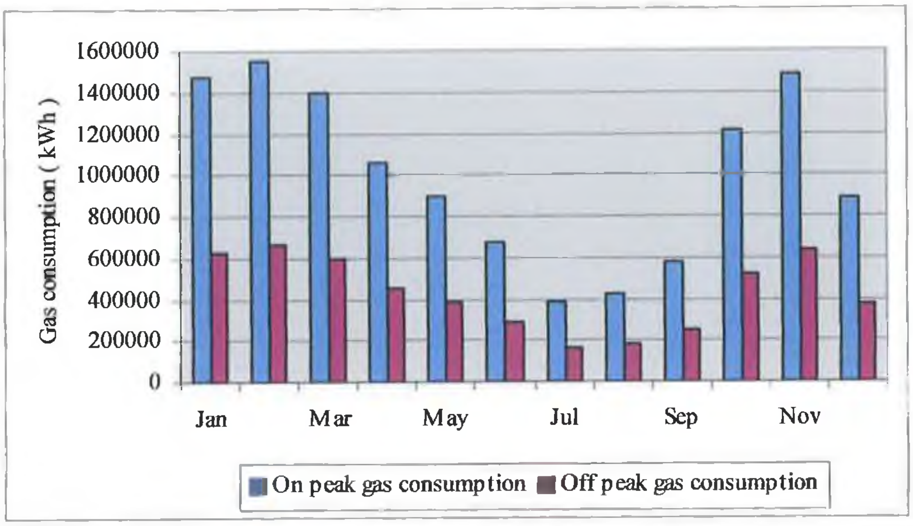

Figure 20 On/Off peak gas consumption (2002)

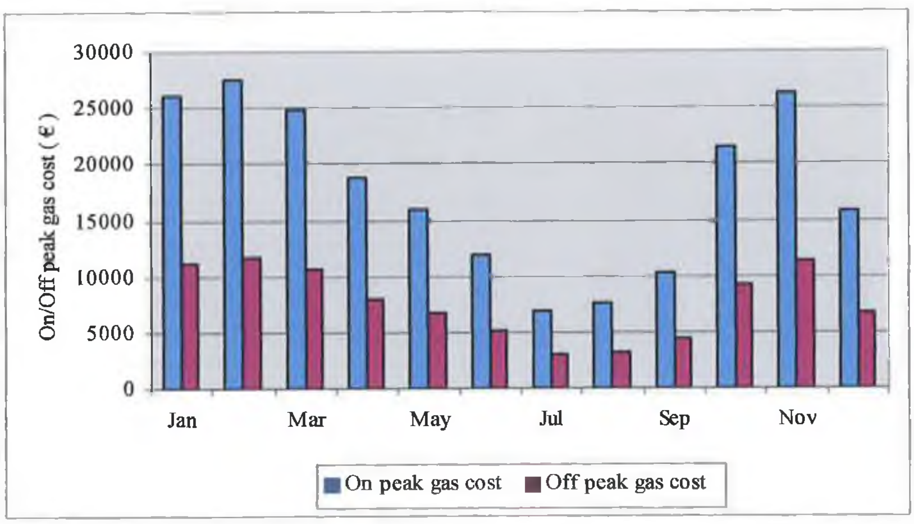

Figure 21 On/Off peak gas cost (2002)

Gas consumption during winter time is naturally higher. Fig. 22 shows the On/Off peak gas consumption for Dublin City University for the twelve months of 2003. The highest consumption in the winter period is in January with 14 Gwh.

A Typical demand profile for gas consumption is as shown in Fig. 30,31. The yearly heat demand was 10.723 GWh. In the low season in April to Sep the heat demand is between 177 MWh and 605 MWh.

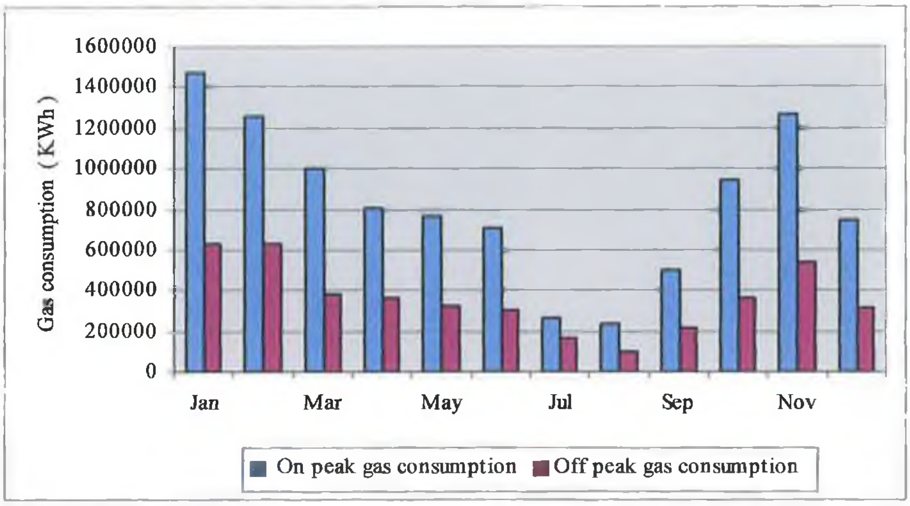

Figure 22 DCU gas consumption (2003)

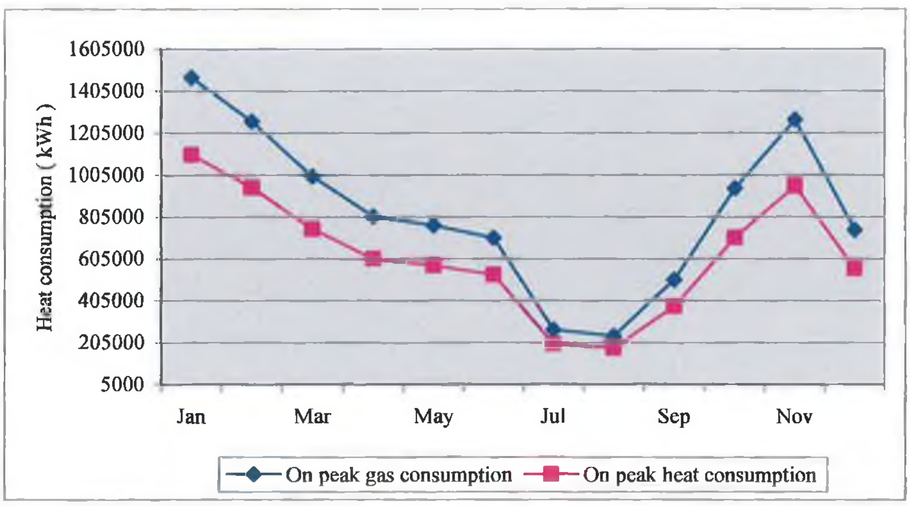

Figure 23 DCU heat demand (2003)

Heat usage is in the form of low temperature hot water generated in boilers using natural gas fuel. The boiler in the energy centre has a total capacity of 4.8 MW_{th}, and supplies heat to Dublin City University's buildings.

Detailed heat and fuel consumption data were analyzed to derive monthly consumption in 2003, monthly consumption pattern with high demand. The analysis led to the following:

· Peak average monthly heat (occurred in January): 1.101Gwh

· Base heat demand (occurred in August): 0.177 Gwh

· Total gas consumption in 2003: 7.467 Gwh

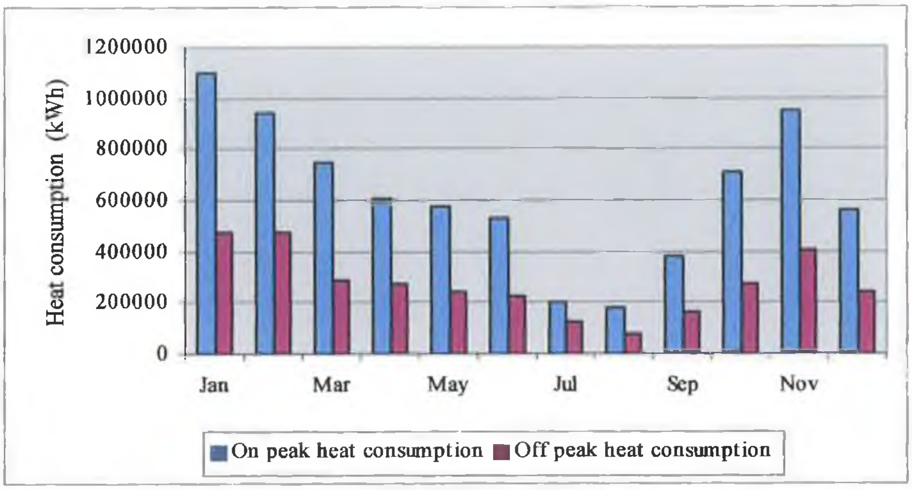

Figure 24 Monthly On & Off peak heat demand (2003)

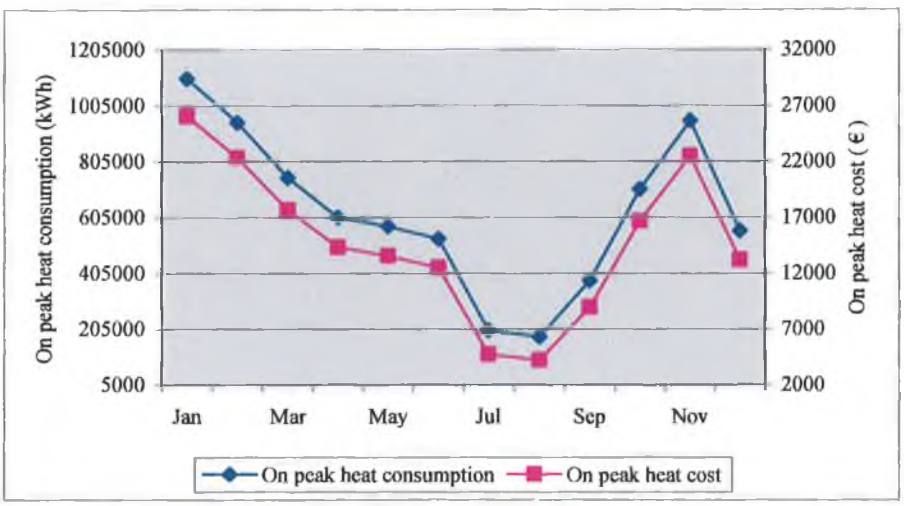

Figure 25 Monthly gas cost (2003)

As stated previously the electrical and thermal loads of the site tend to vary with time, the cogeneration system may require that any shortfall in the electricity supply be met by the purchase of electricity from the grid. These solutions will certainly have consequences on the annual average efficiency and the economics of the project. The ideal operation would thus consist of the use of the maximum electricity on site, while assuring continuous operation of the process at nominal condition and avoiding the generation of excess thermal energy.

Months	Day	On Peak Heat Consumption (kwh)	Off Peak Heat consumption (kwh)	On peak Monthly bill (€)	Off peak Monthly bill (€)
January	31	1,101,650	472,135	26,073	11,175
February	28	944,742	472,500	22,360	11,183
March	31	747,468	290,682	17,691	6,880
April	30	605,301	273,750	14,326	6,479
May	31	572,814	240,000	13,557	5,680
Jun	30	528,084	225,000	12,498	5,325
July	31	199,097	127,500	4,712	3,018
August	31	177,159	75,928	4,193	1,797
September	30	378,228	162,098	8,951	3,837
October	31	705,228	270,000	16,691	6,390
November	30	950,906	407,531	22,506	9,645
December	31	557,232	238,815	13,188	5,652
Total		7,467,909	3,255,940	176,746	77,062

Table 5 Monthly thermal power consumption & cost (2003)

3.4.3 Cost of energy

The average unit cost in the year to December 2003 was 6.42 c/kwh on peak time and 4.6 c/kwh at off peak time.

The current cost of thermal energy to Dublin City University based on the average cost of generation of hot water in the boiler amounts to 2.3668 c/kwh. This is based on the fuel cost of 1.7751 c/kwh and boiler efficiency of 75% (ESB data sheet).

3.5 Summary

The energy consumption profile was studied at Dublin City University from January 2000 to December 2003. This study was through a computerisation of the billed data, which gave a good assessment of performance highlighting trends. Both electricity and gas consumption at Dublin City University were found to be seasonal.

The electricity consumption varies less than the gas consumption because of the high base load of the site. There has been variation in gas consumption the last few years with more gas used in the winter months.

A cogeneration system can satisfy the same Dublin City University energy requirements as a conventional system, which is electric power produced at a central station (ESB) and on site boiler but with reduced requirements for source energy. If the end user of energy is inefficient, the cogeneration system will not eliminate that inefficiency. In fact, as a cogeneration system will typically reduce the cost of energy and power, it could lengthen the pay back period for energy conservation and efficiency.

4 Chapter four

4.1 Economic and technical viability of cogeneration for DCU

Cogeneration is a proven technology that saves fuel resources. Irrespective of all its technical merits, the adoption of cogeneration would principally depend on its economic viability, which is very much site-specific [29,31,37]. The equipment used in cogeneration projects and their costs are fairly standard, but the same cannot be said about the financial environment that varies considerably from one site and/or country to another. The best way to assess the attractive of a cogeneration project is to conduct a detailed financial analysis and compare the returns with the market rates for investments in projects presenting similar risks.

Well-conceived cogeneration facilities should incorporate technical and economic features that can be optimized to meet both heat and power demands of a specific site. A comprehensive knowledge of the various energy requirements as well as characteristics of the cogeneration plant is essential to derive an optimal solution. As a first step, the compatibility of the existing thermal system with the proposed cogeneration facility should be determined. Important user characteristic, which need to be considered, include electrical and thermal energy demand profiles, prevalent costs of conventional utilities (fossil fuels, electricity) and physical constrains of the site. A factor that should not be overlooked at this stage is the need for a reliable energy supply at Dublin City University site, which is extremely sensitive to an increase the energy costs.

To fully exploit the cogeneration installation throughout the year, the site should have the following characteristics.

a) Adequate thermal energy needs, matching with the electrical demand;
b) Reasonably high electrical load factor and/or annual operating hours;

These are essential for full exploitation of the cogeneration installation. Any CHP feasibility study is design to provide an estimate of the cost savings and financial returns that can be achieved by installing an appropriate CHP plant.

The feasibility study was carried out using the best assessment of Dublin City University future energy consumption, based on past consumption data, which was obtained from Dublin City University 's utility bills. This provides a good indication of future demand, but it is also important to take site-specific factors into account when assessing future energy requirements [38-42]. The following, in particular, must be considered:

A) Efficiency of energy use: It is important to ensure that energy is used as efficientlly as possible. Eliminating energy wastage and improving the efficiency of consumption are the most cost effective measure for reducing energy bills, and the evaluation of potential CHP plant should always be carried out against true energy demands, not against consumptions inflated by wastage and inefficiency.

B) Future change in site energy demands: most sites undergo changes in use and equipment over a relatively short period of time, so a CHP plant must be assessed not only against present energy demand, but against those anticipated for the future. Most significant projects that affect site energy demand are conceived several years before their completion, and knowledge of these can give valid indications of future energy demand. In addition, many sites undergo a gradual growth in energy use, particularly electricity, as a result of numerous minor site alterations.

C) Use of heat to replace electricity: there may be opportunities to replace electricity driven refrigeration plant with a heat pump using waste heat from the CHP system.

Dublin City University had an electric demand of 11.606 GWh in 2000. This demand increased to 16.5 GWh in 2003, about 63 % of this demand was during the

on peak period. Dublin City University's heat demand for the year 2003 was 9.957 Gwh of gas.
A CHP plant at the University site is a method to meet this increased electric requirement as the existing demand increases gradually and to avoid the expense of bills. In this thesis a CHP plant will be sized according to the year 2003 data.

This study included whether installing a CHP plant at the university site can satisfy the increased electric load, decrease the energy costs, and increase the savings in electric and gas bills. It shows that Dublin City University could install three different sizes of plant, but the choice will be depend on whether Dublin City University will be allowed to sell electricity to the grid or not.

Dublin City University will not have to sell electricity to ESB by choosing the base load option, and will have to import electricity from ESB some times during the year. Choosing the other operation options Dublin City University would have to export electricity to the grid most of the times during the year.

In this chapter we will analysis three engine sizes to have a very clear idea about the choice we will have to make depending on the operation option.

4.2 Methodology used

Since CHP produces power and heat simultaneously, it is essential to consider the extent to which Dublin City University has concurrent heat and power demands that can use the output of a CHP installation. This requires a time base assessment of Dublin City University's energy demand.

Dublin City University has fairly constant levels of energy demands over long period of time, with only minor variations resulting from occasional changes in the site activity. Dublin City University requires large amount of energy for space heating which show significant variations between winter and summer heat demands.
The study has sufficient consideration of consumption over a one- year period (2003), sub-dividing this period into twelve months.

4.3 Site calculation procedure

4.3.1 Tabulation and use of DCU's energy supply data

Once a decision has been taken on the appropriate time periods, the electricity and heat demand data should be assessed and recorded in a way that they can be readily used to calculate the potential energy cost savings (table 6).
Dublin City University energy supply data required include:

- A number of hours of the year allocated to each time period. That total is 5475 hours, which represent Dublin City University's demand over a full year during on peak time.
- The last two weeks of December have very low electricity and thermal energy due to Christmas holiday, the engine will not be efficient during this period when the engine output less than 50 % of its production. This fact has not been taken into account in this calculation.
- The average site electricity demand in kw for each time period (table 6)
- The average site heat demands in kw for each time period (table6). The data represents the heat supplied by the existing boiler.
- The average cost per unit of electricity consumed is 0.0642 €/kwh (on peak), 0.046 €/kwh (off peak). This cost exclude fixed cost components such as availability, capacity and fixed charges.
- The quantity of fuel consumed by Dublin City University to provide the heat demand. The cost per unit of the fuel is 0.017751€/kwh.

The data will be used to make an assessment of the annual cost of meeting Dublin City University energy demands. These are the cost that a CHP plant would reduce by supplying the energy requirements more efficiently.

Dublin City University's site requirements (table 6) and characteristics determine the type of cogeneration system that can be used by comparing Dublin City University's heat to power ratio with different type of engines heat to power ratio as mentioned in chapter 2. Choosing the type of the engine will be explained in the next section, but first the site must undergo some assessments, which are illustrated below.

4.3.1.1 Average purchased power rate

The purchased power rate was determined by dividing the total annual cost of purchased power by the total annual consumption. No consideration has been given to taxes, rate structure, etc. as can be seen from table 6.

4.3.1.2 Monthly electric consumption

Dublin City University's electrical data are available and can frequently be used as metered. This data can show Dublin City University's energy requirements for different seasons. Figure 17 illustrates monthly demand data for Dublin City University for the year 2003, and can be seen on month-to-month variation.

4.3.1.3 Monthly purchased power cost

Monthly purchased power is computed by multiplying the electricity monthly consumption by the average power rate. The monthly cost ranging from a low 57,651 €/kWh for several of the consumption months to a high of 73,579 €/kWh (fig.18).

4.3.1.4 Monthly electrical average consumption

Monthly average demand by Dublin City University is computed by dividing monthly power consumption by monthly site on peak working hours, the minimum average is 1.944 kW occurs in June (figure 34).

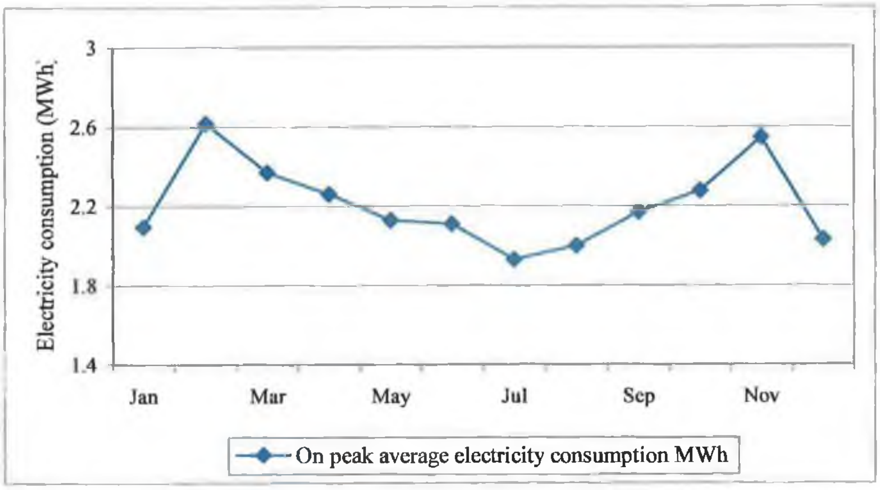

Figure 26 Average monthly electricity consumption for 2003

4.3.1.5 Monthly purchased gas

Purchased gas is determining from Dublin City University's historic billing and is computed to be €176,750 per year (2003).

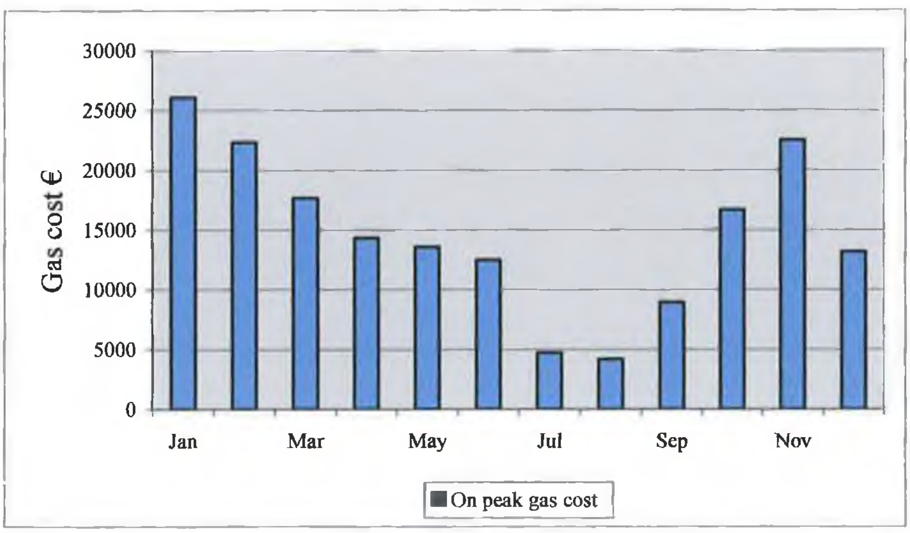

Figure 27 DCU's monthly gas cost (2003)

4.3.1.6 Monthly heat demand

The heating season is around 32 weeks, the heating load during this period was 5.99 GWh. A Typical demand profile for heat and site gas consumption is as shown in Figures (30,32). Yearly heat demand was 7.467 GWh.

Table 6 illustrate the monthly power consumption for Dublin City University that provided by ESB, and the monthly gas consumption provided by Gas Board.

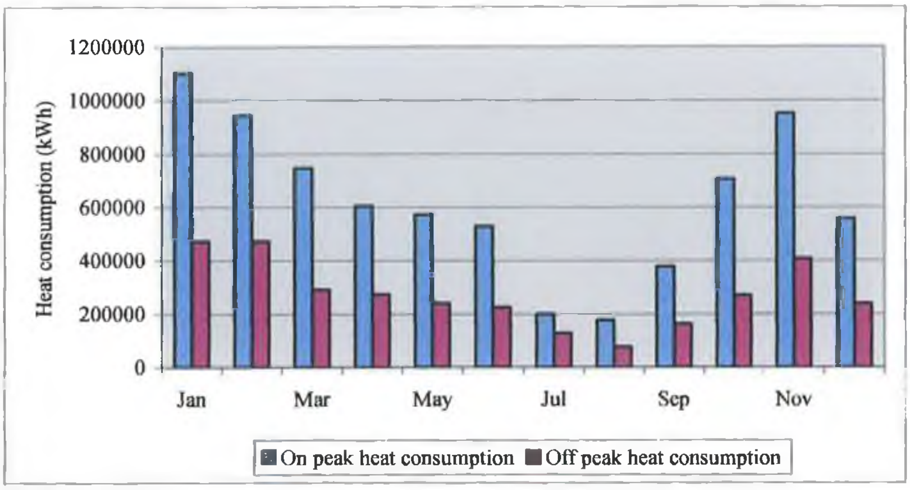

Figure 28 DCU monthly heat consumption (2003)

		Jan		Feb		Mar
	Period	Day	Night	Day	Night	....
	Hours	465	279	420	252	....
Electricity consumptions						
Unit consumed	KWh	975,720	310,000	1,1002,280	398,000	....
Cost per unit	C/KWh	6.42	4.6	6.42	4.6	....
Total cost	€	62,641	14,260	70,637	18,308	....
Average consumptions	MW	2.098	1.111	2.619	1.579	....
Fuel consumptions						
Unit consumed	KWh	1,468,867	629,514	1,259,656	630,000	....
Cost per unit	C/KWh	1.7751		1.7751		....
Total cost	€	26,073	11,174	22,360	11,183	....
Efficiency of fuel conversion	%	75		75		....
Heat demand	KWh	1,101,650	472,135	944,742	472,500	....
Heat to power ratio		1.129	2.03	0.858	1.583	....

Table 6 DCU site energy consumption & cost calculations (see appendix B for a full table)

Once the energy cost and data have been collected and tabulated, the next stage of the feasibility study is to select a potentially suitable CHP system. In doing this a range of equipment data was obtained from suitable suppliers and detailed calculations made to obtain the optimal engine size.

4.3.2 Heat To Power Ratio

For any prime mover/electrical generator used in a CHP plant, there is a balance between the electrical power that can be generated and the heat that can be recovered for use on site. This is generally referred to as the heat to power ratio, and is expressed as the quantity of heat recovered per unit of electricity generated. For example, a plant producing 500 kw of electricity and 1000 kW of heat has a ratio of 2:1 on the same basis, a site requiring 800 kw of electricity and 4000 kw of heat has a ratio of 5:1. The heat to power ratio is, therefore, a useful way of assessing the suitability of a CHP generator for a particular site.

It is considered important that a CHP plant achieves a high ratio between heat and electricity production. This is because the numbers of suitable heat loads are limited and if the heat/electricity ratio is low the potential for CHP electricity is not utilized in a good way. A minimum limit for the electricity / heat ratio could be introduced as a criterion for "Quality CHP". That would give incentives to use technologies with a high heat production for a certain electric load. However, it is important to stress that this high heat to power ratio must be obtained during "real" CHP operation with high overall efficiency [3-6].

4.3.2.1 Dublin City University site heat to power ratio

The heat-to-power ratio is one of the most important technical parameters influencing the selection of the type of cogeneration system (Table 2). The heat-to-power ratio of a facility should match with the characteristics of the cogeneration system to be installed. Heat to power ratio required by Dublin City University vary during different times of the season of the year. Dublin City University's site heat to power ratio value changes due to the season (figure 37), the smallest ratio value occurred in summer time precisely in July around 0.2 where the electricity and heat consumption are very low (figure 39). Dublin City University site requiring 2208 kw of electricity and 1364 kw of heat has a ratio of 0.5:1.

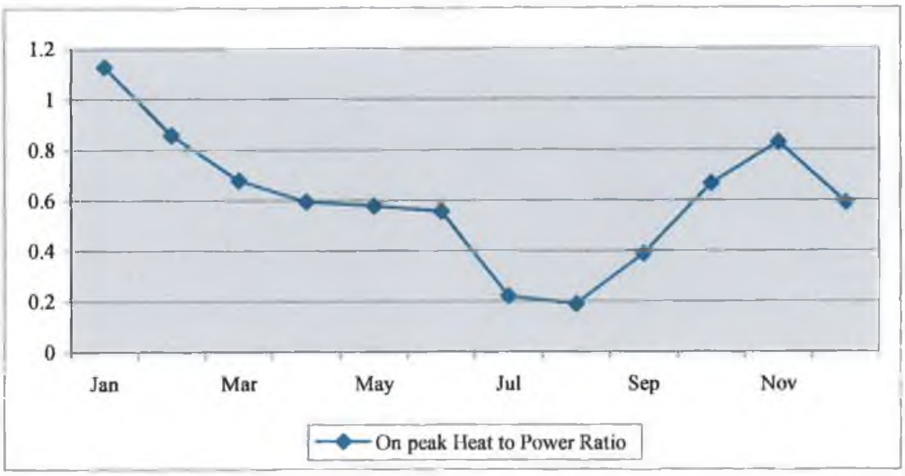

Figure 29 DCU' site heat to power ratio

Due to the heat to power ratio values determined above, a reciprocating engine would be the best choice for Dublin City University site.

Today reciprocating engine based CHP plants generally operate from natural gas, but some operator with diesel or biogas from landfill sites. The smaller units from about 30 kw_e and above are available as complete packages, comprising an engine, generator, heat exchanger and control system to provide a ready to go product.

The heat generated by the engine is extracted from several points. The engine coolant flows through the engine jacket, lubrication oil cooler, and the exhaust manifold cooler is used to extract the engine heat. Heat from the exhaust gas is then passed through a shell and tube heat exchanger, which is cooled, by the engine cooling circuit. Passing the coolant circuit through the primary side of a plate heat exchanger, allows connection to the user heating system. Fig 38.

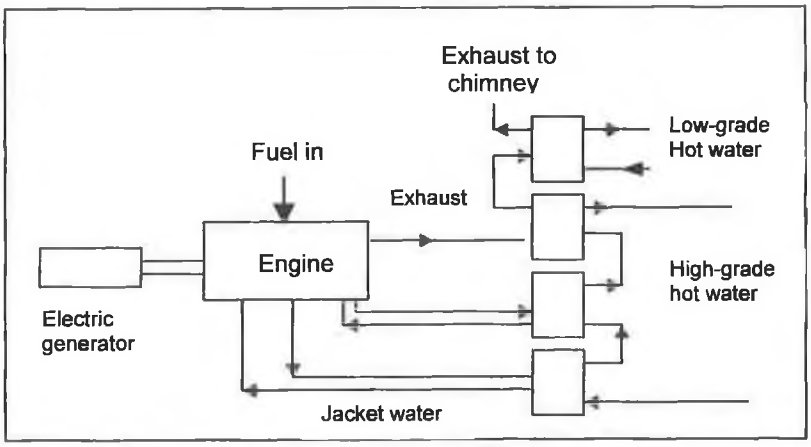

Figure 30 schematic diagram of reciprocating engine cogeneration

Typically a CHP plant based upon a reciprocating engine will have an energy output and useful heat to power ratio of up to 0.5-2.5, and an overall efficiency of 87 %. These statistics will show variations depending on model type [22].

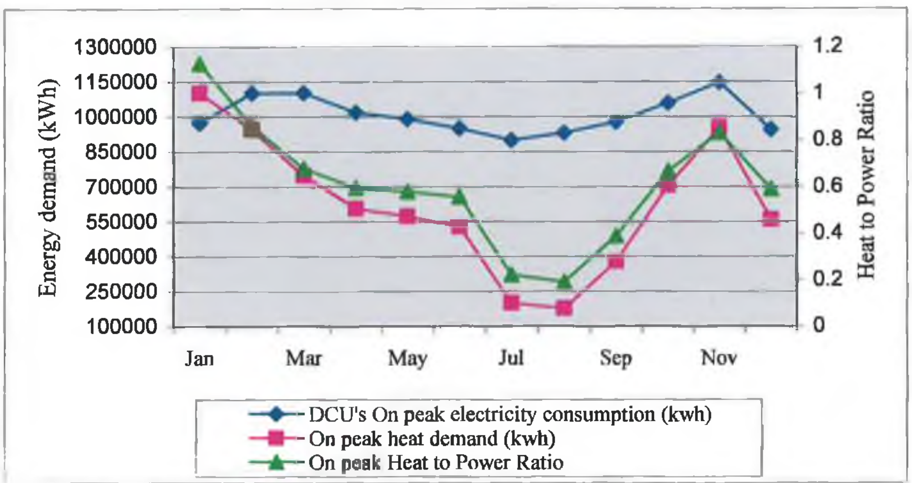

Figure 31 Monthly energy demand & heat to power ratio

4.4 Plant sizing

The selection of an appropriate CHP unit and size is presently something of an art, the majority of CHP companies now have extensive experience sizing and, more importantly, running units for particular building types, sizes and end uses.

A number of models have been developed for analysing the economic of CHP in existing buildings [43-45]. They nearly all require that at least some data on sizing CHP plant.

As a minimum, information should be obtained for a number of options, and should include:

- Electrical output
- Heat output that can be recovered
- Fuel consumption of the equipment
- The cost of supplying and installing equipment
- The approximate cost per kilowatt hour (kwh) generated.

A cogeneration system can satisfy the same Dublin City University requirements as a conventional system, which is defined as electric power produced at a central station and on site boiler but with a reduced requirement for source energy. If Dublin City University energy is inefficient the cogeneration system will not eliminate that inefficiency. In fact as a cogeneration system will typically reduce the cost of energy and power, it could lengthen the payback period for energy conservation and efficiency improvement investment.

Sizing on heat demand will maximise energy and environmental savings. Depending on the heat to power ratio of site energy demand, sizing to match the heat requirements will result in a scheme that may offer a surplus of electricity generation, or may require top-up electricity supplies (e.g. at times of peak electricity demand). The economy of exporting electricity then becomes a key issue in determining economic CHP plant size [46-48].

Sizing a CHP plant on electrical demand will result in surplus heat to be rejected to the environment and supplemental thermal energy may be required from a conventional source.

Plant sizing involves matching the technical and economical requirements of a given site to establish the CHP unit, which is both technically feasible and best fits the site economically. Plant sizing is critical to the economic viability of the scheme.

Through the establishment of a detailed database concerning electrical and heat demand profile, methodology for plant sizing can be established based on the following considerations operation regimes for CHP plants [49-50].

4.4.1 Base-load design

Fig.40 illustrates a cogeneration system can be sized to the minimum electric loads. In practice, the minimum may occur during a different season than will the site peak requirements. In this case, the amount of on site capacity is 1944 kw, and then the system is operated at its full capacity and peak efficiency for its full availability. Up to 8,000 hours per year are possible for reciprocating engine. This approach maximizes on-site production capacity and the use of the end-user investment and maintenance costs. Additionally, operation at rated output also results in maximum fuel efficiency and reduces fuel costs per kilowatt-hour delivered.

4.4.2 Average-load design

A CHP unit can be designed to provide average load electrical or thermal output, with any surplus electricity being sold to the grid & surplus hot water dumped. The graph (fig.39) shows an example of this, representing average load thermal energy. Due to the variation of fuel and electricity price, electrical average load sizing is the most cost effective solution if the surplus electricity could be sold.

4.4.3 Peak-load design

Sizing a CHP unit to the electricity peak load would lead to a large amount of surplus electricity that has to be sold to the grid and at the same time a large amount of hot water would be dumped. By taking this option unless there is a heating storage at the site which would be an economic issue and very efficient.
Figure 40 shows the month on which min/max loads occur. In practise, the min/max could occurs during different seasons.

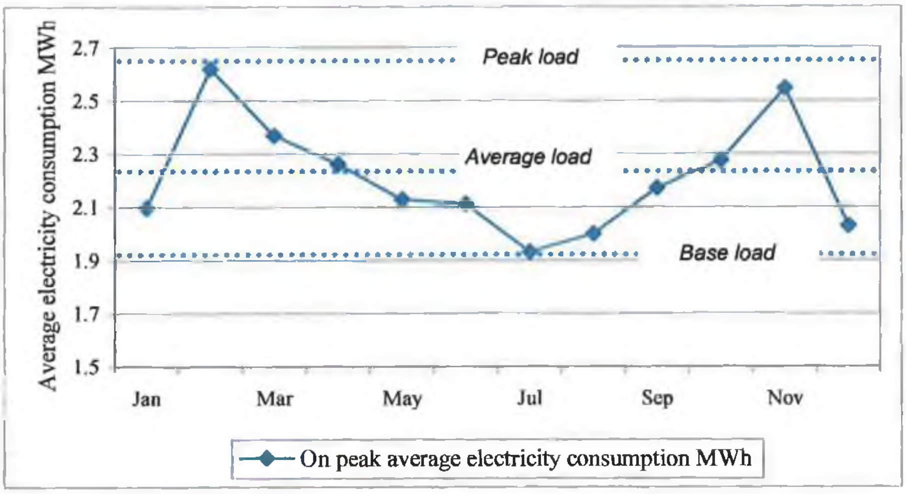

Figure 32 Different operation regimes (2003)

The Initial selection of CHP plant is dictated by two factors, the electrical demand of the site, and the site heat demand in terms of quantity, temperature etc., that can be met using heat from the CHP plant. The proposed plant will be sized to meet this electrical & thermal demand.

From the analysis of the site's electricity and the heat patterns, based average, and peak process electricity requirements of 2012 kw, 2179 kw, 2619 kw are chosen for electrical matching. The design will start deliberations with on-site generation options ranging from demonstration to natural gas reciprocating engines.

A feasibility analysis was used to narrow the technologies for consideration using heat to power ratio data (see table 6) to reciprocating engine generators sized at 2012kw, 2179kw, and 2717kw. The same assessment narrowed the operating regime for detailed consideration to base load, average load, and peak load strategy. Grid independent operation was found to be too expensive while three operation regimes of chosen systems enable Dublin City University to avoid the expense of purchasing energy.

We examined the performance of three different sizes, operating in a peak shaving mode at Dublin City University. Peak shaving mode means that during occupied daytime at Dublin City University, the generators would be operated during ESB peak hours. At these times, the generators would operate in parallel with the utility system and reduce the load seen by ESB as much as possible.

At the present time, engine generators have modest differences in their performance characteristics and costs. Reciprocating engines appear to have an economic edge at the present time.

During the operation hours, the waste heat from the electricity generators would be used to the maximum extent possible to displace heat supplied by the boilers for space heating and domestic heat water.

The key parameters describing any combined heat and power system are rated electricity and thermal energy production, installed cost, and operations and maintenance cost. The following table shows our estimates of these costs for the natural gas reciprocating engine.
Table 7 shows the three engine sizes and their characteristic that are necessary to know before making any feasible study.

	Engine size		
	2012 kw	2179 kw	2717 kw
Unit thermal output (kw)	2,212	2,350	2,890
Unit fuel use (kw)	5,185	5225	6438
Electrical efficiency	38.8%	41.7%	42.2%
Thermal efficiency	42.6	45%	44.9%

Table 7 Characteristics of Combined Heat and Power Systems (Jenbacher data sheet form)

The primary differences between these engines are unit fuel use and estimated installed cost. The 2012 kw engine uses 8% less natural gas than the 2179 kw and 19.5 % than 2717 kw. The result of this difference in electricity conversion efficiency plus the fundamental operating principles of these units is that these engines produces 3 % less useable waste heat per kilowatt hour of electricity production than the 2179 kw engine. Our estimates of installed cost suggest that there are small differences in installed cost between these units. However under competitive bidding we would expect these differences to be eliminated. Likewise, the O&M costs and oxides of nitrogen emissions for these technologies are comparable.

4.5 Engine calculation procedure

Various assumption and calculations are reviewed below. These choices were based on the amount of information available from the CHP supplier Jenbacher Company and Dublin City University's historic bills.

4.5.1 Capacity

The initial choice of equipment size is based on a review of Dublin City University's historic demand data. Minimum billing demands have been more that 1931 kw, with high load factors suggesting that demand is rather steady.

1) System size

The size of the base load system was determined by dividing the on peak monthly site demand by the on peak monthly working hours (fig40). The base load size considered in this case is 2012 kw.

The proposed CHP unit for Dublin City University is sized by examining the minimum monthly electricity consumption. Figure 40 illustrates a CHP system sized for Dublin City University based on the minimum electrical load of the site, i.e. the level below which the site electrical demand seldom falls. For illustration purpose the figure represents the month in which minimum loads accrue.

2012 kw reciprocating engine was chosen as the base load technology. The proposed engine is taken to have efficiencies of 38.8 % for electricity generation, 42.6 % for thermal generation, fuel consumption is 5185 kw, exhaust heat recovery 2212 kw, and engine availability 95%.

2) Engine's Power production

Based on a 2012 kw engine, it is possible to determine the amount of electrical energy that must be produced to satisfy DCU electrical requirements by multiplying net electricity output, monthly working hours and engine availability makes the computation of the system's electrical output. The yearly-generated electricity based on a 2012 kw engine size is determined to be 10.464 GWh.

The following equations ((1), (2), (3)) show how to calculate the monthly engine electrical output by knowing the engine characteristics, and how to calculate the electricity shortfall/surplus and its cost in case of electrical surplus and in case of electrical deficit, respectively [21,30,38]. A full monthly calculation is included in appendix (D).

Electricity generated by CHP (Q_e)

$Q_e = H_p * Q_a * \eta_v$ ....(1)

Electricity shortfall/surplus

$Q_s = Q - Q_e$ .... (2)

A positive figure indicates a shortfall of electricity in that time band, and the shortfall is given the same unit value as the unit purchased price, and a negative figure means the opposite.

Electricity (shortfall/surplus) cost

$E_c = Q_s * E_s$ ....(3)

In case of electricity surplus, the purchased electricity to the grid is given an estimate unit value of 2/3 times the unit purchased price.

The CHP plant is designed for Dublin City University to the electricity base load, because of that surplus heat will be dumped and supplemental thermal energy will be required in January, February, and November (fig.41). The balance between the electrical and thermal load is as important as the size of the plant. It is not economically feasible to design a small scale CHP scheme to meet both electricity & heat demand.

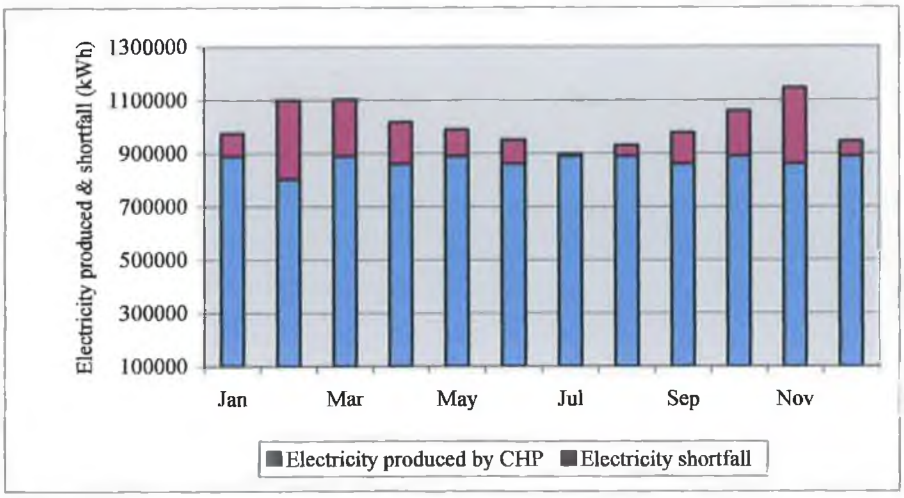

Figure 33 Electricity produced and shortfall for 2012 engine

Figure 41 shows the amount of electricity generated by the engine during each month and the supplemental electricity that needed to cover the demand, which would be imported from the grid to satisfy Dublin City University demand.

Electrical shortfall would be 86,919 kwh during January where the electrical demand is 975,720 kwh and the engine output is 888,801 kwh and starts growing in February until reach over 297,492 kwh due to an increase in electricity demand, as day light gets shorter.

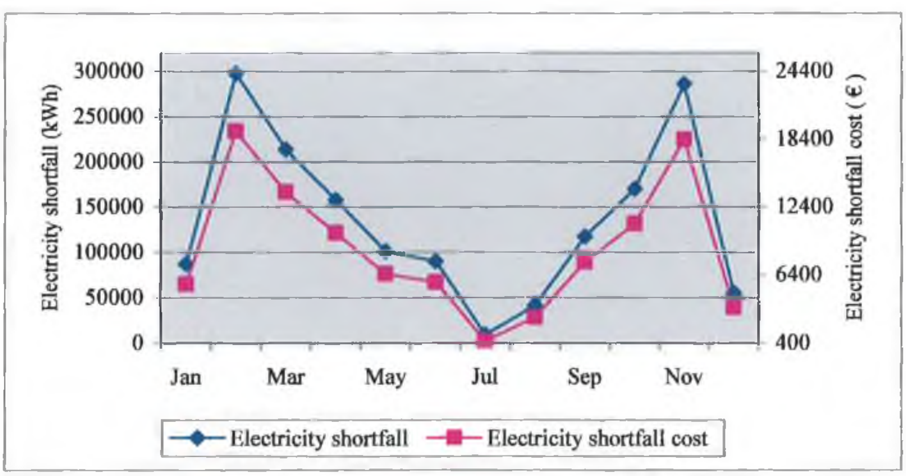

Figure 34 Shortfalls of electricity & cost

The electrical consumption for Dublin City University is shown in Tables 6&8. Electricity generated nearly matches the baseline case since the electrical and thermal loads in the plant remain the same. The difference between the demand and the CHP facilities is to be imported from the grid.

Months	On peak demand (kwh)	Generated (Kwh)	Sold back (Kwh)	Purchased (Kwh)
Jan	975720	888,801	------	86,919
Feb	1100280	802,788	------	297,492
Mar	1102400	888,801	------	213,599
Apr	1017600	860,130	------	157,470
May	990000	888,801	------	101,199
Jun	950000	860,130	------	89,870
Jul	898000	888,801	------	9,199
Aug	930000	888,801	------	41,199
Sep	977280	860,130	------	117,150
Oct	1058720	888,801	------	169,919
Nov	1146100	860,130	------	285,970
Dec	943900	888,801	------	55,099
Total	12,090,000	10,464,915		1,625,085

Table 8 Electricity needed & produced

3) Engine fuel requirements

The fuel requirement is determined from the manufacture's specification. The value specified by the main manufacture data is 5,185 kw.

4) Cogeneration fuel cost

The hourly cost of cogeneration fuel is determined by multiplying the fuel requirement by the average rate for fuel. Fuel costs are computed to be 87.4369 €/h for January 2003.

CHP fuel cost can be determined from equation 4.

$$CHP_f = H_p * F_c * \eta_v * CHP_c \ldots\ldots\ldots\ldots\ldots(4)$$

5) Annual fuel cost

The annual system's fuel cost of € 478,718 is calculated by multiplying the monthly working hours by the engine fuel consumption (kw) by the engine availability.

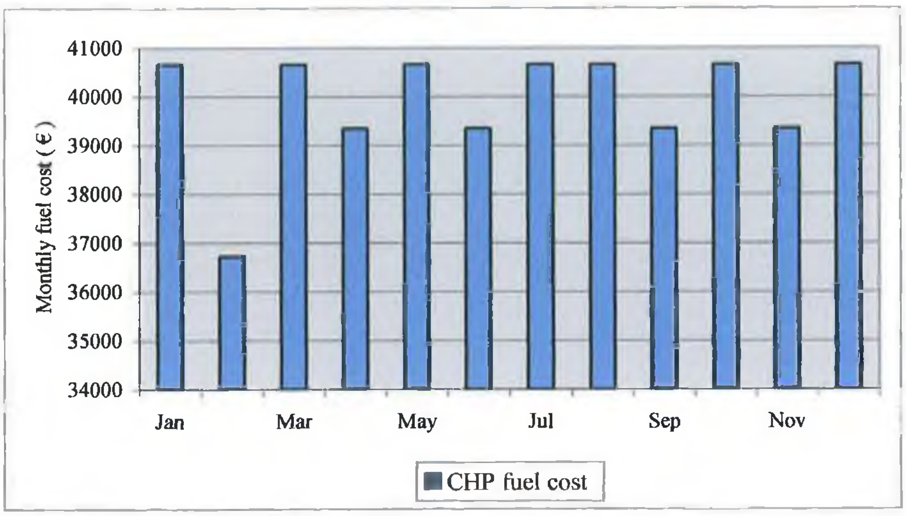

Figure 35 Monthly fuel cost

6) Operating hours

The number of operating hours for the proposed engine will be 15 hours a day in which the ESB time tariff applies (On peak), that means 5475 hours a year.

7) Maintenance rate

The maintenance rate of the engine generator set is given by the Jenbacher company to be 0.015 €/kwh for 2012kw engine.

8) Maintenance cost

The maintenance cost computed to be € 28.671 per engine hour for the 2012kw engine.

The annual maintenance cost is the product of the system's electrical output of 10.433GWh and the maintenance rate of 1.5 c/kwh running. Maintenance costs are estimated to be € 156,974 per year (see appendix B).

9) Total variable operating costs

The total cost of the fuel and maintenance cost approximates the system's variable operating costs. In this case, determined to be 116.1079 €/h.

10) Variable operating cost

The monthly variable operating cost (January) is computed as the product of the number of monthly operating hours and the variable hourly operating cost.
The product is 53,990 €/month.

11) Stand by rate

The stand by reservation charge is determined by an inquiry to the ESB, from a rate sheet. In this case the monthly reservation charge is 3 €/kw.

12) Monthly standby cost

It is assumed that the standby would be taken for the full capacity of the engine. If the capacity exceeded the site peak demand, it might be possible to contract for the peak site demand rather than the engine capacity. In this case, the monthly standby cost of € 6036 is computed as the product of the reservation fee and engine site capacity.

13) Total monthly operating cost

The total of all operating costs is the sum of the variable costs, standby costs, and is computed to be 68,553 €/month.

14) Cogeneration power sale

Because the engine capacity is almost the same as the site base load, therefore, no power would be exported.

15) Value of cogenerated power

To realise the benefit of CHP, the plant operator needs to buy fuel and convert it to electricity in such a way that the total costs of such conversion produce a saving in costs compared with the purchase of electricity from external source.

This rate is computed as the average of the cost of power used internally and the value of power sold to the grid weighted by the amount of power used for each purpose. In this case, with no power sales, the value of cogenerated power is explained below.

A typical illustration based on the energy tariffs outlined earlier would be.

Electricity cost = Gas Cost / Electricity conversation efficiency

= 1.7751 / 0.388 = 4.1 c/kwh

CHP operation & maintenance cost = 3.2751 c/kwh

Total cost of electricity generated = Electricity cost + CHP operation cost

= 4.1 + 3.2751 = 7.3751 c/kWh

Credit for value of CHP heat = 2.3668 c/kwh

Net cost of electricity = Total cost of electricity generated - Credit for Value of CHP heat

Net cost of electricity = 7.3751 – 2.3668 = 5.0083 c/kwh

When comparing an electricity cost of this level with the tariff rates shown previously, it is evident how the energy cost savings from CHP are produced.
However, comparison of the figures shows that it is often not cost effective to operate the CHP during the night, when the cost of power purchase is less than the marginal cost of generation by CHP.

16) Hourly value of cogenerated power

In this case, the hourly cogenerated power is determined as the product of the rate per kilowatt-hour, or 0.052373 €/kwh, and the engine capacity of 2012 kw.
It is computed to be 105.374 €/h.

17) Heat recovery

The amount of recoverable heat is given by the Company data sheet to be 2212 kw.

18) Value of recovered heat

The value of available heat was computed, as the fuel cost divided by the boiler efficiency. It is found to be 2.3668 c/kwh.

19) Recovered thermal energy

Multiplying net engine exhaust gas output, monthly working hours and the engine availability makes the computation of the systems thermal output. The yearly-generated heat based on 2012 kw engine is determined to be 11.505 GWh (see appendix B).

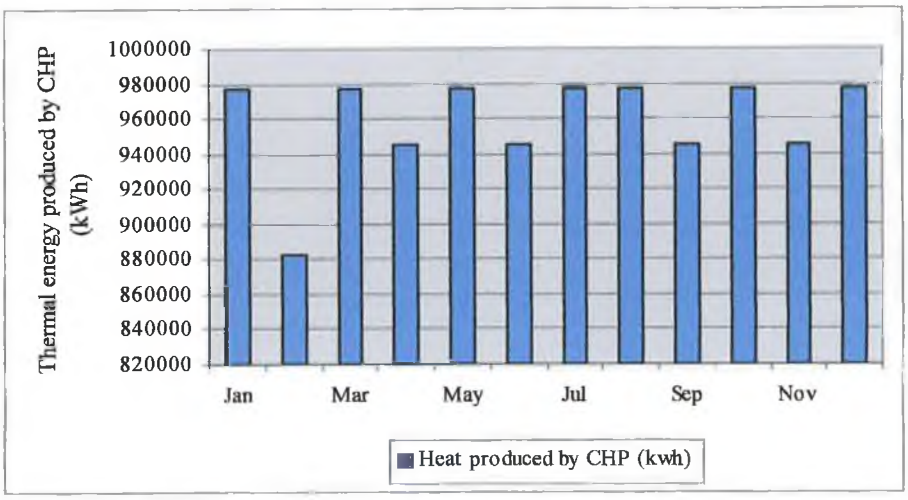

Figure 36 Thermal energy produced by CHP

The following equations ((5), (6), (7)) presents the way the monthly engine's heat output was calculated, and how to calculate the heat shortfall/surplus cost in case of heat surplus and in the case of heat deficit, respectively [21,30,38].

Thermal energy recovered from CHP

$H_e = H_p * E_h * \eta_v$ ....(5)

Heat shortfall/surplus

$Hs = H - H_e$ ....(6)

A positive figure indicates a surplus of thermal energy in that time band, which has to be dumped if there is no heat storage available.

Heat (shortfall/surplus) cost

$H_c = (Hs / \eta f) * Hf$ ....(7)

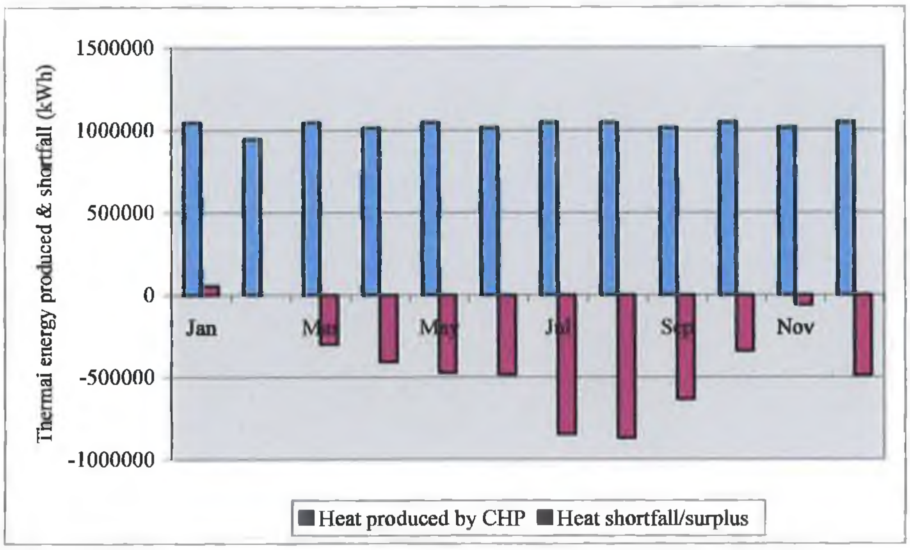

Figure 37 Thermal power produced

It can be seen from fig.44 when the heat demand exceeds the engine output and the cost of the required heat energy heat energy to cover the shortfall. We presume that the energy would be dumped to the atmosphere and would cost Dublin City University nothing (figure 46). The figure illustrates the amount of energy that is produced by CHP and the amount of energy required. From this figure we find the energy shortfall and surplus used and required every month of the year.

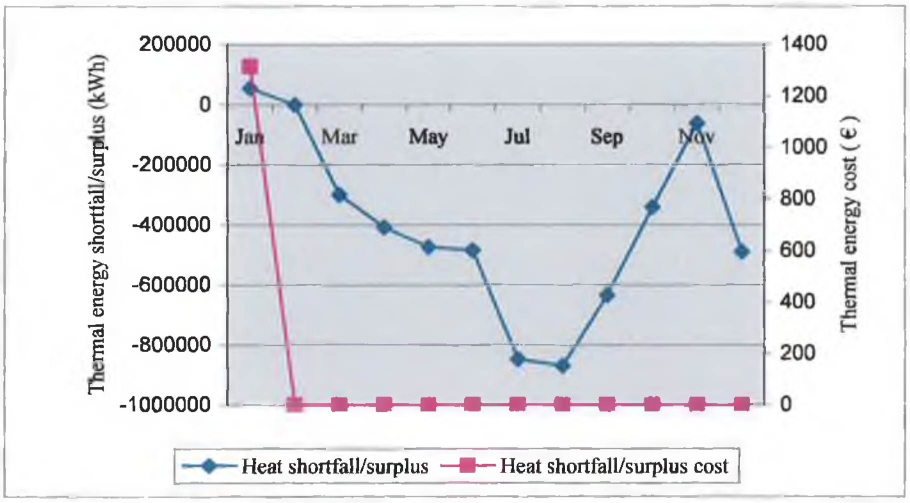

Figure 38 Heat shortfall/surplus

Months	Recovered heat (kwh)	Dumped heat (kwh)	Purchased heat (kwh)	Delivered (kwh)
January	977,151	------	124,499	1,101,650
February	882,588	------	62,154	944,742
March	977,151	-229,683	------	747,468
April	945,630	-340,328	------	605,302
May	977,151	-404,337	------	572,814
Jun	945,630	-417,546	------	528,084
July	977,151	-778,054	------	199,097
August	977,151	-799,991	------	177,160
September	945,630	-567,401	------	377,750
October	977,151	-271,922	------	705,229
November	945,630	------	5,276	950,906
December	977,151	-419,919	------	557,232
Total	11,505,165	4,229,181	191929	7,467,434

Table 9 CHP heat generated, dumped, purchased & delivered

Figure 47 illustrates the amount of energy that is produced by CHP and the amount of energy needed. It can be seen the energy shortfall and surplus used and required every month of the year.

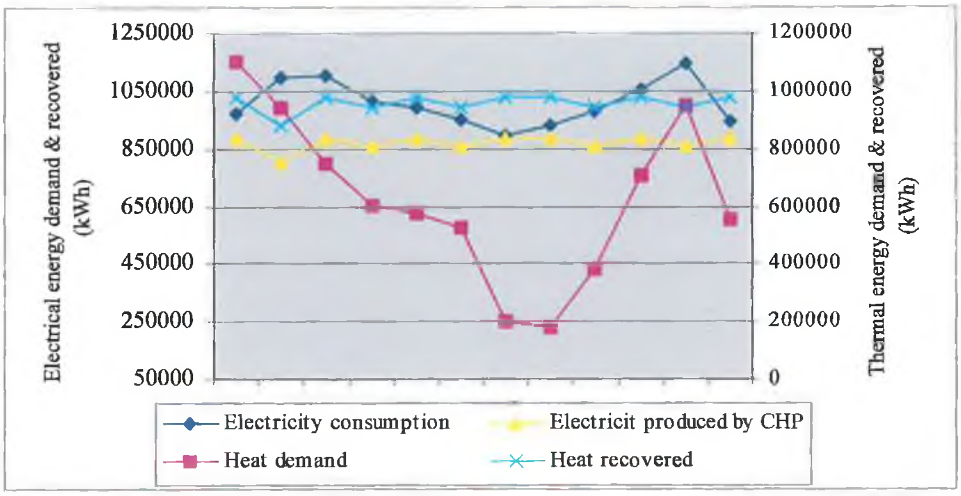

Figure 39 Power produced & demanded

The thermal energy provided by the CHP Plant is shown in Table 9. The thermal load provided by CHP will be large than demand, therefore the extra load would be dumped when there is no need for it.

An analysis of cogeneration economics must also consider the value of recovered heat. The value of the useful, recoverable heat is based on both the cost of the fuel that is displaced and the efficiency with which that fuel is converted to useful heat.

In valuing recovered heat, it is important to note that the heat recovered from a prime mover is available as heat, while fuel must be purchased as fuel and then converted to useful thermal energy in some combustion device.

20) Hourly value of recovered heat

This value is computed as the products of the rate and the amount of recovered heat. It is computed be 56.073 € per hour of operation.

21) Fuel displaced

The amount of fuel that that can be displaced from the boiler is computed by dividing the recovered thermal energy of 9.957 GWh per year by the boiler efficiency, which is 75%. The total displaced fuel is estimated to be 13.276 Gwh annually (figure 48).

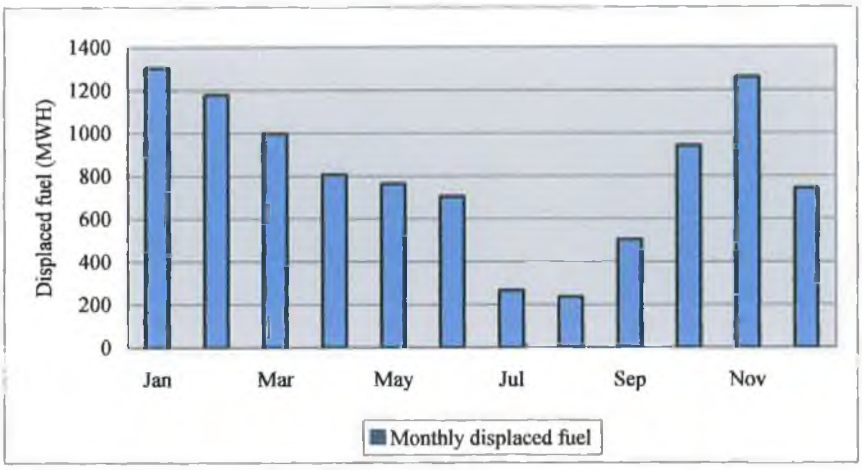

Figure 40 Monthly displaced fuel

22) Heating fuel savings

The value of displaced fuel is computed as the product of the total fuel displaced and the rate for heating gas, which was 1.7751 c/kwh. The project fuel saving is € 172,208.

23) Monthly electricity (shortfall/surplus) cost

It is determine by subtracting the amount of electricity demand from the amount of electricity produced by CHP. The negative figure indicates a surplus of electricity in that time band, which has to be purchased from the grid. It is computed to be €19,099 in February where the electricity shortfall is the highest.

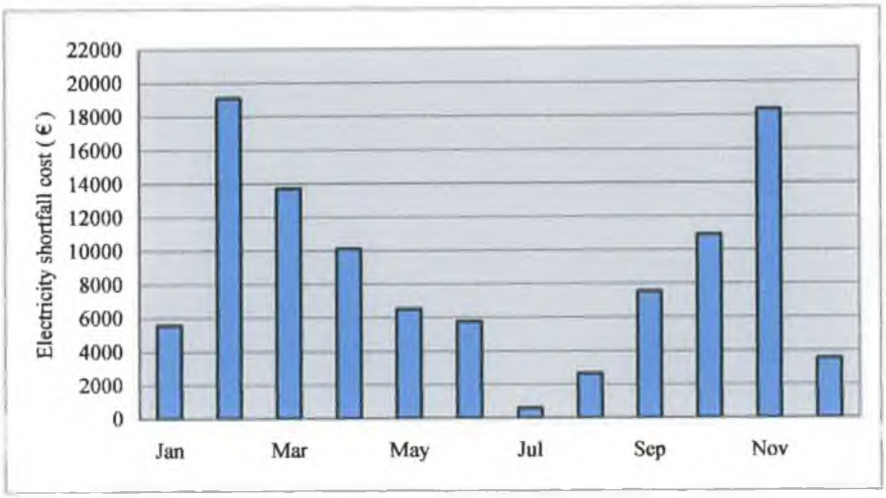

Figure 41 Monthly electricity shortfall cost

24) Monthly heat (shortfall/surplus) cost

It is determine by subtracting the amount of thermal demand from the amount of the heat produced by CHP. The negative figure indicates a surplus of heat in that time band, which has to be dumped. It is computed to be 191.929 Mwh for the whole year.

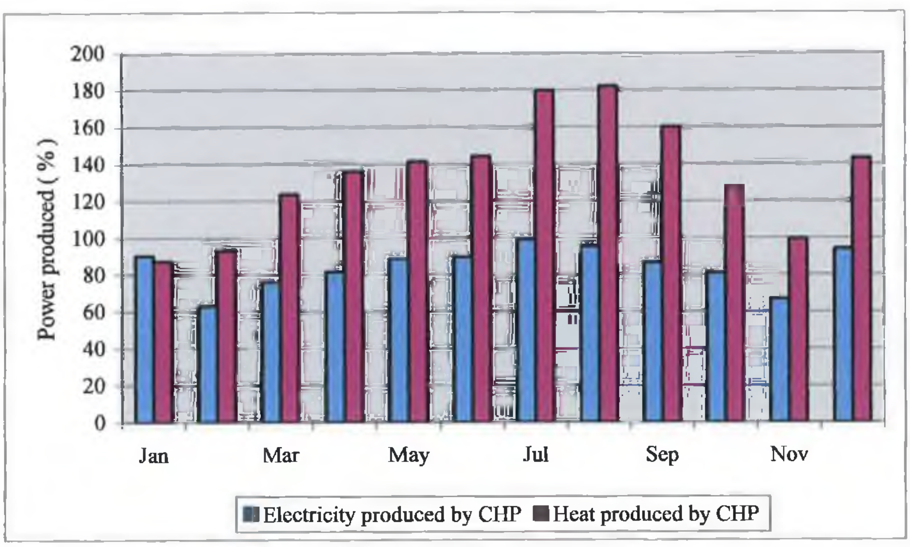

Figure 42 percent of power produced

25) Energy cost with CHP system

Energy cost with CHP of € 816,996 determined by computing the cost of fuel that is used by CHP to generate the energy added to the cost of the electricity shortfall, which is required from the grid to cover the shortage and the cost of the shortfall of thermal energy (table 10).
Energy cost with CHP computed as it seen below. Equation (8) and (9) show the savings due to electric power production in the case of electrical deficit [38].

$E = CHP_f + E_c + H_c$ ....(8)

$E = CHP_f + Es\,(Q - H_p * Q_a * \eta_v) + H_f\,((H - H_p * E_h * \eta_v) / \eta_f)$ ....(9)

26) Energy cost without CHP system

This is determined by adding the cost of the electrical consumed by DCU and the cost of the gas used by DCU boiler. It is computed to be € 88,715 for January 2003. Energy cost without CHP is the sum of electricity cost and the heat cost.

$E_{in} = Q * E_G + G * H_f$ ....(10)

27) Energy cost savings

Energy cost savings determined by subtracting the energy cost without CHP from the energy cost with CHP. The annual savings is € 135,932.

Energy cost savings is the difference between the power cost from the grid and the power cost generated from CHP. The annual saving is calculated using the equation (11).

$E_S = E_{in} - E$ ....(11)

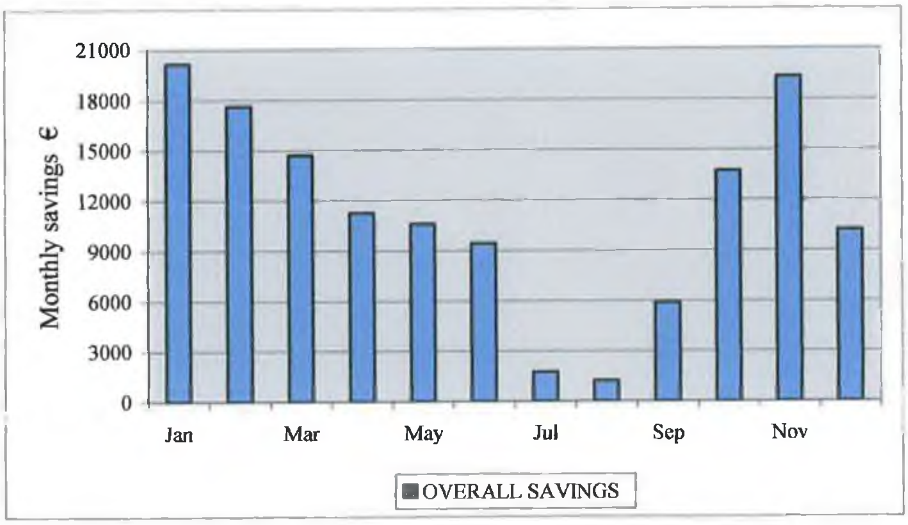

Figure 43 Monthly saving with 2012 kw reciprocating engine

The monthly savings as shown in fig 43 shows a large saving occurs in Jan as the site would use all the electricity and heat generated by CHP, and the smallest savings would be in Aug because the heat consumption would be very low, so most of the heat generated would be dumped.

Fig 44 gives a clear idea about the percentage saving that DCU would make for each month of the year.

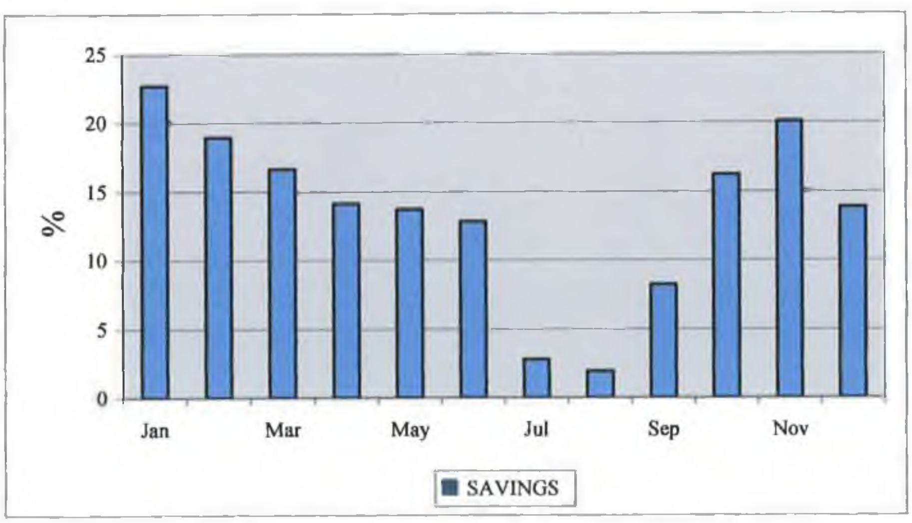

Figure 44 Monthly energy cost savings (%)

28) Budget

The budget was estimated based on typical values and was estimated at 370 €/kwh for a total budget of €750,000.

29) Simple payback

The payback on investment is computed by dividing the total price investment by the annual saving of €135,932 annually. Simple pay back is estimated to be 5.5 years.

Table 10 Engine characteristic (see appendix B for full table)

Net electricity output	kW	2012	....		....		....
Fuel consumption	KW	5185	....	5185	....	5185	....
Exhaust heat recoverable	KW	2212	....	2212	....	2212	....
Engine availability	%	95	....	95	....	95	....
Electricity produced	kWh	888,801	----	802,788	----	888,801	....
Electricity shortfall/surplus	KWh	86,919	----	297,492	----	213,599	....
Heat recovered	KWh	977,151	----	882,588	----	977,151	....
Heat shortfall/surplus	KWh	124,499	----	62,154	----	-229,683	....
CHP Fuel input	kWh	2,290,724		2,069,041		2,290,724	
CHP fuel price	€	1.7751		1.7751		1.7751	
CHP fuel cost	€	40,658		36,724		40,658	....
Standby cost	€/k.m	6,036		6,036		6,036	
Electricity shortfall/surplus -unite price	C/kWh	6.42	....	6.42	....	6.42	....
Electricity shortfall/surplus -cost	€	5,580	----	19,099	----	13,713	....
Heat shortfall-fuel price	C/kWh	1.7751		1.7751		1.7751	
Heat shortfall-cost	€	2,947	----	1,471	----	0	....
Energy cost without CHP	€	88,714	----	92,998	----	88,465	....

The objective of this analysis is to determine if a cogeneration system could be viable at this installation and to identify the preliminary bounds of that system. Based on the alternative analyses reviewed above, it is concluded that a reciprocating engine system ranging in size from approximately 390 kW to 6000 kW is available.

The base load 2012 kw system is found to produce a simple payback of 5.5 years (see section 4.29), different sizes were also reviewed to determine whether they should be considered in the scope of work for the more detailed screening analysis. Two alternatives engines were also analysed. One consisted of a bigger reciprocating engine rated at approximately 2179 kW based to the site average load, with the second consisting of a slightly larger engine rated at almost 2717 kW based to the site full load. The results are summarised in table 11, 12, and 13.

Table 11: characteristic 2012 kW reciprocating engine

	Parameters	**Unit**		**Source**
1	Capacity	kW	**2012**	Mfg.data
2	Fuel requirements	kW	5185	Mfg.date
3	CHP fuel rate	€/kW	0.017751	ESB
4	CHP fuel cost	€/h	87.4369	L2 * L3
5	Maintenance cost	€/h	0.015	Mfg.data
6	Total variable operating costs	€/h	116.1079	L4+L5
7	Operating hours	h/month	465	Computed
8	Variable operating cost	€/month	53,990	L6 * L7
9	Stand by rate	€/kw/month	3	Estimated
10	Monthly standby cost	€/month	6,036	L1 * L9
11	Total monthly operating cost	€/month	68,553	L8+L10
12	Value of power used at rate	€/kWh	0.0642	ESB
13	CHP power sales	%	0	Computed
14	Value of CHP power	€/kWh	0.050083	Computed
15	Hourly value of CHP power	€/h	100.766	L1 *L14
16	Heat recovery	kW	2212	Mfg.data
17	Boiler fuel cost	€/kWh	0.017751	ESB
18	Value of recovered heat	€/h	0.04166	Computed
19	Hourly value of recovered heat	€/h	92.172	L18 * 17
20	Total power cost	€/h	192.937	L15 + L19
21	Gross monthly operating cost	€/month	89,716	L7 * L20
22	Net annual savings	€/year	135,932	Computed
23	Budget	€	750,000	Mfg.data
24	Simple payback	Years	5.5	L23/L22

Table 12: characteristic of 2179 kW reciprocating engine

	Parameters	Unit	Size	Source
1	Capacity	kW	**2179**	Mfg.data
2	Fuel requirements	kW	5225	Mfg.date
3	CHP fuel rate	€/kWh	0.017751	ESB
4	CHP fuel cost	€/h	92.748	L2 * L3
5	Maintenance cost	€/h	0.015	Mfg.data
6	Total variable operating costs	€/h	119.162	L4+L5
7	Operating hours	h/month	465	Computed
8	Variable operating cost	€/month	55,410	L6 * L7
9	Stand by rate	€/kw/month	3	Estimated
10	Monthly standby cost	€/month	6537	L1 * L9
11	Total monthly operating cost	€/month	61,947	L8+L10
12	Value of power used at rate	€/kWh	0.0642	ESB
13	CHP power sales	%	1	Computed
14	Value of CHP power	€/kWh	0.05165	Computed
15	Hourly value of CHP power	€/h	112.545	L1 *L14
16	Heat recovery	kW	2350	Mfg.data
17	Boiler fuel cost	€/kW	0.017751	ESB
18	Value of recovered heat	€/h	0.0394	Computed
19	Hourly value of recovered heat	€/h	92.59	L18 * 16
20	Total power cost	€/h	205.135	L15 + L19
21	Gross monthly operating cost	€/month	95,387	L7 * L20
22	Net annual savings	€/year	170,627	Computed
23	Budget	€	820,000	Mfg.data
24	Simple payback	Years	4.8	L23/L22

Table 13 : characteristic 2717 kW reciprocating engine

	Parameters	Unit		Source
1	Capacity	kW	2717	Mfg.data
2	Fuel requirements	kW	6627	Mfg.date
3	CHP fuel rate	€/kW	0.017751	ESB
4	CHP fuel cost	€/h	117.635	L2 * L3
5	Maintenance cost	€/h	0.015	Mfg.data
6	Total variable operating costs	€/h	150.47	L4+L5
7	Operating hours	h/month	465	Computed
8	Variable operating cost	€/month	69,968	L6 * L7
9	Stand by rate	€/kw/month	3	Estimated
10	Monthly standby cost	€/month	8151	L1 * L9
11	Total monthly operating cost	€/month	78,119	L8+L10
12	Value of power used at rate	€/kWh	0.0642	ESB
13	CHP power sales	%		Computed
14	Value of CHP power	€/kWh	0.052378	Computed
15	Hourly value of CHP power	€/h	142.311	L1 *L14
16	Heat recovery	kW	2543	Mfg.data
17	Boiler fuel cost	€/kWh	0.017751	ESB
18	Value of recovered heat	€/kWh	0.0462	Computed
19	Hourly value of recovered heat	€/h	117.554	L18 * 16
20	Total power cost	€/h	259.865	L15 + L19
21	Gross monthly operating savings	€/month	120,837	L7 * L20
22	Net annual savings	€/year	118,328	Computed
23	Budget	€	1,022,459	Computed
24	Simple payback	Years	8.6	L23/L22

The 2012 kW, 2179 kw, and 2717 kW systems operating in different regimes provide 86.5 %, 93%, and 116 %, respectively, of the total electricity needs of Dublin City University. They produce waste heat per unit of electrical production, satisfies 154 %, 163 %, and 177 % of the thermal load of the building. The contributions of the three CHP systems to the electrical and thermal needs of Dublin City University are summarized in the following table:

Table 14 :Combined heat and power system contribution

Electricity capacity	CHP Technology	Electric load satisfied	Thermal load satisfied
2012 kW	Jenbacher	86.5 %	154 %
2179 kW	Jenbacher	93 %	163 %
2717 kW	Jenbacher	116 %	177 %

These systems should reliably maintain the maximum demand placed the existing capacity limitation. The sizing enable us to assess the economics of using a CHP system in conjunction with a load control capability implemented in the building to limit the independency on the grid.

Another benefit of adding a combined heat and power system is that the University would then present a more favorable year-round gas use pattern to suppliers. This more favorable profile would be rewarded by reduced natural gas prices compared with the base case building. ESB estimates that this benefit would be 0.368224 c/kwh.

The sizing results show that the three systems can potentially be cost effective over a long period of time based on reduced electricity bills and captured waste heat.

Summary

The structure of the calculation procedure depends on the accuracy of the data that is available from the energy supply data, and also on the electricity supply tariff structure that needs to be considered. Calculation of CHP output (electricity & heat), CHP fuel cost, electricity and heat surplus/shortfall cost, energy cost with CHP, energy cost without CHP, CHP maintenance cost, over all cost savings, are all carried out for each month, and these are added together to give an annual total. We avoided too much averaging of consumption or of unit energy costs in broad time bands, this is one of the main causes of inaccuracy highlighted when the results of actual plant operation are compared with a detailed feasibility study calculation.
The calculation has so far ignored the crucial factor of taxation. CHP unit will have to run 15 hours a day (corresponding to the hours during which the ESB daytime tariff applies) for 365 day. Therefore, annual running of 5475 hours will be assumed here. To achieve a minimum pay back time, a CHP scheme typically must operate for a minimum of around 4500 hour per year.
By determine the operating hours of the CHP plant for each month of the year, a cost saving analysis can be performed. By taking, firstly the cost of conventional

operation, and subtracting from that the cost of running a CHP plant and the energy import it displaces then saving can be calculated.

5 Chapter five

5.1 Thermodynamic analysis

The fuel savings and economics of CHP are grounded in the laws of thermodynamics, which state that a heat source at an elevated temperature has a greater capability to perform work than the same amount of heat at a lower temperature. Thus, high temperature heat converts readily to electricity, and the lower temperature exhaust streams are used for process heat.

If only process heat were needed and the electricity in a resistance heater was used to obtain additional process heat, using electricity to create heat indirectly would produce a net loss, compared with using an efficient single purpose boiler supplying steam for process heat. All energy savings, which avoid purchasing grid electricity for both process electrical and thermal requirements, results in increased efficiency.

The financial benefit that a CHP system depends may stimulate companies to invest in such systems. To evaluate the simple payback period for a CHP installation, the cost of purchasing, maintaining and running the unit must be apparent, coupled with the value of the generated heat and power. The latter depend on the existing facility, cost of electricity and tax. The daily and annual hours of operation are also critical in determining the cost effectiveness of the installation.

The considerations of economic attractiveness of a CHP plant are that there must be a demand of heat, either for room heating or for a process the electrical and thermal base loads must form a large portion of the demand.

The heat to power ratio (HPR) of the site should be nearly steady both daily or seasonally. The HPR of the site and that of the prime mover should be compatible. In the case of varying HPR, the plant must be capable of meeting the requirements. In process industries/public are considered, the quality and quantity of the waste stream must be adequate to generate power [51-55].

In this chapter we map the heat and power components so as to explain the magnitude of the heat load that can be obtained for a given electric load for three engine sizes (2012 kW, 2179 kW, 2717 kW) as chosen previously. This will help in the rational and optimal matching of the CHP unit, and to propose a suitable expression for the global efficiency of a CHP plant in order to avoid the difficulties in determination of the primary energy consumption. The ultimate goal is to undertake a thermodynamic approach for the considered sizes in order to easily determine the thermo-economic viability of a CHP project.

The following analysis is based on thermodynamic principles, which reveal the thermodynamic performances of a conventional power plant and a cogeneration system. In evaluating the primary energy demand of a cogeneration system and comparing it to the primary energy demand for the separate generation for the same energy systems power and heat, the thermodynamic analysis obtained can be considered the difference for Dublin City University case.

5.2 Performance indices of conventional systems

Conventional plants produce separate units of electricity and heat with efficiencies η_W and η_Q.

- Power plant efficiency is:

  $\eta_W = W / H_{fp}$ ....(1)

- Boiler efficiency is:
  Heat recovered from the engine / total heat input

  $\eta_Q = Q_B / H_{fw}$ ....(2)

- Heat to Power Ratio

  $HPR = Q_B / W$ ....(3)

- Total efficiency for separated power will be:

  $\eta_T = (w + Q_B) / (H_{fp} + H_{fw})$ ....(4)

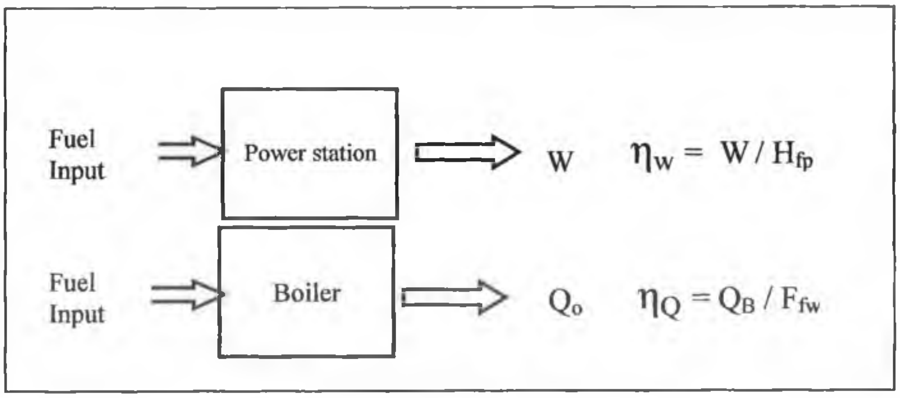

Figure 45 conventional power plants

Conventional power generation, on average, is only 40 % efficient – up to 60 % of the energy is released as waste heat. More recent combined cycle generation can improve this to 55 %, excluding losses for the transmission and distribution of electricity (figure1).

5.3 Performance indices of cogeneration systems

Before proceeding with the description of cogeneration technologies, it is necessary to define certain indices, which reveal the thermodynamic performance of a cogeneration system and facilitate the comparison of alternative solution (system).

For a cogeneration power the same fuel is used to product electrical and heat energy, so the electrical efficiency for cogeneration is defined below, Fig.54. Gives a schematic of a CHP system, the parameters, which are important in the analysis of a CHP, are indicates below.

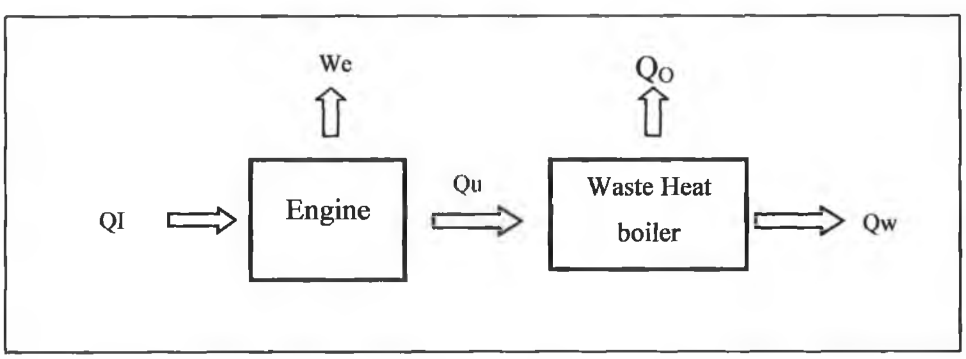

Figure 46 Cogeneration plant

Numerous indices have appeared in the literature. The most important of those are defined in this chapter.

5.3.1.1 The prime mover work

$$W_G = QI * \eta_m \text{ ....(5)}$$

$$W_e = W * \eta_G \text{ ....(6)}$$

Where

W_G	prime mover work (kW)
W_e	electrical out put (kW)
Q_I	fuel power consumed by the system
η_m	prime mover efficiency
η_G	generator efficiency

5.3.1.2 System electric efficiency

$$\eta_e = W_e / Q_I \text{............(7)}$$

Where W_e is the net electric power output of the system, i.e.

From equations (1), (3), (4) electric efficiency can be written as:

$$\eta_e = \eta_m * \eta_G \text{ ....(8)}$$

5.3.1.3 Engine thermal efficiency

Thermal efficiency is a measure of how efficiently a heat engine converts the energy input to work. In this case the heat transfers to water and uses to heat up buildings.

$$\eta_{th} = ((Q_I - W_e) / Q_I) \text{ ....(9)}$$

5.3.1.4 The useful thermal power output of the engine

$$Q_U = Q_I * \eta_{th} \text{ ....(10)}$$

$Q_U > 0$

$Q_U < Q_I$

The entire thermal energy generated cannot be usefully extracted; most of the losses cannot be recouped because of their low quality and quantity, difficulties in extraction and utilization. The fraction of waste heat utilization considers these losses.

5.3.1.5 The useful thermal power produced by the system

$$Q_O = Q_U * \eta_W \text{............(11)}$$

η_W waste heat boiler efficiency

5.3.1.6 System thermal efficiency

$$\eta_t = Q_O / Q_I \text{ ....(12)}$$

This is the ultimate efficiency of useful thermal energy that can go into the heating process.

5.3.1.7 System total efficiency

Overall efficiency of the system is the total useful energy divided by the energy input from the gas. Thermodynamically the over all efficiency is the percent of the fuel converted to electricity plus the percent of fuel converted to useful thermal energy. This is in the range 85 – 90 % for most reciprocating engines available today.

$$\eta = \eta_e + \eta_{th} = (W_e + Q_o) / Q_I \text{.................(13)}$$

The entire energy extracted cannot be usefully extracted due to losses. In the generator, radiation losses, and exhaust losses. Figure 53 illustrate the losses happened in the 2012 kW reciprocating engine was provided by Jenbacher Company.

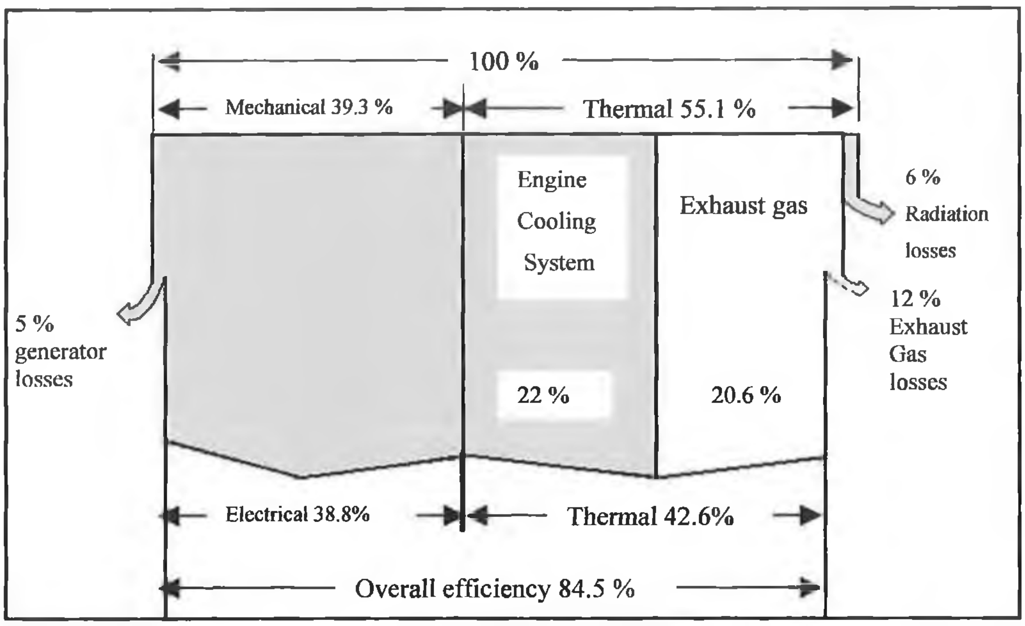

Figure 47 Heat balance of a 2012 kw reciprocating engine

5.3.1.8 Prime mover's Heat to Power Ratio

The combined heat and power index HPR is specially defined for prime movers by

$$HPR = Q_o \;/\; W_e \text{ ....(14)}$$

From equations (4), (13), and 14 lead to the following relations:

$$\eta = \eta_e (1 + HPR) \text{ ....(16)}$$

$$HPR = \eta_{th} / \eta_e \text{ ....(17)}$$

Equations (15), and (16), help in determining acceptable values of the power to heat ratio, when the electrical or thermal efficiency of a system is known, given the fact that total efficiency does not exceed typically 90 %.

It should be mentioned that the heat to power ratio is one of the main characteristics for selecting a cogeneration system for a particular application.

If it can be considered that a cogeneration system substitutes separate units of electricity and heat production with presumed efficiencies $\eta_w = 50\ \%$ and $\eta_Q = 75\ \%$ respectively.

5.3.1.9 Fuel energy saving

$$FES = (H_{fs} - H_{fc}) / H_{fs} \quad \text{..................(18)}$$

Where:

H_{fs} = total fuel power for separate production of W_e and Q

H_{fc} = fuel power of the cogeneration system producing the same amount of W_e and Q.

It can be written

$$H_{fs} = H_{fp} + H_{fw} = (mf\,H_u)_W + (mf\,H_u)_Q$$

$$H_{fp} = (m_f H_u)_W = (W / \eta_w)$$

$$H_{fw} = (m_f H_u)_Q = (Q_B / \eta_Q)$$

In order for a cogeneration system to be a rational choice from the point of view of energy savings, it must be FES > 0.

Where the subscripts W and Q denote the separate production of electricity and heat (e.g. by a power plant and a boiler), respectively.

If it can be considered that a cogeneration system substitutes separate units of electricity and heat production with efficiencies η_w and η_Q, respectively, then it can be proved that

$$FES = (1 - ((1+ HPR) / (\eta\ ((1 / \eta_{w}) + (HPR / \eta_Q))))\text{.........(19)}$$

In the previous definition, electric, thermal, and fuel power are used (energy per unit time), which results in values of the indices valid in a certain instant of time or at a certain load. All the previous equation are valid also if power is replaced by energy in a certain period of time; then integral values of the indices are obtained, which reveal the performance of the system over this period.

The proposed 2012kw reciprocating engine system with a total efficiency 81.4 % and a heat to power ratio 1.099 substitute a power plant of efficiency 50 % and boiler efficiency 75 %. Then, equation 19 gives FES = 0.2795, i.e. the cogeneration system in this case reduces the total energy consumption by 27.95 %. Table 14 shows the three engine cases.

Table 15 : Three sizes reciprocating engines characteristic

	Unit	2012 kW	2179 kW	2717 kW
η_e	%	38.8	41.7	42
QI	kW	5185	5225	6469
QU	kW	3173	3046	3745.5
Q_O	kW	2380	2285	2808
η_{th}	%	61.2	58.3	57.9
η_t	%	45.9	43.7	43.4
η	%	84.7	85.4	85.4
HPR	kW_{th} / kW_e	1.182	1.048	1.033
FES	%	27.95	29.4	29.5

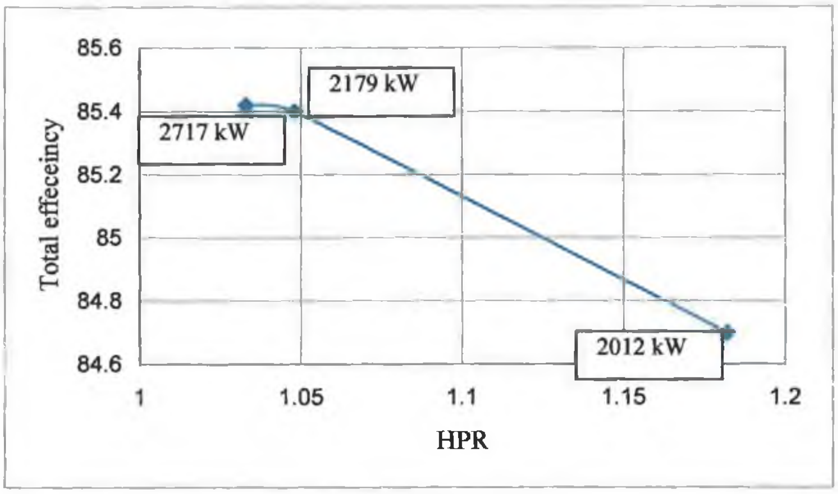

Figure 48 Variation of HPR with overall efficiency for three different sizes

It is instructive to carry out these calculations for different engine sizes and to present the results graphically against HPR. It can be seen clearly from figures 56 and 57 that HPR has dramatic influence on FES and the total efficiency. By increasing the HPR the total efficiency and FES show slight decreases. An increase in electrical efficiency would result in an increase in thermal efficiency which lead to decrease in heat to power ratio (eq.17). A decrease in heat to power ratio would make the total efficiency decrease (figure 57).

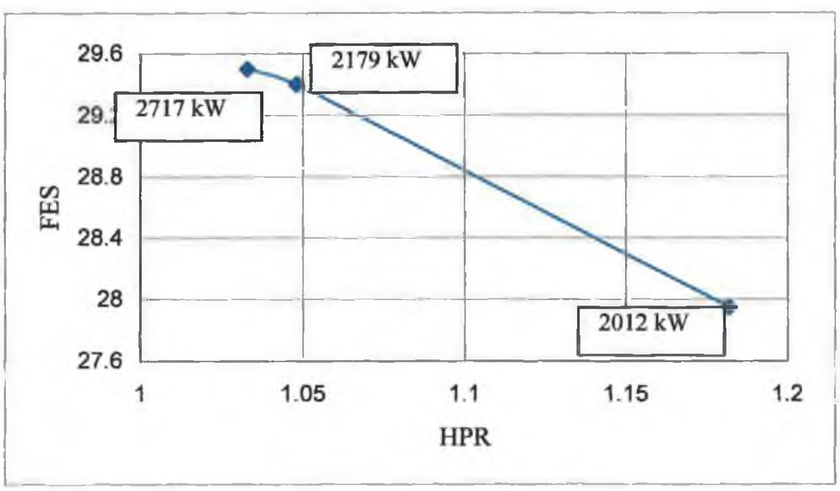

Figure 49 Relation between FES & HPR

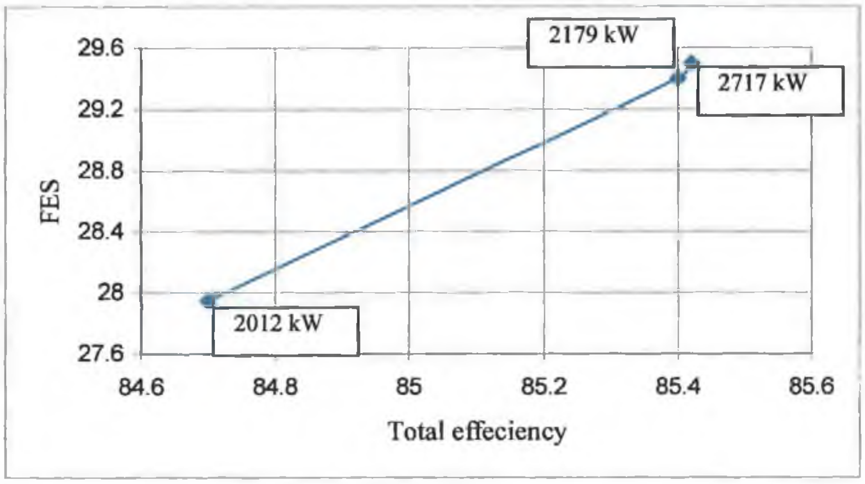

Figure 50 Relation between FES & overall efficiency

Figure 58 gives the variation of Total efficiency with the FES for assumed waste heat boiler efficiency 75 % and conventional plant efficiency 50%. It can be seen that overall efficiency increases as the FES increases. The FES ranges between 27.95 % (electrical efficiency 38.8%), 29.4 % (electrical efficiency 41.7 %), 29.5 % (electrical efficiency (42 %). But increasing the overall efficiency by increasing FES will lead to increasing the system size, which will be considered as an oversized system.

From figure 58 it can be seen clearly that increasing the overall efficiency will lead to an increase in FES. Therefore, it is important to ensure that energy is used as efficiently as possible. Eliminating energy wastage and improving the efficiency of consumption are the most cost effective measure for increasing the total, and the evaluation of potential CHP plant should always be carried out against true energy demands, not against consumptions inflated by wastage and inefficiency.

In general for CHP systems, as the fraction of electrical output increases, the overall efficiency of the system increases. The maximum overall efficiency cannot exceed 90 % because of inextricable losses in the waste heat boiler, prime mover and generator.

An increase in HPR decreases the overall efficiency. However, there are some feasible options for matching the HPR of the engine and that of the load by either exporting electric power, decrease on HPR of the engine, increase in HPR of load.

Table 15 gives the possible ways in which these can be matched. One of the solutions to matching is export/import of electric power, while the other is improvement in thermodynamic quality. Matching by degradation of the thermodynamic quality through an increase in HPR is not suggested.

Table 16 : Possible ways of matching the HPR of the engine and the site

Condition	Matching action
$HPR_E > HPR_S$	
$Qo = Q_B; We < W_G$	Import electricity
$Q_O > Q_B; We = W_G$	Dump heat
$Qo = Q_B; We < W_G$	Increase HPR of site
$HPR_E < HPR_S$	
$Qo = Qb; We > W_G$	Export electricity
$Q_O < Q_b; We = W_G$	Import heat
$Qo = Qb; We > W_G$	Decrease HPR of site

6 Chapter six

6.1 Conclusion and recommendation for future work

After the analysis of the results, the following conclusions could be made about the CHP plant assessment.

Development of complex mathematical method to determine the optimum size of CHP plant and its operating times are only of academic use. CHP plants only come in limited capacity range due to the nature of the engine manufacture industry. Each installation and building is also unique, therefore, requiring individual attention to get the best out of the set, thus there is no one unified formula.

The economic viability of a CHP plant is currently dependant on competitive gas price and electricity price (sold, purchased). A decision to install a CHP plant should take into account the high thermal efficiency achievable in the long term, with resulting major economic savings and if the country's regulations allows selling electricity to the grid.

Various data analyses reveals the success of a CHP is quantified by the installed electric capacity of CHP. Energy savings is strongly dependent on the efficiency of the site and CHP system.

We have assessed the technical feasibility and commercial viability of available technologies, and have concluded that reciprocating engine cogeneration technology is the best available technology for Dublin City University because of its higher efficiency, low emission and lower capital cost.

A number of different gas engine combined heat and power configuration were considered. As a result of this assessment, a configuration based on 1 Jenbacher JMS 320 gas engines with an electrical output of 2.012 MW has been selected as the optimum solution.

6.1.1 Energy outputs

The waste heat from this gas engine exhaust and cooling jacket will be recovered and used to generate hot water at 90 °C. It is envisaged that Dublin city university's existing natural gas fired boiler will make up the balance of the site's heat load giving a total heat output capacity sufficient to meet present and future demand. In addition, the balance of the existing boiler would also provide standby capacity to ensure integrity of heat supplied in the event of the gas engine or auxiliary boiler being unavailable.

It is recommended that sufficient boiler plant be retained to cater for all present and future site heat load even after combined heat and power has been installed. This is necessary in order to ensure that the university can continue to operate in the event of the planned or unplanned outage of the CHP plant.

6.1.1.1 Electricity

The engine is capable of producing a net electrical output of 2012 kW. The output of the engine can be modulated to take account of demand. The engine's output can be reduced to 50% of full rated output as required. This allows considerable flexibility in matching instantaneous electrical demand, as the engine may be run at either full or part load at any time.

When running at part load, the engine will have slightly lower electrical efficiency and a slightly higher heat to power ratio.
At those times when maximum electrical output of the engine is insufficient to meet the need of the college, and when the engine is unavailable, it will be possible to import electricity from the grid as required.

6.1.1.2 Thermal energy

The limiting of the engine output based on the electrical load can affect the thermal efficiency of the site. During periods when thermal requirements exceed the engine's heat recovery capability, supplemental boilers must provide the additional heat.

Additionally, as the engine is constrained to follow the site electrical load, considerable amount of heat may be rejected if the site thermal and electrical loads are not balanced or not coincident. The supplemental thermal energy that is covered by the existing boiler in January, and November, and also shows the thermal energy dumped.

Dublin City University's boiler will be used to cover the shortage in certain months. Heat shortfall will be just for three months in which the consumption will exceeds the heat generated by CHP. The whole amount of heat the boiler has to produce is around 400 MWh all the year around.
Heat demand will be dumped during some months, when the heat produced by CHP exceeds the heat demand.

6.2 Operation of CHP plant

The Jenbacher JMS 320 engine solutions have been chosen for its close match to the projected base energy requirements of the college.

The plant will also produce 1 x 2012 kW (net) of electrical power at full rated output. On those occasions when the electrical demand on site is less than 2000 Kw , the engine output can be modulated to deliver less electricity and heat. In the likely event that the electrical site demand dips below 500 kw for a protracted period however, the engine will have to be shut down, as the engines can not be run continuously at less than 50 % of rated load. It is not expected that this situation will often rise.

Demand for hot water at Dublin City University is currently supplied by use of natural gas boilers to generate hot water. In order to maximise the commercial benefits of the CHP plant to Dublin city university, it will be necessary to use the hot water from the CHP plant to satisfy as much as possible of this demand.
For nine months or more of the year, the site demand will be sufficient to absorb all of the heat output of the plant.

6.3 Import of electricity

According to ESB prices, it will be uneconomic to run the CHP plant at night, during the nine hours in which ESB night tariff operates. It is therefore envisaged that the plant will be run for 15 hours a day, 5425 hours a year.

Availability of the plant has been estimated at 95%, with a further 50 hours of unexpected outages per engine during the course of the year. During those times when the plant is unavailable due to either planned services or unplanned services as well as at night, electricity must be imported from the grid. In addition, during those periods when the electricity demand on campus is greater than what is being supplied by the CHP plant, the excess demand must be supplied by imports.

6.4 Future work

Future work should be directed at establishing how accurately sized CHP units are in existing building. The results of this work will enable a more accurate assessment of sizing requirements in existing building. It will also allow an estimation of the current sizing errors for CHP in existing building.

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1. Tarik Elkarim, Economic feasibility of combined heat and power for Dublin City University. 7^{th} Annual Sir Bernard crossland symposium and Postgraduate research workshop. March 30 & 31, 2004, at Dublin City University.

2. Tarik Elkarim, Economic and technical viability of cogeneration for Dublin City University. The 4^{th} International Association of Science and Technology for Development (IASTED), June 28-30, 2004, Greece.

Appendixes

Appendix A

Electricity consumption tables

Month	On peak hours	On-peak electric demand (kw)	Off peak hours	Off-peak electric demand (kw)
Jan	465	856800	279	204800
Feb	420	1047200	252	307200
Mar	465	1073600	279	292600
Apr	450	878400	270	239400
May	465	957000	279	226000
Jun	450	783000	270	226000
Jul	465	693000	279	254400
Aug	465	847000	279	169600
Sep	450	993600	270	290000
Oct	465	1214400	279	290000
Nov	450	1272320	270	386400
Dec	465	999680	279	257600
Total	5475	11616000	3285	3144000

Table 17 Electricity consumption (2000)

Month	On peak hours	On-peak electric demand (kw)	Off peak hours	Off-peak electric demand (kw)
Jan	465	1061240	279	283920
Feb	420	1406760	252	392080
Mar	465	1364000	279	374000
Apr	450	1116000	270	306000
May	465	1136800	279	312400
Jun	450	952200	270	255600
Jul	465	1000000	279	289680
Aug	465	1060000	279	278320
Sep	450	1024200	270	264880
Oct	465	1250800	279	351120
Nov	450	1562400	270	415280
Dec	465	1041600	279	300720
Total	5475	13976000	3285	3824000

Table 18 Electricity consumption (2001)

Month	On peak hours	On-peak electric demand (kw)	Off peak hours	Off-peak electric demand (kw)
Jan	465	1021440	279	287240
Feb	420	1410560	252	380760
Mar	465	1456400	279	405440
Apr	450	1191600	270	262560
May	465	1249600	279	360240
Jun	450	1022400	270	271760
Jul	465	957600	279	296000
Aug	465	1170400	279	296000
Sep	450	1131760	270	275840
Oct	465	1500240	279	392160
Nov	450	1611880	270	350000
Dec	465	1120120	279	249000
Total	5475	14844000	3285	

Table 19 Electricity consumption (2002)

Month	On peak hours	On-peak electric demand (kw)	Off peak hours	Off-peak electric demand (kw)
Jan	465	975720	279	310000
Feb	420	1100280	252	398000
Mar	465	1102400	279	372000
Apr	450	1017600	270	372000
May	465	990000	279	368000
Jun	450	950000	270	366000
Jul	465	898000	279	348000
Aug	465	930000	279	348000
Sep	450	977280	270	360000
Oct	465	1058720	279	396000
Nov	450	1146100	270	450000
Dec	465	943900	279	362000
Total	5475		3285	

Table 20 Electricity consumption (2003)

Appendix B

A

DCU site energy consumption & cost calculations

		Jan		Feb		Mar		Apr		May		Jun	
	Period	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	Hours	465	279	420	252	465	279	450	270	465	279	450	279
Electricity consumptions													
Unit consumed	KWh	975,720	310,000	1,100,280	398,000	1,102,400	372,000	1,017,600	372,000	990,000	368,000	950,000	366,000
Cost per unit	C/KWh	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6
Total cost	€	62,641	14,260	70,637	18,308	70,774	17,112	65,329	17,112	63,558	16,928	60,990	16,560
Average consumptions	MW	2.098	1.111	2.619	1.579	2.371	1.333	2.261	1.377	2.129	1.318	2.111	1.333
Fuel consumptions													
Unit consumed	KWh	1,468.867	629.514	1,259,656	630,000	996,624	387,576	807,069	365.000	763,752	320,000	704,112	300,000
Cost per unit	C/KWh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
Total cost	€	26,073	11,174	22,360	11,183	17,691	6,879	14,326	6.479	13,557	5,680	12,498	5.325
Efficiency of fuel conversion	%	75		75		75		75		75		75	
Heat demand	KWh	1,101,650	472.135	944,742	472,500	747,468	290,682	605,301	273,750	572.814	240.000	528.084	225.000
Heat to power ratio		1.129	2.03	0.858	1.583	0.678	1.041	0.595	0.981	0.578	0.869	0.555	0.833

Net electricity output	KW	2012	—										
Fuel consumption	KW	5185	—										
Exhaust heat recoverable	KW	2212	----										
Turbine availability	%	0.95	—										
Electricity produced	KWh	888,801	----	802,788	----	888,801	----	860,130	----	888,801	----	860,130	----
Electricity shortfall/surplus	KWh	86,919	----	297,492	—	213,599	----	157,470	—	101,199	----	89,870	----
Heat recovered	KWh	977,151	----	882,588	—	977,151	----	945,630	—	977,151	----	945,630	—
Heat shortfall/surplus	KWh	124,499	----	62,154	—	-229,683	----	-340,328	—	-404,337	----	-417,546	----
CHP Fuel input	kwh	2,290,724		2.069,041		2,290,724		2,216,829		2,290,724		2,216,829	
CHP fuel price	€	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
CHP fuel cost	€	40,658		36,724		40,658		39,347		40,658		39,347	....
Electricity shortfall/surplus-unite price	C/kwh	6.42	----	6.42	—	6.42	----	6.42	----	6.42	—	6.42	----
Electricity shortfall/surplus-cost	€	5,580	----	19,099	----	13,713	----	10,110	----	6,497	----	5,770	----
Heat shortfall-fuel price	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
Heat shortfall-cost	€	2,947	----	1,471	----	0	----	0	—	0	—	0	----
Monthly standby cost	€	6036		6036		6036		6036		6036		6036	
CHP maintenance cost	€	13,332	----	12,042	----	13,332	----	12,902	—	13,332	----	12,902	----
Energy cost without CHP	€	88,714	—	92,998	----	88,465	----	79,656	----	77,115	----	73,489	----
Energy cost with CHP	€	68,553	—	75,371	----	73,379	----	68,394	----	66,523	—	64,054	—
Overall CHP cost saving	€	20,162	----	17627	—	14,726	----	11,262	----	10,592	—	9,434	—

	Month	Jul		Aug		Sep		Oct		Nov		Dec		Total (on)
	Period	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	
	Hours	465	279	465	279	450	270	465	279	450	270	465	279	5475
Electricity consumption														
Unit Consumed	Kwh	898,000	348,000	930,000	348,000	977,280	360,000	1,058,720	396,000	1,146,100	450,000	943,900	362,000	12,090,000
Cost per unit	C/kwh	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	
Total cost	€	57,,651	16,008	59,706	16,008	62,741	16,560	67,969	18,216	73,579	20,700	60,598	16,652	776,178
Average consumption	MW	1.931	1.247	2	1.247	2.171	1.333	2.276	1.419	2.546	1.666	2.029	1.297	
Gas consumption														
Unit consumed	Kwh	265,463	170,000	236,213	101,238	504,306	216,131	940,305	360,000	1,267,875	543,375	742,976	318,420	9,957,218
Cost per unit	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
Total cost	€	4,712	3,017	4,193	1,797	8,951	3,836	16,691	6,390	22,500	9,645	13,188	5,652	176,750
Efficiency of fuel conversion	%	75		75		75		75		75		75		
Heat demand	kwh	199,097	127,500	177,159	75,928	378,228	162,098	705,228	270,000	950,906	407,531	557,222	238,815	7,467,914
Heat to Power Ratio		0.222	0.488	0.190	0.291	0.387	0.6	0.666	0.909	0.829	1.207	0.590	0.879	

Gas Engine option														
Net electricity output	KW	2012	----											
Fuel consumption	KW	5185	----											
Exhaust heat recoverable	KW	2212	—											
Turbine availability	KW	0.95	—											
Electricity produced	KWh	888,801	—	888,801	----	860,130	—	888,801	—	860,130	----	888,801	----	10,464,915
Electricity shortfall/surplus	KWh	9,199	----	41,199	----	117,150	----	169,919	—	285,970	----	55,099	----	1,625,085
Heat recovered	KWh	977,151	—	977,151	----	945,630	----	977,151	----	945,630	----	977,151	—	11,505,165
Heat shortfall/surplus	KWh	778,054	----	799,991	----	567,401	—	271,922	----	5,276	----	419,919	----	
CHP Fuel input	kwh	2,290,724	----	2,290,724	----	2,216,829	----	2,290,724	----	2,216,829	—	2,290,724	----	26,971,430
CHP fuel price	€	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
CHP fuel cost	€	40,658	----	40,658	----	39,347	----	40,658	----	39,347	----	40,658	----	478,718
Electricity shortfall/surplus-unite price	C/kwh	6.42	----	6.42	----	6.42	----	6.42	----	6.42	----	6.42	----	
Electricity shortfall/surplus-cost	€	591	----	2,645	----	7,521	—	10,909	----	18,359	----	3,537	----	104,330
Heat shortfall-fuel price	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
Heat shortfall-cost	€	0	....	0	....	0	....	0	....	125	....	0	....	4,543
Monthly standby cost		6,036	----	6,036	----	6,036	----	6,036	----	6,036	----	6,036	----	72,432
CHP maintenance cost	€	13,332	—	13,332	----	12,902	—	13,332	----	12,902	----	13,332	—	
Energy cost without CHP	€	62,364	----	63,899	----	71,693	----	84,661	----	96,086	—	73,787	----	952,929
Energy cost with CHP	€	60,617	----	62,671	----	65,806	—	70,935	----	76,769	—	63,564	----	816,996
Overall CHP cost saving	€	1,747	----	1,228	----	5,888	—	13,726	----	19,317	—	10,223	----	**135,932**

Appendix B

B

		Jan		Feb		Mar		Apr		May		Jun	
	Period	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	Hours	465	279	420	252	465	279	450	270	465	279	450	2
Electricity consumptions													
Unit consumed	KWh	975,720	310,000	1,1002,280	398,000	1,102,400	372,000	1,017,600	372,000	990,000	368,000	950,000	366,000
Cost per unit	C/KWh	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6
Total cost	€	62,641	14,260	70,637	18,308	70,774	17,112	65,329	17,112	63,558	16,928	60,990	16,560
Average consumptions	MW	2.098	1.111	2.619	1.579	2.371	1.333	2.261	1.377	2.129	1.318	2.111	1.333
Fuel consumptions													
Unit consumed	KWh	1,468,867	629,514	1,259,656	630,000	996,624	387,576	807,069	365,000	763,752	320,000	704,112	300,000
Cost per unit	C/KWh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
Total cost	€	26,073	11,174	22,360	11,183	17,691	6,879	14,326	6,479	13,557	5,680	12,498	5,325
Efficiency of fuel conversion	%	75		75		75		75		75		75	
Heat demand	KWh	1,101,650	472,135	944,742	472,500	747,468	290,682	605,301	273,750	572,814	240,000	528,084	225,000
Heat to power ratio		1.129	2.03	0.858	1.583	0.678	1.041	0.595	0.981	0.578	0.869	0.555	0.833

Net electricity output	KW	2179	....										
Fuel consumption	KW	5225	....										
Exhaust heat recoverable	KW	2350	....										
Turbine availability	%	95	....										
Electricity produced	KWh	962,573	....	869421	....	962,573	....	931523	....	962,573	....	931,523	
Electricity shortfall/surplus	KWh	13,147	....	230,859	....	139,827	....	86,078	....	27,427	....	18,478	
Heat recovered	KWh	1,038,113	....	937,650	....	1,038,113	....	1,004,625	....	1,038,113	....	1,004,625	....
Heat shortfall/surplus	KWh	63,538	....	7,092	....	-290,645	....	-399,323	....	-465,299	....	-476,541	....
CHP fuel price	€	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
CHP fuel cost	€	40,972	....	37,007	....	40,972	....	39,650	....	40,972	....	39,650	....
Electricity shortfall/surplus-unite price	C/kwh	6.42	....	6.42	....	6.42	....	6.42	....	6.42	....	6.42	....
Electricity shortfall/surplus-cost	€	844	....	14,821	....	8,977	....	5,526	....	1,761	....	1,186	....
Heat shortfall-fuel price	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
Heat shortfall-cost	€	1,504	....	168	....	0	....	0	....	0	....	0	....
CHP maintenance cost	€	14,439	....	13,041	....	14,439	....	13,973	....	14,439	....	13,973	....
Monthly standby cost	€	6,537		6,537		6,537		6,537		6,537		6,537	
Energy cost without CHP	€	88,715	—	92,998	—	88,465	----	79,656	----	77,115	—	73,489	----
Energy cost with CHP	€	64,295	—	71,574	----	70,924	----	65,686	----	63,708	—	61,346	—
Overall CHP cost saving	€	24,420	----	21,424	—	17,541	—	13,970	—	13,407	—	12,142	—

	Month	Jul		Aug		Sep		Oct		Nov		Dec		Total
	Period	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	
	Hours	465	279	465	279	450	270	465	279	450	270	465	279	8760
Electricity consumption														
Unit Consumed	Kwh	898,000	348,000	930,000	348,000	977,280	360,000	1,058,720	396,000	1,146,100	450,000	943,900	362,000	12,090,000
Cost per unit	C/kwh	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	
Total cost	€	57,.651	16,008	59,706	16,008	62,741	16,560	67,969	18,216	73,579	20,700	60,598	16,652	776,173
Average consumption	MW	1.931	1.247	2	1.247	2.171	1.333	2.276	1.419	2.546	1.666	2.029	1.297	
Gas consumption														
Unit consumed	Kwh	265,463	170,000	236,213	101,238	504,306	216,131	940,305	360,000	1,267,875	543,375	742,976	318,420	9,957,218
Cost per unit	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
Total cost	€	4,712	3,017	4,193	1,797	8,951	3,836	16,691	6,390	22,500	9,645	13,188	5,652	176,750
Efficiency of fuel conversion	%	75		75		75		75		75		75		
Heat demand	kwh	199,097	127,500	177,159	75,928	378,228	162,098	705,228	270,000	950,906	407,531	557,222	238,815	7,467,913
Heat to Power Ratio		0.222	0.488	0.190	0.291	0.387	0.6	0.666	0.909	0.829	1.207	0.590	0.879	

Gas Engine option														
Net electricity output	KW	2179	....											
Fuel consumption	KW	5225	....											
Exhaust heat recoverable	KW	2350	....											
Turbine availability	KW	95	....											
Electricity produced	KWh	962,573	....	962,573	....	931523	....	962,573	....	931523	....	962,573	....	11,333,524
Electricity shortfall/surplus	KWh	-64,573	....	-32,573	....	45,758	....	96,147	....	214,578	....	-18,673	....	756,476
Heat recovered	KWh	1,038,113	....	1,038,113	....	1,004,625	....	1,038,113	....	1,004,625	....	1,038,113	....	12,222,938
Heat shortfall/surplus	KWh	-839,015	....	-860,953	....	-626,396	....	-332,884	....	53,719	....	480,881	....	
CHP fuel price	€	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
CHP fuel cost	€	40,972		40,972		39,650		40,972		39,650		40,972		482,411
Electricity shortfall/surplus-unite price	C/kwh	4.28	....	4.28	....	6.42	....	6.42	....	6.42	....	4.28	....	
Electricity shortfall/surplus-cost	€	-2,764	....	-1,394	....	2,938	....	6,173	....	13,776	....	-799	....	51,044
Heat shortfall-fuel price	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
Heat shortfall-cost	€	0		0		0		0		0		0		
CHP maintenance cost	€	14,439	....	14,439	....	13,973	....	14,439	....	13,973	....	14,439	....	170,006
Monthly standby cost	€	6,537	....	6,537	....	6,537	....	6,537	....	6,537	....	6,537	....	78,444
Energy cost without CHP	€	62,364	....	63,899	....	71,693	....	84,661	....	96,086	....	73,787	....	776,178
Energy cost with CHP	€	59,184	....	60,553	....	63,098	....	68,120	....	72,664	....	61,148	....	782,302
Overall CHP cost saving	€	3,180	....	3,346	....	8,596	....	16,541	....	23,421	....	12,639	....	170,627

Appendix B

C

		Jan		Feb		Mar		Apr		May		Jun	
	Period	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
	Hours	465	279	420	252	465	279	450	270	465	279	450	2
Electricity consumptions													
Unit consumed	KWh	975,720	310,000	1,1002,280	398,000	1,102,400	372,000	1,017,600	372,000	990,000	368,000	950.000	366.000
Cost per unit	C/KWh	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6
Total cost	€	62,641	14,260	70,637	18,308	70,774	17,112	65,329	17,112	63,558	16,928	60.990	16,560
Average consumptions	MW	2.098	1.111	2.619	1.579	2.371	1.333	2.261	1.377	2.129	1.318	2.111	1.333
Fuel consumptions													
Unit consumed	KWh	1,468,867	629,514	1,259,656	630,000	996,624	387,576	807,069	365,000	763,752	320,000	704,112	300,000
Cost per unit	C/KWh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
Total cost	€	26,073	11,174	22,360	11,183	17,691	6,879	14,326	6,479	13,557	5,680	12,498	5,325
Efficiency of fuel conversion	%	75		75		75		75		75		75	
Heat demand	KWh	1,101,650	472,135	944,742	472,500	747,468	290,682	605,301	273,750	572,814	240,000	528,084	225,000
Heat to power ratio		1.129	2.03	0.858	1.583	0.678	1.041	0.595	0.981	0.578	0.869	0.555	0.833

Net electricity output	KW	2717	....										
Fuel consumption	KW	6627	....										
Exhaust heat recoverable	KW	2543	....										
Turbine availability	%	95	....										
Electricity produced	KWh	1,200,235	....	1,084,083	....	1,200,235	....	1,161,518	....	1,200,235	....	1,161,518	....
Electricity shortfall/surplus	KWh	-224,515	....	16,197	....	-97,835	....	-143,918	....	-210,235	....	-211,518	....
Heat recovered	KWh	1,123,370	....	1,014,657	....	1,123,370	....	1,087,133	....	1,123,370	....	1,087,133	....
Heat shortfall/surplus	KWh	-21,720	....	-69,915	....	-375,902	....	-481,831	....	-550,556	....	-559,049	....
CHP fuel price	€	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
CHP fuel cost	€	51,966	....	46,937	....	51,966	....	50,289	....	51,966	....	50,289	....
Electricity shortfall/surplus-unite price	C/kwh	4.28	....	6.42	....	4.28	....	4.28	....	4.28	....	4.28	....
Electricity shortfall/surplus-cost	€	-9,609	....	1,040	....	-4,187	....	-6,160	....	-8,998	....	-9,053	....
Heat shortfall-fuel price	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751	
Heat shortfall-cost	€	0	....	0	....	0	....	0	....	0	....	0	....
CHP maintenance cost	€	18,004	....	16,261	....	18,004	....	17,423	....	18,004	....	17,423	....
Monthly standby cost	€	8,151	....	8,151	....	8,151	....	8,151	....	8,151	....	8,151	....
Energy cost without CHP	€	88,715	—	92,998	—	88,465	—	79,656	—	77,115	—	73,489	—
Energy cost with CHP	€	68,511	—	72,389	—	73,933	—	69,703	—	69,122	—	66,810	—
Overall CHP cost saving	€	20,204	—	20,609	—	14,532	—	9,953	—	7,993	—	6,679	—

	Month	Jul		Aug		Sep		Oct		Nov		Dec		Total
	Period	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	
	Hours	465	279	465	279	450	270	465	279	450	270	465	279	8760
Electricity consumption														
Unit Consumed	Kwh	898,000	348,000	930,000	348,000	977,280	360,000	1,058,720	396,000	1,146,100	450,000	943,900	362,000	12,090,000
Cost per unit	C/kwh	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	6.42	4.6	
Total cost	€	57,,651	16,008	59,706	16,008	62,741	16,560	67,969	18,216	73,579	20,700	60,598	16,652	776,173
Average consumption	MW	1.931	1.247	2	1.247	2.171	1.333	2.276	1.419	2.546	1.666	2.029	1.297	
Gas consumption														
Unit consumed	Kwh	265,463	170,000	236,213	101,238	504,306	216,131	940,305	360,000	1,267,875	543,375	742,976	318,420	9,957,218
Cost per unit	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
Total cost	€	4,712	3,017	4,193	1,797	8,951	3,836	16,691	6,390	22,500	9,645	13,188	5,652	176,750
Efficiency of fuel conversion	%	75		75		75		75		75		75		
Heat demand	kwh	199,097	127,500	177,159	75,928	378,228	162,098	705,228	270,000	950,906	407,531	557,222	238,815	7,467,913
Heat to Power Ratio		0.222	0.488	0.190	0.291	0.387	0.6	0.666	0.909	0.829	1.207	0.590	0.879	

Gas Engine option														
Net electricity output	KW	2717	....											
Fuel consumption	KW	6627	....											
Exhaust heat recoverable	KW	2543	....											
Turbine availability	KW	95	....											
Electricity produced	KWh	1,200.235	....	1,200,235	....	1.161,518	....	1,200.235	....	1.161,518	....	1,200,235	....	14.131.800
Electricity shortfall/surplus	KWh	-302,235	....	-270,235	....	-184,238	....	-141,515	....	-15,418	....	-256,335	....	
Heat recovered	KWh	1,123.370	....	1.123.370	....	1,087,133	....	1.123.370	....	1,087,133	....	1,123,370	....	13,226,779
Heat shortfall/surplus	KWh	-924,273	....	-946,211	....	-708,903	....	-418,142	....	-136,226	....	-566,138	....	
CHP fuel price	€	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
CHP fuel cost	€	51,966	....	51,966	....	50,289	....	51,966	....	50,289	....	51,966	....	611.855
Electricity shortfall/surplus-unite price	C/kwh	4.28	....	4.28	....	4.28	....	4.28	....	4.28	....	4.28	....	
Electricity shortfall/surplus-cost	€	-12,936	....	-11,566	....	-7,885	....	-6,057	....	-660	....	-10,971	....	-87,042
Heat shortfall-fuel price	C/kwh	1.7751		1.7751		1.7751		1.7751		1.7751		1.7751		
Heat shortfall-cost	€	0	....	0	....	0	....	0	....	0	....	0	....	
CHP maintenance cost	€	18,004	....	18,004	....	17,423	....	18,004	....	17,423	....	18,004	....	211,981
Monthly standby cost	€	8,151	....	8,151	....	8,151	....	8,151	....	8,151	....	8,151	....	97,812
Energy cost without CHP	€	62,364	....	63,899	....	71,693	....	84,661	....	96,086	....	73,787	....	952,929
Energy cost with CHP	€	65,185	....	66,554	....	67,978	....	72,063	....	75,203	....	67,149	....	834,600
Overall CHP cost saving	€	-2,821	....	-2,655	....	3,716	....	12,598	....	20,882	....	6,638	....	**118,328**

Appendix C

Gas consumptions tables

Month	On-peak electric demand (kw)	Off-peak electric demand (kw)
Jan	1518405	532227
Feb	1401493	524691
Mar	875410	475232
Apr	830929	335206
May	609495	245876
Jun	331026	110273
Jul	409768	111504
Aug	413555	124587
Sep	380715	118277
Oct	392255	178298
Nov	1010014	359124
Dec	1287127	585058

Table 21 Gas consumption (2000)

Month	On-peak electric demand (kw)	Off-peak electric demand (kw)
Jan	1728239	740673
Feb	1295054	555023
Mar	1219038	522445
Apr	869372	372588
May	637053	273023
Jun	261339	112002
Jul	312876	134090
Aug	315768	135329
Sep	290692	124582
Oct	425394	182312
Nov	1083210	464233
Dec	1380325	591567

Table 22 Gas consumption (2001)

Month	On-peak electric demand (kw)	Off-peak electric demand (kw)
Jan	1472371	631016
Feb	1547443	663190
Mar	1395168	597929
Apr	1060757	454610
May	896885	384379
Jun	670301	287271
Jul	387154	165923
Aug	425297	182270
Sep	581378	249162
Oct	1211131	519056
Nov	1483237	635673
Dec	886013	379719

Table 23 Gas consumption (2002)

Month	On-peak electric demand (kw)	Off-peak electric demand (kw)
Jan	1468867	629514
Feb	1259656	630000
Mar	996624	387576
Apr	807069	365000
May	763752	320000
Jun	704112	300000
Jul	265463	170000
Aug	236213	101238
Sep	504306	216131
Oct	940305	360000
Nov	1267875	543375
Dec	742976	318420

Table 24 Gas consumption (2003)

Appendix D

- **Monthly calculations for Jan 2003** (see appendix B for source data)

DCU's site Heat to Power Ratio (HPR)

HPR = Heat demand / Electricity demand

HPR = 1101650 / 975720 = 1.129

Electricity generated by CHP (Q_e)

$Q_e = H_p * Q_a * \eta_v$

$Q_e =$ 465 * 2012 * 0.95 = 888801 (kWh)

Electricity shortfall/surplus

Electricity demand (Q) = 975720 (kWh)

$Q_s = Q - Q_e$

Q_s = 975720 – 888801 = 86919 (kWh)

Electricity (shortfall/surplus) cost

$E_c = Q_s * E_s$

E_c = 86919 * 0.0642 = 5580 (€)

CHP fuel cost

$CHP_f = H_p * F_c * \eta_v * CHP_c$

CHP_f = 465 * 5185 * 0.95 * 0.017751 = 40658 (€)

Thermal energy recovered from CHP

$H_e = H_p * E_h * \eta_v$

H_e = 465 * 2212 * 0.95 = 977151 (kWh)

Heat shortfall/surplus

Heat demand (H) = 1101650 (kWh)

$Hs = H - H_e$
$Hs = 1101650 - 977151 = 124499$ (kWh)

Heat (shortfall/surplus) cost

$H_c = (Hs / \eta f) * Hf$

$H_c = (124499/0.75) * 0.017751 = 2947$ (€)

Monthly standby cost = 3 * 2012 = 6036 (€)
CHP maintenance cost = 888801 * 0.015 = 13332 (€)

Energy cost with CHP

$E = CHP_f + E_c + H_c$

E = 40658 + 5580 + 2947 + 6036 + 13332 = 68553 (€)

Energy cost without CHP

$E_{in} = Q^* E_G + G * H_f$
$E_{in} = 88714$ (€)

Overall CHP cost savings = Energy cost without CHP - Energy cost with CHP

= 88714- 68553 = 20161 (€)